Danish Utility Regulator's Anthology Project Series on Better Regulation in the Energy Sector

Danish Utility Regulator

VOL. 2.

EDITORIAL TEAM
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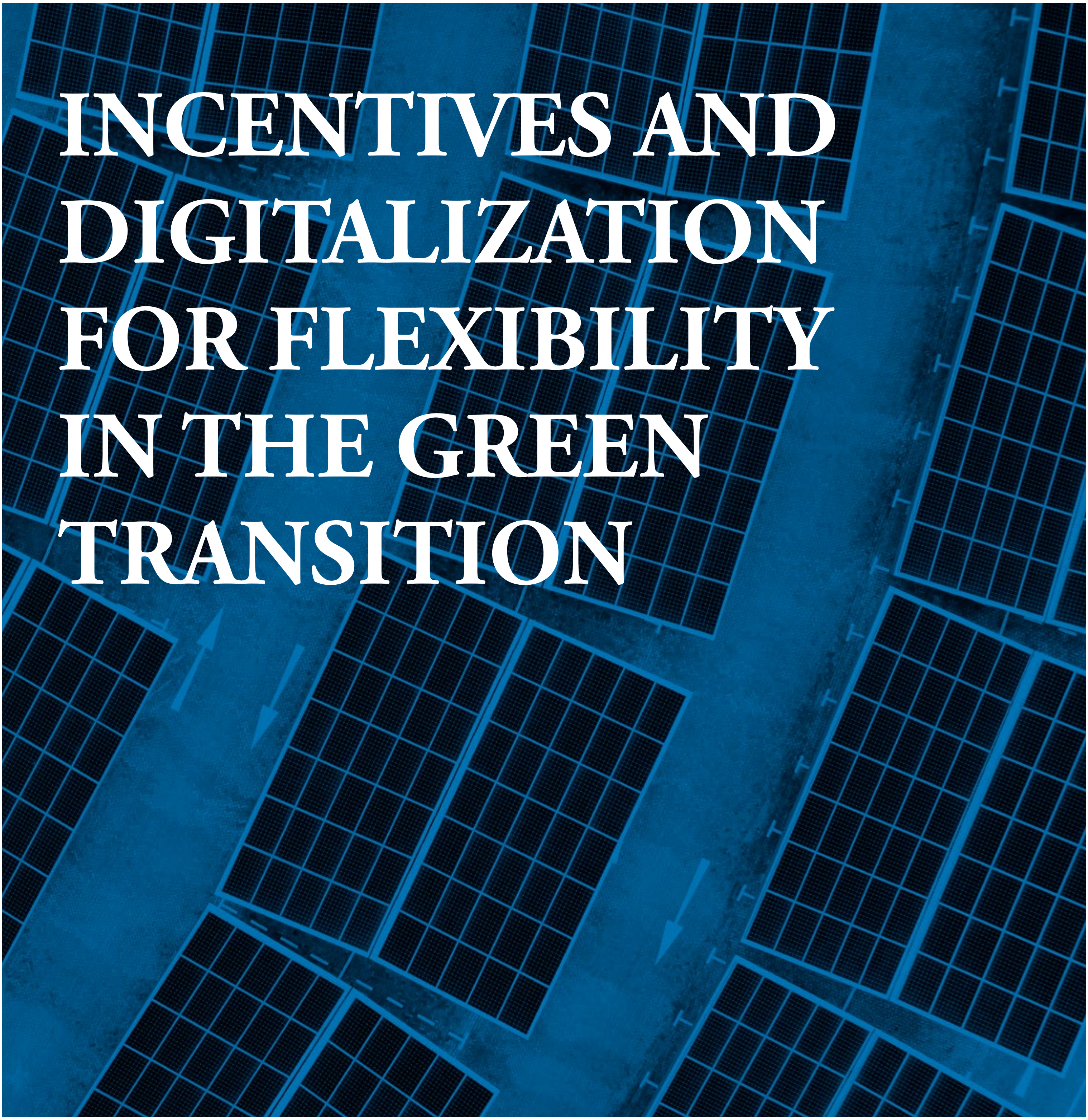
FREDERIKSVÆRK
2024

INCENTIVES AND DIGITALIZATION FOR FLEXIBILITY IN THE GREEN TRANSITION



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ISBN: 978-87-975187-0-0

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FOREWORD

The political momentum toward green transition of the energy sector coupled with a widespread electrification driven by anticipated significant increases in i.a. electrical vehicles and heat pumps has significantly heightened projected demands for capacity across national and international electricity grids. These developments have also intensified a long-term interest among policymakers, practitioners and scholars in finding ways to increase the flexibility in retail demand as a way to mitigate the substantial costs associated with the anticipated expansion of grid capacities. The more household and business consumption can shift away from traditional peak load periods, the better electricity grid companies will be able to utilize existing grid capacities and thereby reduce the need for capacity expansions.

The Danish Utility Regulator (DUR) is deeply engaged in the practical development of regulatory frameworks to better accommodate an increase in demand flexibility, always with a firm eye towards safeguarding consumer interests and the proper functioning of the European electricity markets. Within the European Union, we provide input to discussions in both the EU Council of Ministers and the Agency for the Cooperation of Energy Regulators (ACER), addressing e.g. proposed new provisions for the proper reporting on the national needs for flexibility in demand. We also play a role in common EU efforts to develop a new network code for flexibility in demand crafted by the European Network of Transmission System Operators for Electricity (ENTSO-E) and the Entity of electricity Distribution System Operators (EU DSO). Finally, it is also our particular role in Denmark to make sure that new tariff designs developed to increase demand flexibility by the Danish Transmission system operator and Distribution System Operators meets current regulatory checklists, such as cost-reflectiveness, non-discrimination and transparency.

Given our wealth of practical experiences in the field of demand flexibility, I am now particularly thrilled to introduce The Danish Utility Regulators second anthology on better regulation in the energy sector. The reason being that this anthology features six scholarly contributions to enhance our overall understanding of the current state of flexibility in electricity consumption. Providing valuable insights into some of the possible general techno-economic barriers and possibilities associated with incentives and digitalization for an efficient green transition, my hope is that the scholarly results will feed positively into our further development of the regulatory frameworks, network codes, tariff designs etc., and vice versa. All with the aim of harnessing the potentials of increased flexibility in demand to the benefit of cost efficiency in the green transition and the defense of consumer interests in low prices and stable electricity supply. The six contributions each voice varying levels of concern or critique regarding the existing regulation framework. At DUR, we are committed to thoroughly analyzing these concerns. While certain criticisms may find remedy within the current regulatory landscape, others may inspire recommendations for new improved regulation.

Let me finally take this opportunity to thank all the contributors and to the editorial board, who with their contributions have made this anthology possible.

Yours Sincerely

Carsten Smidt
General Director of The Danish Utility Regulator

Incentives and Digitalization for Flexibility in the Green Transition

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1. INTRODUCTION

"Homeostasis is a biological term referring to the existence of a state of equilibrium … between the interdependent elements of an organism. It is appropriate to apply this concept to an electric power system in which the supply systems and demand systems work together to provide a natural state of continuous equilibrium to the benefit of both the utilities and their customers. A set of interrelated physical and economic forces maintains the balance between electric supply and customer load"

Schweppe et al. [1, p. 1151]

As the share of non-dispatchable electricity supply increases throughout Europe and many other parts of the world, enabling demand-side absorption of supply-side changes has gained importance. Accordingly, the papers in the Danish Utility Regulators' second anthology on better regulation in the energy sector address the current state of affairs in and around flexibility in electricity demand.

Considering flexible consumption a significant end in its own right, the authors identify techno-economic barriers and possibilities associated with incentives and digitalization for an efficient green transition. Significantly, the obstacles and potential pathways presented in the contributions pertain to system governance and tariff design, with digitalization as a key enabler across concepts and solutions.

The electricity market lies at the heart of electricity sector liberalization and decarbonization in Europe. Moving away from centralized production planning and the idea that supply should follow demand, the marketization of electricity implies a push towards system operation through the mutual adjustment of production and consumption. In this way, the notion of demand side flexibility is at least as old as the concept of the electricity market itself. Yet, the implementation of demand-side flexibility has not been synchronized with the development of supply-side stochasticity.

Coincidentally, while electricity sector liberalization has progressed throughout the EU and many other parts of the world, the electricity system has been designated as key infrastructure in the effort to integrate renewable energy sources and mitigate climate change. An increasing part of total energy consumed is set to take the form of electricity from renewable sources, making electricity system operation, maintenance and development a key aspect of the green transition.

As part of system operation in a liberalized electricity sector, the ability to move consumption in time is a doubly valuable resource. Demand side flexibility can help maintain system equilibrium through efficient operations, while also protecting against component overload and lowering the cost of reinforcing an increasingly utilized energy infrastructure. Several large research and development programmes have thus been supported and undertaken at EU level to introduce and demonstrate demand side flexibility – especially among retail consumers e.g. [2].

In sum, demand side flexibility is an integral part of the way in which modern electricity markets are set to ensure the ongoing operation and development of the electricity system. Creating demand side flexibility in retail electricity consumption has had a high priority in several EU-policies throughout a number of years. Regulators, the scientific community and the industry have furthermore considered demand side flexibility to be of great importance to the efficient use and limited expansion of electricity infrastructure as well as the continued integration of renewable energy sources. Despite the high political priority, many insights and large R&D-efforts, demand side flexibility in the form of price elastic retail electricity consumption is currently not a substantial part of the European electricity system nor the green transition.

To address the discrepancy between the significant international ambitions and the actual progress being made, the anthology on better regulation in the in the energy sector presents a collection of works that show the potential of demand side flexibility and the pathways through which it can be achieved. The contributions cover a vast terrain by funneling the possibilities and barriers associated with demand side flexibility from the larger principles of system governance to the concrete technicalities of tariff design.

2. SYSTEM GOVERNANCE

Bergaentzlé reviews the current state of incentives for electricity system digitalization in national regulatory frameworks, maps the features and benefits of digital solutions and discusses the use and usefulness of regulatory frameworks for investment in digital technology as part of the green transition of the electricity sector. While uncovering shared developments in policies for digitalization among European countries, asymmetries in the number, width and depth of policies are analyzed in pointing to the need for a shared cadence of adoption throughout the inner market for electricity.

Llorca, Soroush, Giovanetti, Jamasb & Davi-Arderius address a series of cross cutting themes of key importance to the formation of future electricity system operations hospitable to demand side flexibility. Their investigation connects the technicalities of fostering flexible demand (e.g., digital technologies for communication and control and requirements for interoperability) with considerations about standardization and levels of centralization in the governance of digitalization. The inquiry is coupled with practical experience, to suggest regulation favorable of demand side flexibility and system design based on key concepts for economic efficiency.

Madsen et al. describe the economic potential of demand-side flexibility in the electricity system, as well as barriers to demand-side flexibility found in grid tariffs and energy taxes. To address these challenges and create an environment conducive of demand side response, the authors suggest embedding initiatives such as dynamic pricing (e.g., real-time prices reflecting the state of the electricity market as well as the distribution grid) into a smart energy operating system. The authors envision and analyze an arrangement that is set to coherently digitalize and coordinate aggregation, forecasting, control and optimization in the currently fragmented system.

In continuing the shift in focus from system principles and towards implementation, the second half of the anthology is centered on the topic of designing tariffs and incentivizing demand side flexibility.

3. TARIFF DESIGN

Bovera & Rancilio use the findings from a study of the impact of electric vehicles in the future Italian power system to demonstrate the benefits of system adequacy and system safety that can be derived from successful integration of electric vehicles. Six policy initiatives that can pave the way for efficient vehicle grid integration are then structured around considerations of implicit and explicit economic signals, as well as the possibilities of signal transfer across time and space while comparing economic burdens and the complexity of implementation.

Morell-Dameto, Chaves-Ávila, San Roman & Schittekatte use the findings from a previous study to design a forward-looking dynamic electricity network tariff to incentivize load shifting to off-peak hours and align individual customer incentives with expected system benefits, in order reduce future network investments. Key characteristics of a dynamic forward-looking tariff are described as entailing injection-withdrawal neutral peak coincident charges that vary across voltage levels, hours, days, seasons and costumer groups, with residual charges for consumers based on voltage levels and connection capacity.

Lund reports on a mathematical inquiry into optimal energy infrastructure tariff design and finds that constructing welfare-maximizing tariffs should be done with a view to the marginal cost of grid capacity. Solutions to the problem of optimal tariff design are presented alongside a description of the feasibility of their gradual implementation using only historical data.

4. INCENTIVES AND DIGITALIZATION

The articles in the Danish Utility Regulator's second anthology on better regulation of the energy sector are characterized by diversity in several respects. The contributions are rooted in different methods, institutions, countries and subjects of study. Yet, they share an emphasis on the barriers and opportunities associated with demand side flexibility as part of electricity system operation and development in a world characterized by non-dispatchable renewable energy sources. Improvements in incentives, communication and control are recurrently highlighted as crucial initiatives for an electricity sector ready for current and future challenges.

In addition to funneling insights for fostering demand side flexibility from high level system governance towards the practicalities of implementation, the contributions point to the need for incentives and digital solutions that span the entirety of the electricity system and beyond. The future electricity sector that appears in the overlap between the articles is highly dependent on developing new economic structures and data intensive networked systems. The amalgamated techno-economic challenge of the green transition is as formidable as it is unavoidable. Magnitude notwithstanding, this second anthology chips away at the monolith by pointing out important parts, reducing them to smaller, solvable problems and presenting solutions for the tip as well as the base.

In conclusion, the anthology serves three purposes. First, the work points to central ways of thinking about and prioritizing incentives, digitalization and regulation as part of the green transition. The anthology thus expresses and directs regulatory and scientific interests - interests that need to be cultivated in conjunction with central actors, not least the industry. Second, the anthology addresses the need for dialog by serving as an invitation to the actors involved in the green transition. In showcasing ideas and concepts of key importance from a regulatory and scientific perspective, the anthology constitutes a nexus for the discussion and development of regulation that is fit for purpose in the context of the green transition. Third, in serving as a vector of regulatory and scientific interest as well as platform for dialog and development, the anthology demonstrates the gist of a renewed approach to energy sector regulation more generally. A forward-looking and problem oriented way of working. In a setting characterized by the need for rapid and fundamental change, a proactive stance on energy sector regulation is nothing but pertinent.

5. REFERENCES

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Regulation for digital investment: Linking gains to incentives

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ABSTRACT

In the move towards more decentralized, low-carbon systems, the digitalization of networks should provide the missing link that integrates the grid with a growing range of flexible resources for advanced grid operation and optimal sizing. In other words, digitalization is underway. However, a two-speed adoption can be observed between digital technologies at the interface with the grid users and the technologies deployed before the meter, suggesting a misalignment between national regulatory frameworks and digitalization. This study provides an overview of the current state of digitalization in European distribution networks, maps the features and benefits of digital solutions, and uses them as a canvas to discuss how supportive frameworks regulating investments in digital technology really are.

KEYWORDS: Distribution grids, regulation, digitalization, economic incentives, investment

1. INTRODUCTION

The present decade promises upheavals to our energy systems and their transition to decarbonized energy. The transformations that are taking place are large-scale and systemic, since they involve a radical change in our modes of production and consumption. On the scale of electricity distribution networks, this change implies a rapid adaptation of existing operating modes, which invites us to rethink the regulation that frames them. Distribution grids especially will compel the most significant adaptation efforts from the electricity industry so that it can address three challenges simultaneously. The first is that of renewing ageing assets. About half of Europe's grid assets will be over forty years old by the end of this decade [1]. Second is integrating growing shares in the production of decentralized energy resources (DER) (e.g. solar PV), which affects grid-planning, extension and reinforcement, and operation. Third is accommodating the energy volumes and peak effects of the electrification of transportation and heating. Projections indicate that 45 million electric heat pumps and 50 to 70 million electric vehicles will be connected to European grids by 2030 [2]. This, in combination with DER, will affect the distribution grid with reverse flows, reactive power and different types of electricity demand with various degrees of both variability and flexibility at different times and places [3]. Several European Distribution System Operators (DSOs) have already started to include the need for grid flexibility and active management in their five- to ten-year network development plans to minimize the “sizing” effect of this integration [4]. Despite this, traditional investments, such as new larger cables and transformers, remain the priority technological solution to managing the effects of electrification [1], [5]. For many, this "fit and forget" model will generate unsustainable transition costs for society [6], [7].

All the above phenomena will affect the short- and long-term grid costs and therefore the end-users' grid bill [8], as well as calling for more active grid management and the efficient integration of the available flexibility potential on the demand side [7], [9]. While there is no silver bullet for transforming the system at the lowest possible cost, network digitalization may unlock efficiency gains capable of improving overall network operations and enabling flexibility, hence limiting the cost of upsizing the grid. Overall, Euros 400 billion in investment is expected in distribution grids, of which Euros 170 billion should be earmarked for digital investment [1], [10], [11].

Currently, large deployments of digital technologies are occurring on the grids. According to the IEA, global digital electricity infrastructure and software have grown by over 20% annually since 2014, reaching USD 47 billion in 2016 [12], with half the investments captured by smart metering and behind-the-meter solutions [1]. In comparison, a recent study indicates a slow and disparate spread of digital technologies ‘before the meter’ (i.e. monitoring and automation devices on grid assets such as transformers) [4]. This relative share seems surprising when considering the cost of metering assets relative to the total distribution network operators' book value, which suggests a two-speed adoption of digital technologies between consumer-centred and grid-centred solutions. While the former serves as a gateway to the development of advanced energy-service products from retail market players and is stimulated by the framework laid down in the EU's Clean Energy Package, the latter responds to the economic incentive established by the regulatory frameworks set out at the member state level by national regulatory agencies.

Today, there seems to be a broad consensus among policy and academic experts that the incentive framework that governs DSOs' activities is not fit to drive digital investment [13]–[17]. Many point to a misalignment between the financial incentives provided by regulation and the level of investment in digital technologies and in innovation in general [4], [16], [18]–[20], and suggest adaptations to regulatory models [21]. For [7], regulation should move away from sending asset-based incentives and foster an arrangement that rewards innovation, active grid management and the deployment of flexible technologies. Recent surveys of DSO representatives seem to support this view [5], [22]. However, it is not always clear why and to what extent current national incentive frameworks limit or distort digital investment. This study proposes a breakdown of the points of contact between the features of digital technology, efficiency gains and incentive instruments. It reviews the main incentive instruments governing DSOs' activities and discusses them in light of current regulatory frameworks in EU countries. Ultimately, the study points to shortcomings and distortive effects in current regulatory frameworks and makes some regulatory recommendations.

2. DIGITALIZATION: DEFINITION AND DEPLOYMENT

This study refers to [23]'s definition of digitalization as the integration of 'digital systems and information and communication technology (ICT), along with the new business models and interaction opportunities these support, into the energy system'. Grid digitalization is expected to provide access to data, tools and expertise capable of generating operational benefits for future electricity systems [6]. [24] subdivides digital technologies into hardware and software. Hardware equipment encompasses smart meters and devices, sensors to enhance the monitoring of grid assets and handling of reverse power flows, and automation devices for transformers such as advanced compensators or robotics. Software connects the smart devices deployed on the network, supervisory control and data acquisition (SCADA) and has developed into a wide range of operational solutions. These include big data for data-processing; advanced communication infrastructure and architectures such as cloud-based computing to manage data; artificial intelligence (AI) for advanced predictions; internet of things to interconnect physical devices; cybersecurity technologies for data access protection; blockchain for decentralized transaction recording; and virtualization, using, for example, digital twins for real-time simulations [15], [25]–[28]. On top of that, communication protocols allow interoperability between the deployed solutions within the utility's boundaries and with third parties (consumers, TSOs, other DSOs etc.).

Beyond the multitude of solutions exist significant discrepancies between the type of adopted solution and the actors deploying them [12]. The worldwide survey of the power and utilities sector by [1] reveals that DER management solutions, analytics, AI and machine-learning are the main solutions that were explored or adopted and that digital solutions are effectively used or considered by fewer than half of the respondents, most of whom are independent actors. Historically, market-based activities have driven investment in digital technologies. Electricity markets have been automated and are monitored in real time over vast geographical areas. On the grid's side, there is a clear difference between the automation and communication levels of the transmission and distribution networks [14]. The lowest voltage grids show comparatively fewer advanced technologies, even though many operators have initiated a roll-out of digital technologies.

A closer look indicates that most investment occurs at the consumer interface, driven by the prospect of new energy services development by market actors. Current investment in ICT and smart equipment is captured by the deployment of smart meters and their Advanced Metering Infrastructure systems and by the progressive development of platforms. Today, about half of European households and businesses are equipped with a smart meter [29]. 22 EU member states have issued a legal framework for their roll-out, and 16 have committed to full deployment [30]. In four countries, including Denmark and the UK, a newly-created independent data hub handles all electricity market metering data. Other countries, like Sweden, are currently implementing similar models. According to [1], this trend will continue throughout 2020-2030, at the end of which digital investment should represent 40% of total European distribution grid investment, of which half will go to smart metering.

In comparison, grid-centred digitalization appears to be lagging behind and shows significant heterogeneity across DSOs [15]. This is visible in the recent survey by [4] that gives an overview of the level of the EU's grid digitalization level.[1] The report shows that, the more DSOs move to the lowest voltage levels, the less visibility they have on their assets. This discrepancy is particularly acute in substations. Nearly all substations at high-to-medium voltage levels are equipped with smart controllers, against less than 40% at the medium-to-low voltage level, with important differences depending on the DSO's size, location and supply area. Regarding data exchange, more and more communication protocols exist between the DSOs and their Transmission System Operators (TSOs), based, in particular, on the deployment of SCADA[2]-type systems. About two third of the respondents already share generation and load forecasts, and exchange real-time SCADA measurements with their TSO. However, here again the survey shows that fewer DSOs use these systems as we decrease in the voltage level. The report does not state the number of assets covered by such communications systems but indicates that large pockets of non-communication exist on several European distribution networks. Finally, there seem to be some inherent discrepancies between types of DSO. Distribution grids with a large supply area and relatively low demand are often the least advanced in digital technology deployment.

3. MAIN FEATURES AND BENEFITS OF DIGITALIZATION

The following extracts the main features of digital investment as a regulated investment and outlines its resulting gains, detailed in Table 1.

TABLE 1. INVENTORY OF THE KEY FEATURES AND BENEFITS OF DIGITAL SOLUTION INVESTMENT

Digital investment characteristics	Digital investment benefits
Innovative solutions	Enhanced productive efficiency
Low(er) capital costs	Low maintenance cost and asset-life duration extension
High operating costs	Improved quality of supply
	Lower capital costs through CAPEX-OPEX substitution

1 The survey involved 56 European DSOs of different sizes and supply areas.
2 Supervisory Control and Data Acquisition.

Investment in digital solutions has several distinctive features as a regulated investment. First, it calls on an extensive portfolio of innovative solutions with varying degrees of complexity, technological maturity and market readiness. Some solutions are already known, largely in use (smart meters) and not disruptive, while others present cutting-edge features and support for innovation and experimentation. One of the characteristics of innovation is that it generates substantial short-term costs, whereas the possible gains are to be expected over the long term and are challenging to quantify ex-ante [17]. Second, the cost structure of most digital solutions is distinct from business-as-usual network assets since it relates to asset-light technologies with low to moderate capital costs and high short-term operating costs [31]. Such asset-light/high operating cost investments correlate positively with R&D investment, especially in regulated industries [32]. Finally, even though this last feature is outside of the scope of the study, the digitisation effort will unconditionally have to be accompanied by an upgrade of a whole range of internal organizational functions to keep pace with technological advances. This will notably require short-term investments in tools, processes and ICT infrastructure, not to mention upskilling and reskilling the workforce at the interface with digitalized assets or digital service providers [15].

Looking now at the gains, the expected benefits of digitalization are diverse, substantial and distributed among many core activities at the DSO level, from planning to short-term operations [22] and beyond, outside the DSOs' boundaries [33]. Digitalization could result in grid cost savings of approximately 1.2 trillion USD globally by 2040, of which 60% come from OPEX savings and 40% from savings on capital expenditure [12]. Such aggregated values mask important differences related to the type of solutions deployed, the grid system (old vs new) or enabled functionality (bill management vs advanced power-flow operation), but they nevertheless point to substantial cost savings.

This study identifies four types of intertwined benefit: improved productive efficiency, reduced maintenance costs, improved quality of service, and lower capital costs. Starting with productive efficiency, or enhanced operation, [7] gives a detailed review of how digital technologies will affect future system operations and improve system control for increased output. Real-time data collection, remote monitoring, and advanced forecast and analytics enhance the monitoring of the dynamic state of the grid at the component level, generating value in terms of lower operating costs, increased output delivery and a better quality of service. Advanced monitoring of the state of the network and remote control improves flow management and operational efficiency. Assets can be utilized more efficiently in output delivery without affecting degradation. Efficiency gains are measured, for example, in terms of reduced losses and lower associated costs for buying back this energy or reducing outages and downtime [34].

Limiting the degradation of network components through more advanced flow and power management also offers the possibility of making systems more resilient and cheaper to maintain and restore. Going one step forward, a better appreciation of the risk of failures and their consequences at the component level with the deployment of sensors enhances system robustness to faults and preventive action. Digital technology may allow grid components to operate closer to their limits without overloading them and improve control of the parameters affecting their early ageing and maintenance [35]–[37] with potentially beneficial impacts on operational lifetimes. The scope of this component seems to be gaining momentum. The International Electrotechnical Commission recently set up a technical committee to consolidate existing practices for power grid component management and some countries like the UK and Denmark have implemented or are incorporating condition-based risk models for grid components into their regulatory framework [38], [39].

Similarly, in supporting preventive action and other functions such as fault and failure detection or self-healing control strategies, digitalization enables power grids to operate more reliably and resiliently for enhanced levels of security and continuity of supply and the overall quality of electricity delivered. The issues of resilience and security of supply are also becoming increasingly important in light of the increased frequency of extreme events like those caused by climate change or cyber attacks [7].

Finally, digital solutions may also directly replace capacity investment when they enable demand response and storage [40]. The value proposition comes from the substitution between incremental capacity and the flexibility to accommodate peaks in demand or RES production within the existing safety margins. In the UK, this corresponds to sizing the distribution network at minimally four times greater than the peak demand under current regulatory conditions [7]. Several past studies have simulated possible break-even points between incremental capacity and demand-side flexibility solutions [38] and have investigated ways to remunerate them based on the avoided capacity cost [41]. DSOs have also started to estimate the cost of not activating flexibility for capacity adequacy in grid-upgrade projects. The Reforming the Energy Vision (REV) project carried out in New York estimated that such non-wired solutions could reduce the estimated grid reinforcement cost fivefold from USD 1bn to 200m [42]–[44]. A similar initiative by the Flemish DSO estimated it would result in an extra cost of Euros 2 billion over its 2023-2032 investment plan [45].

From an investment viewpoint, and a fortiori a regulated one, the listed features and benefits should serve as a canvas for discussing current economic incentives for investment and operation and suggesting possible alternatives.

4. WHAT CAN REGULATION DO TO SUPPORT DIGITAL INVESTMENT?

Grid expenditure is subject to various incentive instruments designed to provide the necessary funding to cover the operators' costs, grant them a fair return on investment, encourage cost efficiency and improve performance [46], [47]. The incentive force of a regulatory framework for digitalization will depend on how the incentive instruments are calibrated and the expenditure items they apply to, distinguishing between capital and operation expenditure (CAPEX & OPEX), and innovation spending. Table 2 connects the key regulatory instruments to the digitalization features and benefits. Let us start with a quick summary of the cost-recovery instruments and dominant incentive frameworks that apply to grid operators.

Input-based tools. Input-based regulation serves to stimulate investment and to share the rent with the grid-users. This is achieved mainly through conditions or adjustments affecting the rate of return (RoR) granted on the capital expenditure. With a few exceptions, all CAPEX are reported to the regulated asset base (RAB). The CAPEX book value generates an RoR, usually set based on the weighted average cost of capital, which represents the allowed return on investment that the operator can earn on its regulated assets. The RoR applies to the value of the assets over their useful life, which may extend beyond their depreciation period and may be identical regardless of the asset type or differ to reflect different risk profiles, cost structures, or specific regulatory requirements. A regulator may grant mark-ups or premiums to stimulate investment in a specific asset type that is considered critical. This would be the case, for example, with bonuses or with sharing the benefits generated by a new investment (e.g. a more efficient asset) or a new operating mode (e.g. automatic billing) [46], [48]–[50]. Such an input-based mechanism offers multiple options for promoting digitalization, provided it is appropriately targeted and calibrated, meaning that the RoR appropriately reflects the investment risk associated with the different solution types and their readiness levels. The type of expenses exposed to the RoR is also critical, as it establishes a direct link between investment choice and revenue. For example, whether or not the RoR applies to software solutions, expenditure may affect the adoption of digital solutions. Depending on the regulation, expenses other than CAPEX may be recorded in the RAB. Some frameworks combine CAPEX and OPEX into a TOTEX (total expenditure) approach to shift the focus away from capital investment and alleviate the distortive effects of applying a RoR on some expenditure items and not on others. In a regulatory framework where the RoR applies to TOTEX, the operator should no longer be influenced by the spending type in its decisions [51]. It then becomes possible to capitalize on OPEX such as the operating costs associated with the implementation and processing of advanced communication infostructure.

Innovation and R&D spending. Another critical point worthy of attention is how R&D spending is considered within the framework set by regulation and the level of financial risk it leaves to the operator. To begin with, regulation should unambiguously define spending on innovation and provide a committed investment framework [52]. In practice, spending on innovation can be treated in the same way as any other expenditure recorded in the RAB and be eligible for a RoR, or it may give rise to a specific rate of return, ideally reflecting the level of financial risk incurred by the investment [17]. R&D spending can also be passed-through in tariffs. In this case, the operator only recovers its investment without generating extra return and does not face any investment risk since all the incurred costs will be covered. This latter case may support innovation, but not necessarily its successful realization. Here, the balance of risk between grid operator and rate-payers is a key impact on R&D spending [53]. For [33], the sharing of risk should be set to reflect the features and benefits of each innovation investment and involve a strong rent-sharing mechanism when the innovation brings substantial gains. Practical applications of this balance are developed in [54] with a sequence of regulatory tools that follow the solution's readiness level. This opens up some interesting methodological avenues for incentive instruments targeted at innovation in digitalization investment, since digitalization shows a wide range in levels of technological maturity, the expected gains and therefore risk.

Economic incentives for productive efficiency. The emergence and rapid adoption of incentive regulation instruments over the last twenty years illustrates the widespread desire to encourage short-term cost efficiencies from the operators. Incentive regulation defines ex-ante price or revenue caps associated with efficiency factors (X factors), thus reducing the revenue allowed during a defined regulatory period. The incentive lies in granting part to all of the difference between the realized efficiency gains and the operator's efficiency ratio. The higher the efficiency ratio and the shorter the period, the more stringent the incentive to cut costs. The strength of the incentive and how it may affect digitalization will depend on the way it is designed and on the types of expenditure item it applies to. When applied to the TOTEX, incentive regulation will have a neutral effect on the choice of investment and drive the most cost-efficient decision [21], [33], [55]. However, in its most common form, revenue or price caps only affect OPEX or a subset of it, which may distort some initiatives for digitalization. [15] and [48] report such a bias among European TSOs and point to the relationship between smart grid technologies, the lower need for physical investments and the subsequent impact on the TSOs' financial return on investment. ACER[3] later estimated this bias as creating an incentive to invest in business-as-usual capacity seven times more than in innovative solutions [14]. To our knowledge similar studies do not exist at the DSO level, but the general conclusion that 'the gap between the compared profits seems too wide to be bridged by existing incentives' is likely to be valid at the distribution-grid level as well.

Output-based regulation. Output-based or performance-based tools serve to maintain a level of quality of service and performance that meets pre-defined criteria. They reward the achievement of performance objectives or, on the contrary, penalize poor results, and can be directed to incentivize the deployment of digital solutions when they directly impact the performance metrics to which the DSO is subject [56]. Performance indicators are historically used for tracking the reliability and continuity of supply [57]. More recently, new performance metrics start to be used decentralize the integration of energy resources [56] and to measure DSOs' activities as market facilitators [58]. In the future, performance indicators should be extended to measure digitalization efforts, as the European Commission requires that national regulatory agencies and ACER set up advanced metrics to measure progress in deploying smart and digital investments. [13]. Currently existing performance metrics follow a corrective approach. However, recent studies show considerable potential in using smart-grid data to develop new performance metrics [55], suggesting there is a positive feedback loop between digitalization and the regulatory process.

3 The European Union Agency for the Cooperation of Energy Regulators.

TABLE 2. INVENTORY OF THE KEY REGULATORY TOOLS FOR DIGITALIZATION

Digital investment		Incentives for innovation	CAPEX-OPEX remuneration scheme	Efficiency factor on O&M	Performance-based regulation
Key features	Innovative solutions	●			
	Low(er) capital costs		●		
	High operating costs		●		
Main benefits	Enhanced productive efficiency				●
	Low maintenance costs and asset-life duration extension			●	
	Improved quality of supply				●
	Lower capital costs through CAPEX-OPEX substitution		●		

5. OVERVIEW OF CURRENT EUROPEAN REGULATORY FRAMEWORKS

A series of reports from the European Commission, ACER and CEER[4] give a comprehensive overview of the regulatory frameworks applying to European electricity grids. Their cross-reading enables an assessment of how supportive regulation is of digital investments [14], [19], [56], [59], [60].

It is possible to group EU member states based on whether their capital costs are subject to economic incentive mechanisms. The vast majority of national regulatory frameworks (23 out of 26) use incentive-based regulation. They can be divided into three sub-groups depending on the expenditure items the incentive affects, such as: OPEX only, TOTEX, or depending on the type of OPEX or CAPEX. The three remaining countries are regulated under a cost-plus mechanism which directly allows the full-cost recovery of all expenditure without an incentive mechanism, and grants a return on capital. Building on this grouping, the remaining of this study describes how national regulations provide or do not provide a clear framework for innovation and whether they apply any type of input- and output-based mechanisms before discussing the main implications for investing in digital solutions. The Table in the Appendix gives the details for each country.

5.1. THE GENERAL LACK OF A FRAMEWORK FOR INNOVATION

[16] and [31] remind us that regulation that ignores opportunities for innovation will ultimately result in high grid costs for society. However, practical applications often diverge from best practices [59]. In Europe, the sector lacks a common definition for innovation and R&D investment, and a significant number of EU countries lack a formal regulatory framework for innovation spending, especially penalizing the least mature technologies. A similar conclusion is made at the EU TSO level by [14].

In 2022, only a minority of national regulations explicitly incentivized innovation, with different potential impact on digitalization [59]. For example, Austria uses R&D financing schemes that are not subject to price caps, but only for projects subject to authorization. Slovenia applies Research and Innovation incentive financing for pre-selected pilot smart grids projects, demand response and DER integration. The allowed budget is capped at 0.5% of the DSOs' allowed revenue. For smart grid projects, the Slovenian regulation also guarantees that related OPEX will be passed in full on to the end users, and allows a CAPEX premium of 2% of the asset value for three years. France allows an envelope for R&D projects, but without differentiating between investment types, maturity levels, or financial risks, and without a rent-sharing mechanism. The Spanish regulation guarantees to cover the expenditure for pilot projects showing a positive cost-benefit analysis. Finland applies an innovation incentive that is earmarked for technical and operational solutions in grid operation using smart grids. The reported gains resulting from the innovation spending are retained as a bonus within a limit of up to 1% of the DSOs' profit [60]. The UK implemented several innovation funds, such as the Network Innovation Allowance, allowing DSOs to spend 0.5% to 1% of their permitted revenues on demand side-related projects, or the Innovation Roll-out Mechanism, which funds the rolling out of innovative solutions that meet pre-defined criteria. A handful of countries, like the UK, Finland, Slovenia and Ireland [61], also introduced output-based mechanisms to reward innovation and R&D using dedicated key performance indicators. Lastly, several national regulatory agencies started to implement regulatory sandboxes which offer regulatory freedom to test solutions and to fast-forward their adoption [9], [63]. For a recent in-depth review of multiple sandbox experiments in European countries and how they affect innovation, see [62].

However, in the great majority of member states, national regulations include either no incentive for innovation (e.g. Estonia or Hungary) or promote it indirectly via the general regulatory framework, meaning that it is treated separately from the RAB, treated as an OPEX and is subject to the incentive regulations that may apply to them. In this case, innovation may be driven by the gains expected from cost efficiencies or the better performance they may induce as further discussed below [19], [64].

4 The Council of European Energy Regulators.

5.2. THE INTERTWINED IMPACTS OF INCENTIVE REGULATION AND ITS SIGNALS FOR DIGITALIZATION

Incentive regulation consists in setting ex-ante an incentive instrument to lower costs over a given period. However, the way this type of regulation is implemented can have different effects on digitalization. Incentive instruments focusing solely on OPEX, including operation and maintenance (O&M), send mixed signals regarding digitalization, signals that are predominantly negative. The relationship between digital investments and operations and maintenance is special and needs to be broken down.

- A positive link between low maintenance cosst and digitalization

Real-time monitoring and automation allow vulnerabilities to be identified for preventive action at the component and asset level, resulting in lower maintenance costs. As a result, using incentives to reduce this type of expenditure type tends to favour digital solutions capable of keeping maintenance costs down. Such incentives are already largely in place. Twenty-two European member states use instruments promoting cost efficiency, of which thirteen direct this incentive to O&M (Appendix 1). The incentive scope associated with incentive regulation will vary according to the tool's calibration, which mainly means the financial incentive associated with the efficiency gains (or penalties related to the loss of efficiency), the way the X factor is determined (based on average sector practice or first–best) and the length of the regulation period. The longer the period, the more likely the DSO will be able to reap the benefits of its efficiency gains invest in new solutions. In this case, the Italian scheme may provide one of the highest incentives for using digitalization to reduce maintenance costs (see Appendix).

- A negative link between low operating costs and digitalization with substantial side effects

On the other hand, efficiency incentives for operation may damage digital solutions even when they are mature. While some digital technologies, like smart meters, directly reduce operating costs from meter readings, other solutions may inflate short-term operating costs during technological adoption and adaptation and affect short-term profitability in an incentive regulation framework. Symmetrically to what was described with reductions in maintenance costs, the level of incentives for reducing operating costs depends on the steepness of the efficiency effort given by the X factor. But in general, this measure will damage the profitability of deploying the digital solutions, showing a short-term cost increase and long-term benefit, especially when the cost-efficiency instrument is targeted at OPEX alone.

Incentive regulation directed at OPEX may also trigger other damaging side effects for digital investment if they are not adequately counterbalanced. In particular, this type of regulation creates a risk of lower R&D spending especially when innovations are not earmarked, and of lower output quality. Both effects have been widely documented in the literature [17], [21], [65] and are well exemplified by the UK case, where the revenue cap (RPI-X model) applied from 1990 to 2015 susbtantially affected the innovation effort and reduced the long-term quality of service. In response, the UK decided to recapitalize R&D beyond the newly created innovation fund within the new regulation model[5] and to introduce performance-based regulation instruments.

- A bias for asset life extension

Another less well documented side effect occurring with incentive regulation of OPEX is that grid activities are mainly driven by cost reductions and not by the efficient use of assets, and that they receive low incentives to keep existing assets in operation after they have reached the end of their depreciation period. Most heavy assets, such as cables and substations, have a physical life duration that goes beyond their deprecation, meaning that an ageing yet functioning asset may no longer generate a cash flow, while it will likely require more maintenance [66]. Incentive regulations targeted at OPEX expose operators to the risk of a decline in their productive efficiency and profits while cutting back on the RoR they might otherwise have achieved with an earlier replacement. This incentive framework is particularly detrimental to digital investments allowing better asset use in time and is all the stronger when the framework is based on a short regulatory period, a high efficiency factor and a high RoR.

In response to that, Spain has introduced a special mechanism that rewards asset lifetime [60]. The scheme implies an O&M remuneration per asset type that the operator keeps on receiving after the asset has fully depreciated and that increases with the number of years exceeding the regulatory lifetime. Similar schemes are also being investigated at the TSO level in Germany [67] and should create a fertile ground for arbitrating in favour of advanced solutions rather than early replacement.

5.3. MIXED SIGNALS SENT BY INPUT- AND OUTPUT-BASED INSTRUMENTS

The great majority of EU regulators use a mixture of input- and output-based instruments. Examining the member states' different frameworks shows that multiple special provisions exist to give a nudge to digitalization or digitalization-friendly activities, but with important disparities in the form these incentives take, the type of remuneration they offer and their expected effects. Of the nearly ninety reported incentives in [59], one-third directly target digital solutions, while two-thirds could trigger indirect support to digital solutions. Figure 1 groups the number of incentive schemes based on their direct or indirect impacts on digitalization.

The most recurrent direct schemes reward the deployment of smart meters. In France, a premium of 3% of the total cost of meters is awarded for meeting the deployment plan, and it applies a per-meter penalty to penalize delays. Slovenia introduced a financial incentive and KPIs for qualified smart grid investments and allowed the passing on of related OPEX. DSOs in Portugal are awarded a fixed annual bonus per supply point that delivers a list of smart grid services to consumers. Other noticeable incentives are the increase in the revenue cap for eligible spending in cybersecurity in Denmark or the passing on of energy transition-related spending within the limit of 1% of the O&M cost in Hungary. As for smart grid investments, this term may seem more opaque. Of the ten member states that use a special scheme

5 Known as RIIO for Revenue = Incentives + Innovation + Outputs.

for it, only Finland and Slovenia specify that the incentive is directed at innovative technical and operational solutions for grid network operations and at research and innovation trials respectively. Hungary earmarks this scheme to fund the workforce working on energy transition, digitalization and smart grids.

Indirect incentives for digitalization fall into two main categories of actions: actions linked to integrating DERs and electrification, and those related to improved quality. The latter is the most widespread across DSOs and mainly takes the form of performance-based instruments. Targets for the continuity and quality of supply and commercial quality are historically associated with the essential activities of electricity grids and have been compiled for more than twenty years by some DSOs [19].

Incentives targeted at DER and electrification are seldom described. Some regulators indicate objectives such as increasing the number of consumers participating in demand response programmes (Slovenia), or the procurement of flexible demand services (Ireland). But in general little detail is provided, which suggests that interpretation may be left to the operator's discretion. If the integration of distributed energy resources implies a trade-off between capacity expansion and active management, the incentive effect on OPEX and CAPEX will steer the investment.

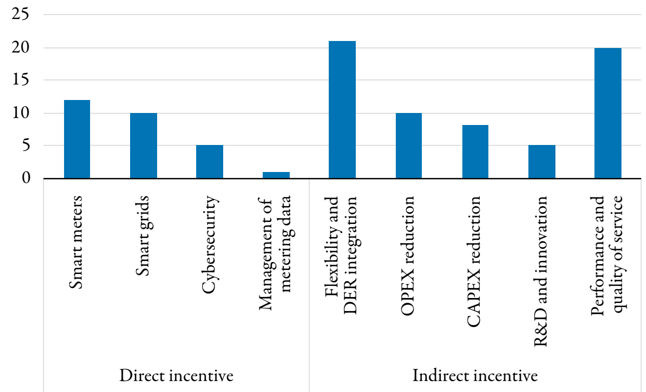

FIGURE1. NUMBER OF SPECIAL PROVISIONS INCLUDED IN EUROPEAN REGULATORY FRAMEWORKS AFFECTING DIGITALIZATION

Source: author, based on [59]

This outlook also suggests that the TOTEX approach alone may not be sufficient to erase all bias between traditional and digital investments. The conditions applying to TOTEX differ significantly between member states, which may explain the difference in the incentive received to engage in a digital strategy.[6] Nevertheless, under this approach, the operator's decisions should no longer be influenced by the nature of the investment but should focus on the most effective solution for improving efficiency. Yet, five of the eight TOTEX countries use at least one incentive scheme directly targeted at digital investment (Figure. 2). Portugal reports that despite the elimination of the CAPEX-OPEX bias, investment in digital technologies was still not beneficial to the DSOs due to the diffuse nature of efficiency gains resulting from it and the benefit-sharing mechanism in place with the consumers [60]. In response to that, the regulator introduced further output-based incentives for the availability of smart grid services.

