Global Gas Security Review 2020

Abstract

Global gas demand is expected to fall by 3% or 120 billion cubic metres (bcm) – its largest drop on record. Amid this slowdown, LNG continues to play a central role in balancing global gas markets, ensuring flexibility and security of supply. Faced with a historic fall in global gas demand in the first half of the year, gas producers and exporters have had to provide flexibility to adjust supply. LNG was one of the key enablers of this adjustment, with monthly global exports decreasing by 17% between January and July.

In this extraordinary context, LNG contracting activity has collapsed from its high of 95 bcm in 2018 to about 35 bcm in the first nine months of 2020. Meanwhile, the structure of LNG supply is set to be reshaped, since about one-third of active contracts are due to expire between 2020 and 2025, while export capacity is set to expand by 20%. These trends create an unprecedented challenge and opportunity for market participants.

This report offers a detailed analysis of recent LNG contracting developments and assesses the role of flexibility in gas supply adjustment during the Covid-19 crisis. It also provides updates on the latest developments in global gas markets and on the near-term outlook.

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Executive summary

Low LNG contracting activity, contract expiry and capacity expansion set to shape LNG supply to 2025

After a wave of strong contracting activity culminating in 2018 with 95 bcm signed, LNG contracting slowed down in 2019 with a total volume of 74 bcm. Activity collapsed in 2020 with only 35 bcm signed to date - with no further contracting activity, this would mark a year-on-year decrease of over 50%.

Although Covid-19 is contributing to a historic demand shock, a well-supplied market since 2019 is a larger driving factor behind this decreased activity. From 2015-19, the share of total contracts with fixed destination clauses decreased as new flexible-destination volumes entered the market. By contrast, despite the decline in total volumes, fixed-destination contracts have grown to date in 2020.

About 190 bcm of legacy contracts are due to expire in the next five years, accounting for about one-third of current active volumes. Over the same period global liquefaction capacity is to increase by 20% from projects currently under development. These two factors will strongly impact the structure of LNG supply, and create new opportunities for buyers and challenges for marketers in a context of demand uncertainty.

LNG takes centre stage in the supply response to gas demand drop in H1 2020

Faced with an unprecedented fall in global gas demand in the first half of the year, the whole natural gas value chain has had to provide flexibility to adjust supply, including production shut-ins, contractual flexibility mechanisms to reduce LNG and pipeline gas volumes or optimising storage utilisation onshore as well as at sea.

Although pipeline gas exporters bore the brunt of the supply-side adjustment to the demand drop caused by Covid-19, the majority of LNG exporting countries also experienced varying degrees of supply curtailment over the first half of 2020. The United States accounted for the biggest share of the downward adjustment in global LNG supply, underscoring the outsized role of US LNG in market balancing at a time of a historic oversupply.

Without the flexibility of global LNG supply, the adjustment to the 2020 demand shock would have been less orderly, and could potentially have had a damaging effect on the commercial and contractual structures underpinning global gas trade.

Short-term outlook: A historic fall with slow rebound

Global natural gas demand is forecast to fall 3% y-o-y or about 120 bcm in 2020. The decline in demand has been revised from our previous June forecast, which was projecting a 4% fall for this year. In spite of this revision, 2020 is still assumed to experience the largest recorded drop in global natural gas demand.

Most of the declines in gas consumption have been observed in mature markets across Europe, Eurasia, North America and Asia. Taken together these markets account for over 80% of the expected drop in global natural gas demand for 2020.

Natural gas demand is forecast to increase by 3% y-o-y in 2021 (or about 130 bcm). The resurgence of Covid-19 cases and the prospect of a prolonged pandemic brings further uncertainty to the pace of recovery in 2021, which has led to a downward adjustment from the previous report. The recovery of global gas demand in 2021 is likely to be supported by fast-growing markets in Asia, Africa and the Middle East. More mature markets should see gradual recovery, and some may not reach their 2019 level in 2021.

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Update on LNG market flexibility metrics

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Update on LNG market flexibility metrics

Each year the Global Gas Security Review assesses the flexibility of the liquefied natural gas (LNG) market by analysing LNG supply availability, seller and buyer behaviour, and the evolution of destination flexibility in LNG contracts. This section focuses on the most recent LNG contracting trends, analysing how a pullback in contracting affects global market opportunities for LNG contracts and their pricing methods. The analysis here is based on the contractual positions of importers and exporters and their actual traded volumes, using the International Energy Agency (IEA) internal LNG contract database.

The IEA tracks metrics of market flexibility, liquidity and supply security. Since 2015 the market has become increasingly liquid and global: contracts are more flexible, total traded volumes have climbed, new pricing trends have emerged, buyers are more numerous and diverse, and optionality in contracts has gained further ground. So far, this year has been one of the most challenging in the history of LNG markets, requiring creativity from both sides of the market to manage one of the strongest demand shocks the market has ever experienced. A number of supply-side effects and other market-scale trends set the stage for this imbalance.

New projects on the horizon: 2019 was a landmark year in liquefaction sanctioning. Over USD 65 billion was committed for the development of 96 billion cubic metres (bcm) of new liquefaction projects around the world, crowning 2019 as the most significant year for sanctioned capacity in history.

Lower project sanctioning activity in 2016 and 2017 introduced concerns about a potential supply crunch in the medium term. Supported by outlooks for strong medium-term demand growth, the market emerged from this low point and rushed towards the historic wave of project sanctioning and contracting in 2018 and 2019. Momentum picked up in 2018 when projects in the United States, Canada, Senegal and Mauritania, and Argentina were sanctioned.

Financing pivoted: 2019 was also distinguished by the large amount of capacity that achieved final investment decision (FID) under the equity financing model. Historically most projects have reached FID using an offtake model based on project financing where developers take FID once the project offtake is secured through long-term supply contracts with third parties. In comparison, the majority of newly sanctioned capacity employs an equity financing model that does not rely on such deals, allowing projects to take FID sooner.

Contracting strength matched sanctioning: 2018 and 2019 also recorded a pick-up in the rate of contracting activity. Over the past six years, 2018 is marked as the peak for contracted volumes concluded in a single year (95 bcm). This contracting strength persisted into the following year, though at slightly lower levels. The total volume of contracts concluded in 2019 exceeded 70 bcm, outpacing contract expiry in that year by over 20 bcm.

Activity on pause: The demand shock from Covid-19 – combined with oversupply – has cast ripples across the LNG market: feedgas flows have declined, the year has yet to see a single project take FID and the number of concluded contracts has steeply declined. Globally gas supply topped 4 trillion cubic metres for the first time in 2019, increasing by 3% year-on-year (y-o-y). Demand did not keep pace, only absorbing some 60% of this supply increase with the remainder pushed into storage. Prices fell across all regions, in some cases to all-time lows.

Numerous developers have postponed investments, announced project schedule delays and adjusted milestones. In this context, each market player and region is affected according to their unique contractual positioning and future needs.

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Contracting slowdown: 2019 and 2020 contracting summary

After two strong years of contracting activity in 2018-19, the current market uncertainty has put the brakes on contracting so far this year.

The total volume of concluded contracts in 2019 was about 74 bcm, a decrease of over 22% from 95 bcm in the previous year. From 2014 to 2019 average contract volumes concluded annually averaged 72 bcm.

In 2020 so far only 35 bcm of contracts have been concluded, about half the volume of this time last year. With no further contracting activity, this would mark a y-o-y decrease of over 50%. On average 63 contracts were concluded annually from 2015 to 2019. Only 32 contracts have been signed so far in 2020.

Although Covid-19 is contributing to a historic demand shock, a well-supplied market since 2019 is a larger driving factor behind this decreased activity. Despite this year's relative low volume of concluded contracts so far, the contract details indicate some market trends:

Buyer need determines destination flexibility. Over the past four years the share of total contracts with fixed-destination clauses has steadily decreased as new flexible-destination volumes entered the market. By contrast, despite the decline in total volumes, fixed-destination contracts have grown since 2019 and account for almost four-fifths of the volumes contracted so far this year (25 bcm). Although destination-flexible volumes account for a larger proportion of total volumes in the market, fixed-destination contracts continue to play a role for end users and price-oriented buyers. Only a small number of flexible-destination contracts have been signed so far in 2020, totalling less than 10 bcm. An average of 60 bcm of destination-flexible volumes were signed in 2018 and 2019.

No single region has dominated the exporting or importing picture in 2020's concluded contracts. As in previous years, contracts concluded with portfolio players as the offtaker or seller are the anchor of the market and account for about 40% of volumes so far in 2020. Contracts for gas to be exported from Africa are a significant proportion this year at about 30% of volumes signed (11 bcm), represented mostly by multiple contracts at the NLNG facility in Nigeria.

Portfolio players make up the largest share of offtake. Of the contracts signed in 2020, the largest share is for portfolio player offtake for portfolio trade (8 bcm), comparable to levels contracted by this group during 2015 and 2016. After this group, the People's Republic of China ("China") is the next largest offtaker in concluded contracts (7 bcm), mostly volumes signed from portfolio players. In 2019 China led the pack with the highest concluded contract volumes for a single destination (32.5 bcm), just below the total volume of concluded contracts globally so far this year.

Contracts of all sizes and lengths are represented in 2020. Medium-term contracts (5-10 years) represent 40% of contracts concluded this year, up from an average of only 15% over the last 5 years. In 2018 and 2019 long-term contracts (over 10 years) were the largest share of concluded contracts. So far this year the large contract category (> 4 bcm) shows only a single contract signed, while small (< 2 bcm) and medium-sized contracts (2-4 bcm) account for almost equal shares.

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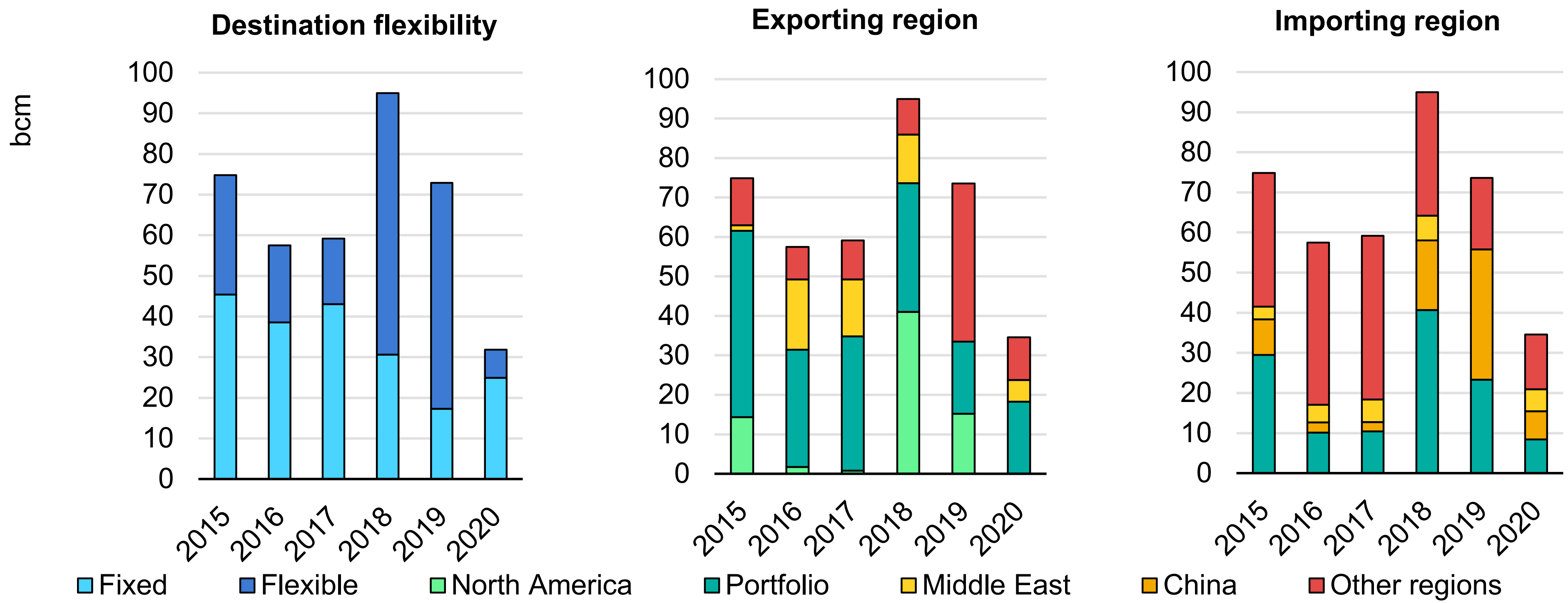
Contracting slowdown: Total contracted volumes of LNG show a substantial reduction in 2020 to-date, although fixed-destination and portfolio-backed contracts are resilient

Volume of contracts concluded in each year split by contractual element (2015-20 to date)



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Note: 2020 represents volumes signed through to end of September 2020. “Portfolio” volumes are contracted from a market player who may source product from one or multiple regions to fulfil contractual obligations.

Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required).

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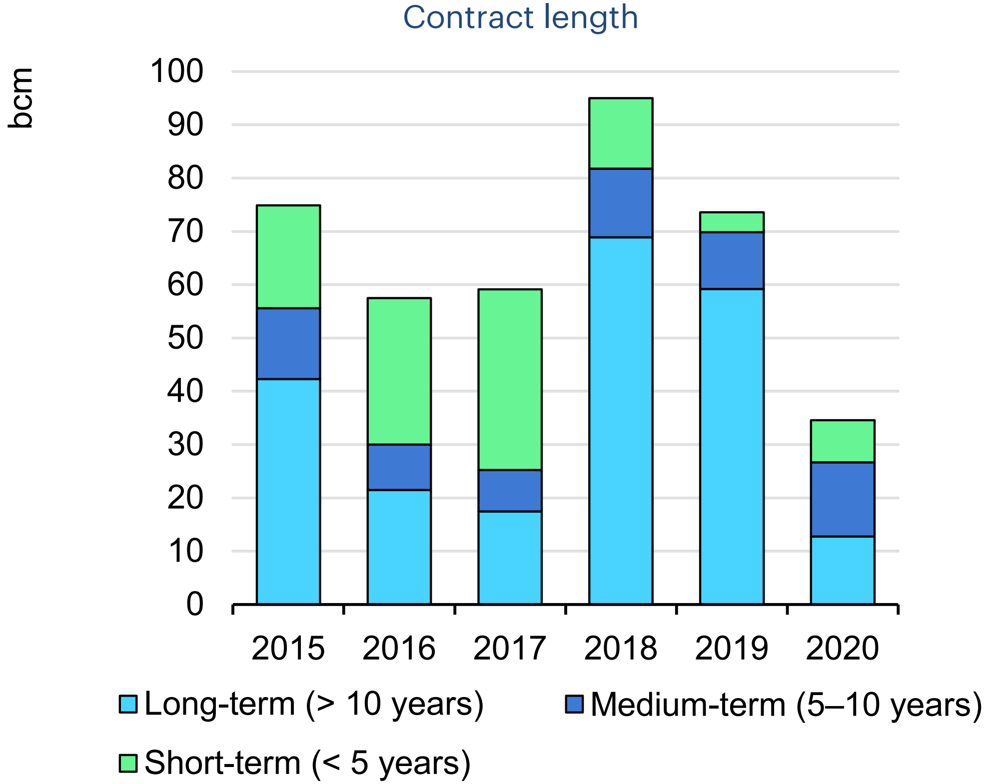
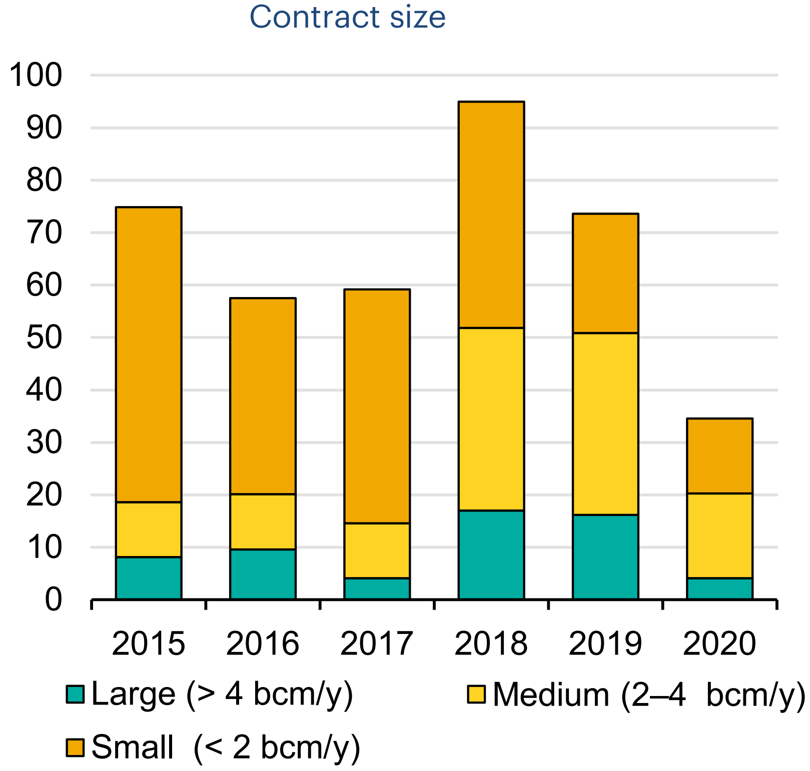
Contracting slowdown: Among the few contracts concluded in 2020, most are medium-term (5-10 years) and long-term agreements (> 10 years)

Volume of contracts concluded in each year split by length and size





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Note: 2020 represents volumes signed through to end of September 2020.
Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required).

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Marketing growing pains: Portfolio players and flexibility

After building up their purchased volumes in 2018 and 2019, portfolio players are looking to market volumes to buyers under term sales agreements. Portfolio players hold both purchase and sale contracts, aiming to have the majority of their portfolio marketed to buyers under long-term agreements. The total volume of sale contracts signed by portfolio players has fallen from 47 bcm in 2015 to 18 bcm in 2019 and 8 bcm so far this year. In 2015 and 2016 most of the volumes in their portfolios (made up of purchase contracts or equity stakes) had already been marketed through term contracts or spot deals, leaving less spare portfolio capacity from which to enter additional sales contracts. As product delivery from these contracts begins, more gas is being supplied via portfolio players each year.

2018 and 2019 brought high spot price volatility and strong expectations for demand growth, and buyers were willing to secure supply mostly under long-term conditions. This group had a strong appetite for long-term contracts (> 10 years), which represented 74% of total concluded volumes in 2018 and 80% in 2019. While some contracts have been signed this year, macroeconomic uncertainty and ample supply have cast a shadow over the market and left deals hanging.

A major theme of contracting activity in 2018 and 2019 was the rebuilding of supply portfolios by the major portfolio players, a trend which supported the development of the wave of new liquefaction capacity that reached FID in these years. About two-thirds of this capacity was signed under equity financing, and much of this purchased gas still needs to be marketed to end users.

