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Current and Future Challenges to Energy Security

The energy transition, the pathway from low carbon to decarbonization

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Dear Energy Colleague,

The **Italian Association of Energy Economists - AIEE**, affiliate of **t**he **International Association for Energy Economics - IAEE**, is organizing the **6h AIEE Energy Symposium on Energy Security - 2021**, in cooperation with the **SDA Bocconi School of Management**, of Milan, programmed as usual for **mid December**.

Altough we are on the cusp of winning our battle against the pandemic, thanks to healthcare and innovators, there is still uncertainty regarding travelling around the world, social distancing and possibility to attend the event physically.
Therefore we decided that the AIEE Energy Symposium 2021 will be organized as a **virtual online conference** hoping that with our next edition we will all be able to meet again in a normal face to face event, in 2022.

The **AIEE Energy Symposium on Energy Security** has become an important yearly appointment and an opportunity to discuss energy security, climate change, to explore new and existing trends, creative solutions of new technologies, the emergence of new market conditions and of new market operators.

An appointment we do not want to miss!

A recent survey conducted in the European Union has confirmed a general consensus of all countries to support the efforts to strengthen energy security. All Europeans agree the EU's energy policy priorities should be to ensure secure, clean, and affordable energy, to combat climate change, decreasing energy consumption across the EU and facilitating more competitive prices for consumers.
For the coming 10 years the main priority is investing and developing clean energy technologies, ensuring that costs are as low as possible and stepping up international efforts to reduce climate change.
After the crisis of COVID-19, energy security will remain an important issue of the world energy policy and the key for a more resilient society. The pandemic has set in motion the largest drop in global energy investment in history, with spending expected to plunge in every major sector this year – from electricity to renewables and energy efficiency.
The overall share of global energy spending that goes to clean energy technologies – including renewables, efficiency, carbon capture, utilization and storage – has been stuck at around one-third in recent years. Power sector spending is on course to decrease by 10% in 2020, with worrying signals for the development of more secure and sustainable power systems. Energy efficiency, a central pillar of clean energy transitions, is suffering too. Estimated investment in efficiency and end-use applications is set to fall by an estimated 10–15%. The slowdown in spending on key clean energy technologies also risks undermining the much-needed transition to more sustainable energy systems.

The **AIEE Symposium** will be a forum to discuss all these problems, continuing the dialogue of the past editions analyzing the transformations of the concept of energy security in this new context.

A comprehensive program, with Plenary sessions and keynote presentations, and several concurrent sessions will give the attendees from all over the world the occasion to participate in an interactive, collaborative networking and information-sharing event, in the prestigious context of the **SDA Bocconi School of Management** (that was ranked 3rd in the 2019 Financial Times' European Business School Ranking and 8th in the world for business and management studies).

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6th AIEE Energy Symposium

Current and Future Challenges to Energy Security

14-16 December 2021, Italy
virtual conference organized with the scientific contribution of the SDA Bocconi School of Management

Published by: AIEE - The Italian Association of Energy Economists, Rome, Italy

6th AIEE Energy Symposium - Current and Future Challenges to Energy Security - Executive Summaries.
virtual conference, 14-16 December, Italy.
Published 2021 by: The Italian Association of Energy Economists (AIEE), Rome , Italy

ISBN: 978-88-942781-6-3

The 6th AIEE Energy Symposium - Current and Future Challenges to Energy Security was organized by AIEE (Associazione Italiana Economisti dell'Energia) with the scientific contribution of the SDA Bocconi School of Management
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ACKNOWLEDGEMENTS

The editors and the publisher acknowledge the support of the following sponsors of the **6th AIEE Energy Symposium on Current and Future Challenges to Energy Security**

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INTRODUCTION:

CURRENT AND FUTURE CHELLENGES TO ENERGY SECURITY

– the energy transition, a pathway from low carbon to decarbonization –

The AIEE - Italian Association of Energy Economists (Italian affiliate of the IAEE - The International Association for Energy Economics) has organized this international with the scientific cooperation of the SDA Bocconi School of Management to bring together energy experts engaged in academic, business, government, international organizations for an exchange of ideas and experiences on the present and future landscape of energy security.
The previous editions of the AIEE Symposium on Energy Security, organized in Milan and Rome, were an opportunity to explore new energy trends, challenges and creative solutions for the energy security, the availability of new technologies, the emergence of new market conditions and of new market operators.
The AIEE Energy Symposium on Energy Security has become an important yearly appointment and in our uncertain world of possible pandemics organizing also this edition as a virtual event was an excellent alternative.
Following up on the success of the past editions this fifth AIEE Energy Symposium to provided a fresh look on the major forthcoming issues offering an excellent occasion to continue the dialogue and to share best practice and experience with delegates from all over the world.
During the Summit held on 11–13 June 2021, the G7 nations have agreed to step up action on climate change and renewed a pledge to raise $100bn a year to help poor countries cut emissions. This will enable these countries to move towards a climate-neutral economy and implement the commitments under the Paris Agreement.
All Europeans agree the EU's energy policy priorities should be to ensure secure, clean, and affordable energy, to reduce climate change, decreasing energy consumption across the EU and facilitating more competitive prices for consumers. In order to achieve this, for the coming 10 years the main priority is investing and developing clean energy technologies, at the lowest possible cost.
The European Union within its Green Deal decided to raise the 2030 greenhouse gas emission reduction target, including emissions and removals, to at least 55% compared to 1990. After the crisis of COVID-19, the energy security will remain an important issue of the world energy policy and the key for a more resilient society. The pandemic has set in motion the largest drop in global energy investment in history, with spending expected to plunge in every major sector this year – from electricity to renewables and energy efficiency.
The overall share of global energy spending that goes to clean energy technologies – including renewables on shore and off shore and the low-carbon investments covering alternative energy and technologies increased by 9% in 2020, according to an analysis by Bloomberg New Energy Finance (BNEF). The trend is expected to continue and global institutional investors plan to increase their allocation to green energy, energy efficiency, carbon capture, utilization and storage and hydrogen in the next decade.
The AIEE Symposium will be a forum to discuss all these problems, continuing the dialogue of the past editions analyzing the transformations of the concept of energy security in this context

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Carlo Di Primio, AIEE Past President, Steering Committee Chair
Carlo Andrea Bollino, Honorary President AIEE and Chair of the Organization Committee

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Silvia Pariente-David, Consultant on energy and climate change and Senior advisor – Center for Mediterranean Integration, World Bank, France
Alicia Mignone, Senior Energy Advisor, MAECI and Ex President of the IEA Committee on Energy Research and Technology, Italy

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Carlo Di Primio, AIEE President, Italy
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APPRAISAL OF NIGERIA'S ENERGY PLANNING: PROSPECTS FOR SUSTAINABLE DEVELOPMENT

Olasunkanmi Olusogo Olagunju, University of Lagos, Akoka, No. 3 Ogunbiyi Avenue, off Akiwowo road, Akowonjo, Lagos, Nigeria State

Abstract

This research endeavours to chronicle the impacts of effective planning on sustainable development. Having examines the contributions of energy planning to climate change, public health, social welfare, economic growth and/or responsible consumption, the paper unveils that viable institutional planning can culminate into job creation, business growth and investments. With institutional model and content analysis, the paper revealed that poor planning has effect on the capacity of Nigeria energy sector. Based on proper review of data from government archives, journals, conference or seminar papers, the research work scrutinizes the need for energy planning to implement the sustainable development goals in Nigeria. However, it is concluded that policy reforms and strategic collaboration can boost the capabilities of the Nigerian energy sector. This research paper initiated some policy endorsements which may be instrumental for coupling energy planning into sustainable development strategies of government.

Guillaume Gonzalez, Jean-Baptiste Arnoux, Jules Parolin

ASSESSMENT OF THE FRENCH CAPACITY MECHANISM: A MARKET TOOL GUARANTEEING POWER SECURITY OF SUPPLY?

Guillaume Gonzalez, RTE[1], Power system economy direction,
Jean-Baptiste Arnoux, RTE[1], Power system economy direction,
Jules Parolin, (RTE[1], Power system economy direction when the study was carried out),

Abstract

The capacity mechanism is an electricity market regulatory framework whose principle was instituted by law[2] in 2010 to guarantee the French power security of supply within the European internal market of electricity. The capacity mechanism provides capacity owners with a revenue complementing the income generated by the usual electricity markets. This additional remuneration is designed to maintain existing units necessary for the security of supply or develop new capacities (generation or demand-response) if needed.

Following the liberalisation of European electricity systems initiated in 1996, France first set up an energy market according to the "energy-only" market design, which is mainly based on the remuneration of the delivered energy or the reduced consumption (for demand side response - DSR) with no requirements in terms of availability for capacity owners. The "energy-only" market design should theoretically lead to a power system which is optimal from an economic perspective. This theoretical result however relies on several major hypotheses: i) the operation of the market corresponds to pure and perfect competition (purely rational stakeholders with no market power), ii) prices are established during outages period at the level corresponding to the loss of utility for the consumer (price caps are set up accordingly) and iii) stakeholders decide investments in new power generation (or DSR) only taking into account expected revenues from energy markets, even if these revenues are obtained during loss of load periods which are uncertain and infrequent [Joskow, 2007; Léautier, 2012].

In France, the economic difficulties met by generation technology (CCGT for example[3]) in the beginning of the 2010s, at a time when the security of supply indicators were deteriorating, triggered the debate on the imperfection of the "energy-only" market design and led to the introduction of a capacity mechanism. Concretely, each electricity supplier has the obligation to buy capacity certificates up to the consumption level of its portfolio during peak hours. On the other hand, capacity certificates are delivered to capacity owners, provided they commit to be available during peak hours. The exchange of capacity certificates between electricity suppliers and capacity providers creates a capacity market which provides a reference market value to security of supply.

[1] Réseau de Transport d'Electricité
[2] Loi du 7 décembre 2010 relative à la « Nouvelle organisation du marché de l'électricité »
[3] In March 2013, GDF Suez announces the mothballing of 3 out of its 5 CCGT located in France.

The French capacity mechanism is calibrated so that the loss of load expectation[4] is lower than 3 hours per year[5] (this criteria is called
"Reliability standard"). After years dedicated to decide upon its appropriate design and fine-tune its features with both the national stakeholders and the European authorities, the French capacity mechanism was implemented in 2017.
The market rules of the capacity mechanism foresaw a review clause, based on a full-fledged overview which aimed at assessing its actual functioning and its efficiency after 3 years of operation. The present paper, which derives from the aforementioned analyses, provides an assessment of both the appropriateness and the economic relevance of the French capacity mechanism over the 2017-2019 period:

- **Addressing the policy objective**: Did the capacity mechanism enable the respect of the security of supply criteria (the actual purpose for its introduction)?
- **Economic relevance**: Is the economic value provided by the French capacity mechanism sufficient to exceed the actual cost incurred by its implementation?

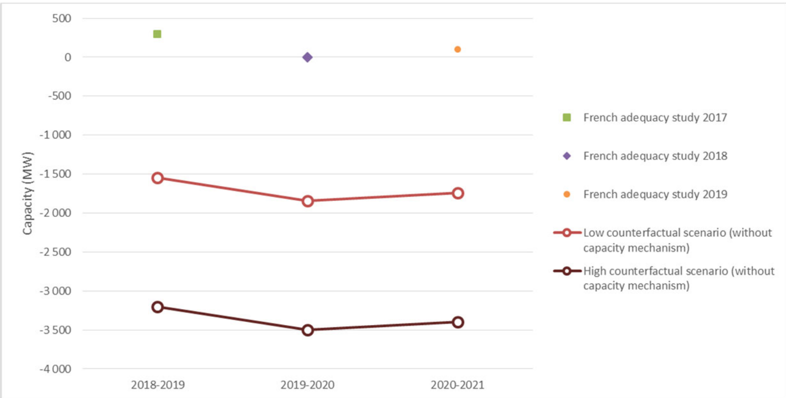
The present paper constitutes, to the knowledge of its authors, the first economic assessment of a capacity mechanism carried out ex-post. It relies, as much as can be, on observed data, which constitutes its major contribution to the economic literatures.

Addressing the policy objective

Determining whether the French capacity mechanism has been useful in reaching the security of supply criteria, requires reconstituting the evolution of the French power system in a counterfactual situation in which no capacity mechanism would have been in place.
In order to build such counterfactual trajectories (two extreme scenarios were considered to account for uncertainties which are inherent to such a modelling exercise), an economic viability assessment was carried out on each relevant technology constituting the French electricity mix. Based on this analysis, technologies which could have been at risk of decommissioning without the remuneration introduced by the capacity mechanism have been identified. These scenarios have been established considering that the portion of mothballed or decommissioned capacities depending on would have been higher the larger the deficit between electricity market revenues and functioning costs or the more substantial the share represented by the capacity mechanism revenues. These trajectories have been presented for public consultation gathering French power system stakeholders and chaired by RTE[6,7].

[4] Also referred to as LOLE, the loss of load expectation represents the number of hours per annum in which, over the long-term, it is statistically expected that supply will not meet demand.
[5] The security of supply criteria, now defined at article 25 in the Regulation (EU) 2019/943 on the internal market for electricity as "Reliability standard", is set up by national authorities.
[6] French Transmission System Operator.
[7] The functioning costs considered, the methodologies used to model the actual energy remuneration (spot and/or forward prices) as well as the scenarios deducted from the economic viability assessment have all been presented for public consultation gathering national stakeholders in order to ensure the robustness of the results.

The two counterfactual scenarios resulting from this analysis show that, in the absence of capacity mechanism, the French power system would have been deprived of between 1,8 GW and 3,5 GW of available capacity over the 2017-2019 period. In details, only semi-base (Combined cycle gas turbine) and peak units (mainly gas and fuel turbines, demand side response – DSR) have been decommissioned in the counterfactual scenarios.
The expectation of remuneration for these units is reduced in an energy only-market because it only depend on the occurrence of high energy prices which is quite uncertain from one year to another (it varies depending on weather condition and availability of base power-plants).
On the other hand, capacity mechanism bring a more stable remuneration enabling risk adverse generators to maintain their plant or DSR.
Based on these counterfactual scenarios, the ex-post evaluation of the improvement in security of supply enabled by the capacity mechanism is a complex exercise. Indeed, evaluating its contribution to the security of supply based on historical data (periods of loss load that actually occurred) is impossible due to the insurance role of the capacity mechanism. Its contribution to security of supply can only be determined with a statistical approach considering all possible situations (weather conditions, incidents on power plants, etc…) that could have occurred. This method corresponds to the approach used in the prospective analysis carried out by RTE, which is based on a stochastic modelling tool of the power system (Antares[8]).



Evolution of capacity margins in France with and without capacity mechanism

The gradual decommissioning of 10 GW of thermal power plants since 2010 resulted in a French power system with no margin regarding the reliability standard (3 hours of loss of load expectation in France) from winter 2017-2018 onwards.

[8] Available open-source : Eclairer l'avenir du système énergétique (antares-simulator.org)

In the presence of the capacity mechanism, the French security of supply level as remained slightly above the security of supply criteria, according to yearly adequacy studies led by RTE [Bilan Prévisionnel, RTE]. However, in whichever aforementioned counterfactual scenario without capacity mechanism, the reliability standard would not have been met over the 2017-2019 period (between 5,5 hours and 10 hours of loss of load expectation). The French capacity mechanism thus reached the policy objective for which it was instituted: it enabled to reach the reliability standard which would not have been the case in an "energy-only" market design. Nevertheless, it did not overreach this target as it did not delay the closure of the fuel power plan (2017-2018) – which were no more useful to security of supply.

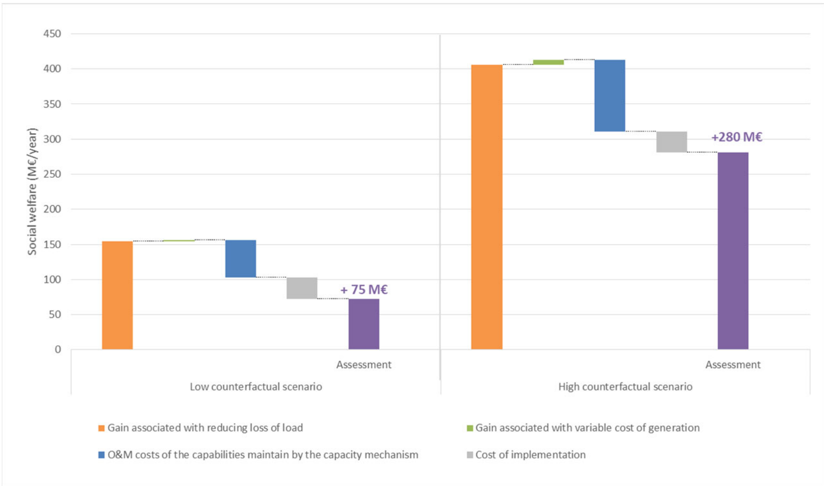
Economic relevance

By maintaining the LOLE below the reliability standard, the capacity mechanism have contributed to improve security of supply which constitutes per se an economic value benefiting social welfare. So as to assess the economic relevance of the French capacity mechanism, all the costs and benefits that the capacity mechanism generates for the social welfare were taken into account. Stakeholders taken into account for calculating social welfare include power plants and DSR owners, electricity consumers as well as the entities which operate the mechanism (transmission and distribution grid operators, French National Regulation Agency, Energy ministry).
Before the actual implementation of the French capacity mechanism, several theoretical analyses were carried out - they have since been compiled in the report *Impact analysis of the French capacity mechanism* [RTE, 2018] - and illustrate the economic value brought by the implementation of such mechanisms. The present study, based on the data collected during 3 years of operation of the French capacity mechanism (e.g. energy and CO_2 prices, mothballing observed, implementation costs), is, according to the authors knowledge, the first ex-post cost-benefit analysis.
Main economic benefits of capacity mechanisms that have been identified by the economic literature are the following: i) the improvement of security of supply (reduction of the energy not served, also referred to as ENS), ii) securing investments in new capacities by reducing the risk induced by the remuneration volatility on energy markets.
By maintaining generation capacities which are crucial for France's security of supply and by avoiding the potential decommissionning of 1.8 GW to 3.5 GW – depending on the counterfactual scenario considered –, the capacity mechanism have reduced the expected ENS by between 8 GWh/year and 20 GWh/year. Taking into account a value of lost load (VoLL) of 20 000 €/MWh[9], the estimated gain associated to the reduction of energy not served is estimated between 150 and 400 M€/year depending on the counterfactual scenario considered. Due to the low volume of new generation capacities and DSR that emerged without dedicated public support over the 2017-2019 period, the second impact of the capacity mechanism on the social welfare has been neglected in the current economic analysis. Another possible but more marginal benefit from capacity mechanism consists in the reduction of variable electricity production costs: due to their increased availability of

[9] The Clean energy package defines a method for calculating VoLL that is in line with RTE's historical practice.

semi-base capacities in the scenario with a capacity mechanism (actual state of play of the power system over the 2017-2019 period) compared to the counterfactual scenarios without capacity mechanism, semi-base generation capacities run more, which reduces the use of more expensive peak generation resources. Evaluated at less than 10 M€/year in the current analysis, this socio-economic gain appears to be negligible.
Compared to a situation *"without capacity mechanism"*, the benefit for the security of supply provided by the mechanism comes with an additional cost corresponding to the fixed costs of capacities that would not be maintained without capacity mechanism. This additional cost for the social welfare is estimated at between 50 and 100 M€/year depending on the counterfactual scenario considered. In addition, the total cost incurred by all the stakeholders (suppliers, generators, DSR and network operators) for the implementation of the mechanism is estimated at around €100 million at the end of 2019, or around €30 million per year (due to the existence of investment costs, amortized on more than three years).

Operators of the capacity mechanism (RTE and distribution system operators) only carry part of these costs: decentralized design of the French capacity mechanism.
Although the implementation costs of the capacity mechanism are not negligible, they appear to be lower than the benefits brought to the power system and consumers (in terms of security of supply according to an insurance logic). The capacity mechanism creates value for the social welfare, between 75 M€/year and 280 M€/year depending on the scenario considered. This analysis leads to the conclusion that the implementation of the capacity mechanism in France is economically advantageous compared to a situation where the energy-only architecture would have been maintained.



Cost-benefit analysis of the capacity mechanism

Conclusion

All in all, the French capacity mechanism contributed to improving security of supply as it enabled the economic profitability of several technologies, which would have been at risk without capacity mechanism. As the security of supply was respected with little margin over the 2017-2019 period, the capacity mechanism was therefore crucial to reach the level of supply established by national authorities (3 hours of loss of load expectation) and did not overreach its objective. Moreover, the cost-benefit analysis carried out ex post – and which includes the implementation costs – demonstrates that the mechanism created net gain to social welfare estimated between 75 M€/year and 280 M€/year, thus attesting that introducing a capacity mechanism in France was a relevant economic decision.

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Yermone Sargsyan
THE IMPACT OF ELECTRICITY OUTAGES ON HEALTH OUTCOMES OF CHILDREN IN KYRGYZSTAN

Yermone Sargsyan, Institute of Economic Studies, Faculty of Social Sciences, Charles University,

Overview

As electricity prices in developing countries are relatively low to recover the costs of provision, proper investment in infrastructure for generation and distribution of electricity is usually absent. These results in frequent outages or rolling blackouts by the electricity suppliers aimed to manage the difference in supply and demand. Such outages commonly occur in some developing countries and can have a significant impact on certain households (Ali, 2016).
The frequent electricity outages may create sizeable problems for the households in terms of storing food, and cooling their households as the work of refrigerators and AC's is constantly interrupted, especially in countries like Kyrgyzstan where extremely hot summers are rather a rule than exception. This in turn may affect the health status of the households negatively, especially among very young (aged 0-5) parts of population.
In winter if reliable electricity supply is absent households often use coal or wood to heat their homes. Most of the residents in these regions who do not have access to the centralized infrastructure burn coal in self-made coal stoves to heat their homes. These self-made stoves are usually of a poor quality resulting in indoor air pollution, which in turn is a catalyst of various respiratory diseases (Akhmetov, 2014).

Methods

The paper will utilize household level data from Kyrgyzstan. We track the same 3,000 households and 8,000 individuals in all major Kyrgyz regions.
We analyze the effect of electricity outages on health outcomes of children aged from 0 to 5 using two distinct anthropometric outcomes, weight for age, and height for age.
Anthropometric outcomes of children are calculated with accordance to World health organization (WHO) in form of deviations (z-score) from the given reference groups. We use the following econometric model for each of the three anthropometric outcomes of interest:

$$Health_{it} = \beta_2 \text{ In } (outrages_{it}) + \theta_2 \; Income_{it} + Z_{it} \, \varphi_2{}' + H_{it} \, \delta_2{}' + \gamma'_{2\,i} + \gamma'_{2\,r} + \gamma'_{2\,t} + u_{irt}$$

where and stand for household and time subscripts. On the left hand side we have two anthropometric outcomes used as proxies for child health (weight for age, and height for age). The terms γ_i and γ_t are household, and year fixed effects, γ_r stands for region fixed effects.

Besides our main variable of interest, the frequency of the electricity outages reported by the households, our model also controls for region specific time varying variables Z_{it} and household specific time varying variables (H_{it}) like household size, the number of rooms in dwelling, access to gas, piped water, and phone connection, and demographic controls, such as years of schooling, age and age squared (as a proxy for skill and experience of the household members), among others.

Results

We find a negative and statistically significant association between height for age z-score of children, and reported frequency of electricity outages. We also observe generally negative relationship between outages and weight for age z-score. However, this relationship is statistically insignificant.

Conclusions

Our results indicated that frequent electricity cut-offs affecting height of the children from 0 to 5 year age negatively and has significant and independent (of income) impact on household well-being.

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Fazel M. Farimani, Soroosh Rahmatian, Mohammad Hassanzadeh
IRAN'S HYDROGEN INVESTMENT POTENTIALS TOWARDS SMOOTH ENERGY TRANSITION

Fazel M. Farimani, Shahid Beheshti University, Tehran, Iran
Soroosh Rahmatian, Shahid Beheshti University, Tehran, Iran
Mohammad Hassanzadeh, Shahid Beheshti University, Tehran, Iran

Overview

Hydrogen is counted as one of the energy transition pillars towards net zero emission initiatives. Hydrogen is either blue, green or grey, depending on the amount of CO_2 emitted over the course of hydrogen producing and transmission. Blue hydrogen is heavily dependent on the solar panels and water electrolysation. Green and grey hydrogen are however mainly rely on the natural gas reserve and the ability to capture the carbon (either in depleted underground reserve or producing oil or gas fields). In this study we show that Iran has the required resources and capacities to produce all types of hydrogen production. We also discuss a case of hydrogen investment in southern part of Iran nearby largest gas field in the world, showing the feasibility and profitability of such an investment plan.

Methods
We first review the natural gas, solar and water availability in the country. We then employ a cost-benefit framework to show to what extent a gas based hydrogen plan in Iran would be both feasible and profitable.

Results
The research is still undergo, however, early results show that:
Iran is one of the most reliable sources of clean energy of future, namely hydrogen.
Production of all types of hydrogen, including blue, green and grey, is doable.
Green gas based hydrogen is both feasible and profitable.

Conclusions
Energy importing countries, including European countries can rely on Iran in providing clean and affordable hydrogen energy for their future and towards net zero emission.

Clément Cabot, Manuel Villavicencio

ELECTRIFICATION OF THE HARD-TO-ABATE CHEMICAL SECTOR: IMPLICATION FOR NET-ZERO POWER SYSTEMS IN EUROPE

Cabot Clément, MINES ParisTech, PSL University, Centre for industrial economics (CERNA), i3 UMR CNRS, 60 Bd St Michel 75006 Paris, France
Villavicencio Manuel, Research associate, Chaire European Electricity Markets, PSL Research University, LEDa [CGEMP], Place du Maréchal de Lattre de Tassigny, 75775 Paris, France.

1. Overview

The net-zero ambitions in the EU by 2050 encompass emission reductins in hard-to-abate sectors such the chemical industry. Yet, the pathways to Net-Zero for those sectors are uncertain, even if electrification, CCS[10], use of low-carbon hydrogen, and use of sustainable biomass are seen as the key enablers to reach climate neutrality. The chemical sector is one of the identified hard-to-abate sectors alongside steel, cement, aluminum, aviation, heavy dutty transport, among others. The chemical sector is based on many organic feedstocks and requires constant heat furniture for many processes, part of it being high temperatures with little low-carbon alternatives demonstrated at scale. The transition to low-carbon emission is therefore an important challenge for the sector, that is still underlooked in most transition models. A first observation is that given electrification of end-use is foreseen as one of the biggest levers to reach climate neutrality, a net-zero power system is a prerequisite (Bataille et al., 2021, 2018; Bistline and Blanford, 2021). Low-carbon power systems have been studied in recent years (Després et al., 2017; Pavičević et al., 2019; Pedersen et al., 2021; Shirizadeh and Quirion, 2021). Those scenarios typically provide quantified paths and first-best policies for low-carbon power systems. If the respective role of renewables, nuclear, CCS, and flexibility providers such as batteries are often discussed, identified uncertainties lie on the demand-side level of electrification.

Current total electricity consumption in the EU28 is around 2900 TWh (Eurostat, 2021). Grey literature estimates for 2050 vary widely depending on the underlying assumption. McKinsey foresees a demand of 4900 TWh in 2050 (2010), while IEAE (2019) estimate reaches only 3200 TWh in 2050. The International Energy Agency (2021) forecast a consumption between 3577 TWh and 5040 TWh depending on the climate ambitions, with notably more than 25% of the flexibility provided by demand response in 2050. The scale of the effort to reach net-zero is therefore very different from one scenario to the other, but all rely on top-down approaches based on a GDP growth assumption. Such approaches don't provide detailed transitions taking place in industrial sectors, notably for the chemical sector.

Another stream of the literature focuses on low-carbon options and electrification in the chemical industry.

[10] CCS stands for Carbon Capture & Storage.

The current level of electricity consumption of the chemical industry is close to 170 TWh (Cefic, 2021). Dechema (2017) considers for the chemical industry alone a range of future electricity consumption in Europe from 960 TWh to more than 4900 TWh, with a "realistic" scenario requiring 1900 TWh to reduce emission by only 84%, which is still
below the Net Zero target. Fraunhofer and ICF (2019) consider also low-carbon pathways for the industry and estimate the chemical electricity consumption might reach m1016m TWh in
2050, which is about the same amount as the electricity consumption of entire industry in 2015 electricity consumption. The JRC (2017) performed a complete overview of the chemical processes and assesses the potential for GHG reductions. It notably described the Best Available Technics (BAT) and Innovative Technology (IT) for a set of key processess. Results however don't reach Net Zero emissions but only a 36% emission reduction when accounting for retrofits with an increase of 14.5% of the electricity consumption. Such levels are therefore often higher than the increase foreseen for the electricity consumption in the whole European Union in most scenarios, and non of them expect to reach net-zero for the sector. Therefore, the interlinks between deep electrification of the chemical industry, the investment required to cover such new electricity demand with low-carbon technologies and the value that the higher demand from industrial uses can bring as flexibility to the power sector in return deserve further research.
This article examines the long-term industrial transformation required to accomplish the Net-Zero ambitions of the European chemical industry by including the challenges and complementarities induce in the power sector. Our article notably expands the literature by providing a quantification of a Net-Zero pathway for both sectors. A first detailed quantification on the electrification needs for the hard-to-abate chemical sector and resulting investment for the power system is therefore proposed. We estimate moreover the short and long-term flexibility value provided by the chemical sector through direct and indirect electrification of industrial-uses (e.g. electric boilers, production of hydrogen from electrolysis).

2. Methodology

We consider the Central West Europe (CWE) region for the purposes of this article, being both the main producers of chemicals and the region with the highest electricity demand in Europe. The time horizon has been set to 2050, aligned with Net-zero ambitions as for the EU Green Deal.
Two optimization models have been used for the purpose of the article. The first one consists of an investment model of the power system based on Palmintier formulation (2011), where a portfolio of power plants is optimized given the power demand and subject to the Net-Zero objective. The second model is a value chain investment model of the European chemical industry. The formulation is based on Sahinidis and You (Sahinidis et al., 1989; You et al., 2011), adjusted with a Net-Zero constraint and expanded to consider investment in low-carbon technologies and abatement option (CCS).

3. Results

The methodology allows to identify the low-carbon options for the chemical and power sectors and provide a first detailed quantification of the range of electrification needed in the chemical sector to reach net-zero. The impact in terms of investment in the power sector is assessed, as well as the benefits for renewable integration resulting from deep electrification and increased use of hydrogen in the chemical sector.

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Linda Reinert

THE DECARBONIZATION OF THE EUROPEAN CHEMICAL INDUSTRY: A SCENARIO ANALYSIS

Linda Reinert, SDA Bocconi School of Management, Italy

Abstract

Chemicals are among the top European greenhouse gas emitting industries and have been characterised as a hard-to-abate sector because of immense heat requirements, high process emissions, long asset life, large capital intensity and trade exposure. With more stringent regulations, increasing stakeholder pressure as well as rising carbon prices, the European chemical industry is compelled to act now by implementing circular processes, adopting low-carbon emitting technologies and electrifying chemical processes. For immediate and steep emission reduction, one possible strategy turns to decarbonising highly GHG-intensive chemical building blocks, such as ammonia. The purpose of the thesis is to explain the concept of decarbonisation as well as provide an overview of the currently available decarbonisation options that differ in purpose, functioning, and above all in technology transition stages. A scenario analysis provides quantitative data on promising alternative ammonia production processes and estimates the impacts on emission reductions and related costs. Finally, the thesis creates input for discussions and dialogue between public and private stakeholders on the future of the European chemical sector.

Keywords: Climate Change, Decarbonisation, European Chemical Industry, Ammonia, Brown Ammonia, Blue Ammonia, Green Ammonia, Hydrogen, Carbon Capture Utilisation and Storage

Giacomo Benini, Valerio Dotti
INCENTIVE SCHEMES TO ELIMINATE NATURAL GAS FLARING & VENTING

Giacomo Benini, Department of Energy Resources Engineering, Stanford University, CA, USA
Valerio Dotti, Department of Economics, Ca Foscari University, Italy

Oil wells extract large quantities of associated gases. They are flared and vented for economic, operational, and safety reasons. All over the world, regulation discourage *both* practices due to their negative economic, environmental, and health effects.
We show that the current legislation backfires due to a hidden substitution effect. Namely, producers intentionally vent a fraction of gas, which they would flare in absence of regulation. Since carbon dioxide has a smaller global warming potential than methane, even a small substitution effect could accelerate climate change. To defuse the substitution effect, we propose an original tax scheme, which eliminates both practices without affecting the consumers' income. We estimate its environmental outcome analyzing the behavior of 4,336 United States onshore oil & gas fields over the time interval 2012-2020.
According to our calculations, the proposed tax scheme would avoid the waste of 61 billion cubic meters of gas per year (6.4% of annual production) while reducing greenhouse gas emissions by 106 million metric tons of carbon dioxide equivalent per year (2.1% of annual United States emissions).

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Carla Mazziotti Gomez de Teran, Vincenzo Delle Site

THE METHANE SUPPLY CHAIN, FROM PRODUCTION TO TRANSPORT AND CONSUMPTION, IN THE LIGHT OF THE EU STRATEGY

Carla Mazziotti Gomez de Teran, National Research Council of Italy - Department of Engineering, ICT and Technology for Energy and Transport (DIITET)
Vincenzo Delle Site, National Research Council of Italy - Department of Engineering, ICT and Technology for Energy and Transport (DIITET)

Overview

This paper presents the results of the project work for the Luiss Business School Executive Master in Circular Economy
– Energy and Waste Management. It aims to provide a framework of the methane supply chain, from production to transport and consumption, in the light of the EU Strategy, highlighting the transversal and multidisciplinary nature of the matter. In fact, there are many aspects to focus on, also considering the recent financial opportunities due to the economic and social crisis caused by the pandemic. They range from the legislation on environmental protection, which identifies assessment, management, and monitoring tools for corporate sustainability, passing through the recent developments in engineering to manage methane emissions.
As illustrated in the European Green Deal, renewable energy / renewable gases should play a vital role in the future decarbonized Europe. The contribution of renewable sources is increasing, and the perspective is to produce green energy and bio-based feedstock from them in a productive circular system and on proximity dimension.
The investments in innovative and renewable technologies will guarantee a reliable and safe supply of energy and the achievement of the objectives set by COP21 in Paris. A substantial improvement of ambient air quality may be reached, especially in urban areas. In the short term, the use of biofuels and renewable gas, biomethane and green hydrogen produced from renewable electricity - power-to-gas (P2G), can accelerate the decarbonisation.
The replacement of the present linear production model to develop a low-carbon, more resource-efficient and competitive production model represents an opportunity to prevent the environmental impact in the industrial production sector. According to the circular economy's principles (CE), the end-of-life product becomes a resource to be reused, repaired, or recycled to be used again within a new production cycle (*Figure 1*). Thus, closed-loop supply chains cascade in recirculation paths with minimum environmental impacts. The circular economy paradigm has the advantage of integrating sustainability principles while supporting the economy. Moreover, this new paradigm decouples non-renewable material use and GDP growth and provides new qualified job opportunities. It also makes it possible to reduce dependence on imports and to generate new economic prospects with production possibilities never before explored.

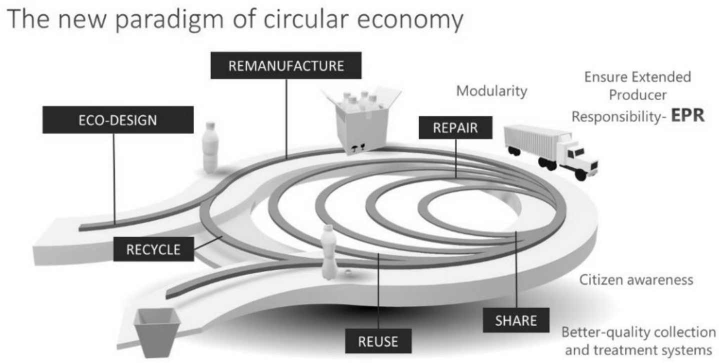

Figure 1: The paradigm of circular economy

Additionally, technological development with intelligent applications and a new range of "product as services" are essential to address the growing demand for energy, goods (e-commerce), sustainable management, and improvements of value chains

Methods

Biogas is a versatile renewable fuel for heating and electricity production or both in CHP plants (Bioenergy Europe, 2020). The bio-methane derived from the upgrading process has the same composition as fossil methane and fits the gas grid. Besides, digestate production may be an alternative to synthetic chemicals as fertilizers and the consequent reduction of greenhouse gas emissions related to the production process, transport, and use of chemical substances.
Further perspectives are connected to the studies that investigate methane's use as a feedstock to produce polyhydroxyalkanoates – PHAs for bio-based industry (Vu et al., 2020; Pérez-Rivero et al., 2019, Moretto et al., 2020; Yadav et al. 2020; Andersen at al., 2020; Rostkowski et al., 2012; López et al., 2018).
Finally, this paper presents a use case on a Company, Tonissipower (with ETW ENERGIETECHNIK GmbH), which set up a biogas/biomethane generation system. Value optimisation is the basis of the circular economy. Companies are now more aware that a sustainable business model creates a competitive advantage by generating more excellent customer value and sustainable development for the society. In such a framework, the value proposition makes the product available to the customer to satisfy his specific need, including energy-efficient technologies and reduced operating costs.
The circular bio-economy allows the exploitation of biological resources' potential preventing the dependence on imports while preserving (and possibly restoring) ecosystems' integrity.

Results

The presented use case concerns the mentioned company designing and producing an upgrading/ cogeneration system to exploit waste of a food and drink industry. The waste produced by the food and drink industry is suitable for anaerobic digestion. Biogas/biomethane resulting from the waste treatments may supply local need of heat, hot water and electricity. Actually, biomethane could also be injected into the gas grid and employed as vehicle fuel.

The proposed use case fits into a context of the circular economy: the circular economy paradigm is pervasive, and it is possible to give a new direction to how the company does business. Existing assets are examined in a new perspective and re-evaluated to find new business opportunities.

Conclusions

The present project work investigates the framework of the methane supply chain in the light of the EU Strategy to contribute to the commitment to limiting global temperature rise below two Celsius degrees. The EU Strategy aims to obtain a clear understanding of global methane emissions data through the extension of methodologies for Measurement, Reporting, and Verification.

It also foresees the expansion of the market for biogas from biogenic sources. The exploitation of biomethane resulting from the treatment of the organic fraction of waste in a proximity condition, may introduce substantial reductions of fossil-based GHG emissions. A sustainable processes transforming waste into clean energy and sustainable materials are presented. From a circular economy perspective, the technology improvements, and digital technologies in the B2B market can accelerate the “new growth” foreseen in the EU Green Deal.

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Marzia Sesini, Sara Giarola, Adam D. Hawkes

SOLIDARITY MEASURES: ASSESSMENT OF STRATEGIC GAS STORAGE COORDINATION AMONG EU MEMBER STATES ON EU NATURAL GAS SUPPLY RESILIENCE

Marzia Sesini: Chemical Engineering Department, Imperial College London, SW7 2AZ, London (UK)
Sara Giarola: Chemical Engineering Department, Imperial College London, SW7 2AZ, London (UK)
Adam D. Hawkes: Chemical Engineering Department, Imperial College London, SW7 2AZ, London (UK)

Overview

This work focuses on strategic natural gas storage as a solidarity measure to enhance energy security among EU countries in response to natural gas supply crises. The energy security at national levels requires that special plans are in place, particularly when it comes to face "high impact-low probability" events (HILP), mega-disasters (i.e. failure in the infrastructure system due to technological faults, natural disasters, or political turmoil) that are not likely to occur, but where the market is unable to cover the demand and policy intervention is required (Stern, 2002). Most EU member states, for example, rely heavily on natural gas with little diversification of sources. This, together with heavy import dependence and the impact of the declining indigenous production on market seasonality and flexibility, could jeopardize the natural gas supply threatening Europe in case of HILP (IEA, 2016; IHS, 2017). The call to a solidarity principle among member states (2016 EU Energy Security Package), tapping into risk-pooling to both create cost- effective alternatives and avoid negative spillovers from national supply-security policies, implies that joint measures be pursued at the EU level (EC, 2016a;EC 2016b; EC 2017). Among several unused alternative to face supply disruption situations, the role of gas storage could play a significant insurance instrument to provide flexibility in the liberalized gas market and a quick response emergency measure (Fevre, 2013).
Three trends are consolidating the role of gas storage in the EU gas market: (i.) heavy import dependence, (ii.) little diversification of sources, and (iii.) the impact of declining indigenous production. In addition, there has been little research linking strategic storage to Security of Supply, HILP, and the securing of energy services, as well as including a policy perspective, solidarity and the 2016 EU Security Package/EU Regulation 1938/2017 in the modeling framework that have been used to discuss supply disruption in the gas network.

Methods

This study presents a model framework that, through a policy perspective, examines the coordinated use of strategic gas storage (i.e. a gas stock that is put aside from the market to smooth out disruption in supply) as the first non-market based response measure (i.e. a measure which does not influence actors' behavior by changing their economic incentive structure, but works through the imposition of certain obligations or by enacting non -monetary incentives

(Görlach, 2013)) in mitigating the ripple effect of natural gas supply disruptions on regional risk groups in the EU system over a short-term time horizon, assessing the value of solidarity measures (i.e., strategic storage) between MS. To do so, a number of scenarios are formulated representing the uncertainty in the gas supply volumes at different severity level to depict the capability of the model to yield efficient cost and distance allocation of the resource, as well as survival time, natural gas supply mix and network costs in case of unprecedented exceptional weather shocks in conjunction with gas demand peaks,. By contrast, this latter aspect gives the maximum time one country can rely on strategic storage in case of emergencies before it needs to put in place alternative non-market based measures.
The methodology is based on an optimization model formulated as a two stage stochastic linear programming model to minimize the expected system cost of gas supply in a multi-country region. The model includes
infrastructures technical constraints, such as storage volume limits, pipeline capacity limits, availability of interconnections among states, country gas demand. The proposed case study is the interconnected regional EU gas system.

Results

Results highlight how further investigation and detailed description of the coordinated use of strategic storage as an emergency measure to respond to HILP could shed a light on the reliability and value of storage as such a measure, as well as the strong interplay between strategic storage and LNG during emergencies. In addition, they show that geographic proximity alone, without solidarity measures, is inadequate in providing system resilience. In contrast, solidarity measures lead to a longer survival time for regional risk groups (14 days) and to a reduction in system (15%) and LNG (70%) costs relative to a base scenario with no strategic storage

Conclusions

The analysis stresses that not only infrastructure availability and diversification of sources are crucial components of the puzzle, but also that solidarity, and in particular strategic storage, acquires significant value as an overlooked option in response to the possibility of HILP events. This is relevant to policy makers to understand the value of strategic storage as an unused flexible resource as well as its coordinated use in balancing the natural gas network during emergencies, and provides further evidence supporting the EU legislative path towards an Energy Union.

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Ernesto Cassetta, Consuelo R. Nava and Maria Grazia Zoia

RETAIL PRICE CONVERGENCE ACROSS EU ELECTRICITY AND NATURAL GAS MARKETS

Ernesto Cassetta: Department of Economics and Statistics, University of Udine,
Consuelo R. Nava: Department of Economics and Political Sciences, University of Aosta Valley,
Maria Grazia Zoia: Department of Economic Policy, Università Cattolica del Sacro Cuore

Overview

Building a fully integrated internal energy market is one of the five dimensions of the Energy Union Strategy. In a fully integrated internal energy market, energy can be produced in one EU country and delivered to industrial consumers and households in another, thus creating competition between energy suppliers and promoting convergence in wholesale and retail prices (Böckers and Heimeshoff, 2014; Ciferri et al., 2020). The impact on national prices of the EU market integration process has spurred increasing academic research. From a theoretical perspective, the main argument refers to the law of one price, which is deemed to hold in perfectly competitive markets (Helpman and Krugman, 1985; Miljkovic, 1999). As other tradable goods, electricity and natural gas are expected to have the same price in unified energy markets, once transaction and transportation costs are accounted for (Bastianin et al., 2019; Dreger et al., 2007). On this ground, the empirical literature has been mainly devoted to estimate whether the European single market has reduced average prices and price dispersion as it is expected according to the theory. However, results remain mixed (Batalla et al., 2019; Bower, 2002; Castagneto-Gissey et al., 2014; Dreger et al., 2007; Robinson, 2007; Saez et al., 2019; Telatar and Yaşar, 2020; Zachmann, 2008).

Method

To investigate price convergence in the energetic European market, the trends of retail prices of electricity and natural gas are determined for each EU country, as required by the club-convergence analysis. To this end, a low-pass filter is used to extract the long- term fluctuations from each price series and removing the shorter-term cyclical components. In details, the Hodrick-Prescott (HP) filter, which is widely used in the literature and represents a standard tool in macroeconomics, has been employed for this scope. The HP filter, first introduced by Whittaker (1923) and popularized by Hodrick and Prescott (1997), has been recently applied in the energy field by Bastianin et al. (2019).
The club convergence measures the tendency to converge to multiple steady-state equilibria (Apergis et al., 2012).
The notion of club convergence was initially introduced by Baumol (1986) and further extended by Phillips and Sul (2009, 2007) which proposed a time- varying factor model for controlling individual and transitional heterogeneity in the identification process of convergent economies or clubs. This convergence allows for periods of transitional divergence given that it evaluates the long-run trend.

Therefore, it has been used to investigate convergence patterns among many markets, such as labor markets, productivity measures, equity markets, etc. (Apergis et al., 2014) as it has many advantages, including allowing for different transitional paths, endogenous determination of convergence clubs and no need for stationary assumption. In case the full panel of countries under scrutiny does not converge to a common steady state, this methodology allows to identify groups of countries that converge to different equilibria, while leaving individual countries to diverge.
According to Phillips and Sul (2007), a non-linear panel model for prices is proposed to test for convergence. Then, a time series P_{it} for country i is decomposed as follow

$$P_{it} = \delta_{it}\mu_t$$

where μ_t is a common path (or a deterministic trend) while δ_{it} is a time varying idiosyncratic component which captures the deviation of country i from the common path μ_t. Here δ_{it} is a vector of weights that measure the distance between the PPP of the energy market in country i and the common deterministic trend μt. Club convergence exists if the following limit in probability for $i \neq j$ holds true

$$\operatorname*{plim}_{t\to\infty} \frac{P_{it}}{P_{jt}} \to 1.$$

The above hypothesis can be tested by considering the following regression model:

$$\log\left(\frac{H_1}{H_t}\right) - 2\log(\log t) = \alpha + \beta \log t + \varepsilon_t$$

where

$$H_t = \frac{\sum_{i=1}^{N}(h_{it} - 1)^2}{N}$$

is the sample transition distance and

$$h_{it} = \frac{P_{it}}{(1/N)\sum_{i=1}^{N} P_{it}}$$

is the relative transition curve (namely the relative measure which captures the transition path with respect to the panel average) for
$t = \lceil \mathrm{rT} \rceil, \lceil \mathrm{rT} \rceil + 1, \dots, \mathrm{T}$ for $r = 1/3$ which represents the trim time suggested by Phillips and Sul (2009, 2007).

The null hypothesis of convergence for all i is: H_0: $\beta \geq 0$ vs H_1: $\beta < 0$ and can be tested with a standard one-sided t-test based on heteroskedasticity and autocorrelation consistent standard errors (Newey and West, 1987).

Results

To investigate the club convergence, a log-t test is firstly implemented over the whole sample of the price filtered series in four markets. The log-t test assumes convergence under the null and it has power against forms of club convergence (Phillips and Sul, 2009, 2007).
The null hypothesis of convergence is: rejected since the t-value is equal to -99.145 and the associated p-value is less than 0.0001 in the household electricity market; rejected since the t-value is equal to -23.987 and the associated p-value is less than 0.0001 in the non- household electricity market; rejected since the t-value is equal to -1113.635 and the associated p-value is less than 0.0001 in the household gas market; rejected since the t-value is equal to -16.683and the associated p-value is less than 0.0001 in the non-household gas market.

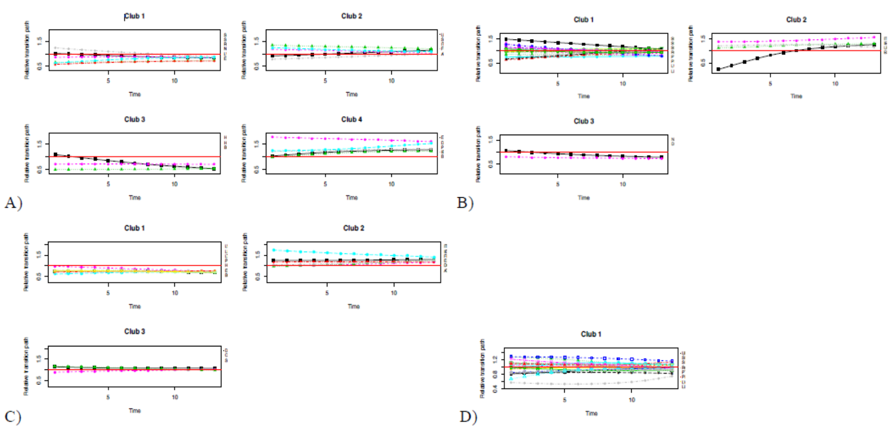

Figure 1: Transition paths of the clubs within A) household and B) non-household electricity market and C) household and D) nonhousehold gas markets

These empirical results confirm that an overall price convergence in the EU energy markets is absent when studying the price trends. This is the condition to evaluate the presence of clubs, given that different paths of price convergence can be identified within each club. Figure 1 shows the resulting groups of countries, across the different energy markets, based on the use of the price filtered series and a suggested trim time of 1/3 (Phillips and Sul, 2009, 2007).

As can be noted, while a single club characterizes the non-household gas market, more than two clubs of relative convergence emerge within the other markets. Four clubs emerge in the household electricity market, and three clubs in non-household electricity market and in household gas market. Moreover, all clusters exhibit divergent units, apart from the non-household electricity market. We have checked the robustness of this results using the Phillips-Sul merging algorithm

Conclusions

Taken together, the results from our analysis indicate that the electricity and natural gas prices across the EU-28 member states have not converged at retail level, despite significant efforts in market integration and regulatory harmonization. Our findings suggest that some key characteristics of energy markets, rather than simple wholesale market integration, geographical proximity and cross-border exchanges, may help to explain the difficulties of the convergence process at a retail price level.

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Marina Bertolini, Marco Agostini, Massimiliano Coppo, Giulia De Matteis

OPTIMIZE URBAN TRAFFIC THROUGH VEHICLE-TO-GRID PRICE SYSTEM.

Marco Agostini, University of Padova, Department of Industrial Engineering
Marina Bertolini, University of Padova, Department of Economics and Management,
Massimiliano Coppo, University of Padova, Department of Industrial Engineering
Giulia De Matteis, University of Padova, Department of Economics and Management

Introduction

In the last two decades, concern for the increasing levels of pollution and GHG emissions has increased pushing to take concrete actions at national, European and international level (Lindsey and Santo, 2020).
The European Green Deal has mapped out the way at European level with the aim of making Europe the first carbon-neutral continent by 2050. Being transports among the main perpetrators of emissions (approximately a quarter of total European emissions), the Green Deal claims for a reduction of 90% in emissions due to transports (European Commission, 2019). Electric mobility has been seen by many as the technology that will allow us to reduce emissions due to transport (Xue et al., 2021; Zhao et al., 2021; Gryparis et al., 2020). In addition, it is undeniable that electric mobility can open up new opportunities and produce benefits that go beyond the reduction in GHG emissions (Sovacool et al., 2020). However, it would be at least simplistic to consider electric mobility as a magic bullet. Emissions attributable to electric vehicles, for example, depend to a large extent on the source of energy production to fuel them (Nimesh et al., 2020; Rapa et al., 2020) and that the increase in EVs poses new challenges on the power grid (Dong et al. 2018).
Moving from these very last considerations, our work aims at studying how to design recharging prices associated to stations widespread on a municipal territory. Charging stations will serve both private and commercial electric vehicles at a price that will be determined by:

- A baseline price for electricity (€/kWh);
- +/- a network parameter that will indicate network's technical needs in a specific time span (€/kWh);
- +/- a policy parameter that will represent needs at level of traffic management (€/kWh).

Our ambition is to model electric charging prices considering both network needs (i.e. needs for energy absorption in specific areas to keep the system balanced or to reduce balancing costs) and urban traffic regulation. The latter issue will be represented by a policy parameter that will allow for tailored measures in different urban contexts: this aspect is particularly challenging and shall be investigated considering specific urban frameworks and type of services (eg. Car sharing, buses, etc.)

The V2G technology

Despite the potential for renewable energy sources' integration, the penetration of these energy sources is still quite limited.

At European level, for example, the Renewable Energy Directive 2018/2001/EU, as part of the Clean energy for all Europeans package, has imposed a target of at least 32% of energy produced by RES by 2030[11] . In order to exploit the potential connected to RES, electric vehicles may prove to be helpful (Raveendran et al., 2020). The V2G technology, in particular, can play a major role with this respect as it allows to exploit car batteries' storage capacity (Quddus et al., 2019) to neutralize the time shift between RES production peak and energy demand peak (Jovanovic et al., 2021; Porse et al., 2020). Beyond that, the use of V2G can benefit grid operators contributing to frequency regulation and peak reduction and it can also offer financial incentives for vehicles' owners (Zhou et al. 2020). Nevertheless, the flip side of V2G is that its capacity strongly depends on factors like: the number of EVs available for charging and discharging at a given time, the battery state of charge when the vehicle is plugged in, the duration of the charging phase and the availability of non-residential charging stations (Tarroja et al., 2016).

The model

We want to study an electric mobility system to be implemented in the context of smart cities adopting an interdisciplinary approach. We will consider the technical feasibility of the charging stations' network with a view to integrating RES, a fundamental aspect for the energy transition. Alongside with RES integration, our model will deal with the development of a charging pricing strategy capable of optimizing the use of the charging stations for users and for the grid. In literature, different ways to determine charging prices have been suggested, such as: dynamic pricing (Limmer and Rodemann, 2019; Gong et al., 2020) and Stackelberg game model (Rui et al., 2019). However, the possibility to use vehicles as energy storage systems implies that EVs' owners can both buy and sell energy to the grid and they might realize positive payoffs from this trading.
We propose to add an additional parameter to the charging price: the parameter will include policy decisions regarding traffic regulation and parking lots usage. The necessity of considering parking issues in the price paid for charge has already been argued (Latinopoulos et al., 2017; Guo et al., 2020), we aim at studying also how to theoretically use charging stations to deliver information to citizens and contributing to improve traffic management.

The theoretical model developed will be later calibrated through simulations so as to enhance its positive impact in the context of the smart city.

The technical aspects related to the charging energy demand and the availability of ancillary services will be considered in an optimal network dispatching approach reacting to the expected operation by charging infrastructures. This will entail an evaluation of network externalities involved in the process, impacting the economic sustainability of the model.

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Lukas Gnam, Markus Schindler, Christian Pfeiffer, Markus Puchegger

OPTIMIZING A COMPANY FLEET OF ELECTRIC VEHICLES UNDER TECHNICAL AND SOCIETAL UNCERTAINTIES

Lukas Gnam, Department of Energy and Environmental Management,University of Applied Sciences Burgenland, Austria
Markus Schindler, Forschung Burgenland GmbH, Austria
Christian Pfeiffer, Forschung Burgenland GmbH, Austria
Markus Puchegger, Forschung Burgenland GmbH, Austria

Overview

With an increasing number of electrical vehicles and the ambitious goals of increasing the share of renewable energy in the existing energy systems, novel challenges and opportunities arise. In this work, we cover the case of a company's electrical vehicle fleet, whose purpose is to replace conventional vehicles as efficiently as possible while simultaneously work as flexibility with regard to the intermittent production characteristics of photovoltaics systems. The latter is particularly interesting as past research already proved that charging times of electric vehicles, either at work or at home, deviate from the production from photovoltaic systems [1].
Furthermore, most of the time electric vehicles are parked and connected to the grid. This enables the utilization of their batteries as flexibilities for the power grid in order to increase self-consumption or stabilize the local grid. However, most optimization models focus particularly on technical or economic factors [2] [3]. In this work we include societal factors into the mixed-integer linear optimization model, e.g., discomfort if a car user has to wait during a daily tour because the electric vehicle needs to be charged. These factors are included as extra terms into the objective function of the optimization problem. Eventually, we evaluate the impact of these societal factors on the solutions of the optimization problems.

Methods

A mixed-integer linear optimization problem is formulated covering technical, economic as well as societal factors influencing both the use of electric vehicles and their charging schedules. The electric vehicles are used as flexibility during the usually long parking times where they are connected to the grid. The optimization problem is solved in two different stages: The first stage covers a period of one week and sets the upper and lower bounds for the second optimization stage, i.e., the intra-day optimization conducted several times every day. As basis for the both optimization stages forecasts for different input time series are computed. Based on the uncertainties of the forecasts different scenarios for the optimizations are created: Worst, average and best-case scenarios. In consideration of the uncertainties in the forecasted time series, the optimization problem is formulated as a stochastic program [4].
If the calculated schedules change significantly due to some uncertainties, e.g., in generation or demand, the vehicle reservation and the route planning of the vehicles will be adjusted

accordingly. Subsequently, for each day an optimized schedule is obtained with a balance between cost efficiency and user comfort.

Results

Our results prove that big company fleets can be used twofold: Once for transforming the fleet from conventionally fueled vehicles to electric vehicles. These electric vehicles provide additional benefits, as grid stability or serving as temporal electrical storage increasing the self-consumption of the electricity stemming from a company's photovoltaic system. This yields on the one hand reduced electricity costs and on the other hand alleviates the challenges arising from high shares of renewables, e.g., grid instabilities.

Conclusions

In this work we present a mathematical optimization problem including not only technical and economic factors but also societal factors like comfort and user behavior. This shows that the management of an e-car fleet is subject to many external factors. The technical factors, such as charging power, available energy quantity or energy consumption are easier to quantify. Above all, the human factor in such an application should not be neglected, since the social acceptance of such a system is the only way to gain the full benefit from it.

Acknowledgement

This work was done within the project "Car2Flex". This project is supported with the funds from the Austrian Climate and Energy Fund and implemented in the framework of the RTI-initiative "Flagship region Energy".

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Nallapaneni Manoj Kumar and Shauhrat S Chopra

ELECTRIC VEHICLES PARTICIPATION IN LOAD FREQUENCY CONTROL OF AN INTERCONNECTED POWER SYSTEM IS NOT SUSTAINABLE

Nallapaneni Manoj Kumar, School of Energy and Environment, City University of Hong Kong, Kowloon, Hong Kong,Shauhrat S Chopra, School of Energy and Environment, City University of Hong Kong, Kowloon, Hong Kong

Overview

Interconnected power systems (IPSs) are prevalent in modern-day high voltage power networks where two or more power system areas agree on power-sharing between them through tie-lines. In such IPSs, two operation modes are possible; 1). regular operation mode where each area should have the capacity to meet its electricity demands plus the scheduled interchange between the neighbouring areas as per the power-sharing agreement from its power generation systems; 2). emergency operation mode where a sudden loss of power generation would arise, creating imbalances and ultimately leading to frequency deviations. In emergency operation mode, the system operators in respective areas should regulate the load and generation to bring back the frequency to an equilibrium value. The process of bringing back the frequency to a nominal value is known as load frequency control (LFC). At this point, the required energy demands can immediately be drawn from all the neighbouring areas' reserve capacity to meet the power-sharing agreement. The reserve capacity is something that can be planned by adopting various systems; in literature, many have proposed options like EVs, renewables, and storage systems. Among these, EVs use as an auxiliary power source to mitigate the LFC seems more popular. There are already many studies showings how EVs participation is solving LFC better compared to its counterparts. However, most of these studies were limited to participation protocols, standards, performance. Well, EVs might address the LFC and enable the interconnected system's reliable and stable operation, but is it happening sustainably is a question? This has motivated us to investigate whether the EVs use in IPS for LFC is a sustainable option or not by viewing the EVs and the electric power system from a life cycle perspective.

System Design, Methods and Data Collection

The designed IPS is a two-area power system. It consists of fossil fuel-based thermal generators, solar power generators and EVs. Between the two areas, a high voltage direct current (HVDC) tie-line exists. The total load in area-1 is 800 MW and has three generators with a cumulative generation capacity of 1400 MW. Whereas in area-2, the total load is 2200 MW, and the generation is 1420 MW from two generators.

A mixed-method approach called RePLiCA that combines Resilience Performance and Life Cycle Analysis is applied (Kumar, 2021). Resilience performance is estimated based on a supply and demand variation followed by EV participation.

For this, we applied four disruptive scenarios (5%, 10%, 15%, and 20%) to see the variation in frequency and power imbalances with 20% as the maximum allowable shock considering limitations with the physical infrastructure. A meta-heuristic optimization technique, i.e., particle swarm optimization (PSO) based on swarm intelligence, is chosen to set the LFC controller parameters. The life cycle analysis is conducted using the ReCiPe 2016 Midpoint (H) V1.02 method in SimaPro 8.2.20 to estimate the carbon dioxide (CO_2) emissions possible from the participated EVs in LFC by taking 1 kWh of energy stored as a functional unit.

Results and Conclusions

The applied RePLiCA approach gave clear insights on EVs participation in IPS. The results include the power deviation (MW), load change (MWh), change in frequency (Hz), response time or settling time (sec), and carbon dioxide emissions (kgCO_2 eq.). The observed power deviation and load change under four disruptive scenarios are varied between 40 to 160 MW and 62.75 to 251 MWh, respectively. The change in frequency in area-1 is 0.36 to 0.83 Hz and in area-2 is 0.28 0.72 Hz. The recovery time was observed to vary between 18.60 to 46.43 sec, which is acceptable under the secondary control. While analysing the environmental sustainability results, Ontario state in Canada energy mix is considered. According to the sustainability results, the participated EVs in the LFC of IPS under the four disruptive scenarios could emit approximately 4769 to 19076 kgCO_2 eq. Overall, the results of this study suggest that the EVs participation role in LFC is promising in enabling the interconnected system's reliable and stable operation, but it is not sustainable. At the same time, we also investigated the possibility of reducing the emissions released. However, we understood that this is only possible if EVs are charged with renewable sources or the national energy mix is free from fossil fuel energy.

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Jim Stodder, Ivan Julio

CARBON TAX WITH MACROECONOMIC STIMULUS: GDP AS AN INFERIOR GOOD

Jim Stodder, Boston University, Mailing Address: 10 Arnoldale Rd., West Hartford, CT, 06119-1702, USA
Ivan Julio, Boston University, USA

Overview

A major debate is underway on how carbon taxes will affect GDP. Based on data from countries with low to moderate carbon prices or taxes (averaging $22 per metric tonne of CO_2), leading researchers like Metcalf and Stock (2020) and Rafaty et. al. (2020) find that such carbon prices/taxes have minimal effects on GDP. Unfortunately, their evidence shows that carbon prices or taxes at these levels have a minimal effect on CO_2 as well.

By contrast, the International Energy Agency (IEA, 2021) and Wood-Mackenzie (2021) base their forecasts on the tight historic linkage between energy and GDP. These studies conclude that current ambitious goals of decarbonization imply either unprecedented improvement in both green energy and the energy efficiency of GDP or sharp falls in GDP itself. Some economists like Joseph Stiglitz (2021) fear that a collapse in fossil-fuel assets may cause severe macroeconomic shock.

Our study simulates US Carbon Taxes ranging from $40 to $120 per metric tonne. We treat historic prices plus simulated taxes as exogenous. Our simulations show sharp reductions in both CO_2 and GDP. If the resulting fall in Disposable Income is compensated, that additional income drives a further decline not only in CO_2, but in GDP. Reductions in GDP and CO_2 are projected to result from either Carbon Taxes or a subsidy to Disposable Income, with greater effect still when the two are combined. Carbon-heavy GDP is thus seen to be an inferior good for the US, one that falls as Disposable Income rises.

Methodology

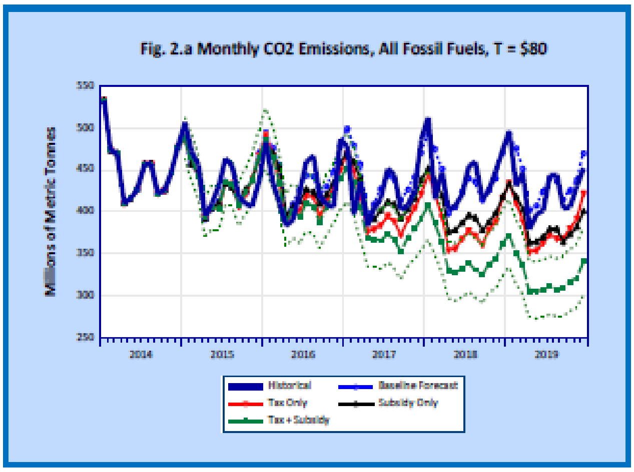
We use monthly US Energy Information Administration data from 1973 to 2019 on Coal, Petroleum, and Natural Gas – total consumption and prices. We include monthly series on US GDP, Disposable Income, the Consumer Price Index minus Energy, and CO_2 a total of 10 variables. All dollar-valued series are in nominal terms; the CPI-less-Energy serves as a proxy for the prices of non-energy goods. A Structural Vector Error-Correction (SVEC) model is built on three cointegrating equations with dependent variables of CO_2, Coal Consumption, and GDP respectively. All equations are identified.

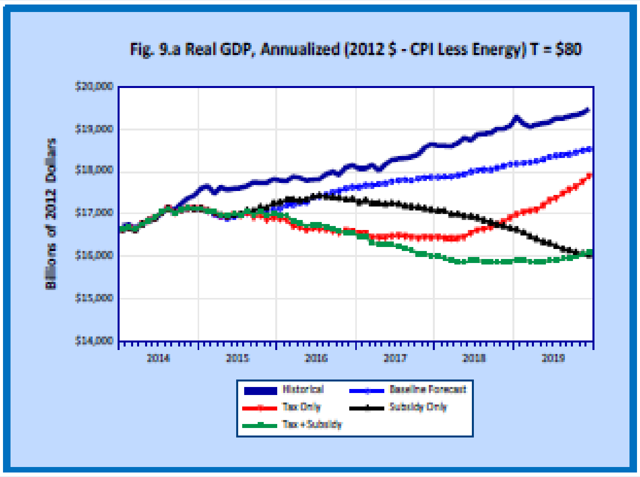
Using the SVEC estimated for the years 1973 to 2014, we create pseudo-forecasts for the years 2015-2019 under the following four conditions:

1) No simulations – our baseline forecast.
2) Simulated fossil-fuel taxes of $40, $80, and $120 per metric tonne of CO_2.
3) Simulated fiscal stimulus equal to the drop in Disposable Income created by the taxes of 2), but with no taxes.
4) Simulation combining both the taxes of 2) and the stimulus to Disposable Income of 3).

Results

These graphs show that a Carbon Tax of \$80 per metric tonne of CO_2 approximately doubles its impact in reduced emissions when the resulting drop in Disposable Income is fully compensated. The effect on GDP is similar: Tax and Subsidy lower CO_2 and GDP when applied separately, and with additive effect when combined. The \$120 Tax has a stronger effect, but at a 39% reduction in CO_2, this is still short of the 50% reduction targeted by US President Biden by 2030.





Conclusions

A tax of $120 per metric tonne in our simulations is not sufficient to cut CO_2 emissions by half within 5 years, suggesting that the carbon taxes required to meet the carbon reduction goals of the US Administration must be even larger. Our model also suggests that without unprecedented advances in abundant green energy, the shock to GDP will be severe, greater than the worst months of the COVID crisis, but longer lasting. Such a fall in human welfare will argue for a strong fiscal stimulus to Disposable Income. Surprisingly, our simulations show that such a stimulus, rather than boosting the consumption of carbon-heavy GDP, decreases it still further, and without serious inflation.
Thus, the good news/bad news results of our study are that:

- On the good side, the fall in consumer welfare caused by a higher carbon tax can be largely reversed by fiscal policy, while actually strengthening the goal of less carbon-heavy consumption
- On the bad side, this fall in carbon-heavy consumption has the effect of further reducing GDP, at least as presently constituted.