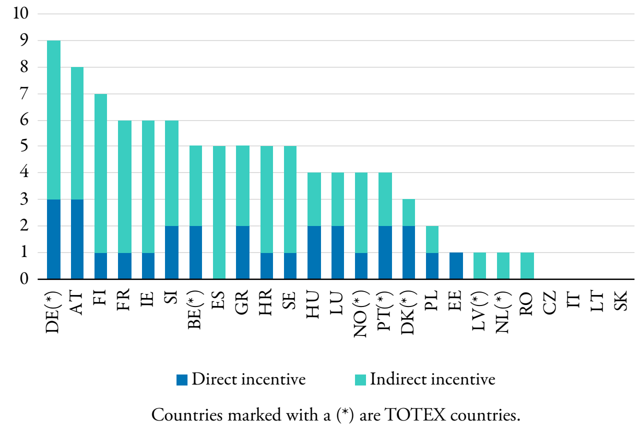

FIGURE 2. NUMBER AND TYPE OF INCENTIVE SCHEMES AFFECTING DIGITALIZATION PER COUNTRY.

Countries marked with a (*) are TOTEX countries.
Source: author, based on [59]

6. CONCLUSION

This study has provided an overview of the major incentives used in national regulatory frameworks and compares them with the features and benefits of digitilization. The analysis has revealed several underlying trends that indicate a gradual shift in regulatory ideologies from the least-cost rationale established by incentive regulation to a better-quality motivation driven by the growing use of the TOTEX approach. Another underlying trend is a renewed interest in stimulating R&D and demonstration by establishing dedicated funds and trials, among others. The range of specific incentive instruments to promote investment in smart technologies or distributed energy resources integration is also conducive to deploying digital technologies.

However, there are also several significant shortcomings. First, the good practices mentioned above are concentrated in certain countries, indicating a heterogeneous technological deployment across Europe that could ultimately affect the effectiveness of interconnected systems and markets in responding to production and demand contingencies. Second, several widespread limitations in regulatory frameworks under-

6 The Netherlands applies individual X factors to the TOTEX based on the volumes sold by each operator. Germany applies to each DSO's TOTEX efficiency scores based on a mixture of sectoral and individual benchmarking techniques, as well as a distribution key on the realized efficiency gains or losses before granting it as a bonus or charging it as a loss. The types of benchmark carried out, the relative efficiency gap between a given DSO and its benchmark, and the effective financial incentive are three determining factors affecting decisions.

mine decisions for advanced digital solutions, especially in operation activities. Regulation still lacks a dedicated framework for R&D in many countries that predominantly rely on efficiency and performance instruments to drive innovation. The difference in treatments between operation and capacity expenditure strongly emphasizes the networks' short-term cost efficiencies in many EU frameworks. This likely occurs at the expense of innovation and improvements in output. When both a CAPEX-OPEX differentiation and OPEX-based cost-efficiency incentive jointly apply, digitalization is doubly punished at the expense of asset-light investment, advanced operations and asset life extension, which is especially problematic in the current situation of ageing infrastructure.

The deployment of digital tools must precede the massive growth of distributed energy resources and electrification. Failing to do so will likely result in costly and potentially significant under-used assets. The major challenge facing regulation is to review and revise current regulatory frameworks in light of technologies whose impact is still uncertain. On a more positive note, digitalization should not only serve grid operations but also the improvement of regulations. The benefits of deploying digital technologies on top of the more agile management they enable is to generate information. This information should be fed into the regulatory process and allow diversification and sophistication in incentive tools and benchmarking techniques for advanced performance criteria as in Norway, the UK or Germany. The newly generated knowledge can ultimately drive better planning, moving away from current conservative dimensioning criteria for power assets and promoting a more forward-looking regulation.

APPENDIX 1. MAIN FEATURES OF EUROPEAN REGULATORY FRAMEWORKS

	Regulation type	**Special conditions for innovation**	**Special conditions pply to CAPEX**	**Scope of the X factor**	**X factor (when relevant)**	**Duration of the regulatory period**
AT	Revenue Cap	Yes	Individual efficiency score based on TOTEX affects the WACC	opex	0.95%	7.5 years
B.E.	Revenue Cap			totex		6 years
C.Z.	Revenue Cap			opex	0.511%	5 years
D.E.	Revenue Cap			totex	Individually set	5 years
D.K.	Revenue Cap			totex		5 years
E.E.	Cost Plus			none	-	-
E.S.	Incentive-based regulation	Yes	Grid availability incentive + remuneration scheme for extended lifetime	Efficiency factors based on family of asset	-	No explicit duration
F.I.	Revenue Cap	Yes		opex		4 years
F.R.	Revenue Cap	Yes		opex		4 years
G.B.	Revenue Cap	Yes		totex	Individually set	8 years
G.R.	Cost Plus			none	-	-
H.R.	Cost-plus			none	-	-
H.U.	mix of price & revenue cap			opex	1.50%	5 years
I.E.	Revenue Cap	Yes		opex	0%	5 years
I.T. (2017)	Price cap			opex	1.90%	5 years
L.T.	Price Cap			opex	1%	5 years
L.U.	Revenue Cap		Mark-up for specific investment (incl. digital)	none	-	n/a
LV	Revenue Cap			totex	2.57%	No explicit duration
N.L.	Price Cap			totex	Individually set	n/a
NO	Revenue Cap			totex	Individually set	1 year
P.L.	Revenue Cap			opex		3 years
P.T.	Price cap (b)			totex	2%	No explicit duration
R.O.	Price cap			opex	2%	n/a
S.E.	Revenue Cap			opex	1-1.82 %	8 years
S.I.	Revenue Cap			opex		No explicit duration
S.K.	Price cap			opex		5 years

Source: Author, based on [59], [60]

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Digitalisation and Economic Regulation in the Energy Sector

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ABSTRACT

The green energy transition relies on electricity generation from intermittent renewable energy sources and the electrification of end-consumption such as heating or mobility. At the same time, an increasing number of previously passive consumers are becoming active actors in the energy system, while the quantity of electric devices connected to the grid increases. These trends pose new operational, economic, and regulatory questions as the traditional roles of certain agents are mutating and multiplying. Digitalisation offers the possibility of implementing innovative solutions to the new challenges faced by grid operators, especially at the distribution grid level. We present some potential digital solutions to overcome the operational challenges imposed by the 'future-proof' energy systems currently being devised and we address their economic implications. We also tackle some aspects related to the digitalisation of the energy sector (efficiency and innovation, interoperability and standardisation, centralised vs decentralised solutions) from an economic perspective. Finally, a successful digitalisation of the sector requires adjustments in the regulatory frameworks. In conclusion, we detail some regulatory improvements that are needed.

KEYWORDS: Energy sector, distribution grids, renewables, digitalisation, economic principles, innovation, regulation

1. INTRODUCTION

Digitalisation is mostly related with the fourth industrial revolution [1], which relies on recent computational innovations brought out by the combined developments in the fields of Artificial Intelligence (AI) and quantum computing. As the Digital Economy and Society Index (DESI)[1] shows, the share of businesses that provided fully digitalised products and services increased from 34% before the COVID-19 lockdown up to 50% during the pandemic [2]. This was also connected to the use of cloud computing services that increased from 24% in 2019 to 41% in 2021. Precisely, about 9 million people worked as Information and Communication Technology (ICT) specialists in the EU in 2021, while the EU targets by 2030 require to have 20 million ICT specialists, which represents 10% of the total employment. The current trend towards the all-encompassing digitalisation of key parts of the economy has also reached the energy sector [3][4]. Digitalisation plays a crucial role in conceptualising the green transition while posing new interesting economic and policy questions and trade-offs. The electricity sector is placed at the core of clean energy transition with technologies and options such as batteries and demand response that leverage digital technologies to significantly increase flexibility of the system [5]. Our aim in this chapter is to outline the relevant economic concepts related to digitalisation of the energy sector, with the focus being on the electricity sector.

Digitalisation, often considered as a goal, should rather be viewed as a means to achieving specific ends. In energy policy terms, these ends broadly correspond to the main components of the so-called energy trilemma (namely, energy security, energy equity, and environmental sustainability), three key elements for the achievement of the wider UN Sustainable Development Goals. Digitalisation is a key enabler for an integrated energy system that addresses the energy trilemma [6] [7]. It also has the potential for being a radical transformer of existing market structures. This is due to two conflicting effects: its ability to reduce market entry costs for potential entrants, while also reinforcing incumbents' market power. This last effect is related to the potential of digitalisation to provide economic value or to create markets for new commodities, based on the smart use of digitalised personal data, leading to the development of new business models.

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Acknowledgements: This work has been co-funded by the European Union's Horizon Innovation Actions under grant agreement No. 101069510, EDDIE—European Distributed Data Infrastructure for Energy. Financial support from the Copenhagen School of Energy Infrastructure (CSEI) is acknowledged. The activities of CSEI are funded jointly in cooperation between Copenhagen Business School and energy sector partners.

Disclaimer: The opinions expressed within the contents are solely the authors' and do not reflect those of institutions or companies with which they are affiliated. Daniel Davi-Arderius works at e-Distribucion Redes Digitales, SLU (Endesa) and is also part of the EU DSO Entity.

1 DESI monitors Europe's overall digital performance and also the performance of the individual countries.

In October 2022, the European Commission (EC) launched the Digitalisation of Energy Action Plan in the scope of the European Green Deal and the REPower EU Plan [8]. This action plan considers the necessity to set actions for boosting data sharing and incentivising investments in the digitalisation of the electricity infrastructure, while exploiting the potential benefits for consumers. Indeed, the need to decarbonise the power system and connect a huge quantity of renewables to the grid in a short period of time, requires looking for innovative digital solutions to anticipate and solve future technical and operational needs. At the same time, consumers should be empowered to take their decisions based on the new information available to them.

All these possibilities and changes due to the digitalisation of the energy system (with the electricity system at its core) require addressing new technical and regulatory challenges. First, grid operators should have efficient economic incentives in their regulatory frameworks to adopt, implement and optimise digital solutions. Second, consumer rights should be guaranteed, especially those related to the data privacy and access to the information, while consumers should also derive individual economic benefits from the adoption of end-point digitalisation tools such as electricity smart meters, so that their incentives are aligned with those of the providers and with the collective goal of decarbonisation. Third, minimum interoperability rules should remove technical barriers between different manufacturers' standards and increase market competition. Moreover, interoperability rules should go beyond the technical aspects, and standardise roles and responsibilities of all the involved agents across the European Member States.

This brings us to the debate surrounding decentralised versus centralised digitalisation solutions in the energy sector that encompasses the physical configuration of assets, organisation and regulation, technological advancements and scale, standardisation, interoperability, scalability, and policy and regulatory considerations. The appeal to scholars and practitioners for decentralised approaches to structure electricity generation, transport and distribution networks, and consumption, has grown in the past 20-30 years. A European, decentralised, and open-source energy data space[2] solution fits into this trend.[3] This is evidenced, for example, by the Electricity Directive (EU) 2019/944, which is part of the Clean Energy for all Europeans Package (CEP). This Directive sets the rights to non-discriminatory and transparent access to metering, as well as production and consumption data for customers and third parties of their choice [10].

However, there is no one-size-fits-all solution. The choice between decentralisation and centralisation depends on several factors. Some examples are represented by the characteristics of the energy system, the number of involved agents, the ease of entry, the desired levels of control and coordination, costs, necessary implementation time, and the potential for innovation and flexibility. Balancing these aspects is essential to achieve efficient and effective digitalisation in the energy sector. Moreover, it might be worthwhile to explore alternative combinations of centralised/decentralised solutions that transfer transparency and openness of energy data to the network edges, while relying on a common 'centralised' framework, necessary to maintain trust as an essential element in enabling common dataspaces.[4]

It is helpful to recognise that consumer participation, especially that of residential users in the retail energy market is not a given or exogenous factor. Rather, participation of users should be viewed as endogenous and contingent upon the framework within which they participate. The main factors influencing active demand and the level of participation are technology, incentives, and information, which rely greatly on the ability of accessing and processing large quantities of microdata, evolving in real time.

All these new technical and regulatory challenges should be tackled for an efficient digitalization of the energy sector that can indeed contribute to the clean energy transition. In the following, we discuss these challenges in depth. In Section 2, we first picture how digitalisation can transform the energy industry, especially the electricity sector. In Section 3, we highlight the importance of setting common standards and interoperability rules across the entire energy supply chain to facilitate digitalization. In Section 4, we discuss centralized and decentralized digitalization and governance solutions in the energy sector landscape. In Section 5, by providing a real-world example of digitalization in the electricity sector, we outline several challenges linked to the digital economy. In Section 6, we provide a set of recommendations to improve and adjust several components of regulatory frameworks, required to facilitate the digitalization process. Finally, in Section 7, we provide a summary of our views and a conclusion of the discussions in previous sections.

2. ENERGY TRANSITION AND DIGITALISATION

The decarbonisation of the power system needs the connection of many small renewable plants energy sources as well as expanding the scope for the electrification of the end consumption, e.g., domestic heating and private or public mobility, among others. Most of these are connected to the distribution grid. However, the intermittent nature of electricity production from renewables makes the power flows more variable and transforms the traditional unidirectional nature of electricity flows into a bidirectional one, whereby electricity flows from transmission to distribution and vice versa. Hence, grid operators face new operational challenges and implement new solutions, most of them requiring the fine-grained information only available through the wide adoption and diffusion of digitalisation tools. These tools include innovative solutions to operate the grid and solutions to implement flexibility services and transform traditional passive consumers into active consumers through the control of their end-use devices by independent aggregators. Participants in these flexibility services receive an economic compensation in exchange for modifying their consumption at the request of the grid operator [11].

Digitalisation is needed for a more efficient allocation of resources in

2 According to a Commission Staff Working Document "a common European data space brings together relevant data infrastructures and governance frameworks in order to facilitate data pooling and sharing" [9].

3 The European Distributed Data Infrastructure for Energy (EDDIE) project financed by the European Commission through its Horizon Europe programme represents a perfect example of this type of energy data space solution. https://eddie.energy/.

4 For more detail see: https://www.opendei.eu/wp-content/uploads/2022/10/OPEN-DEI-Energy-Data-Spaces-EHM-v1.07.pdf.

the power system, both from a current and a dynamic perspective. In the transmission and distribution networks, digitalisation includes detailed monitoring of the energy flows through each asset, thus improving the network design and operation processes, while also easing the implementation of advanced operating techniques such as Dynamic Line Rating (DLR).[5] Grid planning processes are used to forecast the future grid investments and to provide a more efficient allocation of resources, benefiting from a more detailed and accurate historical data of energy flow accessible through digitalisation. Concerning the grid operation processes, increased grid monitorisation allows for a better forecast of local overloads, an improved preventive identification of events in the grid, and also for a more efficient resolution of unforeseen events in real-time. Lastly, digitalisation and artificial intelligence helps reduce the interruption times and improve the quality of supply [13][14].

Another relevant example of digitalisation is related to the replacement of the traditional electricity meters by smart meters able to measure hourly, or even 15-minute, energy use (Regulation EU/2017/2195) [15]. Smart meters provide comprehensive information to both users and providers about households' detailed consumption profiles that are essential to implement energy efficiency solutions. Moreover, smart meters also allow setting individually tailored hourly (or quarterly) tariffs to customers, which incentivises electricity consumption planning based on time-of-use over a 24-hour interval. Accordingly, customised hourly tariffs reshape the profiles of electricity consumption in certain hours over others and enable the implementation of specific flexibility services.

The deployment of smart meters requires the adoption of implementing acts on interoperability data for consumption and metering data to enable a smooth exchange of data, avoid excessive administrative costs for eligible parties, and ultimately promoting competition in the retail market [16]. A related EU regulation on interoperability requirements about metering and consumption data to rule (non-validated) near-real time metering and consumption data provided through smart meters, was approved in 2023.[6] In this regulation, data should be provided through a standardised interface or through remote access in order to be used and processed by an energy management system, an in-home display, or another system.[7]

As shown in Table 1, digitalisation covers a wide spectrum of activities and functionalities in the power system. From a grid operator point of view, better information about what is happening in real-time in its network, improves the reliability of energy flows forecasts and anticipates congestions or voltage problems that might ultimately affect the quality of supply. However, this is not straightforward and grid operators need advanced tools using big data analytics. Some studies quantify that DSO in EU-27+UK would need to invest between 25 and 30 billion Euros between 2020 and 2030 to successfully achieve the decarbonisation targets [17], with relevant investments in the digitalisation of the Low Voltage networks where most of the small customers are connected. These are connecting many DER behind the meter – self consumption – and charging points for domestic Electric Vehicles (EVs).

TABLE 1. LINK BETWEEN DIFFERENT SOLUTIONS BASED ON DIGITALISATION AND ITS TECHNICAL BENEFITS.

Benefits / Digital Solutions	Anticipate congestion and voltage issues in the grid	Implement hourly tariffs to incentivise time profiles of consumption	Improve the quality of supply	Improve the efficiency of the grid infrastructure	Other additional benefits
Monitoring devices in the distribution grid assets	Yes		Yes	Yes	Reduce electricity losses
Monitoring DER in real-time	Yes		Yes	Yes	
Replace traditional meters by smart meters	Yes	Yes	Yes	Yes	Increase users' awareness of their consumption patterns, helping reducing inefficiencies
Dynamic line rating				Yes	Adapt loads to the optimal conditions of each asset, i.e., aging
Implement advanced network operating systems (DER Management Systems or DERMS)	Yes		Yes	Yes	DERMS can use all the other digital solutions to operate the grid

Source: Own elaboration.
Note: DER stands for distributed energy resources.

5 DLR, also known as Real-Time Thermal Rating (RTTR), allows the operation of the grid at a maximum load without damage, depending on the environmental conditions [12].

6 'Near real-time metering and consumption data' means metering and consumption data provided continuously by a smart meter or a smart metering system in a short time period, usually down to seconds or up to the imbalance settlement period in the national market, which is non-validated and made available through a standardised interface or through remote access in line with Article 20(a) of the Electricity Directive (EU) 2019/944 [16].

7 An energy management system is a framework for energy consumers, including industrial, commercial, and public sector organisations, to manage their energy use. It can be useful to adopt and improve energy-saving technologies. For a more detailed description, see, e.g., https://www.unido.org/stories/what-energy-management-system.

All these processes are implemented in parallel with important developments in technologies and data processing. These include the establishment of (energy intensive) data centres hosting cloud solutions to store increasingly large and distributed amounts of data; the development of appropriate algorithms for big data analytics to obtain added value from multiple sources (historical metering data, real-time monitoring data, weather forecasts, etc.); continuous development of AI solutions, often based on natural language processing tools, to improve the customer service (day-to-day processes, customer call centres or claims management); edge computing to decentralise the data processing (primary or secondary substations); and possibly quantum computing to expand the limits on calculation powers and address the needs of the big data requirements [18][19].

3. INTEROPERABILITY AND STANDARDISATION

A key success element of digitalising the different sectors of economy is setting synchronised interoperability measures which simplifies data exchange and communication across a sector and even at a cross-sectoral level. In this section, we discuss interoperability and standardisation in the context of digitalisation.

According to the Electricity Directive (2019/944), 'interoperability' means *the ability of different energy or communication networks, systems, devices, applications or components to interwork to exchange and use information in order to perform required functions*, in the scope of the smart, efficient and sustainable energy systems [10]. The same Directive mandates Member States to ensure interoperability of the deployed smart meters.

For integration and coordination of various energy resources and end-use devices, they should be designed to be interoperable. From a technical point of view, data interoperability is one of the components of the technology building blocks in data spaces.[8] In this context, achieving full interoperability requires adoption of compatible data models and data formats for data sharing purposes (via application programming interfaces). It also requires data to be traceable and trackable from its generation point to its end-use point.

Given the critical role of interoperability, a survey conducted by EU Commission in 2018 lists it as the main technical barrier for data sharing [20]. In fact, lack of interoperability acts as an entry barrier as it hinders seamless exchange of data between different stakeholders and formation of innovative data-driven solutions. Information-asymmetry is another consequence of lack of interoperability: critical data is exclusively possessed and used by certain stakeholders and competition is hindered. Therefore, from an economic perspective too, interoperability should be promoted and facilitated. To this end, it is essential to establish common standards, protocols, information models and data formats.

In the EU, policymakers have addressed the issue of interoperability in several cases. Article 24 from the Electricity Directive (2019/944) mandates the interoperability for access to energy data to promote competition in the retail market and avoid excessive administrative costs for eligible parties. According to the EU Digital Market Act, if deemed necessary, the Commission has the authority to request European standardisation bodies to develop the necessary standards with the goal of promoting interoperability [21]. These standards aim to ensure technical compatibility and safety across diverse energy systems, devices, and processes as well. The creation and enforcement of common technical and operational standards remove the entry barriers associated with interoperability issues in a data sharing context.

In June 2023, the Commission adopted the Implementing Act on metering and consumption data [16]. This legislation aims to ensure that metering and consumption data across countries follow a common reference model. This legislation is part of the Digitalisation of Energy Action Plan launched by the European Commission in October 2022. It is stated that the focus of the Implementing Act is on "interoperability requirements and non-discriminatory and transparent procedures for access to data." However, it should be noted that the legislation does not address the 'technical interoperability issues.' Rather, the act focuses on legislative and administrative procedures. Interoperability, nevertheless, is a technical barrier too and should be solved through setting industry-wide standards first. The EU legislator addressed the technical aspect of interoperability by establishing the Data Spaces Support Centre (DSSC) in October 2022, funded by the European Commission under the Digital Europe Program, to identify common standards, technologies, and tools to support the establishment of sectoral data spaces in Europe.[9]

However, both the Implementing Act and the Digital Europe program do not address the potential for market failures, that can materialise if upcoming technical standards end up favouring certain stakeholders or companies. Focusing on the energy sector, on the one hand, historically and due to infrastructure ownership, utilities and system operators have the highest degree of access to consumer data and the corresponding demand and supply, and network data. Accordingly, their ICT infrastructures are designed to support their specific operations, and, in many cases, they have their own technical standards. On the other hand, digitalisation is a new concept in the energy sector while the digital market itself is filled with big technology companies which have vast sources of the required knowledge to quickly take up the market share in other sectors when these sectors integrate digital solutions. They often do this by leveraging their own technical standards. Setting standards that reflect the infrastructure or the know-how of the incumbents of both sectors can quickly become an entry barrier for smaller third-party service providers that would require access to consumer data for providing their innovative data-driven solutions. Therefore, it is crucial to involve smaller/new stakeholders in initial stages of establishing standards and interoperability rules to avoid favouring incumbent providers and manufacturers to others.

8 The other components are data sovereignty and trust and data value creation. For more detail see: https://www.opendei.eu/wp-content/uploads/2022/10/OPEN-DEI-Energy-Data-Spaces-EHM-v1.07.pdf.

9 See https://internationaldataspaces.org/the-data-spaces-support-centre-is-now-launched/

TABLE 2. PROS AND CONS RELATED WITH THE IMPLEMENTATION OF INTEROPERABILITY REQUIREMENTS AND STANDARDISATION.

	Pros	Cons
Interoperability	• Seamless communication and data exchange among different systems and devices	• Setting interoperability requirements might favour some providers or manufacturers over others
Standardisation	• Standards are known in advance • Existing devices comply	• Listing standards in EU or national regulation might limit the adoption of future innovative standards and might let outside some manufacturers • Difficult process to approve new standards • Standards in EU might differ from those in the US

Source: Own elaboration.

4. CENTRALISED VS DECENTRALISED SOLUTIONS

There are two distinct, but interrelated aspects to the debate around decentralised vs. centralised digitalisation solutions. One relates to the physical configuration of the assets. The other is concerned with its governance, i.e., organisation and the rules and regulation governing the system. Both aspects are in turn related to technology and scale. Historically, the usefulness of many energy solutions has been dependent on our ability to up-scale or down-scale technologies. For instance, in the 1990s, Combined Cycle Gas Turbines (CCGTs) experienced renewed technological progress that enabled building of new plants that were smaller, cheaper, and faster. This enabled entry of Independent Power Producers (IPPs) into the newly liberalised electricity markets, removing some of the pre-existing barriers to competition. Progress in wind and solar power technologies was also accelerated by allowing the emergence of initially small wind turbines, then gradually leading to entry of ever larger installations.

The development of early electricity and town gas systems in the 1800s provided our first encounter with key policy questions around centralised vs. decentralised infrastructure models. The early systems were mainly the result of local private or public initiatives. National and central systems emerged only later, as the need for technical standardisation and operational coordination grew. For instance, in the UK, at the time of establishment of the national electricity grid in 1926, there were more than 600 electricity distribution networks that operated at different voltage levels. A national system was clearly needed for technical standardisation of assets and harmonisation of system operations. Also, the network benefits of systems supporting Automated Teller Machines (ATMs) and mobile phones was vastly enhanced with the harmonisation of standards and protocols for access to these networks of networks, by all users. Different from these technologies, the Internet, evolved around the development of a unified protocol (TCP-IP), allowing universal interoperability, across many different international networks, whereby cross network digital exchanges were managed by Border Gateway Protocols (BGP) [22]. Still national governments and corporations, managed to create spaces outside universal connectivity (intranets and other type of national walls), while the governance of digital interconnection, and its contractual agreements (peering, transit), limited the scope of economic interconnection incentives, notwithstanding the technical interoperability.

'Centralisation' may promote competition or achieve better regulation, since it is often a means for achieving technical and non-technical 'standardisation.' Standardisation is, in turn, important for promotion of 'innovation.' Markets alone cannot be relied on to provide these three elements in an efficient way due to the specific 'public' nature of the good provided (network infrastructure). In fact, economic theory suggests that markets do not supply enough public goods and the above elements of the energy systems, bear characteristics of public goods, with consequences for private underinvestment due to incentives for free riding [23]. These might emerge when there are nonexcludable and/or non-rivalrous elements of the energy infrastructure, for instance, due to asymmetric data referring to individual usage of the shared grid. Similarly, the presence of diverse types of (direct, indirect, cross side) network externalities pose challenges to markets for delivering efficient outcomes. These 'market failures' call for regulatory and policy intervention.

However, implementing centralised solutions might not always be the most efficient solution, especially when some pieces of the puzzle are already developed in different platforms. The idea that the existing energy data systems can be coordinated and used to form a data exchange platform falls in line with this attribute. In these cases, decentralised and interconnected solutions might be more efficient, less costly, and easier to interconnect the individual parts. Indeed, the Internet is working nowadays as a network of networks, of different scales and sizes, interconnected, granting universal end to end connectivity. However, also the Internet, is exposed to threats to the universal connectivity, due to many proprietary sub-ecosystems, as for example those of mobile social networks, and apps, that require additional elements/memberships/apps to be accessible by their users.

In the debate on the relative merits of decentralised vs. centralised solutions, it is important to look at the requirements for effective delivery of policy objectives. In this debate, it is important to consider the new approach stated by the European Regulators [24], when they declare as priority implementing "single and common-front door" for the independent aggregators in the flexibility registers. This solution enables that several decentralised platforms can act as a unique (centralised) platform by the third party. Similar solutions are already implemented with the metering data in the Spanish Datadis Platform [25].

As discussed in Section 3, a successful and quickly available energy data space requires both technical standardisation and harmonisation of the rules governing the access to and use of data across systems and borders. Both requirements can, in principle, be met in decentralised models. Indeed, a centralised system is not a prerequisite of a technically and operationally functional data space. However, some degree of coordination and standardisation is necessary for a decentralised network of networks. In other words, centralisation is neither necessary nor sufficient for standardisation and harmonisation of an interoperable network of networks, and implementing a single and common front-door can be a feasible solution. The aim is to maximise the efficiency of the system using its positive network externalities.

From technological and business perspectives, in the last decade, many companies dedicated large resources to centralise their data processes in the cloud, data coming from many (decentralised) physical servers. This reduced costs, and increased security and accessibility, among others. Nowadays, there is a trend towards another decentralisation of the data, but in an alternative approach and related with the edge computing. This implies moving from a central cloud platform that operates and makes decisions for all the network assets towards multiple small edge devices that take their own decisions and operate decentralised assets. This provides relevant benefits: reduces the data flows, simplifies the calculation needs, reduces vulnerabilities of the power system, reduces computation latency and increases their reliability. Nowadays, their implementation in the power system is still in an incipient stage, but future developments are expected in the next years, mostly related with the operational challenges related with renewables [19]. However, the economic impact of decentralization due to edge computing should be followed and analysed as well to understand whether such decentralization pathway has the potential to become a tool for market power.

5. ECONOMICS OF ENERGY DATA SHARING

In previous sections we discussed some of the key links between digitalisation and energy transition (Section 2), the key requirements for rolling out digitalization and making data accessible to all energy sector stakeholders (Section 3) and, whether energy sector digitalization should follow a centralized or a decentralized path. In this section, we focus on economic issues that are relevant for this process.

In detail, as seen in Table 1, different digitalisation activities can be mapped into different technical potentials. One of the key elements of this process resides in the replacement of traditional meters by smart meters. These are essential to implement hourly tariffs and change the rigid consumption profiles, which is necessary to efficiently integrate large amounts of variable Renewable Energy Sources (RES). At the same time, by modifying demand, smart meters also implicitly affect the energy supply of prosumers, that feed into the grid their surplus of generated energy, mirroring their changed load profiles. Moreover, smart meters also enable implementing the flexibility services introduced in the previous section when they validate the modification of the household consumption in real-time. Smart meters were shown as possibly affecting all of the technical potentials identified in Table 1. Moreover, all these identified potentials entail economic consequences. For instance, they impact the market definition, both from a geographic and from a product perspective. Moreover, they also influence the incentives to enter the relevant markets, users' switching and the lock-in costs, the incentives for incumbent providers to price more or less aggressively, and to offer profiled pricing and bundling strategies, aimed both at generating new surplus, through quality innovations, but also at maximising this surplus' extraction by exploiting potential rent due to the access to, and algorithmic operability on, users' data. These economic consequences are also relevant to the grid operators' business since implementing smart meters requires hiring high-skilled workers or adopting new digital solutions across all their low voltage networks to communicate with smart meters.

In the following, we focus on one specific case, exemplifying how smart meters might play a key role in shaping economic incentives linked to the supplier activities. Moreover, we use this case to explore some key related economic issues, including economies of scale due to network effects [26], cross platforms benefits [27], the incentives to enter into the market [28][29], and the economic value of personal data and data portability [30][31].

Consider, as an example, the choices offered to a new customer, by a transnational supplier such as Octopus Energy.[10] The possibilities are multiple, as indicated in the section on "Smart Meter Data Preferences."[11] Here, the supplier asks the customer: "How would you like your readings stored?" (this is essential to set customer's tariffs) and provides three alternatives for price discrimination: 1) Half-hourly, 2) Daily, and 3) Monthly. After the choice is made, the user is made aware that by: "Choosing to store your readings half-hourly, will help us better match the electricity you are using with renewable generation and reduce carbon emissions." This statement implicitly induces, or nudges [32], the consumer to use the smart meters through the "feel good" factor of knowing that this choice affects the collective benefit of reducing carbon emissions.[12] This is followed by a seemingly 'deterring statement': "Important: If you choose daily or monthly reporting, you will not be able to access your half-hourly data through us." However, implementing efficient half-hourly tariffs requires that the customer can adapt their consumption to the different prices, either through demand that can be remotely activated (EV charging point, storage device) or through changes in their behaviours.

By continuing reading on the potential usage of the personal data collected, one finds more interesting elements that help in describing economic incentives towards the sharing of personal data. Indeed, the conditions a user needs to agree with are that: "We may use your smart meter readings to":

1. "Help reduce costs." This statement focuses on emphasising the benefits of half-hourly information transmission from the user to the provider, who will supply, in turn, information to the consumer, on how to adapt their timing of energy consumption in view of reducing costs. Such reduction is based on the improved efficiency, congestion modelling, market outcomes, and on the "promise" to share these insights with the user for its own private benefits. This information flows, based on half-hourly smart meter reading will also provide systemic benefits for the forecasting and optimisation

10 Octopus Energy Group is a British renewable energy group specialised in sustainable energy. It was founded in 2015. It now supplies green energy in the UK, Germany, the USA, Japan, Spain, Italy, France, and New Zealand.

11 See https://octopus.energy/blog/track-my-energy-use/.

12 In behavioural economics, a nudge is a way to set a choice framework that affects people's behaviour in a desired direction without restricting options (for full details and policy examples, see [32].

modelling of the provider. While the efficiency gain of a detailed information flow is obvious, the reverse flow of promised advice from provider to consumer might introduce an element of "brand loyalty" [33] that will decrease the consumer's willingness to look for alternative providers, hence reducing potential competition by implicitly increasing the consumer's search costs.

2. "Reduce carbon emissions," the second statement linked to the choice of half-hourly readings is also interesting from an economic incentive viewpoint. It links the most frequent metering reading option to the provision of a higher quality product, i.e., one associated to reduced carbon emissions. This increases the satisfaction of the user, if carbon emissions negatively affect its preferences (if they are an economic bad rather than a good). Higher preferences also lead to a higher willingness to pay, expressed in the consumers demand function, that might lead to higher prices, absent other competitive effects. Otherwise, under more competitive scenarios, such higher perceived quality allows the incumbent provider to maintain a price differential vs. its immediate competitors or entrants when these are unable to match such quality. While these effects are standard elements of traditional economic competition analysis, the difference in this setting (the frequency of smart meter readings), is that this increased perceived product/service quality, has a cost that is not borne by the seller, but it only results from the improved quality of timing and allocation of energy infrastructure flow, that is only due to the feeding of the most frequent user data into the grid optimisation algorithms. Hence, we might paradoxically find that, due to the economic value of private users' data, with no extra costs, the provider might charge user a higher price, based on the higher perceived quality of energy unit with a reduced carbon footprint. In short, the provider might either extract extra 'rent' from the user data, by selling a higher priced service or a better quality one, whereby the quality investment is based on the interaction between the user data and the (already existing and paid for) algorithms. Or, in a more competitive market the provider might use these customer's personal data to outcompete possible entrants or existing competitors that have no direct access to these data or to their derived versions when matched with the existing provider's algorithms. In this second case, while regulation on data portability [16] seems to be a clear indication on how to redress these potential rent extraction activities,[13] clearly, these effects depend on the range/scope/definition of personal data. For example, on whether these include derived products/services that are the outcome of (proprietary) algorithms to whom the portable data were fed. Indeed, this is linked to data traceability or data provenance which is a dimension of data quality. Denoting that data sources and any transformation of data should be easily traceable during its entire lifecycle. In this sense, including data traceability as a standard might play a role in changing the dynamics of rent extraction.

3. "Make recommendations and offer free or discounted energy, based on your consumption." This third element of the smart tariff offer is a composite one. The key statement here is that, in exchange of the users half-hourly information provided by the smart meter, the provider will make recommendations (this is fairly generic) and it is possibly related to advertising and bundling the supply of energy services with additional type of services or commodities (for example a home EV charger, or an air source or ground source heat pump replacement for gas boilers). However, this third incentive also promises to offer free or discounted energy. Economics is traditionally the discipline that studies allocation of scarce resources to competing ends based on price systems, used as a self-regulating mechanism. The allocative efficiency of price systems depends on a set of critical assumptions (never actually met in the real world, but a useful benchmark). In traditional markets, therefore, zero prices are an indication of a lack of scarcity or economic trade-offs. Discarding a priory, the hypotheses that zero prices are the result of charitable behaviours, the offer of zero prices must be linked to a related cross-subsiding product, so that the combined offer, has an averaged positive price. These zero-price offers are typical of the digital economy [34] whereby many services, from WIFI access in coffee shops to social media accounts, email addresses, and basic cloud services are priced at "zero". However, the network/platform structure of these services implies that a zero price is averaged with different values, often extracted from the personal information users agree to provide when signing the agreements on terms of use of the free service, after confirming of having read lengthy complex contractual agreements. Such terms and conditions, often refer to the use of personal information, either directly provided, but more interestingly, even indirectly provided (for example by agreeing on the use of cookies and tracking, whose detailed information is clearly richer than what the user is aware of). Zero prices can be of relevance in platform competition as they might be strategically used to attract critical masses of customers on one side of the platform. Thus, the other side of the platform, for example advertisers or sellers of complementary products, might be willing to be pay higher prices to the platform due to the cross platform benefits they receive due to the number of customers on the opposite side of the same network. Such cross-side platform externalities might be pivotal in inhibiting competition and entry into platform markets [27]. Their interplay with the lock-in costs introduces further policy dilemmas often linked to distributional judgments since alternative regulatory scenarios might help one side of a platform while weakening the other. They can also have differential and opposite effects even within each single side of the platform [29], if, for example, users suffer from different switching costs due to an asymmetric distribution of search costs or cognitive abilities.

The economic potential and risks of digitalisation of the energy systems, are better understood through the additional details of this case-example. Octopus asks its customers whether they are willing to join a "tracker-based" cutting edge beta smart tariffs. The tariff is advertised as being "Built with fairness in mind." It features energy prices that change daily based on the wholesale cost of energy (i.e., what we pay for) and requires monthly submission of meter readings, but crucially, requires the installation of a smart meter.

The provider may also analyse information collected from smart meters to develop new products and services and to tailor these to the customer's (data owner) needs. The stated rationale for doing this is "because of our legitimate interest to develop new products and services for the energy market" (innovation). Product and service development are of-

13 The European Commission has addressed the issue of data portability in Art. 20 of the General Data Protection Regulation (GDPR), granting data subjects the right to request transferring their data to other service providers than the data holder.

fered based on customer's data process to:

- "Better understand our customer demographic and the content of customer communications and requests to create more relevant campaigns, products, and services" (Advertising; **economic benefit:** increased information; **economic risk:** reduced competition due to asymmetric providing of the information).

- "Make predictions about future behaviour based on current behaviour, to help develop and tailor our products and services" (Tailoring; **economic benefit:** increased preference due to product differentiation [35]; **economic risk:** softening of competition, linked to stronger brand loyalty effects due to tailoring and induced increasing switching costs [36].

- "To build a profile personally for you, so we can do things like show you products and services that we think will be of particular interest and relevance to you." (Market segmentation; **economic benefit:** better identification of preferences due to better profiling of the services; **economic risk:** softening of competition, e.g., the increased market power resulting from increased market segmentation).

At the core of these "smart strategies" there are data collection processes. These also work when consumers are simultaneously energy producers/exporters or prosumers [37]. For them, the same company offers a "Smart Export Guarantee" as one of available export tariffs, reserved for customers who also want to benefit from any of the smart EV tariffs at the same time as being paid for their export electricity, without the need of being a customer for importing energy.

Finally, it is important to understand the nature and the source of information on which such tariffs are based and whether such information is easily accessible to a wide range of service providers.[14] Are these just personal data, or derived data, are they collected from a sole source of information or merged from different sources, so that implementing regulation on actual data portability might be feasible in theory but complex in practice? As an example, the above discussed tariffs are based on a mix of data sources. These include third parties such as price comparison websites, and affiliates or partners, which may send customers' personal information. These tariffs are also based on the provider's access to the national energy databases, including information about a customer's property, meter details, and previous suppliers from these databases (e.g., notifications from property owner or letting agent may provide the name and email address, as well as the date that a customer occupied the property from, and any opening meter readings that were taken from old suppliers if they hold information that the provider needs to provide their services). Electric vehicle charge point services, location data in line with the location settings on customers' phones when using the mobile app. Cookies are also used to distinguish users of the provider's website. Moreover, third parties (including, for example, advertising networks and providers of external services like web traffic analysis services) may also use cookies, which the provider does not have any control over. These cookies are likely to be analytical/performance cookies or targeting cookies.

6. FUTURE REGULATORY FRAMEWORK

The current regulatory framework includes laws and regulations for all the involved agents in the energy sector and interrelated sectors. More precisely, the digitalisation in the energy sector also requires making some improvements and adjustments in several components of its regulatory framework. These include: the remuneration framework for grid operators, the standardisation and interoperability of all the involved devices and data formats, and the provisions to incentivise and promote innovative solutions. Below, we detail some of the most relevant regulatory improvements.

First, the EC has defined the EU Data Strategy to improve the access to data and incentivise the data-driven innovation.[15] In this frame, the EC has adopted several legal instruments:

- The Directive on open data and the re-use of public sector information (Directive (EU) 2019/1024) mandates the release of public sector data in free and open formats [38].

- The Data Act (DA) aims to make more data available for use and set rules on who can use and access data. EC expects that DA provides cheaper prices for aftermarket services, new opportunities and services related to the data and better access to data collected by devices.

- The Data Governance Act (DGA) sets the frame to share data across sectors and Member States, also incentivising the development of common European data spaces in several sectors such as energy, agriculture, mobility, finance, environmental or health [39].

Second, implementing the digitalisation in the energy sector requires that the incentive schemes for regulating the grid operator's investments are well addressed and properly designed. This is not straightforward because the nature of digitalisation investments made by grid operators is very different than those traditional investments in electrical assets such as lines, cables, and transformers (Table 3). These differences increase the complexity for regulators to approve and supervise investments in digitalisation made by grid investments.

14 Designing and introducing data spaces where energy data is efficiently shared with all the energy sector stakeholders is at the core of the EDDIE project, funded by the European Commission.

15 https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/europe-fit-digital-age/european-data-strategy_en.

TABLE 3. COMPARISON BETWEEN TRADITIONAL INVESTMENTS IN ELECTRICAL ASSETS AND INVESTMENTS IN DIGITALISATION MADE BY GRID OPERATORS.

	Electrical asset investments	Digitalisation investments
Useful life of investments	• Long-term capital investments whose useful life is 40 or more years.	• Short-term capital investments whose useful life is between 4 and 10 years.
Standardisation of investments	• Wide number of international standards and regulations. • High standardisation of grid investments: cables, transformers, substations. • Easy to set benchmark costs by NRA.	• Lower number of international standards and regulations because of recent and constantly innovative solutions. • Mid/low standardisation of digitalisation investments related with constant innovative solutions and lower standardisation. • Difficult to set benchmark costs by NRA
Criteria to assess the investment needs by NRA	• NRA sets network design criteria for grid operators. • NRA can assess using the grid structural information applied to an optimal power flow software and the network design criteria.	• NRA sets digitalisation design criteria for some activities (smart meters), but not for others (IT communications, characteristics of monitoring devices). • Digitalisation design criteria are more complex and highly dependent on a wide variety of open issues: standardisation, cybersecurity, interoperability
NRA replicability and assessment of the investment needs	• Easy replicable by NRA with the grid structural information and the network design criteria	• More difficult to replicate by NRA. • Difficult to define and compare digitalisation structural information between grid operators.
Implementation of economic incentives	• Easy to implement incentives to make investments below benchmark costs (easy to have benchmark costs for grid investments).	• More difficult to implement incentives to make digitalisation investments below benchmark costs. Benchmark costs are more difficult to be set, and digitalisation grid investments might not be easily comparable. • Many grid investments should be paid according to the incurred costs, making difficult to improve economic efficiencies. • Difficult to calculate profitability of investment, as this depends upon faster obsolesce, and results depending on different type on network externalities, the dynamic of which might be highly path dependent [40] [41].

