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A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

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INTRODUCTION

The ongoing shift in the energy system due to decarbonization objectives will have important implications for energy networks. Achieving the net-zero carbon objective through electrification means that in 2050 the dominant fuel source in all transport, domestic, and service sectors would be electricity, whereas for the industrial sector it is likely to be hydrogen and electricity. This means that the pattern of utilization and investment in existing energy network infrastructures is going to change significantly. Electricity networks are going to face the full brunt of energy sector transformation, given the current strategy of decarbonization of activities and processes based on electrification. On the electricity transmission level, there is the issue of connecting significant amount of variable and remote renewable energy resources such as offshore/onshore wind and solar PV farms. The distribution grid, on the other hand, is expected to face even more challenges due to increased level of electricity demand and its variability, as well as significant penetration of distributed energy resources (DERs).

The future of natural gas networks is highly uncertain, especially at the low-pressure distribution level. One idea is to repurpose existing gas infrastructures to transport hydrogen, but that is not straightforward. This is not only because significant volumes of hydrogen may not be available for the adjustment of the existing natural gas infrastructure to make economic sense, but also because hydrogen can be transferred by a variety of means. These range from repurposed gas networks and new dedicated hydrogen pipelines, to existing transportation networks such as rail, road, and waterway. It is also possible to transfer electrical energy instead, and produce hydrogen on site.

Apart from established energy networks, we have the problem of emerging energy networks such as heating and cooling. Although they are not yet common globally, their share of meeting energy demand for heating and cooling is expected to increase in the future because of their higher efficiency, lower costs, and possibility of them operating with local low-carbon energy resources.

Given the above background, the articles in this issue of the Oxford Energy Forum investigate key challenges and opportunities that energy transition will bring for energy networks, including: electricity transmission and distribution grids, natural gas networks and future hydrogen, heating and cooling networks.

The issue of anticipatory and proactive transmission planning is discussed in an article by Felder and Athawale. The authors argue that, in many regions, decarbonizing the electricity sector with large amounts of renewable generation requires significant transmission investments, while the pendulum is swinging toward more assertive transmission planning processes. However, for anticipatory and proactive transmission planning policies to be successful over the long term, which is necessary to achieve decarbonization, policy proposals should be integrated into the entire market–regulatory structure in such a way that efficient incentives and strict regulatory controls reduce the risk of underutilized and inefficient transmission assets.

Given the importance of offshore wind power in the future energy system of European countries, an article by Akinci discusses future offshore wind grid connection models, focusing on multilinked wind farms. Multilinked windfarms – where a number of windfarms are connected, creating a so-called ‘energy island’ at sea – are an optimization solution that avoids building interconnectors in parallel. This energy island is then connected to different onshore markets in different countries, exposing the wind farms to a higher number of competing markets. The author highlights the challenges facing implementation of this model; these include coordinating activities among different actors involved in the process, as well as the risk of conflict between union-wide and national interests.

The issue of transmission network development in the context of Sub-Saharan African (SSA) countries is discussed in an article by Hochberg. The author argues that the business-as-usual approach for transmission investment in SSA is insufficient to raise the financing for the transmission capacity that the region needs and deserves. He suggests that a model which encourages the development of independent power transmission (IPT) projects is needed. The author further asserts that the establishment of a Joint Transmission Organization (JTO), an entity that is responsible for facilitating and pursuing investment opportunities in a specific geography, would help advance projects. In the author’s view, not only does this model bring about new transmission that would otherwise have gone unbuilt, but it also helps to free up public budgets earmarked for transmission investment that is already planned.

Meeus, Beckstedde, and Nouicer analyse the issue of flexibility in electricity distribution grids. They assert that distribution grids need to be expanded because of decarbonization objectives; however, we can also tap into the flexibility that is increasingly present in these networks to avoid unnecessary investments and to deal with uncertainty. They offer three policy recommendations. The first suggests complementing flexibility contracts with cost-reflective grid tariffs. The second states that flexibility contracts can combine mandatory with voluntary flexibility contracting (although the existence of a mandatory scheme

does not have to imply that it is often used). Their final policy recommendation is to keep an open mind regarding the issue of short-term versus longer-term contracting of flexibility services by DSOs. For example, if long-term reservations to manage local congestion turned out to reduce the distribution costs at the expense of the whole system costs, policymakers need to intervene.

In an article on a similar topic, Ruiz, Gómez, Cossent, and Chaves argue that the high uncertainty faced during the energy transition urges a paradigm change in current distribution network planning practices, to avoid incurring unnecessary costs. Flexibility mechanisms allow the planner to delay network reinforcement until the risk of underutilization is reduced. However, traditional planning approaches based on discounted cash flow ignore the fact that future investment decisions are flexible and DSOs can respond to demand evolution over time. They propose instead a 'real options'-based conceptual framework, and argue that it has the potential to unveil the economic value of flexibility mechanisms, as future decisions can be modelled in response to information becoming available over time.

The issue of coordinating the activities of transmission and distribution system operators in the future decarbonized and decentralized power systems is discussed in an article by Apostolopoulou and Poudineh. They argue that under the current system operational paradigm, obstacles to integrating DERs arise both at the level of the transmission system operator (TSO) and the distribution system operator (DSO). They propose a framework to coordinate the activities of the TSO and DSOs. In this framework, DSOs optimize local markets at each point of common coupling (PCC) by taking into account the cost of energy at the PCC and the value of DERs' services. Then, the TSO optimizes the bulk power system, rather than that of individual DERs (only seeing one virtual resource at the PCC), and is responsible for meeting the net interchange at the PCC. In this model, the power system is treated as a collection of subsystems at different layers that are connected with each other (a 'fractal grid'), exchanging power and non-private information, and operating under a market environment.

There are three articles in this issue of Forum that focus on natural gas and hydrogen networks. The first article, by Yafimava, discusses the future of natural gas networks in Europe. The author argues that the future of natural gas networks in Europe is uncertain because of the double challenge of (a) achieving net-zero by 2050 and (b) phasing out Russian gas. In the author's view, the first objective means that some existing gas networks will have to be repurposed to carry hydrogen, whereas the remaining gas networks will increasingly need to transport (bio)methane. The second objective, on the other hand, means that new gas networks will have to be built to enable the importing and transporting of non-Russian gas in the EU. Although the second objective is political rather than legally binding, it completely undermines the regulatory framework for building new LNG (and possibly other) infrastructure in the EU that took several decades to create. It is against this backdrop of uncertainty that investment decisions in respect of gas networks will have to be made.

The article by Pototschnig and Tesio discusses the role of hydrogen infrastructure in promoting climate neutrality. The authors argue that because of uncertainty, it is not easy to identify a clear picture of the future demand and supply of renewable hydrogen in Europe, and therefore of the demand for hydrogen transportation services across the continent. Also, the authors assert the likelihood that in all countries in Europe, potential demand for hydrogen will be much higher than local production and thus the scope for cross-border trade in hydrogen would not be obvious. The authors further suggest that a system of integrated network planning across electricity, gas, and hydrogen would assist in dealing with this uncertainty more efficiently. In addition, they argue that the idea of planning an energy network well ahead of the demand for transport services does not apply to hydrogen, because a large part of a future hydrogen network will be based on the adjustment of existing natural gas networks. Thus, while Europe should ensure the existence of sufficient hydrogen transport capacity, it should also avoid developing networks which are not going to be used.

Palovic and Poudineh, in an article about integrating hydrogen into the existing energy transfer infrastructure, argue that approaches to encourage investment in hydrogen transport infrastructures need to avoid redundancy and inefficiency. In addition to the issues of technology uncertainty, investment irreversibility of grid-based infrastructures, and uncertainty about future levels of supply and demand for hydrogen, climate-neutral hydrogen can be transported by a variety of infrastructures. These range from dedicated new-build pipelines and repurposed gas networks, to existing transportation networks (such as truck, rail, and marine transport) or even, instead, to the transfer of electrical energy followed by the production of hydrogen on site. They assert that in order to make the future hydrogen transport infrastructure efficient, hydrogen-driven investment into these infrastructures needs to be coordinated. In their article, they review three possible approaches to achieve such a coordination (centrally-coordinated approach, market-based approach, and regulatory approach) and highlight their shortcomings and advantages.

On the issue of heating and cooling networks, there are two articles in this issue. The first article, by Boscán, describes Denmark's decades-long experience with district heating (DH). The author argues that the regulatory instruments that govern the Danish DH sector are more reflective of a governance framework in which involved stakeholders – notably consumers and local governments – interact to reach decisions of common interest, than one in which profit-driven agents (namely private natural monopolies) participate. While the existence of such a framework has many positive traits, it also reveals important weaknesses, such as the lack of direct incentives for economic efficiency and the system's slow adaptation to technological innovation and exposure to much-needed competition from alternative, individual heating sources which are more economic. The framework also suffers from complexity, bureaucracy, and an insufficiently clear separation of the roles played by involved stakeholders who manage DH utilities and occupy political positions at the same time. The author concludes that despite its many environmental and technological benefits, the Danish DH regulatory framework risks becoming irrelevant for Denmark's ambitious green transition, unless it quickly comes of age and delivers solutions to the present-day challenges facing the country – the pressing need for a green transition and the energy crisis.

The issue of cooling is addressed in an article by Ugalde-Loo. The author argues that there is no silver bullet solution to address the cooling challenge in a warming world. It has been a 'blind spot' and an often-overlooked issue when discussing decarbonization of energy. He asserts that it is necessary to explore how cooling demand may develop in the future and to understand how cooling and energy storage technologies, and their relationship with heat decarbonization, can support an integrated, socially acceptable, cost-effective, and sustainable energy system change. The author concludes that it is necessary to reinforce the electrical power system to cope with the additional demand, with the possibility of utilizing the flexibility provided by a coordinated operation of heating, cooling, gas, electricity, and perhaps hydrogen networks to maximize infrastructure use, while minimizing operation costs. Nevertheless, significant investments in the modernization, digitalization, and automation of cooling infrastructure and buildings are needed to ensure a safe, efficient, reliable, and sustainable energy system.

The next article, by Brandstätt, addresses the issue of European network development planning for integrated energy systems. Developing infrastructure with a lifespan of several decades within a dynamically evolving energy system is inherently challenging. As a consequence of the energy transition and the current geopolitical situation, network planning is faced with increasing uncertainties. In the view of the author, the most pressing issues with respect to network planning at the European level are (a) handling the uncertainty in some of the decisive factors for infrastructure needs, such as volume and location of electrolysis and demand flexibility and (b) coordination with a growing and diverse subset of stakeholders. The author argues that the intuitive way forward consists of increased transparency and agility in the planning process.

The final article in this issue of Forum, by Billimoria and Simshauser, analyses earnings and dividend policy for Australia's listed electricity utilities, against the backdrop of the falling interest rate environment which characterized the 2010s. They show that for regulated utilities the lifecycle theory of dividend policy applies, making such utilities a proxy for the fixed-income asset class, whereas for merchant utilities, the pattern of dividends and earnings is consistent with information content theory, with dividends signalling future firm prospects. Going forward, and in the context of rising inflation, interest rates, and turmoil in global energy markets, new risks present for both regulated and merchant utility business models. While this environment will affect each business model differently, the authors argue that important common factors such as leverage, business responsiveness, operational flexibility, and regulatory/sovereign risk are likely to drive near-term opportunity and business economic resilience.

A CAUTIONARY TALE OF ANTICIPATORY AND PROACTIVE TRANSMISSION PLANNING

Frank A. Felder and Rasika Athawale

The large-scale and widespread deployment of renewable energy sources to reduce greenhouse gas emissions, enhance energy security, and develop economic opportunities has motivated numerous calls to change transmission planning policies. Examples of bodies calling for changes include:

- the United States (US) Federal Energy Regulatory Commission's (FERC's) April 2022 notice of proposed rulemaking ([‘FERC Issues Transmission NOPR Addressing Planning, Cost Allocation’](#));
- the International Energy Agency ([‘Energy transitions require innovation in power system planning’](#));
- the World Bank ([‘World Bank Releases Study on Proactive Energy Transmission Expansion in Preparation for Scaling-Up Renewables’](#));
- the US Agency for International Development ([‘Renewable Energy Zone \(REZ\) Transmission Planning Process: A Guidebook For Practitioners’](#)).

The general thrust is that transmission planning needs to change from being reactive to adopting an anticipatory or proactive approach (collectively referred to as being assertive) (see, for example, [A Call for More Pro-Active, Multi-Value Transmission Planning - ESIG](#)). We define each of these terms in more detail below.

The motivation for transmission reform is that while wind and solar are the two most prominent sources of renewable energy, their locations are generally far away from load centres, and transmission development has a much longer lead time than renewables development. Therefore, waiting to develop transmission until renewable resources are built (reactive approach) would substantially delay their implementation. Furthermore, reactive transmission planning increases financing costs for renewable projects due to the uncertainty surrounding the additional transmission needed to deliver their power to load centres.

Other reasons proffered for a more assertive approach to transmission planning include the fact that transmission systems are often woefully undercapitalized and poorly integrated – with the US serving as an example. Furthermore, transmission development has many other benefits, such as reducing production costs and market power (and therefore electricity prices), improving reliability and resiliency, and lowering the costs of variable renewables integration by diversifying renewable energy production. Finally, in percentage terms, transmission costs are small compared to generation and distribution costs. Therefore, according to this view, it is unlikely that more assertive transmission planning will result in unnecessary or underutilized assets whose costs exceed their benefits.

In many regions, decarbonizing the electricity sector with large amounts of renewable generation requires significant transmission investments, and the pendulum is swinging toward more assertive transmission planning processes. If anticipatory and proactive transmission planning policies are to be successful over the long term, which is necessary to achieve decarbonization, policy proposals should be integrated into the entire market–regulatory structure in such a way that efficient incentives and strict regulatory controls reduce the risk of underutilized and inefficient transmission assets.

A taxonomy of transmission planning

Underlying the case for transmission reform is the need – due to the introduction of wholesale electricity markets – to separate generation investment decisions from transmission investment decisions. Before their introduction, integrated generation and transmission utilities co-planned their generation and transmission investments, including when power purchase agreements would be used to procure generation competitively. In this regulatory model, the utility planned, and the regulator ensured that the timing of generation and transmission investments were integrated and coordinated; otherwise, the utility risked not fully recovering its costs.

A primary motivation for introducing wholesale electricity markets is to give the responsibility and accountability for generation investment decisions to developers. First, this helps align incentives and reduces the Averch–Johnson effect,¹ at least for generation. Second, generation developers are likely more efficient at developing generation assets than is the case for

¹ Named after two economists who found that when firms are subject to rate-of-return regulation, if the allowed return is greater than the required return on capital, the firm will tend to over-invest in capital beyond what is needed for economically efficient production. (The Averch–Johnson Effect: <https://regulationbodyofknowledge.org/glossary/a/averch-johnson-effect-aj-effect/>).

integrated utilities. Third, ratepayers bear less of the risk of uneconomical generation investments if markets are properly designed and implemented.

With the formation of electricity markets, *reactive transmission policy* took hold: Transmission planners waited for generation investments to occur and then planned additional transmission facilities based upon reliability requirements or economic considerations, depending on the jurisdiction. This approach streamlined the analysis needed to plan new facilities since the uncertainty regarding generation locations was resolved. It also vastly reduced the risk of underutilized transmission investments. Since a significant motivation for electricity market liberalization was to avoid future stranded assets, it is not surprising that it resulted in reactive transmission planning.

The next step in the evolution of electricity markets was *co-optimizing generation and transmission investments*. Co-optimization tries to undo some of the consequences of the generation–transmission separation by having transmission planners account for anticipated generation investments. The premise for this is that co-optimization results in the same cost as, or is less costly than, the separate optimization of generation and transmission investments. In practice, co-optimization produces substantial cost savings, among other benefits. For example, in regions with a single buyer who procures electricity from developers via power purchase agreements, the buyer's coordination with the transmission utility can successfully result in co-optimization.

Once the door is opened to planned generation in transmission planning, not all planned generation is developed. The deterministic approach is to have a rule that classifies which potential generation source is sufficiently likely to be considered for transmission planning. Whatever the rule, the decision is a trade-off between the costs of overbuilding and underbuilding transmission. The more expansive the classification, the more it risks overbuilding transmission, but the more likely it is to garner the benefits of integrated generation and transmission planning. The challenges, however, of undertaking a long-range regional transmission planning process and associated cost allocation are substantial.

Another approach is to explicitly account for the uncertainty of the development of planned generation via *stochastic planning*. The significant uncertainties and their likelihoods are identified, quantified, and incorporated into a stochastic transmission model. The general result of such models is that the generation–transmission expansion plan is not optimal for any actual outcome except the most probable one.² Stochastic transmission planning results in lower costs than deterministic planning, although, after the fact, the plan is suboptimal. This after-the-fact suboptimality may raise regulatory issues regarding cost recovery.

Anticipatory transmission planning identifies geographic regions to site new generation. It develops a transmission plan that foresees the siting of large amounts of generation at those locations even if there are no existing plans that rise to the level of co-planning. Anticipatory planning mainly makes sense for wind and solar power, where geographic sites with considerable potential that do not have other conflicting uses or restrictions are readily identifiable. Anticipatory planning mitigates the risk of overbuilding, by developing the major transmission infrastructure from distant load centres to locations that are highly likely to site large quantities of renewables. Nonetheless, the risk of overbuilding exists due to delays in renewable development, changes in regulatory policies, unexpected deployment of distributed solar, or erroneous demand forecasts.

Proactive transmission planning takes anticipatory planning one step further. Instead of 'build it, and they will come', the mantra is 'build it, and they should come'. A proactive transmission plan attempts to direct generation development by making it more attractive to locate in areas envisioned in the plan. It goes beyond just providing transmission to remote areas with high renewable energy potential, further directing the size and type of development based on the joint optimization of the combined generation and transmission system.

Table 1 summarizes these types of transmission planning and their most significant implications.

² Hobbs, B.F., et al., (2016), 'Adaptive Transmission Planning: Implementing a New Paradigm for Managing Economic Risks in Grid Expansion', *IEEE Power and Energy Magazine*, Volume: 14, Issue: 4, July–August.

Table 1: Types of transmission planning and their major implications

Transmission planning approach	Description	Implications
Reactive	Occurs after generation investments are confirmed.	Reduces the risk of underutilized transmission assets but creates a suboptimal generation–transmission system.
Stochastic	Accounts for uncertainty in planning models.	Improves expected outcomes, but defining and quantifying uncertainties is challenging and raises used-and-useful issues with transmission assets that are not utilized as expected.
Anticipatory	Based upon anticipated generation investments.	Improves the joint optimization of the power system but risks underutilizing transmission assets.
Proactive	Determines the desired locations, types, and quantities of generation and plans the transmission system around these findings.	Integrates power system optimization but risks underutilizing transmission assets and undercutting the wholesale generation market by trying to direct power plant investments.

The broader policy context matters

Any transmission planning process is part of an overall regulatory–market structure and, within a regulatory–governance process, interacts with the rules related to allocating transmission costs, environmental policies, and siting. The regulatory–market structure creates the issue of whether and how to align generators’ investment decisions with transmission planning. Since energy storage costs are falling and its performance is improving, large-scale storage investments also need to be considered in the planning process, making transmission planning even more complicated. Energy storage can be considered a generation or transmission resource or both, making its integration into transmission planning challenging.

There are three other essential elements of the energy market’s structure:

- how transmission congestion is priced;
- to what extent, if at all, the cost of greenhouse gases and of other emissions harmful to public health is embedded into wholesale market prices;
- whether the system operator is financially incentivized to reduce transmission congestion costs.

Cost allocation, such as whether the costs are borne by the system’s beneficiaries (versus socializing the costs), is another issue that affects the outcomes of various transmission planning approaches. If generation developers are allocated transmission costs, this creates complications as, at the time of development, the generation developer is not identified, limiting the potential for a proactive approach. In short, assigning costs to an as yet unidentified developer is problematic. The transmission developer or its ratepayers would be on the hook for the initial development costs. These costs could potentially be assigned to generation owners later, but it could create regulatory roadblocks.

One motivation for favouring more assertive transmission policies is to reduce the cost allocation of transmission to renewable energy projects. The ability of planners to anticipate or direct renewable investments to socially optimal locations without attenuating developers’ economic incentives, by shifting costs and risks to ratepayers, determines the extent to which the latter group benefits from these more assertive policies. The danger in that scenario is that the developers have a strong incentive to shape the regulatory process in their favour against the diffused interests of electricity consumers.

Finally, all these elements occur when a transmission planning governance structure is embedded in a broader regulatory and political process. The independence and capabilities of the regulators, the access by regulators and stakeholders to timely and accurate information, the capacities of stakeholders to inform versus influence outcomes, and the costs of participating in this system, are all intermingled.

Overbuilding is a risk

The many calls for more assertive transmission planning are understandable. They are motivated by well-founded analyses and long-standing frustrations with the slowness of transmission planning and renewable energy development. However, there is a real risk of overbuilding transmission if the policymaking process does not correctly manage transmission planning.

In our SSRN working paper '[Over Building Transmission: A Case Study and Policy Analysis of the Indian Power Sector](#)' we find that transmission overbuilding has occurred in India. Starting with its 2003 Electricity Act and subsequent legislation and policies, India implemented an overarching transmission planning philosophy of building transmission in advance of generation, and ensuring that generation is never curtailed due to transmission limitations. Furthermore, transmission costs were allocated to consumers, not generators. Finally, most transmission investments were made by government-owned entities that benefited from very high rates of return on transmission projects of 15.5 per cent. These government-owned entities had substantial influence over transmission planning, including critical assumptions such as future demand projections, which were overstated by 25 per cent. This almost quadrupled the cost of transmission within a decade, with 60 per cent of new transmission assets underutilized, and numerous audits uncovering inflated revenue requirements and inefficient investments. The opportunity costs of these wasteful expenditures are substantial, particularly for an emerging economy such as India.

Advocates of more assertive transmission planning may argue that the Indian case study only illustrates the consequences of poor incentives and regulatory governance. The overbuilding was not the result of anticipatory or proactive transmission planning. It is possible to separate the principle of assertive transmission planning from incentives and governance. However, transmission planning, as noted above, does not exist in a vacuum. It operates within the broader energy market and regulatory and political contexts, which need to be assessed and perhaps amended to mitigate the risk of overbuilding under a more assertive transmission policy. Furthermore, the strong financial interests of transmission developers do not always align with the public's welfare, and they may use assertive transmission policies to circumvent or overwhelm regulatory processes and controls.

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OFFSHORE WIND GRID CONNECTION MODELS

Elin Akinci

The role of offshore wind in Europe's climate policy objectives

Europe's ambitious climate plan to reach net-zero greenhouse gas emissions by 2050, and its 55 per cent emission reduction target for 2030, will require huge investments into renewable energy sources such as solar and onshore and offshore wind. While the EU Commission has signalled that the use of all renewable energy sources is necessary to reach the Union's renewable energy target, as well as its emission reduction targets, it is quite clear that the main large-scale sources of energy production in the coming five to ten years will be from offshore wind. A large-scale uptake in offshore wind deployment in Europe is therefore one of the EU's top energy and climate priorities.

In November 2020, the European Commission presented an EU-wide strategy for offshore wind. The strategy includes both the Commission's vision and targets for offshore wind in Europe, as well as non-binding guidance for European member states on how to reach their individual national goals and contribute to achieving the EU's overarching targets for the uptake of offshore wind.

The strategy defines a non-binding volume target of 300 GW by 2050, with a sub target of 60 GW by 2030 for the whole of the EU. The Commission realizes that the current policy environment will have to be adjusted to offer better conditions for investment in offshore wind. The discussion on policy changes is chiefly centred on how to adjust the current legal framework within the 'Fit for 55' package to help stimulate the uptake in offshore wind investments. This will first be achieved by including offshore wind in all the relevant legal texts, but then by also prioritizing offshore wind projects in the EU's various financing programmes.

The two main regulatory challenges for the offshore wind industry identified in the strategy are:

- long national permitting processes and,
- a lack of directed infrastructural investments.

Dealing with the latter would enable offshore wind to become an integrated part of the electricity system and market. These challenges are very much related to national legislations and bureaucracy. The Commission is therefore investigating how to adjust the relevant legal texts at EU level to put more pressure on member states to address these challenges. Following Russia's invasion of Ukraine, the focus has been further strengthened through the Commission's REPowerEU document.

Another challenge, one that to a large extent is related to regulatory risks, is the relatively high project costs for offshore wind. Even though technological breakthroughs are evident – especially when it comes to bottom-fixed technologies, which today meet grid parity – the potential for large-scale projects is to be found further from shore where the water depth is deeper and therefore requires floating technologies. Floating technologies are still expensive and struggle to compete with other cheaper energy sources on a pure commercial basis, but they are expected to fall in cost as the number of projects coming onstream grows.

In this article, future offshore wind grid connection models will be discussed from a capacity and cost perspective.

Offshore grid connection models – a step-by-step development

The current legal framework for offshore wind in Europe has, to a large extent, been based on national legislations and policies concerning both projects and infrastructure expansions that connect offshore production with the onshore market. This has resulted in an infrastructural approach that focuses on so-called radial connections – such as park-to-shore solutions where one (or in some cases a couple of) offshore wind park(s) transmit power to the onshore market through an HVDC/DC cable. The idea of realizing one project at a time through investments in one HVDC/DC cable to serve one specific market has been challenged recently. From both a cost, but also a capacity, point of view, the approach to offshore grid connection could benefit from being broadened, to include several offshore wind projects in the same grid network that also connects several different onshore markets.

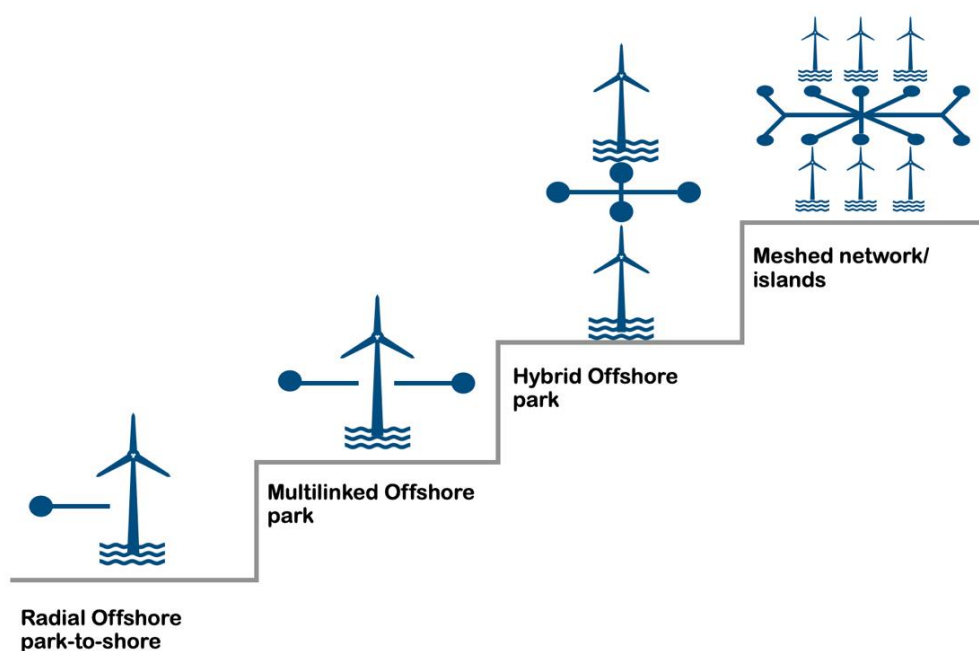
Even in the EU Commission's offshore wind strategy, it becomes very clear that a new approach to infrastructure buildouts is needed in the Union. First of all, in order to reach the EU's offshore wind target of 300 GW by 2050, while also being compliant with EU internal market rules and the Union's security of supply objectives. According to the Commission, the type of infrastructure required to reach its offshore wind target is a so-called multilinked/hybrid/meshed grid system. Member states are expected to identify 'go-to-areas' where offshore wind projects would be most suitable. These areas will most likely provide a base from where the national Transmission System Operators (TSOs) will build out cables and, in the future, connect so-called 'energy islands'. The concept of energy islands involves linking offshore wind sites and connecting them to shore, but it should also involve more than one cable – connecting the energy island to several markets. Further, the idea of energy islands has raised a discussion about introducing price areas at sea, which would require changes to the current electricity market design. For the above to be realized, strong regional cooperation and a robust regulatory framework are needed.