The ratio of purchase obligations to sales offtake is the portfolio player contracted ratio, which is a metric of relative exposure to certain types of market risk. The portfolio players' contracted ratio was at 84.2% in 2016, meaning that the remaining 15.8% of their purchase obligations were not covered through term sales contracts. By 2019 this contracted ratio had decreased to 63.3%. Due to an increase in liquefaction capacity and additional portfolio purchase contracts entering into force, portfolio players are seeing greater exposure to short-term market conditions as the contracted ratio shrinks and their open position widens. As recently sanctioned liquefaction capacity continues to come online, the trend continues and the contracted ratio reaches 55.5% by 2025, based on existing contracts in force and all things being equal (i.e. assuming that expiring contracts are not renewed and with no specific assumption on any contracts yet to be signed).

Without a sharp increase in the volumes sold to end users under term contracts, portfolio players will have a much greater exposure to both market risks and market opportunities than at any time in the recent past. This is a positive development for market liquidity and flexibility, but a disconnect between project development timelines and expectations for demand growth can put pressure on participants. Any mismatch between these conditions may be challenging for sellers with obligations in hand. The IEA's *Gas 2020* report expects continued overcapacity into 2025 as liquefaction growth outpaces incremental LNG trade.

These conditions provide additional flexibility and room for opportunity in the event of an uptick in medium-term demand. With ample purchasing opportunities ready for buyers, the market is well-suited for end users to take their pick of supply from their region of choice and under contract conditions they find appropriate. Fortunately, this increase in supply permits the market to better serve many emerging buyers in varied locations and with diverse pricing and purchase requirements.

Even more capacity may be sanctioned over the next two years, further exacerbating the sellers' challenge of marketing their gas. Plenty of projects are in the pipeline, the most advanced in the near term being the Qatargas expansion.

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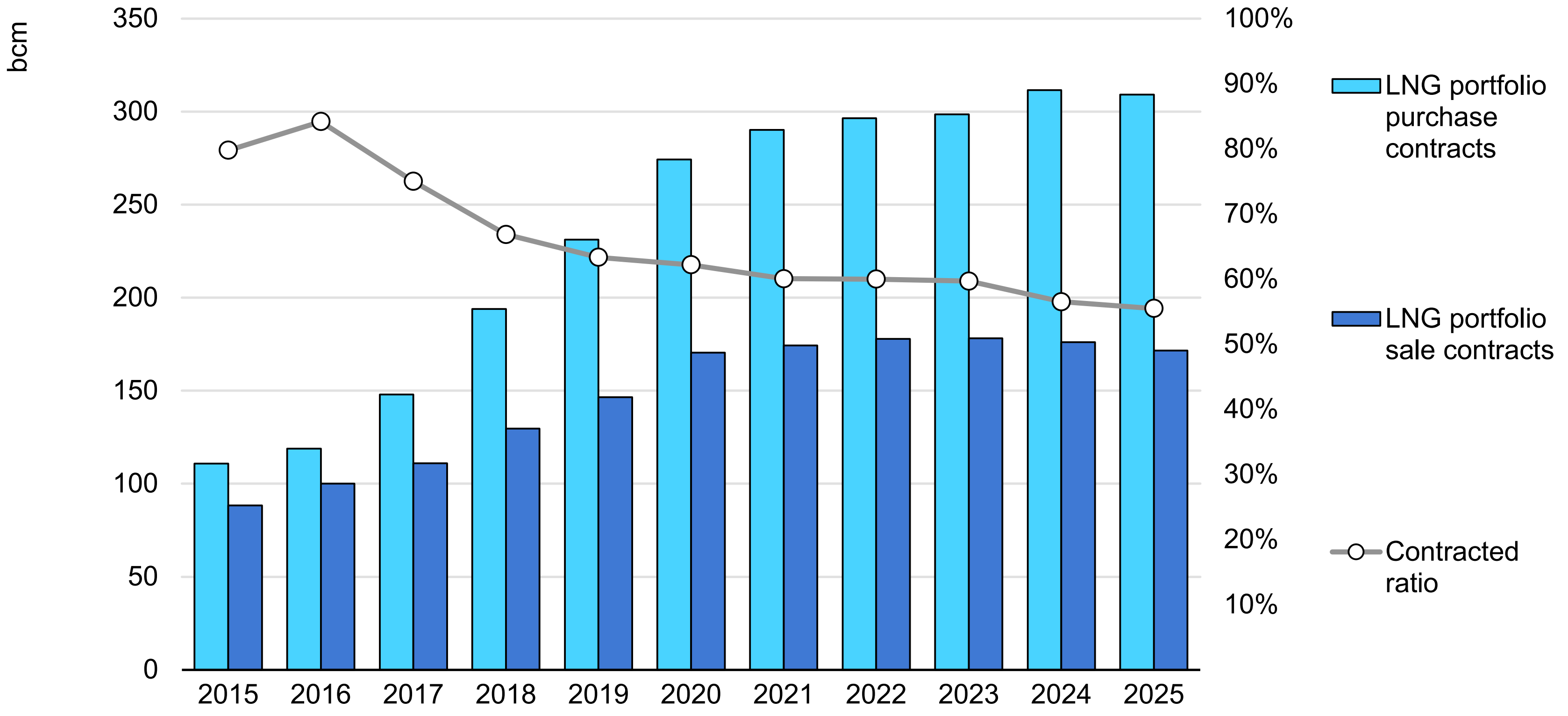
Portfolio players' open position widens through to 2025, underscoring the need for future sales contracts

Contracted volumes in natural gas purchase and sale contracts signed by portfolio players



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Note: Portfolio players are market players who hold both purchase and sale contracts. They often hold an equity stake in LNG facilities or purchase LNG from other sellers in multiple regions, permitting them to independently market a share of the facility production capacity to end users.

Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required).

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Competing for buyers: Contract turnover presents further market opportunity

About one-third of active contracts expire between 2021 and 2025, highlighting an unprecedented challenge and opportunity for market participants. Destination-flexible contracts are accounting for a growing share of market volumes and are set to represent half of total contracted volumes by 2024.

The recent move towards more flexible volumes has been spearheaded by portfolio players and new liquefaction capacity from the United States, which have been overwhelmingly contracted with terms that differ from legacy projects. In 2018 and 2019 almost 70% of all contracts signed were destination flexible. This push for destination flexibility in recent years has been led by traditional buyers and new entrants alike, and supported by portfolio players who require flexible conditions and equity lifting projects that are less exposed to the rigidity of end user/buyer needs. Yet in 2020 only 20% of total volumes concluded were destination flexible, as many of the contracts signed were for delivery directly to end users under fixed-destination conditions.

With new liquefaction capacity coming online, by 2025 total capacity is due to increase by 20% from 2020 year-end capacity. As older fixed-destination contracts expire and new flexible contracts enter into force, we see destination-flexible contracts accounting for over half of delivered gas volumes by 2024. This year for the first time, destination-flexible volumes will represent a larger share of contracted volumes than those with restricted destinations.

Critically, uncontracted capacity grows to 189 bcm through to 2025 (based on existing contracts at the time of writing). This highlights the scale of the marketers' challenge to reach new buyers as liquefaction capacity mounts and older contracts reach expiry.

Contract turnover volume is significant in the years to come: about 190 bcm of active contracts will expire between 2021 and end-2025. By 2030 over 40% of currently active LNG contracts will have expired.

The largest current holder of contracted purchase volumes, the Asia Pacific region, sees the highest volume of expiry at 76 bcm to end-2025 and 125 bcm to end-2030. This is followed by Europe which has 45 bcm of contract volume expiry to end-2025, being almost half of the active import contract volume in 2020. Yet with greater access to flexible spot volumes from the United States at lower shipping cost, Europe is more detached from this turnover. On the seller's side, the Middle East will see the most turnover, with Qatar facing about 35 bcm of contract expiry to end-2025.

This process is an opportunity for the market to look forward to the future and pursue the options that more closely provide for the needs of purchasers and sellers. 2018 and 2019 showed the continued adoption of more diverse contractual approaches, such as recent promising trends in increasing gas-to-gas indexation, hybrid formulae, greater flexibility surrounding price review, and hub pricing. Current market conditions have set the stage for these trends to continue once the pace of contracting begins to increase.

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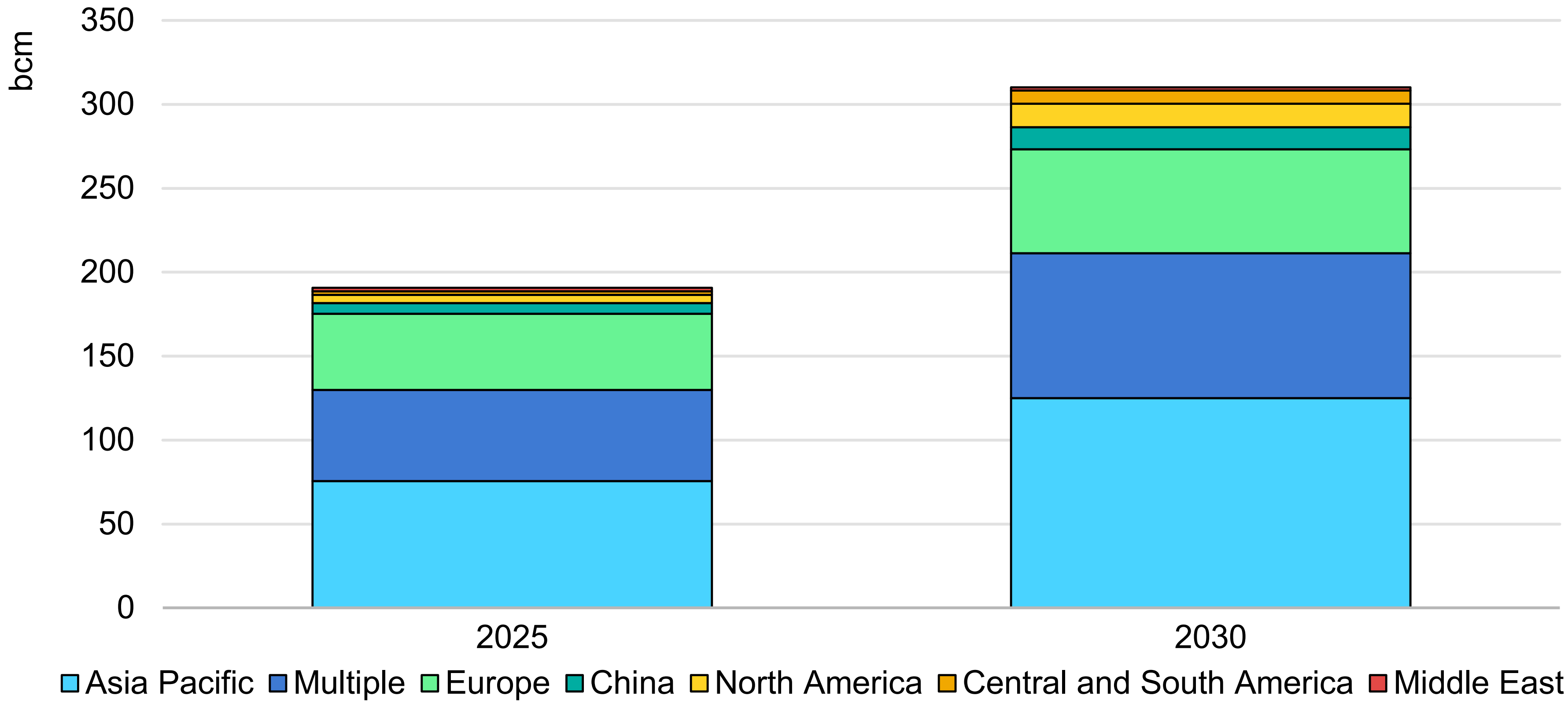
About 190 bcm of active contracts will expire from 2021 to 2025 and over 300 bcm will have expired by 2030

Expiring volumes of active LNG contracts, 2021-30



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Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required).

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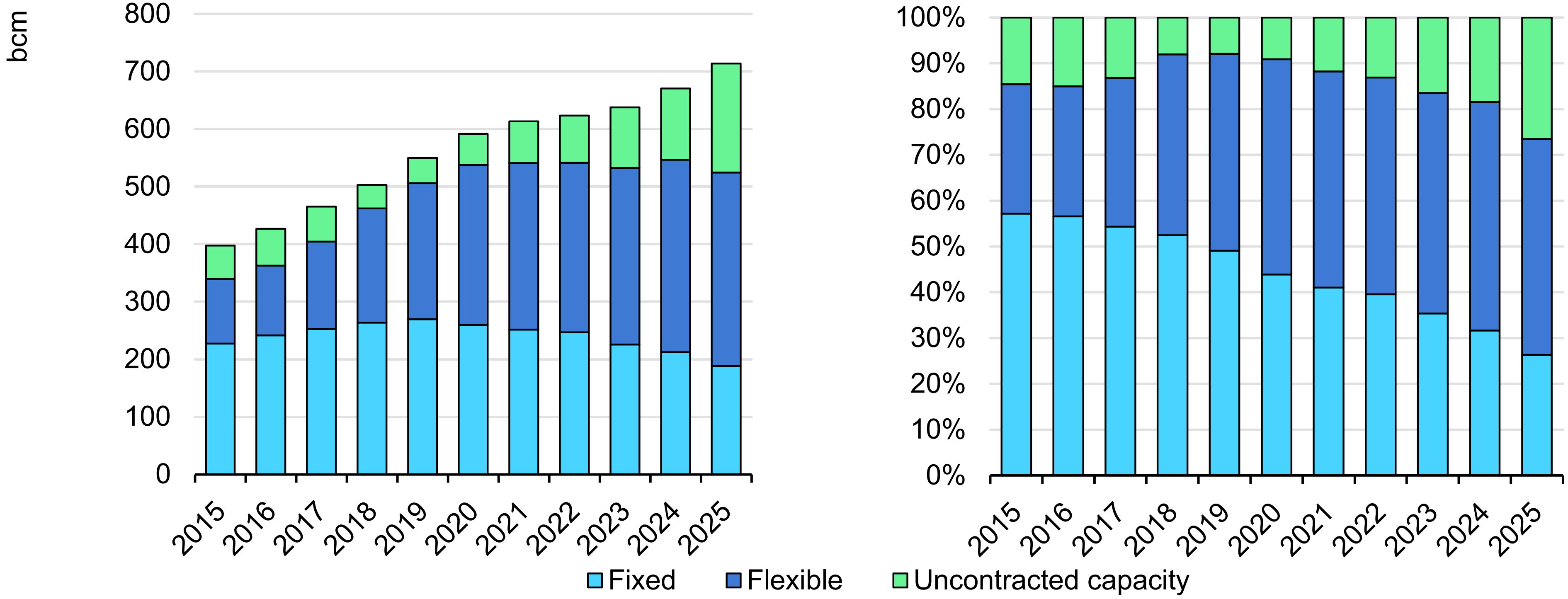
Destination-flexible volumes represent the largest market share from 2020, while uncontracted volumes increase through to 2025

Contracted volumes for LNG delivery by destination flexibility clause (excludes portfolio purchase contracts)



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Note: Analysis is based on project nameplate capacity.

Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required).

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Slowly but surely: Pricing developments

While contracts with oil-indexed pricing are still dominant in the LNG market, gas hub-linked pricing continues to gain ground as new contracts enter into force – especially among export contracts – and oil-linked contracts expire.

With the continued addition of volumes from the United States coming online, the market is likely to see further growth in Henry Hub and other gas-linked contracts in the next few years. US-based projects also provide buyers with contract advantages, including full destination flexibility, which fit current buyer needs well.

While gas-linked contracts have seen a fall in prices over the past year, holders of oil-linked contracts are just beginning to experience lower prices, given the fall of oil prices in March 2020 and the typical 3-4 month lag between a change in oil price and adjustment of the oil-indexed contract price.

The analysis of LNG contracts – by price formula, addressing the split between oil-index and gas-to-gas pricing, by export and import, by region and country – shows a recent trend towards gas-to-gas indexation in both LNG export and import contracts since the first US LNG shipment in 2016. Gas hub-linked LNG contracts (especially to Henry Hub, but also to the Title Transfer Facility [TTF] or the National Balancing Point [NBP]) are gaining a larger share of contracts signed than in previous years, not only in Europe but also in Asia.

Sellers are keeping up with this contract trend of price diversification by offering a variety of indexation features, such as oil-related ceilings/floors, hybrid pricing with Brent and Henry Hub, and S-curves (upper and lower limits). A growing open position among portfolio players and the increasing availability of supply volumes may accelerate such new pricing structures. However, equally this feature could narrow as these volumes are marketed and the open position closes. Continuing from 2019's rise of new pricing schemes, including a coal-linked agreement between Shell and Tokyo Gas, 2020 is also seeing LNG markets continue to diversify from oil pricing with JKM-linked pricing signed for both spot and term cargoes. Recent examples include two regasified natural gas contracts signed by BP in July 2020 with two Chinese companies (ENN and Foran Energy), both of which used JKM-linked pricing.

Beyond pricing and flexibility conditions, offsetting carbon content has become an attribute buyers are beginning to value. Last year Tokyo Gas and GS Energy purchased the first carbon-neutral LNG cargoes on the market from Shell, where the carbon content of the fuel was offset. This was followed by a delivery to CPC Corporation in March 2020 and CNOOC signing for receipt of two cargoes in June 2020.

Further development of these trends in contract diversification and market liquidity will be facilitated by the large volumes of uncontracted LNG supply entering the market in the coming years, leaving buyers free to explore their options.

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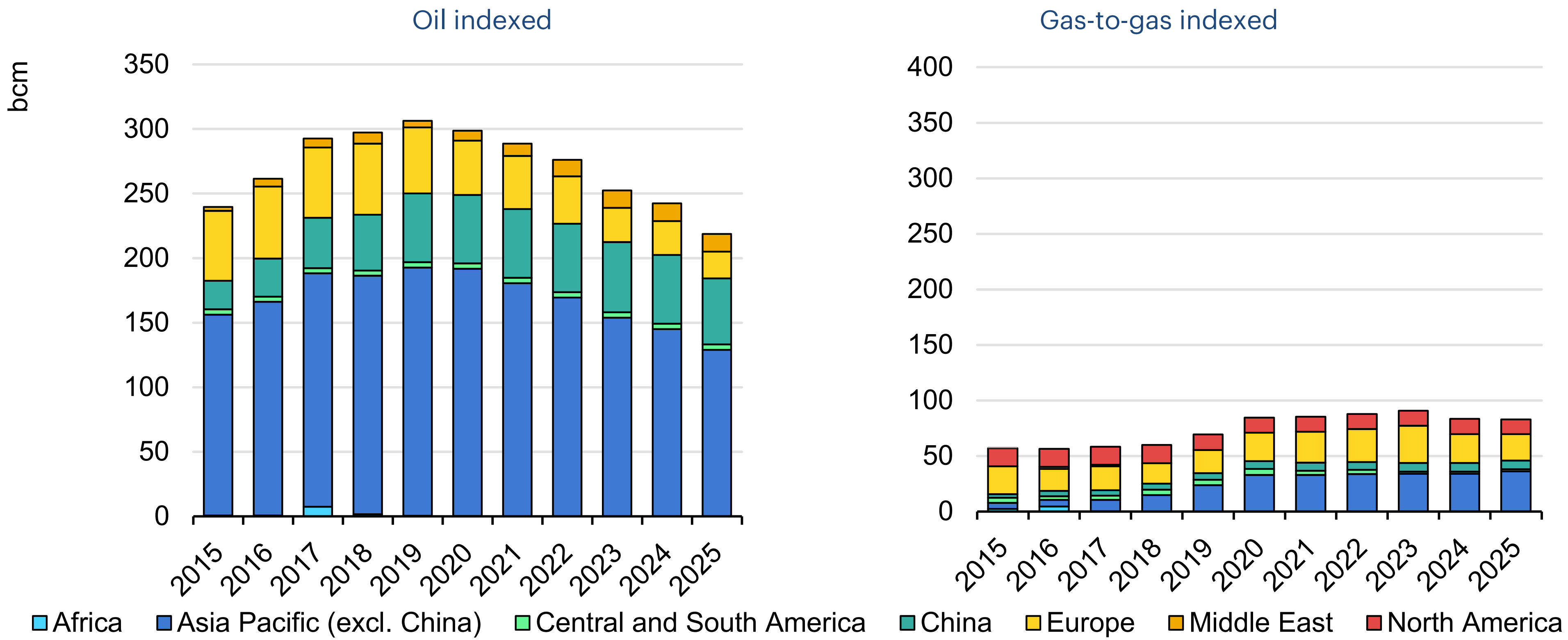
Oil-linked pricing remains dominant in import contracts, though gas-to-gas indexation is gaining ground

LNG import contract volumes with oil-indexed and gas-to-gas pricing by region and country, 2015-25



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Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required).