Source: Own elaboration
Note: NRA means the National Regulatory Authority for the power system of each country

Third, the implementation of innovative digital solutions needs a specific regulatory framework. For instance, the technical developments in smart meters have opened the possibility to install them beyond the point of connection with the grid and for specific purposes. They are known as submeters (or second meters) and are devices installed to record the flexibility provided by a specific unit within an industrial building or household, i.e., a cooling device, a water heating device, an electric vehicle charging points, etc. Aggregators and providers of flexibility consider them as key in the deployment of flexibility service from small resources and consider them useful for billing or settlement. Submeters were included in [24] and should be ruled in the next Network Code on Demand Response, also as an alternative in those countries where smart meters are not fully deployed. A variant of submeters is dedicated metering devices, which are submeters embedded within an appliance or devices. They were introduced for first time in the EC proposal for the Reform of Electricity Market Design for the observability and settlement of flexibility services.[16]

Nowadays, the regulatory framework for submetering is pending. However, defining this is challenging because they should also fulfil some metrological requirements and certificates to perform the billing and settlement activities. Moreover, these smart meters should also follow some interoperability requirements to ensure interoperability with the existing ICT communication systems.

Fourth, setting interoperability requirements becomes increasingly relevant with the connection of more digital devices in the power system and is essential to ensure fair competition in the provision and adoption of digital solutions. Few interoperability frameworks might result in economic barriers to manufacturers, additional devices to enable the communication with devices, higher administrative costs, etc. In this context, the Article 24 of the Electricity Directive (EU) 2019/944 mandates setting implementing acts, interoperability requirements and procedures for access to data to promote competition in the retail market and avoid excessive administrative costs. The first Implementing Regulation on interoperability was approved in 2023 [16]. Future implementing acts to be developed should be related with the implementation of new flexibility services.

16 https://energy.ec.europa.eu/system/files/2023-03/SWD_2023_58_1_EN_autre_document_travail_service_part1_v6.pdf.

7. CONCLUSIONS

In the coming years, digitalisation will be a key factor for efficient use of the physical energy assets within a given economic framework. The overarching aim of an energy data space should be to enable the emergence of new business models supported by appropriate regulatory frameworks. In doing so, such frameworks should aim to (i) maximise the network effects, (ii) minimise the transaction costs of using the data space, and (iii) prevent the emergence of dominant players, whose market power might be greatly enhanced by access to, and processing of, vast sets of integrated micro, meso, and macro data. In an ideal world, the transaction costs of a centralised data space can be lower. However, political economy considerations of cooperation among the constituent systems and countries that make the enterprise feasible are more likely to be present in a decentralised structure.

It is important to note that new areas for utilising decentralised energy data will evolve gradually over time. Again, just as the early town gas networks evolved over time and with the new uses of the fuel, a future energy data space will also evolve with the increased electrification of the economy and services as a path-dependent process. Therefore, it is important to allow for time and co-evolution of the data space and the energy sector to generate new business models. However, innovative solutions such as edge computing enable another transformation from the centralised solutions towards the decentralisation.

Finally, the aim of regulation when assessing centralisation, standardisation, and innovation perspectives is to maximise 'network benefits' or 'positive externalities.' As the data space facilitates the emergence of new services, it should also aim to reduce information asymmetry and prevent market power and formation of private information rent. Market competition, regulation, and data spaces should act as instruments of transferring whole sector efficiency gains to consumers.

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Incentivising and Activating Multi-Purpose Flexibility for the Future Power System

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ABSTRACT

The green transition and the electrification that comes along with it, call for huge investments in infrastructure. Traditional energy systems are operated and planned such that the production follows the demand. Similarly, investment needs in e.g., distribution grids, are typically planned according to the future electricity demand, the number of electric vehicles, and the renewable capacity connected to the distribution grid. However, in the era of high penetration of intermittent renewable energy supply, the focus has to shift towards demand-side flexibility. A pivotal development refers to harnessing and integrating the available flexibility of virtually all types of end-users on all aggregation levels, including from other sectors (cf. the energy-water nexus). Such unprecedented levels of complexity call for massive digitalization of energy systems using data-sharing principles, AI, big data analytics, data-driven digital twins, cloud-fog-edge computing, systems-of-systems, IoT, resilience and user-involvement using apps and Smart Energy Management systems. This paper outlines the large economical benefits of demand-side flexibility both with respect to direct savings related to infrastructure investment and indirect savings for the consumers through cheaper electricity prices and lower grid costs. It is argued that one of the main barriers for the green transition and for achieving these benefits is the existing regulatory framework and most importantly the existing tariffs and energy taxes. Another challenge is the conventional market design which is a barrier for activating flexibility both locally at DSO-levels and in multi-energy carrier settings. The paper will outline principles for proper tariffs and energy taxes as well as new disruptive methodologies needed for integrating flexible assets into energy markets. It will be argued that for a bulk part of the flexible assets, we need to use dynamic pricing, and the actual price should be linked to the real operational challenges and costs of e.g., the distribution grids. A key element is the so-called flexibility function for describing the flexibility of the assets. The methodologies are embedded into the Smart-Energy Operating System (OS), which is a hierarchical framework for coherent digitalization of energy systems consisting of aggregation, forecasting, control and optimization. The framework represents new solutions for activating local flexibility. The framework can seamlessly accommodate different behind-the-meter resources (e.g., electric vehicles, heat pumps, etc.), as the distributed flexibility is activated indirectly simply by broadcasting a dynamically changing price signal, overarching the nature of the distributed resources. This ensures simplicity and transparency while keeping the users in control. The intention is not to replace existing methods for direct activation, but to enrich them through indirect, efficient, and scalable activation of distributed flexibility.

KEYWORDS: Dynamic tariffs, Energy taxes, Demand-side flexibility, Flexibility functions, Smart-energy OS, Digitalization of energy grids

1. INTRODUCTION

In Denmark, the Climate Act of 2020 has set an ambitious medium-term goal, that is a 70% reduction in 2030, relative to 1990. EU's 'Fit for 55' [1] establishes the target of reducing net green house gas (GHG) emissions for all 27 member states by at least 55% by 2030 compared to the 1990 levels. To reach this, electrification will play a key role, accompanied by a continued increase in the share of renewable generation in the electricity mix, aiming at reaching at least 75% renewable installed capacity by 2030 in the EU. Renewable generation will be installed at all levels, from roof-top PV to large off-shore wind farms. As a result of the energy systems' decarbonisation, the systems will shift away from the traditional centralized and top-down operational approach towards weather-driven, decentralized operation.

Classical energy systems planning models use a static, predicted energy demand profile as input. As an important example, the energy systems planning study by Eurelectric [2] concluded that the future investment needs in distribution grids are mostly driven by the final electricity demand, the number of electric vehicles, and the renewable capacity connected to the distribution grid. However, this assessment of the investment needs does not adequately take into account the benefits of demand-side flexibility which can be activated by digital technologies.

For optimally planning the future weather-driven energy system, the renewable energy production characteristics must be considered as the essential input and the final load profile will emerge as a result of various factors e.g. local production, selfconsumption, and demand response capabilities. As a step towards the next generation of energy systems optimization and planning [3] has suggested a new framework, named Frigg, for linking the energy system and consumer's demand response models. In [4] an intensive study of Renewable Energy Communities and their potential impact on the electric distribution grid has been carried out. The results showed that when a battery is located at the beginning of the feeder, then the energy community does not impact the observed minimum and maximum voltage. Moreover, it was found that depending on the energy community's operating strategy the low-voltage grid loading can be reduced by up to 58%.

Also sector coupling at all levels of the energy system, and technologies like PtX, are very important for being able to unlock the needed flexibility and support the future weather-driven energy system in its need for energy storage solutions. Projects focusing on individual aspects of the energy system, such as zero emissions buildings or power systems provide valuable insight, but overlook the efficiency, cost and emissions savings possible with an integrated approach that facilitates flexibility throughout the energy system e.g., by sector coupling and PtX technologies [5].

In an efficient implementation of the weather-driven energy system, demand response solutions must play an essential role [6]. This, however, calls for a focus on digitalization of the energy systems, and intensive use of data-driven technologies such as AI, digital twins, and IoT. Demand-Side Flexibility (DSF), and the ability of the customers to change their consumption intelligently in space and time based on external signals, is a crucial prerequisite for an efficient and fast transition towards a carbon-neutral society.

Examples from simulation and sandbox pilot studies show that savings by activating demand-side flexibility are typically from 10% to 50%; see e.g., [7], [8], and [9]. National projects like Center for IT-Intelligent Energy Systems (CITIES) [10], and the Flexible Energy Denmark (FED) project [11] as well as international projects like SmartNet [12] and ebalanceplus [13] have demonstrated savings in a number of pilot studies. These projects have demonstrated different digital solutions for activating flexibility in living labs.

The power price spikes in 2022 have shown flexibility in consumption at the end-users at scale, with many consumers scheduling e.g., the charging of their electric vehicles (EVs) and washing of their clothes such that they benefit from low electricity prices. This has induced a shaping of the system's demand such that consumption is reduced at times of low renewable energy output. Still, the constant energy tax, seen in many countries e.g. Denmark, reduces the incentive for flexibility. To avoid this, it is purposeful to consider replacing fixed billing structures (including e.g. taxes) to dynamically calculated ones.

Moreover, while dynamic energy prices are beneficial for the system's efficient balancing operations, flexible consumption has not been extensively utilized to curate local, distribution network problems. While distribution system operators have tried to harvest the energy flexibility with time-of-use tariffs, these are only loosely connected to the problems they experience. This will remain the case until electricity prices become time- and location-dependent, reflecting the actual needs of the local grid. Thereby, the end users need to be provided with dynamic pricing signals that reflect both the local distribution grid's problems, as well as the balancing needs of the macroscopic power system.

Thanks to the wide deployment of smart meters in recent years, proper and more granular demand-side pricing is realistic but calls for intensive data-driven methodologies, a disruptive thinking related to local flexibility markets, as well as interoperable mechanisms, as outlined in this chapter. Digitalization and new data-driven methods create new opportunities which will allow also small consumers to provide flexibility and, consequently, all consumers can benefit from lower operational and energy balancing costs. In addition, digitalization has the potential to increase transparency and predictability which again can lead to a positive effect related to trust and fairness. The status and challenges on digitalization of the distribution grids in Denmark is outlined in [14].

Empowering end-users towards uptaking an active role in the energy systems' decarbonization is a pivotal development. We need urgently, both due to climate crises and the geopolitical situation, to empower the end-users to play an active part in decarbonising the energy system. However, the activation of end-user flexibility still faces a sequence of regulatory barriers as well as a few technical challenges. As a result, the potential of demand-side flexibility is frequently an overlooked solution in policy decisions as the key for accelerating a cost-efficient low-carbon transition.

New technologies allow consumers to change consumption, self-produce, and provide self-storage options, which the current tariff is not suited to cope with [15]. In addition, the current regulatory framework contains rules and barriers which hinder flexibility and the green transition [16]. A few of the low-hanging fruits along with the essential barriers will be mentioned in this paper, but the most critical barrier is the existing tax and tariff structures.

As mentioned, demand-side flexibility becomes essential and, regarding the tariffs, we will suggest how to define distribution tariffs in harmony with the physics and the power system markets. Secondly, the paper will prescribe a framework for establishing interoperability between the markets and the components' physics including their aggregated dynamics. Finally, we will briefly touch upon the need for changes of the taxes related to the energy system.

2. BENEFITS OF DEMAND-SIDE FLEXIBILITY

In a study conducted by DNV [6], the benefits of demandside flexibility are outlined. The input data and assumptions in the study are focused on the 'Fit for 55' objectives [1] and REPowerEU Communication [17]. The study considers only the low- and medium-voltage grids, and hence the study did not take into account the positive energy efficiency impact of DSF activations, nor potential savings from TSO redispatch costs and TSO grid reinforcement costs.

The benefits of DSF are assessed in the savings in the different segments, i.e., wholesale, generation adequacy, system balancing, and grid infrastructure. Altogether, this translates to benefits for the consumers. Today, prices and tariffs typically come in time blocks (often hourly). For tariffs, this is also known as the Time-of-Use (ToU) tariffs. The recent levels and variations of the ToU tariffs are often discussed and criticized. An example is that the abrupt variations of the existing ToU tariffs cause unwanted variations of the grid load. Moreover, location-agnostic ToU prices can cause a simultaneous shifting of loads into low-price times creating significant operational dangers for the distribution systems to which such loads are connected.

According to [6], 'demand-side flexibility' means the capability of any active customer to react to external signals and adjust their energy generation and consumption in a dynamic time-dependent way, individually as well as through aggregation, and it is assumed that they react to a dynamic price-signal. Thanks to the smart meter deployment in recent years, proper and more granular demand-side pricing is realistic but calls for intensive data-driven methodologies and digitalization as outlined in this paper. It is important to underline that the whole benefits of dynamic pricing can be harnessed only when the end-users are equipped with digital controllers, able to react to price changes quickly and without manual intervention.

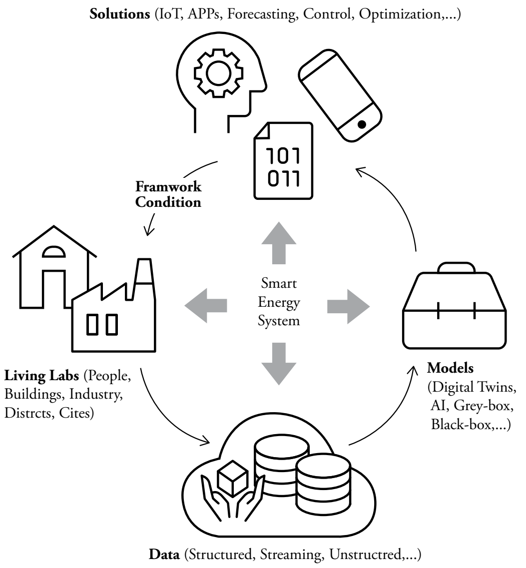

FIGURE 1: PRINCIPLES FOR DEVELOPING AND TESTING SMART ENERGY SOLUTIONS.

Regarding the distribution grid, the study on the benefits of DSF in [6] estimates that 11.1-29.1 billion EUR would be saved annually in investment needs in the 27 EU countries annually between 2023 and 2030. This represents between 27% and 80% of today's forecasted investment needs for low and medium voltage distribution grids.

Moreover, regarding the security of supply and balancing, the results show that efficient activation of demand-side flexibility in European balancing markets in 2030 could save between 43% and 66% of the balancing costs. The analysis also suggests that the energy system in EU in 2030 would lack at least 60 GW of generation capacity to ensure security of supply during highest demand peaks. Enabling 60 GW of DSF would save 2.7 billion EUR annually compared to installing the same amount of peak generation capacity. This would directly benefit consumers with flexible assets, as well as indirectly benefit all customers through cheaper electricity prices due to lower generation costs.

Finally, today the curtailment of wind and solar power is considerable. While 2-3% of RES curtailments is deemed acceptable, today's rather high curtailment levels is an indication of system inefficiency. It is estimated that with demand-side flexibility the renewable energy curtailment would be 61% less (15.5 TWh annually), which will improve the economics of wind and solar energy and increase the availability of decarbonized electricity to consumers.

In the FED and CITIES projects, solutions for activating flexibility have been developed, and tested in a large number of Living Labs. The solutions have demonstrated large costs and CO_2 emission savings, but due to the current regulatory setting, most of the solutions were only running in shorter periods for a verification of the potentials. The principles for development of the smart energy solutions are sketched in Figure 1.

Before a full scale implementation it would be possible to test the digital, data-driven and smart energy solutions in collaboration with e.g., Center Denmark[1], in sandbox or test zones jointly with a next generation of proposals for the regulatory framework as indicated in Figure 1.

3. FLEXIBILITY FUNCTION

For price-responsive customers, prices can be used to control the load as first suggested in [18]. Methods for using experimental data for estimating the energy flexibility of households with a price-responsive load were suggested at least as early as 2009, as part of the FlexPower project [19]. It is shown by [20] how the variations in penalties can be used to shift the load from peak hours to off-peak hours. The authors in [21], [22] went a step further and described how also the frequency and voltage in power grids can be controlled by this method.

However, a model for forecasting how clusters of consumers in e.g., a DSO area will react to a particular sequence of prices is needed. [23] introduced the so-called *Flexibility Function*, which is simply a model which can be used to forecast the response (e.g., the load) as a function of a sequence of incentivizing signals (typically the prices); see Figure 2.

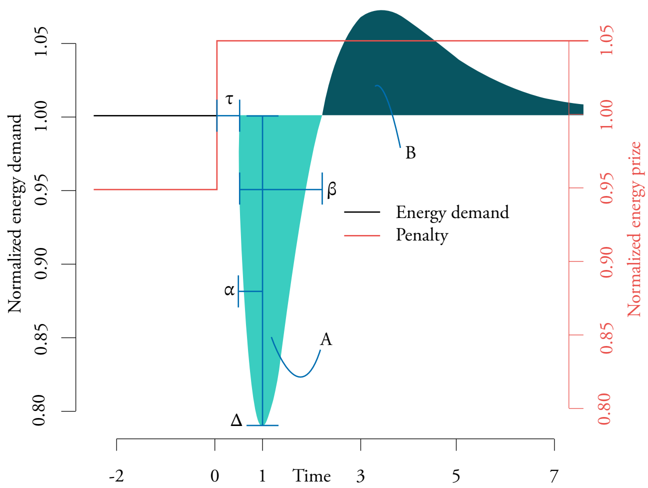

FIGURE 2: FLEXIBILITY FUNCTION (FF). THE FF DESCRIBES THE RESPONSE AFTER A STEPCHANGE IN PRICE.

The flexibility function could be implemented using any type of dynamical model, and it is suggested as one of the fundamental MIMs (Minimum Interoperability Mechanisms) for energy systems [24].

1 Center Denmark is a EDIH - European Digital Innovation Hub for Smart Energy Systems. See also https://www.centerdenmark.com

The Flexibility Function shown in Figure 2 is adequate for linear and time-invariant systems. For nonlinear systems, it is shown in [25] that a grey-box model using a set of non-linear stochastic differential equations might be more appropriate. The approach essentially models the flexibility using a battery-like model including a state-variable representing state-of charge. In general, the flexibility function should be considered simply as the link between price and demand.

4. THE REAL COSTS OF DISTRIBUTION GRIDS AND PRINCIPLES FOR PROPER GRID TARIFFS

Here we will focus on distribution grids, but many of the same principles hold also for transmission grids.

There are two overall costs associated with distribution grids:

1. Power losses in transformers and cables due to resistances in the power conducting equipment (energy, i.e., kWh related).
2. Need for investments in the power grid either due to maintenance or needs for expanding capacity (power, i.e., kW related).

Energy losses are easily understood since they are purely physical, and have a well-defined price in the power markets. If, in a particular hour, in a particular part of a distribution grid, there is a loss of 10 kWh, then, the corresponding DSO has to cover this loss by purchasing 10 kWh of energy at whatever the price of the hour in question. Thus, the part of the DSO tariff of this particular hour for this particular part of the DSO grid should be closely linked, if not directly given, by the 10 kWh times the energy price.

Allocating investment costs is not as easily quantified, since the need for expanding the capacity can not be tied directly to the power consumption of particular consumers at a particular point in time. Still, only demand during times when the grid is (close to) having congestion problems is directly contributing to the need for expanding it. Therefore, the need for expanding the grid is decreased by reducing the power consumption (kW) during these times. Using dynamic tariffs that reflect the actual power congestion challenges implies that consumers representing the congestion-inducing consumption are also the ones responsible for the need for grid reinforcements. Such an investment cost mechanism has a built-in fairness of allocating the costs for grid expansions. Consequently, a high power (kW) consumption should dynamically lead to higher local tariffs.

Another typical issue for distribution grids is to ensure that the voltage level is within reasonable limits along the feeder for all local grid areas. If no problems exist, then the voltage related component of the tariffs should ideally be zero. In the case of voltage issues, demand-side flexibility can be activated to control the load. Obviously this also calls for dynamic tariffs. Some details on principles for generating dynamic prices and tariffs will be proposed in Section 7.

The philosophy behind the proposed principles is simply that the dynamic tariffs should reflect the system's needs in such a way that users that cause issues (e.g. congestion) are facing high prices and hence incentivized to contribute to the resolution (e.g. by shifting EV charging), while users that contribute to alleviating or serving the system are rewarded. This naturally incentivizes micro-investments in digital technologies that automate DSF (by creating an attractive return-on-investment) and serve the system.

The suggested procedure might lead to higher dynamic tariffs e.g., in areas with a large number of EVs demanding fast charging. This is most likely areas with people with a high income. In areas with a low electricity consumption there might not be the same need for high tariffs.

Most of the methods outlined in the following for distribution grids will be also apply for transmission grids. Tariffs should reflect the physics, and hence power generated and used within the same distribution grid should not be exposed to transmission tariffs. Such principles should also be implemented e.g. for gas grids. Today biogas is penalized with transmission tariffs even though a minor part of the biogas reaches the transmission system. Both for power and biogas it is important to implement a level of tariffs such that it is incentivized to used produced green energy locally, and not penalised by tariffs for infrastructure that is not used.

5. LOOK-AHEAD INCENTIVES

Energy consumption is a dynamic phenomenon, since a change in consumption at a given time will impact the consumption in the near future as well. Moreover, consumers will need to know tariffs *before* they, or their controllers, decide on their consumption. Thus, rather than solely reacting to the current situation, the DSO tariffs should look ahead, to make tariffs that give the best overall incentives, and with a lead time that is enough for consumers to react. Of course, consumers react to the total prices, e.g. the power prices including taxes and tariffs, and thus, given the energy price, C_t, and tax, T_t, the DSO tariffs should be found by solving for them in the following equation:

$$\mathrm{FF}(C_t + T_t + L(P_t) + E(P_t)) = P_t,$$

where L is the loss tariff and E is the expansion tariff. This equation expresses how the total power price for a given area consists of the energy cost, the tax, the loss tariff and the expansion tariff. Since the tariffs are functions of demand, and the demand a function of the tariffs, this equation needs to be solved, so that the tariffs calculated from the demand P_t, gives an expected consumption of exactly P_t, a fix-point of the flexibility function, FF, which was introduced previously in Section 3.

6. HIERARCHICAL CONTROL FOR SOLVING GRID AND BALANCING PROBLEMS

This section describes how sequential dynamic optimization implemented as controllers in a multi-level or hierarchical control setup, can be used to solve both grid and balancing problems. In order to illustrate how this can be used to activate flexibility also in the residential sector, we will use buildings as an example. Briefly speaking we will describe how the physics (dynamical formulations) of the buildings and grids can be linked to the conventional electricity markets which is characterized by bidding and clearing (static formulations). Subsequently, we shall briefly outline how these principles can be generalised to multi-level and hierarchical control problems.

6.1. CONTROL DESIGN FOR ACTIVATING FLEXIBILITY

In this section, it will be explained how to control the demand of smart buildings by generating prices such that the building reacts and adapts its consumption accordingly. The basic concept is illustrated by Fig. 3, where a smart building, from an external perspective, takes an input (price) and gives an output (demand). Data-driven techniques are used to estimate the Flexibility Function, which then can be used for predicting demand as a dynamic function of price.

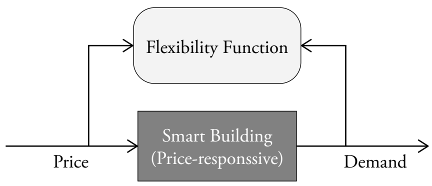

FIGURE 3: THE DEMAND OF A SMART BUILDING CAN BE PREDICTED AS A FUNCTION OF PRICES.

Given a Flexibility Function for the building, a second controller can be formulated where the objective is to control the building's demand according to some criteria, and the decision variable is the price (say, electricity price as a function of time). As shown in Figure 4, the Flexibility Function can be used to generate prices according to some references. The reference could be a desired energy consumption in time. Notice how the demand acts as the feedback to the controller, closing the loop.

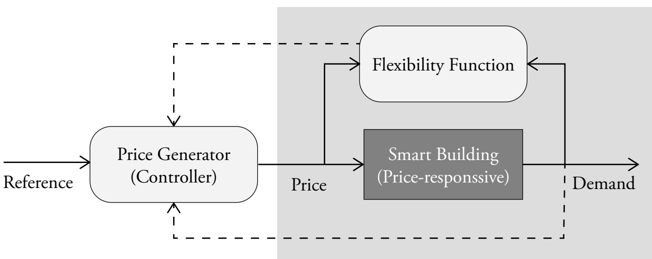

FIGURE 4: USING A FLEXIBILITY FUNCTION TO GENERATE PRICE SIGNALS AND DEMAND AS CONTROL FEEDBACK.

Let FF be the Flexibility Function that takes energy prices as input and gives the building's expected demand as output, while r_l is a reference load profile. Then, a simple upper-level controller (the price generator in Fig 4) can be defined as the following optimization problem

$$\min_{C_u} (\mathrm{FF}(C_u) - r_l)^2, \tag{1}$$

where C_u is the future energy prices. An example of such a controller is the minimum variance controller [26]. Obviously, it might be necessary to impose limits on how much the price can change or requirements on the average value, and a more sophisticated optimization problem than the minimum variance formulation can be formulated, as discussed in [27].

Combining the optimization problem in (1) with a lower level optimization problem of the building's heating system or it's Energy Management System, the Flexibility Function couples the two levels in an elegant fashion:

$$\begin{array}{ll} \min\limits_{C_u} (\mathrm{FF}(C_u) - r_l)^2, & \text{Upper level} \\ \hline \min\limits_{u_k} \sum\limits_k C_u^\top u_k & \text{Lower level} \\ r.t.\ \mathrm{d}x = f(x,u,d,t)\mathrm{d}t + g(x,u,d,t)\mathrm{d}w, & \\ \quad \Pr(x_{\min} \le x \le x_{\max}) \ge 1 - \alpha & \end{array} \tag{2}$$

where, in this case, the lower optimization problem is formulated as an economic MPC problem [28].

A main reason why the Flexibility Function is considered to be one of the fundamental MIMs (Minimum Interoperability Mechanisms) for energy systems is that the FF is instrumental for interoperability between the building level and the upper level representing the grids and aggregators.

Notice how the two optimization problems are solved independently from each other, thus preserving autonomy and privacy for the building owners while simultaneously allowing a stakeholder (e.g. supplier, aggregator, or balance responsible party) to utilize the energy flexibility. In practice, there are going to be a lot of smart buildings for each aggregator that all have independent control problems and preferences. The development of building energy management systems and smart buildings is left open to competition among commercial stakeholders, while the flexibility function remains agnostic to specific types and technologies of controllers. Finally, this method scales well to this case since the computational burden for the upper-level remains constant — with the Flexibility Function simply representing the expected aggregated response from the relevant cluster of smart buildings [27]. Moreover, on-line identification and adaptive methods can help simplify offering the flexibility services without the need to conduct a study for each resource separately.

7. MULTI-PURPOSE CONTROL

In the previous sections the upper-level controller has taken the load reference as input and then generated a sequence of prices that, given the known flexibility dynamics as represented by the Flexibility Function, will provide the wanted demand. This setting is appropriate if we want to establish demand-side load management, which could be useful for peak-shaving or for maximizing self-consumption e.g., in the case of local PV production.

The sketched methodology is, however, easy to generalize to other situations. Let us for instance consider the problem of voltage control with a reference voltage $r_{voltage}$. Then, the voltage controller can be defined as the upper-level controller

$$\min_{C_u} (\mathrm{FF}_{voltage}(C_u) - r_{voltage})^2, \quad (3)$$

where the $\mathrm{FF}_{voltage}$ is a flexibility function describing the dynamical relations between prices and voltage for the considered low-voltage distribution area.

Power transformers are one of the most costly assets in power grids. Due to increasing electricity demand and levels of distributed generation, they are more and more often loaded above their rated limits. Transformer ratings are traditionally set in a controlled environment with conservative margins. In [29] it is demonstrated how to set up a digital twin model for transformers which can be used for *Dynamic Transformer Ratings*, such that the transformers dynamically can be overloaded up to 60% without any risks for damages. In combination with hierarchical controllers as outlined here, the setting can be used to postpone costly investments and ensure safe operations of the transformers.

Until now the purpose of the low-level controller has been to minimize the operational cost, but also the low-level controller can be changed. If, for instance, the real-time CO_2 emission linked to the electricity consumption is used as the penalty signal, then the controller will minimize the carbon footprint of the system. This example of low-level controllers are used e.g., in [30], [31] for controlling the temperatures in summerhouses with a swimming pool such that the carbon footprint is minimized.

As explained in [30] and shown in Figure 5, by changing the cost function, the low-level controllers can be used for

1. cost minimization,
2. carbon footprint minization, or
3. energy efficiency optimization.

A goal of a modern regulatory framework would be to incentivize electricity consumption at periods with low carbon electricity production; it would be advantageous to ensure that the dynamic prices are designed such that the costs are low when the emission is low. Unfortunately, this is not the case today. An example is, as also explained in [7], that wastewater treatment plants could save up to 50% on their emissions, but the current regulatory settings prevents this. Here a main problem is that taxes are not properly linked to the emission.

8. CONTROLLERS AND MARKETS

Ultimately the purpose of the future smart energy system is to establish a connection between the controllers operating at local scales, and high level markets operating at large scales. This includes coupling sectors and establishing dynamic markets to reflect an increasingly dynamic supply and demand of energy. Essentially a spectrum of all relevant spatial aggregation levels (building, district, city, region, country, etc.) has to be considered. At the same time, the established markets and controllers must ensure that all power systems (on all temporal and spatial scales) are balanced. Consequently, data-intelligent solutions for operating flexible electrical energy systems have to be implemented on all spatial and temporal scales.

To address these increasingly important issues, several solutions have been proposed in recent years. Some significant solutions are Transactive Energy, Peer-to-Peer, and Control-Based solutions, as described in [32], and [33], while computational issues also need to be addressed by leveraging the whole spectrum of computational resources (namely, edge-fog-cloud) [34].

Traditionally, power systems are operated by sending bids to a market. However, in order to balance the systems on all relevant horizons, several temporal-specific markets are needed.

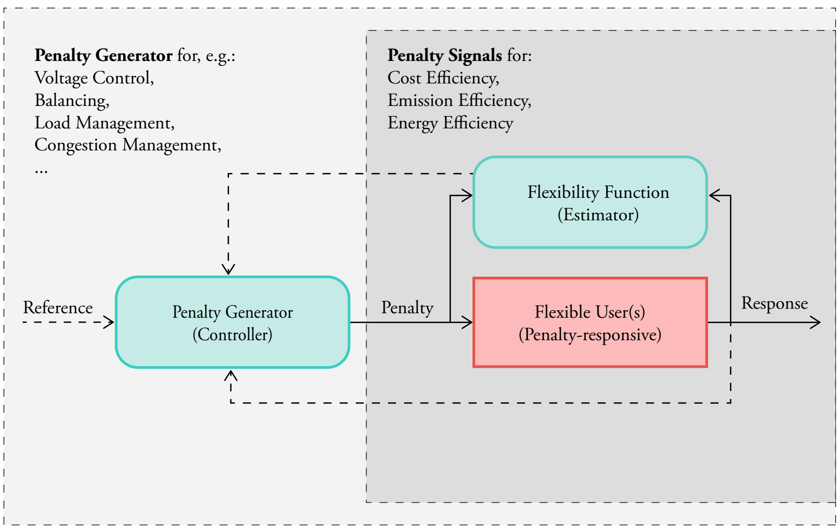

FIGURE 5: HIERARCHICAL CONTROL FOR UTILISING FLEXIBILITY

Examples are day-ahead, intra-day, balancing and regulation markets. The bids are typically static and consisting of a volume and duration. Given all the bids, the so-called supply and demand curve for all the operated horizons can be found. Mathematically, these supply and demand curves are static and deterministic. *Merit order dispatch* is then used to optimise the cost of generation. However, if the production is from wind or solar power, then the supply curve must be stochastic, and the demand flexibility has to be described dynamically - e.g. by the introduced Flexibility Function. Consequently, it is believed that it is necessary to introduce new digitised markets, which are *dynamic and stochastic*. Also instead of using a large number of markets for different purposes (frequency, voltage, congestion, etc.) and on different horizons, we will suggest to use concepts based on the Flexibility Function and stochastic control theory; exactly as described in the previous section for the two-level case. We call this the Smart-Energy Operating-System (Smart Energy OS) [22], [31], [24].

If we zoom out in space and time, i.e. consider the load in a very large area on a horizon of days, or maybe next day, then both the dynamics and stochasticity starts to matter less (and might be eliminated), and hence we can use conventional market principles as illustrated in Figure 6. If we zoom in on higher temporal and spatial resolutions (like for instance a house), the dynamics and stochasticity become important, and consequently we will suggest to use the control-based methods for the flexibility as discussed previously. This implies that in real-time the link is handled simply by a one-way communication or broadcasting of a price-signal, and the consumer can

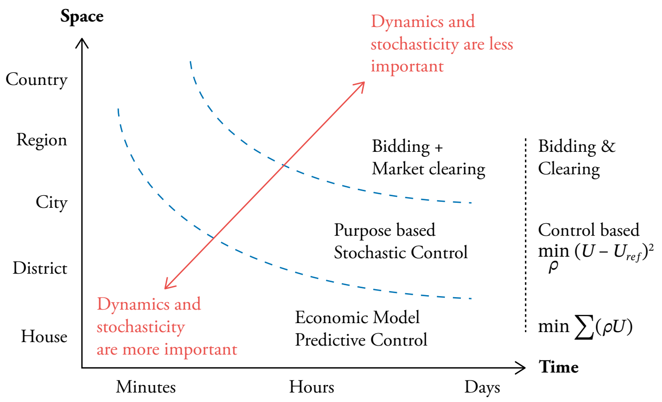

FIGURE 6: HIERARCHICAL CONTROL AND MARKETS.

simply self-dispatch according to prices, without any further complications e.g., having to submit bids.

The simplicity of broadcasting price signals for activating demand-response needed e.g., for a distribution system operator,implies that basically all appliances can contribute to unlocking the needed flexibility at the relevant spatial and temporal coordinates. At the same time the end-user can easily set up local preferences in their Home Energy Management Systems (HEMS) in a weighted combination of a focus on e.g., comfort, costs, emission and energy efficiency [35]. A comprehensive model, integrating these concepts into a TSO-DSO coordination framework is presented in [36].

Basically, the setup distributes the computational effort across many levels of the hierarchy. Similarly, the Home Management Information Systems (HMIS) can be used to provide information about the aggregated flexibility which can be offered from a particular building, and for energy communities similar aggregation principles apply.

The simple setup with a simple broadcast of a price-signal provides directly a possibility for sector coupling and multienergy supply systems, where e.g., air-to-air heatpumps can be used jointly with natural gas heating systems; maybe as a stepping stone away from natural gas. The Home Energy Management System (HEMS) can simply change from natural gas to electricity when the electricity prices are low. This system would accelerate the green transition and offer extra flexibility which will reduce the number of times e.g., wind turbines are stopped by grid operators.

9. MARKET DESIGN CHALLENGES

9.1. MARKET DESIGN FOR ACTIVATING LOCAL FLEXIBILITY

Several projects and initiatives have studied the possibility of controlling e.g., the load in a distribution grid by setting up a local DSO market [12], [37]. However, it has been concluded that conventional market mechanisms are not suitable here [31]. First of all, the number of potential bidders and the market size is very limited. Moreover, even for larger flexible assets, energy flexibility is only of secondary concern. As an example we can consider the conclusion from a series of workshops for wastewater treatment plants organized by Energinet and Center Denmark. Wastewater treatment can be highly flexible, but the primary concern for the operator of wastewater treatment plants is to avoid overflow in the city, the second priority is to keep the flow at the plant below some given values to ensure that the active part of the sludge stays on the plant, while saving money due to energy flexibility is at best a third priority. Given even a small probability of a severe rain event, wastewater plants will not bid into the markets.

The workshops with wastewater treatment plants operators concluded that the price-volume bidding strategy would be difficult or impossible to use for the plant operators. Instead the suggestion was to introduce a specialized aggregator which trades on the electricity markets and then broadcasts a dynamic price signal to the wastewater plants. However, from the wastewater treatment plant's perspective, it does not matter where this dynamic price signal comes from. The up to 50% savings due to flexible operation reported in [7] can be shared between the aggregator and the wastewater treatment plant.

9.2. WHERE DOES THE MARKETS STOP AND THE PHYSICS BEGIN?

Another barrier is the fact that the conventional market design with merit order bidding and subsequently clearing represents a *static problem* but the local flexibility represents a *dynamic problem*, and hence the bidding formats of traditional market mechanisms do not offer enough expressive richness to capture the temporally coupled characteristics of the new market players [38].

Let us for instance consider a supermarket. Here the cooling represents a flexible asset. The problem is however, that if a supermarket has lowered the electricity consumption for the cooling during a given hour, then it might not be possible to offer a similar flexibility for the subsequent hour due to considerations to keeping the goods within the typical temperature ranges (typically below 5-6 degrees Celsius).

Another challenge related to the conventional market structure is that if a given flexibility is bid into a specific market and hence only available for solving the market specific problem, then this flexibility is out of the game for solving other and maybe more critical grid ancillary service problems. In the Smart Energy OS framework the flexibility will be available for solving all grid and balancing service problems. In addition market bidding includes a volume, a price and a time period, but most systems can deliver a lot of power flexibility (kW) in a short period, or less flexibility in a long period [39]. If the price is high enough all consumers will be flexible, and essentially the causality is from price to load flexibility. Finally, the stochasticity implies that a probabilistic assessment of the flexibility are needed in order to provide proper calculations related to resilience and risks.

However, it is clear that at higher aggregation levels - e.g., day-ahead at price-zones operated at the NordPool spot market, the existing market mechanisms should be preserved, since they act as an important mechanism to find the overall level for the electricity prices. At that level the dynamics and stochasticity are of less importance and can be ignored.

The conclusion is that we need an interoperability mechanism to define the link between the high level static markets and the low level physics. We will suggest to use the Flexibility Function as a fundamental Minimum Interoperability Mechanism (MIM) for this purpose, and hence for describing the link between the markets and the physics. The MIMs [40] are now becoming an important instrument in the twin transition in Europe and globally the MIMs are approved by ITU and 17 member organisations [41].

10. THE SMART ENERGY OS

Let us consider the outlined principles for forecasting, control and optimisation which constitute the so-called Smart Energy OS (SE-OS), in more detail. The framework used in several projects to develop, implement, and test solutions (layers: data, models, optimisation, control, communication) for hierarchical and coherent operation of flexible electrical energy systems at all scales. See [22, 31, 42] for further information.

An efficient implementation of the future low-carbon energy system requires the electricity demand to follow the weatherdriven energy production at all scales of the power system. In addition the future calls for more coordination between the low and high-voltage system operators and, consequently, there is a need for coherence between actions taken by the TSO and DSOs, who operate at different spatial scales. As an example a new method for hierarchical forecasting of wind power production suggested in [43] has lead to a significiant improvement of

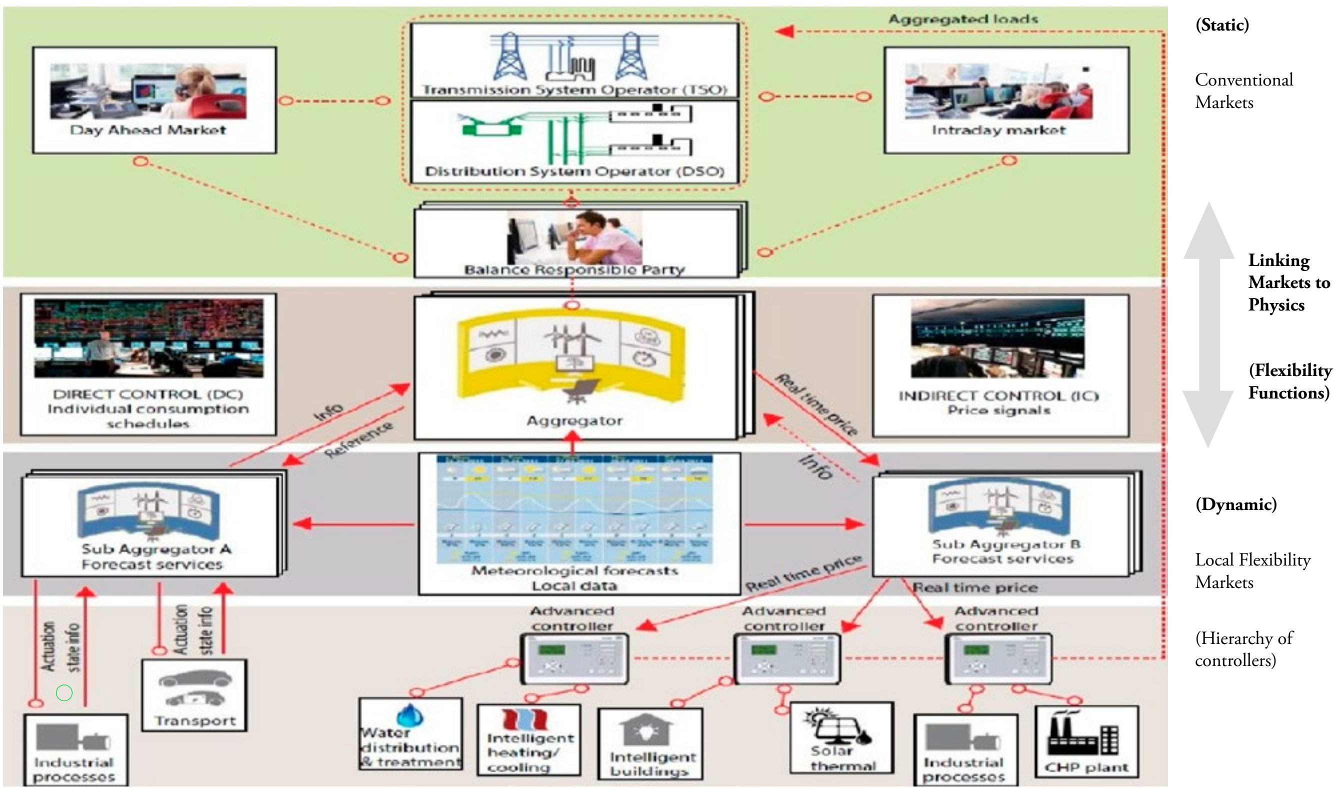

FIGURE 7: THE SMART ENERGY OS

wind power generation forecasts and at the same time the forecasting hierarchy ensures that the forecasts seen by the TSO and the DSOs are coherent. In [44] similar hierarchical forecasting techniques are used for improved load forecasting in all four price areas in Sweden.

The study in [45] considers the power grids as a hierarchy consisting of the transmission, distribution, and microgrid levels and develops interfaces among these levels showing how the flexibility at the microgrid level can be activated at the higher levels. In [45] community batteries are considered as a primary source of flexibility. Finally, [36] describes a generic modeling framework towards integrating distributed flexibility across different hierarchy levels and markets for energy management decisions.

The Smart Energy OS principle is using the Flexibility Function as one the fundamental MIMs to ensure a minimal but sufficient interoperability on all relevant levels. For many applications low-cost solutions can be established using mobile phones, smart home management systems, and similar edge computing technologies. Data is typically kept at the edge, and computations are carried out in a *coherent hierarchy* consisting of edge, fog and cloud computing levels with security, privacy, transparency and fairness in mind.

The Smart Energy OS is a hierarchical setup as indicated in Figure 7. At the top level it consists of conventional markets, but at the lower levels it consists of methods for a combined direct and indirect control. The experience at, e.g., the smart energy hub, Center Denmark, is that most of the building related demand response methodologies should be based on indirect price-based control.