The current approach of radial park-to-shore solutions has served a great purpose of developing new technologies and thereby cutting costs, and future new grid connection models should be viewed as a step-by-step development while the offshore industry and electricity markets mature. In markets where there has been a great focus on developing both the regulatory framework for offshore wind as well as seeing many project realizations, this discussion is already on the political agenda. A good example of this is the UK Government's latest proposal in its Energy Security Bill to introduce multi-purpose interconnectors as a licensable activity. The Government is referring to a study by National Grid ESO which found that a more integrated approach to connecting offshore wind, by including the use of multi-purpose interconnectors, could reduce consumer costs by £3–6 billion. Depending on how soon it can be implemented, this could also reduce the number of onshore 'landing points' by up to 50 per cent.

So, what are multilinked windfarms?

Multilinked windfarms are an optimization solution that avoids building interconnectors in parallel and increases synergies among different windfarms. It means that a number of windfarms are connected, creating a so-called energy island at sea. This energy island is then also connected to different onshore markets, exposing the wind farms to a higher number of competing markets since flows will be directed to where demand and prices are the highest. Multilinked projects can look quite different and are expected to evolve as offshore wind projects are built out. As Figure 1 shows, a windpark is first referred to as being multilinked when it is connected to more than one onshore market. However, solutions can look different where more than one windfarm is connected into a hybrid solution that connects the parks to several onshore markets. As these types of solutions evolve, so-called energy islands can emerge where a highly interlinked network connects many windfarms to many different onshore markets.

Figure 1: A step-by-step development of offshore wind interconnector models



Source: ELS Analysis, ENTSO-E.

Cost-saving example

By looking at an already existing project, the point made by the British Government about saving cost through hybrid and multilinked offshore wind projects is evident.

The Kriegers Flak Combined Grid Solution (CGS) is one of the first projects to combine offshore wind farms with interconnectors between two countries. It joins the 605 MW Danish Kriegers Flak wind farm with the German 288 MW Baltic 2 and 48 MW Baltic 1 wind farms, connecting them to the 400 kV Bjaeverskov, Ishøj, and Hovegård substations in Denmark and the 220 kV/110 kV Bentwisch substation in Germany. The connections consist of 220 kV and 150 kV offshore and onshore cables traversing over 200 km, capable of transmitting 400 MW of power in either direction – a significant transmission capacity increase compared to the 1000 MW DC cable connecting the two countries' grids. Along with the back-to-back converter installed in Germany to match the phase frequencies of the Danish and German grids, and a 220 kV–150 kV transformer at one of the Danish offshore platforms, the cost of the Multilinked/Hybrid grid solution was approximately €300 million. (This sum covered only the back-to-back converter station and its controller, the cables connecting the two wind farms over 25 km, and transformer stations in the offshore wind platforms.) The investments in the wind farms, including their cables to shore, increased the cost to over €3 billion.

Compare this to another location with the potential for such a cross-border connection: the Baltic Sea area between Sweden and Poland. Four wind farms have applied for permits here: the 5500 MW Aurora and 2000 MW Södra Victoria for Sweden, and the Bałtyk II and Bałtyk III, each 720 MW, for Poland. Three of these, Södra Victoria, Bałtyk II and Bałtyk III present an opportunity for a meshed grid connection between the two countries. Connecting these wind farms to only their respective countries' grids would require cables traversing 350 km, with 150 km being sub-sea. If the power from all three wind farms is to be accessible by either country, additional DC cables will be needed to bolster the connection between the two countries. This amounts to some 250 km of sub-sea HVDC cables, which would need to have a capacity of at least 1500 MW, or 2.5 times the current 600 MW SwePol DC connection, which cost €250 million. This brings the total subsea distance to 400 km, with a conservative estimate of the cable cost at over €1.3 billion.

If, instead, a Multilinked/Hybrid/Meshed grid was used with the same approach as the Kriegers Flak CGS, the transmission capacity between countries could be covered by some 370 km of cables, with 210 km sub-sea, allowing 1500 MW of power to flow in either direction. The cost is estimated at around €900 million, saving over 30 per cent of the cable costs.

Union-wide interests over national interests

This new approach to offshore wind connection models does, however, not come without challenges. The first big hurdle to overcome is coordinating all these activities among the different actors involved in both offshore wind park, as well as infrastructure, projects. But it also means coordinating several different national decision-making bodies and work around different national legislations, which currently can vary quite a lot. Even today, planning and constructing offshore windfarm projects and transmission lines takes years of analysis and permissioning before construction even begins. Thus, all actors involved will have to agree on technical specifications and the timing of the project.

To avoid conflicts between different national legislations as well as complicating the procedure by including too many national decision-making bodies, bilateral or multilateral cooperation between relevant member states is necessary. One starting point could be that relevant member states jointly identify so-called 'go-to-areas' which (from a strategic point of view) are interesting both from a pure offshore wind production point of view and are also suitable for connecting their respective markets. In order to gather several offshore wind developers for one multilinked project, competitive auctions, jointly held by relevant national TSOs, or alternatively a common TSO at sea, should be held. For this to work, a common legal framework, and auction rules designed for multilinked projects, will have to be developed. There is already guidance provided by the EU Commission, specifically focusing on offshore wind, that could form the basis for such cooperation between member states and more is to be expected. Furthermore, offshore wind should be viewed as an integrated part of the overall EU electricity market rules; also, export cables connecting onshore markets already exist, which means some lessons can be learned from previous export projects.

Another challenge that might be more difficult to overcome is the risk of conflict between union-wide and national interests. The idea of connecting different markets offshore through multilinked projects has huge benefits for realizing not only the EU's offshore wind targets, but also the idea of an EU internal market where electricity should flow freely. The European electricity market is today divided into different bidding zones/price areas and electricity prices vary quite a lot between these zones. This means that when different zones are connected to production sites, the price will determine where the electricity will flow. In many countries, offshore wind deployment is viewed as a national security of supply solution – to either reduce the country's dependence on fossil fuels, or just as a measure to meet the country's electrification targets. If there are no guarantees that the electricity produced from offshore wind will serve national interests, but instead risk being directed to another market where prices are higher, governments might not be willing to stimulate or support multilinked projects.

The conflict between union-wide and national interests has only intensified this year, amid the current European energy crisis and the sky-rocketing energy prices. Examples of countries discussing, and in some cases introducing, limitations in power exports are highlighting this risk. For this conflict to be resolved, it is most likely that EU legislation will be needed to create a market design where multilinked projects are rewarded.

ELECTRICITY TRANSMISSION NETWORKS IN SUB-SAHARAN AFRICA'S POWER SECTOR: PROPOSAL FOR A JOINT TRANSMISSION ORGANIZATION

Michael Hochberg

A bulk electricity transmission system is integral for quality of life, economic growth, and decarbonization objectives. The presence of an adequate and reliable transmission network is key, as it increases the size of the power market and facilitates competition. Yet in many cases, it is easier to produce electricity than it is to transport it. This phenomenon is most pronounced in geographies that lack reliable access to electricity, and where public budgets are stretched.

Given the nature of transmission as a natural monopoly, power transmission deregulation is more intricate than the same process within the generation segment. Project development concerns, such as access to transmission corridor right of ways, can also be more complicated. Independent power transmission (IPT) projects are therefore less common relative to independent power producer (IPP) projects. Yet, IPT projects may increasingly make sense in coming years.

The world is approaching the mid-2020s in a higher interest rate environment, with mounting uncertainty regarding investment conditions and geopolitical alliances. The necessity to decarbonize electricity systems, and the corresponding recognition of this among corporations and national governments, is greater than ever. Such conditions may help necessitate the inclination for an increase in IPT projects, in order to realize the benefits associated with access to financing, project cost, decarbonization, and scope for new partnerships.

The potential for IPT projects is particularly interesting in Sub-Saharan Africa (SSA), which has untapped renewable energy potential and is home to 77 per cent of the world's 770 million individuals without power.³ In the decades ahead, electricity access in SSA will expand. Driven by growing middle- and higher-income households and industry, power demand on the African continent is projected to increase by 75 per cent by 2030.⁴ The region also continues to experience the fastest population growth in the world. As such, SSA will play a key role in decarbonization globally, and the business-as-usual case will not suffice.

Sub-Saharan Africa in context

In SSA the number of people without access to electricity increased in 2020 for the first time since 2013. Nearly 600 million individuals lack electricity access.⁵ In terms of demographics, the region's population is growing by almost 3 per cent annually, meaning that SSA is adding the population of France every two years. If growth continues at the current pace, by 2050 the total population will double to 2.5 billion, who will then represent about a quarter of the global population.⁶ By then, there will likely be more Nigerians than Americans. Electricity demand in the region is rising rapidly as well. The imperative to ensure that new power demand is serviced by clean energy sources is enormous. Investment in the interconnected grid has a significant role to play, as do private transmission arrangements.

Power sector structure

To appreciate where private sector engagement in electricity transmission may be most appropriate, it is helpful to review the general structure of the regional power sector. Three utility sector models⁷ are represented across SSA⁸:

1. Vertical integration with no private sector participation (PSP) – In this group, power sectors are unreformed and governed by the traditional vertically integrated, state-owned utility model. About 19 Sub-Saharan African nations subscribe to this model.
2. Vertical integration with PSP – Within this category, the vertically integrated utility model persists, albeit with a degree of private sector involvement, usually through an independent power producer (IPP) scheme. In some cases, for example in Zambia, private network businesses exist through concessions. About 19 Sub-Saharan African nations subscribe to this model as well.
3. Vertically unbundled – This group represents nations that have partially or fully unbundled the utility, with most structures permitting private sector investment through IPPs and/or concessions. About ten nations subscribe to this model.

Within each of these categories there may be scope to introduce private transmission schemes, yet budgets of public utilities are already over extended. This inhibits the ability of these organizations to respond to public policy objectives such as electricity access, renewable energy deployment, and grid reliability. The majority of SSA's public utilities are loss making; this reduces their budgets for investment and maintenance in new and existing transmission assets.⁹ The region requires around \$4 billion of investment in transmission annually until 2040, but the public sector is unable to meet this target.¹⁰ The restricted ability to invest in transmission has outsized consequences – reducing reliability, affordability, and growth in renewable energy generation.

Distributed generation, off-grid power, and bulk transmission

Off-grid power solutions and distributed generation are essential for electricity access and clean energy deployment in the region. Leapfrogging the electric grid makes great sense in decreasing the friction in terms of reducing cost, raising financing, and facilitating project development. Distributed generation and off-grid investment should be pursued in parallel with build-out of the bulk transmission system. Distributed generation solutions often make the most sense for low-demand applications and in remote locations with low population densities, while the extension of the transmission grid is economical when there are

³ Access to Electricity – SDG&: Data and Projections, International Energy Agency (IEA), 2022.

⁴ Africa Energy Outlook 2022, IEA.

⁵ Access to Electricity – SDG&: Data and Projections, IEA, 2022.

⁶ Africa's population will double by 2050, Economist, 2020.

⁷ Eberhard, Anton & Godinho, Catrina, UC Berkley, A Review and Exploration of the Status, Context and Political Economy of Power Sector Reforms in Sub-Saharan Africa, South Asia and Latin America (2017).

⁸ The precise number of countries that subscribe to each model has varied since 2017, as countries roll out private sector participation initiatives.

⁹ Utility evolution in Africa to reshape global electricity demand, WoodMac, 2022.

¹⁰ Linking Up: Public–Private Partnerships in Power Transmission in Africa, World Bank, 2017.

economies of scale. To provide power to the hundreds of millions of individuals without access to electricity, meet growing power demand, and enable new renewable power capacity, diverse solutions are necessary and must be pursued in parallel.

Investment considerations and risks

A number of risks must be accounted for in order to incentivize investment in independent transmission. The degree of power sector unbundling is fundamental, as it impacts investor comfort with independent power projects, and dictates the viability of specific independent transmission business models. The levels of unbundling and market liberalization also help determine the regulatory model of grid revenue setting. This is critical, as defining attractive mechanisms for cost recovery and revenue generation are central to both maintaining a financially viable transmission sector and appealing to private investors.

In a liberalized market, merchant transmission models are introduced. Merchant transmission takes advantage of arbitrage opportunities associated with nodal markets and point-to-point delivery. This market-driven model requires advanced levels of power market competition supported by strong regulatory institutions and highly efficient pricing. Such an approach could become more relevant in the future if the region's utility sectors institute market liberalization initiatives.

A concession model is more likely for private transmission investment in Sub-Saharan Africa. Such a model would likely form via a regulated tariff, either under cost-of-service regulation or incentive regulation. A fundamental consideration is sound tariff setting, to incentivize investment. A sound tariff should allow investors to recover costs plus a reasonable rate of return. Yet the revenue model must also be defined in terms of how costs are set, which creates two issues for policymakers:

1. determination of the efficient cost within the particular transmission network for both investment and operational costs,
2. determination of the efficient and equitable way to recover this cost.

These calculations must be done while considering the way in which the proposed network infrastructure and the existing transmission network are to be utilized.

An integrated approach

A model that encourages the development of independent power transmission (IPT) projects is needed. The establishment of a Joint Transmission Organization (JTO), an entity that is responsible to facilitate and pursue investment opportunities in a specific geography, would help advance projects. The structure could take shape under a concession agreement, in which the government defines key aspects affecting the investment environment around private transmission. JTOs determine these key features – including policy, regulation, and remuneration – in consultation with the private sector. If deeper market liberalization reforms are undertaken in the future, the JTO model could also take form via a merchant transmission structure.

In terms of business entity structure, each JTO is responsible for project companies that sit under the JTO parent company. Each JTO project company will enjoy equity participation from both the JTO parent and private investors. The level of JTO participation relative to private sector ownership will vary by project, according to the most suitable financing arrangement given the project objectives and risk–reward profile. Each individual project requires its own business entity and bespoke shareholder agreement, all under the purview of the JTO.

JTOs specify the need for proposed transmission investments. To increase the likelihood that investments are efficient, certain principles should be applied to project evaluation. Each transmission project must be viewed as a multi-value project, capable of addressing multiple needs and providing a range of benefits. Evaluation will include quantification of economic, public policy, and technical benefits. This will include the project's impact on economic output, economic development and human capital, electrification, and grid reliability. To account for uncertainty, future scenario analysis should be performed to understand risks and benefits under a range of sensitivities. As part of this analysis, 'least regrets' planning approaches are to be considered.¹¹

In addition, JTOs are incentivized to consider non-network solutions prior to issuing recommendations on transmission investment. This analysis will vary depending on the objectives of the project. For example, if the primary project objective is to relieve a transmission constraint by connecting a high supply area to a high demand area with a new wire, alternatives are considered to ensure that a new transmission line is the most efficient solution. In this case, alternatives that should be considered include:

- battery deployment to store energy when supply is high,
- a demand aggregator to help balance demand with supply,

¹¹ [Transmission Investment Needs and Challenges](#), Brattle Group, 2021.



- a voltage service provider to respond to challenges associated with unanticipated increases in supply, particularly in the case of wind generation.¹²

Depending on the specific context, such solutions may be more efficient relative to new transmission build.

While JTO projects are multi-value projects, each JTO project has specific objectives, some of which weigh more heavily than others depending on local conditions and broader policy objectives. For example, while one project may focus on facilitating renewable energy deployment via additional transmission capacity, another project may emphasize grid stability, while another may prioritize electricity access. Linking projects to social and economic development may also be a primary aim. The objectives of the JTO and the aims of the specific projects help determine the structure of the specific arrangement, the investor and developer profiles, and the capital stack.

A clear vision for transmission investment, supported by policy, regulation, and a robust investment framework will help de-risk projects, lowering the cost of capital for investors, and making it cheaper to raise funds for transmission investment relative to the status quo model. Translating vision into successful projects takes time, and investors may wish to observe the success of the JTO model prior to making material adjustments to risk and cost of capital calculations. Yet as the model advances beyond proof of concept, and projects come to fruition, cost of capital will improve. Enhanced access to competitive capital for transmission infrastructure has ripple effects, facilitating economic growth and the energy transition.

JTOs are regulated by the national energy regulator, which will review and approve the revenue-setting models and the final tariffs associated with the new transmission infrastructure. To increase the independence of the JTO and reduce the likelihood that investment decisions are politically driven, each JTO utilizes a comprehensive scoring tool to prioritize the investment according to objectives, while considering the uncertainties and sensitivities that are studied in parallel.

JTOs provide clarity of vision to the investment community. They champion independent power transmission project initiatives, acting as a driving force to advance the steps required to bring projects to fruition. The government side of JTOs are equipped with staff whose expertise includes utility strategy, corporate and project finance, investment promotion, social impact, real estate, legal, and project feasibility. JTOs have seven complementary responsibilities and objectives:

- Definition of vision, objectives, and strategy – JTOs coordinate with existing energy policy and regulatory entities to define realistic goals, including determination of primary, secondary, and tertiary objectives related to renewable penetration, electricity access, reliability, grid stability, and social development.
- Initial feasibility – JTOs work with government agencies and non-governmental stakeholders (including local populations, NGOs, environmental organizations, and land holding entities), to study the feasibility of potential project locations. They also launch and oversee initial feasibility studies from specialist vendors to begin de-risking projects.
- Investment promotion – This role involves market-facing promotion including the propagation of information related to the new independent power transmission investment objectives, frameworks, and implementation plans.
- Investor engagement – JTOs engage financing parties, project developers, and longer-term investors to seek feedback regarding policy, regulation, and remuneration mechanisms, as well as feasibility of projects. To this end, Requests for Information from the investment community should be issued during the early stages of project analysis.
- Government relations – JTOs work closely with the regulator to ensure sound tariff setting and revenue model definition. JTOs also collaborate with the energy policy entity and other relevant agencies to help align JTO objectives with broader national ones.
- Partner selection – JTOs ultimately select the most appropriate group of project developers, financing parties, and project partners through competitive processes that consider economic competitiveness and experience relative to proposed projects and project objectives.
- Long-term owner – JTOs will maintain an equity share in the projects throughout their operating terms, and participate in the oversight of operations and maintenance.

¹² [Energy Networks in the Energy Transition Era](#), Rahmat Poudineh, Oxford Institute for Energy Studies, 2022.

This model differs from traditional public–private partnerships. The JTO model combines a public–private partnership model with a cross-sector agency approach. The JTO is ultimately responsible for project feasibility, completion, and management. The private sector remains engaged throughout the process to provide feedback and, ultimately, to finance a portion of the project.

Conclusion

Transmission networks are a key piece of the decarbonization puzzle. Large-scale, grid-connected generation projects that transport clean sources of the power to replace polluting ones require adequate transmission to deliver electrons to market. The business-as-usual approach for transmission investment in Sub-Saharan Africa (SSA) is insufficient to raise the financing for the transmission capacity that the region needs and deserves. The JTO model offers a new impetus, from which private transmission projects in SSA can be pursued. In addition to bringing about new transmission that would have otherwise gone unbuilt, the JTO model can help to free up public budgets earmarked for transmission investment that is already planned. Many nations globally, such as Algeria and India, have created new renewable energy-specific agencies to oversee and facilitate the deployment of zero-carbon power. An empowered version of this approach should be applied to investment in private transmission.

TOWARDS A REGULATORY FRAMEWORK FOR THE USE OF FLEXIBILITY IN DISTRIBUTION GRIDS

Leonardo Meeus, Ellen Beckstedde, and Athir Nouicer

Introduction¹³

Electricity distribution grids are dimensioned to handle peaks. The more grid users produce electricity and inject it into the grid at the same time, or the more they consume and withdraw electricity from the grid at the same time, the more DSOs have to invest in the grid to handle these peaks. For the average household in Europe, distribution grid costs make up a third or a quarter of the electricity bill, so this is a significant cost that we want to keep under control.

Household consumption peaks in the evening when kids return from school and when their parents return from work. A household can easily double or triple its evening peak if it switches to a heat pump and an electric vehicle. As distribution grids are increasingly integrating solar and wind power production units, they can also experience injection peaks in some locations. Households or neighbourhoods can produce more than they consume. Solar farms or wind farms can also create new peaks in new locations. We also continue to discover new phenomena that cause unexpected peaks, like the data centres that caused congestion in medium-voltage distribution grids in some countries, such as Ireland, the Netherlands, and Norway.

We can do a lot to limit peaks by tapping into the ‘flexibility’ that is increasingly present in distribution grids. We can, exceptionally, curtail solar and wind power production to deal with critical peaks. Building owners can invest in energy efficiency to reduce the need for heating. In well-insulated homes, it is also easier to pre-heat a home before the evening peak. The charging of electric vehicles at home can be spread out over the night, and there are also alternatives to home-charging, such as charging in public parking, offices, shops, or along the road. Other electrical appliances can also become increasingly ‘smart’.

For all these reasons, it is challenging to plan the investments in distribution grids, and to give the right signals to the users of these grids. It is even more challenging if we consider the whole system perspective. We are evolving into consumer-centric electricity markets with decentralized energy resources that can respond to short-term price signals in wholesale and balancing markets. These system signals will sometimes conflict with the distribution grid signals. Handling these conflicts is a key challenge for future electricity markets.

Thanks to the EU Clean Energy Package, smart grids are becoming a reality. After many years of R&D, regulatory frameworks are being adapted to upscale the demos. The initial approach is mainly local or national, but there is also a process to develop network codes that can harmonize and standardize some aspects of these approaches. Network codes have proven successful at spreading the best wholesale and balancing market initiatives in Europe. We hope they can do the same for flexibility in

¹³ Acknowledgements: The PhD of Ellen Beckstedde is supported by the European Union's EUniversal Horizon 2020 (grant agreement No 864334). The PhD research of Athir Nouicer is supported by the European Union's INTERRFACE Horizon 2020 project (grant agreement No 824330). Leonardo Meeus contributed to both projects.

distribution grids.¹⁴

This brief is structured in two sections to give an answer to two questions:

- Is there a potential to use flexibility to save investments in distribution grids?
- How should DSOs contract flexibility?

Is there a potential to use flexibility to save investments in distribution grids?

We can only answer this question after clarifying what we mean by ‘using flexibility to save investments in distribution grids’ and ‘regulatory tools to mobilize that flexibility’.

The first clarification is about ‘using flexibility to save investments in distribution grids’. We know that we need to expand distribution grids to decarbonize our energy system. We will have more wind and solar power, and a lot of it will be connected to distribution grids. We will, at least partly, electrify transport and the heating of buildings. We also know that investments in distribution grids are slower than the decisions of individual users to switch heating systems, switch cars, or invest in solar and wind farms. We should therefore start to plan distribution grid investments before congestion occurs, but we also want to limit the risks/costs of overinvestment. Using flexibility can be a way to delay investments to the point that the business case is more certain. The EU Clean Energy Package does require DSOs to consider flexibility as an alternative to grid expansion at the planning stage. The DSOs that have already started to use flexibility mostly did so out of necessity, to handle unexpected situations, so we still have to discover how planning for flexibility will be implemented.

The second clarification is about ‘regulatory tools to mobilize flexibility’. Electricity bills are mainly expressed in price per volume. You consume more, you pay more. This makes sense for the commodity electricity that is priced in wholesale markets, but not for the usage of the distribution grid.¹⁵ Most countries have started to reform their distribution tariffs to include components that are partly fixed (to share the costs of past investments that still need to be recovered), and partly driven by peaks (to signal the costs of future investments that need to be made to handle peaks). In our research on the topic, we concluded that tariffs can be significantly improved, but they will never be fully cost-reflective.¹⁶ Tariffs alone will not enable the full potential of using flexibility to save distribution grid investments. It is therefore very welcome that the EU Clean Energy Package foresees different ways for DSOs to contract flexibility, which we categorize into two options:

- Flexibility as a grid service. Regulatory frameworks are being developed to allow DSOs to tender for grid services that they can activate to manage local congestion.
- Flexibility as a right/obligation. We are used to getting a connection to the distribution network with ‘unlimited’ access. This practice can be replaced by contracts that allow DSOs to curtail the injection or consumption peaks, and this can be done on a voluntary or mandatory basis with or without compensation.

In our research, we analyse the costs and benefits of these options.

Our current thinking is that there is a potential to use flexibility to save investments in distribution grids. When we started to simulate the potential, we were working with a mathematical model for a typical day. We gave the DSO the option to contract flexibility to optimize the system in that setting, but our welfare-maximizing DSO never used that option. We first thought we had a mistake in our model, until we realized that it can indeed be cheaper to dimension the distribution grid to handle the peak of a typical day. The business case for using flexibility is stronger on critical days with unusually high peaks that only happen a few times every year. By bringing the peaks on these critical days closer to the peak of a typical day, we can more easily save investments with limited use of flexibility. We also found that flexibility contracting can help to correct the imperfect signals provided by distribution tariffs and/or to address the peaks of passive consumers that do not respond to tariff signals. The

¹⁴ The importance of network codes and the EU Clean Energy Package is discussed in our open access book and corresponding training at the Florence School of Regulation.

Leonardo Meeus, 2020, *The Evolution of Electricity Markets in Europe*. Edward Elgar Publishing.

¹⁵ Note that paying per volume could also be questioned for the supply of energy as we transition towards renewable power production with more fixed capacity costs than variable costs.

¹⁶ Limited granularity in space and time, fairness concerns (Schittekatte and Meeus, 2020), the use of historical cost models instead of forward-looking cost models and the fact that perfect tariffs require information about the willingness to pay of grid users that the regulator does not have (Govaerts et al., 2021).

Schittekatte, T. and Meeus, L., (2020), ‘Least-cost Distribution Network Tariff Design in Theory and Practice’, *Energy Journal*.

Govaerts, N., Bruninx, K., Le Cadre, H., Meeus, L., Delarue, E., (2021), ‘Forward-looking distribution network charges considering lumpy investments’, *J. Regul. Econ.* 59, 280–302.

combination of these two regulatory tools, however, also has its limits.

If the tariffs are too imperfect, it can become too costly to fix the corresponding behaviour with flexibility contracts. Note also that the costs of contracted flexibility are typically recovered via distribution tariffs, so by trying to fix the imperfect signals of the tariffs, you are also increasing them.¹⁷

Our future research will revisit these findings, and also address new questions. We need to revisit the findings because our research so far has focused on flexibility coming from prosumers with PV-rooftop installations and batteries, while we know that flexibility from electric vehicles and heat pumps is at least as important, and a system with different types of flexibility might behave differently. We also identified new questions for research:

- To what extent do we want distribution grid investments to be proactive?
- How important is it to consider the whole system perspective versus the local dimension when making the trade-off between flexibility and distribution network expansion?
- What is the impact of TSO–DSO coordination on the trade-off?
- How context-specific is the flexibility potential; in other words, ‘low-voltage versus medium voltage grids’, ‘rural versus urban distribution grids’, ‘congestion caused by generation peaks versus consumption peaks’?

How should DSOs contract flexibility?

In our research,¹⁸ we have identified two important regulatory choices that need to be made: the provision of flexibility by grid users can be mandatory or voluntary, and we can have short- versus long-term flexibility contracts.

	Mandatory	Voluntary
Short-term		- Flexibility markets.
Long-term	<ul style="list-style-type: none"> - Default non-firm connection contract. - Grid connection requirements (active and reactive power). 	<ul style="list-style-type: none"> - Flexibility markets. - Choosing between firm and non-firm connection agreement.

As illustrated in the table, mandatory flexibility is typically long term. The default connection contracts can become non-firm, or firm for a certain basic level of production and consumption, and non-firm for everything above.¹⁹ ‘Non-firm’ means that the grid user can be curtailed under certain circumstances. This can also be implemented as a grid connection requirement. As this flexibility is mandatory and long term, there is more clarity on the volume that will be available, and the price at which it is available. This makes it easier to do the trade-off between flexibility and investing in the network at the planning stage.

