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Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2019

Gas Wholesale Markets Volume

September 2020



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Executive Summary

MMR relevance in an energy markets' shifting context

- 1 **This monitoring report covering 2019 is published against the backdrop of an unprecedented and ongoing health crisis with important repercussions for the EU energy sector.** Economic lockdowns associated with the crisis have resulted in severe reductions of energy consumption throughout the EU¹. In the case of gas, EU demand fell by 8% YoY up to May 2020. Since the beginning of the summer, demand destruction has been easing but has not reached pre-lockdown levels.
- 2 **These exceptional circumstances coincide with a possible reconsideration of elements of the gas market regulatory framework,** in view of the sharp uptake in decarbonised gasses and the looked for enhancement of the integration of energy sectors, all while ensuring the ongoing functioning and further establishment of a competitive and integrated Internal Gas Market (IGM).
- 3 **Policy makers are scrutinising the necessary policies under the so-called Green Deal strategy², including possible financial support that should contribute to achieving climate goals³.** This support will be framed throughout areas such as the expansion of renewable power generation, clean hydrogen production, energy-saving building renovations and sustainable mobility. MSs National Recovery Plans to overcome the COVID-19 crisis shall also significantly back-up climate investments.
- 4 **In this respect, the relevance of a thorough market monitoring exercise becomes even more crucial.** An exhaustive monitoring activity allows the assessment of functioning of the energy markets as well as a better understanding of the impact of regulatory policies, such as gas Network Codes, backing the roll-out of the IGM. Overall, monitoring helps EU decision-makers to identify pending market barriers and outline EU energy markets' design venues of progression.
- 5 **The key findings of this MMR 2019 are enumerated below and elaborated further in depth in this Volume.** They attest that even within a gas market scenario that registered important shifts during 2019, which turned critical in the spring of 2020, the EU's IGM ambition has continued to progress in various dimensions; market integration is already quite effective in areas covering three-quarters of EU gas consumption, and importantly, is advancing across several other jurisdictions.

Internal Gas Market

- 6 **In 2019, the supply of gas to EU markets underwent a substantial shift,** impacting prices, hub liquidity and other key metrics, some of which moved into levels not seen before:
 - a) **LNG imports rose 90% YoY** with LNG accounting for 20% of EU natural gas demand – by far its highest aggregated market share to date. Global surplus LNG supply⁴ found a market of last resort in Europe, attracted by ample regasification and storage capacity and gas hub's rising liquidity.
 - b) **EU hub prices dropped to ten-year lows,** with record LNG deliveries together with robust pipeline imports and high underground storage stocks creating a low-pricing environment.
 - c) **Record volumes of gas were injected into underground storage sites,** a trend that has accelerated in 2020, driven by continuous LNG arrivals and lower energy demand triggered by the economic slowdown caused by COVID-19.

1 The IEA maintains a thorough analytical review of COVID-19 impacts on global energy markets.

2 See EC's Green Deal Roadmap presented in December 2019.

3 At least 30% of the EUs 2021–2027 budget, as well as the new Recovery Fund, have been earmarked to support future climate action.

4 Originated from the slowdown of demand in the Asia-Pacific region concurring with increasing global LNG production across the year.

- d) **The volume of natural gas traded at hubs was at an all-time high**, with 20% more volume changing hands YoY. Market participants continuously readjusted their positions due to price movements related to changing supply balance and higher price volatility.
- e) **The EU became more dependent on gas imports** as domestic gas production continued to decline (-8% YoY and -30% compared with 2014).
- 7 **The COVID-19 crisis has further contributed to some of these trends**, with EU hub prices plummeting to new record lows⁵ as gas demand has fallen severely, and hub trading activity rising, pushed by extra hedging needs (+20% YoY, from January to June 2020).
- 8 **Simultaneously, as referred, the future of the EU gas sector is being discussed by policy makers**, with the aim of identifying the best ways it can contribute to Europe's decarbonisation targets as well as underwrite a more efficient integration with the other energy sectors.
- a) Today, carbon neutral gasses account for a minor share of EU gas consumption (around 4%, mainly biogas which is not injected into the gas grid) while the objective is **to fully decarbonise the gas sector by 2050**.
- b) The **price competitiveness of different technologies**, together with the cost of upgrading the grid⁶, **will be very important in determining the future reach** of the various options. Hydrogen has become central in many strategies⁷.
- c) It is imperative to ensure that **sustainability is sufficiently taken into account** for any new gas infrastructure project.
- d) In order to achieve the lowest-cost solutions, **new developments shall be backed by competitive markets wherever possible**, although supportive measures may be foreseeable, which may bring some trade-offs with competition.
- 9 In this last regard, **the European Green Deal represents an ambitious framework for investments in low carbon technologies**, providing support for innovation and scaling-up of relevant technologies. The plan is expected to mobilise economic resources on a large-scale with the ambition of obtaining the triple benefits of stimulating economic growth, job creation and decisively contributing in the fight against climate change⁸.
- a) **Up to 10 billion euros** – involving co-financing – **is expected to be mobilised over the next ten years** to scale-up and reduce risks of projects related to renewable gasses, including hydrogen.
- 10 In accordance with the Green Deal strategy, **decarbonisation efforts must go hand in hand with ensuring a well-functioning, fully integrated and competitive gas market. It is essential that clean transition does not lead to national market fragmentations**, which may then need many years to align back. To safeguard that aim, endorsing further the ACER Gas Target Model (AGTM) – a EU market view that cements the IGM

5 By the end of May 2020, spot gas was sold at less than 4 euros/MWh at various EU hubs. For the first time ever EU hub prices were concurrently below US and Russian exchange ones.

6 ACER performed in July 2020 a [survey among NRAs](#), aimed at identifying the technical ability of the EU gas transportation system to accept carbon neutral gasses as well as taking stock of the related planned network adaptations and investments. The purpose of the exercise was to collect background information in support of the regulatory discussions for the development of future EU gas infrastructure. The results of the survey show that only eight MSs accept at present injection of hydrogen in their gas networks. Germany reports the highest blending limit (up to 10%) though it is only applicable under certain conditions. Overall, in North-West and Central European MSs hydrogen blending limits – as well as injected biomethane volumes – are higher than in South East MSs. Section 2.2.1 discusses further on the subject.

7 Hydrogen is deemed to constitute at present less than 2% of the EU total energy system, but projected to grow to circa 15% in long-term decarbonisation strategies. The recent [EC hydrogen strategy](#) ambitions at least 40 GW of renewable hydrogen electrolyzers installed by 2030 in the EU plus other 40 GW in Europe's neighbourhood with export to the EU.

8 MSs shall in parallel design National Energy and Climate Plans to determine in an integrated manner their low carbon gasses objectives, targets and policies

construction by means of integrating well-functioning trading hubs⁹ – is essential. In addition, trans-national coordination of clean strategies of MSs is also important¹⁰. The MMR 2019 results show that **these market integration ambitions continue to advance** to various degrees.

- a) **European gas supply sourcing costs have converged to a significant extent since gas markets were liberalised**, bringing tangible benefits to EU consumers¹¹. In 2019, the sourcing cost gap grew bigger than in the past couple of years in some MSs, in particular in markets more reliant on long-term contracts where gas hubs are less developed – as prices in these markets did not fall at the same time and as sharply as in NWE markets.
- b) **While hub price convergence has reached very high levels in past years**, higher spreads appeared more frequently in 2019 than in 2018. Different exposure of hubs to the LNG market or to the Russia-Ukraine transit uncertainty were two major drivers behind the lower levels of hub price convergence. Other factors with some likely effects on convergence are the gradual expiration of long-term transportation contracts and consequently higher short-run marginal costs of locational arbitrage¹².
- c) **Gas flows are progressively becoming more responsive to hub prices**, although the situation differs between interconnectors as their price responsiveness is dependent on their specific market role and their prevailing transportation contracts. Market participants are increasingly using LNG and UGS capacity as short-term flexibility tools, allowing for optimisation of portfolios and short-term price hedging.
- d) **The hub model continues to deliver benefits in terms of facilitating competition and liquidity** as shown by improving AGTM metrics' results of hubs in various MSs. Furthermore, there are now more market integration initiatives promoted in Europe than in the past, called to offer welfare gains for the gas consumers at the integrated jurisdictions.

Gas Target Model

- 11 Figure i presents a classification of EU gas hubs based on 2019 AGTM trading metrics results. Most EU gas demand is consumed at wholesale **markets that are generally functioning well, but significant differences persist** among MSs:

- a) **TTF in the Netherlands and NBP in the UK¹³ have kept their place as the two most liquid and competitive trading hubs**, accounting for the bulk of forward gas trading activity in the EU. A level below are other NWE's, and some Mediterranean and CEE's hubs where spot markets are liquid and competitive but forward liquidity is limited compared to TTF and NBP.
- b) **Various MSs, chiefly located in the CEE and SSE regions, still have weak or no hub dynamics**. In these markets, a trading venue with a transparent price mechanism is either absent or not visible during many trading days of the year. This year notable positive developments were observed in Hungary, resulting in its hub no longer being classified as illiquid¹⁴.

9 The AGTM is a model for the internal gas market developed by the Agency, NRAs and gas sector's stakeholders. It envisages a competitive European gas market comprising entry-exit zones that host liquid virtual trading points and where market integration is served by appropriate levels of infrastructure, which when utilised efficiently, enables gas to move freely to the locations where it is most valued.

10 For example the Dutch-German ambition to co-ordinately exploiting North Sea offshore wind production for hydrogen generation, which includes looking into the setting of joint standards and combined large-scale storage and transportation infrastructure, is a promising signal.

11 EU gross welfare losses remaining due to supply price discrepancies among MSs reached 3 billion euros in 2019. Assessed yearly losses have decreased significantly – by more than 60% – since the Agency started this analysis in 2013. Price convergence has been prompted by the combined effect of regulatory and market factors which chiefly led to the review of long-term contracts (LTCs) pricing systems and the progression of the hub price sourcing model.

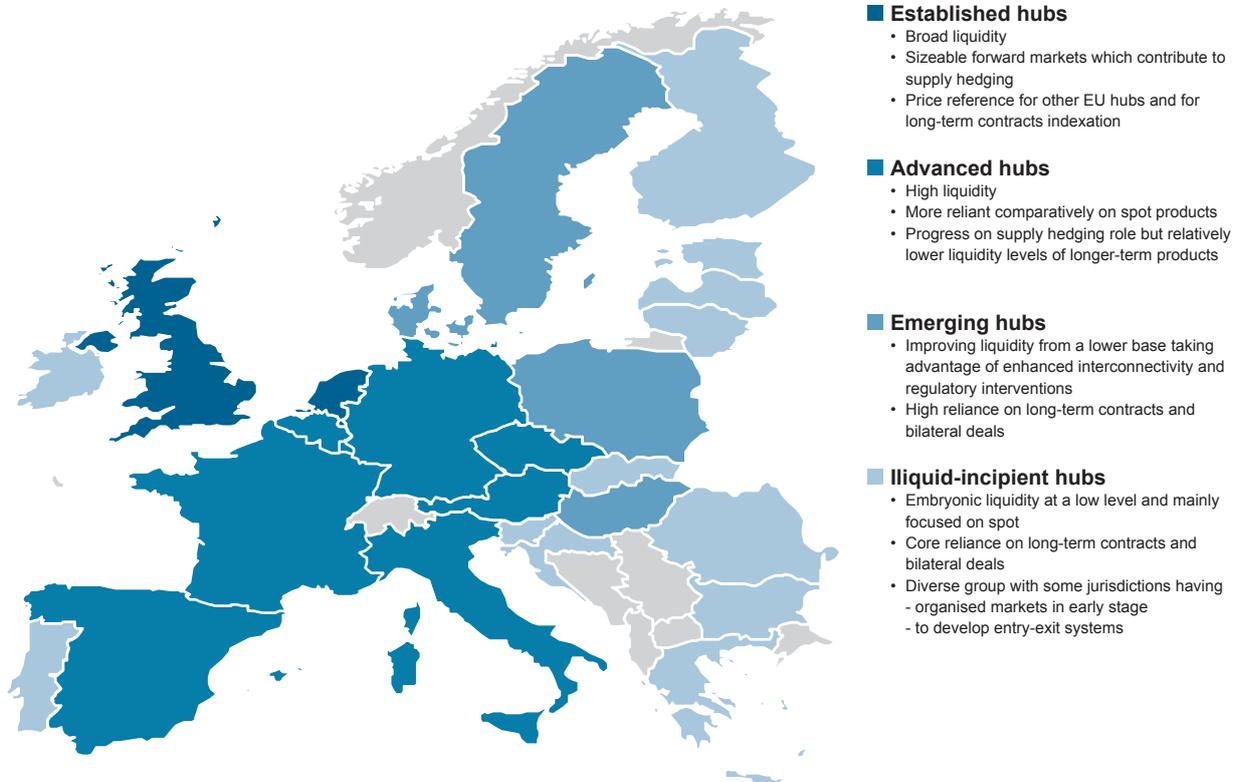
12 The long-term over-contracting by EU midstreamers had originated in recent years a mismatch between some historical LTCs and actual demand needs. This surplus often turned into sunk costs for companies, that when confronted with this situation, increased inter-hub trading placing bids around the short-run marginal costs (SRMCs) of inter-hub gas transportation. Given that SRMCs tend to account for a fraction of transportation costs, this practice favoured price convergence, with hub spreads frequently falling below cross-border fees. The expiry of surplus LTCs is deemed to start limiting SRMCs bidding, affecting convergence.

13 NBP shows a diminishing role though, likely due to the regulatory uncertainty created by Brexit.

14 Section 3.5 expands on the reasons.

- c) In terms of market structure, the concentration of upstream supply sources is still high in many MSs. Markets in NWE and those with access to LNG have the healthiest level of supply source diversification.

Figure i: Ranking of EU hubs based on monitoring results – 2019



Source: ACER based on ICIS Heren and REMIT data

- 12 A number of **tailored-regulation measures is considered to close the functionality gap** and eliminate some persisting barriers at selected markets still lagging behind.

Network Codes effects

- 13 Being natural monopolies, gas transportation networks must be operated following standardised, transparent and non-discriminatory rules. The Third Gas Package set the legal basis **establishing more detailed common European rules** – the gas Network Codes and Framework Guidelines – with the aim to further advance the interconnection of gas markets as well as to promote the AGTM hub-cemented vision.

- a) **ACER ensures that NRAs apply an EU-wide cooperative approach** in setting up Network Codes and their possible amendments, **and monitors the market effects of their implementation.**

- 14 **Five gas Network Codes and Guidelines have been adopted since 2013¹⁵.** The effects of their implementation are monitored in this Report. The exercise reveals that Network codes are becoming a key driver for the integration of the EU Internal Gas Market.

15 The NC on interoperability coordinates the technical procedures used by network operators. The NC on gas balancing (BAL NC) sets out gas balancing rules, including the responsibilities of transmission system operators and users. The NC on capacity allocation mechanisms (CAM NC) sets the rules for capacity acquisition, including the use of harmonised auctions when selling access to pipelines. The rules on congestion management procedures (CMP GLs) aim to reduce congestion in gas pipelines, while the NC on transmission tariff structures enhances tariff transparency and cost-reflectivity by harmonising basic tariff-setting principles. The market effects brought by NCs are covered in detail throughout Chapter 4.

- b) **The Capacity Allocation Mechanism Network Code has facilitated a more efficient and flexible booking of capacity, more closely in accordance with market participants' needs.** The analyses of this Report show that in most MSs expiring long-term capacity contracts have been amply replaced by new CAM products (40% of the legacy contracts in place in 2015 had expired by 2020). The Report identifies that the market preference has been to book short-term products whereas new multi annual bookings have been limited so far. Legacy long-term contracts will have almost completely expired by 2035, which implies that much more capacity will become available for the market and that new bookings will depend more than in the past on market conditions¹⁶.
- c) In the area of transportation tariffs, new reference price methodologies set in accordance with the **Tariffs Network Code are progressively starting to be implemented, improving network tariffs' transparency and cost-reflectivity.** This Report examines the variations of cross-border tariffs that will occur once all new methodologies will have been implemented and assesses the likely effects of such variations on MSs' price formation, also in terms of tariff competition between supply routes.
- d) **The analysis of gas balancing markets reveals how an ambitious implementation of the BAL NC reduces the active role of TSOs in balancing activities,** which also benefits spot markets' liquidity. This Report analyses the balancing markets of MSs where the BAL NC was implemented before 2020. The results show significant differences across MSs in terms of the role of the TSO. It also detects the need to remove a series of national measures – directly and indirectly related to balancing design – which currently hinder its effectiveness in various markets.

Recommendations

IGM STATUS AND POLICY PRIORITIES

- 15 Gas accounts for more than 20% of EU's energy final consumption – more than 30% at industrial level – while EU IGM yearly purchases are estimated in 100 billion euros¹⁷. What is more, the average EU household consumer spends some 700 euros per year on gas¹⁸. Therefore, the gas sector plays a crucial role in the energy market, which shall last in spite of the ambitions to decarbonise it in the years to come.
- 16 Given that relevance, a competitive European gas market lies at the core of bringing tangible benefits to end consumers. This Report shows that the EU IGM continued to progress in 2019. This is demonstrated by the growing role of gas hubs, the improved supply-side competition – markedly influenced by the ample surge in LNG imports – and the uphold high levels of price convergence despite rising gas price volatility.
- 17 Market integration is quite effective in areas covering three-quarters of EU gas consumption, and importantly, is gradually advancing across several other jurisdictions. An enhanced interconnection of markets is being facilitated by a proper implementation of gas network codes, which are proving instrumental in assisting more liquid hubs to play a transnational supply hedging role (principally TTF, but also other hubs such as AT-VTP, at a more regional level). This results in a certain concept of an EU market, even in the absence of formal cross-border market mergers.
- 18 However, a more complete realisation of the IGM can still produce more tangible benefits. The differences in maturity and competitiveness across EU hubs, including in their degree of interconnectivity, still result in a price disadvantage for consumers in the MSs where the hub model is less of a reality.
- 19 Therefore, the relevant national decision makers are called to fully implement the Third Energy Package, guided

16 Overall, and as [Section 2.4.2](#) will further discuss, the expectation is that more and more EU gas cross-border transportation capacity will remain far from being highly utilised. A confirmation of that expectations was obtained in the latest [ACER monitoring update of incremental capacity projects](#). The report evaluates the application of the first incremental-capacity process - a market-based approach to the expansion of gas-transport capacity in which project promoters test the economic viability of new projects requesting binding capacity commitments - that ran from July 2017 to July 2019. The process resulted in no new firm capacity commitments within the whole EU, an indication that, from the market perspective, the existing capacity addresses well current and future gas needs.

17 Considering the 2015-2019 MSs gas wholesale price average.

18 See a detailed overview of the average gas expenditure per MS at ACER MMR Electricity and Gas Retail Markets Volume.

- by the vision of the Gas Target Model. This entails an ambitious and regionally coordinated implementation of gas NCs and the promotion of transparent hub trading. If this proves insufficient, targeted regulation could be applied to MSs with less competitive and more illiquid gas markets. Such regulation might include gas release programmes to reduce the market power of incumbents.
- 20 Critically, MSs should avoid taking measures that go against the interest of the IGM, as those tend to have an immediate adverse impact on market functioning. They should, for example, remove any remaining barriers to market entry, like limitations to free cross-border trade of locally produced gas or excessive storage obligations for market participants.
- 21 Since the current regulatory model has proven successful in terms of promoting economic efficiency, any upgrading of gas market design, for instance in the context of the decarbonisation goals, shall be built on its basis. This will create more regulatory certainty and thus support market-based investments. Although large redesigns are not envisioned, it is overall important to see if the regulatory framework fits the evolving market conditions well. In addition, when monitoring results indicate a certain need for adjustments, it should be made possible, for example, to adapt NCs' provisions more dynamically.
- 22 These considerations are all valid - and even more essential - for the Energy Community Contracting Parties (EC CPs). Those countries still show a sub-optimal level of market development and higher supply-side concentration than MSs. Continuous alignment of the EC CPs to the *acquis communautaire* of the EU is a precondition for enhancing market integration and cross-border trading with the EU and among themselves.

GAS INFRASTRUCTURE

- 23 EU gas transportation networks have, in general, reached high levels of interconnectedness, which has helped market integration and increased competition, while also contributing to high levels of security of supply. However, parts of the gas transportation infrastructure are far from being highly utilised. Given the ambitious energy decarbonisation targets, as well as some changes in gas flows that could deter certain cross-border lines relevance, those lines are likely to be used even less in the future. This implies a risk that some regulated infrastructure will become stranded, potentially resulting in social welfare losses for consumers. Therefore NRAs and MSs should continue to apply a careful approach when approving new investments in traditional natural gas infrastructure¹⁹. Particular caution should be used regarding public financial support, for example for PCI projects, which must from now on critically include the sustainability criteria to assist gas decarbonisation transition. In this last regard, there is also a need to further coordinate infrastructure planning between electricity and gas, but also heat and carbon emissions carriers, in view of moving towards a smarter sector integration approach.
- 24 For the specific case of LNG, this infrastructure has become one of the biggest sources of supply to EU gas markets, highlighting the need for greater transparency regarding access conditions of terminals²⁰. Furthermore, while acknowledging that there is no consensus on the need for a harmonised LNG-specific EU regulatory framework – and recognising that the distinct features of LNG terminals and offered services would make this very intricate – there is a need to better understand if the existing framework is hindering fairer competition between MSs and terminals. This infrastructure is only regulated at national level, and in certain cases, some access provisions are perceived as not being sufficiently transparent²¹. In addition, it seems to be difficult to reach a level-playing-field in the competition between exempted and non-exempted LNG terminals, given that many obligations on transparency (e.g. on tariffs, on running consultations for new products) only apply to the regulated ones, which may distort cross-border competition dynamics. In all cases, an effective access to virtual trading points (VTPs) has to be guaranteed to LNG shippers.
- 25 An enhanced LNG supply role is in parallel an important part of the EU's diversification strategy. In some regions (e.g. in CEE, SSE), the expansion of LNG terminals could still bring positive effects in terms of increased supply

19 The fitness of these investments may vary per case. Selectively located infrastructure gaps would still clearly promote market integration in some areas, but, overall, prudence and clear market-driven support shall be the guiding lines. As an illustration of that, the number of gas projects of common interest (PCI) selected by the EC dropped from 32 to 21 in the latest 2019-2020 list, and so far none of the incremental capacity processes to obtain market support for new infrastructure investment has been successful.

20 Further transparency about tariff levels or capacity availability will be interesting to achieve, possibly using an EU-wide platform.

21 See for example the [EC consultancy study](#) on gas market upgrading and modernisation.

competition and greater hub liquidity, if access mechanisms are set so as to enable fair use of the capacity for market participants from multiple MSs. Therefore, when assessing the CBAs of additional LNG regasification capacity, the impact on diversification and liquidity should be assessed at regional level, but only if the project under consideration would sufficiently guarantee fair regional access.

- 26 When examining underground storage sites (UGSs), another crucial piece of infrastructure, evidence suggests that seasonal security of supply (SoS) needs tend to be sufficiently guaranteed in most MSs by a market-based approach to the capacity use of UGSs. However, it is the prerogative of MSs to decide to hold strategic gas reserves based on their risk assessment and, understandably, SoS concerns are a key responsibility for national authorities. On the other hand, storage obligations imposed on market participants that limit or prescribe the use of commercial storage of cross border capacity are perceived as distortive to market functioning and a barrier to trade. Therefore, the latter should aim at being replaced with regulations that enable flexible and market-driven use of UGSs.

RENEWABLE AND DECARBONISED GASES

- 27 While there is an ample consensus among most stakeholders²² that the gas sector will need to be carbon neutral by 2050, production of decarbonised or renewable gases in the EU is currently modest. Together, they account for less than 4% of the EU's gas consumption, the big bulk in form of biogas, as the right commercial conditions for viable production of greater volumes do not exist yet. However, this differs significantly between MSs, with ad-hoc favourable policies appearing crucial for achieving higher production volumes in selected jurisdictions. A higher price of carbon emissions allowances would help to make all decarbonised energy technologies more price competitive. For example, in the case of natural gas, conventional production is three to five times cheaper than carbon-neutral technologies at 2019 prices. Therefore, reconsidering the environmental cost – and as such the pricing – of carbon emissions is one of the crucial factors that would stimulate the use of lowest-cost cleaner technologies. If carbon neutral gas managed to position among those technologies, this would lead to a meaningful increase in the production of decarbonised gasses.
- 28 The regulatory framework governing decarbonised gasses transition must clarify a number of essential and interrelated aspects. As it has been well reflected by a number of policy documents by the EC²³, as well as amply discussed in venues like the Madrid Forum, those aspects can be grouped as:
- 1) Setting the technical rules that will define gas quality, blending and interoperability aspects. A certain level of standardised criteria is necessary to ramp up the production of decarbonised gasses and to govern the interactions between the different gas types but also with the electricity and heat sectors.
 - 2) Outlining the market and competitive framework. This entails determining the activities and the conditions that the diverse market participants will be allowed to invest in but also define the supportive mechanisms that will incentivise efficient investments, including locational signals.
 - 3) Defining the specific regulatory design of the decarbonised gas market, which will be more interconnected with electricity and possibly heat. This chiefly entails determining network access conditions for new gasses, where tariffs will be a key element.
- 29 The transition entails in turn two challenges. First, although there is a drive to foster decarbonised gases foremost under competitive markets, ad-hoc supportive financial measures will be needed to achieve the exigent goals²⁴, which may lead to trade-offs with competition. Second, a variant presence of distinct gas types across various markets may entail some risk of market fragmentation or hindered wholesale trading if some technical aspects are not made compatible. Therefore, the regulatory community should carefully evaluate and highlight the benefits of decarbonisation, verifying that they offset the extra costs that consumers will have to pay

22 Although the extent of this aim is yet to be confirmed in a few cases, e.g. the Polish government has not yet confirmed the carbon neutrality aim.

23 See EC's 2050 long-term policy strategies [portal](#).

24 These measures may take different forms: favourable access tariffs, ad-hoc fiscal frameworks, set production targets, subsidies, certificates of origin, production auctions, priority dispatching, carbon taxing, etc.

for its development. The discussion should include approaches to deal with the existing regulated asset bases (RABs). Moreover, regulators should thoroughly monitor the possible risks of market fragmentation and try to address them using a sufficiently coordinated regional view.

- 30 As there is still a lack of clarity on which the most cost-efficient technologies and market designs that would allow reaching decarbonisation targets will be, there is an initial aim to back R&D and implementing *regulatory sandboxes* – the latter only if specific reasons are judged to require them –, as cautious initial approaches. They both shall help to foster innovation and reach a scale-up level, so that most cost-efficient technologies emerge²⁵. This seeks to avoid the inefficiencies and extra costs that final electricity household consumers have seen in their bills to back electricity RES developments, which, at least in their first stages, were not deemed sufficiently cost-effective.
- 31 Given the projected increase of decarbonised gas production and related transportation needs, some parts of European gas networks will require adaptation investments. Again, in order to protect consumers from an excessive cost burden, sound technical decisions that optimise resources will be needed (e.g. deciding on a blending's mix²⁶). Also, the role of network operators should be legally clarified in order to ensure that their involvement does not foreclose potentially competitive activities. Overall power-to-gas and any other energy-sector-integration activities should be contestable, in order to reach a broader market participants' audience other than TSOs.
- 32 For this last and other related points, continuing discussions are taking place. Offering very detailed recommendations on the subject falls out of the scope of this particular edition of the MMR. CEER is working in more specific proposals that will be communicated in the autumn of 2020, in the form of white papers. In addition, the Agency and CEER have recently issued some policy proposals in its Bridge Beyond 2025 conclusion paper, released in November 2019, looking at those regulatory dimensions – of the many interconnected aspects – that fall more closely in its remit.

ACER GAS TARGET MODEL

- 33 The results of AGTM indicators show that the liquidity of gas hubs is improving in most MSs, particularly on spot markets. However, the thresholds envisaged for AGTM indicators are generally still not met, especially when considering the modest liquidity of forward markets (apart from TTF and NBP) as well as markets' structural upstream supply-side competition. In addition, the monitoring results show that while there has been progress made in some of the EU's least liquid gas markets, many national wholesale markets have yet to see any meaningful liquidity develop at their gas hubs.
- 34 Therefore, NRAs are called upon to give a further impulse to the AGTM, to further reap the number of benefits that it was set to achieve. These benefits – i.e. pursuing liquidity, competition and price integration – will be assisted by the enhanced integration of markets that the model aims at, even if decarbonisation ambitions may partly alter the general market scenery. The AGTM recommends actions focused on domestic markets, but also importantly, deepening or formalising regional hub integration, following, for example, recent initiatives in BeLux and the Baltic States.
- 35 The delineation of gas wholesale markets mostly along MSs borders has resulted in the existence of numerous small markets, a market set-up that may hinder their functioning. This is demonstrated by the fact that at the end of 2019, 12 hubs for which monitoring results indicate illiquidity accounted for less than 10% of total EU consumption. The AGTM establishes that when the AGTM indicator thresholds are not met the concerned NRAs should consider measures aimed at improving integration between hubs as outlined, e.g. in some form of a merger.
- 36 In order to make progress in the realisation of the AGTM, the regulatory community should:

25 Cost-efficiency determination should also consider polluting costs.

26 For example, it is deemed more effective to fully shift gas pipelines into hydrogen dedicated pipelines after a certain admixture threshold. However, the exact quantity can vary among MSs, in accordance to the technical features of their networks.