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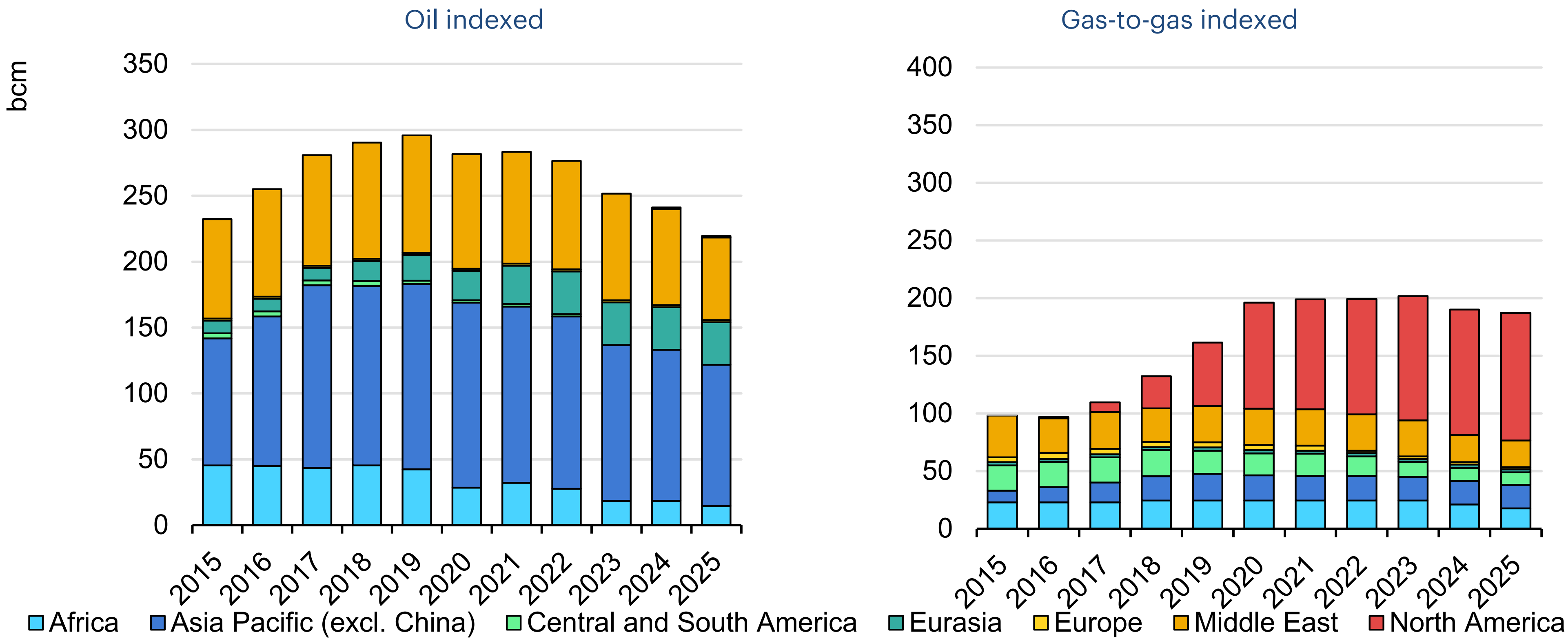
Among export contracts, gas-to-gas indexed volumes show a rapidly increasing share of total volumes thanks to the United States

LNG export contract volumes with oil-indexed and gas-to-gas pricing by region and country, 2015-25



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Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.

Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required).

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Flexibility and security of supply during the Covid-19 pandemic

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Supply-side solutions to cope with an unprecedented drop in demand

According to our preliminary estimates, global natural gas consumption fell by 4% y-o-y in the first half of the year, and 2020 is on its way to seeing the worst demand shock ever recorded for natural gas markets. Faced with such unprecedented market conditions, the whole natural gas value chain has had to provide flexibility to adjust supply.

Wellhead flexibility was provided by production shut-ins – some of it resulting from crude oil production cuts in the case of associated gas output, while contractual flexibility played a major role for export-driven producers. Russian gas production has been particularly impacted, falling close to 10% y-o-y in the first seven months of 2020.[1]

Pipeline gas flows provided the principal source of midstream flexibility, with inter-regional supply falling over 15% y-o-y for the first nine months of 2020. European pipeline imports have been the most impacted, with a sharp fall in flows from traditional suppliers, while some contraction has also been observed in Asia and North America.

A majority of LNG exporting countries have experienced varying degrees of curtailment, led by the United States which saw its monthly exports decline by nearly 3 bcm between January and July, followed by Australia (down 2 bcm). US LNG accounted for one-third of the decrease in global LNG exports between January and July 2020.

Storage – underground and at sea – also contributed to balancing gas oversupply. Inventories in underground gas storage are at high levels in Europe and the United States as the injection season draws to an end, standing at 14% and 12% above their respective five-year averages. Floating LNG storage provided an alternative in other markets lacking underground capacity, supported by lower gas prices and charter rates, and reached up to 9% of monthly trade volume at one point during the second quarter of 2020.

Supply-side adjustments to adapt to lower demand are particularly challenging in the case of LNG-dependent markets, particularly in Asia (Japan, Korea, Singapore and Thailand), where natural gas is a major component of power generation – hence strongly affected by lower activity – while domestic means of supply flexibility (from storage or production) are limited. Observations from the recent months show examples of successful co-ordination across the LNG supply chain that enabled additional flexibility at a time of need without affecting the security of supply in these markets.

[1] Production trends and figures are not covered in this chapter; a more detailed analysis can be found in the following chapter as part of the global gas market update analysis and forecast.

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Old but gold: Pipeline flexibility helps balance out the global gas market

Pipeline gas trade absorbed the majority of the demand shock caused by a particularly mild winter season, followed by the Covid-19-induced lockdowns and consequent economic slowdown. As presented in our latest market analysis, inter-regional pipeline supplies decreased by over 15% y-o-y (40 bcm in absolute terms) in the first three quarters of the year. Flows to Europe from its traditional suppliers plummeted by close to 20% and pipeline trade between Canada and the United States contracted by 10%, while flows to China from Central Asia fell by 15% in the first eight months of the year.

This highlights the significance of the intra- and inter-annual flexibility mechanisms embedded in pipeline gas supply agreements and the role they can play in balancing out regional and global gas markets when confronted with an unprecedented demand shock.

The nomination regime in pipeline gas contracts typically allows buyers to nominate day-ahead volumes according to their changing requirements up to the maximum daily contracted quantity, often with the option to make intra-day renominations. These short-term adjustment mechanisms are not available under LNG sale and purchase agreements, given that LNG is traded in cargoes where delivery rescheduling requires longer lead times (typically between one and two months). With LNG spot prices falling more rapidly than gas prices under long-term pipeline contracts (either linked to oil products or hub prices with several months of lag), buyers had a preference to exercise downward flexibility on their pipeline supplies, to the advantage of price-taking LNG spot cargoes.

Whilst a minimum daily nomination quantity is rarely defined in pipeline contracts, the aggregate nominated and purchased volumes through the contract year have to fall within the range defined by the annual contracted quantity (ACQ) and the take-or-pay (ToP) level. Typical ToP levels range between 70% and 90% of the ACQ. If the buyer's offtake is below that level, it would be still be liable to pay for the volumes not taken and hence commercially would be highly incentivised to take those volumes. Besides annual ToP volumes, some contracts include monthly and/or quarterly ToP obligations.

Under certain contractual arrangements, the buyer will have the option to recover some of those quantities at a subsequent time during the term of the contract as make-up gas. In addition, certain contracts allow buyers to earn carry-forward credits, meaning that any quantity which has been taken in excess of the ToP commitment can adjust the ToP levels of the consecutive periods, providing further downward flexibility if needed.

Pipeline gas flows into China also exhibited substantial volume flexibility, with imports from the three Central Asian suppliers declining by 15% y-o-y in the first eight months of the year. The Chinese case is all the more interesting, because CNPC appears to have found new sources of volume flexibility in its pipeline supply mix outside the traditional contractual arrangements. It was first reported in February that CNPC reduced pipe gas imports by curtailing its equity production from Turkmenistan's Amu Darya project, while honouring its other pipeline import commitments. As global gas markets loosened in the aftermath of Covid-19, CNPC issued force majeure notices to its Central Asian pipeline gas suppliers in March, who accepted the request to reduce volumes without objection, and started negotiations on a burden-sharing agreement under which Turkmenistan, Kazakhstan and Uzbekistan would share the Chinese import cuts proportionally among each other.

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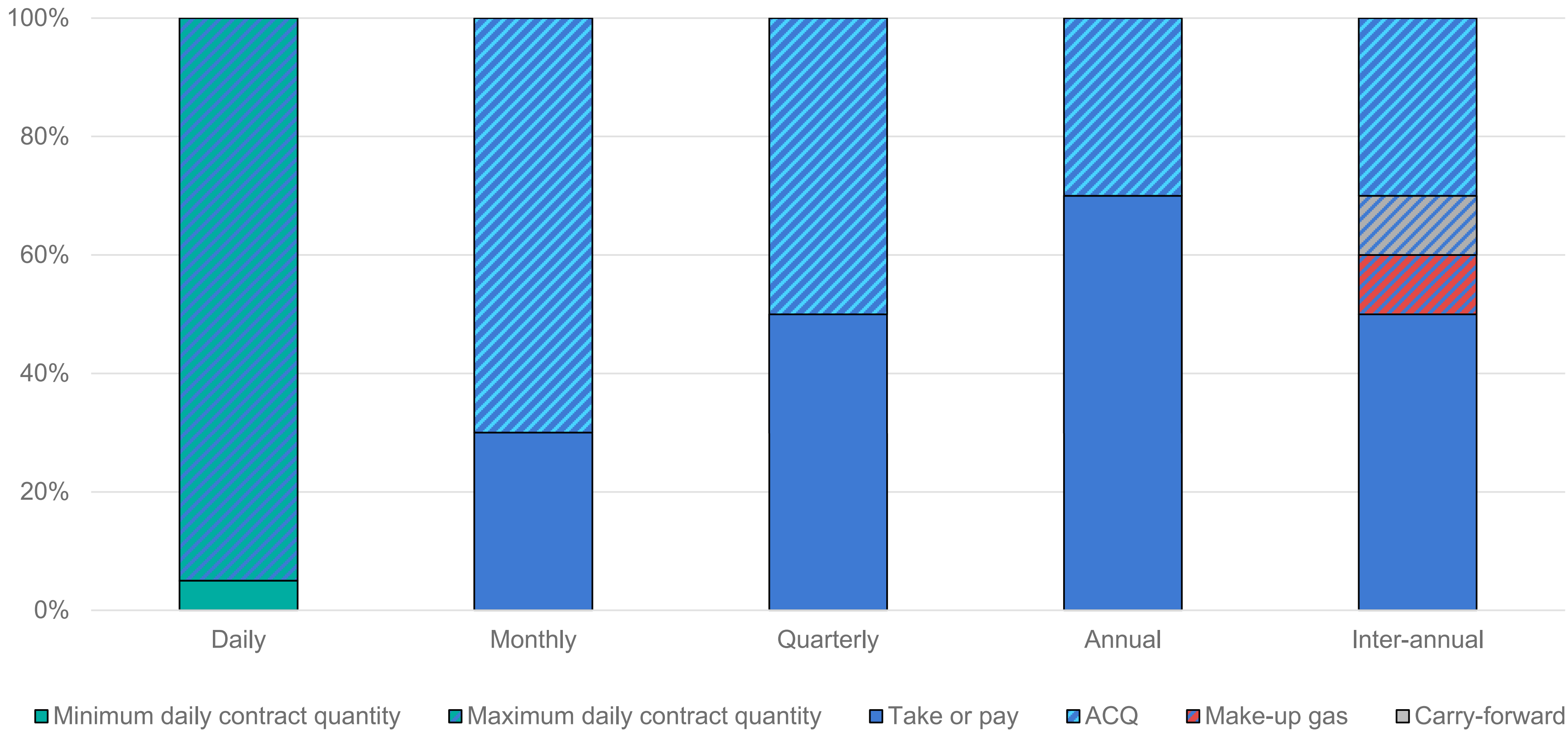
Pipeline supply offers a wide range of short- to medium-term flexibility

Illustrative example of flexibility in gas supply agreements



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LNG supply response: Capacity shut-ins take centre stage

Although pipeline gas exporters bore the brunt of the supply-side adjustment to the demand drop caused by Covid-19, the majority of LNG exporting countries also experienced varying degrees of supply curtailment during the first nine months of 2020.

Volume flexibility of US LNG at work

The United States accounted for the biggest share of the downward adjustment in global LNG supply between June and September 2020, underscoring the outsize role of US LNG in market balancing at a time of a historic oversupply. Recent market developments confirm the ability of US LNG to provide such volume flexibility on a large scale thanks to the optionality embedded in the commercial model of US LNG contracts. This requires buyers only to pay a fixed liquefaction fee, but allows them to cancel cargoes without having to pay for the feed gas and other variable costs if the lifting of US gas is uneconomic on a short-run marginal cost basis.

As global gas price benchmarks collapsed and the arbitrage window for exporting LNG from Gulf Coast terminals closed during the first half of 2020, US LNG buyers started to exercise their right to cancel cargoes in April, and the utilisation rate of US liquefaction capacity dropped to less than one-third of nameplate capacity by August. The total number of cargo cancellations during the first three quarters of 2020 reached 167 by one estimate.

It is noteworthy, however, that US capacity shut-ins started to unfold a few months after the global gas market oversupply set in. This is mainly due to the one- to two-month notification period for cargo cancellation, which is reportedly standard in most US LNG contracts.

Moreover, the supply curtailments affected only a little more than two-thirds of US export volumes, even when all US flows appeared unprofitable based on a simplified calculation of netback economics. There can be many reasons for the relative resilience of US LNG exports. Some offtakers – including those lifting from the Cove Point terminal, where feed gas is sourced from the low-cost Appalachian shale plays – probably have a lower pricing basis than Henry Hub plus 15%, which is often assumed to apply to all US LNG when estimating export economics. They may have sunk pipeline and shipping costs, while others might refrain from cargo cancellations due to their limited trading ability, lack of flexibility on feed gas supply, or downstream LNG supply obligations, which are riskier to fulfil from the spot market, for example. Commissioning volumes at newly inaugurated liquefaction trains (including at Elba Island, Freeport LNG train 3 and Cameron LNG train 3), which need to be produced as part of the start-up process, also limited export declines earlier in 2020, albeit only temporarily.

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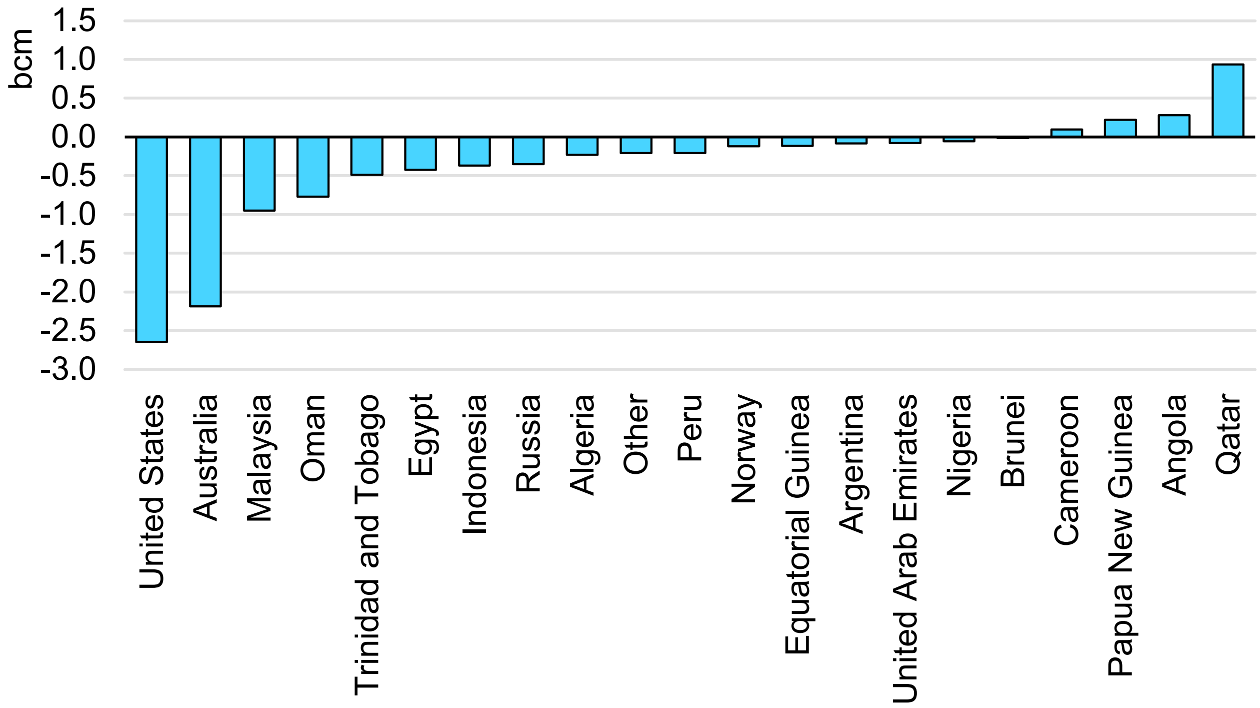
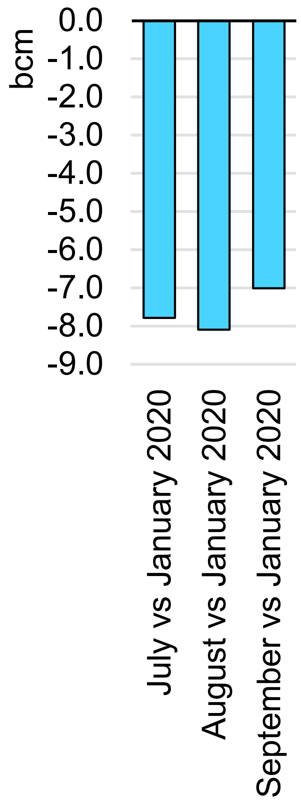
Most LNG exporting countries experienced supply curtailment during 2020

Monthly LNG exports by country, July 2020 vs January 2020



Monthly Global LNG Exports, July, August and September 2020 vs January 2020



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Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required).