At the same time the Smart Energy OS is designed as a hierarchical system for data handling and information exchange frameworks, ensuring a unique coherence across all relevant spatial and temporal aggregation scales, and with a focus on multi-objective criteria like energy efficiency and flexibility.

Conceptually, the Smart Energy OS relies on the Minimal Interoperability Mechanisms (MIMs) roadmap, which aims at providing building blocks for an efficient digitalization of the society in general, and in providing functionality across different but related domains like energy, transportation and water. The intention is not to replace existing market mechanisms, but to accomplish this with a MIMs-compliant framework for an efficient scale-up of local flexibility concepts (e.g., for large-scale integration of wind and solar energy) while supporting local initiatives like district heating and local energy communities.

Data for energy systems forecasting and services is an important example being built upon the Smart Energy OS concepts. Here unique frameworks and data spaces for exchange of information between all relevant aggregation levels have been established. More specifically, the Smart Energy OS concept contains a framework of spatial and temporal hierarchies for ensuring that forecasts of, for instance, the wind power generation are coherent across all relevant aggregation levels, as explained e.g., in [46].

Integrity – including privacy (GDPR), transparency, security and reliability – has foremost importance in the Smart Energy OS, and in all essential cases such issues are dealt with by design in a consistent and verifiable way. For instance, the work in [47] proposes a privacy-preserving, distributed framework for residential demand response. Energy efficiency and flexibility of residential buildings are important examples where design-specific data exchange metrics have been adopted.

A key element of the data exchange framework between, e.g., residential homes and grid operators is the Flexibility Function [23], as previously introduced in Section 3. The Flexibility Function is one of the fundamental MIMs-related features within the Smart Energy OS setup, and it represents a condensed information exchange or interoperability framework which is used, for instance, to create a coherent link between the low-level physics (e.g. the thermal inertia of the buildings) and high-level electricity markets.

The Flexibility Functions are used also for sector coupling and for hybrid energy systems; an example being buildings with both district heating and heat pumps. Finally, the Flexibility Function can be used at all aggregation levels, e.g., for the appliance, the house, the district, the city and larger regions.

Another key element of the Smart Energy OS is the datadriven digital twins or grey-box models. The grey-box models allow for information from real-time data from sensors and measurements to be assimilated into the models in almost realtime, and consequently this improves the forecast and control performance. Moreover, the Smart Energy OS manages to keep privacy-related information at the edge. This is possible due to the fact that the Flexibility Function contains all relevant information for instance for the balance responsible parties as well as for the distribution grid operator.

The Smart Energy OS concepts, and in particular the integrated standard Flexibility Function for activating flexibility at all levels and across all relevant energy vectors, imply that flexibility and interoperability can be obtained everywhere using low cost technology. The simplicity of broadcasting price signals for activating demand-response implies that basically all appliances can contribute to unlocking the needed flexibility at the relevant spatial and temporal coordinates. At the same time the end-user can easily set up local preferences in a weighted combination of a focus on costs, emission and energy efficiency. The overall simplicity of the concepts ensures fast adaptation and stimulates an effective scale up of the use of flexibility and demand response technologies in the market.

In the Smart Energy OS framework, the computations are done at many levels of the system hierarchy. The Smart Energy OS for Power Systems, Home Energy Management Systems (HEMS) and Home Management Information Systems (HMIS) can be used to provide information about the aggregated flexibility which can be offered from a particular building, and for energy communities similar aggregation principles apply. The Smart Energy OS concepts have been demonstrated in several national and international projects like ebalanceplus [9], Flexible Energy Denmark [48], Center for IT-Intelligent Energy Systems (CITIES) [10], and SmartNet projects (EU H2020) [31].

11. DYNAMIC AND STOCHASTIC RESERVE SCHEDULING FOR POWER SYSTEMS

Solving the unit commitment and economic dispatch problem is one of the main responsibilities of power systems operators. Power systems already face important challenges due to the forecast uncertainties for renewable generation, demand response solutions, and behind-the-meter renewable PV generation. As discussed, when introducing the Flexibility Function, these uncertainties are both dynamic and stochastic.

Traditionally, operators have been dealing with uncertainties by committing reserves, i.e., making sure that enough amounts of spare generation capacity are available at every operational timeslot to meet possible demand needs. In systems with high penetration of renewables, even if the energy supply is adequate, there is a significant curtailment of renewables to make room for conventional generators that provide the necessary reserves. While storage and flexibility are envisioned as the remedy to the intermittent and time-differentiated renewable supply, it is far less discussed how they are going to replace conventional generators in the need to procure reserves.

More specifically, and in contrast to generators, storage and flexible demand are temporally coupled, which means that if they decrease consumption in one timeslot they bear a reduced ability to decrease consumption again in subsequent timeslots. This is less problematic when scheduling their consumption profile since, as discussed in previous sections, one can account for the temporal couplings and co-optimize the flexible assets' profile across the whole of a look-ahead horizon. Nonetheless, when it comes to reserves there is the additional subtlety that a committed reserve capacity may or may not be actually used, which makes it difficult to reason about the effect of the dispatch schedule (and reserve commitment) on a battery's stateof- charge or on a flexible asset's inter-temporal energy state and needs.

Specifically, consider a cluster of batteries or EVs with 500 kWh of energy stored at the start of a horizon of K timeslots. Naturally, it is not operationally safe to consider the asset capable of providing 500kWh of reserve in each of the K timeslots, since if some amount of this reserve is activated in one timeslot, it would be depleted and would not be available for the subsequent timeslots. Although this is fairly obvious, notice how it is not the case for generators, and how traditional (per-timeslot) reserve products made for generators do not account for such issues. On the other end, if the flexible asset is allowed to offer its 500 kWh as its total reserve across the K timeslots (e.g. an amount of $500/K$ kWh of reserve in each timeslot), it would be severely underutilized, because it is not really the case that the asset cannot provide more than $500/K$ kWh at each timeslot (it actually can); it is just that it cannot provide a total of more than 500 kWh of reserve activation across the K timeslots.

These two approaches make it clear that traditional reserve products (originally made for generators) are inadequate to capture the flexibility capabilities and characteristics of the system's new players. The first approach compromises the system's security, while the second is over-conservative and compromises the system's efficiency. In the face of these problems, [49] proposes a new notion of reserve that effectively resolves the utilization of storage and flexible demand for optimal unit commitment. The proposition points to the new notion of Energy Reserves, which generalizes the concept of per-timeslot reserves to energy reserves *across* time intervals.

Such a reserve product that is more nuanced around storage and flexibility, enables the new assets to be integrated in the system and replace traditional generators, not only in terms of balancing the system, but also in terms of providing the necessary reserves to support renewables-based energy supply. This effectively means that the system can be operated with fewer generators committed which can lead to more than substantial cost benefits. The study goes on to quantify this effect, on the standardized case study [50], and reports a secure operation of the system at a whopping 10% of the cost of traditional practices. For the European system, this translates to weekly savings in the order of billions of euros, just by changing the reserve products.

12. ENERGY SYSTEM TAXES

12.1. THE COMPLEXITY OF TODAY

Today, the system-related taxes are complex. Historically, the purpose has been to increase the cost of energy to incentivize energy efficiency. The related tax is often called the energy tax. Later on, environmental taxes related to greenhouse gas (GHG) emissions were put in place, such as the CO_2 emission related to fossil fuels, but also other gasses like NO_x and SO_2. In the following, we will also discuss the CO_2*-eq tax*[2]. Figure 8 shows how the taxes today are introduced differently when e.g., coal is used for producing either electricity or heat (district heating).

While these instruments are politically desired, the approach of including them in the form of rigid taxes or levies in the electricity bill hampers the pricing effects of both market signals and an efficient tariff design. According to [51] numerous studies show that a high share of taxes has a strong negative impact specifically on cost-reflectiveness and fairness.

The different ways of introducing the taxes indicated in Figure 8 also exemplify the challenges of the system today. For instance, the industrial sector is typically exposed to a very low energy tax on electricity, and hence excess heat from industry without extra taxes could represent an unfair situation, leading to inefficient use of electricity, as waste heat can be sold off without penalties.

The taxes also depend on the fuel. As an example, biomass is treated as fossil-free fuel, and even in district heating applications, there are no taxes on energy produced by biomass. This seems reasonable if the biomass is produced 'this year and just outside the city', since then we are faced with a local recycling

2 A carbon dioxide equivalent or CO_2 equivalent, abbreviated as CO_2-eq is a metric measure used to compare the emissions from various greenhouse gases on the basis of their global-warming potential (GWP), by converting amounts of other gases to the equivalent amount of carbon dioxide with the same global warming

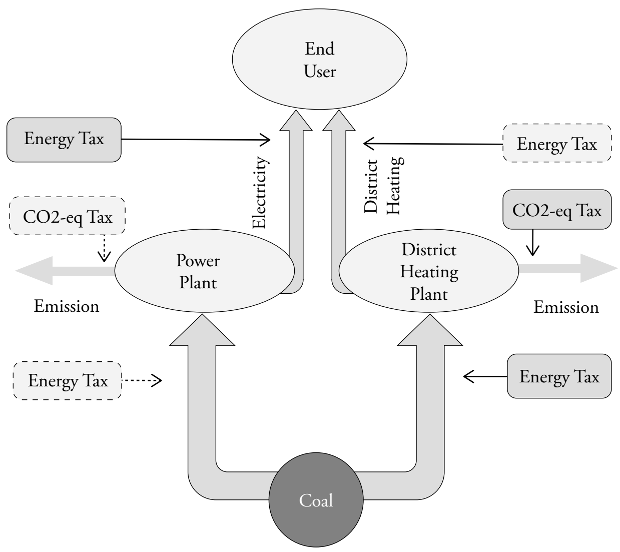

FIGURE 8: EXAMPLE ON TAXES THAT COULD BE INTRODUCED IN CONVERTING COAL TO EITHER ELECTRICITY OR HEAT. THE SOLID LINE BOXES SHOW THE TAXES USED TODAY, WHEREAS THE DASHED LINE BOXES SHOW OTHER POSSIBILITIES FOR TAXATION.

of the CO_2. However, if the biomass is 100 years old trees, imported from overseas, then it is reasonable to consider it partly as fossil-based fuel. As another extreme, biogas delivered by the existing natural gas pipelines is treated as fossil fuel even though it would be possible to make tax exemptions based on certificates. The fact that it is possible e.g., for the industry outside Denmark to use biogas supplied by the existing pipelines, just highlights a taxation problem that has to be solved as soon as possible. A similar paradox is seen for the transport sector, where e.g. bio-diesel is exempted from tax, while biogas is not.

Existing solutions related to green or renewable energy certificates have to be revised. For green gas, including biogas, it somehow makes sense to use green certificates, since the costs for transportation is very low, and we have an existing infrastructure in Europe for long-term storage of gas. However, for electricity a lot of efforts have revolved around renewable energy certificates (RECs), but most of these are no better than green-washing. Once electricity is produced - by a wind turbine or a coal power plan - its source can't be tracked, and when an end-user turn on a light, it is impossible to tell whether that power was generated by the wind turbine or the coal power plant. If not co-incident and co-located with usage, then taxation should be conducted accordingly since for electricity storage options are limited and expensive, and hence timing is of the essence. Some efforts have taken place on establishment of Granulated Guarantee of Origin (GGO). Sector coupling to gas storage and electricity grids would however enable storage of power, which could making offsetting of production and consumption possible at low expense, as for instance the biomassbattery [52], [53]. Some loss of energy is however to be expected in these conversions and they should thus primarily be used to balance the "hard to abate" long-term storages. Balancing of shorter fluctuations are better achieved by demand-side flexibility. If power is produced by gas then the gas storage can simply function as a virtual storage of electricity.

With the increased need for green fuel generated by PtX technologies, we need access to large amounts of biogenic / cyclic carbon for the production of e.g., methanol for transportation and for the industry (e.g., plastic production). Unfortunately, the political short-term goals for 2030 implies a focus on Carbon Capture and Storage (CCS) whereas, instead, more attention should be on Carbon Capture and Utilisation (CCU), as this will incite development of long-term applicable PtX value chains. The experience from the establishment of local value chains is much needed if Denmark has to remain competitive and be able to export PtX. The possible sector coupling between PtX and power markets for arbitrage will require access to large amounts of CO_2, and hence it is recommended to develop large scale CO_2 storage solutions in Denmark.

An ideal taxation should be linked to a penalization of the use of fossil fuels such as natural gas and coal when it is brought into the energy system, while we need to incentivize circular use of biogenic CO_2 since this is going to be a scarce resource when ramping up on PtX and the sooner value chains are in place, the more competitive Denmark will be onward. It is clear that this calls for a careful redesign of the taxation in the energy sector, and here for instance a circular view which includes a focus on the use of CO_2, will be important. The revision of the energy-related taxation in Denmark also calls for a revision of the existing favorable tax rate for electricity consumption above a certain threshold for households dominantly heated by electric sources and schemes that support the use of roof-top PV, selfconsumption, and local energy communities.

Today curtailment of renewable energy is substantial, and this holds for both wind and solar energy. Curtailment is taking place both operationally (e.g., by the TSO) as well as due to the existing sub-optimal rules in the regulatory settings. As an example, we can mention that the maximum production for private wind turbines is 15 kW despite the fact that many turbines can produce much more. Also, rooftop PV production is often curtailed, and it is not allowed to share the power with the neighbours. We need a regulatory setting that can support local energy communities that can optimize self-consumption. Given a proper regulatory design, this would also help resolve grid challenges.

However, the main problem is that taxes are typically rigid or constant, and this is blunting relevant price signals from the market or the network. For instance, for ordinary households, the tax (incl. VAT) represents a large fraction (approx. 60 pct in Denmark) of the electricity price. Even with the suggested revision of the markets and the tariffs, the current electricity tax is so high that the proper system and market-related signals from new markets and tariffs are almost hidden and the incentives for being flexible are almost nonexistent today. A study of tariffs and taxes in Europe ([51]) confirms this by concluding that a main outstanding issue across Europe is the weight taxes take on the electricity bill.

12.2. A TAXATION DESIGN FOR INCENTIVIZING DEMAND-SIDE FLEXIBILITY

Due to the complexity outlined above we will now describe a solution, where the main purpose is to incentivize demandside flexibility. The solution can be considered as a stepping stone towards a more permanent solution which accounts for the complexity outlined regarding the biomass, biogas, the need for CO_2 for PtX, etc.

The energy crisis in 2022 has shown that people are willing and able to react and avoid periods with high prices. Now in 2023 many automatic or semi-automatic smart solutions for rescheduling the load to periods with low electricity prices have been developed.

Previously in Section 2, it was argued that demand-side flexibility enabled by digitalization and proper design of markets and tariffs could lead to huge savings in infrastructure investments and balancing costs. Similarly, it is shown e.g., in the CITIES project [10] that a proper design of dynamic GHG taxes could lead to up to 50% savings of the greenhouse gas (GHG) emission.

As a part of the CITIES project [10] a National Task Force Committee[3] suggested to redesign the energy taxes such that the consumers are motivated to use more energy when it is green and subsequently less when it is black. Consequently, it is recommended that part of the electricity taxes is scaled according to the specific CO_2 emissions per hour to accelerate the development of solutions for flexibility.

The main principles are:

1. The taxes are linked to the physical conditions.
2. The taxes are linked to the current geographical and temporal variation in CO_2-eq emissions.
3. The taxes are harmonized between the forms of energy.
4. Taxes are harmonized between forms of consumption.
5. The taxes are designed with *a fixed part*, which provides an incentive for *energy efficiency*, and a *variable part*, which provides an incentive for *energy flexibility*.
6. The fixed and variable parts can be scaled so that a desired revenue is achieved; for example, they can be designed such that they are revenue-neutral; but this is a political decision.

See [10] for more information.

The taxation of industrial customers is, in general, lower than for households across Europe, in an effort to keep the industry competitive. Nordic countries like Norway and Finland stand out in this regard, offering the lowest taxes on industrial consumption.

The industry must also be motivated to become flexible, energy efficient and, where it makes sense, also electrified. The aim is to accelerate the green transition in the industry, through a gradual introduction of CO_2 taxes. This requires international support. In a Danish context, the CITIES task force suggested

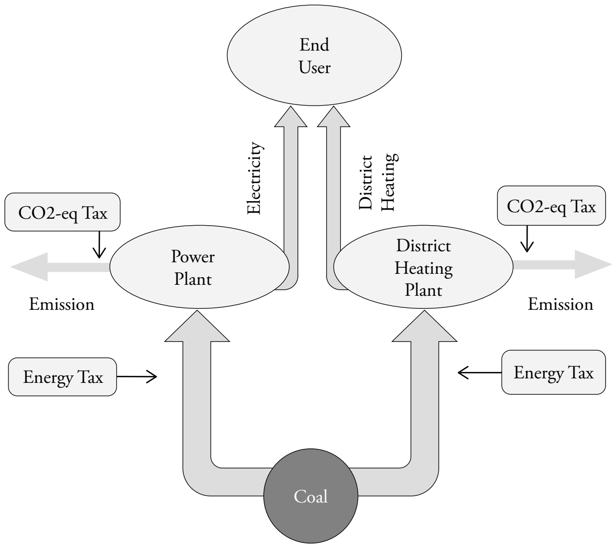

FIGURE 9: ILLUSTRATION OF THE EXAMPLE SOLUTION FOR A STRUCTURE FOR ENERGY SYSTEM TAXES. HERE THE IS AN ENERGY TAX ON THE FUELS WHEN THEY ENTER THE ENERGY SYSTEM, AND A TAX ON EMISSIONS RELATED TO THE FUEL TO ENERGY CONVERSION.

establishing a scheme where these taxes are paid to a fund, which aims to support a transformation of the industry towards being flexible, efficient and electrified. To avoid carbon leakage the outlined principles for CO_2 taxes are designed to allow for a later extension to include life cycle analysis and CO_2-eq total accounting. For example, the life-time CO_2 load for a building will consist of a load which is due to the materials (including the ongoing renovations), as well as a load that is due to the current energy consumption.

Similarly, the costs and emissions related to waste incineration should also be revised. This should include Scope 3 emissions[4] and e.g., the carbon cycles related to waste handling.

12.3. EXAMPLE SOLUTION

Here we present a concrete example solution, that satisfies 1)-6) in the list from the CITIES Task Force, in a simple manner. This solution would put energy taxes directly on the fossil fuels while CO_2 taxes are put on the CO_2-emissions as illustrated in Fig. 9. This ensures that CO_2 taxes are only levied on actual emissions, since this is what physically drives climate change. The energy taxes have to be put on the fuels, to encourage reducing the amount of the fossil fuel that is consumed. This satisfies 1)-4) by harmonizing forms of production and consumption, while linking everything directly to physics. 5) could be satisfied since putting a fixed tax on all fuels encourages energy efficien-

3 Task Force Committee consisted of representatives from: Danfoss, Danish Technological Institute, Grundfos, Ørsted, Green Energy, Tomorrow, Aalborg University, and the Technical University of Denmark

4 The GHG Protocol Corporate Standard classifies GHG emissions into three 'scopes'. Scope 1 emissions are direct emissions from owned or controlled sources. Scope 2 emissions are indirect emissions from the generation of purchased energy. Scope 3 emissions are all indirect emissions (not included in scope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions.

cy, while the CO_2-tax varies with CO_2-intensity, and thus is variable, encouraging energy flexibility.

We will, however, suggest to put the energy tax on fossil fuels only to ensure that green fuels, e.g. from PtX, are competitive on the markets. Lastly, as explained in 6), the fuel-tax and CO_2-tax can be balanced, to strike the right balance between energy efficiency and flexibility, while the overall size of taxes can be chosen as to achieve the desired revenue. Notice that taxes could even be negative at times if one wishes the revenue to be zero. We also suggest to consider the solutions outlined for the industry in order to ensure that the industry is competitive also in the future.

Trade in electricity between EU member states and countries in the EU's close vicinity is gaining in importance, and the post-pandemic energy crisis has made it even more significant. Using real-time tools for finding the current CO_2 content of the cross-border electricity flows will be needed, and here tools like Electricity Map [54] can be used. This tool shows live CO_2 data (measured in gCO_2-eq/kWh) including carbon intensity of both import and export.

13. CONCLUSION

This paper describes the challenges, methodologies and benefits for activating demand-side flexibility for an efficient transition to the fossil-free society. It is highlighted that demand-side flexibility in combination with digital technologies and controllers that harness it, can be seamlessly forecasted and activated to readily serve the needs of both the local distribution system and the macroscopic power system.

Investments in expansions of the electricity grids are considerable and unavoidable. However, it is estimated that demandside flexibility can lead to large savings (between 27% to 80%) of today's forecasted investment needs until 2030 for low- and medium voltage grids. Similar large savings are reported for the balancing costs. A prerequisite for a successful implementation of methods for activating demand-side flexibility is that tariffs are linked to the actual operational costs.

Furthermore, we need dynamic taxes that are linked to the CO_2-eq emission within the hour and the use of fossil fuel. Energy taxes should dynamically be on the fuel consumption, and ideally green fuel should be exempted from taxes.

The optimal solution is tariffs and taxes that are linked to the physics. The methodologies described for enabling dynamic tariffs and taxes will successfully pave the way for a plethora of solutions for activating demand-side flexibility at scale.

The solutions outline for the taxes can be considered as a stepping stone towards a solution incentivizing flexibility for the weather-driven energy system. For the future fossil-free society the tax structure must also reconsider CO_2 recycling, biomass, biogas, and Scope 3 emissions. It is important to incentivize recycling of carbon, which will be needed for the production of green fuel at the future PtX plants.

Demand-side flexibility solutions rely on digitalization of the energy grids. In this paper methods for digitalization of the energy grids and data-driven methods are described. It is argued that we need interoperability mechanisms for connecting different flexible assets (smart buildings, supermarkets, wastewater treatment plants, PtX plants, etc.) to the grids and markets. The suggested methodologies imply that the end-user flexibility can be offered in a multi-level hierarchical control for solving essentially all grid and balancing problems. The suggested interoperability mechanisms allow for sector coupling, which drastically increases the flexibility potential.

We need a regulatory framework which supports an affordable, fair, reliable and fast transition to the weather-driven energy system, and most importantly we need dynamic tariffs that are just high enough to solve the issues in space and time. The tariffs should be linked to the physics, and a methodology is described for linking the dynamics of the physical assets to the electricity markets.

For the taxes, an important step forward would be the outline dynamic energy taxes that motivates use of energy when it is green and penalizes use of energy when it is black. The combined approach for dynamic tariffs and taxes is simply a broadcast of price-signals. The procedure ensures that the consumers are in control and in the center. The simplicity is also an important precondition for transparency and trust.

14. ACKNOWLEDGMENTS

This work is supported by *Nordic Market Based Balancing System* (Energy Cluster Denmark), *SEM4Cities* (Innovation Fund Denmark, No. 0143-0004), *Sustainable plus energy neighbourhoods (syn.ikia)* (H2020 No. 869918), *ELEXIA* (Horizon Europe No. 101075656), *IEA EBC - Annex 81 - Data-Driven Smart Buildings* (EUDP Project No. 64019-0539), *IEA EBC - Annex 82 - Energy Flexible Buildings Towards Resilient Low Carbon Energy Systems* (EUDP Project No. 64020-2131), *IEA HTP Annex - IoT Annex - Digitalization and IoT for Heat Pumps* (EUDP Project No. 64020-2071), and the project PtX, *Sector Coupling* and LCA, which is a part of the Danish Mission Green Fuel portfolio of projects.

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The role of implicit and explicit economic signals for flexibility provision by EV aggregates: technical evidence and policy recommendations

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ABSTRACT

The diffusion of electric vehicles (EVs) is a key for transport sector decarbonization. This raises concerns on compatibility between EVs and power networks. This work presents a comprehensive analysis of impacts and benefits of EV diffusion on a national power system, i.e., Italy. Demand and flexibility profiles are estimated. Distribution network planning and power system dispatching are encompassed. Results show that spread of EVs will have localized impacts on power and voltage limits on the distribution network, while consequences on transmission grids and dispatching would be negligible, in terms of power and energy demand. To exploit flexibility from EVs and turn a potential issue into a resource, we propose a set of regulatory and policy advices for promoting a better vehicle-grid integration.

KEYWORDS: Smart charging, electric vehicles, dispatching, distribution network, flexibility, tariff

1. INTRODUCTION

Electric Vehicles (EV) are constantly increasing their penetration in the transport sector [1]. In EU, decarbonization of transports via electric mobility is considered one of the most effective and efficient ways of achieving the targets of EU Green Deal and Fit for 55 [2]. In any case, many EVs connected to the grid and withdrawing power can challenge the secure operation of power systems [3], [4]. Some argue that EV charging can contribute, for instance, to increase the steepness of the duck curve and enhance evening peak of power demand [5] or to jeopardize some assets in distribution networks, violating the power or voltage profiles thresholds [6]. To mitigate the conflict between EVs and the grid, the development of methodologies and best practices for Vehicle-Grid Integration (VGI) becomes fundamental [7]. VGI includes: the implementation of charging routines, often referred to as smart charging and including monodirectional (V1G) and bidirectional (V2G) techniques for providing flexibility that responds to different needs [8], [9]; the deployment of hardware that can offer local synergies by coordinating with charging, for instance photovoltaic (PV) systems or energy storage systems (ESS). In both cases, the VGI solutions can imply additional costs, e.g., for advanced EV supply equipment (EVSE) able to modulate or revert power flow or for the PV and ESS installation. To create an interest towards the (massive) adoption of VGI techniques, the regulation and policymaking should consider measures for enabling flexibility provision and increase its economic convenience [10], [11]. These measures can include allowing the participation of EV to flexibility markets, tariff discounts for the users implementing VGI, reductions of connection fees for promoting innovative EVSE layouts.

This work will first summarize a previous study on the impact of EVs on Italian power system in 2030 without and with VGI, also considering the results of a previous study [12] (Chapter 2). Then, it will extend on an analysis of the regulatory framework to enable VGI, also describing a list of inherent policy proposals (Chapter 3).

2. THE ITALIAN CASE STUDY: ANALYSIS OF EV IMPACTS IN 2030

The study "Integration of vehicles and electricity networks: challenges and opportunities leading up to 2030" [12] evaluates the impact of a massive EVs diffusion on the Italian power system and quantifies the benefits coming from vehicle-grid integration on both distribution network (DN) development costs and expenses linked to power system dispatching. The first step consisted in the definition of the most important hypotheses about the Italian 2030 scenario, concerning both power system consistency and EVs diffusion along the country. The estimated EV penetration and power system portfolio are presented in Figure 1. They come from an extensive analysis on national plans and targets (such as Italian NECP [13] and the targets of Fit for 55). Even if more than a scenario was analysed, an accelerated scenario coherent with Fit for 55 is presented and adopted in this work. For this work, Metropolitan Area considers all the population and EVs located in cities with >100k inhabitants. Rural Area considers the remainder.

Electricity budget (TWh)	
Total electricity demand	366.0
Total domestic production	322.4
RES production	243.5
Hydro	51.3
Solar	101.4
Wind	68.2
Other RES	22.6
Overgeneration	2.1
Total fossil production	81
Thermoelectric	76.7
Other non RES	4.3
Foreign balance (net import)	48.1

ACCELERATED SCENARIO

Coherent with Fit For 55

[M EV]	Metropolitan area	Rural area	Total
BEV	1.34	4.96	6.3
PHEV	0.25	0.95	1.2

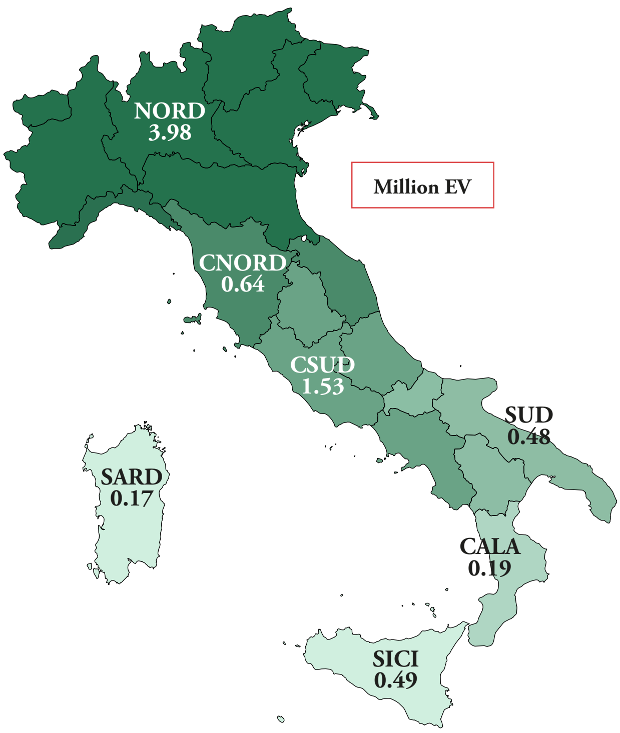

FIGURE 1 POWER SYSTEM SCENARIO (TOP), EV PENETRATION SCENARIO (MIDDLE) AND EV DISTRIBUTION IN ITALIAN MARKET ZONES (BOTTOM) COHERENT WITH FIT FOR 55 [12].

A detailed framework has been developed to classify and characterize the different EV charging modes, including passenger cars, goods and public transportation. Moving from this, EV power charging profiles, together with the corresponding available upward and downward flexibility, have been calculated through a Monte Carlo procedure that simulated the single EV charging episode. The outcome consisted in a specific hourly charging and flexibility profile, defined over a daily horizon, for each charging mode within every market zone, and distinguishing between working days and holidays, warm and cold days, metropolitan and rural areas. Therefore, it was possible to estimate the impact of EV charging on both distribution networks and power system dispatching costs. Concerning the former, a Monte Carlo procedure simulating the EV charging process in 12 different typical days was applied on an archetype of both a metropolitan and a rural distribution network. The outcome consisted in the expected active and reactive power flows along the DN, allowing an estimation of both overloading and voltage fluctuations. For the dispatching costs, a market simulation tool, including both the day-ahead and the balancing market clearing, was exploited to assess the unit commitment, the power system constraints, the exchange of flexibility services and the final dispatching costs. The tool works with hourly resolution, thus allowing a detailed computation of all power system dispatching variables. Finally, VGI practices were included in both distribution and transmission networks management, consisting in the possibility to control the charging power (V1G and V2G), the utilization of battery storage systems coupled with power charging stations, and the maximization of the local nonprogrammable RES (NP-RES) self-consumption for EV charging purposes.

2.1. THE CHARGING MODES: ESTIMATING POWER PROFILES AND FLEXIBILITY

The performed study analyses EV charging from a system perspective. Indeed, EVs are not considered per se, yet they are grouped in a set of charging modes [4], [14], [15]. These are considered representative of most charging events in a mature market. Each charging mode has been characterized with stop duration, with state-of-charge (SoC) ranges of connected EV, with power ranges of EVSE, and with V2G penetration as can be seen in Table 1.

TABLE 1 CHARGING MODES DESCRIPTION [12].

Icon	Charging mode	Stop duration	Range of initial – Final SoC (%)	EVSE charging power (kW)	V2G penetration
	Residential	Long (> 10 hours)	30-60/80-100	3-6	0%
	Workplace	Employees: 8 hours Fleet: > 10 hours	30-70/80-100	7-22	30%
	Public – slow	Medium (3 hours)	10-40/50-80	22-50	20%
	Public – fast	Stop & go (<< 1 hour)	20-50/50-80	50-300	0%
	B2C – shopping centre	Short (1 hour)	30-70/40-100	22-50	20%
	B2C – interchange parking	Long (6 hours)	30-70/100-100	7-22	20%
	Light commercial vehicle (LCV)	Medium (4 hours)	40-70/60-100	22-150	50%
	Heavy commercial vehicle (HCV)	Long (6 hours)	10-40/80-100	22-150	50%
	Public transport (LPT)	Long (6 hours)	10-20/90-100	22-150	50%

Considering the previously mentioned procedure, the power profiles of each charging mode in 12 typical days have been estimated via a Monte Carlo approach. This is coherent with the stop starting and ending time and with the typical initial and target SoC of connected EVs. Indeed, when an EV stops, it starts charging at the maximum available power (considering both EV and EVSE rated powers) until it reaches its target SoC. Then, it keeps connected until the end of stop without charging. The obtained power profiles, referring to the EV aggregate in Italy for each charging mode, are presented in Figure 2. Then, flexibility is estimated considering the energy and power contents that are compatible with a SoC equal or larger than target SoC at the end of the stop. The shaded area in Figure 2 represent the flexibility: the EV charging can be slowed down to the bottom of orange area (upward regulation) or enhanced to the top of blue area (downward service). The substantial weight of some charging modes is highlighted (residential, workplace and LCV). For what concerns flexibility, it is in principle larger where longer stops are foreseen (residential, workplace, B2C – parking, LCV and HCV).

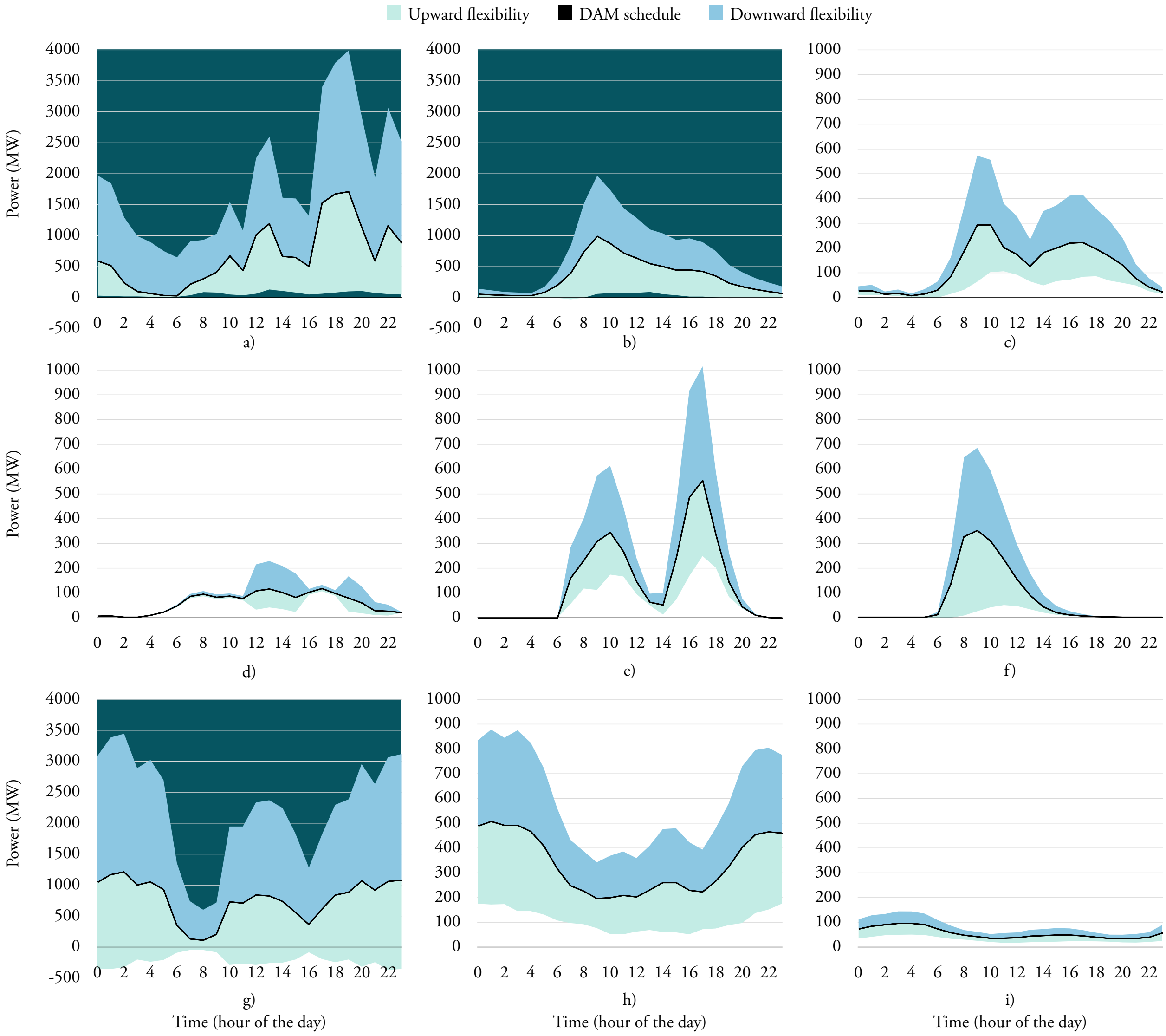

FIGURE 2 DAY-AHEAD SCHEDULE AND FLEXIBILITY PROFILES FOR EACH CHARGING MODE: A) RESIDENTIAL, B) WORK, C) PUBLIC SLOW, D) PUBLIC FAST, E) B2C - MALL, F) B2C - PARKING, G) LCV, H) HCV, I) LPT. PROFILES SHADED IN YELLOW HAVE A LARGER SCALE ON THE Y-AXIS [12].

Summing the charging profiles of each mode, the overall withdrawal of Italian EV fleet in 2030 in a typical day is shown in Figure 3. In this dumb charging scenario, a daytime and an evening peak can be seen. The daytime peak is given by the superposition of the "daytime" charging modes: workplace, public, B2C, and LCV charging. The evening peak is mainly due to "end of business" charging modes: residential and LCV. The provision of flexibility could, for instance, help smoothing this profile or shaving the evening peak, that appears to be the most critical for the power system.

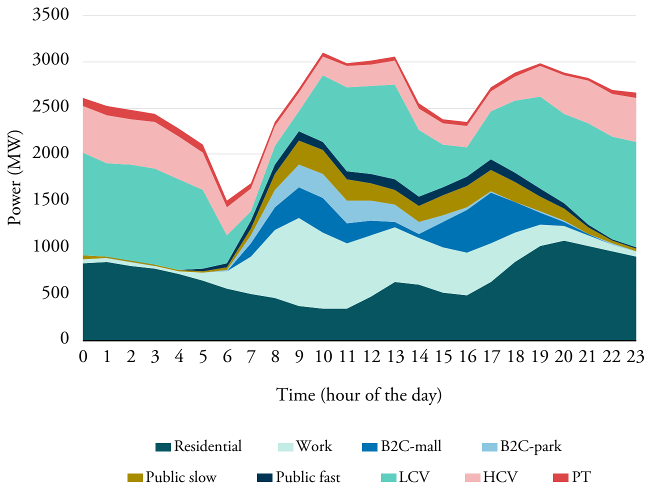

FIGURE 3 POWER DEMAND OF DUMB EV CHARGING AT THE ITALIAN SYSTEM LEVEL IN A WORKING, WINTER DAY.

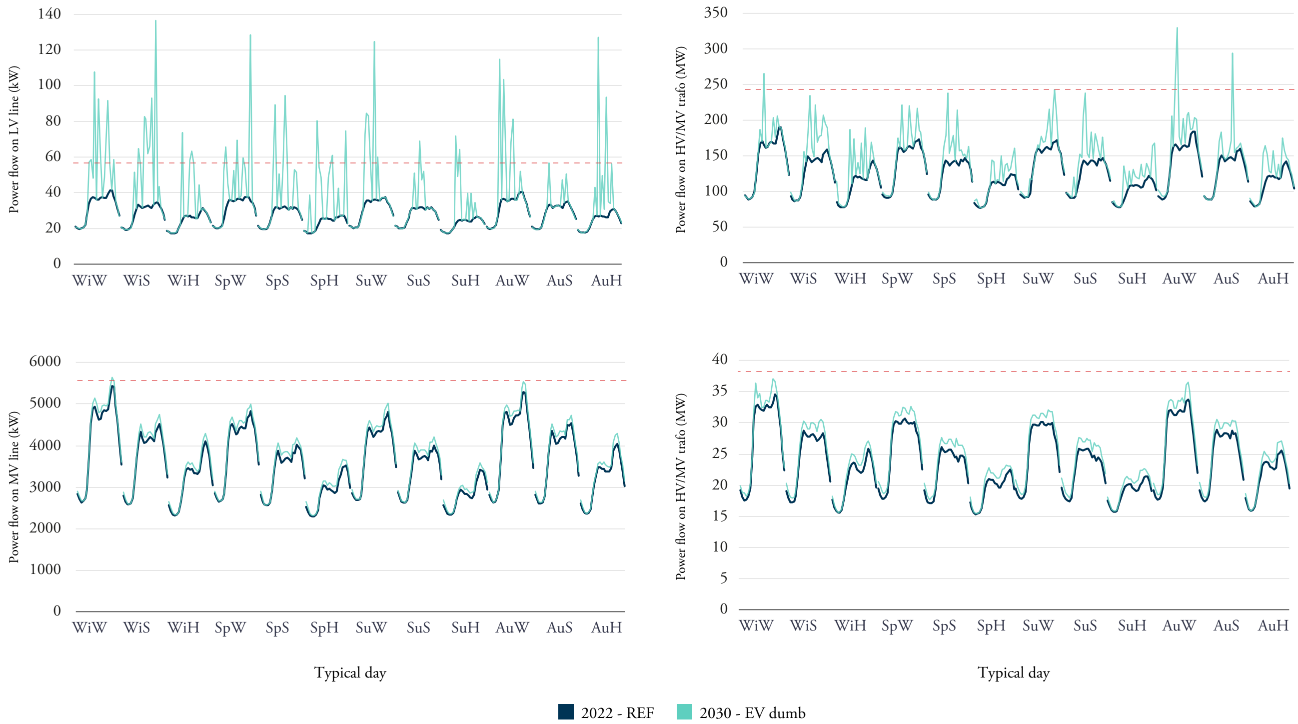

FIGURE 4 EVOLUTION OF POWER PROFILES FOR THE DIFFERENT GRID COMPONENTS IN A RURAL AREA, IN THE REFERENCE YEAR (2023) AND IN THE STUDIED SCENARIO (2030). THE RED DOTTED LINE INDICATES THE THRESHOLDS OF EACH NETWORK COMPONENT [12].

2.2. THE IMPACT OF DUMB CHARGING ON DISTRIBUTION NETWORK AND DISPATCHING COSTS

To assess the possible impact of EV charging on distribution network, power flow analyses have been carried out on two representative networks: a rural and a metropolitan network. They are retrieved from a previous study by Ricerca sul Sistema Energetico (RSE)[1] on the evolution of Italian MV grid [16]. Rural network is characterized by 228 MV nodes, 1371 LV nodes and an MV grid length of 192 kms, while metropolitan network holds 178 MV nodes, 2575 LV nodes and 44 kms of MV grid length. Thus, the metropolitan network shows much higher load density. The EVs located in each network are proportional to the EV scenarios shown in Figure 1, respectively considering rural and metropolitan area.

Figure 4 and Figure 5 show the issues related to EV penetration respectively on power and voltage profiles in distribution networks. Twelve representative days are considered, spanning the four seasons (Wi = winter, Sp = spring, Su = summer, Au = autumn) and the typical weekdays (W = working days, S = Saturdays, H = holidays). Rural network is shown, but metropolitan network presents similar results for power profiles, while it shows lower fluctuations for voltage profiles. Low voltage lines suffer because of spatial and temporal clustering of EVs charging episodes, that cause violations with a short duration but great intensity. The overlapping between vehicles' charging and the base load, especially in the evening, causes violations with a lower magnitude but a longer duration along medium voltage lines. In general, urban distribution networks show mainly problems due to lines' overloading, while rural networks present criticalities related to voltage fluctuations because of the asynchronous operations of PV plants (over-voltages) and load (under-voltages), the latter comprising EVs charging.