- Further develop a framework that facilitates market mergers across multiple MSs, which elaborates on technical, financial (e.g. ITC), governance and process aspects. Any market merger decision should be based on CBAs where, among others, the effect of a merger on the following elements should be considered: liquidity, prices, security of supply and competition.
- Further shape a regulatory tool-kit of tailored-regulation – i.e. gas release, market maker, adapting NCs provisions and others.

37 Where hubs have failed to attract liquidity to their spot markets, NRAs should:

- Guarantee that gas transits and domestically produced gas can be traded at the VTP without restrictions.
- Provide effective hub access for gas imported as LNG.
- Ensure that balancing rules are implemented in a way to promote liquidity, i.e. in line with best practice.
- Guarantee that the licensing regime or other licensing, trading or reporting obligations do not become an undue barrier to trade. Mutual recognition of national trading licenses would bring positive effects as it may create some competition to not impose too stringent requirements, with the possibility to set-up minimal requirements (and the prohibition of specific requirements).
- Instruct TSOs to possibly set up a centralised EU database on creditworthiness and market behaviour of gas shippers, in order to minimise risks of fraud and/or default. Such a database should be accessible to participating TSOs, NRAs, the Agency and ENTSOG.
- Set multipliers for short-term capacity tariffs within the TAR NC boundaries and at levels that safeguard cross-border trade and price integration - considering the tendency of short-term capacity tariffs to represent a reference for hub price spreads. This should be balanced with the principle of fairness in sharing network costs between infrastructure users.

NETWORK CODES

38 The IGM construction requires standardized but also fair and flexible market access conditions. This is both to assist the AGTM hub-based vision, but also to facilitate shippers' reactions to a more dynamic evolution of energy markets. This Report shows that gas Network Codes – i.e. the EU-wide harmonised policies that govern cross-border network aspects but also set common standards for gas system designs²⁷ –facilitate these changes and that their coherent implementation increases transnational hub hedging opportunities, competition and price convergence.

39 In the specific case of capacity bookings, the implementation of the CAM NC has favoured the possibility for shippers to profile their booking portfolios more optimally, using products of distinct durations that also better allow the incorporation of hub price signals when managing bookings' needs.

40 In this context, an analysis of the possibility to review capacity products timeframes and/or their allocation procedures has been requested by various market participants. Moreover, there is a request to get short-term capacity products tariffs' lowered to levels closer to long-term products' ones – the TAR NC sets at present maximum levels for those. These initiatives might create better price signals for acquiring capacity more in line with actual wholesale markets' preferences but have to be assessed in the light of networks' design to fulfil consumers and transit needs and not discourage the acquisition of long-term contracts. In some circumstances it could be relevant to evolve towards a more flexible approach to capacity booking but a detailed assessment on the impacts of such initiatives on the total capacity bookings volumes (and consequently on the total TSOs' revenues) is key. The chosen solution should aim at safeguarding an efficient redistribution of network costs and guarantee a sufficient revenue recovery.

27 See footnote 15 for further considerations about specific NCs.

- 41 ACER is working on issuing some proposals on the subject, exploring via an open public consultation the possibility to further increase the frequency of CAM auctions with a standardised timing or to increase the variety of products if they respect NC principles.
- 42 This is an example that illustrates that the discussion about NCs adequacy should be more continuous to upgrade and fit the market design to the evolving market conditions. The joint ACER-ENTSOG Functionality Platform is proving a useful tool to respond to stakeholders' feedbacks.
- 43 In connection to this, in some MSs conditional capacity products still account for a high proportion of IP bookings (even beyond 50%). The regulatory community should consider whether further assessments or harmonisation requirements on the application of conditional capacity products and services are beneficial. The solution shall consider several elements, including whether the usage of conditional capacity products has a positive CBA, if it meets the transparency requirements and if it is harmonised across MSs.
- 44 In the domain of CAM, and CMP, the degree of concentration for longer-term capacity products tends to be higher than for shorter-term ones, while in selected cases, relevant IPs are fully controlled by upstream suppliers or national incumbents. This raises the question of whether the NCs and the EU and national competition laws are adequate and coordinated enough to handle future concentration issues. NRAs should monitor the concentration levels of capacity bookings, in order to implement any necessary actions in a timely manner. In addition, the new gas Directive establishing rules on third-party access to all the supply lines connected to the EU – and requiring an ownership separation between pipeline owners and suppliers – shall be implemented as rule, while national governments are allowed to grant exemptions.
- 45 Furthermore, NRAs shall continue to implement the NCs with a regional view. For example, NRAs should urge TSOs to coordinate and to apply a standardised approach to creating the virtual interconnection points (VIPs)²⁸ and to facilitate the transfer of (secondary) capacity between network users in order to optimise the usage of the EU network.
- 46 In the domain of tariffs, the implementation of the TAR NC is called to improve the tariffs' cost-reflectivity and overall transparency. A diversity of reference price methodologies (RPMs) has been implemented as NRAs are using some flexibility with the aim to pursue a more efficient operation of their transportation systems. As there might be a risk of competition among MSs on tariffs and/or undue cost transfers to neighbouring markets, NRAs shall fairly set their transportation tariff systems based on the TAR NC principles, in order to guarantee a level playing field. RPMs adjustments must be duly justified. Even if there is not a legal mandate to do so, it is recommended that NRAs take into account the Agency's recommendations, chiefly in cases where relevant deviations have been detected.
- 47 The effects of changes to gas transportation tariffs on market functioning should be regularly monitored by the regulatory community in order to assess if and where they led to possible adverse effects on, for example, utilisation of IPs, market price integration or competition. Particular attention should be paid to the possibility to allow reductions of reserve prices for cross-border capacity combined with ITCs and tariff reallocation measures, when pursuing markets' price integration.
- 48 In relation to the tariffs' role in the context of decarbonisation, the support for carbon neutral gases should be in principle preferably met in a different way rather than with discounts on network access tariffs, in order to become compliant with the relevant TAR NC requirements. Nonetheless, tariffs' role shall be subject to further analysis in the years to come in light of decarbonisation developments. As par (42) has referred, the discussion about NCs adequacy should be more continuous to upgrade and fit the market design; making tariffs' discounts available to promote the expansion of decarbonisation technologies could be a possibility that could entail the code amendment.
- 49 In the area of balancing, as a rule, a proper BAL NC implementation shall be pursued as it also benefits spot trading activity. In some balancing zones, some measures currently in place that limit – directly or indirectly – either the TSO's need to trigger balancing actions or network users' possibility to change positions within the day should be removed.

28 To foster cross-border trade, TSOs shall make efforts to standardise contracts and procedures, (e.g. contracts, guarantees, procedures, information exchange and data exchange formats, products, products descriptions).

1. Introduction

- 50 This MMR, which is in its ninth edition, consists of three volumes, respectively on: the Electricity Wholesale Market, the Gas Wholesale Market, and the Electricity and Gas Retail Markets, the latter also looking at Customer Protection aspects. It covers the MSs and, for selected topics, also the Contracting Parties of the Energy Community.
- 51 The Gas Wholesale Volume presents the results of monitoring the European gas wholesale markets in 2019²⁹ and their trajectory towards an Internal Gas Market.
- 52 The Volume is divided into three analytical chapters. Chapter 2 presents the status of the European Internal Gas Market in 2019; Chapter 3 focuses on assessing the performance of gas markets based on the Agency's Gas Target Model indicators; Chapter 4 analyses the market effects of network codes on market functioning. The Volume also provides a set of recommendations based on the outcome of the analytical work performed by ACER.
- 53 In order to calculate the AGTM indicators, for the fourth year ACER has used anonymised and aggregated REMIT data. For selected AGTM's indicators, this Volume only displays the results for a sample of MSs. The results for all MSs, together with results of other analyses, are published in the CHEST database available on the ACER's website.

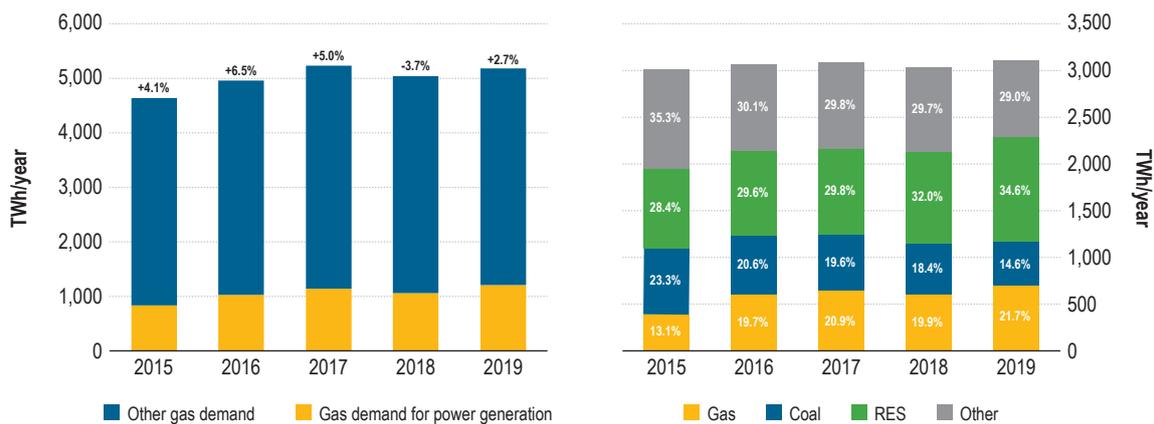
29 Selected analyses are expanded up to summer 2020.

2. Overview of the Internal Gas Market in 2019

2.1 Demand developments

54 In 2019, demand for gas in the EU rose by 2.7%, to 5,188 TWh. Gas-fired power generation, pushed up by lower gas prices, accounted for most of the increase³⁰. Up to May 2020, gas demand fell by 8% YoY, severely affected by the economic impact of the lockdowns related to COVID-19.

Figure 1: EU gross gas inland consumption³¹ and Figure 2: EU electricity generation breakdown by technology – 2015–2019 – TWh/year



Source: ACER calculation based on Eurostat and ENTSO-E data.

55 While the EU as a whole saw rising gas consumption, yearly demand variations between MSs reflected heterogeneous local dynamics³². Overall, economic growth was lower YoY, while weather-driven demand was weaker. Conversely, gas-fired power production generally rose. The UK and Italy had the highest share of gas in their power generation mixes, with more than 40% compared with the EU average of 22%.

56 Although the gas demand picture for 2019 was relatively favourable, the future role of natural gas in the EU is intensely debated. In order to become a carbon-neutral economy by 2050, the use of unabated natural gas would need to drastically decrease. The reduction of methane leakages across the entire supply chain is likewise seen as imperative³³.

2.2 Supply developments

57 In 2019, the EU experienced an important variation in its gas supply balance. LNG deliveries rose by 90% and ended up covering 20% of EU gas demand. The surge in price competitive LNG imports was driven, amongst others, by a global production surplus, with EU companies responding to more favourable LNG price dynamics, and the diversification drives enabled by new terminals in selected MSs. Section 2.4.3 discusses LNG market developments in more detail.

58 The EU's reliance on external gas imports continued to increase (+5% YoY) as domestic production continued to decline (-8.3% YoY). MSs' gas production accounted for just 20% of total supplies, which is a drop of three

30 Gas consumption for power generation accounted for 22% of EU gas demand. Lower gas prices, chiefly the result of record LNG deliveries (see Section 2.3), further underpinned the switching from coal to gas.

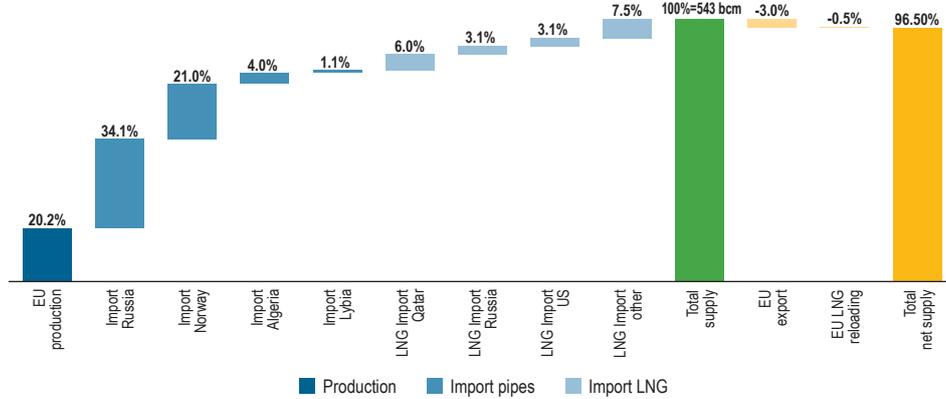
31 Demand varies greatly among MSs: Germany (986 TWh/year), UK (869 TWh/year) and Italy (784 TWh/year) account together for more than half of EU gas consumption, while the twelve MS with the lowest-demand sum less than 10%. Demand data per MS is accessible in the [MMR data portal](#) CHEST.

32 Final gas demand rose in 22 out of 28 MSs. Largest relative growths were registered at those MSs where gas consumption for electricity generation raised the most: Spain (+12%), Greece (+8%) and Germany (8%).

33 Studies suggest that leakages across the entire gas supply chain account for 2-3% of EU gas sales. The EC ambitions to address the issue of methane emissions by developing a strategy based on detection and repair.

percentage points YoY. A lower production cap in the Netherlands for the Groningen field³⁴ and reduced production outputs in the UK, Romania and Denmark explain most of the decrease. Figure 3 shows the EU supply portfolio per origin across the year.

Figure 3: EU gas supply portfolio by origin – 2019 (100 = 543 bcm, %)



Source: ACER calculation based on International Energy Agency, Eurostat and GIGNL³⁵.

- 59 Sales by the main gas supplier to the EU, Gazprom, were rather steady at 185 bcm. However, the LNG glut and the supply diversification ambitions of some of its long-established Central and East markets led to a small drop in the share from its historical highs of 2018. In its main export market, Gazprom covered for circa 35% of supplies despite the low-price environment. Overall, the company has been adapting to the changing EU gas market by incorporating hub-based prices in its contracts, while also increasing its LNG deliveries, like other Russian LNG exporters did. It also organises gas auctions and direct sales on a dedicated platform, in order to provide for delivery at selected NWE and CEE VTPs and IPs. This novel mechanism aims to attract new business by selling uncontracted volumes³⁶.
- 60 Norwegian supplies lost some ground YoY (-7%). Norwegian gas suppliers have a longer tradition of hub price-based contracting and are a relevant source of supply flexibility in NWE. They tend to prioritize value above volume, which made them defer some production in the oversupplied market of 2019. A heavier than usual maintenance schedule in the summer also limited flows. Algerian pipeline supply was substantially lower than in 2018, falling by some 30% YoY. Less flexible and still partly oil-indexed pipeline flows were unable to compete with massive LNG shoring into the Iberian Peninsula and Italy³⁷.
- 61 Gas exports from the EU into Ukraine rose to 14.3 bcm (+35% YoY), backed by lower hub prices and the increased interest of EU shippers in using Ukraine’s ample UGSs facilities. By the end of the year, Ukraine and Russia signed a five-year agreement setting the minimum volumes to be transported across the Ukrainian transit network (see further analyses in Section 2.4).
- 62 The enhanced adaptation to hub-indexes and direct hub sales by upstream suppliers increased the share of hub-price based supplies up to 78% on average across Europe. However, there are still some differences among regions³⁸. Importantly, the EU gas directive establishing rules on third-party access applies to all the supply lines connected to the EU since February 2020. It establishes an ownership separation between pipeline owners and suppliers.

34 The Groningen production cap was set at 11.8 bcm/year for the 2019/2020 gas year, the lowest ever. The field produced 54 bcm/year as recently as 2013. The Dutch government announced that the field will be shut down in mid-2022. UK production totalled some 40 bcm, a -1.8% drop.

35 International Group of LNG importers.

36 ESP sales, plus direct hub trades, accounted for 11% of Gazprom deliveries to the EU. ESP purchases tend to be slightly costlier than at hubs, although, shippers may find opportunities to arbitrage between contracts or avoid certain transportation tariffs.

37 Rising domestic gas consumption in Algeria has also been a driver to lower gas supplies delivered abroad.

38 See the IGU Gas Price 2019 report showing results per EU region and also including selected EnC CPs.

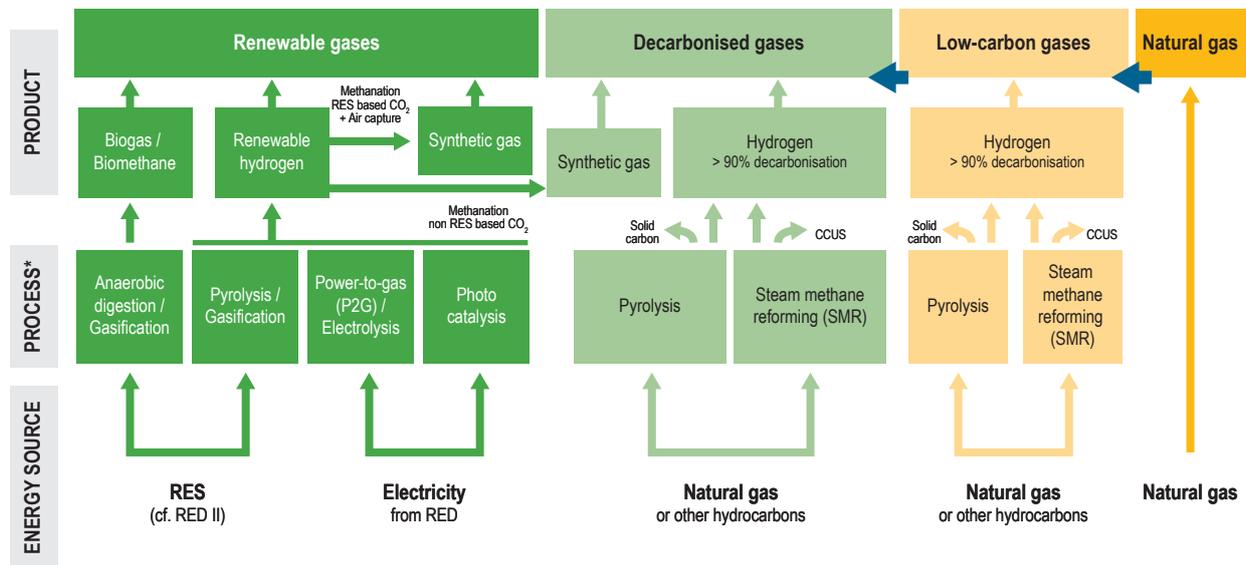
2.2.1 Carbon neutral gases

- 63 The envisaged drop in natural gas demand will coincide with a drive to move from conventional to decarbonised and renewable gasses. This drive is primarily driven by the strict carbon emission reductions endorsed by the EU. The parallel ambitious coupling of energy sectors' will be assisting the decarbonisation goal, as well as it shall promote energy efficiency and security of supply. Further than that, the decarbonisation shift will likely help to lessen EU gas import dependency.
- 64 The challenge is to identify the best suitable technologies and policies that could contribute the most to decarbonisation efforts. This section outlines decarbonised gasses current status among MSs and discusses their growth prospects.

Current importance of decarbonised gases

- 65 Figure 4 initially outlines the main technological options for low-carbon gasses production. A clear-cut classification is challenging, as distinct gases can originate from different processes or feedstock³⁹.

Figure 4: Overview of renewable and decarbonised gas technologies

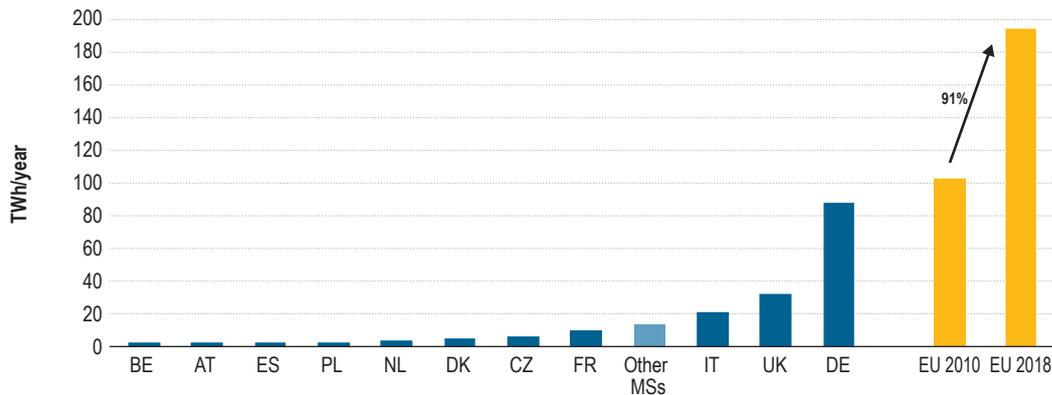


Source: Gas Industry Associations for 32nd Madrid Forum, June 2019.

- 66 While production of decarbonised gas in most MSs is still quite modest, its importance has been increasing in recent years, as illustrated by Figure 5. To date, production efforts have been mainly focused on biogas, which on average accounts for 15% of EU gas domestic production and 4% of EU gas consumption. Germany, the UK and Italy are the frontrunners in absolute terms, while the relative weight of biogas and biomethane over final gas demand varies between MSs; in Sweden, Denmark and Germany, its consumption reached 10% in 2019.

39 See an extended overview of the distinct technologies in this [study from E3G](#). Assessing the lifecycle emissions and the carbon dioxide abatement potential of the different options is also key; the EC is working with the industry on a clearer taxonomy to ensure coherence in terms of definitions and objectives.

Figure 5: Biogas and biomethane production in selected leading MSs in 2018 and EU evolution – 2010–2018 – TWh/year



Source: ACER calculation based on Eurostat.

- 67 Most biogas continues to be produced and consumed close to the production site, either for heating or electricity generation⁴⁰. Upgraded biomethane volumes injected into the network are still low – 5% of biogas production on average – due to higher production costs, gas quality and other technical constraints. The notable exceptions are Denmark and the Netherlands, where injections exceed 15% of biogas production. In absolute terms, Germany is the largest biomethane producer with more than 1 bcm in 2019.
- 68 EU hydrogen production is still moderate relative to future expectations⁴¹. Hydrogen is an established traded commodity in its own right, primarily produced on-site and consumed in certain industrial processes, in the refinery sector and for ammonia production – where its market value is higher than for electricity generation. Absolute hydrogen consumption is the highest in Germany and the Netherlands.
- 69 It is estimated that 95% of EU hydrogen production in 2018 originated from steam methane reforming (without carbon capture storage - CCS) and coal gasification, while only 5% came from electrolysis (for the latter, with a limited use of RES). At the moment, large scale methane reforming to hydrogen with CCS is moving ahead only in the UK⁴². A key limiting factor is the availability of suitable carbon dioxide storage structures. In the area of electrolysis, there are quite a few pilot and small-scale plants in operation, chiefly in Germany, France and the Netherlands. Commercial volumes are still small, but more projects have been announced recently.
- 70 The reasons behind the different degrees of penetration of carbon neutral gases among MSs are linked to combined market and policy factors. Availability of feedstock resources together with the existence of favourable policies, such as fixed deployment targets, encouraging supporting mechanisms and ad-hoc financial support, seem to have been crucial for achieving higher adoption⁴³.
- 71 In the absence of pan-European objectives, MSs may support different decarbonised gas technologies in the coming years, which are outlined in their respective governments’ national energy and climate plans (NECPs)⁴⁴

40 Biogas accounts for approximately 3% of EU electricity production.

41 Exact data are not straightforward to obtain. Hydrogen is deemed to constitute less than 2% of the EU total energy system – including the use of hydrogen as feedstock – but projected to grow to some 15% by 2050. See footnote 7 for further considerations about the EC hydrogen strategy.

42 See a review of the ongoing projects [here](#).

43 An overview of the distinct biogas backing policies and subsidies offered by MSs is maintained by the IEA. For example, in Denmark a subsidy of more than 5 euros/MWh has been granted for biogas used in CHP plants or injected into the grid since 2013. Denmark also has an objective of treating 50% of the country livestock manure in biogas plants by 2020. In Germany, the expansion of biogas in recent years has been chiefly backed by guaranteed tariff levels and substrate bonus for energy crops. Aiming to explore a more cost-effective support mechanism, biogas plants have aimed to take part in RES auctions in recent years. The new German methodology on transmission tariffs proposes a 100% discount for biogas entry points to the network.

44 MSs are required under the CEP package to establish a 10-year national energy and climate plans for the period from 2021 to 2030. These plans must aim to implement the Energy Union objectives and climate targets. NECPs will have a big sway in determining what the EU gas renewable landscape will look like.

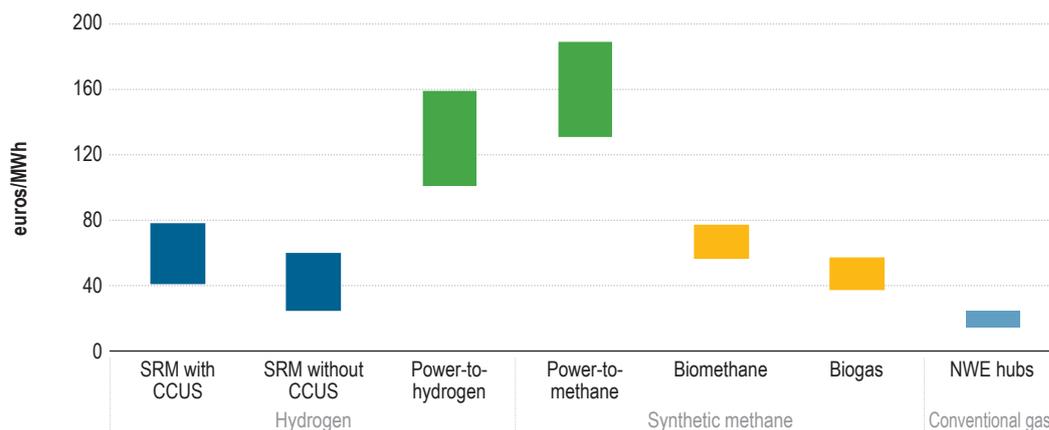
For example, in Germany or Denmark, biogas production is intended to keep growing⁴⁵, while Spanish, Italian and Portuguese NECPs back hydrogen production from RES sources.

72 When it comes to an EU outlook of these technologies, a consensus view has yet to be reached. In accordance to the most recent study done for the EC⁴⁶, power-to-gas technologies fed by RES resources could in theory produce enough hydrogen and synthetic methane to replace EU conventional natural gas by 2050. The same study finds the potential of biomethane to be more limited⁴⁷. The latest ENTSO’s joint scenario considers that hydrogen could become as important as conventional natural gas by 2050. The ENTSO’s scenario also infers that all low-carbon gases together could account for 10% of gas consumption by 2030 as an intermediate step. These future settings attract debate as their magnitudes depend on the underlying assumptions used⁴⁸.

Production costs of carbon neutral gases

73 The price competitiveness of the various carbon neutral gas production technologies will be decisive for determining their future reach. It is, however, difficult to make sound cost estimates – and this falls out of the scope of this report – as they can be affected by local specificities and the prices of raw materials, which can vary over time. Figure 6 summarizes the main technologies’ costs using existing studies.

Figure 6: Illustrative overview of renewable and decarbonised gases technologies’ production costs – 2019 euros/MWh



Source: ACER based on desk research of EC, OIES, E3G, IEA, Hydrogen Europe and other studies.

74 As Figure 6 reveals, fossil derived natural gas sold at EU hubs averaged 15 euros/MWh in 2019. This implies that the cost of low-carbon gases was three to more than five times higher than the price of conventional gas in 2019. Therefore, together with further technological developments and RES prices, a central element for determining the future competitiveness of all decarbonised energy technologies, including carbon-neutral gases, will be the price of carbon emissions under the EU ETS system. Further recognition of the value of avoided emissions would improve the use of all cleaner technologies, and rise low-carbon gases presence if there are competitive enough⁴⁹.

45 Even if power-to-gas will play a rising role, as the ample wind energy potential is aimed to feed hydrogen industrial consumption points, which are called to adopt more and more hydrogen in the years to come (e.g. steel, petro-chemical). German NECP ambitions for example a combined support of nine billion euros to develop up to 10 GW of hydrogen by 2040 and develop international partnership to secure reliable hydrogen supply.

46 See EC study *Impact of the use of the biomethane and hydrogen potential on trans-European Infrastructure*.

47 Biogas and biomethane could account for some 25% of EU demand. The chief limiting factor would be the restricted availability of biomass resources, which should neither compete with food production nor lead to land use changes.

48 E.g. Operating power-to-gas facilities at a scale large enough to replace conventional natural gas would require doubling today’s EU installed power generation capacity over the next 30 years, which is deemed ambitious.

49 Some estimates suggest that a carbon price of 100 euros per tonne would be needed to raise low-carbon gas competitiveness, against a price of 20 euros per tonne in 2019.

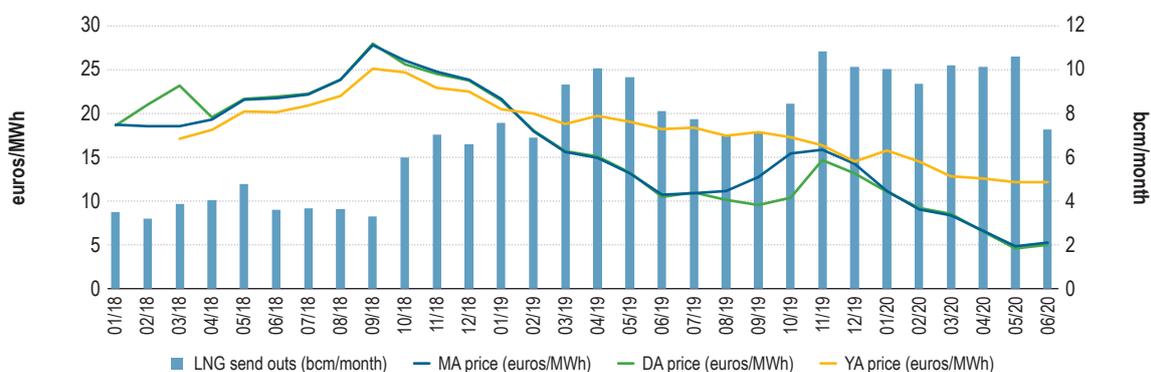
75 When gauging the feasibility of low-carbon gas economics, the cost of upgrading the grid (but also some end-user appliances) is another critical consideration. Existing gas networks should mostly accommodate the envisaged transition, but significant adaptations and expansions may be necessary, at both transmission and distribution networks⁵⁰. The debate about the best suitability of the distinct production options⁵¹ seems to be steering towards a more central role of hydrogen, in accordance to the latest EC strategy.