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Widespread supply adjustment outside the United States as well

The United States was not the only country to experience significant export declines during the pandemic. Global LNG exports decreased by 8 bcm per month between January and July 2020, a 17% fall, and two-thirds of the net drop occurred outside the United States. While US LNG is now undoubtedly the single largest source of price-sensitive LNG supply in the world, the acute market pressure during the Covid-19 crisis revealed that economic shut-ins could occur in a wide range of other suppliers as well, sometimes even more rapidly than in the United States.

Egypt, which only restarted LNG exports in 2018, halted the loading of LNG cargoes completely by March due to unfavourable economics, well before any cancellations of US LNG cargoes. Sporadic exports have since resumed in the third quarter but volumes remain significantly below 2019 levels. Malaysia, which like Egypt has a relatively high exposure to spot market sales, cut LNG exports by nearly a half between January and May when US LNG shut-ins only started to gain momentum. Capacity utilisation in Indonesia, Oman, and Trinidad and Tobago dropped to around 60-70% by July from much higher levels at the beginning of 2020, as reduced spot market sales and deferred contract deliveries took their toll. The substantial 22% reduction in Australia's LNG exports between January and July was partly due to unplanned outages at the Prelude FLNG facility and at Gorgon train 2, but price-induced cargo deferrals reportedly also played a part in Australia's LNG supply drop in 2020. Despite the overall decline of LNG exports, some producers managed to increase production during the pandemic. Qatar, the world's largest LNG exporter, raised output by 10% from January to July 2020, for example.

This relatively widespread supply response outside the United States to a historic demand shock and price collapse highlights the fact that the ability to reduce volumes quickly without penalties (either from heavily spot-exposed suppliers or within existing contractual flexibility mechanisms) can be as important a driver of capacity shut-ins as the high marginal cost in the case of US LNG supply.

Without the flexibility of global LNG supply, particularly US supply, the adjustment to the 2020 demand shock would have been less orderly, and could potentially have had a damaging effect on the commercial and contractual structures underpinning global gas trade.

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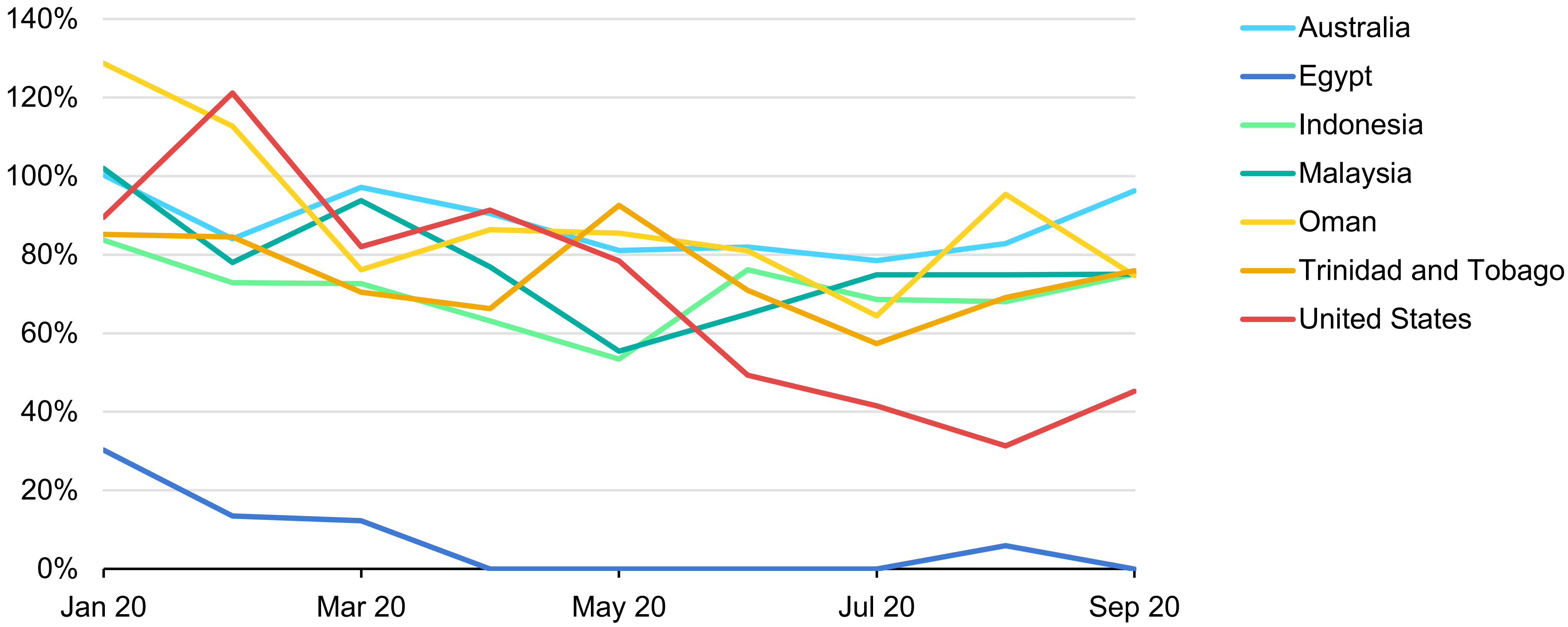
The United States was not the only – or even the first – country to experience significant export declines during the pandemic

Utilisation of LNG export capacity in selected countries



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Note: utilisation rates are calculated based on nameplate capacity; utilisation rates exceeding 100% are possible due to higher operational than baseload nameplate capacity at certain liquefaction plants, as well as due to the variability of monthly data.

Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required)

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LNG floating storage: Excess LNG stranded at sea

In the first three quarters of 2020 the LNG tanker fleet increasingly acted as a safety valve helping to cushion the growing oversupply of LNG globally. Using tanker ships for floating storage is a well-established practice in oil trading (as well as in LNG deliveries under term contracts to provide flexibility for buyers). However, until very recently its role in spot LNG markets had been limited due to the higher freight rates and the cost of LNG boil-off.[2] LNG floating storage in spot market activities has started to gain ground only in the past three years, mainly as a trading tool to delay deliveries from the autumn shoulder season to the peak winter months. In both 2018 and 2019 temporary increases in LNG floating storage corresponded with sharp increases in spot LNG vessel charter rates, which put a natural end to the seasonal storage play by mid-winter.

In 2020, however, LNG volumes in floating storage increased counter-seasonally starting in February, and remained at elevated levels through most of the year to date. This is a clear signal that the LNG shipping fleet is being used – for the first time – as a complementary flexibility mechanism to absorb some of the excess LNG on the market. Estimates of the volumes "parked" on the water vary, but one indicator suggests that it reached about 9% of monthly LNG trade volume in some periods during May and June. LNG floating storage has become a flexibility tool in the current market context for a number of reasons.

Covid-19-related disruption: the initial rise of floating LNG volumes in February and March was driven by necessity rather than by commercial considerations, as Covid-19-related force majeure declarations and port closures prevented the timely delivery of scheduled LNG cargoes and left a number of vessels stranded at sea.

Excess shipping capacity: while previous periods of floating storage led to sharp spikes in LNG charter rates, this has largely been avoided so far in 2020. Daily spot LNG charter rates averaged between USD 30 000 and USD 40 000 during the second and third quarter, which is low by historical standards (and below the long-term breakeven level required by ship owners for an adequate return). LNG charter rates were kept in check by improving vessel availability on the spot market, partly thanks to continuing new additions to the fleet (despite the erosion of demand), and partly as a result of LNG capacity shut-ins and US cargo cancellations, which freed up additional shipping capacity temporarily.

Supportive economics: at low spot LNG charter rates, storing LNG on the water is cheaper and thus can be commercially sustainable for several months. Boil-off adds further to the cost of floating storage, but as long as spot LNG prices remain depressed, the opportunity cost is low. Moreover, modern LNG carriers, which are available in greater numbers in a deflated shipping market, have significantly lower boil-off rates than older vessels. The relatively low cost of floating storage, averaging around USD 0.3 per million British thermal units (MBtu) per month in Q2-Q3, and the contango structure of the forward curve provided a strong economic incentive to keep excess LNG on the water during most of the spring and summer season this year.

Supplier strategies: at least one major LNG suppler, Qatar, has reportedly been using some of its sizeable LNG carrier fleet for floating storage as part of a broader strategy to maintain LNG production levels at full capacity during the pandemic, regardless of the cost of storage.

If spot LNG charter rates rise, the forward curves flatten, or shut-in LNG capacity comes back online requiring additional vessel capacity, then the economic viability of floating storage can rapidly dissipate. During the first nine months, however, it played a key part in the balancing of a heavily oversupplied market, which needed additional sources of market flexibility beyond the conventional toolbox.

[2] Long periods of floating storage may also impact LNG quality specifications, although the tolerance for receiving "off-spec" cargoes varies among buyers.

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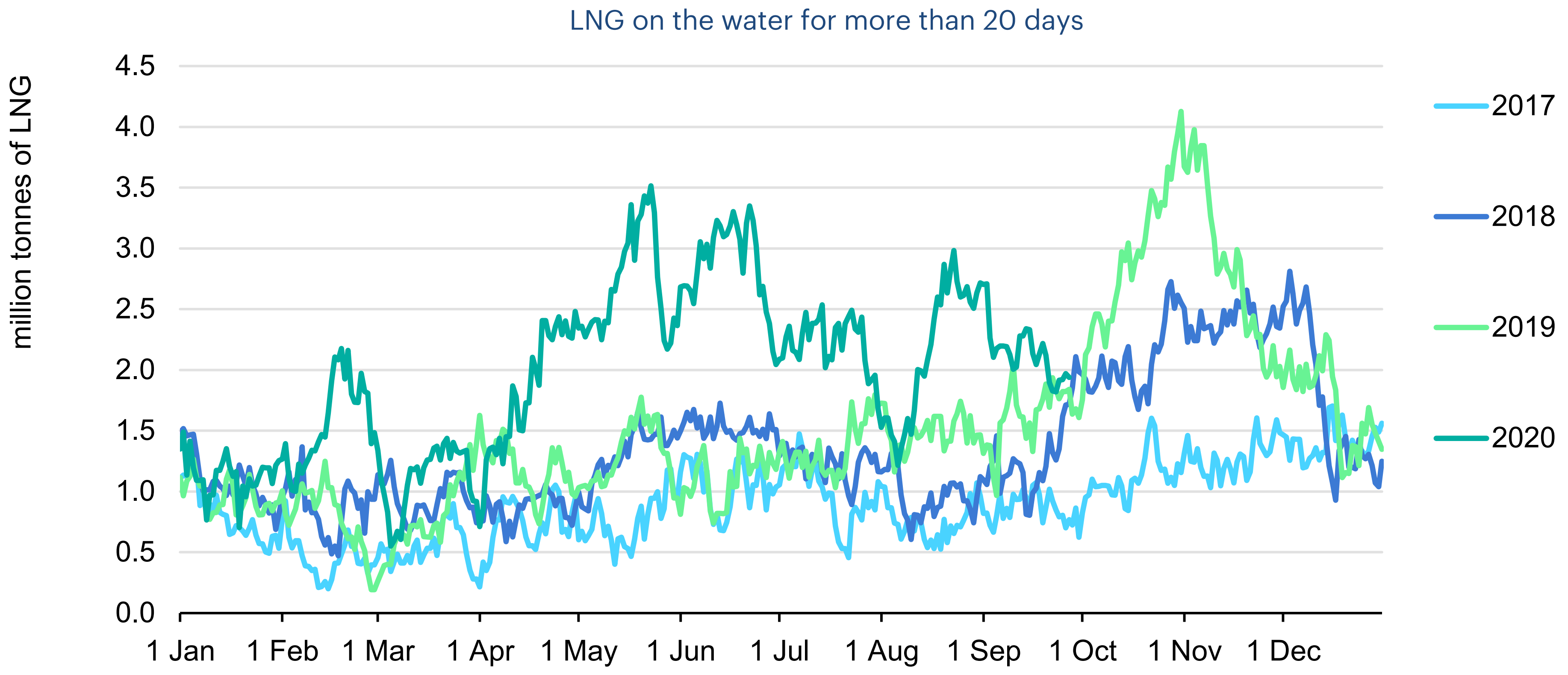
In 2020 LNG in floating storage has increased counter-seasonally amid the market oversupply



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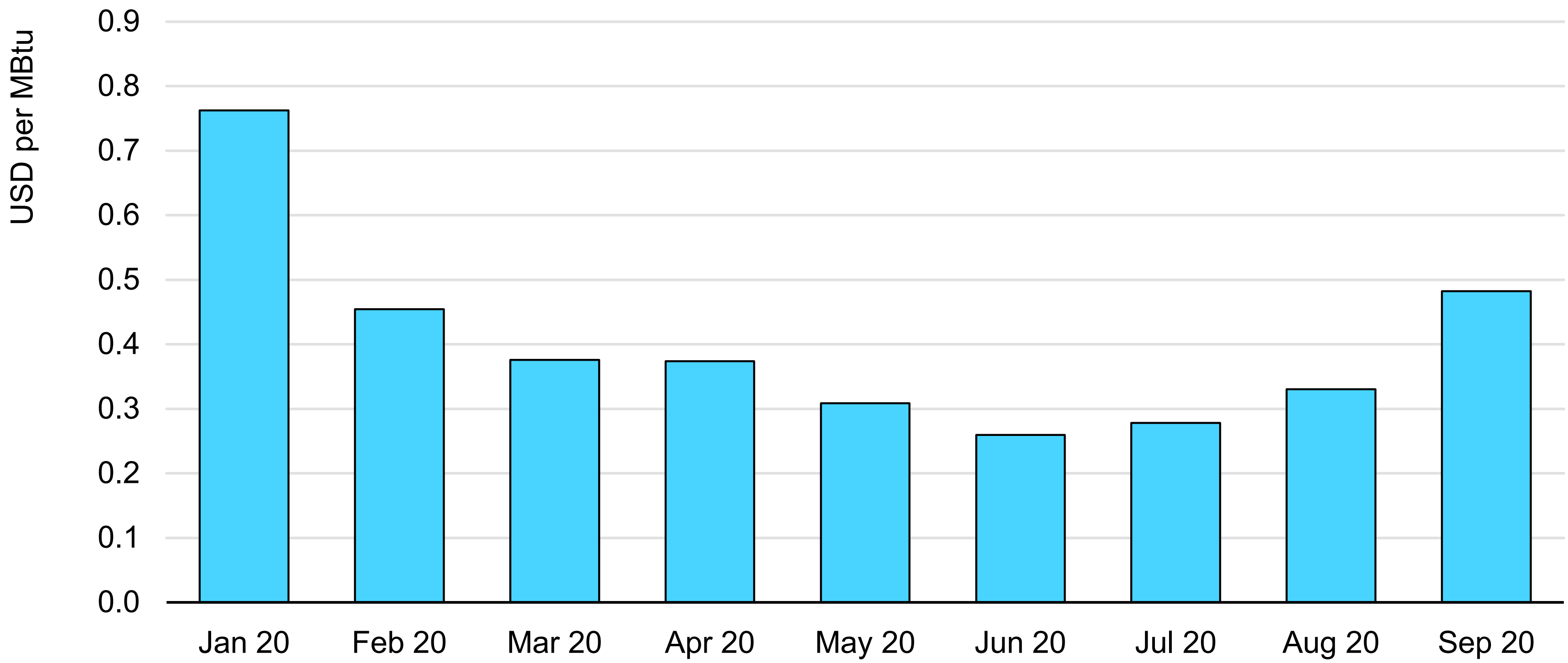
The monthly cost of LNG floating storage has been relatively low, averaging around USD 0.3 per MBtu in Q2-Q3 2020

Monthly cost of LNG floating storage



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Source: IEA analysis based on ICIS (2020), *ICIS LNG Edge*, https://lngedge.icis.com/ (subscription required)

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Adjusting to strong demand shifts in power generation and guaranteeing secure delivery

The sudden adjustments in electricity demand resulting from lower economic activity have had a strong impact on natural gas requirements, as gas often plays the role of base load or balancing source of power generation in many systems. This is especially the case in mature Asian markets, where LNG supply accounts for the largest source of flexibility in the general absence of pipeline and underground storage capacity.

Adapting to sudden power demand drops in LNG-importing Asian markets

Natural gas is a major contributor to power generation in several Asian markets, such as Japan, Korea, Singapore and Thailand, ranging from 30% to more than 90% of the generation mix. This critical gas supply mainly comes from LNG imports in the absence of domestic production – except for Thailand where local supply still accounts for a substantial share of input but is declining fast, and where natural gas accounts for almost 60% of electricity generated.

Preventive measures enacted to curb the impact of Covid-19, including partial lockdowns, resulted in lower activity from early April and electricity demand dropped by up to 9% y-o-y. Adjustment on the electricity supply side came principally from natural gas-fired generation, with a 52% reduction in Korea and 40% in Japan from January to May. Meanwhile, natural gas remained a large contributor in the generation mix, ranging from around 30% (Korea and Japan) to 60-96% (Thailand and Singapore). Adjusting to such unprecedented demand reduction and potential yet unforeseeable demand rebound has required a complex exercise of adjusting contractual flexibilities and scheduling of LNG imports well in advance of delivery. This is due to the requirement for specific gas quality and vessel compatibilities, which limit importers' ability to take or reject available LNG cargoes. In addition, the absence of underground storage capacity requires imported LNG to be immediately regasified and transported to the power plant directly. This means that managing specific contracted LNG cargoes, not simply any cargo available, is essential to meet the expected fluctuations in electricity demand, while maintaining LNG import and gas delivery activities at the same time.

Guaranteeing secure supply conditions in times of pandemic

The nature of the health crisis has added complexity to securing the necessary LNG cargoes according to schedule. As the LNG value chain involves close contact and frequent travel, it has been affected by new safety and public health procedures. These extra procedures – affecting offshore feed gas production sites, LNG plants, sea transport, and loading and unloading at the port – had an impact on the planned delivery of LNG cargoes at the early stages of the pandemic.

The authorities and the industry took co-ordinated action to adjust procedures to ensure safe and timely transactions. Examples include reduced shifts and crew changes, authorisation of electronic exchanges of documents, and exemption from commercial penalties for contractual amendments and demurrages. These measures enabled the minimisation of human contact, thus avoiding the shutdown of the entire infrastructure due to the health issues. Such examples of successful co-ordination across the whole LNG value chain could lead to further international process standardisation and implementation of such best practices.