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Diyun Huang and Geert Deconinck

CAN A JOINT ENERGY AND TRANSMISSION RIGHT AUCTION DELIVER WELL FUNCTIONING LONG-TERM CROSS-BORDER ELECTRICITY MARKET IN EUROPE? - COMPARISON OF LONG-TERM MARKET PERFORMANCES UNDER NODAL AND ZONAL PRICING

Diyun Huang, Electa department, University of Leuven/ EnergyVille, Kasteelpark Arenberg 10, 3001, Heverlee, Belgium
Geert Deconinck, Electa department, University of Leuven/ EnergyVille,Kasteelpark Arenberg 10, 3001, Heverlee, Belgium

Benefit of cross-border long-term electricity market in Europe

An organized forward markets or bilateral long-term contracts can be seen as important parts of the electricity market and complement to the competitive spot market. In this research, long term refers to a period of at least one year or several years ahead of the electricity delivery.
The positive effect of long-term contract for renewable integration can be multi-folds. For both renewable generation and interconnection network, the high fixed investment costs and CAPEX dominant characteristics do not encourage investment under the unstable spot market price. Hedged against the volatility from spot market, long term contract enables the investors to invest in high fixed cost technology. The prospect of certain future cash flows in a long-term contract can help solve the counterparty credibility problem and facilitate bank financing [**Errore. L'origine riferimento non è stata trovata.**]. In the climate policy context, one salient characteristic of bilateral long-term contract is that it allows the buyers to express preferences in terms of technology choice. Long-term contracts shielded the market participants from too high or too low prices in the sport market.

As the decarbonization is accelerated by the FIT for 55 package, EU legislation is expected to translate the new greenhouse gas reduction target into actionable plans, including raising the renewable electricity target for the next decade. Top-down set renewable target and growing demand for renewable electricity from consumer side both call for large scale of new generation investments in the most cost-efficient locations. Natural resources for developing renewable energy are not evenly distributed among Member States, therefore the development of long-term market across borders is instrumental for a cost-efficient energy transition in Europe. Furthermore, the lessons learned from California crisis shows that the lack of long-term contracts increases the risk of market power within a bidding zone [**Errore. L'origine riferimento non è stata trovata.**]. In other words, long-term contracts across borders can potentially benefit the consumers in the national electricity market with new entries and thus potentially yield anti-trust effect.

The long-term transmission rights that give involved players the options to hedge congestion risk are essential to complement the cross-border long-term contracts. Long-term contracts are not uniform in terms of risks depending on the contracting parties' positions in market and preferences. Therefore, different players may want to choose different risk hedging instruments for their cross-border trade. Not only is the interest very high to hedge the cross-border congestion risk financially or physically, but also there are buyers that wish to procure energy with standardized contract in forward market that implicitly

contains the transmission access. It is important to include a variety of options and make them compatible in the long-term market design.

History account and status quo: from long-term priority access to interconnections to the long-term transmission right challenges

When liberalization started, a large portion of the interconnection capacity had been granted to the former vertically integrated utilities in the form of long-term priority access. De Hauteclocque discusses the EU perspective of long-term priority access of interconnection capacity for the electricity liberalization [**Errore. L'origine riferimento non è stata trovata.**]. The Third Package has focused on mandating Third Party Access to provide level playing field to all market entrants. The prioritized long term transmission access to interconnection capacity granted prior to the liberalization is viewed from competition perspective to be monopolization of essential facility and anti-competitive by European institutions. Therefore, the European solution has been standard textbook market reform to develop short term market and coordinate transmission and generation in this time frame [**Errore. L'origine riferimento non è stata trovata.**].

Commission Regulation 2016/1719 requires TSOs to develop harmonized rules for allocating physical transmission rights and financial transmission rights [**Errore. L'origine riferimento non è stata trovata.**]. The regulation sets out rules to the development and cost allocation of long-term transmission rights. The allocation of cross-zonal capacity at long-term time frame can be organized through explicit auction. In the Joint Auctioning Platform set up by the TSOs, currently available long-term transmission rights for interconnections only cover one-year.

Will the implementation of joint explicit auction of interconnection capacity in long-term time frame bring an efficient cross-border long-term market? From the cost and risk allocation perspective, Beato points out there exist different incentives of TSOs and transmission users for the development of long-term transmission right products [**Errore. L'origine riferimento non è stata trovata.**]. Unless the TSOs are guaranteed cost recovery from their regulators, they would be reluctant to increase the quantity and duration of long-term transmission rights. TSOs are required to ensure the firmness of the long-term transmission rights, or otherwise they need to compensate the right holders and face the risk this cost is not approved to be reimbursed in the network tariff.

As a consequence of incomplete information, it is difficult for the market participants to form a portfolio of physical transmission rights for bilateral contract under zonal pricing. There will be some bilateral contracts made infeasible by the system operator. History in PJM also supported the analysis outcome where a lot of bilateral contracts collapsed under zonal market and facilitated the transition from zonal to nodal pricing [**Errore. L'origine riferimento non è stata trovata.**]. Another implication is in the long-term time frame, the common grid model needs to be calculated in a conservative way to take account of higher uncertainties and the nature of zonal model. Consequently, much less cross-border long-term trade would be allowed if all the bilateral contract needs to be feasible, which leads to lower network utilization in this time frame.

Joint energy and transmission right auction as tentative improvement for European long-term market

The joint energy and transmission right model developed by O'Neil et al is proposed to answer the question in this research [[9]]. Firstly, the simultaneous optimization of energy and transmission usage promises economic efficiency. In addition, the model makes the allocation of financial and physical transmission right both feasible in the auction. Secondly, an important aspect that makes a difference in the performance of hedging instruments or cost structure for network users is whether the market clearing result is physical or financial. One advantage of introducing a multi-settlement system as proposed in the model is that market clearing before real-time does not interfere with physical dispatch. Only the clearing of real-time market has physical commitments. This could enable the network user to financially hedge the congestion risk while allowing system operator to optimize the resources of the whole system at the time of delivery. However, does it work efficiently under European market to offer congestion hedging possibilities for trades across borders?

With a stylized network, zonal market outcome is compared with that of the nodal market using the joint energy and transmission auctioning model. In particular, two dimensions are examined for evaluation with nodal market outcome as reference: 1) Is the market outcome revenue adequate for a system operator? 2) Can the congestion risk be hedged for network users?

In our case study, JETRA is used for all time frames in the nodal market. In the zonal market, the JETRA model is implemented in the long-term market, while the market coupling mechanism is used day-ahead market and redispatch is constructed according to the current European market design. Our result shows that the mechanisms after day-ahead gate closure such as redispatch and balaning breaches the revenue adequacy for system operator. The higher cost of redispatched generation is in the congested zone, the larger the revenue adequacy gap is for system operator. Although a coordinated redispatch and balancing mechanism significantly reduces system cost, the revenue gap for system operator creates the issue of additional cost distribution among user groups in different countries.

In comparison with a nodal market, the transmission rights and energy contracts obtained by market players in the earlier stage of joint auction, exhibit weaker hedging performance in the zonal market. The policy implication of this study is to point out the need for reforming zonal pricing and replacing it with nodal pricing in European electricity market, in order to facilitate the development of a long-term market as well as congestion hedging instruments across borders.

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Corinne Chaton and Coline Metta-Versmessen

CARBON CONTRACT FOR DIFFERENCES FOR THE DEVELOPMENT OF LOW-CARBON HYDROGEN IN EUROPE

Coline Metta-Versmessen, EDF, 4 ter rue Louis Scocard, Orsay, France

While developing a low-carbon hydrogen economy in the European Union is currently an energy transition keystone, electrolysis based production is not yet competitive compared to steam reforming. This study aims to characterize a new political tool, the Carbon Contract for Difference (CCfD), in the specific case of scaling up electrolysis based hydrogen production. Our analysis suggests that an economically efficient CCfD can be defined for each area with homogeneous electricity mix. This CCfD should be designed depending on the gas prices and the current State aids being used in the EU-ETS system. This paper offers a methodology for policy makers to design CCfD according to their region and the sector application.

Key words: CCfD, low-carbon hydrogen, emission reduction, EU-ETS.
JEL Codes: D47, Q48, Q52.

Paolo Bertoldi

THE EUROPEAN COMMISSION PROPOSAL FOR REACHING -55% GHG REDUCTIONS BY 2030 IN THE JOURNEY TOWARDS CLIMATE NEUTRALITY.

Paolo Bertoldi, European Commission DG JRC

The European Commission adopted a package of proposals to for reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels. Achieving these emission reductions in the next decade is crucial to Europe becoming climate-neutral by 2050 as indicated in the European Green Deal.
The measures and policies in the Fit for 55 Packages are an interconnected set of proposals for all the sectors of the economy buildings, transport, energy supply, etc..

The presentation will focus on the proposal for the revision of the:

- The EU Emissions Trading System (ETS) including revenues recycling on climate and energy-related projects and the separate new emissions trading system is set up for fuel distribution for road transport and buildings.
- The Effort Sharing Regulation assigns strengthened emissions reduction targets to each Member State for buildings, road and domestic maritime transport, agriculture, waste and small industries. Recognising the different starting points and capacities of each Member State, these targets are based on their GDP per capita, with adjustments made to take cost efficiency into account.
- The Renewable Energy Directive
- The Energy Efficiency Directive
- CO_2 emissions standards for cars and vans
- The revision of the Energy Taxation Directive
- The new Carbon Border Adjustment Mechanism A Socially Fair Transition
- The new Social Climate Fund

The presentation will also shows the some of the key figures and results of the recently adopted State of the Energy Union Report 2021.

Giuseppe Dell'Olio

ENERGY EFFICIENCY OF BUILDINGS: A SIMPLE BUT ACCURATE WAY TO PERFORM CALCULATIONS

Giuseppe Dell'Olio, GSE, Italy

Overview

In order to assess yearly energy demand of a building, many current standards require a heat balance to be performed monthly during heating season. As a result, six or more heat balances are needed every year.
Such a time-consuming calculation is justified by its alleged accuracy: the figure it provides is thought to be extremely precise. However, this is not necessarily the case.
Based on "real life" calculations, this paper shows that a single, seasonal calculation can replace numerous, monthly ones, with no significant loss of accuracy.

Methods

With reference to a real case (a country house in central Italy), the Energy Performance Index was first calculated based on TS 11300-1 and TS 11300-2. Monthly heat balances were performed from January to (first two weeks of) April and from November to December. The six monthly outcomes were then summed.
On the same building, the seasonal calculation described in Standard ISO 13790:2008 was then performed. The seasonal calculation was much simpler, as it only involved one heat balance instead of six.

Results

The monthly calculation yielded an Energy Performance Index of 4,393.69 kWh per square meter and per year.
The seasonal calculation yielded an Energy Performance Index of 4,345.17 kWh (or 4,375.66, depending on values assumed for a few parameters in the balance equation) per square meter and per year. The error as compared to month- by-month calculation was as little as -1.1% (or -0.4%) .

Conclusions

The seasonal calculation yields basically the same results as the monthly one. The seasonal calculation should be adopted instead of the monthly one, as much simpler (and less expensive) and providing the same accuracy.

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THE EXTENT OF BARRIERS AND DRIVERS TO ENERGY EFFICIENT RETROFITS IN RESIDENTIAL SECTOR: A BIBLIOMETRIC ANALYSIS

Janez Dolšak, School of Economics and Business, University of Ljubljana, Slovenia

Overview

There are several different categorizations of barriers and drivers to energy efficient building retrofits and related measures in the literature on barriers and drivers. Some studies categorise them according to their role in the decision-making process, e.g. (Broers et al., 2019), others according to their type e.g. (Hrovatin & Zorić, 2018; Bravo et al., 2019; Bjørneboe et al., 2018). According to the first approach, six stages in the decision-making process can be identified: Raising interest, gaining knowledge, forming an option, making a decision, implementing the measure, and experiencing the measure (Broers et al., 2019). On the other hand, barriers and drivers can be categorised according to their type. For example, Bravo et al. (2019) focused on identifying socioeconomic attributes and attitudes and categorised barriers and drivers into three categories: financial, attitudinal, and social. Bjørneboe et al. (2018) also classified them into three categories, namely informational, financial, and process barriers and drivers. Hrovatin and Zorić (2018) provide an extended version of the categorization with five categories: Information and Policies, Economic factors, Household Socioeconomic Characteristics, Technical factors - Building Characteristics, and Behavioural Drivers.

Despite the large volume of work describing and categorising the determinants of residential energy efficiency, there is a lack of comprehensive quantitative analysis of this literature. Camarasa et al. (2019) conclude that a more holistic and consistent understanding of the decision leading to the implementation of energy efficient and energy saving measures is needed. Simpson et al. (2020) conducted a similar analysis, but limited to North Western Europe. Therefore, in addition to a literature review that led to a description and categorization of the determinants of energy efficiency in residential buildings, a bibliometric analysis of the determinants of energy efficient behaviour was carried out, which allows to better understand the evolution of knowledge in this area.

Methods

I conducted a detailed literature review of the factors that influence energy efficient retrofits in residential buildings. In reviewing empirical studies to identify the most influential factors, I limited myself to studies that examine residential energy efficient retrofits (alone or together with general building or heating renovations) to identify both the barriers and drivers to energy efficient building retrofits. In general, they can be categorised into five groups: 1) technical factors - building characteristics; 2) economic factors; 3) socioeconomic characteristics of households; 4) behavioural factors; and 5) information and policies.

In addition, I conducted a bibliometric analysis consisting of four main bibliographic methods, namely citation analysis, co-citation analysis, co-authorship analysis, and co-word analysis.

The bibliometric analysis was performed using VOSviewer, an open source tool used for network data mapping and visualisation (van Eck and Waltman, 2011).

By analysing the content of the abstracts of the selected literature, I generated a visualised knowledge of the barriers and drivers of energy efficiency in residential sector. The subsequent analysis of the selected literature enabled me to summarise the main determinants of energy efficiency identified in the literature and thus propose the answer to the original research question about the importance of these determinants. This type of analysis also allows for the creation of a network of determinants that provides information on the co-occurrence of determinants in the literature.

Results

Residential energy efficiency has attracted considerable attention over the last two decades as the number of published papers in this area has increased significantly. The results show that different clusters of determinants of energy efficient and energy saving behaviour have been identified in the literature. While firm characteristics are mainly associated with barriers to energy savings, behavioural aspects such as pro-environmental attitudes co-occur with other drivers. In addition to the thorough examination of selected papers, the bibliometric analysis provides interesting aspects of the evolution of these determinants.

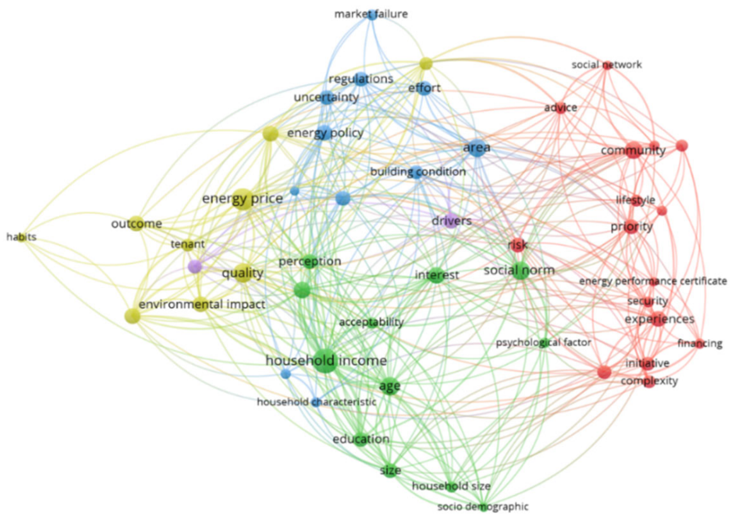

Figure 1: Term map showing the determinants that occurred 10 times or more in papers' abstracts

Figure 1 shows the term map with determinants that occurred 10 times or more in papers' abstracts, presumably believed to be important. As can be seen from the figure, some groups of determinants are typically studied in common models. The largest nodes denote the most frequently mentioned determinants.

Although bibliometric analysis is a powerful tool that makes an important contribution to knowledge, a thorough literature review is also required to identify the direction of the impact of the determinants. Therfore, the analysis provides a detailed literature review of the authors who identify these determinants.

Conclusions

There are three important contributions of this thesis. First, I am able to identify key research streams based on the historical development of published work in this area. Second, analysis of co-citations provides me with the network of influences between authors. Finally, an analysis of the content of the papers' abstracts allows me to visualise the current state of knowledge on the determinants of energy efficient and energy saving behaviour in the literature. Since this type of analysis is usually equipped with a large collection of data and analytical approaches, it can support the development of effective strategies for retrofitting residential buildings in the future. The bibliometric analysis is based on the text mining algorithms, which can identify research trends and classify the results based on different approaches, and thus can also assist research agencies in developing research fields.

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Francesco Castellani, Maria Carmen Falvo, Federico Santi, Maurizio Della Fornace

ENERGY EFFICIENCY AS A KEY FACTOR FOR THE SUSTAINABILITY PATHWAY OF ORGANIZATIONS. THE CASE OF THE EUROPEAN SPACE AGENCY ESA-ESRIN IN ROME

Francesco Castellani, Studio Santi, Via E. Fermi 46 - 00058 Santa Marinella (RM) - Italy
Federico Santi, Studio Santi, Via E. Fermi 46 - 00058 Santa Marinella (RM) - Italy,
Maria Carmen Falvo, Associate Professor at University of Rome Sapienza, Italy,
Maurizio Della Fornace, ESA ESRIN, ESA Estates and Facility Management Department, Rome Italy

Within the framework of the European 2020 strategy for a smart, sustainable and inclusive growth of the euro zone, the European Council committed to the achievement by 2020 of the following targets (also referred to as “20-20-20 goals”):

- 20% emission reduction of greenhouse gases compared to 1990 levels;
- 20% increment in the use of renewable energy for the coverage of EU energy demands. This commitment also includes 10% biofuel use of the total fuel consumption in the transport sector;
- 20% emission reduction of the primary energy consumption compared to the levels originally forecasted in 2007 (so called business as usual scenario, BAU).

The targets related to the 20-20-20 Strategy had to be adapted from the Community level to the different national contexts. The commitments assigned to each Member State were determined according to parameters such as the GDP growth, the added value of productive sectors, and the energy international price.
In this context, the real case study of the ESA ESRIN facility in Italy has been investigated. The aim of the work is to demonstrate how a complex facility could participate in achieving of the EU 20-20-20 goals through the improvement of energy performance and environmental sustainability.
The target related to CO_2 emissions level, total energy consumption and renewable energy penetration had to be adapted to the particular context, in order to perform a compliance analysis of the local situation of ESA ESRIN facility to the European 20-20-20 Strategy.
ESA ESRIN facility is located in Largo Galileo Galilei 1, 00044 Frascati (RM).
Its size is approximately 35.000 sqm and serves almost 1.000 employees on site, plus a large number of visitors attending ESA conferences. The site consists of 20 buildings, 2 main data centres (Corporate IT and Earth Observation), ESA Archive, 2 power stations, antennas, sport facilities (gym, tennis and football), canteen and bar, conference facilities, solar thermal and photovoltaic installations.
The most relevant energy users are Data Centres (including UPS, HVAC, power distribution, etc.) and office buildings (AHUs, heating boilers, lighting, power distribution, etc.).
Energy carriers enter ESA-ESRIN site as: electricity from the grid, electricity from local photovoltaic production, natural gas, thermal energy from local solar production, diesel for emergency generators.

The path of energy efficiency for the ESA ESRIN facility over the reference period 2010-2018 has resulted into a marked decrease in energy consumption of the site, with consequent substantial reduction in the indirect greenhouse gases emissions, despite the constant and significant growth of all the activities in the site.
The pathway covered both the reduction of the total energy consumption and the increase of the renewable energy sources quota. It was not interrupted in 2018, but it continued with a series of interventions realized in the following years, whose effects are excluded from this discussion.
With the necessary adjustments and adaptations – essential to apply to a local worksite such ESA ESRIN a Strategy conceived at the European level for a whole continent – the research have proved the full compliance of the facility with the three targets of the 20-20-20 Strategy, i.e. the achievement by 2020 of:

- 20% reduction of GHGs emissions compared to 1990 levels (-96% compared to 2010 for ESA ESRIN);
- 20% reduction of primary energy consumption compared to the 2020 level forecasted in 2007 (-37% compared to 2010 for ESA ESRIN);
- 20% coverage of the consumption with renewable energy sources (95% coverage in 2018 for ESA ESRIN).

The benchmarking with similar facilities in Rome and literature data shows that, in terms of energy consumptions, ESA ESRIN performance is better than the literature data and the selected facilities even if they are larger (in surfaces and energy consumptions) and they can benefit of important scale effects. In terms of energy production, ESA ESRIN is the only facility that owns and manages a large on site PV plant that provides renewable energy for the site.

Alessandro Pelliccia, Valerio Di Prospero, Laura Antonuzzi, Annalisa Zuppa, Francesco Castellani, Romano Acri, Federico Santi

ENERGY EFFICIENCY IMPROVEMENT STRATEGIES FOR IMPORTANT HISTORIC BUILDINGS USED AS OFFICES. A CASE STUDY IN ROME

Alessandro Pelliccia, corresponding author, University of Rome la Sapienza, Itlay

The buildings sector accounts for almost a third of global final energy use. This sector covers a lot of energy-consuming activities that provide basic energy services, including lighting, space and water heating, cooling and the use of appliances.
In Italy the building sector accounted for almost 43,5% of the total energy consumption in 2018. It is clear how this sector will play a key role in reducing GHG emissions going forward. A high number of buildings, due to their early construction and their architectonic value, are considered historic, and only actions which don't compromise the architectural and core values can be taken in account.
The following research will discuss a case study of an historic building situated in the center of Rome. The aim of the study is to enhance the comfort of the building for its users, as well as providing savings for energy bills and reducing GHG emissions.
The analysis began by carrying out the energy diagnosis of the building under the directives of the guide AICARR and the normative UNI 16247. The energy diagnosis is a procedure which is used to analyze the energy consumption of the building in order to identify the energy flow and the possible actions to improve the energy system. The first step was collecting the building's data (energy bills) to build the energy consumptions.
The energy efficiency process is a "way of managing and restraining the growth in energy consumption". The actions identified to improve the energy system without damaging the building and its historic value are the following:

- Electrification of the heating system
- Building integrated Photovoltaic
- Technological upgrades and BACS
- Redevelopment of the transparent casings

The electrification of the heating system is aimed at reducing the use of natural gas as the energy vector used for heating.

An interesting solution is to install aerothermal heat pumps which will be connected to the medium temperature collectors of the thermal substation, and the low temperature circuits, because these reversible heat pumps can also cover a high percentage of the cooling load. The architecture of the building remains unaltered, and this action will lead to a reduction of almost 50% of primary energy, and about 70% of CO_2-eq emissions.

It has been decided to install a photovoltaic system to enhance the self-energy production. Different technologies have been analyzed to install the highest possible power: photovoltaic
modules placed on the roof, identifying the most suitable zones not characterized by shadowing effects, and the integration of photovoltaic glass made of crystalline silicon on the
skylight of the building. Different scenarios have been taken into consideration due to the various colors which will be proposed to reduce the visual impact of the PV modules.
Technological upgrades and Building Automation Control Systems is a further action carried out to enhance the environmental quality and strongly reduce the energy consumption of the building. It consisted in relighting with LED technology and introducing a high technology control system, which results in installing presence and illuminance sensors, fancoil's activation directly connected with the windows closure. These upgrades are focused on minimizing the energy waste as well as reducing total energy consumption. The previously low BACS class due to the inefficiency of historic buildings, will reach a higher level leading to a 15% electrical energy saving thanks to the new control system.
A further action that has been analyzed is the substitution of the transparent casing. This very delicate action has been carried out to save the historic value of the building while improving its energetic values. All the window frames will be in wood, also to respect most of the frames already existing, and all the single glasses will be changed with double glazing. Solar shields will also be introduced with respect to the architectural constraints. A study has been carried out taking in account the solar factor, the thermal transmittance, and the light transmission, with the aim to reduce the heat loss during the winter season and the solar gain in the summer period, leading to a reduction of almost 40% of the incoming heat.

ASSESSMENT OF RENEWABLE ENERGY SOURCES IMPACT ON NUCLEAR POWER THE CASE OF FRANCE

François Benhmad, Montpellier University, Site Richter, Avenue Raymond Dugrand, CS79606, 34960 Montpellier Cedex2, France,
Jacques Percebois, Art-Dev, Montpellier University, Site Richter, Avenue Raymond Dugrand, CS79606, 34960 Montpellier Cedex2, France

Abstract:

In France, the nuclear energy share of gross electricity generation is more than 70% whereas wind and solar feed-in does not exceed 8.5%. However, due to priority access to grid and support scheme, EDF (Electricité de France), operating the world's largest fleet of nuclear reactors, is challenged by the growing market share of renewable energy sources especially wind and solar.
In this paper, we use hourly data for 2019 (avoiding Covid-19 effect) to explore the link between the wind and solar feed-in and nuclear power generation. Moreover, we investigate the impact of interaction between nuclear and these renewable energy sources on electricity spot prices. Our empirical results show that there a strong negative correlation between the two energy sources as wind and solar energy often replace nuclear power. Moreover, the equilibrium price level on the spot market induced by this negative correlation is much lower, which could jeopardize the profitability of nuclear plants.

1. Introduction :

In ordrer to tackle global warming and make an important contribution to the EU's long-term strategy of achieving carbon neutrality (net-zero emissions) by 2050, the EU nations agreed in 2019 on a new energy rulebook – called the Clean Energy for all Europeans package. To show global leadership on renewables, the EU has set an ambitious, binding target of 32% for renewable energy sources in the EU's energy mix by 2030. In this context, National Energy and Climate Plan (NECP) of France builds on the Multiannual Energy Planning and the National Low-Carbon Strategy proposed a 32% national contribution for renewable energy,mainly wind ans solar power, in gross final energy consumption in 2030.
It is worth noting that various support schemes for renewable energy sources (RES) are operating in Europe, mainly feed-in tariffs, fixed premiums, and green certificate systems. The feed-in tariff (FIT) is the most favourable one for a variety of RES especially for wind and solar power generation. There is also a growing use of the auction mechanism to set the level of subsidies for renewable.
The RES were also given priority access to grid over conventional power plants, i.e. fossil-fuel, nuclear-fuel and hydro-based power plants. It is also because their marginal cost is close to zero, which gives them an advantage in a market where the merit order is based on marginal costs.

Therefore, the RES development induced a disruption of electricity generation across Europe. Some power generators were forced to mothball. Some other power plants closed as they were not used enough to be profitable. Some other power plants, among them nuclear plants, couldn't quickly accommodate swings in supply and demand.

Although the nuclear energy share is more than 70% in France whereas combined generation from wind and solar power accounted for less than 6 or 7 per cent of gross electricity production. EDF (Electricité de France), operating the world's largest fleet of nuclear reactors, is thus challenged by the growing market share of intermittent energy sources like wind and solar. Indeed, nuclear power plant in France have showed an ability in loading following providing flexibility to French electricity system. Thus, nuclear feed-in is progressively behaving as a back-up capacity to cope with renewables intermittency replacing carbon-emitting technologies, predominantly gas-fired plants. Consequently, renewable energy especially wind and solar photovoltaic often replace nuclear power.
In this paper, we carry out an empirical analysis in order to investigate the impact of wind feed- in and solar power production on nuclear electricity generation in France.
This study makes three main contributions to the literature. Firstly, an OLS regression is used to explore the joint impact of wind and solar photovoltaic feed-in on nuclear energy generation, using 2019 year as a dataset. Secondly, we control for power demand in France (load) throughout the 24 hours of the day over the 365 days of our data sample. Thirdly, we take into account electricity imports from Germany, the European leader on European installed capacity of renewables (more than 100 GW installed).
Our main empirical findings confirm that increasing the share of wind generation and solar feed-in could have a downward effect on nuclear generation. It confirms the fact that nuclear energy could be a victim of crowding-out effect from renewables as it will increasingly play a role of a back-up technology to cope with intermittence of renewables. This crowding-out effect coupled with the merit order effect due to a lower equilibrium price level on the spot market induced by renewables could jeopardize the profitability of nuclear plants.
The paper is organized as follows. Section 2 provides the background on RES effect and the corresponding literature review. In section 3, we present the results and discuss the main findings. In section 4, we conclude and explore the policy implications of our findings.

2. Literature survey

A number of authors have studied the impact of RES on the pricing on the spot electricity market. For Germany, (Würzburg et al., 2013) explored the merit order effect on the joint
German and Austrian market using daily data on electricity prices. They showed that each extra GWh of renewables generation led to a reduction of the daily average price by approximately 1 €/MWh in the German and Austrian markets and estimated an overall reduction in the electricity spot price of 7.6 €/MWh between mid-2010 and mid-2012.
(Ketterer, 2014) also examined wind power in German electricity markets and found that additional RE generation of 1GWh led to a reduction of the daily spot price of approximately 1€/MWh. (Cludius et al., 2014) estimated the merit order effect of wind and photovoltaic electricity generation in Germany between 2008 and 2012.
They show that the average specific effect (reduction of the spot market price per additional GW of renewable energy) lies between 0.8 and 2.3 €/MWh.

(Benhmad and Percebois, 2016) also examined daily data of wind power in German electricity markets between 2009-2013 and found that additional wind generation of 1GWh led to a reduction in the daily spot price of approximately 1€/MWh, and given average wind electricity generation during 2009-2013, the merit order effect corresponds to an average price decrease, in absolute terms, of approximately 6 €/MWh.

For Denmark, (Munksgaard and Morthorst, 2008) conclude that if there is little or no wind (<400MW), prices can increase up to around 80 €/MWh (600 DKK/MWh), whereas with strong winds (>1500MW) spot prices can be brought down to around 34 €/MWh (250 DKK/MWh).

(Huisman et al., 2007) obtained equivalent results for the Nord Pool market by modelling energy supply and demand.

(Sáenz de Miera et al., 2008) find that wind power generation in Spain would have led to a drop in the wholesale price amounting to 7.08 €/MWh in 2005, 4.75 €/MWh in 2006, and 12.44 €/MWh during the first half of 2007. (Gelabert et al., 2011) find that an increase of renewable electricity production of 1 GWh reduces the daily average of the Spanish electricity price by 2 €/MWh.

(Woo et al., 2011) carried out an empirical analysis for the Texas electricity price market and showed a strong negative effect of wind power generation on the state's balancing electricity prices.

(Percebois and Pommeret, 2018a) show that the introduction of renewable energy paid off- market disrupts the demand-price relationship in the electricity wholesale market and then, for the French case, they quantify the transfers of revenues induced by this disturbance among consumers, producers and providers.

Conversely (Traber and Kemfert, 2012) calculated that the accelerated phase-out of nuclear power in Germany would lead to an increase of the wholesale electricity price between € 2 and € 6 per MWh.

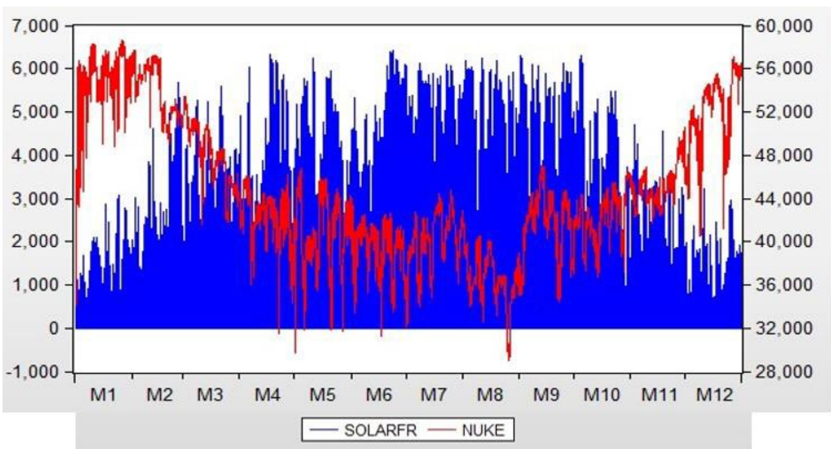
3. Empirical evidence:

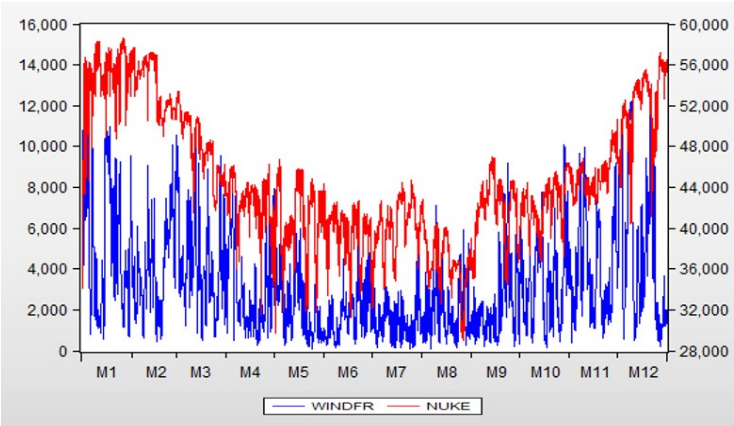
3.1 Data

The analysis is based on time-series data of the French power system as provided by ENTSOE. Our dataset is based on hourly information on nuclear power feed-in and RES

electricity generation (wind and solar photovoltaic). The sample data covers the period from 1 January 2019 to 31 December 2019, summing to 8760 hourly data.
The following figure 1 and figure 2 provide a plot of the data for the whole period.

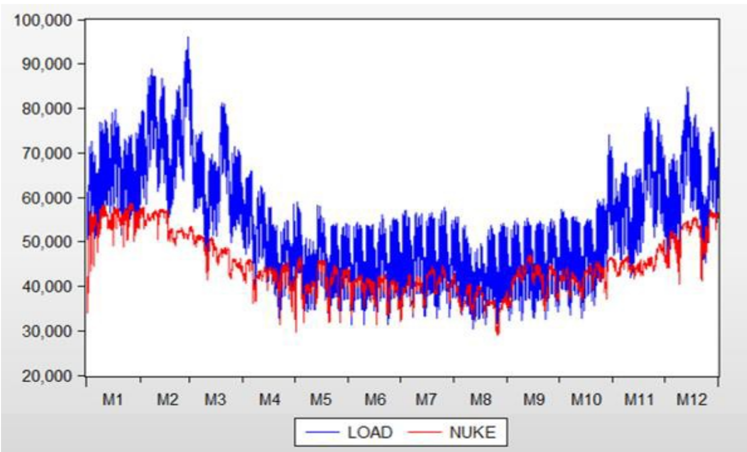
Figure 2. Nuclear power feed-in vs wind generation (hourly)





It is easy to see that the nuclear power feed-in exhibits a clear seasonal profile which can be subdivided in two semesters: a first semester beginning in October and ending in late March corresponding to a high level of generation followed by a second semester from April to end September corresponding to high level of nuclear power feed-in.
It is worth noting that the seasonal profiles of nuclear and wind are about the same; on the contrary the seasonal profile of solar is opposite.
In France, the wind blows when the power demand is high especially during winter season whereas the solar plants produce when the demand is low especially during summer season.
As the nuclear generation depends on the power demand dynamics (load), we should control for the load level. The following figure 3 shows clearly the following load behavor of nuclear fleet in France.

Figure 3. Nuclear power feed-in vs load (hourly)



3.2 Empirical results:

In order to explore the link between nuclear feed-in in France and RES (Photovoltaic and wind power feed-in), and controlling for both the electricity demand (load) in France, we run an OLS regression where the depend variable is nuclear power generation and where the explaining variables are respectively wind feed-in, solar PV generation, load (power demand), and electricity imports from Germany.

As there is a strong seasonal behavior of all the studies variables, we will carry out our empirical analysis on seasonally adjusted variables. Moreover, when we tested for unit roots in variables time-series using the augmented Dickey-Fuller (ADF) test (Dickey and Fuller 1979), the null hypothesis of a unit root is rejected.
The empirical results are reported in the following table 1 and table 2(not reported).
The empirical results show a negative impact of both solar and wind feed-in on nuclear generation in France. Although wind generation share in gross electricity generation is much higher than the solar's one, this evidenced downward effect is more pronounced for solar photovoltaic than for wind feed-in as the solar plants produce when the demand is low especially during summer season.
Indeed, the average hourly impact of solar generation should induce a decrease of 0.26 MWh of nuclear feed-in for each additional MWh of solar output, whereas the average hourly impact of wind feed-in should induce a decrease of 0.17 MWh of nuclear feed-in for each additional MWh of wind generation.
Moreover, the imported electricity from Germany exacerbates the downward pressure on nuclear generation in France as both wind and solar power coming from Germany play the same role of the wind and solar generated in France. Indeed, the high level of electricity demand during winter induces a negative impact of the German imports (mainly wind) on nuclear generation. In contrast, during summer season, the German power imports (mainly solar PV) This negative impact is much more important on nuclear generation as the power demand is low
The impact seems to be quite low as the solar and wind lowering effect on nuclear feed-in represents a small market share of power generation lost by nuclear energy. However, we should take into account that this "low" effect corresponds to an installed capacity of just 26 GW in 2019 of both wind and solar. Therefore, if we make a comparison with Germany where the renewable installed capacity in 2019 is a total of more than 110 GW –almost five times of installed capacity in France-, we can conclude that the more RES capacities would be installed in France, the more their crowding effect on nuclear feed-in could be much stronger.
Furthermore, as France is surrounded by countries with a lot of solar and wind, especially Germany, the renewable power peaks in Western Europe might be squeezing out French nuclear power.

4. Conclusion and policy implications

In this paper, we have studied how wind and photovoltaic electricity feed-in influences the nuclear generation in the French electricity market and have shown that they have a negative impact. Moreover, the electricity imported from Germany, the country with the highest installed capacity of renewable energy sources increases this negative effect.

Therefore, the large-scale penetration of renewables could have a crowding-out effect on nuclear plants jeopardizing their profitability as the recovery of their fixed costs will be highly challenged by lower equilibrium prices due to merit order effect.

> The French electricity system must increasingly deal with two problems simultaneously: lack of peak electricity and too much fatal renewable electricity during off-peak periods (which will either have to be exported or stored). In a period of low power demand, nuclear power, which has shown its flexibility, is squeezed out which risks compromising its profitability in the long term. Moreover, this crowding out effect is induced by electricity which, contrary to what many people think, is not free since it is often subsidized.

Indeed, to reduce the share of nuclear power in the French electricity mix, a new production capacity should be available during peak hours. Otherwise, the demand for electricity demand should be reduced to cope with lower generation during peaking periods.

As renewables could not be available during peaking periods, either conventional gas-fired power plants will have to be used or imports will be required. Imports or gas-fired power plants are costly options and will induce a sharp increase in CO_2 emissions in contrast to idea behind renewable energy sources support policies. Moreover, the management of the load curve (load-following) will require more and more flexibility in terms of demand and it will have to be accompanied by efforts in terms of electricity storage, another costly option.

In terms of trade, the French electricity system could be a net exporter. However, we could have situations where exported power volumes are so important but at quite low price inducing a deficit in value.

Therefore, considering the French context, the use of renewables does not appear as the best suitable option to decarbonize the electricity system due to the crowding out effect of renewables. In addition, since nuclear act as a back-up to renewables, lowering the share of nuclear energy in the electricity mix without further increase the flexibility of the system could induce significant balances issues.

Hence, there is a need of a redesign in electricity markets in particular in the way the fixed costs could be recovered ensuring the plants to be well available to meet the demand for electricity.

It is a complete reform of electricity pricing mechanisms that is expected: a wholesale market based on the "merit order" works well as long as the fleet of plants is a heterogeneous park composed of several categories of power stations presenting highly differentiated variable costs. It is conceivable to set prices according to average costs, opt for a "Ramsey-Boiteux" type of pricing, which would be tantamount to fixing the price per kWh above marginal cost, the differential between this price and the marginal cost being inversely proportional to the price elasticity of demand, or choosing non-linear pricing in which the fixed part would be very important and adjusted to finance the fixed costs of the called equipment. In the latter case, this amounts to permanently backing up a capacity market for the spot market.

The merit order can be modified by taking into account the full cost, i.e. by introducing the externalities linked to the production of the MWh, hour by hour. In the case of fossil fuels, this is already the case when there is a carbon price as in Europe (around 60 euros per tonne of CO2 in August 2021). For nuclear power, the cost of radioactive waste storage should be taken into account since the volume of waste is proportional to the volume of electricity produced. In the case of renewables, the cost of storage and retrieval of MWh should be taken into account. This would allow the calculation of pivot values on the basis of which the substitution between power plants is made. If the cost of storing renewable electricity is high, a high carbon price is needed for renewables to be called before gas or coal-fired power plants, especially if at the same time the price of gas is low. If the carbon price is high, gas-fired plants will be called before coal- fired plants, even at low coal prices, given the high carbon intensity of the MWh produced from coal.

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RENEWABLE ENERGY PROLIFERATION FOR ENERGY SECURITY: ROLE OF CROSS BORDER ELECTRICITY TRADE

Amit Prakash Jha, LMTSM, TIET Patiala, Punjab, India
Sanjay Kumar Singh, IIM Lucknow, Lucknow, UP, India
Aarushi Mahajan, LMTSM, TIET Patiala, Punjab, India

Overview

The environmental and economic fallout of anthropogenic climate change, triggered mostly by energy production, are increasingly obvious and relevant (Buso and Stenger, 2018). A prominent mitigation strategy is to replace the polluting fossil fuel based resources for renewable energy resources (Silva et al., 2018), but there are multiple barriers. These barriers include technical, institutional, political, regulatory, social and environmental barriers; also, economic barriers such as high cost, and market barriers such as inconsistent pricing structures are unfavourable to renewable energy expansion (Painuly, 2001). Reliability is one of the key criteria in selecting renewable technology (Wang et al., 2009; Kahraman et al., 2009). Intermittency is another matter of concern with renewable energy, be it solar (Gowrisankaran et al., 2016) or wind (Kaffine et al., 2020). Cross border electricity trade, by offering potential solutions to these problems, provides a new direction for sustainable development and energy security through its positive effects on the renewable energy (Pu et al., 2021). Cross border trade of electricity can, in principle, address reliability and intermittency issues and naturally opens the door to a larger market. Hence, integrating national renewable energy markets does make sense. With this background, we set out to explore two research questions. First, what is the causal direction between renewable energy generation and cross border electricity trade? Second, how are these variables related? The findings should throw light on possible critical role of cross border trade in the expansion of renewable energy market.

Methods

For the first objective, we are adopting the procedure proposed by Dumitrescu & Hurlin (2012). A significant value for the test statistic will indicate presence of causal linkage for at least one individual in the panel. For the second objective, we are adopting a nonparametric kernel regression method on the lines of Racine & Li (2004) and Li & Racine (2004). Nonparametric methods avoid the specification of a potentially unsuitable functional form for the relationship between the explanatory variables and the dependent variable (Czekaj and Henningsen, 2013). We have used multiple model variants for robustness.

We have used a dataset of 35 countries for 29 years (annual data from 1990 to 2018) obtained from The International Energy Agency (https://www.iea.org/data-and-statistics) and The World Bank (https://data.worldbank.org/).

Results

Panel Granger Causality Test clearly indicates bi-directional causality. Results, based on multiple model variants, clearly show that cross border trade in electricity positively and significantly affects the renewable energy expansion. The economic output, as expected, also significantly and positively affects renewable energy generation. We have also estimated parametric models, Common Correlated Mean Groups Model and Mean Group Model, for comparisons and they too give results similar to the nonparametric ones, though the model specification is subject to the validity of the model assumptions. For parametric models to give meaningful results, we have tested for time series stationarity and cointegration. The results provide empirical justification to Jacottet (2012). Empirical results of the present work points that welfare gains arising from cross border trade are indeed being utilised by countries, thereby, boosting the renewable energy growth. This calls for increased cross border electricity trade to further advance the renewable energy proliferation.

Conclusions

Strong cross border interconnections have direct economic benefits and decreases generators possibility to exercise market power, increases the security of supply for all trading partners and lowers the risk on investments (Androcec et al., 2009). Our findings show that renewable energy production is indeed benefited from cross border electricity trade. Our results augment the findings of Boz et al. (2021) through a less restrictive nonparametric approach. The findings have far-reaching policy consequences. It is recommended to promote cross border electricity trade to support renewable energy generation which will in turn lead to energy security apart from being a cleaner alternative to address our energy needs. The present work provides a strong and unambiguous empirical justification for cross border electricity trade. The study advocates for concerted policy intervention to promote cross border electricity trade. Policy intervention is needed to address barriers such as diverging interests, administrative problems, price distortions and inadequate financing to promote cross border trade in the spirit of Puka & Szulecki (2014). The study unequivocally advocates for increased cross border electricity trade. In the interest of economic and environmental sustainability any pricing stability issue arising out of market expansion must be dealt with appropriate and concerted market intervention by the trading partners.

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Francesco Gullì, Maurizio Repetto

COMPARING SOCIAL COSTS OF ENERGY SUPPLY DECARBONIZATION: ELECTRIFICATION VERSUS GREEN FUELS (BIOMETHANE)

Francesco Gullì, Bocconi University; Italy
Maurizio Repetto, Politecnico di Torino, Italy

Abstract

Given the objective of energy supply decarbonization, this paper explores how “scarce” renewable sources could be allocated among different final uses in order to minimize the social cost of CO_2 abatement. The paper focuses on a relevant case consisting of a medium-large industrial customer close to a small-medium city where a CHP plant can be constructed delivering power and heat to the industrial customer and heat to the city through a DH (district heating) grid. The simulations (based on the estimation of the “levelized cost” of abatement) highlight that green fuels might be preferable to a deep electrification of final uses.

Animesh Singh, Nallapaneni Manoj Kumar and Shauhrat S Chopra

TECHNO-ECONOMIC ANALYSIS OF A BLOCKCHAIN-ENABLED ROOFTOP SOLAR PHOTOVOLTAIC BASED PEER-TO-PEER ENERGY MARKET USING AGENT-BASED MODEL

Animesh Singh, School of Energy and Environment, City University of Hong Kong, Kowloon, Hong Kong
Nallapaneni Manoj Kumar, School of Energy and Environment, City University of Hong Kong, Kowloon, Hong Kong
Shauhrat S Chopra, School of Energy and Environment, City University of Hong Kong, Kowloon, Hong Kong

Overview

The rise in distributed energy resources (DER) has enabled the modernization of electric power grids, especially in shifting the energy generation from utilities to end-users. This shift permits the end-users to become prosumers where they can produce and consume energy, leading to localized renewable-based power markets. Though this shift has resulted in prosumers, many end-users may remain as consumers, due to socio-economic conditions, who depend upon either utilities or prosumers for their energy needs. For this reason, localized power markets have been emerging lately, where the transfer of energy can occur among the end-users with the help of a peer-to-peer (P2P) energy trading platforms, e.g., power ledger. P2P energy trading is a free-market system that allows end-users to trade excess electricity with neighbours through a bidding model. Though the P2P markets may help manage the distributed generation of electricity, the issues such as trading prices, end-users priorities and behaviours, trading governance, network structures, energy billing still exist and influence their feasibility. Hence, this study explores the performance of a P2P market considering rooftop solar photovoltaics for distributed power generation through an Agent Based Model (ABM) to simulate a real-world implementation and quantify its techno-economic performance.

Data Collection, System Design and Methods

A preliminary survey is performed to identify a set of cities in India that experience the most power outages. The data for modelling rooftop solar photovoltaic system energy systems include the number of houses in the selected city, rooftop areas for each house and weather data experienced by each house (e.g., solar radiation, wind speed, ambient temperature). For the cities selected in our study, the data collection for the aforementioned parameters has been performed. In addition, the data on central and state-level subsidies and feed-in tariffs are collected for economic feasibility assessment.
The system design includes the sizing of rooftop solar photovoltaic array specific to end-user requirements (prosumer and consumer) along with storage units.

Then, the localized power market pool of various prosumers and consumers is created along with the power transmission network by following individual end-user behaviours. To allow the end-users and utility interaction, we developed a blockchain-enabled P2P power market governance system architecture.

We applied the ABM approach to simulate the end-users, followed by techno-economic, to understand the influence of end-user behaviour on performance and proposed system feasibility.

Results and Conclusions

The simulated interactions of end-users gave insights regarding the localized electricity market pool and the alternative governance structure of the P2P network. The ABM simulation results include the net energy, energy prices, and sold energy within and out of the market pool. We also observe that the dynamics of electricity prices are influenced by the physical arrangement of the P2P network. In addition, the technical parameters in the design aspects of the rooftop solar photovoltaic system have also influenced the prices and energy available for initiating the trade transactions at the prosumer and consumer level. The economic assessment results revealed that individual end-users could make a reasonable amount of revenue after the payback period. The proposed blockchain-enabled P2P transactions has eased the participation of end-users in the localized market.

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Angelo Facchini, Alessandro Rubino, Alfonso Damiano
IMPACT OF INCENTIVE REGULATION FOR BATTERY SIZING AND MANAGEMENT

Angelo Facchini, IMT School for Advanced Studies Lucca, Italy
Alessandro Rubino, University of Bari, Italy
Alfonso Damiano, University of Cagliari, Italy

Smart grids and battery energy storage systems are rising in importance both for technical and economic aspects as they can enable a series of services such as active demand response, load peak reduction or mitigation, and improved voltage stability etc. However, the economic viability of distributed generation coupled with storage systems is still being debated, as hidden costs associated to their use are complex to consider and remain difficult to evaluate ex-ante, limiting the large-scale penetration of electrochemical storage technologies. This paper proposes a method for the planning and the real time management of electrochemical storage systems tested in the operation of a microgrid acting as a virtual power plant. Under the planning point of view results show that storage sizing is critical, as it is observed that the larger is not the better, while an optimal size must be tailored for each specific application case. WE explore the impact of the economic incentive established in the Italian setup, to evaluate the economic sustainability of energy storage infrastructure in a microgrid setting.

Ionut Purica
THE ELECTRICITY MARKET: RISKS AND OPPORTUNITIES: DYNAMICS OF POWER MARKETS AND COMPETITION

Ionut Purica, Hyperion University /Advisory Center for Energy and Environment, Romania,

The reform of a one player power sector (i.e. a natural monopoly) into a multiple players' power market brings to the clients not only the benefits of competition but also the costs of complexity. In between the two, an optimal number of players is found in the market corresponding to the minimum price of power to the clients. Considering time as the third dimension, the optimum curve becomes a potential surface on which the evolution of the market entities is seen as oscillations along the valley of minimum price. Every oscillation triggers a price burst which is detrimental to the clients. To avoid this, the role of the regulator is better defined in the sense of smoothing the transition from monopoly to market. The example of the US power sector evolution is relevant here. In the above approach long range competition resulting from the future opening of power markets in Europe, or from the penetration, 70 years ago, of the interconnection technology in USA, is compared with the short range (local) competition. Finally, the price limits are determined which ensure that (i) the new entrants on the market are not eliminated and, (ii) that the market avoids oscillations which may drastically shock a non-resilient economy. A case study calculation is done for Romania and a method is proposed where the cost of complexity is assessed based on the ratio of traded energy to consumed one i.e. more traded energy means that the price increases with every transaction that is not bringing the energy to the consumer but to other traders. An example Is presented for the present open market of Romania.

Karim L Anaya, Michael G Pollitt

THE VALUE OF FLEXIBILITY: A COST BENEFIT ANALYSIS OF MERLIN PROJECT

Karim L Anaya, University of Cambridge, UK
Michael G Pollitt, University of Cambridge, UK

Overview

The integration of distributed energy resources (DER) and changes in consumers patterns are changing the way in which distribution utilities are operating and managing their networks (i.e. too much generation and lower levels of demand). Utilities can take advantage of these changes by opting for less traditional solutions such as contracting flexibility services to solve grid constraints, instead of reinforcing it. The democratisation of smart technologies is facilitating the management and trading of flexibility services provided by DER and demand customers (Anaya and Pollitt, 2021a). Regulation also plays an important role because it may encourage distribution utilities to experiment via innovation projects that help to test smart solutions and new business models, which contributes to shape their future operation. Flexibility market design is still a work in progress across many jurisdictions and it is not clear yet whether these markets are cost effective at a sustainable scale (Anaya and Pollitt, 2021b). This paper assesses the value of flexibility services under the context of one such innovation project.
The aim of this paper is to quantify and compare different intervention models to deal with thermal constraints in Fort William region, in the context of Project Merlin, which is being implemented by Scottish & Southern Electricity Networks (SSEN), a distribution utility from the UK.
A social cost benefit analysis (SCBA) for the period 2026-2035 is performed for this purpose based on the Common Evaluation Methodology (CEM) CBA tool developed for the Energy Networks Association – ENA (Baringa, 2020). The benefits are represented by the net present value (NPV) difference of the baseline approach (i.e. traditional solution) and other alternative options such as the procurement of flexibility services. The traditional solution in this study suggests the upgrade of two conductors, at 11kV and 33kV among other assets (SSEN, 2021)
The first part of the analysis was made using a realistic approach. This means actual power flow under normal operating conditions (i.e. consideration of both load and generation) was assumed. The scenario used for forecasting generation and load growth was the National Grid ESO Future Energy Scenarios (FES): Community Renewables (NGESO, 2019). Accordingly to SSEN, the realistic approach is not currently applied by them but in the future, there is a chance to adopt it if there is enough liquidity in the market. Based on this statement, we have assumed that only utilisation payments will be paid to flexibility providers. In the second part of the analysis, the worst-case approach is evaluated (which is a work in progress) and involves the upgrade of additional assets, then reinforcement costs are higher than those identified in the first approach. We will proceed then to compare the value of flexibility using both approaches.

Methods

A SCBA method is used to estimate the value of flexibility services as an alternative to more traditional solutions. The SCBA allows to compare different models of intervention including traditional (business as usual - BAU solutions) ones and alternative network intervention ones such as the procurement of flexibility services (e.g. storage units, controllable loads, demand response).
The SCBA estimates NPV of the different models of intervention in a specific time horizon (i.e. lifetime of the assets involved). A straight-line depreciation approach is applied, then network assets are assumed to be depreciated gradually over their useful economic life (set at 45 years). Capitalisation assumptions are applied to financial costs (Ofgem, 2021).
The benefits are given by the NPV difference of the BAU or traditional solution and other alternative options. In this study, the BAU solution implies the upgrade of the conductors, 11kV and 33kV, in the presence of thermal constraints. The alternative network intervention is given by deferring for 1 or more years the upgrade of the asset and contracting flexibility services during those years to deal with the constraints.

The analysis is made separately per each type of asset. A set of sensitivities was selected for analysing the value of deferring the conductor upgrades, a central case is also proposed.
The CBA involves three scenarios. Scenario 0 (baseline) represents the BAU (i.e. upgrade of conductors). In Scenario 1 flexibility services are contracted to deal with thermal constraints on both conductors. Scenario 2 is similar to Scenario 1 but includes societal costs or benefits (e.g. emission costs due to power losses and community generation credit).

Results

Initial results suggest that at 11kV flexibility does not bring value. One of the reasons behind this is the use of the realistic approach in the power system analysis, which requires much lower level of investment in comparison with those that are based on worst-case scenarios. The number of violation events is very high too, which means that flexibility services would be continuously required, consequently flexibility procurement costs increase importantly. The introduction of societal costs/savings does not increase the cumulative NPV.
In relation to the 33kV, savings from procuring flexibility as an alternative option of network investments are still very low or non- existent, even with the consideration of the lowest utilisation price (set at £25/MWh). In this case, we have larger reinforcement costs and a smaller number of violation events.
When the societal savings/costs are included in the analysis, the cumulative NPV is reduced slightly across all the time horizons and deferral durations.
We also observe that in both cases (11kV and 33kV conductors), savings increase without the consideration of network losses. This happens due to the type of upgrade suggested such as the replacement of conductors (the new conductors have higher ratings than the existing ones). During the years that we defer the upgrade, we will continue using the current conductor (with high and increasing network losses) and contracting flexibility (which can be very costly), then an increase in NPV is expected.

Conclusions

Our initial conclusions suggest that the value of flexibility is quite small, regarding the realistic approach. It might be different with better performing existing conductors and more expensive replacement assets. What we model is a situation where the requirement for flexibility is high and hence the operational cost of this is also high. An alternative setting where the quantity of flexibility required was low and the existing assets were performing better would make the NPV of a flexibility solution higher.

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Sania Wadud, Marc Gronwald, Robert B. Durand, Seungho Lee

CO-MOVEMENT BETWEEN COMMODITY AND EQUITY MARKETS REVISITED – AN APPLICATION OF THE THICK PEN METHOD

Sania Wadud, University of Aberdeen and Curtin University, UK
Marc Gronwald, International Business School Suzhou, Xi'an Jiaotong-Liverpool University, UK
Robert B. Durand, Curtin University, Australia
Seungho Lee, University of Aberdeen, UK

Overview

The dynamics of price, or return, correlation plays an important role in energy and non-energy commodity,and equity investing. Increasing interconnectedness between the returns across commodities (Tang and Xiong 2012; Bhardwaj, Gorton, and Rouwenhorst 2015) and between commodities and equities (Büyükşahin and Robe 2014; Bruno, Büyükşahin, and Robe 2017) since financialisation of commodities (2004) (Tang and Xiong 2012), a phenomenon of increasing non-commercial investors in commodity derivative markets, or later during the Global Financial Crisis (GFC in 2008) (Büyükşahin and Robe 2014) offer less diversificationbenefits for investors. The change in co-movement between commodity futures and equity market since financialisation may lead to a change in the equilibrium levels of codependency. This may later reflect in price information of commodities when it is important that commodity prices particularly oil price should reflect its economic fundamental price. Hence, we investigate dynamics of return co- movement between commodity futures and equity markets in different frequencies including short-run and long-run components of co-movement.

Our empirical strategy is inspired by Barberis, Shleifer, and Wurgler (2005) and Bonato and Taschini (2018).Barberis, Shleifer, and Wurgler (2005) show that the co-movements between a stock and the equity index are greater when the stock is included in the equity index than the stock is excluded. Similarly, Bonato and Taschini (2018) show that the price co-movements of index commodities are greater than off-index commodities. Likewise, we assess the differences between the index and off-index commodity co-movements with the equity index. In the context of the financialisation of commodities, Wadud, Durand, and Gronwald (2021) explore the interconnectedness between commodity futures and equity index by using the VAR-DCC- GARCH approach. In a similar vein, we investigate whether and how the change in return co-movements between energy commodity futures and equity index differ from non-energy commodity-equity co-movements concerning financialisation.

We assess return co-movement between 22 commodity futures and equity index using a novel nonparametric approach called the 'Thick Pen Measure of Association (TPMA)' of Fryzlewicz and Oh (2011) and later extended by Jach (2021) to 'Multi-thickness Thick Pen Measure of Association (MTTPMA)' to provide new insights on the changes in the co- movement dynamics following the

financialisation. To the best of ourknowledge, we are the first to apply this technique in measuring commodity-equity co-movements. Multi-thickness
Thick Pen Measure of Association as a standard measure for quantifying co-movement can i) be employed to both stationary and non-stationary data, (ii) be employed to multiple time series, (iii) be time-varying, (iv) capture co-movement in a given time scale and (v) measure codependency in multi time scale (Jach 2021, 1). TPMA technique allows usto empirically examine co-dependencies between the commodity futures and equity index for a given time scale or for a range of time scales, whereas MTTPMA technique allows to examine the co-dependencies to across different time scale, that is capturing short-term component of commodity futures series with long term components of an equity index or the other way around.
Following Fryzlewicz and Oh (2011) and Jach (2021), we measure co-movements between the commodity futures and equity index. We calculate the Thick Pen Measure of Association (TPMA) of Fryzlewicz and Oh (2011) using [12]

$$\rho_t^{\tau}(X^{(1)}, X^{(2)}, \ \ , X^{(k)}) = \frac{min_k\left(U_t^{\tau}(X^{(k)})\right) - max_k\ \left(L_t^{\tau}(X^{(k)})\right)}{max_k\left(U_t^{\tau}(X^{(k)})\right) - min_k\ \left(L_t^{\tau}(X^{(k)})\right)}$$

where, $X = \ (Xt)_{t=1}^{r}$ represents time series of weekly log returns; K = 23 which represents 22 commodities and the S&P500 index; τ_i is positive thickness parameter (scaler superscript) i.e. $\tau = 1$ is week 1 data, $\tau = 4$ is month 1 data and $\tau = 52$ is year 1 data.
L_t^{τ} = min $(X_t, X_{t+1}, \ldots, X_{t+\tau})$ shows lower boundaries of thickness and
U_t^{τ} = max $(X_t, X_{t+1}, \ldots, X_{t+\tau})$ shows upper boundaries of thickness.

$$\rho_t^{(\tau(1),\tau(2),\ldots.\tau(k))}(X^{(1)}, X^{(2)}, \ \ , X^{(k)}) = \frac{min_k\left(U_t^{\tau}(X^{(k)})\right) - max_k\ \left(L_t^{\tau}(X^{(k)})\right)}{max_k\left(U_t^{\tau}(X^{(k)})\right) - min_k\ \left(L_t^{\tau}(X^{(k)})\right)}$$

where, scaler τ of Equation 1 is replaced by vector τ in Equation 2.

Results

The empirical result suggests that there is an increased association between equity and energy index futures, non-energy futures, and some off-index commodities since the financialisation of commodities.
Particularly, we find MTTPMA of crude oil- equity are higher on average than other commodities. In the majority of cases, the dependence between equities and energy and non-energy commodity futures are found to be weak during 2002/2003 for which financial investors started to invest in commodities around 2004 which has consequently increased the co-movement between the equities and commodities. In the long term time scale, we find weak co-movement between the equity index and softs and livestock futures.

[12] see Jach (2021) for details of the model

This indicates that there is an opportunity to diversify the portfolio using softs and livestock for long-term investors. Similar to Jach (2017), we also find some evidence where the TPMA measure of a given scale resembles results of the MTTPMA measure of cross-correlation. Comparing our results with Wadud, Durand, and Gronwald (2021), we find similar results of

interdependencies of commodity futures-equities. Additionally, the results showthat in short term (i.e. in higher frequencies) co-movements are lower than of longer-term (i.e. in lesser frequencies) co-movement.

Conclusions

Our study reveals that TPMA and MTTPMA measures are promising techniques to quantify cross-dependency between series. The results of using this technique provide new insights into the interdependence between equity and energy and non-energy commodity futures uncovering asymmetric effects of the short-term and long-term features of co-movement. We find that there is a benefit of diversifying by combining equity and off-index futures in the short term as well as in the long term. These results are beneficial from both short-term and long-term policy perspectives. This method can help to formulate a trading strategy for energy-based companies. In the long run, energy futures and equities co-move to a larger extent, which has potential effect. While most of the energy companies invest in higher return projects on a long- term basis, switching to renewable investment would limit their higher return. In such cases, the long-term feature of the data is relevant for making long-term decisions.

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Sigit Perdana, Marc Vielle

CARBON BORDER ADJUSTMENT MECHANISM IN THE TRANSITION TO NET-ZERO EMISSIONS: COLLECTIVE IMPLEMENTATION AND DISTRIBUTIONAL IMPACTS

Sigit Perdana, LEURE Laboratory, Ecole Polytechnique Fédérale de Lausanne (EPFL), CH-1015 Lausanne, Switzerland
Marc Vielle, LEURE Laboratory, Ecole Polytechnique Fédérale de Lausanne (EPFL), CH-1015 Lausanne, Switzerland

Overview

As an instrument to minimize carbon leakage, the effects and feasibility of Carbon Border Adjustments Mechanism (CBAM) will depend on multiple design options. While the EU has committed to introducing CBAM as part of its green climate deal, pursuing climate efforts to limit global warming successfully requires a collective implementation involving major emitters China and the US. This paper quantifies the distributional impacts of a joint CBAM implementation in a climate club (Nordhaus, 2015) with the member of the EU, the US, and China. Differing from a myriad of studies that focus on unilateral CBAM, this analysis emphasizes collective implications on leakage, sectoral competitiveness, and welfare by projecting climate neutrality relative to current policies and National Determined Contribution (NDC) targets as reference cases. The scope of analysis also covers the decomposition of leakage channels, the comparisons between the alternate methods of implementation, and methodologies of emissions contents that comply with the European Commission's proposal and WTO proof.

Methods

This study uses the latest modification of GEMINI-E3 based on the study of Bernard and Vielle (2008). The model incorporates multi-country, multi-sector, recursive dynamic computable general equilibrium model with backward-looking (adaptive) expectations. The current version is built on the GTAP 10 data base (Aguiar et al., 2019) with the year 2014 as the reference year. For analytical purposes, the regional aggregation of this version covers the EU, the US, China and the rests of the world which is represented by 8 countries and regions. Scenario design for reference case uses a more updated complementary climate-development of CD-Links policies database (McCollum et al. 2018, Roelfsema et al. 2020), with harmonized assumptions detailed in our previous work of Giarola et al. (2021).
Methodologies for leakage, welfare and sectoral decompositions follow our previous work on Li et al. (2021), while scenario designs of policy scenario with CBAM are developed from Cosbey et al. (2019).

Results

- In achieving net-zero emissions, stringent climate ambitions in the EU, China and the US indicate positive GHG emissions change in all other regions, confirming the leakage. But the decomposition does not identify dominant channel of leakage between energy production and production. Leakage caused by reallocating production Energy Intensive Industries (EII) becomes significant especially to Brazil, Russia and Middle East.
- It follows that the implementation of CBAM has to be applied only in EII in order to be effective in reducing leakage and protecting domestic production. Add to this, switching from a direct carbon content basis (scope 1) to include the electricity consumption (scope 2) in calculating CBAM tariff, significantly reduces leakage and increases EII's production. Extending to include indirect emission contents (scope 3) gives insignificant change in results. These findings contradict the recent EC proposal on CBAM to use only direct carbon contents to both EII and electricity sectors.
- Implementing CBAM in a coalition (or forming climate club), reduces more leakages, improves productivity on energy intensive industries, and increases club's welfare relative to a non-CBAM and a unilateral implementation. Gains on trade improves welfare for the US, while the negative deadweight loss of revenue gained from import tax is more dominant for the EU and China. CBAM may increase the comparative advantage and competitiveness but reduces the output value due to the negative Income Effect of post-import tariff on imported intermediate goods.

Conclusion

Our findings confirm that a coalition reduces leakage, improves productivity on energy intensive industries, and increases clubs' welfare relative to a non-CBAM and a unilateral implementation. These are in contrast with some unilateral analytical studies, especially for the US. The effects are robust for EII. Our analysis confirms of the potential of CBAM as collective instruments to facilitate mitigation and trade competitiveness.

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Carlo Andrea Bollino

EXERCISE OF MARKET POWER DURING COVID-19 PANDEMIC LOCKDOWN

Carlo Andrea Bollino, University of Perugia, Italy

The Italian electricity market was characterized by a remarkable decrease in demand during the COVID-19 lockdown (10 March to 2 June 2020). There were also negative peaks of over 50% and record low prices of about 20 Euro/MW.

This paper aims to investigate the exercise of market power in the Italian power exchange during the pandemic, explicitly considering transmission line congestion, and disentangling the measure of the unilateral market power from congestion rent and re-dispatching costs. We computed the Zonal Lerner Index for every hour in January–June 2020 for the main operators on the supply and the demand side in the Italian day-ahead market. Furthermore, we analyzed the correlation between market power, congestion, and the effect of COVID-19.