2.3 Price developments

76 EU hub prices dropped to ten-year lows in 2019, chiefly due to the downward price pressure of record LNG deliveries. Robust pipeline imports, falling prices of other energy commodities and high UGS stocks all contributed to the overall low-price sentiment.

77 Gas prices had started a sharp decline by the end of 2018, following soaring LNG imports, confirming the more and more global character of the gas market. As shown in Figure 7, LNG deliveries strengthened as the year 2019 advanced, pushing prices further down. By September 2019, spot gas was sold at 9 euros/MWh, three times cheaper than just a year before.

Figure 7: Evolution of TTF spot and forward hub prices vs LNG imports – 2018 – June 2020 – euros/MWh



Source: ACER calculations based on ICIS Heren.

78 Prospects of price recovery had been anticipated during most of 2019. Forward hub products leaned into that direction, showing a premium against spot and prompt hub prices, as Figure 7 also shows⁵². Expectations of demand recovery in the Asian-Pacific area region and concerns about the continuation of Ukrainian transits were among the key reasons for that.

79 However, as the year advanced, EU spot prices remained at low levels, as high LNG imports were maintained. Mild weather, the Russian-Ukrainian gas transit agreement and UGSs high stocks all contributed to the oversupply situation, moving down forward prices accordingly.

80 This setting extended into 2020. In fact, spot and prompt hub prices plummeted to new lows during the spring of 2020, due to the economic slowdown caused by COVID-19 pandemic and the lockdown measures (most notably, by June 2020 spot gas was sold at just 4 euros/MWh at the most liquid EU hubs, noticeably below US Henry Hub prices but also lower than prices at the Russian gas exchange).

81 Low prices prevailed throughout 2019, despite some short-lived rises due to specific circumstances. For example, at the end of September, there were three relevant announcements: extra production cuts at the

50 In its climate neutrality objectives for 2050, the EC identifies the need for doubling EU energy investments not only in power and gas RES generation, but also infrastructure. At transmission level, eleven TSOs published a [Hydrogen Backbone Initiative](#) in July 2020, building hypothesis regarding cost of upgrading the gas network to accommodate hydrogen.

51 Certain partakers advocate for chiefly supplying decarbonised methane rather than cementing the transition in hydrogen, in order to reduce the costs of upgrading gas grids. On the other hand, a transition based on methane would result in higher carbon emissions, while there are concerns about land use and agricultural sustainability if opting for heavily procuring biomass resources to produce methane.

52 The gap was higher for year-ahead and season-ahead products. Month-ahead prices were more aligned in comparison to spot ones, given the shorter time difference and their closer price formation interlinks.

Groningen field⁵³, flagging of French nuclear woes and limitations to capacity accessing at the OPAL pipeline. Also, in the last months of the year, EU shippers had to take more gas from costlier pipeline contracts to fulfill their take-or-pay obligations, which they had deferred as they had sought to take advantage of cheap LNG. All these factors contributed to a moderate price rebound.

82 Spot price volatility was high throughout the year with two key factors seen as major contributors: the increasing presence of intermittent RES in the electricity generation mix (favorable wind conditions mean wind turbines can displace gas-fired power generation, and vice versa, moving gas hub prices accordingly) and the requirement to send out LNG imports into the network in a limited time. This may create system imbalances in some markets, which lead to price volatility spikes. Spot price volatility values at a selection of EU hubs in recent years can be consulted in the MMR data portal.

83 At global level, the interdependence in gas price formation continued to consolidate during 2019, facilitated by greater availability of LNG and the growth of inter-regional hub hedging. Even so, the distinct fundamentals of each specific global region still explain some price disparities. Henry Hub prices were the lowest, falling by 14% YoY as a result of strong shale gas production in the US (+10% YoY). Figure 8 offers an overview of the evolution of various international gas wholesale price references in recent years.

84 Finally, even if the correlation among energy commodities prices continues to remain generally robust, there were some price disconnections in the second half of the year, more marked for spot products. The specific fundamentals of gas throughout 2019 put strong downward pressure on spot gas prices, leading to some price divergence with oil and coal. The interlinkages between coal and gas had been stronger in the last couple of years⁵⁴, whereas the oil-gas price connection, even if still relevant, has been losing some ground. This is due to both the reduced presence of oil prices in gas supply contracts' price indexes and because of some specific movements observed in global oil markets (political aspects, trade issues, weaker demand forecasts, etc.) are not always fully reflected in gas prices⁵⁵.

2.4 Infrastructure and system operation developments

85 This section reviews the main gas flow and infrastructure developments that occurred during the year and includes an assessment of both LNG and UGS market perspectives.

2.4.1 Physical gas flows across EU borders

86 Figure ii in Annex 1 shows an overview of EU and EnC gas cross-border flows in 2019. As already mentioned, LNG imports rose to an all-time high. In spite of that, pipeline imports were overall solidly upheld to cover for declining domestic production and (slightly) higher demand, as well as to fill UGSs' rising stocks.

87 The Russian northern supply routes, Nord Stream and Polish Europol, kept operating close to their peak capacities⁵⁶. This was despite a higher reliance on LNG in NWE and notwithstanding the September decision of the European Court of Justice to limit access for Gazprom to just 50% of the OPAL pipeline capacity across Germany (the cap entails a flow reduction of 12.5 bcm/year).

53 The rapid pace of the decline is entailing growing requirements for conversion of high calorific gas into low calorific gas (the one produced in the Groningen field) which could result in price divergences among products.

54 Driven by gas and coal switching opportunities for power generation. However, since coal-fired power generation has started to lose ground across the EU, the switching opportunities are turning more limited, affecting the robustness of price correlations.

55 As an illustration, when oil prices rose on 16 and 17 September 2019 by some 15% following drone attacks in Saudi Arabia oil production facilities, TTF prices dropped by 6%.

56 Russian exports' flow profile is becoming flatter, aided by a relatively higher MS demand in the summer. From the beginning of 2020, high LNG imports pressed down pipeline supplies more noticeably. LNG was in the lead in January in terms of share, while Russian and Norwegian pipeline flows stood at five years lows.

- 88 By the end of 2019, Ukraine and Russia had signed a five-year agreement setting minimum transit flows across the Ukrainian network: 65 bcm/year for 2020 and 40 bcm/year onwards. The latter figure is half the sum of the volumes transited across Ukraine in 2019⁵⁷. These future supplies will be mainly targeted to Central Europe and Moldova. By contrast, the new Turk Stream will re-route Russian flows towards South-East Europe.
- 89 Germany kept cementing its transit role for transporting Russian gas to other parts of the EU. This role will increase further once Nord Stream 2 comes online. The first string of the EUGAL pipeline opened a new supply route to the Czech Republic at the end of 2019. The new corridor will likely decrease Russian gas transits across the Ukrainian-Slovakian route. However, the surge in EU LNG imports led to some declines across other German supply routes. For example, flows from Germany into France fell by 40%, as French LNG imports soared by more than 90% YoY⁵⁸.
- 90 The new ROHU interconnector has enabled Romania to receive additional reverse flows from Hungary since October 2019. Bulgaria acquired some small deliveries of LNG from the Greek Revithoussa terminal. These developments underline the supply diversification taking place in the region. TAP flows were initiated at the beginning of 2020 across Greece and Albania.
- 91 Flows from the Continent into the UK kept falling, as hub spreads do not usually cover for the transportation costs of new capacity. For example, the flows across IUK from Belgium into the UK have dropped by more than 80% since 2017, when the last LTCs expired⁵⁹. Section 4.2.3 offers more insight into the issue.
- 92 Overall, the larger imports of LNG in Spain and Italy diminished their gas sourcing needs from northern routes in winter months. These routes tend to be relatively flexible in terms of operation, but face comparatively high transportation costs. The consolidation of the single TRF market zone in France generally made gas exports into Spain more price favourable. However, flows through the VIP Pirineos reversed the dominant direction in the last quarter of the year, when Spanish hub prices sank following LNG surplus deliveries.

2.4.2 Infrastructure investment

- 93 Several MSs keep striving to diversify their interconnection capabilities to enhance supply competition. This has resulted in various proposals for new pipelines and LNG terminals⁶⁰. A number of new large supply corridors, relevant enough to visibly affect the competition framework at regional level, started to materialise towards the end of 2019.
- Gas flows across *Turk Stream* – an offshore pipeline connecting Russia and Turkey through the Black Sea – started in 2020 across its first line, which serves Turkey. A second line will further transit gas to Bulgaria, Serbia and Hungary⁶¹. Each of the lines has a capacity of 15.75 bcm/year. The project has started to divert exports that used to be transported via Ukraine.
 - *The Southern Gas Corridor initiative*⁶² will diversify EU supplies by bringing volumes from the Caspian and Middle Eastern regions. The TAP line, with a capacity of 10 bcm/year, is expected to reach Italy by the end of 2020.
 - Finally, Nord Stream 2 will add 55 bcm/year of extra import capacity. After some delays, this second line is expected now to enter in operation in the beginning of 2021.

57 The OPAL cap has favoured the rerouting of some Russian gas volumes across Ukraine and Slovakia since September 2019. However, Russian flows via Ukraine plummeted at the beginning of 2020. This was attributed chiefly to low EU gas demand, the use of Gazprom gas in UGS stocks (see Section 2.4.4) and changing export patterns once the EUGAL and Turk Stream pipelines came online.

58 Flows from Belgium to France also decreased for the same reason.

59 In fact, the surge in LNG imports and the lack of domestic storage capacity spurred some winter exports from the UK to continental Europe. Though volumes were limited, this had been something unusual in previous years.

60 See further considerations on the subject in [footnote 19](#).

61 Supplies for Bulgaria (also Greece and North Macedonia) also started at the beginning of 2020, whereas flows into Serbia are expected for mid-2020 and for Hungary in 2021.

62 The initiative comprises [a number of subprojects](#).

- 94 Further than these main corridors, various other projects are progressing, including the ROHU interconnector, which has enabled 1.75 bcm/year of capacity from Hungary to Romania since October 2019. A similar magnitude of reverse capacity is expected to become operational by October 2020 and will allow additional flows of Romanian and future Black Sea gas into Hungary. Capacity is planned to increase up to 4.4bcm/year, targeting other markets such as Austria
- 95 Developments in the Balkan area are also significant, with the enabling of reverse flows from Croatia into Slovenia and Hungary⁶³, plans to interconnect Hungary and Italy across Slovenia and, as referred, the linking of Bulgaria to Hungary through Serbia. Besides, the forthcoming IGB interconnector between Bulgaria and Greece will allow access to Azeri gas via TAP and also possibly to LNG. These developments should reduce the region's high reliance on Russian supplies, and transform it into a more interconnected trading area.
- 96 The Baltic Connector pipeline linking Finland and Estonia was commissioned in the beginning of 2020, marking the end of full dependence of any member state on a single source of gas supply, as discussed further in Section 3.1. It offers bidirectional capacity of 7 bcm/year. In addition, a new Baltic Pipe, set to connect Denmark and Poland to Norwegian fields, is to start operation by October 2022 (10bcm/year). Expansions on the Polish-Ukraine route could allow Ukraine to access LNG imports from Poland.
- 97 With regard to LNG, several new projects are in the pipeline, for example in Croatia and Greece, having as main aim to enhance competition by enabling regional accessibility to LNG⁶⁴ (see an overview of all existing and planned EU LNG terminals in Figure iii in Annex 1⁶⁵). Germany has also announced plans to operate a new terminal by 2023. In addition, some terminals in France, Belux and Poland are exploring capacity expansions, driven by market-interest.

2.4.3 Analysis of LNG market developments

- 98 The dynamics of EU LNG imports underwent a huge shift in 2019: deliveries rose by +90% YoY and LNG covered 20% of EU gas demand, its highest ever market share by far. The largest countries of LNG origin were Qatar (31%), Russia (16%) and the US (16%), while North African suppliers lost relative market share. LNG imports rose markedly all-around Europe, as shown in Figure ii in Annex 1.
- 99 The slowdown of demand in the Asia-Pacific region⁶⁶ – and parts of South America and the Middle East – concurring with increasing global LNG production capacity (+13% YoY)⁶⁷ resulted in surplus supply of LNG that found Europe to be its market of last resort. There are several reasons for the EU to have assumed such a role:
- In terms of infrastructure, the EU can attract sizeable volumes of surplus LNG cargoes thanks to its ample regasification capacity, which could meet 45% of total EU demand, and large UGSSs. Furthermore, extra LNG deliveries tend to exert downward pressure on prices, which helps to displace coal by gas for power generation, using the spare capacity of CCGTs plants.
 - The rising liquidity of EU hubs consolidate them as key price benchmarks for hedging global LNG portfolios. Most liquid hubs, chiefly TTF, are not only becoming a substitute for oil in indexing new LNG contracts, but

63 Those shall back the possibility of exporting Croatian domestic production and using of the new Krk LNG terminal.

64 An enhanced LNG supply role is an important part of the EU's diversification strategy. The aim is not only to guarantee security of supply, but also to discipline prices from competing pipeline suppliers. Increasingly integrated EU markets enable LNG supply even in MSs with no direct access.

65 There is a total of 24 large-scale terminals in 11 MSs. Eighteen additional ones are planned, six of which will be in MSs that do not have any yet. Not all, but several of these projects are well-advanced. Besides various capacity expansions will take place in existing facilities.

66 Japan (26.5%), China (17%) and South-Korea (13.5%) account for more than half of global LNG imports, while other smaller Asian markets are also increasing supplies. Europe absorbed 21% in 2019, up from 13% in 2018. Japan (-7%) and South Korea (-8%) saw declining YoY demand, led by stronger nuclear power generation, while Chinese demand showed a lower YoY increase (+17%) due to economic disturbances and well-preserved coal consumption.

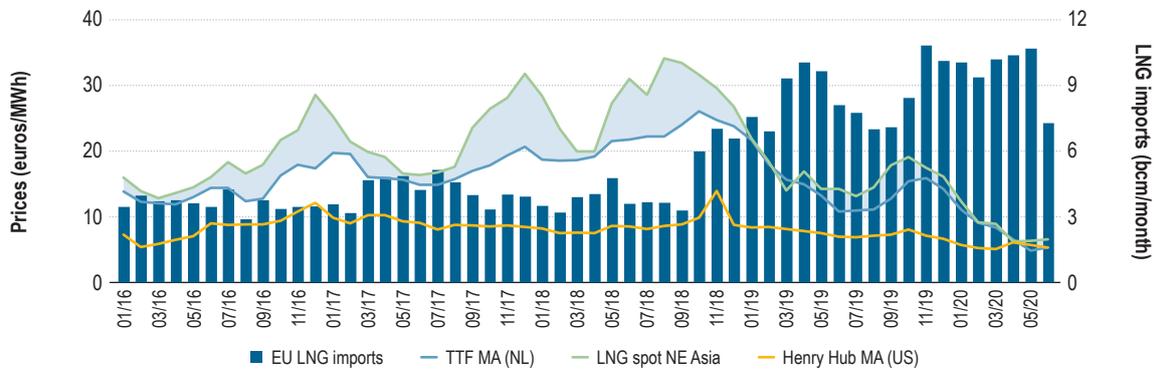
67 Global LNG liquefaction capacity has grown extensively in recent years, moving from 420 to 550 bcm/year in the 2014–2018 period. In addition, 2019 saw record FIDs for new projects (+90 bcm/year), even with gas prices falling to record lows. Most of the new capacity will be available in the 2025 horizon, mainly from the US and Australia, but also from Qatar and Russia. In accordance to IEA estimates, US and Australia will both overpass Qatari LNG production by 2025. Volumes of surplus LNG have further grown in 2020, due COVID-19 demand impacts.

are also increasingly used to create a netback price for LNG supplies⁶⁸. By doing so, they are shifting the traditional ‘Henry Hub cost plus’ pricing-strategies of US producers, putting some pressure on their margins to the benefit of EU buyers⁶⁹.

- The decline in EU gas domestic production, expirations of some long-term supply pipeline contracts and the shift of global LNG markets to more flexible supply terms⁷⁰ also support increasing LNG imports.

100 As a result of the rising influence of LNG trading⁷¹, the interdependence of gas price formation between global regions is strengthening. Greater price convergence is a sign of stronger integration; the Pearson correlation coefficient between TTF and the OTC Japanese index JKM reached 0.87 in 2019 (and 0.95 up to May 2020), whereas the average yearly spread dropped to 0.5 euros/MWh. As illustrated in Figure 8, the price spread between Europe and North-East Asia had shown a pronounced seasonal component until recent years, and spreads of more than 6 euros/MWh were not infrequent in winter⁷².

Figure 8: Comparison of international wholesale prices spreads vs EU LNG imports– 2016 – June 2020 - euros/MWh – bcm/month



Source: ACER calculation based on GIE ALSI and ICIS Heren data.

101 Overall, EU market participants have increasingly used LNG for some years as a competitive instrument that serves to balance portfolios and hedge prices on shorter horizons. This has been making LNG deliveries, and chiefly spot LNG purchases, more price-responsive, although also more volatile. Noticeably, some non-EU LNG producers took a more active role in bringing surplus cargoes into EU terminals in 2019 (sometimes under their own control⁷³).

102 Backed by more favorable global LNG prices, the utilisation of EU terminals has increased in the last few years, from 21% in 2016 to 45% in 2019. Overall, there is still ample surplus regasification capacity in the EU. However, selected terminals were close to maximum capacity during 2019, and there have been examples of congestion, chiefly in storage tanks, creating some bottlenecks.

68 Though global LNG contracts keep being mostly traded in dollars, in **selected cases** a switch in trading currency into euros is being observed.

69 This trend has been exacerbated in 2019 and the spring of 2020, when the price gap between the US and the EU did not always cover for liquefaction, transportation and regasification fees. US LNG spot sales are much higher than from other producers.

70 In 2019, 34% of global LNG imports had a spot contractual basis (i.e. were delivered within 90 days from the transaction date) while destination-free contracts accounted for 40% of total deliveries. Most of the additional LNG that shored into EU in 2019 was purchased on a spot or mid-term basis, or was sourced by producers.

71 Global LNG trade increased in 2019 by 13% YoY, while LNG accounted for more of 35% of total gas global trade. By 2030, some projections forecast this figure will have reached 50%. The LNG chain is also becoming more efficient, driving costs down thanks to technological advancement.

72 Asian countries still tend to have fewer pipeline supply options and storage capacities, which have tended to make prices more volatile. The rising price convergence of EU and Asian markets led to fewer LNG arbitrage opportunities in 2019. As a result, re-exports from EU buyers' sharply decreased YoY.

73 A Qatari company acquired in 2019 all the regasification capacity at the Zeebrugge terminal for 20 years from 2023. The Qatari incumbent chiefly controls various UK terminals.

103 Therefore, it is important to look at the regulatory aspects that govern terminals' capacity access to evaluate if they may hamper competition or hinder the intra-European LNG market. Particular attention needs to be paid to exempted regimes. The EC recently published a study summarising the access provisions in place in distinct markets. It reaffirmed that tariff competition among LNG system operators affects the utilisation of individual terminals⁷⁴. The scrutiny of MSs tariff methodologies by the Agency has revealed that discounts to access LNG is granted in most systems, justified by the positive externalities they may induce⁷⁵. A comparison of LNG terminals' tariff levels is shown in Figure iv in Annex 1.

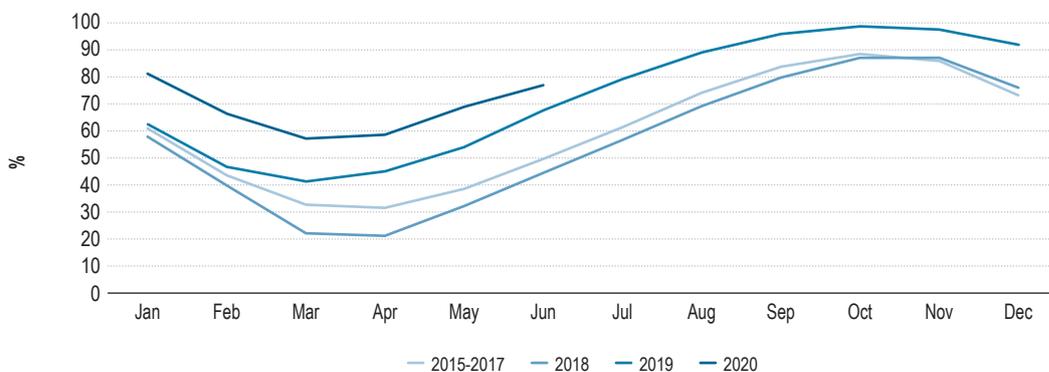
104 The distinct access and technical conditions of terminals partly explain the differences between gas wholesale markets in MSs in terms of price-responsiveness of LNG imports. The differences further arise due to a combination of other factors, including the local role of LNG supply, the ease of access to liquid hubs or the prevailing contracts. Interestingly, in Spain, all six LNG terminals started to be operated in April 2020 as a single virtual tank. This is expected to ease operations and contribute to the liquidity of the Spanish PVB hub.

105 LNG is projected to keep increasing its share in the EU gas mix in the coming years, as a means to diversify supplies and compensate for lower EU domestic gas production. The extent to which these projections materialise will mainly depend on market developments in the Asian-Pacific region. In the longer-term, the role that LNG will play in the low-carbon gas transition remains to be seen.

2.4.4 Analysis of underground storage facilities market developments

106 UGS facilities play both a security of supply and a market role, the latter oriented to price management⁷⁶. The varying supply needs throughout the year, the technical specificities of the sites, obligations prompted by security of supply regulations, access conditions and prevailing contracts all impact the operational strategy of UGS users. All these factors combined led to unprecedented high stock volumes in EU storages in 2019 and in the beginning of 2020, as Figure 9 shows.

Figure 9: Evolution of EU storage site levels – 2015 – June 2020 – % of EU stock capacity



Source: ACER calculation based on GIE ALSI+ data.

107 This extraordinary outcome is the result of a combination of events:

- Much of Europe experienced a mild 2018/2019 winter and higher than usual LNG deliveries. Both factors dampened UGS withdrawals. By March 2019, UGS stocks had more than doubled compared to March 2018⁷⁷

74 See the study [here](#). The study aims also to identify and analyse legislative measures intended to address these barriers. In accordance to the study, the main reasons why shippers choose a specific EU LNG terminal are the possibility to access a more liquid hub and the tariff levels of terminal services.

75 LNG tariffs are not fully cost-reflective in various markets. Cross-subsidisation – which further than network accessing discounts, can also imply terminals' costs recovery from transmission users – is defended either for SoS reasons or in the aim of disciplining the prices offered by pipeline suppliers, chiefly where LNG sets the marginal price.

76 These two roles are also related to the timeframe; in the mid-term, storage sites tend to back seasonal supply flexibility and assist forward price hedging, while in the shorter-term they tend to assist managing physical portfolios and the arbitrage of hubs' spot prices.

77 In March 2018, following a cold spell, EU UGS sites recorded the lowest stock levels for the last eight years.

- Despite the high stocks limiting the need to fill storages, injections were high throughout the injection season as shippers took advantage of low prices and high LNG availability to store more gas.
 - Towards the autumn, concerns rose about the continuation of Ukrainian gas transits. EU shippers – as well as Gazprom – stored gas as a hedge to a possible disruption of deliveries⁷⁸. EU UGSs hit their yearly peak by the end of October 2019 at 1,085 TWh – more than 20% of EU yearly demand.
 - During the first winter months of 2019/2020, storage withdrawals were low. LNG kept coming, weather-driven demand was mild again and uncertainties about Ukrainian transits still remained. In addition, the price premiums held by hubs' medium-curve contracts vs prompt ones reduced the incentive to withdraw gas.
 - At the beginning of 2020, UGS withdrawals somewhat increased. Gazprom had filled 11.4 bcm of gas in EU sites in case of no transit agreement⁷⁹ and began emptying its surplus stocks. Hub price signals were also supportive. However, sites' extractions were not robust enough to alter the dominant picture. By the end of May 2020, UGS stocks were at 68%, fifteen points higher than the average of the five preceding years, pushed upwards by continuous LNG arrivals and lower demand induced by COVID-19.
- 108 These physical gas movements were driven on the whole by hub price signals, reflecting market expectations. Overall, UGS operation strategies had shifted in most market towards shorter-timeframes, at the expense of reducing mid-term hedging and security of supply roles⁸⁰, even if the Russian-Ukraine disputes tested these dynamics in 2019. This trend better supports the management of volume and price risks in shorter horizons, making it easier to accommodate rising gas price volatility and variable gas demand spurred by intermittent RES production.
- 109 Indeed, since mid-2010s, seasonal price spreads at EU hubs have been narrowing, making UGSs mid-term bookings financially less attractive⁸¹. However, remarkably, seasonal spreads surged higher in 2019 and even more in 2020 (when spreads reached a 10-year record high), as [Figure 10](#) reveals. Steeper seasonal spreads chiefly came out of prospects for very depressed prices during summer months⁸². This is notable, as customarily high seasonal spreads are connected to projections of supply tightness in winter, pushing prices up.

78 In Ukraine UGSs stocked higher volumes too, following alike concerns (+20% YoY). About 10% of the gas had been injected by EU suppliers. Storage use has been promoted in the country via lower storage fees and cuts in transportation tariffs. The Slovak TSO also announced in April 2020 a 40% discount for the exit capacity at the border, making access to Ukrainian storages more appealing. These measures may put pressure in revenue recovery for TSOs though.

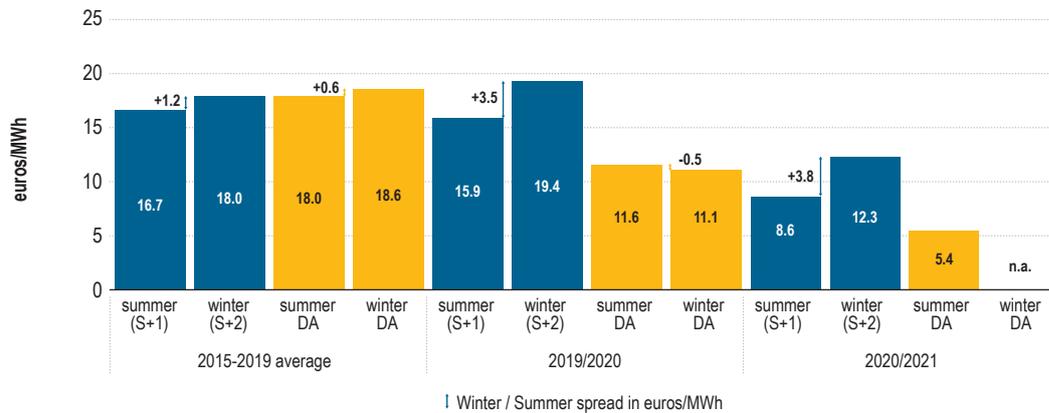
79 This is more than twice of previous years' stored levels.

80 Both the strategies are interrelated as market participants may initially conclude trades in order to hedge seasonal spreads and physical needs but then arbitrage those contracts as they cascade, adding profitability to the initial intrinsic positioning. The expiring of some storage long-term contracts also contributes to the shorter-term shifting. Though UGSs price-responsive use degree varies per MS – merchant-based models are more acute in NWE – in general most of Europe has liberalised to a point in which financial signals well drive storage users' strategies.

81 E.g. from 4 euros/MWh in 2012 to 0.9 euros MWh in 2018 for TTF. The reasons include lowering total demand on the one hand and enhanced gas supply flexibility on the other. The latter also brought about enhanced market interconnection, increased access to LNG and less pronounced seasonal gas demand variations.

82 I.e. expectations of lower-than-usual prices at the middle of the forward curve (summer) vs higher prices at its end (winter). For 2019, this situation was mostly the outcome of record LNG deliveries. For 2020, the setting occurred due also to record gas stocks and COVID-19 impacts in the economy, projected to be more dramatic for the summer months.

Figure 10: Comparison of ex-ante season summer/winter spreads vs actual spot prices at the TTF hub – 2015–2020 – euros/MWh



Source: ACER calculation based on Platt's and ICIS Heren data.

Note: The ex-ante summer/winter spread is calculated as the difference between the Season-ahead+2 and Season-ahead+1 hub product prices, both negotiated on the month of March. The actual summer/winter spread is calculated as the difference between the spot average prices along both seasons. Summer 2020 day ahead prices have been assessed until mid-July. It was not possible to assess winter 2020/2021 day ahead prices given MMR publication dates.