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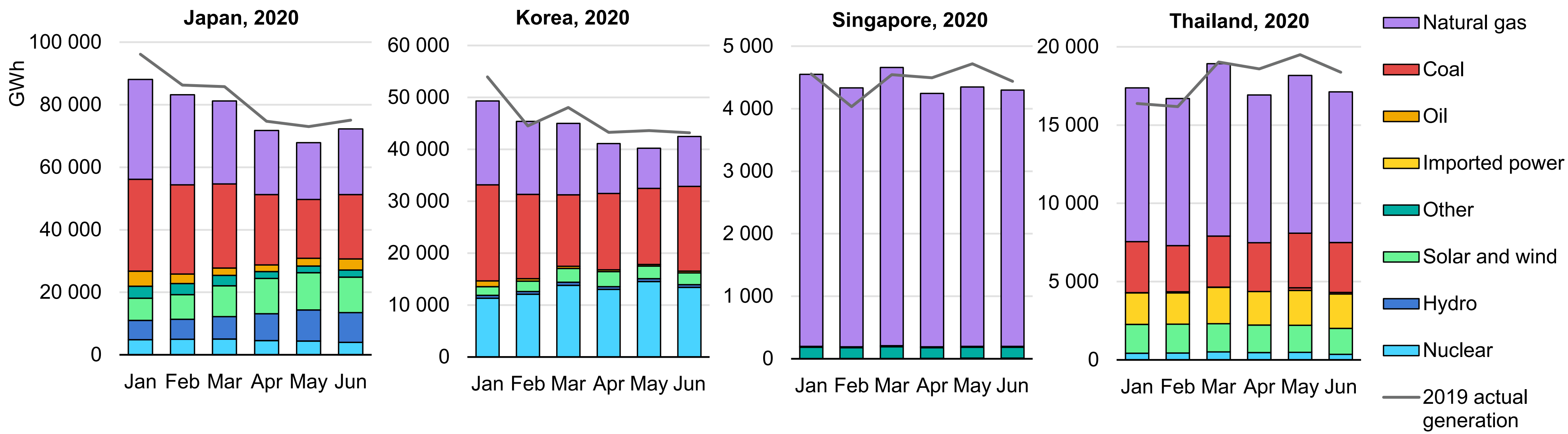
LNG is a major source of power generation, providing reliability and flexibility

Monthly electricity generation by source, Japan, Korea, Singapore and Thailand, January–June 2020



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Note: GWh = gigawatt hour.

Source: IEA (for Japan and Korea), IEA estimates from Energy Market Authority (for Singapore) and Energy Policy and Planning Office, Ministry of Energy (for Thailand).

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Buyers will require more contract flexibility in preparation for demand uncertainty

The Covid-19 crisis in 2020, which is expected to be one of the largest demand shocks in the history of natural gas markets, has proved particularly challenging for contracted buyers. By design, options for buyer-side supply flexibility extend beyond destination-flexible volumes and provide additional breathing space in unpredictable market conditions.

In the midst of Covid-19, LNG offtakers (particularly in Asia) resorted to deferring or rescheduling cargo deliveries using their contractual right to flexibility based on their mutual agreement with sellers. By exercising the rights of volume flexibility in term contracts, buyers could better handle storage capacity constraints resulting from reductions in demand. However, the fact that most buyers have to declare a downward flexibility adjustment in the preceding year, based on the downward quantity tolerance (DQT) provisions in their contracts, remains a constraint for buyers seeking to manage demand fluctuations, especially during black-swan events like Covid-19.

Prior to this year's demand shock, buyers sought to have a wider array of flexibility options in term contracts (such as destination flexibility). The lessons learned from Covid-19, coupled with the current well-supplied market, may accelerate the need to satisfy buyers' requirements for greater flexibility in and optionality of offtake volumes to help them manage their demand uncertainties. The transition towards greater contract flexibility, mainly demanded by traditional buyers, will be further accelerated by the emergence of new buyers and the growth of emerging markets, which are hesitant to commit to large volumes due to potential demand fluctuations.

Low spot price expectations, coupled with increased present-day supply affordability, is another reason for buyers to seek greater flexibility in term contracts. In a market with rapidly increasing volumes sold as spot cargoes, these customers can replace some of their high-priced term cargoes with cheaper spot LNG, if they have the option to exercise DQT or cargo cancellation rights within the contract year. Spot market volumes are climbing higher, making it easier for some buyers to buy on spot and wait out the storm while considering the proper time to move forward with further term contract purchases. Having said that, it is hard to imagine that sellers will simply accept all the requests for flexible terms from buyers, given that the market is cyclical and the potential remains for rapid demand recovery once the Covid-19 crisis abates.

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Supply affordability provides an unprecedented opportunity for emerging Asian economies

In June 2020 Myanmar became the latest country to begin importing LNG. It joins a long list of emerging Asian economies that import LNG, and follows Bangladesh and Pakistan. According to the IEA's *Gas 2020* report, emerging Asian economies as a whole are the second-largest contributor to growth in global gas demand in Asia Pacific after China, adding about 35 bcm/y during the 2019-25 period. Due to the lack of inter-regional pipeline connections and stagnating domestic production, these countries' reliance on LNG has been growing. Despite the growth of LNG imports being dependent on infrastructure development and policy support in these countries, supply affordability in the market is providing an unprecedented opportunity for emerging economies in Asia to begin or expand LNG imports.

The Asia Pacific region will account for about 40% of the 190 bcm of contracted annual volumes due to expire by 2025. In addition to these expiring volumes coming onto the market, there is a chance that traditional buyers including Korea and Japan will exercise downward volume adjustment in their existing contracts or require more DQT rights in their new contracts, due to the uncertainty of demand resulting from Covid-19. These two factors – expiring contracts and downward adjustment of term volumes – could facilitate market liquidity and keep prices in check. For emerging Asia, which is a price-sensitive market that has coal as a competitive fuel, this increased availability of affordable supply is an unforeseen chance to meet rising demand. At the same time it highlights the need for these countries to accelerate the pace of infrastructure development to avoid bottlenecks in the growth of their imports.

Notably, these emerging Asian economies have recently become more active in developing their LNG infrastructure, and other market players, which are eager to supply LNG into this market, are also actively participating. Three recent examples explain the growing interest in emerging Asia from market participants.

- **Viet Nam**: Chan May LNG (a US-Viet Nam joint venture) plans to invest up to USD 6 billion in an LNG power project, as the country faces the risk of severe power shortages from 2021 (July 2020).
- **Thailand**: Thailand's first floating storage regasification unit is poised to be approved by the board of EGAT (Electricity Generating Authority of Thailand) and is set to begin construction in 2020 (July 2020).
- **Bangladesh**: A group of Japanese public and private lenders agreed to lend nearly USD 645 million to fund the construction of an LNG power plant in Bangladesh (July 2020).

While current conditions present the opportunity to take advantage of a buyer's market, it is important to remember that the market is cyclical and current prices will most likely rise at some point in the future. Suppliers and buyers need to work together to ensure the availability of affordable LNG supply in the long term, and to develop LNG infrastructure in emerging Asian economies to resolve their energy security issues on a sustained basis.

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Gas market update and short-term forecast

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Is the "meltdown" softer than expected?

The IEA Gas 2020 report in June estimated gas consumption in 2020 to decline by 4%, calling 2020 a year of "meltdown". In this update, based on the latest available data, we adjust our 2020 demand decline estimate to a 3% decrease.

More recent market data show that natural gas demand proved to be quite resilient during the first half of 2020 in spite of lockdowns. Our estimate, based on a sample of countries and territories accounting for over 85% of global gas demand, shows a year-on-year decline of close to 4% for the first six months of 2020. China bucks the trend with a 4% increase reported by the National Development and Reform Commission (NDRC), followed by emerging markets in Africa, Asia and the Middle East, all of which reported positive growth and account for about 20% of global gas consumption. Conversely, most of the reported negative growth occurred in more mature markets, almost all of which are in the northern hemisphere and felt the impact of mild temperatures on their gas consumption in the first quarter.

The first partial figures for the third quarter tend to confirm the slow but continuous recovery trend, especially for Europe where gas-fired power generation grew by 4% y-o-y. Taking these latest market developments into consideration, the forecast has been revised to a 3% decline in gas demand in 2020.

In spite of this upward revision relative to previous expectations, the significance of the decline is unmatched and 2020 would still remain the largest drop ever recorded in the history of natural gas markets. If the rate of global gas decline looks limited compared to other fuels, some major individual markets such as France, Italy and Spain have experienced double-digit negative growth rates in the first half of the year. Global gas consumption showed resilience in spite of the exceptional events that occurred in the first half of 2020, but the resulting economic slowdown is a major source of uncertainty for future demand recovery, and has prompted a revision of the expected 2021 rebound in this forecast. Global gas demand in 2021 is expected to recover by 3% to slightly above its 2019 level with the contribution of emerging markets.

The drop in gas demand also triggered a strong supply-side adjustment, as highlighted in previous chapters. Pipeline gas flows were the first to adjust to low heating demand in response to the impact of lockdowns, leading to substantial production drops for traditional exporters such as the Russian Federation ("Russia") (falling 8% y-o-y in the first three quarters of 2020). US dry gas production and LNG trade remained relatively stable over the first months of 2020, but started to decline during the second quarter as Covid-19-induced measures curbed gas demand. These two still show year-on-year growth for the first three quarters, but with much lower growth rates than in previous years. In this updated forecast, we expect for the remainder of 2020 and 2021 a slight contraction in US production, progressive (but not full) recovery in Eurasian output, slower yet still positive gains in LNG trade, and a rebound in European imports.

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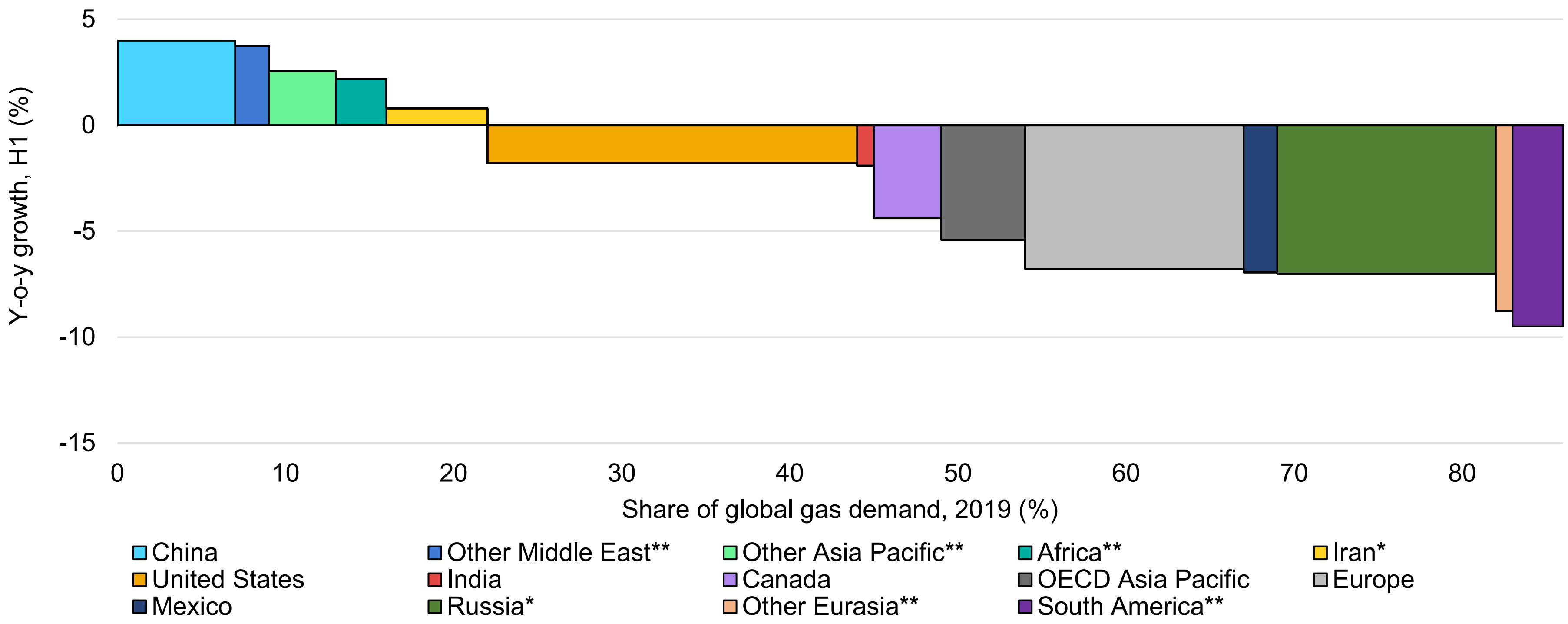
Preliminary data show an estimated 4% y-o-y drop in global gas demand for the first half of 2020

Estimate of y-o-y natural gas demand change, H1 2020 vs 2019



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Notes: (*) based on apparent consumption; (**) partial regional coverage; "OECD Asia Pacific" comprises Australia, Japan, Korea and New Zealand.

Sources: IEA analysis based on Analytical Center of the Government of the Russian Federation (2020), Gas Production; ENTSOG (2020), Transparency Platform; Financial Tribune (2020), Iran Natural Gas; Gazprom (2020), Quarterly results; IEA (2020), Monthly Gas Data Service (subscription required); JODI (2020), Gas World Database; MME (2020), Natural Gas Industry Monthly Bulletin; NDRC (2020), Communiqué; NIGC (2020), News; PPAC (2020), Gas Consumption.

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European gas consumption returned to positive growth in Q3 2020…

European gas markets faced the perfect storm in the first half of 2020. Demand fell by over 6% (or 15 bcm) y-o-y, with unseasonably mild temperatures in winter and Covid-19-induced lockdowns through the second quarter. North- and southwest European countries[3] – where the strictest lockdown measures were imposed – accounted for 85% of the decline in gas consumption during Q2. Gas-fired power generation was particularly hit during this period, declining by 25% y-o-y in April and May.

In contrast with the first half of the year, European gas consumption increased by 3% y-o-y in the third quarter of 2020, primarily driven by higher gas burn in the power sector.

Despite electricity consumption declining by 2.5% y-o-y and renewable power output rising by 8% (or 15 TWh), gas-fired power generation increased by 4% (or 6 TWh) y-o-y in the third quarter of 2020 due to shifting fuel dynamics in the power sector.

As a result of the Covid-19 outbreak, the maintenance schedule of several nuclear power plants has been adjusted. In France the outages at the Flamanville 1 and 2 nuclear reactors – offline since September and January 2019 respectively – have been extended from April 2020 until the end of October 2020. Similarily, the outage at the Paluel 2 reactor – offline since October 2019 – has been extended from August 2020 until the end of the year. Moreover, the Chooz nuclear power plant was shut down at the end of August due to low water levels and remained offline through September 2020. This and other nuclear outages translated into a Q3 decline of 20% (or 17 TWh) y-o-y in nuclear power generation in France. In Belgium output from nuclear plants dropped by over 40% (or 5 TWh) y-o-y in Q3 on a combination of high-temperature-driven restrictions on cooling water use and the extension of outages, including Tihange 1 whose restart was delayed from July to the end of the year. The outcome has been additional market space for other supply sources, both in France and Belgium as well as in their main electricity export markets. Most of this was captured by gas-fired power plants.

The combination of very low gas prices and a sharp recovery in carbon prices in the European Union and the United Kingdom increased the competitiveness of gas-fired power generation vis-à-vis coal- and lignite-fired power plants, which saw their output fall by 8% (or 10 TWh). The switch was particularly large in Germany, where gas-fired power generation rose by over 10% y-o-y in Q3, with coal and lignite power generation down by 9% and 7% respectively.

The largest contributor to additional gas burn in the European power sector was Turkey, where gas-fired power generation rose by 34% or 5.5 TWh y-o-y in Q3. This offset the reduction in lignite-fired generation, which was restricted for environmental reasons (plummeting by 25%) and lower hydro availability (down 6%). Consequently, the share of gas-fired power generation in thermal generation in Europe rose to 60% in Q3 2020 from 57% during the same period last year.

Preliminary data from certain markets suggest that the steep fall in gas demand from the industrial sector experienced under the lockdowns has moderated. In France industrial gas demand fell by 3% y-o-y in Q3 (compared with a 13% decline y-o-y in Q2), while in both Belgium and Italy industrial gas demand increased by 1% y-o-y in Q3, according to data from transmission system operators. In Spain the fall in industrial demand moderated to 5% y-o-y in July and August against a decline of almost 17% y-o-y in Q2. Turkey's gas demand from industry grew by close to 3% during June and July.

[3] Belgium, France, Italy, the Netherlands, Portugal, Spain and the United Kingdom.

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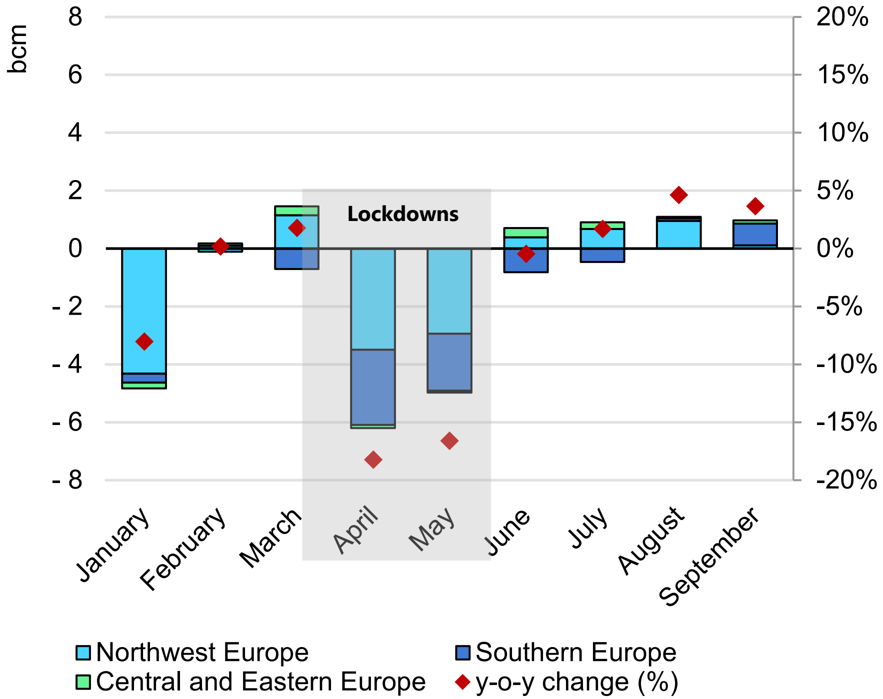
...supported by coal-to-gas switching and nuclear outages in the power sector

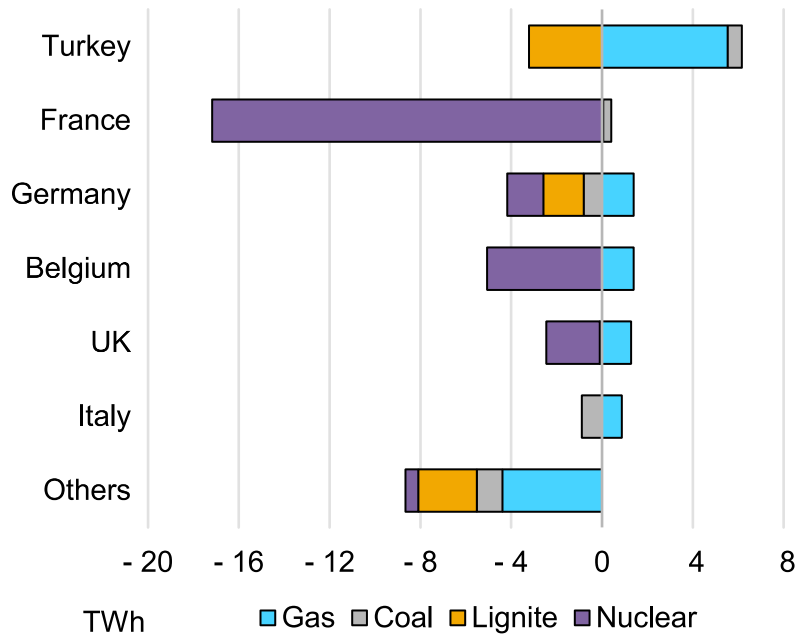
European natural gas consumption

2019-20 y-o-y change



Nuclear, gas, coal and lignite-fired power generation

Q3 2019-20 y-o-y



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Sources: IEA based on ENTSOE (2020), Transparency Platform; ENTSOG (2020), Transparency Platform; Gaspool (2020), Consumption Data; NCG (2020), Consumption Data; EPIAS (2020), Transparency Platform.