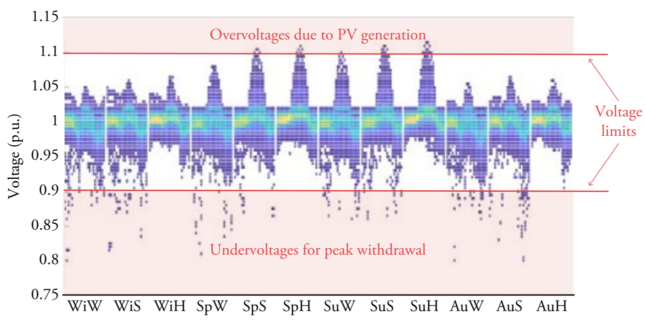

FIGURE 5 VOLTAGE PROFILES AND VIOLATIONS IN RURAL NETWORKS [12].

1 https://www.rse-web.it

Power system dispatching in 2030 has been modelled using two proprietary tools: PROMEDGRID [17], simulating the DAM dispatching, and the Market Operation and DISpatching (MODIS) tool [18], both by CESI[2]. The tools solve a security constrained unit commitment (SCUC) problem with a deterministic optimization approach minimizing the total costs sustained by the system operator to balance the power system and keep it secure. Such a problem is formulated as a Mixed Integer Linear Programming (MILP), exploiting Gurobi as a solver[3].

Considering power system dispatching costs, the impact of EVs charging on total energy demand and on system peak load is negligible, being respectively equal to 4% and 5% as presented in Figure 6. The main issue is related to the higher uncertainty that EVs charging introduces with respect to the forecast of the power demand profile; however, while implying the need for greater power reserves, the resulting impact on dispatching costs is negligible.

WEIGHTING FACTOR OF EV CHARGING ON TOTAL(2030):

ENERGY DEMAND

15.5 TWh

of the Italian system's
366 TWh
(4.2%)

PEAK DEMAND

3.1 GW

on the Italian system peak of
approx 60 GW
(5.2%)

FIGURE 6 IMPACT OF EVS ON ITALIAN SYSTEM CONSIDERING ENERGY AND PEAK DEMAND [12].

Table 2 summarizes the most important impacts of EVs charging emerging from the simulation, distinguishing between distribution network and power system dispatch contexts.

TABLE 2 IMPACTS OF EV CHARGING.

Impacts on distribution network development costs	Violations with short duration (some minutes) but high intensity on LV lines, well distributed during the daytime and mostly linked to fast charging
	Violations with good duration (>30 min) and low intensity on MV lines, mainly due to EVs charging and base load overlapping during the evening
	Urban areas characterized by over-loading phenomena (short lines + high load density), while rural areas interested by voltage fluctuations (long lines + major PV penetration)
Impacts on power system dispatching expenses	Poor impact on total system demand (+4%) and peak load (+5%)
	Negligible impact on dispatching costs because the uncertainty linked to EVs charging is anyhow much lower than that of NP-RES production

2.3. VEHICLE-GRID INTEGRATION: THE BENEFIT OF EV PARTICIPATION TO SYSTEM REGULATION

VGI techniques are then implemented to simulate a scenario that includes smart charging and asset implementation. Figure 7 represents the smart charging techniques implemented and the deployed assets. Residential smart charging performs evening peak shaving (see also Figure 8). Workplace smart charging performs valley filling during daytime. The deployment of ESS is aimed to decrease and stabilize the power withdrawal for fast charging. The deployment of diffused PV systems allows local balancing of loads during daytime.

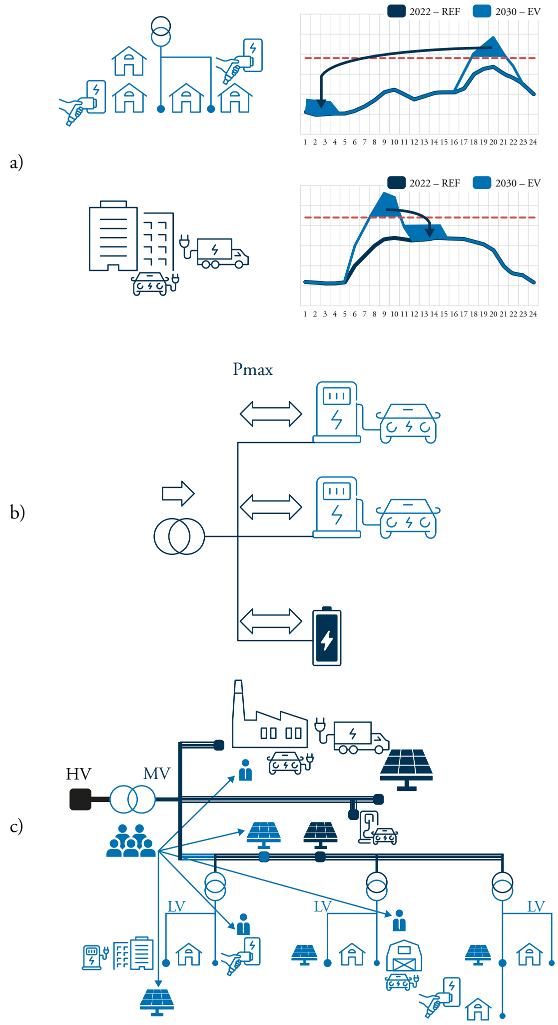

FIGURE 7 THE TECHNIQUES IMPLEMENTED FOR VGI ON DISTRIBUTION NETWORKS: A) RESIDENTIAL (TOP) AND WORKPLACE SMART CHARGING (BOTTOM); B) ESS IMPLEMENTATION; C) PV IMPLEMENTATION AND LOCAL BALANCING OF LOAD [12].

2 https://www.cesi.it
3 https://www.gurobi.com

Smart charging is implemented in the considered charging mode as a constant power charging for the whole stop duration: instead charging and the maximum available power, each EV charges at the minimum constant power allowing him to get to the desired target SoC within the end of the stop (see Figure 8).

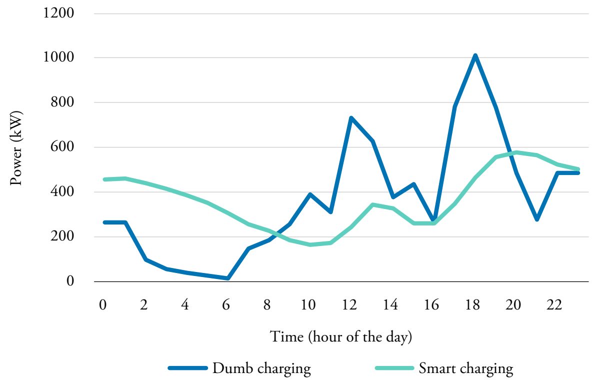

FIGURE 8 POWER PROFILES FOR DUMB (BLUE) AND SMART (GREEN) RESIDENTIAL CHARGING.

Considering distribution networks, VGI is linked to three main benefits, also summarized in Figure 9. First, demand response actions applied to EVs charging on distribution networks, and mainly driven by implicit price signals such as time-of-use charging tariffs, allow an average 13% reduction of the DN load factor. The implementation of smart charging procedures results in a general smoothing and flattening of the demand profile, that brings advantages on both the average load factor and the volume of energy during violations. Demand response is particularly important in two situations: in the first part of the evening (18:00 – 21:00) within clusters characterised by the presence of residential load; during the morning (8:00 – 11:00) where the penetration of commercial and business users is higher. In addition, demand response (including both V1G and V2G) is fruitful especially for long-duration charging, that allows a proper flexibility in the management of the charging power to both allow power modulation and reach the desired state-of-charge. Second, ESS, on the other hand, are useful when coupled with fast charging, resulting in a very high reduction of the overloading episodes (-30%). Since fast charging is characterised by short duration stops, it is typically not possible to directly modulate the charging power since it would increase charging time; the use of a BESS allows to preventively store part of the energy needed for charging the EV, thus reducing short but very high power peaks, with a great benefit especially for low voltage lines. Moreover, the lower peak power required for fast charging allows to connect to low voltage networks also charging infrastructures characterised by a high overall power (>100 kW). Finally, also the possibility to coordinate EV charging with photovoltaic production implies a great benefit for DN, reducing up to 70% the energy exchanged during violations, thanks to a reduced frequency and intensity of violation events themselves. This contingency is particularly relevant for metropolitan networks, while the long distances in rural areas make it less useful. The summary of the results for metropolitan network is shown in Figure 9. Moving from left to right in each diagram, we pass from a dumb charging situation to the implementation of VGI techniques in an additive way.

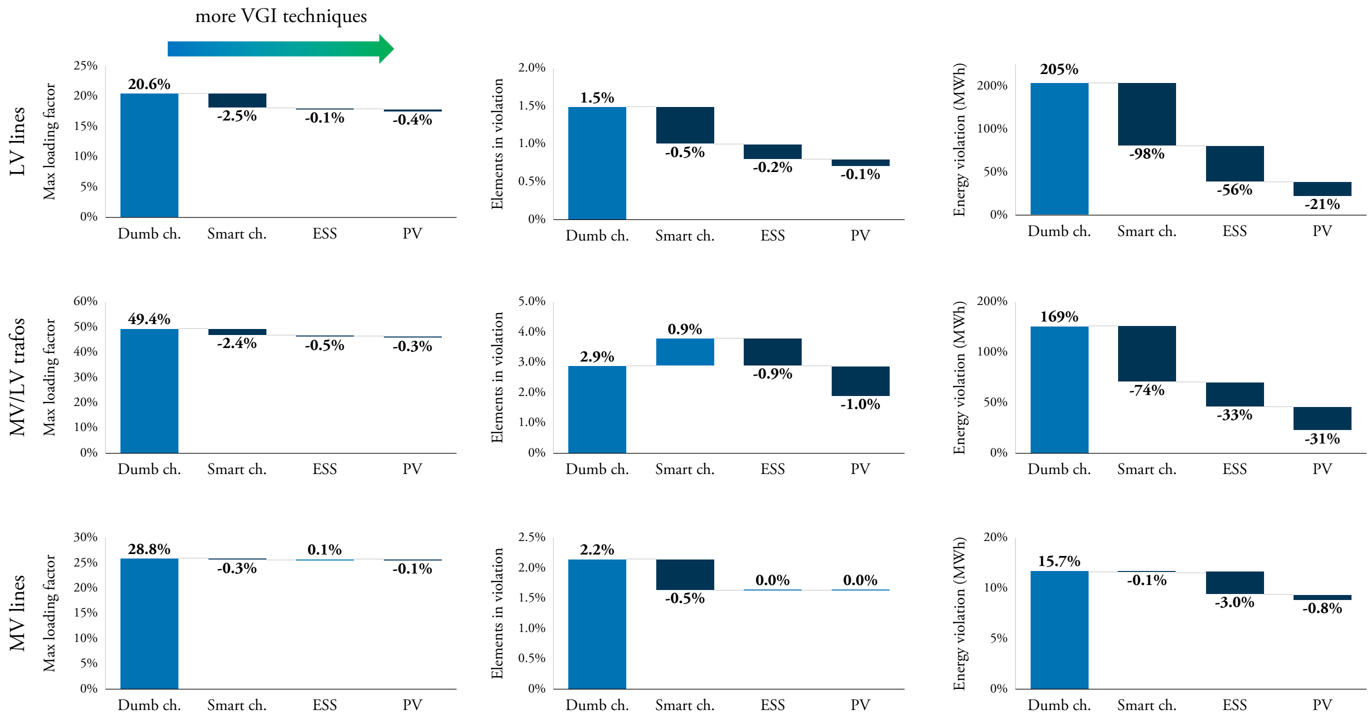

FIGURE 9 IMPACT OF VGI IMPLEMENTATION ON LV LINES (TOP), MV/LV TRANSFORMERS (MID), MV LINES (BOTTOM) FOR THE DISTRIBUTION NETWORK IN A METROPOLITAN AREA [12].

Considering power system dispatching, it is possible to individuate technical, financial, and environmental advantages coming from VGI. First, the participation of EVs to system dispatching almost halves the PV overgeneration associated with the Ancillary Services Market (ASM) scheduling phase (-2.5 TWh/y), where power reserve margins are procured. Indeed, the exploitation of the reserve margins provided by EVs unlocks those allocated on NP-RES, avoiding RES curtailment but also avoiding the obliged operations of thermoelectric units, with both economic and environmental benefits. Second, EVs aggregates play a fundamental role within the power system dispatching, providing both important reserve volumes (15% of the total) and contributing to electricity balancing (26%). The daily profile of flexibility provision is shown in Figure 10 for both scheduling (left) and balancing phase. During the scheduling phase, EVs are replacing mainly thermoelectric and ESS, especially providing downward regulation reserve; during the balancing phase, EVs contribution is very strong in the central part of the day, when they are used to absorb the excess PV production. To this purpose, long-duration charging shows a specific importance, including both nighttime deposits (private or public) and daytime parking, mainly linked to workplaces and modal exchange hubs. The great contribution from EVs to system dispatching is related to the natural predisposition of power charging profiles towards the provision of power regulation reserves, without the need to better arrange the units scheduling resulting from the DAM as it happens with thermoelectric plants.

These technical benefits result in an overall saving of 800 M€ per year linked to the dispatching activity, equal to 40% of the reference dispatching costs at 2030 (about 3 B€/y). This sums up both scheduling and balancing savings, respectively equal to -550 M€/y and -250 M€/y. In addition, the exploitation of EVs brings a big environmental advantage thanks to the displacement of thermoelectric units (-1.5 TWh/y of produced energy), with an estimated reduction of the social costs around 30 B€/y including both CO2 and other pollutants. These results are net of the EV revenues on ASM. In the original study [12], a sensitivity analysis on ASM bid prices by EV was performed, too.

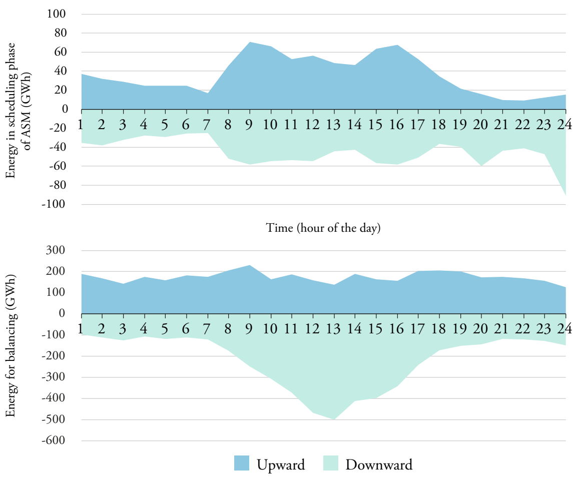

FIGURE 10 HOURLY PROFILE OF YEARLY ACTIVATED ENERGY FROM EVS ON ASM EX-ANTE (TOP) AND BM (BOTTOM). THE HEIGHT OF THE SHADED AREAS REPRESENT THE TOTAL ACTIVATED GWH IN A YEAR, WHILE THE X-AXIS POSITION REPRESENTS THE ACTIVATION HOUR IN THE DAY [12].

Results of the conducted analysis show that power grids can greatly benefit from VGI practices implementation. Table 3 reports the main outcomes of the simulations for both distribution networks and power system dispatching.

TABLE 3 BENEFIT OF VGI.

Benefits on distribution network development costs	Smart charging (V1G and V2G) practices reduce the network load factor by 13% on average, with a specific advantage during morning and evening load peaks
	BESS coupled with fast and ultra-fast charging reduce the number of overloading violations, especially on low voltage lines
	The coordinated exploitation of NP-RES production for EVs charging reduces the overloading and voltage fluctuations issues
Benefits on power system dispatching expenses	Enabling EVs to system dispatching avoids the start-up of thermoelectric units and the curtailment of NP-RES during the ASM ex-ante phase, reducing the corresponding over-generation by 2.5 TWh/y (45% of the ASM-related overgeneration)
	EVs contribute to system dispatching is relevant both ex-ante and in real time, with: 15% of total power reserves allocated on EVs (6% of upward ones, 21% of downward ones); 9 TWh/y of regulating energy provided by EVs over a total of 15 TWh/y (4 TWh/y upward and 5 TW/y downward)

3. HOW TO ENABLE VGI? PROPOSALS FOR A NEW POLICY AND REGULATORY FRAMEWORK

It is clear that the contribution coming from EVs to power system adequacy and security could be very relevant if VGI is properly and diffusely exploited. Evidence collected from the presented study allow us to draw some relevant policy implications. These could be tackled within an overarching framework that considers two layers.

- First, flexibility actions put in place by EVs charging managers should be driven by some economic signals. The EV charging cost can be influenced in two ways: implicit economic signals assume that the final user undergoes a certain charging price structure that pushes him to modify its charging profile; explicit economic signals remunerate the final user for the provision of flexibility services that he was available to provide, typically through some market mechanism.

- Second, the activation and usefulness of flexibility actions is strongly correlated to temporal and locational dimensions. Both refer to how much and how well we can transfer a certain economic signal to the final user: the former concerns the importance of time in this transfer, the latter regards the relevance of the spatial dimension.

Based on this, we present a policy intervention matrix that correlates the two layers cited above. Along the rows, proposals are distinguished based on their impact on the temporal or spatial dimensions of the problem; along the columns, they are classified based on their exploitation of implicit or explicit economic signals. Each action is firstly described and then assessed in terms of its impact on the final users, considering the charging modes mostly involved, and estimating the public expense possibly needed to support it. All the items of Table 4 are better described in the following paragraphs, where both a theoretical explanation of the mechanism and a possible estimation of the results applying it to the Italian system are presented.

TABLE 4 POLICY INTERVENTION MATRIX

	Implicit price signals	Explicit price signals
Temporal dimension	Time-of-Use charging tariffs	Short-term balancing auctions
Locational dimension	Smart connection procedures Renewable energy sharing	Non-firm connections Promotion of aggregated flexibility

3.1. TIME-OF-USE CHARGING TARIFFS

Time-of-use pricing consists in a set of price-based signals, merging within the overall charging tariff, that aim at indirectly influencing the charging behaviour of the EV user. The flexibility action resulting from this implicit economic signal originates from a self-dispatch of the final user, that responds to some external price variation adapting its withdrawal profile according to the most economic conditions; this kind of flexibility action is usually indicated as demand response or smart charging. Since the total charging costs depend on a set of diverse tariffs, it is possible to imagine different ways to implement ToU actions. In particular, the charging tariff can be split into three main components: the energy price, the volume-based part of grid fees, and their power-based component.

The energy price is directly linked to the retailing price, i.e., the price applied for energy consumption from the retailer that has bought it on the wholesale markets. While spot markets such as the day-ahead market and the intra-day market already have a good temporal granularity all over Europe, with products ranging from 5 to 60 minutes, it is difficult to transfer this price signal to the final user. This is due to both technical and economic constraints: from the technical point of view, a higher billing granularity entails a higher metering granularity, which can be achieved only through advanced metering systems; from the economic standpoint, limits concern the possibility of the final user to effectively and timely react to very granular price signals, that could potentially entail a too high commitment.

Grid fees are defined by the regulatory authority and usually consist into a volume-based and a power-based component. The volume component, paid in €/kWh, is depending only on the total amount of electricity consumed: if this was the only cost voice, it would make no difference to charge 50 kWh in one hour or one day. However, grid costs are mainly linked to network capacity, thus to the possibility to provide to the final user the power he requested at any time. This approach pushed DSOs to size each connection point according to the requested power, justifying the so-called fit-and-forget approach power grids development. Because of this, grid fees always have a power-based component: the final user pays a specific amount of money according to the peak power withdrawn from the network in a given period, generally a month.

ToU tariffs could be applied in a dynamic way, changing the pricing profile every day, or in a more static way, fixing some pre-defined time-bands (e.g., peak, off-peak, shoulder bands) and updating the price level on a yearly basis. The presented analysis showed that VGI advantages are mostly relevant: during nighttime, when the EV can provide power reserve margins during long-duration stops; around midday, when there is a high solar irradiation to cope with, possibly increasing the demand. Because of this, it would be possible to reduce users' tariff from 23:00 to 6:00 and from 12:00 to 15:00, to move EVs charging from evening and morning peaks to night and afternoon time. This scheme is exemplified in Figure 11, where red periods present higher tariff, while green periods present a lower one. We could act on either variable or power-based tariff components (or both). Coherently with the adopted approach, the user is disincentivized to withdraw (in terms of energy and/or power) in red periods and moves its demand towards green ones.

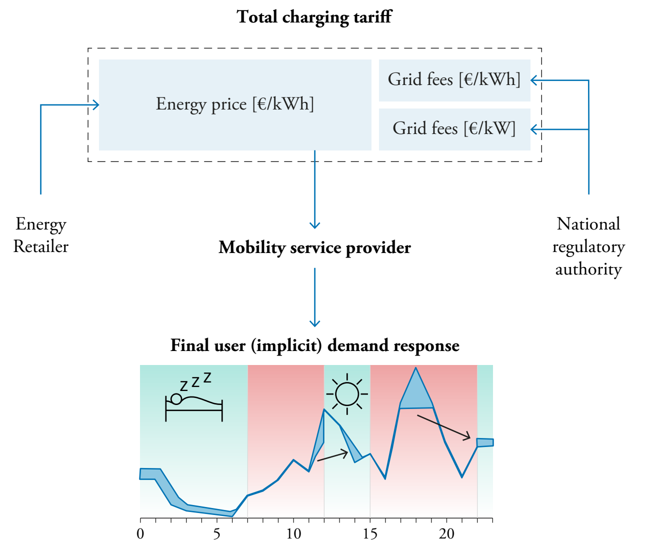

FIGURE 11 TIME-OF-USE CHARGING TARIFF APPLICATION HIGHLIGHTING ITS DIFFERENT COMPONENTS AND THE EXPECTED DEMAND RESPONSE ACTION INDUCED.

The estimation of potential reduction of variable components, including energy price and volume-based grid fees, is straightforward: specifically, a 30% reduction in the above-cited time slots of the variable component (€/kWh) of the Italian grid fees (comprising transmission, distribution and metering costs) implies an estimated volume of missing money coming from volume-based network charges paid by EVs users at 2030 around 200 M€/y (10% of total variable network charges revenues).

The ToU mechanism applied to power-based components of grid fees entails a more complex mechanism. Today, a single value in €/kW is applied: the maximum withdrawal monthly is paid at that cost. The assumption is that withdrawing power in some time bands causes larger system costs than in others. Therefore, we propose to split the day in two or more time slots, each one characterized by its maximum power withdrawal and a given power-based tariff (in €/kW); the final tariff could be calculated as the average of the tariffs weighted according to the maximum power withdrawn in each time slot. Therefore, this final tariff could be applied to the peak power withdrawn during the entire month, under the hypothesis of a monthly billing frequency. An example is provided in Box 1, where the overall power-based fee is reduced by 50%.

BOX 1 EXAMPLE OF TIME-OF-USE TARIFF USED FOR POWER-BASED GRID CHARGES, WHERE THE FINAL USER IS GRANTED WITH A LOWER PRICE IF ITS POWER WITHDRAWAL OCCURS OUTSIDE THE CRITICAL TIME BANDS.

ASSUMPTIONS:

- $tariff_{today} = 2.5$ €/kW; $tariff_{1,proposal} = 0.5$ €/kW; $tariff_{2,proposal} = 3$ €/kW;
- $P_{max,1} = 100$ kW; $P_{max,2} = 50$ kW

TOTAL:

$$\text{total charge} = 2.5\,\frac{€}{kW*month}*100\,kW = 250\,\frac{€}{month}$$

PROPOSAL:

$$\text{tariff} = \frac{0.5\frac{€}{kW}*100\,kW+3\frac{€}{kW}*50\,kW}{100\,kW+50\,kW} = 1.33\,\frac{€}{kW*50\,kW}$$

$$\text{total charge} = 1.33\frac{€}{kW}*MAX(100\,kW;\,50\,kW) = 133\,\frac{€}{month}$$

BOX 2 EXAMPLE OF A CONNECTION FEE REGRESSIVE WITH THE NUMBER OF CHARGING LOTS MADE AVAILABLE BEHIND A SINGLE POINT OF DELIVERY.

ASSUMPTIONS:

- distance fee = 200 €; power fee = 75 €/kW; EV charging point bonus = 250 €/CP
- power connection requested = 110 kW; number of charging points = 5 to 12

TOTAL:

$$\text{expense} = 200\,€ + 75\frac{€}{kW}*110\,kW = 8450\,€ \text{ constant with 5 and 12 CP}$$

PROPOSAL:

$$\text{expense} = 200\,€ + 75\frac{€}{kW}*110\,kW - 250\frac{€}{CP}*5\,PdR = 7200\,€ \text{ with 5 CPs}$$

$$\text{expense} = 200\,€ + 75\frac{€}{kW}*110\,kW - 250\frac{€}{CP}*12\,PdR = 5450\,€ \text{ with 12 CPs}$$

3.2. SMART CONNECTION PROCEDURES AND RENEWABLE ENERGY SHARING

The spatial distribution of EV charging points needs to match two locational issues: the demand of the final users and the presence (and capability) of the power grid. The interaction between these two issues influences both the design and the operation of EV charging infrastructures. The objective of the present subsection is to understand how it is possible to use some implicit economic signals to optimize the location of EV charging points and their operations with respect to the network context in which they are operated.

The location of EV charging points is driven by the structure of connection charges. The usual trade-off in tariff design is between the capability to maintain cost-reflective fees against the provision of a uniform and simple billing structure. Especially for points of delivery (PoD) dedicated only to EV charging, there is often the need to have a high connection power with a very low contemporaneity factor. For example, it is possible to request a 110-kW connection for five 22-kW EV charging points. Public EV charging points usually present a utilization rate (i.e., total energy withdrawn in a year divided by the rated power times 8760 hours) of 2-5%. Hence, it is unlikely that total contractual power is required. This results in an oversizing of the power network by the DSO and a larger connection fee for the final user. We propose to make connection charges regressive with the number of charging points. This would favor those infrastructures that make available a higher number of parking slots with the same connection power, being able to properly manage them. The example in Box 2 illustrates how this mechanism could impact on a generic EV charging hub in Italy passing from 5 to 12 parking lots associated with the charging point (CP).

Another factor influencing the location of EV charging points during the design phase is the quickness of the connection procedure, i.e., the amount of time that it takes to the DSO to grant a connection to a user requiring it. The coordination between DN development plans and power plants connection is becoming more and more relevant because of both the electrification process and the proliferation of dispersed generation. DSOs need time to reinforce or develop their networks to cope with higher peak loads and an increased penetration of non-programmable plants. A possible solution to preserve the DN security, while accelerating the connection of new resources, consists in the definition of so-called suitable areas: DSOs could exploit a specific codification to disclose towards CPOs the situation of its network, highlighting where new EVs charging infrastructures could undergo a fast connection procedure. Different solutions could be employed for this purpose: it is possible to signal only suitable areas where connection would be prioritized; it possible to indicate only non-suitable zones where connection will not be available soon; or it is even possible to utilize a more complex codification, such as a "traffic light" one, where each zone would be colored according to the connection availability and velocity. This solution, where DSOs reveal the state of their network, should involve both producers and consumers connection, promoting as much as possible their coordinated development, thus favoring the local self-consumption of renewable electricity. For this reason, it would also be necessary to foresee a regular update of the maps provided by the DSOs, beyond a periodical reporting of the situation to the National Regulatory Authority (NRA). In Italy, some DSOs already provide this kind of tool: Figure 12 reports an extract of the map available on the website of Unareti, the DSO of Milan.

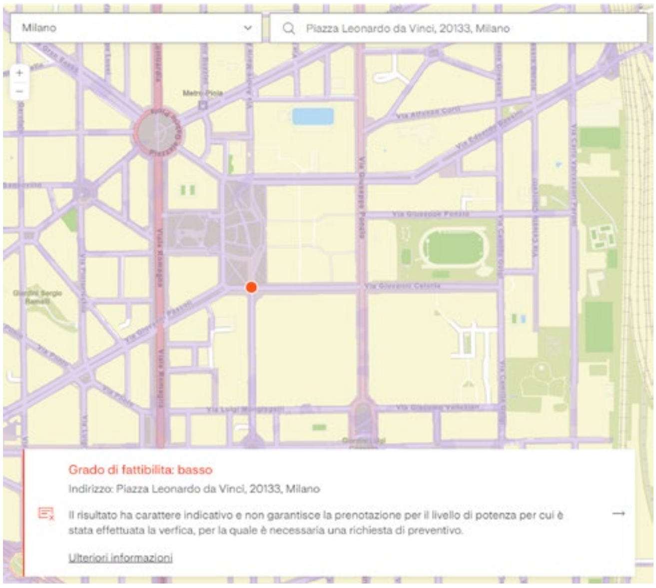

FIGURE 12 EXAMPLE OF THE INFORMATION PROVIDED BY UNARETI ABOUT THE AVAILABILITY OF A SPECIFIED CONNECTION POWER IN A ZONE OF MILAN (PIAZZA LEONARDO DA VINCI).

3.3. RENEWABLE ENERGY SHARING

The locational problem is also related to the operational phase of EVs charging points. In particular, EU Directives highlighted the role of local renewable energy sharing as a tool to promote RES diffusion properly matched with its local consumption. The fundamental principle that moves EU decarbonization is summarized in the energy "efficiency first" principle. It refers to the promotion of energy-saving solutions and to the reduction of primary energy consumption as the first mean to reach energy system decarbonization. Indeed, the exploitation of EVs is firstly a matter of energy saving, since the efficiency of an electric motor is much higher than that of an internal combustion engine. In addition, when electricity is produced by a RES power plant, this energy efficiency is maximized. Therefore, it would be possible to introduce specific incentives to promote self-consumption and sharing of renewable electricity for EVs charging. This will favor a coordinated management between NP-RES installed at MV and LV levels, and EVs charging, mainly through the exploitation of demand response and energy storage solutions. Supposing an incentive of 20 €/MWh applied only on the energy shared between a RES power plant and an EV user, the estimated incentive volume needed for Italy in 2030 is around 6 M€/y.

3.4. SHORT-TERM BALANCING AUCTIONS FOR ELECTRIC VEHICLES PARTICIPATION TO THE POWER SYSTEM BALANCING PROCESS

We now move towards explicit price signaling. The utilization of EVs within the balancing process has been demonstrated as a valuable practice. The Italian TSO historically applies a central dispatch model, where the system operator centrally controls all the steps of the balancing process, with a scheduling (ex-ante) phase holding a great importance. However, the correct exploitation of dispersed resources, such as EVs, for balancing purposes implies a migration towards a self-dispatch model. In particular, the most relevant aspects to be dealt with include:

1. the clear classification of dispatching resources in standard market products, allowing a better market liquidity and increasing the competitiveness and transparency of the balancing process;

2. the promotion of a market management based on the aggregation of different resources within heterogenous portfolios, allowing market operators to optimize their bidding and operational strategy according to the current condition of their power resources;

3. the removal of unjustified technical constraints, such as those linked to the symmetry of frequency regulation bands, the too stringent limits on the minimum balancing power that can be qualified, or an excessive balancing service provision duration requested to limited energy resources;

4. the exploitation of short-term balancing capacity auctions to cope with the higher non-programmability of the resources that will provide balancing services in the future, resorting to long-term capacity payments only as an *extrema ratio*.

Indeed, in the next years we expect a fast-paced diffusion of EVs all over Europe. This means that there will be a big variation of the available balancing capacity coming from EVs also between one year and the following one. To be able to exploit these resources, it is necessary to avoid technological lock-in that could happen if long-term capacity payment, justified by either adequacy or security concerns, are allocated to other resources, especially on fossil-fueled ones. To this purpose, while long-term energy trading, under the form of PPAs or CfDs, is a fundamental tool to cope with future energy price uncertainty, we believe that the balancing process should be kept as much as possible near real-time, utilizing short-term balancing and energy auctions to create and activate power reserves, and leaving to market operators the possibility (and responsibility) to optimally manage their resources and the corresponding imbalances.

3.5. EXPLOITATION OF NON-FIRM CONNECTIONS TO THE DISTRIBUTION NETWORK

One of the main concerns for DSOs is the obligation to be always available to grant to the final users the requested connection power, independently from the network conditions. Although being oriented towards consumers' protection, this is obviously a sub-optimal solution, that finally implies a higher burden on both DSOs' and users' shoulders, in terms of technical and financial duties. A solution consists in the exploitation of so-called non-firm connections: they entail the possibility to connect a resource to a power network without the obligation to provide the connection power at any time. This means that DSOs would have the possibility to reduce the withdrawn power whenever they verify that the grid would possibly undergo unsafe operation. The freedom for the DSO to act on the withdrawn power could be formalized in the connection contract, explicitly defining when and how this is possible, or could be managed through advanced network automations.

While this proposal seems to reduce consumers' rights, since it assigns more decisional power to DSOs, this is not necessarily the case. First, we expect that DSOs could concede in certain conditions higher peak power connection if they know that this will be limited and under their control. For example, low voltage connections could be permitted also for peak withdrawals above 100 kW. Second, the possibility to manage critical situations afterwards could accelerate the connection procedures, allowing to both mobility service providers and EVs users the possibility to access to the grid under its current potential, instead of waiting for its further expansion. It is worth noting that, in Italy, an experimentation close to the concept of non-firm connection is already ongoing. With Deliberation 541/2020[4], the Italian NRA defined for private EV charging point, the possibility to access to a non-firm connection, providing 3 kW of connection power in daytime and 6 kW in nighttime and during holidays without paying for the power increment. This is an incentive for early-EV driver, while in the future there could be a scheme allowing, for the same connection cost, to get a firm connection of n kW or a non-firm connection providing $n+\alpha$ kW all time but m hours per year (for instance, during critical hours, where the granted power would be $n-\beta$).

3.6. PROMOTION OF AGGREGATED FLEXIBILITY

New resources are distributed and small-scale, while traditional dispatching schemes and ASM are made for large-scale, centralized production units. To reach the minimum bid size, dispersed resources can be aggregated in a virtual power plant (VPP) by a Balancing Service Provider (BSP), hence working as an aggregator. The provision of flexibility in VPP is the way for enabling ASM to EVs, too. Most of the ASMs are updating their rules to welcome smaller and smaller VPPs. Some golden rules should be followed by system and market operators to ease this process and enable a larger flexibility by EVs.

- The management of the VPP as a portfolio of resources: it is not a matter for the system operator to assess the performance of each unit included in a VPP. Instead, the portfolio of resources (potentially mixed: consumption, production, and storage units) should provide the service and be remunerated. This allows a simplification for the BSP of procuring resources and financially managing the VPP.

- Connected with the first rule, the metering should not require continuous (e.g., 4 seconds) data communication from each unit in the VPP to the system operator. Instead, the system operator should prequalify the BSP based on the demonstration it can monitor, communicate, and control each unit in its VPPs, then leave to the BSP the burden of supervision and only monitor the overall performance. This allows to keep lower the costs for the units: they do not need to purchase a specific monitoring and control unit able to constantly communicate with both the BSP and the system operator, but they can agree with the BSP on the most efficient communication and control scheme.

- The aggregating perimeter should be differentiated for each service, and as large as possible. This would allow the same BSP to aggregate resources in a small portion of territory for local services (e.g., voltage regulation on DN), while including also farther resources for a global service (e.g., frequency regulation).

These indications, generally valid for all dispersed resources, are particularly important for EVs, characterized by a multitude of small delivery points on the territory featuring different communication standards.

3.7. SUMMARY AND EVALUATION OF THE PROPOSED POLICY INTERVENTIONS

Figure 13 summarizes all the policy interventions proposed above, indicates the charging modes mostly impacted by each one of them, and provides a qualitative evaluation of two most important policy issues: the associated economic burden and the implementation complexity.

Measures related to implicit economic signals show a lower implementation complexity while having a major expected financial burden. Time-of-use tariffs are already a reality in many European countries, even if their granularity is usually not so high; the main technical obstacle for their utilization is related to the presence of smart meters, able to transfer to the final user a flexible pricing profile. Moreover, as illustrated above, ToU tariffs need to cope with both regulated and non-regulated price components, entailing a possible overlapping of different price signals. A tool similar to ToU tariffs consists in specific incentives or exemptions for local energy sharing, already applied in several European countries when it comes to Renewable Energy Communities (REC) legislation. Thanks to the implicit convenience in sharing locally the excess energy produced by RES plants, distribution grids are expected to benefit from reduced phenomena linked to reverse power flows, grid losses and supply voltage variations. Finally, smart connection procedures can favor the presence of smartly managed charging infrastructures, requiring a lower connection power for the same number of charging points made available to the final users. This would reduce the impact of EVs charging on the distribution network, allowing serving the final users in a more intelligent manner.

Measures related to explicit signals do not typically entail some overcosts but are characterized by a higher implementation complexity. In particular, a complete balancing market reformation is needed if one should pass from a central to a self-dispatching model. Also, the possibility to dynamically control the maximum power available at the connection point entails direct control by the DSO at the connection point. This is possible only through updating both DSO and final users' telecommunications and control networks, according to the prescription of the Requirement for Generators Network Code (RfG NC)[5] and the System Operation Guidelines (SO GL)[6].

4 https://www.arera.it/it/docs/20/541-20.htm
5 https://www.entsoe.eu/network_codes/rfg
6 https://www.entsoe.eu/network_codes/sys-ops

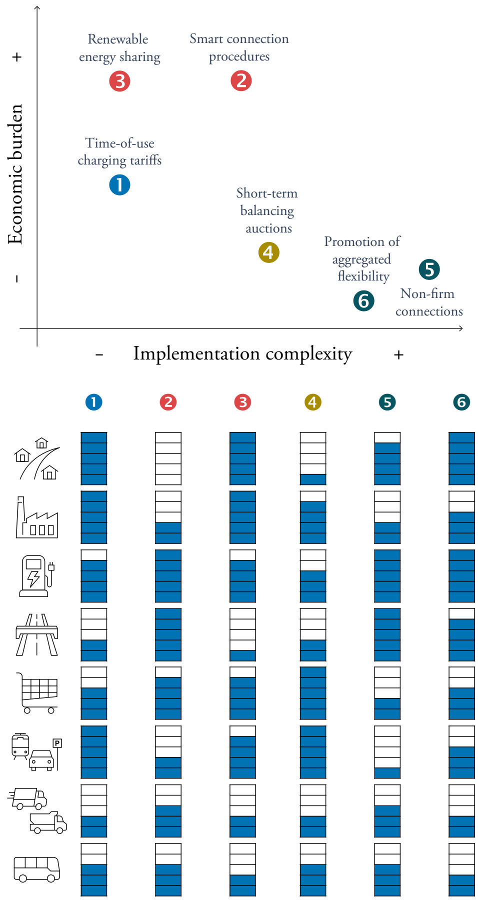

FIGURE 13 SUMMARY OF PROPOSED POLICY INTERVENTIONS AND EVALUATION OF THEIR IMPLEMENTATION COMPLEXITY, THE ASSOCIATED ECONOMIC BURDEN, AND THEIR IMPACT ON THE DIVERSE CHARGING MODES.

4. FINAL REMARKS AND CONCLUSIONS

While the presented analysis provides an clear and overarching view of the VGI technical and economic potential, there are still some specific issues that should be addressed. The most relevant ones concern the boundary conditions, consisting of both the diffusion of electric vehicles and the consistency of the power system. First, it is apparent that EVs diffusion is not depending on their potential as balancing resources for the power system; rather, it is linked to technical and financial evaluations made by citizens and varying from one country to another. The possibility to exploit EVs for VGI purposes is obviously linked to their presence. Therefore, it would be necessary to perform a sensitivity analysis on the results obtained in this study to understand the impact of a different number and/or a different spatial diffusion of circulating EVs. Second, the working operations of the power systems are mainly influenced by NP-RES installation and by the infrastructural development rather than by EVs diffusion. The advantage of VGI implementation stands in the possibility to exploit for balancing purposes something which is there with a different goal (moving people and goods around). Indeed, a myriad of portable ESS that will be connected to the grid could be worth some effort to let them be a resource for the system, instead of a burden.

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Forward-looking dynamic network tariffs: an efficient solution for price-responsive customers

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ABSTRACT

Electricity network tariffs intend to recover network costs and adhere to economic efficiency and equity principles. Most network tariffs in real-world systems focus on cost recovery, implicitly assuming non-responsive customers. This article proposes a forward-looking dynamic network tariff that could be implemented in real-world electricity systems. First, when considering the entire network, consumers and generators must be clustered into subsystems by voltage levels, enabling the calculation of the network utilization levels; this is the so-called cascade model. After, per voltage level, the network tariff needs to be computed. The forward-looking tariff consists of a peak-coincident energy charge, which is symmetric for injections and withdrawals, a per-kWh component for energy losses, and a fixed residual network charge. This tariff design incentivizes shifting flexible loads to off-peak hours and aligns individual customer incentives with expected system benefits, reducing future network investments. In addition, the symmetric nature of the proposed tariff enables a level playing field for active customers providing flexible services. The Slovenian regulator has considered the designed tariff for future implementation. This article summarizes the findings of [1] by the same authors.

KEYWORDS: Electricity tariffs, decarbonization, network tariffs, active customer response, distributed energy resources, long-term marginal costs, residual costs, electric vehicles

1. INTRODUCTION

The electricity system is witnessing a revolution with the network as the backbone guided by decarbonization, decentralization, and digitalization.

Decarbonization objectives lead countries to adopt climate actions to reduce their carbon footprint [2]. Consequently, renewable electricity generation is rapidly growing, mainly intermittent solar and wind. At the same time, decarbonization is also leading to the electrification of transport and buildings through electric vehicles (EVs) and heat pumps, respectively, increasing electric demand. Hence, network investments to connect and integrate renewable generation with supplying higher demand will increase [3].

Decentralization is putting customers at the center of the electricity system. Emerging distributed technologies, including distributed generation, energy storage facilities, and flexible demand, increase the value of having consumers coordinate their electricity usage with the wider power system [4]. In this article, active customers refer to consumers installing distributed technologies behind the meter, such as generation, storage, demand response, or others, and responding to price signals or participating actively in flexibility markets providing local or system services.

Finally, digitalization enhances customer possibilities to optimally use public electricity networks if they receive proper incentives through network tariffs. Smart-metering devices, along with information and communication technologies, are decreasing in cost and becoming ubiquitous even in low voltage (LV) metering points.

In addition to cost recovery, network tariffs should aim to establish a level playing field for all centralized and distributed connected resources, including new customers like active customers, to get the most efficient network development. Better utilization of the existing network assets, and smarter energy consumption and generation, hold great potential for cost savings. Increasing data from advanced meters enable detailed monitoring of electricity withdrawals and injections and facilitates more efficient tariffs. Once smart-meter data are available, it is required to revisit network tariffs to signal users when future network costs are foreseen.

As a consequence, in recent years, network tariff design has become a hot topic, not only in the European Union [4], [5], [6], [7] but also in the United States [8], [9], Australia [10], [11], and other parts of the world [12]. It is crucial to design electricity network tariffs adapted to the changing needs of the electricity grid, avoiding inefficient network investments, and promoting a fair distribution of costs among customers.

According to the literature, besides the recovery of network costs, network tariffs should fulfil some principles, which can be summarized in economic efficiency and equity. These two principles are usually competing with each other, meaning that an increase in economic efficiency could lead to a reduction in equity, and vice versa [4], [13].

From a theoretical point of view, if network tariffs were optimally designed, network costs would be allocated to customers in a way that the maximum social welfare would be achieved. In this context, network tariffs would perfectly reflect the underlying network costs; and since network costs are time and location-dependent, network charges would be calculated on a customer-by-customer basis and would have very fine granularity. Current network tariff designs, mainly based on flat, static and volumetric charges, are far from that first-best approach. The main reasons are: such a fine granularity requires a massive amount of data which was not available until smart meters were deployed, and customer acceptability when most of current tariff designs include social cross-subsidization.