- 110 Growing seasonal spreads and rising prompt price volatility have supported the profitability of storage assets in the last couple of years. The transition towards a carbon-neutral economy will further test their significance in the medium-term. UGS sites are expected to be increasingly used to store methane to feed hydrogen production in SRM processes⁸³ or to store green hydrogen produced by RES⁸⁴ (some facilities might need to be adjusted to allow for a more dynamic operation⁸⁵).
- 111 The extent of the envisioned energy system integration will be crucial for determining the role that UGSs can play in the future⁸⁶. Decarbonised gases have potential to be transported and stored at lower cost and in larger volumes than electricity, which could support UGSs' business cases. The EC recently published a strategy on the subject, identifying the challenges ahead and the regulations that might support more effective energy system integration⁸⁷. The discussions about the business case for electrolysis facilities (i.e. it is possible that they may rely on continuous rather than flexible RES input for economic reasons) and a plausible revision of access tariffs in order to make power-to-gas plants further competitive are also relevant for gas storage sites.

83 But also to inject the massive quantities of carbon dioxide generated in CCS procedures. The location for both of these facilities is yet unclear, but could boost the relevance of EU UGSs if placed within Europe.

84 Hydrogen and/or methane produced from RES could be injected into UGSs and get latter reconverted into electricity to deal with seasonal demand swings or low RES electricity production periods.

85 UGSs' injection and withdrawal utilisation rates are moderate compared to their nominal capabilities (e.g. See MMR 2018, Figure 16). This shows that there is further ground to increase their market responsive operation. Moreover, due to the lower energy density of hydrogen, UGS capacities would be reduced by a third if used to store hydrogen instead of gas.

86 The improvements in energy efficiency and growth in electrification projected for the coming years are called to steadily erode gas demand, which could also diminish gas UGSs current relevance.

87 See [EU Strategy for Energy System Integration](#).

3. Assessment of EU gas markets according to Gas Target Model metrics

- 112 The ACER Gas Target Model is a conceptual guide for implementing the EU's internal gas market. It was developed and endorsed by the Agency, national energy regulators and gas sector stakeholders. At its core are ideas of competition at, liquidity of, and price integration between gas hubs⁸⁸.
- 113 Integral to the AGTM is a set of indicators, the so-called market health and market participants' needs metrics⁸⁹, the values of which are presented and analysed in this Chapter. The analyses focus on market structure, transactional activity and resulting prices at various hubs in order to assess whether there is a gap between their current and the AGTM-envisioned performance.
- 114 Hubs that persistently fall short of the benchmarks should be, according to the AGTM guidance, integrated with other hubs so as to facilitate greater competition and boost liquidity to the benefit of market functioning and ultimately of consumers.
- 115 The Chapter employs both the already mentioned indicators⁹⁰ and other, supplementary market performance indicators. Furthermore, some metrics have been calculated using anonymised and aggregated data reported to the Agency under Regulation (EU) No 1227/2011 (REMIT). As in previous editions of the MMR, some assessments are necessarily limited to the gas hubs where standard products are traded on transparent trading venues⁹¹.

3.1 Market health and gas sourcing cost

- 116 In the context of the AGTM, structural competition aspects of gas hubs⁹² are covered by the term market health; the related market health indicators measure the number and concentration of supply sources as well as a hubs' potential to meet demand using the capacities not controlled by its largest upstream supplier.
- 117 Better market health results – together with a better functioning hub – tend to predict lower gas supply sourcing costs⁹³. Differences in gas sourcing costs can therefore reveal how effective the structure of a hub is in facilitating supply competition.

GAS SOURCING COST

- 118 Gas supply sourcing costs⁹⁴ fell by more than 3 euros/MWh in 2019 compared to 2018 in most MSs; this resulted in a substantially lower gas import bill for the EU – according to EC estimates the 2019 EU gas import bill totalled 69 billion euros, a drop from 98 billion in 2018, reflecting the impact of falling import prices⁹⁵. Among other factors this was due to record LNG deliveries, above average winter temperatures and gas storages that had already been well stocked at the beginning of the gas injection season (see [Section 2.3](#) for a more in depth analysis of the topic).

88 See [European Gas Target Model](#) review. [Footnote 9](#) in the Executive Summary adds further clarifications.

89 Results of market health metrics indicate whether a gas wholesale market is structurally competitive, resilient and exhibits a sufficient degree of diversity of supply; the results of market participants' needs metrics indicate the level of liquidity of a gas wholesale market.

90 Indicators that were developed concurrently with the Target Model itself. See [here](#).

91 Transparent trading venues refer to organised wholesale market places, either exchanges or OTC deals facilitated via brokers. AGTM Annex 3 further clarifies the metrics methodology and provides a definition of technical concepts.

92 Due to the relevant data being available only per MS, it is not feasible to calculate the metrics for the two German hubs in a disaggregated fashion.

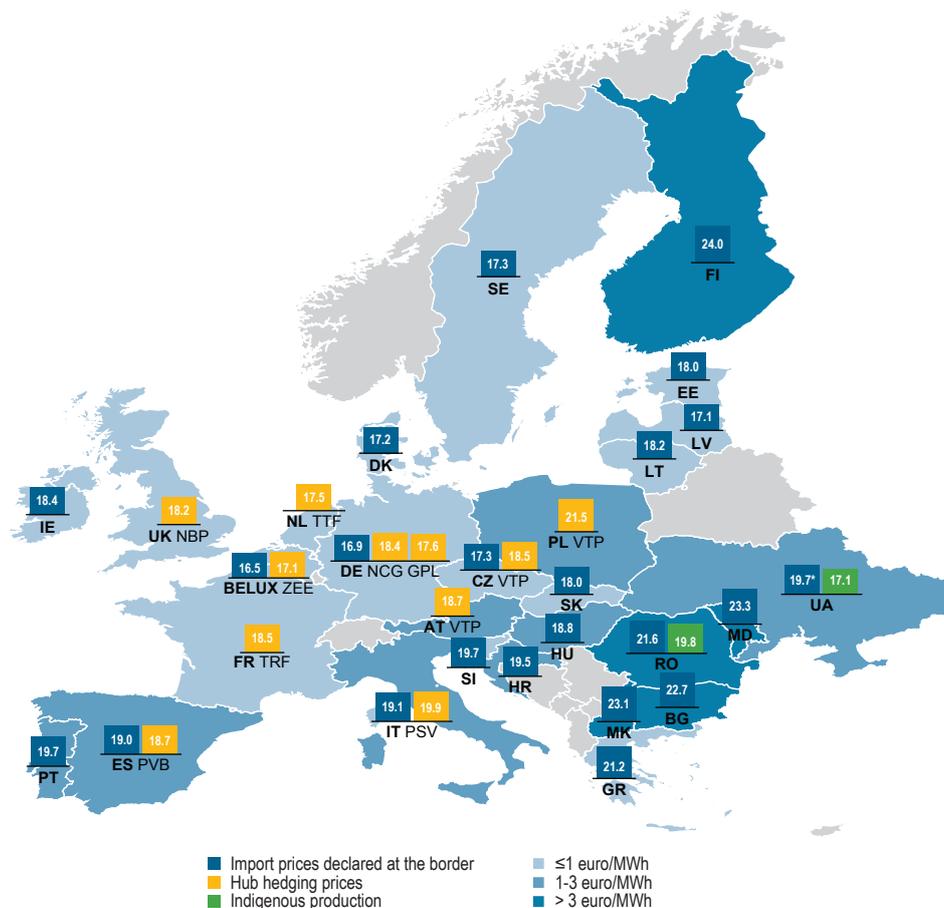
93 Sourcing costs are also affected by factors other than upstream competition and liquidity. For example, lower prices are observed occasionally at MSs with prevailing oil-indexations under certain favourable conditions, even if they are not that competitive.

94 To gauge the average theoretical supply sourcing costs prevalent at individual EU gas wholesale markets, the Agency uses a proprietary methodology with which it calculates three types of sourcing costs: i) based on an explicit basket of hub products (possible for markets with sufficient liquidity), ii) based on declared imports and iii) based on domestic production prices. See MMR 2014, Annex 6 for details on the general methodology and specific data used for selected MSs.

95 See the EC [quarterly gas market monitoring report](#) for more details.

- 119 Convergence in sourcing cost remained robust in 2019 among most MSs⁹⁶ as shown in Figure 11. However, as gas prices did not fall simultaneously and to the same extent across all MSs, there were some gas markets where the gap between their cost and the benchmark TTF-based sourcing costs grew bigger than in recent years. The gap was the biggest for less integrated and diversified markets, where reliance on LTCs has remained higher (prices of oil-indexed LTCs and hub prices tend to diverge in periods of hub price volatility, as the former do not necessarily respond to gas market developments).
- 120 Supply costs in the EnC CPs, with the exception of Ukraine, continue to be sensibly higher than in MSs – a result of the prevalence of less favourable LTCs in the absence of sufficient upstream supply competition.

Figure 11: 2019 estimated average suppliers' gas sourcing costs by MS and EnC CP and delta with TTF hub hedging prices – euros/MWh



Source: ACER calculation based on Eurostat Comext, ICIS and NRAs from both MSs and EnC CPs.

Note: Import prices for AT, NL, FR and PL could not be assessed. For Ukraine, the import price estimate is based on the supply sourcing cost assessment of the Austrian hub plus gas transportation costs. Depending on the actual procurement strategies of Ukrainian importers, actual import prices could have been different. For instance, if their procurement strategies were predominantly based on month-ahead hub products of EU hubs, but also if they use storage capacities under certain conditions that liberate them from paying taxes or custom duties, the resulting import prices are estimated in around 17 euros/MWh.

MARGINAL SOURCE OF GAS SUPPLY

- 121 Generally, the combination of marginal supply and market opportunity pricing⁹⁷ explains the enduring sourcing cost differences among some MSs. Both are in turn affected by factors like competition, transportation costs,

96 EU gas market integration keeps delivering benefits to consumers in terms of sourcing costs enhanced convergence. It is to be considered that a few years ago, sourcing costs in the Baltic or SSE regions were in the order of 5 euros/MWh higher than at NWE.

97 Marginal supply denotes the price signal sent by the last (i.e. most expensive) supplier sourcing at the hub. It commonly disciplines the prices of the rest of competitors, which tend to offer some discount to secure sales and maximize revenues. This is the so-called 'market opportunity price'.

predominant sourcing mechanisms and market structure. Price differences may also appear between the various sourcing mechanisms within a country⁹⁸. In practice, determining the exact impact of the most expensive supply source over the price formation of individual gas markets – and more specifically, over the price formation of organised trading hubs – is not straightforward and its importance may vary between gas hubs.

- 122 In some of the analysed MSs (e.g. Italy, Spain) the most expensive supply source tends to only cover a modest percentage of demand, but is deemed important for the price formation at their gas hub⁹⁹. However, in some MSs the most expensive source covers a substantial share of demand, which might indicate that the supplier cannot be replaced, making it a pivotal rather than a marginal source of supply¹⁰⁰. This latter setting may lead to scarcity pricing situations¹⁰¹. Specific geographical aspects¹⁰² as well as conditions of existing LTCs can also be relevant factors. Finally, in the most competitive and interconnected hubs, the identity of the so-called marginal source of supply tends not to be fixed but fluctuates throughout the year as market conditions change¹⁰³. In less diversified markets, the marginal supply source tends to be more fixed and identifiable and its price influence larger. These situations tend to reveal a higher supply concentration, possibly also at midstream level.

NUMBER OF SOURCES OF GAS SUPPLY

- 123 Gas flown via pipelines from Russia, Norway and Algeria, gas produced in the EU, and gas shipped in liquefied form are currently the most relevant types of upstream gas supply in the EU. In addition to these supply sources, also EU gas hubs, which are increasingly being used by shippers as sourcing options, are included in the number of distinct gas sources assessment.
- 124 In 2019, the Finnish wholesale market was the only EU market to be fully supplied by a single gas source, as presented in Figure 12; therefore, the start of operations of the Balticconnector pipeline in 2020¹⁰⁴, which links Finland and the newly formed Latvian-Estonian market area, represents the end of full dependence of any MS on a single source of gas supply.
- 125 Gas hubs with LNG regasification capacity, the largest of which boast 10 or more distinct sources, have the highest number of distinct gas supply geographical origins. Markets without LNG receiving terminals have a more limited sourcing portfolio like, for instance, CEE markets which are supplied by a combination of Russian imports and gas sourced via NWE hubs. Diversity of supply was also assessed for the EnC CPs. As Figure 12 shows, apart from Ukraine (which in 2019 was fully supplied by domestic production and gas sourced, though likely not produced, in the EU) EnC CPs have a high reliance on one external supplier.

98 E.g. considerable price deltas may appear within a given market between the sourcing costs at its trading hub and the declared import prices at the border.

99 For example, at Italian and Spanish trading hubs, imports from NWE are deemed more key for price formation, while LTC imports from, for example, Algeria may not always reach the hub. The former supplies tend to be priced such as to include transportation costs across NWE supply routes. However, in the 2019, gas supplies from Algeria – and Russia, in the case of Italy – were reported on average costlier than NWE imports. The discussed non-simultaneous price drop of sourcing mechanisms and LTCs take-or-pay clauses tends to explain this.

100 This would be for example the case of Russian supplies in the Baltic region, which tend to set a higher price reference than competing LNG deliveries from Norway. Again, the existence of LTCs supply commitments may hinder the possibility to replace those sources.

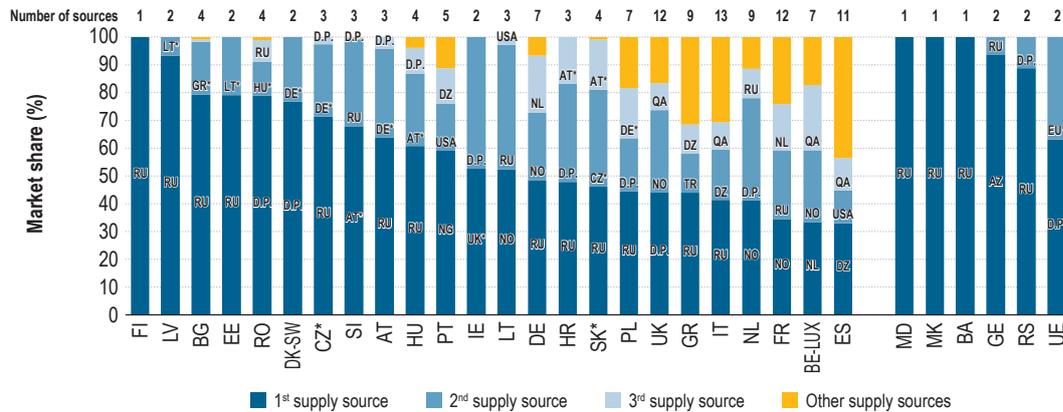
101 E.g. if supply capabilities are lesser and demand edges close to supply limits, prices rises are expected to occur reflecting the growing scarcity.

102 Geographical aspects can play a relevant part in setting-up marginal supply sources. The link is chiefly made across transportation costs, as Section 4.2.3 will further discuss.

103 To cite another example, in the UK, the most expensive supply source identified, on average, for 2019 was Norway. Flows across the EU-UK interconnectors were reported costlier, but represented negligible volumes. However, the availability of these flows also influences the prices for other competitors, including Norway.

104 Find more information [here](#).

Figure 12: Estimated number and diversity of supply sources in terms of the geographical origin of gas in selected MSs and EnC CPs – 2019 – % of actual volumes purchased¹⁰⁵



Source: ACER calculation based on Eurostat, IEA, British Petroleum and EnC Secretariat data.

Note: D.P stands for domestic production (domestic production is only included as a source when it represents at least 0.5% of gas demand; some countries, e.g. Georgia, have domestic production that was not considered relevant for this analyses due to the relatively small volumes). The asterisk refers to MSs with liquid hubs where gas is thought to have been purchased. For the Danish-Swedish market, the share of domestic production also includes the Norwegian offshore fields that are part of the Danish upstream network. The values for Slovakia and the Czech Republic are from the 2018 MMR due to lack of data availability for 2019. For Ukraine, the number of supply sources is likely higher than 2, based on the assumption that gas is sourced at various EU hubs, but could not be estimated more precisely.

CONCENTRATION OF UPSTREAM GAS SUPPLIERS AND RESIDUAL SUPPLY INDEX

- 126 A further sign of market health is a relatively low concentration of supply. This competition aspect is assessed through the Herfindahl-Hirschmann Index (HHI)¹⁰⁶ of upstream (as opposed to midstream or shipping) companies' supply share at individual hubs.
- 127 Healthy upstream market concentration is the benchmark that most hubs fail to meet¹⁰⁷ (i.e. in most markets upstream concentration is too high according to the benchmark). MSs that either host, or source from well-functioning hubs, those with less concentrated domestic production and/or those that benefit from a flexible supply source, i.e. LNG, exhibit lower (thus better) HHI values¹⁰⁸.
- 128 The residual supply index (RSI) completes the picture of the market health assessment – it measures possibility of upstream competition and indicates a market's theoretical supply dependency on its largest gas supplier. As Figure 13 shows, most MSs have sufficient residual supply import capacities¹⁰⁹, which suggests that, notwithstanding high concentration levels, the largest suppliers' ability to set prices are curtailed by prices at which other connected suppliers are willing to sell to the market. However, in the MSs with the RSI below the threshold – i.e. Bulgaria, Finland and to a lesser extent Hungary and Poland – the largest supplier is pivotal. This means that competitors cannot fully replace this supplier and, as such, the latter could exert market power over price formation.

105 The metric looks at the geographical origin of the sourced gas and not at the number of distinct interconnection capabilities. At selected MSs both figures may differ.

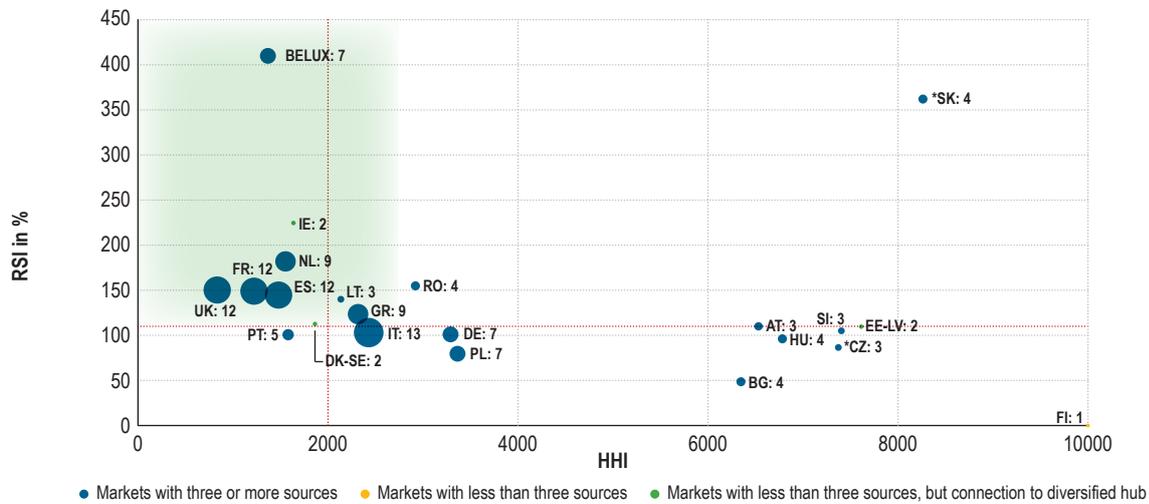
106 The HHI assessment is more detailed when compared with the number of supply sources. It looks into gas producing companies' market shares as opposed to only the supply country origins, however it is also more theoretical as it tries to trace back gas to the company that produced it – something that is not always easily done or apparent.

107 Transparency of information on market shares of upstream producers is limited in many markets. Also, the assumptions made may affect the calculations, so the results have to be treated with some caution. In this MMR 2019 REMIT relevant data have been initially explored, although just to contrast Eurostat main source. Further utilisation of REMIT data in the future will provide more precision to the assessment. Therefore, this MMR does not attempt to interpret the thresholds of the AGTM by the letter.

108 The HHI for the EnC Contracting Parties also point out to a high concentration of gas supply. While in Moldova and North Macedonia they reach maximal value, in Serbia and Georgia it amounted to 8042 and 4385 respectively. The equivalent value of the HHI could not be calculated for Ukraine, however, according to the NRA, an index referring to a midstream concentration (taking into account the shares of importing and producing companies) was 4026 in 2019.

109 MSs whose gas transmission system accommodates significant transit flows – e.g. Slovakia, Belgium, the Netherlands and the Czech Republic – perform the best for this metric. In addition, MSs with significant LNG regasification capacities relative to current demand, like Spain, the UK and Greece, also score high for the RSI.

Figure 13: Overview of MSs according to AGTM market health metrics (Upstream company RSI, HHI and number of supply sources) – 2019



Source: ACER calculation based on ENTSOG capacity data, Eurostat and NRAs.

Note: Y-axis measures the percentage of demand in MSs that can be met without an entry capacity reliant on the largest supply origin. RSI gauges pipeline, LNG and domestic production supply capacity not controlled by the largest supplier. It is intended to quantify the competitive strength of the market. RSI disregards storage, but accounts for transits. The feasibility of physical volumes being acquirable is not evaluated, which could result in an overestimate of the RSI. The X axis measures the concentration of companies on the supply side – The HHI¹¹⁰ (see MMR 2015 Annex 1 for further details on the approach). The bubble size represents the number of distinct supply origin sources. The values for Slovakia and the Czech Republic are from the 2018 MMR due to lack of data availability for 2019.

129 Figure 13 shows the results of the three upstream market health metrics: number of supply sources, RSI and HHI. It illustrates that the wholesale markets in the Netherlands, the UK, France, Spain and Belux meet all three AGTM market health benchmarks, while a growing number of hubs have reached levels close to the AGTM recommended thresholds in 2019¹¹¹.

130 Though it is more of an exception, high supply-side concentration at upstream level does not necessarily preclude the possibility for some liquidity developing at a hub, if there is, for instance, a competitive retail market and a sufficient number of midstream market participants sustaining it. L-gas hubs in NWE (L-Gas NCG, L-Gas GPL and the Belgian L zone) are to some extent examples of this: their liquidity is better than that of many hubs (see for instance Figure 17) that likely have much lower upstream supply concentration¹¹².

3.2 Gas hub categorisation

131 Figure i in the Executive Summary presents the 2019 classification of EU gas hubs. The ranking reflects the results of the AGTM market participant’s needs metrics, which are presented in more detail in Section 3.4. Compared with 2018 the classification shows one change, with the Hungarian MGP progressing from the illiquid to the emerging hubs category.

132 TTF in the Netherlands and NBP in the UK continue as the only hubs in the established category. Even though liquidity at the two hubs is diverging, with TTF traded volumes again growing strongly in 2019 and NBP posting a fifth straight year of decline (see Figure 14), the liquidity of the forward markets at both is evidently at a different level to that seen at any other EU hub.

110 Figure 13 HHI values differ from other estimates (e.g. CEER wholesale reports) that measure supply concentration per supply country origin, not per supply company origin.

111 The use of estimates suggests that ‘target levels’ cannot be taken at face value.

112 Market health metrics have not been assessed for NWE L-gas hubs specifically; however, only the Netherlands is a source of L-gas in this part of the EU.

- 133 TTF has been growing by virtue of establishing itself as the preeminent hub for those either hedging exposure or seeking exposure to the EU gas markets and therefore attracting the bulk of forward trading activity in the EU – it has, by some liquidity measures, even surpassed Henry hub, which is the most mature gas hub in the US¹¹³. NBP on the other hand has seen its attractiveness diminish, likely due to the regulatory uncertainty created by Brexit. Furthermore, NBP was always compromised in the role of EU's preeminent hub by the use of a different currency and its relatively limited interconnectivity with the rest of the IGM.
- 134 A level below TTF and NBP in terms of hub functioning are the advanced hubs. They are characterised by a similarly liquid and competitive spot markets as those of the established hubs (with results that are to a large extent in line with the AGTM benchmarks) and forward markets where, when compared with the two established hubs, trade is less frequent, smaller in terms of volumes and has a shorter time horizon. The current group of advanced hubs are also similar in that they either have large domestic demand, are crossed by important gas transit routes or both. However, it should be noted that not all gas wholesale markets with large transit routes and domestic demand also host advanced hubs.
- 135 Liquidity at emerging hubs is at a lower level than at advanced hubs in terms of frequency and volumes of trade, which tend to be limited to spot markets. The current group of emerging hubs is small, yet appears to share some characteristics: comparatively limited (and recent) interconnectivity with the rest of the IGM; support for national gas exchanges, limited or no multilateral OTC market; and medium-large demand.
- 136 In this year's assessment emerging hubs are joined by the Hungarian MGP. The reclassification is based on a notable increase in liquidity and competition of MGP's spot market, which has benefited, amongst other factors, from increased transits on the Hungarian gas network. Price competitive transportation tariffs of the Hungarian network have attracted Ukraine destined flows to the detriment of the Slovak and Polish routes (as well as attracting Croatia-destined flows in favour of the Slovenian route). Another factor beneficial to the liquidity development of MGP has been the timely implementation of the Gas Balancing Network Code.
- 137 The illiquid category includes both hubs where some trading of standard gas products on organised market venues took place in 2019 (e.g. hubs in the Baltics, Slovakia, Ireland, Romania, etc.) and hubs where no standard gas products trades were reported for the year¹¹⁴ (e.g. in Portugal, Greece, Slovenia, Croatia, Bulgaria etc.). In terms of hub functioning, the characteristics that are similar in the former sub-group are high concentration and very limited gas traded volumes.
- 138 Most hubs in the illiquid category have low domestic gas consumption (except Romania) as well as limited transit volumes (except Slovakia and to a lesser extent Romania and Bulgaria) and limited interconnectivity with the rest of the IGM (except Slovakia and Slovenia). [Section 3.6](#) presents some possibilities for improving these and other hubs' market functioning.

TRADING ACTIVITY IN THE ENERGY COMMUNITY

- 139 Among EnC CPs, Ukraine is the most advanced in its efforts to develop a trading gas hub similar to those in MSs. There are several characteristics of the Ukrainian gas wholesale market which could help support liquidity of the Ukrainian hub, such as substantial gas consumption and production, plentiful and competitive UGS capacity and large IPs connecting it with several EU gas hubs.
- 140 While Ukraine still trails behind MSs in setting up legal and other institutional arrangements that are needed to support a functioning gas hub, there have been several positive institutional changes and market developments recently. On the market side, the number of registered market participants has been growing since the market opened to competition in late 2015 and the volumes of gas traded and delivered at the VTP have been growing¹¹⁵.

113 The Agency does not assess hubs' churn rates but the OIES has calculated various TTF churn rates for 2019 in the range between 18 and 97, whereas the churn rate of Henry hub was calculated to be 45.5 for the same period. For more details see a related OIS paper [here](#).

114 This does not preclude the possibility that some non-standard gas contracts were traded bilaterally or that the TSO traded with market participants on gas balancing platforms.

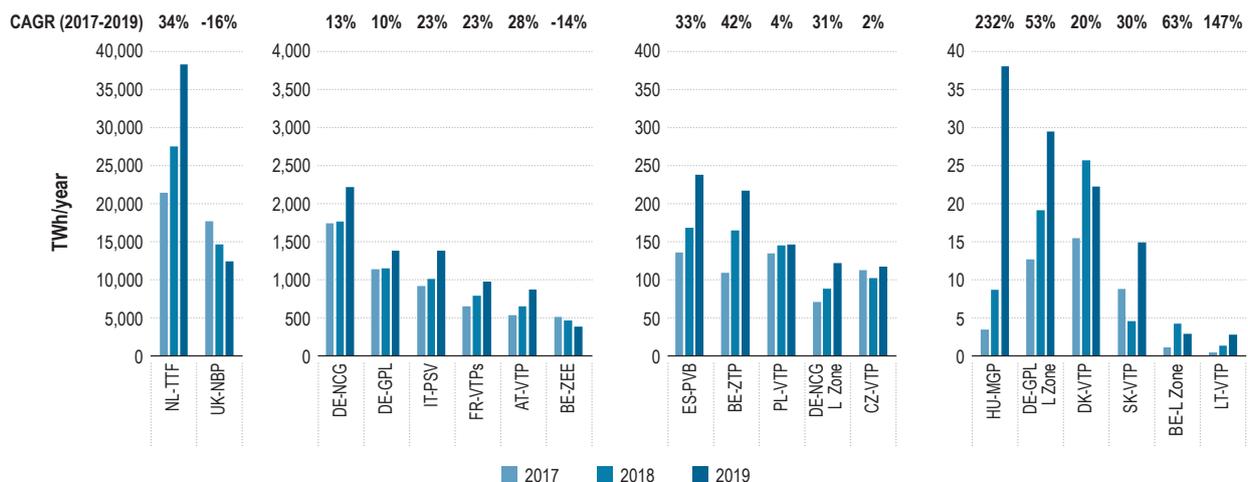
115 According to UA GTSO, Ukrainian VTP registered 41,4 bcm of gas volumes transacted in 2019, though this chiefly entails nominations into the VTP from contract holders and not trades concludes at a transparent trading exchange.

- 141 On the institutional side, after years of stalemate in the Naftogaz unbundling process, a new entity was established as an independent system operator¹¹⁶ in the autumn of 2019. The Ukrainian NRA certified the new gas transmission system operator (UA GTSO) in late 2019, upon positive opinion issued by the EnC Secretariat. Furthermore, the implementation of EU gas NCs has been progressing, as will be discussed in more detail in section 4.1. The updated balancing regime, which was introduced in 2019, is likely to prove particularly relevant for development of spot liquidity, especially once administrative barriers preventing UA GTSO procuring gas on exchanges is removed¹¹⁷.
- 142 Ukraine is also actively trying to attract new shippers to its network: in 2019, short-haul tariffs were introduced for network users accessing transmission network only with the purpose of using Ukrainian storage sites¹¹⁸ and in early 2020 short-haul tariffs were expanded to enable shippers to have more affordable access to transit routes linking central European countries via Ukraine¹¹⁹.