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Consumption is climbing back in post-lockdown North America, with resilient US power generation and a progressive recovery in other sectors

US natural gas consumption decreased by 2.2% y-o-y in January through to September 2020, a rather limited decline considering mild temperatures in the first quarter and the Covid-19 restriction measures in place from March to June. Temperature-adjusted consumption decreased slightly at -0.2% y-o-y (January to end-September).

Natural gas-fired power generation increased during the winter in spite of lower electricity demand, helped by low gas prices and additions of new combined-cycle capacity in 2019. The outbreak of Covid-19 led to the imposition of lockdown measures in most US states, enacted during the second half of March. In spite of the magnitude of the impact on economic activity, natural gas demand increased slightly by 0.5% y-o-y during the lockdown period (mid-March to the first week of June), with consumption for power generation increasing by 3.9% y-o-y and for industry declining by 3.5%.

Gas consumption in the United States has been matching 2019 levels since the lifting of the state-level lockdown measures, until September when gas-fired generation dropped on lower electricity demand. In June through to August natural gas demand showed slight growth of 0.2%. Gas-fired power generation grew by 0.4% y-o-y over the same period, supported by coal-to-gas switching. In late July natural gas consumption for power generation set a daily record high at 47.2 billion cubic feet. Through to the end of August gas consumption for power generation was up 2.6% y-o-y. Preliminary data on natural gas consumption for power generation for September show a sharp decline on August's consumption, as monthly electricity demand dropped by an estimated 17% after record high temperatures in August.

Canadian gas demand decreased by 5% y-o-y in the first half of the year on a combination of lower than usual heating demand, reduced industrial activity and lower gas burn for power generation. Canadian pipeline imports decreased by 1.6% y-o-y during the first half, totalling 13.2 bcm, while pipeline exports to the United States decreased by 3 bcm over the same period, an 8.2% reduction from 2019.

Natural gas demand fell in Mexico by an estimated 5% y-o-y during the first eight months of 2020, driven by lower industrial activity and decreased electricity consumption. In May consumption decreased by as much as 10% y-o-y, mostly due to lower gas-fired power generation.

In 2019 and 2020 completion of additional US–Mexico pipeline increased the available capacity for gas trade to Mexican population centres. During the first half of 2020 US gas exports to Mexico increased by 5% y-o-y, reaching 26 bcm traded through to end of June this year. The introduction of nationwide emergency measures in April coincided with a temporary slowdown in pipeline imports from the United States, which caused flat year-on-year trade levels from April to June before returning to growth. From January to June, LNG imports to Mexico declined by 60% y-o-y from 3.2 bcm to 1.3 bcm, despite low global LNG prices.

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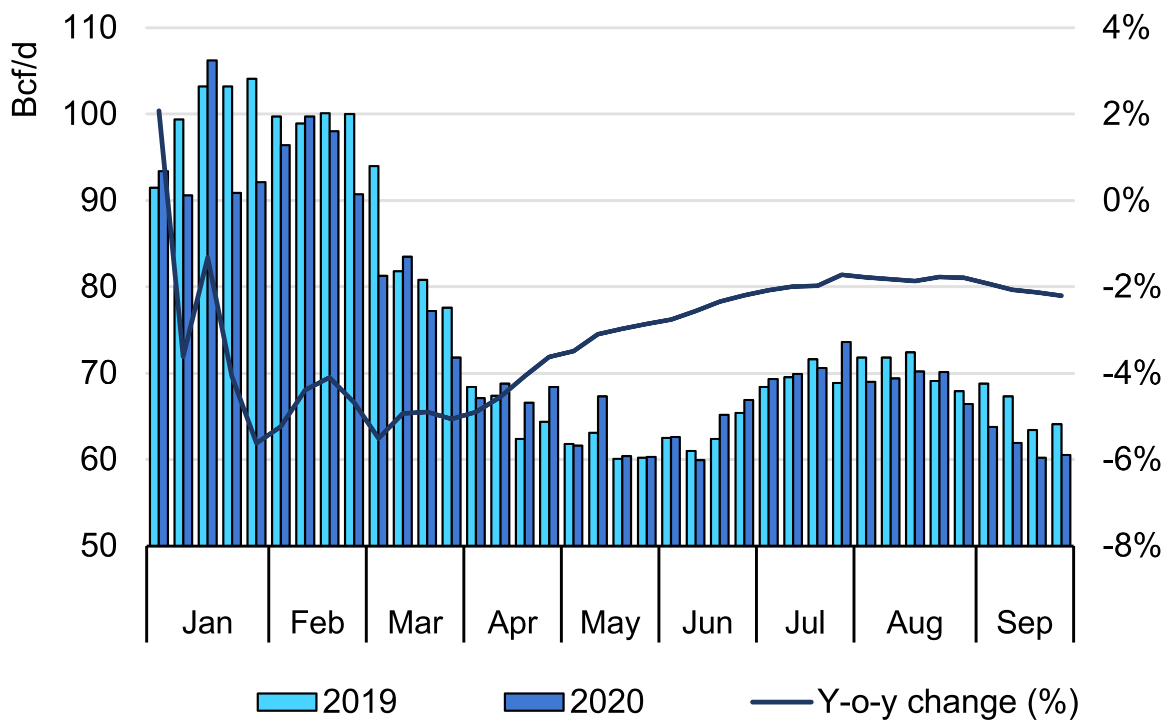
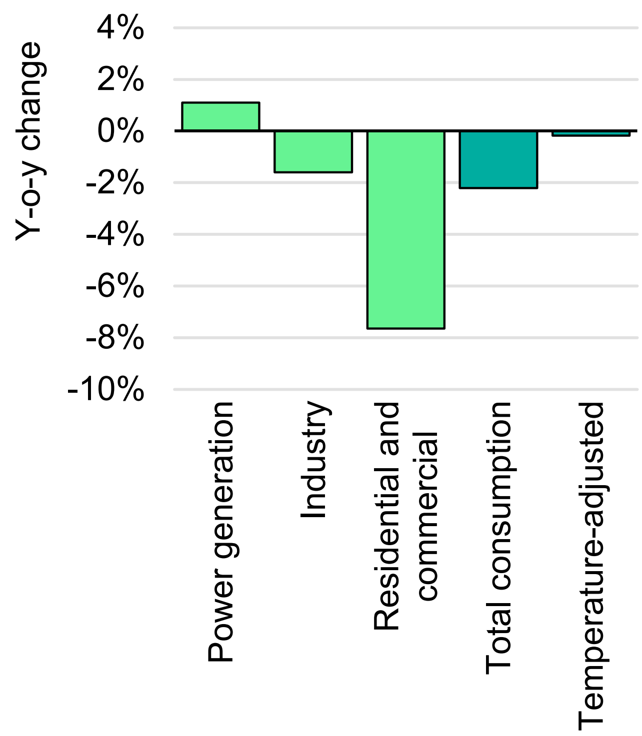
US gas consumption in January to September declined by 2.2% y-o-y

Evolution of weekly US natural gas consumption, 2019 and 2020



Y-o-y change in US natural gas consumption since 1 January by sector



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Note: Bcf/d = billion cubic feet per day.
Source: IEA analysis based on EIA (2020), Natural Gas Weekly Update.

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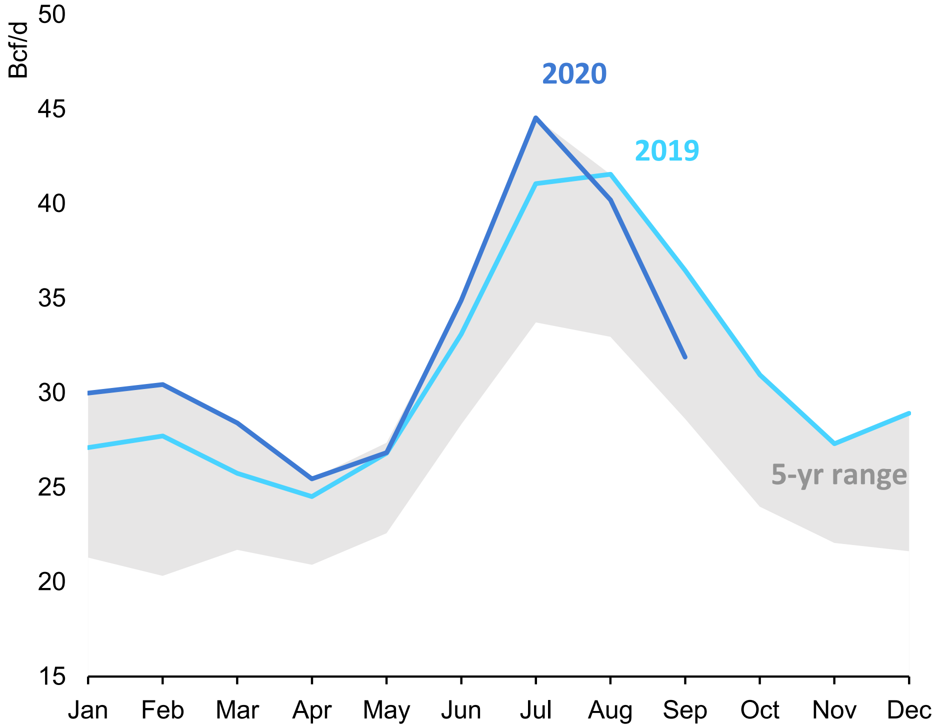
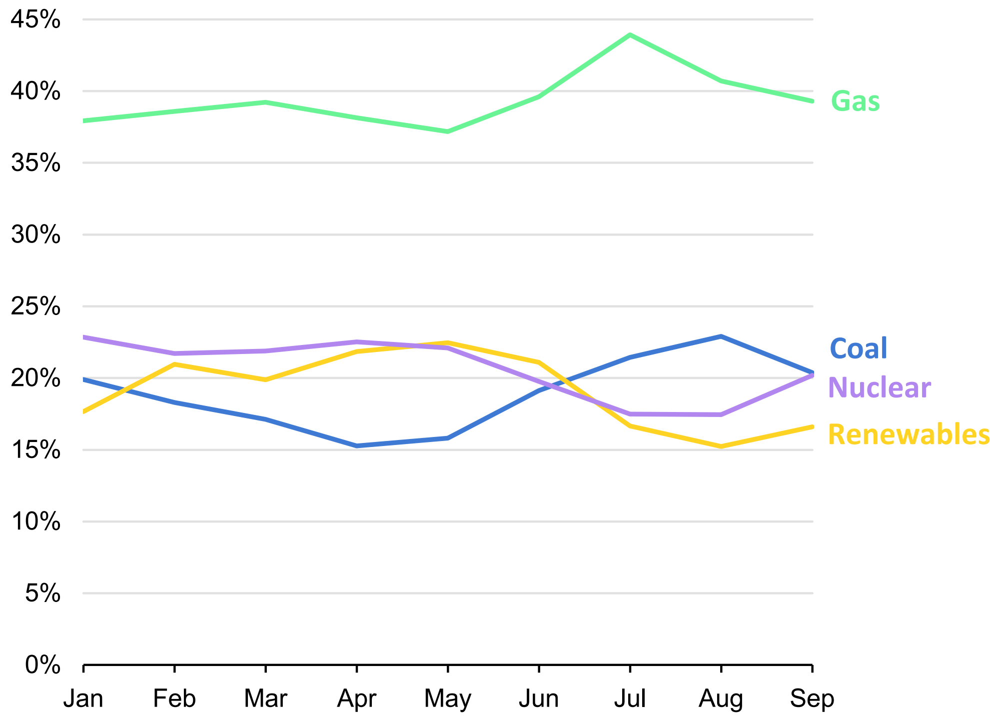
US gas demand for power showed slight y-o-y growth from January to August due to new generating capacity and low prices. Gas averaged a 40% share of power generation in 2020 to date.

Natural gas consumption for power generation



Share of total power generation by source



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Source: IEA analysis based on EIA (2020) Short-Term Energy Outlook and US Electric System Operating Data.

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Asian gas demand: A slow and uneven recovery underway

With Q1-Q2 2020 gas demand data now largely available, and some visibility into Q3 trends, it appears that the year's demand decline in Asia is less severe – but potentially more protracted – than initially expected. Uncertainty remains about the outlook for the second half of the year, especially around winter weather and the pace of recovery in the sectors that were particularly hard-hit by the pandemic.

China was the first major economy to experience a Covid-19-driven demand slump in Q1, and the first to emerge from the initial wave of the pandemic in the early spring of 2020. Gas demand reached a low point in February, when consumption was down by more than 9% y-o-y, with the industrial sector being the hardest hit.

A gradual recovery in demand has been underway since March/April, led by the city gas distribution sector (encompassing residential and commercial users, as well as transport), and – to a lesser extent – by power generation. Overall, gas demand expanded during the first eight months of 2020; market sources indicate a 2% increase y-o-y, while NDRC announced a slightly more robust 3% y-o-y increase over the same period. The rebound in gas consumption was subdued until July, as demand growth in industry – the largest gas-consuming sector in China – remained sluggish. There were tentative signs, however, that the industrial demand recovery started to accelerate in August.

China took a major step towards consolidating its midstream gas infrastructure into a single entity in July with the transfer of PetroChina's and Sinopec's pipeline, storage and LNG assets (valued at USD 56 billion) to the newly established national pipeline company, PipeChina. This followed the asset transfer agreement reached earlier with CNOOC in April 2020. PipeChina became operational at the end of September and is expected to improve connectivity, increase competition and reduce the cost of natural gas to end users over time, thus supporting China's gas demand expansion in the medium term.

India implemented a strict nationwide lockdown between 25 March and 31 May, followed by a gradual lifting of restrictions in the ensuing four months. As a consequence, gas consumption went from a healthy 12% y-o-y increase in Q1 2020 to a sharp 14% y-o-y contraction in Q2, and had only returned to near pre-Covid levels by July. India's gas demand recovery is led by the energy-intensive industrial sector, particularly refining and fertiliser production, which retained strong growth momentum even during the lockdown. Power sector demand declined by 11% y-o-y between January and August, but returned to positive territory and registered a 6% y-o-y increase in the month of July. This upturn reflected the influx of cheap spot LNG, which supported higher gas burn in India's underutilised gas-fired generation fleet during the peak summer season.

Gas consumption in the first eight months of 2020 is still 1.8% lower than during the same period a year ago, and the growth prospects for the second half of 2020 remain modest. Demand in the city gas sector (covering CNG-based transport, small industry, and residential and commercial users) remains especially depressed, down by 30% y-o-y in August. India's falling domestic production continues to weigh on the energy industry's own gas use.

India's import and domestic gas transit capacity could be enhanced in the second half of the year with the completion of two projects: the Kochi–Managalore pipeline, which would double the effective capacity of the underutilised Kochi regasification terminal in the south, and the commissioning of the Jaigarh FSRU terminal. Both projects are now delayed to Q4 2020. The official launch of the Indian Gas Exchange (IGX) in June was a significant first step towards market-based pricing in India. Traded volumes are currently very small, but if the new trading platform proves successful, it could not only improve the transparency of price discovery in India, but also pave the way for greater spot LNG imports in the future.

Japan declared a state of emergency for the period between April and June 2020, but had no mandatory nationwide lockdown. The initial demand impact of Covid-19 was modest until April, but gas use in the

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commercial and export-oriented industrial sectors started to fall sharply in May. Gas consumption in June was down by 9% y-o-y and the negative demand trend is likely to continue in Q3 2020. Overall consumption in the first half of 2020 declined by 7% y-o-y. According to the Japan Gas Association (JGA), industrial gas demand likely contracted by 20-30% y-o-y in May and 10-20% in June, and the service sector, which suffered the biggest y-o-y drop, declined by almost 50% in May and 20-30% in June.

A warm winter contributed to weak residential consumption in H1, but demand growth in this sector is likely to have recovered by the second half of 2020, according to the JGA. Gas-fired power generation was down by 13% y-o-y as of June, as gas plants provided flexibility to the power system amid an overall decline in thermal generation during H1 2020. A notable policy development in Q3 was the Japanese government’s announced decision to shut down 100 of the country’s inefficient coal-fired power stations by 2030 (of a total fleet of 140 coal plants). However, the impact on power sector gas demand is likely to be limited due to the planned nuclear restarts and Japan’s objective to increase renewable generation over the same timeframe.

Korea’s gas consumption decreased by 3% y-o-y during the first half of 2020, with the steepest double-digit y-o-y declines occurring in April and May. Gas demand in the power generation sector held up relatively well with a 2% y-o-y increase in H1, thanks mainly to the government-mandated shutdown of 28 coal-fired power plants during March in an effort to reduce air pollution. Demand growth in the city gas segment was hit hardest by the economic fallout of the global pandemic, and recorded a 7% y-o-y decline in H1.

Bangladesh’s nationwide lockdown lasted between late March and the end of May, during which period gas demand suffered a steep drop, with consumption levels reported at one-third below pre-Covid levels in April. Gas consumption had recovered to around 95% of pre-lockdown levels by the end of June. Gas-fired power generation, which accounts for more than half of natural gas use in Bangladesh, was still down by 3% y-o-y in the month of July. LNG imports remained elevated and rose by almost 24% in the first nine months of 2020, thanks in part to the completion of two key pipeline connections, which has enabled higher utilisation of the country’s LNG regasification capacity.

Pakistan reported a steep 50% drop in daily gas consumption in the immediate aftermath of Covid-19-related restrictions in April. LNG imports through the second quarter of 2020 remained 29% lower than a year ago, following a mild 2% decline in Q1. Some social distancing measures in Pakistan remained in place until August. Consequently, the demand recovery in Q3 was relatively slow and gradual, with LNG import volumes still indicating a 7% y-o-y decline during the quarter. Pakistan received its first spot LNG cargo in August after six months of complete absence from the spot LNG market. Follow-through on the government’s recent decision to allow third-party access to unused capacity at the country’s two LNG import terminals could accelerate spot market purchases – and Pakistan’s gas demand recovery – in the months ahead.