The results showed that the exercise of market power on the supply (mark-up) and demand (mark-down) sides were considerably weakened during peak hours by massive demand reduction. However, it was surprisingly reinforced during emergency periods in specific off-peak hours. Overall, the main players have somehow increased the intensity of market power during the COVID-19 pandemic crisis, which calls for more pro-competitive action by the regulatory authority and paying more attention to heterogeneous players' behaviors.

Amsalu Woldie Yalew

ENERGY, ECONOMIC, AND ENVIRONMENTAL ACCOUNTING FOR BIOMASS FUELS IN ETHIOPIA

Amsalu Woldie Yalew: Ca' Foscari University of Venice, Via Torino 155, 30172 Venice, Italy
Euro-Mediterranean Center on Climate Change, Via della Libertà 12, 30175,Venice, Italy
RFF-CMCC European Institute on Economics and the Environment, Via della Libertà 12, 30175 Venice, Italy

Overview

Energy production and consumption are inextricably linked with the economy and the environment. The energy-economy-environment (E3) nexus is particularly important in developing countries like Ethiopia where access to electricity and other modern energy sources remains limited. Electricity and biomass fuels, respectively, contribute to 3% and 88% of the total energy supply in Ethiopia (MoWIE, 2019). Moreover, roughly one third of wood fuel comes from unsustainable extraction in forests and woodlands (MoFECC, 2017). Forest degradation from fuelwood consumption is one the major sources of GHG emissions (FDRE, 2021). In a country where 93% of the households use solid biomass fuels for cooking (CSA and ICF, 2017), the indoor $PM_{2.5}$ concentration is more than 30 times higher than the WHO standard values (Adane et al., 2021), and causes about 5% of the disease burdens (Sanbata et al., 2014). It is therefore imperative to assess the biomass fuel situation in Ethiopia. Linking energy with economic and environmental accounts is crucial to formulate policy responses to energy-related environmental issues (SEEA-Energy, 2019). This study attempts to provide estimates of energy, economic contribution, greenhouse gases (GHG), and particulate matters (PM) emissions from stationary combustion of biomass fuels. The estimates are built around the 2015/16 Ethiopian fiscal year.

Method

We considered four solid biomass fuels (firwood and charcoal, crop residues, and dungs) consumed by households and services (commercial and public institutions) sectors. Then, for each fuel type, energy consumed (EN) is obtained by multiplying the mass of biomass fuel consumed (BM) by energy content per weight of a fuel (ec). The consumption data are obtained from various sources (MoWIE, 2019; AFREC, 2019; MoFECC, 2017; EUEI, 2013). Economic values (EC) are obtained by multiplying the biomass fuel consumed (BM) by the price of a fuel per ton of a fuel (p). Emission of a specific pollutant from combustion of a specific fuel (EM) is computed as a product of emission factor (ef) and energy consumed (EN). The emission factors are obtained from IPCC (2006) for GHG gases and Amaral et al. (2016) for PMs.

$$EN = ec.BM \quad [1]$$
$$EC = p.BM \quad [2]$$
$$EM = ef.EN \quad [3]$$

Results

Different studies give different estimates of biomass fuels consumption. To retain these possible ranges, the calculations and analysis of the energy consumption, economic contributions, and environmental emissions are built around these original data sources. The total annual solid biomass fuel consumption ranges from 94.6 million tons (MoWIE, 2019) to 125.1 million tons (EUEI, 2013). The equivalent energy consumption is estimated to range from 33,327 ktoe (MoWIE, 2019) to 44,547 ktoe (EUEI, 2013). Firewood is the main biomass fuel as it accounts for 62% to 76% of the total biomass fuels consumed. Households consume about 99% of the total biomass fuels. The sum of economic values of biomass fuels ranges from USD 3.3 to 5.7 billion. These are equivalent to 4.4 to 7.7% of the 2015/16 GDP. Firewood followed by animal dungs takes the biggest share. The average ratio of fuelwood (firewood and charcoal) to GDP is around 4%. The total GHG emissions from stationary combustion of the biomass fuels range from 165 to 219 Mt CO_2eq. The emissions of $PM_{2.5}$ pollutants range from 1.2 to 1.5 Mt. The average emissions of PM_{10} and TSP are 0.35 and 0.50 Mt, respectively. Applying a conversion rate of fuelwood demand to forest/woodland (122 ton/ha, FAO, 2020), meeting annual firewood demand in Ethiopia may induce forest/woodlands degradation of 555 to 642 thousand ha.

Conclusions

The study attempted to link biomass energy with the economy and environment that can be a starting step for future research aimed at accounting and modeling the Ethiopian energy system in line with the SEEA-Energy and E3-nexus approaches, respectively. The results suggest that policy measures aimed at reducing the reliance on biomass fuels have profound implications on the environment, agriculture, and health sectors. Reducing biomass fuel consumption contribute to reduce deforestation and thus underpins the country's ambitious mitigation plans, to use agricultural wastes to enrich soil fertility, and to reduce respiratory infection disease burdens. Therefore, measures to increase households access to cleaner sources of energy and the use of Improved Cooking Stoves (ICS) should be strengthened. Currently, barely 5% of the households use electricity for cooking while only 18.2% of households use a manufactured stove (World Bank, 2018). Compared to traditional cooking stoves, ICS can save the quantity of biomass fuel by up to 31% and reduce $PM_{2.5}$ emissions up to 50 to 58% (Adane et al., 2021). Ethiopia could reduce its total biomass energy consumption by 25–30% and its annual CO_2eq emissions by 18–22% using effectively about 10 million ICSs (Wassie and Adaramola, 2021).

Acknowledgment

This work has received funding from the European Union's Horizon 2020 Research and Innovation Programme under the Marie Skłodowska-Curie Grant Agreement No. 886309. The funder had no role in study design, data collection and analysis, decision to publish, or preparation of the manuscript.

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LIQUID ALTERNATIVE FUELS FOR TRANSPORT DECARBONISATION: MEETING THE FIT-FOR-55 GOALS

David Chiaramonti, Department of Energy Engineering (DENERG),Politecnico di Torino,
Corso Duca degli Abruzzi 24, I-10129, Torino, Italy.
Carlo Cambini, Department of Production and Management Engineering (DIGEP), Politecnico di Torino
Matteo Prussi, Department of Energy Engineering (DENERG), Politecnico di Torino
Chiara Ravetti, Department of Production and Management Engineering (DIGEP), Politecnico di Torino

Overview

The transport sector is crucial for our modern economy, but serious concerns about its environmental impacts significantly grew in the last decades. While the passenger car segment seems to be able to implement a wide set of possible technical solutions (electrification, H2, hybridisation, etc.), this cannot be said for road heavy duty, aviation and maritime. Due to the need of highly energy-dense fuels, freights and passenger aviation are still expected to rely on liquid alternative fuels for the medium term. Under the EU Green Deal, the package Fit-for-55 contains specific initiatives to tackle the decarbonisation of these transport modes, promoting the use of alternative fuels, in particular the initiative Fuel EU maritime and the ReFuel EU aviation. Europe has been a leding contributor to policy development on biofuels for decades, and new targets were set by REDII recast. Here, new categories of fuels were introduced, namely RFNBIO and RCF. These groups were meant to encompass innovative technologies and pathways for liquid fuels productions from waste streams, and renewable electricity. While the introduction of sustainable liquid alternative fuels is becoming increasingly feasible from a technical point of view, it still remains too expensive at current market prices and poses important challenges from a policy perspective to incentivize their adoption, because the additional costs for biofuels and alternative energy sources entails risks for competitiveness and thus for connectivity of the countries introducing stronger regulations.

Methods

A comparative assessment of the key policy choices involved in the introduction of alternative (bio)fuels in the transport sector is carried out, with a specific focus on the European aviation and maritime sectors. We consider the current certification options for new fuels, the mandates needed to promote uptake given current and projected supply and demand, and different regulatory settings to ensure a level playing field.
The analysis of policy options accounts for the different cost structures of production pathways for different fuels, both for technologies already available in the short term, such as HEFA, Fischer-

Tropsch, Alcohol-to-jet, etc, and for technologies commercially available in the medium term (i.e. post 2030-2035) such as those of non-biological origin (e.g., H_2, e-fuels/power to liquid).
We review the specific measures and policy design that can be implemented to enforce SAF mandates, in terms of volume-based approaches, CO_2 intensity approaches, with obligations for suppliers or for the demand side (ports or airports), and the possibility of additional uplift obligations to prevent distortionary practices (such as "tankering" of dirty fuels outside of EU ports and airports).

Results

Production capacity for sustainable aviation fuels does not seem to be a limiting factor to date, but it could soon become necessary to increase investments and significantly in order to achieve the goals set for 2050. Since the transition to massive use of alternative fuels requires significant capital expenditures, it is essential that the regulatory framework provides an organic and stable set of rules with a long-term perspective. In particular, it is essential to prevent individual Member States from creating of a mosaic of disharmonious measures. An element that today is hampering the development of a common understanding about the potential and the limitations of alternative fuels is the use of an uneven set of terms, often referring to the same production pathways: e-fuel, Ptl, RFNBIO, SAF, etc. are just some examples. While in Europe the REDII sets the regulatory guideline, at international level the regulatory framework presents several issues. A good example is the international initiative on aviation decarbonisation (ICAO/CORSIA), where alternative fuels are clustered under the generic term Sustainable Aviation Fuels (SAF). These are defined as renewable or waste-derived aviation fuels that meet the CORSIA sustainability criteria, which however are different for EU REDII ones. The need for harmonisation is relevant especially in light of the mandates currently under discussion in Europe (e.g., the 5% by 2030 in the Fit-for-55 package), that will have to co-exist with international initiatives. The use of alternative fuels in aviation is in fact expected to rump-up significantly, in the next year. However, the impact of this on the airport rights and/or airline tariffs is far from being determined, and it depends on the regulatory framework adopted in each member state. The expected raise in airline tariffs (potentially, around 20/30%) should be compensated by reductions in airport rights, but this needs to be accounted for by national regulators and Ministries through ad hoc incentives that have not yet been designed. These policy issues are today at the center of the debate by a large number of policy makers.13
Furthermore, in order to encourage the development of new fuel supply chains based on zero-/low-emission technologies, three crucial policy actions are needed: the promotion of the updating of the ASTM standard, the implementation of national or European Clearing Houses for new fuels, and the strengthening of the collaboration between companies, institutions and the world of research.

[13] The Italian Ministry of Trasport and Sustainable Mobility is creating an ad hoc research group on this issue to completely rewrite the regulatory framework for airport charges to incorporate specific incentives to sustainable fuels.

Regarding the latter point, trends in patents and research already show that EU leadership has been declining in this field over time as China, India and Brazil are rapidly increasing investment in alternative liquid fuels' research.

Conclusions

Even if several technologies and processes for the production of sustainable fuels are already certified or in the process of being certified, their current use is still almost negligible, mainly (but not only) due to the current high production costs. Thus, the role of policies and regulations in this sector cannot be understated: transparent and coordinated actions can guarantee a growing demand, defined by specific mandates, could stimulate the creation of new production capacity and lead to economies of scale and a reduction in costs. Without strong political support to bridge the price gap between alternative fuels and conventional fossil fuels, the use of these energy sources in hard-to-decarbonize transport sectors and their environmental benefits will remain limited.

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Luca Bacchi, Giampaolo Annoni, Marino Crespi
H2 PIPELINES? NOT A NEW ISSUE: THE SNAM EXPERIENCE

Luca Bacchi, Snam, Italy
Giampaolo Annoni, Snam, Italy
Marino Crespi, Snam, Italy

Overview

Current demand for decarbonized sustainable energy gives to hydrogen a very important role. Hydrogen it's not only a clean energy vector, it can be also a very strategic solution because of the availability in Europe of already existing pipelines operated with natural gas that can be rehabilitated to hydrogen transmission.
Snam asset is nowadays composed by a huge network of pipelines crossing all Italy from the Sicily to the Alps, connecting North Africa in the South and Europe in the North.

Methods

Carbon steel has been used for the transportation and storage of hydrogen for over a hundred years. Nowadays more than 4500km of hydrogen pipelines are in operation worldwide. The use of carbon steel pipelines to carry hydrogen is not a new issue!
A technical standard (ASME B.31.12) is already available with the technical rules both for the design of new hydrogen pipelines and for the rehabilitation of existing pipelines. The conversions criteria assure the same high levels of safety and reliability of the assets currently operated with natural gas.

Results

SNAM is applying the available technical standards for the conversion of its pipelines to hydrogen. This detailed analysis allows to establish, according to the standards, the operating conditions that can be applied to each single converted pipeline (maximum allowable operating pressure and gas mixture).
At the time of writing this paper, because of the new role of hydrogen in the energy transition, many studies and experimental research projects are ongoing in order to put together the best practices and to build new and updated guidelines (reliable, practical and not over conservative) for the conversion to hydrogen of the existing pipelines. An ad hoc European technical standard is looked for by the industry in order to harmonize these approaches also in a European technical reference.

Conclusions

he use of carbon steel pipelines for the transmission of hydrogen is not a new issue. The design of new hydrogen pipelines and the rules for the conversion of existing ones are already included in technical standards that can be applied by the industry.

The paper summarizes the SNAM current activity related to the characterization of its operating network for the use with hydrogen according to the current technical standards. Furthermore, a more long-term road map on the same topic is reported, taking in account the expected updates of the technical standards that could result from the ongoing research projects.

Kaase Gbakon, Joseph Ajienka, Joshua Gogo, Omowumi Iledare

ESTIMATING UPSTREAM OIL PRODUCTION COST FOR OPTIMIZED OIL ALLOCATION: THE NIGERIA CASE

Kaase Gbakon, Emerald Energy Institute, University of Port Harcourt, Nigeria
Joseph Ajienka, Emmanuel Egbogah Chair & Professor of Petroleum Engineering, University of Port Harcourt, Nigeria
Joshua Gogo, Emerald Energy Institute, University of Port Harcourt, Nigeria
Omowumi Iledare, UCC Institute for Oil and Gas Studies, Cape Coast, Ghana

Overview

In developing the framework within which produced crude oil can be optimally delivered to consumers to meet the objective of maximizing the total producer and consumer surplus, it becomes important to ascertain the unit cost of upstream oil production in Nigeria. This paper further derives its impetus from the importance of the unit cost of production metric within the Nigeria jurisdiction as evidenced for example by the assertion contained in the Nigerian National Oil Policy document of 2016 that the cost of producing a barrel of oil in Nigeria at $29/bbl is amongst the highest in the world with peer comparisons showing Saudi Arabia ($8.98/bbl), Indonesia ($19.71/bbl), Brazil ($34.99/bbl) and UK ($44.33/bbl). The unit cost of production metric refers to the total costs required to achieve a given production level which is typically expressed as $/bbl or $/boe. It is an important metric as it impacts project profitability, ability of projects to attract finance, the quantum of tax available to government, ability to balance the budget of a resource dependent state and furthermore, determines the attractiveness or otherwise of energy alternatives.

Methods

In this assessment of unit production costs, we take advantage of the analytical framework for the assessment of the Petroleum Profit Tax (PPT) as contained in the Petroleum Profit Tax Act (Nigeria's Tax code for the assessment of upstream tax). We take the annual PPT receipts as obtained from the Federal Inland Revenue Service (FIRS), oil Royalty receipts from the Department of Petroleum Resources (DPR) and national oil production numbers from the NNPC (State Oil Company) over the period from 2010 to 2019. Our method relies on the analytical framework within the tax code to deduce (or work backwards) the "global" upstream production costs as implied by the fiscal receipts over our period of interest. Furthermore, we note that over our chosen time frame, there have been no structural changes in upstream PPT assessments which is an important consideration for our method.

This method differs from the approach adopted in Gbakon (2017), Toews and Naumov (2015), and Kaiser (2007) in which variables such as oil price, terrain, well type, and peak production are used to explain production costs within an econometric context.

Results

On the basis of the above methodology, we estimate that Nigeria's implied global upstream costs declined from \$54.37Billion (2010) to \$34.32Billion (2019). In unit terms these correspond to \$60.67/bbl (2010) to \$46.48/bbl (2019). Furthermore, we establish that these unit costs on average over the period represent 67% of oil price. Turning our attention to the oil royalty, which is one of the deducts prior to establishing the PPT, we find that the effective oil royalty rate ranges from 4.96% to 8.23%. Furthermore, based on the quarterly PPT and oil production data we collected, we took the opportunity to conduct a multivariable regression of PPT on oil price and production. What we find is that oil price exerts the larger impact on tax receipts than oil production – specifically a 10% increase in oil prices will lead to a 16.6% increase in PPT while, 10% increase in oil production leads to a 2.64% increase in PPT.

Conclusions

The mathematical programme which we formulate for the optimal allocation of crude oil to different utilization options to meet petroleum product demand requires a upstream production cost as a key input. Recognizing the import of the unit production variable to our optimization problem specifically, and to the broader issues bordering on project viability, and government receipts generally, we are able to deduce these costs based on combination of PPT and oil royalty receipts as well as national production. Our preliminary results show that PPT is more responsive to oil price than production and that unit costs in Nigeria (as implied by tax receipts) can be up to 67% of oil price.

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Olivier Massol, Arthur Thomas, Quentin Hoarau

WHO REFINES OIL AND WHY: DISENTANGLING INVESTMENT DECISIONS FROM COUNTRIES AND COMPANIES

Quentin Hoarau, CentraleSupelec, France
Olivier Massol, IFP School, France
Arthur Thomas, ENSAE, France

Overview

Oil still represents a third of gross energy consumption worldwide. Crude oil is one of the most scrutinized commodity, contrary to the products from its downstream industry. In the academic field, little is known on the economics of oil refining. A first approach of the field comes from the energy economics literature (Ghodussi & Wirl, 2021). Oil refining can be seen has a risk-hedging strategy. Indeed, while crude oil offers much stronger returns, oil products show much less volatity in internation markets. Second, the development economics literature has investigated the role of resource-based industries as a robust industrialization strategy (Owens & Woods, 1997). We contribute to both streams of literature by investigating the determinants of investments in expansion in capacity of oil refining. We aim at answering at the following questions. What drive investments at the country-scale : lowering imports, increasing exports, stimulating local consumption? At the company level, we aim at understanding the difference of strategies between firms. For instance, do government-owned firms invest more than private ones?

Methods

We combine several data sets from several sources. First we use the data from the *Oil & Gas Journal* which provides plant-level data on refineries. These include location (city level), total capacity of the refinery. Second, we use data from the IEA for aggregate data at the country scale on imports, exports, consumption and production of refined oil products and crude oil. Third, we include data from the EIA on oil reserves estimations. Fourth, we include socio-economic data from the World Bank. Fifth, we add bilateral trade data on oil products and crude oil from CEPII. Our final panel data contains around 2000 country-year observations, from 1991 to 2019 over 80 countries. Our empirical approaches involves simple fixed effects models.

Results

Preliminary results are the following. Increased capacity in oil refining have a significant effect on economic on exports. However, and surprisingly, we do not find any effect of increased capacity on imports levels. Such result would indicate that in average, newly installed capacities are aiming to serve international markets rather than reducing imports to improve energy security.

Conclusions

This paper aimed at understanding the determinants of investment , in term of industrial strategy from countries on the one hand, and on firm strategies on the other hand. Future works will involve using bilateral trade data to investigate finer effects of increased refining capacities on imports and exports.

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Federico Pontoni, Annamaria Zaccaria, Ilaria Livi and Edoardo Somenzi

STRATEGIC CO-OPTIMIZATION ON THE ITALIAN DAY-AHEAD AND ANCILLARY SERVICES MARKETS: IMPLICATIONS FOR THE PHASE OUT OF COAL AND FOR THE PATH TOWARDS CARBON NEUTRALITY

Federico Pontoni, Fondazione Eni Enrico Mattei and Bocconi University, Italy
Annamaria Zaccaria, Fondazione Eni Enrico Mattei, Italy
Ilaria Livi, Fondazione Eni Enrico Mattei, Italy
Edoardo Somenzi, Fondazione Eni Enrico Mattei, Italy

Overview

Power systems should lead the way towards the full decarbonisation of the energy sector. Combined, the electrification of energy consumption, efficient management of high levels of VRES integration, increased interconnectedness of national power systems and new storage technologies should fasten the phase-out of fossil fuels. The success of the energy transition and of the complete decarbonisation of the power system requires also efficient and transparent market designs and market rules. Over the next five years, Italy will phase-out coal fired generation: by 2025 (2028 including Sardinia), Italy will be among the first countries in the World to ban coal from its generation mix. At present, coal contributes to less than 10% of the total power produced, but it is the cheapest source of baseload power that Italy has, and it also contributes to the stabilization of the Italian transmission network.
Phasing-out coal will have important consequences both on the day-ahead market as well as on the ancillary services market. This explains why the Italian coal phase out has been coupled with the introduction of a capacity-based mechanism, which should ensure enough reserves to the Italian power system. On top of it, there are ongoing discussions to reform the ancillary services market, by introducing price competition in the frequency containment reserve, by allowing VRES to participate into the market and hence reducing the (technical) barriers to be admitted into the ancillary services market.
The recent surge in gas prices has also shown that the Italian power system is still subject to strategic behaviour by pivotal operators, particularly those that can act strategically by co-optimizing their bids and offers on the day-ahead (Italian MGP) and the ancillary services market (MSD): the combination of the phase-out of coal, the capacity market and increased VRES might have ambiguous effects on competition, particularly if we consider the sequential strategies on the different markets.
Understanding the competitive dynamics on the two markets and testing alternative market reforms is of paramount importance if Italy wants to achieve a cost-efficient energy transition.
For this reason, we have developed a comprehensive power-market simulator that incorporates on top of the standard technical transmission and generation constraints, the strategic behaviour of market participants which are allowed to maximize their profits by adopting an optimal strategy in the day-ahead market and in the ancillary services market.

To the best of our knowledge a co-optimization simulator that allows different agents to strategically operate in the market is a novelty for the Italian power system.

Methods

Relying on Plexos, a state-of-the-art power system simulator, we develop a comprehensive model of the Italian power system. Our Italian model simulates, on an hourly basis, the day-ahead equilibria for all the Italian zones and the MSD ex-ante equilibria for the secondary and tertiary reserve. The main inputs for the model are:

1. Zonal hourly demand and its short-term elasticity to allow for demand-response and optimization of pumped- storage.
2. Ancillary services demand and profile according to the security and reliability requirements of Terna, the Italian TSO.
3. Technical and economic characteristics of all existing generation plants (derived from ENTSO-E database and complemented with additional data retrieved with extensive desktop research.
4. Network topology and constraints.
5. Wind and irradiation profiles.
6. Financial data for the existing market players.

At first, we have set a cost-minimization algorithm to jointly solve both the day-ahead market and the ancillary services market. The simulator reproduces the iterative market splitting logic and the hourly equilibrium for the day-ahead and the provision of primary, secondary, and tertiary reserves as prescribed by ENTSO-E and Terna. These results serve as an ideal first best. Then we develop a simple sequential Bertrand strategic competition game, that allows market participants to bid strategically both on the day-ahead market and on the ancillary services market. The models are trained and calibrated using 2019-2021 real data.
After calibration, the simulator is then run for several scenarios simulating the 2025 Italian power market, with different hypothesis on:

Results

The backcasting on real 2019 and 2020 market outcome show a good fit of the model. It is possible to show that simulating separately the day-ahead and the reserve markets reduces both model fits and the level of predictability. Hence, day-ahead markets and ancillary services must be modelled and simulated jointly. The backcasting also shows that strategic Bertrand competition improve the goodness of the fit.

Table 1. **Backcasting on 2021**

	Perfect competition with Reserves	**Bertrand strategic competition with Reserves**
% of hourly prices with less than 1 Eur difference from GME outcome	90%	95%
Correlation	0.83	0.86

From this important achievement, simulations both in perfect competition (PC) and with Bertrand strategic setting (BSS) have been carried out for the phase-out of hard coal power plants at year 2025. For both scenarios, the main results display that the dismission of hard coal power plants in Italy is feasible and there will not be emerging issues for the energy system reliability and security, hence the energy demand will be totally satisfied. On the other hand, ancillary costs will increase. The dismission of coal plants will be replaced by a higher production of gas power plants, which implies a higher price of electricity, particularly in the South. As for emissions, the phase-out of coal has the potential to reduce annual CO_2 emissions in Italy by 9 MT. This translates into a 15% decrease in emissions per year produced by the energy sector. On the other hand, higher baseload prices reduce even further the scope for pumped storage, hence slightly reducing its use. The table below qualitatively shows the main differences between the Bertrand strategic setting and the perfect competition. For each effect, we show in which scenario is stronger and we show differences. Apart from expected results (higher prices and market splitting), it is worth noting that strategic behaviour increases emissions.

Table 1. **Simulations on coal phase-out: qualitative summary of main findings**

	PC	**BSS**
Price increase day-ahead		X
Price increase ancillary services		X
Market splitting		X
Variation of the mix	=	=
Emission reduction	X	

Conclusions

It is possible to conclude that a well-designed model of the Italian electricity market is a powerful tool for carrying out simulations of future energy scenarios. The co-optimization of day-ahead and ancillary services markets allows to better investigate the impact of imperfect competition on energy production compared to a perfect competitive setting. Moreover, simulating sustainable development scenarios displays how competition and market reforms can deliver more rapidly the sustainability of the power sector.

Further research will be conducted to analyse the historical relationships between price-cost markup and system conditions keeping into consideration the recovery of long-run marginal costs to investigate deeper strategic biddings in the market.

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Krzysztof Drachal
OIL PRICE FORECASTING WITH SOME GENETIC ALGORITHM VARIABLE SELECTION MODEL

Krzysztof Drachal, Faculty of Economic Sciences, University of Warsaw, Poland,

Overview

Forecasting oil price is a task in which one has to deal with various challenges. First of all, there are numerous variables that can be potentially important predictors. Secondly, literature review shows that the crucial predictors can be different in different time periods. Thirdly, the relationship between predictors and the oil price itself can be also time-varying.
Consequently, in more formal way: there exists model uncertainty connected with econometric modelling oil price development. Besides, when considering, for example, linear regression models, it happens to be desirable to apply time-varying parameters approach, as this can represent changes in the relationship between predictors and forecasted time-series. Except the mentioned issues, many time-series available to use in practice are not long enough to allow for using the conventional techniques, like, for example, Ordinary Least Squares (OLS). In particular, OLS requires relatively large number of observations comparing to the number of predictors in linear regression model.
The mentioned issues can be overcome with, for example, Bayesian econometric techniques. However, they are also known to be computationally challenging, especially when the number of potential predictors is very large. In this context, some manipulations with the state space of the possible linear regression models can be performed with the genetic algorithm. For example, the Dynamic Model Averaging (DMA) can serve as a starting method for this purpose.
The empirical simulations proved that DMA and its modification based on the genetic algorithm generated similar forecasts of spot oil price. This fact can be helpful when dealing with really large number of predictors. In such a case the original version of DMA becomes computationally infeasible, however, its genetic algorithm modified version becomes an interesting and relatively fast (in a sense of computations) alternative.

Methods

The original DMA (Raftery et al., 2010) method starts with considering all possible multilinear regression models that can be constructed out of n initially given potentially important explanatory variables (predictors).
Each of these K = 2n models are estimated with the recursive Kalman filter, so the regression coefficients are time-varying and short time-series are not an obstacle. For each of these (k = 1, …, K) models time-varying weights $\pi_{t|t-1,k}$ can be computed. The DMA forecast is computed as

$\widehat{y_t^{DMA}} = \sum_{k=1}^{K} \pi_{t\backslash t-1,k} \widehat{y_t^{(k)}}$ where $\widehat{y_t^{(k)}}$ is the fore cast produced by the k-th multilinear regression model. It is not necessary to consider $K = 2^n$; some smaller number of models can also be used.

The genetic algorithm modification of DMA (GA-DMA) starts with some initial set of models M(0) to be averaged by the DMA method. Now, assume that in Step t some set of models M(t) was used. First, this set can be reduced by leaving only those models that obtained high enough weights $\pi_{t\backslash t-1,k}$. Next, some randomly selected models out of the surviving ones can be mutated. For example, a predictor not present in the model can be added to the model, or a present predictor can be deleted. Next, the models can be randomly paired and crossovered. In particular, the algebraic expressions representing the functional form of the models (multilinear regressions) can be split randomly into two parts. These parts can be interchanged between two models and in this way new models are created. Such a new set of models M(t+1) can be treated with the DMA method in the Step t+1 (Koza, 1992; Onorante and Raftery, 2016; Ramirez-Hassan, 2020).

Results

WTI spot oil price was taken as the forecasted time-series. The potential predictors were MSCI World stock market index, U.S. 3-month treasury bill secondary market rate, global crude steel production (as a measure of global economic activity), trade weighted U.S. dollar index, U.S. product supplied for crude oil and petroleum products, total consumption of petroleum products in OECD, and market stress measured by VXO index (i.e., the implied volatility of S&P 100 index). Monthly data between Feb. 1990 and Dec. 2016 were analyzed. Data were taken in logarithmic differences and standardized. First 100 observations were taken as in-sample period. Various probabilities for mutation and crossover were taken, as well as, methods of selecting the initial M(0) set and cut-off for weights $\pi_{t\backslash t-1,k}$ .100 simulations were performed for each specification (version) of GA-DMA models.

Both squared error functions and absolute error functions showed that the forecasts from DMA and GA-DMA do not differ much between each other. GA-DMA produced similar forecasts no matter which specification was used. Besides, forecast accuracy measures, expanded by Mean Absolute Scaled Error proposed by Hyndman and Koehler (2006) showed that both DMA and GA-DMA produced more accurate forecasts than the benchmark models. By the benchmarks Time-Varying Parameter regression with all considered predictors and the no-change (naïve) method were taken.

Conclusions

DMA is a useful method in economic and financial forecasting (Nonejad, 2021) and can be easily used by practitioners (Drachal, 2020). However, K grows exponentially with n leading to serious computational obstacles with really large number of predictors.

The genetic algorithm modification of the original method improves the computational speed, so the method can be also used in extreme cases, leading to similar "econometric" outcomes. Although, GA-DMA requires separate estimations of DMA for each M(t) for every period t, there is a significant computational gain comparing to performing standard DMA once but over large, unrestricted set M(t) constant over t.

Acknowledgements

Research funded by the grant of the National Science Centre, Poland, under the contract number DEC-2018/31/B/HS4/02021.

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Hotaka Minatomoto, Ryoichi Komiyama, Yasumasa Fujii

AN ANALYSIS OF ELECTRICITY DECARBONIZATION IN JAPAN WITH NUCLEAR AND RENEWABLE BY LONG-TERM OPTIMAL POWER GENERATION MIX MODEL CONSIDERING NUCLEAR FUEL CYCLE

Hotaka Minatomoto, The University of Tokyo, 7-3-1, Bunkyo-ku, Tokyo, 113-8656, Japan
Ryoichi Komiyama, The University of Tokyo, Japan
Yasumasa Fujii, The University of Tokyo, Japan

Overview

In this paper, the optimal power generation mix is discussed with the goal of decarbonizing Japan's power supply. The model used in this study to calculate the long-term optimal power supply mix for Japan includes a model for the nuclear fuel cycle, with the goal of evaluating the competitiveness of renewable energy and nuclear power in the future. In recent years, Japan has presented advanced 3E+S values in its Basic Energy Plan, and low-carbon power supply is one of the important goals. Japan's nuclear energy policy in the Plan includes nuclear fuel cycle for not possessing excess plutonium, such as operating reprocessing plants, using plutonium in light water reactors and developing fast breeder reactors through international cooperation. This paper examines the possible role of nuclear and renewable power generations in Japan by long-term optimal power generation mix model considering nuclear fuel cycle model. The results suggest the necessity of commercializing nuclear fuel cycle, since the introduction of MOX fuel and fast reactors becomes economically justified under uranium price rise for the future.

Methods

This paper analyzes the role of renewable energy and nuclear fuel cycle in the decarbonization of the power generation sector in Japan using a long-term optimal power generation mix model combined with a nuclear fuel cycle model. In this model, thermal power, renewable, energy storage facilities and nuclear power are assumed, and the nuclear power sector is detailed by integrating nuclear fuel cycle model. The hourly electricity demand curve (8,760 hours per year) enables elaborate analysis of electricity supply and demand in Japan. The nuclear fuel cycle model also takes into consideration the isotopic composition ratio of nuclear fuel for each reactor type and the electricity consumption in nuclear reprocessing plants. The above model allows us to examine both long-term investment of power generation facilities with supply-demand balance.

Results

As a result of the calculations, for achieving net zero emissions in the power sector in 2050, the major way to minimize total enectricity system cost is to place nuclear power as a major source of long-term electricity supply in Japan through the deployment of FBRs in addition to LWR nuclear fuel cycle.

The results suggest the increased significance of nuclear fuel cycle including MOX fuel utilization under uranium price rise.

Conclusions

This study assesses the optimal investment and operation strategy of power system in Japan under net-zero emissions constraint using a long-term optimal power generation mix model integrating nuclear fuel cycle and large-scale renewable energy. The results suggest that nuclear power is one of cost effective options for decarbonization and that there is a potential significance for the commercialization of nuclear fuel cycle.

Acknowledgment

This work was supported by MEXT Innovative Nuclear Research and Development Program Grant Number JPMXD0220354480, by JSPS KAKENHI Grant Number JP20H02679 and by the Environment Research and Technology Development Fund 2-2104 of the Environmental Restoration and Conservation Agency.

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Nikolai Mouraviev

ENERGY SECURITY: TOWARDS A NEW MODEL

Nikolai Mouraviev, Abertay University, 40 Bell St, Dundee, DD1 1HG, United Kingdom,

Overview

The concept of energy security has many meanings, and there many variations of what academics and practitioners view as the concept's core (for example, see Hughes, 2009; Kruyt et al., 2009; Elkind, 2010; Sovacool and Brown, 2010; Ang et al., 2015). Although the prevailing perspective focuses on security of supply, most conceptualisations seem inadequate as they fail to explain the recent (2021) energy crisis in Europe, which manifested itself in rapidly rising energy prices and lack of natural gas and other energy resources. Furthermore, in light of accelerating climate change and increasingly demanding calls for correcting actions the traditional focus on security of supply becomes even more problematic as this approach could serve as justification for the continued expansion of fossil fuels' extraction to ensure that the needs of the growing economy, particularly during the post-pandemic recovery, are met. This paper's aim is to provide a critical assessment of a range of approaches to energy security and to delineate key features of a novel approach. Drawing on the context of resource-rich nations, e.g. Kazakhstan and Russia, the paper emphasises the need to reconceptualise energy security by focusing on increasing utilisation of renewables and resource use efficiency.

Methods

The paper compares and contrasts various approaches to energy security (e.g. those highlighted by Szulecki, 2018) and identifies their commonalities, advantages and disadvantages. It then applies some of these approaches to the context of selected resource-rich economies and shows the contradictory nature of these approaches as resource-rich nations view energy security differently due to their vested interest in fossil fuels (Koulouri and Mouraviev, 2018). The experience of resource-rich countries is particularly useful as their energy policies are often in sharp contrast with what the rest of the international community expects from them in terms of reduction of their own harmful emissions and incentivising other nations to focus on greater use of clean energy sources. This experience, e.g. that of Russia, allows to sketch the parameters of a novel energy security concept, which are highlighted in the paper.

Results

The central part of a novel conceptualisation of energy security is its focus on increasing utilisation of renewable energy sources, accompanied by the corresponding decrease of fossil fuels utilisation, and on improving resource use efficiency (Mouraviev, 2021).
The term resource use efficiency (or resource efficiency) is used from the perspective of deriving the most value from resource inputs (related to energy production), and incorporates energy efficiency.

Although the calls to increase utilisation of renewables are not new, it is common knowledge that the proportion of clean energy remain very small in most countries across the globe.

This proportion is particularly small in resource-rich nations. This leads to the notion that the public acceptance of ever-increasing use of renewables has to be supported by the governance mechanisms, such as government investment, subsidies, low-interest loans, feed-in tariffs and other incentive schemes for producers and consumers. Also, governance arrangements (e.g. energy-saving incentives, as well as disincentives for wasteful energy use) should underpin resource efficiency. Furthermore, a critically important part of governance is that implementation should rest not only on the increasing utilisation of renewables but also on the corresponding decreases of the use of fossil fuels.

Conclusions

Gradual increases of the share of renewable energy in the total energy generation and consumption will take time. This means that ensuring energy security should be viewed as a process that is likely to take decades, rather than a few years. An elaborate range of governance schemes, procedures and tools is required to ensure that energy security is achieved in a way that delivers all three dimensions of sustainability to society. To date, although the importance of renewable energy is broadly shared by many populations, politicians and governments, it is lack of supporting governance structures and instruments that impedes embedding energy security into policy and its subsequent implementation.

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Magdalena Klemun, Sanna Ojanperae, Amy Schweikert

EVALUATING THE EFFECT OF ENERGY TECHNOLOGY CHOICES ON LINKAGES BETWEEN SUSTAINABLE DEVELOPMENT GOALS

Magdalena M. Klemun, The Hong Kong University of Science and Technology, Hong Kong
Sanna Ojanperä, Oxford University, Oxford, UK
Amy Schweikert, Colorado School of Mines, Golden, USA

Overview

Linkages between the Sustainable Development Goals (SDGs) have sparked research interest because a better understanding of SDG co-benefits and tradeoffs may enable faster progress on multiple sustainability fronts (e.g., [1-3]). However, SDG linkages are often analyzed without considering the characteristics of specific technologies used to implement SDGs. For example, investing in one clean energy technology over another to support progress towards SDG 7 (Affordable and Clean Energy) might lead to stronger or weaker co-benefits between SDG 7 and non-energy SDGs, e.g., due to differences in technology industries and their environmental impacts. Here we outline an approach to study this problem by connecting the industries required to manufacture and deploy the components of a technology to the UN's SDG indicator framework through a combination of literature review and network analysis. We focus on SDG 7 and consider a set of example energy technologies and non-energy SDGs (SDG 6, Clean Water and Sanitation; SDG 8, Decent Work and Economic Growth; and SDG 9, Industry, Innovation, and Infrastructure). We observe that all technologies in our set show potential to create both beneficial and detrimental linkages between SDG 7 and non-energy SDGs, with some notable differences between technologies and deployment scenarios. If components are imported, PV systems show higher potential than other technologies to create beneficial links with SDGs 6, 8, and 9. For locally manufactured components, the more manufacturing-intensive electricity technologies (solar photovoltaics (PV), wind, nuclear) perform similarly, while clean cookstoves show a slightly higher risk of creating negative linkages with SDGs 8 and 9 due to higher labor-related risks.

Methods

We develop a framework in which linkages from one SDG to another are considered likely when the manufacturing and deployment of a technology used to achieve one SDG involves activities that can affect indicators of other SDGs. Technologies are represented through their hardware components and through the industries and services required to deliver these components, as delineated in the North American Industry Classification System. SDGs are represented through the official UN development indicators [4].

For each technology-SDG combination, we define a technology-indicator density metric to measure the number of connections with documented potential for influence over the total number of possible connections. We focus on SDGs 6, 8, and 9, although the method could be applied to other SDGs

where data is available. We consider both beneficial linkages and detrimental linkages. Beneficial linkages are assumed to be possible if we find evidence in the peer-reviewed literature for an industry influencing an SDG indicator in a beneficial direction. For example, growth in semiconductor manufacturing to manufacture solar cells has the potential to improve indicator 9.B.1 (Proportion of high-tech industry value added in total value added) since this industry is a high-tech industry [5,6]. Overall, the relationships between technologies, industries, and SDGs can be understood as a tripartite network connecting technology components to SDG indicators via technology-specific industries. The characteristics of this network are specific to the technology and SDG considered; technologies, for example, differ in the number of manufacturing steps and industries required. Regardless of the details of the network, however, a feature of our framework is that SDG linkages are derived from technology-specific mechanisms (i.e., technology components requiring industries with distinct impacts) that can be used to guide literature reviews to screen technologies for potential multi-SDG impacts and to identify data and research gaps.

Results

For the scenarios considered, all energy technologies show potential to create linkages between SDG 7 and other, non-energy SDGs. Overall, PV's potential to create or strengthen co-benefit linkages with SDGs 6, 8, and 9 appears slightly higher. This is particularly true when innovation-related metrics are emphasized over other metrics for SDG 9, and when rising informal employment is considered beneficial from an economic development perspective (SDG 8). In contrast to PV, clean cookstoves show a higher potential to induce detrimental linkages between SDG 7 and other, non-energy SDGs, compared to the electricity-generating technologies considered.
When technology components are imported rather than manufactured locally, PV ranks as the technology with the highest likelihood of potential co-benefit linkages between SDG 7 and non-energy SDGs, and clean cookstoves exhibit the lowest likelihood. For SDG 6, PV shows higher co-benefit indicator densities because a larger share of PV industries are service industries that tend to have higher water use efficiencies (indicator 6.4.1) than manufacturing industries [7,8]. For SDG 8, PV scores slightly higher than other technologies because a larger share of PV industries shows potential for informal employment (indicator 8.3.1). For SDG 9, a higher potential for official international aid and in small-scale industries is among the reasons for PV's higher co-benefit density. Additionally, PV has a higher share of high-tech industries among its non-manufacturing industries. In the local manufacturing scenario, the differences between technology-specific co-benefit densities are smaller, while trade-off densities differ significantly across the energy technologies considered. These results arise from the similarly important role of both manufacturing and service industries in all energy technologiesconsidered.

Conclusions

This research examines the potential of clean energy technology investments to enhance linkages between the primary investment goal, SDG 7, and three non-energy SDGs. We introduce a framework for screening technologies for their potential to create or enhance SDG linkages based on the manufacturing and service

industries required to build and deploy these technologies, and the risks and opportunities these industries pose when evaluated against SDG indicators. We use an example set of technologies (PV, wind, nuclear, clean cookstoves) and non-energy SDGs (6, 8, 9) to test the framework and explore possible extensions and applications. We find that industries with the potential to enhance co-benefits between SDG 7 and SDGs 6, 8, and 9 are more prevalent in solar PV's 'technology-SDG network' and less prevalent for clean cookstoves. While overall, PV and wind perform similarly across many indicators, there are some notable differences related to SDG 8. For example, informal employment is more common in PV supply chains in the countries for which data is available [9,10].
Some linkages do not depend on the selected indicators, while others are sensitive to which aspect of an SDG is emphasized. For instance, PV appears more suitable to enhance co-benefits between SDG 7 and 9 when indicators related to research and development are emphasized over those focused on manufacturing. These observations suggest that linkages between two SDGs are not universal but should be considered in the context of specific priorities defined by planners and policymakers. Overall, this paper is intended as a starting point to demonstrate challenges and opportunities in screening technologies for SDG linkages using SDG indicators.

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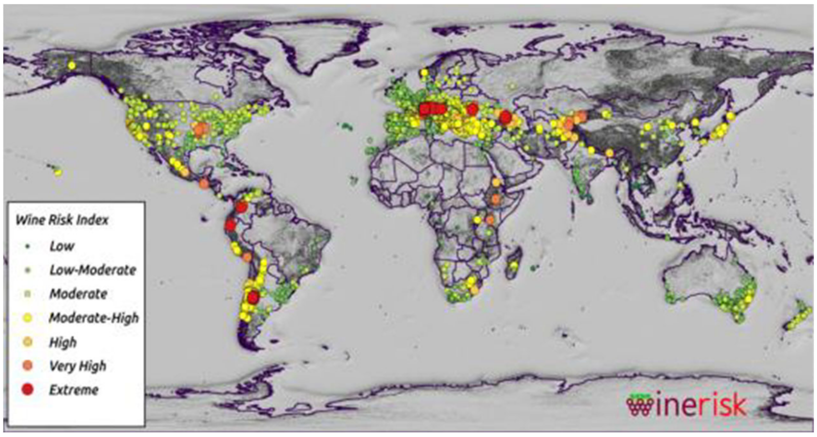
Nallapaneni Manoj Kumar, Shauhrat S Chopra

BLOCKCHAIN-ENABLED DYNAMIC GRAPEVOLTAIC FARMS FOR SELECTED WINE RISK REGIONS ON A GLOBAL LEVEL AND THE POTENTIAL OPPORTUNITIES FOR SYMBIOTIC INDUSTRIAL NETWORKS

Nallapaneni Manoj Kumar, School of Energy and Environment, City University of Hong Kong, Kowloon, Hong Kong, Shauhrat S Chopra, School of Energy and Environment, City University of Hong Kong, Kowloon, Hong Kong

Overview

In the quest for solutions to enhance energy and food security, our immediate goal is to promote sustainable and resilient energy supplies and build adaptive capacity resilient infrastructure for crop production. Here, we considered grape crops for food, feed, and fibre and solar photovoltaics for energy as a representative case. Both grape and solar photovoltaics have more or less similar lifetimes (i.e., 25 years), experience many uncertainties and are proven victims of climate risks. The European-Australian wine risk project also suggested that globally, multiple locations are experiencing these climate risks (see left-hand side Figure). Given the risk urgency, we proposed a novel Agrivoltaic concept called Dynamic Grapevoltaics where the Vitis vinifera cultivation is done under the solar panels, thus allowing the co-production of grapes and solar electricity. Additionally, the dynamic operation of solar panels provides an adaptive capacity resilient infrastructure for crop and auxiliary infrastructure that can be used to promote the resilient operation of solar.



Data Collection and Methods

A preliminary global survey is done on identifying the grape cultivation locations. Out of the list obtained from the survey, only a few selected regions were identified by applying the climate risk classification as proposed in the ongoing European-Australian wine risk project. The proposed dynamic grapevoltaic farms conceptual model is developed per the selected wine risk regions, followed by the multifunctional viability demonstration and a techno-economic and environmental sustainability analysis using mixed methods approaches. The proposed mixed-method approach is RePLiCATE that combines Resilience Performance, Life Cycle Analysis and Techno-Economics (Kumar, 2021). Based on the outcomes obtained and literature support, potential opportunities for symbiotic industrial networks are explored.

Results and Conclusions

The applied RePLiCATE approach gave clear insights on the role of this newly proposed system in promoting sustainable grape farming and solar energy productions. The results include the energy potential, grape crop yields, revenues from grape crop and solar electricity, and carbon dioxide emissions associated with electricity and grape crop. The revenues to both solar photovoltaics operators and grape farm owners considering the capital and operational investments revealed financial viability. The lifecycle-based environmental sustainability results suggest that the proposed farm can harvest solar energy with reduced carbon dioxide emissions and proved that the agriculturally generated global warming potentials and other impacts are lower. Also, the dynamic operation of the photovoltaic arrays provided resilience support to the grape farmer during the climate risks and harvested rainwater. At the same time, this co-existence made the solar photovoltaic operators free from land-use conflicts. Overall, this concept was feasible and opened up new synergies like wine production, raisin production, grape-derived food processing industries, grape seed oil, grape pulp processing, grape-derived pharma products and others.

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Tarun Khanna, Oliver Ruhnau

THE RESPONSIVENESS OF THE AGGREGATE ELECTRICITY DEMAND TO WHOLESALE ELECTRICITY PRICES

Tarun Khanna, Hertie School, Berlin, Germany
Oliver Ruhnau, Hertie School, Berlin, Germany

Electricity is a special economic good which needs to be supplied at the very time of consumption. As a result, prices for electricity can be many times higher than their average and even turn negative in hourly or sub-hourly time scales. This paper studies whether the demand for electricity responds to such price variations in the very short term. To isolate the price responsiveness of demand from the endogenous relationship between price and quantity, we perform an instrumental variable regression with the weather-dependent electricity supply from wind and solar energy as instrument. Using data from Germany, we estimate that a 1 €/MWh increase in wholesale electricity prices causes the aggregate electricity demand to decline by 80 MW. At the average price and demand, this corresponds to a price elasticity of demand of about -0.05. The finding is statistically significant and robust across different historical years.

Overview

Variable renewables and flexible demand. Energy systems worldwide are currently undergoing a rapid transition towards wind and solar energy. Yet, the further expansion of these variable renewable energy sources and their integration into energy systems and market may be challenging because they are not always available when electricity is needed. One part of the solution to this challenge may be flexible electricity demand, which dynamically responds to the availability of renewable electricity.

Elasticity of demand. Electricity supply and demand are coordinated through wholesale electricity markets, which clear at hourly or even sub-hourly intervals. Whenever renewables are available, their additional supply depresses wholesale electricity prices, which will, if the demand is price-elastic, cause an increase in electricity consumption. Likewise, low renewables may cause a decrease in consumption through higher prices. The hourly price responsiveness of demand is hence of high interest when increasing the share of renewables in electricity generation.

Existing literature. Previous econometric studies analyzed the short-term elasticity of electricity demand (see Labandeira et al. (2017) for a review and Cialani and Mortazavi (2018) as well as Csereklyei (2020) for recent examples).
However, most of these studies have used annual data. For them, short-term price elasticity of electricity demand typically means a response of the early electricity demand to a change in electricity prices in the same year. Notable exceptions analyzing the hourly price response are Lijesen (2007), Bönte et al. (2015), and Knaut and Paulus (2016).

These studies use different methods and data yielding a wide range of results. Findings on the hourly price elasticity differ by three orders of magnitude, ranging from -0.0014 to -0.43.

Contribution. This paper presents the first multi-year and multi-country estimates for the hourly price responsiveness of the aggregate electricity demand in European electricity markets, using renewable electricity generation as an instrument.

Methods

Instrument variable. The relationship between prices and quantities is endogenous. They affect each other simultaneously through the increasing marginal cost of supply and through the price-elasticity of demand. To isolate the price-elasticity of demand from this endogenous relationship, we use the generation of wind and solar power as instrument for the electricity price. We estimate the following mathematical model for the first (Eq. (1)) and for the second (Eq. (2)) stage of the instrumental variable regression. Note that we assume a linear relationship between price and demand (and not log price and log demand) because our data include negative prices, for which the logarithm is not defined. Furthermore, we run a sensitivity where the renewable electricity generation is replaced by wind power only.

$$Price_t = \alpha_0 + \alpha_1 Renewables_t + \alpha_2 Temp_t + \alpha_3 Hour_t + \alpha_4 Month_t + v_i \quad (1)$$

$$Demand_t = \beta_0 + \beta_1 \widehat{Price}_t + \beta_2 Temp_t + \beta_3 Hour_t + \beta_4 Month_t + u_i \quad (2)$$

where

$Price_t$	Wholesale electricity price
$\widehat{Price}_t$	Electricity price predicted based on Eq. (1)
$Demand_t$	Electricity demand
β_1	Price-elasticity of demand
$Renewables_t$	Sum of wind and solar power
$Temp_t$	Ambient temperature
$Hour_t, Month_t$	Hour and month dummies

We use the IV-GMM estimator. Compared to the statistically more efficient two-stage least squares approach, the GMM estimator accounts for heteroscedasticity in our input data.
We plan to run similar analysis for other European countries including Italy, France, Netherlands, Spain, and Denmark.
Non-parametric model specification. The relationship between electricity demand and price is dependent on the price level itself and cannot be correctly described using a linear model specification. Since the exact parametric form of the relationship is unknown, we also estimate a non-

parametric model which no longer estimates a set of linear parameters but rather points on the unknown function. To illustrate, consider the following model which assumes the error term enters additively.

$$Demand_t = \Phi(Price_t) + v_i$$

We plan to follow Li and Racine (2007) and use the *npregiv* package in R to estimate non-parametric estimators of Φ in addition to the GMM estimators.

Preliminary results

The results of the IV estimation on data collected from Germany (Table 1, right) shows that for a 1 €/MWh increase in the day-ahead electricity price, the electricity demand is estimated to decrease by about 80 MW. This is about 0.1% of the 76 GW peak demand in Germany. In other words, the full price range of about 200 €/MWh corresponds to about 14 GW demand response (20% of peak demand), and a price range of 50 €/MWh excluding extreme prices corresponds to 3.5 GW of demand response (5% of peak demand).

Table 1: **First stage regression of the price on renewables and wind power, respectively for Germany**

	First stage (DV: Price)		**Second stage (DV: Demand)**	
Variables	**IV: Renewables**	**IV: Wind**	**IV: Renewables**	**IV: Wind**
Renewables (MW)	-0.0008*** (0.0000075)			
Price (€/MWh)			-79.6*** (8.4)	-82.5*** (9.6)
Wind (MW)		-0.00078*** (0.0000079)		
Temperature (°C)	-0.071*** (0.018)	-0.36*** (0.017)	280.0*** (20.7)	282.8*** (21.0)

DV: dependent variable; IV: instrumental variable. All regressions control for hour, month, and year dummies. Standard errors are reported in parentheses. Significance levels: 0 *** 0.001 ** 0.01 * 0.05

Inter-yearly robustness. For the data collected from Germany, the estimated responsiveness of demand to prices is of similar magnitude for each individual year from 2015 to 2019 (Figure 3).

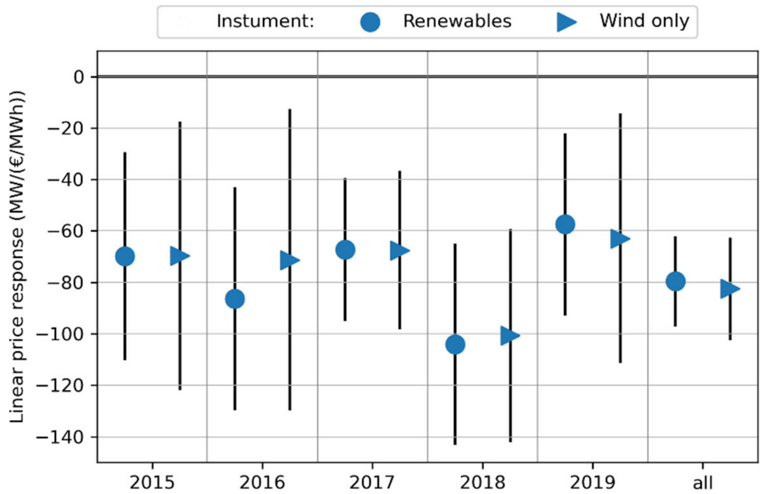

Figure 1: Estimates based on single years compared to the multi-year estimate ("all") for Germany. The whiskers extend over twice the standard error in each direction. As they never cross zero, we can say that all results are significant at the 5% level.

Exponential elasticity. To compare the estimated linear elasticity to previous estimates, we calculated the exponential elasticity for the average electricity price and demand, using the following formula:

$$\varepsilon = \beta_1 \cdot \frac{\overleftarrow{Price}}{\overleftarrow{Demand}} = -79.6 \cdot \frac{35.5}{55.852} = -0.0506$$

Knaut and Paulus (2016) yield similar results for Germany. The estimate from Bönte et al. (2015) is one order of magnitude larger (-0.43). We attribute this to the – apparently important difference – that they consider the demand at the power exchange while we consider the overall demand in the electricity system. The estimate from Lijesen (2007) is one order of magnate smaller (-0.0014). This could be because they use lagged price as an instrumental variable which may not fulfill the exclusion restriction.

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Yueting Yu, Bert Willems

BIDDING AND INVESTMENT IN WHOLESALE ELECTRICITY MARKETS: PAY-AS-BID VS UNIFORM-PRICE AUCTIONS

Bert Willems, Tilburg University and Toulouse School of Economics, The Netherlannds
Yueting Yu, Tilburg University, The Netherlannds

We compare two alternative auction designs, uniform-price auctions and pay-as-bid auctions in wholesale electricity markets. In particular, we focus on their impacts on producers' bidding behaviors and investment incentives. We provide a perfect competition benchmark model with a continuum of generation technologies and uncertain, elastic demand. Our paper addresses the controversial issue – which auction format is superior in the setting of electricity markets. We illustrate with a functional-form model that pay-as- bid auctions are inefficient in the sense that producers' willingness to pay exceeds the marginal cost, while producers' long-run investment incentives are distorted with the load technologies.

JEL Codes: D44, D47, L94
Keywords: Electricity, Market design, Uniform-price auctions, Pay-as-bid auctions, Investment

Dongchen He

WHEN ARE RESERVES NEEDED? CO-OPTIMIZATION OF ENERGY AND RESERVES IN ELECTRICITY MARKETS WITH MULTIPLE TECHNOLOGIES

Dongchen He, Tilburg University, School of Economics and Management,
CentER Ph.D students, The Netherlannds

Overview

Different from many other goods, guaranteeing the continuous supplies of electricity is crucial for social welfare and a mistake in the design of the electricity market can cause tens of billions of dollars of loss. In the electricity market, demand is difficult to forecast and respond to real-time prices. The speed of adjusting imbalance in the electricity spot market is very slow and often results in a price spike or outage. Since not all technologies are flexible in adjusting production and electricity storage is very expensive, reserves are usually regarded as an alternative way to provide reliability, especially when renewable energy is integrated into the electric grid. As one of the ancillary services, reserves are used to satisfy demand when supply and demand uncertainty that would otherwise lead to blackout. However, little is known about the underlying reserves market fundamentals. This paper then provides an economic motivation and studies the optimal procurement of reserves in the electricity market.

Method

This paper is a theoretical one which takes use of mechanism design with private types. To illustrate the main idea, this paper constructs a simple model in which electricity can be procured in two nodes of operations: energy and reserves. Energy is the power that is produced and dispatched to end-use while reserves are backed up and produced only when they are used. The production costs of energy and reserves are the same, but to provide reserves, there must incur an additional standby cost, and the reduction of energy is not cost-free . Hence, with an uncertain demand, there is a trade-off between these two supplies: the reserves provide one unit of flexibility with a standby cost, but decrease the sunk cost of energy when it is not consumed. This paper aims to investigate the optimal allocation of these two supplies which can minimize the total procurement cost. Furthermore, this paper discusses the efficient technology frontier that should be used for production of energy and provision of reserves, and how integration of renewable energy changes the results.

Results

Reserves are procured if standby cost is small enough. Given the reservation price, demand distribution and production cost, it is always possible to find a unique threshold below which total supply and reserves decrease with standby cost while regular supply increases with it.

The reserves are zero above the threshold standby cost. The allocation between regular and reserve supplies is determined such that the virtual marginal costs of both types of supplies are equal.

When there are multiple technologies available, there exists a convex efficient technology frontier such that only technologies lying on this curve are cost-effective to provide energy and (/or) reserves. The allocation of energy among different technologies depends on the tradeoff between sunk cost and production cost, while the allocation of reserves among different technologies depends on the tradeoff between production cost and stand-by cost.

When intermittent renewables are integrated, the value of applying renewables to produce energy is lower and the value of traditional technology as reserves increases. Hence, when supply uncertainty is considered, reserves become more important.

Conclusions

The results have three implications. First, reserves are not always procured, even when the standby cost is smaller than production cost. It also depends on the consumers' reservation price. When the reservation price is high, the expected utility from purchasing one more supply is large enough to cover any cost, in which case we always have both a reserve and energy market (as long as standby cost is smaller than production one). By contrast, if the reservation price is very low, the total supply would be small so that energy market is enough to satisfy it and the reserves market will be shut down.

Second, ceteris paribus, the allocation between reserves and regular supplies also relies on the demand distribution. When there is a higher probability of large demand, energy weighs more over reserves, and reserves play a role when demand is more likely to be low. This is because energy suffers from downward risk while reserves are costly when encountering high demand. When a unit of reserve is activated, it incurs a cost for standby as well as a cost for production. Instead, there is only production cost for energy. Hence, when an additional supply is more likely to be used, energy is cheaper, while if a supply is more likely to be unused, reserve is a more cost-efficient way to provide flexibility.

Third, the importance of the reserves market is possible to be underestimated when supply uncertainty, especially the integration of renewables is ignored. Also, not all technologies are efficient to provide energy and/or reserves. The selection of technologies depend on cost trade-off and the uncertainties we would consider.

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Ryoichi Komiyama

INSTALLABLE POTENTIAL OF SMALL MODULAR REACTORS AND RENEWABLE ENERGY FOR ACHIEVING CARBON NEUTRALITY IN ELECTRIC POWER SYSTEM

Ryoichi Komiyama, The University of Tokyo, 7-3-1, Bunkyo-ku, Tokyo, 113-8656, Japan
Yasumasa Fujii, The University of Tokyo, Japan

Overview

Small modular reactors (SMR) have an advantage in an afforadable initial capital investment, siting flexibility, and enhanced scalability which conventional large-scale reactors have difficulty in providing. SMR's modularised design and inherent passive safety characteristics are expected to improve social acceptability of nuclear energy in electric power system. In addition, SMR can generally serve as not only baseload but also flexible power generator, and this feature increases the adaption of SMR into future power grid integrated with large-scale variable renewable energy (VRE), such as solar PV or onshore/offshore wind power. Therefore, SMR is expected to play an important role in power grid stability and reliability under massive VRE integration. By upgrading an optimal power generation mix model with 383 buses and 472 power transmission lines in an hourly temporal resolution through 8,760 hours, this paper aims to analyze the optimal integration of SMR and VRE into a power grid in Japan under carbon neutrality constraint. Simulated results suggest that SMR installation is economically verified and SMR adopts flexible operation in power grid integrated with extensive VRE.

Methods

This paper performs an assessment of optimal SMR and VRE deployment including solar PV, onshore and offshore winds in power system by developing an optimal power generation mix model. The model can uniquely specify an optimal SMR and VRE deployment together with power system operation through cost minimization of the power system. This paper enhances the authors' previous model [1][2], which deals with a grid topology at 383 buses and 472 bulk power transmission lines, with an hourly representation through 8,760 hours. In addition, the model newly considers hydrogen power generation which assumes the combustion of impoted carbon-free hydrogen and could serve as flexible power generator. This paper assumes reference scenario and net zero emission scenario. Mainly through the latter scenario, optimal SMR and VRE integration is analysed.

Results

The simulated results imply that the optimization of the model promotes SMR installation in the area integrating higher ratio of renewable energy in order to compensate the output variability of solar PV and wind power particularly in the scenario where output curtailment of those variable renewables is not permitted.

On the other hand, power generation from conventional large-scale nuclear reactor declines, which suggests that flexible power sources such as SMR become more favourable option under the extensive VRE integration in power system. From the results, the development of SMR is indispensable to expand renewable energy penetration and to establish zero emission power grid in an effective way.

Conclusions

For evaluating the optimal SMR and VRE integration into power system, this paper develops an optimal power generation mix model characterized by 383 nodes with 472 bulk power transmission lines with hourly temporal resolution through 8,760 hours. The results suggest that SMR is significant for both enabling massive VRE integration and achieving carbon neutrality of power system in an cost-effective manner.

Acknowledgment

This work was supported by MEXT Innovative Nuclear Research and Development Program Grant Number JPMXD0220354480, by JSPS KAKENHI Grant Number JP20H02679 and by the Environment Research and Technology Development Fund 2-2104 of the Environmental Restoration and Conservation Agency.

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THE DIGITAL ECONOMY FOOTPRINT. HOW CAN WE ENGAGE TO REDUCE ITS ENVIRONMENTAL IMPACT?

Gianluca Carrino: Italian Association of Energy Economists - AIEE, Italy

Overview

In a scenario where the process of transition to a sustainable zero-emission economy has an increasingly growing influence, a concrete use of digitalization is strongly needed to reduce environmental problems and to maintain the global temperature increase below 1.5°C.
However, even if the digital ecological footprint in the long term is considered a fundamental component of the decarbonisation process especially considering that it will be an increasingly significant component within our development system; the exchange of data that takes place every day worldwide has a non-negligible impact on climate-altering emissions.
For this reason the global community shall have a more sustainable behaviour towards the implementation of a digital sobriety.
But, why our Internet habits are not as sustainable as we think?

During this analysis we are going to focus on climate consequences of the implementation's digital technologies, examining some effective solutions that need to be implemented in order to reduce its effect on global environment.
How the "Lean ICT – Towards Digital Sobriety" (2019) shows, before the Covid-19 and develop of smart working, digital technologies emitted 4% of greenhouse gas emissions (GHG), while its energy consumption is increasing by 9% a year.
The digital sector looks to be one of the most energy-intensive areas in the world.
The energy consumption of digital, compared to global energy consumption, from 1.9% in 2013 reached 2.7% in 2017 and could reach a variable peak between 8.7% and 15.5% in 2025 if, in addition to energy optimization activities, "digital sobriety" actions are not undertaken correctly.
Considering that "Lean ICT" is a pre-pandemic study, is important to emphasize that the digital sector has soared since the first lockdown in spring 2020 and it will continue to rise up year by year.
For this reason it looks fundamental to find a more effective and efficient way to implement the digital sobriety.

Method and Results

To completely understand the digitalization's footprint is fundamental to analyse the digital technologies and Internet market data.
The environmental impact of digital technology is now recognized as unsustainable, continuing to grow day by day.

The energy consumption of digital technologies is increasing by 9% a year, and already represents a significant percentage of global greenhouse gas emissions especially if we think that their use is going to rise significantly year by year in the road to a net-zero emission in 2050.
The use of digital technology accounts for 55% of its energy consumption compared to 45% for the production of equipment.
In particular: the carbon footprint of our gadgets, the Internet and the systems supporting them, according to some estimates, account for about 3.7% of global greenhouse emissions.
This amount, for the increasing use of digital processes due to smart working and to the growth of E-Commerce, is predicted to double by 2025.

During this analysis, in order to have a better idea of the impact of "smart communication" and digital sector on the GHG emissions, we are going to exanimate the influence of the different online instruments such as :online videos, email messages and Internet searching.
Analysing for example online videos is possible to assert that they generate around 60% of world data flows and thus over 300 million tons of CO_2 per year.
In addiction, in order to have a better scenario of digital strategies' emissions, focusing for instance on the footprint of email messages, is possible to declare that it varies, according to the literatures, from 0.3g CO_2e for a spam email to 4g (0.14oz) CO_2e for a regular email and 50g (1.7oz) CO_2e for one with a photo or hefty attachment.
Although a single email consumes very little this small sum must be multiplied by the more than 300 billion emails that are sent and received every day all over the world.
Moreover, the footprint per email message in the future might be higher than today' levels because of the uncontrollable use of people to communicate and to work.
Paying attention for example on Internet searching is possible to express that it is considered another tricky area.
According to figures released by Google, if a decade ago each Internet search had a footprint of 0.2g CO_2e, today Google uses a mix of renewable energy and carbon offsetting to reduce operations' carbon footprint.
According to Google's own figures, however, an average user of its services – someone who performs 25 searches each day, watches 60 minutes of YouTube, has a Gmail account and accesses some of its other services –produces less than 8g (0.28oz) CO_2e per day.
Instead, the 3.5 billion daily searches on Google and in general the more banal activities carried out by 4.1 billion internet users, (53.6% of the population) are responsible for the production of about 80 kilos of greenhouse gases per year each and its amount is going to increase in the next years.
Newer search engines are attempting to set themselves apart as greener options from the outset. Ecosia, for example, will plant a tree for every 45 searches it performs. This sort of carbon offsetting can help to remove CO_2 from the atmosphere, reducing the rice of temperature and respecting the de-carbonizations goals.

Conclusion

To reduce the impact of the digital economy footprint it is necessary to have a more responsible and conscious attitude towards digital tools. In fact, the general public is often not really sensitive to this issue, underestimating the environmental consequences of their actions and, in this case, of their clicks.
For instance, how data show, according to some calculations, the classic office worker receives around 121 emails a day including newsletters and spam. Therefore, the major email users can create 1.6 kilograms of CO_2 every day just by using email.
The situation does not change that much for other instant communication tools. For example, a single tweet causes 0.2 grams of greenhouse emissions, while messages sent via WhatsApp or Messenger have a slightly higher impact than emails (but their frequency is much higher). Obviously, also in this case an important role is played by the quantity of attachments, photos and even emojis sent.
Only the old SMS, which consumes 0.014 grams of CO_2, has a truly reduced digital ecological footprint, but is dying out in daily use.
In additcion, the impact of the increasingly used video calls and videoconferencing, in which the data transported from one part of the globe to the other, increases exponentially. In fact, a videoconference, whose participants are located in different countries, could alone produce up to 215 kilograms of CO_2 emissions (although the energy consumption of videoconferencing is high, using these software to replace travel by car, train or plane, means saving on average 93% of emissions).
However, it is not just messages, emails and video conferences that cause the bulk of the information and Communication Technology sector's environmental footprint.
Nowdays, streaming videos alone represent 60% of the total traffic of data traveling on the internet, generating over 300 million tons of greenhouse gases every year. By themselves, videos represent around 1% of global emissions and consume the same amount of energy as a nation like Spain.