For the grid users, mandatory, however, implies that their consumption or generation peaks can get curtailed, even if they might not want to be cut short. To soften the pain, regulators typically limit the use of mandatory flexibility, and/or put the

¹⁷ Athir's Ph.D. consists of three papers that discuss the costs and benefits of using flexibility to save investments in distribution grids. In each paper, we made additional steps in the modelling of this trade-off and in the discussion of the main sensitivities, which include regulatory choices (e.g., mandatory versus voluntary flexibility, and the level of compensation for the use of flexibility) as well as context-specific parameters (e.g., the value of the lost load, and the cost of distribution grid expansion) that strongly influence the trade-off. Nouicer, A., Meeus, L., and Delarue, E., (2022), ‘The economics of demand-side flexibility in distribution grids’, *IAEE Energy Journal*. Nouicer, A., Meeus, L., and Delarue, E., (2022), ‘A bilevel model for voluntary demand-side flexibility in distribution grids’, RSC Working Papers. Nouicer, A., Meeus, L., and Delarue, E., (2022), ‘Demand-side flexibility in distribution grids: voluntary versus mandatory contracting’, RSC Working Papers.

¹⁸ A more detailed discussion on how DSOs should contract flexibility and other flexibility market design challenges such as market timing, the role of the independent market operator, bid selection, and counterbalancing can be found in: Beckstedde et al., (2022), ‘Evaluation of market mechanisms: challenges and opportunities’, EUniversal Deliverable: D5.4.

¹⁹ For example, we could (temporarily) set limits to the maximum capacity that a single grid user can expect, to avoid a connection queue for other users; or we could reconsider the voltage quality standards that DSOs have to live up to so that they can add more grid users.

administratively set compensation high enough.²⁰ In our research (see footnote 17), we demonstrated that it will be very difficult for regulators to set the price. If we set the compensation high enough for vulnerable or passive consumers, we will trigger gaming by the prosumers who can create peaks (for instance by charging their batteries during a consumption peak) in order to then get paid for the curtailment of these peaks. This argues in favour of a market for flexibility in which a price can be discovered. The EU Clean Energy Package indeed focuses on the market-based approach,²¹ but it does leave the door open for other schemes if they are justified by a cost–benefit analysis.²²

The table also illustrates that voluntary flexibility can be combined with short- or longer-term contracting. Flexibility markets can be about exchanging shorter- or longer-term flexibility services between flexibility service providers and DSOs. Longer-term flexibility contracting can also be done by offering grid users a choice between (cheaper) non-firm connection agreements and (more expensive) firm connection agreements.²³ The risk of short-term contracting is that market parties deliberately create congestion in distribution grids because they anticipate getting paid to solve that congestion via flexibility markets. This is known as the inc-dec game – it has been observed in transmission grids, and we have shown in our research that it could also occur in distribution grids.²⁴ Longer-term contracts can help to reduce this risk, but they cannot mitigate it entirely.²⁵ Longer-term contracting, however, implies that the DSOs reserve resources to be able to solve congestion when it occurs, which can increase the costs in wholesale and balancing markets. Even if the DSO considers these wholesale and balancing costs when doing the trade-off between flexibility and distribution investments, this will be done imperfectly, in a context of uncertainty with limited information. In our ongoing research, we are trying to figure out to what extent this is an issue.

Note finally that long-term flexibility can also be smartly combined with shorter-term flexibility markets for three reasons:

1. Longer-term contracts (voluntary or mandatory) can provide DSOs with certainty that enough flexibility will be available, while they can use shorter-term flexibility markets to check if cheaper resources are available.
2. Grid users could use these shorter-term flexible markets to trade their flexibility obligations in a kind of secondary market for flexibility.
3. Regulators can use the price discovery in flexibility markets to adapt the compensation for the provision of flexibility under longer-term schemes.

Conclusion and recommendations

The wind and solar units that will be connected to distribution grids, in combination with electric vehicle chargers and heat pumps, will create new peaks in distribution grids. We will need to expand these grids, but we can also tap into the flexibility that is increasingly present in distribution grids to avoid unnecessary investments and to deal with uncertainty. There is a potential to use flexibility to save investments in distribution grids. In particular, the more recent applications to smartly charge our electric vehicles and/or smartly heat our buildings with heat pumps, together with storage solutions, increase this potential. Curtailing solar and wind when they create critical peaks does not look very smart, but it can be a good idea anyway in some circumstances. The EU Clean Energy Package provides a regulatory framework for the use of flexibility in distribution grids. The initial implementation is mainly local or national, but there is also a process to develop network codes that can harmonize and standardize some aspects of these approaches.

Even though there are many details to figure out, we can summarize our current thinking into three regulatory recommendations:

²⁰ An overview of different compensations mechanisms under connection agreements in six European countries can be found in Beckstedde et al., (2019). EUniversal Deliverable: D1.1 'Characterization of current network regulation and market rules that will shape future markets'.

²¹ Article 32(1) of Directive (EU) 2019/944.

²² Art. 13 (5.a) of Directive (EU) 2019/944.

²³ The case of GOPACS in the NL even shows that 'short term' can even mean intra-day counter-trading by the DSO via an existing intra-day market, instead of a new market for grid services. Longer-term contracting can be implemented by offering grid users the choice between firm and non-firm connection contracts, e.g., France and the UK, or by tendering for multi-year contracts in flexibility markets, e.g., Piclo Flex in the UK with tenders for longer-term contracts, such as 3-year contracts.

Schittekatte, T. and Meeus, L., (2020), 'Flexibility markets: Q&A with project pioneers', *Utilities Policy*, 63, 101017.

Yemane Hadush, S. and Meeus, L., (2018), 'DSO–TSO cooperation issues and solutions for distribution grid congestion management', *Energy Policy*, Vol. 120, 610–21.

²⁴ Beckstedde, E., Meeus, L., and Delarue, E., (2021), 'Strategic behaviour in flexibility markets: New games and sequencing options', *Energy Syst. Integr. Model. Group, Work. Pap. Ser. No. ESIM2021-05*.

²⁵ We cannot avoid it entirely. We have illustrated with several simulations that gaming continues in a long-term equilibrium, see the papers referred to in footnote 5.

- First, we should make sure that distribution tariffs become reasonably cost-reflective. Flexibility contracts are not an alternative to cost-reflective distribution tariffs, but they can complement reasonably cost-reflective tariffs.
- Second, signals from tariffs can be combined with flexibility contracts, and we can combine mandatory with voluntary flexibility contracting. The existence of a mandatory scheme does not have to imply that it is often used; it can be the backup scheme.
- Third, we invite everyone to keep an open mind regarding the issue of short-term versus longer-term contracting of flexibility by DSOs. TSOs have just been asked to make a significant reduction in their long-term reservations of resources for balancing or re-dispatching, so it seems contradictory that DSOs would now be allowed to make long-term reservations to manage local congestion. However, in order to fully explore the potential of using flexibility to save distribution grid investments, we could allow this to happen, and it is already happening in some countries. If we then discover that this reduces the distribution costs at the expense of the whole system costs, we will need to intervene.

There are many more details to figure out in the coming years. Key questions include:

- How important is it to consider the whole system perspective versus the local dimension when making the trade-off between flexibility and distribution network expansion?
- What is the impact of TSO–DSO coordination on the trade-off?
- How context-specific is the flexibility potential; in other words, ‘low-voltage versus medium-voltage grids’, ‘rural versus urban distribution grids’, ‘congestion caused by generation peaks versus consumption peaks’?

DISTRIBUTION NETWORK PLANNING DURING THE ENERGY TRANSITION: SYNERGIES BETWEEN REAL OPTIONS & FLEXIBILITY MECHANISMS

Miguel A. Ruiz, Tomás Gómez, Rafael Cossent, and José P. Chaves

The increase in renewable generation and electrification of energy sectors such as heating and cooling, transport, and industrial processes could require massive investment in electricity networks unless flexibility mechanisms are efficiently developed to handle local variability of loads and generation. The need to perform an economic assessment of these flexibility mechanisms urges a paradigm change in current network planning practices.

Distribution system operators (DSOs) face increasing uncertainties about the penetration of distributed energy resources (such as renewable generation and storage) and the advent of new loads due to increasing electrification. Distribution network planning (DNP) presents a trade-off between maintaining a high service level to end consumers and avoiding costly irreversible network reinforcements. When peak demand is close to the network capacity limits, the DSO should decide whether to reinforce the grid. Knowing that if demand does not grow as expected the investment decision would result in an unnecessary cost, whereas if demand grows above expectations this could result in quality-of-service degradation and potential damage to installations.

This article addresses some of the challenges that DNP is expected to face during the following years due to energy transition. We show how real options can be used in the context of DNP, and the potential benefits it brings for valuing grid investment deferral. Finally, we discuss how projected future demand scenarios suit real options strategic planning.

Distribution network planning under the energy transition

Growing renewable connections impose challenges for network operation and planning, since some of these (such as solar and wind) are variable and not dispatchable. However, the uptake of electric vehicles, heat pumps, power-to-gas, and other technologies offers an opportunity, as they can serve as storage devices and flexible demand, offering local flexibility in distribution networks. Nonetheless, the uncertainty about demand evolution during the upcoming years is high, since the adoption pace of these new technologies is unknown. This situation accentuates the trade-off between maintaining a high service level and avoiding unnecessary investments. Thus, presenting a challenge for decision-makers in DNP.

Flexibility mechanisms such as flexibility markets, bilateral contracts, or connection agreements will be necessary to take advantage of flexible demand, generation, and storage. These flexibility mechanisms potentially allow DSOs to delay irreversible network reinforcement. In the context of high uncertainty about future demand, the alternative ‘wait and see’ how

demand evolves while maintaining high service levels thanks to flexibility mechanisms has caught the attention of analysts and policymakers. For example, EU directive 2019/944 article 32.3 indicates that DSOs shall consider demand-side response, energy storage, and energy efficiency as an alternative to system expansion. Ofgem RIIO ED2²⁶ opens the door to new valuation techniques, indicating that DSOs could recognize the option value that flexibility and energy efficiency can provide. The benefit of reducing investment in underused infrastructure by delaying commitment to irreversible investment is well understood.

However, traditional economic analyses based on discounted cash flow (DCF) are still being used and proposed as methods to evaluate alternatives in DNP. These traditional methods ignore the strategic value of flexible management decisions under uncertainty. Thus, we encourage using real options to better evaluate DNP alternatives, especially during the energy transition.

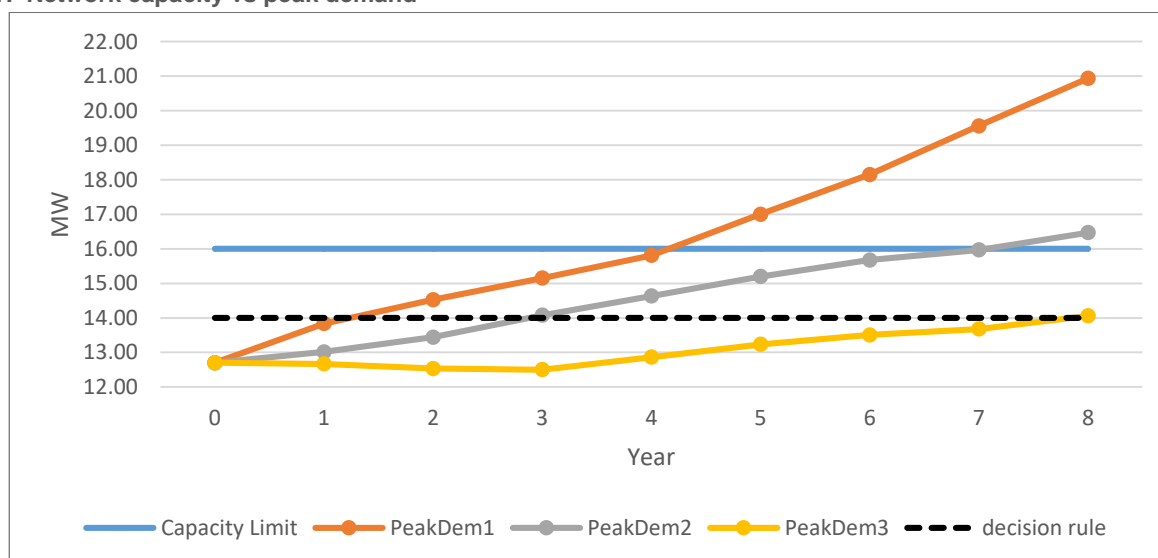
Real options characterization for DNP

Traditional investment valuation techniques based on DCF are deterministic. These techniques result in a series of fixed decisions projected into the future based on today's forecast. In contrast, real options theory is a conceptual framework for strategic planning under uncertainty that captures the decision-maker's flexibility to adapt to future conditions. In real options theory, future investment decisions are contingent on resolving future uncertainties. Thus, it results in dynamic strategies with defined reactions/responses to future events/conditions during the planning period. Next, we characterize deterministic plans and the real options approach in the context of DNP.

Figure 1 illustrates a DNP example, where the blue line (16 MW) represents the initial capacity limit for the network, while three lines (orange, grey, and yellow) represent the projected peak demand under uncertainty, modelled through three scenarios. Let's consider only one upgrade alternative (invest in a feeder with 2-year lead time) to solve any potential overload. A deterministic plan would be a fixed decision for the analysed period. For example, invest in a feeder at the end of year 2. Considering a 2-year lead time for the feeder, this investment will avoid the potential overload from year 5 onwards.

Alternatively, the real options approach would result in a decision contingent to the information generated over time as uncertainty leaves way to information. For example, invest in a feeder when peak demand reaches 14 MW (black dotted line) – this is similar to the proposal by Jonathan A. Schachter et al.²⁷ This strategy avoids potential overloads and results in the same investment as the previously presented plan only if demand grows fast (orange line), but it delays the investment if demand grows slowly (grey or yellow lines). This brief example shows how a real options approach offers a clear advantage versus deterministic plans when planning under uncertainty.

Figure 1: Network capacity vs peak demand



²⁶ RIIO-ED2 Business Plan Guidance, Ofgem, 2021.

²⁷ Jonathan A. Schachter et al., (2016), 'Flexible Investment under Uncertainty in Smart Distribution Networks with Demand Side Response: Assessment Framework and Practical Implementation', *Energy Policy*, 97, 439–49.

Valuing flexibility and investment deferral through real options

There are synergies between flexibility mechanisms and real options. Since one DNP principle is to maintain high service levels by avoiding non-served energy imposed by exceeding network operational limits, any investment decision in traditional planning is highly influenced by the worst possible scenario (fastest demand growth projected). Therefore, not considering the possibility of a greater investment deferral when demand increases slower than the fastest scenario limits the deferral period. Thus, limiting the value of flexibility mechanisms.

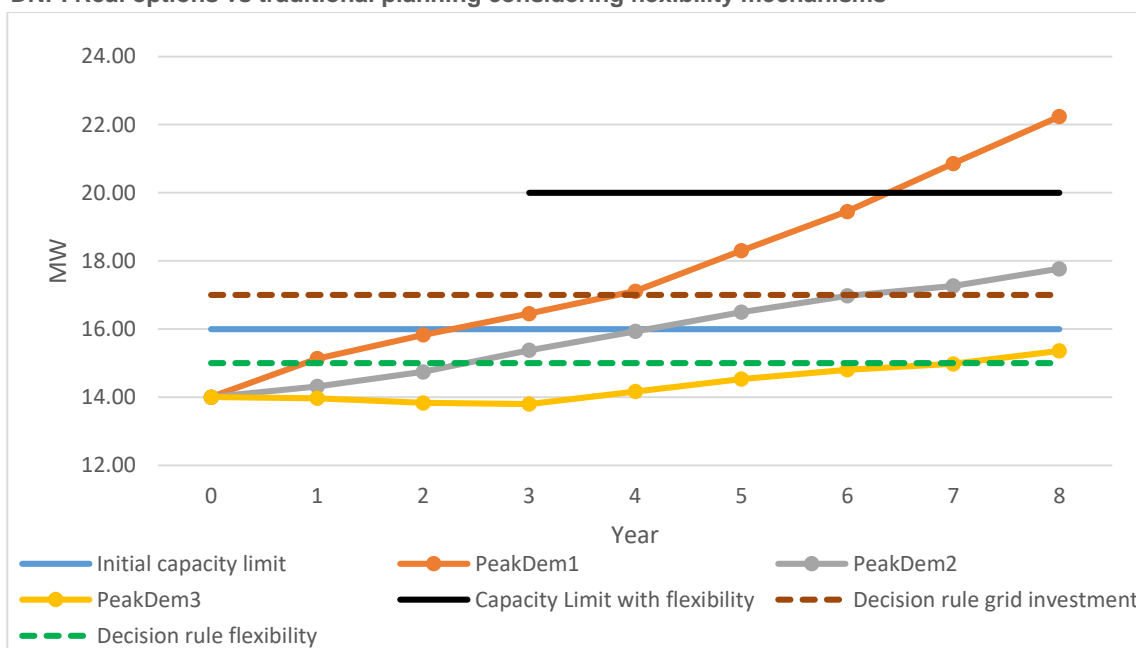
Real options strategic planning allows the decision-maker to evaluate how future decisions are contingent on the newly available information over time. Thus, the investment deferral period will be similar to traditional planning if demand grows at the fastest projected pace. The deferral will increase if demand grows below that pace, increasing the expected investment deferral and, consequently, unveiling the value of flexibility mechanisms.

Let's consider an example with two possible distribution upgrades (depicted in Figure 2). Consider two alternatives:

- Invest in a feeder (2-year lead time and 12 MW additional capacity for the grid).
- Invest in a demand response contract (1-year lead time, 4 MW additional capacity, and yearly contract renovation).

We consider three scenarios for future peak demand (orange, grey, and yellow lines). For the sake of simplicity, no overload is permitted. The grid initial capacity is 16 MW (blue line).

Figure 2: DNP. Real options vs traditional planning considering flexibility mechanisms



For the highest growth scenario (orange line), the first projected overload occurs during year 3, because demand exceeds the initial grid capacity (blue line, 16 MW).

- The first alternative is to invest in a feeder (12 MW) today (end of year 0). This feeder is built during years 1 and 2 (2-year lead time), resulting in the feeder being ready for use at the beginning of the third year (total network capacity of 28 MW), avoiding any potential overload during the planning period.
- A second alternative is investing in flexibility (4 MW), delaying the grid investment.

Next, we evaluate these alternatives by considering traditional planning and real options.

For *traditional planning*, to avoid the projected overload occurring in year 3, we need to invest in a demand response contract at the end of year 1. The additional 4 MW (black line, total admissible peak demand of 20 MW) will be available at the beginning of year 3 (1-year lead time). After this, the second overload is projected during year 7. We invest in a feeder at the end of year 4 with a 2-year lead time, being available at the beginning of year 7, avoiding the projected overload. Table 1 summarizes the

traditional investment plan described in this example (in traditional planning the fastest demand growth is the most influential scenario that imposes the needed investment).

Table 1: Traditional investment planning

(flex investment in year 1, grid investment in year 4)

		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Scen 1	Flex		X							
	Grid					X				
Scen 2	Flex		X							
	Grid					X				
Scen 3	Flex		X							
	Grid					X				

X: decision to invest in demand response contract (flex) or in a feeder (grid). Green/Yellow fill: flexibility mechanism/Grid investment in operation.

For *real options*, we define the strategy with two decision rules:

1. Invest in flexibility when demand reaches or surpasses 15 MW (green line),
 2. Then invest in the feeder when demand reaches or surpasses 17 MW (brown line).
- Scenario 1 (orange line) surpasses the first investment trigger (green line, 15 MW) during year 1. Then, the investment in flexibility occurs at the end of year 1, being available for operation at the beginning of year 3. Later on, during year 4, this scenario surpasses the second investment trigger (brown line, 17 MW). Thus, following the defined strategy, the feeder investment occurs at the end of year 4, resulting in the grid investment operating from the beginning of year 7.
 - Following the same logic, Scenario 2 (grey line) surpasses the green line during year 3. Flexibility investment is decided at the end of year 3 and is available for operation at the beginning of year 5. Afterwards, the feeder investment occurs in year 7 when the grey line crosses the brown line.
 - The third scenario (yellow) crosses the green line during year 8 and never surpasses the brown line. Thus, the strategy results in flexibility investment at the end of the eighth year and no feeder investment.

Table 2 summarizes the investment decisions for this strategy, resulting in no overloads.

Table 2: Real options planning

(flex investment at 15 MW, Grid investment at 17 MW)

		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Scen 1	Flex		X							
	Grid					X				
Scen 2	Flex				X					
	Grid								X	
Scen 3	Flex									X
	Grid									

Notations as in Table 1.

Comparing Tables 1 and 2, traditional deterministic planning leads to the same decisions for all three scenarios (invest in flexibility in year 1, and invest in the grid in year 4). However, the real options approach leads to different decisions contingent on information available over time. It leads to the same investment decision as in traditional planning for the first scenario (highest growth demand), and delays the investment decisions for scenarios 2 and 3. Thus, lowering the expected net present cost compared to traditional planning.

Additionally, traditional planning could lead to the rejection of flexibility mechanisms, due to poor valuation and analysis. To illustrate this, please consider the example presented in Figure 2.

- The first alternative is to invest in grid reinforcement today and not use the flexibility mechanism.
- The second alternative is to invest in the flexibility mechanism and defer the grid reinforcement.

The maximum amount we can spend in the flexibility mechanism is equal to the savings produced by deferring the grid reinforcement in the second alternative. If the flexibility mechanism costs less than this maximum amount, alternative 2 is preferred. Table 1 shows the traditional plan for the second alternative in the mentioned example, where the grid investment occurs in the 4th year for all the scenarios. Therefore, the expected deferral for the second alternative in traditional planning is 4 years. Table 2 shows the real options approach for the second alternative, where the grid investment occurs in the 4th year for the first scenario, in the 7th year for the second scenario, and there is no investment during the eight years planning period for the third scenario. Thus, the investment deferral for the second alternative in the real options approach is greater than in traditional planning. Therefore, the maximum amount we can spend on the flexibility mechanism in the real options approach is greater than in traditional planning. Thus, maintaining traditional planning techniques could lead to not using flexibility mechanisms, due to poor valuation of the DNP alternatives.

In conclusion, the real options approach has the potential to improve decision-making under uncertainty in DNP, reducing costs and capturing the benefits derived from the flexibility mechanisms. Still, one question remains. Are the projected scenarios for electricity peak demand suitable for real options strategic planning?

Projected demand scenarios and real options

The logic behind real options is that considering the unfolding information for flexible decision-making over time would lead to better results. In the context of DNP, this implies the assumption of some positive correlation for peak demand variations over time inside each projected demand scenario. Otherwise, unfolding information would be misleading and future decisions based on that information will lead to poor decision-making. Then, we should look at projected demand scenarios during the energy transition.

UK national grid ESO depicts four different scenarios for future electricity peak demand during the energy transition.²⁸ As shown in Figure 3, these scenarios present trends where unfolding information gives valuable insight of future conditions (since the changes in trend inside each scenario are smooth); a conflicting point is shown at the beginning of the yellow line ('Consumer Transformation' scenario) where the trend rapidly changes from decreasing to growing. In conclusion, these scenarios are suitable for a real options analysis. As distribution grid local projections for demand are influenced by local conditions, some regions will be more suitable for a different transition. For example, single-family homes can take more advantage of solar panels and form energy communities, while generation-driven areas can take advantage of storage technologies. So, we expect variations of peak demand following different trends depending on different regions. Other local conditions highly influencing peak demand projections are urbanistic plans, and industrial development. These types of changes are predictable and are also suitable for real options analyses.

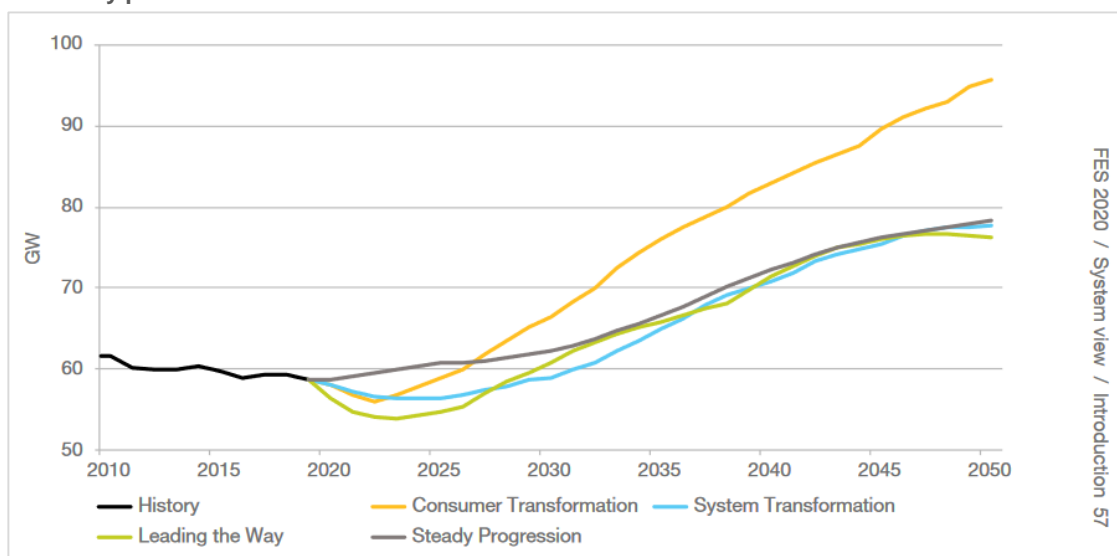
Considering the scenarios presented by UK national grid ESO (Figure 3), traditional planning would be highly influenced by the 'Consumer Transformation' scenario (yellow line), resulting in unnecessary costs if future demand evolves similarly to any of the other three projected scenarios. Otherwise, strategic planning through real options will adapt to information over time, similar to Table 2 in the previous example, avoiding unnecessary costs.

Conclusions

Flexibility mechanisms are commonly accepted as temporary alternatives to traditional network reinforcement of the distribution network (other benefits not discussed in this article include faster connection of new customers and grid operation support). These solutions may mitigate the risk of investing in infrastructures that become underused. Flexibility mechanisms allow the planner to delay the network reinforcement until the risk of underutilization is reduced. However, traditional planning based on DCF ignores the fact that future investment decisions are flexible and the DSO can respond to demand evolution over time, thus limiting the value this delay brings. This can lead to poor decision-making and overinvestment during the energy transition, resulting in a higher cost for bill payers. The presented real options conceptual framework has the potential to unveil the economic value of these flexibility mechanisms, as future decisions can be modelled as responses to information available over time. In conclusion, the high uncertainty faced by DNP during the energy transition urges a paradigm change in current practices to avoid incurring unnecessary costs.

²⁸ United Kingdom National Grid ESO, *Future Energy Scenarios 2020*.

Figure 3: Electricity peak demand scenarios in 2020



Source: [United Kingdom National grid ESO, Future Energy Scenarios 2020](#).

Additional considerations

The example presented here ignores many complexities that real networks can face. The network can experience overloads in different locations during the planning period, the decision-maker could estimate the duration of the projected overloads, and the expected value of the associated non-served energy when comparing the investment alternatives. The uncertainty might concern not only peak demand, but also flexibility prices. Furthermore, the projected scenarios can present variations around each trend. However, these complexities can be modelled and the synergy between flexibility mechanisms and the real options approach still holds.

The interaction between the proposed analytical approach and the current regulatory framework should also be considered. The expected results of the real options approach for cost minimization rely on investment rules defined for the selected strategies. However, misaligned regulatory incentives could push decision makers not to follow the selected strategies and produce unexpected outcomes. For instance, flexibility procurement is an operational expenditure (OPEX), while grid reinforcement is a capital expenditure (CAPEX). Therefore, total expenditure (TOTEX) incentives, non-biased on CAPEX or OPEX, are key to guide cost minimization in this context. This effect has been already highlighted by the Council of European Energy Regulators.²⁹

COORDINATION OF TRANSMISSION AND DISTRIBUTION SYSTEMS: A PROPOSED FRAMEWORK

Dimitra Apostolopoulou and Rahmat Poudineh

Introduction – (R)Evolution of power systems

Power systems are undergoing radical transformations that comprise, among other factors, a shift to renewables-based generation; deployment of ‘edge of the grid’ or distributed energy resources (DERs – in other words, energy resources connected at the distribution level); and a trend towards decentralized power systems (for example, microgrids). These are driven by technological advances, cost declines in DERs and in information and communication technologies, as well as policies, incentives, regulatory paradigms, and consumer preference trends. These changes have led to a shift in the traditional power systems’ operations from a centralized, one-way power flow to a decentralized, bi-directional power flow. The deployed DERs can offer numerous services to the grid such as reserve capacity and voltage support, together with other services that are seen as an alternative to ‘wire only solutions’ to solve network constraints, and which can be used to delay or defer potentially costly network upgrades. However, these can only be fully leveraged under an effective coordination framework

²⁹ *Regulatory Sandboxes in Incentive Regulation*, Council of European Energy Regulators, 2022.

between the distribution and transmission systems at their interface. The coordination framework developed in this article may be used as a guideline for how this may be achieved and how obstacles may be overcome.