3.3 Overview of trading activity at EU gas hubs

- 143 Volumes of natural gas traded at EU hubs were at an all-time high in 2019 (+ 20% YoY). Growth at TTF accounted for over 90% of the increase. In 2019, traded volumes at TTF were three times larger than at the EU’s second largest hub NBP and almost forty times larger than at the third largest hub NCG. Up to summer 2020 hub trading activity has kept escalating (+20% YoY up to June), backed by the additional price hedging needs prompted by the COVID-19 altered market setting.

Figure 14: Traded volumes at EU hubs (GWh/year) – 2017–2019 (four scales)



Source: ACER calculation based on REMIT data, Trayport and hub operators.

Note: Data refer only to volumes traded via transparent market platforms with a price reference and some product standardisation; in some markets, sizeable volumes are traded outside of transparent market platforms. These bilateral deals or swaps can also lack a price reference.

- 144 Traded volumes at most of the larger, mature hubs grew in 2019. Growth ranged from 20% at GPL to 40% at TTF; the exceptions were NBP and the closely related Belgian ZEE, where traded volumes declined for the fifth straight year. In relative terms, some EU’s smaller hubs grew significantly, with the Hungarian, Slovak and Lithuanian hubs all recording growth in triple digits. At some hubs, the changes in traded volumes coincided with

116 An agreement of transfer of human, physical and technical resources between Naftogaz, represented by its daughter company Ukrtransgaz, and MGU was signed. Sales purchase contract MGU – Ukrtransgaz became effective 1 Jan 2020. MGU was a shell company established three years ago with a view to becoming a TSO; at present it acts as the sole shareholder of the UA GTSO. The owner of the transmission network in Ukraine is the State, represented by the Ministry of Finance, and the UA GTSO uses the network under economic management right.

117 There is an ongoing procedure of amending the Law on public procurement in Ukraine, which would enable UA GTSO to obtain gas on exchanges and in that way substantially contribute to increasing liquidity of the existing UEEX (Ukrainian Energy Exchange).

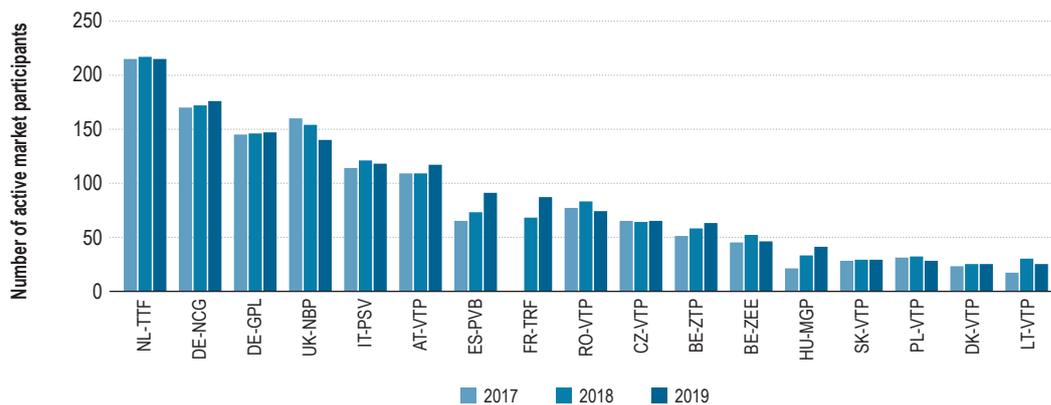
118 Trade of gas in storages has been growing, with an important share represented by trade of gas in the customs warehouse regime, which allows users to store gas without paying duty during a period of 1095 days.

119 See a comparability of these short-haul tariffs [here](#).

businesses either entering or leaving the market; compared to 2017, the Hungarian, Spanish, and Lithuanian hubs were among the hubs with most new active market participants, whereas NBP saw the greatest decrease. Figure 15 shows the estimated evolution of active market participants at EU hubs.

- 145 The influx of LNG was one of the main drivers of changes in hub trade. The altered supply balance, related price movements and volatility saw market participants continuously readjust their positions. The most direct impact on trade was observed at the TTF hub, likely due to its growing role as an important global hedging venue for major LNG producers and contract aggregators. Local gas dynamics, for instance the uncertainty surrounding future Russian gas supplies transiting Ukraine, also proved relevant to changes in hub trade at selected CEE hubs; trade in some products used for hedging gas storage capacity increased, while liquidity of other products - for instance the winter season product - decreased due to the uncertain supply situation in the first quarter of 2020.
- 146 Other, more enduring factors which have proven beneficial to increasing hub liquidity are changes in long-term contracts' price indexations from oil to hub references, which enables contracting parties to manage their LTC-related risk at the hub more easily, and the implementation of the Gas Network Codes (in particular BAL NC), as shown by improvements in spot liquidity after code implementation at, for instance, the Italian PSV, Spanish PVB and Hungarian MGP. See Section 4.3 for a detailed analysis of market effects of the BAL NC.

Figure 15: Estimated number of active market participants – 2017–2019



Source: ACER calculation based on REMIT data.

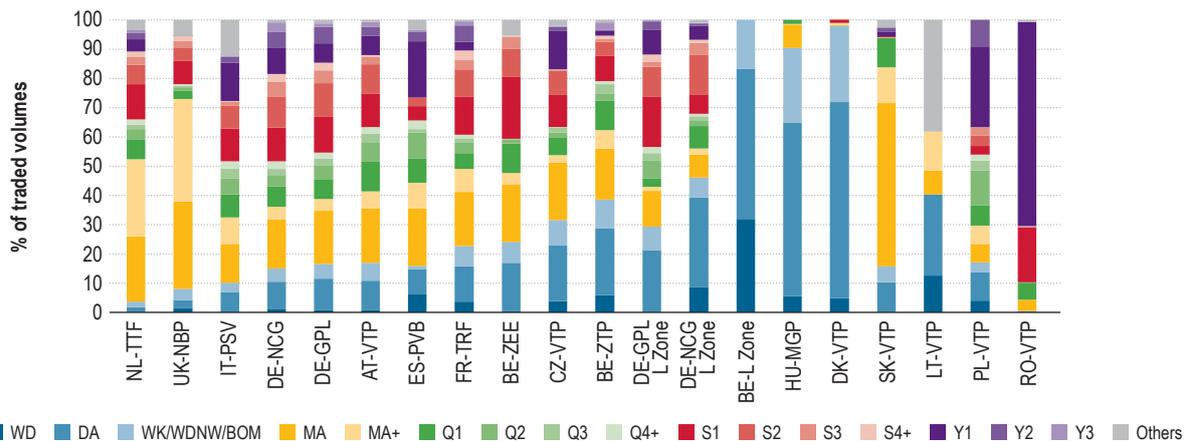
Note: Estimated based on registered users with at least one trade of standard contract for delivery at relevant VTP during the year.

- 147 There were more than six hundred active market participants at EU gas hubs in 2019, an increase of about 5% compared with 2017, while similar to 2018. Unsurprisingly, the hub with the largest number of active market participants is TTF, with a third of all market participants active at EU hubs also active at the TTF.

BREAKDOWN OF HUB TRADED VOLUMES

- 148 Figure 16 shows the relative importance of different types of products traded by market participants at EU hubs in 2019. It shows that spot products (DA, WD, BoM, etc.) make up a relatively small share of overall traded volumes at TTF and NBP, while they represent between 10% and 40% of traded volumes at the so called advanced hubs (not considering L-gas hubs).

Figure 16: Breakdown of traded volumes per product at EU hubs – 2019 – % of traded volumes



Source: ACER calculation based on REMIT data. OTC brokered and exchange trades combined.

Note: TTF and NBP data based on OTC trades only. Product acronyms stand for: Y years, S seasons, Q quarters, MA month ahead, WK/BOM week or balance of month. DA and WD refer to day-ahead and within-day respectively. The number following the acronym denotes the succeeding trading period (e.g. Q3 denotes the next third quarter after trade conclusion. Quarters comprise strips of three individual and consecutive contract months, from either Jan-Mar, Apr-Jun, Jul-Sep or Oct-Dec.)

149 Medium-duration contracts (such as month, quarter and season contract types) represent the largest share of traded volumes at EU hubs, with the exception of some hubs where only spot products are traded. Long-duration products (or yearly contracts) have a large share of traded volumes at the Romanian, Spanish and Polish hubs, a result of local market specificities and legal obligations, but make up a relatively small share of traded volumes elsewhere. Furthermore, yearly products are not particularly liquid at those hubs, but are rather transacted in big volumes on a limited number of occasions.

3.4 Liquidity and competition at EU hubs spot and forward markets

150 As mentioned in the introduction to this Chapter, a central tenet of the AGTM is that the European internal gas market should be comprised of liquid, competitive gas hubs. This section analyses to what extent and where that is the case, based on the results of a number of AGTM indicators¹²⁰. First, hub’s spot markets are analysed, followed by forward markets – which group in this edition both mid-term and long-term transactions¹²¹.

SPOT MARKETS

151 Spot products¹²² are the type of product most often traded at EU gas hubs. The results of the AGTM metrics indicate that liquidity and competition improved substantially at many of EU hubs’ spot markets in 2019. TTF had the best results on all of the measured dimensions – the tightest average bid-ask spread¹²³, highest trading frequency and lowest market concentration on both the buying and selling sides. Other hubs with strong spot market performance in 2019 included NBP and both German hubs, while the recently formed French TRF, the Austrian and Italian hubs were not far behind according to AGTM results.

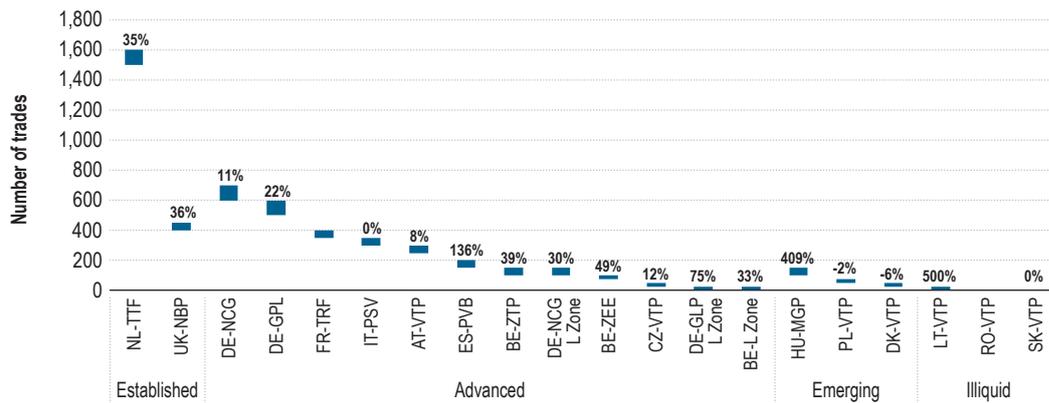
120 Liquidity has been assessed with indicators measuring products trading frequency and bid-ask spread; and hubs trading horizon, amongst others. Competition has been gauged with an indicator measuring the concentration of market participants’ in volumes of concluded trades in different timeframes.

121 In previous MMR editions, the AGTM assessment featured a section on prompt markets based on the Month-Ahead product. The assessment has remained the same but the section has been incorporated into the Forward markets section, in order to avoid repetition as past assessment have shown similar dynamics for both markets.

122 The day-ahead product has been used to assess the liquidity and competition of spot markets.

123 The bid-ask spread is the difference between the prices available in the order book for an immediate sale (offer) and an immediate purchase (bid) of a physically settled gas product. The size of the bid-offer spread is a measure of transaction costs and of liquidity. The lower the bid-ask spread, the lower the transaction costs and the higher the liquidity.

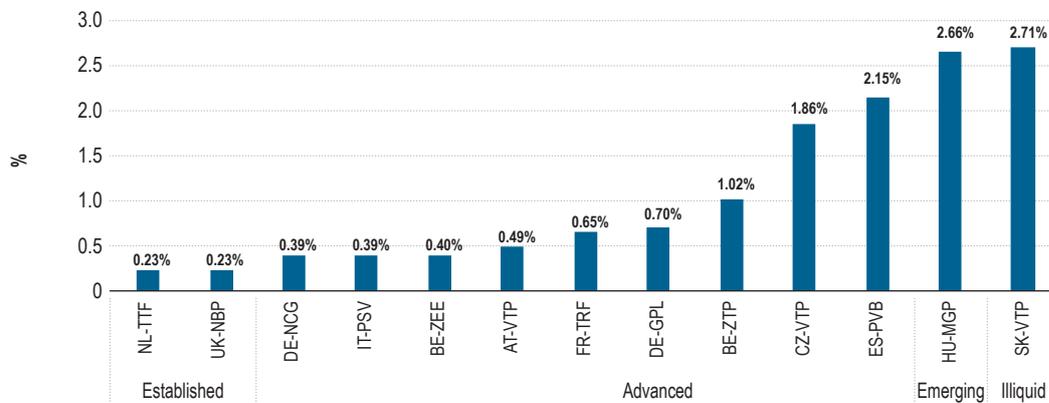
Figure 17: Spot markets trading frequency – 2019 – average weekday number of trades of the Day Ahead product



Source: ACER calculation based on REMIT.

152 At the spot markets of the Belgian ZTP and Spanish PVB, the improvements seen in the past couple of years continued in 2019; the latter hub overtook the former in terms of trading frequency and saw the results of its concentration indicator dip below the AGTM benchmark. Another impressive performer was the Hungarian MGP where the liquidity of spot products accelerated from very modest levels to, for instance, overtaking the Polish, Danish-Swedish, Czech and Belgian ZEE hubs in terms of DA trading frequency. MGP's spot market concentration, which had been amongst the highest in past assessments, also saw a notable improvement, bringing the results to the level of some of the advanced hubs. However, the average bid-ask spread for spot products at ZTP, PVB or MGP is still at least 4 times higher than at the most liquid EU hubs.

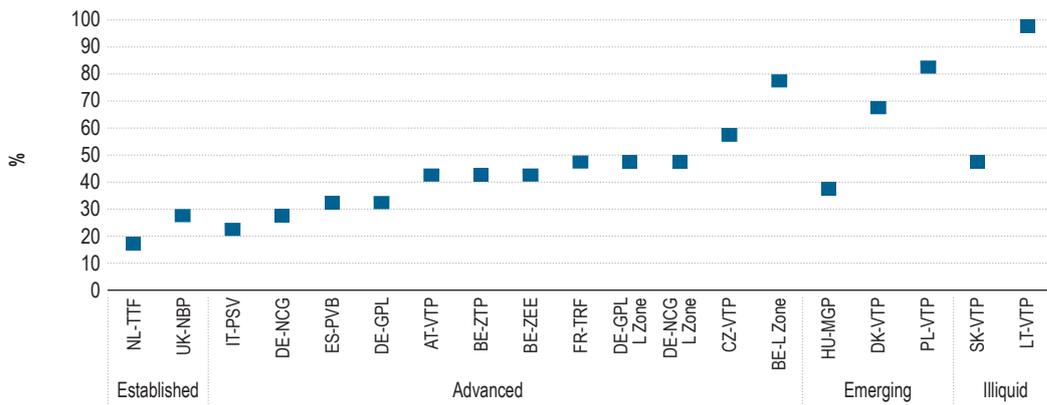
Figure 18: Bid-ask spread of EU hubs spot markets - 2019 - % of DA bid price



Source: ACER calculation based on ICIS data.

Note: For the definition of bid-ask spread see footnote 123.

Figure 19: Spot market concentration – 2019 - CR3 % for concluded DA trades



Source: ACER calculation based on REMIT.

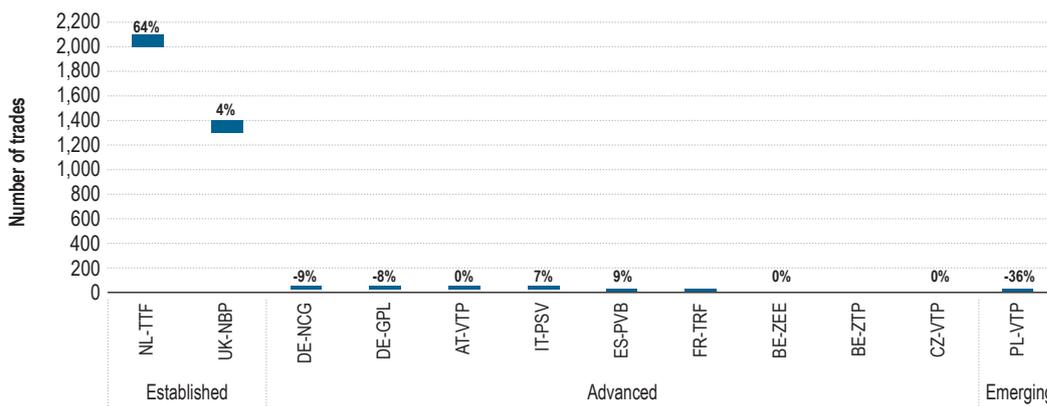
Note: CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was highest.

153 Some of the hubs whose overall spot market performance was stagnant in 2019 were the Italian PSV as well as the Polish, Czech, and Danish-Swedish hubs. In the case of the Czech VOB, it is worth noting that the results of the spot market concentration assessment have worsened over the past couple of years. A similar trend can be observed at two other hubs in neighbouring MSs as spot markets concentration at the German GPL and Austrian AVTP have both increased over the past couple of years.

FORWARD MARKETS

154 The number of hubs that host liquid forward markets is more limited than the number of hubs that host liquid spot markets; furthermore, most of the EU’s forward products trading activity is concentrated at the TTF and NBP hubs. At the two established hubs the month-ahead product is under various criteria the most liquid one.

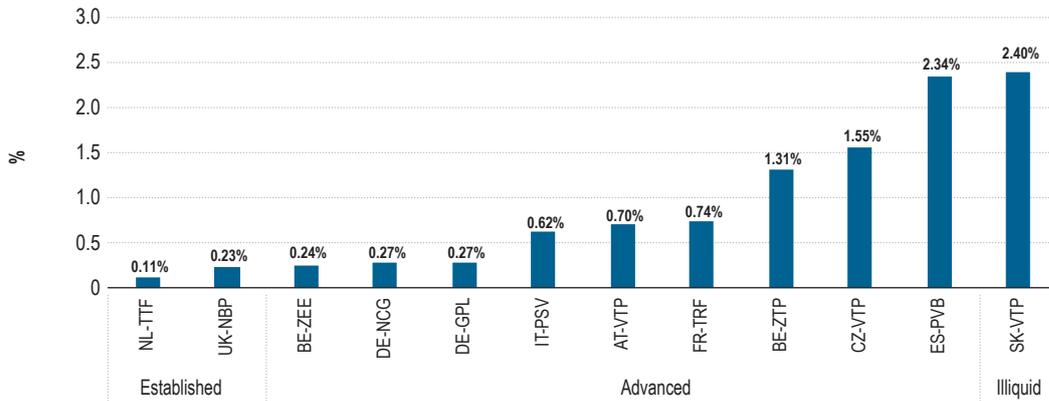
Figure 20: Forward markets trading frequency – 2019 - average weekday number of trades of the MA product and YoY % variation



Source: ACER calculation based on REMIT.

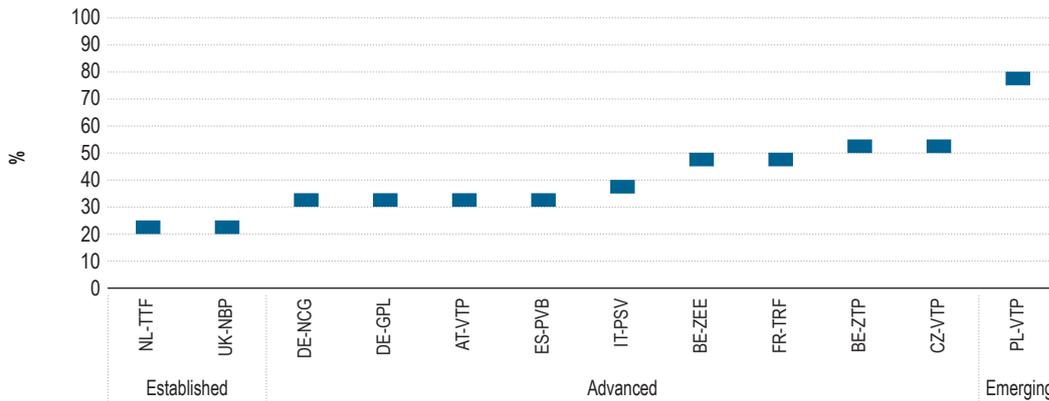
155 After the established hubs, month-ahead products’ trading frequency is the highest at the two German, Italian and Austrian hubs (although the bid-ask spread at the latter two hubs was more than double the AGTM benchmark, while at the former it was mostly in line). Among the emerging or illiquid hubs, market participants only traded the front month regularly at the Polish hub, although it stood out with a very high concentration of trades (CR3: buy ~70%, sell ~80%), whereas concentration at other hubs was assessed in the 20% - 50% range.

Figure 21: Front month bid-ask spread - 2019 - percentage of MA bid price



Source: ACER calculation based on ICIS data.

Figure 22: Forward market concentration – 2019 (average CR3 % shown as a range for concluded MA trades)



Source: ACER calculation based on REMIT.

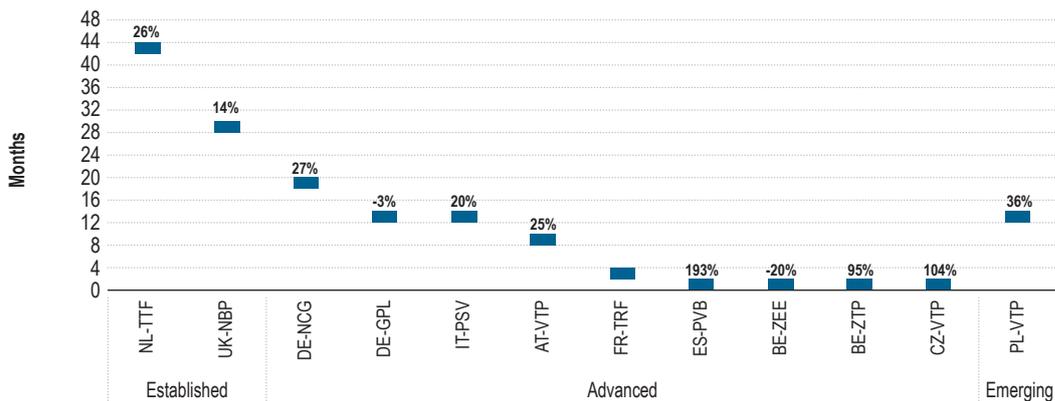
Note: Based on the market for the Month-Ahead product. CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was highest.

156 Like in the previous years, the forward trading horizons were largest at the two established hubs. In a positive development, the trading horizon at NCG, GPL and the Polish¹²⁴, Italian and Austrian hubs continued to expand in 2019. However, other hubs’ trading horizons were considerably shorter¹²⁵.

124 An assessment of concentration of trades for a basket of forward products shows that like in the concentration assessment for the Day-Ahead and Month-Ahead markets, the Polish hub stands out for concentration that is considerably higher than at other hubs.

125 The trading horizon assessment is sensitive to employed criteria – for instance, when the norm is lowered from eight to two minimum daily trades, in addition to TTF and NBP five other hubs have a horizon of 20 months or more.

Figure 23: Hubs trading horizon – 2019 - average horizon in months for minimum 8 trades and YoY % variation



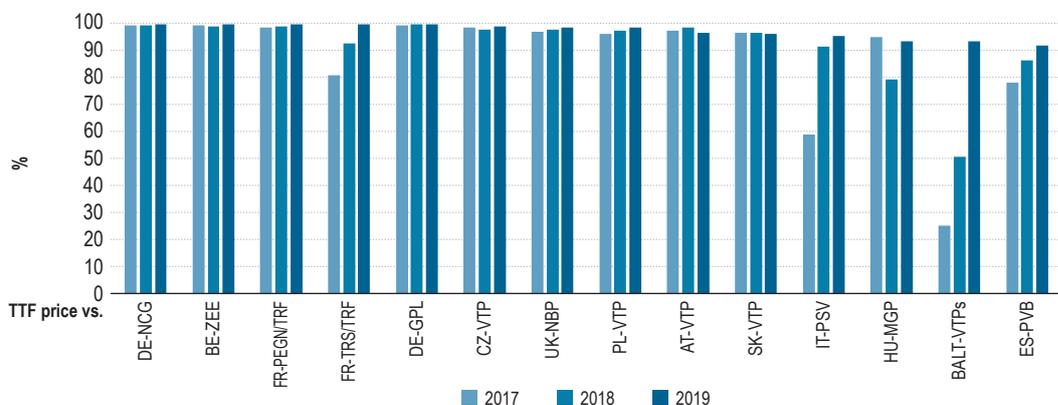
Source: ACER calculation based on REMIT.

157 Results of the indicators presented in this Section¹²⁶ underpin the Agency’s hub ranking presented in Figure i in the Executive Summary.

3.5 Correlation and convergence of prices of gas traded at EU hubs

158 A crucial component of the AGTM is the expectation that its proper implementation will result in growing convergence of hub prices over time (to the extent the efficient use of capacity allows). Convergence has increased to high levels between most EU hubs in recent years; however, in 2019, the unprecedented price decline at some hubs, which has been discussed in detail in Chapter 2, tested these dynamics.

Figure 24: Correlation between TTF and selected hubs’ spot prices – 2017–2019



Source: ACER calculation based on Platts and ICIS Heren.

Note: Correlation measured as Pearson coefficient. The Pearson correlation coefficient is a measure of the linear correlation between two variables X and Y. In this example, X and Y are closing prices of gas for delivery on the next day at two EU gas hubs. 100% is total positive linear correlation, 0% is no linear correlation, and -100% is total negative linear correlation.

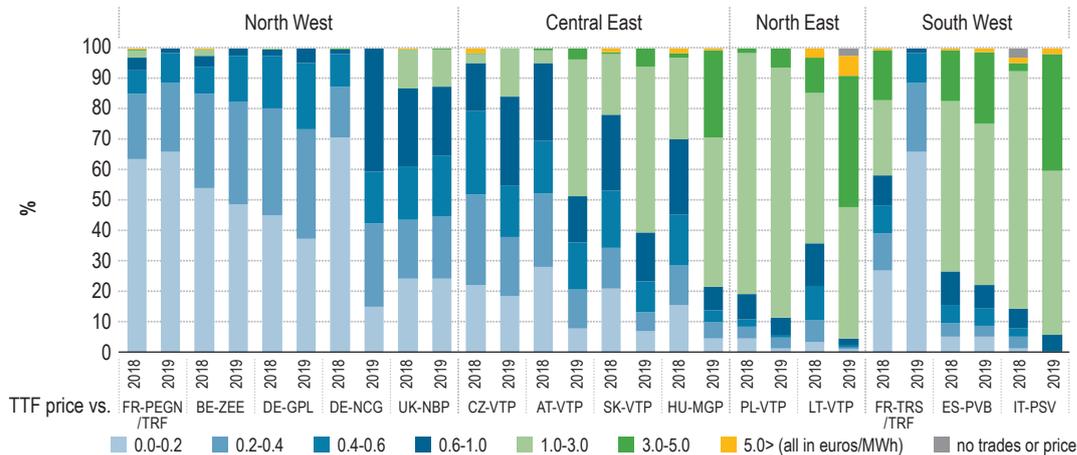
159 The spot price correlation between TTF and other EU hubs increased in 2019, indicating both the growing role of the Dutch hub as a pricing benchmark as well as stronger interdependence of EU hubs.

160 Convergence remained highest amongst NWE hubs – day-ahead spreads between TTF and other NWE hubs stayed below 1 euro/MWh for 90% of trading days in 2019 as shown in Figure 25. Strong price integration of NWE hubs is based on several factors, such as the ample availability of pipeline capacity, more similar market fundamentals, the possibility of flows from North Sea upstream networks to be swung between these markets based on spot price signals, the structural fostering of hub trading and the relatively low tariffs of interconnecting transportation capacity. Surpluses of long-term capacity contracts have also been perceived as

126 See footnote 31.

a relevant factor¹²⁷; however, as some LTCs in the region have started to expire, NWE hubs’ price convergence and correlation seems not to have been significantly impacted. Record deliveries of LNG, as well as the aforementioned flexible North Sea supplies, are deemed to have played a role in limiting any decoupling between hubs despite the expiration of LTCs.

Figure 25: DA price convergence between TTF and selected EU hubs – 2017–2019 - % of trading days within given price spread range



Source: ACER calculation based on Platts and ICIS Heren prices data.