In the last years, some countries have advocated for increasing the share of capacity-based network charges, which are more related to the main network cost driver, the network peak usage, than energy-based charges. According to [14], 13 out of the 27 Member States in the European Union had capacity charges in place in 2021. A more recent trend regarding cost allocation methods is moving towards forward-looking methodologies instead of using the historical accounting approach [15].

Under forward-looking network tariffs, the economic efficiency principle is understood as the search for the most efficient development of the existing network in the long-term. Thus, the main signal to be transmitted to network users should aim at minimizing the network long-term marginal cost (LTMC). Under LTMC methods, dating back to [16], customers are charged according to their marginal contribution to long-term network costs. Theoretically, LTMC methods can improve efficiency compared to more static cost-causality methods; they send economic signals that maximize social welfare [17]. In practice, LTMCs applied to networks are calculated as long-term incremental costs (LTICs). Some academic examples of LTIC applied to network costs are [18] and [19], a summary is provided by [20].

LTIC are determined by the network reinforcements needed in the future driven by network utilization at the peak demand periods [21]. In addition, in underutilized systems, i.e. practically all systems, this signal is not enough to recover the required network revenues. The remaining cost segment to ensure full cost recovery is defined as residual network costs [4].

Forward-looking charges reflect the costs of future network reinforcements, providing a level playing field for customers to decide whether to modify their network usage behaviour or, on the contrary, to face high network charges, in case their network usage increases network utilization at peak periods. However, the practical implementation of forward-looking tariffs in real-world systems presents some challenges.

This article proposes a forward-looking dynamic network tariff, formulated in a context of a real system, as a solution for incentivizing efficient price responses from active customers.

The total network costs to be recovered are divided into the forward-looking incremental network costs, and the residual network costs as the difference between the recognized by the regulator total network costs and the aforementioned forward-looking incremental costs, similar to [22], [23]. For allocating the forward-looking incremental network costs, dynamic forward-looking peak coincident charges are applied to signal the impact of network users' consumption or production on future network investments. Fixed and non-distortive charges are proposed to allocate residual network costs.

First, the article provides the basis for calculating the proposed tariffs with a system model representing real systems. Second, a case study illustrates the application of the proposed formulation in Slovenia. Third, the proposed tariffs are compared to two more traditional tariffs to demonstrate how they incentivize efficient technology adoption from active customers with EVs, PV installations, or participating in demand flexibility mechanisms, revealing the associated benefits.

2. FORWARD-LOOKING PEAK COINCIDENT NETWORK CHARGES

Calculating the proposed tariffs in a real electricity system involves a series of consecutive steps. The selected electricity system is schematically represented through a system-wide cascade network divided into voltage levels, where both generation and demand are connected. Network users are classified according to customer groups depending on the voltage level at which they are connected, and whether they are generators or consumers. The incremental costs for each network voltage level are calculated as the estimated annual cost growth in the following years, assuming estimated load growths. Residual network costs for each voltage level are calculated as the remaining part of the recognized network costs.

Calculated voltage level incremental costs are allocated to forward-looking peak-coincident energy charges in those hours of maximum usage of that voltage level. In contrast, residual costs are recovered through fixed charges based on the installed capacity of each customer.

Finally, energy losses costs are allocated to energy charges calculated as the contribution of each customer group to the energy flow in each network voltage level.

2.1. NETWORK MODEL AND CUSTOMER GROUPS

The adopted network model is a cascade model of hierarchically connected networks, one for each voltage level. In each voltage level, two customer groups are differentiated: 1) generation, including generators and standalone storage installations, and 2) consumption, including both regular and active customers. The proposed final tariffs are different depending on each customer group. While forward-looking peak coincident charges are applied symmetrically to both customer groups, generation, and consumption, residual charges are only applied to the consumption customer group.

Figure 1 illustrates the adopted network model, in which each voltage level takes as inputs, the flow from the generation customer group connected at that voltage level and the flow coming from the upper voltage level, and as outputs, the flow to the consumption customer group connected to that voltage level, and the flow going to the lower voltage level.

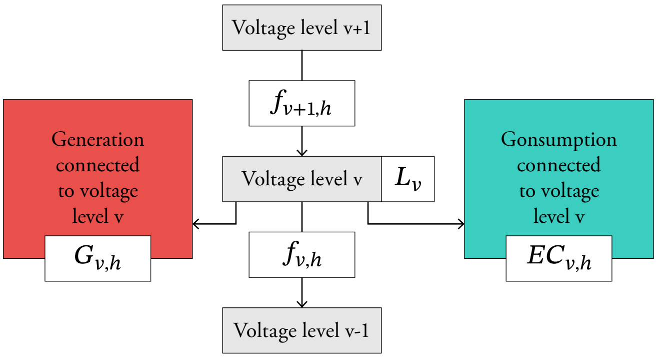

FIGURE 1. NETWORK MODEL, ENERGY FLOWS AT HOUR H, AT VOLTAGE LEVEL V [1]

The adopted network model is based on energy flows data at each hour of the year. It allows calculating the impact of a customer group increasing its generation/consumption at a certain voltage level on the network flow of another voltage level.

The incoming energy flow from the upper voltage level is calculated as the outgoing energy flow, equal to the consumption plus the flow to the lower voltage level minus the generation, and applying the voltage level's energy losses coefficient.

2.2. CALCULATION OF FORWARD-LOOKING PEAK COINCIDENT NETWORK CHARGES

The first step is the network cost segmentation by voltage levels. As an input, it is required to break down the recognized network costs, including CAPEX and OPEX, by voltage levels. Moreover, an estimation of the annual growth of the network costs by voltage level coming from network expansion plans is also required.

The second step is the calculation of the incremental cost for each voltage level as the network expansion cost from the current situation to the considered long-term future. Incremental network costs are calculated as the expected growth for network costs in the next years. Since, in general, incremental network costs would be lower than recognized network costs, residual network costs are calculated as the remaining part of the total recognized network cost.

The third step is to identify the peak hours along the year when the estimated network usage in the future will be higher than the network capacity limit, meaning that utilization of the network on those hours would trigger new network investment. For that, the current network usage is projected into the future considering the annual expected growth of the network peak demand. The number and location on time during the year of peak hours are determined as the ones where the projected network usage would exceed the network capacity limit.

The fourth step is the calculation of peak-coincident energy charges per customer group. These charges are symmetric, meaning that both customer groups, generation and consumption, should be treated equally since an increment in withdrawal has the same effect as a decrease in injection in terms of network usage. The same peak-coincident charges are calculated for injections (-) and withdrawals (+). Assuming that peak-coincident charges are positive in a demand-driven congested network zone, generators, storage facilities and active customers when injecting energy into the grid would be rewarded at the same price as would be paid by regular or active consumers when withdrawing energy from the grid. The opposite would happen if peak-coincident charges are negative in a generation-driven congested zone. Incremental network costs associated with each voltage level are allocated to each customer group, connected to the same or different voltage level, proportionally to the corresponding power transfer distribution factor (PTDF) that relates flows and injections in the network multiplied by the energy withdrawn or injected by the considered customer group. The peak-coincident energy charges for a customer group at each peak hour of the year are calculated as the sum of costs allocated to that group, coming from the same and upper voltage levels where the customer group is connected according to the cascade network model.

The detailed mathematical formulation of all the previous steps for the calculation of the forward-looking peak coincident energy charges can be consulted in [1].

For the sake of illustration, Figure 2 shows the calculated peak coincident energy charges for customer groups connected to different voltage levels in a case study based in Slovenia.

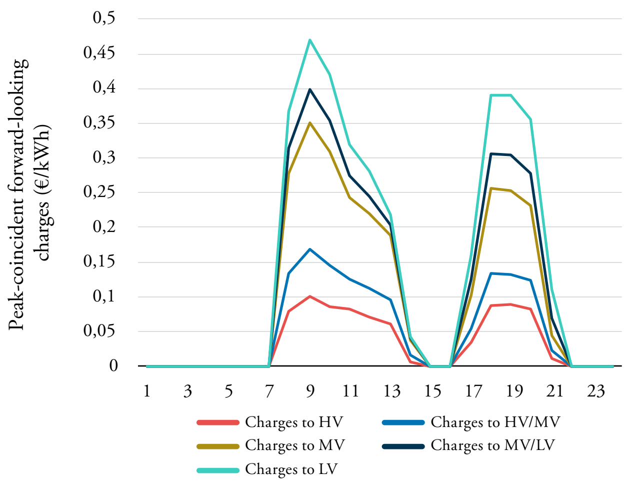

FIGURE 2. PEAK-COINCIDENT NETWORK CHARGES FOR A WINTER WEEKDAY IN THE CASE STUDY OF SLOVENIA [1]

2.3. CALCULATION OF RESIDUAL CHARGES

The remaining part of the recognized network costs are recovered through residual charges. Residual charges are not meant to incentivize specific responses by network users [24]. The basic objective for the allocation of residual costs is to minimize distortions to the already defined economically efficient charges and prices [4]. So, charging generation or storage facilities with residual charges would distort their competition in the market. They would internalize those residual charges into their market offers, distorting the competition among them, and ending final customers paying them within the final energy price. Therefore, residual costs are solely allocated to the consumption customer groups, including passive and active customers.

A fixed charge per customer (€/customer) is formulated to recover residual costs. Residual network costs have no driver, but when the legacy network investment was made the main drivers were the energy consumption and the peak demand. Therefore, residual network costs are allocated to customer groups following the adopted cascade network model. Each consumption customer group is responsible for the residual network costs according to the network flows it produces at the same and in upper voltage levels. Within each customer group, residual charges are calculated for each customer according to their installed capacity, defined as the maximum supply capacity depending on the customer's electrical installation based on technical standards, so it cannot be modified either by changing their peak demand or their contracted capacity subscription.

The detailed mathematical calculation of residual charges can be consulted in [1].

3. PRICE-RESPONSIVE CUSTOMERS

In a context of increasing active customers adopting flexible loads such as EVs, on-site generation such as PVs, and increasingly providing flexibility services, revisiting network tariff design is becoming a crucial task for regulators and policy makers. For the sake of illustration of the benefits associated with advanced tariff designs, as the one proposed in this article, we compare the economic signals provided by the proposed tariff and two other conventional network tariff designs, to analyze how they impact the customer adoption of those new technologies.

Together with the already described forward-looking dynamic network tariff, two other selected more conventional alternatives are considered. First, the current network tariff applied in Slovenia based on energy charges and a capacity charge based on the physical capacity, thus not modifiable and time independent [25]. Second, a more cost-reflective energy and capacity-based tariff, both with time-of-use (TOU) differentiation, based on the current network tariff applied in Spain [26]. In the calculations of the three tariffs, we enforce that all tariff designs recover the same total recognized network costs.

3.1. ACTIVE CUSTOMERS WITH PV AND EVS

On-site generation and flexible loads such as EVs provide customers the ability to react to the network tariffs, as well as to the rest of the electricity bill. In this case, PV generation could decrease long-term network costs if the generated energy is injected into the network during peak hours netting consumption during those hours. Similarly, EV charging at peak periods should pay the future costs they cause, while EV charging at off-peak should be stimulated as long as it does not entail additional future costs.

A representative Slovenian household with a physical capacity of 11 kW and an annual consumption of 8 MWh/year is modelled when adopting solar generation (PVs) or electric vehicles (EVs). Four cases are considered, one for a household customer adopting a 3.5 kW-peak PV installation (annual generation of 4.88 MWh); and three EV cases (annual consumption of 4 MWh) with different charging strategies: slow charging during off-peak periods, slow charging during peak periods and fast charging during peak periods.

Figure 3 shows the annual payment of the selected customer under each network tariff design. Winter from December to March is the season with the highest network utilization.

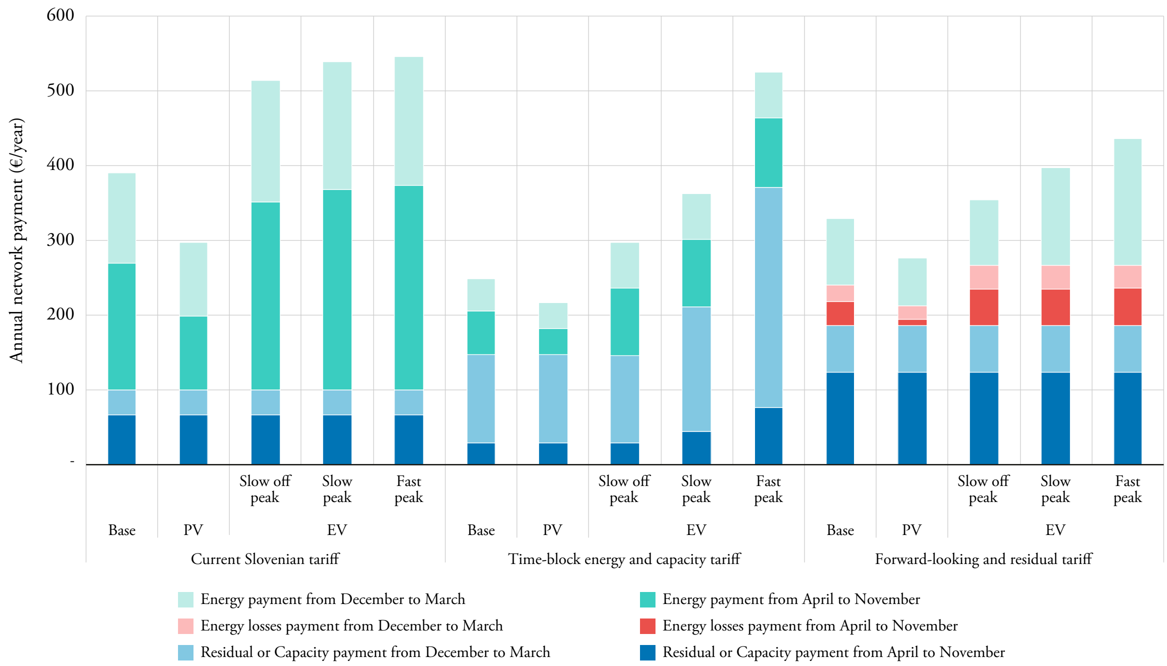

FIGURE 3. NETWORK PAYMENTS (€/YEAR) FOR A LV HOUSEHOLD AFTER INSTALLING PV OR EV WITH THREE DIFFERENT CHARGING STRATEGIES UNDER THREE TARIFF DESIGNS [1]

The current Slovenian shows the disadvantages of a network tariff with a high share of energy charges and low temporal differentiation. The relative benefit from PV adoption is the highest for this network tariff design with a reduction of about 25% of network charges paid compared to the base case. Such reduction overstates the network cost savings of the adoption of PV. At the same time, EV charging during peak times is nearly equally valued as EV charging in-off peak periods, which does not reflect the actual network cost savings of one strategy versus the other and thus not sufficiently incentives off-peak charging.

Under the TOU energy and capacity tariff, for the case of PV adoption, the contracted capacity cannot be reduced as the PV production is not aligned with the individual peak consumption. The observed savings in network charges under PV are due to the lower net energy consumption in almost all time-blocks, and thus failing to incentivize PV adoption when it is able to reduce long-term network costs (e.g., by pairing it with storage and inject during peak periods). In the case of EV adoption, strong incentives are provided to move from fast to slow charging, but assuming that a significant portion of network costs is residual ("sunk costs"), this network tariff design tends to over-penalize a capacity increase due to EV charging, implying, in the end, raising the barrier for transport electrification. For example, fast charging is more expensive than slow charging during April to November (low season) when there would be no issue in accommodating this load.

Finally, the proposed forward-looking tariff succeeds in reducing the energy payment of a customer installing a PV when the generation profile is aligned with peak-coincident hours in winter season. In the case of EV adoption, slow off-peak charging is highly incentivized since the increment in peak network flows is almost negligible when compared to the base case in Fig. 3, the minor increase in network charges is driven by the increase in losses due to the higher volume of total electricity withdrawn from the network. Importantly, fast charging is penalized only during network peak hours in the winter.

3.2. ACTIVE CUSTOMERS PROVIDING FLEXIBILITY

The objective of a regulator is to settle a level playing field for fair competition of all service providers in order to minimize the total costs of system services which are finally levied from all consumers. Historically, generators provided flexibility services, however, today, and even more so in the future, standalone storage and active customers are expected to provide these services.

Flexibility provision is understood as intended energy deviations (upward and/or downward) under flexibility markets or services (e.g., balancing, congestion management), which can be provided by any network user able to modify its baseline demand/generation profile.

Under traditional network tariffs charging only energy withdraws (consumption) and exempting energy injections (generation), i.e., non-symmetric network tariffs, active customers or storage units providing flexibility services by increasing their consumption with respect to the baseline profile would be subject to additional network capacity and energy charges, while generators reducing their injections would not face any initial or additional network charge, as presented in Figure 4.

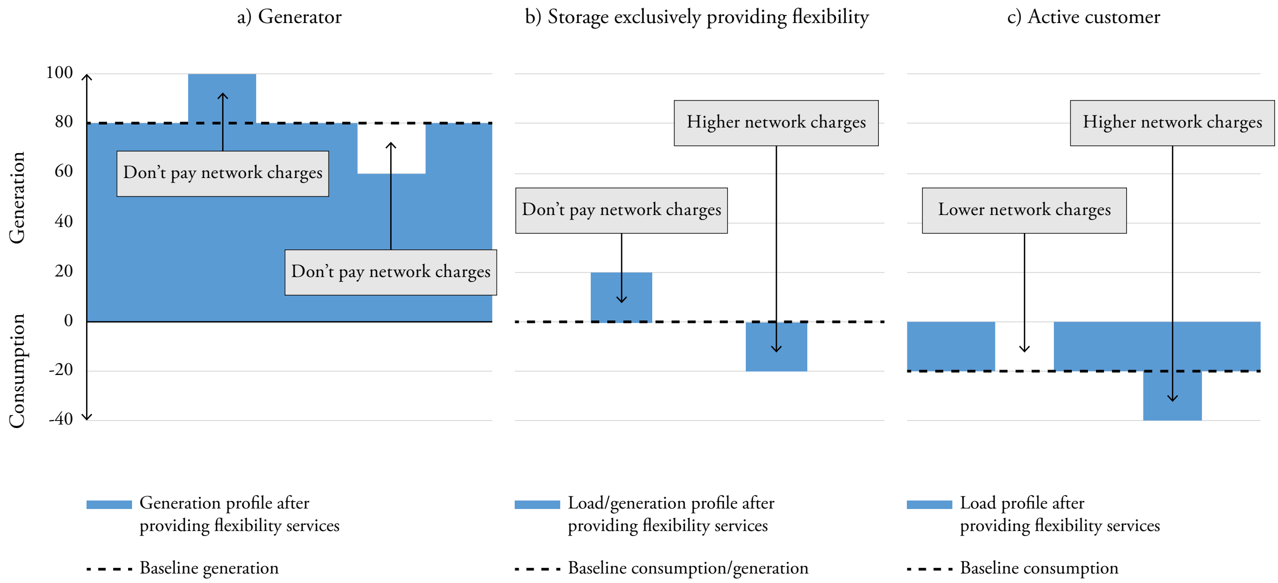

FIGURE 4. NETWORK CHARGES INCREASE/DECREASE AFTER PROVIDING UPWARD OR DOWNWARD FLEXIBILITY SERVICES UNDER NON-SYMMETRIC NETWORK TARIFFS [1]

In some jurisdictions, under non-symmetric network tariffs, regulators exempt those grid users from network charges when they provide flexibility services, as it happens in Spain with stand-alone storage installations [27]. In contrast, under the forward-looking peak coincident tariff, flexibility providers would be charged/rewarded by the final net consumption/injection profile once the flexibility services have been provided. Each flexibility service provider would internalize in their flexibility offers the expected effect on their network charges, resulting in a level playing field among service providers and reflecting correctly the implications of flexibility activation in future network costs.

4. CONCLUSIONS

Under a context of decarbonization, decentralization and digitalization, regulatory authorities are responsible to promote a more efficient, and equitable power system providing the correct economic signals for adequate price-responses from an increasing number of active consumers. Revisiting network tariff design is a powerful tool to move forward in the right direction.

This article proposes a forward-looking dynamic network tariff to illustrate how more advanced tariff designs can be applied in practice to real electricity systems. The proposed solution is intensive in data collection related to hourly measurements and requires extensive implementation of smart meters. Peak-coincident energy charges are differentiated by customer groups per voltage levels, change hourly, by days and seasons, and they are symmetric for network withdrawals and injections. Residual charges, applied only to consumers, are also differentiated by voltage levels and based on the physical capacity of the user´s connection.

The benefits of the proposed network tariff incentivizing the efficient responses from different types of active customers are demonstrated in the case of PV for self-consumption installations, different EV home charging strategies, and active customers providing flexibility services.

For instance, the proposed tariff incentivizes slow versus fast EV charging, and EV charging in off-peak versus peak hours while still promoting the electrification of transport. For customers adopting PV installations, it provides less discount compared to volumetric current tariffs, aligning better individual customer benefits with expected network benefits. Finally, the symmetric nature of the proposed tariff enables a level playing field in which any exemptions of network charges are not required for active customers or storage installations providing flexibility services.

The intrinsic time variability of the proposed tariff may be perceived as a risky and complex price signal that is difficult to be accepted by regular customers. In this case, retailers may find business opportunities by offering supply contracts according to their customer risk profiles tackling accepted levels of price complexity, including diverse formats, from pass-through to fixed price contracts with the associated premiums.

Higher locational and temporal granularity would be a trend for future implementations of cost-reflective advanced tariffs. Network models differentiating more congested from non-congested areas, also depending on the penetration of distributed generation technologies, would be required. Hourly and even 15-min tariffs based on smart meters to discriminate the actual use of the network and the responsibility for those flows of network injections and withdrawals are recommended.

Regarding the anticipation to set tariffs, moving from one year in advance to a more dynamic price setting, with monthly, weekly, or even daily updates, as it happens with dynamic energy prices indexed to wholesale electricity markets, could also be a trend that should shape the future. Regulators and policymakers may find this tariff proposal a good example of how to move forward to improve network tariff designs gradually.

5. ACKNOWLEDGEMENTS

We thank all participants in the project “Expert study implementation: Revision of the methodology for setting the network charge and tariff system” from the regulatory agency and the Elektroinstitut Milan Vidmar in Slovenia for their insightful comments and contributions.

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Optimal regulation of time-differentiated tariffs in the Energy transport sector

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ABSTRACT

I study optimal tariff regulation in a theoretical model with two periods in which a natural monopoly transports energy to a representative household who decides whether and when to carry out energy consuming activities. The model features preferences replicating some aggregate empirical observations regarding energy demand, a requirement that the monopolist must dimension its grid in order to satisfy peak demand, and otherwise only weak technical assumptions. I find that the welfare-maximizing tariffs depend on the marginal cost of extra grid capacity. For a sufficiently low marginal cost, maximum social welfare is achieved by a tariff of zero in the non-peak period and a tariff that equals the marginal cost of extra capacity in the peak period, and all activities are carried out. For higher marginal costs, the optimal tariff in the non-peak period is positive in order to exclude the least beneficial activities and the optimal tariff in the peak period is so high that it equalizes the demands in the two periods in order to save cost. In terms of regulation, no matter the underlying parameter values, I find that zero economic profit, a requirement that the sum of the tariffs be equal to the marginal cost of additional capacity, and a natural relation between the period demands together are necessary and sufficient conditions for achieving the optimal tariffs. Moreover, I show that the optimal tariffs may be implemented in a gradual adjustment process that takes into account the profit history of the monopolist and does not require any new estimations besides readily available, observable quantities. Finally, in the context of [1], I question the applicability of Ramsey pricing, and regarding cost reflectivity, I note that in a multi-period setting, transport of energy is a non-rivalrous good, the implication of which is that the shares of the energy transport cost caused by consumption in each period become impossible to determine.

KEYWORDS: Optimal tariff regulation, Energy transport sector, Tariff differentiation, Efficiency, Cost reflectivity

1. INTRODUCTION

Arguably, two of the most fundamental determinants of social welfare from consumption of energy are access to a desired quantity of energy at a preferred time as well as not having to pay too much for this access. Alas, there is a trade-off between the freedom to choose how much and when to consume and the cost, since the consumption pattern is a main determinant of the grid capacity and, as a consequence, the bill faced by consumers.

Elsewhere in the economy, competitive markets routinely resolve similar trade-offs and achieve maximal social welfare. But in the energy transport sector, the suppliers are natural monopolies, and competition is not an available option. This absence of competition poses significant challenges for the achievement of maximal social welfare. For instance, in the absence of regulation, monopolists may charge too high tariffs, which results in too low consumption and a deadweight loss.

Regulation of revenues of the natural monopolies in the energy transport sector partly exists to ameliorate the deadweight loss from otherwise too high tariffs. For instance, if marginal costs are constant and if there were only one tariff and one time of consumption, then a properly designed revenue cap could enforce the same marginal cost pricing principle that would achieve efficiency in other competitive product markets.

However, in reality, energy consumption varies throughout the day and the year, and several different tariffs may be charged, one for each of multiple time periods. This fact adds to the complexity of achieving maximal social welfare, since in addition to getting one tariff and consumption level right, possible effects of tariff differentials on consumption patterns, cost levels, and social welfare must also be taken into account.

The role of tariff differentials in determining social welfare depends on the nature of demand and supply in the energy transport sector. Four key empirical facts inform us about this nature. First, regarding demand, in the absence of strongly differentiated tariffs, households tend to cluster most of their consumption in one period, the so-called peak period [2]. At the same time, in the aggregate, households also respond to price signals by reducing and re-scheduling demand if a tariff increases [3]. Regarding supply, grids are dimensioned so that their level of capacity can handle peak demand, defined as the demand in the peak period [2]; and the level of capacity is the main driver of the cost of transporting energy when the geographical scale of the transport is fixed [2].

The facts regarding demand suggest that energy consumed in different periods may be considered different, substitutable products. That is, the tariff differential between the peak period and another period should positively (negatively) affect the demand in the other (the peak) period. The facts regarding supply suggest that the cost of transporting energy is increasing in peak demand, which implies that the cost of transporting energy is decreasing in the degree of consumption smoothing across periods.

From these properties of demand and supply, we may infer that optimal tariff differentials strike the right balance between the potential for saving cost through consumption smoothing across periods and the contribution to social welfare from the ability of consumers to freely choose the most convenient time of consumption. The tariff differentials must accomplish this task while still being consistent with an overall tariff and consumption level at which potential utility gains from additional consumption are in balance with what it would cost to provide such additional consumption.

However, more theory is needed in order to identify the optimal tariffs that accomplish these tasks. Three main challenges present themselves. First, the substitutability between energy demand in different periods makes these demands dependent on each other through the tariffs. Second, the fact that the cost of transporting energy is determined by peak demand makes the marginal costs of extra energy transport in different periods dependent on each other through the relative levels of supply. And third, for the same reason, realistic cost functions must be non-differentiable in the period demands. In combination, these three factors necessitate a more careful study.

In this paper, I investigate three broad, theoretical questions. The first question asks what characterizes the optimal tariffs in the energy transport sector when the nature of demand and supply is taken into account. Moreover, I ask what can be inferred about the optimal amount of energy consumption that results from the optimal tariffs, and how the optimal consumption is distributed across time periods.

The context of the second question is a regulator that wants to achieve as high social welfare as possible given the constraint that it cannot set the tariffs directly but must act through regulation that limits the available options of the monopolist. The question is whether a combination of regulation components exists that could implement the optimal tariffs, and under what conditions. Here, I focus on three types of regulation, namely regulation of economic profit, of tariffs, and of quantities. Specifically, I establish how such types of regulation may interact.

The third question revolves around whether there exists a simple way to achieve the optimal tariffs in practice. Here, I seek an action plan that does not require more information than what would already be readily available to national regulators, is customizable to the individual context and profit history of each monopolist, and gradual in its approach to adjustment.

In order to address these questions, I formulate a theoretical, two-period, long-run model that is consistent with the outlined key properties of demand and supply in the energy transport sector. The model has the following characteristics. On the supply side, the cost function features constant marginal cost of additional grid capacity, a grid capacity just big enough to satisfy peak demand, non-differentiability in the period demands, and dependency between the marginal costs of extra demand.

On the demand side, a representative household can choose whether and in which period to carry out energy-consuming activities. For all activities, the household enjoys the highest utility if an activity takes place in the second (the "preferred") period, a lower but positive utility if the activity takes place in the first (the "inferior") period, and zero utility if the activity is not carried out. However, some activities contribute more to utility than others do, and depending on the tariffs in the two periods, the household may choose to prioritize some activities over others. In accordance with the empirical facts, the resulting demand pattern features the possibility of a peak in demand as well as substitution between demands. At realistic tariffs, the least valuable activities are dropped, the activities of medium value are carried out in the inferior period, and the most valuable activities are reserved for the preferred period, sufficiently many for the presence of a peak in that period.

I find that the optimal tariffs depend on the marginal cost of additional capacity. For sufficiently low values of the marginal cost, standard marginal cost pricing is possible and optimal and corresponds to a tariff of zero in the inferior period and a tariff equal to the marginal cost in the preferred period. At such tariffs, all activities take place, and consumption in the preferred period is higher than in the inferior period. For higher values of the marginal cost, the optimal tariff in the inferior period is positive in order to exclude the lowest valued activities, and the optimal tariff in the preferred period is sufficiently higher in order to discourage consumption in the preferred period and achieve equal demands and maximal consumption smoothing over the two periods.

The answer to the second question regarding optimal regulation is that a combination of zero economic profit on the one hand, a restriction that the sum of the tariffs be equal to the marginal cost of additional capacity, and a requirement that demand is weakly greater in the preferred period than in the inferior period together are necessary and sufficient conditions for implementing the optimal tariffs. This result is unconditional in the sense that it holds no matter the values of the parameters of the model.

Third, I find that, in effect, an action plan exists that guarantees arrival at the optimal tariffs in a gradual, experimental manner and takes into account the profit history and local parameter values of the monopolist. The only information needed for the action plan to work is a measure of economic profit, the period demands, and the tariffs currently in effect.

This paper is related to other work in the regulatory environment of the European energy sector. [1] states that one of the current objectives of regulation of tariffs is that "Tariff methodologies shall neutrally support overall system efficiency over the long run through price signals to network users.". Yet, [1] is silent on how maximal social welfare could be achieved through tariffs or through regulation, although the report does suggest that tariff differentiation in general (Chapter 7), Ramsey pricing (p. 15, paragraph 30), and cost reflectivity (p. 68, paragraph 263) could play a role in achieving efficiency.

I offer some perspectives on Ramsey pricing and cost reflectivity. With respect to Ramsey pricing, it would appear that it is not applicable to time-differentiated tariffs in the energy transport sector, since two of the main assumptions for Ramsey pricing to work are independent product demands and differentiability of the cost function, both of which seem to be violated in the sector. With respect to cost reflectivity, I argue that in a multi-period setting, trying to determine the shares of the total cost caused by consumption in each period becomes a futile exercise. The reason is that in a multi-period setting, transportation of energy becomes a club good and thus non-rivalrous, meaning that one party's consumption no longer prevents another's. Indeed, households consuming in different periods may be serviced by the *same* capacity. As a result, it is impossible to identify the period of consumption that drives the need for capacity. Additionally, I argue that the concepts of efficiency and cost reflectivity do not always mean the same thing, as seems to be implied in [1].

The rest of the paper is structured as follows. In Section 2, I present the model and develop the analytical framework. Section 2.1 introduces the assumptions on the demand side, Section 2.2 derives the resulting individual and aggregate demands, Section 2.3 transforms expressions, variables and parameters to a formulation that is easier to analyze, Section 2.4 introduces the monopolist and its cost function, and Section 2.5 deals with non-differentiability of the cost function. In Section 3, I perform the main analysis of social welfare and regulation. Section 3.1 identifies the socially optimal allocation, Section 3.2 analyses zero profit regulation, Section 3.3 demonstrates what the optimal regulation is, and Section 3.4 discusses how to achieve the optimal allocation in practice. Finally, in Section 4 I summarize the key results of the main analysis as well as offer the perspectives on Ramsey pricing and cost reflectivity. Section 4.1 formulates the key results in a non-technical way and discusses the economic intuition behind them, and Section 4.2 comments on the applicability of Ramsey pricing as well as lays out the differences between cost reflectivity in the context of private goods and in the context of club goods, and between cost reflectivity and efficiency.

2. THE MODEL

This section presents the model in five steps. In Sections 2.1 and 2.2, I lay out the assumptions of the model regarding the demand side then solve the household utility maximization problem. Section 2.3 motivates a reformulation of tariffs and time values that is useful for simplifying expressions and analysis. In Sections 2.4 and 2.5, I introduce the monopolist then deal with non-differentiability of the cost function.

2.1. Households and energy-consuming activities

There are given two periods, the "inferior" period 1 and the "preferred" period 2, and a set of activities that, if a representative household chooses to carry them out, consume energy at a given level.[1]

Activities differ in how much they will contribute to the utility of the household if carried out. The potential contribution of an activity is determined by what is referred to as its "activity value", a number θ in the interval $[0;\bar{\theta}]$ where $\bar{\theta} > 0$ is the maximal possible activity value and $[0;\bar{\theta}]$ is the range of possible activity values.[2]

The total potential energy consumption from all activities is distributed on the range of possible activity values according to the distribution $\theta(P_E)$, a continuous probability distribution concentrated on the set $[0;\bar{\theta}]$. For any value $z \in [0;\bar{\theta}]$, $\theta(P_E)([z;\bar{\theta}]) = P_E(\theta \geq z)$ is the share of the total potential energy consumption from all activities coming from activities with activity values greater than or equal to z. The distribution has a density $f_{\theta(P_E)}$ that is positive on $(0;\bar{\theta})$, zero at $\bar{\theta}$, satisfies $\lim_{z\to 0^+} z f_{\theta(P)}(z) = 0$, and is continuous on $(0;\bar{\theta}]$.[3]

The household has quasilinear preferences that are additively separable in activities, and the household decides on whether and when to carry out each activity. The contribution to utility of an activity with activity value θ is proportional to the level of energy consumption of the activity, where the factor of proportionality is $v(t)\theta$ and $t \in \{0,1,2\}$ is the choice of the household for the activity in question. If the household chooses not to carry out an activity, $t = 0$ and the corresponding value of v is $v(0) = 0$; if an activity is carried out in period 1 or 2, the corresponding values are $0 < v(1) < v(2)$ respectively. $v(1)$ and $v(2)$ are referred to as "time values".

The household pays a non-negative, time-differentiated tariff $p(t)$ per unit of consumed energy if consumption of energy takes place. That is, $p(0) = 0$, $p(1) \geq 0$, and $p(2) \geq 0$. The household takes the tariffs as given.

Without loss of generality, I assume that the total potential energy consumption from all activities is one, allowing demand to be measured in absolute terms instead of relative to a grand total. In addition, for simplicity I assume that the level of energy consumption of each activity is one, as one may verify that given the other assumptions made, the level of energy consumption does not play a role in the utility maximization problem nor anywhere else. As a result, in terms of language, referring to activities or to units of consumption is the same thing in the model.

2.2. Demand

Due to the quasilinear and additively separable nature of preferences, after substituting in the budget for the numeraire good and ignoring income, one is left with the sum of the contributions to utility from the activities minus the sum of the amounts of numeraire paid in tariffs. Therefore, the utility maximization problem of the household is equivalent to maximizing the contribution to utility net of tariffs from each activity individually. That is, the maximization problem is simply for each activity to choose $t \in \{0,1,2\}$ such that $v(t)\theta - p(t)$ is maximized.

It follows that the solution to the utility maximization problem will take the form of a policy that depends on the activity value θ and the tariffs.

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[1] Formally: Let I be the set of activities, Σ a sigma-algebra consisting of subsets of I, and let $E: I \to (0;\infty)$ be a Σ-measurable mapping, where for activity $i \in I$, $E(i)$ is the potential energy consumption of the activity.

[2] Formally: Let $\theta: I \to [0;\bar{\theta}]$ be a Σ-measurable mapping, where $\theta(i)$ is the activity value of activity i.

[3] Formally: Let λ be a sigma-finite measure on Σ and assume that E is λ-integrable. For $A \in \Sigma$, define $P_E(A) = \int_A E(i)\, d\lambda(i) / \int_I E(i)\, d\lambda(i)$, a probability measure on Σ such that for $A \in \Sigma$, $P_E(A)$ is the share of the total potential energy consumption from all activities coming from activities in A. Define for $B \in \mathbb{B}_{|[0;\bar{\theta}]}$ (the Borel sigma-algebra restricted to the interval), $\theta(P_E)(B) = P_E(\theta \in B) = P_E(\theta^{-1}(B))$.

Proposition 2.2.1. – solution to the utility maximization problem.

If $\frac{p(2)}{v(2)} \geq \frac{p(1)}{v(1)}$, then:

- $t = 0 \Leftrightarrow \theta < \frac{p(1)}{v(1)}$;
- $t = 1 \Leftrightarrow \frac{p(1)}{v(1)} \leq \theta < \frac{p(2)-p(1)}{v(2)-v(1)}$;
- $t = 2 \Leftrightarrow \theta \geq \frac{p(2)-p(1)}{v(2)-v(1)}$.

If $\frac{p(2)}{v(2)} < \frac{p(1)}{v(1)}$, then:

- $t = 0 \Leftrightarrow \theta < \frac{p(2)}{v(2)}$;
- $t = 2 \Leftrightarrow \theta \geq \frac{p(2)}{v(2)}$.

Proof.

Consider first the case $\frac{p(2)}{v(2)} \geq \frac{p(1)}{v(1)}$. $t = 0$ if and only if $0 > v(1)\theta - p(1)$ and $0 > v(2)\theta - p(2)$, that is, if and only if $\theta < \frac{p(1)}{v(1)}$ since $\frac{p(1)}{v(1)} \leq \frac{p(2)}{v(2)}$; $t = 1$ if and only if $v(1)\theta - p(1) \geq 0$ and $v(1)\theta - p(1) > v(2)\theta - p(2)$, that is, if and only if $\frac{p(1)}{v(1)} \leq \theta < \frac{p(2)-p(1)}{v(2)-v(1)}$ (notice that $\frac{p(2)-p(1)}{v(2)-v(1)} \geq \frac{p(1)}{v(1)} \Leftrightarrow \frac{p(1)}{v(1)} \leq \frac{p(2)}{v(2)}$); $t = 2$ if and only if $v(2)\theta - p(2) \geq 0$ and $v(2)\theta - p(2) \geq v(1)\theta - p(1)$, that is, if and only if $\theta \geq \frac{p(2)-p(1)}{v(2)-v(1)}$ since $\frac{p(1)}{v(1)} \leq \frac{p(2)}{v(2)} \Leftrightarrow \frac{p(2)-p(1)}{v(2)-v(1)} \geq \frac{p(2)}{v(2)}$.

Consider then the case $\frac{p(2)}{v(2)} < \frac{p(1)}{v(1)}$. $t = 0$ if and only if $\theta < \frac{p(2)}{v(2)}$ since now $\frac{p(1)}{v(1)} > \frac{p(2)}{v(2)}$; $t = 1$ never happens because now $\frac{p(2)-p(1)}{v(2)-v(1)} < \frac{p(1)}{v(1)}$; and $t = 2$ if and only if $\theta \geq \frac{p(2)}{v(2)}$ since now $\frac{p(2)}{v(2)} > \frac{p(2)-p(1)}{v(2)-v(1)}$.

Notice that in the case of $\frac{p(2)}{v(2)} \geq \frac{p(1)}{v(1)}$, the optimal household behavior takes the form of a threshold policy with thresholds $\frac{p(1)}{v(1)} \leq \frac{p(2)-p(1)}{v(2)-v(1)}$. Activities with activity values lower than $\frac{p(1)}{v(1)}$ are not carried out and don't consume energy, activities with activity values between the thresholds are carried out in the inferior period, and activities with activity values above $\frac{p(2)-p(1)}{v(2)-v(1)}$ are reserved for the preferred period.

In other words, it takes an activity value weakly greater than $\frac{p(1)}{v(1)}$ to justify the cost associated with consumption, and it takes a higher activity value weakly greater than $\frac{p(2)-p(1)}{v(2)-v(1)} \geq \frac{p(1)}{v(1)}$ to justify consumption in the preferred period, because consumption in period 2 is more expensive than in period 1, even relative to the higher time value in period 2.

In the same vein, notice that it is the tariff in period 1 that determines the extent to which consumption takes place, and given consumption, it is the tariff differential between the periods that determines whether the consumption takes place in period 1 or 2.

In the case $\frac{p(2)}{v(2)} < \frac{p(1)}{v(1)}$, the optimal household behavior also takes the form of a threshold policy, but consumption in period 1 is never optimal. This is because after taking into account the higher time value in period 2, consumption in period 2 is sufficiently cheap compared to period 1 that consumption in period 2 is always preferred to consumption in period 1, no matter the activity value. Thus, activities with activity values lower than the threshold $\frac{p(2)}{v(2)}$ do not take place, and consumption takes place in period 2 for activity values higher than this threshold.

Corollary 2.2.2. – aggregate demand.

If $\frac{p(2)}{v(2)} \geq \frac{p(1)}{v(1)}$, the aggregate demand for energy is

- $P_E(\theta \in \left[\frac{p(1)}{v(1)}; \frac{p(2)-p(1)}{v(2)-v(1)}\right))$ in period 1;
- $P_E(\theta \geq \frac{p(2)-p(1)}{v(2)-v(1)})$ in period 2.

On the other hand, if $\frac{p(2)}{v(2)} < \frac{p(1)}{v(1)}$, then the aggregate demand for energy in period 1 is 0, and the aggregate demand for energy in period 2 is $P_E(\theta \geq \frac{p(2)}{v(2)})$.

In the case of $\frac{p(2)}{v(2)} \geq \frac{p(1)}{v(1)}$, notice how the aggregate demand in period 1 decreases in $p(1)$, due to two effects in the same direction. Firstly, it takes a higher activity value to make consumption worthwhile when the tariff in period 1 is higher, and secondly consumption in period 1 is less attractive relative to consumption in period 2 when the tariff in period 1 is higher. The aggregate demand in period 2 exhibits the opposite pattern of the second effect.

In the case of $\frac{p(2)}{v(2)} < \frac{p(1)}{v(1)}$, the tariff in period 1 does not have an effect (as long as the inequality keeps binding) on any of the aggregate demands, which is because consumption takes place in period 2 if consumption takes place. A higher tariff in period 2 decreases demand, as it takes a higher activity value to make consumption worthwhile.

2.3. A simplifying reformulation of tariffs and time values

Suppose that we wanted to analyze the revenue of the monopolist as a function of the tariffs, for instance in order to understand profits in the model. The revenue in the case $\frac{p(2)}{v(2)} \geq \frac{p(1)}{v(1)}$ would be

$$p(1)P_E\left(\theta \in \left[\frac{p(1)}{v(1)}; \frac{p(2)-p(1)}{v(2)-v(1)}\right)\right) + p(2)P_E\left(\theta \geq \frac{p(2)-p(1)}{v(2)-v(1)}\right).$$

This is a complicated expression and difficult to analyze, because each tariff enters in both probabilities, and the probabilities in turn are multiplied by the tariffs. As a result, separate analyses of the two tariffs or of the two revenue terms are not possible.