Obstacles arise under the current system operational paradigm to integrate DERs both at the level of the transmission system operator (TSO) and the distribution system operator (DSO). For instance, complications for the TSO arise due to the lack of visibility of DERs; unpredictability of DERs' responses to TSO dispatch signals; forecast errors introduced to the interchange between areas in the transmission and distribution interface; and the long-term growth scenarios of DERs that need to be accounted for in transmission planning. On the other hand, DSOs are concerned about the ability to adjust DERs' output to maintain a reliable operation as well as (rather like TSOs) their unpredictability and long-term growth scenarios for planning purposes. In practice, this has led to limited use of DERs in optimizing power system operation. For example, in New York, demand response programmes were only activated on ten days during a three-month period, due to lack of coordination between utilities and the NYISO.³⁰ Furthermore, DERs usually have smaller capacity and cannot participate in, for example, European wholesale markets unless aggregated on the order of 1 to 5 MW.³¹ Efforts have been made by regulatory bodies to propose solutions to overcome such barriers and incentivize investment in DERs. For instance, in the US, the Federal Energy Regulatory Commission (FERC) issued Order No. 2222 to open wholesale markets to competition from DERs. The order allows aggregations of DERs (in the order of a minimum of 100 kW) that meet the physical and operational requirements of the system operator to participate in the market under the same conditions as traditional resources.

Although the aforementioned measures to boost deployment of DERs are necessary, they are unlikely to be sufficient. In order to provide incentives for DER investments and operate the entire grid in an optimum way, a framework is needed to coordinate the operation of different resources at the grid edge with the bulk system. Under such a framework that coordinates the actions of TSO and DSO, DERs could offer a variety of services to the power system. These can be broadly categorized into market-related services (such as energy, capacity, black start, load shifting) and network-related services (such as network constraint management, voltage control, power quality, energy loss reduction).

TSO–DSO interactions

Many different TSO–DSO coordination architectures are proposed in the literature, they vary from centralized to totally decentralized approaches.

- In centralized schemes the TSO is responsible for satisfying the system demand in both the transmission and distribution systems with the use of generators at both levels. This is also referred to in literature as the 'whole TSO model'.
- In decentralized schemes, the TSO and DSO are responsible for the operation of their own grid, but they need to agree on the point of common coupling (PCC)³² power flow interchange. In such schemes, the DSO operates its local system by buying energy from the transmission system, taking into consideration the electricity price at the PCC. The DSO can also sell energy to the transmission system by participating in the TSO market.

Decentralized TSO–DSO coordination approaches can be further categorized into hierarchical or distributed.

- In hierarchical TSO–DSO coordination schemes, the interaction between distributed resources in the distribution system and the transmission power system is akin to a leader–follower type, where the transmission system has priority in making decisions, while the distribution system makes decisions subject to the constraints of TSO decisions. This is also known as the 'hybrid DSO model'.
- In distributed TSO–DSO, all local DERs can participate in the market to meet the load; this is also called the 'whole DSO model'.

Centralized schemes face a variety of regulatory challenges that arise from the fact that private information needs to be exchanged between TSOs and DSOs and ownership of responsibility with regards to reliability and resilience is not clear. These factors make their actual implementation difficult. In contrast, decentralized schemes are likely to be more in line with the decentralization paradigm in the power system but need to be further studied so that they: respect privacy concerns of the

³⁰ Waldoch, C. (2022), 'Coordinating the distributed energy future. Lessons from the NYISO', LeapfrogPower, February 2022.

³¹ ENTSO-E, 'Survey on ancillary services procurement, balancing market design 2017', May 2018.

³² PCC is the boundary between the transmission and distribution systems – namely the transformer between the medium-voltage distribution system, managed by the DSO, and the high-voltage transmission system, managed by the TSO.

stakeholders involved, are computationally efficient, depend on a realistic communication infrastructure, achieve an optimal outcome (for example in terms of cost), relieve congestion, and facilitate the integration of DERs.

In order to further the research in this domain, several pilots have been developed. The SmartNet (2016–2019) was a European project whose aim was to compare different TSO–DSO coordination schemes and real-time market architectures for acquiring ancillary services from distributed resources. More specifically, five different co-ordination schemes were proposed:

- i. centralized ancillary services market model;
- ii. local ancillary services market model;
- iii. shared balancing responsibility model;
- iv. common TSO–DSO ancillary services market model;
- v. integrated flexibility market model.

The main differences between all these architectures are the allocation of responsibility to operate the system and the exchange of information, for example, bids and network topology.³³ CoordiNet (2019–2022) is another European research project, which aimed to demonstrate how TSOs and DSOs should act in a coordinated manner to procure and activate grid services most reliably and efficiently, by defining standardized products that may be exchanged between TSOs and DSOs. In the UK, where it is anticipated that up to 45 per cent of total generation capacity will be connected to the distribution networks by 2030, Centrica has developed a local energy market platform in Cornwall in which the TSO and DSO procure flexibility services. Within the UK system, flexibility markets are already under trial in most distribution network regions; some of these are using the Piclo flex platform that aids in the standardization of flexibility products and the efficient use of DERs, such as for peak shaving, without which, network reinforcement could have been triggered.

Proposed coordination framework – enhanced DSO role

All these efforts have paved the way to a better understanding of coordination requirements between TSOs and DSOs. However, further advances both in technology as well as in market designs are necessary to achieve a smooth coordination between the bulk system and the edge of the grid that will allow for an efficient, reliable, and sustainable operation of the entire grid. In this regard, we envision power systems as a collection of subsystems at different layers that are connected with each other (a ‘fractal grid’), exchanging power and non-private information; and operating under a market environment. Each layer is responsible for its own operation in a sustainable, reliable, and cost efficient manner, only having access to the interchange from the layer above or below but not to its detailed representation. More specifically, under the proposed coordination framework, the layers correspond to the boundaries of operation of TSOs and DSOs.

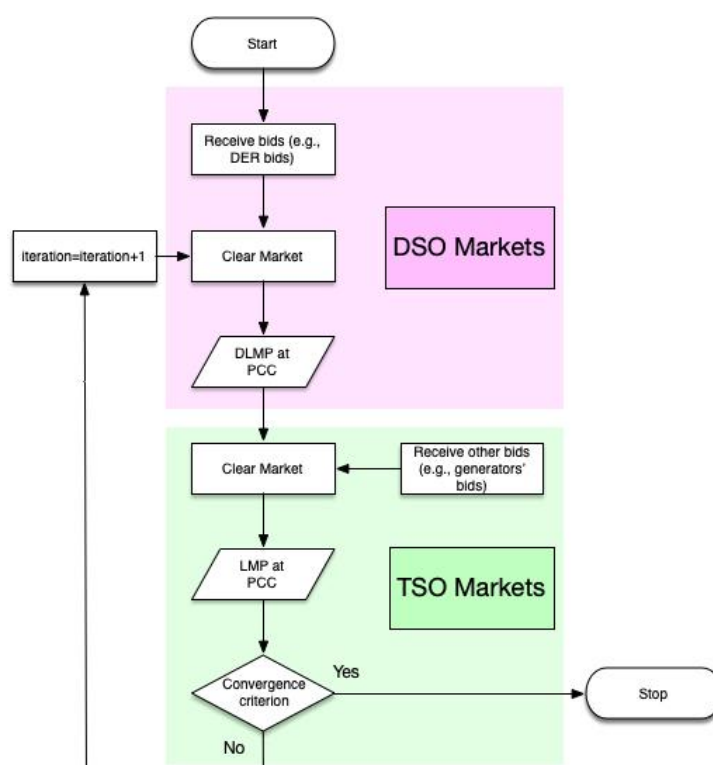
DSOs optimize local markets at each PCC; they do so by taking into account the cost of energy at the PCC and the value of DERs’ services. Then, the TSO optimizes the bulk system rather than that of individual DERs (only seeing one virtual resource at the PCC) and is responsible for meeting the net interchange at the PCC. In such a paradigm, DERs only communicate with the DSO and submit their bids to the local or peer-to-peer markets. The DSO sends appropriate control signals to DERs to meet the TSO instructions. The new role of the DSO includes acting as an interface between TSOs and prosumers – for example, DER owners and consumers. Such an approach solves the issue of decreased visibility of TSOs in terms of connected and ready to be used DERs. The TSO is responsible for system reliability only at the PCC, and the DSO is responsible from the PCC to the customers’ meters. The TSO and DSO share layered responsibilities – for example in terms of frequency response based on load share.

Under the proposed framework, the operating schedule of the resources for the entire system is achieved with an iterative process of non-private information exchange between the TSO and DSO until all parties reach consensus and have no economic incentive to deviate from the agreed schedule. This information includes the locational marginal prices (LMPs) and distribution locational marginal prices (DLMPs) at the PCC. This optimal solution – which performs as if one entity were operating the entire power grid – functions as if it produces an optimal power flow with the objective of maximizing social welfare (such as cost minimization, and voltage regulation) with access to the full nodal network of the TSO and DSOs and all the resources’ bids (which would be unrealistic of course). However, in the proposed framework, this is achieved with no exchange of private information (such as network topology or bids) between the TSO and DSO, by using tools of distributed optimization

³³ Network topology’ refers to the manner in which the links and nodes of a network are arranged to relate to each other.

as depicted in Figure 1. The proposed scheme also includes for all parties to be compensated in a 'fair' manner for services they provide to reach the socially optimum outcome, thus incentivizing them to act accordingly. This is achieved by using information in terms of power flows in each subsystem and pricing signals showing the cost/benefit of providing an additional MW of power at each location in the network, with the use of nodal pricing. This compensation is an important aspect, since there are occasions where actions that benefit the TSO may be detrimental for the DSO and vice versa. The proposed framework is scalable and at the same time increases system resiliency and security, due to the detailed representation of the underlying physical system in parallel with the use of layers that allow for scalability.

Figure 1: Iterative process of TSO–DSO coordination until they reach consensus



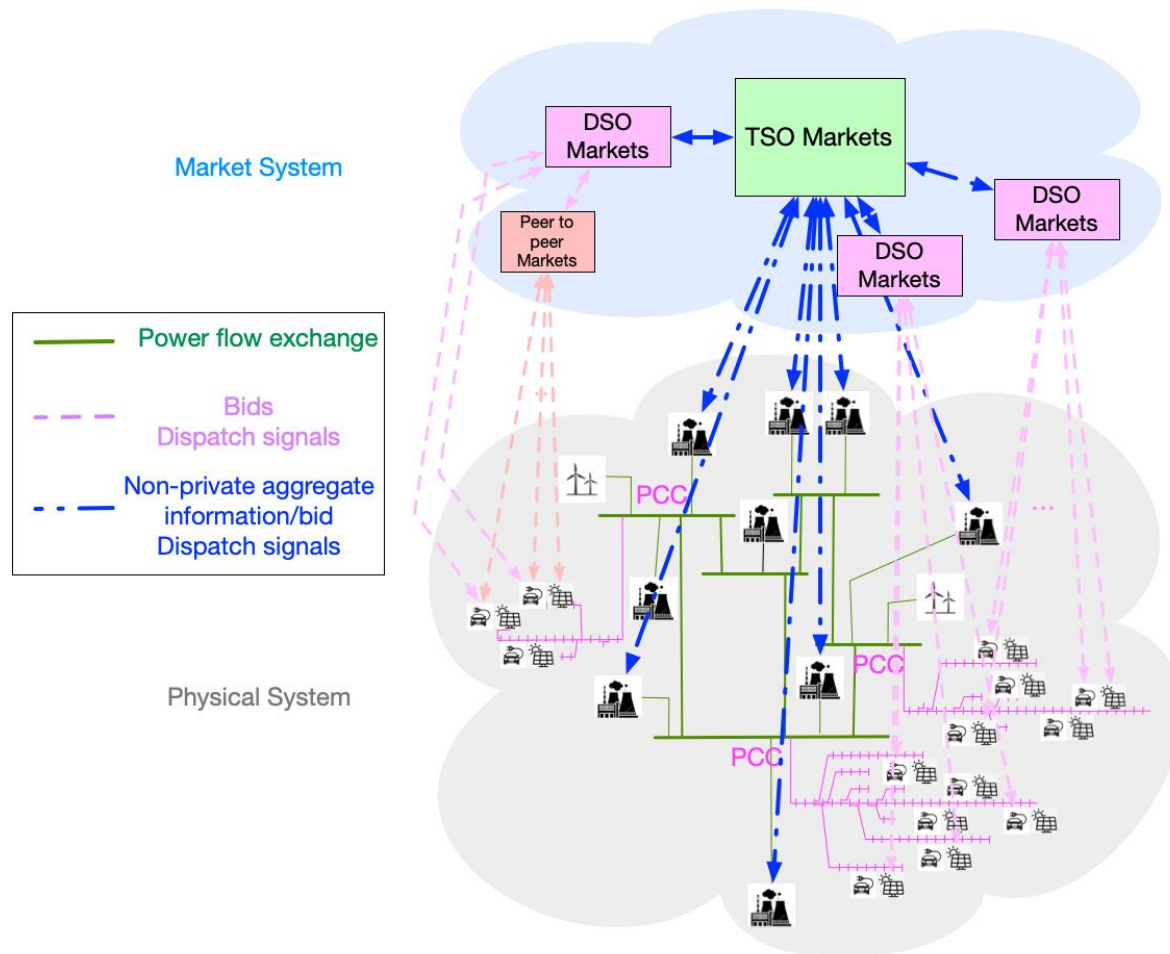
Source: authors

The next question that arises is how often this iterative process, namely the market clearing process, between the TSO and DSOs will be performed. The current day-ahead and real-time markets are poorly designed for DERs. Day-ahead DER forecast errors create exposure to real-time price variations, as resources committed in the day-ahead market are required to rebalance in real time, challenging the business model for DERs. Intraday markets with multiple discrete intermediate auctions between the day-ahead market and real-time market are necessary to enable proper integration of DERs and efficient mitigation of forecast uncertainty risk. The choice of discrete auctions is because continuous intraday markets, as currently designed in Europe, do not provide an appropriate price signal for transmission congestion. This is due to the fact that they are allocated on a first-come first-served basis and result in suboptimal allocations of transmission capacity that in turn lead to increased re-dispatch and curtailment costs. As such, we suggest that the proposed framework is solved in day-ahead (gate closes 12 p.m. the day before dispatch), in discrete intraday (gate is open up to 60 minutes before dispatch), and in real-time (gate is open 5 minutes before dispatch) markets. The proposed framework provides market-based locational value of DER assets through the use of DLMPs for all phases and nodes. The exchange of information and power and the market structure of the proposed framework are depicted in Figure 2.

In the proposed scheme, the role of distribution systems is very active, as DSOs play an important role in its successful implementation. The first question that needs to be answered here is what will the DSO functions include? The DSO is responsible for applying the proposed framework as far as its share is concerned – in other words, to organize local markets that coordinate the purchase and sale of power and energy; forecast future load levels that need to be met; balance load and generation; perform contingency analysis; be responsible for the interchange of power to the TSO markets; respond to outages and perform restoration; and provide billing services to market participants. Besides the aforementioned functions that concern

the operational stage of its system, the DSO is responsible for planning processes – such as interconnection requests within its service area and maintenance.

Figure 2: Physical and market representation of proposed TSO–DSO coordination framework



Source: authors

The next question that needs to be answered is who will serve as a DSO? Is there a need for an independent DSO, or can network utilities serve this role? We envision the DSO role to be taken up by utilities under a regulated framework. In this regard, the economic transactions with prosumers in its territory will be on the basis of regulated tariffs that incorporate the cost of capacity, energy, and ancillaries in the DSO and TSO markets. Under certain conditions, DSOs might be allowed to own DERs, so that they become a potential market participant in addition to being the market operator. Under such a paradigm, the utility will help to first initiate and promote the DSO markets; however, there might be occasions of conflict of interest as well as issues with unbundling which prevent network companies from owning generation assets. These might be resolved by separating distribution network ownership and operation, although such an approach has advantages and disadvantages which need to be properly evaluated in this context.

Challenges and how to overcome them

There are some differences between the new role of DSO and the established role of TSOs, which make the implementation of the proposed framework challenging. For example, no legislation is in place to mandate consumer participation in the local DSO market, unlike the mandate currently governing generators' participation in national TSO markets. However, consumer participation is essential for a successful implementation of the DSO concept.

A desirable outcome of a successful DSO implementation is customer investment in DERs that would increase the number of participants in the DSO market and thus increase its liquidity. The number of market participants in wholesale markets is orders of magnitude smaller than those that will participate in DSO markets; making its clearing more complex. Moreover, due to the nature of the resources connected at the distribution system that inherently generate inter-hour interactions (in other words, market clearing of consecutive hours is correlated), the market clearing needs to be multi-hour compared to spot clearing.

These resources include demand response (such as thermostatically controlled loads; energy storage; electric vehicles; and CHP), whose operation span is several hours. Many market protocols today treat storage when charging as a load and when discharging as a generator, requiring separate schedules/offers for each, which fails to fully optimize the use of storage.³⁴ As such, we propose looking at a rolling 24-hour horizon when clearing the market, so that the natural characteristics of DERs are taken into account. More specifically, the proposed TSO–DSO coordination framework incorporates a multi-hour optimal power flow that is solved across a 24-hour time horizon, using model predictive control. For example, in the real market setting, every five minutes the system states are updated and the multi-hour optimal power flow is solved, and the time horizon recedes by another five minutes. It is evident that the proposed framework, in the real-time markets, results in a large-scale problem when applied in real systems, thus suffering from dimensionality issues besides using layers and distributed optimization techniques, as described above. To address these, we further alleviate complexity issues by using a simplified representation of the physical network, for example, by using linearized power flow equations.

A DSO market can only be realized if appropriate communication infrastructure is installed in distribution systems that are reliable, scalable, and interoperable and will allow for real time monitoring and data exchange, collection, and analytics. However, DSOs are reluctant to invest in such infrastructures and prefer to carry out investments in traditional grid elements – such as overhead lines and transformers. Incentives should therefore be provided in order to encourage DSOs to turn their efforts toward intelligent monitoring schemes in the future.

Final thoughts

As the power grid moves from the ‘Edison Era’ to the ‘Google Era’, there is an opportunity to build a more reliable, secure, sustainable, flexible, and economic electricity grid. This is facilitated with the participation of prosumers in peer-to-peer or DSO markets, the results of which in turn participate in TSO markets. A potential manifestation of this TSO–DSO interaction is described in this article and may be used as a guideline for actual implementations. It achieves the following objectives:

- i. respects privacy concerns of entities involved;
- ii. compensates players for achieving social welfare;
- iii. incentivizes investments and allows efficient use of DERs;
- iv. is scalable, robust, and transparent;
- v. ensures reliable and safe operation of the grid, provides affordability and non-discriminatory access to prosumers, and is resilient to disruptive events.

Obstacles such as scalability can be overcome with the proposed layering structure. The unique characteristics of DERs – namely day-ahead, intraday, and real-time – are taken into account in the structure of the proposed markets designs, with a multi-hour setting that facilitates the use of renewable resources whose forecast error is near zero when approaching real time.

THE FUTURE OF NATURAL GAS NETWORKS IN EUROPE

Katja Yafimava

The tale of two networks: (bio)methane and hydrogen

Over the course of 2020 the European Commission (EC) developed several policy initiatives, aimed at the implementation of the European Green Deal and the Climate Law, including the European Union (EU) Hydrogen Strategy. By promoting hydrogen, the EC has opted for a lower-cost decarbonization pathway of ‘hybrid’ electrification – using a mix of electrification and gas – while accepting that full electrification would be significantly more expensive and would probably not be technically feasible.³⁵ This approach has been supported by the European regulatory authorities, as evident from the 2018 Madrid Forum conclusions, which stated that:

³⁴ G. C. Gisse, P. E. Dodds, and J. Radcliffe, ‘Market and regulatory barriers to electrical energy storage innovation’, *Renewable and Sustainable Energy Reviews*, vol. 82, 2018.

³⁵ Most studies (including EC) see a mix of electrification and gas as a lower-cost decarbonization pathway for most countries than full electrification.

'renewable and low-carbon gases should play a significant and growing role in the energy transition ... which will not be achieved at least cost by using a single energy source but requires a balanced mix of energy sources and technologies'.³⁶

It has also been supported by the European Network of Transmission System Operators (TSOs) for Gas, ENTSO-G, as it would allow the European gas TSOs to transport decarbonized gases (hydrogen, syngas, bio-methane) instead of, or as well as, methane and avoid (large-scale) decommissioning of methane networks.

Hybrid electrification would necessitate conversion and retrofitting of some existing methane networks so that they would be technically capable of transporting hydrogen, as well as construction of new hydrogen networks. While some percentage of hydrogen (varying between networks) could be blended with (bio)methane and transported by the existing methane networks, in many countries significant repurposing, and often complete replacement, of networks would be needed for transport of pure hydrogen. Therefore, while blending methane with hydrogen could be a short-term strategy, the long-term narrative for methane networks is about transition to hydrogen (as well as biomethane) (at TSO level) and biogas (at Distribution System Operator (DSO) level). This suggests that, ultimately, some methane networks will remain (but will increasingly transport biomethane) and there will additionally be hydrogen networks (either new or converted from methane networks).

Thus, ultimately, there will be two gas networks in the EU – one for transporting low- or zero-carbon methane and another for transporting hydrogen – developing in parallel and co-existing. The hydrogen network – also referred to as the European Hydrogen Backbone (EHB) – is expected to consist of new hydrogen pipelines (~40 per cent of the network) as well as repurposed methane pipelines (~60 per cent of the network). The EHB is envisaged to develop in stages, starting from a gradually emerging network of 6,800 km of pipelines connecting hydrogen industrial clusters ('valleys') during 2025–30. In the long term, the EHB could potentially grow further, becoming a pan-European cross-border network of some 53,000 km (a quarter of the total length of the existing EU gas network) and enabling imports of hydrogen from non-EU countries.

The topology of the future hydrogen network will largely depend on the location of hydrogen demand and production. As renewable hydrogen – rather than low-carbon hydrogen produced from natural gas with carbon capture, utilization, and storage (CCUS) – is the EU's 'hydrogen of choice', the location of renewable power generation capacity – needed for producing renewable hydrogen through electrolysis – will have a significant impact on the hydrogen network topology.³⁷ This will also have an impact on the time frame of network development, as renewable hydrogen takes more time to scale up than low-carbon hydrogen. The Hydrogen Strategy sees the EHB development mostly in connection with renewable hydrogen and largely ignores infrastructure needs that could arise if and as new low-carbon hydrogen production develops at scale (beyond retrofitting the existing high-carbon hydrogen production with CCUS). At 2021–22 gas prices, low-carbon hydrogen made from natural gas is uncompetitive with renewable hydrogen, and although natural gas prices will eventually decrease, low-carbon hydrogen is impossible to pursue at present. The combination of (a) natural gas being politically unpopular and extremely expensive; (b) too few CCUS projects making substantial progress; and (c) the EU's unequivocal political preference for renewable hydrogen, makes low-carbon hydrogen progress significantly less likely.³⁸ The REPowerEU Plan, adopted by the EC in May 2022, envisages a sharp (and extremely challenging) increase in production of renewable hydrogen, and suggests the EU is likely to re-double support in the future.

New infrastructure for bringing non-Russian gas to Europe: liquified natural gas (LNG) import terminals and interconnections enabling west-to-east flows

On 10–11 March 2022, the EU Council of Member States adopted the Versailles Declaration, which stated the EU's intention to phase Russian gas out from the EU energy balance 'as soon as possible'. On 18 May 2022, the EC published its REPowerEU Plan, according to which the phasing out of Russian gas is to be achieved by 2027 at the latest. EU dependence on Russian gas has been very significant – in 2021 Russian gas constituted ~30 per cent of EU gas demand and ~40 per cent of EU gas imports. The EC assessment suggests that 'it will be possible to fully compensate the equivalent of Russian gas imports by a combination of demand reduction, a ramp up of domestic production of biogas/biomethane and hydrogen, and limited additions of gas infrastructure', for bringing non-Russian pipeline gas and LNG into the EU and for transporting it within the EU.

According to the REPowerEU Plan, 'the most important' infrastructure needs are linked to meeting gas demand in northern Germany and in Central and Eastern Europe, as well as the reinforcement of the Southern gas corridor bringing Azeri gas to

³⁶ '31st Madrid Forum, The conclusions of the workshop', 16–17 October 2018 ('Madrid Forum Conclusions').

³⁷ This is due to co-location of electrolyzers with renewable power resources. However, it is worth noting that if / as grid electricity becomes sufficiently green, location of renewable resources might be less relevant for green hydrogen production.

³⁸ See 'The TEN-E Regulation: allowing a role for decarbonised gas', K. Yafimava, OIES Paper, NG 174, August 2022.

southern Europe. Correspondingly, in addition to infrastructure that has been included in the latest EU list of Projects of Common Interest (PCI),³⁹ the Plan envisages construction of additional gas infrastructure; this includes German, Dutch, and Finnish/Estonian LNG import terminals, gas grid reinforcement (increasing export capacity from Belgium to Germany), a gas deodorization project (increasing export capacity from France to Germany), and reinforcement of the Southern gas corridor (TAP expansion) (Figure 1). The Plan has also mapped potential hydrogen(-ready) corridors (Iberian, North African, Adriatic, South-Eastern, Nordic/Baltic, and Northern Seas), largely coinciding with the five hydrogen supply corridors mapped in the latest EHB report.

According to the EC, these additional infrastructure projects have been identified by the regional groups of Member States based on the analysis of 'the additional needs strictly linked to REPowerEU' and, as such, 'complement the existing list of PCIs'. However, while the EU PCI lists have been developed in accordance with the detailed rules outlined in the TEN-E Regulation, it is not clear which methodology has been used to identify additional REPowerEU projects. Under the TEN-E Regulation, PCI status is granted to a project which fulfils certain general and specific criteria enabling it to benefit from faster permitting and eligibility for EU financial assistance. A PCI project:

- must be necessary for at least one of the EU energy infrastructure priority corridors and areas;
- must involve at least two Member States or be located on the territory of one Member State and have a significant cross-border impact;
- must have potential benefits which outweigh its costs, including in the longer term;
- must 'contribute significantly' to sustainability;
- must meet at least one other specific criterion, such as market integration, security of supply, or network security.

It is unclear whether the projects identified as part of the REPowerEU Plan have been measured against PCI criteria.

Importantly, while projects associated with construction of new hydrogen pipelines and with repurposing of existing natural gas pipelines for transporting pure hydrogen (transporting blends of methane and hydrogen is allowed until the end of 2029) are eligible for PCI status under the TEN-E Regulation, new natural gas pipelines are not eligible. This means that hydrogen-ready infrastructure – that is hydrogen pipelines, storage facilities connected to these pipelines, reception, storage, and regasification or decompression facilities for liquified hydrogen or hydrogen embedded in other chemical substances (such as ammonia) – would be the only new gas infrastructure eligible for PCI status. As many of the additional projects identified by the REPowerEU Plan are natural gas infrastructure projects – LNG terminals, grid expansion/reinforcement, and deodorization – rather than hydrogen infrastructure projects, it is questionable if they could proceed as hydrogen-ready projects under TEN-E Regulation framework or would require a different ad hoc framework. Notably, while the TEN-E Regulation allows for faster permitting and EU financial assistance for PCIs, it could still take up to four years and three months to receive all the necessary permits for additional REPowerEU projects. The EU Connecting Europe Facility's relatively modest budget is unlikely to be sufficient for their financing. Overall, although the REPowerEU Plan stresses the need for any additional infrastructure to be 'well assessed' in respect of its resilience and future use – including with a view of repurposing gas networks for hydrogen – it does not specify any methodology for that task. This raises questions about whether at least some of this new gas infrastructure might become stranded.