The exchange of data that takes place every day worldwide has a non-negligible impact on climate-altering emissions! So how can we reduce the ecological footprint of digital?

The way forward mainly passes through a transition from digital intemperance to what the NGO Shift Project calls ***digital sobriety***. In this scenario first of all companies that operate on the internet, especially the web, should strive to make their products more efficient.
For instance, it is calculated that giving those who are listening to music on YouTube the possibility of not viewing the videos would reduce emissions caused by the streaming platform by 5%, equal to 11 million tons of emissions every year. Even Facebook could significantly reduce its energy consumption by preventing promotional videos from starting automatically, while Netflix could encourage its users not to always watch movies or TV series in high definition, significantly reducing data traffic and therefore the energy needed to power the platform.
In addition, it looks always more important to increase the life cycle of our technological devices in order to reduce the demand and the consumpion rate of raw materials.

In conclusion, having an aptitude for sobriety means avoiding digital consumerism while at the same time promoting an increasingly pushed digitization that fosters awareness and the use of more efficient digital tricks such as the exchange of office documents on a shared platform or the reduction of the use of the webcame during videocalls.

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Christian Lutz, Maximilian Banning, Lisa Becker, Markus Flaute

SOCIO-ECONOMIC IMPACTS OF AMBITIOUS GHG REDUCTION TARGETS WITH EXPLICIT GREEN TECHNOLOGY INFORMATION

Christian Lutz, Gesellschaft für Wirtschaftliche Strukturforschung (GWS) mbH Institute of Economic Structures Research, Heinrichstr. 30 D-49080 Osnabrück, Germany
Maximilian Banning, GWS mbH, Germany
Lisa Becker, GWS mbH, Germany
Markus Flaute, GWS mbH, Germany
Maximilian Banning, GWS mbH, Germany

Overview

The transition to climate-neutral development leads to various socio-economic effects as e.g. reported in impact assessments for the EU Green Deal (EU 2020). Their recording is made more difficult by the fact that new energy technologies are not yet reflected in the statistical classifications on which economic structural data are based. So far, necessary further breakdowns of technologies in the macroeconomic context are limited to individual technologies and countries (e.g. O'Sullivan, Edler 2020). In the following, the GINFORS-E model is used to investigate what such explicit technology modeling means for the socio-economic effects of a climate mitigation scenario.

Methods

GINFORS-E[14] is a global model that it is designed for assessments of economic, energy, climate and environmental policies up to the year 2050. It is a bilateral world trade model based on OECD data, which consistently and coherently models exports and imports of 25 goods groups for 64 countries and one 'rest of the world' region. All EU-27 countries, additional European economies and international major trade partners are explicitly modeled. It incorporates a macro-model, consisting of exports and imports, other core components of final demand (private and public sector consumption and investment), markets for goods and the labour market, for each country. The models are also divided into 36 goods categories in accordance with the latest OECD (2018) internationally harmonised input-output (IO) tables. For every country OECD bilateral trade data on industry level is linked to the IO tables.

Each national model is linked to an energy model, which determines energy conversion, energy generation and final demand for energy for 19 energy sources disaggregated by economic sector based on IEA energy balances. Energy-related CO_2 emissions are linked to energy use. The model considers technological trends and price dependencies.

[14] https://web.jrc.ec.europa.eu/policy-model-inventory/#factsheet/model/1123

The model is enlarged by explicit information on 14 different energy technologies such as PV, wind, E-mobility and hydrogen, that can reduce GHG emissions, in a project funded by the German Ministry of Economic Affairs and Energy. The idea is to better represent intermediate inputs and value added related to these energy technologies. This representation builds on a literature review of energy technology reports such as IEA Energy Technology Perspectives (2020a), JRC, EC (2020) and IRENA, and collection of data on the cost structures of these energy technologies and expected developments over time.

Results

Two scenarios are calculated with the GINFORS-E model with and without this additional energy technology information. The first is an NDC scenario as a baseline, in which major economies as EU, US and China reach their Nationally Determined GHG reduction targets until 2030 as reported to UNFCCC until summer 2020. The second scenarios build on the Sustainable Development Scenario of the IEA (2020b) World energy Outlook, that ensures to meet the 2° target. Various policy measures are simplified by means of carbon prices, which are uniform for different groups of countries.

Conclusions

By comparing the socio-economic impacts of the more ambitious 2° target scenarios with the respective baselines in 2030, we show the differences due to explicit technology modelling. Results focus on GDP and labor market effects but can also look at changes on the industry level regarding production, prices, international trade, and jobs. Explicit technology coverage will improve modelling of energy and climate mitigation policies.

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Chris Belmert Milindi and Roula Inglesi-Lotz
IMPACT OF TECHNOLOGICAL PROGRESS ON SECTORAL CARBON EMISSIONS: DOES IT DIFFER ACROSS COUNTRY'S INCOME LEVEL?

Chris Belmert Milindi, Department of Economics, University of Pretoria, Pretoria, South Africa
Roula Inglesi-Lotz, Department of Economics, University of Pretoria, Pretoria, South Africa

Overview

A growing number of existing studies in the broader literature have examined the relationship between green technology and CO_2 emissions. These studies have generally neglected differences in carbon emissions per economies sector. We argue that because each sector's contribution to total) carbon emissions varies, the environmental impact of technological advancement may also differ across sectors. This study aims to investigate the impact of aggregate technology and green technology on sectoral carbon emissions in a sample of 45 countries, divided into three income categories (High income, upper middle income, and Lower middle income) between the period of 1999 and 2018.

Methods

This paper selects five economies sectors (Power sector, manufacture sector, transport sector, petrol sector, and building sector) that generally account for more than 75% of carbon emissions across countries, and examine how their respective carbon emissions are impacted by aggregate and green technological progress. Principal component analysis is employed to construct an index of aggregate technology from five usual indicators of technological progress (industrial value-added, patents, R&D expenditure, ICT, and science and technology publications). Renewable energy consumption is employed as an indicator of green technology development. We implement three econometrics methodologies to empirically estimate the results: the fixed effect, the two steps DIFF-GMM, and the Feasible Generalized Least Square (FGLS) methodology.

Results

For the full sample analysis, results show that, on one hand, aggregate technology increases carbon emissions in the power sector, transport sector, and petrol sector. However, aggregate technology reduces carbon emissions in the manufacturing industry. On the other hand, renewable energy significantly lowers emissions in all five economies sectors. Findings also suggest that urbanization and financial development lead to higher carbon emissions in all sectors in the full sample.
Results from subsamples indicate that, generally, aggregate technology is positively associated with carbon emissions in all sectors in upper middle income and lower-middle-income countries; however, it is negatively related to carbon emissions in the manufacturing sector in high-income countries.

Conclusion

Technological progress is considered by many as a fundamental tool for reversing the CO_2 emissions curve in the fight against global warming. The fact that in general technological progress favors carbon emissions in the majority of sectors shows that the efforts made so far to decarbonize technology are not enough. Efforts must be accelerated and multiplied if we are to achieve the objectives set in the Paris Agreement. The fact that technology reduces carbon emissions in the industrial sector of high-income countries demonstrates that the private sector which owns the majority of companies in the industrial sector plays a critical role in the energy transition. The private sector is more flexible than the state sector, and can therefore gradually and much more quickly replace fossil fuel-friendly technology with environmentally friendly technology. From this perspective, one might think that the increase in green technologies will perhaps come from the industrial sector, which could thus disseminate it in other sectors and other countries through technology transfer and spillover effects.

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Paolo Bertoldi
LOCAL AUTHORITIES CONTRIBUTION TO GHG EMISSION REDUCTIONS: THE COVENANT OF MAYORS EXPERIENCE

Paolo Bertoldi, European Commission DG JRC, Italy

Cities and local authorities are key players in addressing climate change. The Covenant of Mayors for Climate and Energy (CoM) has been the first initiative of its kind addressing local authorities to endorse their efforts in the implementation of sustainable energy and climate policies and to provide them with a harmonised data compilation, methodological and reporting framework, supporting them in translating mitigation goals into reality. This report provides the highlight of the last scientific assessment of CoM regarding mitigation.

The assessment describes the plans submitted by signatories, examines planned and implemented policies and gives an overview on the progresses in terms of energy consumption and GHG emission reduction. The key findings show that the overall commitment to reducing GHG emissions by signatories is 30% by 2020 and 47% by 2030, compared to baseline emissions projected to 2005.

Maria Pia Valentini, Valentina Conti, Matteo Corazza,
Maria Lelli, Silvia Orchi

ROAD PUBLIC TRANSPORT DECARBONISATION: A COMPARISON AMONG VEHICLE TECHNOLOGIES

Maria Pia Valentini, ENEA, Via Anguillarese 301, Rome, Italy
Valentina Conti, ENEA, Rome, Italy
Matteo Corazza, ENEA, Rome, Italy
Maria Lelli, ENEA, Rome, Italy
Silvia Orchi, ENEA, Rome, Italy

Overview

Transport is presently one of the most critical sectors for decarbonisation, due to its strictly dependency on fossil fuels. A technical and behavioural revolution is needed to get the 2050 target of 90% GHG emissions cut fixed by the EU Green Deal, based on the actions prescribed in the Fit for 55 Package for cleaner road vehicles and a wider availability of alternative fuels and infrastructures (mainly electric recharge and hydrogen refuelling).
Although urban PT accounts for a minority of the total energy consumption and GHG emissions of passenger road mobility, it is considered an optimal testbed for new vehicle technologies, due to the possibility of taking advantages from "economies of scale" and scheduled vehicles operation.
Moreover, a consistent modal shift from private to public mobility, mainly in urban areas, is encouraged in overall strategies for transport sustainability, considering the highly better performances of collective transport per transport unit, respect to private vehicles.
Batteries and Hydrogen Fuel Cell Electric Vehicles (BEVs and HFCEVs) are considered the most promising solutions to reduce climate impacts of transport, if well linked to low carbon energy sources.
Numerous PT Companies all over the world are already experimenting battery buses (BEBs) since the early 2000ies (Bloomberg calculates that almost 600,000 e-buses are already into operation) [1] and, more recently, also hydrogen fuel cells buses (HFCBs) have been introduced.
In this paper we analyse the effective GHG reduction, internal costs and operational changes for PT companies of this revolution, mainly comparing battery and FC solutions for road PT electrification in the near future.

Methods

An economic analysis of the whole vehicle operating life is performed for different bus technologies, conventional and innovative, from the operator point of view, considering a real Italian case study.
Moreover, an analysis on "Well-to-Wheels" (WTW) greenhouse-gases emissions and energy consumption is carried out for 12 m urban buses powered with both batteries and hydrogen fuel cells, considering different energy production pathways.

Results

A Total Cost of Ownership (TCO) analysis is applied to the bus-lines of Rome in order to compare the comprehensive costs of different bus technologies [2].
First of all, the limits of battery buses in terms of range and recharge needs are taken into account. Results show that BEBs are applicable in more than 94% of the 282 examined bus lines, while HFCBs, as expected, are 100% applicable, as well as conventional technologies like Diesel and CNG buses.
Moreover, HFCBs appear as flexible as conventional technologies and almost as much easy to operate (shorter refuelling time respect to electric recharge); finally, they require less usable areas for refuelling installations.

Yet, from an economic point of view, BEBs result more convenient for 26% of lines, while HFCBs are still too expensive, when compared to other technologies, both for CAPEX and OPEX cost components. These results have been obtained considering the 2019 energy price for electricity from grid and “grey hydrogen” from Natural Gas Steam Reforming (Italian tariffs).

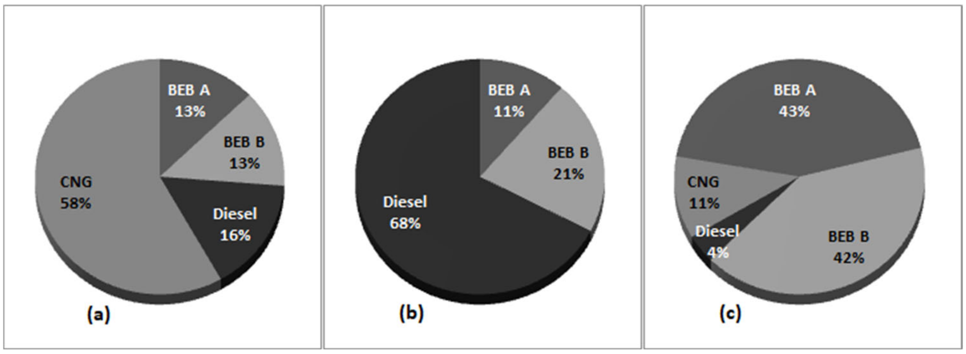

Figure 1: Economic prevalence of bus technologies in the Rome PT network along the operating life according to different energy prices (2019 (a), 2021 (b) Italy end-user tariffs) or also taking into account the cost of externalities (c)

<u>Legend:</u>

BEB A: Battery Electric Bus mostly recharged at deposit, overnight
BEB B: Battery Electric Bus mostly recharged at bus terminals, during daily operation

Taking into account the recent rise of energy prices (2021), BEBs result even more competitive (32% of bus lines) than in the 2019 case, CNG buses being the most penalised. By introducing in the analysis the incidence of the externality costs, such as local pollution, noise and GW, BEBs result more convenient than any other vehicle technological solution along the operation cycle for most of lines.

In other words, energy and environmental costs are extremely relevant in determining the economic prevalence of a vehicle technology on the others.

The more we approach to the 2050 horizon, for which net zero carbon emissions are required to avoid an increase of the global average temperature higher than +1.5 °C, the more carbon costs can result prevalent on other external costs, as it can be deduced from the graph below.

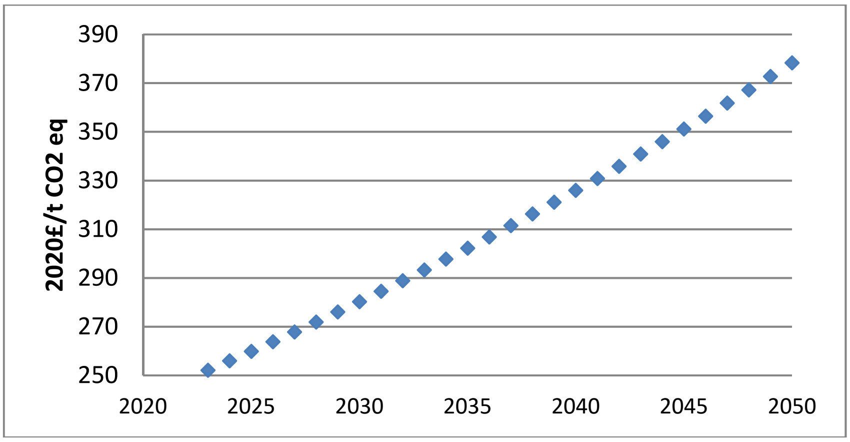

Figure 2: Carbon costs forecast to 2050 according to BEIS Dept of UK Government - 2020 [3]

Total carbon emissions along the Well-to-Wheels cycle for vehicles operation are strictly connected to the pathway chosen for producing the "fuel" employed during operation, whether it is diesel, methane, electricity or hydrogen. This is quantitatively analysed in the JRC-Eucar - Concawe study periodically updated on this subject [4].

From their analysis it emerges, first of all, that Battery and Fuel Cells vehicles can make transports less carbon intensive only if electricity and hydrogen are produced from green sources, as renewable energy sources (RESs) or, at least, natural gas steam reforming with CCS. On the other hand, we notice that also for ICE vehicles relevant overall carbon improvements are possible when using biofuels instead of fossil fuels.
The following graph compares estimates of energy and GHG emission factors of 12 m urban buses for selected low carbon WTW pathways in 2030.

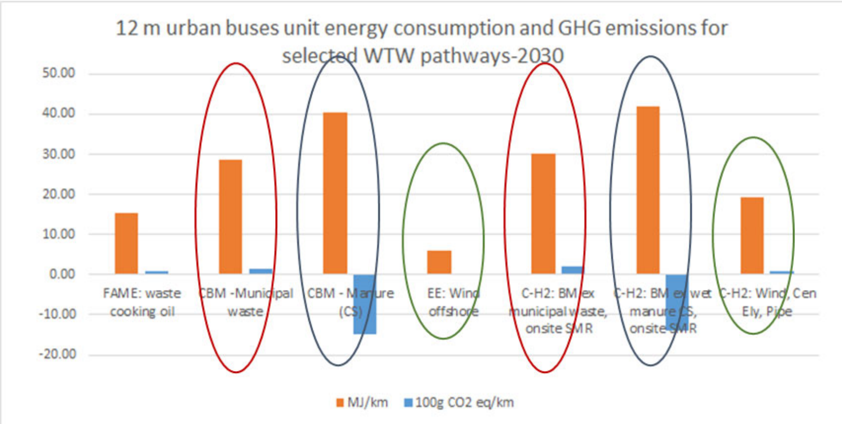

Figure 3: Energy and carbon WTW balance of urban buses according to vehicle technology and energy pathway

Source: ENEA on JRC-EUCAR - Concawe data [4]

In particular, some pathways for biomethane production from municipal waste or farm manure are very promising from a carbonic point of view, as they are able to absorb CO_2, if compared with a no-recycling scenario of the organic wastes. Unfortunately, these processes from organic materials to fuel are also highly energy intensive, and consequently also economically expensive.

In case of BEBs, if the electricity is produced from wind and directly input into the grid, the total energy required along the whole energy cycle is definitively less than for biofuels, but the net CO_2 balance is zero rather than negative.

Finally, in case of HFCBs, mainly two ways to produce green hydrogen are possible: from biomethane via SMR and from green electricity via electrolysis.

Both these processes require additional industrial activities to convert a green fuel (biomethane from waste biomass or electricity from RES) into another green fuel (green hydrogen), implying a surplus of energy consumption and GHG emissions in the WTT phase. This can be justified in case of hydrogen from biomethane, because the net WTW balance of energy consumption and GHG emissions is similar for the two cases of compressed methane engine and HFC, as can be observed in the previous graph (additional upstream consumption and GHG emissions are counterbalanced by a more efficient process at point of use).

On the contrary, comparing the net balances of battery vehicles powered with electricity generated from RES to the ones of a HFC vehicle fuelled with hydrogen produced from green electrolysis (see graph above), it appears that battery cycle is globally more efficient than HFC one.

Conclusions

In a comprehensive strategy for Transport decarbonisation, battery and HFC technologies for electric vehicles should coexist, also considering the potential of Power to X (P2X) technologies to store the excess of RES generation as hydrogen. However, at the current state of technologies and commercialisation, hydrogen in road transport should be preferred for those applications where wide ranges and flexibility are leading requirements, like long haulage.

In general, a mindful use of electricity for automotive uses (both directly o by e-fuels) must be carried out in a future where electricity demand is expected to strongly grow for all end uses, not only for transport, and electric energy will be more and more “green”, expensive and scarce respect to demand. For any transport mission, the most efficient solutions along the WTW cycle must be preferred.

Further analysis is being carried out on the energy and carbon impacts of vehicles and infrastructures construction and dismantling, for a more comprehensive comparison of different vehicles technologies role in the EU energy transition and decarbonisation.

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Christopher Ball, Philip Mayer, Stefan Vögele, Kristina Govorukha, Dirk Rübbelke, Wilhelm Kuckshinrichs

ELECTRICITY MARKET RELATIONSHIP BETWEEN GREAT BRITAIN AND ITS NEIGHBORS: DISTRIBUTIONAL EFFECTS OF BREXIT

Christopher Ball, IEK-STE, Germany
Philip Mayer, TU Bergakademie Freiberg, Germany
Kristina Govorukha, TU Bergakademie Freiberg, Germany
Stefan Vögele, IEK-STE, Germany
Dirk Rübbelke, TU Bergakademie Freiberg, Germany
Wilhelm Kuckshinrichs, IEK-STE, Germany

Overview

The EU's Energy Union foresees a progression towards ever more electricity market integration among member states. This cooperation brings benefits for energy security, greater convergence in terms of wholesale electricity prices and supports the transition to a low- carbon power system (European Commission, 2017). Brexit challenges this further integration to some extent, in that it poses a threat to greater integration between the power grids of GB and its EU neighbors, with this highlighted by the UK leaving the Internal Energy Market. The UK's departure from the IEM is likely to make cross-border power trading between the UK and the EU less efficient and may adversely affect investor incentives to expand interconnection between the GB and EU grid (Geske et al. 2020). We argue, therefore, that Brexit could lead to lower than expected expansion of interconnection capacity between the GB and EU grids by 2030. Moreover, Brexit, reflecting more difficult trading conditions between GB and the EU, has caused a depreciation of the Pound and this has implications for power trading between GB and its EU neighbors in the longer term. In this paper, we consider the distributed impacts of Brexit on the GB and EU power systems in 2030, including (i) cross-border infrastructure utilization, (ii) wholesale electricity prices, (iii) electricity trade balances and (iv) power sector-related CO_2 emissions.

Methods

We use the EMME model (European Market Model for Europe), a bottom-up electricity dispatch model (Govorukha et al., 2020) consisting of 28 EU countries (see figure 1). It is based on a linear optimization method which minimizes total system costs under transmission and operational constraints. Total system costs comprise: electricity generation costs alongside imports and exports of electricity between countries. We alter the parameters by reducing the NTC capacities between GB and the EU and by modelling a depreciation of the British Pound.
Based on these model results, we estimate emissions in addition to consumer and producer surpluses across various scenarios. The input data for the model is based on two scenarios for the evolution of the British power system to 2030, based on ENTSO-E data (ENTSO-E, 2014): (i) a Blue scenario, characterized by a unilateral high carbon price for GB and a lower expansion of nuclear and renewables in GB and (ii) a Green

scenario with a convergence of the GB and EU carbon price and greater expansion of renewables and nuclear in the GB system. For each of these scenarios, we run variants consisting of full and reduced NTC expansion and no depreciation vs. full depreciation of the Pound.

Figure 1: EMME Model Geographical Coverage

Results

Utilization of cross-border interconnection capacity is much more volatile in the Green scenarios than in the Blue scenarios, leading to questions about investment incentives under the Green scenario. Wholesale price effects in the Blue scenario are concentrated in GB and more distributed in the Green Scenario, with greater impacts from depreciation of the Pound than from lower expansion of NTCs. Under the Blue scenario, EU neighbors sell less power to the GB grid, causing a deterioration in their trade balance, whereas, under Green, the exchange rate effect outweighs the NTC effect, with EU neighbors purchasing more electricity from GB, causing their trade balances to worsen. In the Blue Scenario, the NTC effect outweighs the exchange rate effect, with rises in CO_2 emissions in GB mirrored by falls in France, Denmark, Belgium and Spain. In contrast, the Green Scenario shows a larger effect from NTCs, with CO_2 rising in GB, but slight falls in Belgium, the Netherlands and Eastern Europe.

Conclusions

It is important to model the effects of geopolitical shocks and unpredictable events in energy policy. The impacts of Brexit are highly scenario-dependent; they are more one-sided in the Blue scenarios (on GB) and more distributed in the Green scenarios (across EU neighbors).

This masks, however, a greater system-criticality of cross-border infrastructure in Green, to do with the greater reliance on VREs in the GB system.

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Anam Shehzadi, Heike Wetzel

FIRM SELF-GENERATION DECISION AND OUTAGE LOSSES: EVIDENCE FROM EMERGING AND DEVELOPING ASIAN COUNTRIES

Anam Shehzadi, University of Kassel, +4915210115448, Germany
Heike Wetzel, University of Kassel, Germany

Overview

The study investigates the role of self-generation in mitigating the outages loss to the firm and calculates the outage loss differential among the firms that opted for self-generation and those that are functioning without self-generation. The poor access to reliable and quality electricity halters or hampers economic and business activities. This, in return, leads to poor economic growth and development because access to quality and dependable electricity supply leads to improved standards of living, sustainable economic growth, a decline in poverty and unemployment rate, and rapid industrialization (Abdisa 2018). For instance, most Asian countries such as Bangladesh, Sri Lanka, and India are categorized as emerging, and developing countries encounter electricity shortages that lead to power outages. Therefore, the frequent power outages in these regions affect firms' productivity, hence having implications on their global competitiveness as it affects the production efficiency of companies, loss in revenues and outputs, and the profits they earn.

Methods

The study uses firm-level data collected by World Bank Enterprise Survey (WBES) for seven developing and emerging Asian countries from 2009-2016. The results are estimated through an endogenous switching regression model to account for possible endogeneity issues.

Results

The results provide evidence that the firm that opted for self-generation is facing less amount of outage loss. These firms are facing higher unmitigated outage loss compared to those firms that are not involved in self-generation. This finding is in line with Abdisa, 2020 & Oseni and Polliit, 2015. The results show that sign and significance of all outage loss determinants are the same for both backup and non-backup firms, but the magnitude of the coefficient is different. This difference indicates the possibility of the presence of heterogeneity in the sample.

Conclusions

The study concluded that self-generation facilitates and play a significant role in mitigating the amount of outage loss of the firm. Meanwhile, these firms are continuously facing higher unmitigated outage losses than firms that are not self-generated.

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Lyubomira Gancheva

LIBERALISATION OF ELECTRICITY MARKET IN BULGARIA IN THE CONTEXT OF THE CHALLENGES OF THE EUROPEAN GREEN DEAL AND THE GEOPOLITCS OF THE EUROPEAN ENERGY TRANSFORMATION

Lyubomira Gancheva, Sofia University 'St. Kliment Ohridski', Faculty of Economics and Business Administration, Bulgaria

Overview: This paper will provide a study on the challenges the Green Deal brings to the process of liberalisation of the energy markets in Bulgaria. It will analyse the changes to EU climate and energy law to implement the 2030 mitigation target under the Paris Agreement through the Green Deal and will explore the prospects for liberalisation of the energy markets in Bulgaria and the influence of the changes in the EU climate policy and aims for energy transformation over that process. The study will address the possibility for a more radical transformation in light of the European Green Deal and the ongoing COVID-19 pandemic. The paper is an attempt to describe the new geopolitical world that is emerging from the renewables revolution and will demonstrate the need for an active national policy. A bunch of questions will be set, concerning the Bulgarian energy mix, which need to be answered today in order to to maintain the balance of the system in the future and to fasten the course and pace of the energy transformation in the country.

Keywords: electricity, energy policy, Climate and Energy Policy Framework, Green deal, energy transformation, decarbonisation, climate change, energy market liberalisation, decentralisation, democratisation, Bulgaria

JEL Classification System: O-Economic Development, Innovation, Technological Change, and Growth: O3 (Energy), P1-Capitalist Systems: P18 (Energy), Q4-Energy: Q43 (Energy and the Macroeconomy), Q47 (Energy Forecasting), Q48 (Government Policy)

Research: The paper will analyze the measures set in the 2020 Package and 2030 Framework through the prism of the energy-climate objectives of the Paris Agreement and the European Union's Energy Union. It will set the main fundamental changes, that are taking place in the global energy system and which will affect almost all countries and will have wide-ranging geopolitical consequences. The paper will analyse the state of the Bulgarian energy system and the current energy mix on the eve of the forthcoming market liberalization. It will outline the main administrative bottlenecks to decentralisation and the challenges for maintaining the balance of the national system and will answer the question what will be the main driver for energy transformation in Bulgaria?

Conclusions: The 2030 Framework develops and enhances EU climate and energy law, but does not revolutionize it. It puts EU on a highway towards an continuous transition to a new low-carbon world rather than sets off to a radical transformation.

The 2030 Framework clearly falls short of paving the way to the radical transformation implied by the goals in the Paris Agreement, the ambition is also not in line with the EU's goal of becoming climate neutral. There is a clear need to further strengthen EU climate and energy law before 2030.

The process of energy markets liberalisation is seriously delayed in several post-Soviet countries, including Bulgaria. The combination of the forecasted changes and the climate goals will significantly alter the national energy market structure and operation. Bulgaria possesses a good long-term potential capacity for decentralized RES-based power generation. Decentralisation of power supply would empower households and contribute to the decline of energy poverty (highest in the whole EU). It would democratise and bring Bulgaria's energy and climate policies closer to the EU targets, requiring bold and complex policy-making, both at central and local government level. Several strategic national policy decisions must be taken today, in order to maintain the country's energy security tomorrow.

Valentina Gentile, Carla Costigliola, Paola Cicchetti

ENEA FOR DEVELOPMENT COOPERATION

Valentina Gentile, ENEA, Lungotevere Thaon di Revel, 76 – 00196 Rome, Italy
Carla Costigliola, ENEA, Rome, Italy
Paola Cicchetti, ENEA, Rome, Italy

Overview

The current pandemic has emphasized the link between local and global, and how important it is to improve our capacity to adopt a comprehensive approach in response to current challenges. The challenge for energy transition policies is to put in place instruments to mitigate the consequences of adverse conditions on vulnerable countries. Actions and interventions at the global level are strongly needed to protect the most vulnerable areas and their societies, communities and populations. A synergic approach, allowing participative engagements, is indeed desirable for interventions that support environmental and energy transition in developing countries. Development cooperation represents a key instrument to promote these actions, by encouraging collaboration in key sectors.

Methods

Research and innovation can play a crucial role in supporting developing countries to meet today's challenges for a fair transition, towards a stronger science-society link, for the benefit of a sustainable development leading to social well-being and economic growth. Research organizations can contribute to this process by (i) encouraging technological solutions in the fields of energy, agriculture and renewable energy sources that can be accessible and adaptable to developing countries' context; (ii) supporting training and capacity building of local communities and economic actors so that they can gain autonomy in managing technological innovations; (iii) strengthening collaboration on energy and sustainability with local actors and international organizations operating in developing countries.

Results

ENEA – the Italian National Agency for New Technologies, Energy and Sustainable Economic Development –implements cooperation activities through different types of instruments:

- **Agreements, Networks and Partnerships**: ENEA has created a wide network of exchanges and collaboration agreements with the main actors of development cooperation; it is member of national and international networks and collaborates with U.N. Agencies.
- **Technical and Scientific Support**: ENEA provides technical and scientific support at both national and international levels, also operating under specific agreements.
- **Projects**: ENEA participates in numerous projects in several countries of Africa, the Mediterranean Basin, the Near East, Latin America and in the most vulnerable countries highly exposed to climate change. The major intervention sectors are: renewable energy, climate change mitigation and adaptation, agro-industry innovation, efficient use of natural resources, water

cycle, integrated waste management, innovative health solutions, cultural heritage technologies.

- **Technology Transfer**: ENEA actively contributes to transfer technologies and know-how properly targeted at the local contexts of developing countries, creating synergic exchanges of knowledge in close connection with businesses and other actors of the innovation system.
- **Training:** ENEA provides a wide range of attended and e-learning training courses. Consistently with its policy of collaboration with academic and scientific research institutions, ENEA also grants researchers fellowships for training and career-oriented research at its own laboratories through dedicated programmes.
- **Atlas for development cooperation**: In order to strengthen technological transfer and make its expertise known, ENEA has created the "Atlas for Development Cooperation". It is an online database containing a selection of ENEA technologies and services attentive to the 2030 Agenda SDGs, as well as projects in co-partnership, where expert researchers allowed the best use of technologies adjusting them to local contexts. The Atlas also lists the agreements with international institutes and organizations mainly acting in development cooperation.

In addition, ENEA can count on a Task Force for development cooperation, where multi-disciplinary approaches to cooperation issues are discussed.

Conclusions

ENEA plays a pivotal role in researching innovative solutions supporting environmental and energy transitions. As a public body aimed at research and technology, it provides enterprises, public administrations and citizens with advanced services and expertise in the fields of energy, environment and sustainable economic development. The international scope of its activities is also extended to development cooperation through a number of instruments.

The experiences made in developing countries emphasize the central role that development cooperation can play to achieve the ultimate goal of making the energy transition happen, a transition that leaves no-one behind.

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Simona De Iuliis

EXPERIENCES AND CHALLENGES FOR SOLAR ENERGY IN THE MENA REGION

Simona De Iuliis, ENEA, Via Anguillarese 301, 00123, Rome, Italy,

Overview

The combination of a COVID-19 pandemic and a collapse in oil prices has affected all aspects of the economies in the Middle East and North Africa (MENA). In the medium run, there is a strong need to boost productivity to restore growth and stabilize the debt. A powerful way to do that would be to pursue profound institutional reforms that would reshape the role of the state, promote fair competition, accelerate the adoption digital technology, and pursue regional integration. A fragile recovery is expected in 2021 and 2022, amid a modest one in nonhydrocarbon sectors and a strong rebound in the hydrocarbon sector. Despite slowing growth rates, MENA's population will double in size during the first half of the 21st century, which will result in an increase in energy demand.

Although the countries of the MENA region have almost 100% coverage in terms of access to electricity, they are worldwide recognized to play a central role in the global clean energy transition, based on renewable energies potential. Nevertheless, during the last decade, the MENA represented only 1% of global renewables capacity additions in the last decade, remaining extremely far from its potential. Solar photovoltaics potential in the region is more than 4000 terawatt-hours per year, which is three times the current MENA's electricity demand. Despite a heterogenous history and background, the MENA countries share many common features, one of them is to pave the way for a sustainable development of solar photovoltaics.

Methods

This study aims to share ENEA's experience in collaborative projects in the MENA region regarding the development of solar energy and the differences found depending on the beneficiary country or the type of funding that allowed the implementation of the project. The common project's objective was to identify the barriers preventing solar energy market in the MENA region and define integrated roadmaps to overcome them. All the analysed projects have received funding from the European Union through different framework programmes, a summary of which is shown in the table below.

Project name	Southern Mediterranean beneficiaries	European Union funding programme
MATS - Multipurpose Applications by Thermodynamic Solar	Egypt	FP7-ENERGY-2010-2 Grant agreement ID: 268219
ORC-PLUS - Organic Rankine Cycle - Prototype Link to Unit Storage Solar Power Plant	Morocco	H2020-LCE-2014-2 Grant agreement ID: 657690
STS-MED - Small scale Thermal Solar district units for MEDiterranean Communities	Egypt, Jordan	2007-2013 ENPI CBC Mediterranean Sea Basin Programme through the Directorate-General EuropeAid Development and Cooperation Strategic project - *Topic 2.3 Solar energy*
PWMSP - Paving the Way for the Mediterranean Solar Plan	Algeria, Egypt, Israel, Jordan, Lebanon, Morocco, Palestine, Syria, Tunisia	EuropeAid Tender for Technical Assistance - Contract N° EuropeAid/129020/C/SER/MULTI
MED-DESIRE - MEDiterranean DEvelopment of Support schemes for solar Initiatives and Renewable Energies	Egypt, Lebanon, Tunisia	2007-2013 ENPI CBC Mediterranean Sea Basin Programme through the Directorate-General EuropeAid Development and Cooperation Strategic project - *Topic 2.3 Solar energy*
TAKA NADIFA - Programme d'Appui de l'Union européenne aux secteurs des énergies renouvelables et de l'efficacité énergétique en Algérie (PAEREE)	Algeria	EuropeAid Tender for Technical Assistance - Contract N° EuropeAid/138560/DH/SER/DZ
meetMED I & II - Mitigation Enabling Energy Transition in the Mediterranean region	Algeria, Egypt, Jordan, Lebanon, Libya, Morocco, Palestine, Tunisia	Technical Assistance through grant Directorate-General for Neighbourhood and Enlargement Negotiations (DG NEAR) - Southern Neighbourhood

Results

ENEA experiences were challenging and somewhat risky projects, being its objectives ambitiously targeting the legislative and regulatory frameworks of our Mediterranean Partner Countries. Notwithstanding this, we succeeded in promoting a process of change that affected all the key project issues, like the adoption of new training curricula for solar technicians, the introduction of solar photovoltaics standards for system components and the whole plant and the definition of innovative financial support mechanisms for the promotion of distributed solar technologies.

Besides we succeeded in building two technological platform to test solar energy technologies. All was possible due to the strong involvement in the project activities of the key local stakeholders, ranging from national and local authorities and, standardization bodies and certification laboratories, research organizations to financial institutions and banks, energy utilities and companies.
Nevertheless, when the activities involve implementation of measures leading to an improvement of the regulatory and legislative framework what we could offer is just a capacity building programme for policymakers.

Conclusions

Renewable energies are the solution to accelerate the phase out from fossil fuels, but more investment and strong support are needed to aid the energy transition for emerging countries to achieve carbon neutrality in time before climate change becomes irreversible. The cooperation is fundamental to foster the development of a sustainable common energy market in the MENA region. There is still a long way to go to unlock the potential of solar energy in the MENA region. We still need to work on harmonising the regulatory framework, adopting common standards, and decreasing the perception of high risk in private investments.

Massimo D'Isidoro, Lina Vitali, Francesco Pasanisi, Gaia Righini, Mabafokeng Mahahabisa, Mosuoe Letuma, Muso Raliselo and Mokhethi Seitlheko

RENEWABLE ENERGY POTENTIAL MAPS FOR LESOTHO

Massimo D'Isidoro, ENEA, Via Martiri di Monte Sole 4, Bologna, Italy.
Lina Vitali, ENEA, Italy.
Francesco Pasanisi, ENEA, Italy.
Gaia Righini, ENEA, Italy.
Mabafokeng Mahahabisa, Lesotho Meteorological Services - LMS
Mosuoe Letuma, Lesotho Meteorological Services - LMS
Muso Raliselo, Lesotho Ministry of Energy and Meteorology
Mokhethi Seitlheko, Lesotho Ministry of Energy and Meteorology

Overview

The Kingdom of Lesotho is a landlocked African state entirely surrounded by the Republic of South Africa with an area of 30,355 km2, mostly covered by natural vegetation and agricultural land, with built-up areas accounting for 4.1% of the territory, barren lands 5.0%, water bodies and rivers 0.9%, and wetlands 1.1% (FAO, 2017).

Electricity supply in Lesotho has continuously increased over the last decades from about 200 GWh per year in 1990 to 900 GWh per year (UN, 2021); this increase of electricity demand in Lesotho is associated with growing rate of population with access to electricity but its production in Lesotho is not sufficient to meet the internal demand and the deficit is compensated by imports from South Africa and Mozambique. The following main opportunities can be recognized about energy sector on the use of RE sources: an abundance of local RE sources (hydro, solar and wind), still largely unexploited and a possibility to match the development of the national energy sector with environmental policies aimed to preserve the environment from degradation and implement climate change adaptation and mitigation strategies, with access to international cooperation programs. In this regard, over the last decades a great effort was devoted by Lesotho's institutions and stakeholders to electrification projects, funded both with internal resources and from international cooperation programmes, with a particular attention to rural areas.

Considering the context described above, a project was launched in 2018 in fulfilment of the Paris Agreement by the Italian Ministry for the Environment and the Lesotho Ministry of Energy and Meteorology, with the aim to facilitate the local Government in the future planning and development of renewable energy in the country. A user-oriented WebGIS platform was utilised to share and analyse the outcomes of the project: a hydrological map to recognize potential areas for power generation; a wind atlas to identify specific sites with the most potential for wind energy generation; a solar radiation map, defining the different levels of radiation intensity, useful to localise sites for photovoltaic production.

Human capacity building and technology transfer were also carried out to strengthen the local expertise and ability to manage and plan renewable energy sources exploitation.

Method

In order to estimate the photovoltaic and wind power potential over Lesotho, meteorological simulations were carried out using the Weather Research and Forecasting (WRF) numerical model. In particular, a specific augmentation of WRF, the WRF-SOLAR (Jimenez et al. 2016) was used. A preliminary test simulation was carried out to the scope of choosing the best model configuration for our purposes: a yearly simulation was repeated using three different combinations of some relevant parameterisations available in WRF, and the observational data of wind and solar radiation were collected from the Lesotho authorities to be compared to the corresponding modelled quantities. After comparing modelled data with observations, the best performing WRF setup was adopted to perform the multiannual assessment of wind and solar photovoltaic energy resources; a 30-year simulation covering the period 1989–2018 was carried out to obtain renewable energy estimation that is representative of the inter-annual variability of meteorological conditions in Lesotho. The implemented modelling chain consisted of single 30 h simulations restarted every day at 18UTC using the ERA5 reanalysis at the boundary of the parent domain, considering the first 6 h as a spin-up period. Then, hourly model outputs of the following day from 00UTC to 23UTC were retained every day. The computing effort to accomplish the 30-year period simulation was supported by the ENEA HPC facility CRESCO (Computational RESsearch Centre on COmplex systems) (Iannone et al. 2019). Once the whole period was completed, the 1 km resolution WRF 3-dimensional fields in output were post-processed to obtain hourly values of the quantities needed for energy potential estimations. In particular, wind speed and air density, interpolated at four different heights above ground (50 m, 100 m, 150 m and 200 m) were extracted for wind energy estimations, while 2 m air temperature and ground solar radiation were used for photovoltaic estimations. Concerning the hydrological map, the river network and catchment divides were derived from elevation data, described by a DEM (digital elevation model), using state-of-the-art geoprocessing tools operating in GIS Environment. Namely, the QGIS (QGIS, 2021) software integrated with the TauDEM (Tarboton, 2003) suite of hydrological tools, both distributed as free and open-source software, were used in the present work. The following steps were performed using specific algorithms: DEM pre-processing for pit removal, detection and mapping of flow directions, computation of contributing areas, stream definition by threshold, delineation of stream reaches and watersheds. Results were validated by comparison with available cartographic and hydrographic data. In order to visualize and manage the project products, a WebGIS platform was developed with system based on an Ubuntu Linux (version 18.04) machine configured with the open source software Apache HTTP Server, QGIS, version 3.10.4, with web server capabilities (QGIS server) and LizmapWeb Client to interface QGIS and the web.

Results

An interactive WebGIS tool, including more than 120 data layers, was the final and comprehensive outcome of the project as all the developed maps describing spatial distribution of renewable resources

were embedded into the WebGIS database. The home graphical user interface page offers access to four main data sections.
Three of them correspond to the renewable resources investigated within the project: the photovoltaic and wind energy maps, describing respectively the spatial distribution of solar and wind power energy availability, the hydrological map, useful to identify potential sites for hydropower generation. Moreover, since the WRF model provides the whole atmospheric state, a fourth section was added including accumulated annual precipitation fields, which can be useful to deepen the assessment. Additional products produced within the project were integrated too, together with available ancillary data, which could be useful for the identification of promising sites for renewable energy exploitation or, conversely, to point out restrictions or spatial constraints. This tool and the whole dataset were completely delivered and entrusted to the main local beneficiaries and project partners. In order to boost technology transfer, specific activities were focused on the use of the products available. Two different sessions of human capacity building were carried out at the end of the project, in Maseru, capital city of Lesotho: an intensive four days training course for 30 technicians and experts to describe in detail the renewable energy potential maps, the GIS database and the WebGIS tool and a one-day workshop for 20 stakeholders and managers to present and broadly illustrate the renewable energy potential maps and the WebGIS.

Conclusions

The developed WebGIS tool is an important step forward to assist local experts and technicians in gathering and managing comprehensive information on REs in an interactive and integrated way. This provides local authorities with an essential input to the decision-making process in the planning and development of RE exploitation strategies. It is worth mentioning that anyway further investigations on impacts of RE deployment to nature and ecosystems should be carried out, which was out of the scope of this work. Results of the project confirmed the high potential of Lesotho in terms of RE sources, and the long-term vision of the energy policies established by Lesotho's institutions, essentially focused on RE to support electrification programmes and foster the sustainable social and economic development of the country avoiding an increase of greenhouse gas emissions, under the auspice of the U.N. Agenda 2030. The multidisciplinary approach of the project could be replicated, adapted and scaled-up to different developing countries in Sub-Saharan Africa and in other regions of the world.

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Corinna Viola, Alicia Tsitsikalis

meetMED II: REGIONAL COOPERATION FOR AN ENERGY EFFICIENT FUTURE

Corinna Viola, ENEA, Via Anguillarese 301, 00123, Rome, Italy
Alicia Tsitsikalis, ADEME, Frannce

Overview

Energy efficiency and renewable energy strategies and policies are key to the sustainable development of every country. The majority of the SEMCs (South-Eastern Mediterranean Countries) has been working hard on these topics and has put in place national energy strategies, national energy efficiency and renewable energy action plans, as well as investment funds to help promoting the dissemination of good practices.
meetMED II (Mitigation Enabling Energy Transition in the Mediterranean Region – phase II) project's overall objective aims to contributing to enhancing the energy security of beneficiary countries, that is Algeria, Egypt, Jordan, Lebanon, Libya, Morocco, Palestine and Tunisia, while fostering their transition to low carbon economy, thereby contributing to more stable, efficient, competitive and climate-resilient socioeconomic contexts. Its activities aim at strengthening the implementation of energy efficiency measures, and improving countries' energy mix focusing on building and appliances' sectors through a multiscale, multi-partner and inclusive approach at local and regional levels, fostering regional cooperation, capacity building and stakeholders' engagement.

Methods

With the scope of contributing to energy and climate transition in Southern Neighbourhood, meetMED II activities aim at fostering regional cooperation for energy efficiency measures and implementing demo actions.
A set of demonstration actions/projects for energy efficiency in buildings (possibly including RES solutions) and promoting efficient appliances, shall be implemented in a minimum of 2 of SECMs in order to allow for a proper sharing of experience based on in-depth technical and financial analysis, and on the assessment of the methodologies' replicabilities in other countries.
Thematic events, called meetMED weeks, will take place once a year for three years in different countries, with the goal to mobilize and engage national stakeholders, local authorities, private sector operators, civil society and population, at regional and local level, in order to disseminate good practices in building and appliances' sectors, facilitate the development and replication of energy efficiency measures, foster the deployment of renewable energy, and increase public awareness and investments in these sectors.

Results

The project will establish permanent discussion forums at regional level gathering the relevant stakeholders, including but not limited to representatives of governments, local and regional authorities, financial sector and IFIs (International Financial Institutions) / NFIs (National Financial Institutions), homeowners and civil society organizations, industry and construction sectors, ESCOs and business associations. Through the demo actions, beneficiary countries will have exchanged a variety of good practices and learned from them, strengthening the participants' network enabling further cooperation beyond the duration and the scope of meetMED II.

Conclusions

The wide outreach can provide clear and replicable cases that can drive change and establish alliances and partnerships among institutions and conduct common energy efficiency and renewable energy activities in the future. More broadly, governance bodies shall be influenced by the outcomes and policy recommendations stemming from the discussions as well as from the results of the demo actions. That is, decision makers might take the results of the project into account when they will develop new legislative and regulatory acts and strategic decisions, such as the update of NEEAPs (National Energy Efficiency Action Plans), NREAPs (National Renewable Energy Action Plans) and long-term energy strategies. Energy Efficiency indicators and trends on the residential and tertiary sectors (such as energy intensity) are expected to reverse in order to be coherent with Nationally Determined Contributions (NCDs) objectives.

Cecilia Camporeale, Massimo Angelone, Giacomo Pallante, Marco Stefanoni

RENEWABLE ENERGY IN DJIBOUTI: A POLITICAL, TECHNICAL AND ECONOMIC ASSESSMENT

Cecilia Camporeale, ENEA, Via Anguillarese 301, Rome, Italy
Massimo Angelone, ENEA, Rome, Italy
Giacomo Pallante, ENEA, Rome, Italy
Marco Stefanoni, ENEA, Rome, Italy

Overview

The energy sector is a crucial factor for the economic development of every country (Ciscar and Dowling, 2014). Forecasting the energy demand and how to meet it is one of the main issues on the political agenda of the African governments in order to plan appropriate investments that can support the region's economic transition and reduce energy poverty (Dinkelman, 2011) and long term dependence on fossil fuels (Ouedraogo, 2017).
Despite being one of the poorest countries in the world with a scarce stock of natural resources and an industrial sector that still needs to take off, Djibouti – the smallest country in Africa – is located in one of the busiest and strategic maritime trade routes and a GDP growth rates, in real terms, that has been stable around 6% during the past 4 years.
The Djibouti energy system is mainly based on fossil fuels and electricity imports from Ethiopia. In order to cope with the growing demand and ensure energy availability, the Djibouti government has set the ambitious target of 100% renewable energy production, in which the country is particularly rich. This should ensure the sustainability of growth, reduce climate and geopolitical risks arising from the current exposure to both oil fluctuations and the domestic needs of neighbour Ethiopia (avoiding seasonal interruptions).
Given its climate and geography, Djibouti could potentially develop a diversified portfolio of renewable energies, especially geothermal, wind and solar, at different scales, not jet fully explored.
In this work, we analyse three possible scenarios that, with a different mix of RES, ensure an increasing degree of energy independence by 2030. In addition, we want to provide a first technical and economic feasibility study of the potential RES mix, highlighting for each scenario the economic viability of the solution, while the choice of how to plan the future energy strategy is certainly a political option that requires a strategic geopolitical vision, which is not the aim of this paper.

Methods

In this paper, we will analyse the potential for a complete and secure transition of Djibouti to a 100% renewable energy system.
Our results are useful to evaluate how to achieve sustainable and domestic energy security so as to tackle, at the same time, the increasing market price volatility and the climatic risks that could affect the electric supply from Ethiopia.

By predicting the electricity demand to 2030 we provide three scenarios where the assessment of a mix of renewables is evaluated: i) a "full-independence" scenario where the 100% of electricity is supplied with domestic resources; ii) scenarios 2 and scenario 3 both include an increasing trend of dependence on Ethiopian hydroelectric but keeping into account the current agreements between the two countries although limiting the weight that this source would have on the future Djiboutian demand increase.
In addition, we evaluate the *Levelized Costs of Electricity (LCOE)* of the suggested mix, which corresponds to the ratio between the *Net Present Value (NPV)* of an investment in a new electricity technology and the electricity delivered for this technology over its lifetime.

Results

Taking into account, the forecast of real GDP to 2030 as driver to the energy demand, all the scenarios satisfy the estimated electricity consumption to 2030. Scenario 1 requires the lowest total rated power but relies on just three sources and thus the requirements for the power to be installed is higher. On the contrary, Scenario 2 and 3 are similar, with the exception that in Scenario 3 the highest level of import from Ethiopia is compensated with a lower PV installed power.
Consequently, to this mix of primary energy sources, the hydro-storage size in Scenario 1 is greater, in Scenario 2 is smaller, in Scenario 3 it is equal to zero.
These numbers have been selected to balance the electricity grid at monthly level accounting for the seasonality of RES chosen, the hydro storage and the import from Ethiopia.

Conclusions

The country has a high energy potential to develop: solar, wind and geothermal sources. The Government of Djibouti recognizes this potential and it is aware that the economic growth should be characterized by a sustainable development pattern (République de Djibouti, 2014).
The main goal, defined in the intended nationally determined contributions (INDC) of the Paris Agreement, is to reduce the long term GHG emissions at the level of 2010. Djibouti has planned to reduce emissions by 40% relative to the baseline scenario (République de Djibouti, 2015).
This goal also pushed Djibouti to recognize the need to produce domestic electricity with 100% of RES. Investments required to fulfill these goals are huge, but the Government projects to invest more than USD 3.8 billion to reduce its overall emissions by a further 20% by 2030. Additional resources are planned to be received from international donors, as defined in the climate finance mechanisms of the Paris Agreement (République de Djibouti, 2015). Nevertheless, Djibouti is highly reliant on fossil fuel import and hydroelectric power from Ethiopia.
For the RES mix to be considered affordable, it must be at least competitive with the existing generation costs. This means that the generation costs should not exceed the estimated fossil fuel and carbon cost of 0.100–0.150 USD/kWh (Labordena et al. 2017).

Our results concentrate on demonstrating the competitiveness of a suggested mix of RES both when convenient interest rates are applied but also when the country specific risk is kept into account within the calculation of investment costs. Thus, this creates a possibility for the Government of Djibouti to be highly committed to follow its sustainability goals without affecting the national competitiveness.

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Zhao-Rong Huang, Quan-De Qin
HODRICK–PRESCOTT FILTER-BASED HYBRID ARIMA–SLFNS MODEL FOR CARBON PRICE FORECASTING

Zhao-Rong Huang, Shenzhen University, Shenzhen, China
Quan-De Qin, associate professor at College of Management, Shenzhen University, and Shenzhen, China

Accurate carbon pricing guidance is of great importance for the inhibition of excessive carbon dioxide emissions. However, traditional hybrid models and multiscale models cannot easily cast a perfect reflection of erratic fluctuation in carbon trading schemes. By rethinking the rational assignment criteria for the combination hybrid models, this study presents a novel Hodrick–Prescott (HP) filter-based paradigm combining autoregressive integrated moving average with Student's t-distribution (ARIMA-t) and single layer neural networks (SLFNs) for synchronously capturing linear and nonlinear patterns in carbon prices. Moreover, the residual decomposition scheme with adaptive noise is carried out on the random and nonlinear component for error correction to the filter-based models. Bayesian optimization adjusts the structure of SLFNs and the inputs to provide the best generalization performance. In comparison with the decomposition-allocation-based models and other data-driven models in the current studies, the proposed hybrid models using kernel extreme learning machine as the final nonlinear integrator achieve competitive prediction accuracy in the majority of carbon price cases. The findings of this study add to a newborn body of literature on filter-hybrid frameworks and residual analysis in application to price forecasting projects.

Yu-Zhu Wang, Jin-Liang Zhang

ANALYSIS ON THE CURRENT SITUATION OF CHINA'S POWER SYSTEM REFORM

Yu-Zhu Wang, Yantai University, Shandong, China, School of Economics and Management, North China Electric Power University, Beijing, China
Jin-Liang Zhang, School of Economics and Management, North China Electric Power University, Beijing, China

The power reform should break the monopoly and build a competitive power market. The institutional framework of China's power reform is based on the further improvement of the separation of government and enterprises, plant network and main and auxiliary, and the institutional framework of controlling the middle and liberalizing the two ends; The path is "three liberalizations, one independence and three strengthening": that is, orderly liberalizing the price of competitive links other than transmission and distribution, orderly liberalizing the power distribution business to social capital, and orderly liberalizing the power generation and consumption plans other than public welfare and regulation; Promote the relative independence of trading institutions; Strengthen government supervision, strengthen overall power planning, and strengthen safe and efficient operation and reliable supply of power.

Zi-Jie Wang, Lu-Tao Zhao

THE IMPACT OF THE GLOBAL STOCK AND ENERGY MARKET ON CARBON MARKET: A PERSPECTIVE FROM EU ETS

Zi-Jie Wang, Peking University HSBC Business School, Shenzhen for Master of Finance (Fintech Track), China
Lu-Tao ZHAO professor School of Management and Economics and deputy director of the Center for Energy and Environmental Policy Research, Beijing Institute of Technology, Beijing, China

The industrial revolution has brought about great development in the economy, but it has also increased the dependence on fossil energy. The emissions of CO_2 and other greenhouse gases have contradicted economic development and the ecological environment. The establishment of the EU Emission Trading System (EU ETS) has improved the global carbon emission price mechanism, but as a new commodity, its price trend will affect buyers' risk evaluation. Therefore, it is influential to master the driving factors behind carbon emission prices and make effective predictions. First, the paper points out that the driving factors are divided into macroeconomic risk factors and energy factors. Second, the Bayesian Network is used to select variables and make prediction of carbon prices. The results show that its accuracy exceeds other machine learning algorithms. Third, a structural equation model is used to study the impact of the selected markets on the carbon market. Finally, from the perspective of global carbon emission reduction, the relationship between driving factors and the carbon futures market is explained.

Hui Hu, Ming-Fang Li

ANALYSIS OF KEY FACTORS INFLUENCING CARBON MARKET FROM THE TIME-VARYING PERSPECTIVE：EVIDENCE WITH A MARKOV-SWITCHING VAR APPROACH

Hui Hu University of science and technology Beijing. China
Ming-Fang Li associate professor , School of Mathematics and Physics, University Science and Technology Beijing, China.

In order to achieve sustainable human development, many countries have successively committed to reach the goal of carbon neutralization. The establishment of carbon market is widely regarded as an effective means to control global carbon emissions. The paper uses the least absolute shrinkage and selection operator (LASSO) method to select the key determinants, and then uses the Markov switching vector autoregressive (MSVAR) model to study the driving factors of carbon market and analyze the interaction between carbon market and other markets. The results show that the coefficients and variances of MSVAR model are different in the two regimes, but the intercept is the same. Based on the transition probability matrix, it can be found that the low volatility state is persistent. Under different regimes, the impact of energy market and stock market on carbon market is different. In each state, macroeconomic factors can better explain price fluctuations. It should be noted that oil price is the key to monitoring the short-term low volatility risk of carbon futures. In terms of emission reduction actions, countries around the world should change their energy consumption structure, reduce the use of coal and turn to a cleaner energy consumption structure.

Papers

APPRAISAL OF NIGERIA'S ENERGY PLANNING: PROSPECTS FOR SUSTAINABLE DEVELOPMENT

Olasunkanmi Olusogo Olagunju
Centre for Economic Policy Analysis and Research, University of Lagos,

Olufemi Muibi Saibu, PhD,
Department of Economics, University of Lagos

Isaac Chii Nwaogwugwu, PhD
Centre for Economic Policy Analysis and Research, University of Lagos

Maryam Modupe Quadri, PhD,
Department of Political Science, University of Lagos

Oludayo Ayodeji Akintunde,
School of Science and Technology, Pan Atlantic University

Abstract

This research endeavours to chronicle the impacts of effective planning on sustainable development. Having examines the contributions of energy planning to climate change, public health, social welfare, economic growth and/or responsible consumption, the paper unveils that viable institutional planning can culminate into job creation, business growth and investments. With institutional model and content analysis, the paper revealed that poor planning has effect on the capacity of Nigeria energy sector. Based on proper review of data from government archives, journals, conference or seminar papers, the research work scrutinizes the need for energy planning to implement the sustainable development goals in Nigeria. However, it is concluded that policy reforms and strategic collaboration can boost the capabilities of the Nigerian energy sector. This research paper initiated some policy endorsements which may be instrumental for coupling energy planning into sustainable development strategies of government.

Keywords: Energy, Planning, Development, Policy and Institution

Introduction

Energy production and supply plays prominent roles in all aspect of socio-economic livelihoods. Notably, the Covid-19 pandemic, the drastic fall in oil price, coupled with budget cuts by the national government had highlighted the criticality and essentiality of energy planning and policies to enhance optimal production and supply needed for national development (Birol, 2018; Harold, 2019). Moreover, energy planning—coupled with effective decision making—is very vital to implementing the Sustainable Development Goals 2030 due to its contributions to economic and social development of any, nation (Aliyu, et al. 2019). In other words, the development of Nigeria is seriously hampered by weak planning in either energy production or supply.

This has wholly constrained socio-economic activities, weakened the prospects for macroeconomic stabilization and has adversely impaired the quality of human life. However, Iñaki et al. (2019) and Loftus et al. (2015) implied that sustainable energy planning can foster unprecedented upscaling of living standards of Nigerians through incessant growth in the production of food materials, job creation and business growth, increased production of industrial outputs (Diakoulaki, et al. 2020), unrestrained access to ample transportation facilities, and other social services (Ambrose, 2019). All these human needs require incessant increased energy production, distribution and consumption.

According to Energy Commission of Nigeria (2020), energy planning in Nigeria usually occurs at four (4) different levels—national level involves macro-planning which represents part of the multi-sectoral national development policies and plans. These are the responsibilities entrusted to a key national planning institution especially the Energy Commission of Nigeria, established through Act No. 62 of 1979. However, the sectoral level perhaps focuses on overall sectoral planning, monitoring and/or co-ordination of policy implementation in the energy sector, in all its ramifications. At the sub-sectoral level, a more specific sub-sectoral planning and policy frameworks for the development, exploitation and utilization of particular energy-related resources are devised. However, this type of planning is exercised through the various energy sub-sectors—oil and gas, electricity, solid minerals and renewables. At the operational level, planning activities encapsulate the execution of the policies and programmes developed at the sub-sectoral level by the pertinent operational establishments of government.

A strategic planning in energy sector is required to help governments meet the future energy requirement in the nation—this is projected to grow with increase in demands by the citizens, industrialization and a host of other socio-economic factors. In most cases, Nigeria is probably one of Africa’s most prolific oil producing countries, which together with Libya, accounts for two-thirds of Africa's crude oil production and reserves (Lathia, et al. 2017). Nigeria ranks second to Algeria in the availability and production of natural gas. Most of Africa's bitumen and lignite reserves are found in Nigeria. In Nigeria’s mix of conventional energy reserves, it is rarely matched by any other country on the African continent.

However, planning in the energy sector in Nigeria is extremely imperative due to energy use in this nation which has drastically risen overtime more than fourfold over the past decades. This is expected to continue increasing speedily in the near future. The increase in the services that energy provides is necessary and desirable, since energy services are essential to Nigerian economic growth, improved living standards, and to provide for increased human populations. But sustainably funding energy production and supplies to provide these welfare services has led to severe environmental, economic and social problems. Also, building dams or power plants to meet higher demands for electricity has pushed these nations even deeper into debt traps (Bazin, 2012).

However, Edenhofer & Pichs-Madruga et al. (2014) and Martire et al. (2015) explained that weak energy planning has contributed to local environmental havocs, including record levels of air pollution in some urban areas. The swift growth of energy use in Nigeria has wide implications for sustainable production and responsible consumption. More specifically, Vasudev, & Sujal (2017) and Simon (2020) unveiled that the rapid increases in fossil fuel use in Nigeria also represent a growing contribution to the increase in local and regional air pollution as well as atmospheric concentrations of greenhouse gases such as carbon dioxide (CO_2). However, Vierros (2017) and international efforts to control greenhouse gas (GHG) emissions require active action cum coordination from Nigerian government.

Invariably explained by Harold (2019), Nigeria could be adversely affected by chronic climate change which may be much more than most industrial nations such as the United States, China, and the European Union among others. An economically and environmentally sound approach to energy planning and supply reforms offers potentially large benefits for Nigeria and the global economy. Simply put, the primary energy resources have continued to dominate the Nigeria's industrial raw materials endowment. Moreover, Nigeria's industrialization largely depends on how its energy resources are harnessed either as fuel or as industrial input.

However, over-dependence on oil is perhaps ubiquitous in Nigerian economy, this is evident from the fact that oil revenue—as a percentage of the nation's total export earnings—soared from 13.5 per cent in 1956 to 96.5 per cent in 1979. Since then, crude oil production has accounted for 30 per cent of GDP and about 80 per cent of total government revenue (Aliyu, et al. 2018; Lathia, et al. 2017; Harold, 2019). It is against this background that this paper looks into the potential of energy planning on implementing the sustainable development goals in Nigeria. It scrutinizes the nexus between energy planning on reinforcing economic growth—with reference to—higher living standards, reduction of hunger and poverty, and better environmental quality. This strategy also holds higher benefits for the developing countries; improved energy technologies can slow the rate of increase in greenhouse gas emissions for global benefit.

Conceptual Review

Due to the dearth of a universally definition of planning, this paper largely builds on various definitions put forward different scholars, policy analysts, researchers, administrators as well as decision makers to mention but a few. However, planning in Seeley (2008) implies the process of settings goals, developing strategies, outlining the implementation arrangements and allocating resources to achieve those goals. In Ambrose (2019), planning is construed as the process of thinking about the activities that are necessarily required to actualize a desired goal. Each plan leads to several programmes. Hence, planning is effective if it is a rational, dynamic and integrative process. Furthermore, it is of particular significance to an underdeveloped country where a lot has to be achieved with limited resources and within time-frame work. However, Messner et al. (2000) and Diakoulaki et al (2005) conceptualized that planning mostly conceptualized as the bedrock of any nation's development efforts. There can be short-term or medium-term or long-term planning. It is perhaps the future actions envisioned by a corporate body, Ministry, Department or Agency, and perhaps represents the methods to be employed for doing them in order to achieve specified goals.

Energy literally implies the power utilised for transportation, for heat and light in our homes and for the manufacture of all kinds of products (Aliyu, et al. 2018; Ambrose, 2019). In other words, energy has two (2) sources, namely, **renewable** and **non-renewable**. In a nutshell, energy is vital for human growth and industrialization which is necessary for achieving the sustainable development goals. Thus, energy basically includes fossil fuels, such as coal, natural gas and petroleum. Simply put, uranium represents one of the nonrenewable energy, but it is not a fossil fuel. Uranium is converted to a fuel and used in nuclear power plants (Harold, 2019). Once these natural resources are consumed or depleted, they vanish forever. However, renewable sources of energy can be used recurrently. More so, energy varieties also include solar, wind, geothermal, biomass and hydropower energy. The facts remain that they generate much less pollution, both in gathering and production, than non-renewable sources.

Overview of Nigerian Energy Planning

For a comprehensive analysis of energy planning in Nigeria, more emphasis is laid on the Nigeria's power sector. However, the Nigerian power sector still operates well below its estimated capacity, with power outages being a frequent occurrence (Orvika. & Vennemo, 2012). To compensate for the power outages" the commercial and industrial sectors are increasingly utilizing diesel generators for electricity supply. In 2004, the total installed electricity capacity was 5.9 gigawatts (GW), total electricity generation was 19 billion kilowatt per hours (bkwh), while the aggregate consumption was 18 bkwh.

However, less than 60 percent of Nigerians have access to electricity, the majority are concentrated in urban areas (Federal Ministry of Power, 2020). Despite endemic blackouts, customers are billed for services not consumed, which to some extent explains the rationale for Nigeria's widespread vandalism, power theft and compliance problems regarding payment collection. Nigeria has an electricity projection quagmire but nevertheless will improve in ranking, as compared to the African high rated countries with respect to power, such as South Africa.

The government proposes to generate certain minimum power requirement before 2020 which ranges from 15,000MW of electricity by 2008, 20,000MW by 2010 to 200,000MW by 2020 (Federal Ministry of Power, 2020). Transmission and distribution lines projects were to be embarked upon to cover the entire country. Recognizing the primary role of gas to enhancing generation capacity, government also factored pipeline installation into the programme, working harmoniously with the generation (Edenhofer & Pichs-Madruga, et al. 2014; Newburger, 2020; Lathia, et al. 2017). To actualize these mandates and boost operational capability, the government decided to split the responsibilities regarding energy regulation, production and supply among Transmission Corporation of Nigeria, Generation companies and Distribution companies, with ultimate authority regarding planning, regulation, monitoring and evaluation of performance resided in the Ministry of Power.

The Energy Targets in the Power Sector

The targets in Nigeria's energy sector was purposed to be achieved in both power sector and sub-sector and oil and gas sector and sub-sector. Nigeria is set to achieve some aims and objectives for the energy sector particularly the power and oil and gas sub-sectors. For the power sub-sector the **priorities** identified by the national government are to increase power generation from the current 3.5MW to 20 GW by 2018 and to 350 GW by 2043, with focus on gas as the immediate priority and adding alternative sources after 2023 (Federal Ministry of Power, 2020). Another pivotal target of planning in the power sector is to adequately strengthen and increase transmission capacity, with immediate focus on the national productivity.

However, this will foster growth in the distribution capacity, with priority being placed on making power available for industrial users and investors and thereby reducing distribution losses. According to Energy Commission of Nigeria (2020), target in the power sector will aid the finalization of privatization of power generation and distribution, and extend privatization to include Nigerian Integrated Power Project assets. Also included in these targets is to spearhead capabilities which have the prospects of increasing human capacity 20 times by 2023 and 40 times by 2043 (Lathia, et al. 2017; Harold, 2019). Therefore, the target will foster increase and sustained rural electrification as well as aiding the smooth implementation of all power infrastructure projects in compliance with available international best practices.