Thailand’s natural gas consumption registered a 7% y-o-y decline in the first seven months of 2020, with all of the main gas-consuming sectors (namely power generation, industry and the energy sector) contributing to the fall.

Indonesia’s gas demand suffered a 5% y-o-y contraction during the first seven months of 2020 as key gas-consuming industries cut back activities during the pandemic.

Singapore, on the other hand, recorded a sharp 8% y-o-y increase in gas demand in the first seven months of 2020, with a strong 20% y-o-y increase in Q1 followed by a mild 2% y-o-y decline in Q2 2020 and a modest 3% y-o-y expansion in the month of July.

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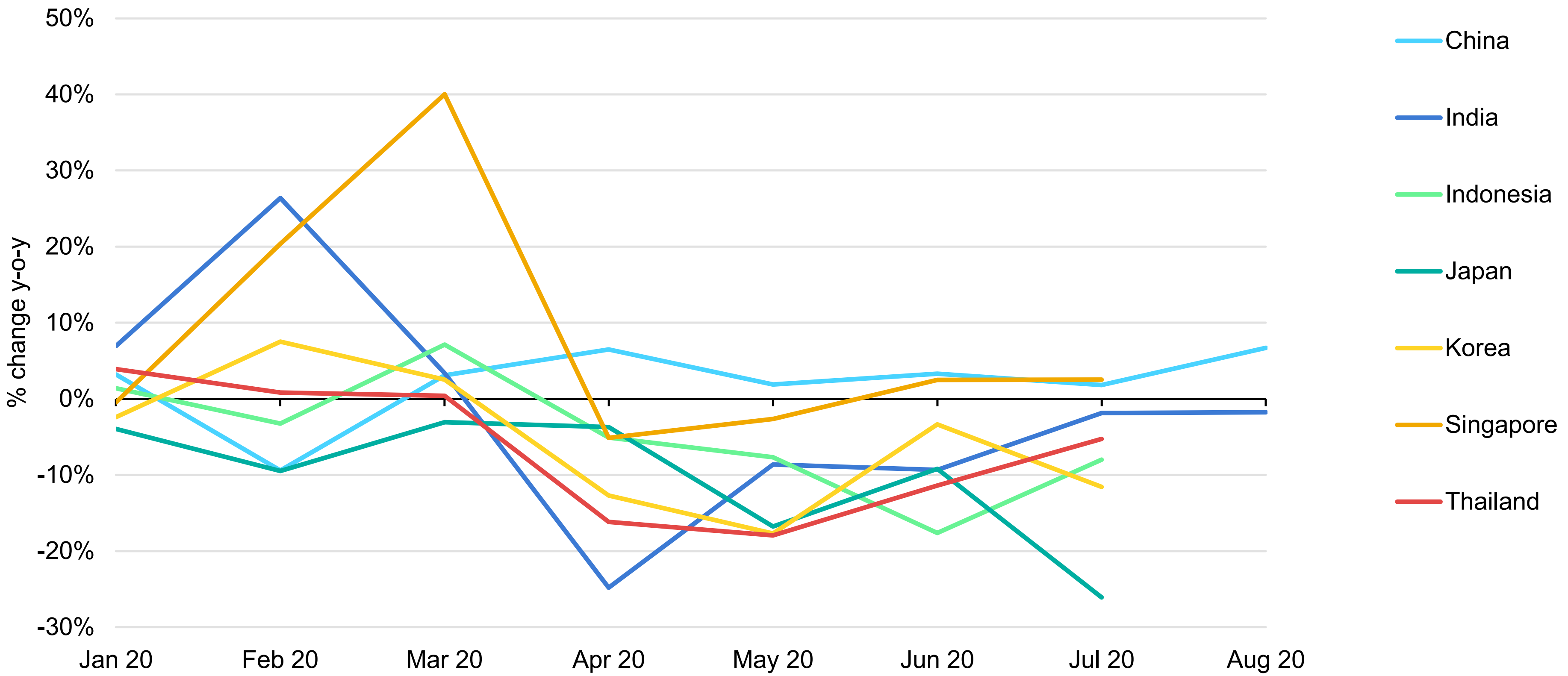
Asian gas demand is not yet back to “normal”

Monthly change in natural gas demand in selected countries in Asia



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Sources: IEA analysis based on CQPGX (2020), Nanbin Observation; IEA (2020), Monthly Gas Data Service (subscription required); JODI (2020), Gas World Database; PPAC (2020), Gas Consumption; Energy Policy and Planning Office (2020), Energy Statistics.

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Demand forecast update: A smaller fall, but with slower rebound

Global natural gas demand is forecast to fall by 3% y-o-y in 2020, or about 120 bcm. We have revised the decline from our previous forecast published in the *Gas 2020* report in June, which was projecting a 4% fall (or about 150 bcm) for this year. This revision is based on more complete data for the first half of 2020 showing a lesser impact than initially anticipated in Eurasia, Africa and the Middle East, as well as faster than expected demand recovery in Europe during Q3. In spite of this revision, 2020 is still assumed to experience the largest-ever recorded drop in global natural gas demand, compared to the 2.3% drop in 2009 (or about 75 bcm) in the aftermath of the 2008 financial crisis.

Most of the declines in gas consumption have been observed in mature markets across Europe, Eurasia, North America and Asia. They were affected by the combination of lower heating needs from exceptionally mild temperatures in Q1, lower gas burn for power generation and commercial sectors resulting from restrictions enacted in Q2 to curb the development of the Covid-19 pandemic, and slow recovery in Q3. Taken together these markets account for over 80% of the expected drop in global natural gas demand for 2020.

Natural gas demand is forecast to increase by 3% y-o-y in 2021 (or about 130 bcm), as electricity demand and industrial activity gradually return, and the presence of abundant and competitive supply favours further use of natural gas in power generation. Residential heating demand is also assumed to return to normal after an exceptionally mild winter in 2019/20. The pace of growth is not assumed to be the same for all markets, and the recovery of global gas demand in 2021 is likely to be supported by fast-growing markets in Asia, Africa and the Middle East. More mature markets should see gradual recovery, and some may not reach their 2019 level in 2021.

The resurgence of Covid-19 cases and the prospect of a prolonged pandemic brings further uncertainty to the pace of recovery in 2021. This has led to a downward adjustment from the previous report, which anticipated a 200 bcm y-o-y increase (5%). We have revised growth prospects for all markets including emerging Asia to take into account the higher likelihood of prolonged disruption to normal economic activity.

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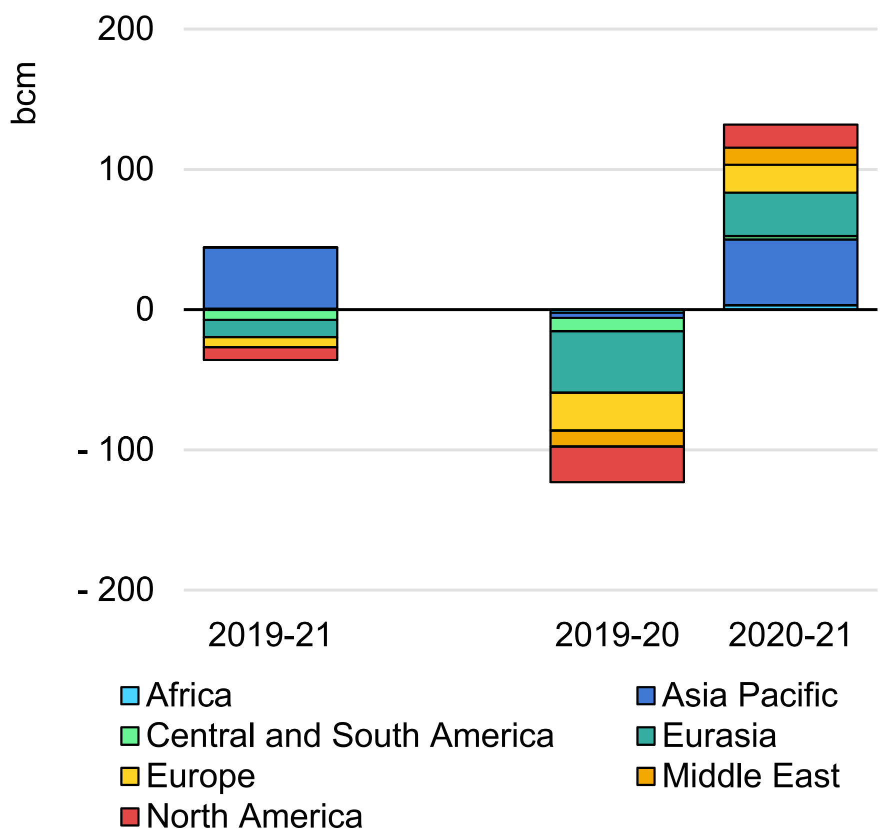
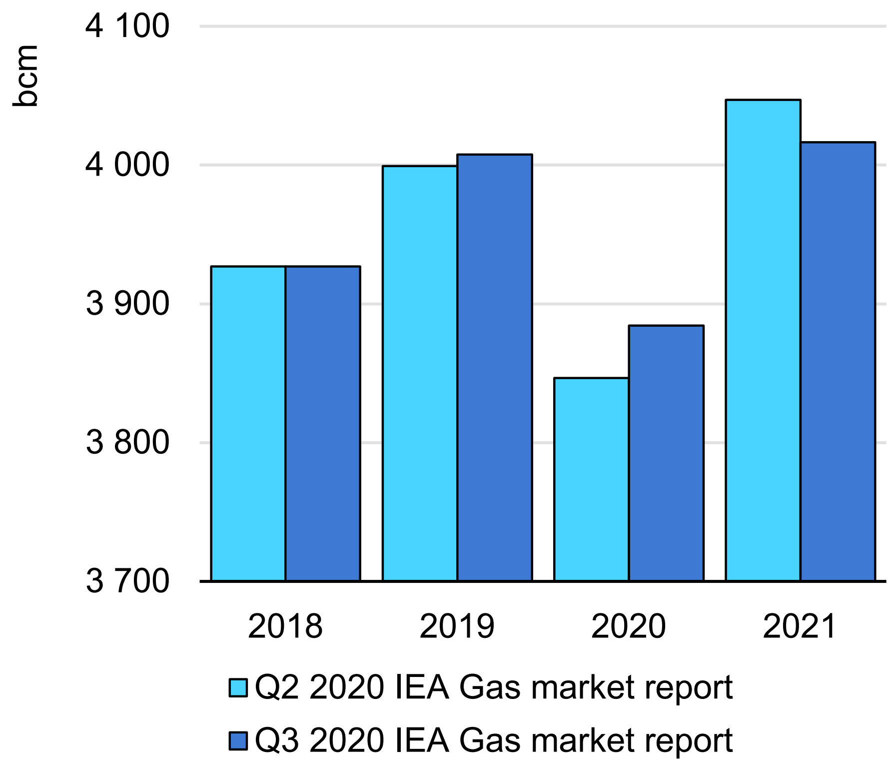
Global gas demand is expected to fall by 3% in 2020; recovery in 2021 is driven by growth in emerging Asian markets

Regional breakdown of demand growth, 2019-21



Evolution of global gas demand between Q2 and Q3 2020 market reports, 2018-21



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US production slides in Q2 after a resilient first quarter and stabilises in Q3

After showing some resilience during the first months of the year against the backdrop of declining domestic consumption, US natural gas production fell in the second quarter to 75.5 bcm in June, its lowest level since April 2019. LNG exports strongly supported US production resilience over the first quarter of 2020, but fell during Q2 as shippers exercised their right to cancel cargoes on lower Asian LNG demand and collapsing regional price spreads. Production rebounded in July and August to an average of 79 bcm per month, but remained under last year's levels for the same months, before dropping again in September to return to its June lows, resulting in a monthly average of 77 bcm for Q3, stable from Q2. In spite of this decline, US gas production still registered slight y-o-y growth for the first three quarters of the year, with an estimated 1% increase.

Associated gas output fluctuates while dry shale production remains strong

Most of the production decline observed in the first three quarters of 2020 came in associated gas output from oil-driven shale basins. Monthly US light tight oil production dropped by about 25% from March to June, out of which the gas-rich Permian basin fell by over 20%. This resulted in a similar fall in US associated shale gas production during Q2, from 25 bcm in March to 20 bcm in June. This decline in associated shale gas production led to a narrowing of differentials between prices at shale supply hubs and the reference Henry Hub index. In particular the Waha Hub in the Permian basin, which traded at a discount of USD 1.50/MBtu at the end of the first quarter, came close to parity with the Henry Hub in early Q2. The price differential then widened during the summer as Henry Hub recovered and stayed above USD 2.00/MBtu in September, while Waha oscillated around a discount of USD 1.00-1.50). Lower oil production also impacted gas output from conventional oil and gas fields – accounting for about a quarter of total US gas production in 2019 – which also declined during Q2 (June output was 7% below the March level).

Dry shale gas plays have, on the other hand, delivered stable output at a total monthly average of 39 bcm for the first eight months of 2020. The Appalachian basin, the largest contributor to dry shale gas production, recovered to its January level during the summer after a decline in early Q2. Its production level is being maintained in spite of low drilling activity thanks to the completion of previously drilled wells (or DUCs – drilled but uncompleted). The rig count has fallen sharply in the Appalachian play, causing a 35% drop in new drilled wells. The DUC inventory fell by 8% between January and August in the northeastern play, from 645 to 591 wells, with a monthly average of 71 new wells drilled for 83 completed. The Haynesville play has also proved resilient, with a stable monthly output of around 9 bcm for the first eight months of the year. It is supported by stable drilling and completion rates (with a monthly average of 33 new wells drilled and completed, thus stabilising the DUC inventory around 300 wells).

Net pipeline imports from Canada declined by 10% y-o-y in the first nine months of 2020. After a 13% y-o-y drop in the first quarter, monthly net imports from Canada were stable in Q2 at around 3 bcm, increasing to an average of close to 4 bcm in Q3 to supplement domestic production during the cooling season.

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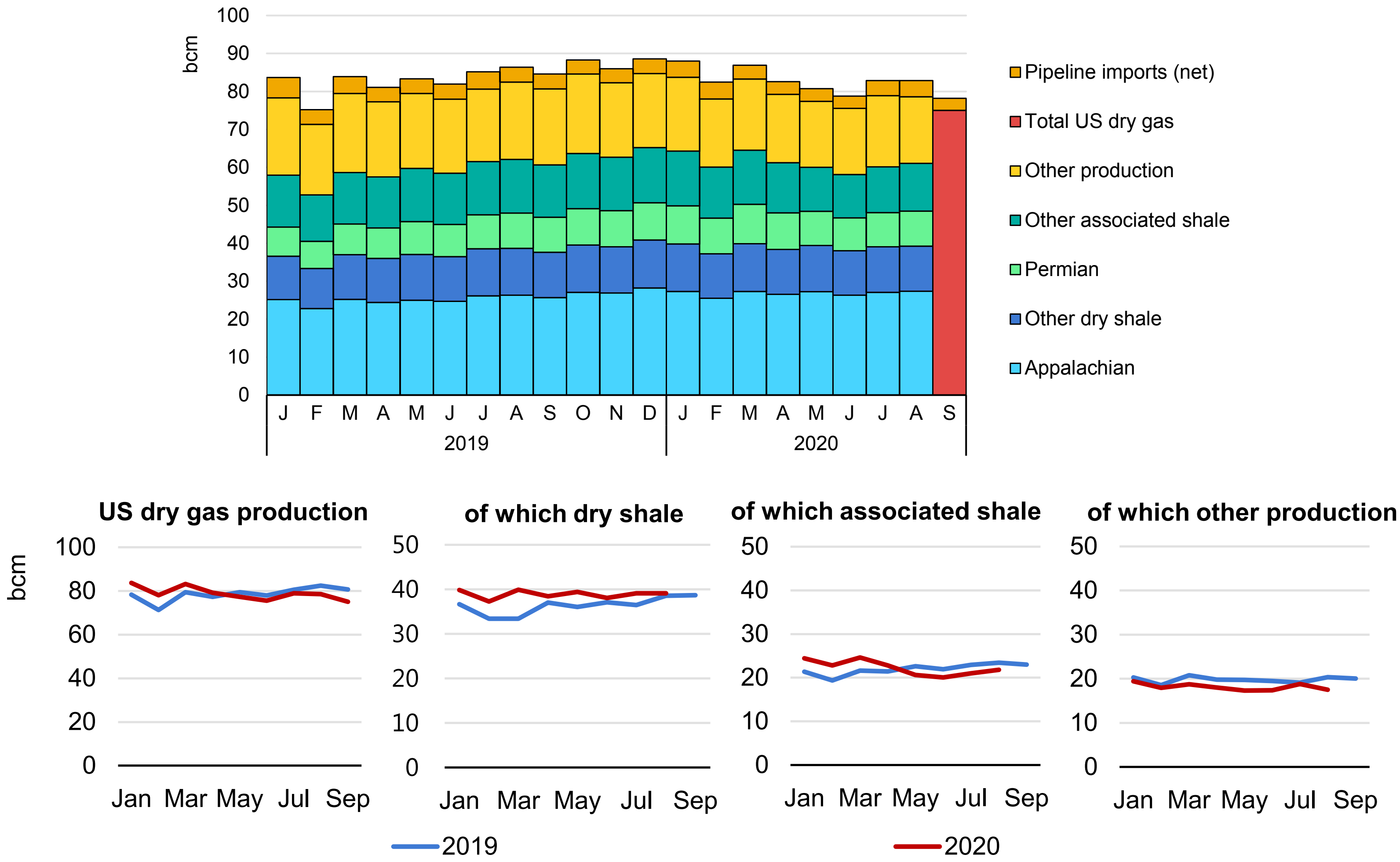
US production still shows y-o-y growth thanks to dry shale gas plays

Monthly US natural gas supply by source, 2019-20



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Sources: IEA analysis based on EIA (2020), Natural Gas Data, Natural Gas Weekly Update.

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US dry gas production is expected to decline slightly from 2019 levels as lower oil output affects associated shale

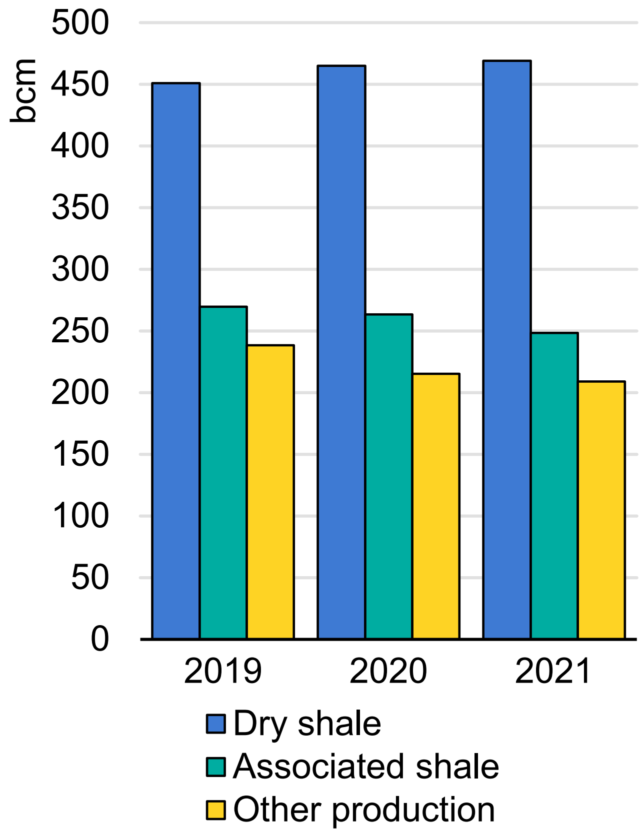
After a decline in the first half of 2020 and relative stability in Q3, US dry gas production is expected to be in the range of 75 to 80 bcm per month for the rest of the year, resulting in a slight year-on-year reduction for the whole year.