If implemented, the REPowerEU plan,⁴⁰ would see a significant change in volume and direction of gas flows. Many EU gas infrastructure projects, which were under consideration for years (if not decades) but which never proceeded because of the lack of commercial rationale, might be implemented as their costs could be underwritten (in part or in full) by Member States' governments, needing to replace Russian gas. The Plan estimates the necessary infrastructure investments – including LNG import terminals, pipelines connecting underutilized terminals with the EU gas transmission network, and reverse flow pipeline capacities – at €10 billion by 2030.⁴¹ Furthermore, it notes that 'additional investments' would be needed to connect Iberian LNG import terminals with the EU transmission network through hydrogen-ready infrastructure, although it does not specify their cost.

³⁹ The fifth list of energy PCIs, Brussels, 19 November 2021 [C\(2021\) 8409 final](#).

⁴⁰ [EC communication, REPowerEU Plan](#), Brussels, 18 May 2022 COM(2022) 230 final.

⁴¹ This money is additional to what is necessary for achieving the Fit-for-55 objectives.

Figure 1: EU gas infrastructure: PCIs and additional projects identified by the REPowerEU Plan



Source: EC, REPowerEU Plan, 18 May 2022.

As the EU announced its REPowerEU policy, Member States, fearing a complete cut off of Russian gas supplies ahead of winter 2022–23, have rushed to develop their own additional LNG import capacity, both offshore (FSRUs) and onshore; this is expected to become operational from the early to mid-2020s. Germany, which has no LNG import capacity at present, intends to install six FSRUs during winter 2022–23 with total capacity of 32.5 bcma (of which four have already been chartered by German companies Uniper and RWE); it also plans to have three onshore LNG import terminals with total capacity of 37–41 bcma to start operations from 2025–26. Italy, which has three LNG terminals at present (one FSRU and two onshore), has followed suit as Italian Snam bought two FSRUs, with capacity of 5 bcma each, to start operations in spring 2023 and in summer 2024 respectively. Other Member States such as the Netherlands, Poland, Greece, Finland, and Estonia are also planning to create additional LNG import capacity.

Such a steep increase in LNG import capacity over such a short time period is unprecedented for the European gas industry. Although it is unlikely that all these projects will materialize, some of them will. Once installed/built, these terminals would have to be connected to national gas transmission networks – a process that normally takes years but which has been expedited, without any legal/regulatory basis. According to the Third Gas Directive and Gas Regulation 715, a project must be part of a national network development plan (developed annually) and EU-level ten-year network development plan (developed bi-annually), based on complex scenario modelling, cost benefit analysis (CBA), and cross-border allocation methodology (CBAM). It must also complete a lengthy permitting process and receive all the necessary permits from national regulatory authorities before construction can start. As some of the new LNG terminals advanced by Member States are expected to become operational as early as the end of winter 2022–23, it is difficult to see how this could be done within the framework of EU and national network development plans. Further, given that Member States intend to build much more additional LNG infrastructure than envisaged by the REPowerEU plan, ensuring consistency between new gas infrastructure at national and EU-level will be impossible. Overall, security concerns are completely undermining the regulatory framework governing development of new gas

infrastructure in the EU that took decades to create, thus removing important metrics by which to measure the need for new infrastructure, and further complicating the task of European regulators and TSOs, already operating under conditions of technology and policy uncertainty associated with energy transition.

Conclusions

The future of natural gas networks in Europe is deeply uncertain as these networks are facing a double challenge posed by EU objectives of (a) reducing net greenhouse gas (GHG) emissions by at least 55 per cent by 2030 and becoming net-zero by 2050 (enshrined in 2021 European Climate Law), and (b) phasing out Russian gas from the EU energy balance as soon as possible and by 2027 at the latest (stated in the EU Versailles Declaration and the REPowerEU policy paper, respectively). The first objective means that some existing gas networks will have to be repurposed to carry hydrogen, whereas the remaining gas networks will increasingly need to transport (bio)methane, as there will be little space left in the EU energy balance for unabated methane if the EU GHG targets are to be met. The second objective means that new gas networks will have to be built to enable the importing and transporting of non-Russian gas in the EU. Importantly, the first objective is legally binding at the EU level, as it is enshrined in 2021 European Climate Law, whereas the second objective is political rather than legally binding at the EU level.⁴² While the EU determination to meet its GHG emissions reduction targets is beyond doubt (although there could be some slippage on 2030 targets), it is unclear how quickly Russian gas will be phased out despite a strong political will to do so. Crucially, security concerns in respect of Russian gas on the part of both the EC and EU Member States, which led them to accelerate construction of new infrastructure for bringing non-Russian gas to Europe, are completely undermining a regulatory framework for the building of new LNG (and possibly other) infrastructure in the EU that took several decades to create. It is against this backdrop of uncertainty that investment decisions in respect of gas networks will have to be made.

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THE ROLE OF HYDROGEN INFRASTRUCTURE IN PROMOTING CLIMATE NEUTRALITY

Alberto Pototschnig and Enrico Tesio

The European Union (EU) is leading the world in fighting climate change. With its first Climate Law in 2021,⁴³ the EU committed to climate neutrality by 2050⁴⁴ and to the intermediate 2030 target of **reducing domestic net greenhouse gas emissions (in other words, emissions after deduction of removals) by at least 55 per cent compared to 1990.**

The overall EU strategy to achieve its ambitious climate goals was outlined by the European Commission in its Green Deal Communication,⁴⁵ and is based, inter alia, on:

- a more circular energy system, with 'energy-efficiency-first' at its core;
- an accelerated electrification of energy demand, building on a largely renewables-based power system;
- the promotion of renewable and low-carbon fuels, including hydrogen, for hard-to-decarbonize sectors.

Hydrogen is therefore expected to play a major role in implementing this strategy. Currently, in the EU, hydrogen is mostly used as feedstock in industrial processes and it is mainly produced through steam methane reforming, which results in significant carbon dioxide emissions.⁴⁶ In its 2020 EU Hydrogen Strategy,⁴⁷ the European Commission envisaged renewable hydrogen becoming an intrinsic part of Europe's integrated energy system by 2030, with at least 40 GW of renewable hydrogen electrolyzers⁴⁸ and the production of up to 10 million tonnes of renewable hydrogen in the EU. The recent energy crisis, exacerbated by the Russian invasion of Ukraine, led the European Commission to review its plans regarding renewable

⁴² Two member states have legally-binding bans on Russian gas: Lithuanian legislation prohibits access by Russian suppliers to its gas transmission system and to its LNG terminal ([Lithuania bans Russian gas imports](#)); Latvian legislation bans Russian gas supplies from 1 January 2023 ([Latvian parliament approves ban on Russian natural gas supplies as of 2023](#)).

⁴³ Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999.

⁴⁴ 'Union-wide greenhouse gas emissions and removals regulated in Union law shall be balanced within the Union at the latest by 2050, thus reducing emissions to net zero by that date, and the Union shall aim to achieve negative emissions thereafter' (article 2(1) of EU Climate Law).

⁴⁵ Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, 'The European Green Deal', Brussels 11.12.2019, COM(2019) 640 final.

⁴⁶ At a rate of approximately 7 kg CO₂/kg H₂.

⁴⁷ Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, 'A hydrogen strategy for a climate-neutral Europe', Brussels, 8.7. COM(2020) 301 final.

⁴⁸ With an additional 40 GW of electrolyzers' capacity being developed in Europe's neighbourhood, with export of the renewable hydrogen produced there to Europe. See footnote 10 of the EU Hydrogen Strategy.

hydrogen. In its REPowerEU Communication⁴⁹ in March 2022, it complemented the 10 million tonnes target of renewable hydrogen domestic production with an import target for an equivalent volume.

Europe's uncertain renewable hydrogen and electricity future

In the longer term to 2050, different scenarios have been developed regarding the penetration of renewable hydrogen in the EU energy mix. In its strategic vision for a climate-neutral EU, published in November 2018,⁵⁰ the European Commission projected the share of hydrogen in Europe's energy mix to grow from the current level of below 2 per cent, to 13–14 per cent by 2050. Almost at the same time, the Fuel Cells and Hydrogen Joint Undertaking, in its Hydrogen Roadmap Europe,⁵¹ outlined an ambitious scenario with hydrogen serving a quarter of the EU's total energy demand by 2050, the bulk of it being produced from renewable electricity.

The wide range of projections regarding the development of (renewable) hydrogen in the future reflects the significant uncertainty in at least three key areas:

- Which industrial processes will still be 'hard-to-abate' in 2030 and 2050, so that they could not be electrified and therefore their decarbonization implies the use of low-carbon/renewable gases, and hydrogen *in primis*?
- Will there be sufficient renewable electricity available in Europe by 2030 and 2050 to produce renewable hydrogen in the quantities that the above-mentioned scenarios imply?
- How will the economics of renewable hydrogen production develop and support the use of hydrogen in hard-to-abate processes and sectors?

Significant advances in the capabilities of electrification have been recently achieved (for example in the performance of electric vehicles and of electric arc furnaces) and more are expected in the future. It is clear that, whenever possible, the use of electricity should be preferred to the use of other types of renewable fuels if, as in the case of hydrogen, these are based on renewable electricity, because an additional energy transformation is thereby avoided.

However, concerns regarding the availability of renewables-based electricity to fulfil the ambitious EU climate objectives have been raised by several commentators. While energy efficiency should reduce overall energy demand, electrification will increase the share of electricity in energy consumption. The net effect of these two counteracting trends is likely to be an increase in electricity demand. If this has to be mostly met by renewables-based generation, the question arises as to whether the EU is sufficiently endowed with renewable resources to meet such demand. In this respect, a recent Policy Brief⁵² published by the Florence School of Regulation warns that:

'It would be technically feasible to supply around 65% of current electricity demand with renewable electricity on the basis of the NECPs [National Energy and Climate Plans]. But there is little room by 2030 for supplying the additional renewable electricity demand due to the electrification of road transport, and of the heating of buildings, not even including electrification of industry and electricity demand for producing synthetic fuels – including hydrogen'.

Uncertainties regarding economics of renewable hydrogen production

The economics of renewable hydrogen production in the future are also still shrouded in uncertainty. Unlike many renewable electricity generation technologies (such as wind, solar PV, geothermal), which are characterized by negligible variable costs, the cost structure of renewables-based hydrogen production has a noticeable variable component, related to the price of renewables-based electricity used by the electrolyzers. So far, most of the scenarios on the future development of the hydrogen sector have rested on the assumption of cheap renewable electricity – at a price around or below €20/MWh – being available to the electrolyzers. It is very difficult to say whether recent developments in the energy markets in Europe, following the Russian

⁴⁹ Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions, 'REPowerEU: Joint European Action for more affordable, secure and sustainable energy', Strasbourg, 8.3.2022, COM(2022) 108 final.

⁵⁰ Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions, 'A Clean Planet for All. A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy', Brussels 28.11.2018, COM(2018) 773.

⁵¹ Fuel Cells and Hydrogen Joint Undertaking, in its Hydrogen Roadmap Europe: a Sustainable Pathway for the European Energy Transition, 2019, available at: [Hydrogen Roadmap Europe Report.pdf \(europa.eu\)](https://www.fuelcells-hydrogen.eu/Hydrogen_Roadmap_Europe_Report.pdf).

⁵² Ronnie Belmans, Piero Carlo dos Reis, and Pieter Vingerhoets, 'Electrification and sustainable fuels: Competing for wind and sun', FSR Policy Brief N. 2021/20, May 2021.

invasion of Ukraine, have changed the energy price future perspective for good; they should not have, as the fundamentals of renewable electricity production have not changed as a result of such developments.

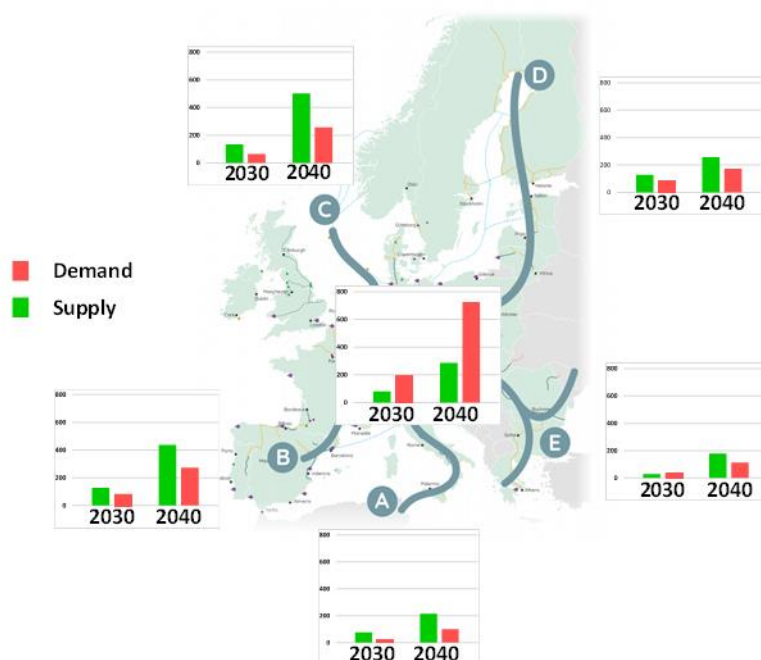
Moreover, the level of utilization of the electrolyzers also has an impact on the cost of hydrogen, with the levelized cost curve flattening out beyond a 50 per cent utilization rate.⁵³ In this respect, the approach which will be put in place to define the requirements for the hydrogen produced by electrolyzers to be considered as renewable, is particularly relevant. In its proposal for a Delegated Regulation published in May 2022,⁵⁴ the Commission envisaged an approach to the definition of renewable hydrogen based on strict 'additionality' requirements, whereby the renewable electricity used in electrolyzers should not only be additional with respect to what would have been consumed anyway, but would also have to come from new renewable generation capacity. Moreover, and equally important, the Commission proposed an hourly temporal correlation between the electricity consumption of the electrolyser and the generation of the related renewable generating unit. While derogations are envisaged for the period to the end of 2026 and, eventually (when most of the electricity in the European system will be from renewable energy sources) the additionality concern would no longer be relevant, it is to be noted that the Commission's proposed approach, if taken at face value and adopted as proposed, would impose limits to the rate of utilization of electrolyzers, linked to the load factors of the related renewable generators. This might increase the cost of the renewable hydrogen produced in these installations.

Matching demand and supply of hydrogen in Europe – the European Backbone network

The above considerations show that it is definitely too early to identify a clear picture of the future demand and supply of renewable hydrogen in Europe and therefore of the demand for hydrogen transportation services across the continent.

However, a group of EU gas TSOs recently presented an outlook for a Hydrogen Backbone network along five corridors,⁵⁵ on the basis of a possible scenario for the implementation of the REPowerEU plan in 2030. This scenario shows that hydrogen demand will exceed supply in the central part of Europe (including Germany, Poland, and the Benelux countries), while in other parts of Europe there could be an excess supply of hydrogen, as shown in Figure 1.

Figure 1: Expected regional hydrogen supply and demand (TWh/y) in 2030 and 2040



Source: Reproduced from European Hydrogen Backbone, Five hydrogen supply corridors for Europe in 2030, May 2022.

⁵³ See, for example, IEA, 'The Future of Hydrogen', Report presented for the G20 Japan, June 2019, page 47.

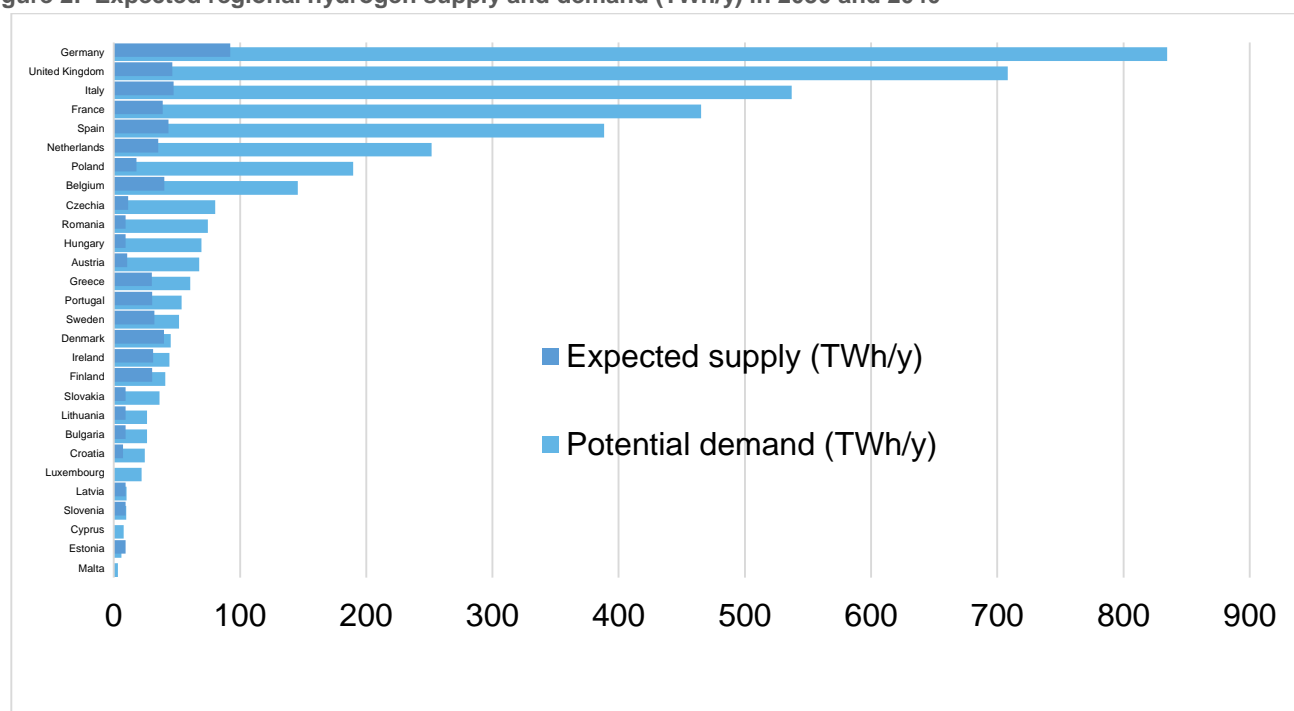
⁵⁴ Proposal for a 'Commission Delegated Regulation (EU) .../... of XXX supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin', published for consultation on 20 May 2022, available at: [Production of renewable transport fuels – share of renewable electricity \(requirements\) \(europa.eu\)](https://european-council.europa.eu/media/en/press-communications/inline-444222.pdf).

⁵⁵ 'Five hydrogen supply corridors for Europe in 2030', *European Hydrogen Backbone*, May 2022. In fact, this is the third proposal from an increasing number of EU gas TSOs for a pan-EU long-range hydrogen network, most of this is composed of repurposed gas pipelines.

Therefore, the five corridors would transport hydrogen from the periphery of Europe and from third countries – in the case that renewable hydrogen were also to be imported – to the centre of the continent. Under this scenario, the hydrogen sector would develop in a way which partly resembles the evolution of the natural gas sector over the last fifty years or so, in terms of counting on external supplies, something which is instead only marginal in electricity. However, in the case of gas, most European demand ended up being met by imports, while in the case of hydrogen, domestic production is expected to be capable of covering most of Europe's demand. There is also another important difference between the gas and hydrogen sectors, and the way in which the former developed and the latter might be expected to develop. Gas needs to be transported from where it is extracted to where it is consumed; there is no alternative to this. Renewable hydrogen can instead be produced close to consumption sites, as long as sufficient renewable electricity and water are available there. In this respect, electricity and hydrogen infrastructures become substitutes: renewable hydrogen can be produced where renewable electricity is generated and then transported to consumers using hydrogen transport facilities; or renewable electricity can be transported close to the hydrogen consumption sites, using the electricity transmission and distribution networks, and renewable hydrogen produced there. All this points towards the increasing and urgent need for an integrated planning of energy transport infrastructure, an issue to which will return later.

Before that, we wish to stress that the latest gas TSOs' Hydrogen Backbone proposal developed a somewhat different picture from the one emerging from an earlier analysis⁵⁶ performed by independent consultancy DFC Economics in 2021; this showed that, in fact, the potential demand for hydrogen in all countries in Europe will be much higher than local production, as shown in Figure 2. Therefore, the scope for cross-border trade in hydrogen would not be obvious. Also, it should be noted that, due to the costs of electrolysis technologies, financial support to renewable hydrogen might well be needed in the short to medium term. As support is likely to be provided at national level, cross-border trading of hydrogen would effectively result in financial transfers between Member States, which might be politically unpalatable.

Figure 2: Expected regional hydrogen supply and demand (TWh/y) in 2030 and 2040



Source: DFC Economics estimates.

⁵⁶ Two previous proposals for a Hydrogen Backbone, published in 2020 and 2021 by an increasingly larger group of gas TSOs, were much vaguer with respect to the outlook for hydrogen demand and supply across the EU. Please refer to: Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, and Teréga, *European Hydrogen Backbone*, July 2020 and to Creos, DESFA, Elering, Enagás, Energinet, Eustream, FGSZ, Fluxys Belgium, Gasgrid Finland, Gasunie, GAZ-SYSTEM, GCA, GNI, GRTgaz, National Grid, NET4GAS, Nordion Energi, OGE, ONTRAS, Plinovodi, Snam, TAG, and Teréga, *Extending the European Hydrogen Backbone*, April 2021.

Need for integrated planning

The fact that the scope for cross-border trading of hydrogen is limited should not strike as surprising, considering that the 2030 target for renewable hydrogen production for the EU is broadly equivalent to the current production of fossil-based hydrogen, which it is expected to replace, and which at the moment does not require a pan-EU network. However, since then, the REPowerEU plan has added a target for hydrogen imports in 2030 and, if they were to materialize, they would definitely require some longer-range transport infrastructure.

Two final considerations relate to the uncertainty as to whether and when a pan-European hydrogen network would be required.

First, integrated network planning across electricity, gas, and hydrogen would definitely assist in dealing with this uncertainty more efficiently. Despite policies that aim at an ever increasing integration and coupling⁵⁷ between these energy carriers,⁵⁸ the planning of the electricity and gas grids is still performed separately, both at the national level – with the multi-year plans – and at the European level – with the Union-wide ten-year network development plans (TYNDPs) developed by the European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Network of Transmission System Operators for Gas (ENTSO-G), for the electricity and gas network respectively.⁵⁹ Unfortunately, in the Decarbonisation Package of last December,⁶⁰ the European Commission missed the opportunity to scale up the ambition in network planning integration, as it did not propose to integrate the TYNDPs for electricity and gas into a single plan that could then, in the future, also include the planning of the hydrogen network. Note that integrated network planning would also help with deciding if and when it would be optimal to repurpose gas infrastructure to be used to transport hydrogen and how to deal with the related costs (also taking into account the opening by the European Commission to the possibility of cross-subsidies between gas and hydrogen network users⁶¹).

Secondly, the typical argument for planning an energy network well ahead of the demand for transport services materializing usually rests on the fact that, in many cases, primarily in electricity, it takes much longer to develop the grid than the production/generation facilities. In the case of the hydrogen network, however, since it is expected that a large part of it will be constituted by repurposed gas pipelines (no longer required to transport decreasing volumes of natural gas), the development of hydrogen transport infrastructure should be clearly much faster and cheaper than greenfield pipeline development. Therefore, while Europe should ensure that the lack of transport capacity does not represent a barrier to the development of an EU hydrogen market, it should also avoid developing networks which are not going to be used.

HOW TO INTEGRATE HYDROGEN INTO THE EUROPEAN ENERGY TRANSFER INFRASTRUCTURE LANDSCAPE?

Martin Palovic and Rahmat Poudineh

Given the prominent role of hydrogen in European plans towards climate neutrality,⁶² adequate hydrogen transport (and storage) infrastructure needs to be established to enable hydrogen penetration in the energy system. However, hydrogen transport infrastructure is costly and has a long lead time. There is also uncertainty about the scale of future hydrogen demand and the extent to which hydrogen outcompetes other means of decarbonizing the energy system. As a result, approaches driving investment in hydrogen transport infrastructures need to avoid redundancy and inefficiency.

Climate-neutral hydrogen can be transported via a dedicated new-build hydrogen pipeline, by a repurposed gas network, existing transportation networks (using, for example, truck, rail, or marine transport), or even produced on site by transferring electrical energy instead of hydrogen. Coordinating the hydrogen-driven investments of the above infrastructures allows the

⁵⁷ In principle, Sector Coupling can be defined as 'the process of progressively and increasingly inter-linking the electricity and gas sectors – by optimising the existing synergies in the generation, transport, and distribution of electricity and gas – with the ultimate scope to build a decarbonized and hybrid EU energy system'. See also: 'Sector Coupling and Energy System Integration', Florence School of Regulation (eui.eu).

⁵⁸ Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, and the Committee of the Regions, 'Powering a climate-neutral economy: An EU Strategy for Energy System Integration', Brussels, 8.7.2020, COM(2020) 299 final.

⁵⁹ So far, the focus has been on integrated modelling – not yet fully achieved – and on common scenarios.

⁶⁰ Hydrogen and decarbonised gas market package (europa.eu).

⁶¹ See the Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast), Brussels, 15.12.2021, COM(2021) 804 final, Article 4(2).

⁶² See European Commission (2020), 'Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of Regions. A hydrogen strategy for a climate-neutral Europe', Document no. COM(2020) 301 final.

establishment of a cross-sectoral hydrogen transport polygrid that minimizes the total hydrogen infrastructure investment needs and the associated cost and lead time. This, in practice, means integrating hydrogen into the available energy transfer infrastructure landscape, such that infrastructures from several different sectors are utilized to deliver hydrogen to end users in an optimum way.

Achieving such a cross-sectoral optimization is, however, not straightforward. The difficulty of the task stems from the fact that there is no explicit mechanism that would ensure cross-sectoral coordination of hydrogen-driven investment into the above-named infrastructures. Currently, the two primary European energy sources – electric power and natural gas – are transported through networks which are regulated natural monopolies. Competition occurs only among generation plants and retail suppliers, who all use the same energy network infrastructure to deliver energy to the end user within a given geographical region. Although consumer switching among retailers is common, the demand for the network infrastructure is not subject to the same dynamic. It is rather stable and independent of the developments in other sectors. As a result of this, future infrastructure demand, whether it relates to electricity or the gas network, can be reliably predicted within a sector-specific planning process. Given the monopoly setup of gas and electricity networks, the planning process and the resulting investments are subject to strict regulatory examination and approval.

However, the issue is more complex when it comes to hydrogen and investment in transportation infrastructure. Hydrogen as an energy carrier establishes new linkages between the monopolistic electricity and gas networks and new infrastructures from different sectors (such as truck, rail, and marine transport) as, in the future, end users can switch from one infrastructure to another for delivery of the hydrogen. This represents a rather new setup where hydrogen-driven investment into the power and gas networks should no longer be solely governed by sector-specific supply and demand, but also coordinate with the production, consumption, and infrastructure developments in other sectors. Therefore, an adjustment to sector-specific energy infrastructure planning processes becomes necessary. Otherwise, efficiency losses and, herewith, unnecessarily high infrastructure costs, might emerge when climate-neutral hydrogen is to be transported in large amounts from production sites to consumption centres.⁶³

Which solutions did European stakeholders propose?

In Europe, three ongoing policy debates are concerned with the integration of hydrogen into the energy transfer infrastructure landscape. Proposals made in these debates each result in a different institutional environment.

The first set of proposals comes from the integrated infrastructure planning debate and is here referred to as the *centrally-coordinated approach*. Independent of the peculiarity of the implementation and the context, proposals associated with this approach suggest introducing a new central planner into the system, who coordinates the infrastructure expansion across different sectors. Such a central planner can either be a new neutral institution or a common information platform that promotes exchange among the stakeholders from different sectors. In this model, the central planner forecasts the energy transport needs of the overall economy within several different scenarios and allocates the identified future energy transportation needs at the different sectors. The allocation decision is guided by the available infrastructure and sector-coupling capacities, congestion, sector-specific infrastructure and sector-coupling investment costs, and potential cross-sectoral synergies. The resulting sector-specific demand for infrastructure serves as an input for the sector-specific planning processes of the infrastructure investors.