However, for the power sub-sector, there are several targets for the period 2014-2043. The overarching goal is to increase average generation capacity from today's about 7 GW to 350 GW by the end of the 2043, and to enable adequate transmission and distribution delivery capacity for energy output to end-users. This is opined to give Nigeria 80 percent of the per capita generation capacity of the present day United States in 2043 (Birol, 2018; Lathia, et al. 2017; Newburger, 2020), and will require Nigeria to build in excess of 10,000 MW of capacity per annum for the next 30 years. To achieve this, Nigeria will need to leverage on national capabilities. This will be achieved through aggressive training and research and development activities. Currently, low local content in both technological and human resource input remains a major challenge in the sector.

The Energy Targets in Nigerian Oil and Gas Sector

As earlier explained, Nigeria has set ambitious objectives for the energy sector. For oil and gas sector, the priorities are to provide gas distribution infrastructure to increase gas utilization; increase capacity in oil/gas production and supply; increase refining capacity to fully meet national demands; intensify exploration activities; increase the percentage of capital expenditure; increase bulk storage capacity for oil and gas; increase the capacity of the pipeline network; and increase the use of sustainable fuels (Federal Ministry of Power, 2020).

However, the prominent goal in the oil and gas sub-sector is to advance "gas to power" in order to meet the rapidly growing energy demand in the ecosystem. The target is to increase oil production to 4 mbpd, and increase refining capacity to a level which would meet local demands and export potential, estimated at 4 mbpd by 2043, with the target of becoming self-sufficient in premium motor spirit (PMS) by 2030 (Orvika & Vennemo, 2012; Sachs, et al. 2019; Vasudev & Sujal, 2017). Similarly, Nigeria plans to boost its gas production capacity from 7,580 to 11,000 mcfpd by 2018, 15,000 mcfpd by 2023 and 30,000 mcfpd by 2043.

The increase in gas production is vital to supply the planned gas power stations and develop other gas-based industries, such as fertilizers, agro-processing and petrochemicals. These are ambitious targets, especially against the backdrop of historical performance (Sachs, et al. 2019; McNeil, et al. 2019). For example, upstream oil production has been between 1.1 and 2.6 mbpd in the last 8 years as a result of security issues, crude oil theft, and long-term funding challenges of Nigerian National Petroleum Corporation (NNPC).

When it comes to midstream, there is an apparent shortfall in refined outputs, with the difference exemplified by the very expensive subsidies. Current data suggests that Nigerian refineries run at a low capacity utilisation rate of below 35 per cent (Ambrose, 2019). The resultant manufacturing capabilities of the gas-based industries are set to grow accordingly. In terms of exploration, the goal is to grow natural gas reserves from 187 Tcf to 191.5 Tcf in 2023 and 200 Tcf in 2043 (ECN, 2020; FMP, 2020).

Energy Planning and Sustainable Development in Nigeria

Invariably speaking, planning in Nigerian energy sector is never done in isolation of the international ecosystem; hence, this paper endeavours to trace the recent reforms in Nigerian energy planning to the United Nations Sustainable Development Goals 2030 (Vierros, 2017; McCurry, 2019). However, Messner et al. (2000) and Sachs et al. (2019) had construed planning and policy strategies in energy sector have been strategically outlined with the fundamental premises that energy is crucial to national development and that government has a prime role in meeting the growing energy demands prevailing in the nation. Furthermore, the dependence on oil outputs can be reduced through the diversification of the nation's energy resources, aggressive research, development and demonstration, as well as human capacity development.

However, energy planning in Nigeria builds on fostering a framework for the development of the nation's energy resources—with diversified energy resources options—for the achievement of national energy security and an efficient energy supply with an optimal energy resource mix (Newburger, 2020; McNeil, et al. 2019). More so, planning in the energy sector will guarantee increased and sustained contribution of energy production activities to improving the national income, spearhead decent work and economic growth and improve public welfare. Strategic planning cum prioritization contributes to actualizing sustainable development goals through a cost-effective production and distribution system of energy resources. Thus, energy planning in Nigeria looked into creating a means of guaranteeing adequate, reliable and sustainable supply of energy at the least costs and in a manner that is friendly to the ecosystem, to the various sectors of the economy (McNeil, et al. 2019), for national development.

More importantly, energy planning is construed accelerate the process of acquisition and diffusion of technology and managerial expertise in the energy sector and indigenous participation in energy sector industries, for stability and self-reliance (Sachs, et al. 2019). It will consequently promote increased and sustained investments and development of the energy-oriented industries with substantial participation from private institutions. The planning in energy sector will ensure a comprehensive, integrated and well informed energy sector plans and programmes for effective development (Energy Commission of Nigeria, 2020). However, planning for sustainable production, consumption and distribution is necessary to foster international co-operation in energy trade and projects development in both the African region and the world at large; more so, it will ensure successful use of the nation's abundant energy resources to promote international co-operation.

The Challenges in Nigeria's Energy Planning

The limitations and failures in the Nigerian power infrastructure is usually attached to poor planning or projection of where the country should be, poor implementation of the few good plans, low funding and poor management system, security anxieties, together with environmental considerations (Newburger, 2020). The Nigerian power challenge has been chronic because achieving socio-economic development has been severely affected due to inadequate and unreliable power availability. Also noted among the numerous problems constraining sustainable energy planning is inadequate supply which has severely restricted socio-economic activities to basic human needs, limits economic growth as well as adversely affects quality of life. However, disgusting is the problem of inadequate or poor electricity supply in Nigeria, that is, total installed capacity is far lesser than demand (Sachs, et al. 2019). In some cases, the installed power capacity is usually much greater than available capacity in the country. More so, this has badly resulted in dwindling economic and social services, hampered by very low per capita electricity consumption.

Effects of Poor Energy Planning in Nigeria

Poor planning has fostered inadequate production and epileptic supply of energy services to the majority of businesses and public users. However, poor planning is widely construed to be responsible for the inability to maintain the available energy infrastructures, transmission lines, improve electric generators, pipelines as well as refineries which have been allowed to deteriorate with dreadful consequences. Most of the accessible oil pipelines and refineries in Nigeria need critical repair and expansion (PremiumTimesNg, 2018). Owing to these shortcomings, securing higher living standards for the increasing population of Nigeria generates high costs to economic planning. More importantly, frameworks for energy planning in Nigeria—to trigger reduction in poverty, sustainable cities or higher net investments—must encapsulate a number of reforms, such as upsurge in agricultural production, growth of manufacturing, and construction of roads, improved infrastructure and urbanization, as well as integrative transportation (The Nation Online Ng, 2020). Effective planning in the energy sector is hampered by lack of domestic ownership of energy production or supply inputs. Coupled with international policy frameworks, these highlighted problems have profound impacts on the amounts and types of energy produced, supplied or consumed.

Conclusion and Recommendations

This research paper therefore concludes that energy planning play a pivotal role in stimulating the groundwork for sustainable development in Nigeria. Without strategic planning in the energy sector and sub-sectors, channeling the abundant energy resources in the country will be problematic. In an oil dependent economy like Nigeria, energy planning goes a long way to spearhead industrial growth and infrastructural development (Vasudev & Sujal, 2017; Ambrose, 2019). The country is highly endowed in energy resources, nevertheless, it requires effective planning to enhance the operational capacity of the sector to sustainably produce and supply energy products to both the industrial and end-users. It is also concluded that institutional planning is required for implementing the national energy planning and strategies to stimulate economic growth without necessarily compromising the sustainability of the environment.

However, it also concludes that a strong nexus actually exists between energy planning and sustainable development in Nigeria. It is therefore recommended that achieving the mandates and objectives of energy planning in Nigeria requires that government to promote an integrated flow of funding—from domestic and international agencies and institutions—to finance a national energy programmes and projects so that the anticipated electricity demands for Nigeria could be actualised. It also recommends that Nigerian government need to unequivocally foster the apt regulatory policies and legal frameworks that can facilitate unrestrained access to appropriate facilities to boost optimal performance in domestic energy production and supply.

Furthermore, there is need for multi-stakeholder policy engagement to facilitate holistic model for managing the importation of electricity equipment from the integrated sources. There is need to constantly to create an avenue for optimal efficiency in energy production by removing unnecessary regulations that might hinder supply chain for distribution of energy products. Proper monitoring and ex ante and ex post evaluation of performance is needed in the energy sector to ensure the operational capabilities of the integrated power projects. There is need for proper engagement between the government and private institutions to ensure that the modalities for periodic planning and decision making in the energy sector are in line with domestic preference s and global best practices.

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THE METHANE SUPPLY CHAIN, FROM PRODUCTION TO TRANSPORT AND CONSUMPTION, IN THE LIGHT OF THE EU STRATEGY

Carla Mazziotti Gomez de Teran
National Research Council of Italy - Department of Engineering, ICT and Technology for Energy and Transport (DIITET), +39 06 49932008, carla.mazziotti@cnr.it

Vincenzo Delle Site,
National Research Council of Italy - Department of Engineering, ICT and Technology for Energy and Transport (DIITET), +39 06 49932698, vincenzo.dellesite@cnr.it

Abstract

This paper presents the results of the project work for the Luiss Business School Executive Master in Circular Economy – Energy and Waste Management. It aims to provide a framework of the methane supply chain, from production to transport and consumption, in the light of the EU Strategy, highlighting the transversal and multidisciplinary nature of the matter. In fact, there are many aspects to focus on, also considering the recent financial opportunities due to the economic and social crisis caused by the pandemic. They range from the legislation on environmental protection, which identifies assessment, management, and monitoring tools for corporate sustainability, passing through the recent developments in engineering to manage methane emissions.

As illustrated in the European Green Deal, renewable energy / renewable gases should play a vital role in the future decarbonized Europe. The contribution of renewable sources is increasing, and the perspective is to produce green energy and bio-based feedstock from them in a productive circular system and on proximity dimension.

The investments in innovative and renewable technologies will guarantee a reliable and safe supply of energy and the achievement of the objectives set by COP21 in Paris. A substantial improvement of ambient air quality may be reached, especially in urban areas. In the short term, the use of biofuels and renewable gas, biomethane and green hydrogen produced from renewable electricity, can accelerate the decarbonisation.

The replacement of the present linear production model to develop a low-carbon, more resource-efficient and competitive production model represents an opportunity to prevent the environmental impact in the industrial production sector. According to the circular economy's principles (CE), the end-of-life product becomes a resource to be reused, repaired, or recycled to be used again within a new production cycle. Thus, closed-loop supply chains cascade in recirculation paths with minimum environmental impacts.

Finally, this paper presents a case study on a Company, Tonissipower (with ETW ENERGIETECHNIK GmbH), which set up a biogas/biomethane generation system to exploit waste of a food and drink industry. Value optimisation is the basis of the circular economy. The waste produced by the food and drink industry is suitable for anaerobic digestion. Biogas/biomethane resulting from the waste treatments may supply local need of heat, hot water, and electricity.

Companies are now more aware that a sustainable business model creates a competitive advantage by generating more excellent customer value and sustainable development for the society. In such a framework, the value proposition makes the product available to the customer to satisfy his specific need, including energy-efficient technologies and reduced operating costs. The technology improvements and digital technologies in the B2B market can accelerate the "new growth" foreseen in the EU Green Deal.

1. Introduction

Despite the strong European commitment, we are still far from succeeding in the challenges related to climate change and air quality. At the end of 2019, through the Green Deal, the European Commission took further steps to make Europe the first climate-neutral continent by 2050 while

stimulating the economy. The exceptional interest in the transition to a circular bioeconomy, as promoted by the European Commission and the European Environment Agency, is believed to play a crucial role in reducing industrial risk and the economic impact of climate change.
In this framework, the present project work investigates the supply chain issue for methane, from production to transport, storage and consumption, in light of the EU strategy.
The energy sector is going through a period of profound transformation: the EU decarbonisation targets by 2030 require a 40% reduction in greenhouse gas emissions compared to 1990 levels, a 32% share of renewable energy sources in final consumption and a 32.5% improvement in energy efficiency (European Union Climate and Energy Framework Review to 2030, 2018).
In this context, low-carbon renewable energy sources, for instance, photovoltaic, will meet a large part of the demand together with natural gas thanks also to the growing use of liquefied natural gas - LNG (SEN, 2017). Also, the demand for gas will continue to grow until 2035, and then stabilize (unique among fossil sources).
The investments in innovative and renewable technologies will guarantee a reliable and safe supply of energy and the achievement of the objectives set by COP21 in Paris. A substantial improvement of ambient air quality will be reached, especially in urban areas. In the short term, the use of biofuels and renewable gas, biomethane and green hydrogen produced from renewable electricity - power-to-gas (P2G), can accelerate the decarbonisation.
The replacement of the present linear production model to develop a low-carbon, more resource-efficient and competitive production model represents an opportunity to prevent the environmental impact in the industrial production sector. According to the circular economy's principles (CE), the end-of-life product becomes a resource to be reused, repaired, or recycled to be used again within a new production cycle (Figure 1). Thus, closed-loop supply chains cascade in recirculation paths with minimum environmental impacts. The circular economy paradigm has the advantage of integrating sustainability principles while supporting the economy. Moreover, this new paradigm decouples non-renewable material use and GDP growth and provides new qualified job opportunities. It also makes it possible to reduce dependence on imports and to generate new economic prospects with production possibilities never explored.
Additionally, technological development with intelligent applications and a new range of "*product as services*" are essential to address the growing demand for energy, goods (e-commerce), sustainable management, and improvements of value chains.
However, the current infrastructure doesn't support the EU vision of the transition yet. The present economic and environmental conditions, characterized by evident imbalances and marked criticalities globally, imply the need to make radical changes to the current production and consumption system, which is now clearly unsustainable. The COVID-19 health crisis has highlighted the procurement system's fragility and the need for further and faster digitization and optimization of processes and operations. Still, at the same time, it represents an opportunity to face the challenges of rapidly changing markets, take advantage of the developments in e-commerce during the pandemic.
An effective approach to circularity starts with product design. Biomethane is "*a renewable, sustainable, programmable source and allows the development of a production chain characterized by economies of scale, variety and integration with positive effects on the economic system in terms of technological innovation in the manufacturing, agricultural and urban public services*" (CIB *et al*., 2016). In biomethane recovery, there is the opportunity to enhance the intrinsic value of the discarded biological materials.

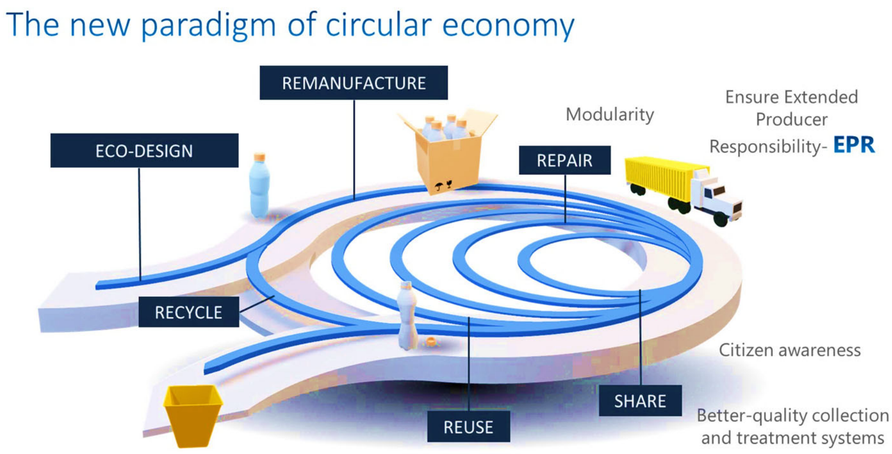

Figure 1: The paradigm of circular economy

As described in the following paragraphs, some innovations generated by this environmental awareness can speed up the shift to a more circular economy. In such a framework, circular economy provides to the companies' new market opportunities and the rethinking of value chains.
Paragraph 3 outlines the policy framework on the EU strategy on methane. Paragraph 4 summarises the methodology in the present project work. To provide context to the study, Paragraph 5 shows current methane emission inventories at European and national scale. Paragraph 6 outlines the sector-specific instruments already in place within the EU for the following relevant sector: agriculture, energy/industry and waste and the available techniques. Paragraph 7 describes how bioenergy technologies can be broadened for energy and bio-based material production. Paragraph 8 presents a use case and related economics concerning a company designing and producing an upgrading/cogeneration system to exploit the waste of a food and drink industry. Paragraph 9 summarises findings and conclusions.

2. General information on methane

Methane is a colourless, odourless and highly inflammable hydrocarbon. It is the primary component of natural gas. Together with carbon dioxide, methane is the most abundant anthropogenic greenhouse gas. Its atmospheric mixing ratio increased steadily since the beginning of the industrial revolution from values of the order of 700 ppbv up to the present days' values of the order of 1750 ppbv (EPA, 2016; IPCC, 2001). The methane rising rate in ambient air is very steep and of the order of 7 ppbv/yr (IPPC, 2001).

After carbon dioxide, methane is the most impacting greenhouse gas. Methane with nitrous oxide N_2O and fluorinated gases are responsible for 25 percent of GHGs emissions contributing to global warming over the last decade (UNEP, 2018). The simplified index GWP, global warming potential, is used to estimate the effect on global warming. It is a *measure of the relative radiative effect of a given substance compared to another, integrated over a chosen time horizon.* It is based on *radiative properties […] to estimate the potential future impacts of emissions of different gases upon the climate system in a relative sense* (IPCC, 2001). The GWP for CO_2 is assumed to be equal to 1, and it is used as a baseline to evaluate the GWP for other species. In the following Table, the GWP values refer to carbon dioxide CO_2, nitrous oxide N_2O, and methane CH_4 in the 20, 100, 500-year horizons. Thus, in a shorter time scale, methane emissions are highly relevant to achieve 2050 climate objectives.

Table 1: Key factors related to global warming

	Radiative efficiency (Wm^{-2} $ppbv^{-1}$)	**Rate of concentration change (ppbv/yr)**	**Lifetime (Years)**	**GWP (20yr)**	**GWP (50yr)**	**GWP (100yr)**
CO_2	0.01548 (Wm^{-2} $ppmv^{-1}$)	1.5 (ppmv/yr)	5 to 200	1	1	1
CH_4	3.7 10-4	7	12	84*	23	28*
N_2O	3.1	0.8	114	264*	296	265*

* IPCC, 2014 Ar5

Source: Elaboration from IPCC, 2001

Methane has natural and anthropogenic sources; the anthropogenic sources are linked to the agricultural sector, followed by the energy and waste sector.

Since the diffuse methane emissions from the agricultural sector (livestock and manure), represents about half of whole methane emissions, a synergic approach with ammonia emissions has been considered an effective in the framework of the new EU directive on National Emission Ceiling (NEC). Such an integrated approach would produce benefits on [background] ground-level ozone too (JRC, 2018). Feasibly, this concept will be assessed in a possible future revision of the Guidance on ammonia emissions from agricultural sources to the Gothenburg Protocol of the UN/ECE Convention of transboundary long-range air pollution (CLRTAP).

According to McKinsey (2021), global natural gas demand will continue to increase until 2035 and then stabilize (unique among fossil sources). The methane strategy may complement the EU political initiatives described in the following paragraphs.

3. Policy framework

3.1 The European Green Deal

On the 11th December 2019, the President of the European Commission, von der Leyen, presented the European Green Deal[15] in the European Parliament. In the past years, the EU made a significant effort

[15] COM(2019) 640 final

to tackle climate and environmental-related challenges, such as air quality and water pollution. With this "Green Plan", the European Commission identified fifty practical steps, a real roadmap for action, towards 2050. Such a vision is aimed to take the opportunity of the green transition as a "new growth strategy", mobilising all sectors as active actors of the change.

The EU raised its ambition to achieve a 55% reduction of 2030 GHG compared to 1990 levels. The use of clean hydrogen and other circular bio-based fuels, the promotion of energy storage, and carbon capture & usage are considered a critical step to achieve these objectives in the European Green Deal.

In such a framework, the Commission adopted several strategies to promote renewable low-carbon gasses. In fact, without a proper community legislative framework on climate and energy infrastructure, it is challenging for National Energy and Climate Plans (NECPs) to make a step forward to meet the climate target. Also, for private investors, it is necessary a clear perspective of the energy system to invest in the production of renewable energy at the lowest possible costs.

Moreover, the COVID-19 pandemic crisis had a huge influence on the economic scenarios, pushing the Commission to mobilized resources to further support the energy transition in consideration of a possible sustainable recovery. The health crisis highlighted the inadequacies of the EU infrastructural context (transport, supply chain, waste management, digitization, etc.), strengthening the desire to accelerate the transformation within a sustainable, circular bioeconomy concept. Such initiative does not arise only from Institutions, but also from the influence of private consumption. Furthermore, the practices based on the IoT and the adoption of advanced platforms for e-commerce make it possible to use more and more a digital environment for the management of trades to further strengthen quality control, traceability, infrastructure management, etc. In the long run, this would have beneficial effects on the environment by strengthening circular business models. The following paragraph describes the EU strategy to reduce methane-related emissions.

3.2 The EU strategy to reduce methane emissions and following acts

As agreed in Paris, the 21st UN Climate Change Conference of the Parties (COP) in 2015 decided on a global action to tackle climate change by limiting global temperature rise below two Celsius degrees.

Concerning methane emissions, the United Nations Environment Programme (UNEP) promotes understanding the overall visions through specific studies and supports developing countries. Moreover, it takes several initiatives to monitor and reduce the release of methane in ambient air. One of these is the Oil and Gas Methane Partnership (OGMP), in cooperation with the European Commission and the Environmental Defense Fund (EDF). According to this initiative, many companies voluntarily progress by adopting emission reduction protocols and reporting their environmental improvement on an international platform.

In such a framework, the International Energy Agency (IEA) estimates that "it is technically possible to avoid around three quarters of today's methane emissions from global oil and gas operations. Even more significantly, around 40% of current methane emissions could be avoided at no net cost." (IEA, 2020)

Alongside these international actions, the European Commission on November 2020 launched the EU strategy to reduce methane emissions in coherence with European Green Deal Communication (2019) by adopting the following holistic approach:

- Measurement, reporting, and verification of detailed national emissions data and information (tier 3) for energy related sectors to the United Nations Framework Convention on Climate Change (UNFCCC);
- Establishing an international methane emissions observatory by supporting the UNEP / IEA / CCAC initiatives;
- The exploitation of satellite-based detection and monitoring of super emitters through the EU's Copernicus programme;
- The revisions of relevant environmental and climate legislation (EU Emissions Trading System - ETS, industrial emissions IPPC-IED and European Pollutant Release and Transfer Register - E-PRTR, National Emission Ceilings - NECD);
- Improvement of the market for biogas from biogenic sources.

However, since only 10% of global methane emissions are due to the EU contribution (EEA, 2018), tackling climate change requires action at the international level. In this perspective, "*trade policy can support the EU's ecological transition. It serves as a platform to engage with trading partners on climate and environmental action*." (European Green Deal, 2019).

Thus, in 2021 during the 26th COP in Glasgow,

1. It was agreed to curb methane emissions by 30% in 2030, using a 2020 baseline.
2. It was reaffirmed the goal of limiting the increase in temperatures to 1.5 °C compared to the pre-industrial era by 2030 will decrease the total cumulative global anthropogenic emissions globally, reaching net zero around 2050. This temperature value would require a 45% reduction in emissions by 2030 by eliminating state aid to fossil fuels by phasing down their use.
3. It was recognised the impacts of climate change on health, livelihoods, food security, water supply (stop deforestation).
4. It was urged developed country Parties to mobilize funding for climate action to accompany developing countries in this transition.
5. It was promoted Parties to strengthen international collaboration on energy transition, clean transport, and protection of nature and biodiversity.

Following the EU strategy to reduce methane emissions and the Fit for 55 package, the European Commission set legislative proposals to decarbonize the EU gas market.

Such proposals aim to ensure access of renewable and low carbon gases, including hydrogen, to the existing methane networks and markets and ensure energy security for all citizens in Europe. The share of natural gas will decrease progressively, while the contribution of biomethane, synthetic methane, and hydrogen will become more relevant. EU-wide certification system to verify their carbon content will make such a process transparent clear. Moreover, these measures are aimed at facilitating the access of biomethane and other renewable gases to the distribution and transmission level, and LNG terminals and storage capacity; promoting the market competitiveness of renewable and low carbon gases through tariff discounts; establishing the hydrogen sector's rules and market principles with dedicated infrastructure to secure investments; ensuring that gas quality issues do not hinder cross-border flows.

4. Methods

Biogas is a versatile renewable fuel for heating and electricity production or both in CHP plants (Bioenergy Europe, 2020). The bio-methane derived from the upgrading process has the same composition as fossil methane and fits the gas grid. Besides, digestate production may be an alternative to synthetic chemicals as fertilizers and the consequent reduction of greenhouse gas emissions related to the production process, transport, and use of chemical substances.
As illustrated in the European Green Deal, its intermediate scenario considers natural gas as a "transition" fuel towards complete decarbonisation in 2050. In such a framework, biomethane can be the perfect instrument to meet sustainable targets for transport and electricity generation since it represents a programmable renewable source that can be optimally integrated with solar and wind energy generation.
Further perspectives are connected to the studies that investigate methane's use as a feedstock to produce polyhydroxyalkanoates – PHAs for bio-based industry (Vu *et al.*, 2020; Pérez-Rivero et al., 2019, Moretto *et al*., 2020; Yadav *et al.* 2020; Andersen *et al*., 2020; Rostkowski *et al*., 2012; López *et al*., 2018). Also, the local proximity dimension plays an important role in improving the efficiency of the proposed solutions.
Moreover, this paper presents a use case on a Company, Tonissipower (with ETW ENERGIETECHNIK GmbH), which set up a biogas/biomethane generation system. Value optimisation is the basis of the circular economy. Companies are now more aware that a sustainable business model creates a competitive advantage by generating more excellent customer value and sustainable development for society. In such a framework, the value proposition makes the product available to the customer to satisfy his specific need, including energy-efficient technologies and reduced operating costs.
Value optimisation is the basis of the circular economy. Companies are now more aware that a sustainable business model creates a competitive advantage by generating more excellent customer value and sustainable development for the society. In such a framework, the value proposition makes the product available to the customer to satisfy his specific need, including energy-efficient technologies and reduced operating costs.
Finally, the overall process of production of biofuel / bio-based products may be considered carbon neutral. The research also explores new options for bioenergy with carbon capture and storage to achieve negative carbon emissions (BECCS).
The circular bioeconomy allows the exploitation of biological resources' potential, preventing the dependence on imports while preserving (and possibly restoring) ecosystems' integrity.
Next Paragraph 5 shows current methane emission inventories.

5. Status of methane emissions

According to Eurostat, 2020 on EEA data 2018 data, in the EU, methane emissions account for about 10% of the total GHG emissions. Methane emissions mainly originate from the agriculture sector and, in particular, from the enteric fermentation and the decomposition of manure under anaerobic conditions, representing about 45% of the total agricultural emissions *(Figure 2)*.

Regarding fugitive emissions, methane emissions for natural gas operation (1.B.2.b) account for 5% of all EU emissions. They may occur from venting, fugitive emissions, flaring, and incomplete combustion named methane slip (EEA, 2019).
In the typical gas supply chain, from extraction to the point of delivery, fugitive methane emissions may originate in each step. The exploration step implies several test drilling to evaluate the availability and adequate gas reservoir. The production step involves the collection of the raw gas using compression. The processing step foresees the gaseous/liquid phase separation and the contaminant removal. Afterward, compression stations send the gas to its destination via pipeline, and then it is stored. The domestic network receives the gas at reduced pressure in city stations.

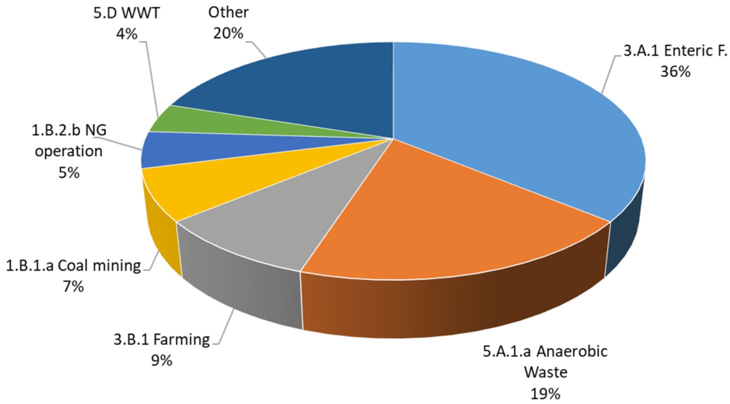

Figure 2: Total EU methane emissions (source: Eurostat on EEA data, 2020)

Natural gas can also be cooled up to approximately -160ºC and liquefied for transportation in regions not served by the gas-distributing system.
Figure 3 shows the contribution to methane emission from the natural gas operation. In all these steps, there is the possibility of fugitive methane emissions from the venting and flaring, in the gas transmission and distribution network through compressors, from pipework, during maintenance procedures, and from pneumatic devices.
The maritime transport sector gas consumption will increase for the recent IMO legislation limiting sulphur emissions from 2020.
In Italy, CH_4 emissions in 2018, are mainly originated from the agriculture sector, which accounts for 43.4% of total methane emissions, and from the waste (35.9%) and energy (17.3%) sectors (MiTE, 2019). In 2017 fugitive methane emissions from fuels accounted for 60.0% of the energy sector emissions and 12% of the total methane emissions (MiTE, 2019).

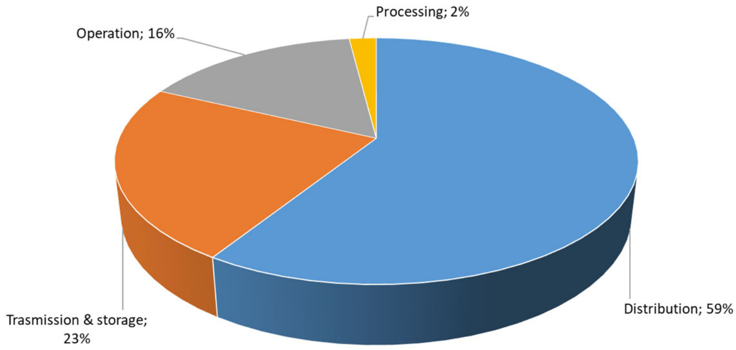

Figure 3: CH_4 emissions from natural gas operations (source EEA, 2019)

In Italy, the main contributor to methane emissions in the agriculture sector is enteric fermentation (72%), followed by manure (19%) and rice cultivation (9%). The waste sector is the second-largest contributor to emissions of methane, with the two primary sources being landfilling of solid waste (84%) and wastewater treatment plants (15%). Concerning landfilling, the primary source is the anaerobic decomposition of organic matter in solid waste. For the WWTPs, the diffuse emissions originate during the handling and treatment of municipal and industrial streams for the decomposition of biological materials and residues from animals, plants, humans.
According to the Italian Composting and Biogas Association – CIC (2017), the organic waste (Municipal and green waste) represents the predominant fraction in the composition of the separate collection, corresponding to 40.4% of differentiated waste in 2018 and 29% of total waste urban (CIC elaboration on ISPRA data). In 2018, approximately 15.5 Mt of organic waste and 7.1 Mt of green waste were collected separately in Italy.
The sludge from WWTPs comprises microbial biomass and inert, organic, and inorganic substances, with low solids and volatile substance content. The anaerobic digestion of the sewage sludge represents a means for stabilizing the organic substance and destroying any pathogenic microorganisms to make the residue suitable for final disposal. It denotes a valid option that reduces the problems of managing sewage sludge while at the same time allowing to obtain the energy necessary for its operation.
There are 308 biological treatment plants in Italy, of which 47 are authorized for anaerobic digestion and composting with a total nominal capacity of over 8 Mt (CIC, 2017).
According to ARERA (2020), in the energy sector, the contribution of fugitive methane emissions to the national total is about 1%. The distribution stage contributes about 80%, followed by transport and storage (17%).
For its necessity, Italy employs natural gas from national production, Russia, Netherlands and Norway, Algeria, and Libya. The composition of natural gas extracted from different reservoirs can be slightly different. Natural gas typically comprises methane, with other impurities such as light and heavy alkanes, nitrogen dioxide, and hydrogen sulphide (H_2S). The imported network has eight points of entrance: Tarvisio, Gorizia, Passo Gries, Mazara del Vallo, and Gela (they are five pipelines);

Panigaglia, Rovigo (Cavarzere), and Livorno (downstream of the three Liquefied Natural Gas (LNG) regasification centres of the LNG shipped by sea).

6. Current regulations and best practices

The EU strategy to reduce methane emissions builds on the current cross-sector and sector-specific actions. The following paragraphs describe measures in place in the agriculture, energy/industry, waste sectors.

6.1 Agriculture

In animal farming, methane is the product of the anaerobic degradation of carbon compounds and in the livestock sector, it originates (MiTE, 2019):

- rumen fermentation (enteric methane), about 72%.
- fermentations of the undigested organic substances in the manure, about 19%
- paddies, about 9%.

For these last, favourable conditions are the anaerobic fermentation typical of the sewage storage and the manure, mainly if characterized by high humidity and little structure. Nevertheless, since the sources are diffuse in the agriculture sector, it isn't easy to carry out the measurement. Also, the release of odorous substances is a local problem that is becoming increasingly important, especially in the release of the IPPC/IED permits and the monitoring of its implementation.

Although in the BAT Reference document IRPP collects information and data on the techniques to mitigate ammonia and methane emissions, no provisions were set on methane in the chapter on BAT Conclusion adopted as Commission Implementing Decision (EU) 2017/302. Up to now the methane is out of the scope of the IED. However, introducing methane in the new directive's scope on National Emission Ceiling (NEC) will produce positive results of reducing ammonia and methane in the animal farming sector.

To promote low-carbon livestock, in 2019, FAO proposed the following five practical actions *(Table 2).*

Table 2: Five practical actions towards low-carbon livestock (FAO, 2019)

1. Boosting efficiency of livestock production and resource use
2. Intensifying recycling efforts and minimizing losses for a circular bioeconomy, including the exploitation and recovery of biogas from agrifood, agricultural and livestock waste
3. Capitalizing on nature-based solutions to ramp up carbon offsets
4. Striving for healthy, sustainable diets and accounting for protein alternatives
5. Developing policy measures to drive change

6.2 Energy/industry

The chemical sector is the industrial branch with a relevant energy consumption: it accounts for about 10% of global total final energy consumption and 7% of greenhouse emissions associated with the industry (Griffin *et al*., 2017). In Italy, the chemical branch adopted specific processes described in the following, contributing considerably to the shift towards a low-carbon economy of the whole industry sector. ISPRA's data related to 2018 show that greenhouse gas emissions generated from the chemical segment have been decreasing by about 70% from 1990 to 2016, while the decrease of the greenhouse gas emissions from the entire "*Industry*" sector is of approximately 20.7%, from 1990 to 2016 (ISPRA, 2020).

In Italy, there are about 2,810 chemical installations (Federchimica, 2017). In the last century, chemical producers have been exploring using by-products, residues, and waste as sources of value, as highlighted by Díaz López and Montalvo (2015). In this framework, technological innovation is explored,

- developing biotechnological systems to convert biomass into biofuels, for instance, from vegetable oil via catalytic transesterification (MiTE, 2020; JRC, 2017); from vegetable oils, waste animal fats, and used cooking oils via catalytic hydroprocessing (MiTE, 2020; JRC, 2015); from algae cultivation (Gambelli *et al*., 2017);
- exploiting primary or secondary substances from biomass into chemicals with an added value in terms of waste management, energy consumption, and emissions, for instance, biodegradable bioplastics and new rubber materials (MiTE, 2019);
- implementing disrupting biological catalytic/enzymatic technologies for more sustainable processes that prevent the use of Platinum Group Metal (PGM) and other critical raw materials (MiTE, 2020).

Concerning the operating and control for prudent resource management, a crucial phase is preventing diffuse/fugitive emissions. The operators adopt specific solutions to collect these fluxes and recycle them into the process or recover such fluxes as fuel (MiTE, 2020).

The Italian legislation on IPPC-IED recommends implementing an Environmental Management System, for instance, according to the EN ISO 14001 and to the Regulation (EC) No. 1221 (EMAS), as amended in 2017.

Moreover, according to ISO140001, specific checks and monitoring satisfy the requests for data and information envisaged by an effective communication strategy.

The main BATs for the prevention of diffuse emissions are: monitoring fugitive emissions by means of LDAR on all accessible components; using a concentration threshold of 10,000 ppmv to classify components as leakers; action plan addressing storage areas for gradual reduction of emissions; facilitate maintenance activities by ensuring access to potentially leaky equipment; ensure good maintenance and timely replacement of equipment (MiTE, 2020).

From the analysis of the reports sent by the operators on the periodic monitoring according to the LDAR methodology, it is preliminarily assessed of the accessible lines of the components, such as valves, safety valves, connectors, pumps, flanges, pipe terminals, agitators, and compressors. Then, it is followed the measurements, or the emissions estimates, according to the LDAR procedure, which refers to the following technical standards: EPA 453 / R-95-017; EPA Method 21; UNI EN 15446; Annex H by ISPRA.

Some operators may use the diffuse emission estimation technique called Optical Gas Imaging (OGI), consisting of a portable infrared camera, to identify the emissions at a safe distance (Fiore *et al*., 2016, Mazziotti *et al*., 2016).

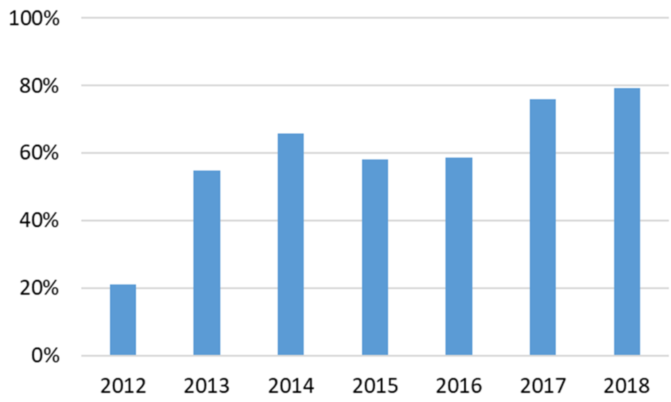

Figure 4: Increasing trend in the removal efficiencies of annual VOC emissions in a national chemical installation (Source: MiTE, 2019)

As a result of the periodic monitoring, operators according to BAT avoid VOC fugitive emissions, precious raw material lost (*Figure 4*), and related invisible costs. Some operators also decided to prevent vented emissions into the air by installing a vapour recovery unit (MiTE, 2018).

Reporting will be of interest to the public concerned and the company's internal workers and stakeholders to make them more aware and involved in the process.

However, although there are specific monitoring provisions in Italian IPPC/IED permits for large installations, for instance, refineries and chemical installations, there is still insufficient reliable information at the EU level. Thus, as suggested in many comments on methane strategy, it is necessary to promote harmonised measurement, reporting, and verification (MRV), for instance by extending the scope of the European Pollutant Release and Transfer Register (E-PRTR).

6.3 Urban waste

Concerning urban waste, the main measure to prevent diffuse methane emissions from landfilling are:

- prevention of food waste, and, possibly, the redistribution of edible food surplus for animal farming (FAO, 2019).
- compliance with separate collection target and pre-treatment/bio-stabilization of all the biodegradable wastes that will be disposed to landfills, encouraging the anaerobic digestion of Municipal Solid Waste in co-digestion with other types of waste such as sludge from municipal WWTPs and slaughtering waste (MiTE, 2019).

"*Currently, every year, one-third of all food produced globally is wasted*" (Ellen MacArthur Foundation, 2021; FAO, 2015). According to Zero Waste Europe and Bio-based Industries Consortium (2020), in the EU, only a small fraction of waste food is recovered (18%). On the other hand, according to Sharma *et al*. (2020), "*roughly 0.1 m3 of CH_4 gas is produced/kg of the food waste*". Moreover, the amount of wasted energy from food production to transport, packaging, and landfill is considerable. All this wasted energy and material turns into GHG emissions.

"A circular food system would be regenerative, resilient, non-wasteful, and healthy" (Ellen MacArthur Foundation, 2021). Organic waste may represent a source of new marketable opportunities. If biological elements are introduced in the productive circles to replace traditional fossil raw materials, the cycle can be further extended. It is the case of biogas production from the organic fraction of urban waste, WWTPs sludge described in the following Paragraph 7. Such a scenario is illustrated on the left side of the "*Circular economy system diagram*", the so called butterfly diagram (Ellen Mac Arthur Foundation, 2019). *The energy required should be renewable by nature, decreasing the resource dependence and increase system resilience (e.g., to oil shocks)* (Elle MacArthur Foundation, 2013).

The technological aspects are fundamental to extending the life cycle through reuse, repair, remanufacture, and recycling. The innovation, the optimisation of productive cycles, accelerates the transition to a circular economy. "*Accounting for and reporting the costs of negative externalities* (GHG, water, toxic substances) *would further support the shift to better resource use and production processes, and thereby generate system-wide benefits*" (Ellen MacArthur Foundation, 2017).

According to this view, the next Paragraph presents two sustainable processes transforming huge quantities of waste into clean energy and sustainable materials.

7. Creating a new value exploiting the potential of a cross-sectoral action

7.1 Sustainable biogas/biomethane production

Anaerobic digestion is a biological process where the biomass, in the absence of oxygen, is transformed into methane and carbon dioxide and traces of other components, which takes the name of biogas. In addition to biogas, at the end of the process, a residue called "*digestate*" is obtained, an organic substance not transformed into methane or CO_2, reused as fertilizer, and an excellent alternative to fertilizers of fossil origin, contributing to the decarbonisation objectives.

The digestion process occurs by different microorganisms in special anaerobic reactors (digesters). It is possible to obtain biomethane from biogas with a composition similar to natural gas of fossil origin through the "upgrading" process, removing CO_2 and other impurities (hydrogen sulphide, ammonia, water, solid particles). The percentage of methane in biogas is 55 - 65% and it depends on the type of feeding matrix.

There are various technologies for biogas upgrading in the biomethane production plants, such as water washing, chemical washing, and variable pressure adsorption (Pressure Swing Adsorption, PSA).

According to the Italian legislation, to prevent agricultural land use for biofuel production instead of food and the biodiversity protection, biomethane is classified as "*advanced*" if obtained from the materials listed in the Decree 10 October 2014 and subsequent amendments (GSE, 2020).

In principle, the methane use allows a significant reduction in polluting emissions compared to other fossil fuels. Biogas consumption, avoiding releasing the carbon sequestered in the fossil fuel fields, contributes significantly to the decarbonisation process. According to the study BioMethER (2020), biomethane as an alternative to fossil fuels reduces greenhouse gas emissions of the order of 40-60% if produced from residual agriculture by-products.

The techniques to produce biomethane are consolidated and this kind of sector is a rapidly growing in several European countries (Pignatelli, 2020).

In Italy, in 2015, the integrated anaerobic digestion & composting plants produced $275GNm^3$ of biogas and 550 GW of renewable energy with a savings of about 3.5 Mt CO_2 equivalent because of the biological treatment of the organic fraction instead of landfilling. (CIC, 2017). There remains much to be done!

Although CO_2 emissions for the industrial and the oil & gas sector in Europe have been decreasing significantly, the transport sector showed the opposite trend (PNIEC, 2020). From the air quality point, the vehicle fleet contributes to the emissions of nitrogen oxides NOx and particulate matter (PM10 and PM2.5). In such a framework, "*biofuels could play an important role in the transport sectors as an alternative to fossil fuels, complementing the greater use of electrification*" (IRENA, 2020). The biomethane use involves significant reductions in the load of pollutants emitted into the urban ambient air (sulphur, benzene, particulate matter, Polycyclic Aromatic Hydrocarbons (PAH), and heavy metals. This issue is crucial in Italy, where specific meteorological and orographic conditions, for instance in Po Valley, produce relevant photochemical smog episodes.

Compared to other European countries, Italy has a long tradition in the use of Natural Gas-powered Vehicles (NGVs); in particular, in 2017, 1,023.421 NGVs were on the road in Italy, representing approximately 2% of the total number of cars in circulation and 2,4% of the total number of vehicles (Kyoto club, 2020). Liquefied bio-LNG biomethane provided an essential contribution to reducing greenhouse gases in heavy transport/ maritime transport.

However, biomethane plants' social acceptability could trigger resistance of local communities due to the lack of information and involvement of the affected population and local authorities due to implicit parallelism with incinerators. According to the study of Maione *et al*. (2020), air pollution is a topic of significant concern in our society due to its effects on human health and the environment. Among the political measures that can be put in place to limit the emissions of atmospheric pollutants, there are innovative technologies, regulatory instruments, and behavioural measures that require citizens' active involvement. Nevertheless, the success of any effort aimed at limiting polluting emissions involves the acceptance of citizens who, in turn, should receive a correct perception of the dynamics of the emissions of the main pollutants.

Concerning the Italian National Energy and Climate - PNIEC (2020), Italy is expected to exceed the specific objective on advanced biofuels set by Directive 2001/2018, equal to 3.5% by 2030, through the incentive mechanism provided for biomethane and other biofuels advanced (Decree 2 March 2018) up to the achievement of a target of around 8%.

7.2 Valorisation of biomethane as a feedstock to produce polyhydroxyalkanoates (PHAs)

Several studies investigate methane's use as a feedstock to produce polyhydroxyalkanoates – PHAs (Vu *et al*., 2020; Pérez-Rivero *et al*., 2019, Moretto *et al.*, 2020; Yadav *et al*. 2020; Andersen *et al*., 2020; Rostkowski *et al*., 2012; López *et al*., 2018). Among the PHAs, there is the poly-β-hydroxybutyrate (PHB) that is s linear polyesters accumulated as intracellular storage granules in micro-organisms (Vu *et al*., 2020). PHB has thermoplastic and mechanical properties similar to conventional plastic. Thus, it can be a possible substitute for fossil plastic tools: biomedical and pharmaceutical applications, packaging, textiles are their potential use.

The production process builds upon the biogas production where the livestock effluents, organic fraction of the municipal waste, and the WWTP sludge are introduced into the acidogenic fermenter. The plant is an adaptation of the anaerobic digesters described in the precedent paragraph (Figure 5).

The fermenter works under anaerobic conditions to produce a stream rich in Volatile Fatty Acid (VFA) and hydrogen. Afterward, the flux is treated aerobically to accumulate PHA. PHA synthesis occurs by bacterial culture. The culture is centrifuged and separated (solid /liquid separation) to obtain a VFA-rich stream and a solid residue. The solid fraction is sent to the anaerobic co-digestion for biogas production. The liquid stream is treated for the extraction and purification of PHA.
"*The production of PHA depends on various factors such as feedstock type, micro-organism used, pre-processing techniques, nutrients, and operating parameters*" (Yadav *et al*. 2020).
Pérez-Rivero et al. (2019) reviewed the suitability of the chemical-free extraction techniques of PHA, while Yadav et al. 2020 explored the potential use of proteins recovered in the remaining liquid stream (animal food, coating, glue).
In principle, the PHA production costs are significantly higher than conventional plastics and similar to those of biopolymer plastics (Liu et al., 2020; Andreassi Bassi *et al*., 2021), mostly because of the costs of carbon feedstock, for instance, palm oil, glucose, sucrose, and corn starch.
The production of PHAs is still under study: in Italy, there is a pilot biorefinery installation inside the Treviso WWTP (Moretto *et al*., 2020). The production cycle employs waste biomass as feedstock to produce new high-quality, marketable products with minimised negative externalities. At the end of life of the bio-plastic products, the process starts again with the waste material introduced in the system coherently with the circular economy principle.
In US, there is a start-up, Mango Materials, that is producing bio-based fabric for fashion and other use.

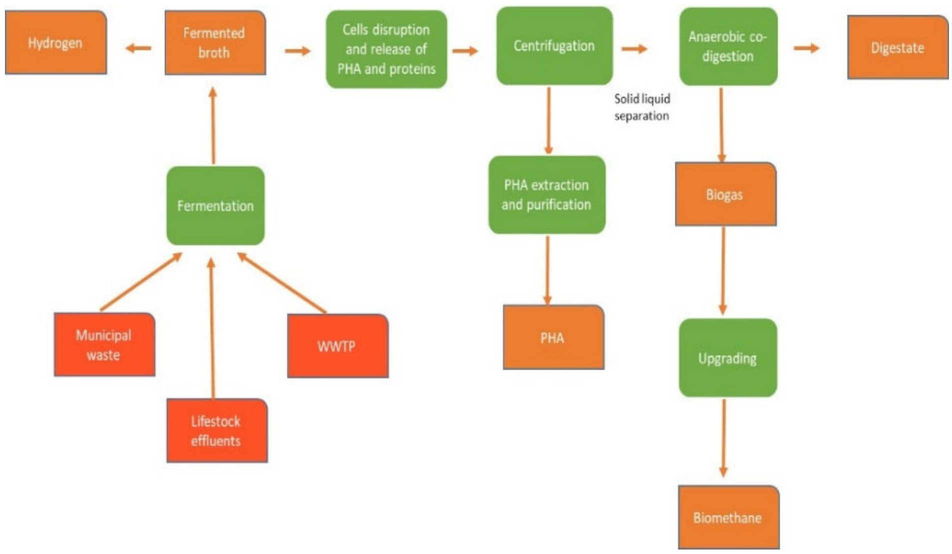

Figure 5: Phases and components in the biorefinery scheme (source: elaboration from Moretto *et al*. 2020; Yadav et al. 2020)

7.3 Production of e-methane

A route to producing carbon-neutral methane from waste other than anaerobic digestion is gasification and methanisation (Zabranska & Pokorna, 2018; Siwal et al., 2021; Lechtenböhmer et al., 2016, Hannula, 2016). With suitable catalysts, this process can convert hydrogen and CO_2 to methane in one step (Lechtenböhmer et al., 2016).

The gasification of biomass / biological waste and oxygen produces syngas which consists of a mixture of carbon monoxide CO, hydrogen, and CO_2. The syngas can also be produced by pyrolysis of woody biomass, biogenic waste, or plastics. The methanisation of CO_2 occurs by feeding the reactor with additional green hydrogen.

The process is carbon-neutral if carbon and hydrogen are of renewable origin, respectively, from biowaste and the electrolysis system. This production route has the advantage of converting the green hydrogen from renewable sources, such as wind and solar energy, into an easily utilizable and transportable form like methane.

Furthermore, besides the carbon derived from the CO_2/CO and hydrogen in the syngas, the carbon can be derived from captured CO_2 in the industrial process (Lechtenböhmer et al., 2016). This option foresees bioenergy production with carbon capture and storage and the achievement of negative carbon emissions (BECCS).

Concerning the synthetic fuels (e-fuel), other production routes via the Fischer-Tropsch results in a mix of fuel gases, naphtha/gasoline, kerosene, diesel/gas oil, base oil, and waxes. Synthetic fuels costs are currently up to 7 €/l, but, possibly, may decrease due to economies of scale, learning effects, and an anticipated reduction in the renewable electricity price (Concawe's Low Carbon Pathways project). In this regard, some companies like Porsche, Mercedes, Ferrari, and Renault have been investing in engine technology that would power their cars with synthetic fuels.

With the increased material efficiency and synthetic fuels, it appears feasible that the growing electricity demand can be better controlled.

Industrial symbiosis and process integration are substantial issues related to energy and resource efficiency. In Italy, there are experiences of biorefineries where biofuels, natural materials, and bioenergies are produced.

These circular value chains could be extended to other industrial sites in close connection with the local reality of the agricultural sector by creating a territorial value chain. In fact, in Italy, there are as many as 41 sites subjected to remediation (ISPRA, 2021). Many of them are former industrial sites that can be considered for such a production cycle.

8. Case study and economics

Overview:

The present use case concerns a company (Tonissipower with ETW ENERGIETECHNIK GmbH) designing and producing an upgrading/cogeneration system to exploit waste of a food and drink industry.

Need:

The food and drink industry generates wet waste with a high organic content to be disposed.

Solution:
The waste produced by the food and drink industry is suitable for anaerobic digestion. Biogas/biomethane resulting from the waste treatments may supply local need of heat, hot water, and electricity. Biomethane could also be injected into the gas grid and employed as vehicle fuel.

What makes the proposed fitting into a context of the circular economy:
The circular economy paradigm is pervasive, and it is possible to give a new direction to how the company does business. Existing assets are examined in a new perspective and re-evaluated to find new business opportunities. It is a systemic vision in which the different aspects are strongly interconnected (resource consumption, waste and pollution, global temperature rise, population growth, food and water shortages, deforestation, and the biodiversity destruction).
This approach is based on the "decoupling concept", where the resource use or the pressure on the environment grows at a slower rate than the economic activity causing wealth creation (Ellen MacArthur Foundation, 2013; European Commission, 2005; IRP, 2017).

The three following principles of the circular economy are applied:

1. Preserve and enhance natural capital by controlling finite stocks and balancing renewable resource flows;
2. Optimise resource yields by circulating products, components and materials in use at the highest utility at all times in both technical and biological cycles;
3. Foster system effectiveness by revealing and designing out negative externalities.

Benefits:

- Improved ratio of the output of products to input of raw materials (material efficiency);
- Increased energy efficiency of the supply chain and production process;
- Use of renewable energy and Reduced use of finite fossil fuel;
- Keep materials in closed loops with a reduction of waste in the production process through a mechanisms of "industrial symbiosis";
- Prevention of further costs due to negative externalities.

In fact, through these actions, the company creates value for its client by anticipating their needs. Attention has been paid to protecting the ecosystem and social needs; to innovate the available asset for a more significant competitive advantage; overcome the inertia that is a critical factor in a world that is changing rapidly, especially in the present pandemic context.
The risks associated with the volatility of prices and the availability of raw materials are reduced. Self-sufficiency was favoured.

Drivers:

The creation of the partnership acts as a driver to create synergies of resources and, possibly, skills.
Description of the use case:
The first stage of the process of pre-treatment of biogas there is the purification process as follows:

- stripping for ammonia removal;
- the removal of hydrogen sulfide, nitrogen, and oxygen by adsorption on activated carbon filters;

- cooling, chemical adsorption, and compression for the water removal;
- filters for solid impurities.

Afterward, there is the process of upgrading for the separation of methane from CO_2. Then, the adsorbents are regenerated by further depressurization, and the stream with CO_2 goes to the off-gas combustion to prevent methane emissions into the atmosphere.
In the process for CO_2 removal during upgrading, the pressurized gas (4-7 bar) passes through an adsorbent material (carbon molecular sieve), which separates the molecules in the stream according to the different strengths of the junction. The process depends on each gas's characteristics and the size in the mixture. Such a technique is called Pressure Swing Adsorption (PSA).
The net calorific value of biomethane (9.8-11.5 kWh/Nm^3) is higher than that of biogas (5-7 kWh/Nm^3) for the absence of CO_2 (Tonissipower, 2018). *Table 3* shows the comparison of the quality of biogas and biomethane.
According to IEA (2019), the levelised cost of generating electricity from biomethane varies according to the feedstock used and the installation's characteristic and is of the order of 50 – 190 $/MWth.
Table 4 shows the cogeneration plant's characteristics that provide energy, steam, and hot water to the food treatment installation.
In the present case, there is the anaerobic digester and the upgrading system located in Germany, 5 – 6 kilometres from the cogeneration plant. Thus, the system foresees a transfer of part of the produced methane between the two installations through local gas grid. The production and use of biomethane in situ may substantially reduce fossil methane emissions and prevent fugitive emissions from transmission and distribution networks effectively. It is necessary to emphasize that the production and use of biomethane in *situ* represent a sustainable solution: it may substantially reduce fossil methane emissions and prevent fugitive emissions from the gas network effectively.

Table 3: Comparison of the quality of biogas and biomethane.

Parameters	Biogas	Biomethane
CH_4	50 – 70 %	90 – 99 %
CO_2	30 – 45 %	1 – 5 %
H_2	< 200 ppm	< 500 ppm
N_2	0 – 2 %	0 – 2 %
O_2	0 – 0.5 %	0 – 0.5 %
H_2S	> 1,000 mg/Nm^3	< 1 mg/Nm^3
H_2O	Saturated with water	Dry

From the energy point of view, the system needs:
- up to 0.146 kWh / Nm^3 process energy requirement
- up to 0.168 kWh / Nm^3 from raw biogas for the digester and the off-gas treatment.

Cogeneration can provide a high energy efficiency level, with around 42.3% of the energy generate electricity and an additional 45.6% of the waste heat for the productive use.
The upgrading system and the co-generation plant have a remote control and an energy management system to check the performance, monitoring, and reporting with graphic consultation tools. The

regular check of relevant parameters allows preventing malfunctioning through adopting predictive maintenance strategies.

Table: 4 Characteristic of the cogeneration plant

Nominal electrical capacity	800 kWe	
Rated thermal input		
Hot water	452 kWth	
	90/70 °C	20 m^3/h (small scale)
Vapour	410 kWth	8 bar
	176 °C	617 kg/h

The costs of biomethane production and cogeneration include the following elements:

- capital related costs (investment into machine technology, structure for the housing, etc. as well as interest for the invested money);
- operation-related costs (maintenance, services, labour cost, etc.);
- consumption-related costs (feedstock, auxiliary energy).

Table 5 shows capital expenditure (CAPEX) and operational expenditure (OPEX) costs for the main process steps:

- anaerobic digestion;
- upgrading to biomethane and cogeneration.

Revenue streams

Revenues derive from the sale of biomethane and from the recognition of the certificates CIC.
A further revenue stream might be possible following creating an e-platform on the availability of sub-products and co-products that allow industrial activities to exchange energy and raw materials. Creating a B2B market for such a sector should facilitate interactions between different stakeholder groups and acts as an intermediary by connecting organic waste owners with those who may carry out the treatment activities together with the potential users. The use of channels owned by a partner company allows sharing costs and having a widespread and faster diffusion of the brand. This B2B market also becomes possible to acquire data to evaluate the environmental impacts, costs, and economic benefits associated with energy and matter sharing for further business/environmental planning.

Barriers:

The most critical issue is related to the whole complex (food and drink industry, anaerobic digestor, upgrading, and cogenerator). Often it becomes the subject of complaints by the population concerned by the ubiquitous emission of malodorous compounds and particular matter (especially for feed mills).

Table 5: Capital expenditure (CAPEX) and operational expenditure (OPEX) costs

Capex **Anaerobic digestion**	**Opex**	
Anaerobic digester[16] Installation and commissioning Decommissioning	Industrial organic waste or residues, handling and storage. Operating and maintenance Auxiliary energy Labour	
3-3.5 Mio€		
Upgrading to biomethane (PSA) & **Cogenerator**		
PSA system Installation, piping and commissioning Data transmission system Decommissioning	Service and maintenance Auxiliary energy consumption	(200k€)
2-2.5 Mio€		

Source: IRENA, 2017

Solutions:

The solution to the problem of odours might be burdensome since there are many variables involved: atmospheric conditions, different sensitivity of the receptors. The answer to the question of odours might be demanding since there are many variables involved: atmospheric conditions, different sensitivity of the receptors.
Sectorial BAT suggests putting the equipment in depression and equipping storage, loading/unloading infrastructure with specific aspiration, and treatment systems.
In principle, to create the enabling conditions, it is essential to involve local and national institutions to appropriately inform policymakers and promote the eventual initiatives related to public-private partnership mechanisms.
Also, effective communication involving the public and interested environmental associations may explain the benefits of the circular model on the environment and society.
Trade associations can intervene in the process by

- setting sectoral best practice;
- promoting communication mechanisms that stimulate public awareness of the proposed value;
- encouraging the creation of cross-industry strategic alliances and synergies of resources and skills.

The presence of certifications (ISO 14001 and EMAS) helps the communication with the stakeholders and within the company to make the mechanism linked to circularity more transparent and overcome psychological barriers.

[16] According to IRENA (2017), it represents the largest share (55-60% for industrial waste).

9. Conclusions

The present project work investigates the framework of the methane supply chain in light of the EU Strategy.
COP26 reaffirmed the goal of limiting global temperature rise to well below 2°C and pursuing efforts to limit it to 1.5°C compared to the pre-industrial era by 2030. The EU Strategy aims to reduce methane emissions and obtain a clear picture of global data by extending methodologies for Measurement, Reporting, and Verification. It also foresees the expansion of the market for biogas from renewable sources. To reduce net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels, the European Commission adopted a successive EU legislative package on "hydrogen and decarbonised gas market" to promote the demand and production of renewable and low-carbon gases.
This paper presents the sustainable process of transforming waste into clean energy. The production and use of biomethane in *situ* may substantially reduce fossil methane emissions and prevent fugitive emissions from transmission and distribution networks effectively.
The global pandemic evidenced the fragilities of the current model of production and consumption. Such a circular approach can also mitigate the effects of the geopolitical uncertainties of gas availability. The circular bioeconomy approach helps companies be resilient by rethinking the production model, preventing dependence on imports, and preserving/restoring the integrity of ecosystems.
The perspective is the contextual implementation of other green technologies to produce sustainable feedstock, such as bioplastic and synthetic fuels. Urban biowaste and wastewaters have long been neglected resources. Their exploitation appears to address fossil gas limited availability and a rich energy source and feedstock. In fact, through a biorefinery approach, it is also possible to produce bio-based materials, energy, and other valuable critical materials. The co-produced compost may contribute to soil regeneration allowing natural and sustainable growth. Moreover, this can be the opportunity to convert old industrial sites into biorefineries working in synergy with the local agricultural sector by creating a territorial value chain.

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CAN A JOINT ENERGY AND TRANSMISSION RIGHT AUCTION DELIVER WELL- FUNCTIONING LONG-TERM CROSS-BORDER ELECTRICITY MARKET IN EUROPE? – COMPARISON OF LONG-TERM MARKET PERFORMANCES UNDER NODAL AND ZONAL PRICING

Diyun Huang
Electa department, University of Leuven/ EnergyVille, Kasteelpark Arenberg 10, 3001, Heverlee, Belgium. diyun.huang@kuleuven.be

Geert Deconinck
Electa department, University of Leuven/ EnergyVille, Kasteelpark Arenberg 10, 3001, Heverlee, Belgium. geert.deconinck@kuleuven.be

Introduction

1.1 Long-term electricity market for renewable integration

An organized forward market or bilateral long-term contracts can be seen as important parts of the electricity market and complement to the competitive spot market. The positive effect of long-term contracts for renewable integration can be multi-folds. For renewable generation plants, the high fixed investment costs and CAPEX dominant characteristics do not always encourage investment under the unstable spot market price. Hedged against the volatility from spot market, long-term contract enables the investors to invest in high fixed cost technology. The prospect of certain future cash flows in a long-term contract can help solve the counterparty credibility problem and facilitate bank financing [1].

In this research, long term refers to a period of at least one year or several years ahead of the electricity delivery. In the climate policy context, one salient characteristic of bilateral long- term contracts is that they allow the buyers to express preferences in terms of technology choice. This is seen as the driver for emergence of renewable power purchase agreement (PPA) contracts for large industrial consumers that prefers to have the green electricity label. At the same time, energy intensive consumers or some retailers are also potential beneficiaries of cross-border renewable PPA as they look for low-cost green electricity at stable price. Long- term contracts shield the market participants from too high or too low prices in the sport market.

Currently, the long-term power purchase agreements are on the rise within national boundaries in Europe [2]. There are mainly two types of PPA contracts: sleeves PPA and financial PPA. Under the sleeves PPA, two contracting parties can sign a long-term contract with a fixed quantity at fixed price, while involving the balancing responsible party with a management fee. The balancing responsible party is responsible to manage the deviation from the contracted quantity. Grid fees are paid to the TSO for the use of the network. Under the form of financial PPA, two contracting parties can sign purchase agreement with a fixed price without physically delivering electricity. The renewable producer sells the electricity in the wholesale market, while the buyer purchases the contract specified amount from other players in wholesale market. The long-term contract fixation price is compared with the wholesale market price. For instance, when the wholesale market price is lower than the contracted price, the buyer needs to pay the difference to the seller. The wholesale market price is the price formed within the bidding zone of the contracting parties

1.2 Benefits of cross-border long-term market

As the decarbonization is accelerated by the FIT for 55 package, EU legislation is expected to translate the new greenhouse gas reduction target into actionable plans, including raising the renewable electricity target for the next decade. Top-down set renewable target and growing demand for renewable electricity from consumer side both call for large scale of new generation investments in the most cost-efficient locations. Natural resources for developing renewable energy are not evenly distributed among Member States, therefore the development of long-term market across borders is instrumental for a cost-efficient energy transition in Europe. Furthermore, the lessons learned from California crisis show that the lack of long-term contracts increases the risk of market power within a bidding zone [3]. In other words, long- term contracts across borders can potentially benefit the consumers in the national electricity market with new entries and thus potentially yield an anti-trust effect.

A well-tailored long-term contract needs to be able to allocate the risks to parties who can best manage it and charges risk premium accordingly. The long-term transmission rights that give involved players the options to hedge congestion risk are essential to complement the cross- border long-term contracts. Long-term contracts are not uniform in terms of risks depending on the contracting parties' positions in market and preferences. Therefore, different players may want to choose different risk hedging instruments for their cross-bordertrade. Not only is the interest very high to hedge the cross-border congestion risk financially or physically, but also there are buyers that wish to procure energy that implicitly contains the transmission access in the long-term time frame. It is important to include a variety of options and make them compatible in the long-term market design.

1.3 History account and status quo in Europe: from long-term priority access for interconnections to the long-term transmission right challenges

When liberalization started, a large portion of the interconnection capacity had been granted to the former vertically integrated utilities in the form of long-term priority access. De Hauteclocque discusses the EU perspective of long-term priority access of interconnection capacity for the electricity liberalization [4]. The Third Package has focused on mandating Third Party Access to provide level playing field to all market entrants. The prioritized long - term transmission access to interconnection capacity granted prior to the liberalization is viewed from competition perspective to be monopolization of essential facility and anti- competitive by European institutions. The antitrust law, in particular, examines the prioritized long-term transmission access granting methods, in order to determine whether the methodology applied gives an unfair advantage to dominant players in certain markets. The access granting from system operator to its affiliated arm within vertically integrated utilities raises concern over abuse of the dominant position.

Therefore, the European solution has been a standard textbook market reform to develop a short-term market and coordinate transmission and generation in this time frame [5]. In particular, firstly explicit and then implicit auction has been used as interconnection congestion management method for a day-ahead market. As market participants need to anticipate and match the bidding of transmission rights with their cross-border energy trade in explicit auctions, the implicit auctioning becomes the preferred method [4].

Commission Regulation 2016/1719 requires TSOs to develop harmonized rules for allocating physical transmission rights and financial transmission rights [6]. The regulation sets out rules to the development and cost allocation of long-term transmission rights. The allocation of cross-zonal capacity at long-term time frame can be organized through explicit auction. In the Joint Auctioning Platform set up by the TSOs, currently available long-term transmission rights for interconnections only cover one-year.

Will the implementation of joint explicit auction of interconnection capacity in long-term time frame bring an efficient cross-border long-term market? From the cost and risk allocation perspective, Beato points out there exist different incentives of TSOs and transmission users for the development of long-term transmission right products [7]. Unless the TSOs are guaranteed cost recovery from their regulators, they would be reluctant to increase the quantity and duration of long-term transmission rights. TSOs are required to ensure the firmness of the long-term transmission rights, or otherwise they need to compensate the right holders and face the risk this cost is not approved to be reimbursed in the network tariff.

1.4 Can the explicit auctioning on interconnection capacity or a joint energy and transmission right auction across borders in the long-term time frame deliver the economic gains for Europe?

As a consequence of incomplete information, it is difficult for the market participants to form a portfolio of physical transmission rights for bilateral contract under zonal pricing. There will be some bilateral contracts made infeasible by the system operator. History in PJM also supported the analysis outcome where a lot of bilateral contracts collapsed under zonal market and facilitated the transition from zonal to nodal pricing [8]. Another implication is in the long- term time frame, the common grid model needs to be calculated in a conservative way to take account of higher uncertainties and the nature of zonal model. Consequently, much less cross- border long-term trade would be allowed if all the bilateral contract needs to be feasible, which leads to lower network utilization in this time frame.