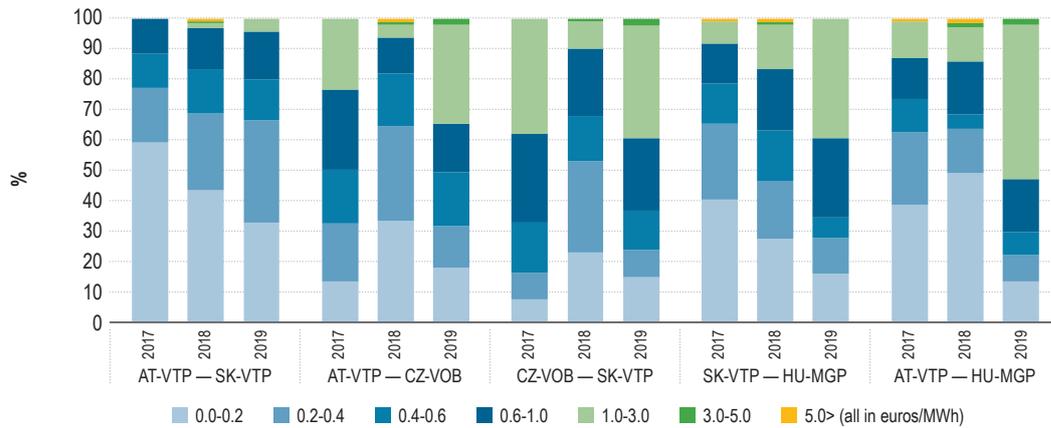
Notes: Spreads in euros/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

- 161 In the NWE group of hubs, convergence remained higher between the hubs that have the capacity to import LNG compared with those that do not. Spot price convergence improved between the TTF and the French TRF hub (when compared to prices at its predecessors PEG Nord and TRS) and, after a couple of divergent years, between TTF and NBP. TTF and other hubs prices grew apart somewhat, particularly noticeably with that of the German NCG and some CEE hubs like AVTP. In the case of NCG, one of the drivers seems to have been high gas demand for power generation, while in the case of AVTP a number of factors like uncertainty about future gas flows via the Ukraine, associated high demand for gas for storage and congested IPs that link the hub (and the region more broadly) with NWE sources seem all to have contributed.
- 162 In the CEE region, while price integration had improved in recent years, it was at a lower level in 2019. Days when spot price spreads were lower than 1 euro/MWh dropped from more than 80% in 2018 to below 50% in 2019. As already mentioned, uncertainty about future gas flows transiting Ukraine and associated high demand for gas for storage were related factors driving prices in 2019 – the higher demand for both commodity and pipeline capacity could have contributed to a divergence of prices¹²⁸.

127 See considerations for this being the case on [footnote 12](#).

128 For example, the Hungarian MGP DA price premiums to its neighbouring hubs AVTP and SKVTP grew throughout the first three quarters of the year to reach an average of 2 euros/MWh in August and only closed in September when Hungarian storages were 90% full. Thereafter, MGP was increasingly frequently priced at a discount to neighbouring CEE hubs as inbound gas flows were not constrained but full storages and limited export capabilities of the Hungarian network depressed prices.

Figure 26: CEE hubs spot price convergence – 2016–2019 - % of trading days within given price spread range



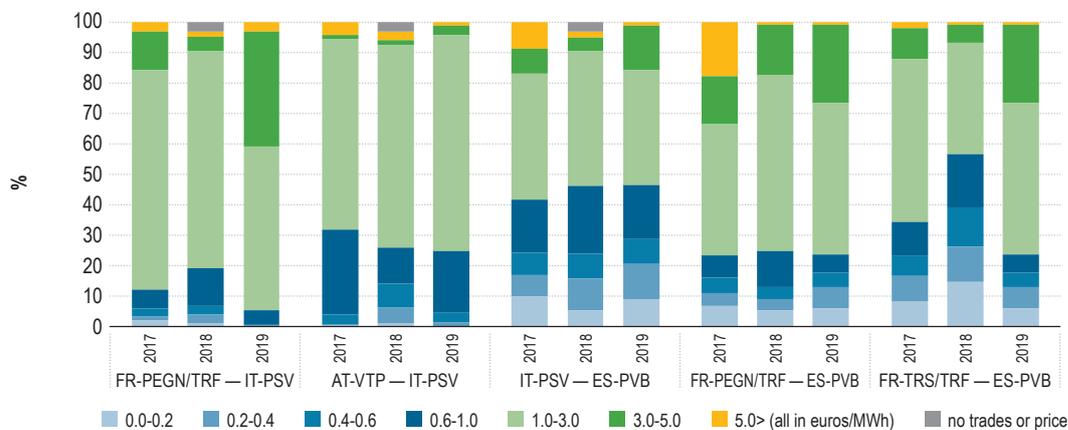
Source: ACER calculation based on Platts and ICIS Heren.

Notes: Spreads in euros/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

163 The building blocks of market price convergence in the CEE region, like infrastructure investments that enabled firm transportation capacity from the West to East direction, market liberalisation and Network Codes based hub development will continue to have an effect and are therefore likely to facilitate a return to higher price convergence in the future.

164 Price integration of hubs in the Mediterranean basin, both within the region and with hubs in neighbouring regions, remained lower when compared with NWE and CEE hubs. The merger of the French PEG Nord and TRS hubs eliminated former price differences between the north and south of France, but did not have any noticeable impact on convergence with either the Spanish PVB or Italian PSV in 2019. In fact, convergence between TRF/PEG Nord and PVB slightly worsened when compared to 2018. There were marginally more very convergent days (with spreads below 0.6 euros/MWh) but days when PVB was at a high or very high premium to TRF were more frequent as PVB was trading around a 2 euro/MWh premium (the reference IP tariff) to TRF throughout 2019 until the start of gas winter. In the last quarter of 2019, the PVB price was frequently at a discount to TRF, which was confirmed by flows from Spain to France (as was discussed in Section 2.4.1 covering gas flows).

Figure 27: Mediterranean hubs spot price convergence – 2016–2018 - % of trading days within given price spread range



Source: ACER calculation based on Platts and ICIS Heren.

Notes: Spreads in euros/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

3.6 The role of the AGTM in gas markets development

- 165 As has been shown throughout this Chapter, the performance of individual EU gas hubs varies significantly in terms of liquidity, competition and level of price integration. While some hubs reach the threshold levels recommended in the AGTM, many hubs are far from reaching them. These gaps seem to be driven by both external factors, such as inadequate upstream supply diversification and limited interconnectivity with the rest of the IGM, and internal factors, such as a slower process of gas market liberalisation and policy hurdles holding back market development and competition, the latter frequently to the benefit of national incumbents.
- 166 Encouragingly, measures promoting competition and liquidity (including the implementation of gas NCs) have been planned and adopted in recent years in many MSs, helping to gradually improve market functioning. This has been reflected in the improving results of AGTM metrics of some gas hubs. However, a recent study conducted for the EC¹²⁹ identified various pending administrative (e.g. licensing, registration requirements) and other types of barriers (e.g. trading or storage obligations) to market entry in multiple MSs.
- 167 To overcome these unresolved barriers to market development, a number of policy solutions are under discussion. For example, in its Bridge Beyond 2025 paper, the Agency recently issued various proposals for enhancing cross-border trade, like the mutual recognition of trading licenses and the creation of a black-list of companies aimed at preventing fraudulent practices related to gas balancing markets.
- 168 The AGTM itself suggests a number of actions to improve hubs' liquidity and competition, the most consequential of which are formal market integrations. Enlarged market areas tend to improve hub functioning due to greater aggregate demand, additional supply competition and larger number of trading counterparties. To date, mergers have taken place amongst various market areas, including Belgium-Luxembourg (2018), Denmark-Sweden (2019) and Finland-Estonia-Latvia (2020). Market areas inside individual MSs have also been merged in France (2019) while the two German hubs NCG and GPL are planned to be fully integrated in 2021. Other initiatives under discussion are potential mergers of Spain-Portugal, Croatia-Hungary¹³⁰, Italy-Austria and a further integration of the Baltic market areas.
- 169 Under the AGTM, itself an informal initiative, market mergers are based on a voluntary approach. However, experience to date shows that MSs may be reluctant to commit to formal mergers that entail some loss of autonomy in controlling gas wholesale markets' parameters like setting gas network tariffs. It is becoming evident that awareness of the benefits of closer and formal gas markets integration needs to be raised and that guidelines and processes related to addressing challenging topics inherent to the merger process, like inter-TSO compensation (ITC), are needed.
- 170 Alternatively, as recommended in the Agency Bridge Beyond 2025 paper, dynamic regulation could be established to help target only those markets where poor hub functioning warrants it. In such a regulatory approach, corrective actions would be triggered by monitoring results, and in that the Agency could play a relevant role. Among the measures under discussion for facilitating better market functioning – a regulatory tool-kit could be defined – are capacity and commodity release programs, changes in storage regulations, tariff adaptations and the use of market makers at organized trading venues.

129 See the [study](#) Regulatory and administrative requirements to entry and trade on gas wholesale markets in the EU. Other regulatory mechanisms that may introduce distortions on competition are also under scrutiny by the EC, as for example transmission tariff rises for compensating [UGS assets under-recovery](#).

130 This project is in a more initial phase. See [here](#) for more details.

4. Impact of Gas Network Codes on market functioning

- 171 This Chapter looks at the market effects brought about by the implementation of the Gas Network Codes and Guidelines. As a novelty compared to previous editions, it includes an analysis of the volume of currently booked transportation capacity for the next years and until its full expiration.
- 172 As highlighted in previous MMR editions, drawing a clear line between the effects deriving from changes in market fundamentals as opposed to those deriving from specific regulatory reforms is challenging. This analysis should be understood in the current market context where market fundamentals can rapidly evolve.
- 173 All EU Network Codes are also applicable in the EnC CPs¹³¹, however their implementation started only in 2020, with Ukraine being the most advanced in this process. Therefore the market effects of network code implementation could not be assessed for 2019.

4.1 CAM Network Code effects

CAPACITY BOOKED FOR THE 2016–2019 PERIOD

- 174 The main aim of the CAM NC is to set a transparent and standard framework for the allocation of transportation capacity. Before the implementation of the CAM NC, the platforms and rules for capacity allocation were heterogeneous and considered one of the greatest barriers to fair market access¹³². Now capacity is allocated by market-based auctions of primarily bundled products of standardised duration, managed through centralised booking platforms. Most CAM NC provisions have been mandatory since November 2015, others since 2017 due to the amendment of the CAM NC. Some MSs choose to implement a large number of the NC provisions before the abovementioned dates.
- 175 Figure 28 shows the evolution over the 2016–2019 period of booked and technical capacity at all IP sides and directions to which the CAM NC applies, as well as at some IPs connected with third countries¹³³. The booked capacity is split according to the way and moment it was purchased, i.e. acquired before (legacy contracts) or after the CAM NC's implementation (CAM products).
- 176 The amendment of the CAM NC¹³⁴ has been an important regulatory driver that produced an immediate effect upon its implementation, with increased bookings of quarterly and yearly products. The TAR NC implementation could be another important driver in the future, but it has not yet led to significant changes in booked volumes, at least in the limited period observed (since October 2019 in some MSs).

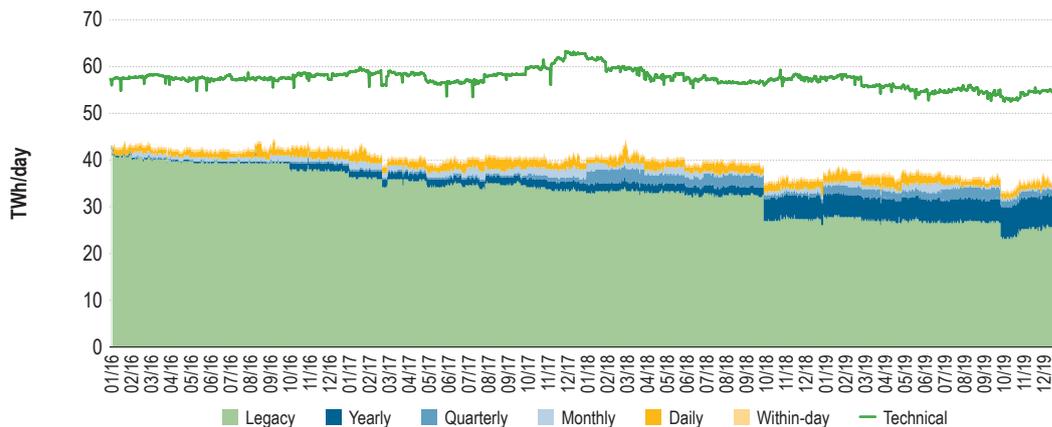
131 While the Interoperability NC and CMP Guidelines are applicable since October 2018, the implementation deadline for the CAM NC and TAR NC are set to end February 2020. BAL NC is to be implemented by December 2020.

132 Before the implementation of the CAM NC, capacity was allocated via varying procedures, not that market-based as auctions which in some cases gave priority to the incumbent. The CAM NC also overcame difficulties created by the utilisation of cubic meters as unit of allocation by establishing that capacity shall be offered in kWh.

133 The figure includes 273 interconnection point sides and directions (commercial capacity) located in the twenty-one MSs with transportation networks in place, where capacity is auctioned via centralised booking platform as per CAM Network Code and for which reliable data are available on ENTSOG TP. Interconnection point sides of Estonia, Finland, Latvia, Lithuania and Sweden are not included because those MSs did not allocate capacity with CAM auctions, while Cyprus and Malta do not have a gas transportation network.

134 In 2017, the CAM auction calendar was amended with effects starting from 2018, making the auctions of the quarterly and yearly products more respondent to the network users' commercial needs (see previous MMR). As an example, the volumes of quarterly booked capacity for the last quarter of 2019 was the highest volume of all the last quarters over the four considered years.

Figure 28: Evolution of EU technical capacity and of type of booked capacity products – 2016–2019 – TWh/day



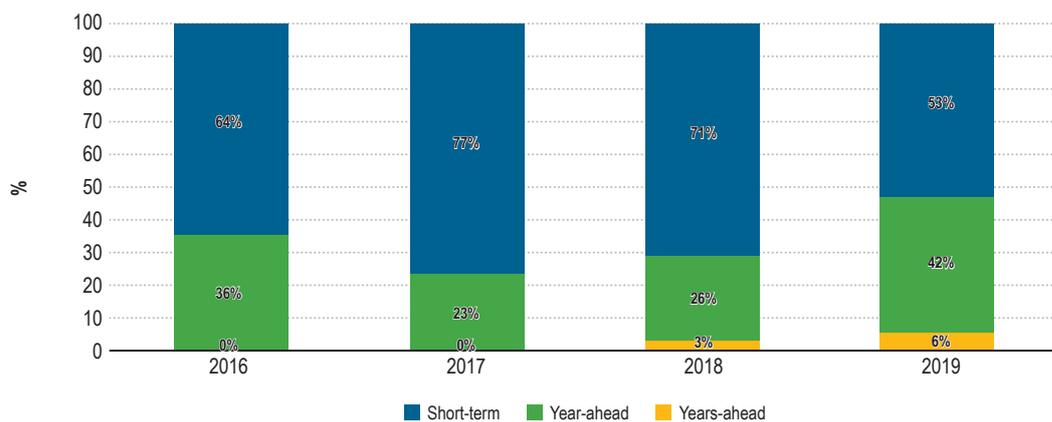
Source: ACER based on ENTSOG TP, PRISMA, GSA, RBP.

Note: The legacy-booked capacity also includes capacity allocated via the implicit allocation mechanism at BBL and IUK, which explains the series' rise in the last 3 months of 2019. The scope of the IPs is the same for the entire period considered.

177 More than 40% of the legacy-booked capacity in place in January 2016 had expired by December 2019. In most MSs, the volume of expired legacy capacity was either replaced (or more than replaced in some cases) by new CAM bookings or it was limited and additional new bookings were made regardless. Only in a few other MSs expiring capacity was not replaced¹³⁵. Most of the expired legacy volumes not replaced are concentrated at some of the biggest EU IPs, such as at BBL (which experienced progressive expirations since 2016), at IUK (October 2018) and at Brandov-Opal (October 2019, driven by an EU court ruling). As such, the share of total booked capacity represented by legacy contracts decreased from more than 90% at the beginning of 2016 to circa 70% at the end of 2019, in line with the policy goals.

178 Figure 29 shows the share of new CAM booked volumes for the period 2016–2019 per product duration type.

Figure 29: Breakdown of CAM products over the years 2016–2019 - % of total booked capacity



Source: ACER based on PRISMA, GSA, RBP.

179 In 2019, there was an almost even split between shorter-term (53%) and year-ahead(s) products (48%)¹³⁶. Such an outcome had been facilitated by the CAM NC implementation, which has as purpose that capacity bookings

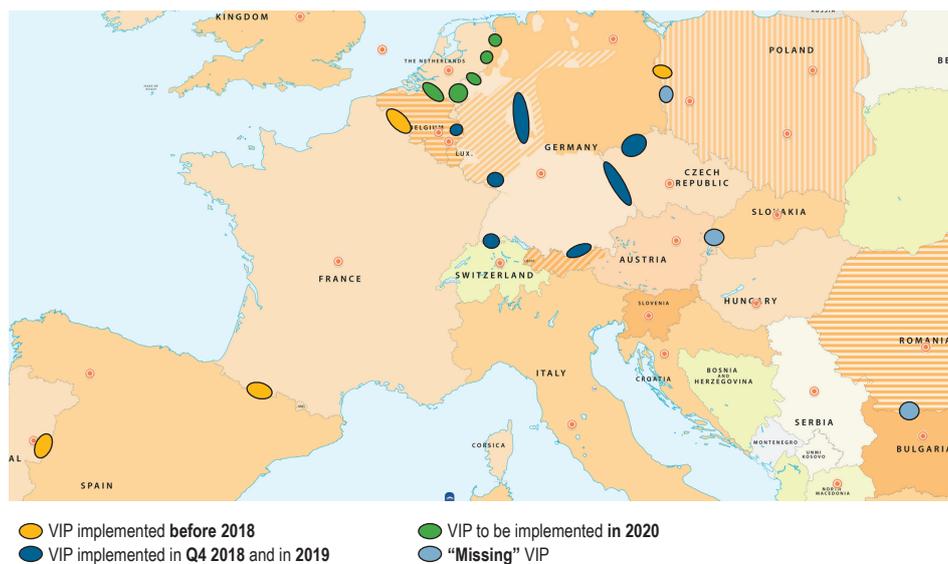
135 Legacy capacity contracts were replaced or more than replaced in Croatia, France, Greece, Germany, Hungary, Ireland, Italy, the Netherlands, Poland, Portugal and Slovakia. Limited legacy contracts volume expired in Austria, Bulgaria, Spain and on the Yamal zone and additional new bookings were made. MSs where expired capacity was not fully replaced are Belgium, the Czech Republic, Romania and Slovenia.

136 Since the CAM NC go-live, the IP sides in Germany alone have accounted for almost 40% of total EU CAM bookings. In this period, the top three MSs – Germany, the Netherlands and Poland – have accounted for 60%, while the top seven MSs for almost 85%. The results reflect various elements, e.g. the bigger size of these MSs within-EU IP sides, their higher gas consumption – or high transits across – and the higher volumes of expired legacy contracts. Data at MS level are published on the MMR data portal CHEST.

occur when actually needed, depending on the network users' business purposes. This enables the use of the network by those players that can generate the highest value in the market, which positively impacts the transparency and efficiency of the price formation in the interconnected markets.

- 180 Despite yearly capacity tending to be less expensive than shorter-term capacity (given usually higher short-term multipliers), network users' general preference at the moment is to book capacity up to one year ahead, with limited volumes booked for longer durations¹³⁷. Network users seek to pursue as much flexibility as possible, while tend to avoid lock-in effects. Flexibility is reflected in the need for demand profiling, short-term optimisation and ability to choose shipping gas via pipelines or via LNG. Lock-in effects prevention arises from the uncertainties with respect to the forward conditions of the market, given among others EU decarbonisation targets, developments of transportation tariffs and the still prevalent overbooked legacy capacity contracts.
- 181 One of the main tools established by the CAM NC to increase transparency and ease market access is the creation of Virtual Interconnection Points¹³⁸ between zones connected by more than one IP. In 2019, eleven VIPs were operational and five more became operational in 2020 (Figure 30). Some VIPs apply a *full* model while others apply a *dual* model¹³⁹. The consolidation of VIPs, the progressive expiration of the IPs' booked capacity in the hybrid model and the merging of the two market areas in Germany¹⁴⁰ planned for October 2021 are expected to increase even more the efficiency of EU cross-border capacity resources.

Figure 30: Virtual Interconnection Points in Europe



Source: ACER based on ENTSOG.

Note: 'Missing VIP' indicates a situation where more IPs connect two market zones and a VIP was not implemented in line with the conditions established in the CAM NC.

- 182 With regard to bundled capacity – another key element of the CAM NC – such bookings are still not facilitated everywhere due to non-harmonised TSO's transportation contracts' conditions (e.g. financial guarantees, contract obligations, language) and broader aspects, such as access conditions or the balancing designs and

137 The evolution of short-term tariff multiplier levels could constitute an additional relevant factor in booking behaviour. Further assessments on the subject will be included in forthcoming MMR editions.

138 See footnote 16.

139 In the *full model*, each IPs' contracted capacity is transferred fully into the VIP, so that the old IPs cease to exist; this model was implemented at Virtualys (FR-BELUX), VIP Iberico (ES-PT), VIP Pirineos (FR-ES). In the *dual model*, each IPs' contracted capacity remains at the single IPs and the new capacity is auctioned only at the VIP, so that the IPs and the VIP coexist until the expiration of all the old capacity; this model was implemented at VIP Belgium (BELUX-NCG), VIP Germany-CH (NCG-CH), VIP France – Germany (TRF-NCG), VIP Oberkappel (VIP NCG only side-AT), VIP Waidhaus NCG (CZ-NCG), VIP L GASPOOL-NCG (GPL,L-NCG,L) and VIP Kiefersfelden-Pfronten (NCG-AT).

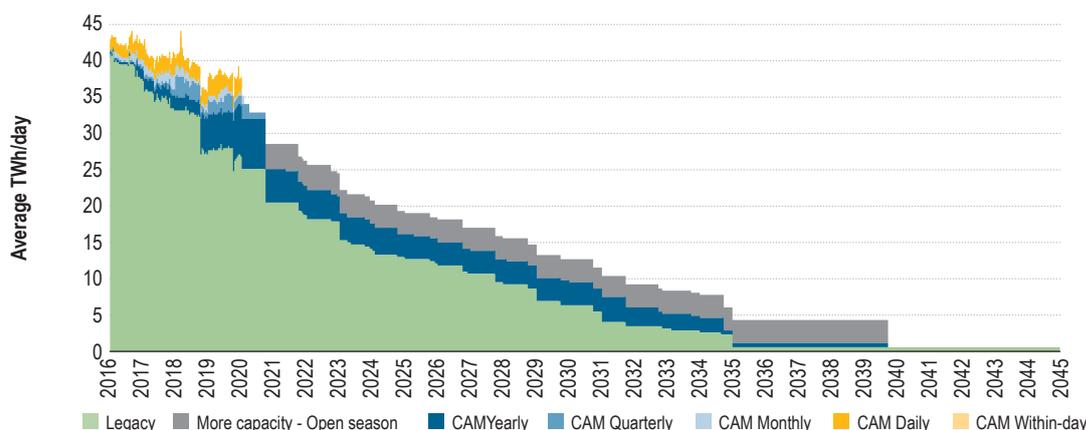
140 However, one of the consequences of the market merger is the reduction in available cross-border capacity.

imbalance fees in place at the various VTPs¹⁴¹. Furthermore, non-standardised capacity products and services are still offered in some MSs. The share of the latter reaches 50% of the total capacity booked in certain MSs, e.g. in Germany.

CAPACITY BOOKED BEYOND 2020

183 Figure 31 gives an overview of the volume and type of booked capacity underlying EU gas networks’ use rights in the past (2016–2019) and for the next twenty-five years (2020–2045), until existing capacity commitments fully expire. The analysis has been done using data from ENTSOG. The figure includes IP sides and directions that are CAM-relevant and all those connected to a third Country.

Figure 31: Evolution of capacity booked by capacity type - 2016–2045 – TWh/day



Source: ACER based on ENTSOG.

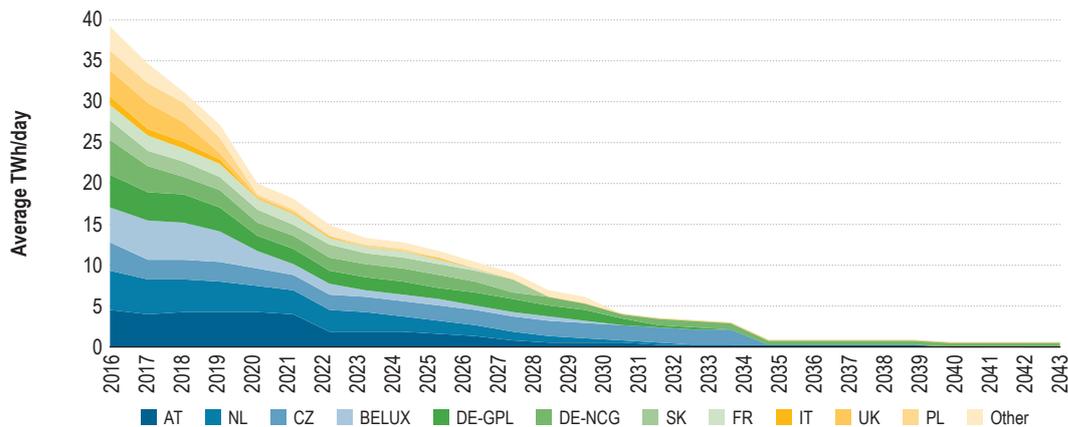
Note: Includes all EU interconnection points’ sides and directions, also with third countries, which are in the scope of the EU regulation on transportation capacity allocation (CAM Network Code). From 2020, the new products’ categories only include volumes allocated in auctions held until 31/12/2019. The legacy capacity for 2020 has been interpolated in the absence of data. The category “More capacity - Open Season” includes specifically the long-term capacity allocated in 2017 via auctions in an ad-hoc open season for two interconnection points located along the routes for further transport from Nord Stream II: Lubmin II and Deutschneudorf-EUGAL. This capacity was assigned before the incremental capacity amendments to the CAM Network Code entered into force.

184 More than a third of the EU legacy contracts’ volume in place at end of 2019 will have expired by the end of 2023, while more than 60% of them will no longer be in place by 2028. Legacy contracts will almost completely expire by the end of 2035.

185 Figure 32 shows contract expiration calendar per MS – more detailed data are accessible in the MMR data portal. In several MSs, chiefly Belgium, Germany, Poland and Italy, most legacy contracts will have expired already in 2022. By then, the legacy capacity volumes in just six MSs will account for almost 90% of the EU total (Austria, the Netherlands, Czech Republic, Belux, Germany and Slovakia).

141 E.g. imbalance fees have an impact on market liquidity. For example, in a zone where severe and restrictive portfolio-based within-day obligations apply, the development of a liquid spot market is discouraged given that network users must pay within-day fees in case of imbalances created not only at the end of the day but within the day. Within-day fee could cost more than a short-term market opportunity.

Figure 32: Legacy booked capacity per market zone - 2016–2043 – Average TWh/day

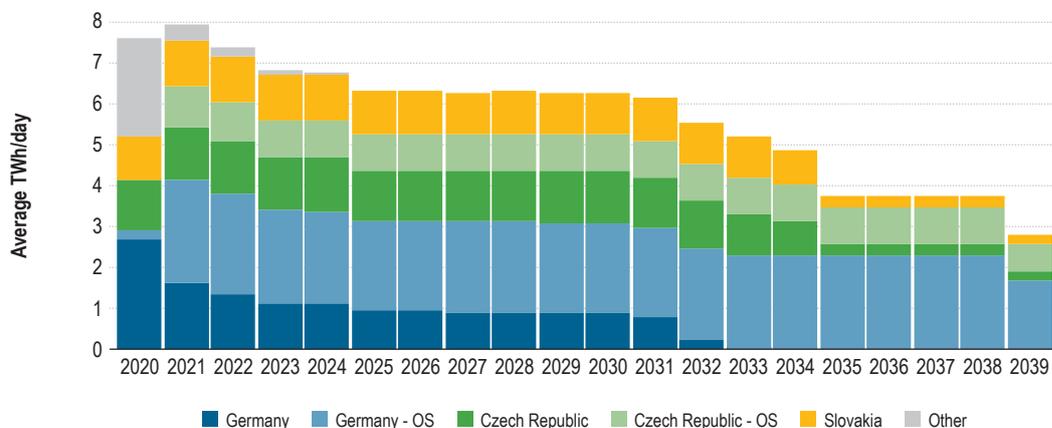


Source: ACER calculation based ENTSOE.

Note: Values represent the daily average throughout the year. Includes CAM-relevant points and EU pipelines' imports and exports.

- 186 The expiration of most legacy contracts between 2020 and 2022 in several MSs will be a test to prove if the trend observed up to 2019 will be maintained – i.e. products up to one year-ahead almost fully replacing expired legacy contracts.
- 187 Figure 33 analyses complementarily the multi-yearly bookings committed from 2016 to the end of 2019 and for use from 2020 to 2039. The CAM NC establishes that yearly capacity must be offered for at least the subsequent five gas years and up to the next 15 gas years of the auction organization. The figure identifies the volumes booked at the two referred points located along the routes for further transport from Nord Stream I in a separate category as the volumes were booked during an open season process carried out in 2017 – i.e. before the CAM NC amendments were introduced in 2017 – and for a horizon of 20 years.
- 188 Multi-yearly products booked from 2023 onwards are only located in Germany, the Czech Republic and Slovakia. These capacities are almost exclusively associated to the Nord Stream and Nord Stream II landing points and to the onshore routes for further transport from there. While data show that multi-yearly capacity has been booked in some instances, it also shows that these products have only been acquired for specific needs of selected market players so far, and always at the auctions' reserve price – which shows that there was limited competition.

Figure 33: Volumes of multi annual capacity booked in MSs from 2016 to 2019 and for use for the period 2020–2039 – Average TWh/day



Source: ACER calculation based on GSA, PRISMA, RBP.