Within the energy sector, the interlinked model of ENTSO-G and ENTSO-E (associations of European gas and electricity transmission system operators) represents the most prominent European example of this approach. At the national level, examples can be found in the proposal of the German Energy Agency to develop a 'Systementwicklungsplan', namely a system development plan,⁶⁴ and in the ongoing discussion of the 'energy future system operator' in the UK.⁶⁵ Given the authoritative character of the resulting institutional environment, where the individual transactions are managed by clearly defined roles and administrative procedures, proposals associated with the centrally-coordinated approach can be said to implement a hierarchical economic organization towards cross-sectoral hydrogen infrastructure investment.

The second set of proposals to integrate hydrogen within existing energy transfer infrastructures promotes a *market-based approach*. Within the hydrogen and gas markets decarbonization package debate, arguments have been raised in favour of this

⁶³ See, for example, European Commission, (2020), 'Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of Regions. Powering a climate-neutral economy: An EU strategy for energy system integration', document no. COM (2020) 299 final.

⁶⁴ Deutsche Energie-Agentur, (2020), 'Der Systementwicklungsplan. Entwicklungsvorschlag für eine integrierte Infrastrukturplanung in Deutschland', progress report from dena Netzstudie III project.

⁶⁵ Department for Business, Energy and Industrial Strategy & Office of Gas and Electricity Markets, (2021), 'Energy future system operator consultation', Consultation Report from July 2021.

approach. In this model, unregulated private investors decide where and when to build hydrogen infrastructure based on purely commercial considerations. Given such an environment, the cross-sectoral coordination of hydrogen transport infrastructure is ensured by a decentralized individual stakeholder optimization that occurs in response to price signals at energy markets that are partly driven by the cost of utilization of different energy transfer modes. This approach was brought to discussion by the European energy network regulators in reaction to calls by policymakers and stakeholders for regulated hydrogen network development.⁶⁶ Regulators highlight the possibility of cross-sectoral infrastructure competition when regulated infrastructure is expanded for the purposes of hydrogen transport. Aiming to avoid distortions and technological lock-in effects, they are critical of any setup where hydrogen infrastructure investment is decided by the established administrative planning processes of the regulated power and gas networks. Instead, hydrogen-driven investment on behalf of regulated power and gas infrastructures, identified through such processes, is suggested to represent only an investment proposal that, in the view of the approving regulator, competes against transport options from other sectors.⁶⁷

The third set of proposals is associated with the *regulatory approach*. These emerged out of the debate on energy system integration, and propose a regulatory action that motivates operators of regulated infrastructures to decide their hydrogen-driven investment based on the net social benefit for the entire system, instead of taking the perspective of their own grid. Put differently, network operators should abstain from expanding their networks if other modes of transport are found to be socially more preferable, and to coordinate with the respective providers of these alternatives to achieve a socially optimal solution. The regulatory approach was originally introduced at the European level to prevent situations where different electricity network operators purchase conflicting electricity network services from distributed resources.⁶⁸ Due to positive reception by diverse European stakeholders,⁶⁹ adoption of this approach is currently discussed also with respect to cross-system optimization of hydrogen integration.⁷⁰

Although the implementation is complex, the basic idea behind the regulatory approach is rather simple. Cost-minimization incentives promoted by traditional network regulation drives operators of regulated infrastructures towards socially optimal behaviour as long as the consequences of their decisions are fully priced in their actions. Given that there are situations where such a cost transfer does not fully occur (in other words, external effects are only insufficiently internalized), the individually rational action of an infrastructure operator might not benefit the overall system. Regulatory action needs to be taken to prevent such incentive misalignments. Herewith, the regulatory approach focuses on the complementarity of resources and the resulting degree of interdependence between the operators of established energy networks, and the providers of alternative hydrogen transport infrastructures. As a result, this approach promotes a network form of governance towards cross-sectoral hydrogen infrastructure investment.

What are the lessons learned from the European hydrogen debates?

Proposals raised within the three aforementioned policy debates are reminiscent of the three classical institutional environments known from institutional economics – hierarchy, market, and network.⁷¹ While each of these proposals can introduce a degree of cross-sectoral coordination with respect to hydrogen transport infrastructure development, the three underlying institutional environments are typically understood as alternatives to each other.

A suitable institutional environment is one that is aligned with the technological development of hydrogen transport.⁷² The difficulty of the task stems from the fact that climate-neutral hydrogen can be produced locally or in clusters, transported in larger quantities by a traditionally monopolistic energy network (for example a gas network), or by traditionally competitive transportation infrastructures (for example trucks). Each of these transportation possibilities is characterized by a different technological architecture and requires a different institutional environment. Taking the early stage of the hydrogen economy into account, future hydrogen demand and supply and, consequently, the volume of future hydrogen transport needs are highly

⁶⁶ See, for example Council of European Energy Regulators, (2021), 'Input on the hydrogen and gas markets decarbonization package Combined evaluation roadmap/inception impact assessment', Document No. C21-GWG-169-03.

⁶⁷ European Union Agency for the Cooperation of Energy Regulators & Council of European Energy Regulators, (2021), 'When and how to regulate hydrogen networks?', European Green Deal Regulatory White Paper Series, 1.

⁶⁸ Council of European Energy Regulators, (2016), 'CEER position paper on the future DSO and TSO relationship', Document ref. C16-DS-26-04.

⁶⁹ See Council of European Energy Regulators, (2018), 'Incentives schemes for regulating distribution systems operators, including for innovation: A CEER conclusions paper', Document ref. C17-DS-37-05.

⁷⁰ Council of European Energy Regulators, (2021), 'CEER 2022–2025 strategy empowering consumers for the energy transition'.

⁷¹ See Powell W. W., (1990), 'Neither market nor hierarchy: Network forms of organization', *Research in Organizational Behaviour*, 12, pp. 295–336.

⁷² See Finger M., Groenewegen J., & Künneke R., (2005), 'The quest for coherence between institutions and technologies in infrastructures', *Journal of Network Industries*, 6, pp. 227–59.

uncertain. This makes determining the dominant mode of future hydrogen transport difficult. Furthermore, with the transport sector in transition towards climate neutrality and the expected developments in truck technologies, as well as the evolution of pipeline systems, the borderlines between different modes of hydrogen transport are going to shift. The direction and size of the shift are difficult to predict, as these are not only dependent on the pace of technological developments, but also on the local circumstances of the implementing country.⁷³ As a result, the technical architecture of the future hydrogen transport infrastructure is highly uncertain and context-dependent.

Considering this technological uncertainty, one would on theoretical grounds⁷⁴ expect a preference towards hierarchical administrative processes that can be found within the centrally-coordinated approach. However, this solution implies a regulatory commitment with respect to the technical architecture of the future hydrogen transport infrastructure that the European energy network regulators have proved to be hesitant to provide. This can be observed in the reluctance of the energy network regulators when approving costs associated with repurposing gas into hydrogen pipelines, even if these projects emerge out of the established energy infrastructure planning processes on many occasions as a cost-effective solution for hydrogen transport. The worries of energy network regulators are too big to make a decision that leads to stranded infrastructure investments or technological lock-in effects.⁷⁵

With market-based and regulatory approaches,⁷⁶ the need for regulatory commitment with respect to the technical architecture of future hydrogen transport infrastructure is reduced. Nonetheless, two problems arise with such a technology competition.

First, hydrogen transport is likely to be associated with cross-sectoral external effects among infrastructures. These external effects are, so far, only poorly understood – a fact that makes their internalization through markets difficult. For example, current works on the electricity sector indicate that interactions among electricity networks in different regions (in other words, external network effects within one sector) that already exist are not conclusively understood.⁷⁷ Hydrogen, in this context, interlinks infrastructures from different sectors, something that introduces a completely new layer of complexity into such analysis. External effects resulting from this additional layer are hardly explored, and a consensus on the problem is missing. The risk of socially inefficient hydrogen transport infrastructure investment increases as a result. Hierarchical solutions are expected to outperform markets for as long as external network effects are unknown and hence difficult to internalize.⁷⁸ Therefore, proposals based on central coordination, emerging out of the European hydrogen debates, seem to represent the only implementable option to address the problem of external effects. Consequently, administrative planning processes are expected to be established even with the adoption of market-based or regulated approaches, in order to facilitate cross-sectoral information exchange on infrastructure investment and, herewith, to allow the identification of cross-sectoral external effects.

Second, investment in grid-bound infrastructures is associated with higher risks of irreversibility compared with that of other alternatives. Given the difference in the risk profile of different infrastructure types related to stranded assets, hydrogen investment into grid-bound infrastructures is likely to be sub-optimal when this investment is driven by the decentralized energy markets.⁷⁹ Providing a regulatory commitment with respect to cost recovery, within a centrally-coordinated approach, for selected grid-bound infrastructure projects reduces such risks. The regulatory approach can also provide this type of regulatory commitment and represents an alternative solution to the problem. When compared to the centrally-coordinated approach, the regulatory model introduces an additional incentive for infrastructure investors to coordinate with the hydrogen transport infrastructure investment in other sectors. This reduces the need on the behalf of the regulator to define the technical architecture of the future hydrogen transport infrastructure. The implementation is more challenging, however, as continuous regulatory oversight covering decentralized hydrogen transport infrastructure investment from different sectors is necessary.⁸⁰

⁷³ Owen N., (2009), 'Fuel cells and hydrogen in a sustainable energy economy', final report on Roads2HyCom project, document no. R2H8500PU.6.

⁷⁴ See Williamson O. E., (1975), *Markets and hierarchies: Analysis and antitrust implications*, Free Press: New York.

⁷⁵ European Union Agency for the Cooperation of Energy Regulators & Council of European Energy Regulators, (2021), 'When and how to regulate hydrogen networks?', *European Green Deal Regulatory White Paper Series*, 1.

⁷⁶ The two alternatives that use market-driven processes to determine not only the most efficient mode of hydrogen transport, but also the extent of hydrogen transport needs.

⁷⁷ Grøttum H Grotto, Bjerland S F, del Granado P C, & Egging R., (2019), 'Modelling TSO–DSO coordination: The value of distributed flexible resources to the power system', Conference paper on 16th International Conference on the European Energy Market, Lubljana.

⁷⁸ Williamson O. E., (1975), *Markets and hierarchies: Analysis and antitrust implications*, Free Press: New York.

⁷⁹ See McDonald R & Siegel D, (1985), 'Investment and the valuation of firms when there is an option to shut down', *International Economic Review*, 26, pp. 373–413.

⁸⁰ See, for example, Council of European Energy Regulators, (2021), 'CEER 2022–2025 strategy empowering consumers for the energy transition' and Brunekreeft G., Kuszniir J., & Meyer R., (2020), 'The emergence of output-oriented network regulation', *Oxford Energy Forum*, (124), pp. 34–8.

All in all, there is no silver bullet solution to the problem of cross sectoral coordination of hydrogen transport infrastructure. It depends on contextual factors specifically on the stage of development of the sector. Given that hydrogen is a nascent sector and is thus at an early stage of development, administrative planning processes associated with the centrally-coordinated approach seem to be a reasonable way of coordinating hydrogen transport infrastructure investment across different sectors. Such processes not only provide the regulatory commitment that is necessary for hydrogen infrastructure projects to take off quickly, but also allow the addressing of cross-sectoral external effects when such effects are not well understood, and the social consensus is missing.

However, this institutional setup (in other words, the approach based on central coordination) should not be considered as final. As the industry evolves, institutions governing cross-sectoral hydrogen transport infrastructure coordination should also evolve. This is because the understanding of cross-sectoral hydrogen transport infrastructure coordination, and the associated challenges, are likely to develop over time. Furthermore, central coordination is expected to perform well with respect to clear-cut projects, but to hit the limit when addressing the fringe, where it is difficult to define the most socially efficient mode of hydrogen transportation. While having only a limited understanding of cross-sectoral coordination, the central planning should, in our view, be used to get clear-cut hydrogen transport mode projects off the ground, while intentionally postponing the less clear-cut cases. Those less well-defined projects can be addressed, at a later point, by decentralized regulatory or market-based approaches after the first experience with cross-sectoral coordination has been gained.

DANISH DISTRICT HEATING REGULATION: OVERVIEW, RECENT DEVELOPMENTS AND LESSONS FOR EMERGING AND EXPANDING NETWORKS

Luis Boscán

District Heating (DH) – also known as heat networks – is a business and technology model in which thermal energy is produced at a central source and is transmitted and distributed through a network of insulated pipes. DH is credited with the ability to bring about substantial energy efficiency gains through co-generation and the possibility to utilize excess heat from industrial processes, as well as facilitating the coupling of sectors in energy systems. DH can also support the integration of renewables and facilitate decarbonization through electrification.

While many of the technical characteristics of DH networks are well understood, it is less clear what an ideal regulatory framework for DH networks should be able to achieve. This article argues that DH regulation should incentivize:

- i. economic efficiency,
- ii. the consolidation and expansion of networks,
- iii. the choice of fuels and technologies that support decarbonization.

Unlike other areas of the energy sector, such as electricity and gas, in which regulatory models have evolved from a series of common principles and have been applied similarly across jurisdictions – for example, in the EU and in the US – the regulation of the DH supply chain is less understood. After all, DH networks are much less widespread than electricity and gas infrastructure.⁸¹ However, the decarbonization agenda is bringing increasing attention to DH from countries establishing or expanding this model as an element of their decarbonization strategy, such as the UK.⁸²

To shed light on the question of an ideal regulatory framework for DH, this article describes Denmark's decades-long experience within DH to shed light on how it addresses the abovementioned objectives but also to identify a few lessons from their regulatory framework. The Danish framework is an example of both good and evolving practices, as its already mature DH system is in an ongoing process of adaptation to the requirements of an ambitious green transition, which aims at being economically efficient.

Denmark's experience is relevant not least because the country – as measured by different indicators – has the most developed DH network in the EU (European Union): it has the longest trench length (more than 30,000 km), the highest density per resident (5.3 km/1,000 residents) and the highest share of supplied citizens (65 per cent).⁸³ DH is also the most common

⁸¹ DH length density is only 0.38 km/1000 inhabitants in the EU-27 countries, 'District heating and cooling in the European Union: Overview of markets and regulatory frameworks under the revised Renewable Energy Directive. Annexes 6 and 7: final version'.

⁸² Further details to be found at: 'Energy Security Bill factsheet: Heat networks regulation and zoning', Gov.UK.

⁸³ 'District heating and cooling in the European Union: overview of markets and regulatory frameworks under the revised Renewable Energy Directive', EU Publications Office.

heating form in Denmark's built environment, as 55.3 per cent of all heated space in the country (measured in m²) is served by a DH installation.⁸⁴

There are other leading countries in Northern Europe – such as Sweden, Germany, and Finland – with highly developed DH systems from which lessons could also be learned. For example, Germany has a comparable trench length (approximately 29,000 km) but covers a much smaller share (14 per cent) of residential heat demand. Similarly, the DH markets of Sweden and Finland are bigger than Denmark's in terms of total heat delivered. Sweden is also the leading EU country in terms of renewable energy integration into DH – excluding, here, Iceland which is not an EU country but boasts almost 100 per cent renewable energy in DH and 89 per cent coverage of residential demand, due to its availability of geothermal resources.

DH supply chain

Common to all DH networks is the presence of various degrees of vertical integration in the utilities delivering heat for both space and process heating purposes in residential and non-residential buildings.

In densely populated areas, heat may be jointly produced with electricity in independent co-generation and waste incineration plants and then sold and delivered to end users through both transmission and distribution pipelines, which are usually owned by the DH utility facing the customer. In other settings, there are utilities specializing in the transmission part of the business, which functions as a link between independent producers and distributors. A case in point is the economic dispatch of DH plants in the Metropolitan Area of Copenhagen with the common participation of heat generators who obtain voluntary third-party access to transmission infrastructure.⁸⁵

In less densely populated areas, heat generation assets are located closer to the end user and vertical integration is more evident, as companies own assets in all phases of the supply chain. There are also closed-area heat generation plants (in other words, block heating stations) serving residential areas, industries, educational institutions, or hospitals.

Denmark's DH regulatory tradition

The Danish approach to DH regulation relies on the tradition of energy planning – both centralized and decentralized. Although DH has existed in Denmark since the early 20th century, it expanded in the wake of the energy crises of the 1970s. National (namely centralized) energy policy agreements dictated the need for DH in the country then, but since the very beginning of the process municipalities, consumers, and representatives of local communities became directly involved.

The main instruments that exist in today's Danish DH regulation – local energy plans, cost-benefit analyses, the economic regulation of utilities, as well as other direct regulations – are a compendium of traditions that have evolved over the course of approximately four decades. Both centralized and decentralized energy planning continue to dictate the role of DH in the broader context of Danish energy policy.⁸⁶

Incentives for economic efficiency DH utilities in Denmark are regulated in accordance with a form of cost-plus regulation, in which utilities are allowed to include 'necessary costs' in their price to produce and deliver thermal energy. Such costs include both capital and operational expenditures and comprehend specific categories such as financial costs, fuel costs, and other public service obligations for which utilities are liable.

The same regulatory approach is applied regardless of their participation in one or all parts of the value chain. For example, independent heat producers can recover their heat production costs in this manner. However, as many heat suppliers co-generate electricity and heat, there is a considerable risk of cross-subsidization, which may work to the disadvantage of heat users.

As applied in Denmark, the key principle behind this form of cost-plus regulation is that utilities must 'rely on themselves' which in practice means that they should not maximize profit.⁸⁷ Because many of the DH utilities have traditionally been municipality or consumer-owned, these should produce neither a deficit nor a surplus, such that end users are not taxed or subsidized. This should – at least in principle – create a framework in which end users obtain thermal energy at the lowest possible price and prevent municipalities from cross-subsidizing other activities.

Upon authorization from the regulator, utilities are allowed to receive a reasonable return on the capital invested in network

⁸⁴ 'District Heating and Natural Gas are the most widespread forms of heating' (in Danish), Danmarks Statistik.

⁸⁵ Further details can be found at: 'What is load dispatching', Varmelast.

⁸⁶ It is worth highlighting that the use of cost-benefit analyses as a tool in energy policy and planning was introduced in the early stages of the zoning process in Denmark, to determine if an area would be served either by gas or by DH.

⁸⁷ In Danish regulatory circles, this principle is referred to as '*hvile-i-sig-selv*' which translates as 'rely-on-oneself'.

expansions or other heat generation projects, as well as including the depreciation of existing assets into their necessary costs. A portion of earnings can also be retained to finance new investments, providing access to capital at no (or very low) financial cost.⁸⁸

Historically, the Danish approach to cost-plus regulation with absence of profit maximization can be explained by the relevant role of consumer ownership of DH utilities in the country: of the approximately 396 regulated utilities delivering heat to end users, 330 are consumer owned.

Consumer ownership is a widespread form of co-operativism in Danish society, and it is known to have played an important role in other areas, such as in the early stages of wind energy production in the late 1970s. In theory, utilities owned by consumers don't have an incentive to overspend or to misreport their true cost information. However, this understanding of consumer-owned utilities may overlook corporate governance frictions which, in practice, may lead to economic inefficiencies. For instance, even if shareholders are consumers themselves, they do not necessarily manage DH utilities.

On the other hand, consumer-owned utilities only account for 34 per cent of all heat delivered to end users in the Danish DH sector, whereas municipality-owned utilities deliver the largest share (64 per cent) of thermal energy to end users (see Table). Thus, local state ownership controls most of the heat supplied by DH utilities in Denmark.

Table 1: Ownership model and heat delivered in the Danish DH

Ownership type	Number of utilities	Share of heat delivered (%)
Consumer owned	330	34
Municipality owned	52	61
Commercially owned	14	5

Source: [The Danish Utility Regulator's Heating Statistics \(2018\)](#) (in Danish).

Consolidation and expansion of DH networks The first DH network was established in Denmark as early as 1903, but it was only after the energy crises of the 1970s that heat planning became organized, becoming the key building block for the consolidation and expansion of DH. The first heating supply law – which after multiple amendments still governs the sector – was passed in 1979. Back then, the main driver for the establishment of collective heat systems was the need for a massive and rapid substitution of oil-fired boilers, in response to nearly complete dependence on petroleum products.⁸⁹

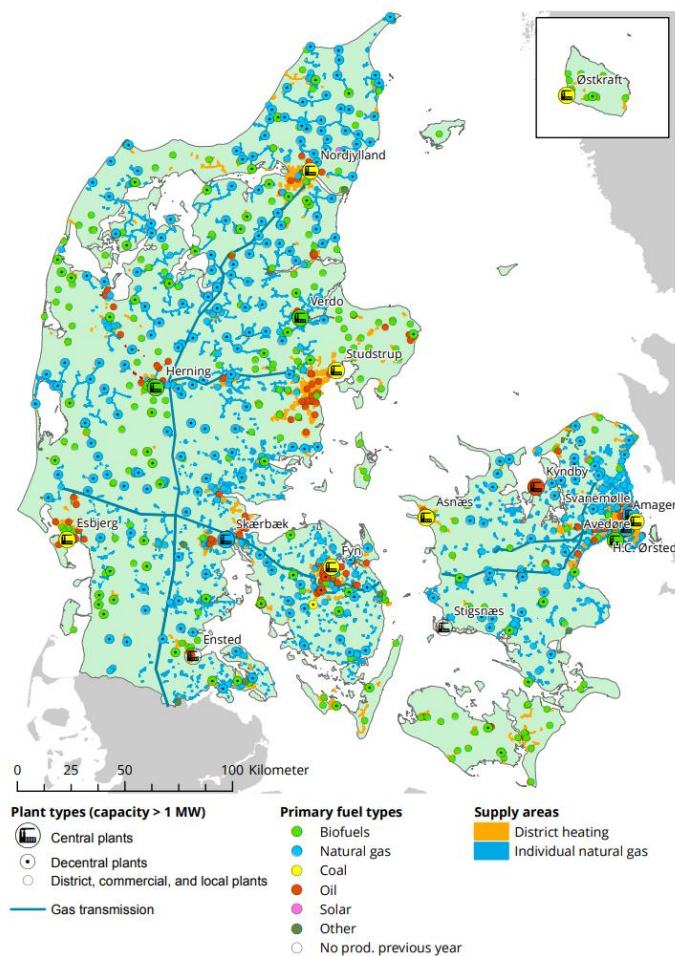
In the governance framework for Danish DH, municipalities have the responsibility for identifying heating requirements in their area of competence and approving DH projects that can objectively demonstrate benefits for DH utilities, end users, and society. Municipal boards are responsible for laying out local heating supply plans for the municipality, ensuring that projects to satisfy the heating requirements are proposed, approved, and delivered within the proposed timeline. Local heat planning must be advanced in direct dialogue and cooperation with energy suppliers and other stakeholders, such as companies, with specific requirements regarding their energy and heat demand.

The initial zoning process of the country was completed in the period 1981–82, leading to a designation of zones which were to be served either by natural gas or by DH (see Figure 1 for a recent visual overview of Denmark's heating supply). At the time, there was a need to develop non-overlapping energy infrastructure, which would simultaneously support the development of collective heating systems and the domestic utilization of the natural gas reserves from the Danish North Sea. End users would have the alternative of mandating connection to either the DH network or the gas network for heating purposes. Alternatively, consumers could continue to be supplied by individual sources of heat supply, such as oil or biomass-fired boilers.

⁸⁸ Unlike the more traditional cost-plus regulation applied in other industries and countries, which allows a return on the utilities' overall capital base, the Danish approach is more restrictive in this respect. On the other hand, it is more lenient with respect to critical issues such as the achievement of cost efficiency gains and cross-subsidization in heat production.

⁸⁹ Further details can be found in L. Boscán et al., (2021), 'Beyond Wind: Challenges to the Expansion of Renewables in Denmark', *New Challenges and Solutions for Renewable Energy*, Palgrave Macmillan, 319–48.

Figure 1: Map of Denmark's heating supply



Source: '[Regulation and planning of district heating in Denmark](#)' Danish Energy Agency, June 2017

Cost–benefit analyses and other direct regulations One important instrument in the heat planning process is the execution of cost–benefit analyses, which are prepared according to a unified methodology and common assumptions centrally laid out by the relevant authority in Denmark's energy policy and planning framework (the Danish Energy Agency). Any project proposal to renovate, expand, or establish a new heat production unit, or to expand the coverage of a DH zone, must be evaluated against relevant alternative types of heat supply (beyond the status quo), and must demonstrate that the proposed project is the most socio-economically advantageous one.

A typical project proposal will include:

- a private economic assessment of costs and benefits accruing to the DH utility,
- an end user economic assessment, focusing on the heating prices paid by consumers,
- a broader socio-economic assessment, which includes costs and benefits accrued to society.

Table 2: Main elements in private economy, end user economy, and socio-economic assessments for DH projects

	Private and end user economic assessments	Socio-economic assessment
Investment costs	✓	✓
Operation and Maintenance costs	✓	✓
Fuel costs	✓	✓
Rate of return for the producer	✓	
Income from co-generation	✓	✓

CO ₂ (within the EU quota system)		✓
CO ₂ (outside the EU quota system)		✓
Further emissions and externalities		✓
Taxes and subsidies	✓	
Fiscal deadweight losses		✓
Indirect taxation factors		✓

Source: '[Guidance on cost-benefit analyses for the energy sector](#)' (in Danish).

Besides cost-benefit analyses, there are two additional instruments of direct regulation which, in the early stages of DH networks, helped to consolidate and expand the networks:

- i. *An obligation to connect to the DH network*, which is imposed by the municipality on the building and entails an economic contribution to the collective heating system.
- ii. *An obligation to remain connected to the DH network*, which is imposed on buildings that have already been connected to the DH system.

Fuel and technology choice Historically, Denmark's DH networks have been bound by two centrally determined requirements regarding fuel and technology choice. These direct regulations are:

- *Cogeneration requirement*: since 1986, a co-generation requirement between electricity and heat was imposed, meaning that all new projects in DH areas would have to be based on Combined Heat Power (CHP) plants and in this case fuel choice would remain open.
- *Fuel choice requirement*: if the project is in a zone supplied by natural gas, then this would have to be chosen as fuel. If the project is to be developed in a zone without natural gas supply, the choice of fuel could be made between biomass, waste, biogas, landfill gas, and other gasified biomass.

Adapting DH to Denmark's ambitious green transition

Throughout the last decade, Danish policymakers have expressed increasing interest in 'modernizing' the regulatory framework of Denmark's DH by introducing greater incentives for economic efficiency and by reforming some of the long-standing direct regulations that supported its consolidation and expansion in earlier stages.⁹⁰

Some of the proposals have gone as far as suggesting full-fledged market de-regulation, taking Sweden's approach as role model. Other suggestions have proposed introducing income cap regulation together with benchmarking, following Danish practice in electricity distribution. Many of the proposals are considered controversial and have been met with resistance by industry representatives, but have in any case motivated a national debate, ultimately resulting in the adaptation of the DH regulatory framework to an ambitious and cost-effective green transition.

Relaxation of direct regulations An important change in the revised regulatory framework for DH has been the relaxation of some of the longest-standing regulations:

- Since 2019, municipalities cannot commission new mandatory connections to an existing DH network, which has increased end users' freedom to choose. This has resulted in more direct competition between DH and individual heat pumps.
- Since 2021, both fuel and technology choice requirements have also been relaxed. A revised co-generation requirement allows municipalities the possibility to choose other forms of heat generation than CHP. Similarly, municipalities may choose other fuels than natural gas in designated gas areas. In practice, this opens the possibility to establish large-scale heat pumps and other biomass-fired solutions.

Price-cap regulation and strengthened managerial separation One of the most critical aspects of the existing economic regulation of Danish DH networks is the lack of explicit incentives for economic efficiency. Although the existing approach has allowed the expansion and consolidation of DH, utilities have too strong an incentive to pass on their costs to end users.