The underlying market structure of explicit auctioning of physical transmission rights is decentralised with the market participants obtaining the physical transmission capacities given by the network owners. In this research, we make the attempt to move one step forward by implementing a joint of energy and transmission right auctioning in the long-term time frame in conjunction with day-ahead market across-borders with a stylized network. The objective of the study is to assess that with energy and transmission use simultaneously optimized in the long-term market, will the zonal market design in Europe deliver the same level of economic gains in comparison with that of the nodal pricing? Are the current market design and settlement rules in Europe compatible to embrace the cross-border long-term market development?

2. Joint transmission right and energy auction model

2.1 Model description

This research uses a central auction model proposed by O'Neil on the case studies to compare system wide economic efficiencies of auctioning transmission rights and energy under nodal pricing and zonal pricing [9]. The joint transmission right and energy auctioning model is selected to compare its implementation values as several features of the model are desired:

i. It includes both the financial transmission rights and the physical transmission rights in the same model. The physical transmission right is also called flow gate right in some literatures. Among the two rights, the calculation of financial transmission rights requires a central view of the network conditions from the system operator. The physical transmission rights can be acquired without central auction as the physical limits of certain transmission elements can be determined separately by the owners of network assets [10]. This joint model presents a way to include the two types of transmission rights in the centralised auction process.
ii. The development of congestion hedging tools enables bilateral contracts at scale across borders by giving the contract parties the means to choose instruments to hedge congestion risks in different market time frames. It also supports the user flexibility by choosing financial transmission rights or physical transmission rights and allowing them to adjust positions in different time frames.
iii. The energy sale or purchase are brought in the forward market with transmission access prior to day-ahead market.

The auction model maximizes the value of accepted bids, including flow gate rights, point to point financial transmission rights and energy sale purchase contract. The market players can reconfigure the rights and trade them in secondary market. Inequality constraint includes the load flow constraint and energy supply demand balance. The bids need to include price as well as lower and upper constraints for energy sale/ purchase and transmission rights. In this study, only DC load flow constraints are included. There is no change of network typology in different time frames. In the nodal system, after each round of the forward market auctioning, the energy and transmission rights granted in the previous round are liquidated. It means all the financial positions held by the right holders are being bought back or sold back. The bid winners get their revenues according to the accepted volumes determined in the previous auction and prices determined by bids in the current auction. To sum up, the wide range of product and services that cover generation and transmission, the flexibility it gives to market players to choose different services as well as consistent market settlement rules across time frames makes the joint auction appealing in the development of a long-term electricity market.
The mathematical formulation of the auction model can be summarized by the formula:

$$Max\ \boldsymbol{b_1 t_1} + \boldsymbol{b_2 t_2} + \boldsymbol{b_3 t_3} + \boldsymbol{b_g g} \qquad (1)$$

$$\boldsymbol{\beta_1 t_1} + \boldsymbol{\beta_2 t_2} + \boldsymbol{\beta_3 t_3} + \boldsymbol{\beta_g g} \leq \boldsymbol{F} \qquad (\boldsymbol{\mu}) \qquad (2)$$

$$\boldsymbol{\alpha_2 t_2} + \boldsymbol{\mu g} = 0 \qquad (\lambda) \qquad (3)$$

Where:

$\boldsymbol{t_1}$ is a vector of the flow gate rights awarded to bidders. t_{1i} represents the ith bid by bidders to obtain rights and collect revenues from one or a portfolio of transmission element constraints. The term flow gate rights and physical transmission rights are interchangeably used in this research to refer to the rights for physical capacity on certain transmission element. Bidders can specify the highest and lowest amount with T_{1Lj} and T_{1Uj} respectively
$\boldsymbol{t_2}$ represents the point-to-point financial transmission rights awarded to bidders. t_{2j} represents the jth bid for the right to collect nodal price differences between the designated node pairs. Bidder can specify the lowest and highest amount of the transmission rights they want to obtain with T_{2Lj} and T_{2Uj} respectively.
$\boldsymbol{t_3}$ is a vector of point-to-point financial transmission options. t_{3k} represents the kth bid for the option to collect nodal price difference between specified nodes. Bidder can specify the lowest and highest amount of the transmission rights they want to obtain with T_{3LK} and T_{3UK} respectively.
$\boldsymbol{g}$ is a vector of energy sale or purchase bids awarded to bidders. Lower and upper value of the bidder are given in the bid and represented by G_L and G_U.
$\boldsymbol{\beta_1}$, $\boldsymbol{\beta_2}$, $\boldsymbol{\beta_g}$ is a vector of the transmission rights needed on each transmission element per unit of each bid type. $\beta_{1ih}t_{1i}$ is the transmission capacity needed on transmission element h with per unit value of ith bid for flow gate rights. $\beta_{2jh}t_{2j}$ is the transmission flow induced by per unit of financial transmission right bid t_{2j} on the transmission element h. $\beta_g g$ represents the flow created on the transmission element by the energy purchase and sale bids.
F is a vector of the capacity limits of transmission network.
$\boldsymbol{\mu}$ is a vector of dual variables of the constraints. For each transmission constraint, there is a dual.
$\boldsymbol{\lambda}$ is the marginal cost of meeting demand at hub node defined for the power transfer distribution factor calculation.
As O'Neil et al analysed, point to point financial transmission option will be very unattractive under certain circumstance to the market players with the defined settlement rules. Therefore, this type of rights is not included in the case study of the research.

2.2 Spatial and temporal dimensions of the nodal and zonal market

The multi time frame joint transmission and energy auctioning model includes several types of products in a joint centralised auctioning: financial transmission rights, physical transmission rights and energy products in forward market and real time market. There is an integrated network and market operation by the system operator in the joint auctioning of energy and transmission right under nodal system. As O'Neil pointed out, Independent System Operator (ISO) responsible for market and network operation is at an advantageous position to host a joint energy and transmission right auction in forward market to include network constraint, generation, load, net import or export [11].
Locational marginal pricing is defined as the marginal system cost for delivering an incremental unit power to the specified node. Congestion revenue is the difference between the total payment from the buyers and the total receipt of the sellers, with both payment and receipt based on their respective LMPs. The financial transmission rights are settled based on the LMP differences between the node of withdrawal and the node of injection, thus from the user perspective holding the financial

transmission rights would be sufficient to pay congestion charges based on nodal difference, regardless of how the power flows through the network. The physical transmission rights are paid based on the shadow price of the specified transmission paths, so it requires the user to calculate accurately the usage of transmission paths of the desired transaction. The supply side of the FTR auction is determined by auction revenue rights (ARR). The ARR holder can opt to receive the financial transmission right auction revenue or convert the ARR into FTR. In this study, the user holding ARR are all assumed to participate in FTR auction and receive the revenue from system operator. Since all the network capacity constraints are included in the optimization of different auctioning timeframes, there is no need for redispatch under nodal pricing

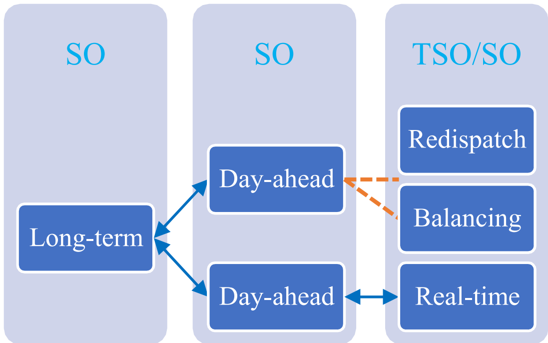

Figure 1 Market time frames and responsible institutions under different pricing schemes

In *Figure 1*, arrowed lines represent the auctions linked by the multi-settlement rules of the joint energy and transmission right auction. The auction winners from the previous auction pay for the rights in the time frame when the rights are allocated and receive the price determined in the current auction. For instance, for a bidder who wins a 100 MWh of FTR between the specified locations in the long-term auction with a price of 5 €/MWh, the FTR bid winner pays to the SO the price determined in the long-term auction 5€/MWh multiplied by the allocated quantity by the SO: 100 MW. In the long-term, this bidder pays the SO 500€ to obtain the rights. If the day-ahead price difference between the specified locations turns to be 10€/MWh, the bid winner will be paid by 1000 € for the 100 MWh of FTR.

The upper part of the figure shows that the multi-settlement rules link the long-term and day- ahead auction under zonal pricing. The system operator in these two periods can either be power exchange or the TSO in the decentralised governance structure. After the gate closure of spot market, day-ahead market in the case study of this research, the redispatch and balancing are the sole responsibility of the TSOs who manage the grid and act as single buyer in the market place. So naturally TSOs are at the better position to make settlement. The term system operator in this time frame refers to the TSOs only. The lower part of the route depicts the markets linked by multi-settlement rules in the case study: long-term, day-ahead and real- time. The bid winner who holds rights from the market in the left side of the arrowed line will be rewarded in the market time frame at the right side of the arrowed line. The term system operator refers to an independent system operator that acts as market operator and network operator.

In the proposed implementation under nodal pricing, the auctions of transmission rights and energy before real time markets are financial, so the auctioning bids will not be linked with the physical dispatch and actual use of the transmission network. The market participants can participate in the bid, in order to hedge the price differences between nodes or congestion price over certain transmission link. The auctioning outcome is liquidated after each round. Only in real time market, the cleared bids are treated as physical commitments. Generation capability and bilateral contracts are taken as constraints for the real-time market under the JETRA model.

Therefore, the problem discussed in section, i.e prioritized long-term physical access to interconnections that may possibly exert anticompetitive effect by blocking the new entrants, does not apply with the auctions that provide financial hedging in nature. Temporal and spatial dimension of the JETRA under nodal pricing is summarized in *Figure 2*

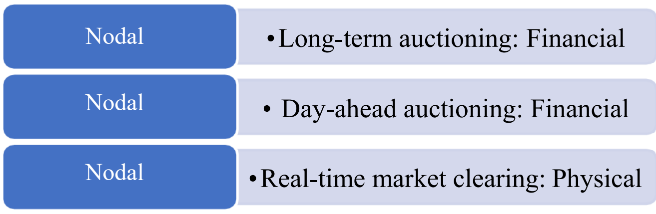

Figure 2: Temporal and spatial dimension of the JETRA under nodal pricing

Under the zonal pricing, the joint energy and transmission right auction in the long-term and day-ahead market can be organised by power exchange with grid input from system operator, followed by redispatch and balancing markets organised by system operator. In theory, the nodes with similar electrical characteristics and geographical proximity can be aggregated into the same zone. The intra-zonal congestion cost should be minimal compared to inter-zonal congestion [12]. The zonal market is compatible with a decentralised market structure, in which the power exchange and system operator at national level interact to clear the market. In the long-term and day-ahead time frame, the system operator calculates a simplified grid model with nodes aggregated into zones. The power exchange accepts bids from market players and clears the market incorporating the inter-zonal constraint from grid model. At the closure of the day-ahead market, the power exchanges need to submit the schedules resulting from market clearings to system operator.

Both long-term and day-ahead market follow the inter-zonal network constraint in optimization. The awarded bids of financial transmission rights, physical transmission rights and forward energy contracts are financial in the long-term market. That is to say, in the day-ahead market coupling, all the previously awarded rights and energy contracts are liquidated and the right holders are paid the

quantity awarded in long-term auction with the zonal prices determined at the day-ahead market.
Sequential allocation of the physical network capacity is implemented since day-ahead market. In day-ahead market, implicit auctioning guaranteed the optimal use of both energy and transmission capacity. In the redispatch and balancing, system cost optimization is performed while taking into account transmission network constraint. The sequential allocation in these time frames means that unlike the joint auction under nodal pricing, the physical capacity that is allocated to market participants have physical commitment. In other words, they can not be liquidated by system operator without compensation.
A major difference in these markets is that the day-ahead market considers only inter-zonal constraints and the redispatch balancing market incorporates both inter-zonal and intra-zonal constraints in the case study. This sequential approach also has implication for the market size, a larger cross-border market is segmented into two small markets with less competition within the bidding zones. It is important to note that the energy and transmission rights settled at day- ahead market prices do not cover the cost after the day-ahead market gate closure. The temporal and spatial dimension of the JETRA under zonal pricing is summarized in *Figure 3*.

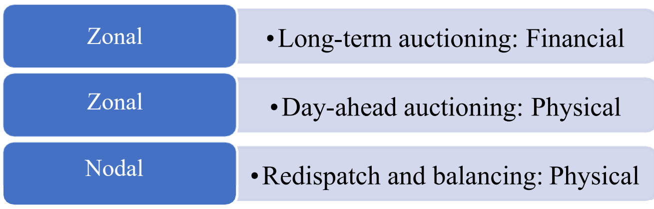

Figure 3: Temporal and spatial dimension of the JETRA under zonal pricing

2.3 Case study network and comparison indices

Using the network shown in Figure 4, a case study is constructed. The network capacity limit of line 1-2 is 200 MW and the capacity limit of line 4-3 is 250 MW. The other lines have a capacity limit of 400 MW. Given this network topology and the maximal demand in this case study being 525 MWh, the maximal flow on any transmission element will not exceed 328 (525 *0.625) MW. Lines with 400 MW capacity can be seen as transmission elements without capacity constraints. In the zonal network representation, node 1 forms zone west, while node 2, node 3 and node 4 form zone east. In the joint transmission and energy auctioning, suppose there are 5 bidders. As the bids are hourly based, the energy and transmission rights are represented in unit MW in the tables showing results.

- Bidder 1 bids for financial transmission right from node 1 to node 3 at 10 €/MWh with lower bound of 200 MWh and upper bound of 500MWh.
- Bidder 2 bids for energy sale from node 2 at 35 €/MWh with upper bound of 150 MWh.
- Bidder 3 bids for energy sale from node 4 at 20 €/MWh with upper bound of 300 MWh.

- Bidder 4 bids for physical transmission right for 100MW at 10 €/MW on the interconnection between node 1 and node 2 with upper bound of 150 MW.
- Bidder 5 bids for energy purchase from node 3 at 22 €/MWh with upper bound of 300 MWh.

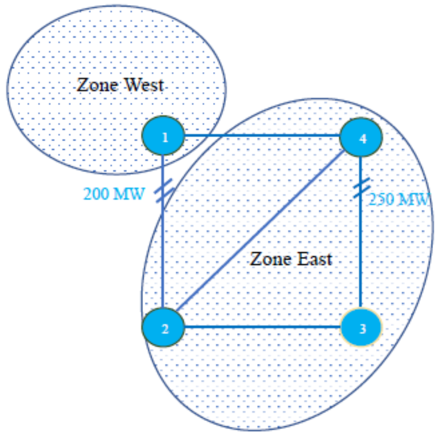

Figure 4 Four nodes network with two capacity constrained lines

Here we study three scenarios to compare the results in the nodal and zonal pricing market.

- In the first scenario, carbon price is low, so the marginal generator in the gas fired power plant at node 2 has a cost of 35€ /MWh. The real time load locates at node 3 and equals 500 MWh.
- In the second scenario, carbon price is high, so the marginal generator in the gas fired power plant at node 2 has a cost of 80€ /MWh. The real time load locates at node 3 and equals 500 MWh. Under the zonal model with the same amount 500 MWh cleared at the day- ahead market coupling with redispatch mechanism at play to alleviate network congestion, high carbon price will exert impact on redispatch costs.
- In the third scenario, carbon price is high, so the marginal generator in the gas fired power plant at node 2 has a cost of 80€ /MWh. The real time load locates at node 3 and equals 525 MWh. Under the nodal model, the deviation between the day-ahead auctioned volume and the real time load is dealt with in the real-time market clearing. In the zonal market, while there is 500 MWh cleared at the day-ahead market coupling in the zonal market, there is 25 MWh load deviation to be delivered by the balancing market. Therefore, both redispatch and balancing mechanism are at work after gate closure of the day-ahead market.

This case study assumes only the network users participate in the joint energy and transmission right auction in the market. There are no financial or virtual bids that are not backed up by physical generation or demand. In particular, the bidders who bid for financial transmission right and energy purchase contract are assumed to be agencies associated with demand at node 3.

Several indices are calculated to compare the outcomes in a nodal and a zonal market:

i. Firstly, revenue adequacy for the system operator is assessed. The ability to reach revenue adequacy or close to reach is desirable in cross-border cooperation. Revenue adequacy is defined as the capability of a system operator to pay the energy and transmission right holders from collected surplus from selling and buying energy and rights. The revenue adequacy for the system operator means the cost can be recovered from the market-based mechanism, therefore it can avoid administrative procedures to socialize the cost gap across different jurisdictional areas to pay for the bid winners.

ii. Secondly, total net payment for the user at demand node across different time frames is calculated in order to compare the dynamic efficiency of employing the congestion hedging instruments in the nodal and zonal market. It is important to note that in this research we assume the cost of transmission network usage is ultimately paid by the user that represent demand at node 3.
Thirdly, the total payment for the ARR holding user is calculated to measure the economic efficiency of using the hedging instruments while taking into account different network utilization levels under nodal and zonal pricing for network investors. In the U.S market, the auction revenue of FTR can be given to the transmission network investors to remunerate their investment or to utilities as give back to ratepayers. In this study, we assume the user that represent the demand at node 3 is responsible to pay for construction and maintenance of the transmission network and therefore receives auction revenue right allocation from the SO. The reason to calculate the total payment net of the ARR revenue is that intra-zonal network use is not explicitly priced in the zonal pricing market process in this study, while all the transmission constraints are reflected with the nodal pricing. The net payment by user taking account the receipt from ARR rights in the FTR auction will give a better approximation of the total costs for users that will benefit from higher network utilization under nodal or zonal pricing.

3. Joint energy and transmission rights analysis under nodal pricing

In this section, a joint auctioning process of energy and transmission right is set in efficient manner to maximize the bidding values in each time frame. In the following scenario calculations, first the reference case is established under nodal pricing by showing the market process and we further investigate different scenario outcomes. Several topics are worth careful examination:

- How does the bid payments link markets in different time frames from user perspective?
- How is the settlement associated with auction clearing result?
- How does the higher marginal generation costs or bidding expectation such as a minimum energy and FTR procurement in day-ahead market change the LMP and thus the bidding payments?

In the cross-border market mechanism, low system cost across different time frames and the ability to send efficient short-term and long-term price signals market mechanism are both important considerations. Efficient market facilitates competition in a larger geographical area and lowers cost for users. Effective cross-border cooperation will require market mechanism to play its role, so less cost allocation negotiation and administrative process set in.

Table 1 presents the β values of each bid using node 3 as hub. In the nodal market, the β values of each bid correspond to the nodal PTDF values of the bid, with node 3 defined as hub node in this network. The β values and link capacities are given in positive and negative direction. For instance, the β values for bid 1 is shown in the fifth column in Table 1. Bid 1 represents financial transmission rights between node 1 and node 3. One unit of FTR means 1 MWh of injection at node 1 and withdrawal at node 3 that makes 0.5 MW of the power to flow through line 1-2 and then line 2-3. 0.5 MW of the power flows through line 1-4 and then line 4-3. The PTDF values on line1-2, line1-4 and line 2-3 are 0.5, while the negative directions of the same lines denoted as line 2-1, line 4-1 and line 3-2 have PTDF values of -0.5.

In the three scenarios under nodal pricing, regardless of the marginal generator cost the scenario selects or the set real time load value, the accepted bids in the case study are always bidder 1 and bidder 5 in the long-term auction. The auctioning results payment from the bid winners to SO in long-term auctioning are the same across the three scenarios.

	Capacity (MW)	Bid 1	Bid 2	Bid 3	Bid 4	Bid 5	Shadow price (€/MW)
Line 1-2	200	0.5	-0.125	0.125	1	0	15
Line 2-1	200	-0.5	0.125	-0.125	-1	0	0
Line 1-4	400	0.5	0.125	-0.125	0	0	0
Line 4-1	400	-0.5	-0.125	0.125	0	0	0
Line 2-3	400	0.5	0.625	0.375	0	0	0
Line 3-2	400	-0.5	-0.625	-0.375	0	0	0
Line 2-4	400	0	0.25	-0.25	0	0	0
Line 4-2	400	0	-0.25	0.25	0	0	0
Line 3-4	250	-0.5	-0.375	-0.625	0	0	0
Line 4-3	250	0.5	0.375	0.625	0	0	5

Table 1 β values of each bid in nodal pricing on each network element

The last column in Table 1 displays the shadow prices of congested links as the dual variables of flow constraint. The interdependence between shadow prices of and the FTR is discussed by Oren [10]. The FTR price can be derived from equation 4. LMP difference between two nodes can be calculated using shadow prices of the transmission network path linking the two nodes and the nodal PTDF of these links. In the case study, node i is always the hub node, so its PTDF value on any transmission link is 0. The duality of energy balance gives the hub nodal price. The locational marginal pricing of other nodes can be derived based on the hub energy price.

$$LMP_m - LMP_l = \sum_{all\ flowgates\ h} SP_h * (PTDF_{h,m} - PTDF_{h,l}) \qquad (4)$$

Where:
m denotes the withdrawal node.
l denotes the injection node.
h denotes the transmission element h on the transmission path that connects node m and node l.
LMP refers to locational marginal price of certain node.
SP refers to shadow price of certain transmission element.

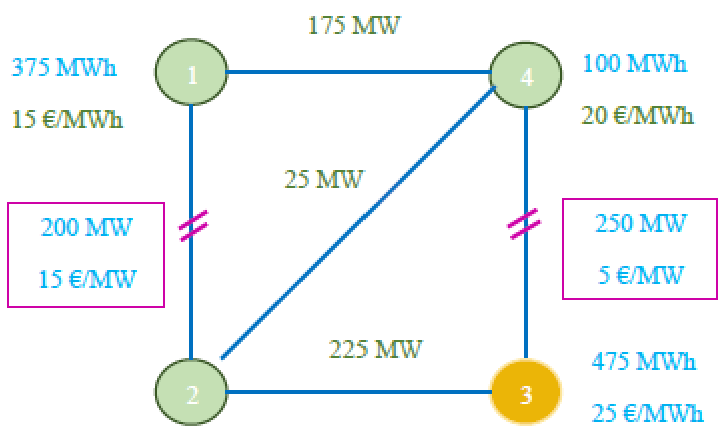

Figure 5 Long-term auctioning results under nodal pricing

denotes the injection nodes in the system

denotes the withdrawal nodes in the system

— denotes the congested lines in the system

— denotes the values directly obtained in the optimization

— denotes the values indirectly derived from the optimization

In the long-term auction, bidder 1 is awarded 375 MWh of financial transmission rights from node 1 to node 3. Bidder 2 and bidder 4 do not get their bids accepted. Bidder 3 is awarded 100 MWh of energy sale and bidder 5 is awarded 100 MWh energy purchase. The flow on the line 1-2 is 200 MW (0.5*375 + 0.125*100) and on line 4-3 is 250 MW (0.5*375 + 0.625*100).
The flow on line 1-4 is 175 (375*0.5 + 100*(-0.125)) MW, line 4-2 being 25 (100*0.25) MW and line

2-3 being 225 (375*0.5 + 100*0.375) MW. Shadow price of link 1-2 and link 4-3 is 15€/MW and 5€/MW respectively. From shadow prices obtained in optimization we can also see that line 1-2 and line 4-3 reach the capacity limit. The locational marginal price in hub node 3 is the dual of energy balance equation that equals 25 €/MWh.

Using LMP and shadow price calculation formula, the FTR price for bid 1 that accounts for nodal price difference between node 1 and node 3 is 10 (15*0.5 + 5*0.5) €/MWh. Nodal price difference between node 4 and node 3 is 5 (15*0.125 + 5*0.625) €/MWh. The LMP at node 4 for bid 3 is 20 (25-(15*0.125 + 5*0.625)) €/MWh. Similarly, nodal price difference between node 4 and node 1 can be calculated to be 10 (15*0.5 + 5*0.5) €/MWh. LMP at node 1 is 15 (25-(15*0.5+5*0.5)) €/MWh. The payments from long-term auction bid winners to the SO are listed in the last row from Table 2. Bidder 1 pays 3750 € to the SO for the 375 FTR between node 1 and node 3 and bidder 5 pays 2500 € to SO for 100 MWh of energy purchase rights. At the same time, SO pays 2000 € to bidder 3 for 100 MWh of energy sale rights.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Upper bound (MW)	500	150	300	100	300
Lower bound (MW)	200	0	0	0	0
Bid price €/MWh	10	35	20	10	25
Result quantity (MWh)	375	0	100	0	100
Result price (€/MW)	10	0	20	0	25
Payment to SO (€)	3750	0	-2000	0	2500

Table 2 Payment from the bid winners to the SO in the long-term auction

3.1 Scenario 1 under nodal pricing: Low carbon cost and real time load 500 MW

The first scenario assumes low marginal generation cost at node 2 with a cost of 35€/MWh as a base case for comparison. In the day-ahead market, assume that the five bidders take part in auctioning with the same bids as in long-term auctioning. If the network condition remains the same, there will be no change in the bidding result using the same algorithm for the auctioning. As the resulted day-ahead auctioning price is the same as in the long-term auction, the system operator (SO) will pay the same amount to the long-term auction bid winners as the bidders have paid to the SO in the last round. Afterwards, the bid winners in the day-ahead market auctioning pay the SO exactly the same amount as in the long-term auctioning.

In the real-time market, only bilateral contracts and the energy bids are allowed in the optimization process. All the transmission users are paid the locational marginal pricing. All the right holders are cashed out in this final round of market according to real time price. In this scenario, the real time load at node 3 is set to be 500 MWh, which corresponds to the redispatch case in the zonal market. In this study, all the energy bidders and FTR bidders are assumed to be backed by physical dispatch ability. For instance, the bid 1 offer upper value corresponds to generation production limit at node 1. The generation plant at node 1 offers energy sale at 15€/MWh, plant at node 2 with energy sale offer at 35€/MWh and plant at node 4 with energy sales at 20€/MWh in the last round of auction with physical dispatch. The real time market clearing result is shown in *Figure 6*

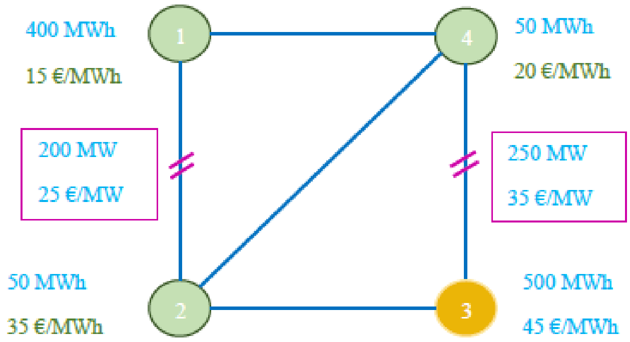

Figure 6 Real time dispatch results

The generator at node 1 will produce 400 MW and the generators at node 2 and node 4 will each produce 50 MW. Under this dispatch pattern, line 1-2 and line 4-3 are congested with a shadow price of 25€/MW and 35€/MW respectively. The LMP at the node 3 is 45 €/MWh. The LMP at node 1, node 2 and node 4 is 15 €/MWh, 35€/MWh and 20 €/MWh respectively.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MWh)	375	0	100	0	100
Price (€/MW)	30	0	20	0	45
Payment to SO (€)	11250	0	-2000	0	4500

Table 3 Payment from the SO to day-ahead bid winners at real time market

With the LMP being 45€/MWh at node 3, the SO receives 22500 € from load. At the same time, the SO pays out 6000 € to generator at node 1 at 15€/MWh, 1000€ to generator at node 4 at 20€/MWh and 1750 € to generator at node 2 at 35€/MWh. There is a surplus of 13750 € as congestion revenue for the SO. This surplus is used to pay bid winners in the previous round of auctioning. The payment from SO to day-ahead bid winners is shown in Table 3. Bidder 1 holds 375 MWh of FTR with a price that equals nodal price difference between node 3 and node 1, so FTR for bidder 1 is worth 30 €/MW. Bidder 1 receives 11250€ from the SO. Bidder 5 that holds energy purchase right at node 3 is paid at the nodal price of 45€/MW andreceives 4500€ from SO for the 100 MW right it owns. Bidder 3 who has been paid by the SO for the energy sale contract in the previous auction round needs to pay the SO according to the real- time LMP at node 4. In total, bidder 3 pays the SO 2000€ at the price of

20€/MWh. The total net payment from the SO to the bid winners is 13750€. This equals the congestion revenue from surplus between load and generation payment. Revenue adequacy is reached for the SO, i.e., no revenue short fall for the SO to settle the energy and transmission right bids cleared at day-ahead market. In the long-term, day-ahead auctioning and real-time market, the line 1-2 and line 4-3 are congested with full capacity utilization. The total payment from the user across different market time frames includes the initial payments for obtaining the rights, day-ahead bid payment and right receipt, final load payment and the cashing out of the rights from SO at real time. In this scenario, the net payment from the user across different time frames is 13000 (3750 + 2500 + 22500-11250-4500) €. When the user is entitled the FTR auctioning revenue, in this case the 3750 € FTR payment in the long-term auctioning, the net payment for the ARR holding user is 9250 €.

3.2 Scenario 2 under nodal pricing: high carbon price and load value 500 MW in real time

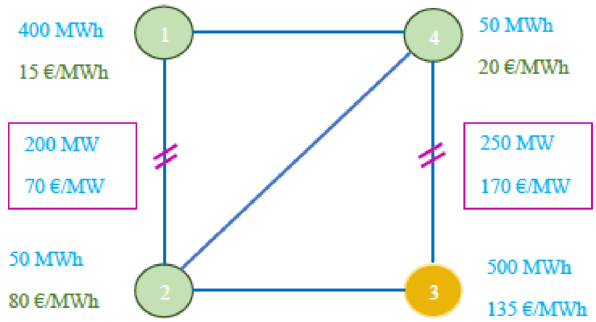

Figure 7: Real time dispatch in scenario 2 under nodal pricing

Under scenario 2, the marginal generator has a higher cost of 80 €/MWh due to high carbon price. The long-term and day-ahead auctioning results stay the same as in scenario 1. Therefore, the long-term auctioning payment from bid winners is the same as in Table *2*. The bid winners in the day-ahead market auctioning pay the SO exactly the same as in the long-term auctioning round and they get paid back this same amount from the SO as right holders.

In real time market, the dispatch is shown in *Figure 7*. Load at node 3 and generation bid offers at node 1 and node 4 are the same as in scenario 1. Only the plant at node 2 offers energy at 80 €/MWh. The generator at node 1 will produce 400 MW and generators at node 2 and node 4 will each produce 50 MW. Under this dispatch, both line 1-2 and line 4-3 are congested with a shadow price of 70 €/MW and 170 €/MW respectively. The LMP at the hub node is 135 €/MW. The LMP at node 1, node 2 and node 4 is 15 €/MW, 80 €/MW and 20 €/MW respectively. The interconnection in the long-term, day-ahead and real-time market is fully utilized.
The SO receives 67500 € from load at node 3, while it pays out 6000 € to generator at node 1, 1000€ to generator at node 4 and 4000 € to generator at node 2. There is a surplus of 56500 €. The surplus is used to pay bid winners in the day-ahead market auctioning. FTR for bidder 1 is worth 120 €/MW. As

Table 4 shows, bidder 1 receives 45000€ from the SO for the 375 MW of FTR it holds. Bidder 5 that holds energy purchase right at node 3 is paid at the nodal price of 135€/MW and receives 13500€ from SO for the 100 MWh right. Bidder 3 who is paid by SO for the energy sale contract in the previous auction round needs to pay to the SO according to the real-time LMP at node 4. In total, bidder 3 pays SO 2000€. The total net payment from the SO to the bid winners is 56500€. The surplus from load and generation payment equals net payment to bid winners. Revenue adequacy is reached for the SO in the day-ahead market, i.e., no short fall of revenues for the SO to settle the energy and transmission right bids

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	375	0	100	0	100
Price (€/MW)	120	0	20	0	135
Payment to SO (€)	45000	0	-2000	0	13500

Table 4 Payment from SO to the previous round bid winners in day-ahead market under scenario 2

If both bidder 1 and bidder 5 represent the user who wants to hedge congestion risk by obtaining FTR and an energy purchase contract or link to the user indirectly as trader or retailer supplying electricity at the load node, how effective do the hedging instruments function? In the following calculation, the price paid or received by bidder 1 and bidder 5 is categorized as the user expenditure. The user will pay 3750€ to obtain 375 MWh FTR and 2500 € for the 100 MWh energy purchase contract in the long-term auctioning. In the long-term and day-ahead auctioning, the user has paid 6250 € for hedging instruments that covers 475 MWh of the total load. In the day-ahead, the user pays and receives the same amount. At real-time, the user at node 3 pays 67500€ for the 500 MWh total load. However, the SO pays back the user 45000€ for the FTR and 13500€ for the energy purchase contract. In total, 58500€ is paid back to the user at real time and this accounts for a significant share of the 67500 € of the load payment at real-time price. In this scenario, the total net payment from the user across different time frames is 15250€. When the user is entitled the FTR auctioning revenue, the net payment for the ARR holding user is € 11500. This scenario calculation shows that in times of large price variations, holding energy and congestion hedging instruments such as FTR in long-term and day-ahead market reduces the risk exposure significantly from user perspective.

3.3 Scenario 3 under nodal pricing: high carbon price and load value 525 MW in real time

This scenario investigates the impact of load deviation between day-ahead and real-time market time frame. Assume at day-ahead time frame, the user estimates the load to be at least 500 MWh and in the real time the load value is 525 MWh. Two bidding strategies by the user are compared. Under strategy A, the user at load 3 that bid both energy purchase and FTR between node 1 and node 3 does not set a minimum value of the sum of FTR and energy purchase at day-ahead market. Only at real time market, the load is set at 525 MWh. Under strategy B, the user at load 3 sets a minimum value of 500 MWh for the sum of FTR and energy purchase.

Strategy A: load-bid-without-setting-a-minimum-value-at-day-ahead-market

Assume under this strategy, the bidding price, lower and upper bounds from the five bidders are the same as in the long-term auctioning market. As shown in Figure *8*,when the load value becomes 525MWh at real time, generator at node 1 will produce 425 MWh and generators at node 2 will produce 100 MWh.

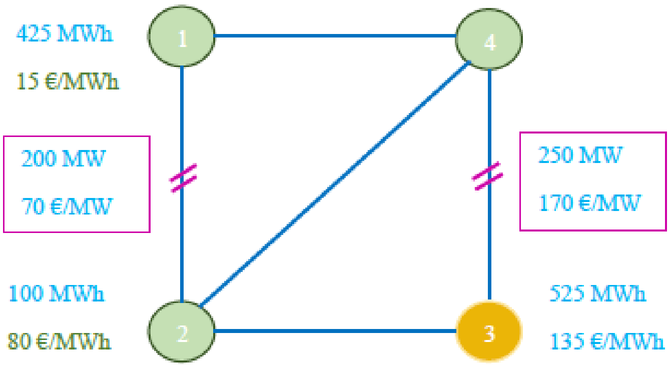

Figure 8 Real time dispatch result in scenario 3 under nodal pricing

In the real time market, both line 1-2 and line 4-3 are congested with a shadow price of 70 €/MW and 170 €/MW respectively. The LMP at the hub node is 135 €/MW. The LMP at node 1, node 2 and node 4 is 15 €/MW, 80 €/MW and 20 €/MW respectively. The SO receives 70875 € from load at node 3, while it pays out 6375 € to generator at node 1 and 8000 € to generator at node 2. There is a surplus of 56500 €. The surplus is used to pay bid winners in the day- ahead market auctioning. The payment to the bid winners is shown in Table 5

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity(MW)	375	0	100	0	100
Price(€/MW)	120	0	20	0	135
Payment to SO (€)	45000	0	-2000	0	13500

Table 5 Payment from the SO to the bid winners

The total amounts to 56500 €, exactly the same as scenario 2. The surplus from load and generation settlement equals the payment to energy and transmission right bids. Therefore, the revenue adequacy is achieved for the SO. Across different time frames, the user at the load node that represents bidder 1 and bidder 5 accumulates a total net payment of 18625 € (3750 + 2500 + 70875 -45000-13500). When the user holds the ARR that gives back FTR auctioning revenue between node 1 and node 3, then the net payment becomes 14875 €.

Strategy B: Minimum-bids-of-500 MWh-at-the-day-ahead-auctioning-by-bidders- that-represent-load

In the day-ahead time frame, the user has gained better insights of the real time load evolvement. Under this strategy, assume that user estimates the load value to be at least 500 MWh and is determined to secure 500 MWh as a combination of FTR and energy purchase contract in the day-ahead auctioning. Like assumed in all scenarios, bidder 1 and bidder 5 both represent the user at node 3. Bidder 1 observes the long-term auctioning result and submits 375 MWh as the minimum value of its FTR bid. Bidder 5 then submits the energy purchase bid with 125 MWh as its minimum value. The lower bound of 375 MWh FTR and 125 MWh energy purchase contract is a randomly chosen number, but the sum of them adds up to 500 MWh.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Upper bound (MW)	500	150	300	100	300
Lower bound (MW)	375	0	0	0	125
Bid price (€/MW)	10	80	20	10	25
Quantity	375	62.5	62.5	12.5	125
Resulted Price (€/MW)	120	80	20	10	165
Payment to SO (€)	45000	-5000	-1250	125	20625

Table 6 Payment from the bid winners to the SO in day-ahead auctioning

As Table 6 shows, bidder 1 pays SO 45000€ for the 375 MWh FTR between node 3 and node 1. Bidder 4 pays 125 € to the SO for the 12.5 MW of flow gate rights. Bidder 5 pays 20625 € to the SO for the awarded 125 MWh energy purchase contract. The SO pays 5000 € to bidder 2 for the 62.5 MWh energy sale and 1250 € to bidder 3 for the 62.5 MWh energy sale. In total, the net receipt for the SO is 59500 €.

Payment from the SO to the previous bid winners is listed in Table 7. The payment from the SO to bidder 1 who holds 375 MWh FTR accounts for 45000 €. The payment from the SO to bidder 5 is 16500 € for its 100 MWh energy purchase rights. Bidder 3 pays the SO 2000 € for its 100 MWh energy sale rights. The net payment from SO to previous bid winners is 59500€. There is revenue adequacy for the SO at day-ahead auctioning.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	375	0	100	0	100
Price (€/MW)	120	0	20	0	165
Payment to SO (€)	45000	0	-2000	0	16500

Table 7 Payment from SO to previous round right holders in day-ahead auctions

In the real time market, resulting physical dispatch is the same as in strategy A, 425 MWh generation at node 1 and 100 MWh at node 2. The LMP at node 3 is 135 €/MWh. Shadow price of congested line 1-2 is 70 €/MWh and for congested line 4-3 170€/MWh. LMP at node 1, node 2 and node 4 are 15 €/MWh, 80 €/MWh and 20 €/MWh respectively. The SO receives 70875 € from load. Meanwhile, the SO pays 6375 € to generator at node 1 and 8000€ to generator at node 2. There is a surplus of 56500 € for the SO. The payment by the SO to previous bid winners in real time market is shown in Table 8. The total net payment from SO to bid winners is 56500€. Revenue adequacy is achieved for the SO again.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	375	62.5	62.5	12.5	125
Price (€/MW)	120	80	20	70	135
Payment to SO (€)	45000	-5000	-1250	875	16875

Table 8 Payment by SO to previous bid winners in real-time

An immediate observation can be made from strategy B that nodal prices in the auctions that are financial can be higher than the real time price which reflects the value of the physicalusage of electricity. While the user has bid in the day-ahead market with updated load forecast information, the total costs increase compared to strategy A. This is mainly due to the setting of lower boundary, which means the user is willing to pay whatever it takes to obtain the specified rights. The total net payment for the user behind bidder 1 and bidder 5 is 19375 € (3750 + 2500 + 45000+ 20625 – 45000- 16500 + 70875- 45000 – 16875). When the user is allocated the ARR to be rewarded the long-term FTR auction revenue, the net payment becomes 15625 €.

The intertemporal relationship of the cost components for the user can be clearly observed in equations in Appendix. An interesting finding is that the total payment made by the user employing congestion hedging instruments in the long-term and day-ahead auctioning can be decomposed into costs in different time frames. The user pays the real time LMPs of the load node for the incremental load value compared to the sum of FTR and the energy contract procured in the previous auction. At the same time, these rights obtained with the quantityand price determined in the previous auctioning round are paid back with real-time price. For instance,1 MWh of energy from node 1 to node 3 can be interpreted as the sum of real time nodal price at node 1 and the FTR price the user pays at day-ahead auctioning. In the case of FTR, what the user pays at day-ahead market can further be linked to its long-term right bid and payback. A consistent breakdown of costs creates a settlement system that rewards the deployment of hedging instruments for market players. The effectiveness for hedging congestion risk relates to the ability of user to forecast the load, its estimation of the market condition and also network congestion in bidding round.

Nodal pricing	Scenario 1	Scenario 2	Scenario 3 A	Scenario 3 B
Total cost for user without ARR rewards (€)	13000	15250	18625	19375
Total cost for user with ARR rewards (€)	9250	11500	14875	15625

Table 9 Total payment for the user at node 3 without or with the ARR reward

The total payment from user at node 3 with or without the ARR reward is summarized in *Table 9* . Several policy implications can be observed from the three scenarios in nodal pricing:

- Revenue adequacy is always achieved for system operator under the nodal pricing.
- A major part of the congestion risk in the real time market is hedged for user in the case study by obtaining FTR and energy purchase contract in the long-term and day-ahead market auctions.
- The total payment of user has clear cost components in each time frame. In essence, the user pays at the locked-in price for the bids secured at previous auctioning round and pay for the real-time LMP for the incremental amount of energy not covered by any hedging instruments. The pricing rule is consistent across different markets.

4. Joint energy and transmission right auction under zonal pricing

4.1 Long-term, day-ahead market coupling, redispatch and balancing in the zonal market

In this section, first a joint energy and transmission right auction is implemented in the long term and day-ahead market coupling. Then the redispatch and balancing take place after day- ahead market gate closure. The market process and involved actors are illustrated in *Figure 10*

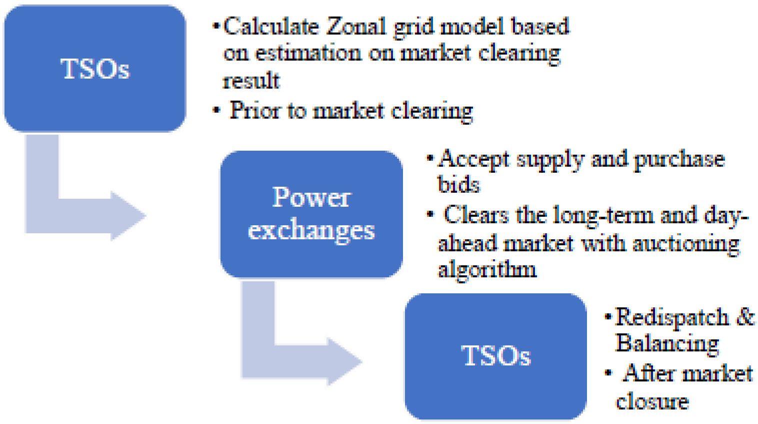

Figure 10 Market process of the long-term, day-ahead and redispatch& balancing in zonal pricing

The development of long-term market and effectiveness of its hedging instruments is the focus of this study. However, long-term market is not only about the long-term time frame, the payback of the energy and transmission rights procured by market participants in long-term auction are priced at later auction round. In this simplified case study to illustrate market logic, the long-term market is directly linked to day-ahead market coupling in the zonal model as day-ahead market coupling serves as the backbone of EU internal market. The envisioned institutions and their responsibilities in the long-term joint auction are made similar to the arrangements in current day-ahead market coupling. Day-ahead market is treated as the real- time market in the nodal pricing with physical dispatch.
Currently, a cross-border intra-day market exists in Europe. Two forms of market mechanisms coexist in this time frame: auction and continuous trading. However, the interconnection capacity under the continuous trading is allocated on a first come, first served basis. There is no optimization of interconnection capacity in this design. Therefore, the intra-day market is not included in the calculation. In the case study, deviation of load from forecast only appears and thus is dealt with in the balancing time frame.

After gate closure of the short-term market, redispatch and balancing are performed by the SO as the single buyer. In the case study, the schedules from day-ahead market clearing are submitted to the TSO to evaluate whether they are feasible. Redispatch is the activity by the TSO to dispatch up or dispatch down some generation or load, in order to alleviate network congestion from the short-term market schedule. The redispatch happens before real time.

Balancing is organised by TSOs to correct deviations between previously predicted generation and load volume that are bid into short-term market and the real time values. Unlike the long- term or spot market organised by power exchanges where the buyers bid their price preference the TSOs would always need to acquire enough electricity to meet instantaneous load and ensure the power flows are within the network capacity limit.

4.2 Grid representation and market clearing mechanisms

In this section, the joint energy and transmission right auction is implemented in the long-term market under zonal pricing. Governance structure of the joint auctioning in the long-term time frame follows the currently implemented day-ahead market coupling in Europe. Electricity market is split into zones with different TSOs that are responsible for grid control in each zone. TSOs make a common network model that is a simplified zonal model of the full grid and pass it to the power exchanges. Within a bidding zone, the power exchange accepts supply/demand bids and clears the market. The bidding zones are formed by aggregation of nodes to act as virtual nodes in the JETRA. Zones are linked by the interconnection lines. The zonal PTDF values that give the distribution of power flow from a unit change of net injection or withdrawal of a specified zone on the interconnection lines defines the relationship of inter-zonal trade and interconnection flow.

The auction objective is to maximize bid values while respecting the energy supply and demand equilibrium as well as interconnection flow limit. The shadow prices are calculated as the dual variable of the inter-zonal line flow constraint, while the dual variable from energy balance equation gives the hub zone price, which is the demand zone in the case study. The hourly prices are determined in market clearing while taking into account the inter-zonal flow limits. The bilateral contracts are traded outside of the power exchange. All the sellers within a bidding zone receive the same zonal price and all the buyers pay the same zonal price.
This case study uses a simplified network representation in long-term auctioning following the transfer capacity (TC) case studies by D'Aertrycke and Smeers [13]. Equation 5 shows that zonal PTDF on the interconnection lines can be derived from nodal PTDFs and generation demand shift keys (GDSK). Generation demand shift keys represent the nodal change of generation or demand level in proportion to the zonal net injection/withdrawal change. In day- ahead market coupling, TSOs use a base case usually from two days ahead (D-2) in flow-based market coupling to calculate the generation shift keys related to the base case generation load patterns [14]. Before the clearing of long-term auction, the TSOs do not acquire supply and offer bidding information. The unclarity of the exact location of supply, purchase bidders or the exact injection and withdrawal nodes of financial transmission right bidders needs to be considered while constructing the simplified grid model for the long-term market clearing.

$$PTDF_{l,z} = \sum_n PTDF_{l,n} * GDSK_{n,z} \tag{5}$$

Where:
$PTDF_{l,z}$ denotes the zone to line power transfer distribution factors of zone z on interconnection line l.
$PTDF_{l,n}$ is the node to line power transfer distribution factors on interconnection line l.
n refers to the nodes within zone z.

Computation of a well performing GDSK that gives accurate zonal network representation is linked to how close the base case represents for the actual generation load pattern. The base case is the system snapshot chosen by the TSO to calculate the zonal PTDF, usually at zero zonal export or import condition. In particular with large scales of intermittent renewable energy resource, forecast of the GDSK a few years prior to the electricity delivery time will be a very challenging task. Moreover, the network operational aspect of long-term forecast may compound with new generation investment uncertainties. There might be new generation commissioned in unknown locations in a few years, which makes the GDSK forecast approach less suitable. In the long-term market, we do not use a base case approach since finding a representative base case a few years ahead of market operation is very difficult, if ever possible. Given the high uncertainties in the long-term time frame, the worst-case approach taken by Smeers to determine interconnection transfer capacity under TC model is adopted for long- term auction to determine the zone-to-zone transaction volume limit and zonal PTDF values.

The method applies the same nodal PTDF values from the most critical transaction for long- term energy sale/purchase offers and inter-zonal FTR, in order to calculate flow on the interconnections. The most critical transaction refers to the injection and withdrawal pattern from the node pair located in two bidding zones that has the largest PTDF values on interconnection lines. In addition, the impact of intra-zonal transaction on interconnection capacity needs to be taken into account when setting interconnection flow limit in the grid model.

Unlike the auction under nodal pricing, the flow limit under zonal pricing does not include an internal network bottleneck. In reality, the impact of cross-border network impact on the internal network is reflected in the critical branch identified by the TSOs. However, Van den Berghe et al point out that transparency of setting critical branch flow parameters is subject to questions [14]. The selection of critical branches could vary substantially depending on the criteria. This case study uses a simplified flow-based market coupling grid representation that does not calculate the impact of critical branches. The network constraint consistency issues investigated can be extended to cases where critical branches can not be effectively identified for all time frames. Here we focus on the GDSK uncertainties in the simplified inter-zonal model and inter-temporal market consistency issue.

For day-ahead market coupling, the objective function is to maximize the social welfare while respecting constraints of the allowed inter-zonal trade volume. The zonal network representation is made by the TSO as a result of the forecast for market clearing. In this timeframe, the GDSK forecast uncertainties can be caused by many reasons. For instance, the linearity of the increase or decrease of generation production at certain node in relation to the base case may not be guaranteed as a result of generation plant capacity limit. The intermittency of renewable energy resources can also make the generation forecast more difficult, thus predicting the nodal generation or load change in proportion to net export/import becomes more challenging. In the next subsection, the GDSK in day-ahead market time frame is made by excluding some unlikely transaction patterns and putting some safety margin with load distribution in the GDSK formation. The impact of intra-zonal trade on the interconnection is also calculated while constructing the inter-zonal network constraint. The net position and market price are calculated by power exchanges.

As the intra-day market uses continuous bids, there is no uniform zonal price or optimization of interconnection capacity in the European intra-day time frame. Therefore, the day-ahead market outcome is used to settle the last round of joint energy and transmission right auction. After the day-ahead market closure, the case studies directly come to redispatch and balancing phase. Different levels of cross-border redispatch coordination have a significant impact on the system cost as the studies from Oggio et al and Kunz et al show respectively [15][16].

Two redispatch and balancing market models are implemented in the case study. The first model follows a national redispatch approach that only allows TSOs to use the resources within their bidding zone to alleviate internal network congestion. In this case, the interconnection capacity utilization is kept unchanged from the day-ahead market clearing. Only the intra- zonal network capacity limit is imposed as the constraint for altering generation load patterns.

The second model implements a deeply integrated cross-border redispatch and balancing mechanism. Under this approach, the TSOs coordinate as if there is a single system operator across the borders that can optimize the generation resources and network capacity to minimize the system cost. The real flow on the interconnection as a result of day-ahead schedule is calculated and the remaining interconnection capacity can be utilized in the redispatch process. At the same time, the intra-zonal constraint is included in the optimization to alleviate the congestion on the overloaded lines.

A simplified assumption is made here regarding redispatch cost: 1) the TSO pays the generation that increases production according to its original bidding price in day-ahead market; 2) the generation that is required to decrease the production pays back the avoided generation costs to the system operator, which is approximated by the generation bid price in day-ahead market.

4.3 Scenario 1 under zonal pricing: Low carbon cost and real time load 500 MW

This section constructs a case study with low carbon price and low marginal generation cost for the zonal market. In order to fulfil the revenue adequacy requirement of enlarging the transmission right portfolio in the later round of joint auction, larger portfolios of transmission rights should be made available from long-term to day-ahead market. This is achieved by relaxing the constraints in GDSK calculation assumption, so that the zonal PTDF values are smaller in the day-ahead compared with long-term market. In both time frames, the imperfect GDSK estimation leads to market clearing results that deviate from the most economical transaction patterns in the nodal system.

Assume the same five bidders participate in the auction and offer the same price and lower upper limits as in the nodal case in Figure 4:

- Bidder 1 bids for financial transmission right from zone west to zone east at 10 €/MWh with lower bound of 200 MWh upper bound of 500MWh.
- Bidder 2 bids for energy sale from zone east at 35 €/MWh with upper bound of 150 MWh.
- Bidder 3 bids for energy sale from zone east at 20 €/MWh with upper bound of 300 MWh.
- Bidder 4 bids for physical transmission rights between zone west and zone east at 10€/MW at 10 €/MW with upper bound of 100 MWh.
- Bidder 5 bids for energy purchase from zone east at 25 €/MWh with upper bound of 300 MWh.

Using the model of O'Neil et al, the joint auctioning can be organized between two zones. The system operator in the zonal model is the TSOs in each bidding zones. Examining the network topology, the internal transaction within zone east that is likely to create congestion on the interconnection line 1-2 is the transaction from node 4 to node 3. For the interzonal transmission and energy auction in the long-term time frame, a conservative view of the internal transaction is needed to ensure the system security

The most critical scenario for interconnection line 1-2 with capacity limit is the transaction from node 1 to node 2, whose PTDF on the positive direction of interconnection line 1-2 is 0.625. Implicitly, using this zonal PTDF assumes all the transaction from zone west to zone east will be withdrawn at node 2. The maximal transaction allowed from zone west to zone east can be calculated to be 320 MWh (200/0.625). The energy sale and purchase within zone east is assumed to have the same zonal PTDF value 0.125 on the positive direction of interconnection line 1-2, which equals the nodal PTDF from transaction from node 4 to node
3. PTDF values of the five bidders are displayed in *Table 10*.

	Capacity (MW)	Bid 1	Bid 2	Bid 3	Bid 4	Bid 5	Shadow price (€/MW)
Line 1-2	200	0.625	0.125	0.125	1	0	16
Line 2-1	200	-0.625	-0.125	-0.125	0	0	0
Line 1-4	400	0.375	-0.125	-0.125	0	0	0
Line 4-1	400	-0.375	0.125	0.125	0	0	0

Table 10 PTDF of the bidders in the long-term auction under zonal pricing

The dual variable of the flow constraints gives shadow price on link 1-2: 16 €/MW. The dual variable of energy balance equation gives zonal price at demand zone east: 25 €/MWh. Using equation 5.4, the price of FTR for bid 1 can be calculated: 10 (16*0.625) €/MW. The zonal price for west zone is 15 (25-16*0.625) €/MWh.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Upper bound(MW)	500	150	300	100	300
Lower bound (MW)	200	0	0	0	0
Bid price (€/MW)	10	35	20	10	25
Quantity	260	0	300	0	300
Price (€/MW)	10	0	25	0	25
Payment toSO (€)	2600	0	-7500	0	7500

Table 11 Payment from bid winners to SO in the long-term auctioning

With assumed interzonal PTDF of 0.625 from zone west to zone east, the resulting flow on interconnection line 1-2 is 200 MW (260*0.625 + 300*0.125). Rewarded FTR to bidder 1 is 260 MWh and energy sale offer to bidder 3 is 300 MWh. Bidder 2 and bidder 4 do not get their bid. 300 MWh energy purchase from bidder 5 is accepted. Payment from bidders to the SO can be summarized

in Table 11. Bidder 1 pays 2600 € to the SO and bidder 5 pays 7500 € to the SO. At the same time, bidder 3 receives 7500 € from the SO for its energy sale
The day-ahead market adopts simplified flow-based market coupling algorithm and the clearing result is used to settle long-term auction bids. For the day-ahead market, the price formation in the two zones under scenario 1 can be written as:

$$P_W = 15 \tag{6}$$

$$P_e = \begin{cases} 20, q_e \leq 300 \\ 35, 300 < q_e \leq 450 \end{cases} \tag{7}$$

$$q_w = e_x \tag{8}$$

$$q_e = 500 - e_x \tag{9}$$

Equation 6 can be rewritten to express price in zone east as a function of the net export from zone west:

$$P_e = \begin{cases} 20, & e_x > 200 \\ 35, & 50 \leq e_x \leq 200 \end{cases} \tag{10}$$

Market coupling objective function maximizes the social welfare while taking into account of the maximal allowed inter-zonal transaction:

$$Max \int_0^{288.9} P_E(e_x)\, de_x - \int_0^{288.9} P_W(e_x)\, de_x \tag{11}$$

Where
P_w, P_e are the prices in zone west and zone east respectively.
q_w, q_e are the production in zone west and zone east respectively.
e_x is the export from zone west to zone east.

The price level in zone west is often lower than zone east. The TSOs estimate that the inter- zonal transaction will be from west to east. The internal transaction from node 4 to node 3 can create flows on the interconnection line 1-2. Bid 2, bid 3 and bid 5 as energy supply/purchase bids in zone east can create interconnection flows, which in turn have an impact on the allowed inter-zonal transaction volume. In the case study, an assumption is made that the internal transaction in east zone follows the pattern from node 4 to node 3. Another assumption made for grid model construction is that the internal transaction within zone east is 300 MWh. The resulted flow from internal transaction on the interconnection 1-2 is 37.5 MW. On the positive direction from node 1 to node 2, the remaining capacity for inter-zonal trade is 162.5 MW. On the negative direction of the line, the remaining capacity becomes 237.5 MW. On the positive direction of line 4-1, the remaining network capacity for inter-zonal trade is 362.5 MW. On line 1-4, the remaining network capacity for inter-zonal trade is 437.5 MW. The maximal net export from zone west to zone east can be derived to be 288.9 (162.5/0.5625) MWh.

In this case study, a simplified approach is used to construct GDSK. The approach resembles heuristic method in practice and takes a safety margin into account to reflect the uncertainties that arise from load locations and distributions. Suppose that the TSOs conclude from analysing historical data that node 4 can be excluded as injection node in transactions from zone west to the zone east and also that the load is likely to be distributed between node 2 and node 3. Node 3 is usually the main load centre. This information can be used to translate into inter-zonal PTDF value for day-ahead time frame. A more conservative assumption is used here such that the withdrawal in zone east from net import is equally distributed between node 2 and node 3. With the generation demand shift key set by the assumption, we can calculate the inter-zonal PTDF value: 0.5625 (0.625*0.5+0.5*0.5). The intra-zonal PTDF values of zone east on line 1-2 take the value from transaction between node 4 and node 3: 0.125. Similar to the joint auctioning, the hub zonal price is the dual variable of the energy balance equation. The shadow price of the inter-zonal transmission link is given by the dual variable of the power flow constraint. Prices of other zones can be derived by the inter-zonal PTDF relations in equation

5.4 by treating zones as virtual nodes. All the buyers pay the same zonal prices and the purchase bids that are equal or higher than the zonal prices are accepted. The inter-zonal PTDF in the day-ahead market can be represented in *Table 12*.

	Capacity (MW)	Bid 1	Bid 2	Bid 3	Bid 5	Shadow price (€/MW)
Line 1-2	162.5	0.5625	0	0	0	8.89
Line 2-1	237.5	-0.5625	0	0	0	0
Line 1-4	400	0.4375	0	0	0	0
Line 4-1	400	-0.4375	0	0	0	0

Table 12 Zonal PTDF values in the day-ahead market clearing

The resulting dispatch is shown in Figure 11. Generation in zone west produces 289 MWh and generation in zone east produces 211 MWh. It is important to note that the 200 MW on interconnection line 1-2 is the estimated flow using the PTDF values and assumptions at the time of day-ahead market clearing.

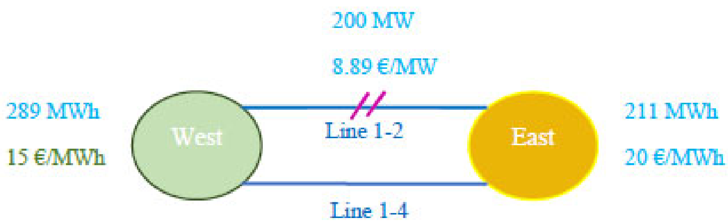

Figure 11 Day-ahead market clearing result under zonal pricing

The shadow price of congested lines determines the price spread between zones. Zone east has a price of 20 €/MWh and line 1-2 has a price of 8.89 €/MW. The FTR between zone east and zone west is 5 (0.5625*8.89) €/MWh. The price in zone west is 15 (20-5) €/MWh. Payment from generation and load to the SO is summarized in Table 13. Load in zone east pays 10000 € for the 500 MWh demand. The generator at node 4 in zone west receives 4220 €, while the generator at node 1 in zone east receives 4335 €. There is a surplus of 1445 € for the SO.

Type	Generation	Generation	Generation	Load
Zone	Zone west	Zone east	Zone east	Zone east
Quantity (MW)	289	0	211	500
Price (€/MW)	15	0	20	20
Payment to SO (€)	4335	0	4220	10000

Table 13 Generation and load payment to the SO at day-ahead market

Payment from the system operator to previous auction winners in the day-ahead market is shown in Table 14. The SOs pay 1300 € to bidder 1 who holds 260 MWh FTR from the long- term auction and pays 6000 € to bidder 5 for holding 300 MWh energy purchase rights. Meanwhile, bidder 3 pays back the SO 6000 € for the 300 MWh of energy sale rights. The total net payment for the SO in day-ahead time frame for the previous auction winners is 1300 €. The surplus of 1445 € can cover the net payment to bid winners in previous around. Revenue adequacy is achieved at day-ahead time frame

However, neither the long-term energy and transmission right auctioning nor the day-ahead market coupling have considered the internal network bottleneck under zonal pricing. After gate closure, the system operator will assess the feasibility of day-ahead market clearing outcomes by calculating the resulting load flows on the network elements. When the estimated power flow exceeds the limit of network elements, the system operator can alter the scheduled generation or load pattern from day-ahead market, in order to relieve congestion. Some generators that have not been scheduled in the market coupling since their costs are higher than the market clearing price are required to dispatch up and some generators that have been scheduled to produce in day-ahead market are required to reduce their production.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	260	0	300	0	300
Price (€/MW)	5	0	20	0	20
Payment to SO (€)	1300	0	6000	0	6000

Table 14 Payment from the SO to bid winners in day-ahead market

In scenario 1, real-time load does not deviate from the forecasted value after gate closure of the day-ahead market. Therefore, only redispatch by the TSOs is required. The resulting flow from day-ahead market scheduling will be 276.4 MW on line 4-3, which has a limit of 250 MW. To avoid the physical congestion, a redispatch based on cost minimization is conducted.

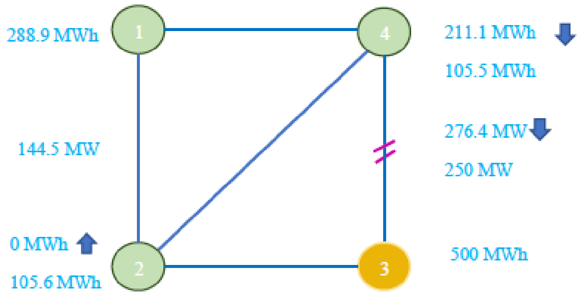

Figure 12 National based redispatch

With a national redispatch approach, the inter-zonal transaction and the associated inter-zonal capacity utilization is kept unchanged from day-ahead market. The eastern zone TSO with the congested internal line only has access to resources located in zone east. The generator at node 4 will decrease from 211.1 MWh to 105.5 MWh, while the generator at node 2 will start from zero and produce 105.6 MWh. While the flow on intrazonal line 4-3 becomes 250 MW after redispatch, the flow on interconnection line 1-2 is 144.5 MW.

The TSO pays 3696 € to the generator at node 2 for the 105.6 MWh it redispatches at 35 €/MWh and the generator at node 4 pays back 2112 € to the SO for the avoided 105.6 MWh generation at 20 €/MWh. As a result of national based redispatch, system cost will increase by 1584 €. The 145 € left for the TSO after day-ahead settlement with bid winners is not sufficient to cover the redispatch cost. The redispatch will need to be born by grid users. In this case study, we assume the redispatch costs are ultimately born by the user at node 3. Similar to the nodal pricing setting, assume the user at load node represents bid 1 for FTR and bid 5 for energy purchase contract from long-term to day-ahead market, the total net cost incurred to the user is 14384 €. When the user holds ARR that gives back the FTR auctioning revenue between zone west and zone east, then the total amount paid by the user is 11784 €.

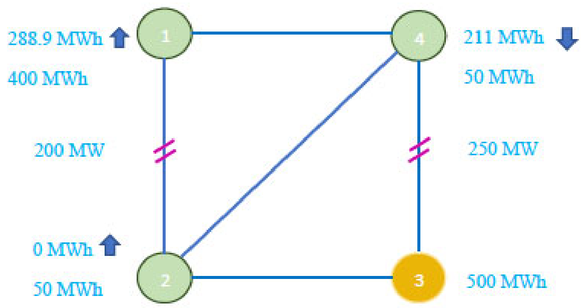

Figure 13 Integrated cross-border redispatch result

As *Figure 13* shows, when a cross-border redispatch is conducted, the TSOs will require the generator at node 1 to increase generation by 111 MWh, the generator at node 2 to increase 50 MWh and the generator at node 4 to decrease 161 MWh. To account for the added generation cost by dispatching up plant at node 1 and node 4 as well as avoided costs by dispatching down generation at node 3, a net cost of 195 € is incurred in redispatch. Revenue adequacy is breached for the TSO. The total net payment by the user from long-term auctioning to redispatch is 12995 €. When the user holds ARR that gives back the FTR auctioning revenue between zone west and zone east, then the total amount paid by the user is 10395 €.

4.4 Scenario 2: high carbon price and load value 500 MW in real time

Under scenario 2, the long-term joint auctioning and day-ahead market coupling results will stay the same as scenario 1. Therefore, the payment between the bidders and the SO at long- term and day-ahead time frames are the same as scenario 1. After the day-ahead market clearing, estimated flow on line 4-3 is 276.4 MW and redispatch by the TSO is needed. Under national based redispatch, the same redispatch volume is needed at node 4 and node 2 as in scenario 1. Generator at node 4 will be required to reduce its generation from 211 MWh to 105.5 MWh and pays the TSO 2112 € for avoided generation cost. Generator at node 2 will be asked to produce 105.6 MWh and is paid 8448 €. The additional cost for the TSO is 6336 €

In the long-term auctioning, payment to the SO from bidder 1 and bidder 5 that represent the user at node 3 is 2600 € and 7500€. In day-ahead market, the user gets paid 1300 € for the FTR and 6000 € for the energy purchase rights. At the same time, the user pays 10000 € to the SO as load payment. After the gate-closure of day-ahead market, the user further pays 6336 € under national based redispatch. In total, the user pays 19136 € across all time frames. When the user is awarded the FTR auctioning revenue for holding ARR, it will need to pay 16536 €.

When cross-border redispatch is conducted, the TSO will require the generator at node 1 to increase generation by 111 MWh, the generator at node 2 to start and increase 50 MWh and the generator at node 3 to decrease 161 MWh. The result is the same as in *Figure 13* .To account for the added generation cost by dispatching up plant at node 1 and node 4 as well as avoided costs by dispatching down generation at node 3, total cost 2445 € is incurred in redispatch.

Compared to redispatch within the bidding zones, the system cost of an integrated cross-border redispatch is significantly reduced. However, it is important to note that neither the national based nor cross-border redispatch costs covers the transmission usage tariff for internal network in the redispatch process. The interconnection link 1-2 will now be fully utilized. In this case study, node 1 is a zone by itself. In a larger system, internal network congestion may also be induced in the zones with dispatching up generations. Compared with the national redispatch approach, the beneficiaries of the integrated redispatch are generator 1 at node 1 and consumer at node 3. As opposed to the national redispatch, the dispatching up volume for generator at node 2 will be reduced and the total dispatching down generation at node 4 will be increased in the integrated redispatch. With welfare winners and losers locating in different zones that are not conform to national borders, agreeing the

allocation of cross-border redispatch cost is likely to be very difficult, when a market mechanism that sends price signals with spatial granularity is absent.
The total cost for the user at node 3 in the integrated redispatch accounts for 15245 €. When the user is given back auction revenue for holding the ARR, a total amount of 12645 € is paid. The FTR pay back to the user from long-term market participation will be more limited compared with the nodal case study, since the availability of FTR is constrained by the zonal grid representation. From the user perspective, the FTR payback to hedge the congestion risk as a result of market mechanism is more transparent than allocation rules for system cost after the market closure.