Fortunately, there is a way around this challenge. Define the activity value thresholds x and y as

$$(*) \qquad x = \frac{p(1)}{v(1)},$$

$$(**) \qquad y = \frac{p(2)-p(1)}{v(2)-v(1)}.$$

In the case $\frac{p(2)}{v(2)} \geq \frac{p(1)}{v(1)}$, x is the lowest activity value for which consumption takes place, and y is the lowest activity value for which consumption takes place in period 2. Now, instead of thinking in terms of one tariff for each period, it is helpful to think in terms of a base tariff paid in both periods and a (potentially negative) mark-up tariff paid in period 2. Rewriting the revenue expression using the thresholds and the concepts of base and mark-up tariffs, one obtains

$$v(1)xP_E(\theta \geq x) + \big(v(2)-v(1)\big)yP_E(\theta \geq y).$$

As can be seen, now the revenue consists of two terms that can be analyzed independently, since one term involves only x and the other only y.

Motivated by this insight, I reorient the analysis around the activity value thresholds. I rewrite parameters, variables, and expressions using the threshold formulas and conduct the entire analysis using this formulation before finally in Section 4.1 expressing the results of the analysis in terms of tariffs once again.

To begin, define the parameters

(***) $$a = v(1),$$

(****) $$b = v(2) - v(1)$$

and notice that they comprise a bijective, linear transformation of the time values. Similarly, notice that the thresholds defined above comprise a bijective, linear transformation of the tariffs. What this means is that the translation of parameters, variables, and ultimately results between the two formulations is possible and unambiguous in both directions. For instance, "choosing tariffs" can be re-phrased as "choosing thresholds" – each choice of tariffs implies a choice of thresholds, and each choice of thresholds implies an underlying choice of tariffs.

Denote by $\epsilon_1(x, y)$ and $\epsilon_2(x, y)$ the aggregate demands in period 1 and 2 respectively as functions of the thresholds. After substituting in the new parameters and variables, the aggregate demands take the following form:

- On the set $\{(x, y): x \geq 0, y \geq x\}$:
  $\epsilon_1(x, y) = P_E(\theta \in [x; y))$;
  $\epsilon_2(x, y) = P_E(\theta \geq y)$.
- On the set $\left\{(x, y): x > 0, \frac{-ax}{b} \leq y < x\right\}$:

$\epsilon_1(x, y) = 0$;

$$\epsilon_2(x, y) = P_E\left(\theta \geq \frac{b}{a+b}y + \frac{a}{a+b}x\right).$$

I refer to the sets $\{(x, y): y \geq x \geq 0\}$ and $\left\{(x, y): x > 0, \frac{-ax}{b} \leq y < x\right\}$ as threshold regions. One may verify that they correspond to the tariff cases in corollary 2.2.2 as follows:

$$\left\{(p(1), p(2)): \frac{p(2)}{v(2)} \geq \frac{p(1)}{v(1)} \geq 0\right\} = \{(x, y): x \geq 0, y \geq x\},$$

$$\left\{(p(1), p(2)): 0 \leq \frac{p(2)}{v(2)} < \frac{p(1)}{v(1)}\right\} = \left\{(x, y): x > 0, \frac{-ax}{b} \leq y < x\right\}.$$

2.4. The monopolist

Energy is transported by a monopolist whose incurred cost is proportional to the capacity of the monopolist's grid. The marginal cost of higher capacity is constant and denoted by $c > 0$.

The monopolist is obligated to dimension its grid in such a way that the same grid has enough capacity to satisfy the demand for energy in both periods. In order to comply with this requirement, the capacity of the grid must be at least as large as the peak energy demand, defined as the maximum energy consumption in the two periods. In order to minimize cost, the monopolist chooses the capacity to equal peak demand. Hence, the cost of transporting energy in the model is

$$c \cdot \max\{\epsilon_1(x, y), \epsilon_2(x, y)\}.$$

In addition to dimensioning the grid, the monopolist sets the tariffs subject to regulation enforced by a national regulator.

2.5. Non-differentiability and further partition of the threshold regions

The cost function $c \cdot \max\{\epsilon_1(x, y), \epsilon_2(x, y)\}$ is non-differentiable with respect to the thresholds in the set $\{(x, y): 0 < \epsilon_1(x, y) = \epsilon_2(x, y)\}$, that is, when the aggregate demands of both periods are positive and equal. The cost function is also non-differentiable at the point where the aggregate demands become zero in both periods. In order to handle this technically, it is necessary to divide the threshold regions into sub-regions in whose interior the cost function is differentiable.

In order to do this, notice that $0 < \epsilon_1(x, y) = \epsilon_2(x, y) \Leftrightarrow P_E(\theta \geq y) = \frac{1}{2}P_E(\theta \geq x), x < y < \bar{\theta}$. From this observation, one may prove the following Lemma (the proof is in the Appendix).

Lemma 2.5.1.

There exists a unique function $g: [0; \bar{\theta}) \to [0; \bar{\theta})$ satisfying that for all $x \in [0; \bar{\theta})$, $P_E(\theta \geq g(x)) = \frac{1}{2} P_E(\theta \geq x)$; moreover, this function has the following properties:

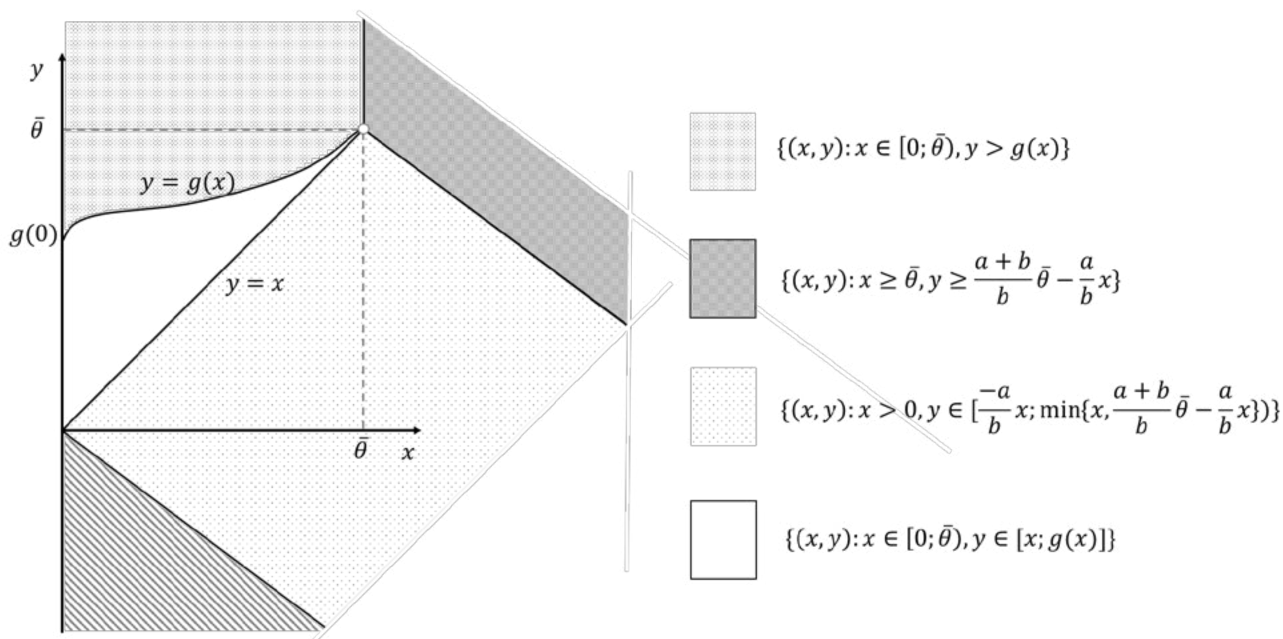
- g is continuously differentiable on $(0; \bar{\theta})$ with $g'(x) = \frac{1}{2} \frac{f_{\theta(P_E)}(x)}{f_{\theta(P_E)}(g(x))} > 0$;
- g is continuous;
- For all $x \in [0; \bar{\theta})$, $x < g(x) < \bar{\theta}$;
- $\lim_{x \to \bar{\theta}^-} g(x) = \bar{\theta}$;
- $g(0)$ is the median of the distribution $\theta(P_E)$.

Equipped with the function g, the threshold regions to consider are the following (Figure 2.5.2):

- $\{(x, y): x \in [0; \bar{\theta}), y > g(x)\}$:
  $\epsilon_1(x, y) > \epsilon_2(x, y) \geq 0$;
  $\epsilon_1(x, y) = P_E(\theta \in [x; y))$;
  $\epsilon_2(x, y) = P_E(\theta \geq y)$.
- $\{(x, y): x \in [0; \bar{\theta}), y \in [x; g(x)]\}$:
  $\epsilon_2(x, y) \geq \epsilon_1(x, y) \geq 0$ with at least one of the inequalities sharp;
  $\epsilon_1(x, y) = P_E(\theta \in [x; y))$;
  $\epsilon_2(x, y) = P_E(\theta \geq y)$.
- $\{(x, y): x > 0, y \in \left[\frac{-a}{b} x; \min\left\{x, \frac{a+b}{b} \bar{\theta} - \frac{a}{b} x\right\}\right)\}$:
  $0 = \epsilon_1(x, y) < \epsilon_2(x, y)$;
  $\epsilon_2(x, y) = P_E(\theta \geq \frac{b}{a+b} y + \frac{a}{a+b} x)$.
- $\{(x, y): x \geq \bar{\theta}, y \geq \frac{a+b}{b} \bar{\theta} - \frac{a}{b} x\}$:
  $\epsilon_1(x, y) = \epsilon_2(x, y) = 0$.

Recalling the assumptions on $\theta(P_E)$, one may verify that the cost function is differentiable with respect to x and y on the interior of these threshold regions.

Figure 2.5.2. – threshold regions.



3. ANALYSIS OF SOCIAL WELFARE AND REGULATION

In this section, I perform the main analysis of the paper in four steps. First, in Section 3.1 I deal with the question of what thresholds, if any, give rise to a socially optimal allocation of energy consumption and what properties such an optimal allocation has. In Section 3.2, I portray the threshold values that achieve zero economic profit by means of four key properties that I determine. In Section 3.3, I combine the findings of Sections 3.1 and 3.2 and identify the optimal regulation. Finally, in Section 3.4 I discuss implementation of the optimal regulation in practice.

3.1. Optimal social welfare

The objective is to maximize the social welfare function SWF, a mapping defined on the union of the threshold regions, $\{(x, y): x \geq 0, y \geq \frac{-a}{b}x\}$, quantifying the aggregate utility from consumption minus the aggregate cost of transportation. Maximal social welfare is (in the model of this paper) equivalent to Pareto optimality or efficiency. SWF evaluates to the following on the threshold regions:

- $x \in [0; \bar{\theta}), y > g(x) \Rightarrow$
  $SWF(x, y) = a\int_x^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta + b\int_y^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_x^{y} f_{\theta(P_E)}(\theta)\, d\theta;$
- $x \in [0; \bar{\theta}), y \in [x; g(x)] \Rightarrow$
  $SWF(x, y) = a\int_x^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta + b\int_y^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_y^{\bar{\theta}} f_{\theta(P_E)}(\theta)\, d\theta;$
- $x > 0, y \in \left[\frac{-a}{b}x; \min\{x, \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}\right) \Rightarrow$
  $SWF(x, y) = (a + b)\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\, d\theta;$
- $x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x \Rightarrow SWF(x, y) = 0.$

The main result is the following proposition.

Proposition 3.1.1. – socially optimal thresholds.

If $c < (2a + b)\bar{\theta}$, there exists a unique social optimum $(x^*, y^*) \in \{(x, y): x \geq 0, y \geq \frac{-a}{b}x\}$. If $c \leq bg(0)$, $(x^*, y^*) = \left(0, \frac{c}{b}\right)$, and if $bg(0) < c < (2a + b)\bar{\theta}$, $(x^*, y^*) = (\tilde{x}, g(\tilde{x}))$, where $\tilde{x} \in (0; \bar{\theta})$ is the unique solution to $2ax + bg(x) = c$. On the other hand, if $c \geq (2a + b)\bar{\theta}$, then all thresholds in the region $\{(x, y): x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}$ are optimal.

Proof.

I provide a sketch of the proof. A full proof may be found in the Appendix.

The region $\{(x, y): x \in [0; \bar{\theta}), y > g(x)\}$

Calculate $\frac{\partial SWF(x,y)}{\partial y} = -f_{\theta(P_E)}(y)(by + c)$; for $g(x) < y < \bar{\theta}$, $\frac{\partial SWF(x,y)}{\partial y} < 0$, and for $y \geq \bar{\theta}$, $\frac{\partial SWF(x,y)}{\partial y} = 0$, which suggests that for all $y > g(x)$, $SWF(x, y) < SWF(x, g(x))$, that is, the social welfare is greater in the region $\{(x, y): x \in [0; \bar{\theta}), y \in [x; g(x)]\}$ analyzed further below.

The region $\{(x, y): x > 0, y \in \left[\frac{-a}{b}x; \min\left\{x, \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\right\}\right)\}$

In the full proof, I show that either $\{(x, y): x \in [0; \bar{\theta}), y \in [x; g(x)]\}$ or $\{(x, y): x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}$ yields higher social welfare than $\{(x, y): x > 0, y \in \left[\frac{-a}{b}x; \min\left\{x, \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\right\}\right)\}$.

The region $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$

Let $x' \in (0;\bar{\theta})$ and $y' \in (x'; g(x'))$. $\frac{\partial SWF(x\prime,y\prime)}{\partial x} = -ax' f_{\theta(P_E)}(x') < 0$, suggesting that the highest social welfare in the region is to be found in the segment $\{(x,y): x = 0 \leq y \leq g(0)\} \cup \{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$.

Consider then the subsegment where $x = 0$ and $y \in [0; g(0)]$. $\frac{\partial SWF(x,y)}{\partial y} = -f_{\theta(P_E)}(y)(by - c)$, suggesting that within this subsegment, $y = \frac{c}{b}$ is optimal if $\frac{c}{b} \leq g(0)$ and $y = g(0)$ is optimal if $\frac{c}{b} > g(0)$. As a result, $(x,y) = (0, \min\left\{\frac{c}{b}, g(0)\right\})$ is optimal on $\{(x,y): x = 0 \leq y \leq g(0)\}$.

Further, if $\frac{c}{b} \leq g(0)$, the point $(0, \min\left\{\frac{c}{b}, g(0)\right\})$ is actually optimal in all of the region, since all points in the other subsegment $\{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$ satisfy $y = g(x) > g(0) \geq \frac{c}{b}$, the implication of which is that the directional derivative in any such point is $\frac{\partial SWF(x,g(x))}{\partial y^-} = -f_{\theta(P_E)}(g(x))(bg(x) - c) < 0$ and moving "down" from $y = g(x)$ is beneficial. If on the other hand $\frac{c}{b} > g(0)$, it holds that points exist in $\{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$ at which social welfare is greater than in $(0, g(0)) = (0, \min\{\frac{c}{b}, g(0)\})$.

What remains is to optimize on the segment $\{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$ if $\frac{c}{b} > g(0)$. Recall (Lemma 2.5.1) that for $\in (0;\bar{\theta})$, $g'(x) = \frac{1}{2}\frac{f_{\theta(P_E)}(x)}{f_{\theta(P_E)}(g(x))}$. Thus, the welfare gain from increasing $x > 0$ infinitesimally is $\frac{d}{dx}SWF(x, g(x)) = \frac{\partial SWF(x,g(x))}{\partial x} + \frac{\partial SWF(x,g(x))}{\partial y} g'(x) = -\frac{1}{2} f_{\theta(P_E)}(x)(2ax + bg(x) - c)$. If $bg(0) < c < (2a+b)\bar{\theta}$, the point $(\tilde{x}, g(\tilde{x}))$, where $\tilde{x} \in (0;\bar{\theta})$ is the unique solution to the equation $2ax + bg(x) = c$, is the unique optimal point in all of the region; and if $c \geq (2a+b)\bar{\theta}$, no optimal point exists in the region since $\frac{d}{dx}SWF(x, g(x)) > 0$ for all $x \in (0;\bar{\theta})$.

The region $\{(x,y): x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}$ in comparison with $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$

In the full proof, I show that for $c < (2a+b)\bar{\theta}$, $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$ yields higher social welfare, and if $c \geq (2a+b)\bar{\theta}$, $\{(x,y): x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}$ yields the highest welfare.

The proposition tells us what the optimal thresholds are as a function of the marginal cost of extra capacity relative to the other parameters. From the optimal thresholds, features of the optimal amount and distribution across periods of energy consumption can be deduced.

Corollary 3.1.2. – optimal consumption pattern.

(i) If $c \leq bg(0)$, $\epsilon_2(x^*, y^*) \geq \epsilon_1(x^*, y^*) > 0$ and $\epsilon_1(x^*, y^*) + \epsilon_2(x^*, y^*) = 1$.
(ii) If $bg(0) < c < (2a+b)\bar{\theta}$, $\epsilon_2(x^*, y^*) = \epsilon_1(x^*, y^*) > 0$.
(iii) If $c \geq (2a+b)\bar{\theta}$, $\epsilon_2(x^*, y^*) = \epsilon_1(x^*, y^*) = 0$.

Proof.

By Proposition 3.1.1, if $c \leq bg(0)$, the optimal thresholds satisfy $(x^*, y^*) \in \{(x,y): x \in [0;\bar{\theta}), y \in (x; g(x)]\}$, from which it follows that $\epsilon_2(x^*, y^*) \geq \epsilon_1(x^*, y^*) > 0$ and $\epsilon_1(x^*, y^*) + \epsilon_2(x^*, y^*) = P_E\left(\theta \in \left[0; \frac{c}{b}\right)\right) + P_E\left(\theta \geq \frac{c}{b}\right) = 1$. Statements (ii) and (iii) follow directly from the same proposition.

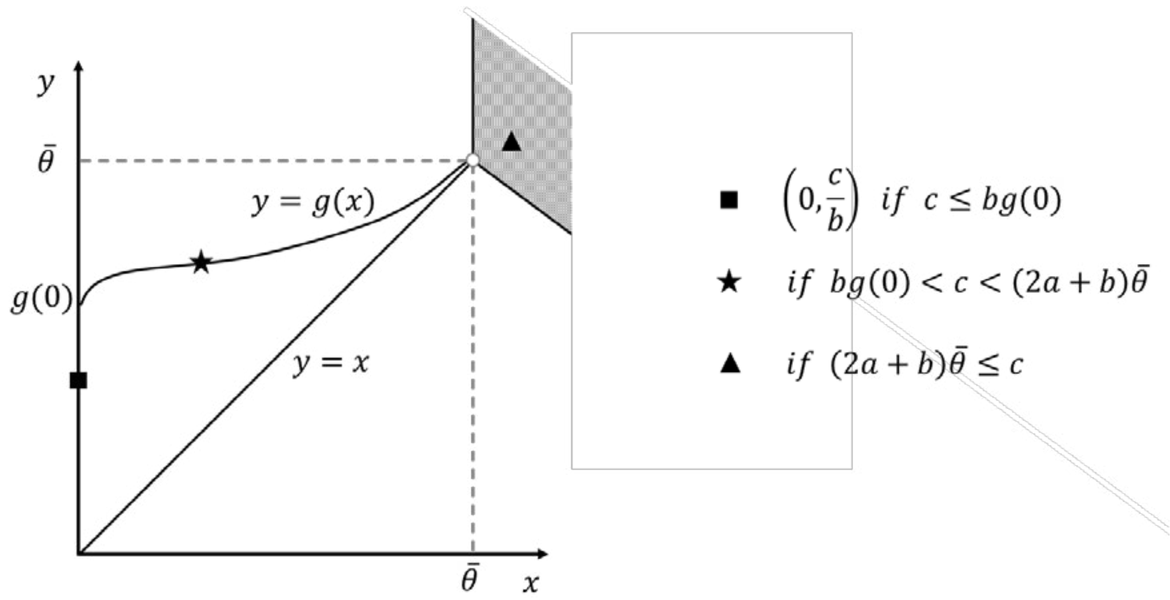
In words, if $c \leq bg(0)$, all activities consume energy in one of the two periods, the consumption in the preferred period is at least as large as the consumption in the inferior period, and the consumption in the inferior period is positive. When c increases, consumption moves from period 2 to period 1.

If $bg(0) < c < (2a + b)\bar{\theta}$, consumption is positive and equally distributed across the two periods. As c increases, x^* and y^* both increase, and consumption decreases in both periods by progressive exclusion of activities with the lowest activity values from consumption in period 1 while activities in period 2 progressively are moved to period 1.

Corollary 3.1.3.

- It is never optimal to consume more energy in the inferior period than in the preferred period.
- A level of consumption in the inferior period that is strictly lower than the level in the preferred period is optimal only if the threshold x^* is zero and all activities consume energy.

Figure 3.1.4. – socially optimal thresholds.



3.2. Regulation that achieves zero economic profit

From Proposition 3.1.1 we know that the welfare is maximized in the region $\{(x, y): x \in [0; \bar{\theta}), y \in [x; g(x)]\}$, unless the marginal cost of higher capacity is so high that the best for consumers is not to consume any energy at all ($c \geq (2a + b)\bar{\theta}$). In the latter case, no kind of regulation is needed, so for the rest of this paper I assume $c < (2a + b)\bar{\theta}$.

The question explored in this section is which points (if any) in $\{(x, y): x \in [0; \bar{\theta}), y \in [x; g(x)]\}$ yield zero profits.

I begin with an analysis of the graph of the zero profit condition, that is, what properties the set $\{(x, y): x \in [0; \bar{\theta}), y \in [x; g(x)], \pi(x, y) = 0\}$ has. One may verify that the profit at a point (x, y) in the region $\{(x, y): x \in [0; \bar{\theta}), y \in [x; g(x)]\}$ is given by $\pi(x, y) = axP_E(\theta \geq x) + b\left(y - \frac{c}{b}\right)P_E(\theta \geq y)$.

Denote by $HR_{\theta(P_E)}(x) = \frac{f_{\theta(P_E)}(x)}{P_E(\theta \geq x)}$ the hazard rate of $\theta(P_E)$ in $x < \bar{\theta}$.

Lemma 3.2.1. – properties of the graph of the zero profit condition in the optimal region.

Case 1: $c \leq bg(0)$

Define $x_1 = 0$ and $x_2 = \frac{c}{a+b} < \frac{c}{b} \leq g(0) < \bar{\theta}$.

Then $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)], \pi(x,y) = 0\} = \{(x, f(x)): x \in [x_1; x_2]\}$, where $f: [x_1; x_2] \to \mathbb{R}$ is a continuously differentiable function satisfying the following four properties:

1) $f(x_1) = \frac{c}{b}$; $x \in (x_1; x_2) \Rightarrow f(x) \in \left(x; \frac{c}{b}\right)$; $f(x_2) = x_2$;
2) f is right-differentiable at x_1 with right-derivative $\frac{-1}{\frac{b}{a} P_E\left(\theta \geq \frac{c}{b}\right)} \in [-2\frac{a}{b}; -\frac{a}{b})$;
3) For $x_1 \leq x < x' \leq x_2$, $\frac{P_E(\theta \geq x)}{P_E(\theta \geq f(x))} > \frac{P_E(\theta \geq x')}{P_E(\theta \geq f(x'))} > 0$;
4) f is left-differentiable at x_2 with left-derivative $\frac{-1 + x_2 HR_{\theta(P_E)}(x_2)}{\frac{b}{a} + x_2 HR_{\theta(P_E)}(x_2)} > -\frac{a}{b}$.

Case 2: $bg(0) < c < (2a+b)\bar{\theta}$

Define $x_1 \in (0;\bar{\theta})$ as the unique solution to the equation $2ax + bg(x) = c$ and $x_2 = min\{\frac{c}{a+b}, \bar{\theta}\} \leq \bar{\theta}$.

If $\frac{c}{a+b} < \bar{\theta}$, then $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)], \pi(x,y) = 0\} = \{(x, f(x)): x \in [x_1; x_2]\}$, where $f: [x_1; x_2] \to \mathbb{R}$ is a continuously differentiable function satisfying the following four properties:

1) $f(x_1) = g(x_1) < \frac{c}{b}$; $x \in (x_1; x_2) \Rightarrow f(x) \in \left(x; min\left\{\frac{c}{b}, g(x)\right\}\right)$; $f(x_2) = x_2$;
2) f is right-differentiable at x_1 with right-derivative $\frac{-1 + x_1 HR_{\theta(P_E)}(x_1)}{\frac{b}{a}\frac{1}{2} + x_1 HR_{\theta(P_E)}(g(x_1))} > -2\frac{a}{b}$;
3) For $x_1 \leq x < x' \leq x_2$, $\frac{P_E(\theta \geq x)}{P_E(\theta \geq f(x))} > \frac{P_E(\theta \geq x')}{P_E(\theta \geq f(x'))} > 0$;
4) f is left-differentiable at x_2 with left-derivative $\frac{-1 + x_2 HR_{\theta(P_E)}(x_2)}{\frac{b}{a} + x_2 HR_{\theta(P_E)}(x_2)} > -\frac{a}{b}$.

If $\frac{c}{a+b} \geq \bar{\theta}$, then the following four changes apply to the statement: the interval $[x_1; x_2]$ is replaced everywhere with $[x_1; x_2)$, in 1) the property $f(x_2) = x_2$ is omitted, in 3) the inequality $x_1 \leq x < x' \leq x_2$ is replaced by $x_1 \leq x < x' < x_2$, and property 4) is omitted.

Proof.

Case 1: $c \leq bg(0)$

The following observations i.-iv. may be verified by immediate calculation:

i. $\pi\left(x_1, \frac{c}{b}\right) = 0$; $\pi(x_2, x_2) = 0$;
ii. $x < x_2 \Rightarrow \pi(x,x) < 0$; $x > x_1 \Rightarrow \pi\left(x, \frac{c}{b}\right) > 0$;
iii. $y \in \left[x; \frac{c}{b}\right], y < y' \leq g(x) \Rightarrow \pi(x,y) < \pi(x,y')$;
iv. $x > x_2, y \in \left[x; \frac{c}{b}\right] \Rightarrow \pi(x,y) \geq \pi(x,x) > 0$; $\frac{c}{b} < y \leq g(x) \Rightarrow \pi(x,y) > 0$.

Existence of solutions y to $\pi(x_1, y) = 0$ and $\pi(x_2, y) = 0$ satisfying $x_1 < y \leq \frac{c}{b} \leq g(x_1)$ and $x_2 \leq y < \frac{c}{b} \leq g(x_2)$ respectively follows from i.; existence of solutions y to $\pi(x,y) = 0$ for $x \in (x_1; x_2)$ satisfying $x < y < \frac{c}{b} \leq g(x)$ follows from ii., continuity and the Intermediate Value Theorem; uniqueness of solution $y \in [x; \frac{c}{b}]$ for all $x \in [x_1; x_2]$ then follows from iii.; that no solutions exist outside of $\{(x,y): x \in [x_1; x_2], y \in [x; \frac{c}{b}]\}$ follows from iv. and the definition of the region ($x \geq 0$).

It now follows from the assumptions on $\theta(P_E)$, observation iii., and the Implicit Function Theorem that the graph of the zero profit condition is the image of a function $f: [x_1; x_2] \to \mathbb{R}$ that is continuously differentiable on $(x_1; x_2)$.

Regarding property 3), for all $(x, f(x))$ og $(x', f(x'))$ such that $x_1 \le x < x' \le x_2$ it is the case that $P_E(\theta \ge x) > P_E(\theta \ge x') > 0$, $P_E(\theta \ge f(x)) > 0$, and $P_E(\theta \ge f(x')) > 0$. If $\frac{P_E(\theta \ge x)}{P_E(\theta \ge f(x))} \le \frac{P_E(\theta \ge x\prime)}{P_E(\theta \ge f(x'))}$, then $f(x') = \frac{c}{b} - \frac{a}{b}\frac{P_E(\theta \ge x')}{P_E(\theta \ge f(x'))}x' < \frac{c}{b} - \frac{a}{b}\frac{P_E(\theta \ge x)}{P_E(\theta \ge f(x))}x = f(x) \Rightarrow P_E(\theta \ge f(x')) > P_E(\theta \ge f(x)) \Rightarrow \frac{P_E(\theta \ge x)}{P_E(\theta \ge f(x))} > \frac{P_E(\theta \ge x\prime)}{P_E(\theta \ge f(x'))}$, which is a contradiction. Hence, $\frac{P_E(\theta \ge x)}{P_E(\theta \ge f(x))} > \frac{P_E(\theta \ge x\prime)}{P_E(\theta \ge f(x'))} > 0$.

In the Appendix, I show the remaining statements regarding the endpoints.

Case 2: $bg(0) < c < (2a+b)\bar{\theta}$

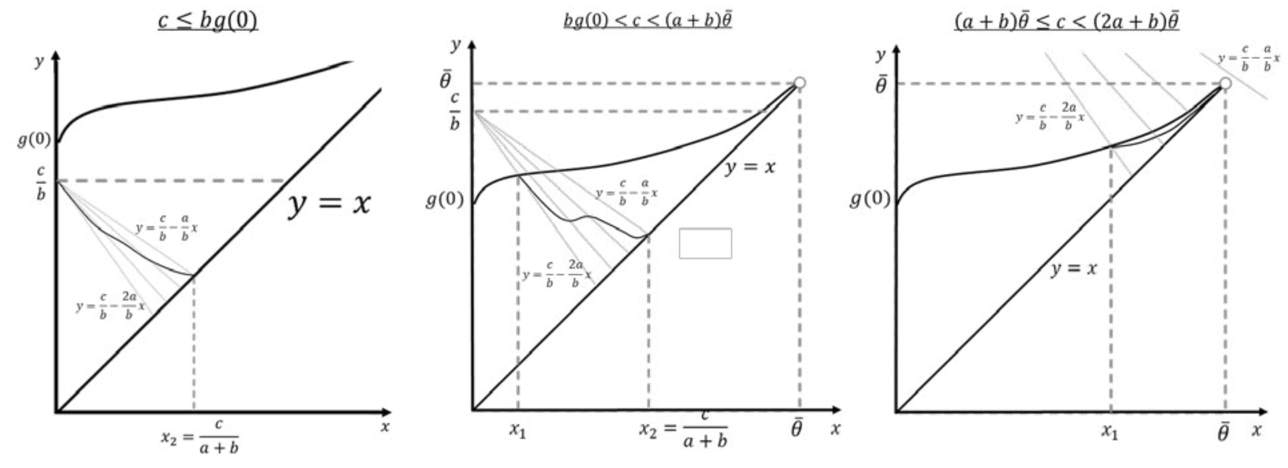
The proof is quite similar to that of case 1; the details are in the Appendix.

Lemma 3.2.1 tells us that the graph of the zero profit condition in the threshold region $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$ is a smooth curve and gives us some support points. Moreover, the possibilities regarding the slopes of the curve are limited given properties 2)-4). In order to see how, notice that the zero profit condition can be rewritten as follows

$$\pi(x,y) = 0 \Leftrightarrow y = \frac{-a}{b}\frac{P_E(\theta \ge x)}{P_E(\theta \ge y)}x + \frac{c}{b}.$$

While y and x are not isolated in this expression, any point (x', y') satisfying the zero profit condition will also lie on a line $y = A'x + \frac{c}{b}$ where $A' = \frac{-a}{b}\frac{P_E(\theta \ge x\prime)}{P_E(\theta \ge y\prime)}$. The slope A' of this line is negative and becomes flatter as x' increases (Property 3)). Moreover, by Lemma 2.5.1, in Case 2, A' evaluates to $-2\frac{a}{b}$ at $x' = x_1$, and in both cases the right-derivative of f at x_1 is greater than $-2\frac{a}{b}$ (weakly if $\frac{c}{b} = g(0)$). Similarly, if $\frac{c}{a+b} < \bar{\theta}$, A' evaluates to $\frac{-a}{b}$ at $x' = x_2$, and the left-derivative of f at x_2 is greater than $-\frac{a}{b}$. These facts restrict the possible slopes of the curve of the zero profit condition, as displayed in Figure 3.2.2.

Figure 3.2.2. – possible graphs of the zero profit condition in the optimal region.



3.3. The optimal regulation

The question now is whether there exist regulation components that implement the welfare maximizing threshold values irrespective of the underlying parameter values. As it turns out, the answer is “yes”.

I begin by showing that the welfare maximizing threshold values satisfy the zero profit condition.

Lemma 3.3.1. – zero economic profit is necessary, but not sufficient, for optimal welfare.

Let the marginal cost of additional capacity satisfy $0 < c < (2a+b)\bar{\theta}$. Then maximal social welfare is achievable only by a regulation that imposes or implies zero economic profit. However, zero economic profit is not on its own a guarantee for optimal welfare.

Proof.

Let (x^*, y^*) denote the welfare maximizing thresholds. By Proposition 3.1.1 and Lemma 3.2.1, irrespective of the value of $c < (2a+b)\bar{\theta}$, $\pi(x^*, y^*) = 0$, that is, profit at the welfare maximizing thresholds is necessarily zero. Moreover, by Lemma 3.2.1 there exist threshold values $(x, y) \neq (x^*, y^*)$ satisfying $x \in [0; \bar{\theta})$, $y \in [x; g(x)]$, and $\pi(x, y) = 0$.

I then proceed to show that the welfare maximizing threshold values also satisfy another condition, namely $y = \frac{c}{b} - \frac{2a}{b}x \leq g(x)$.

Lemma 3.3.2. – another necessary condition for optimal welfare.

Let $c \in (0; (2a+b)\bar{\theta})$. Then maximal social welfare is achievable only by a regulation that imposes or implies satisfaction of the condition $y = \frac{c}{b} - \frac{2a}{b}x \leq g(x)$. However, this condition is not on its own a guarantee for optimal welfare.

Proof.

By Proposition 3.1.1, the welfare maximizing thresholds (x^*, y^*) satisfy $y^* \leq g(x^*)$. Additionally, if $\frac{c}{b} \leq g(0)$, $(x^*, y^*) = (0, \frac{c}{b})$ satisfies $y^* = \frac{c}{b} - \frac{2a}{b}x^*$, and if $bg(0) < c < (2a+b)\bar{\theta}$, $(x^*, y^*) = (\tilde{x}, g(\tilde{x}))$ also satisfies $y^* = \frac{c}{b} - \frac{2a}{b}x^*$, since $\tilde{x} \in (0; \bar{\theta})$ is the unique solution to $2ax + bg(x) = c$. Thus, irrespective of the value of $c \in (0; (2a+b)\bar{\theta})$, $y^* = \frac{c}{b} - \frac{2a}{b}x^* \leq g(x^*)$. It is clear that other threshold values also satisfy this condition.

Finally, I show that zero economic profit and $y = \frac{c}{b} - \frac{2a}{b}x \leq g(x)$ together are sufficient conditions for optimal welfare, irrespective of the value of $c \in (0; (2a+b)\bar{\theta})$.

Proposition 3.3.3. – optimal regulation.

Let $c \in (0; (2a+b)\bar{\theta})$. The restriction $y = \frac{c}{b} - \frac{2a}{b}x \leq g(x)$ on the threshold values and the zero profit condition $\pi(x, y) = 0$ are together necessary and sufficient for implementing the welfare maximizing threshold values.

Proof.

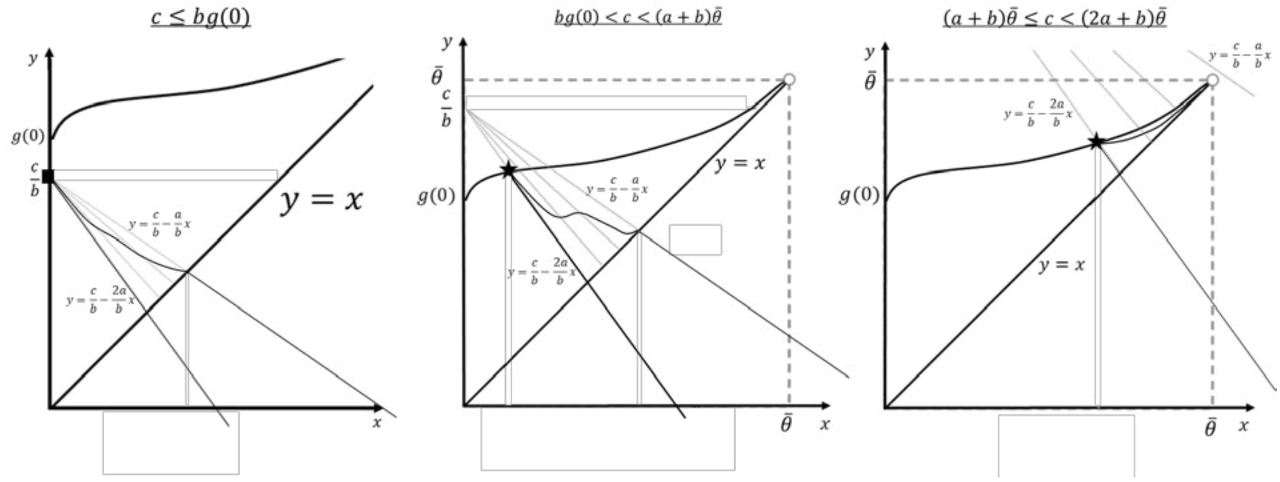
Necessity follows from Lemmas 3.3.1 and 3.3.2.

For sufficiency, I determine if any other intersection points than (x^*, y^*) exist between the restrictions $\pi(x, y) = 0$ and $y = \frac{c}{b} - \frac{2a}{b}x \leq g(x)$. Evidently no intersection points exist in the threshold region $\{(x, y): x \in [0; \bar{\theta}), y > g(x)\}$.

No intersection points exist in the threshold region $\{(x, y): x > 0, y \in \left[\frac{-a}{b}x; \min\left\{x, \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\right\}\right)\}$. First notice that in this region, $\pi(x, y) = (a+b)\left(\frac{a}{a+b}x + \frac{b}{a+b}y - \frac{c}{a+b}\right)P_E\left(\theta \geq \frac{a}{a+b}x + \frac{b}{a+b}y\right)$ and $\frac{a}{a+b}x + \frac{b}{a+b}y < \bar{\theta}$, the implication of which is that zero profit in the region is possible if and only if $\frac{c}{a+b} < \bar{\theta}$. In that case, $\pi(x, y) = 0 \Leftrightarrow y = \frac{c}{b} - \frac{a}{b}x$. Now, it is impossible that $y = \frac{c}{b} - \frac{a}{b}x$ and $y = \frac{c}{b} - \frac{2a}{b}x$ at the same time, unless $x = 0$, but $x = 0$ is not part of the region.

The region $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$ remains. Pick any point $(x,y) \neq (x^*,y^*)$ in the region such that $\pi(x,y) = 0$. By Proposition 3.1.1 and Lemma 3.2.1, $x > x_1 = x^*$, $y = f(x)$, and $\frac{P_E(\theta \geq x^*)}{P_E(\theta \geq f(x^*))} > \frac{P_E(\theta \geq x)}{P_E(\theta \geq f(x))} > 0$. Moreover, $f(x^*) = y^* \leq g(x^*)$, so $\frac{P_E(\theta \geq x)}{P_E(\theta \geq y)} < \frac{P_E(\theta \geq x^*)}{P_E(\theta \geq g(x^*))} = 2$. It follows that $y = \frac{c}{b} - \frac{a}{b}\frac{P_E(\theta \geq x)}{P_E(\theta \geq y)}x$ and $y = \frac{c}{b} - \frac{2a}{b}x$ cannot be satisfied simultaneously for any $x \neq x^*$ in the region.

Figure 3.3.4. – Optimal regulation.



3.4. Optimal regulation in practice – approaching the welfare maximizing threshold values

A remaining question is how to achieve the welfare maximizing allocation in practice given available information.

Any regulation that quantifies the true economic costs, including costs of capital, of energy transportation and limits the permissible revenue levels to those that just cover the true economic costs, will impose the condition of zero economic profit $\pi(x,y) = 0$. A revenue cap is a widely used regulation that could achieve zero economic profit, provided that the economic costs are properly accounted for.

Any regulation attempting to achieve zero economic profit will produce a measure of economic profit, $\pi(x,y)$, which then is part of the observable, available information. For revenue cap regulation, $\pi(x,y)$ would be the difference between the actual revenue and the determined cap.

In total, the available information typically is the economic profit $\pi(x,y)$, the aggregate demands $\epsilon_1(x,y)$ and $\epsilon_2(x,y)$, and the tariffs. The latter are ax and $by + ax$ by Section 2.3, equations (*) and (**). If it is not known which of the two periods is the preferred period, it is always possible to check it by setting the tariffs equal to each other and observe in what period demand is greatest under those tariffs.

From these quantities, for any threshold pair (x,y) satisfying $0 < \epsilon_1(x,y) \leq \epsilon_2(x,y)$ it is possible to back out c as follows:

$$c = by - \frac{\pi(x,y) - ax\big(\epsilon_1(x,y) + \epsilon_2(x,y)\big)}{\epsilon_2(x,y)}.$$

However, $\pi(x,y)$, $\epsilon_1(x,y)$, $\epsilon_2(x,y)$, ax, $by + ax$, and c are not enough to identify the optimal thresholds and allocation. What is missing is the function g, about which nothing is known besides its basic properties listed in Lemma 2.5.1.

This suggests that a direct way to go about achieving optimal welfare is to estimate the distribution $\theta(P_E)$, from which g could be calculated. This would allow setting the tariffs at their optimal levels straight away.

However, there are good reasons for not attempting to jump to the optimal allocation at once. Firstly, the profit history of the monopolist and resulting accumulation of assets or liabilities vis-à-vis consumers may warrant a step-by-step approach in which new profits gradually cancel out the historically accumulated assets or liabilities. Secondly, in practice it takes time for the monopolist to adapt the capacity of its grid to the changing demand, so a big one-off adjustment may not be desirable. And thirdly, a step-by-step approach might be more consistent with other regulatory priorities.

If a step-by-step approach is deemed appropriate, other options than estimating the distribution $\theta(P_E)$ and calculating the optimal allocation become available. Avoiding the estimation of $\theta(P_E)$ may be particularly desirable given that estimation would be necessary for each monopolist/grid area, potentially a large number of estimations.

In fact, it is possible to adjust gradually to the optimal allocation only knowing what is readily observable, that is, $\pi(x,y)$, $\epsilon_1(x,y)$, $\epsilon_2(x,y)$, ax, $by+ax$, and c. In particular, it is possible to arrive at the optimal allocation without knowing in advance what it is. The approach takes advantage of the fact that according to the results stated previously in this paper, the values of the observable quantities can be used as markers of the required direction of adjustment of the thresholds.

There are three different courses of action depending on the starting point. First, if $by > c$, y (or the tariff in the second period) should be adjusted down until $by \leq c$. Such adjustment is possible because by is observable as $(by+ax)-ax$ and desirable because by Proposition 3.1.1, the optimal point always satisfies $by^* \leq c$.

Second, if $by \leq c$ and one or more of the inequalities $0 < \epsilon_1(x,y) < \epsilon_2(x,y)$, $ax > 0$ is not satisfied, the following procedure can be used while always maintaining $by \leq c$, either to arrive at the optimum or to arrive somewhere in the set $\{(x,y): 0 < \epsilon_1(x,y) < \epsilon_2(x,y), ax > 0, by \leq c\}$:

1. $\epsilon_1(x,y) > \epsilon_2(x,y) \geq 0$: Reduce y.
2. $\epsilon_2(x,y) > \epsilon_1(x,y) = 0$: Reduce x.
3. $\epsilon_2(x,y) = \epsilon_1(x,y) > 0$:

a. $\pi(x,y) > 0$:

i. $x > 0$: Reduce both x and y;

ii. $x = 0$: Maintain x and reduce y to $by = c$.

b. $\pi(x,y) < 0$: Raise both x and y.

c. $\pi(x,y) = 0$: Stay put, this is the optimum.