⁹⁰ Three key documents underlying this discussion are (in Danish): '[Moderniseret Regulering i Fjernvarmesektoren](#)'; '[Forsyning for Fremtiden](#)', and '[Konkurrenceanalysen af fjernvarmesektoren](#)'.

More fundamentally, the existing regulatory approach ignores the coexistence of diverging ownership models, frictions in corporate governance, different operating conditions and management abilities, and – not least – the existence of competing individual heating alternatives such as heat pumps, which end users are free to choose.

Based on this understanding, a recent political agreement has decided to implement price-cap regulation on DH utilities.⁹¹ However, the implementation of a price cap does not substitute the existing cost-based framework. Instead, it supplements it by mimicking competition from an alternative individual heating supply solution, such as a heat pump.

The price cap will be complemented with relaxed financial rules that facilitate investments in new projects by DH utilities, including longer depreciation periods, adjustment to the allowed rate of return, and the removal of limitations on retained earnings. Furthermore, a clearer managerial separation in municipality-owned utilities will be introduced, as independent board members will have to be elected.

Conclusions and lessons

The Danish framework for DH regulation is based on the energy planning tradition, in which the combination of top–bottom (centralized) with bottom–top (decentralized) approaches has helped DH networks to consolidate and expand.

The regulatory instruments that govern the Danish DH sector are more reflective of a governance framework in which involved stakeholders – notably consumers and local governments – interact to reach decisions of common interest, than one in which profit-driven agents (namely, natural monopolies) participate.

While the existence of such a framework has many positive traits, it also reveals important weaknesses, such as the lack of direct incentives for economic efficiency, and a slow adaptation to both technological innovation and exposure to much needed competition from alternative, individual, heating sources which may be more economic. The framework also suffers from complexity, bureaucracy, and an insufficiently clear separation of roles played by involved stakeholders who manage DH utilities and occupy political positions at the same time.

Despite its many environmental and technological benefits, Danish DH risks becoming irrelevant for Denmark's ambitious green transition unless it rapidly comes of age and quickly delivers solutions to the present-day challenges posed by the coexistence of pressing green transition and energy crisis needs. Denmark presently requires the conversion of heating form of at least 450,000 households (27 per cent of Denmark's heated space) from fossil fuels to a different form of heating. Whether this share will be gained by DH or by individual solutions (such as heat pumps) will depend on the adaptability of DH and on how swiftly utilities are able to expand.

From our analysis of Danish DH regulation, we can identify three lessons for countries willing to expand and consolidate their networks:

- *Lesson 1 – planning could be part of the answer to consolidate and expand:* rather than dealing with un-coordinated decisions by individual firms and stakeholders, an inclusive and holistic planning approach to DH could support the consolidation and expansion of heat networks. This has, of course, certain caveats, as inherent cultural, legal, and even political barriers that limit the benefits of planning may be present.
- *Lesson 2 – cost-plus regulation is unlikely to deliver sufficient economic efficiency incentives:* some sort of incentive-based regulation could be beneficial to protect the interests of DH consumers. The ultimate choice should strike the balance between simplicity of implementation and the power of incentives.
- *Lesson 3 – a common understanding of desirable fuel and technology choices may be necessary:* a series of pre-defined technologies and fuels from which to choose, which are adapted to the local context and bring about decarbonization benefits, may be required. This can be operationalized in the design of technology and fuel catalogues, on which heat supply decisions made by policymakers can be based.

⁹¹ The Climate agreement on green electricity and heating of 25 June 2022, in Danish, ('[Aftale om et mere grønt og sikkert Danmark](#)').



ARE WE PREPARED TO COOL DOWN IN A WARMING WORLD?

Carlos E. Ugalde-Loo

Introduction

We are facing an unprecedented man-made climate emergency threatening life on our planet. Limiting global surface temperature rise to 1.5°C above pre-industrial levels is key not only to meet the legally binding Paris Agreement, but also to ensure irreversible effects for nature and people are not triggered. Heatwaves are a stark reminder of the severity of global warming, due to their dramatic effect on ecosystems and societies, as evidenced, for example, by the recent wildfires in France, significant heat-related excess mortality tolls in Europe, and ambient temperatures reaching 40°C in several countries.

Decarbonizing energy is crucial to mitigate the effects of climate change. In 2019, the UK became the first major economy in the world to pass legislation to end its contribution to global warming by 2050 by reducing its greenhouse gas (GHG) emissions to net-zero, while the European Union confirmed its commitment to meet this objective through the European Green Deal. A significant reduction in emissions has been achieved in the electricity sector, where the grid integration of renewables has played a key role. However, progress has been more muted in other areas, such as heating.

Heating, including space cooling, accounts for over a third of GHG emissions in the UK. Heating and cooling are central to our lives for comfort, daily activities, to facilitate productive workplaces, and to run a myriad of industrial processes. Decarbonizing heating and cooling are thus a cornerstone to meet net-zero targets.

Scratching the tip of the iceberg in cooling decarbonization

Decarbonization of heat has received increased awareness from key stakeholders, with some heat decarbonization pathways proposed and already under assessment, and some development of heat policy. Notably, the UK's Department for Business, Energy & Industrial Strategy (BEIS) considers that 'decarbonizing heat is our most difficult policy and technology challenge to meet our carbon targets'.⁹² The government's approach to decarbonize heat has considered a range of measures, such as the '£3B pledge' to improve the energy efficiency of buildings within the post-Covid19 green recovery programme.⁹³ Efforts are underpinned by innovation aimed to reduce heat demand, increase low-carbon heating, and define a long-term policy framework ahead for a national transition (see footnote 92). The growing demand for cooling had not previously received a similar attention, but this is now changing.

Cooling is mostly used for cold supply chains and for indoor space cooling. Space cooling includes air conditioning, electric fans, and dehumidification. Cooling is key for public health, food security, and productivity, as cooling services provide thermal comfort, prevent overheating, avoid food waste, and keep medical products safe.⁹⁴

In the UK, it is estimated that up to 10 per cent of all electricity is used for cooling,⁹⁵ but this figure will likely increase. The UK's ten warmest years have occurred after 2002⁹⁶ and climate modelling estimates a temperature increment of 3–5°C for the average regional summer by 2080 and an increase in the number and frequency of heatwaves.^{97,98} Globally, space cooling accounted for approximately 20 per cent of total electricity use worldwide in 2020, and this may more than triple by 2050 as the climate warms.⁹⁹

The cooling challenge

Decarbonizing cooling poses major obstacles. This is not only a technical challenge, as transforming effectively large systems such as the energy sector relies on social elements (including public expectations, beliefs, and acceptability of novel technologies and solutions, behavioural changes, and policy and institutional change), as well as how these factors interplay

⁹² 'Clean Growth – Transforming Heating. Overview of Current Evidence', Department for Business, Energy & Industrial Strategy, December 2018.

⁹³ 'Chancellor set to announce £3bn green investment package', *The Guardian*, 6 July 2020.

⁹⁴ 'Sustainable cooling', *POSTnote 642*. The Parliamentary Office of Science and Technology, April 2021.

⁹⁵ 'Study on Energy Use by Air Conditioning: Final Report', A. Abela, et al., BRE Client Report for the Department of Energy & Climate Change, June 2016.

⁹⁶ 'UK Climate Projections: Headline Findings', Met Office, September 2019.

⁹⁷ 'Adapting to climate change. UK Climate Projections', Department for Environment Food and Rural Affairs, June 2009.

⁹⁸ 'UKCP Convection-permitting model projections: Science report', E. Kendon, et al., Met Office, September 2019.

⁹⁹ 'The Future of Cooling. Opportunities for energy-efficient air conditioning', International Energy Agency, May 2018.

with the various technical elements.¹⁰⁰ At the same time, driving low-carbon outcomes likely will require policy and legislative support, given that system change can be slow because of lock-in and incumbency.

Summertime cooling of buildings is becoming prevalent, and consumer demand for greater comfort levels will also increase the energy used for cooling services, while increased working from home and changes in lifestyle may need to be accounted for. In the UK, the National Health Service have confirmed an increase in space cooling demand due to overheating. However, how will overheating be predicted for a large variety of domestic buildings? Thermal models may be employed to assess the likelihood of overheating. While it may be easier to model new buildings, doing this for an ageing housing stock may not be straightforward due to the diversity of materials used in foundations, walls, windows, doors, roofs, and insulation, and consequently in the heat transfer coefficients and indoor heat gains used for calculations. This is without considering geographical conditions, such as latitude, ambient temperatures, solar irradiance, orientation, or humidity. All these attributes play a role in quantifying cooling demand.

Follow-up questions arise. How is cooling demand being quantified? How is this demand being considered in energy policy? There is a limited awareness of future cooling demand for domestic buildings. The most complete dataset on cooling energy consumption in the UK is available from BEIS.¹⁰¹ However, this is restricted to the non-domestic sector, so an understanding on how domestic buildings and households respond to extreme heat, and how this might create greater demand for space cooling, is yet to be developed. Compounded to this, assessing occupant behaviours and strategies in households, influenced by social norms and personal preferences, is important, as these may affect cooling demand. As evidenced during the recent heatwave this summer, a clear guidance towards preventing overheating which effectively reaches households is needed. Depictions associating extreme heat with people happily sunbathing do not help. Is the general population aware of the impacts of overheating, such as health risks, productivity decline, and loss in efficiency and capacity of infrastructure? Have people considered incorporating cooling methods to their homes for thermal comfort? There seems to be a lack of recognition of the importance of cooling and how it affects our lives.

Cooling approaches and technologies

There are two main approaches towards cooling provision. In passive methods, heat gains are avoided, and heat is dissipated, to improve thermal comfort without the use of additional energy. This may involve building design considerations including ventilation, window glazing, sun orientation, building materials, and insulation. Recent literature highlights that energy savings from passive strategies are high.¹⁰² Occupant behaviour is also considered a passive approach. It relies on occupants' knowledge to ensure cross-ventilation, night ventilation, and adoption of behavioural strategies to reduce cooling demand. Passive strategies, however, may not be sufficient in urban heat islands lacking green infrastructure, or in less affluent areas of a city (see footnote 94).

The other method is active cooling, where demand is commonly met using electrical energy. Active technologies include air conditioners (ACs), chillers, and refrigerators. A refrigerant, which is a chemical circulated in a closed system, is used to absorb heat when evaporating to a gas, and to release it when condensing to a liquid (see footnote 99). Heat transfer is thus achieved by absorbing heat from the environment to be cooled down and released elsewhere.

Despite the latest climate projections, and research in the UK showing that several households experience overheating during summer, new houses are not obliged to consider overheating in their designs.^{103,104} In fact, the Committee on Climate Change (CCC) recently stated that homes in the UK are not 'fit for the future'.¹⁰⁵ Following recommendations from the CCC, the government considered reducing cooling demand¹⁰⁶ and published revisions to the existing Building Regulations to address overheating through passive methods in all new residential buildings.¹⁰⁷ However, as with heat decarbonization,¹⁰⁸ the large and

¹⁰⁰ 'Net Zero. The UK's contribution to stopping global warming', Committee on Climate Change, May 2019.

¹⁰¹ 'Cooling in the UK', Department for Business, Energy & Industrial Strategy, August 2021.

¹⁰² A. Sharifi, 'Co-benefits and synergies between urban climate change mitigation and adaptation measures: A literature review', *Science of The Total Environment*, vol. 750, pp. 141642, January 2021.

¹⁰³ W. Wilson and C. Barton, 'Tackling the under-supply of housing', *House of Commons Library*, February 2022.

¹⁰⁴ C. Brimicombe, 'Heatwaves: An invisible risk in UK policy and research', *Environmental Science & Policy*, vol. 116, pp. 1–7, February 2021.

¹⁰⁵ 'UK housing: Fit for the future?', Committee on Climate Change, February 2019.

¹⁰⁶ 'Heat and Buildings Strategy', Department for Business, Energy & Industrial Strategy, October 2021.

¹⁰⁷ 'Building (Amendment) Regulations 2021: circular 01/2021', Department for Levelling Up, Housing & Communities, December 2021.

¹⁰⁸ 'Hot stuff: Research and policy principles for heat decarbonisation through smart electrification', R. Lowes, et al., *Energy Research & Social Science*, vol. 70, pp. 101735, December 2020.

less energy efficient existing housing stock was ignored. To bridge this gap, it may be required to scale up home retrofitting programmes for existing buildings.

It is estimated that the split AC unit represents 78 per cent of the total sales of active technologies in the UK,¹⁰ although there is a limited understanding on the actual use of AC systems once installed.¹⁰⁹ If this trend continues, with the foreseen increased cooling needs, the knock-on effect on the share of electricity used for cooling would be enormous. Impulsive decisions being made to install ad hoc ACs will increase peak cooling loads, which will strain the electricity system. For instance, the National Grid has estimated an uptake of 18 million units of AC systems in UK households by 2050, which could add up to 39 GW of peak electricity demand on a typical summer weekend day (see footnote 92). At the same time, summer electricity demand is changing dramatically, with a surge in solar PV generation, causing concern for balancing the power system.

Another relevant aspect is the use of refrigerants in active systems. Most refrigerants in the market are fluorinated gases (F-gas) and constitute 35 per cent of global cooling-related GHG emissions.¹¹⁰ Among them, hydrofluorocarbons (HFC) make up 95 per cent of the emissions.¹¹¹ Reducing F-gas use in cooling equipment is supported internationally through the Kigali Amendment of the UN Montreal Protocol, European regulations, and HFC bans for industrial refrigeration, domestic refrigerators, and ACs. Even when the UK has phased out a significant amount of HFC for cooling-related services, most ACs still operate with F-gas (see footnote 94). Using natural refrigerants such as water, air, ammonia, and hydrocarbons is an alternative, but these come with their risks, such as flammability, toxicity, and demanding operating conditions (see footnote 110).

Integrating heat pumps and thermal stores

Heat pumps (HPs) are energy-efficient devices capable of heating buildings. They operate using electricity and a refrigerant to extract heat from the environment. HP technologies are conventionally named after the medium from which heat is extracted (such as the air, ground, or water). The extracted heat is then circulated inside the building around a heating and hot water system. To provide cooling, the HP operating cycle can be reversed to essentially work as an AC. This way, a reversible HP can be used to decarbonize buildings while meeting heating and cooling demand.

HP units play a key role in most UK heat decarbonization scenarios,²⁰ although there is limited awareness of the technology among domestic owners and their deployment level is significantly lower compared to other countries.¹¹² Recent low-carbon heat policy is, however, expected to increase HP penetration.¹¹³ The Renewable Heat Incentive supports homeowners in the installation of HPs and other renewable options.¹¹⁴ However, compared to a gas boiler, HP cost per kWh continues to be high¹¹⁵ and its up-front cost remains prohibitive for the general population. Installation labour ramps up costs, and this needs to be addressed for HPs to become an economic alternative to gas boilers. In addition, some units rely on F-gases (see footnote 94), and there is concern that new prohibitions from the European Commission may restrict their deployment.¹¹⁶ Provision of further financial and regulatory incentives towards decarbonizing domestic heat through HP uptake is therefore still required. There is an opportunity to link these initiatives to cooling decarbonization too, but this argument needs to be articulated.

The role of thermal energy storage (TES) could be crucial, as it can be deployed into cooling systems to act as a buffer between supply and demand. TES may also provide flexibility, enabling peak cooling demands to be shaved, electrical loads to be shifted, and electricity costs to be reduced. For example, a thermal store may act as an energy sink during cooler night hours, when cost of electricity is reduced, and operate as a cooling source during peak demand when cost of electricity is high.¹¹⁷ Latent heat TES is a preferred choice for cooling applications. The storage medium is a phase change material (PCM), which

¹⁰⁹ 'Air conditioning demand assessment', C. McLachlan, et al., *Tyndall Manchester Climate Research Centre*, University of Manchester, May 2016.

¹¹⁰ 'Technical report on energy efficiency in HFC-free supermarket refrigeration', K. Zolcer Skacanov and A. Gkizelis, *Environmental Investigation Agency*, 2018.

¹¹¹ 'The Sixth Carbon Budget. The UK's path to Net Zero', Committee on Climate Change, December 2020.

¹¹² 'Important social and technical factors shaping the prospects for thermal energy storage', D.G. Barns, et al., *Journal of Energy Storage*, vol. 41, pp. 102877, September 2021.

¹¹³ 'The Energy White Paper. Powering our Net Zero Future', Department for Business, Energy & Industrial Strategy, December 2020.

¹¹⁴ 'Policy change, power and the development of Great Britain's Renewable Heat Incentive', R. Lowes, B. Woodman, and O. Fitch-Roy, *Energy Policy*, vol. 131, pp. 410–21, August 2019.

¹¹⁵ 'Experience rates of low-carbon domestic heating technologies in the United Kingdom', R. Renaldi, et al., *Energy Policy*, vol. 156, pp. 112387, September 2021.

¹¹⁶ 'Press Release on Proposed new F-Gas Regulation: EU risks undermining its own climate and energy security goals', European Heat Pump Association, 5 August 2022.

¹¹⁷ 'Dynamic modelling of ice-based thermal energy storage for cooling applications', H. Bastida, et al., *IET Energy Systems Integration*, vol. 4, no. 3, pp. 317–34, September 2022.

may have a high energy density. PCM units can also be used within cold chains, such as in shipping containers, to reduce reliance on fuel or electricity (see footnote 94).

System integration and district networks

Energy networks have been traditionally decoupled for operation and planning, with their design and implementation being independent, due to regulatory and market arrangements. However, interactions among networks have always existed. In an integrated energy system, different energy vectors are connected through distributed coupling technologies. For example, when using active technologies, a cooling system is coupled with the electricity grid. Similarly, a reversible HP is a coupling technology transforming electricity into cooling energy. Analysing and operating energy networks with a holistic approach may help balancing energy supply and demand efficiently and economically, as sharing energy among networks can enable a flexible operation. For instance, the cooling vector can facilitate demand-side response: large AC or refrigeration users may receive financial incentives from electricity system operators to turn down their systems during periods of peak electricity demand without compromising food safety or thermal comfort (see footnote 94).

Adoption of district thermal networks will also contribute towards achieving carbon neutrality. These networks use infrastructure interconnecting dwellings, buildings, or facilities within a city, district, or neighbourhood to supply thermal energy.¹¹⁸ District heating has been supported in Europe since the Renewable Energy Directive and the Energy Efficiency Plan. Notably, Nordic countries have made substantial progress with heating and cooling networks. In the UK, only 2 per cent of heat demand in buildings is met through district heating,¹¹⁹ although it could deliver up to 20 per cent of the demand by 2050.¹²⁰ Moreover, the Clean Growth Strategy requires meeting 17 per cent of heat demand in households and 24 per cent in industrial buildings with heating networks to meet net-zero targets (see footnote 92). Compared to successful cooling networks in the Middle East, Malaysia, Canada, and other European countries, these are still emerging in the UK. Projects integrating district heating with district cooling networks and renewables into a single network are already under operation (see footnote 118). Given their immense decarbonization potential, important lessons can be learned.

Conclusions

There is no silver bullet to address the cooling challenge in a warming world. It is thus critical to raise awareness as it has been a 'blind spot' and an often-overlooked issue when discussing decarbonization of energy. It is necessary to stimulate discussion involving key stakeholders from the energy sector, government, academia, housing developers, and individual consumers to support future energy policy decision-making around cooling and buildings.

It is timely to investigate how cooling may develop and to understand how cooling and energy storage technologies, and their relationship with heat decarbonization, can support integrated, socially acceptable, cost-effective, and sustainable energy system change. Integrating cooling, storage, and wider approaches to building decarbonization, will involve understanding future cooling demand to strategically inform infrastructure investments. Progress has been limited, and a potential demand increase due to changes in lifestyle could further complicate or slow building decarbonization.

It will be necessary to reinforce the electrical power system to cope with the additional demand, with the possibility of utilizing the flexibility provided from a coordinated operation of heating, cooling, gas, electricity, and perhaps hydrogen networks to maximize infrastructure use while minimizing operation costs – alongside weighing carbon neutrality targets. Anticipating and then successfully integrating cooling loads and low-carbon cooling solutions smoothly, while complex, could have benefits from a cost and consumer perspective, while relieving pressure on electricity networks. Nevertheless, significant investments in the modernization, digitalization, and automation of cooling infrastructure and buildings are needed to ensure a safe, efficient, reliable, and sustainable energy system.

¹¹⁸ 'District heating and cooling systems', I. De la Cruz and C.E. Ugalde-Loo, in: N. Jenkins (Ed.), *Microgrids and Local Energy Systems*, pp. 91–126, IntechOpen, London, UK, December 2021.

¹¹⁹ 'Opportunity areas for district heating networks in the UK. National Comprehensive Assessment of the potential for efficient heating and cooling', Department for Business, Energy & Industrial Strategy, September 2021.

¹²⁰ 'Heat networks', *POSTnote* 632. The Parliamentary Office of Science and Technology, September 2020.

EUROPEAN NETWORK DEVELOPMENT PLANNING FOR INTEGRATED ENERGY SYSTEMS

Christine Brandstätt

Network planning is central to a future-proof energy system which is viable within the framework of the European Green Deal and suitable for energy systems integration. The new TEN-E regulation¹²¹ underlines this for European energy networks. The planning of cross-border network infrastructure in the European Union is carried out biannually by the European networks of transmission system operators (ENTSOs) for gas and electricity via their Ten-Year Network Development Plan (TYNDP).¹²² The objectives of this process comprise:

- streamlining the planning of network interconnections in Europe,
- assessing planned projects,
- pointing out remaining infrastructure gaps as per the current planning.

While initially, the challenge was to harmonize independent national planning processes, the focus has since shifted towards coordination between the electricity and gas sector, and between transmission and distribution networks. Figure 1 depicts the analytical steps of the TYNDP, namely scenario building, identification of system needs and infrastructure gaps, and cost–benefit analysis. This provides the basis for the subsequent selection of projects of common interest (PCIs). Based on their pan-European relevance, these projects are eligible for additional support as well as funding via the Connecting Europe Facility.

Figure 1: TYNDP process and PCI selection according to TEN-E



Source: adapted from ENTSO-E¹²³.

The planning starts with the development of a set of typically three scenarios and their respective storylines:

- National Trends focuses on the myopic realization of current national plans and trends.

Two further scenarios relate to alternative longer-term futures, namely:

- Distributed Generation – a distributed and local energy supply.
- Global Ambition – a rather centralized and intra-regional energy system.

The scenarios comprise data and assumptions regarding the future demands for different energy carriers (such as electricity, methane, hydrogen, and liquid fuels) along with domestic resources and import potentials. Other inputs into the scenario modelling include projections of energy prices and the current and reliably planned infrastructure levels for electricity and gas grids, as well as generation and storage capacity. As the first step towards integrated energy system planning, the scenarios and assumptions for the development of electricity and gas grids have been streamlined since 2018.

¹²¹ Regulation EC 2022/869 on guidelines for trans-European energy infrastructure.

¹²² Regulations EC 714/2009 and EC 715/2009 tasked the ENTSOs with the community-wide planning of 'viable electricity transmission networks and necessary regional interconnections, relevant from a commercial or security of supply point of view' in connection with generation and supply adequacy outlook. Regulation EU347/2013 (TEN-E) links the TYNDP to the selection of Projects of Common Interest (PCIs) and establishes oversight of the process by the Agency for the Cooperation of Energy Regulators (ACER) and the European Commission.

¹²³ ENTSO-E (2021) Completing the map – Power system needs in 2030 and 2040 (p. 70)

The actual identification of infrastructure gaps occurs via a number of soft-linked tools and models to replicate the energy system, at the core of which are a market and a network simulation.¹²⁴ Both feed into the evaluation of individual incrementally planned projects in a cost–benefit analysis. The benefit indicators for this are determined by the ENTSOs in line with criteria set out in the TEN-E regulation, such as sustainability, market integration, security and quality of supply, as well as smart sector integration.

Stakeholder participation in the TYNDP process is focused mostly on the development of storylines and scenarios. The ENTSOs hold a sequence of webinars with interested and concerned parties, such as companies with commercial interests and non-governmental organizations.¹²⁵ The process results in several versions of a scenario report and guidelines, along with spreadsheet data and a visualization platform. After the publication of an initial draft, stakeholders can submit written feedback, to which the ENTSOs reply and which they consider for subsequent versions.

Current challenges: uncertainty and coordination

Developing infrastructure with a lifespan of several decades within a dynamically evolving energy system is inherently challenging. As a consequence of the energy transition, and more recently also due to the current geopolitical situation, network planning is faced with increasing uncertainties.

One significant challenge originates in the development of hydrogen infrastructures. The energy strategy of the European Union, in line with many of its member states, envisions a considerable shift of conventional energy supply towards hydrogen-based fuels within the next decade, envisioning 40 GW electrolyser capacity and 10 million tonnes of renewable hydrogen by 2030.¹²⁶ The REPowerEU plan has since increased this ambition, including the addition of considerable imports. Consequently, the need for new infrastructure to generate and transport hydrogen emerges.

Hydrogen grids can originate on the one hand from repurposed natural gas infrastructure. In that case, they are likely owned and operated by the existing gas network operators. A framework for this, within or in parallel to their regulated business of transporting natural gas (and biomethane), is largely still missing. Alternatively, some local hydrogen networks for dedicated customers already exist and may continue to evolve outside the regulated realm of natural gas infrastructure. Discussions of the regulation of hydrogen infrastructure at a later, more developed stage of the sector, are led openly among the concerned stakeholders.¹²⁷ Thus, from the current planning perspective, part of the projected infrastructure need for natural gas (and biomethane) might manifest as a need for hydrogen infrastructure (and vice versa). Figure 2 presents a vision for a future hydrogen grid based on repurposed and new pipelines.

The emerging hydrogen infrastructure also affects the planning of electricity grids. A projected need for hydrogen (or its derivatives) can be satisfied in principle by transporting electricity and subsequent conversion into hydrogen. Alternatively, electricity can be converted to hydrogen at the source or before a bottleneck, with the energy subsequently transported in the form of hydrogen. Rather like part of the current development of hydrogen grids, the siting of electrolyzers occurs outside the regulated realm, by commercial and competitive actors. It is therefore largely independent of the regulated network planning. Yet, depending on the location of electrolyzers, network planning will, on a particular route, handle a need for electricity, or alternatively a hydrogen grid. If the electrolysis occurs close to the renewable energy source, hydrogen needs to be transported to the demand location; if, instead, electrolysis occurs close to the energy demand, there is a need to transmit electricity to the electrolyser.

Another considerable impact on network planning emerges from flexibility at the distribution level. New actors both on the generation and demand sides are increasingly able and willing to adapt their feed-in or withdrawal in coordination with the larger system. Many of these actors are small and decentral actors, such as electric vehicles, district heating systems, and biogas plants, and are located at the distribution level. Nonetheless, their operation may influence the infrastructure needed for energy transmission, potentially also across borders.