Some immediate observations can be made in comparison with scenario 2 under nodal pricing. The long-term auctioning market has adopted virtual node system that aggregates nodes into zones. The forward contracts that are priced based on the zonal pricing with only inter-zonal constraints that can not hedge against the intra-zonal congestion costs. The cost to alleviate intra-zonal congestion incurs since low-cost generations that are dispatched in the day-ahead markets need to reduce production and high-cost generation is required to increase generation. This scenario shows that when the marginal generator has higher cost, the unhedged redispatch costs increases significantly for the user that holds FTR and forward energy contracts.

4.4 Scenario 3: high carbon price and load value 525 MWh in real time

In scenario 3, the high carbon price assumption that implies high marginal generation cost is kept. In addition, the load in real time rises to 525 MWh, which requires balancing from the TSOs. Balancing refers to the service the TSO uses to keep the system stable within predefined frequency range. When the generation production or the load deviates from the day-ahead or intra-day market schedule, there arises the need to acquire additional energy to keep the energy balance in system. In the day-ahead auctioning, the market clearing results in 288.9 MWh generation production from node 1 and 211.1MWh production from node 4. This set of dispatch will lead to 276.4 MW power flow on the intra-zonal line from node 4 to node 3. The TSOs will have to conduct redispatch to relieve the transmission congestion as in scenario 2. After gate closure, the load has increased 25 MWh and the TSOs also needs to manage this imbalance by the use of reserves. To calculate the national based redispatch and balancing within zone east, the inter-zonal transaction and the interconnection utilization is kept unchanged from day-ahead market clearing. The internal network capacity limits and energy balance in the system are used as constraints for cost minimization.

As *Figure 14* shows, the generator at node 4 reduces its generation from 211.1 MWh to 78.8 MWh and generator at node 2 starts to produce 150 MWh. At the point where the intra-zonal network constraint is reached at 250MW and generator at node 1 in zone east reaches its capacity limit, there will be 7.22 MWh of energy not served at node 3. With a loss of load cost at 1000 €/MWh, the total loss of load cost amounts to 7220 €. The additional costs for generation at node 2 equals 12000 € and the avoided costs for generator at node 4 equals 2646 €. The redispatch and balancing costs for the user is 9354 €. The total redispatch, balancing and energy not served costs to the TSO amounts to 16574 €.

In the long-term auctioning, the payment from bidder 1 and bidder 5 who represent the user at node 3 is 2600 € and 7500 €. In day-ahead market, the user gets paid 1300 € for its FTR and 6000 € for energy purchase contract.

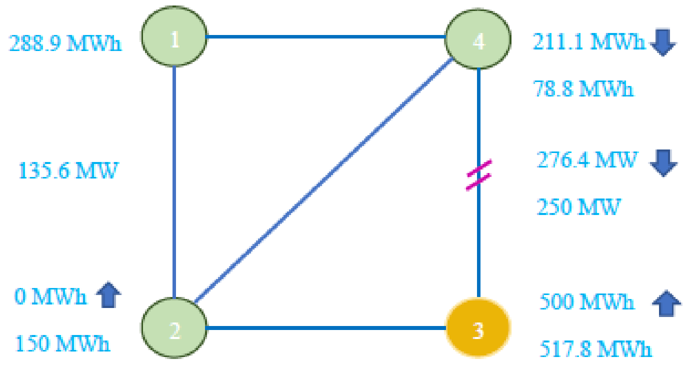

Figure 14 National based redispatch and balancing result

At the same time, the user pays 10000 € to the SO as load payment. After gate-closure of day-ahead market, the user further pays 9354 € for redispatch and balancing cost. Under the national based redispatch, the user pays 22154 € in total across all time frames in scenario 3 under zonal pricing. At the same time, there is 7.22 MWh of energy not served. The total payment for the user that is rewarded the FTR auction revenue for holding the ARR is 19554 €.

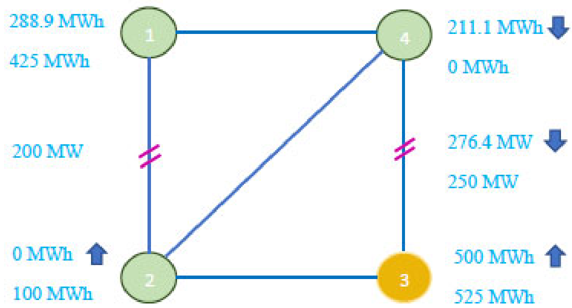

Figure 15 Integrated cross-border redispatch and balancing result

As Figure 15 shows, in an integrated cross-border redispatch and balancing, generation plant at node 1 increases production by 135.8 MWh. Generation plant at node 2 increases generation by 100 MWh and the plant at node 4 decreases by 211 MWh. The total cost for the cross- border redispatch and balancing is 5820 € (136*15+100*80 – 211*20). The user pays 18620 € in total across all time frames. When the user that holds ARR is given back the FTR auctioning revenue in the long-term market, the total payment becomes 15020 € under zonal pricing, which is even lower than the total amount 14875 € for the ARR holding user in strategy A and 15625 € for the ARR holder in strategy B under nodal pricing.

Zonal pricing	Scenario 1 national redispatch	Scenario 1 integrated redispatch	Scenario 2 national redispatch	Scenario 2 integrated redispatch	Scenario 3 national redispatch& balancing	Scenario 3 integrated redispatch& balancing
Total cost for user without ARR rewards (€)	14384	12995	19136	15245	22154 (7.2 MWh Energy not served)	18620
Total cost for user with ARR rewards (€)	11784	10395	16536	12645	19554 (7.2 MWh Energy not served)	15020

Table 15 Total cost for user with and without ARR under zonal pricing

The total cost for users across different time frames are summarized in Table 15. Several observations and policy implications can be made from zonal case studies:

- Under zonal pricing, the FTR cleared in the long-term joint auction is significantly reduced as a result of the conservative zonal grid model regarding the inter-zonal flow limit and the inter-zonal trade relationship.
- Under national based redispatch, the overall cost the user at load node pays is higher as opposed to nodal pricing. By comparing the total costs paid by the ARR holders, the difference in user payment between the zonal and nodal pricing becomes higher.However, the redispatch that is based on generation or load cost still does not price the internal network use. The difference in total user payment under nodal and zonal pricing could be enlarged when the use of internal network is paid by the user in east zone.
- Cross-border redispatch and balancing can lower the total system cost significantly under zonal model. The total payment of the user may get closed to nodal system in this arrangement. However, several issues arise. Implementing integrated cross-border redispatch requires centralised operation that coordinates market and system operation across borders. In addition, the need of cost allocation by negotiated rules arises. As far as the pricing rule for redispatch is concerned, this research assumes that the power plants that are dispatched down need to pay back the system operator their avoided generation costs. The welfare losing market players in the process of redispatch may prefer to have the day-ahead market functioning properly and send efficient price signal at first place, otherwise a compensation scheme might be expected.

Furthermore, the revenue adequacy for system operator is breached with the national based and integrated cross-border redispatch. The market player can not effectively hedge the risk of the redispatch cost as they are incurred after the market closure.

Conclusion

Long-term wholesale market as well as bilateral contracts are important components of cross- border electricity market. In light of the accelerating decarbonization, long-term electricity market that sends stable price signals gains increasing attention. Given the history of liberalization in electricity sector, the long-term transmission rights across borders that play a determinant role in shaping market are underdeveloped in Europe. Looking back, prioritized long-term transmission access had been examined by European institutions with critical views. Is there another way to design long-term transmission rights to facilitate the market development at this time frame without creating barriers for new entrants for competition?

The joint energy and transmission right model developed by O'Neil et al is proposed to answer the question in this research. Firstly, the simultaneous optimization of energy and transmission usage promises economic efficiency. In addition, the model makes the allocation of financial and physical transmission right both feasible in the auction. Secondly, an important aspect that makes a difference in the performance of hedging instruments or cost structure for network users is whether the market clearing result is physical or financial. One advantage of introducing a multi-settlement system as proposed in the model is that market clearing before real-time does not interfere with physical dispatch. Only the clearing of real-time market has physical commitments. This could enable the network user to financially hedge the congestion risk while allowing system operator to optimize the resources of the whole system at the time of delivery.

The success of developing the long-term market depends not only on implementing an efficient auction model, but also on the underlying market structure. This research investigated compatibility of current market design and governance with long-term market development from two dimensions: the consistency between market in different time frames and consistency between intra and inter bidding zone market design.

- Spatial and temporal dimensions are navigated by comparing market outcome with grid models reflecting different pricing granularity in different time frames. It is important to note that in the European electricity market, the market and network operation are separated. From day-ahead market coupling to balancing, physical network capacity usage is allocated sequentially in different market time frames. For instance, the physical capacity allocated to day-ahead market can not be liquidated without cost and be granted in other time frames. Given the nature of multi-settlement system in the joint auction model, this study assumes awarded bids of financial transmission rights, physical transmission rights and forward energy contracts in the zonal market are made financial in the long-term time frame. Once the network utilization in day-ahead market becomes physical commitment, the final payback to the transmission right holders or forward energy contract will be settled at day-ahead price. Therefore, day-ahead market coupling takes the important role to connect the long-term and short-term market. In other words, the governance revolving the day-ahead market coupling has a fundamental influence on the development of markets in the other time frames.

- The case study shows that the volume of FTR that can be made available to market participants between the same injection and withdrawal location in the long-term auction is much more constrained under zonal pricing as opposed to that of nodal pricing. A simplified zonal grid model is constructed by the TSOs prior to market opening and passed to power exchanges where purchase and offer bids are submitted by market participants. In the long-term time frame, the uncertainty for forecasting GDSK is particularly high, so very conservative assumptions need to be made when aggregating nodes into zones and representing the inter-zonal relationship. Furthermore, transmission rights and forward energy contracts exhibit weaker hedging function in the zonal market compared with the nodal market. The main reason is different level granularity of network constraints used in the optimization process. Nodal pricing provides a consistent nodal grid model for the market in different time frames. For instance, when the FTR price is fixed in the auctions prior to spot market, the user in effect pays the nodal price at the injection node and the FTR price set in the previous auction. Under zonal model, the nodal view of grid is only implemented in the redispatch and balancing market where the TSO is the single buyer, which means buyer bids are not open to market participants anymore. Thus, the transmission rights and energy contracts issued from joint auctioning based on inter-zonal model prior to day- ahead market can not hedge the redispatch costs incurred after the market closure that reflects intra-zonal constraints.

- Moreover, variations of marginal generator cost are set in the case study scenarios to reflect the impact of changing carbon price. The higher the cost of the marginal generator in redispatch process, the higher the unhedged redispatch cost for the user. The integrated redispatch across borders where TSOs have full access to resources of the whole system can reduce the redispatch costs significantly. Under the decentralised governance structure where national based TSOs and power exchanges interact to clear market, redispatch cooperation that merges market and network operation is unlikely.

To sum up, the lack of effectiveness of market instruments that expand between different time frames under zonal pricing as opposed to nodal pricing is related to the inconsistency of adoption of inter or intra zonal network constraints in different markets. Moving towards nodal pricing and integrated market and network operation will be the prerequisite to the successful development of long-term electricity market across borders that provides effective hedging products for market players.

This research does not include strategic bidding behaviours or cover detailed auction design options when comparing the nodal and zonal market. A simplified zonal market that mainly investigates uncertainties from GDSK are constructed. There are other factors that can influence zonal model uncertainties. Future research should be expanded in these areas

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Appendix

Decomposition of the total payment

In the in long-term auction, the payment from right holders to system operator can be summed up as:

$$TR_L = Q_{L1} * P_{L1} + Q_{L5} * P_{L5} = Q_{L1} * (LMP_{L3} - LMP_{L1}) + Q_{L5} * LMP_{L3} \quad (1)$$

Where:

TR_L means total receipt by the SO in long-term auctioning.

Q_{Li} is the quantity rewarded to bidder i at long-term auctioning.

P_{Li} is the price received by bidder i at long-term auctioning.

LMP_{Lj} is the locational marginal pricing at node j at long-term auctioning.

In the day-ahead auctioning, payment from right holders to system operator can be written as:

$$TR_D = Q_{D1} * P_{D1} + Q_{D5} * P_{D5} = Q_{D1} * (LMP_{D3} - LMP_{D1}) + Q_{D5} * LMP_{D3} \quad (2)$$

Where:

TR_D means total receipt by the SO in day-ahead auctioning.
Q_{Di} is the quantity rewarded to bidder i at day-ahead auctioning.
P_{Di} is the price received by bidder i at day-ahead auctioning.
LMP_{Lj} is the locational marginal pricing at node j at day-ahead auctioning.
Total payment TP_D from SO to the bid winners from long-term auction at the day-ahead auctioning can be written as:

$$TP_D = Q_{L1} * P_{D1} + Q_{L5} * P_{D5} \quad (3)$$

In the day-ahead time frame, the net payment from the user that represent bidder 1 for FTR between node 1 and node 3 and bidder 5 for energy purchase at node 3 is:

$$TP_D - TR_D = (LMP_{D3} - LMP_{D1}) * (Q_{D1} - Q_{L1}) + LMP_{D3} * (Q_{D5} - Q_{L5}) \quad (4)$$

The net payment from the user in the day-ahead consists of two parts: additional FTR acquired by the right holder in day-ahead auction on the basis of long-tern auction quantity at the day- ahead price where the FTR node pairs locate; additional energy purchase amount for the right holders at the day-ahead price where the load locates

Suppose the sum of energy purchase and FTR cleared at long-term auctioning is Q_L. The sum of energy purchase and FTR cleared at day-ahead auctioning is Q_D. The difference of the sum of cleared FTR and energy purchase between day-ahead and long-term auctioning is denoted as Q_{DL}. The load at real time is Q_R. The difference between the real time load and the sum of FTR and energy purchase in day-ahead auctioning is designated as Q_{RD}.
At real time, the load can be represented as:

$$Q_R = Q_{D1} + Q_{D5} + Q_{DR} \tag{5}$$

The SO receipt from load at real time is:

$$TR_R = LMP_{R3} * Q_R \tag{6}$$

Where:

LMP_{Ri} is the real time price at node i.

TR_R is the total load payment from user to the SO.

The total payment from SO to day-ahead bid winners can be expressed as:

$$TP_R = (LMP_{R3} - LMP_{R1}) * Q_{D1} + LMP_{R3} * Q_{D5} \tag{7}$$

Where:

TP_R is the total payment from the SO to the day-ahead auction winners. The net payment from the user to the SO at real-time can be represented as:

$$TR_R - TP_R = LMP_{R1} * Q_{D1} + LMP_{R3} * Q_{DR} \tag{8}$$

The total payment from load across time frames can be added up:

$$TP = TR_L + TP_D - TR_D + TR_R - TP_R \tag{9}$$

For the amount covered by FTR, the user will first pay in the long-term auctioning at the long- term clearing price. In the day-ahead auctioning, the user will pay at the day-ahead clearing price for the additional amount of FTR awarded in comparison to the long-term auctioning award. The amount of energy purchase related to the amount of FTR awarded in the day-ahead market is multiplied by the energy price at the injection node at the real time price.
For the energy purchase contract, the user will first pay in the long-term auctioning at the locational marginal price at the load node. In the day-ahead auctioning, the user will pay for the additional amount of energy purchase contract awarded in this time frame compared to long-term auctioning at day-ahead locational marginal price for load node. Finally, the difference between the clearing volume in real-time market and day-ahead auctioning, is paid the real time locational marginal price at load node.

A key finding from strategy B is that the total payment made by the user employing congestion hedging instruments in the long-term and day-ahead auctioning can be decomposed into costs in different time frames. The intertemporal relationship of the cost components can be clearly observed in equation. While the user pays the LMPs of at the load node, the FTR and energy purchase contract it bids in the previous market time frames is paid back at real-time price. This relationship creates a consistent breakdown of costs that rewards the employment of hedging instruments for market players. The effectiveness for hedging congestion risk relates to the ability of user to forecast the load, its estimation of the market condition and also network congestion in bidding round.

ENERGY EFFICIENCY IMPROVEMENT STRATEGIES FOR IMPORTANT HISTORIC BUILDINGS USED AS OFFICES. A CASE STUDY IN ROME

Alessandro Pelliccia
University of Rome la Sapienza, Itlay,

Valerio Di Prospero
Studio Santi, Italy

Laura Antonuzzi
Studio Santi, Italy

Annalisa Zuppa,
Agri Island, Rome , Italy

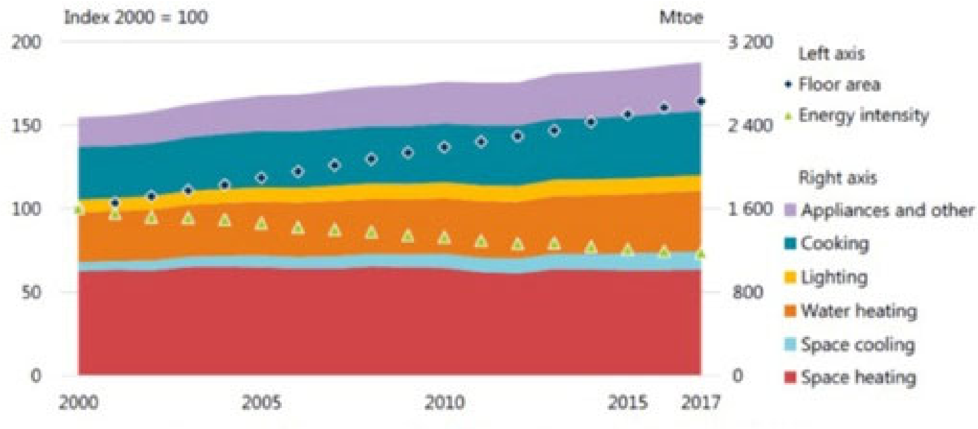
Francesco Castellani
Studio Santi, Italy

Romano Acri,
Federico Santi, University of Rome la Sapienza, Itlay,

The buildings sector accounts for almost a third of global final energy use. This sector covers a lot of the energy-consuming activities that provide basic energy service, including lighting, space and water heating, cooling and the use of appliances. The increasing number of activities covered by this sector will lead to an increase of the space covered and an always increasing energy demand. In the 2000-2017 period, the floor space in buildings has grown by roughly 65%, which in turn has led to an increase in energy demand and an increase in GHG emissions.

In Italy, the building sector accounted for almost 43,5% of total energy consumption in 2018. The energy-consumption is mainly driven by space heating (69%), followed by electrical appliances (13%), water heating (11%), cooking and air cooling (1%) [as found from research made by Odyssee-Mure].

It is clear that this sector will play a key if we are to effectively reduce GHG's emissions in line with global climate goals. The following paper will discuss a case study of a historic building situated in the center of Rome. The aim of the study is to enhance the comfort of the building for its users, as well as providing savings for energy bills and reducing GHG emissions.



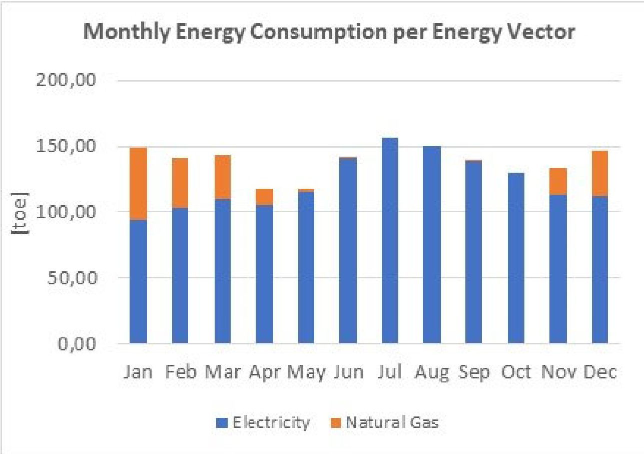
Source: IEA (2019) Global Energy annd Co2 Status Report 2019 http://www.iea.org/geco /

Figure 1: Energy Demand in Buildings. Floor area and Energy Intensity trend

The analysis began by carrying out the energy diagnosis of the building under the directives of the guide AICARR and the normative UNI 16247. The energy diagnosis is a procedure which aims to analyze the energy consumption of the building in order to identify the energy flow and the possible actions to be taken in order to improve the energy system. The first step was collecting the building's data (energy bills) to build the energy consumption of the building. The following graphs show our findings:

As the following charts show, natural gas consumption tends to be concentrated in winter months, while electricity consumption is highest in summer.
To improve the energy system without damaging the building and its historic value, the following actions have been identified:

- Electrification of the heating system
- Building integrated Photovoltaic
- Technological upgrades and BACS
- Redevelopment of the transparent casings



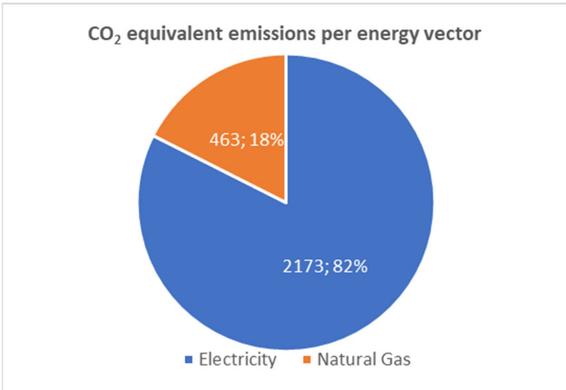


Figure 2: Primary Energy Consumption per Energy Vector and CO_2 equivalent Emissions per Energy Vector

Electrification of the Heating System

The first intervention proposed is the electrification of the heating system. Aerothermal heat pumps are incredibly efficient machines which manage to transfer heat from a lower temperature source to a higher one. Since they are electricity driven, they can also be supplied by renewable energy systems leading to a higher decrease of emissions. Air source heat pumps also have the possibility of providing cooling in the summer season, increasing the efficiency of the HVAC system. The intervention consists in connecting the heat pumps on the medium temperature collectors already present inside the building, substituting part of the thermal load now covered by the gas heater. This will lead to a reduction in the use of fossil fuels which will result in lower emissions and lower energy bills, due to the lower cost of electricity compared to the increasing price of natural gas. The primary energy reduction obtained by using heat pumps is of 27% compared to the actual thermal plant production, and even more significant is the reduction of the GHG emissions. This is due to the dismission of fossil fuels as the main energy vector for heating.

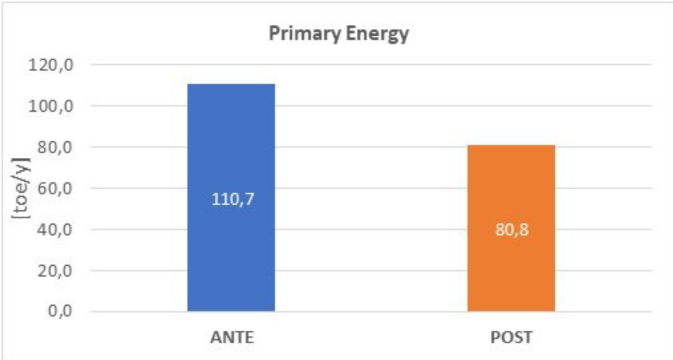


Figure 3: Primary Energy Reduction

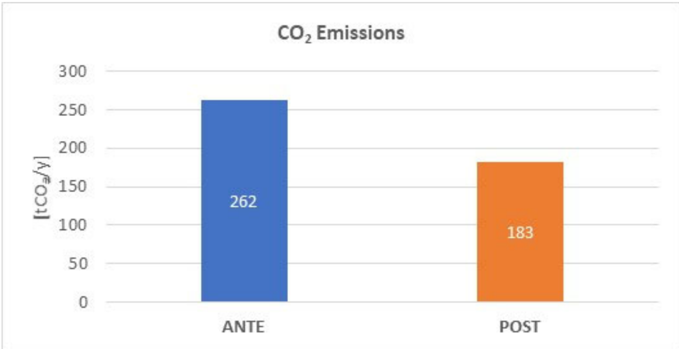


Figure 4: CO_2 Reduction

Building Integrated Photovoltaic

Building Integrated Photovoltaic has the goal of increasing energy self-production. This technology consists in installing PV modules in such a way that they assume not only the role of producing energy but become part of the architectural structure of the building. The hardest part of the installation consists in meeting both the necessities of increasing the surface where to install the modules as well as minimizing the aesthetic and visual impact. The Italian government has recently released the guidelines to improve energy efficiency in historic buildings to meet the goals of the PINR with an important focus on BIPV.

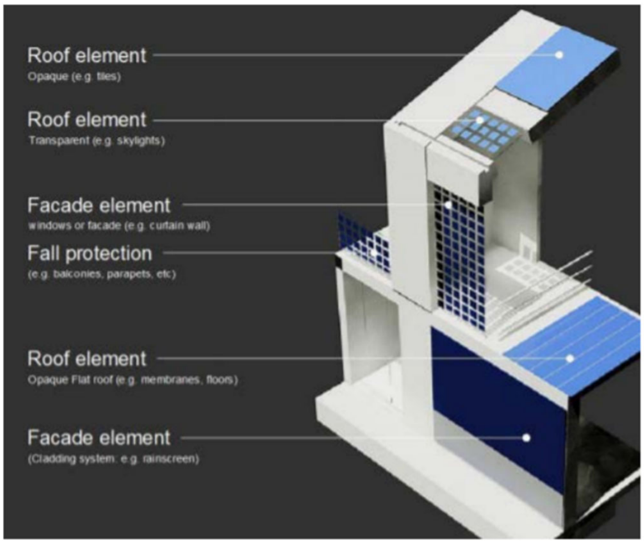


Figure 3: Building Integrated Photovoltaic

Different technologies were adopted to enhance the installation surface of the PV modules. The first and most revolutionary solution consists in replacing the skylight's glazing with PV glass made of amorphous silicon. This solution will guarantee energy production without eliminating the natural light illuminance. Another solution presented is the installation of PV modules on the rooftop of those areas which are not affected by shading. Lastly, installation of shelters to cover the plants already present on the roof, will enhance the available installation surface of PV modules. These last solutions will have the possibility of covering the modules with a colored film. Despite losing a percentage of the energy produced, this solution will reduce the aesthetic impact making the modules perfectly integrated with the architecture of the building. The following tables show the results obtained. The BIPV system will produce about 150 MWh and avoid the emissions of 6 tons of CO_2 equivalent. It will partially cover the energy request of the aerothermal Heat Pumps and save approximately 25 thousand euros on the energy bill.

Energy Production and Energy Savings	
Annual production BIPV skylight [MWh]	12,2
Annual production BIPV coverage [MWh]	41
Annual production BIPV plant shielding [MWh]	95,6
Electricity saved [kWh]	148,8
Primary Energy Saved [toe]	27,8
CO_2 saved [kgCO_2]	61.008

Table 1: BIPV Energy Production and Energy Savings

Technological upgrades and BACS

The next intervention consists of relighting the building by substituting the actual fluorescent lamps with LED technology. Lighting consumes almost 10% of the final electric energy of the whole complex. The much higher luminous efficiency of LED technology will lower the total power by almost 200 kW reducing the fraction of electrical energy consumed below 6%. Adding a daylight control system, a further reduction of about 50% of the energy used for lighting will be obtained.
In the following graph we can see the results obtained. The Lighting energy numeric indicator passes from 13,4 to 7,7 kWh/m2 y and an additional 30% is reduced by adding the daylight control system. Also, the GHG emissions will be reduced of almost 50%.

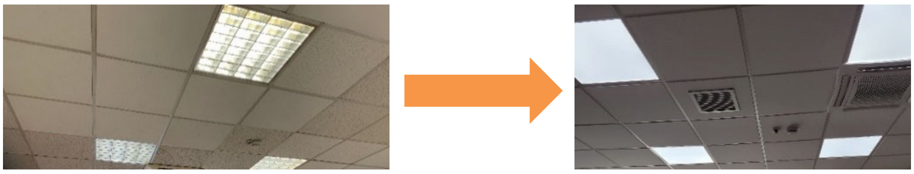


Figure 4: Relamping

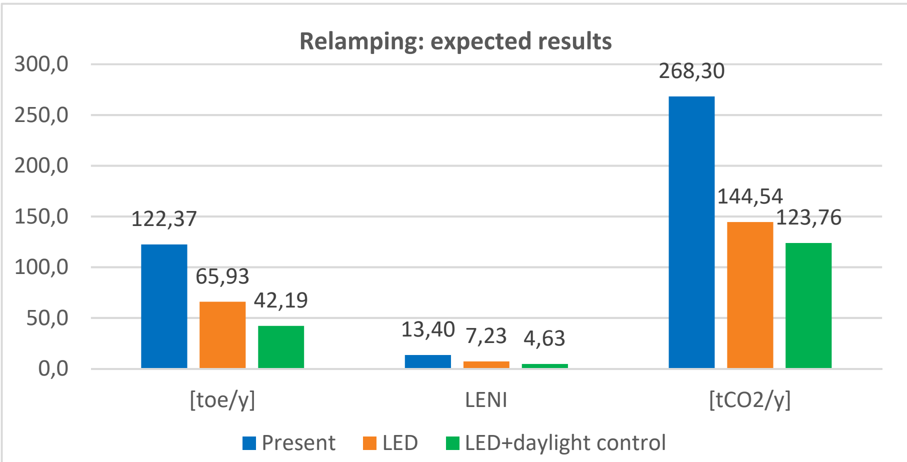


Figure 5: Relamping Primary Energy, LENI, and CO2 Emissions Reduction

Other technological upgrades proposed are the installation of inverters to the electrical pumps, which will lead to an energy saving of more than 200 MWh. The substitution of the ups system of 400 KVA

which now works with a low efficiency due to the low load factor, with two UPS of 100 KVA each increasing the efficiency to more than 95% and leading to an energy saving of 175 MWh.
In the end, the improvement of the BACS (*building automation and control system)* class of the buildings can lead to a large saving in terms of primary energy. The building nowadays is in the D class, that corresponds to a “non-energy efficient” building, mainly due to its age and the fact that the technical plants are the result of overlapping interventions through the years. In the present work the aim is not to bring the building to classes B or A, that correspond to an efficient or highly efficient building, as this action involves a proper revolution in the technical plants; the aim is instead to bring the building up to a sufficient class, which is class C (the standard). To reach this class, the adjustments needed are the following:

- Rescheduling of the on/off time of the heat/cold generators
- External sensors for the generators
- New sensors for the room terminals

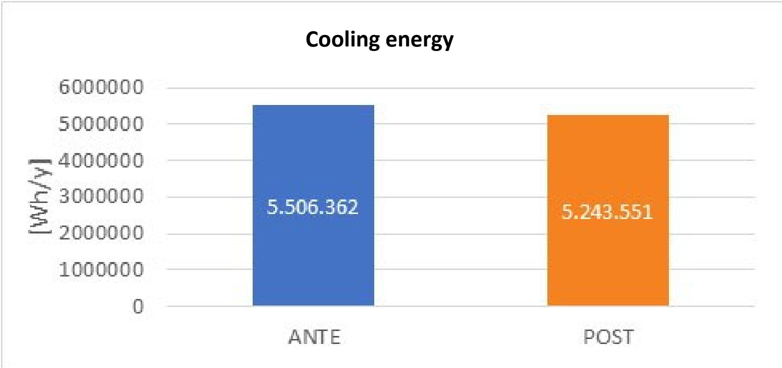
These interventions go to sum with the impact of the dotation of inverters on the electrical pumps, that has been calculated separately but is essential for the correct operation of the BACS improvement. The transition from class D to class C leads to a saving of 31% of the primary energy for HVAC purposes.

Redevelopment of the transparent casings

The substitution of the transparent casing is one of the most delicate interventions made. The necessity to keep in line with the architectural standards of the building had to meet with the energy efficiency improvement requirements. The final solution was to substitute the aluminum fixtures with wooden ones and the single glazing with a double glazing. Furthermore, an analysis on the solar factor, the transmittance and the light transmission has been carried out to choose the best solution between low emissive glass and selective glass according to the position of the window respect to the sun.

Figure 6: Redevelopment of the Transparent Casing

The best solution in order to meet the desired results consists in installing the low emissive glass on the north side of the building and the selective glass on the rest of the building. Doing so, we obtain a 17% reduction in the energy needed for cooling and a reduction of about 10% for heating.



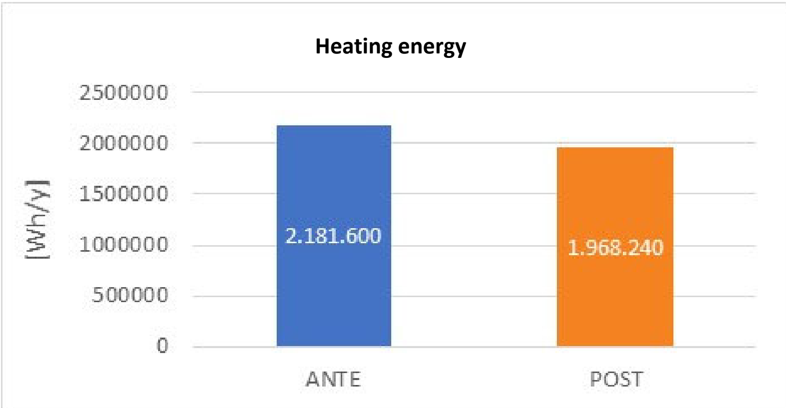
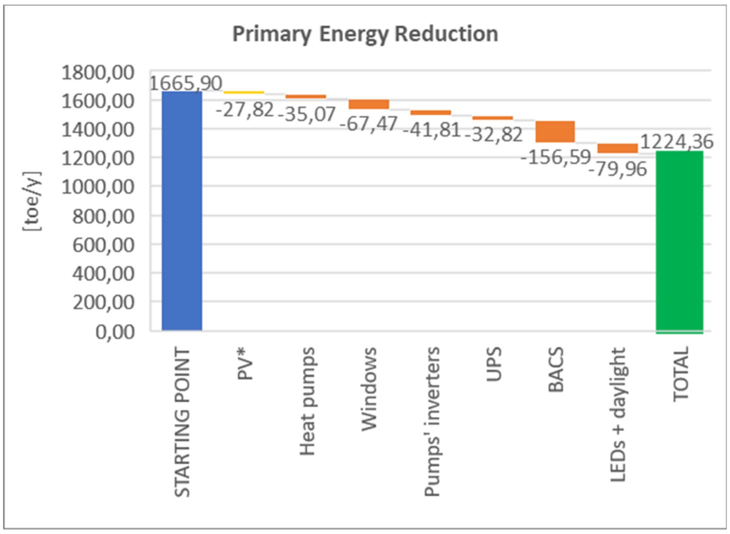


Figure 7: Thermal and Cooling Energy Reduction

Conclusions

The solutions proposed will all lead to a primary energy reduction. The different color of the PV's savings in the graphs below is due to the fact that this energy is not really a primary energy reduction. Nevertheless, it can be considered a reduction of electrical energy acquired from the grid, which is mostly produced by thermal plants.



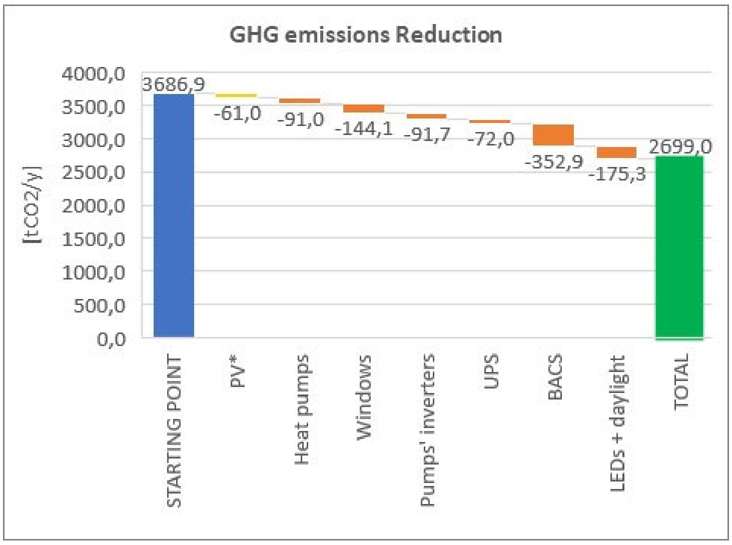


Figure 8: Total Primary Energy and CO2 emissions Reduction

The total primary energy passes from 1665,9 toes to 1229 which means a reduction of almost 27% respect the starting situation. A same reduction can be seen in the GHG emissions of the building which lead to a saving of almost 1000 tons of CO_2 equivalent.

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ENERGY EFFICIENCY AS A KEY FACTOR FOR THE SUSTAINABILITY PATHWAY OF ORGANIZATIONS. THE CASE OF THE EUROPEAN SPACE AGENCY ESA-ESRIN IN ROME

Francesco Castellani,
Studio Santi, Italy

Maria Carmen Falvo,
University of Rome Sapienza, Rome, Italy

Federico Santi,
University of Rome Sapienza, Rome, Italy

Maurizio Della Fornace
ESA ESRIN, ESA Estates and Facility Management Department, Italy

Abstract

EU achieved the 20-20-20 goals of the 2020 Climate and Energy Package: 20% emission reduction of greenhouse gases compared to 1990 levels, 20% increment in the use of renewable energy for the coverage of EU energy demands, 20% reduction of the primary energy consumption compared to the 2020 levels originally forecasted in 2007.
This EU achievement was possibile thanks to the commitment of each nation and its public and private organizations, led to this achivement by mandatory rules, incentives but also by voluntary sustainability pathway of which energy efficiency is one of the most important components.
The case study of ESA ESRIN, the European Space Agency facility in Rome, shows how an organization can plan a sustainability pathway, follow it and then achieve the 20-20-20 goals «within its walls», helping to achieve the general target. ESA ESRIN achieved the 20-20-20 goals (specifically adapted for a single organization) in this way: 55% reduction of GHG emissions, 37% reduction of primary energy consumption, 20% coverage of the total energy consumption with RES.

1. Introduction

The European Union has placed the challenges related to the climate change and the negative effects of the air pollution to the centre of its politics. One of the main concerns lies on the greenhouse effect, i.e. the average global temperature increase caused by gases generated from combustion process. The most relevant one in terms of emission is the carbon dioxide (CO_2).
As a consequence of the accession to the Kyoto Protocol (*3rd UNFCCC Conference of Parties, Kyoto 1997*), the whole EU has been engaged in 8% greenhouse gases (GHGs) emission reduction compared to 1990 levels (European Council Decision 2002/358/EC) in the period between 2008-2012. This commitment has been differently allocated among the Member States, considering parameters such as the industrial structure in each country, the mix of energy sources used to produce energy and expectations for economic growth. For Italy, the Commission commitment provided for a 6.5% GHGs emission reduction.

The Copenhagen Summit (*UNFCCC COP15, Copenhagen 2009*) was regarded as the opportunity to formalize an international agreement for continuing the fight against climate change in the post-Kyoto phase. It was not possible to approve unanimously a binding commitment, despite the common aim of the participating states.
The Doha Amendment (*UNFCCC COP18, Doha 2012*) represented the Kyoto Protocol extension up to 2020, including additional efforts of emission reduction. The agreement, however, has not entered into force yet. The minimum number of signatory countries, indeed, has not been reached.
Whether or not an agreement is reached, the European Council in 2007 laid down the need of a transition to a low carbon economy in the EU, following an integrated approach between policies implemented for the GHGs reduction and energy policies.
Within the framework of the European 2020 strategy for a smart, sustainable and inclusive growth of the euro zone, the Council is committed to the achievement by 2020 of the following targets (also referred to as "20-20-20 goals"):

- 20% emission reduction of greenhouse gases compared to 1990 levels;
- 20% increment in the use of renewable energy for the coverage of EU energy demands. This commitment also includes 10% biofuel use of the total fuel consumption in the transport sector;
- 20% emission reduction of the primary energy consumption compared to the levels originally forecasted in 2007 (so called business as usual scenario, BAU).

The targets related to the 20-20-20 Strategy had to be adapted from the Community level to the different national contexts. The commitments assigned to each Member State were determined according to parameters such as the GDP growth, the added value of productive sectors, and the energy international price. For Italy, the 20-20-20 Strategy is represented by the following targets:

- Effort Sharing extra EU-ETS for emission reduction: 13% of emission reduction in 2020 compared to the 2005 baseline (Commission Decision 2013/162/EU and Decision 2013/634/EU);
- Energy efficiency: 24% of primary energy consumption reduction compared to the 2007 scenario (European Directive 2012/27/EU, Article 7);
- Renewable energy: increment up to 17% on the gross final energy consumption. The national commitment, in turn, have been allocated among region and autonomous provinces, following the mechanism of *"Burden Sharing"* (Ministry of Development Decree, March 15, 2012).

In this context, a real case study, related to a complex facility in Italy, has been investigated. The aim of the work is to demonstrate how a complex facility can participate in achieving of the EU 20-20-20 goals through the improvement of energy performance and environmental sustainability.
The target related to CO_2 emissions level, total energy consumption and renewable energy penetration have to be adapted to the particular context, in order to perform a compliance analysis of the local situation of ESA ESRIN facility to the European 20-20-20 Strategy.

2. The case study

2.1. Overview on the facility

ESA ESRIN facility is located in Largo Galileo Galilei 1, 00044 Frascati (RM). Its size is approximately 35.000 m^2 and serves almost 1.000 employees on site, plus a large number of visitors

attending ESA conferences. The site consists of 20 buildings, 2 main data centres (Corporate IT and Earth Observation), ESA Archive, 2 power stations, antennas, sport facilities (gym, tennis and football), canteen and bar, conference facilities, solar thermal and photovoltaic installations.
The most relevant energy users are Data Centres (including UPS, HVAC, power distribution, etc.) and office buildings (AHUs, heating boilers, lighting, power distribution, etc.).
Energy carriers enter ESA-ESRIN site as: electricity from the grid, electricity from local photovoltaic production, natural gas, thermal energy from local solar production, diesel for emergency generators.

The list below reports some of the systems that consume energy:

- Heating systems: in total, 9 boilers are installed: three different thermal power plants, each consisting in two boilers, provide heating to the buildings, while the sport centre and the canteen are served by three dedicated boilers.
- Air Conditioning systems: they are located in three different central air conditioning plans. There are 9 AERMEC chillers, characterized by different sizes. There is a continuous need of cooling, because of the three operating data centres; moreover during the summer period the energy consumption increases due to the office building demand.
- External Lighting system: there are 112 lampposts and 22 wall mounted lamps. The streetlights serve the whole site and they are important for the site control and car circulation. The wall lamps are installed nearly the electric and thermal power plants. The *in-situ* self-production of energy commodities comes through the following plants:
- Solar thermal plant: 4 solar thermal panels are used to produce hot water; the global installed surface is about 50 m^2 and it produces around 65 kWh/day.
- PV power plants: there are 10 photovoltaic installations, each one with a dedicated converter, summing a total installed power of 180 kW at peak. The average yearly electricity production is over 240 MWh.

2.2 Main activities in the facility and available input data

The main activities carried out on site – and their growth – can be summarized as follows.

- Office work: The ESRIN population over the last 10 years increased from 644 units in 2010 (217 ESA staff, 427 non-staff with office activities) to 850 units in 2019 (230 ESA staff, 620 non-staff with office activities).
- Large meetings – Conferences: ESA ESRIN manages a number of events (large meetings or conferences) involving visiting staff and, above all, visitors who are hosted on site for the time of the event with a full usage of the facilities. The best key indicator to represent the trend of such activity is the number of visitors per year, which increased from 41.535 in 2010 to 48.367 in 2019.
- Datacentre: The site hosts two main ESA datacentre, one dedicated to corporate IT services (email, SAP, cloud, network, …) and the other one to Earth Observation activities (core business of the Agency). Both those datacentres have increased the number of provided services over the

years, in terms of number of users and number of services. The increase of the IT services provided to the ESA population is clearly related to the development of the IT technology in the last decade. The introduction of collaboration tools (videoconferencing, share point, online community, instant messaging) corporate applications (HR space, ESANOW portal, centralized access control system) and centralized cloud are examples of this trend. On the core business side, the EOP datacentre increase can be demonstrated by the growth of indicators like data per satellite and quantity of satellite at the beginning and the end of the analysed timeslot.

- Physical archive: One important part of the ESA ESRIN facility is its paper document archive: it stores corporate current and historical documents in a temperature and humidity-controlled environment. Due to its nature - storage of historical data - the quantity of document in the archive has constantly increased year by year, on top of that on 2017, due to the closure of the ESA-HQ archive, a consistent block of document from the ESA head quarter where transferred to the ESRIN site. The lenght of the shelves for stored documents increased from the 3.000 m of 2010 to the 6.600 m of the 2019.

All the points above are convergent in demonstrating a significant increase of the ESA ESRIN site activities, in the time slot 2010-2018, still going on in 2021.
The data provided by ESA ESRIN have as reference period 2010-2018. In summary, they are:

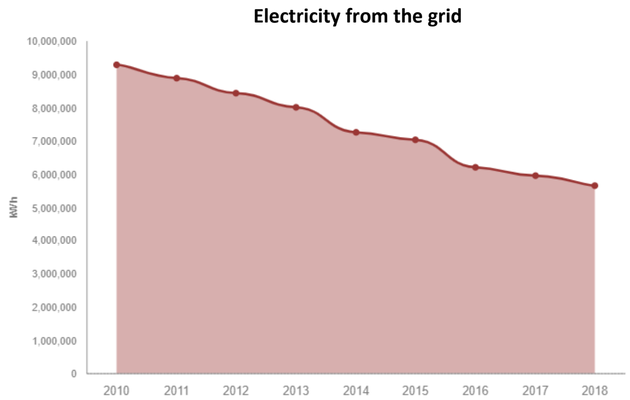
- Annual electricity bills (2016-2018) and annual measured data (2010-2015);
- Energy supply contract based on 100% renewable sources with GO;
- Electricity production from photovoltaic installations (in-site self-consumed) for 2010-2018;
- Annual natural gas consumption bills (2014-2018) and annual measured data (2010-2013);
- Data collection of winter day degrees on site (2010-2018);
- List of energy efficiency interventions realized between 2010-2019, with related estimation of annual energy savings.

The data have been processed, verified via on-site inspections and consequently used for the drafting of the present work.
ESA ESRIN realized many energy efficiency interventions and introduced renewable energy sources since 2010 up to date. The most important realizations are listed below:

- 185 kWp photovoltaic plants and 30 kW solar thermal plant;
- Freecooling for datacentres;
- Thermal cut windows;
- Building Management Systems for the metering and optimization of the consumptions;
- High efficiency chillers, rooftops and pumps;
- Inverter and brushless AHU;
- Full LED lighting;
- 4 more degrees in hot and cold isles in datacentres;
- ISO 50001 Energy Management certification.

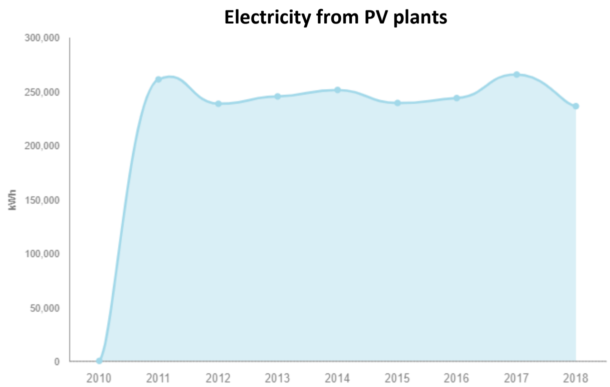
2.3. Analysis of the energy consumption and production

The trend of the grid-electricity consumption in the reference period is reported in figure:



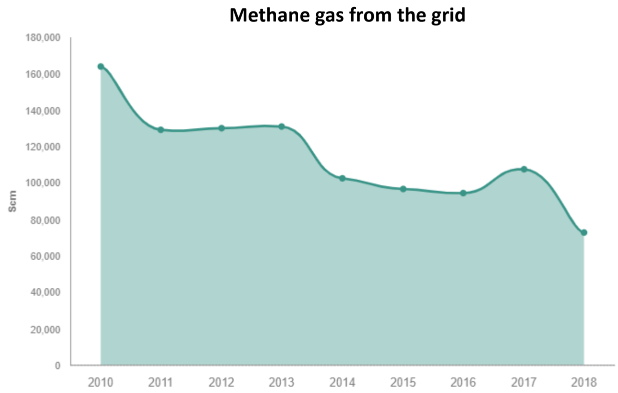
Grid electricity consumption (kWh) in the reference period 2010-2018

The trend of the electricity produced on-site by the PV power plants and self-consumed by the site - read from the metering systems and referred to the reference period - is reported in figure:



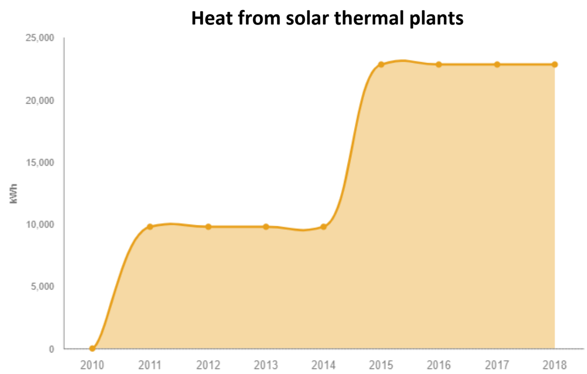
Electricity from the PV plants (kWh), consumed in the site, in the reference period 2010-2018

The trend of natural gas consumption, purchased from the natural gas grid and referred to the reference period, is reported in figure:



Natural gas consumption (Scm) in the reference period 2010-2018

The heat generation comes from two different plants: a thermal solar plant, built in 2010, and a thermal solar plant for the canteen, built in 2014.
The trend of heat generated by thermal solar plant and consumed on site, calculated on the base of an estimation of the annual heat production of the plants and referred to the reference period, is reported in figure:



Heat from solar thermal plants (kWh th) consumed in the site in the reference period 2010-2018

3. Analysis on the compliance of the facility with the European 20-20-20 goals

An analysis performed on the facility energy consumption and on the energy efficiency interventions, over the reference period, has been limited to the perimeter of the site. Therefore, it has included:

- The direct energy consumption (and emissions) related to the combustion process taking place in the site (such as natural gas boilers);
- The indirect energy consumption (and emissions) related to the energy carriers produced elsewhere and transported and consumed on site.

  Vice versa, it will be excluded from the analysis:
- The indirect energy consumption that are not controllable from the organization (such as employees' mobility, etc.);
- The greenhouse gas emissions that are non-energy related (such as leakage of refrigerant gases coming from air conditioning systems, etc.).

3.1. Revision of the EU 20-20-20 goals to ESA ESRIN facility

The aim of this work is to demonstrate how a complex facility such as ESA ESRIN can participate in achieving of the EU 20-20-20 goals through the improvement of energy performance and environmental sustainability.
The target related to CO_2 emissions level, total energy consumption and renewable energy penetration have to be adapted to the particular context, in order to perform a compliance analysis of the local situation of ESA ESRIN facility to the European 20-20-20 Strategy.
The first consideration concerns the differences in the baseline and the reporting period:

- The European strategy compares the 2020 levels to the 1990 levels, as regards the GHGs emission reduction: in case of ESA ESRIN the comparison is performed between the 2018 levels and 2010 levels, because the reference measurement is available for this period.
- About reduction in energy consumption, the European strategy compares the effective 2020 values to the estimated level in 2020: in case of ESA ESRIN the comparison is performed between the 2018 levels and 2010 levels, because the reference measurement is available for this period. The adaptation is conservative, because of the constant increasing of the activities in the period.
- The 20-20-20 Strategy takes 2020 as reference for coverage with renewable energy of the total consumption: for ESA ESRIN the reference year is the 2018, i.e. the last year documented in terms of measured data.

Another major difference is that, considering the energy performances of a limited perimeter, it is necessary to deal not only with the measures of energy efficiency and the introduction of renewable energy sources produced on site, but also with the characterization of the in-coming energy carriers. About this, the progressive reduction of the environmental impact of the Italian electricity mix (mainly due to the strong growth of renewable energy sources penetration) has to be taken into account. Beside this, it must be also considered the ESA-ESRIN Energy Management choice of purchasing 100% renewable electricity from the grid.

In the current work the factors causing indirect consumption, such as the mobility of employees, are not considered, because they cannot be monitored or controlled by the company: these aspects are normally included in the analysis for EU and its member Countries.

3.2. 20% reduction of GHGs emissions

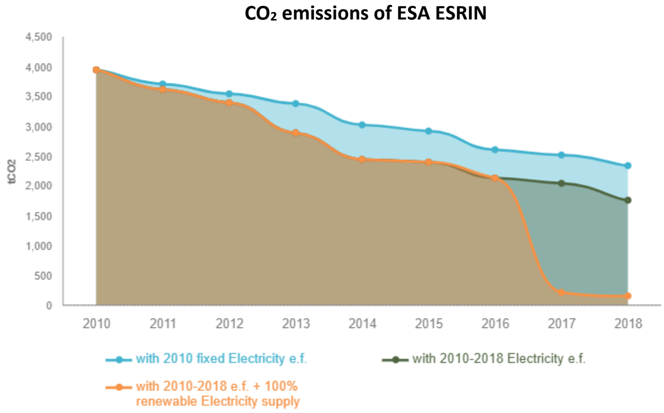
The Appendix II of the Directive 2003/87/CE defines as "greenhouse gas" the carbon dioxide (CO_2), the methane (CH_4), the nitrous oxide (N_2O), the hydrofluorocarbons (HFC), the perfluorocarbons (PFC), and the sulphur hexafluoride (SF_6). The analysis are performed in terms of "equivalent CO_2", although in the combustion process of electricity and heat generation, even GHGs different from CO_2 are released, in limited quantities but with high global warming potential (25 for methane and 298 for nitrous oxide). This approach allow considering the other gases emitted considering their global warming potential.
In the current paragraph, it is analyzed the impact in terms of GHGs emissions, i.e. CO_2, for each energy carrier concerning the ESA ESRIN facility. For each carrier it will be specified the emission factor used for the analysis in the subsequent chapter.
Regarding the energy carrier, it is useful to distinguish the two different sources of supply available:

- National electricity grid: the source is the Report 303/2019 by ISPRA, titled "Emission factors of GHGs in the national electricity sector and in the main European countries". In the reference period, the emission factor for the electric energy consumption for users varies over the years with an important decrease, due to the progressive introduction of renewable energy sources in the national electricity system, being this sources characterized by emission balance equal to zero: the emission factor decreased from 388 gCO_2/kWh (2010) to 284 gCO_2/kWh (2018).
- In ESA ESRIN, since 2016 the electricity supplied by grid – for voluntary decision of the management – comes from 100% renewable sources guaranteed by GO (Guarantee of Origin). It is an electronic certification attesting the renewable origin of the sources used by the qualified IGO ("Impianti con Garanzia d'Origine") plants. The GSE (Gestore dei Servizi Energetici, State-owned company controlled by the Ministry of Economy and Finance) release a GO certificate in accordance with the European Directive 2009/28/CE. For these reasons, the emission factor of the electricity from the grid is equal to zero from the date of coming into effect of the 100% renewable supply with GO.
- Photovoltaic installation in site: the energy produced has an emissive balance equal to zero, because it comes totally from renewable energy source.

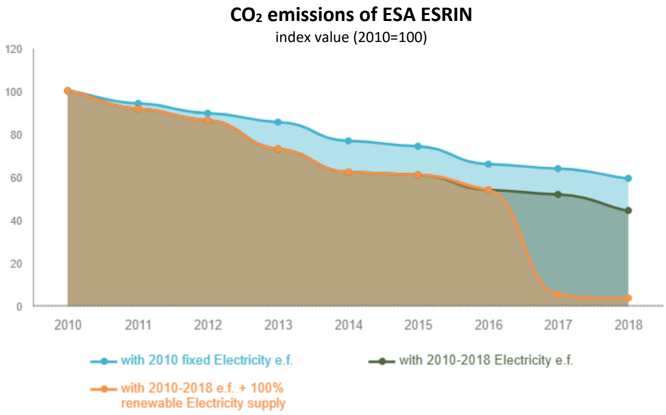
Regarding Natural Gas, the emission factor is assumed to be constant and equal to the last values published in the "Table of national standard parameter" annually drawn up by the Ministry of Environment, i.e. 1.972 gCO_2/Scm. The table collects the coefficient to be used for the CO_2 emission inventory from the 1st January 2018 to 31st December 2018 in the national inventory UNFCCC (United Nations Framework Convention on Climate Change). The annual variation of the emission factor (linked to small changes in the fuel LHV) never exceed 1% of the value. For this reason, the emission factor is assumed to be constant for the current work calculations.

Regarding heat produced by solar thermal installation, even in this case the emission balance is equal to zero, as it is energy from renewable source.

It is possible to obtain the CO_2 annual emission of the ESA ESRIN site for the individual years by applying the emission factors (provided for in the previous paragraph) to the energy consumption data of each energy carrier; the 20-20-20 Strategy involves comparison between the 2020 values and the 1990 values: in the case of ESA ESRIN the analysis is limited to the reference period.



(a)



(b)

CO_2 emissions of ESA ESRIN in the reference period in (**a**) tCO_2 and (**b**) index value (2010=100)

The Figures shows three different trends of CO_2 emissions of ESA ESRIN facility, described as absolute value of tCO_2, and as a percentage of the original value (2010):

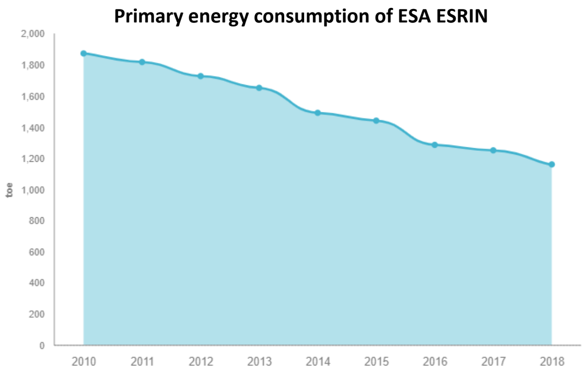
- Annual emissions with a fixed emission factor for the national electricity grid, equal to the value of the first year of the reference period (2010): the analysis allows visualizing the variation of emission in ESA ESRIN facility due solely to the energy efficiency interventions and to the introduction of renewable sources in the site. Therefore, it is independent from the annual fluctuations of the emission factor of the electricity grid, and from the signature supply contracts of energy 100% from renewable sources with GO.
- Annual emission with the correspondent emission factor of the national electricity grid: the analysis allows visualizing the variation of emission of ESA ESRIN due both from local energy efficiency interventions and the variation of the emission factor of the grid.
- Annual emission with the correspondent emission factor of the national electricity grid and considering the 100% renewable energy supply with GO: this analysis allows to take into account all the beneficial effects: local interventions, reduction of the emission factor in the national electricity grid and introduction of energy supply characterized by 100% renewable sources.

In the first case, the energy consumption reduction in the site and the introduction of renewable energy sources (photovoltaic and thermal solar installations) allow to move from 3.929 tCO_2 in 2010 to 2.333 tCO_2 in 2018 (-41%).
In the second case, the effect of the emission factor reduction is added to those of the previous point: the sum of the effects allows moving from 3.929 tCO_2 in 2010 to 1.749 tCO_2 in 2018 (-55%).
In the last case, considering the introduction in 2016 of energy supply characterized by 100% renewable sources with GO, the emissions of the ESA ESRIN facility move from 3.929 tCO_2 in 2010 to 143 tCO_2 in 2018 (-96%): the natural gas is the only non-renewable energy carrier with CO_2 emissions.

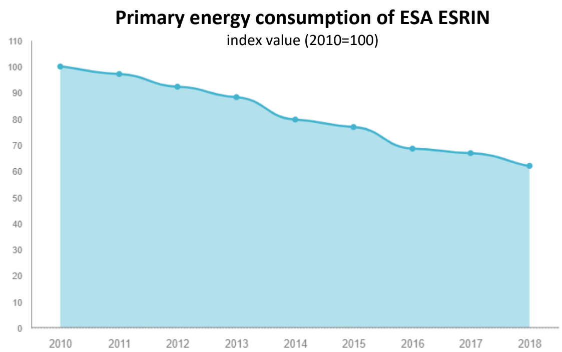
3.3. 20% reduction of energy consumptions

According to Directive 2012/27/UE, the primary energy saving target for Europe Union is equal to 20% with respect to the projections, made in 2007, of energy consumption in 2020: essentially, in 2007 was developed a projection in which the primary energy consumption of the Europe Union in 2020 will be equal to 1.842 Mtoe; therefore, the target is to arrive to 2020 with an energy consumption less than or equal to 1.474 Mtoe, i.e. 20% less than projected in 2007.
The current paragraph intends to obtain the corresponding annual consumption, expressed in primary energy, by summing all the energy carriers that are involved in the ESA ESRIN energy supply. A conversion coefficient is specified for each carrier, in order to define the consumption in toe, i.e. tons of oil equivalent, the measurement unit used by the Directive to express the primary energy.
Regarding to the energy carrier Electricity, for the conversion in primary energy the electrical energy produced from photovoltaic plants is assimilated to that one from the grid, using a coefficient specified by ARERA (Autorità di Regolazione per Energia Reti e Ambiente) through the Resolution EEN 3/08, equal to 0,187 $x10^{-3}$ toe/kWh. The target related to the 20% reduction of energy consumption, indeed, is not achieved by producing energy from renewable sources, rather by decreasing the energy consumption: for this reason, it is allowed to assimilate (in primary energy) the electrical energy produced from renewable sources to that one from the power grid.
Regarding to the energy carrier Natural Gas, for the conversion in primary energy it is used the value of Annex IV of the Directive 2012/27/EU, equal to 1,126 x10-3 toe/kg of natural gas; considering a gas density of 0,71682 kg/Scm in standard condition, a conversion factor of 0,807 $x10^{-3}$ toe/Scm is

obtained; the same factor is used to evaluate the heat generated by solar thermal plant, parameterized on the thermal kWh consumed by users.
It is important to underline that for the current target, the introduction of renewable energy sources cannot be interpreted as an operation of energy efficiency: the users' energy consumption do not decrease, but the related environmental (and economic) impact is reduced, satisfying the consumption by using a renewable (free) source. With the activation of the solar thermal and photovoltaic installations, indeed, the heat and electrical consumptions on the site are not decreased, but they are satisfied by the solar renewable source: therefore, the benefit of using renewable sources is null for the present target.
It is possible to obtain the primary energy consumption of the ESA ESRIN site for the individual years by converting the energy consumption in primary energy as described in the previous paragraph; the 20-20-20 Strategy provides that the real consumption in 2020 is 20% less than the projections made in 2007 for 2020: in case of ESA ESRIN, in absence of these data, we proceed in a more conservative way, comparing the consumption of the last year of the reference period to that of the first year.



(a)



(b)

Primary energy consumption of ESA ESRIN in the reference period in (**a**) toe and (**b**) index value (2010=100)

According to the conditions and the conversions described in the previous paragraph, the energy consumptions of the ESA ESRIN site move from 1.868 toe in 2010 to 1.159 toe in 2018 (-37%).

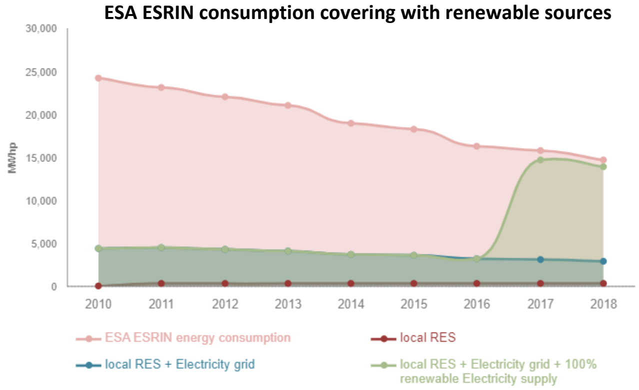
3.4. 20% coverage of the total energy consumption by renewable sources

The Directive 2009/28/CE makes explicit in the art. 2 letter a) the definition of "energy from renewable sources", i.e.: *"energy from renewable sources' means energy from renewable non-fossil sources, namely wind, solar, aerothermal, geothermal, hydrothermal and ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases"*. In Italy, this definition was fully incorporated in the current D.Lgs. 28/2011 in the art. 2 letter a).
The DM 26 June 2015 "Application of the computation methodologies for energy performances and prescription of definition and minimum requirements for buildings" presents in Table 1 of Appendix 1, the conversion factors in kWh of primary energy of the energy carriers, distinguishing between renewable and non-renewable primary energy, on the basis of the definitions of the Directive 2009/28/CE and the D.Lgs. 28/2011. The conversion factors for the energy carriers of ESA ESRIN are presented below:

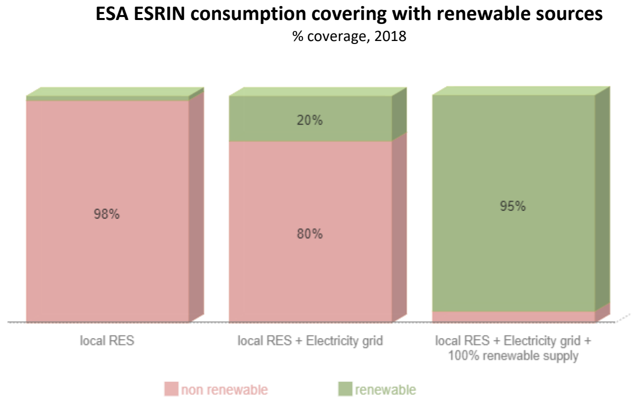
Conversion factors in kWh of primary energy of the energy carriers, extracted from DM 26 June 2015, Appendix 1, *Table*

Energy carrier	kWh nren	kWh ren	kWh tot
Electricity from the grid	1,95	0,47	2,42
Electricity from the PV plants	-	1,00	1,00
Natural gas	1,05	-	-
Thermal energy from solar plant	-	1,00	1,00

It is important to underline that according to the Table extracted from the current legislation, a share of the 19% of the electrical energy from the grid comes from renewable sources.
The consumption coverage of the ESA ESRIN facility through renewable sources is analized by using the coefficient presented in the previous table, currently in force in Italy for the calculation methodology of buildings energy performances.
It is possible to identify the portion covered by renewable energy of the ESA ESRIN site for the individual years, according to what is stated in the previous paragraph, by converting the energy consumption in primary renewable energy and non-renewable energy; the 20-20-20 Strategy provides that in 2020, 20% of total energy consumption will be covered by energy from renewable sources: in the case of ESA ESRIN the year in question is the last one of the reference period, i.e. 2018.



(a)



(b)

ESA ESRIN consumption covering with renewable sources (**a**) in kWh of primary energy for the reference period and (**b**) in percentage in the last year of the reference period (2018)

The Figure presents three different results for the consumption covered by renewable sources in ESA ESRIN site:

- Coverage of the annual consumption from renewable sources produced and self-consumed in site: it allows to visualize the variation in the consumption coverage from renewable energy in the facility, thanks exclusively to the renewable energy produced and self-consumed in site;
- Coverage of the annual consumption from local renewable sources and national energy mix: the analysis allows to visualize the variation in the consumption coverage from renewable energy in

the facility, considering the renewable energy produced and self-consumed in site and the composition of the national electrical mix (19% of energy from renewable sources, as stated in the D.M. 26 June 2015);

- Coverage of the annual consumption from local renewable sources, national electrical mix and electricity supply from 100% renewable sources: it allows to visualize the variation in the consumption coverage from renewable energy in the facility, taking into account the renewable energy produced and self-consumed in site, national electrical mix (19% renewable) and the adoption from ESA ESRIN since 2016 of electrical energy supply 100% from renewable sources with GO.