4. $\epsilon_2(x,y) > \epsilon_1(x,y) > 0$, $x = 0$:

a. $\pi(x,y) > 0$: Maintain x and reduce y to $by = c$.

b. $\pi(x,y) < 0$: Increase x.

c. $\pi(x,y) = 0$: Stay put, this is the optimum.

Third, if the inequalities $0 < \epsilon_1(x,y) < \epsilon_2(x,y)$, $ax > 0$, and $by \leq c$ are satisfied, by Proposition 3.3.3, there is a simple way of moving towards the optimum. Recall the restriction $y = \frac{c}{b} - \frac{2a}{b}x$ defining a straight line towards the optimum. This line can be rewritten as $by + 2ax - c = 0$, whose terms are all observable. Thus, it is possible to approach the optimal thresholds in a straight line by first moving to the line $by + 2ax - c = 0$ and then move along the line by raising by and reducing ax in such a way that $by + 2ax - c = 0$ is maintained. There are indicators for when to stop or reverse, as follows. When $\pi(x,y) = 0$, the thresholds are the optimal ones and no more adjustment is needed. If $\epsilon_1(x,y) > \epsilon_2(x,y)$, the adjustment has gone too far. And by the proofs of Lemma 3.2.1 and Proposition 3.3.3, $\pi(x,y) < 0$ along the adjustment path and a sign that more adjustment is needed. As a result, this approach should only be used if the monopolist has a history of positive profits and has accumulated liabilities vis-à-vis consumers.

Yet the approach can be adapted to monopolists with histories of negative profits. Simply move to the line $by + 2ax - (c+\delta) = 0$, where $\delta > 0$ is some chosen number that should increase with the accumulated assets vis-à-vis consumers. Then move along the line as above. By Lemma 3.2.1, profits will become positive eventually, and when they do, the monopolist may stay put there until the accumulated assets have been reduced sufficiently. In order to make it to the optimal allocation, eventually the line $by + 2ax - (c+\delta) = 0$ must be abandoned, for example in favor of $by + 2ax - c = 0$.

A second method is simply to be led by the sign of the profits. If a monopolist has had a history of zero economic profits, then the monopolist could reduce x and increase y gradually in such a way that profits remain as close to zero as possible or alternate around zero. Specifically, if profits become positive, x should be further reduced, and if they become negative, y should be increased more. In this way, one may arrive at the optimal thresholds.

In practice, more specific information about $\theta(P_E)$, for instance in the form of local elasticities, or about the slope of the zero profit condition relative to the line $by + 2ax - c = 0$, could be brought to bear for a more direct adjustment path than what a general treatment allows for here.

4. CONCLUSIONS AND PERSPECTIVES

I now present the key results from Section 3 in a nontechnical format along with their intuition. In addition, I offer two perspectives on the concepts of Ramsey pricing and cost reflectivity appearing in [1].

4.1. Intuitive summary of key results formulated in terms of tariffs

Denote by M the median activity value of the distribution $\theta(P_E)$, that is, if all activities were consuming energy, half of the consumption would come from activities with activity values lower than M, and the other half would come from activities with activity values higher than M. Recalling that $g(0) = M$ (Lemma 2.5.1), and reverse transforming the parameters and variables back to time values and tariffs (Section 2.3, formulas (*)-(****)), one obtains the following key results.

Key result 1 – optimal tariffs and consumption pattern (Proposition 3.1.1 and Corollary 3.1.2).

If $c \leq (\nu(2) - \nu(1))M$, the optimal tariffs are $(p(1)^*, p(2)^*) = (0, c)$, that is, transport of energy is free in the inferior period, and in the preferred period the tariff equals the marginal cost of extra capacity. At these tariffs, all activities are carried out, and energy consumption is positive in the inferior period and weakly larger in the preferred period.

On the other hand, if $(\nu(2) - \nu(1))M < c < (\nu(1) + \nu(2))\bar{\theta}$, the optimal tariffs are those satisfying the condition that the demands in period 1 and 2 be equal while simultaneously $p(1)^* + p(2)^* = c$, that is, the sum of the tariffs equals the marginal cost of extra capacity. Only one such pair of tariffs exists, and it satisfies $p(2) > p(1)\frac{\nu(2)}{\nu(1)} > 0$. Demands are positive, but activities with sufficiently low activity values do not take place.

Intuition.

Recall that the quantity $\big(\nu(2) - \nu(1)\big)\theta$ is the utility gain from moving an activity with activity value θ from period 1 to period 2. As such, it is also the maximum tariff differential a consumer is willing to pay for moving an activity with activity value θ from period 1 to period 2. Hence, an activity that consumes energy takes place in period 2 if and only if the utility gain from moving the activity from period 1 to period 2 is greater or equal to the tariff differential.

Define for a given tariff differential the marginal activity given consumption as the activity that consumes energy and whose owner is indifferent between the two periods. By the logic above, the tariff differential is the additional utility obtained by switching the marginal activity from period 1 to period 2. In a similar fashion, $p(1)$ is the utility obtained from consumption in period 1 if the owner of an activity is indifferent between consuming in period 1 and not consuming at all.

Recall also that the cost function is non-differentiable. As long as demand in period 2 is weakly larger than in period 1, the marginal effect on the cost to society of moving an activity from period 1 to period 2 is $c > 0$, since the grid must be scaled up correspondingly. On the other hand, if demand is at least as large in period 1, and an activity is moved in the reverse direction from period 2 to 1, the marginal effect is also $c > 0$.

Now, if $c \leq (\nu(2) - \nu(1))M$, the tariffs $(p(1)^*, p(2)^*) = (0, c)$ are optimal for four reasons. First, the consumption pattern associated with the tariffs is such that all activities take place ($p(1)^* = 0$). Second, since $p(2)^* - p(1)^* = c \leq (\nu(2) - \nu(1))M$, the incremental utility from switching the marginal activity to period 2 is weakly lower than the incremental utility of switching the median activity, from which it follows that the marginal activity has an activity value weakly lower than the median. Thus, the energy consumption in period 2 is at least as large as in period 1. Third, the activities that take place in period 2 are those for which $\big(\nu(2) - \nu(1)\big)\theta \geq p(2)^* - p(1)^* = c$, that is, those for which the incremental utility from switching to period 2 is at least as large as the incremental cost to society associated with the switching. Fourth, the marginal cost to society of consumption in period 1 is zero, thus $p(1)^* = 0$ ensures that consumption takes place whenever it is of net benefit to social welfare.

Essentially, when $c \leq (\nu(2) - \nu(1))M$, standard marginal cost pricing is possible, that is, marginal cost pricing under the assumption that demand is weakly larger in period 2 gives rise to a consumption pattern according to which demand is indeed weakly larger in period 2. In the resulting allocation, no deviating action (switch or consumption stop) for any activity would result in a higher contribution from such activity to social welfare.

Now consider the case $c > (\nu(2) - \nu(1))M$ and suppose that $p(1) = 0$ so that all activities are carried out. In such a scenario, due to the non-differentiability of the cost function, no tariff differential exists for which the additional contribution to utility and to social cost when switching the marginal activity are equal. For tariff differentials low enough that demand in period 2 is weakly larger than in period 1, the marginal activity value is weakly lower than the median. As a result, at any such tariff differential, switching the marginal activity to period 2 would increase social cost by more than it would increase utility, since the utility gain from switching the marginal activity would be less than from switching the median activity and the latter is less than c. On the other hand, from any tariff differential at which demand in period 1 weakly exceeds demand in period 2, switching the marginal activity from period 2 to period 1 would raise social cost *and* reduce utility. In effect, switching towards equal demands is always beneficial, but at the point of equality, the marginal social net benefit of further switching drops from positive to negative and skips all the values in between.

As a result, in an optimal allocation, the demands in the two periods are equal, and consumption in period 1 no longer has a social cost of zero. In fact, the social price received for giving up some period 1-consumption now is the positive difference between the marginal decrease in cost and the marginal loss of utility induced by a marginally higher tariff differential from where the demands are equal.

Turning to the benefit of consumption in period 1, the lowest-valued activity for which consumption takes place contributes to utility in the amount of $p(1)$. Thus, if $p(1)$ is raised from a value of zero, the marginal loss of utility from consumption in period 1 is zero. It follows that it is socially beneficial to raise the tariff in period 1 above zero and hereby exclude some of the low-value activities from period 1-consumption.

Actually, the net benefit from raising $p(1)$ is positive for low values of $p(1)$, decreasing in $p(1)$, and negative for large $p(1)$, for two reasons. First, the marginal loss of utility ($p(1)$) from lower consumption in period 1 is clearly increasing in $p(1)$. And second, the social price received for less period 1-consumption decreases in $p(1)$ commensurate with the exhaustion of the cost-saving potential from switching to period 1 as the marginal activity values and thus the utility loss of the switched activities increase.

The net benefit of raising $p(1)$ will reach zero before $p(2) - p(1) = c$, because at this point the social price of period-1 consumption becomes zero, which means that utility could be increased for free by reversing some of the increases in $p(1)$. In fact, the optimal tariff pair satisfies $p(1)^* + p(2)^* = c$ (and that the demands are equal). To see this, simply consider removing two of those activities with the lowest activity values from consumption in period 1, and switch one activity from period 2 to period 1. The resulting utility loss would be $2p(1) + p(2) - p(1) = p(1) + p(2)$, while the cost saved would be $c \cdot 1$.

Key result 2 – optimal regulation (Proposition 3.3.3).

For a constant marginal cost of additional capacity $c \in (0; (\nu(1) + \nu(2))\bar{\theta})$, the following three regulation components are together necessary and sufficient for achieving the maximal social welfare in the model:

- Zero economic profit (for instance, a revenue cap);
- The restriction that the sum of the tariffs be equal to the marginal cost of extra capacity;
- The requirement that demand is weakly greater in the preferred period.

The result holds irrespective of the unknown underlying parameter values and distribution $\theta(P_E)$.

Intuition.

Recall the basic economics of constant marginal cost in a competitive environment with a single product. In such an environment, maximal welfare is achieved in equilibrium, and the equilibrium price of the product is equal to the marginal cost, the consequence of which is that revenue equals cost and profits are zero. A sufficient, alternative way to achieve the same efficient allocation in the same economic environment would be to impose a revenue cap (zero profit-condition), which given the constant marginal cost would force the price of the product to equal its marginal cost.

The optimal regulation in the model of this paper is essentially a two-product version of the basic one-product, constant marginal cost economics. Energy transportation may be considered as two products, one for each period, where the demand for each product depends on its own tariff and on the tariff of the other product.

First consider the case $c > (v(2) - v(1))M$. Regarding necessity of the regulation components in this parameter case, consider the optimal tariffs, that is, when the demands are equal and $p(1) + p(2) = c$. Due to the equality of the demands, in effect it is as if there were only one product, sold at unit price $p(1) + p(2)$ and supplied at unit cost c. Thus, profits must be zero at the optimal tariffs, and the remaining two regulatory requirements must obviously hold as well.

Regarding sufficiency of the regulation components, when $p(1) + p(2) = c$ and demand in period 2 is weakly greater than in period 1, the zero profit condition in effect excludes the possibility of greater demand in period 2. To see this, notice that for demand in period 2 to be (strictly) greater than in period 1, $p(2)$ must be lower and $p(1)$ higher compared to if demands were equal, thus the demand in period 2 is higher than it would be if demands were equal and demand in period 1 is lower than it would be if demands were equal, implying a higher cost than if demands were equal. However, the revenue cannot be correspondingly higher, because changing the tariffs initially in opposite directions does not change the revenue as the quantities are equal initially, while the subsequent change in quantities has a smaller effect on revenue than on cost since $p(2) < c$ and the quantity in period 1 decreases. As a result, profits are lower than if demands were equal, that is, they are negative.

The case $c \leq (v(2) - v(1))M$ is similar. First, recall from Key result 1 that at tariffs of zero in period 1 and c in period 2, demand in period 2 (weakly) exceeds demand in period 1. A lower tariff in period 2 and higher tariff in period 1 will only reinforce this relation between the demands, which means that demand in period 2 always (weakly) exceeds demand in period 1 whenever $p(1) + p(2) = c$. Now, regarding necessity, the optimal tariffs of 0 and c respectively imply $p(1) + p(2) = c$ as well as zero profits, since with a tariff of zero in period 1 and (weakly) higher demand in period 2, the revenue and cost only stem from the period 2 demand, while the period 2-tariff equals the unit cost. Regarding sufficiency, by the same argument as above, zero profits exclude other tariffs than 0 and c.

Key result 3 – optimal regulation in practice (Section 3.4).

By observing a measure of economic profits, such as excess revenue under a revenue cap, the aggregate demands in the two periods, and the tariffs, it is possible to arrive at the optimal tariffs in a step-by-step, experimental manner without knowing in advance what the optimal tariffs are or resorting to estimation. Moreover, the approach to the optimal tariffs may be adapted in a way that takes into account the individual profit history of the monopolist.

Intuition.

The result hinges on the fact that once equipped with the observed quantities, c becomes observable, and thus all three regulation components that uniquely identify the optimal tariffs no matter the parameter values become verifiable, meaning that it may be observed whether they hold or not. Moreover, due to the relationship between the regulation components, there is sufficient information in such observation to guide the next tariff adjustment in a fruitful direction towards the optimum.

4.2. Perspectives: Ramsey pricing, cost reflectivity

[1], Chapter 7, offers a glimpse of the current thinking among regulatory bodies on time-differentiated tariffs as instruments for achieving efficiency (high social welfare). The general idea behind time-differentiated tariffs as referenced in [1] is that a higher tariff in the peak period relative to off-peak periods could be desirable since it would encourage consumption in off-peak periods and potentially save costs. In practice, according to [1], tariffs today are time-differentiated in about 75% of the EU countries.

This line of thinking is consistent with the results in this paper, according to which the optimal tariff in the preferred period always is higher than in the inferior period, no matter the underlying parameters.

Besides the general rationale for time-differentiation, [1] contains two other main principles for achieving efficiency in energy transportation to households. In paragraph 30, Ramsey pricing is mentioned as a pricing rule, the use of which could avoid distortion of price signals. To this point, I would recall the two fundamental assumptions of Ramsey pricing, namely differentiability of the cost function and independent demands. However, in the case of energy transportation in a multi-period setting, it would appear that neither of these two assumptions is satisfied. The cost function would be non-differentiable, given that the cost is determined by peak demand [2], and the demands would be dependent, given that the demand in one period depends on the tariff of the other period [3].

The second principle in [1] is that of cost reflectivity. Cost reflectivity is not an aim in itself, but rather a way of achieving the underlying goal of marked efficiency. While [1] does not contain an explicit, uniform definition of the term, one possible definition is the one appearing in paragraph 138: “In order to ensure cost-reflectivity and avoid market distortions, the cost caused by a network user should be properly reflected in its tariffs. If a network user only withdraws from or only injects into the transmission or distribution grid, in principle, only the costs relevant for withdrawal or the costs relevant for injection should be attributed to this network user."

If this definition is appropriate, it seems important to recall a basic classification of types of goods in four categories. Private goods are excludable and rivalrous, public goods are non-excludable and non-rivalrous, common goods are non-excludable and rivalrous, and club goods are excludable and non-rivalrous. "Excludable" means that the seller can prevent consumers from consuming the good and "rivalrous" means that one consumer's consumption prevents another's.

Equipped with this terminology, notice that energy transportation becomes a club good when there is more than one period. Specifically, in the case of a single time period, consumption is simultaneous, and the consumption of each household adds to the required capacity of the grid because one household cannot be served by the same capacity used by another household. In effect, transport of energy in a single-period setting is rivalrous, and since it is also excludable (delivery can be cut), it is a private good. However, in the case of more than one period, the same grid handles consumption that is no longer simultaneous, and consumption in one period does not prevent consumption in another period. As a result, energy transport becomes non-rivalrous, thus a club good.

The implication of energy transport being a non-rivalrous good is that trying to determine the shares of the total cost caused by consumption in each period is a futile exercise, since it is impossible to identify the period of consumption that has driven the need for capacity. In effect, a definition of cost reflectivity such as the one considered above would not be applicable as a guiding principle for the determination of the time-differentiation of tariffs. This calls for a broader and more holistic approach to the definition of cost reflectivity than the traditional interpretation described above. This result is in line with recent decisions from the Danish Utility Regulator. One example is the approval of a tariff methodology, that applies an increase consumer tariff in 'expected' peak hours in order to prevent consumption here. The idea is, that the implied peakshaving will lead to saved infraststructure investments to the benefit of all consumers. Another example is the recent approval of consumption tariffs that applies a reduced tariff for very large annual volumes, as the larger volumes benefit all consumers.

An analogy from the academic literature on cost sharing emphasises the point. Consider two people taking a taxi [4]; one gets off on the way to the destination of the other. As one might imagine, several principles and rationales for sharing the bill exist, such as the equal split rule or one passenger obtaining a free ride, but it is impossible to determine who caused what share of the cost (at least until the point where the first person gets off).

In fact, the literature [4] (sections 2.1 and 2.3) specifically considers non-rivalrous energy transportation. In the absence of an obvious way to allocate the cost, the literature explores the properties of a number of alternative cost sharing rules. If cost reflectivity had been an operational criterion for sharing the cost of a club good, it would have appeared here, or perhaps there would not have been a need for the literature to deal with the issue in the first place.

More generally, cost reflectivity as defined above and efficiency are not the same concepts, as would appear in some sections of [1]. Indeed, the model of this paper provides an example in which maximal social welfare is pursuable through appropriate tariffs but cost reflectivity is not.

This is not to say that cost reflectivity is not a useful principle. It may be useful in other contexts that are outside the scope of this paper.

5. REFERENCES

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[3] Danish Energy Agency, "Danskerne bruger strømmen, når den er billig: Fire ud af 10 har ændret deres energiforbrug", 30th of May 2022.

[4] Hougaard, Jens Leth, "An Introduction to Allocation Rules", 2009.

APPENDIX

PROOFS NOT INCLUDED IN THE MAIN TEXT

This appendix presents the proofs or parts thereof not included in the main text.

Proof of Lemma 2.5.1.

Recall that $\theta(P_E)$ is a continuous distribution. By the Intermediate Value Theorem, for all $x \in [0;\bar{\theta})$ a unique $y \in (x;\bar{\theta})$ exists such that $P_E(\theta \geq y) = \frac{1}{2}P_E(\theta \geq x)$. Consider the open subset $(0;\bar{\theta}) \subset [0;\bar{\theta})$ and recall the other assumptions on $\theta(P_E)$. By the Implicit Function Theorem, there exists a unique function $g: (0;\bar{\theta}) \to (0;\bar{\theta})$ satisfying that for all $x \in (0;\bar{\theta})$, $P_E(\theta \geq g(x)) = \frac{1}{2}P_E(\theta \geq x)$; moreover, g is continuously differentiable on $(0;\bar{\theta})$ with derivative $g'(x) = \frac{1}{2}\frac{f_{\theta(P_E)}(x)}{f_{\theta(P_E)}(g(x))} > 0$. In fact, g is monotone and bounded below since, by definition, $\forall x \in [0;\bar{\theta})$, $g(x) \geq g(0)$.

In order to show that $g: [0;\bar{\theta}) \to (0;\bar{\theta})$ is continuous at $x = 0$, pick a sequence $(x_n)_{n\in\mathbb{N}}$ such that $\forall n \in \mathbb{N}$, $x_n \in [0;\bar{\theta})$, and $\lim_{n\to\infty} x_n = 0$. This sequence has a monotone subsequence. Also, any monotone subsequence converges to zero and is weakly decreasing. Then consider the sequence $\left(g(x_n)\right)_{n\in\mathbb{N}}$. Any monotone subsequence $\left(g(x_{n_k})\right)_{k\in\mathbb{N}}$ is weakly decreasing since g is monotone and thus $\left(g(x_{n_k})\right)_{k\in\mathbb{N}}$ stems from a monotone, weakly decreasing subsequence $\left(x_{n_k}\right)_{k\in\mathbb{N}}$. Moreover, bounded monotone sequences must converge by the Monotone Convergence Theorem. As a result, any monotone subsequence $\left(g(x_{n_k})\right)_{k\in\mathbb{N}}$ converges to a limit and, additionally, such limits must be equal, since all monotone subsequences of $(x_n)_{n\in\mathbb{N}}$ converge to the same limit. Since all monotone subsequences $\left(g(x_{n_k})\right)_{k\in\mathbb{N}}$ converge to the same limit, the sequence $\left(g(x_n)\right)_{n\in\mathbb{N}}$ converges.

Now, due to the continuity of $\theta(P_E)$, $P_E\left(\theta \geq \lim_{n\to\infty} g(x_n)\right) = \lim_{n\to\infty} P_E(\theta \geq g(x_n)) = \lim_{n\to\infty}\frac{1}{2}P_E(\theta \geq x_n) = \frac{1}{2}P_E(\theta \geq 0) = P_E(\theta \geq g(0))$. As the cdf of $\theta(P_E)$ is strictly increasing around $g(0)$, it must be the case that $\lim_{n\to\infty} g(x_n) = g(0)$. It follows that g is continuous at $x = 0$, hence continuous everywhere.

That $\lim_{x\to\bar{\theta}^-} g(x) = \bar{\theta}$ follows from $x < g(x) < \bar{\theta}$.

Full proof of Proposition 3.1.1.

The region $\{(x,y): x \in [0;\bar{\theta}), y > g(x)\}$

Calculate $\frac{\partial SWF(x,y)}{\partial y} = -f_{\theta(P_E)}(y)(by + c)$; for $g(x) < y < \bar{\theta}$, $\frac{\partial SWF(x,y)}{\partial y} < 0$, and for $y \geq \bar{\theta}$, $\frac{\partial SWF(x,y)}{\partial y} = 0$. Notice that for all $x \in [0;\bar{\theta})$, SWF is continuous in $y \geq g(x)$. Thus, for all $x \in [0;\bar{\theta})$ and all $y > g(x)$, $SWF(x,y) < SWF(x,g(x))$, that is, the social welfare is greater in the region $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$ analyzed further below. This holds no matter the value of $c > 0$.

The region $\left\{(x,y): x > 0, y \in \left[\frac{-a}{b}x; \min\left\{x, \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\right\}\right)\right\}$

I show that for $\frac{c}{a+b} < \bar{\theta}$, social welfare is higher in $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$, and for $\frac{c}{a+b} \geq \bar{\theta}$, it is higher in $\{(x,y): x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}$. To begin, notice that for $x > 0, y \in \left[\frac{-a}{b}x; \min\left\{x, \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\right\}\right)$, $\frac{a}{a+b}x + \frac{b}{a+b}y < \bar{\theta}$.

If $\frac{c}{a+b} \geq \bar{\theta}$, the following calculation shows that social welfare is negative in $\left\{(x,y): x > 0, y \in \left[\frac{-a}{b}x; \min\left\{x, \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\right\}\right)\right\}$, and thus higher in $\{(x,y): x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}$ (where it is zero):

$$SWF(x,y) = (a+b)\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta < \left((a+b)\bar{\theta} - c\right)\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta \leq 0.$$

If $\frac{c}{a+b} < \bar{\theta}$, calculate for any point in $\{(x,y): x > 0, y \in \left[\frac{-a}{b}x; \min\left\{x, \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\right\}\right)\}$

$$SWF(x,y) = (a+b)\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta$$

$$= (a+b)\int_{\frac{c}{a+b}}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{\frac{c}{a+b}}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta +$$

$$(a+b)\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\frac{c}{a+b}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\frac{c}{a+b}} f_{\theta(P_E)}(\theta)\,d\theta$$

$$\leq (a+b)\int_{\frac{c}{a+b}}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{\frac{c}{a+b}}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta +$$

$$\left((a+b)\frac{c}{a+b} - c\right)\int_{\frac{a}{a+b}x+\frac{b}{a+b}y}^{\frac{c}{a+b}} f_{\theta(P_E)}(\theta)d\theta$$

$$= (a+b)\int_{\frac{c}{a+b}}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{\frac{c}{a+b}}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta.$$

The right hand side is the social welfare in the point $(x,y) = (\frac{c}{a+b}, \frac{c}{a+b})$ in the region $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$ analyzed here below.

<u>The region $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$</u>

Let $x' \in (0;\bar{\theta})$ and $y' \in (x'; g(x'))$. $\left(\frac{\partial SWF(x\prime,y\prime)}{\partial x}, \frac{\partial SWF(x\prime,y\prime)}{\partial y}\right) = \left(-ax' f_{\theta(P_E)}(x'), -f_{\theta(P_E)}(y')(by'-c)\right)$. Thus, for all $\delta > 0$ sufficiently small, $SWF(x'-\delta, y') > SWF(x',y') > SWF(x'+\delta, y')$. Since for the given y' SWF is continuous in x on $\{x: 0 \leq x \leq y' \leq g(x)\}$, for $\underline{x}(y') = \min\{x: 0 \leq x \leq y' \leq g(x)\}$ and $\bar{x}(y') = \max\{x: 0 \leq x \leq y' \leq g(x)\} = y'$ it is the case that $SWF(\bar{x}(y'), y') < SWF(x',y') < SWF(\underline{x}(y'), y')$. Since (x',y') is an arbitrary point in the region, this shows that if an optimum exists in the region, it exists on the subset $\{(x,y): x = 0 \leq y \leq g(0)\} \cup \{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$.

Consider then $x = 0$ and $y \in (0; g(0))$. $\frac{\partial SWF(x,y)}{\partial y} = -f_{\theta(P_E)}(y)(by - c)$, and $SWF(0,\cdot)$ is continuous in $y \in [0; g(0)]$. Since $\frac{c}{b} > 0$, for $y \in (0; \min\{\frac{c}{b}, g(0)\})$ we have $\frac{\partial SWF(0,y)}{\partial y} > 0$ and $SWF\left(0, \min\left\{\frac{c}{b}, g(0)\right\}\right) > SWF(0,y) > SWF(0,0)$. A similar argument holds if $y \in (\frac{c}{b}; g(0))$; in this case $SWF\left(0, \min\left\{\frac{c}{b}, g(0)\right\}\right) > SWF(0,y) > SWF(0, g(0))$. As a result, $(x,y) = (0, \min\left\{\frac{c}{b}, g(0)\right\})$ is optimal on $\{(x,y): x = 0 \leq y \leq g(0)\}$.

Further, if $\frac{c}{b} \leq g(0)$, the point $(0, \min\left\{\frac{c}{b}, g(0)\right\})$ is actually optimal in all of the region, since all points in $\{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$ satisfy $y > g(0) \geq \frac{c}{b}$, and according to L'Hôpital's rule for an end point (Cauchy's Mean Value Theorem) together with continuity of $f_{\theta(P_E)}$ and $g(x)$,

$$\frac{\partial SWF(x,g(x))}{\partial y^-} = \lim_{\delta \to 0^+} \frac{SWF(x,g(x)) - SWF(x,g(x)-\delta)}{\delta} = \lim_{\delta \to 0^+} -f_{\theta(P_E)}(g(x)-\delta)(b(g(x)-\delta)-c) = -f_{\theta(P_E)}(g(x))(bg(x)-c) < 0.$$

If on the other hand $\frac{c}{b} > g(0)$, points exist in $\{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$ at which social welfare is greater than in $(0, g(0)) = (0, \min\{\frac{c}{b}, g(0)\})$. To see this, recall (Lemma 2.5.1) that for $\in (0;\bar{\theta})$, $g'(x) = \frac{1}{2}\frac{f_{\theta(P_E)}(x)}{f_{\theta(P_E)}(g(x))}$. Thus, the welfare gain from increasing $x > 0$ infinitesimally is $\frac{d}{dx}SWF(x, g(x)) = \frac{\partial SWF(x,g(x))}{\partial x} + \frac{\partial SWF(x,g(x))}{\partial y}g'(x) = -\frac{1}{2}f_{\theta(P_E)}(x)(2ax + bg(x) - c)$, the right-hand side of which is positive for all $x > 0$ sufficiently small; that $(0, g(0))$ is dominated follows from this fact and the continuity of g in 0.

If $bg(0) < c < (2a+b)\bar{\theta}$, the point $(\tilde{x}, g(\tilde{x}))$, where $\tilde{x} \in (0;\bar{\theta})$ is the unique solution to the equation $2ax + bg(x) = c$, is the unique optimal point in all of the region; that this is the case follows from the fact that $\frac{d}{dx}SWF(x, g(x))$ is strictly decreasing in x and becomes negative for $x < \bar{\theta}$ sufficiently big.

Finally, if $\frac{c}{2a+b} \geq \bar{\theta}$, no optimal point exists in the region as $\frac{d}{dx}SWF\big(x, g(x)\big) > 0$ even arbitrarily close to $\bar{\theta}$.

The region $\{(x,y): x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}$ in comparison with $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$

To begin, notice that in $\{(x,y): x \geq \bar{\theta}, y \geq \frac{a+b}{b}\bar{\theta} - \frac{a}{b}x\}$, consumption and social welfare are zero. For $c < (2a+b)\bar{\theta}$, I show that positive social welfare is available in $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$, and for $c \geq (2a+b)\bar{\theta}$, I show that only negative social welfare is obtainable in $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$.

If $c < (2a+b)\bar{\theta}$, consider a point $(x, g(x))$ where x is sufficiently close to $\bar{\theta}$:

$$SWF(x, g(x)) = a\int_x^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta + b\int_{g(x)}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_x^{g(x)} f_{\theta(P_E)}(\theta)\,d\theta$$

$$= a\int_x^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta + b\int_{g(x)}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{g(x)}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta$$

$$> ax\int_x^{\bar{\theta}} f_{\theta(P_E)}(\theta)d\theta + bg(x)\int_{g(x)}^{\bar{\theta}} f_{\theta(P_E)}(\theta)d\theta - c\int_{g(x)}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta$$

$$= 2ax\int_{g(x)}^{\bar{\theta}} f_{\theta(P_E)}(\theta)d\theta + bg(x)\int_{g(x)}^{\bar{\theta}} f_{\theta(P_E)}(\theta)d\theta - c\int_{g(x)}^{\bar{\theta}} f_{\theta(P_E)}(\theta)\,d\theta > 0.$$

If $\frac{c}{2a+b} \geq \bar{\theta}$, consider the social welfare in a point $(x', y') \in \{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$.

$$SWF(x', y') = a\int_{x'}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta + b\int_{g(x')}^{\bar{\theta}} \theta f_{\theta(P_E)}(\theta)d\theta - c\int_{x'}^{g(x')} f_{\theta(P_E)}(\theta)\,d\theta$$

$$< (\bar{\theta}(2a+b) - c)\int_{g(x')}^{\bar{\theta}} f_{\theta(P_E)}(\theta)d\theta \leq 0.$$

Since for all points in the region $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$ there exists $(x', y') \in \{(x,y): x \in (0;\bar{\theta}), y = g(x)\}$ with higher social welfare, non-negative social welfare is impossible in $\{(x,y): x \in [0;\bar{\theta}), y \in [x; g(x)]\}$.

Proof of the statements in Lemma 3.2.1, case 1, regarding endpoints

Regarding continuity of f at the endpoints x_1 and x_2, I need to show that if $c < (a+b)\bar{\theta}$, $f: [x_1; x_2] \to \mathbb{R}$ is continuous at the endpoints x_1 and x_2; and if $(a+b)\bar{\theta} \leq c < (2a+b)\bar{\theta}$, f is continuous at x_1. I consider the case $c < (a+b)\bar{\theta}$ and show that f is continuous at x_2; a similar proof exists regarding continuity at x_1 for $c < (2a+b)\bar{\theta}$.

First, let $(x_n)_{n\geq 3}$ be a sequence in $[x_1, x_2]$ satisfying that $\lim_{n\to\infty} x_n = x_2$. Then by Property i. of the proof of Lemma 3.2.1, it is the case that

$$b\left(f(x_n) - \frac{c}{b}\right)P_E(\theta \geq f(x_n)) = -ax_nP_E(\theta \geq x_n) \to_{n\to\infty} -ax_2P_E(\theta \geq x_2) = b\left(x_2 - \frac{c}{b}\right)P_E(\theta \geq x_2).$$

Moreover, from the remaining properties and the paragraph below them, $x_n \leq f(x_n) \leq \min\{\frac{c}{b}, g(x_n)\}$. Now let $0 < \epsilon < g(x_2) - x_2$ and define $\delta = b\left(x_2 + \epsilon - \frac{c}{b}\right)P_E(\theta \geq x_2 + \epsilon) - b\left(x_2 - \frac{c}{b}\right)P_E(\theta \geq x_2)$, which by Property iii. is positive. It follows from these observations that there exists $N > 2$ such that $n \geq N \Rightarrow \left|b\left(f(x_n) - \frac{c}{b}\right)P_E(\theta \geq f(x_n)) - b\left(x_2 - \frac{c}{b}\right)P_E(\theta \geq x_2)\right| < \delta$. If for such $f(x_n) \geq x_2$, $b\left(f(x_n) - \frac{c}{b}\right)P_E(\theta \geq f(x_n)) - b\left(x_2 - \frac{c}{b}\right)P_E(\theta \geq x_2) \geq 0$, implying that

$$\left|b\left(f(x_n) - \frac{c}{b}\right)P_E(\theta \geq f(x_n)) - b\left(x_2 - \frac{c}{b}\right)P_E(\theta \geq x_2)\right| < \delta \Leftrightarrow$$

$$b\left(f(x_n)-\frac{c}{b}\right)P_E(\theta \geq f(x_n)) - b\left(x_2-\frac{c}{b}\right)P_E(\theta \geq x_2) < b\left(x_2+\epsilon-\frac{c}{b}\right)P_E(\theta \geq x_2+\epsilon) - b\left(x_2-\frac{c}{b}\right)P_E(\theta \geq x_2) \Leftrightarrow$$

$$b\left(f(x_n)-\frac{c}{b}\right)P_E\big(\theta \geq f(x_n)\big) < b\left(x_2+\epsilon-\frac{c}{b}\right)P_E(\theta \geq x_2+\epsilon)$$

$$\Leftrightarrow$$

$$f(x_n) < x_2+\epsilon.$$

Hence, $N > 2$ exists such that $n \geq N, x_2 \leq f(x_n) \Rightarrow f(x_n) < x_2+\epsilon$. Moreover, there exists $N' > 2$ such that $n \geq N' \Rightarrow x_n > x_2-\epsilon$. That is, for $n \geq \max\{N, N'\}$ we have $x_2-\epsilon < f(x_n) < x_2+\epsilon$. Taken together, $f(x_n) \to_{n\to\infty} x_2$, so that by Property i. $\lim_{n\to\infty} f(x_n) = f(x_2)$; Hence f is continuous at x_2.

I proceed to show that f is right-differentiable at x_1 with right-derivative $\frac{-a}{bP_E\left(\theta \geq \frac{c}{b}\right)}$. For $x > x_1$, by the continuity of $\theta(P_E)$ and of f on $[x_1; x_2]$, $\frac{f(x)-f(x_1)}{x-x_1} = \frac{\frac{-axP_E(\theta\geq x)}{bP_E(\theta\geq f(x))}+\frac{c}{b}-\left(\frac{-ax_1P_E(\theta\geq x_1)}{bP_E(\theta\geq f(x_1))}+\frac{c}{b}\right)}{x-x_1} = \frac{\frac{-aP_E(\theta\geq x)}{bP_E(\theta\geq f(x))}x}{x} = \frac{-aP_E(\theta\geq x)}{bP_E(\theta\geq f(x))} \to \frac{-aP_E(\theta\geq x_1)}{bP_E(\theta\geq f(x_1))} = \frac{-a}{bP_E\left(\theta\geq\frac{c}{b}\right)}$ as $x \to {x_1}^+$.

That f is left-differentiable at x_2 with left-derivative $\frac{-1+x_2HR_{\theta(P_E)}(x_2)}{\frac{b}{a}+x_2HR_{\theta(P_E)}(x_2)}$ is a consequence of L'Hôpital's rule for the right interval end point (Cauchy's Mean Value Theorem) combined with the Implicit Function Theorem and the continuity of $f_{\theta(P_E)}$, $\theta(P_E)$, and f, from which it follows that for $x \in (x_1; x_2)$, $f'(x) = -\frac{a}{b}\frac{xf_{\theta(P_E)}(x)-P_E(\theta\geq x)}{\left(f(x)-\frac{c}{b}\right)f_{\theta(P_E)}(f(x))-P_E(\theta\geq f(x))} \to -\frac{a}{b}\frac{x_2f_{\theta(P_E)}(x_2)-P_E(\theta\geq x_2)}{\left(f(x_2)-\frac{c}{b}\right)f_{\theta(P_E)}(f(x_2))-P_E(\theta\geq f(x_2))}$ as $x \to {x_2}^-$. A simplifying calculation shows that the limit is equal to $\frac{-1+x_2HR_{\theta(P_E)}(x_2)}{\frac{b}{a}+x_2HR_{\theta(P_E)}(x_2)}$.

Finally, If $f'(x_2)$ denotes the left-derivative of f at x_2, then it follows that f' is continuous at x_2. Moreover, if $f'(x_1)$ denotes the right-derivative of f at x_1, then, since $f_{\theta(P_E)}(x) = o\left(\frac{1}{x}\right)$ by assumption, $f'(x) \to \frac{-a}{bP_E\left(\theta\geq\frac{c}{b}\right)} = f'(x_1)$ as $x \to {x_1}^+$; Hence f' is continuous at x_1.

Proof of Lemma 3.2.1, case 2 ($bg(0) < c < \bar{\theta}(2a+b)$)

First notice that $2a\frac{c}{a+b} + bg\left(\frac{c}{a+b}\right) > \frac{c}{a+b}(2a+b) > c$, from which it follows that $x_1 < x_2$; additionally, by the definition of x_1, $g(x_1) < \frac{c}{b}$.

The following observations may be verified by immediate calculation (regarding ii., notice that $x < x_2 \Rightarrow x < \bar{\theta} \wedge x < \frac{c}{a+b}$):

i. $\pi(x_1, g(x_1)) = 0$; $\pi(x_2, x_2) = 0$;
ii. $x < x_2 \Rightarrow \pi(x,x) < 0$; $x_1 < x < \bar{\theta} \Rightarrow \pi\left(x, \min\{\frac{c}{b}, g(x)\}\right) > 0$;
iii. $y \in \left[x; \min\{\frac{c}{b}, g(x)\}\right], y < y' \leq g(x) \Rightarrow \pi(x,y) < \pi(x,y')$;
iv. $x < x_1 \Rightarrow \pi(x,y) \leq \pi\big(x, g(x)\big) < 0$;
v. $x_2 < x < \bar{\theta}, y \in \left[x; \min\{\frac{c}{b}, g(x)\}\right] \Rightarrow \pi(x,y) \geq \pi(x,x) > 0$;
vi. $\frac{c}{b} < y \leq g(x) \Rightarrow \pi(x,y) > 0$.

Existence of solutions $y \in \left[x_1; \min\{\frac{c}{b}, g(x_1)\}\right]$ to $\pi(x_1, y) = 0$ follows from i. and $g(x_1) < \frac{c}{b}$; if $\frac{c}{a+b} < \bar{\theta}$, existence of solutions $y \in [x_2; \min\{\frac{c}{b}, g(x_2)\}]$ at $x_2 < \bar{\theta}$ to $\pi(x_2, y) = 0$ also follows from i.; existence of solutions $y \in \left(x; \min\left\{\frac{c}{b}, g(x)\right\}\right)$ to $\pi(x,y) = 0$ for $x \in (x_1; x_2)$ follows from ii., continuity and the Intermediate Value Theorem; That the solution $y \in [x; \min\{\frac{c}{b}, g(x)\}]$ for any $x \in [x_1; x_2)$, and also for $x = x_2$ if $\frac{c}{a+b} < \bar{\theta}$, is unique follows from iii.; that no solution exists outside the set $\{(x,y): x \in [x_1; x_2], x < \bar{\theta}, y \in [x; \min\{\frac{c}{b}, g(x)\}]\}$ follows from iv.-vi. and from the definition of the regionen ($x < \bar{\theta}$).

I have shown that the graph of the zero profit condition in the set $\{(x,y): x \in [0; \bar{\theta}), y \in [x; g(x)]\}$ is a unique function $f: [x_1; x_2] \to \mathbb{R}$ if $\frac{c}{a+b} < \bar{\theta}$ and $f: [x_1; x_2) \to \mathbb{R}$ if $\frac{c}{a+b} \geq \bar{\theta}$. By the Implicit Function Theorem, f is continuously differentiable on $(x_1; x_2)$; And by the proof above, f is also continuous at x_1, and at x_2 if $\frac{c}{a+b} < \bar{\theta}$.

That f is right-differentiable at $x_1 > 0$ with right-derivative $\frac{-1+x_1 HR_{\theta(P_E)}(x_1)}{\frac{b}{2a}+x_1 HR_{\theta(P_E)}(g(x_1))}$ follows from L'Hôpital's rule for left interval end-point (Cauchy's Mean Value Theorem) combined with the Implicit Function Theorem and continuity of $f_{\theta(P_E)}$, P_E, and f, from which it follows that for $x \in (x_1; x_2)$, $f'(x) = -\frac{a}{b}\frac{x f_{\theta(P_E)}(x)-P_E(\theta \geq x)}{\left(f(x)-\frac{c}{b}\right)f_{\theta(P_E)}(f(x))-P_E(\theta \geq f(x))} \to -\frac{a}{b}\frac{x_1 f_{\theta(P_E)}(x_1)-P_E(\theta \geq x_1)}{\left(f(x_1)-\frac{c}{b}\right)f_{\theta(P_E)}(f(x_1))-P_E(\theta \geq f(x_1))}$ as $x \to x_1{}^+$. A calculation shows that the limit is equal to $\frac{-1+x_1 HR_{\theta(P_E)}(x_1)}{\frac{b}{2a}+x_1 HR_{\theta(P_E)}(g(x_1))}$.

Point 3) is shown as in case 1: $c \leq bg(0)$, except that the inequality $x_1 \leq x < x' \leq x_2$ becomes $x_1 \leq x < x' < x_2$ if $\frac{c}{a+b} \geq \bar{\theta}$.

That f is left-differentiable at x_2 with left-derivative $\frac{-1+x_2 HR_{\theta(P_E)}(x_2)}{\frac{b}{a}+x_2 HR_{\theta(P_E)}(x_2)}$ if $\frac{c}{a+b} < \bar{\theta}$ also follows in the same way as in case 1: $c \leq bg(0)$.

If $f'(x_1)$ denotes the right-derivative of f at x_1, it is the case that $f'(x) \to \frac{-1+x_1 HR_{\theta(P_E)}(x_1)}{\frac{b}{2a}+x_1 HR_{\theta(P_E)}(g(x_1))} = f'(x_1)$ as $x \to x_1{}^+$; Thus f' is continuous at x_1. If $\frac{c}{a+b} < \bar{\theta}$ and $f'(x_2)$ denotes the left-derivative of f at x_2, it follows analogously that f' is continuous at x_2. In this sense f is continuously differentiable in its entire domain.

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Danish
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A well-functioning electricity system based on renewables and governed by electricity markets is envisioned as entailing a high degree of demand-side response to price signals that reflect the state of generation as well as system operation. But while the concept and recognized importance of demand-side flexibility is as at least as old as the idea of the electricity market itself, the implementation of a price responsive demand-side lags behind the development of a non-dispatchable supply-side based on renewable energy sources.

The papers in this second volume in the Danish Utility Regulators anthology series on better regulation in the energy sector address the discrepancy between an increasingly stochastic supply and an inert demand, by presenting approaches to system governance and tariff design that can foster a market environment fit for increasingly price responsive electricity consumers.

With this anthology on incentives and digitalization for flexibility in the green transition, the Danish Utility Regulator once again aims to investigate present regulatory structures and open avenues for the making of new and improved regulation in the energy sector.

FREDERIKSVÆRK 2024