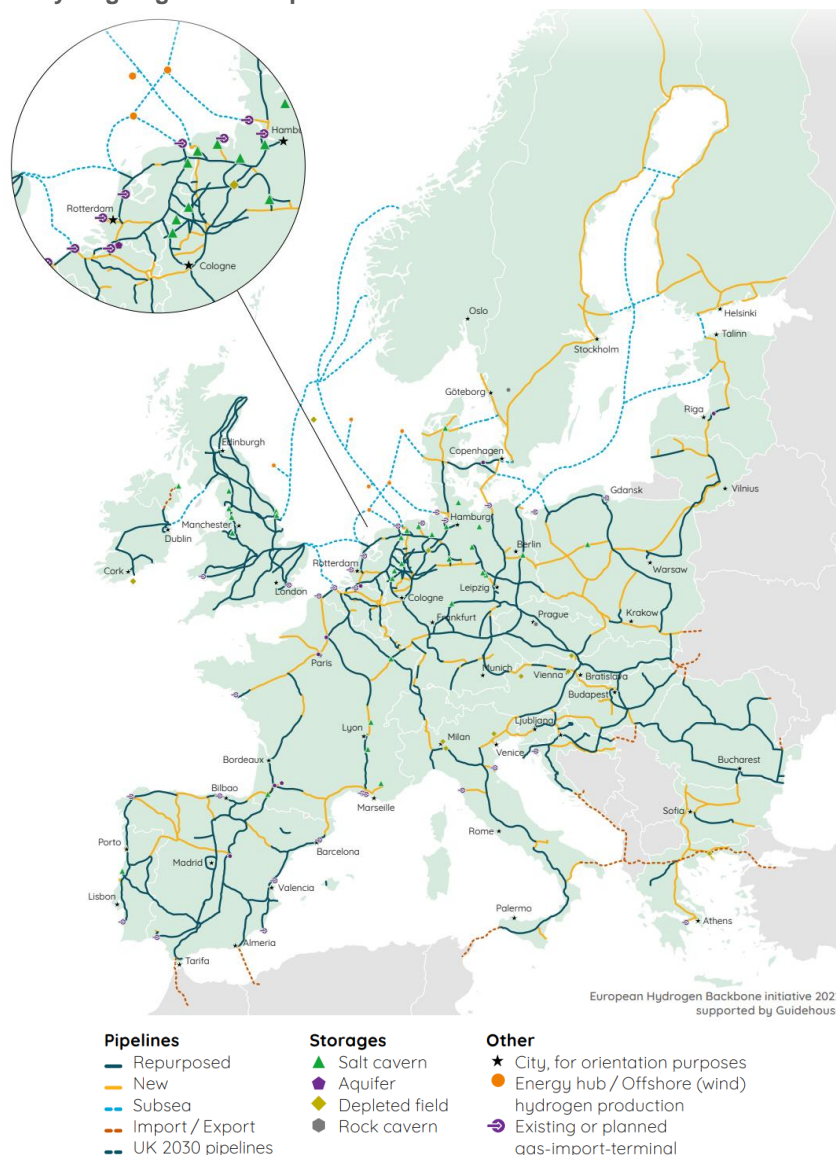
¹²⁴ The demand balance, for example, is built fundamentally using the ‘Ambition Tool’; this output serves as an input to the ‘Trapunta Tool’ producing hourly profiles. Both tools are not openly available.

¹²⁵ As opposed to earlier years, the most recent scenario-building exercise largely limited the role of stakeholders to commenting on preliminary scenario data produced by the ENTSOs.

¹²⁶ EC Communication 2020/301 on ‘A Hydrogen Strategy for a Climate-Neutral Europe’.

¹²⁷ See for example Kantor & ACER (2021): Possible Regulation of Hydrogen Networks.

Figure 2: Possible future hydrogen grid in Europe



Source: From European Hydrogen Backbone & Guidehouse¹²⁸.

For the longest time energy, and particularly electricity demand, has been deemed largely inelastic. Gradually, the commercialization of medium-scale batteries, together with the electrification of energy sectors where storability is less demanding, are changing this paradigm. Local aggregation of supply and demand in less centralized structures additionally provides for locally balanced or responsive grid uses. The possibility of active congestion management can reduce the need for network investments both at the distribution and transmission level, and across borders. Management or control of these demand flexibilities and distributed generators lies often with the distribution grid operator or dedicated aggregators. Thus, when trading off the use of flexibility against conventional network development, the incentives of actors accessing the flexibility are not necessarily aligned with the optimization of cross-border grid infrastructure.

The frameworks for such management of distributed supply and demand are currently evolving. Network operators contract capacities in dedicated local markets as long- or short-term flexibility, or alternatively offer price signals and rebates for controllable access. In some jurisdictions and under certain circumstances, mostly for the sake of grid stability, they can also have the freedom to curtail network users with or without compensation. The multitude of possible and sometimes parallel frameworks, the lack of longer-term experience with them, and the sometimes-voluntary nature of the response cause considerable uncertainty for current network development planning.

¹²⁸ European Hydrogen Backbone & Guidehouse (2022): A European Hydrogen Infrastructure Vision Covering 28 Countries.

Ways forward: towards an inclusive and open process

In sum, the most pressing challenges revolve around:

1. Handling the uncertainty in some of the decisive factors for infrastructure needs – such as volume and location of electrolysis and demand flexibility.
2. Coordination with a growing and diverse subset of stakeholders.

The intuitive way forward, therefore, consists of increased transparency and agility in the planning process. The recast of the TEN-E regulation underlines the focus on coordination with other infrastructures, formalizes cooperation with a number of stakeholders, and introduces oversight by the European regulator, ACER, and the European Commission.

The new TEN-E covers five different infrastructure categories, namely electricity grids, smart gas grids, hydrogen grids, electrolyzers, CO₂ networks. These lie only partially within the realm of traditionally regulated network operation, but will follow similar criteria for assessment and planning processes. As a consequence, the group of stakeholders and users for the scenarios and guidelines developed for the TYNDPs is growing. Despite the enormous time pressure, the role of stakeholders will ideally evolve from merely (dis-)approving of the ENTSOs' proposals, to early involvement in designing the storylines and setting the decision scope covered by the scenarios. The intertwined nature of energy supply in a net-zero future may eventually even elevate this process from stakeholder involvement more towards collective system planning.

Furthermore, the TYNDP process will likely see a further integration of network planning between gas and electricity. The cooperation required to plan a highly coupled energy system goes well beyond common scenarios. So far, scenario demands have included some simplified flexibilities as part of the time series and have considered alternative infrastructures only if submitted by project promoters for assessment. To effectively assess planned network projects and identify infrastructure gaps, the substitution potential and complementarities between infrastructures, together with the interactions with developments outside the regulated networks, need to be an integral part of the optimization.

In addition, the benefit indicators for the assessment of submitted projects will likely evolve in light of the new TEN-E. The assessment of additional flexibility,¹²⁹ for example, is currently qualitative and based on self-reported calculations of balancing cost savings due to the project. This is set to evolve in order to cover flexibility in the spirit of TEN-E and the Commission's Energy Efficiency First guidelines.¹³⁰ Other aspects of the new TEN-E regulation, such as cybersecurity and competition, still need to be introduced into the methodology.

Openness and transparency are at the heart of involving new stakeholders and streamlining the processes between the different infrastructures. This concerns the inputs and assumptions for the process as well as the tools and models used. This need for transparency and openness is, however, not limited to scenario building, to generate conclusive energy demand scenarios and translate these demands into profiles. It also relates to the further processing of these energy needs into infrastructure needs and the benefit assessment.¹³¹

Consequently, openness and stakeholder involvement make the planning process inclusive and more agile. Some stakeholders are interested in more varied scenarios and in exploring a larger decision space. In an open and inclusive process, they can advocate for this at the beginning of the network planning exercise. If their requirements are not eligible for consensus, they can even pursue their analysis individually in parallel to the official process. Such additional inputs can improve the quality of political decisions given the immense uncertainties discussed above. It may also speed up the process of adjusting to new realities – as was necessary with the Covid19 pandemic, or in view of the REPowerEU package – and add to the robustness of the assessment.

Lastly, empowering stakeholders to do their own analysis can source methodological advances and validate existing analyses and conclusions. Thus, the necessary developments for planning integrated energy networks will likely also boost acceptance and resilience of networks.

¹²⁹ This corresponds to the benefit indicator B7 in the TYNDP methodology.

¹³⁰ [European Commission \(2021\): Guidelines and examples for the implementation of EE1st in decision-making in the energy sector and beyond.](#)

¹³¹ The process currently relies largely on grey box models and tools, which are documented to some extent, but are not fully transparent or readily available to stakeholders. Partially, the process even utilizes black box tools which are exclusively available to the ENTSOs and are described only rudimentarily in the TYNDP documentation.

NETWORK BUSINESS MODELS IN EVOLVING RATE ENVIRONMENTS: WHO DARES WINS?

Farhad Billimoria and Paul Simshauser

Abstract

Electricity utility business models are typically bookended by regulated monopoly providers of network services on one end, and merchant competitive utilities on the other. An analysis of earnings and dividend policy for Australia's listed electricity utilities reveals interesting insights against the backdrop of the falling interest rate environment which characterized the 2010s. First, that for regulated utilities, the lifecycle theory of dividend policy applies, making such utilities a proxy for the fixed income asset class; and second, for merchant utilities the pattern of dividends and earnings are consistent with information content theory, with dividends signalling future firm prospects. Going forward, and in the context of rising inflation and interest rates, together with turmoil in global energy markets, new risks present for both regulated and merchant business models. While this environment will affect each business model differently, we argue that important common factors such as leverage, business responsiveness, operational flexibility, and regulatory/sovereign risk are likely to drive near-term opportunity and business economic resilience.

Introduction

Multiple factors – including the war in Ukraine, together with ongoing supply chain and logistical constraints combined with the impact of multiple pandemic stimulus packages – have pushed inflation to levels not observed in recent history, and are projected to go higher in many economies. This has necessitated a tightening of global monetary policy, with the US Federal Reserve recently announcing a 75 basis point increase to rates, and other central banks following in the same vein. Global energy commodities have been a key source of inflationary pressure. This has been driven by short-term threats to energy supply and security, with risks felt most acutely in gas markets (and its transmission to electricity markets through gas-fired power generation), and being particularly pronounced in Europe, against the prospect of threats to permanent disruption of gas supply from Russia. Electricity prices in many major economies have been pushed to record levels, with futures data expecting that some markets may not return to normalcy until beyond 2025+.

From an investment perspective, in Australia, energy networks have traditionally been thought of as being inflation resistant and substantially less susceptible to market volatility (Simshauser, 2022).¹³² This has driven significant financial investment into the sector, especially by infrastructure funds, pensions, and other investors seeking lower-risk stable returns.

Today's market conditions and financial environment are likely to provide an apposite test of this thesis. While potentially a global issue, we look to examine this in the context of utility market data from Australia.

Electricity utility business models tend to fall into two main categories – economically regulated monopolies and merchant competitive utilities. In this piece we investigate the potential risks and opportunities facing electricity utility models in an inflationary and hawkish interest rate policy environment. We review the insights from assessing the dividend policy of merchant and regulated publicly listed electricity utilities in Australia. Australian energy markets have experienced similar shocks to gas and electricity prices from the global environment, with average electricity and gas prices climbing by over 200 per cent and 340 per cent respectively over the first half of 2022, compared with the previous half year. The energy-only market design for the National Electricity Market, which is the market in which the analysed utilities participate, allows a degree of confidence that spot price dynamics flow into business outcomes without potential revenue distortions introduced by administrative capacity mechanisms. Sovereign risk is also considered relatively low (with a AAA credit rating) in Australia, which allows for a focus on industry risk outcomes. Our analysis suggests that while the fundamental headwinds facing the two business models will be different, common factors such as leverage, sovereign risk, and operational flexibility could differentiate the investment prospects of different firms.

Regulated network and merchant utility business models

The electricity sector in a variety of economies went through a wave of economic liberalization in the late 1980s and early 1990s (Newbery, 2005).¹³³ This involved the separation and segregation of what were previously vertically integrated suppliers into

¹³² Simshauser, P., (2022), 'On dividends and market valuations of Australia's listed electricity utilities: regulated vs. merchant', Working Paper 71).

¹³³ Newbery, D. M (2005), 'Electricity liberalisation in Britain : The quest for a satisfactory wholesale market design', *The Energy Journal*, 26(2005), pp. 43–70).

three sub-segments of generation, transmission & distribution, and retailing. Electricity generation, and in certain markets retail, was uncoupled from networks, and competition was introduced in markets such as the UK, Australia, New Zealand, and parts of the US. Transmission and distribution were segregated and operate as regulated monopolies. For Australia, in the aftermath of the introduction of full retail contestability in particular, 14 out of 15 distribution networks divested their retail supply divisions (Simshauser, 2022). Other markets, including many states in the US, continue to maintain integration of retail and network operations.

The development of new transmission corridors and lines (particularly point-to-point lines) drove the development of merchant network business models, involving the transmission owner bearing commodity, volumetric, contracting, and operating risks relating to the network, in addition to development and construction risk, as relevant (Joskow, 2021);¹³⁴ (Joskow, P. & Tirole, J., 2005).¹³⁵ Hybrid or capped risk models have also developed over time, particularly in the context of new UK interconnectors – which involve a cap-and-floor business model which limits the exposure of the asset to electricity price spreads (Hogan, W., Lindovska, M., Mann, H., and Pope, S., 2018).¹³⁶

Learnings from earnings & dividend policy

In order to understand the potential exposures of regulated and merchant business models, it is instructive to consider the insights gleaned from an analysis of earnings and dividend policies of publicly listed utilities.¹³⁷ Dividend policy is a critical focus of boards and management, and while a uniform theory of dividend policy remains challenging, two bodies of work in dividend theory appear of particular relevance in a utility context – information content theory and lifecycle theory. The information content theory posits that dividend policy provides significant information content about future earnings given the shareholder–agent information asymmetry in public markets. Three core implications of unanticipated changes in dividend policy are: directional changes in share prices, market expectations of future earnings, and actual future profits (Grullon, G. and Michaely, R., 2004).¹³⁸ The hypothesis of lifecycle theory is that firms with assets in mature stages of their life cycle are likely to generate cash well in excess of investment opportunity and are consequently likely to have high and more stable dividend payouts (DeAngelo, H., DeAngelo, L., and Stulz, R. M., 2006).¹³⁹

Simshauser (2022) presents a timely examination of the dividend policy of publicly listed merchant and regulated utilities in Australia's National Electricity Market (NEM). The study considers financial data over a period of 14 years from three (out of four) publicly listed utilities:

- Spark Infrastructure (SKI) and Ausnet Services (AST) – both regulated transmission and distribution networks.
- AGL Energy (AGL) – a merchant energy utility with integrated generation and retail operations (in other words, a classic gen-tailer business).

Insights of the comparative analysis are instructive in informing the nature of risk faced by companies within the same industry but with very different business models.

The results of the analysis from Simshauser (2022) of earnings, returns, and dividend policy for merchant utilities, appear consistent with information content theory. Any dividend raise is followed by flat to modest increases in earnings, while a cut is followed by sharp declines in profits (see Table 1). This result also holds for assets returns, with symmetrical returns following dividend increases, and corresponding declines following dividend decreases (Table). This aligns with a business model with direct symmetrical profit exposure to commodity forward curves.

¹³⁴ Joskow, P. L., (2021), 'Facilitating transmission expansion to support efficient decarbonization of the electricity sector', MIT Center for Energy and Environmental Policy Research.

¹³⁵ Joskow, P. & Tirole, J., (2005), 'Merchant transmission investment', *The Journal of Industrial Economics*, 53(2), 233–64).

¹³⁶ Hogan, W., Lindovska, M., Mann, H., and Pope, S., (2018), 'Embracing Merchant Transmission Investment', FTI Consulting Report.

¹³⁷ In particular, the study considers data from two regulated utilities: Spark Infrastructure and Ausnet, and one merchant utility AGL Energy.

¹³⁸ Grullon, G. and Michaely, R. (2004), 'The Information Content of Share Repurchase Programs', *Journal of Finance*, 59(2), pp. 651–80.

¹³⁹ DeAngelo, H., DeAngelo, L., and Stulz, R. M., (2006), 'Dividend policy and the earned/contributed capital mix: a test of the life-cycle theory', *Journal of Financial Economics*, 81(2), pp. 227–54.

Table 1: Changes in dividends and net profits after tax (NPAT)

Dividend Raise	Dividend Chg t	NPAT t+1	NPAT t+2
Regulated Utilities	9%	-4%	-10%
AGL Energy / Merchant	12%	0%	1%
Dividend Cut	Dividend Chg t	NPAT t+1	NPAT t+2
Regulated Utilities	-14%	7%	4%
AGL Energy / Merchant	-26%	-14%	-42%

Source: Simshauser (2022).

The references to t+x represent an annual delay of x years to the dividend data as part of the information content analysis.

Table 1: Changes in dividends and return on assets (ROA)

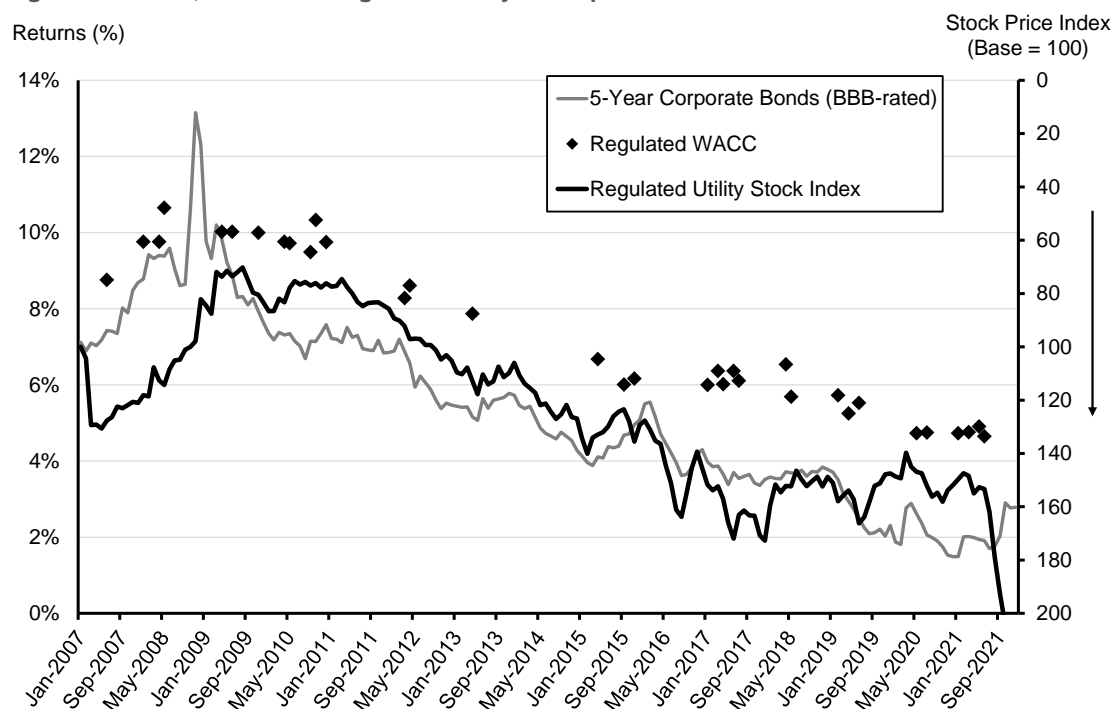
Dividend Raise	Dividend Chg t	RoA t+1	RoA t+2
Regulated Utilities	9%	6.8%	6.6%
YoY Chg		-0.3%	-0.2%
AGL Energy / Merchant	12%	10.6%	10.7%
YoY Chg		0.4%	0.2%
Dividend Cut	Dividend Chg t	RoA t+1	RoA t+2
Regulated Utilities	-14%	7.1%	7.3%
YoY Chg		-0.3%	0.2%
AGL Energy / Merchant	-26%	8.9%	6.5%
YoY Chg		-1.1%	-2.4%

Source: Simshauser (2022).

By contrast, earnings, returns, and dividend policy for regulated utilities appears to be aligned with lifecycle theory. When regulated utilities raise dividends, profits fall in years t+1 and t+2 by 4 per cent and 10 per cent, respectively (Table 1). Conversely, when they cut dividends, profits rebound in years t+1 and t+2 by +7 per cent and +4 per cent, respectively. Similarly returns on assets moderate when utility dividends are raised, and rise in the aftermath of dividend cuts. The converse relationship can be explained by business exposure to falling weighted average costs of capital (WACC) resulting in higher free cash flow to the firm and harvested into dividends, though with more muted future prospects in such an environment.

Over a longer term this has explained the notion of regulated utilities being viewed as ‘bond proxies’ – as investors search for higher yielding assets against the backdrop of a systematically declining interest rate environment (see Figure 1). Merchant utilities do not tend to reflect this view, and as discussed above are more consistent with information content theory.

The application of information content theory to dividends and gearing levels appears to support the notion that there are certain common factor risks between both business models. While both groups of businesses appear to target an investment grade (BBB) credit rating, the absolute level of gearing across the business models is at variance with average gearing of ~64 per cent for regulated utilities and ~30 per cent for merchant utilities. Nevertheless, changes to gearing as dividends change appears directionally consistent between both regulated and merchant businesses, with increased dividends portending a leveraging cycle up to long run averages, and decreased dividends pointing to deleveraging. This point is particularly important as leverage and capital structure provides one form of indication of the level of financial cushion a firm has to weather challenging conditions. By definition, a firm with higher debt financing has limited capacity to weather cash flow degradation before suffering financial stress, or worse distress, given the impacts of debt service and financial covenants on operating flexibility. Below we also examine other common factor risks that may impact firms in a shifting rate environment.

Figure 1: Regulated WACC, bonds and regulated utility stock prices

Source: Simshauser (2022).

Overall analysis of earnings and dividend policy provides important insights as to directional links between cash flow distribution policies and underlying profitability. Merchant utility dividends appear supportive of information content theory, while regulated utilities support life cycle theory. However, this analysis comes with the strong caveat – that the data is collected from a period of historical loosening of monetary policy and in the absence of strong inflationary pressure. We also note that the sample size is limited, particularly given the raft of public-to-private transactions occurring in the industry. Hence while we extend the analysis in what follows to an environment of inflation and rising interest rates, we can only surmise what the underlying relationships are in such a situation. Fundamental support for the thesis and precepts presumed here can only be verified with larger datasets of such environments that could arise with passage of time. However, the prospects of directly extending the previous analysis appear closed, with the public-to-private takeovers of both regulated utilities in the dataset in 2021.

Headwinds and opportunities in the face of rising inflation and rates

The specific factor risks that arise from rising inflation and interest rates will emerge for each of the merchant and regulated utility subsectors in different guises, given the fundamental economic differences between the two business models.

The putative resilience of regulated utilities to inflation arises from the notion that economic regulators will naturally adjust the costs of capital and of operating and capital cost allowances to reflect the prevailing economic environment. This aligns with the insights from dividend policy that regulated utilities have been viewed as a form of bond proxy. However a large body of research points to the potential for regulatory lag and delay in adjusting such rates, especially where such adjustments result in higher cost imposts on the consumer. The stability of regulatory regimes and sensitivity to political risks is also relevant in understanding to what extent, and how quickly, this passes through. On this basis, headline risks could diverge between markets such as Australia and the UK which adopt a ‘formulaic’ building block approach in periodic regulatory determinations, and others which adopt broader ‘public interest’ tests (Simshauser, 2022). More granular factors that can impact all regimes include inflation passthroughs to operating costs, performance incentives and penalties, and (for utilities that retain a form of retail exposure) the timeliness and extent of commodity price passthrough.

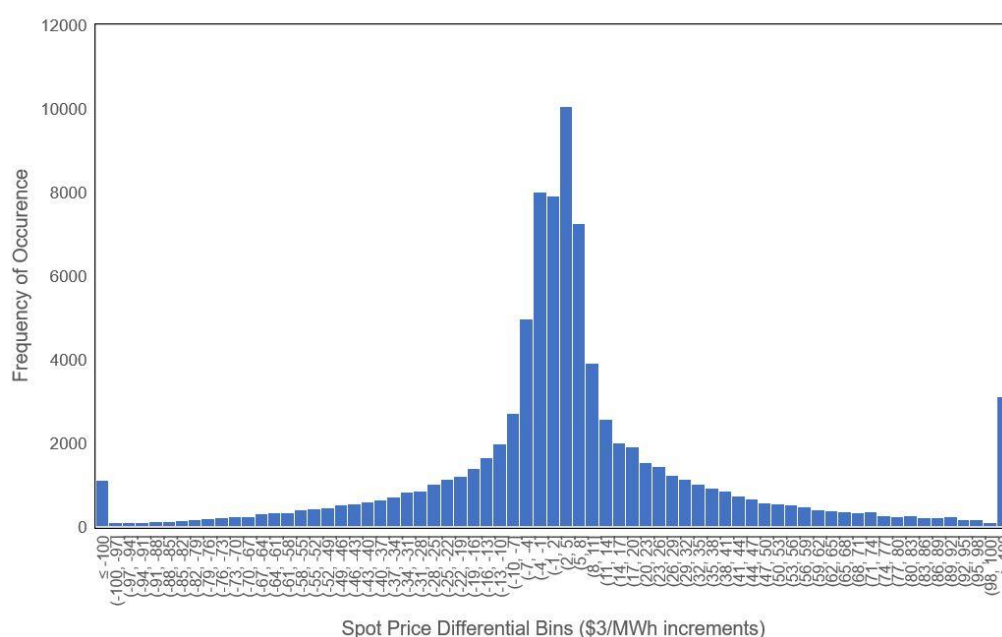
Crucially for many regulated utilities, a strong imperative for network augmentation has emerged to support higher levels of decentralized energy resources and utility-scale renewable energy deployment. At scale, this will unwind any notion of regulated utility earnings and dividend policies fitting neatly with a lifecycle theory. It will also test the nerve of economic regulators and the stability of regulatory regimes to support such capital cost deployment in the face of cost-of-living pressures to consumers.

The dividend policy analysis points to the relevance of commodity prices for merchant businesses, in general, across the spectrum of spot and forward curve exposure. The business of merchant networks is further nuanced – being exposed not to

absolute commodity scarcity, but in relative locational scarcity differentials between and within the regions of network connection.

An interesting case in point is the only unregulated (merchant) transmission line in the NEM – Basslink, that connects the regions of Victoria and Tasmania. The potential for scarcity differentials persists given the different supply characteristics of the regions, with Tasmania (primarily a hydro-renewable island with limited thermal) and Victoria (with a more diverse supply mix, and connections to two other regions). The historical distribution of price differentials between the regions suggests a slight negative skewing of spreads (see Figure). The other challenge relates to the absence of an exchange forward market for financial transmission rights between the two regions, pointing to limited hedgeability of risk, which exacerbates cashflow sensitivity. Notably Basslink has been in receivership since 2021. Merchant transmission assets in the UK have adopted a regime that incorporates cap–floor arrangements which limit potential gain, but also risk (Hogan et al., 2018).

Figure 2: Histogram of VIC–TAS spot price differentials (\$/MWh) – FY 2017–22



Common factor risks

While there are a range of sector-specific risks that impact regulatory and merchant businesses separately, the earnings and dividend policy analysis also points to common factor risks that can affect both models.

Most relevantly, the impact of leverage, which has directional consistency in the link to earnings stability and dividend policy, affects both businesses similarly. Leverage magnifies volatility and risk and reduces the available cushion for equity investors, and also more broadly for the firm given the constraints on financial flexibility imposed by debt service and financial covenants under stress (Vague, R., 2019).¹⁴⁰ The degree of financial cushion is a prime determinant of a firm's capability to weather extreme outcomes and unanticipated risks. Both merchant and regulatory utilities will be similarly affected by the degree of aggressiveness of capital structure policy adopted during the 'good times'. This is also influenced by the nature of ownership. While public ownership tends to impose explicit or implicit guidelines on leverage and capital structure, private owners can adopt atypical financial structures. Relevant for utilities under such ownership is the practice of imposing 'double leverage' – a layer of leverage which is observable to regulators and the market, and an incremental layer that is held by holding companies in the capital structure (Chen, J. M., 2018).¹⁴¹ In a similar working space, a recent analytical survey of capital structures in Australian renewable finance suggests a potential mismatch between leverage and required equity returns in project finance transactions (Gohdes, N. and Simshauser, P., 2022).¹⁴² The re-financing periodicity is also important vis-à-vis firms that have locked in long-term finance at lower rates relative to those that face refinancing exposure during market correction.

¹⁴⁰ Vague, R., (2019), *A brief history of doom: Two hundred years of financial crises*, University of Pennsylvania Press.

¹⁴¹ Chen, J. M., (2018), 'Speculative Undertakings: Rate Regulation as a Branch of Corporate Finance', *Yale Journal on Regulation*, 35, 779.

¹⁴² Gohdes, N. and Simshauser, P., (2022), 'Renewable entry costs, project finance and the role of revenue quality in Australia's National Electricity Market', Cambridge Working Papers in Economics 2206, Faculty of Economics, University of Cambridge.



Operational frameworks are another important element – with factors such as the tenor and terms of contracts, and operating and capital expenditure planning – impacting the flexibility and capability of the business to respond to shocks and changing business environments. Here the dividend clientele theory also has relevance with firms that have established ‘dividend clients’ with certain payout expectations which impose potential constraints on capabilities to effectively adapt business strategy and to restructure operations.



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