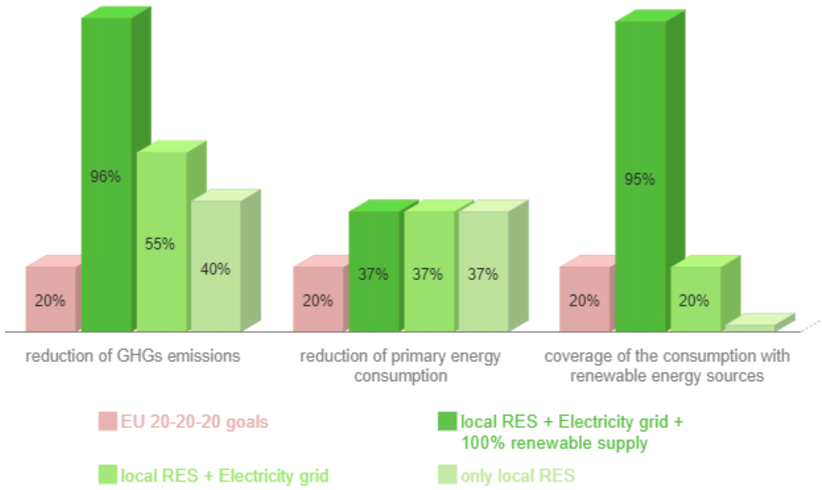
In the first case, considering only the renewable source of energy in site and used for self-consumption, the consumption coverage from renewable sources is 2% in 2018.
In the second case, by summing the effects of the renewable sources in site to those of the electricity from the grid (19% from renewable sources, as stated in the D.M. 26 June 2015), the consumption coverage from renewable sources in 2018 moves to 20%.
In the last case, the beneficial effects arising from the adoption from ESA ESRIN in 2016 of an electrical energy supply 100% from renewable sources with GO, are added from 2017 to the results obtained in the previous case. The consumption coverage from renewable sources in 2018 moves up to 95%.

4. Conclusions

The path of energy efficiency for the ESA ESRIN facility over the reference period 2010-2018 has resulted into a marked decrease in energy consumption of the site, with consequent substantial reduction in the indirect greenhouse gases emissions, despite the constant and significant growth of all the activities in the site.
The pathway covered both the reduction of the total energy consumption and the increase of the renewable energy sources quota. It was not interrupted in 2018, but it continued with a series of interventions realized in the following years, whose effects are excluded from this discussion.
With the necessary adjustments and adaptations – essential to apply to a local worksite such ESA ESRIN a Strategy conceived at the European level for a whole continent – the previous chapters have proved the full compliance of the facility with the three targets of the 20-20-20 Strategy, as showed in the diagram below, i.e. the achievement by 2020 of:

- 20% reduction of GHGs emissions compared to 1990 levels (-55% compared to 2010 for ESA ESRIN without considering the GO);
- 20% reduction of primary energy consumption compared to the 2020 level forecasted in 2007 (-37% compared to 2010 for ESA ESRIN);
- 20% coverage of the consumption with renewable energy sources (20% coverage in 2018 for ESA ESRIN without considering the GO).

Compliance of ESA ESRIN withh the EU 20-20-20 goals



ASSESSMENT OF RENEWABLE ENERGY SOURCES IMPACT ON NUCLEAR POWER. THE CASE OF FRANCE

François Benhmad
Montpellier University, France

Jacques Percebois
Art-Dev, Montpellier University, France

Abstract:
In France, the nuclear energy share of gross electricity generation is more than 70% whereas wind and solar feed-in does not exceed 8.5%. However, due to priority access to grid and support scheme, EDF (Electricité de France), operating the world's largest fleet of nuclear reactors, is challenged by the growing market share of renewable energy sources especially wind and solar.
In this paper, we use hourly data for 2019 (avoiding Covid-19 effect) to explore the link between the wind and solar feed-in and nuclear power generation. Moreover, we investigate the impact of interaction between nuclear and these renewable energy sources on electricity spot prices.
Our empirical results show that there a strong negative correlation between the two energy sources as wind and solar energy often replace nuclear power. Moreover, the equilibrium price level on the spot market induced by this negative correlation is much lower, which could jeopardize the profitability of nuclear plants.

Keywords: Nuclear, Wind, Solar, electricity spot prices, profitability
JEL classification: Q41, Q42, Q48

Introduction

In ordrer to tackle global warming and make an important contribution to the EU's long-term strategy of achieving carbon neutrality (net-zero emissions) by 2050, the EU nations agreed in 2019 on a new energy rulebook – called the Clean Energy for all Europeans package. To show global leadership on renewables, the EU has set an ambitious, binding target of 32% for renewable energy sources in the EU's energy mix by 2030. In this context, National Energy and Climate Plan (NECP) of France builds on the Multiannual Energy Planning and the National Low-Carbon Strategy proposed a 32% national contribution for renewable energy,mainly wind ans solar power, in gross final energy consumption in 2030.

It is worth noting that various support schemes for renewable energy sources (RES) are operating in Europe, mainly feed-in tariffs, fixed premiums, and green certificate systems. The feed-in tariff (FIT) is the most favourable one for a variety of RES especially for wind and solar power generation. There is also a growing use of the auction mechanism to set the level of subsidies for renewable. The RES were also given priority access to grid over conventional power plants, i.e. fossil-fuel, nuclear-fuel and hydro-based power plants. It is also because their marginal cost is close to zero, which gives them an advantage in a market where the merit order is based on marginal costs.

Therefore, the RES development induced a disruption of electricity generation across Europe. Some power generators were forced to mothball. Some other power plants closed as they were not used enough to be profitable. Some other power plants, among them nuclear plants, couldn't quickly accommodate swings in supply and demand.

Although the nuclear energy share is more than 70% in France whereas combined generation from wind and solar power accounted for less than 6 or 7 per cent of gross electricity production. EDF (Electricité de France), operating the world's largest fleet of nuclear reactors, is thus challenged by the growing market share of intermittent energy sources like wind and solar. Indeed, nuclear power plant in France have showed an ability in loading following providing flexibility to French electricity system. Thus, nuclear feed-in is progressively behaving as a back-up capacity to cope with renewables intermittency replacing carbon-emitting technologies, predominantly gas-fired plants. Consequently, renewable energy especially wind and solar photovoltaic often replace nuclear power.

In this paper, we carry out an empirical analysis in order to investigate the impact of wind feed-in and solar power production on nuclear electricity generation in France.

This study makes three main contributions to the literature. Firstly, an OLS regression is used to explore the joint impact of wind and solar photovoltaic feed-in on nuclear energy generation, using 2019 year as a dataset. Secondly, we control for power demand in France (load) throughout the 24 hours of the day over the 365 days of our data sample. Thirdly, we take into account electricity imports from Germany, the European leader on European installed capacity of renewables (more than 100 GW installed).

Our main empirical findings confirm that increasing the share of wind generation and solar feed-in could have a downward effect on nuclear generation. It confirms the fact that nuclear energy could be a victim of crowding-out effect from renewables as it will increasingly play a role of a back-up technology to cope with intermittence of renewables. This crowding-out effect coupled with the merit order effect due to a lower equilibrium price level on the spot market induced by renewables could jeopardize the profitability of nuclear plants

The paper is organized as follows. Section 2 provides the background on RES effect and the corresponding literature review. In section 3, we present the results and discuss the main findings. In section 4, we conclude and explore the policy implications of our findings.

2. **Literature survey**

A number of authors have studied the impact of RES on the pricing on the spot electricity market. For Germany, (Würzburg et al., 2013) explored the merit order effect on the joint German and Austrian market using daily data on electricity prices. They showed that each extra GWh of renewables generation led to a reduction of the daily average price by approximately 1 €/MWh in the German and Austrian markets and estimated an overall reduction in the electricity spot price of 7.6 €/MWh between mid-2010 and mid-2012.

(Ketterer, 2014) also examined wind power in German electricity markets and found that additional RE generation of 1GWh led to a reduction of the daily spot price of approximately 1€/MWh. (Cludius et al., 2014) estimated the merit order effect of wind and photovoltaic electricity generation in Germany between 2008 and 2012. They show that the average specific effect (reduction of the spot market price per additional GW of renewable energy) lies between 0.8 and 2.3 €/MWh.

(Benhmad and Percebois, 2016) also examined daily data of wind power in German electricity markets between 2009-2013 and found that additional wind generation of 1GWh led to a reduction in the daily spot price of approximately 1€/MWh, and given average wind electricity generation during 2009-2013, the merit order effect corresponds to an average price decrease, in absolute terms, of approximately 6 €/MWh.

For Denmark, (Munksgaard and Morthorst, 2008) conclude that if there is little or no wind (<400MW), prices can increase up to around 80 €/MWh (600 DKK/MWh), whereas with strong winds (>1500MW) spot prices can be brought down to around 34 €/MWh (250 DKK/MWh).
(Huisman et al., 2007) obtained equivalent results for the Nord Pool market by modelling energy supply and demand.
(Sáenz de Miera et al., 2008) find that wind power generation in Spain would have led to a drop in the wholesale price amounting to 7.08 €/MWh in 2005, 4.75 €/MWh in 2006, and 12.44 €/MWh during the first half of 2007. (Gelabert et al., 2011) find that an increase of renewable electricity production of 1 GWh reduces the daily average of the Spanish electricity price by 2 €/MWh.
(Woo et al., 2011) carried out an empirical analysis for the Texas electricity price market and showed a strong negative effect of wind power generation on the state's balancing electricity prices.
(Percebois and Pommeret, 2018a) show that the introduction of renewable energy paid off-market disrupts the demand-price relationship in the electricity wholesale market and then, for the French case, they quantify the transfers of revenues induced by this disturbance among consumers, producers and providers.
Conversely (Traber and Kemfert, 2012) calculated that the accelerated phase-out of nuclear power in Germany would lead to an increase of the wholesale electricity price between € 2 and € 6 per MWh.

3. Empirical evidence:

3.1 Data

The analysis is based on time-series data of the French power system as provided by ENTSOE. Our dataset is based on hourly information on nuclear power feed-in and RES electricity generation (wind and solar photovoltaic). The sample data covers the period from 1 January 2019 to 31 December 2019, summing to 8760 hourly data.
The following *figure 1* and *figure 2* provide a plot of the data for the whole period.

Figure1. Nuclear power feed-in vs solar generation (hourly)

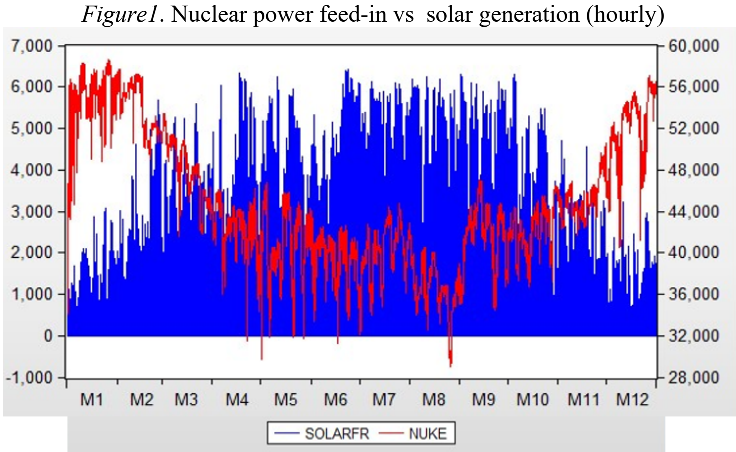
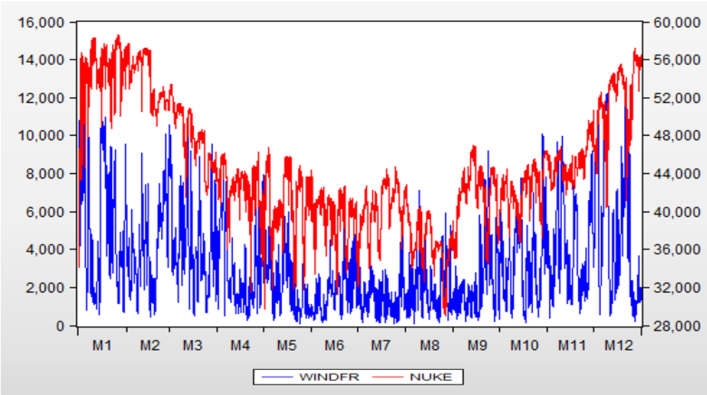
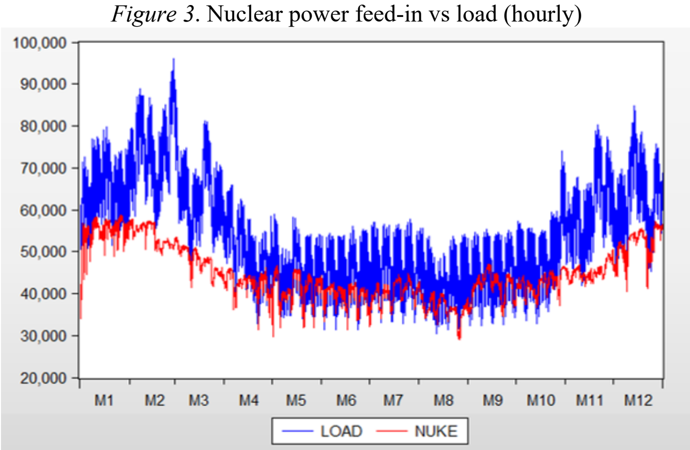


Figure 2. Nuclear power feed-in vs wind generation (hourly)



It is easy to see that the nuclear power feed-in exhibits a clear seasonal profile which can be subdivided in two semesters: a first semester beginning in October and ending in late March corresponding to a high level of generation followed by a second semester from April to end September corresponding to high level of nuclear power feed-in.
It is worth noting that the seasonal profiles of nuclear and wind are about the same ; on the contrary the seasonal profile of solar is opposite.
In France, the wind blows when the power demand is high especially during winter season whereas the solar plants produce when the demand is low especially during summer season.
As the nuclear generation depends on the power demand dynamics (load), we should control for the load level. The following *figure 3* shows clearly the following load behavor of nuclear fleet in France.

Figure 3. Nuclear power feed-in vs load (hourly)



3.2 Empirical results:

In order to explore the link between nuclear feed-in in France and RES (Photovoltaic and wind power feed-in), and controlling for both the electricity demand (load) in France, we run an OLS regression where the depend variable is nuclear power generation and where the explaining variables are respectively wind feed-in, solar PV generation, load (power demand), and electricity imports from Germany.

As there is a strong seasonal behavior of all the studies variables, we will carry out our empirical analysis on seasonally adjusted variables. Moreover, when we tested for unit roots in variables time-series using the augmented Dickey-Fuller (ADF) test (Dickey and Fuller 1979), the null hypothesis of a unit root is rejected.

The empirical results are reported in the following *Table 1:*

Dependent Variable: NUKESA

Method: ARMA Conditional Least Squares

Variable	Coefficient	Std . Error	t-Statistic	Prob.
C	37495.37	436.0564	85.98742	0.0000
LOADSA	0.153572	0.008183	18.76741	0.0000
SOLARFRSA	-0.261116	0.0186 11	-14 .02992	0.0000
WINDFRSA	-0.169471	0.020848	-8.128877	0.0000
IMPORTSA	-0.188975	0.035305	-5.352570	0.0000
AR(1)	0.968964	0.004059	238.7102	0.0000

R-squared	0 .952693	Mean dependent var	44846.43
Adjusted R-sq	**0.952666**	S.D. dependent var	2359.567
S.E. of regression	513.3574	**Akaike info criterion**	**15.32051**
Sum squared r	2.31E+09	Schwarz criterion	15.32535
Log likelihood	-67090.16	Hannan-Quinn criterion	15.32216
F-statistic	35254.35	Durbin-Watson stat	1.500402
Prob(F-statistics)	0.000000		

Table 1. Impact of renewables on nuclear generation

The empirical results show a negative impact of both solar and wind feed-in on nuclear generation in France. Although wind generation share in gross electricity generation is much higher than the solar's one, this evidenced downward effect is more pronounced for solar photovoltaic than for wind feed-in as the solar plants produce when the demand is low especially during summer season.

Indeed, the average hourly impact of solar generation should induce a decrease of 0.26 MWh of nuclear feed-in for each additional MWh of solar output, whereas the average hourly impact of wind feed-in should induce a decrease of 0.17 MWh of nuclear feed-in for each additional MWh of wind generation.

Moreover, the imported electricity from Germany exacerbates the downward pressure on nuclear generation in France as both wind and solar power coming from Germany play the same role of the wind and solar generated in France. Indeed, the high level of electricity demand during winter induces a negative impact of the German imports (mainly wind) on nuclear generation. In contrast, during summer season, the German power imports (mainly solar PV) This negative impact is much more important on nuclear generation as the power demand is low

The impact seems to be quite low as the solar and wind lowering effect on nuclear feed-in represents a small market share of power generation lost by nuclear energy. However, we should take into account that this "low" effect corresponds to an installed capacity of just 26 GW in 2019 of both wind and solar. Therefore, if we make a comparison with Germany where the renewable installed capacity in 2019 is a total of more than 110 GW –almost five times of installed capacity in France-, we can conclude that the more RES capacities would be installed in France, the more their crowding effect on nuclear feed-in could be much stronger.

Furthermore, as France is surrounded by countries with a lot of solar and wind, especially Germany, the renewable power peaks in Western Europe might be squeezing out French nuclear power.

4. Conclusion and policy implications

In this paper, we have studied how wind and photovoltaic electricity feed-in influences the nuclear generation in the French electricity market and have shown that they have a negative impact. Moreover, the electricity imported from Germany, the country with the highest installed capacity of renewable energy sources increases this negative effect.

Therefore, the large-scale penetration of renewables could have a crowding-out effect on nuclear plants jeopardizing their profitability as the recovery of their fixed costs will be highly challenged by lower equilibrium prices due to merit order effect.

The French electricity system must increasingly deal with two problems simultaneously: lack of peak electricity and too much fatal renewable electricity during off-peak periods (which will either have to be exported or stored). In a period of low power demand, nuclear power, which has shown its flexibility, is squeezed out which risks compromising its profitability in the long term. Moreover, this crowding out effect is induced by electricity which, contrary to what many people think, is not free since it is often subsidized.

Indeed, to reduce the share of nuclear power in the French electricity mix, a new production capacity should be available during peak hours. Otherwise, the demand for electricity demand should be reduced to cope with lower generation during peaking periods. As renewables could not be available during peaking periods, either conventional gas-fired power plants will have to be used or imports will be required. Imports or gas-fired power plants are costly options and will induce a sharp increase in CO_2 emissions in contrast to idea behind renewable energy sources support policies. Moreover, the management of the load curve (load-following) will require more and more flexibility in terms of

demand and it will have to be accompanied by efforts in terms of electricity storage, another costly option.
In terms of trade, the French electricity system could be a net exporter. However, we could have situations where exported power volumes are so important but at quite low price inducing a deficit in value.
Therefore, considering the French context, the use of renewables does not appear as the best suitable option to decarbonize the electricity system due to the crowding out effect of renewables. In addition, since nuclear act as a back-up to renewables, lowering the share of nuclear energy in the electricity mix without further increase the flexibility of the system could induce significant balances issues.
Hence, there is a need of a redesign in electricity markets in particular in the way the fixed costs could be recovered ensuring the plants to be well available to meet the demand for electricity.
It is a complete reform of electricity pricing mechanisms that is expected: a wholesale market based on the "merit order" works well as long as the fleet of plants is a heterogeneous park composed of several categories of power stations presenting highly differentiated variable costs. It is conceivable to set prices according to average costs, opt for a "Ramsey-Boiteux" type of pricing, which would be tantamount to fixing the price per kWh above marginal cost, the differential between this price and the marginal cost being inversely proportional to the price elasticity of demand, or choosing non-linear pricing in which the fixed part would be very important and adjusted to finance the fixed costs of the called equipment. In the latter case, this amounts to permanently backing up a capacity market for the spot market.

The merit order can be modified by taking into account the full cost, i.e. by introducing the externalities linked to the production of the MWh, hour by hour. In the case of fossil fuels, this is already the case when there is a carbon price as in Europe (around 60 euros per tonne of CO_2 in August 2021). For nuclear power, the cost of radioactive waste storage should be taken into account since the volume of waste is proportional to the volume of electricity produced. In the case of renewables, the cost of storage and retrieval of MWh should be taken into account. This would allow the calculation of pivot values on the basis of which the substitution between power plants is made. If the cost of storing renewable electricity is high, a high carbon price is needed for renewables to be called before gas or coal-fired power plants, especially if at the same time the price of gas is low. If the carbon price is high, gas-fired plants will be called before coal-fired plants, even at low coal prices, given the high carbon intensity of the MWh produced from coal.

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ESTIMATING UPSTREAM UNIT PRODUCTION COST FOR OPTIMAL ALLOCATION OF CRUDE OIL: A CASE STUDY OF NIGERIA

Kaase Gbakon
Emerald Energy Institute, University of Port Harcourt, Nigeria

Joseph Ajienka
Emmanuel Egbogah Chair & Professor of Petroleum Engineering, University of Port Harcourt, Nigeria

Joshua Gogo
Emerald Energy Institute, University of Port Harcourt, Nigeria

Omowumi Iledare
UCC Institute for Oil and Gas Studies, Cape Coast, Ghana

Summary

The mathematical programme in this paper for optimal allocation of crude oil to different utilization options requires upstream production cost as a key input. The importance of the unit cost of production to the optimization problem specifically, and its broader importance for project profitability, project financing, the quantum of tax available to government, ability to balance the budget of a resource dependent state and the attractiveness or otherwise of energy alternatives motivate the analysis in this paper. Taking advantage of the analytical framework for assessing Petroleum Profit Tax (PPT) in Nigeria, the unit upstream production cost is estimated from the annual PPT receipts, oil Royalty receipts and national oil production data from 2010 to 2019. The methodology applied to derive the "global" upstream production costs, enjoys the important consideration, that during the selected period, there have been no structural changes in upstream PPT assessments. Empirical results suggest that the implied global upstream costs in Nigeria declined from \$54.37Billion (\$60.67/bbl. in 2010) to \$34.32Billion (\$46.48/bbl. in 2019). Furthermore, Monte-Carlo Simulation based multivariable regression of unit cost (UC) on oil price and production shows that a unit change in oil price leads to about \$1/bbl change in unit costs, while a unit change in production leads to approximately \$0.04/bbl change in UC.

1. Introduction

Crude oil production in Nigeria increased rapidly from approximately 50 Mbpd in 1961 to a peak of 2.30 MMbpd in 1979 (2.07 MMbpd on average, between 1974 and 1979) and then fell to 1.24 MMbpd in 1983. It was not until 2001, when again production reached the level noted in 1979 – in 2001 production recorded was 2.36 MMbpd and in 2005, production peaked at 2.52 MMbpd from which it declined to 1.91 MMbpd in 2018. Crude oil production over time has gone to service different end uses such as domestic refining, direct export, and offshore refining or swap for petroleum products. The distribution of this use of the produced oil has altered over time in response to petroleum product demand, the state and capacity of domestic refining, and the fiscal demands of the government. Demand for petroleum products, mostly made up of the transport fuels of gasoline, diesel, and kerosene, has increased over this period – from estimated 169 Mbpd (~27 million litres/day) in 1995 to 440 Mbpd (70 million litres/day) in 2018 – 96% of which has been met by imports (as of 2018). Added to this context is that domestic refinery performance has been vacillating and declining, thus giving leeway to the high level of oil exports seen such that by 2018, 100% of Nigeria's oil production was exported compared to 78% of OPEC's (collective) own production.

Consequently, the troika of the increased oil exports ratio, low domestic refining capacity utilization, and increasing petroleum demand gives rise to the question of whether crude oil production is optimally allocated to the various end uses identified above. A mathematical model is espoused in the paper to address the allocation optimality question. Estimating of the key parameter of the mathematical model, which is the upstream production cost, is the aim of this paper.

Cost of production refers to as the total costs required to achieve production level and is typically expressed on a unit basis as \$/bbl or \$/boe. Within the Nigerian context, the cost of production is captured by the Unit Technical Cost (UTC), which is the sum of T1 and T2. In Nigeria, T1 is the Unit OPEX (\$/bbl) obtained by dividing OPEX (\$) by production (bbls). T2, on the other hand, is the Unit Capital Allowance obtained by dividing Capital Allowance (\$) by production (bbl). In Nigeria specifically, cost of production is impacted by the length of contracting process in the upstream, volatile production occasioned mostly by security breaches, cost of doing business – security costs, high insurance premiums, absence of competitively priced local inputs as alternatives, absence of synergies between operators to deploy shared infrastructure and services and the existence of a fiscal system that incentivises cost build-up rather than restraint (National Oil Policy, 2016; Mansfield, N.R, 1994). Taking a more global perspective, the applicable factors that impact cost of production include the terrain of production – offshore wells cost more than onshore, Technology Improvement, oil price, and well geometry (complexity).

2. Literature review

There are sophisticated platforms for energy system modelling (Fattahi, *et. al.*, 2019; Subramanian, *et. al.*, 2018; Neshat, *et. al.*, 2014; Bhattarcharya, *et. al.*, 2010; Beller, 1976; Hoffman & Wood, 1975). Due to the diversity in the modelling approaches, which depend on the purpose, emphasis, and scope to which the model is to be deployed, several categorizations of the model frameworks are plausible (Fattahi, *et. al.*, 2019). Bhattarcharya, *et. al.*, 2010 for example, provided a comparative overview of the existing energy system models by reviewing available literature published between the 1970s and 2010. Table 1 lists the model types, which the authors identify and then map to known "institutional" models.

Table 2: Model Types Compared in Bhattarcharya, et. al. (2010)

S/N	Model Type	Examples
1	Bottom-up, optimization-based	– Energy Flow Optimisation model (EFOM) – Market Allocation model (MARKAL)
2	Bottom-up, accounting models	– Long-range Energy Alternatives Planning model (LEAP)
3	Top-down, econometric models	– Department of Trade and Industry model (DTI[17])
4	Hybrid Models	– National Energy Modelling System (NEMS) – Prospective Outlook on Long-term Energy Systems (POLES) – World Energy Model (WEM)
5	Electricity system models	– Wien Automatic System Planning (WASP) – Electricity Generation Expansion Analysis System (EGEAS)

[17] Now called Department for Business, Enterprise and Regulatory Reform, BERR

The model types identified in *Table 1* correspond, roughly to the classification in the schematic from the Worldbank depicted in *Figure 1*(Timilsina, 2011).

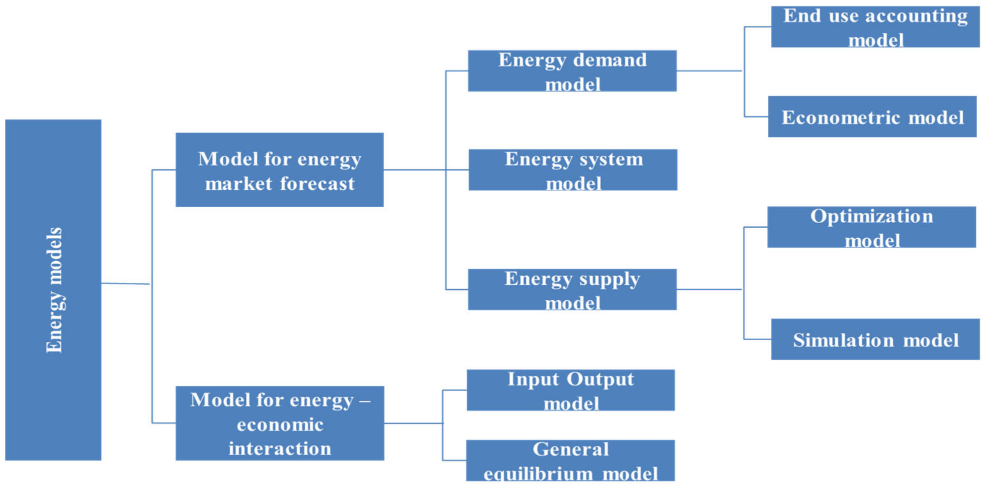

Figure 9: Energy models classification adapted from Alahmadi (2016)

Laha and Chakraborty (2017) conducted a comprehensive review of different energy system modelling classifications including eight categories: (i) the purpose of constructing the energy model, (ii) the analytical method employed for the model, (iii) the methodology incorporated while designing these models, (iv) the mathematical approach implemented, (v) the topographical area the energy model covers, (vi) the sector(s) for which the energy model has been constructed specifically for, (vii) the time frame of the energy model analysis, and (viii) the type of data required. *Figure 2* is a schematic of the possibilities in energy system model classification as per the eight (8) categories above.

Optimization is a common energy system modelling methodology (Fattahi, *et. al.*, 2019), that allows answers to specific energy modelling questions – such as what the optimal allocation of an energy resource to diverse uses ought to be to achieve a stated objective. Other modelling methods are: Simulation, Accounting, Multi-Agent, and Equilibrium and Econometrics (see Figures 1 and 2). Rowse (2008, 1987), for example, examined the question of what the optimal allocation is of natural gas from Canada between exports and domestic consumption to maximize social welfare objective under differing scenarios. Kazemia, Mehregana, Shakouri, and Hosseinzadeha (2012) formulated a fuzzy multi-objective linear programming model to optimally allocate energy resources to meet the future Iranian energy demand in Residential & Commercial, Industry, Transport and Agriculture sectors from 2011 to 2020. Askar (2012) developed a mathematical programme with the objective to find the least cost combination of technologies to meet Turkey's energy demand between 2010 and 2025, while decreasing CO_2 emissions. Askar's results showed that energy demand is met by renewables for electricity, solar heat-based energy systems for the heating sector, and hydrogen for transportation (coal based or mix of solar and gas based depending on acceptable CO_2 emissions).

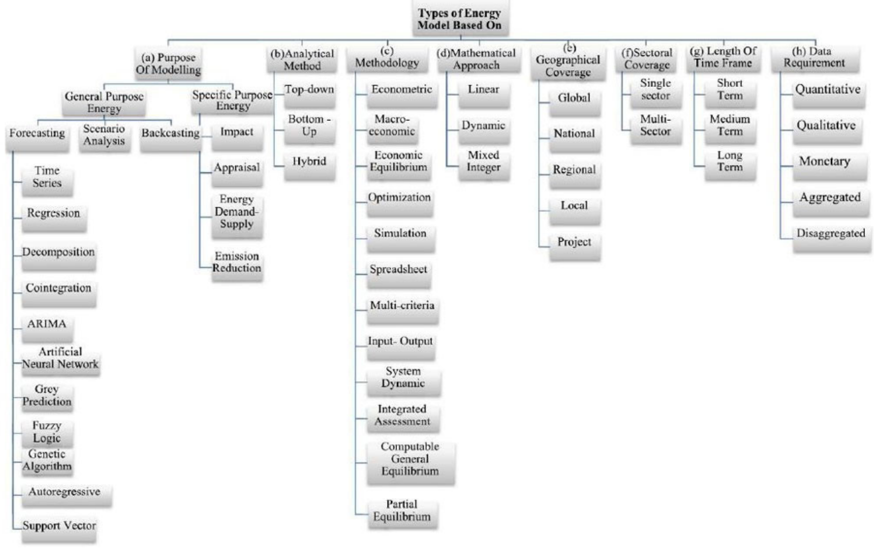

Figure 10: Energy System Model Classification (Laha and Chakraborty, 2017)

The review of literature suggests that common across these energy systems modelling approaches, is the inclusion of the cost of the energy resource as a critical parameter for the optimization of the energy systems. Specific to oil and gas as an energy resource, Alahmadi (2016) represented oil (and gas) production costs as a function of the respective cumulative production using an exponential functional form. Alahmadi had developed a model to optimize energy investments and policies from the perspective of an energy producer. Al-Qahtani (2008) determined the optimal production level for Saudi Arabia's different oil grades to maximize economic profit. To do so, Al-Qahtani estimated marginal costs functions (oil supply functions) using production capacities and price elasticities of oil supply. Gao, Hartley, and Sickles (2008) model an economically optimal dynamic oil production decision for a stylized oilfield resembling Ghawar (the largest developed oil field in Saudi Arabia). To deliver as comprehensive model as possible, Gao *et. al.* incorporated a production cost function by combining exploration cost, development cost, and operating costs – three key elements of upstream oil field costs, which the authors estimated using rule of thumb, industry surveys, and published reports/studies. The National Energy Modelling System (NEMS) developed for the US energy sector policy (EIA, 2009) contains an Oil and Gas Supply Module (OGSM), which captures production cost with the application of both econometric and engineering principles. Utilizing a bottom up, field approach, the OGSM estimated production costs as summed costs of the various activities that give rise to oil supply – exploration costs, drilling costs, surface treatment facilities.

The lifecycle of oil field development captures license acquisition, exploration, development, and then production. Each of the phases of the oil field development lifecycle attracts costs classed either as CAPEX or OPEX. CAPEX would refer to investments for the development of assets that will produce over the long horizon. While OPEX are those costs required to maintain the running of the production facilities – lease operating expenses, gathering and transport costs, water and effluent disposal and general and administrative costs (EIA, 2016). Well costs constitute a significant portion of upstream development (EIA, 2016) and thus, has frequently been the subject of several studies and assessment (EIA, 2016; Kaiser, 2007; Makasiar G. S. *et. al.*, 1985). According to Toews & Naumov (2016), in recent years the drilling of exploration wells has been responsible for between 40% and 50% of capital expenditure and consequently provides a good sense of overall cost of development over time. Furthermore, because Drilling and Completion (D&C) costs make up between 60% to 80% of the well cost (EIA, 2016), there's a lot of focus on D&C costs in the literature. Makasiar *et. al.* (1985) estimated drilling costs in the Philippines by identifying the major determinants, which include well depth, geology (rock hardness used as proxy), lost time (rig availability used as proxy) and front-end expenditure (mobilization, transport). Kaiser (2007) in a review of drilling cost estimation models, highlighted the difficulty in estimating drilling costs due to the numerous factors that impact drilling. However, the paper posits that formation geology and location of target reservoir are the primary factors that impact drilling costs. This assertion is corroborated by Lukawski *et. al.* (2014) using 2009 well cost data from the US with measured depth (MD) as an explanatory variable in a power function model specification for well costs. The power function regression model explained 97% of well costs variability.

Toews & Naumov (2014), however, investigated upstream oil production costs from a more strategic level by including oil price as an explanatory variable of unit production costs variation. They found that a sustained 10% increase in the price of oil triggers a sustained 3% increase in global upstream costs with a lag of 1 – 2 years. Given the import of unit production cost in benchmarking projects and estimating government revenues, there is an interest in the nexus between costs and investment performance. Dahl *et. al.* (2017) identified cost over runs as a non-trivial problem in the oil and gas industry and their study revealed that cost overruns, in relative terms, are higher when oil prices and other indicators for economic activity increase during project implementation. In Nigeria, specifically, Mansfield *et. al.* (1994) observed that "finance and payment arrangements", "poor contract management", "materials shortages", "inaccurate estimations", and "overall price fluctuations" have been the major factors underlying cost overruns. While admittedly their focus was on the construction industry, the issues they identified are germane in the Nigerian oil and gas context.

Kupolokun (2011), summarised the key fiscal weaknesses of the recently abrogated petroleum tax laws in Nigeria to include fiscal inefficiencies, which encourage excessive contractor spending as well as low Savings Index occasioned by high oil tax rate of 85%. The Savings Index is an indication of the incentive of an investor to save on costs. The logic being that if costs are minimised then the government will tax the bulk of profits away (Pedro, 2015).

3. Methods

Upstream oil production cost is critical to the development of the framework to ascertain the optimal allocation of crude oil to meet petroleum product demand in Nigeria. The technique of Mathematical

Programming solves the problem of determining the optimal allocations of limited resources required to meet a given objective. The technique finds use in different domains, but specific to oil and gas, it has been applied to upstream production operations (Kaufman *et. al.*, 2020; Ghaelia, 2019; Aziz, 2002; Wang, *et. al.*, 2002;), refinery production (Murty, 2020; Ejikeme-Ugwu, 2012, Chairat, 1971), and oil and gas portfolio optimization (Huang, 2019; Domnikov, *et al.*, 2017; Aibassov, 2007).
Literature reviews show that other researchers have addressed the challenge of finding production cost for use within optimization models by either developing marginal cost functions or using bottom-up engineering approaches that sum up the costs of the various activities of upstream development. For the development of the optimization framework in this paper, however, the analytical framework for the assessment of the Petroleum Profit Tax (PPT) is utilized. Using annual PPT receipts, oil Royalty receipts and national oil production numbers from 2010 to 2019, the "global" upstream production costs is derived. The method used in this paper is upheld by the absence of structural changes to the upstream tax code over the considered time frame.

3.1 Upstream cost modelling

By mapping the fiscal provisions in the PPTA, Okon (2006) showed the steps required to estimate Petroleum Profit Tax (PPT) as illustrated in *Figure 3*. Translating the scheme below into mathematical formulation of the relationship between costs and tax payments is a critical step in deriving production costs.

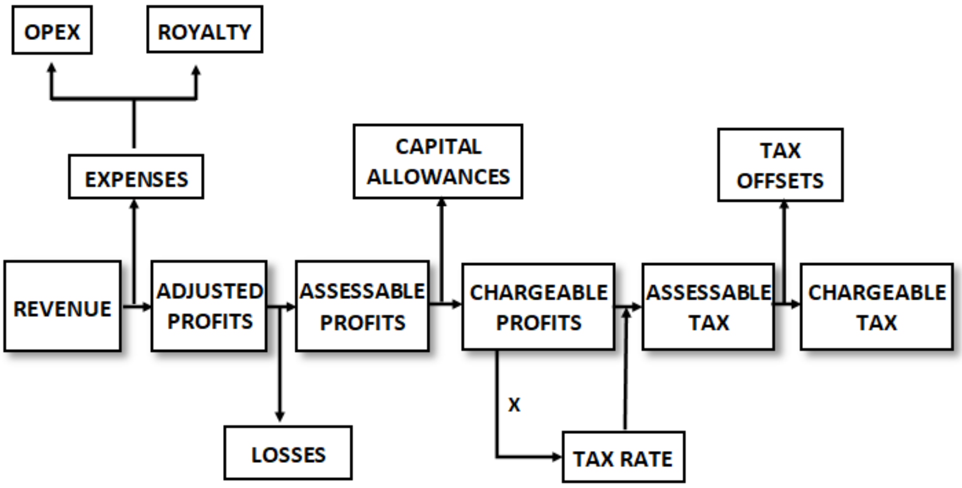

Figure 11: Schema for Tax Computation as per PPTA (Okon, T.E., 2006)

$$PPT_t = R_{PPT} * [REV_t - ROY_t - OPEX_t - CapALLOW_t - R_{ITA}CAPEX_t - UALLOW_{t-1}] \quad (1)$$

Considering that industry costs, $COST_t$, for tax purposes, can be expressed as:

$$COST_t = OPEx_t - CapALLOW_t - R_{ITA}CAPEx_t - UALLOW_{t-1} \quad (2)$$

Equation 1 is re-expressed thus:

$$PPT_t = R_{PPT} * [REV_t - ROY_t - COST_t] \quad (3)$$

Rearrange the above such that $COST_t$ is the subject of formula:

$$COST_t = REV_t - ROY_t - \left[\frac{PPT_t}{R_{PPT}}\right] \quad (4)$$

Allowing that $REV_t = P_t^O Q_t^O$, then the Cost function above is expressed as:

$$COST_t = P_t^O Q_t^O - ROY_t - \left[\frac{PPT_t}{R_{PPT}}\right] \quad (5)$$

Equation 5 is a $COST_t$ function, which is sum of Capital Allowances, OpEx, Investment Allowances, Tax Credits (if any), unrecovered Allowances from prior year assessment, Education Tax[18], and NDDC[19] Levy. We have assumed that the Education Tax and NDDC would be relatively small percentages of OPEX, Capital and Investment Allowances which have been allowed here to constitute a part of the Costs.

The expression in Equation 5 allows the estimation of $COST_t$ (and unit costs by extension) given that the other variables are known and can be readily sourced as per Table 2 below

Table 3: Data and Corresponding Source

S/N	Variable	Data Source
1	Oil Price	NNPC ASB, F&O Reports
2	Oil Production (Nigeria)	NNPC ASB, F&O Reports
3	Oil Royalty	Department of Petroleum Resources (DPR), CBN
4	Petroleum Profit Tax (PPT)	FIRS, CBN
5	Tax Rates	Petroleum Profit Tax Act

[18] Education Tax is at 2% of Assessable Profits (see Sec. 1(2) of the Tertiary Education Trust Fund Act, 2011)

[19] NDDC is Niger Delta Development Commission Levy charged at 3% of the total annual budget of any oil producing company operating, on shore and offshore (NDDC Act Sec. 14(2)-b).

Where:
- $\boldsymbol{REV_t}$ is the Gross Revenue
- $\boldsymbol{P_t^O}$ is the Oil Price
- $\boldsymbol{Q_t^O}$ is the Oil Production
- $\boldsymbol{ROY_t}$ is the Oil Royalty
- $\boldsymbol{COST_t}$ is the Production Cost
- $\boldsymbol{CAPEX_t}$ is the CAPEX
- $\boldsymbol{CapALLOW_t}$ is the Capital Allowance
- $\boldsymbol{OPEX_t}$ is the OpEx
- $\boldsymbol{UALLOW_{t-1}}$ is the Unrecovered Allowances from prior year assessments
- $\boldsymbol{PPT_t}$ is the Petroleum Profit Tax receipts
- $\boldsymbol{R_{PPT}}$ is the Petroleum Profit Tax rate
- $\boldsymbol{R_{ITA}}$ is the Investment Tax Allowance rate (multiplied by $\boldsymbol{CAPEX_t}$ results in the Investment Allowance)

To improve the estimate, it is noted that PPT rate for Deepwater production is 50% while production elsewhere attracts a PPT rate of 85%. There is also the provision for a PPT rate of 65.75% which applies to companies in their first five years of production, which have not fully amortized their pre-production costs. However, over the period chosen practically all the production registered arose from companies which had been in production more than five years. Consequently, the average of the two applicable rates (50% and 85%) weighted by the relative production from Deepwater and non-Deepwater is taken.

Year	DW Oil Prod. (MMBBLS)	ON/SH Oil Prod. (MMBBLS)	Wgtd PPTax Rate (%)
2008	195.128	573.618	76%
2009	268.792	511.556	73%
2010	316.887	579.156	73%
2011	289.334	576.912	73%
2012	320.434	532.342	72%
2013	313.965	486.523	71%
2014	320.200	478.341	71%
2015	320.626	452.833	70%
2016	324.334	345.664	68%
2017	303.952	385.792	70%
2018	270.610	430.822	71%
2019	314.125	424.240	70%

The Weighted PPT rate, $\boldsymbol{R_{PPT}}$, is what is now applied to the cost function in the paper.

3.2 Crude oil utilization in Nigeria: reference energy system

The network schematic in *Figure 4* represents a typical Reference Energy System (RES) applied to crude oil from production to end utilization. A RES is a network representation of all the technical activities required to supply various forms of energy to end-use activities (Hoffman & Wood, 1975). The optimization model applied in this paper is derived from the network schematic depicted in *Figure 4*.

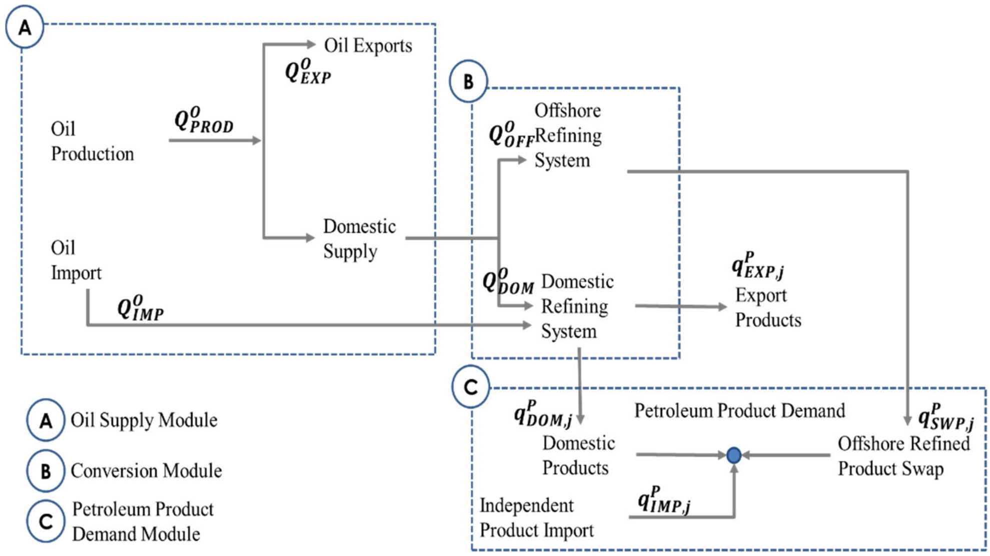

Figure 12: Schematic Showing Crude Oil Utilization for Product Supply

3.2 Development of objective function

The optimization model developed to address the central objective of this paper is given by the general framework:

$$\begin{aligned} &\text{Maximize } \boldsymbol{Z} = \boldsymbol{C^T X} \\ &\text{Subject to } AX \le b \\ &X \ge 0 \end{aligned} \tag{6}$$

where, $Z = C^T X$ is the Objective Function, $AX \le b$ represents the functional constraint, and $X \ge 0$ is the non-negative constraint. The symbols used in the model are explained as follows:

- $\boldsymbol{P^O}$ is the Price of Crude Oil ($/bbl)
- $\Delta \boldsymbol{P^O}$ is the quality differential for crude oil imported ($/bbl)
- $\boldsymbol{P^P_{EXP,j}}$ is the Price of Refined Product *j* for Export ($/bbl); *j = 1…5*
- $\boldsymbol{P^P_{DOM,j}}$ is the Price of Product *j* to domestic ($/bbl); *j = 1 … 5*
- $\boldsymbol{P^P_{IMP,j}}$ is the Price of Product *j* in the source market (to be imported) ($/bbl); *j = 1…5*

- $\boldsymbol{C_{DIST}^{P}}$ is the cost of product distribution to domestic ($/bbl)
- $\boldsymbol{C_{LOSS,j}^{P}}$ is the cost of loss of *jth* product distribution to domestic ($/bbl); *j = 1…5*
- $\boldsymbol{C_{DIST}^{O}}$ is the cost of oil distribution to domestic ($/bbl)
- $\boldsymbol{C_{PROD}^{O}}$ is the cost of upstream oil production ($/bbl)
- $\boldsymbol{C_{DT}^{O}}$ is the cost of Dirty Tanker Freight (oil shipping) ($/bbl)
- $\boldsymbol{C_{CT}^{O}}$ is the cost of Clean Tanker Freight (product shipping) ($/bbl)
- $\boldsymbol{C_{DREF}^{O}}$ is the cost (variable) of domestic refining ($/bbl)
- $\boldsymbol{C_{OREF}^{O}}$ is the processing fee for offshore refining ($/bbl)
- $\boldsymbol{C_{LOSS}^{O}}$ is the cost of crude oil loss ($/bbl)
- $\boldsymbol{FC_{DREF}}$ is the Fixed Cost of domestic refining ($MM)
- $\boldsymbol{FC_{DIST}}$ is the Fixed Cost of domestic distribution ($MM)
- $\boldsymbol{Q_{PROD}^{O}}$ is the Upstream Crude Oil Production (MMBBLS)
- $\boldsymbol{Q_{EXP}^{O}}$ is the Crude Oil Exported (MMBBLS)
- $\boldsymbol{Q_{DOM}^{O}}$ is the Crude Oil for domestic refining (MMBBLS)
- $\boldsymbol{Q_{OFF}^{O}}$ is the Crude Oil that goes into offshore refining (MMBBLS)
- $\boldsymbol{Q_{IMP}^{O}}$ is the Crude Oil Imported into the domestic refining system (MMBBLS)
- $\boldsymbol{q_{DOM,j}^{P}}$ is the *jth* Product from domestic refining into the domestic market (MMBBLS); *j = 1…5*
- $\boldsymbol{q_{EXP,j}^{P}}$ is the *jth* Product from domestic refining which is exported (MMBBLS); *j = 1 … 5*
- $\boldsymbol{q_{SWP,j}^{P}}$ is the *jth* Product from offshore refining/swap (MMBBLS); *j = 1…5*
- $\boldsymbol{q_{IMP,j}^{P}}$ is *jth* Product imported independently into the domestic market (MMBBLS); *j = 1…5*
- $\boldsymbol{q_{DEM,j}^{P}}$ is the *jth* Product demand of the domestic market (MMBBLS); *j = 1 … 5*
- $\boldsymbol{TDRC}$ is the Total Domestic Refining Capacity (MMBBLS)
- $\boldsymbol{TORC}$ is the Total Offshore Refining Capacity (MMBBLS)

where j = 1 … 5 is the subscript representation for the five (5) different products that are majorly produced from Nigerian refineries – Naphtha, Gasoline, Diesel, Kerosene, and Fuel Oil. The objective is to maximize the profit (or net benefit) of the system, which is the difference between the "Inflows" and "Outflows" summed up across the nodes of the network.

The Inflow is given by Equation 7 as:

$$\text{INFLOW} = \mathrm{P^{O}}\left[\mathrm{Q_{EXP}^{O}} + \mathrm{Q_{DOM}^{O}}\right] + \sum_{j=1}^{5} \mathrm{q_{EXP,j}^{P}}\left[\mathrm{P_{EXP,j}^{P}}\right] + \sum_{j=1}^{5} \mathrm{P_{DOM,j}^{P}}\left[\mathrm{q_{DOM,j}^{P}} + \mathrm{q_{SWP,j}^{P}} + \mathrm{q_{IMP,j}^{P}}\right] \tag{7}$$

There are three components to Equation 7, the first, $\mathrm{P^{O}}\left[\mathrm{Q_{EXP}^{O}} + \mathrm{Q_{DOM}^{O}}\right]$, represents inflow from crude oil sale to the export market and domestic refining. The second, $\sum_{j=1}^{5} \mathrm{q_{EXP,j}^{P}}\left[\mathrm{P_{EXP,j}^{P}}\right]$, captures the receipts from the export of domestically refined products, and the third component, $\sum_{j=1}^{5} \mathrm{P_{DOM,j}^{P}}\left[\mathrm{q_{DOM,j}^{P}} + \mathrm{q_{SWP,j}^{P}} + \mathrm{q_{IMP,j}^{P}}\right]$, represents the receipts from refined products sale into the domestic market.

Further, the Outflow is represented in Equation 8.

$$\begin{aligned}\mathrm{OUTFLOW} = {} & \mathrm{Q^{O}_{EXP}}\left[\mathrm{C^{O}_{PROD}} + \mathrm{C^{O}_{LOSS}}\right] \\ & + \mathrm{Q^{O}_{OFF}}\left[\mathrm{C^{O}_{DT}} + \mathrm{C^{O}_{OREF}} + \mathrm{C^{O}_{PROD}} + \mathrm{C^{O}_{LOSS}}\right] + \mathrm{Q^{O}_{DOM}}\left[\mathrm{C^{O}_{DIST}} + \mathrm{C^{O}_{DREF}} + \mathrm{C^{O}_{PROD}} \right. \\ & \left. + \mathrm{C^{O}_{LOSS}}\right] + \mathrm{Q^{O}_{IMP}}\left[\mathrm{P^{O}} + \Delta\mathrm{P^{O}} + \mathrm{C^{O}_{DIST}} + \mathrm{C^{O}_{DREF}} + \mathrm{C^{O}_{LOSS}}\right] \\ & + \sum_{j=1}^{5} \mathrm{q^{P}_{SWP,j}}\left[\mathrm{C^{P}_{CT,j}} + \mathrm{C^{P}_{DIST,j}} + \mathrm{C^{P}_{LOSS,j}}\right] \\ & + \sum_{j=1}^{5} \mathrm{q^{P}_{IMP,j}}\left[\mathrm{P^{P}_{IMP,j}} + \mathrm{C^{P}_{CT,j}} + \mathrm{C^{P}_{DIST,j}} + \mathrm{C^{P}_{LOSS,j}}\right] + \sum_{j=1}^{5} \mathrm{q^{P}_{DOM,j}}\left[\mathrm{C^{P}_{DIST,j}} + \mathrm{C^{P}_{LOSS,j}}\right] \\ & + \sum_{j=1}^{5} \mathrm{q^{P}_{EXP,j}}\left[\mathrm{C^{P}_{LOSS,j}}\right] + \mathrm{FC_{DREF}} + \mathrm{FC_{DIST}}\end{aligned} \tag{8}$$

The "Outflow" equation has nine components. The first, $\mathrm{Q^{O}_{EXP}}\left[\mathrm{C^{O}_{PROD}} + \mathrm{C^{O}_{LOSS}}\right]$,captures the cost of upstream oil production. The second, $\mathrm{Q^{O}_{OFF}}\left[\mathrm{C^{O}_{DT}} + \mathrm{C^{O}_{OREF}} + \mathrm{C^{O}_{PROD}} + \mathrm{C^{O}_{LOSS}}\right]$, represents the cost of refining in an offshore refinery; the third, $\mathrm{Q^{O}_{DOM}}\left[\mathrm{C^{O}_{DIST}} + \mathrm{C^{O}_{DREF}} + \mathrm{C^{O}_{PROD}} + \mathrm{C^{O}_{LOSS}}\right]$, represents the cost of domestic refining, while the fourth term, $\mathrm{Q^{O}_{IMP}}\left[\mathrm{P^{O}} + \Delta\mathrm{P^{O}} + \mathrm{C^{O}_{DIST}} + \mathrm{C^{O}_{DREF}} + \mathrm{C^{O}_{LOSS}}\right]$, captures the costs associated with oil imports to domestic refineries. The fifth term, $\sum_{j=1}^{5} \mathrm{q^{P}_{SWP,j}}\left[\mathrm{C^{P}_{CT,j}} + \mathrm{C^{P}_{DIST,j}} + \mathrm{C^{P}_{LOSS,j}}\right]$, describes the costs associated with refined product swaps, the sixth term, $\sum_{j=1}^{5} \mathrm{q^{P}_{IMP,j}}\left[\mathrm{P^{P}_{IMP,j}} + \mathrm{C^{P}_{CT,j}} + \mathrm{C^{P}_{DIST,j}} + \mathrm{C^{P}_{LOSS,j}}\right]$, captures the costs of direct petroleum product imports while the seventh component, $\sum_{j=1}^{5} \mathrm{q^{P}_{DOM,j}}\left[\mathrm{C^{P}_{DIST,j}} + \mathrm{C^{P}_{LOSS,j}}\right]$, represents the expense associated with distributing domestically refined products into the domestic market. $\sum_{j=1}^{5} \mathrm{q^{P}_{EXP,j}}\left[\mathrm{C^{P}_{LOSS,j}}\right]$ is the eighth term which captures losses associated with refined products exports and $\mathrm{FC_{DREF}} + \mathrm{FC_{DIST}}$ is the ninth term which is the fixed costs associated with domestic refining and pipeline distribution.

$$\begin{aligned}\mathrm{Z} = {} & \mathrm{Q^{O}_{EXP}}\left[\mathrm{P^{O}} - \mathrm{C^{O}_{PROD}} - \mathrm{C^{O}_{LOSS}}\right] \\ & + \mathrm{Q^{O}_{OFF}}\left[-\mathrm{C^{O}_{DT}} - \mathrm{C^{O}_{OREF}} - \mathrm{C^{O}_{PROD}} - \mathrm{C^{O}_{LOSS}}\right] + \mathrm{Q^{O}_{DOM}}\left[\mathrm{P^{O}} - \mathrm{C^{O}_{DIST}} - \mathrm{C^{O}_{DREF}} - \mathrm{C^{O}_{PROD}} \right. \\ & \left. - \mathrm{C^{O}_{LOSS}}\right] + \mathrm{Q^{O}_{IMP}}\left[-\mathrm{P^{O}} - \Delta\mathrm{P^{O}} - \mathrm{C^{O}_{DIST}} - \mathrm{C^{O}_{DREF}} - \mathrm{C^{O}_{LOSS}}\right] \\ & + \sum_{j=1}^{5} \mathrm{q^{P}_{SWP,j}}\left[\mathrm{P^{P}_{DOM,j}} - \mathrm{C^{P}_{CT,j}} - \mathrm{C^{P}_{DIST,j}} - \mathrm{C^{P}_{LOSS,j}}\right] \\ & + \sum_{j=1}^{5} \mathrm{q^{P}_{IMP,j}}\left[\mathrm{P^{P}_{DOM,j}} - \mathrm{P^{P}_{IMP,j}} - \mathrm{C^{P}_{CT,j}} - \mathrm{C^{P}_{DIST,j}} - \mathrm{C^{P}_{LOSS,j}}\right] \\ & + \sum_{j=1}^{5} \mathrm{q^{P}_{DOM,j}}\left[\mathrm{P^{P}_{DOM,j}} - \mathrm{C^{P}_{DIST,j}} - \mathrm{C^{P}_{LOSS,j}}\right] + \sum_{j=1}^{5} \mathrm{q^{P}_{EXP,j}}\left[\mathrm{P^{P}_{EXP,j}} - \mathrm{C^{P}_{LOSS,j}}\right] - \mathrm{FC_{DREF}} \\ & - \mathrm{FC_{DIST}}\end{aligned} \tag{9}$$

Subtracting Equation 8 from Equation 7 provides the objective function to be maximized.

4. Analysys

The FIRS captures the oil tax receipts on a quarterly basis, while royalty receipts are captured on an annual basis by the DPR. NNPC publishes Crude Oil production monthly in the Financial and Operations reports. Due to the different timing of the data, all the data obtained have been annualized. Tax and Royalty receipts reported in Naira by the relevant institutions are converted to USD at the prevailing exchange rate from the Central Bank of Nigeria (CBN).

<u>Unit Cost</u>
Table 3 shows the relevant data and the implied upstream oil production cost as per Equation 5 above repeated here for convenience.

$$COST_t = P_t^O Q_t^O - ROY_t - \left[\frac{PPT_t}{R_{PPT}}\right]$$

Table 4: Data for Estimating Cost of Production

Year	**Oil Price ($/BBL)**	**Nat. Oil Prod. (MMBBLS)**	**Royalty ($MM)**	**PPTax ($MM)**	**Wgtd PPTax Rate (%)**	**Implied Cost ($MM)**	**Unit Cost ($/BBL)**
2010	79.496	896.0434	4653.449	8,868.59	73%	54,366.048	60.67
2011	111.26	866.2452	7004.105	20,248.15	73%	61,750.505	71.29
2012	111.67	852.7767	6746.128	20,617.01	72%	59,788.116	70.11
2013	108.66	800.4881	6167.053	16,144.19	71%	58,161.410	72.66
2014	98.946	798.5416	6281.911	15,634.17	71%	50,699.978	63.49
2015	52.387	773.4586	2824.208	4,613.03	70%	31,150.657	40.27
2016	43.734	669.9979	1732.538	4,566.29	68%	20,859.774	31.13
2017	54.192	689.7435	2303.769	4,972.49	70%	27,928.304	40.49
2018	71.31	701.4319	3934.229	8,061.27	71%	34,809.965	49.63
2019	65.081	738.3652	3924.473	6,879.46	70%	34,316.425	46.48

The Unit Costs (UC) obtained above are useful in the optimization framework to determine the extent of optimality of historical oil allocations. However, to make forecasts of optimized oil allocations, it is important to develop a model of unit costs using oil price and oil production as explanatory variables. Figure 5 below depicts graphically the trend of unit costs, oil price, and oil production.

Table 4 is the matrix of correlation coefficients between the three variables of UC, Oil Price, and Oil Production. The UC exhibits the stronger correlation with oil price (at 0.99) compared to oil production (correlation of 0.78). There is also a strong positive correlation of 0.74 between oil production and oil price.

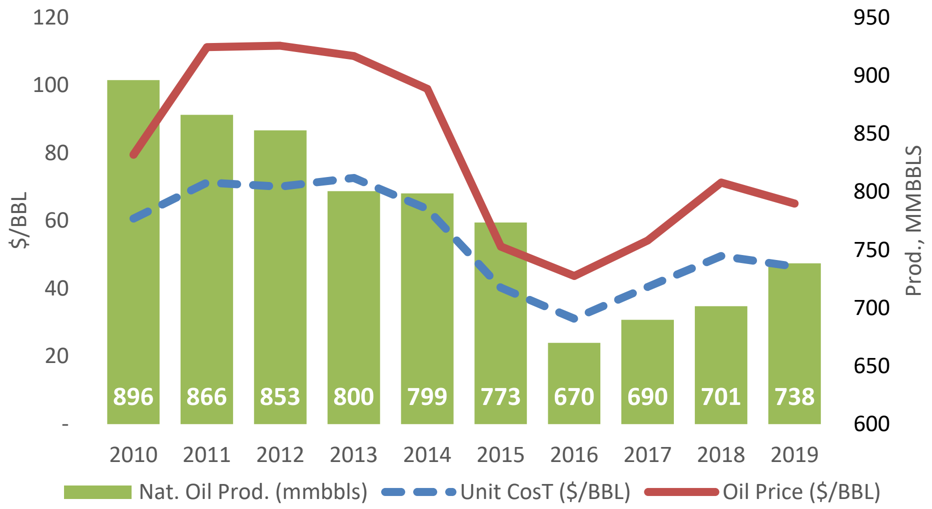

Figure 13: Unit Costs, Oil Price, and Production Trends

Table 5: Correlation Coefficients, Using the Observations 2010 - 2019

	Oil Price ($/BBL)	Oil Prod (MMBBLS)	Unit Cost ($/BBL)
Oil Price ($/BBL)	1.0000	0.7397	0.9915
Oil Prod. (MMBBLS)		1.0000	0.7760
Unit Cost ($/BBL)			1.0000

However, given paucity of the dataset, direct estimation of regression coefficients will not be carried out. Instead, the Monte-Carlo simulation technique will be employed to estimate regression coefficients for the model of unit cost as a function of oil price and oil production. The general steps to be followed in this paper are modified from Ojaraida, Iledare and Akinlawaon (2018), Hong and Kaiser (2010), Adenikinju and Oderinde (2009), Kaiser and Pulsipher (2004):

1. Specify the limits of the variable of interest $(X_1, X_2, X_3, X_4, X_5\ ) = (P_t^O,\ Q_t^O,\ \ PPT_t,\ ROY_t,\ R_{PPT})$ within the design interval, $LB_j < X_j < UB_j$, where the values of LB_j and $UB_j$are the lower and upper bounds respectively. These bounds specifically in this set correspond to the minimum and maximum values in the period from 2010 – 2019 for X_j.
2. Randomly sample from the parameters $(P_t^O,\ Q_t^O,\ \ PPT_t,\ ROY_t,\ R_{PPT})$ over the design interval specified in step 1 above. A 1,000-simulation run is executed from which the $COST_t$ is

computed using equation 5 for each set of drawn samples ("trial runs") and then unit cost is further computed as follows: $UC_t = \frac{COST_t}{Q_t^O}$.

3. Construct a regression model of $UC_t = f(P_t^O, Q_t^O)$ based on the simulated data set from Step 2

The descriptive statistics shown below for the parameters to be sampled:

Table 6: Descriptive Statistics

	Oil Price (\$/BBL)	**Nat. Oil Prod. (MMBBLS)**	**Royalty (\$MM)**	**PPTax (\$MM)**	**Wgtd PPTax Rate**
Mean	76.25	766.46	4,449.00	10,418.00	0.71
Median	71.31	773.46	3,934.20	8,061.30	0.71
Minimum	41.96	643.94	1,732.50	3,994.70	0.68
Maximum	111.67	896.04	7,004.10	20,617.00	0.73
Std. Dev.	27.38	84.65	1,857.10	6,480.60	0.01
C.V.	0.3591	0.1104	0.4174	0.6221	0.0204
Skewness	0.1671	0.0693	0.0702	0.5614	-0.2529
Ex. kurtosis	-1.5267	-1.2773	-1.3856	-1.3127	-0.1490
IQ range	56.27	163.03	3,457.70	11,531.00	0.02

A linear functional form shown in Equation 10 is used to model UC based on metadata generated from time series.

$$UC = K + A_1P^O + A_2Q^O \tag{10}$$

Table 7: OLS, using 1,000 simulation trials / observations

Dependent variable: UC

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
K	−57.3676	3.31980	−17.28	<0.0001	***
P^O	0.995976	0.0144202	69.07	<0.0001	***
Q^O	0.0381809	0.00399160	9.565	<0.0001	***

Mean dependent var	49.05964	S.D. dependent var	21.69652
Sum squared resid	81120.40	S.E. of regression	9.029288
R-squared	0.827156	Adjusted R-squared	0.826808
F(2, 995)	2444.228	P-value(F)	0.000000
Log-likelihood	−3610.671	Akaike criterion	7227.342
Schwarz criterion	7242.059	Hannan-Quinn	7232.936

$$UC = -57.37 + 0.996P^O + 0.038Q^O$$

The unit costs in the optimization framework are modelled as per the meta-model above. Diagnostics and model fit are captured in the Appendix. Based on the model above, a unit increase (decrease) in oil price ($1/bbl) will lead to increase (decrease) in unit cost of ~$1/bbl, while a increase (decrease) of production by 1MMBBLS will increase (decrease) unit costs by ~$0.04/bbl.

5. Conclusion

A mathematical program has been developed for optimal end-use allocation of nationally produced crude oil. The program enables the challenging of the historical decisions of oil allocation to the export market, offshore refining, and domestic refining. Additionally, the framework developed, allows comment on the optimum allocation of oil to the different end-use destinations. A key cost element in the optimisation model is the upstream cost of oil production, which is important both for the optimization model as well as the wider industry issues that costs attract. The cost estimation approach used in this paper, which utilizes tax receipts to infer industry costs, differs from the approaches adopted by other researchers.

Furthermore, the paper presents a successfully estimated model of unit cost as a function of oil price and oil production, which enables the forecast of upstream oil production costs in the optimisation framework. While it is acknowledged that the passage of the Petroleum Industry Act in Nigeria will structurally alter the tax regime, we believe that those effects take time to be consequential.

The key policy recommendation is to track costs across the oil industry in Nigeria for the purposes of performance reporting, government budgeting, project planning, as well as tax forecasting and energy system modelling. Additionally, based on the outcomes of literature review and analysis, more research is required into Sub-Sahara Africa-focused energy system modelling to help address challenges with energy security.

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Appendix

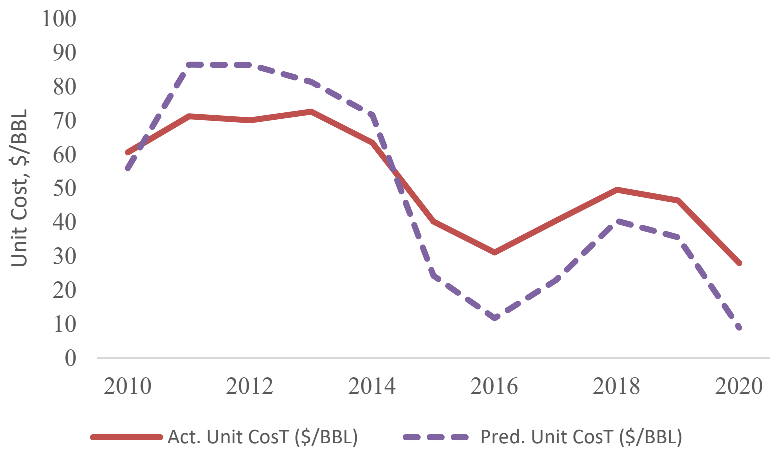
RESET test for specification -
Null hypothesis: specification is adequate
Test statistic: F(2, 993) = 0.682485
with p-value = P(F(2, 993) > 0.682485) = 0.505597

White's test for heteroskedasticity -
Null hypothesis: heteroskedasticity not present
Test statistic: LM = 40.2786
with p-value = P(Chi-square(5) > 40.2786) = 1.31213e-007

Breusch-Pagan test for heteroskedasticity -
Null hypothesis: heteroskedasticity not present
Test statistic: LM = 18.0744
with p-value = P(Chi-square(2) > 18.0744) = 0.000118905

Test for normality of residual -
Null hypothesis: error is normally distributed
Test statistic: Chi-square(2) = 65.3513
with p-value = 6.44383e-015

Figure 14: Actual vs Model Fit Unit Costs



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