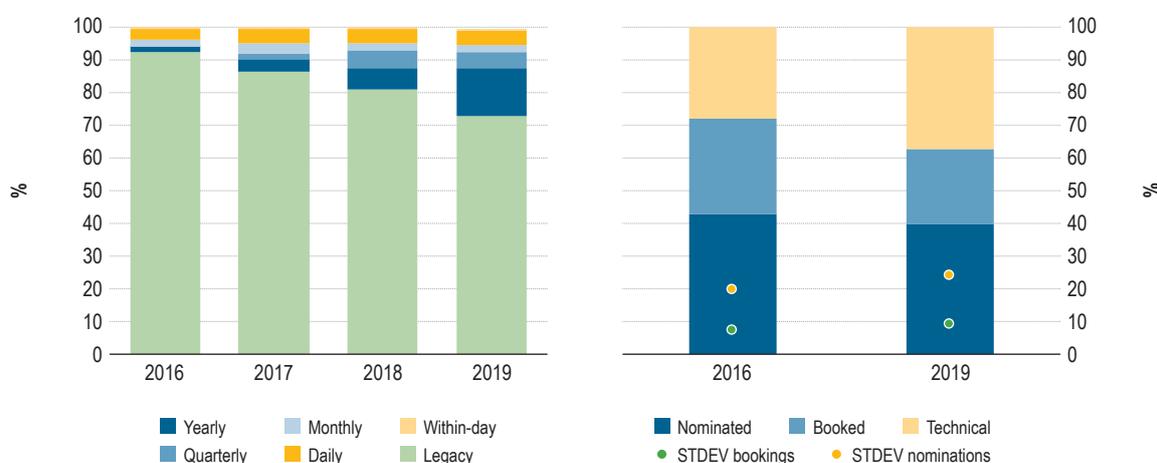
Note: Volume of incremental capacity could be included in the allocated auctioned volumes. "Other" includes the other 14 MSs where CAM NC is implemented. "Germany - OS" and "Czech Republic - OS" includes specifically the long-term capacity allocated in 2017 via auctions in an ad-hoc open season for two interconnection points located along the onshore routes for further transport from Nord Stream: Lubmin II and Deutschneudorf-EUGAL. This capacity was assigned before the incremental capacity amendments to the CAM Network Code entered in place.

189 The different role played by CAM products and legacy contracts explains their different bookings' concentration levels. This topic was analysed in the MMR covering 2018. The concentration of CAM products (and of the products booked via the open season process of 2017) tends to be lower, especially for the shorter-term products, compared to the concentration of legacy contracts¹⁴². Overall, the new capacity products tend to attract additional market participants in pursuit of prompt supply optimisation, although their concentration is high at some specific IPs, chiefly for the longest-duration products. The reducing interest of EU shippers in committing to long-term bookings is leading to an increased presence of upstream producers.

CAPACITY UTILISATION

190 Figure 34 shows the booked capacity's breakdown by type of capacity product (a) and the share of utilisation of such booked capacity over the 2016–2019 period (b) for the same IP sides and directions as in Figure 28.

Figure 34: (a) Breakdown of capacity booked per type of product - 2016–2019 - % (left) and (b) ratios¹⁴³ of capacity booked and nominated and their standard deviation - 2016 and 2019 – % (right)



Source: ACER calculation based on GSA, PRISMA, RBP and ENTSG TP.

Note: Ratios refer to the available technical capacity and overlap graphically.

191 The commercial utilisation of IPs capacity is influenced by many elements¹⁴⁴. The increased profiling of capacity bookings observed at many EU IPs – favoured by CAM implementation – has resulted in higher average utilisation ratios. This is because while aggregated nominations have been overall well-maintained, the bookings underlying them have decreased, as shown in Figure 34 (b). As a result, an increasing gap between technical and actually booked capacity is being observed¹⁴⁵; while 72% of the available firm technical capacity was booked for 2016, this share decreased to 63% for 2019. The ratio of IP nominations over the technical capacity also slightly decreased over this period, due in part to the increased supply of LNG replacing pipeline imports.

192 The standard deviations of nominations and bookings – which evaluate the distribution of their daily levels – have both generally increased over the last four years. This shows that IPs tend to be more dynamically booked and commercially used, responding to variable demand needs and price signals. However, significant differences persist among IPs and also among network users, as not all users prefer to hedge their short-term

142 Based on REMIT data. The Agency cannot show the exact figures due to the confidentiality covering the non-aggregated REMIT data.

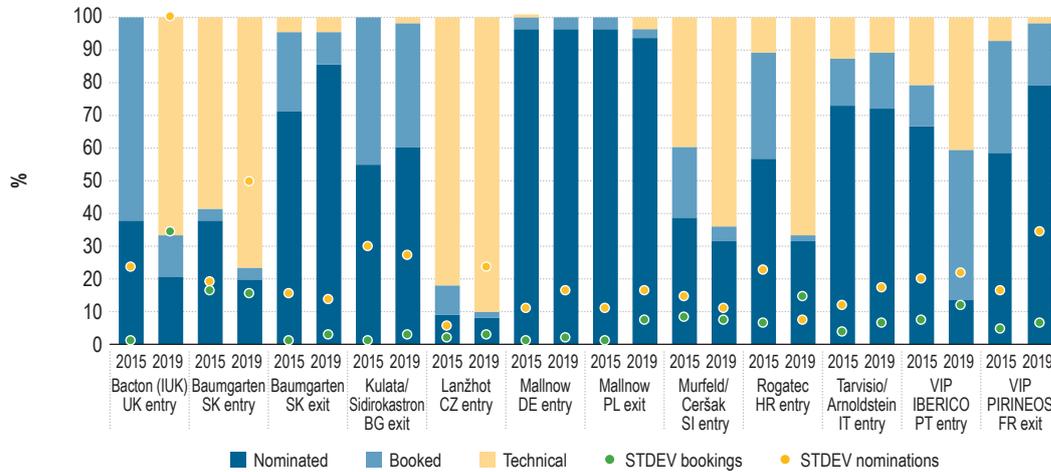
143 Nominated: renominations / total technical capacity; Booked: total booked capacity / total technical capacity; Technical: offered technical capacity, e.g. in 2016, 42% of the technical capacity was nominated and 72% of the technical capacity was booked; in 2020, 40% of the technical capacity was nominated and 63% of the technical capacity was booked. STDEV bookings: standard deviation of daily Booked ratio; STDEV nominations: standard deviation of daily Nominated ratio.

144 Intended as nominations of booked capacity by network users. The main elements are: demand, supply, transportation contracts conditions, hub spreads, tariff levels, hub liquidity, availability of alternative supplies, possible regulatory and administrative barriers, wholesale market competition, presence of regulated retail gas or electricity prices, TSO's unbundling the market demand needs and supply alternatives, the level of legacy-booked capacity, supply prices and the relative positioning of hub spreads and tariffs.

145 The usage of averages is illustrative in order to show the overall European situation. Peak utilisation ratios of infrastructure are also needed when dimensioning the gas system.

transactions. This is further shown in Figure 35 that presents the results of the same indicators as Figure 34 (b) for selected CAM relevant points.

Figure 35: Booking and utilisation ratios of transportation capacity at selected CAM relevant points – 2015–2019 – %



Source: ACER calculation based on ENTSOG TP.

193 Figure 35 shows that at various highly used and relatively large IP sides, the total booked capacity for the 2015–2019 period increased or remained high, for example in the main direction of the Baumgarten, Kulata, Mallnow, Tarvisio and VIP Pirineos IPs. However, at most other IP sides, less capacity was booked for 2019 and, in some cases, even less was nominated on average. Also, the standard deviation of both booked capacity and nominated capacity increased at most IP sides.

194 Finally, the observed decrease in capacity nomination and booking levels call for caution about new investments, as no incremental capacity was allocated since the new CAM NC provisions became operational¹⁴⁶.

4.2 TAR Network Code effects

4.2.1 Effects on Reference Price Methodologies following TAR NC implementation

195 As Section 2.2 shows, almost all MSs heavily – and increasingly – rely on gas imports: 80% of EU gas consumption is imported from third countries and the declining domestic production is concentrated in only a few MSs. In parallel, many legacy contracts will expire in the upcoming years. Gas transportation tariffs - and their variations - will thus have an even greater effect on the EU internal market functioning in the years to come, by supporting or hindering gas supplies from specific origins¹⁴⁷.

196 In this context, one of the key aims of the NC TAR has been to set a more transparent and harmonised framework to determine tariffs, with a view to avoiding discrimination between network users. This aim is safeguarded, among others, by charging network users in a more cost reflective manner, avoiding undue cross-subsidies.

197 Furthermore, by increasing harmonisation and transparency, the TAR NC also aims to facilitate cross-border trade. TAR NC's transparency provisions lead to better market functioning by allowing network users to better reproduce and forecast future transportation tariffs and by publishing the reserve price of capacity before the capacity auctions¹⁴⁸.

146 See footnote 16.

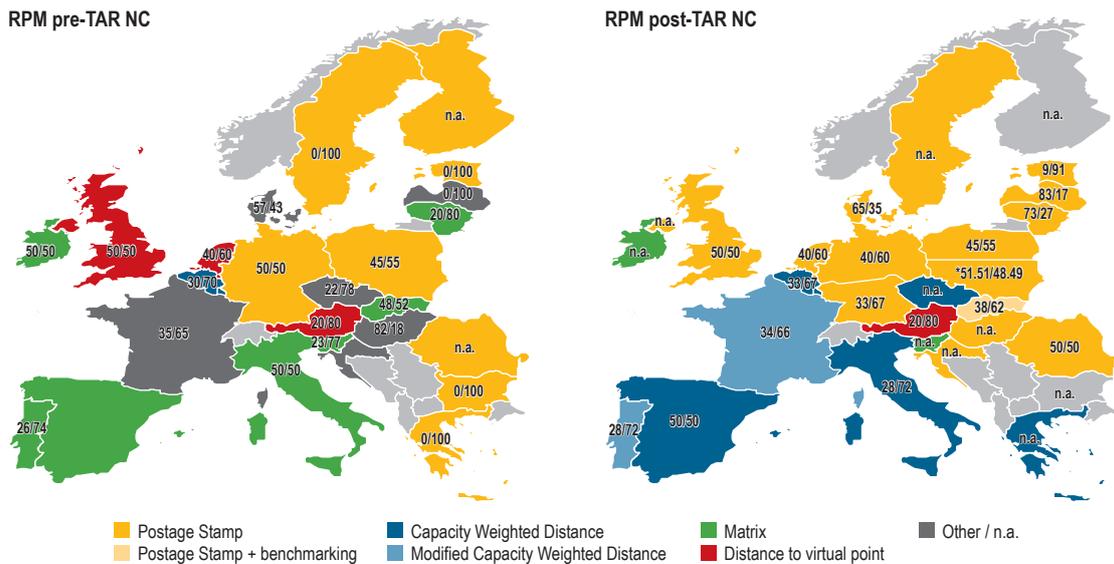
147 Usually, the gas supply prices in an entry/exit zone are set by summing the gas commodity cost to the transportation tariffs at the relevant IP sides and directions. In some cases, cross-border tariffs are not fully included in the final gas supply prices, see section 4.2.3.

148 Before the TAR NC, the yearly capacity tariffs and the short-term multipliers in many MSs were published only after the yearly transportation capacity auctions were carried out, so network users did not know the price of the capacity booked until some months after its having been allocated.

198 In April 2020, the Agency published its first TAR NC Implementation Monitoring Report¹⁴⁹, which analyses in depth the reference price methodologies¹⁵⁰ proposed by NRAs at each EU entry/exit zone to fulfil TAR NC’s implementation. The report, among other elements, analyses whether some proposed tariffs’ *adjustments*¹⁵¹ respect the TAR NC’s criteria.

199 Figure 36 shows, for each MS, the tariff methodology before and after the implementation of the TAR NC as well as the variations in the entry/exit split.

Figure 36: Evolution of tariff methodologies and entry/exit splits in MSs before (left) and after (right) TAR NC implementation



Source: ACER calculation based on NRAs’ approved RPMs (2020).

Note: For Poland, the RPMs of both the H-gas and the Yamal entry/exit zones are shown.

200 Figure 36 shows that the TAR NC implementation has increased the harmonisation of RPMs. The postage-stamp is the prevailing methodology, seen as a good trade-off between simplicity and efficient competition, followed by capacity weighted distance (CWD). Most RPMs are easy to understand, enabling a better predictability of future tariffs, while in a few entry/exit zones the methodologies implemented are more complex because of certain design choices, like combined distance cost drivers, flow scenarios, floating entry exit split or benchmarking (e.g. in Austria, France, Poland-Yamal, Portugal and Slovenia). The increased harmonisation of RPMs and an enhanced tariffs’ predictability are the main positive outcomes of the TAR NC as more standardised and predictable tariffs reduce some of the barriers to enter and to operate in the EU gas wholesale markets.

201 As for the choice of the entry/exit split¹⁵², in most zones, the chosen RPM has led to an increase in the exit share (e.g. exporting IP sides or exits to the national distribution network). Generally, lower entry tariffs incentivise access into the VTP and a lower hub price formation, while higher exit tariffs tend to increase the transportation costs for national consumers and/or for exporting gas acquired at the VTP. As the entry/exit split can considerably affect the distribution of transportation cost levels, it shall use stable cost drivers and follow a cost-reflectivity

149 The internal gas market in Europe: The role of transmission tariffs, See [here](#).

150 RMPs are methodologies and criteria that TSOs apply to allowed/target revenue in order to set transportation tariffs in an entry/exit zone and that shall ensure tariffs’ cost-reflectivity and predictability.

151 The general principle set in the TAR NC is that the same RPM must apply to all network points in an entry/exit zone and consider specific cost drivers, but the TAR NC also allows for some discretion in the implementation of RPMs if the aim is to pursue a better operation of the gas network. Adjustments include, for example, discounts for specific points (storage, LNG terminal, infrastructure ending isolation), benchmarking (in order to avoid that certain points become non-competitive), equalisation, rescaling. The use of adjustments may stimulate competition between different interconnection points, e.g with the aim to attract market interest and promote infrastructures’ use.

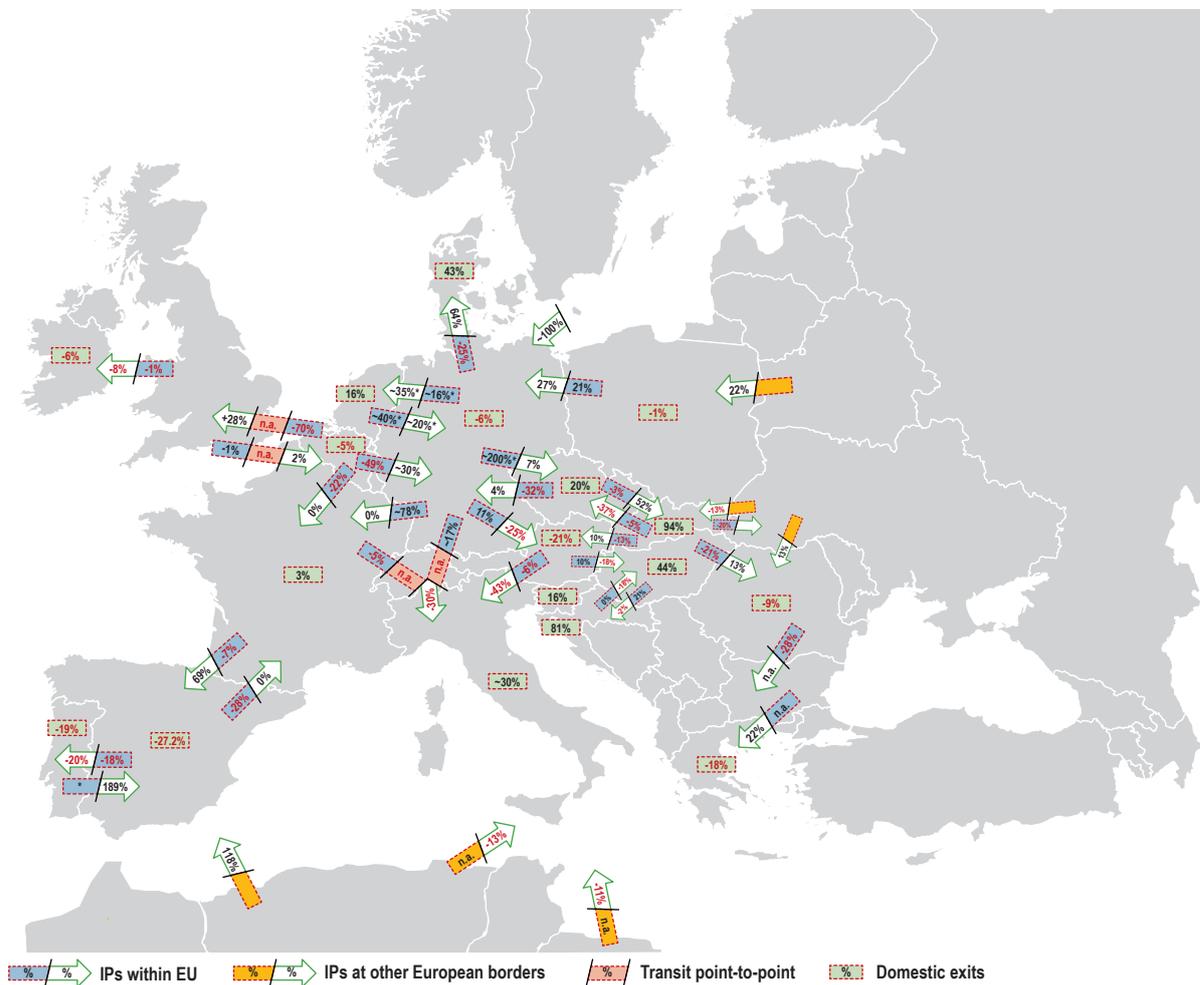
152 One of the key parameters of the RPMs is setting the split between the entry and the exit points to allocate the TSO’s allowed revenues (including exits to the distribution network, to another entry/exit zone, UGS and final customers) in an entry/exit zone, the so-called entry/exit split. In most zones, the entry/exit split is an ex-ante assumption however it can also be determined ex-post as an output of the cost allocation methodology.

principle. Any deviation from the cost-reflectivity principles needs to be duly justified as it may entail a risk of cross-subsidisation and/or impact cross-border trade and market integration.

4.2.2 Transportation tariffs levels and variations

202 In order to analyse one of the most likely and direct effects of the TAR NC implementation, Figure 37 shows a forecast of tariff variations at domestic exits and cross-border IPs before and after the implementation of the new RPMs at selected MSs. An overview of the absolute levels of cross-border tariffs at all the EU IP sides and directions in 2020, including the system access costs of LNG and those of the EnC CPs, is presented in Annex 1. In addition to RPMs, several elements drive the changes in tariffs, e.g. the allowed or target revenue of the TSO, the changes in capacity bookings, the entry/exit split and the market geographical position.

Figure 37: Comparison of average gas cross-border transportation tariffs before and after the TAR NC implementation for selected gas supply routes and domestic exits – tariff delta in %¹⁵³



Source: ACER calculation based on ENTSOG, CEER and individual TSOs (2020).

Note: In the UK, the new RPM does not affect the transmission tariffs resulting from contracts concluded before.

153 The figure includes capacity and commodity tariffs (if in place). Yearly capacity products are considered. If two entry/exit zones are connected by more than one IP, the variation is calculated as the average tariff change, weighted by the IP sides' capacity at each border, except for the entries from Russia into Germany and the flows between Germany and the Netherlands where a simple average is considered. At German IPs where more than one TSO operated with dissimilar tariffs in 2019, also a simple average is calculated. All MSs' border tariff variations are accessible at CHEST and a detailed comparison per IP side can be found in the TAR IMR as well. For Poland two cases have to be distinguished: 1) a decrease of 1.3% for exit tariff from Poland to Germany for gas transmission network owned by Gas-System TSO, 2) an increase of 21.7% for part of the Yamal pipeline through Poland (Europol Gaz), where Gas-System is ITO. The tariffs of 2017 still apply in fact. The tariffs sanctioned for 2018, 2019 and 2020 were challenged and a court proceeding is pending.

- 203 The analysis shows that some relevant tariff variations occur with the application of the newly proposed RPMs. Selected entry/exit zones (e.g. NCG, GPL, AVTP) see mostly an increase in cross-border exits¹⁵⁴ and a parallel decrease in domestic exits. These zones share a central location in the transit of gas in Europe and a consistent amount of legacy booked capacity that will not expire soon. In some other zones, both cross-border and domestic exits either decrease (e.g. ZTP, PVB, PT VTP) or increase (e.g. TTF). In some other zones, cross-border exits decrease whereas domestic exits increase (e.g. Czech VTP, Slovak VTP, TRF). This latter case is likely to stimulate exports – or transits – at the expense of higher internal transportation costs. Finally, import tariffs decrease whereas domestic exits increase in other zones (e.g. PSV, HR VTP), which is likely to favour a lower wholesale market price formation that compensates higher domestic transportation costs.
- 204 Tariff variations are among the key drivers of future price convergence levels. Variations of cross-border tariffs may impact the wholesale price formation and extent of cross-border flows not only in immediately neighbouring zone(s) but also in more distant ones. Changes may be especially relevant where they impact the hub's marginal supply price by changing the IPs' booking and utilisation.
- 205 Given the limited observation time after the TAR NC tariffs became effective (the last three months of 2019, in only some zones) and the fact that in most zones the new tariffs will become effective starting from 2020, the effects of the abovementioned tariff variations will be analysed more in detail in the next MMR that will include additional analyses on IPs' utilisation and price convergence aspects.

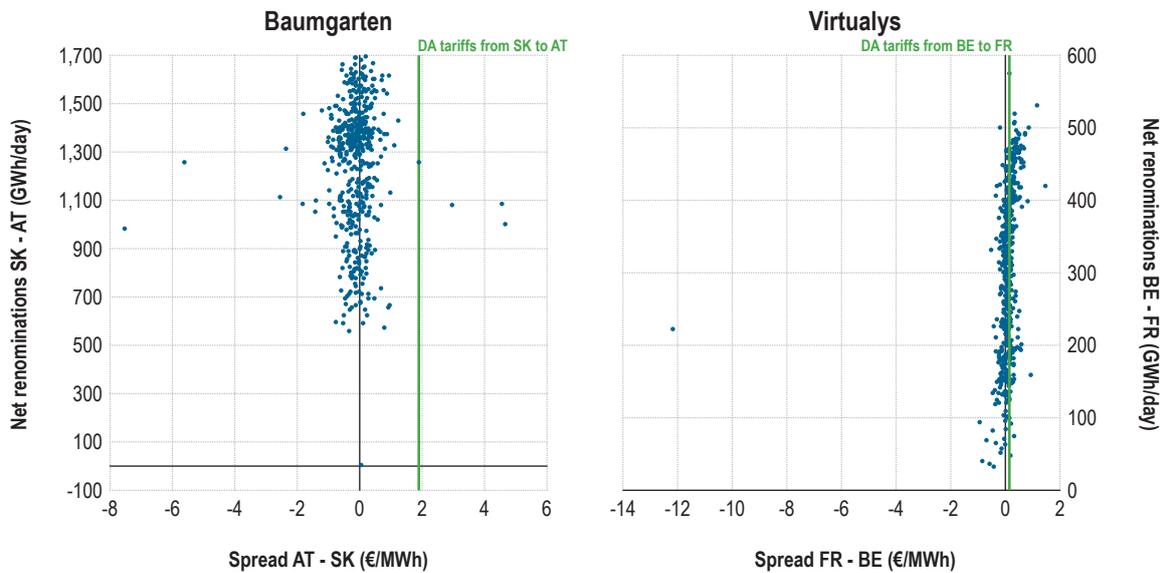
4.2.3 Relationship between hub price spread and tariffs

- 206 Transportation tariffs play an important role in determining IPs' utilisation. The shifting approach into shorter-term capacity bookings (discussed in [Section 4.1](#)) is called to further stress the relative positioning of hub spreads and tariffs as a crucial driver behind IPs' use. However, today long-term supply and capacity contracts are still dominant at many EU IP sides and directions and this setting tends to still partly limit IPs price-responsiveness. Limited flows' responsiveness to hub spreads tends also to derive from the EU networks' design and the geographical location of the hubs; i.e. large transit flows are needed to flow gas from external producers to big EU consumers, while peripheral zones tend to have less supply options than more central zones. Figure 38 analyses the price-responsiveness of net gas flows at two physically bidirectional IPs, which are noticeably core to supply gas between zones – Baumgarten and Virtualys – while Figure 39 shows the price-responsiveness of net gas flows at two noticeably more hub-spread oriented IPs (Zelzate and IUK)¹⁵⁵.

154 The impact of these rises on cross-border trade and prices are aimed to be analysed in future MMR editions.

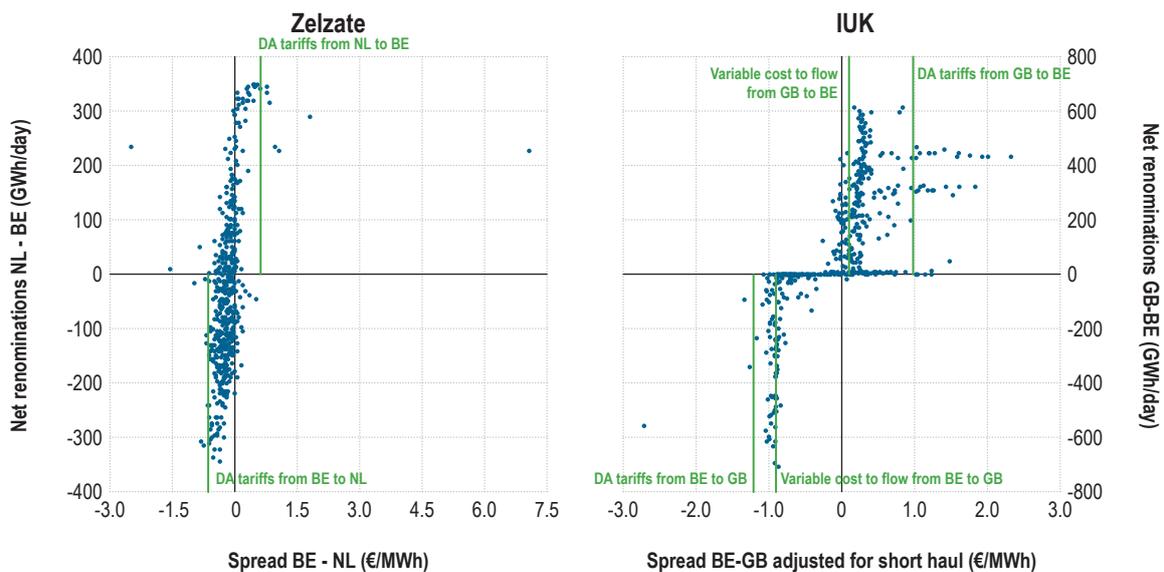
155 The correlation has some limitations because the two variables are partly interdependent. Prompter hub products and obligations drive IPs' use as well – i.e. some nominations take place independently of the spread. Owners of prevailing LTCs also have an incentive to increase their nomination in those days when spreads are more favourable.

Figure 38: Day ahead tariffs, spreads and net renominations at Baumgarten and Virtualys – 2018 and 2019



Source: ACER based on ENTSOG TP and ICIS Heren.

Figure 39: Day-ahead tariffs, spreads and net renominations at Zelzate and IUK - 2018 and 2019



Source: ACER based on ENTSOG TP and ICIS Heren.

Note: The spread between Zeebrugge Beach and NBP included in the IUK figure is adjusted for short-haul tariff. The adjusted price takes account of the option available to shippers to make use of the short-haul charge and it is derived by subtracting 1.67p/th (avoided NTS entry commodity charge) from the Heren quoted NBP price to create a proxy Bacton-Beach price.

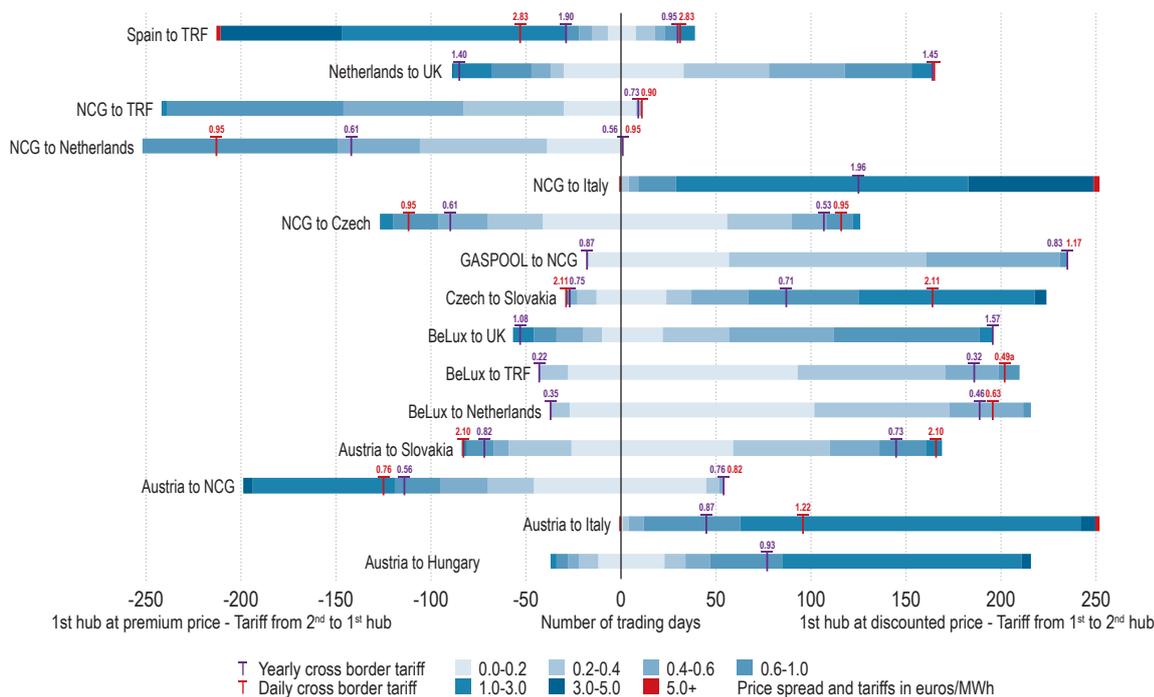
- 207 The net flows across the two designated core-to-supply IPs (Figure 38) always follow the dominant direction while their actual levels are not markedly dependent of the hub-spread actual value, but more driven by evolving supply needs. Besides, flows are not restricted when spreads between the interconnected hubs are below or close to the transportation costs, a situation prevailing in the first of the IPs analysed.
- 208 At the two selected more spread-oriented IPs (Figure 39), net flows have a higher tendency to change direction in accordance to the spreads while flow volumes tend to be higher whenever spreads exceed transportation costs. In the particular case of IUK, this is more visible when reflecting in the hub spread – as a discount – the savings from the backhaul tariff. This reveals a more efficient link between hub spreads dynamics and IPs utilisation.

- 209 Still, there is room for improvement in terms of efficient utilisation of gas IPs. On the one hand, variables other than price may influence network users' portfolio and flow decisions, which may not appear efficient from an outside perspective while still being rational at an individual entity level e.g. hedged positions, portfolio adjustments, balancing actions. On the other hand, even the most hub-spread oriented IPs can, for example, host long-term supply obligations or may be used for additional purposes (e.g. net flows at IUK can occur against spreads – or spread vs tariff signals – for example, in order to inject or withdraw gas from the continental storage sites).
- 210 In EU electricity markets, progress made in implementing market coupling in recent years has resulted in a relatively higher efficiency of use of interconnectors in the day-ahead timeframe. However, comparing the efficient use of gas and electricity interconnectors is not a like-for-like comparison¹⁵⁶ due to, amongst other reasons, differences in market design. Furthermore, contrary to the EU electricity markets, almost all EU gas markets have limited or no domestic gas production. Gas supply is mainly guaranteed by imports (and mainly from a few third countries), so long-term contracts are and will be to a certain degree prevalent in some MSs. The latter implies that certain gas supply routes still remain unidirectional in use, despite of the physical bidirectional capability of the IPs.
- 211 The progressive expiration of legacy contracts in more MSs, the VIPs implementation, the parallel promotion of the hub sourcing model, the increased diversification of sources provided by LNG imports and a possible more frequent organisation of capacity auctions, are some of the drivers that will support the increased efficient utilisation of capacity at IPs.
- 212 In this setting, Figure 40 shows the relationship between transportation tariffs (for yearly and daily products) and hub spot price spreads at selected EU borders. Cross-border tariffs tend to have a referential role over hub price spreads, although the role may vary per case. In hub pairs, mainly in the NWE area, day-ahead price spreads are regularly below daily transportation tariffs and frequently also below yearly transportation tariffs (the latter being usually more economic). This tends to be due to overall higher market interconnection levels, higher hub competition, relatively more flexible gas supplies from the North Sea and, importantly, high presence of SRMCs bidding¹⁵⁷ derived from LTCs (for further details, see MMR covering 2018).

156 The efficiency in the use of electricity interconnectors in the day-ahead timeframe is defined as the percentage of available capacity (NTC) used in the 'right economic direction' in the presence of a significant (>1 euro/MWh) price differential. For more details see the [Electricity Wholesale Markets volume](#) of the MMR.

157 See further clarifications in [footnote 12](#).

Figure 40: Day-ahead price convergence levels between EU hub pairs compared to reserve daily and yearly transportation tariffs – 2019 – euros/MWh



Source: ACER calculation based on ICIS and hub operators' data for prices and ENTSOG TP for transportation tariffs.

- 213 However, in 2019 the results were slightly worse for most NWE hub-pairs compared to 2018 with reference to some indicators. This applies to a higher number of days when spreads were above tariffs, a lower occurrence of very low spreads and a less neutral distribution of premium positions at hubs¹⁵⁸ (e.g. at NCG-TTF, AT-NCG, NCG-TRF, NCG-GPL, BELUX-TTF the first hub was more frequently at premium than in 2018). On the contrary, improved results compared to 2018 for the abovementioned indicators were registered between NBP and the continental hubs (TTF and ZEE), likely given the record high supply of LNG at NBP that amply replaced the Continental interconnectors' utilisation.
- 214 The slightly worsening convergence among NWE hubs lead also to higher price gaps of Mediterranean hub vis-à-vis TTF, which also registered rising spreads among them (e.g. PVB-TRF, NCG-PSV, AVTP-PSV). Price convergence results at EU hubs and their key drivers are extensively analysed in Section 3.5.
- 215 However, these increased hub spreads did not hamper a new YoY increase in cross-border hub traded volumes that moved to all ever records. As analysed in Section 3.3, cross-border hub trading activity has consolidated in recent years due to, among others, the management of physical portfolios at adjacent hubs, active trading by market players with surplus bookings bidding at SRMCs, the opportunities to arbitrage from positions between distinct contracts and timeframes and the increase in algorithmic trading.
- 216 Situations when spreads are more frequently and more highly above tariffs can be generally observed between hub pairs with a lower level of liquidity (in one or both of the interconnected hubs, e.g. AVTP-MGP VTP, CZVTP-SKVTP), in case of administrative or regulatory barriers (e.g. AVTP-SKVTP), where networks are more isolated or not adequately connected and last but not least in case of contractual congestion¹⁵⁹. The absence of SRMCs bidding is also a very relevant factor. The latest ACER congestion report found an increased number of contractually congested IP sides and directions in 2019 compared to 2018, mainly because of increased presence of

158 Compared to 2018, in 2019 even at hub-pairs connecting the most well-functioning hubs, the price-spreads followed a more dominant direction, rather than the usual more balanced direction on both sides of the IP.

159 For example, the IPs from Germany to Italy passing via Switzerland and from Austria into Hungary are labelled as congested according to the latest ACER Congestion Report.

auction premia¹⁶⁰. A proper implementation of the Gas Network Codes and guidelines will reduce the situations when hub-pair-spreads exceed tariffs.

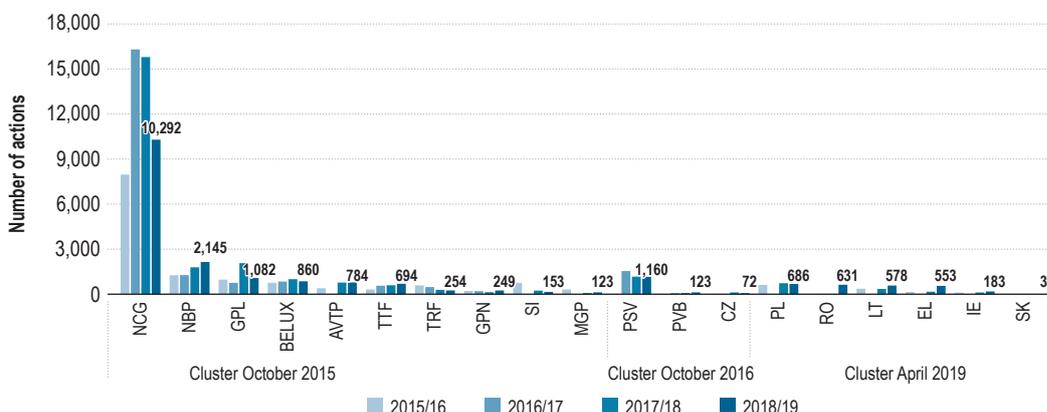
4.3 BAL Network Code effects

217 This Section analyses the market effects of the implementation of the Balancing Network Code¹⁶¹ also based on the latest edition of the Agency’s Gas Balancing Network Code Implementation Monitoring Report¹⁶².

218 The analysed balancing zones are divided into three clusters based on the chosen BAL NC’s implementation date: Cluster October 2015, Cluster October 2016 and Cluster Interim Measures (April 2019). The analysis includes zones for which complete data could be extracted from ENTSOG’s files. The analysis covers four gas years, from October 2015 to September 2019. A detailed analysis of the elements of the balancing systems of Cluster October 2015 and Cluster October 2016 is provided in the previous MMR editions.

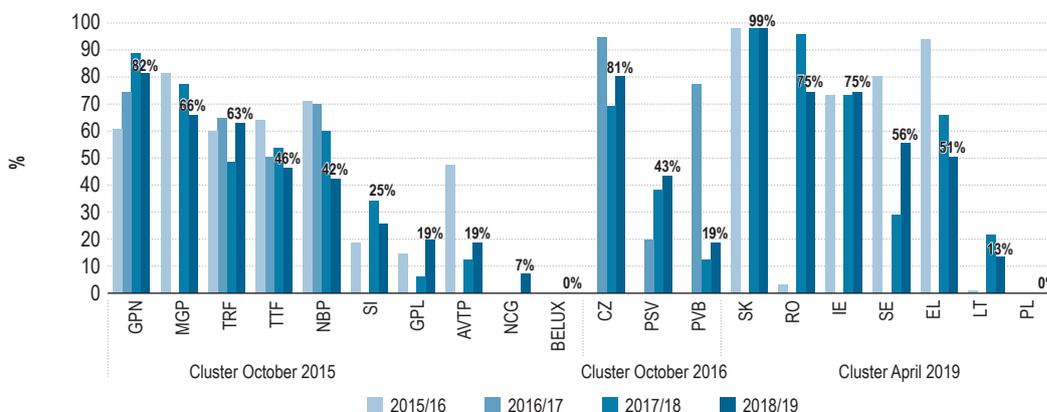
219 Figure 41, Figure 42 and Figure 43 assess the level of TSO intervention for balancing the system by using three indicators: (1) TSO balancing actions, (2) percentage of days without TSO’s intervention, (3) TSO balancing volumes.

Figure 41: Number of TSO’s balancing actions at selected balancing zones – Gas Years 2015/16 – 2018/19



Source: ACER based on ENTSOG data.

Figure 42: Percentage of days without TSO’s balancing actions at selected balancing zones - 2015/16 and 2018/19 gas years



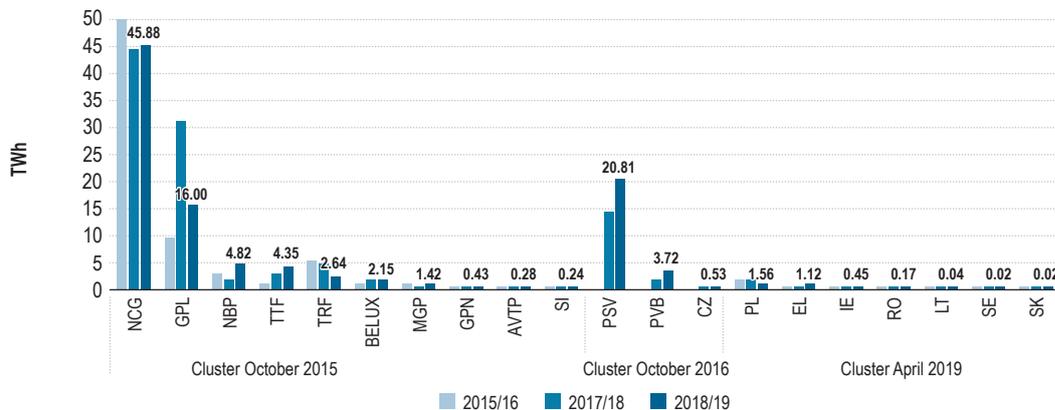
Source: ACER based on ENTSOG data.

160 See footnote 159.

161 More information on the indicators are included in the previous editions of the Gas Wholesale Volume.

162 The latest ACER Implementation Monitoring Report of the Gas Balancing Network Code was published in April 2020.

Figure 43: Volumes of balancing actions triggered by the TSO at selected balancing zones - gas years 2015/16, 2017/18 and 2018/19 – TWh/year



Source: ACER based on ENTSOG data.

Note: ENTSOG data include TSOs’ balancing actions carried out at the trading platforms, at the balancing platforms, and via balancing services. The following volumes are not considered in the figures above because not included in ENTSOG data: contracted and not used balancing services, where in place; “Alizes” and “SET” services at TRF; “Operational Storage” and “TSO-nominated storage” at PSV; flexibility provided by network users’ tolerances at OTE; data for the gas year 2015/2016 for Cluster 2016, L-gas and Yamal balancing zones volumes in Poland due to no TSO’s balancing activities.

Cluster October 2015

220 In the 2018/19 gas year, the TSOs at TTF and NBP continued to play a very residual role in balancing their systems, even if their balancing systems are differently designed. The network users’ friendly TTF’s balancing system is one of the drivers of the exponential rise in traded volumes over the last years, mainly due to the transparent and reliable balancing information, which creates a reliable balancing (real time) price signal. This stimulates not only the real-time and spot trades but also the more forward and longer-term trades up to investments’ decisions. The Dutch balancing system was more exposed to imbalances compared to the previous years, as such more TSO’s balancing actions had to be triggered. This was driven by, among others, the decreased availability of Groningen flexibility, the increased volume of more rigid (compared to pipelines) LNG supplies which may cause more volatility in markets and consequently more system imbalances, L-gas specific issues, and the record high spot trades carried out at TTF in 2019. At NBP, in the gas year 2018/19, the TSO triggered more balancing actions than in the previous years, which was mainly driven by the same drivers as TTF (increased LNG supplies, increased spot traded volumes).

221 The situation for balancing of BeLux remained constant compared to the previous gas years: the level of TSO intervention is limited and a full market-based balancing system is in place, where only short-term standardised products are used by the TSO for balancing.

222 The TSO’s balancing volumes and balancing actions at Danish GPN increased in the gas year 2018/2019 but spot liquidity at GPN decreased. In April 2019, the GPN balancing zone was merged with the Swedish balancing zone. The impacts of this merger will be evaluated in the next Gas Wholesale Volumes because the limited observation period does not allow to draw any conclusions yet.

223 In the 2018/2019 gas year, the two balancing zones in Germany – NCG and Gaspool – confirmed to be the ones with the highest TSOs’ “explicit” intervention in the EU. NCG remains the balancing zone with the highest TSO balancing volume (over 45 TWh) and the highest numbers of TSO’s balancing actions (almost 10,000) in the EU. The balancing actions are triggered almost every day. Nevertheless, at both NCG and Gaspool, the level of Market Area Managers’ (MAM) intervention slightly decreased in the gas year 2018/2019 compared to the two previous gas years. At both NCG and Gaspool, the balancing platform was not operational anymore since January 2018 and was permanently cancelled after April 2019. However, still around 25% of the TSO’s balancing products traded at NCG are locational, meaning that only network users holding capacity at specific points in the gas network can trade them. The portfolio-based Within-Day Obligations (WDOs) and the Firm Day-Ahead Use-It-Or-Lose-It (FDA UIOLI) that apply at the IP sides may discourage shippers from taking spot

positions. The situation may improve with the merger of the NCG and Gaspool hubs into a single balancing zone planned for October 2021.

- 224 The results of the TSO's intervention in the balancing zone in France is not fully representative of the real TSO's balancing role as it does not include the volumes related to the TSOs' flexibility services (GRTgaz' Alizes and Teréga's service d'équilibrage transport – SET)¹⁶³. These linepack flexibility services have been offered since 1 October 2015 after approval by the NRA. Whereas the network users are responsible for daily balancing on their portfolio, these products exempt network users supplying end customers (who subscribed to this service) from the full-end-of-the-day cash-out fee in the days when the network is balanced and TSOs do not carry out balancing actions to keep the system within its operational limits (neither via purchases/sales on the exchange, nor via the use of locational products).
- 225 In Austria, the TSO's explicit intervention is limited because of the design of the balancing system, which excludes the distribution network and imposes restrictive portfolio-based WDOs (as opposed to the system-wide WDOs implemented at TTF and BeLux) in addition to the end-of-the-day imbalance charge. Both previous elements discourage the development of a liquid balancing market. After several recommendations by the Agency on a number of necessary improvements in order to ensure compliance to the BAL NC, a process to redesigning the Austrian balancing market began. A new gas balancing design was approved by the NRA in 2019 and will enter into force on April 2022.

Cluster October 2016

- 226 In Italy, the number of TSO balancing actions and the percentage of days without TSO balancing actions decreased year-on-year while the TSO's balancing volumes increased. The latter was also due to a rise in the spot trades at PSV in 2019, which led to a need for increasing TSO's balancing volume. This confirms that balancing volumes and balancing actions are not always correlated and that the balancing role of the TSO is becoming more and more marginal¹⁶⁴.
- 227 In Spain, the TSO's intervention increased. TSO volumes and actions increased by 70% and 50%, respectively. This is also due cases of fraud¹⁶⁵ carried out both OTC and at the MIBGAS exchange in 2019, which required the TSO to buy high volumes of gas in order to cover for the system imbalances. Beyond that, it is expected that with the increased usage over the years of the BAL NC provisions and tools, both the TSO and the network users will become more experienced and as such more confident in managing the system with the BAL NC tools, making the TSO's balancing role more marginal.
- 228 In the Czech Republic, only three balancing actions were triggered in the gas year of 2018/19, for volumes even lower than the limited volumes of the previous gas years. This is due to the balancing design that discourages the creation of a spot market, as portfolio-based within-day obligations for transit network users are in place, furthermore the TSO uses a significant volume of linepack in order to balance the network. Therefore, the balancing role of the TSO is still central due to measures which are *implicit* and *ex-ante* (compared to the balancing timeframe).

Cluster April 2019

- 229 The results of the balancing zones where interim measures have been implemented according to the BAL NC¹⁶⁶ are heterogenous. The legal deadline for the end of almost all interim measures was April 2019 but some balancing zones have kept them.

163 The usage of Alizes and SET may *de facto* discourage trading among network users to balance their portfolio with spot products the days when the network is balanced.

164 "Operational Storage" and "TSO-nominated storage" are in place at PSV, which are not included in this analysis as corresponding volumes are missing in ENTSOG data.

165 See further insight for example in this [piece of news](#).

166 List of interim measures allowed by the BAL NC until April 2019: balancing platform (can be prolonged for further 5 years until April 2024), *interim imbalance charge*, network users' *imbalance tolerances*, *alternative to balancing services*. Interim measures were implemented in ten MSs: Bulgaria, Gaspool, NCG, Greece, Ireland, Lithuania, Poland, Romania, Slovakia, Sweden and the UK - Northern Ireland.

- 230 In Poland, all interim measures (tolerances, balancing platforms and interim imbalance charge) had been removed by April 2019. All tools required by BAL NC for balancing are implemented but the TSO triggers balancing actions every day. There are several causes for the low development of spot trades in Poland (e.g. some regulatory and administrative barriers, for example storage obligations, trading obligations, the requirement of an additional cross-border license, licensing requirements, reporting obligations etc).
- 231 In Slovakia, the TSO's market-based activities for balancing are almost non-existent: in the gas year of 2018/2019 only three TSO balancing actions were triggered and more than 80% of them were procured via balancing services. After April 2019, two interim measures were kept (balancing platform and interim imbalance charge). Despite the balancing platform being operational, the TSO tends to trade short-term balancing products in the adjacent Austrian market instead of the national market. Renomination restrictions on legacy-booked capacity, which on average accounted for more than 80% of the total capacity booked at the Slovakian IPs in the gas year 2018/2019, and the exclusion from the balancing market of the distribution areas hamper the development of a wholesale gas market in Slovakia. As the legacy-booked capacity at Slovakian IPs will not expire soon, it is unlikely that a spot market will develop if the restrictions on renominations are kept.
- 232 In Romania, all interim measures were terminated in 2018. However, balancing volumes and actions triggered by the TSO were low in the gas-year of 2018/2019, compared to the size of the market and to the gas consumption. The reason is that a high share of total injections and withdrawals into the gas network is not exposed to the BAL NC's obligations because of the presence of supply obligations at regulated prices that apply to most gas consumed volumes. Furthermore, a parallel market for balancing via within-day and day-ahead products applies to these supply-obligations volumes, and this market has a regulated imbalance price-cap. As long as these provisions are in place, it is unlikely that a spot market will develop in Romania.
- 233 In Greece, a balancing platform was set up on April 2019 close to the legal deadline for the end of the interim measures. The platform is planned to be in place until April 2024, while the interim imbalance charge was kept after April 2019. However, the BAL NC implementation has already started producing positive effects. The TSO's balancing volumes and actions increased year-on-year, signalling that the increased number of trades carried out at the centralised platform for balancing are stimulating the creation of a spot market, with the TSO still having a central explicit role in driving the increase in spot liquidity via balancing actions in this first phase. Also, for the gas year 2018/2019, volumes procured via balancing services account for only 30% of TSO's total trades, whereas, before the NC implementation, this share was 100%. The next few years will show if the progressive increase of TSO's actions in the short-term market contributes to the development of a spot market and leads to the removal of the interim imbalance charge.
- 234 In Lithuania, despite of the removal of all interim measures, the level of TSO intervention did not change compared to the previous gas year. Network users can trade a product that allows them to exchange their imbalance position after the end of the gas day, both OTC and at the exchange. Since the overall imbalance volume of network users is very low, the majority of network users' imbalance volume is adjusted by using the previous-day product. As long as this product for balancing is kept, it is unlikely that a spot market will develop in Lithuania.
- 235 In Ireland, some interim measures were removed in 2019 (interim imbalance charge and alternative to the balancing platform) but some tolerances were kept. All indicators remained stable compared to the previous gas years. The NRA plans to remove the current tolerances by October 2020. Until then, it is unlikely that the spot and balancing markets will become more liquid in Ireland.
- 236 Sweden terminated the interim measures in place after the merger with Denmark in April 2019. A system fully based on balancing services was replaced with title products. It is too early to draw conclusions deriving from this merger¹⁶⁷.

167 The Agency does not have the number of actions triggered by the TSO, as it is missing in the ENTSOG data.

Figure iii: Overview of EU LNG terminal and UGS capacities per MS – 2019

LNG terminals

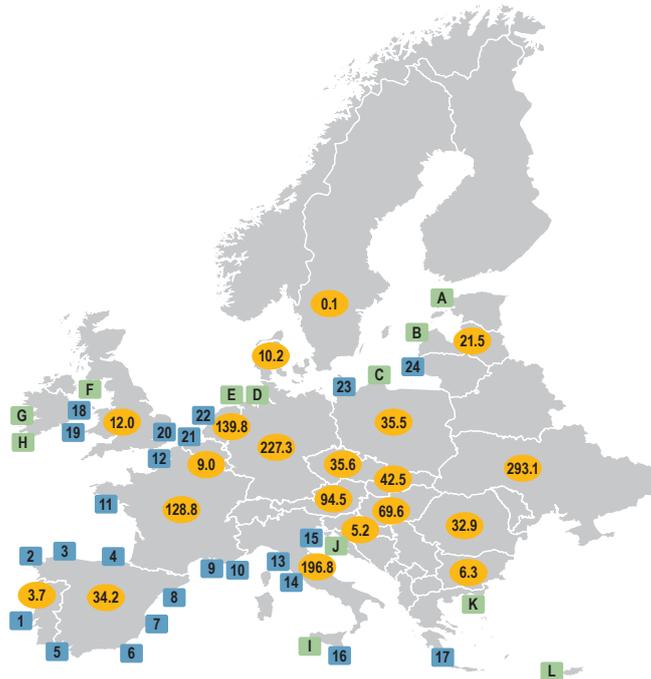
Name	Storage capacity (x 1000 m ³)	Regasification (bcm/y)
1 Sines	390	7,6
2 Mugardos	300	3,6
3 Gijón (Musel)	300	7,0
4 Bilbao	450	8,8
5 Huelva	691	11,8
6 Cartagena	587	11,8
7 Sagunto	600	8,8
8 Barcelona	760	17,1
9 Fos-Tonkin	80	3,0
10 Fos Cavaou	330	8,2
11 Mtoir-Bretagne	360	10,0
12 Dunkerque	600	13,0
13 Panigaglia	100	3,4
14 FSRU Toscana	137	3,7
15 Porto Levante	250	7,6
16 Delimara	125	0,7
17 Revithoussa	225	7,0
18 Dragon	320	7,6
19 South Hook	775	21,0
20 Isle of Grain	1.000	19,5
21 Zeebrugge	386	9,0
22 Gate	540	12,0
23 Świnoujście	320	5,0
24 FSRU Indep.	170	4,0

Underground Storage

10.2 Working gas volume (TWh)

Planned terminals

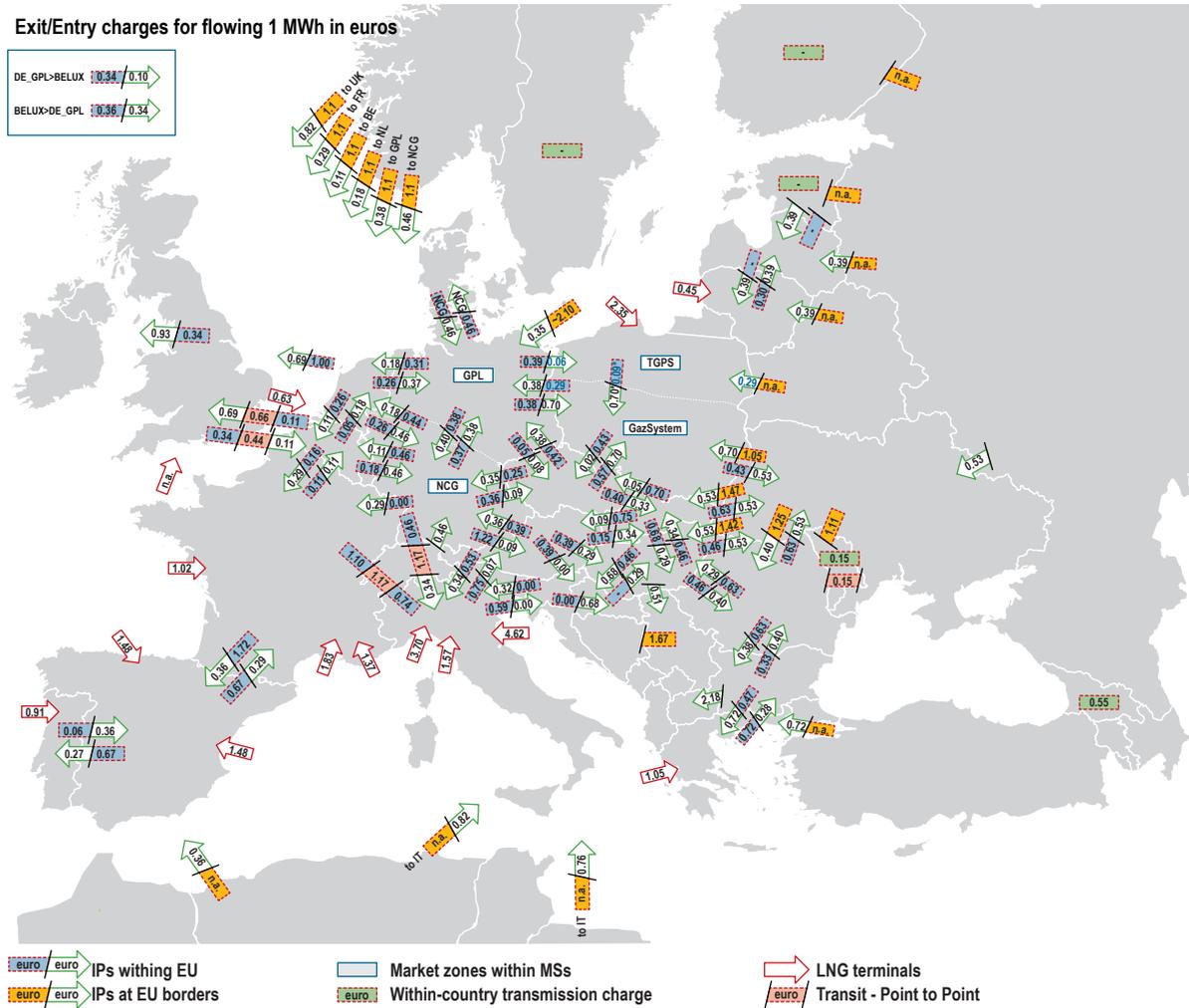
- Name
- A Paldiski
- B Kundzinsalas
- C FSRU Polish Baltic Sea
- D Brunsbüttel
- E Wilhelmshaven
- F Port Meridian
- G Shannon
- H Cork
- I Porto Empedocle
- J Krk Island
- K Alexandroupolis
- L Vassiliko



Source: ACER calculation based on GIE (2019)

Note: The design capacity of the Latvian Inčukalns UGS is 24,2 TWh. In 2019, the capacity offered was limited to 18,5 TWh due to technical restrictions.

Figure iv: Comparison of average gas cross-border transportation tariffs and LNG system access costs – 2019 – euros/MWh



Source: ACER calculation based on ENTSOG, CEER and individual TSOs (2020).

Note: For cross-border IPs, the map displays 2020 exit/entry charges in euros/MWh for the yearly product. See MMR 2016 annex 1 for further clarifications. For LNG terminals, the figure considers the costs derived from the bundled service (unloading + storage + regasification) of a 1,000 GWh LNG cargo, which regasifies the whole amount in a period of 15 days, plus the entry tariffs from the LNG terminal into the transportation network. At the Slovak IPs only a range of tariffs can be provided since the final price is a function of the booked capacity volumes. Nord Stream tariff is an educated guess on the basis of market intelligence reports assessments. In Poland, the tariffs referring to Yamal are shown in blue colour. Besides physical flow between the Yamal Pipeline (TGPS) and the Polish VTP (Gaz-System) a backhaul reverse flow is possible.

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