Dry shale gas production remained stable over the first eight months of 2020 and increased by 6% y-o-y. It is assumed to stay around the same level for the rest of the year and into 2021. The slow but continuous rate of DUC completions in the Appalachian basin supports stable dry shale gas output in spite of a prolonged period of low drilling activity. Drilling could find further support in the event of a natural gas price recovery in the coming months.

As mentioned in the IEA Oil Market Report, US crude oil output is expected to oscillate around 11 million barrels per day (mb/d) for the remaining months of 2020 and decline into 2021 to an average 10.7 mb/d, resulting in an average decline of 0.9 mb/d in 2020 and a further 0.6 mb/d in 2021. Slightly lower US light tight oil output results in a proportionate decline in monthly associated shale gas output. Natural gas output from conventional fields (both dry and associated) is also likely to decline on a combination of the abovementioned oil production adjustment and continuing depletion for the most mature assets.

The positive contribution of dry shale gas is not sufficient to offset declines from other sources, resulting in an anticipated 2% decline in US gas output in 2020. The same decline is forecast for 2021 on lower contributions from associated shale and conventional production sources.

US natural gas production by main source, 2019-21



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Eurasian swing: Adjusting production and fine-tuning export pipelines

Eurasia accounted for around 30% of inter-regional gas supply in 2019 and played a crucial role in balancing the global gas market in 2020 by absorbing the majority of the demand shock caused by the Covid-19-induced lockdowns and economic slowdown. This has been largely facilitated by the intra- and inter-annual flexibility mechanisms incorporated in pipeline gas supply agreements.

First estimates suggest that the region's gas production fell by over 7.5% y-o-y (or above 50 bcm) in the first three quarters of the year – more than in any other gas-producing region. This has been driven by domestic consumption falling by 5% and exports plummeting by 14% y-o-y, despite the start-up of new export corridors.

Russia alone accounted for close to 90% of the gross decline in production, with its gas output falling by 8.4% (or 46 bcm) y-o-y in Q1-3. This has been partly driven by domestic demand decreasing by 7% in H1 2020, and partly by exports to Europe falling by over 20% y-o-y. The country's large swing fields in Western Siberia bore the brunt of the supply adjustment, with the giant Zapolyarnoe field producing at below 60% of its designed capacity during H1 2020. Russian pipeline exports to China started via Power of Siberia in December 2019 and totalled 2.3 bcm in the first eight months of 2020, supplied from the Chayandinskoye field. The initial ramp-up plan of supplies foresees deliveries increasing to 5 bcm in 2020. Russia's LNG exports remained resilient, increasing slightly by 2.4% in the first three quarters of the year. The strong growth in LNG sales during the first five months of the year (up 8.6% y-oy), outpaced the declines recorded through June to September (down 5.5% y-o-y).

Central Asian pipeline deliveries to China fell by 15% (or 4.6 bcm) in the first eight months of 2020, amid fierce competition from LNG imports (up by 11% y-o-y in Q1-3) in a context of lower than anticipated demand.

In March it was reported that China requested supply reductions from Central Asia under its long-term import contracts. Turkmenistan accounted for 75% of the reduction, while by the end of August Lukoil reported that it had suspended its exports from Uzbekistan to China. Consequently the utilisation rate of the Central Asia–China pipeline system fell from an average of 84% in the first eight months of 2019 to 72% during the same period in 2020.

Azeri exports to Turkey increased by an impressive 25% in the first eight months of 2020 y-o-y, as supplies from the Shah Deniz II field via the TANAP pipeline system continued ramping up. This was primarily at the expense of Russian and Iranian gas deliveries. Coupled with an increase in domestic demand, Azeri gas production of sales gas rose by 12% in the first eight months of 2020.

Eurasia's gas production and exports are set to increase by 8% and 17% respectively in 2021, but total natural gas output is not expected to recover to 2019 levels, due to slower growth from domestic demand. The region's export-oriented energy- and gas-intensive industries are expected to suffer from the economic slowdown in key markets, ultimately weighing on the recovery in the region's gas demand.

Exports through the traditional pipeline export corridors from Russia to Europe and from Central Asia to China are expected to increase by 9% and 5% respectively in 2021, despite the continuing strong supply of LNG. Pipeline exports from Russia to China are expected to reach 10 bcm in 2021, supported by output ramping up from the Chayandinskoye field. Azeri exports from the Shah Deniz II field to Europe are expected to further increase in a range of 4-6 bcm in 2021, with the commissioning of the TAP pipeline in Q4 2020 and deliveries scheduled to reach Italy. The start-up of train 4 at Yamal LNG in Russia could increase LNG exports by 1.2 bcm/y from 2021.

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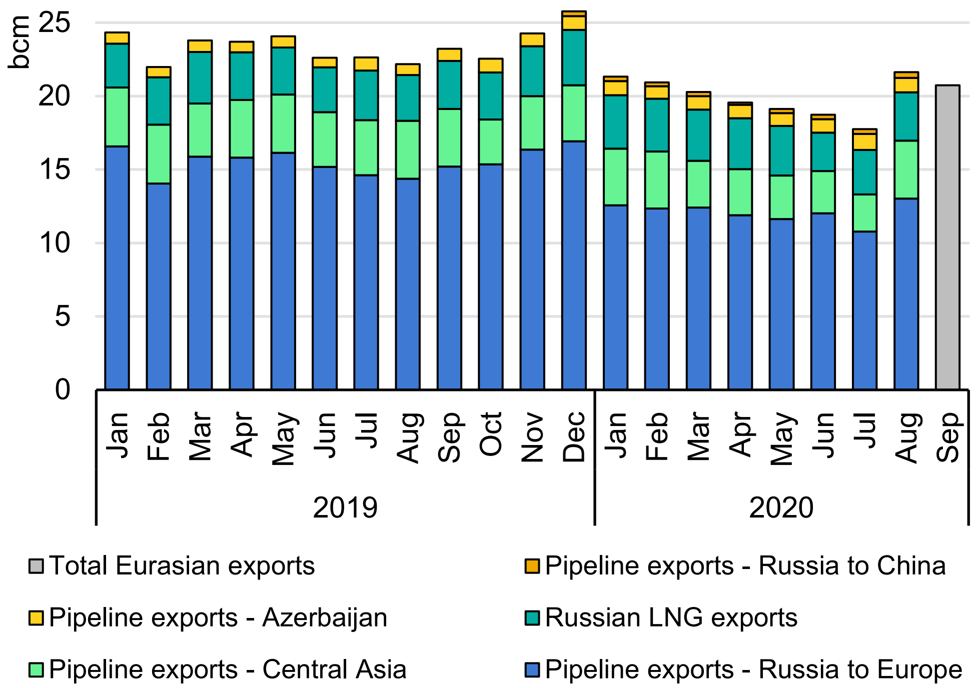
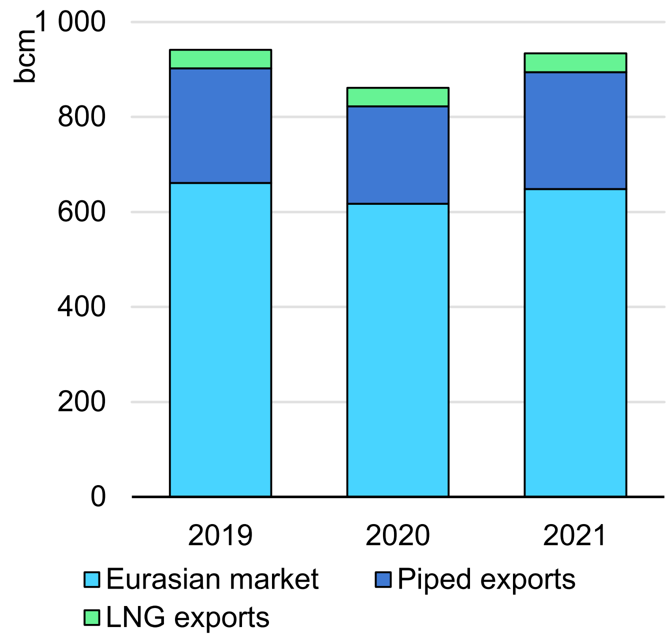
Rocky road to recovery: strong gains and new export corridors in 2021 will not be enough to surpass 2019 production levels

Monthly extra-regional Eurasian natural gas exports, 2019-20



Eurasian natural gas production by destination market, 2019-21



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Sources: IEA based on ENTSOG (2020), Transparency Platform; Eurostat (2020), Imports of Natural Gas by Partner Country – Monthly Data; General Administration of Customs of People's Republic of China (2020), Customs Statistics.

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Global LNG trade: Expansion continues despite Covid-19

Despite the overall decline in global gas demand, global LNG trade expanded by 3% (or 11 bcm) y-o-y during the first nine months of 2020. This was driven largely by continued capacity additions on the supply side, and buyer response to low spot LNG prices on the demand side. However, this rate of growth is relatively modest compared with the previous years; traded LNG volumes increased by 13% (41 bcm), 8% (23 bcm) and 11% (28 bcm) y-o-y in each of the corresponding periods of 2019, 2018 and 2017. The overall increase during the first three quarters of 2020 also masks a gradual weakening of trade growth throughout the year. A strong 12% y-o-y expansion in Q1 was followed by flat y-o-y growth in Q2 and an outright 2% y-o-y contraction in Q3, when a number of LNG exporting countries cut production to keep the market in balance.

The US leads global LNG export expansion in 2020 to date

This year's LNG export growth was mainly driven by the United States, which recorded a 38% (12 bcm) y-o-y increase in LNG outflows during the first nine months of 2020. The year-on-year expansion of US LNG exports was limited to the first five months of the year, however, while the period from June to September saw a sharp reduction in LNG production as offtakers cancelled more than 150 cargoes that would have been uneconomic to offtake. Qatar increased LNG exports by 3% (2.4 bcm) y-o-y during the first nine months in a deliberate move to leverage world-beating production costs to gain market share. Russia's LNG output increased by 4% (1.1 bcm) y-o-y in the January to September period as both the Yamal LNG facility and the Sakhalin 2 LNG plant operated at well above nameplate capacity during the first five months of the year.

Traditional exporters in the Asia Pacific region registered flat year-on-year growth. Declines in Malaysia and Indonesia were partially offset by increased output from Australia during the first nine months of the year, although Australia's production fell in Q3 2020 due to the unplanned outage at Gorgon LNG train 2. Africa's 6% (2.6 bcm) y-o-y export decline in the first nine months is largely due to the complete halt of LNG exports from Egypt between March and July and the decline of Algerian exports in the first half of the year. The 3% (1.3 bcm) y-o-y decline in the rest of the world during the January to September period is mainly due to supply curtailments in Trinidad and Tobago, as well as in Oman.

Europe, China and India support continuing LNG import growth in Q1-Q3

Among the main importing markets, Europe continued to play the role of the market of last resort, and recorded a strong 8% (6.7 bcm) y-o-y increase in LNG inflows during the first nine months of 2020. Europe's role in absorbing excess cargoes was especially pronounced until May, after which the market-balancing role of supply curtailments increased, while that of Europe progressively diminished.

LNG imports into China rose by 11% (6.5 bcm) y-o-y in the first nine months, supported by a gradual demand recovery, opportunistic LNG purchases by independent city gas distributors and a sharp reduction in Central Asian pipeline gas imports between March and July.

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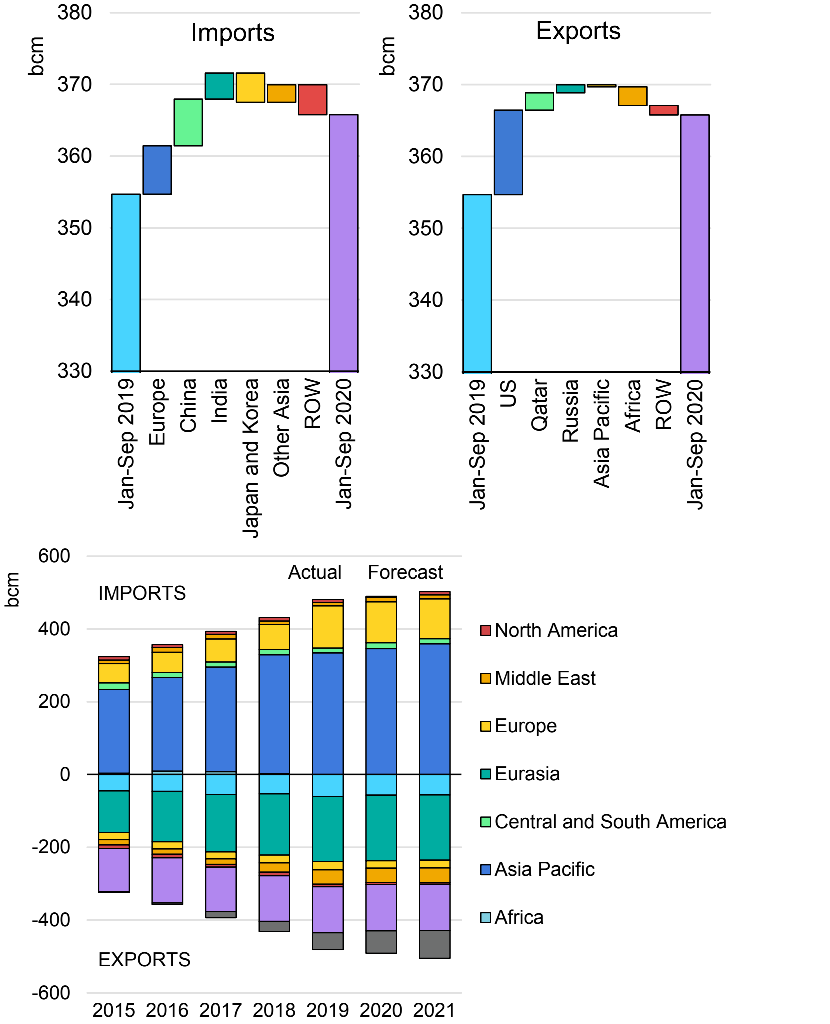
India increased its overall LNG intake by 15% (3.6 bcm) y-o-y during the first nine months of 2020 thanks to exceptionally strong imports in Q1 (driven in part by opportunistic buying of cheap spot LNG cargoes), and – after a short reversal during India's lockdown in April and May – a modest recovery in demand coinciding with falling domestic production since June.

Combined LNG imports to Japan and Korea dropped by 3% (4.1 bcm) y-o-y during the first nine months of 2020 as the Covid-19 crisis had a negative impact on natural gas demand in both countries, despite an increase in Korean gas-fired generation. The sharp 15% (4.2 bcm) y-o-y fall in the rest of the world was largely due to Covid-19-related demand declines in Brazil and Mexico, which were further exacerbated by strong pipeline gas imports from the United States in the case of Mexico.

Global LNG trade is set to increase by 2% in 2020 and 3% in 2021. This is significantly slower growth than seen in the 2015-19 period, when LNG trade expanded at an annual average rate of 10%. LNG import growth is led by the Asia Pacific region, which will increase its LNG imports by 3% and 4% in 2020 and 2021, respectively. The scope for greater European LNG imports is limited by an anticipated recovery in Russian pipeline gas deliveries from 2021. Among the main LNG exporters, the United States leads the expansion of global LNG trade with year-on-year increases of 33% and 24% in 2020 and 2021, respectively. LNG exports from all other regions combined see a slight decrease in 2020, and stay flat in 2021 as modest increases in Central and South America, Eurasia and the Middle East offset small declines in other regions.

World LNG imports and exports by region, 2015-21



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Source: IEA analysis based on ICIS (2020), ICIS LNG Edge (subscription required).

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Opportunistic LNG buying in Asia helps sustain LNG trade growth amid declining gas demand

The fact that global LNG trade continued to grow amid the overall decline in natural gas consumption in the first three quarters of 2020 is due in part to Europe being able to absorb excess LNG volumes as the market of last resort, and in part to a handful of Asian importing countries that were able to take advantage of the favourable price environment and increase spot LNG purchases during the pandemic. This dynamic in Asia was most pronounced in China, India and Thailand, where weak – or outright negative – gas demand growth has coincided with a sharp rise in LNG imports so far in 2020. Had there been no year-on-year growth in LNG imports in these three countries, global LNG trade would have stayed flat instead of growing 3.1% y-o-y in the January to September period.

China's natural gas consumption increased only modestly at 2% (4 bcm) y-o-y in the first eight months of the year, while LNG imports expanded at a relatively healthy rate of 10% (5.3 bcm) over the same period. The opportunistic LNG buying behaviour, which helped sustain strong LNG inflows, was mainly led by independent city gas distributors, which were able to snap up cheap spot LNG cargoes in large numbers thanks to China's recent gas market liberalisation and third-party access to at least nine import terminals. China's existing network of truck-based LNG delivery was also a key enabler of aggressive spot LNG buying by the independents, as it provided a competitive means of transport at a time of record-low LNG prices where pipelines were missing or inaccessible. As domestic production remained strong (growing 9% y-o-y in the first eight months), it fell mainly to China's state-owned majors to reduce oil-indexed pipeline gas deliveries from Central Asia (and – to a lesser extent – LNG deliveries under term contracts), thus making room for cheaper spot LNG in a weak domestic market.

India also increased its LNG imports substantially (by 15% or 3.6 bcm y-o-y), despite a 2% (0.7 bcm) y-o-y decline in total gas consumption during the first eight months. Spot cargoes selling at well below USD 3 per MBtu made imported LNG cost-competitive in most end-use sectors in India, and state-owned GAIL as well as a number of private companies (including Reliance and Torrent Power) stepped up spot LNG purchases to take advantage of the low price environment. Opportunistic buying activity was the strongest in Q1 (prior to India's nationwide lockdown), but after a brief interruption in April and May, LNG inflows (led by spot market purchases) rebounded sharply from June, and continued well into the third quarter. The commissioning of the Mundra LNG terminal in the state of Gujarat in February has facilitated India's accelerated LNG import growth in 2020. Domestic production was the primary victim of the low international gas price environment, registering a 13% y-o-y decline in the first eight months.

Thailand followed a similar trajectory to India, only with a much steeper 7% (2.1 bcm) y-o-y consumption decline coupled with a sharper 27% (1.1 bcm) y-o-y LNG import increase in the first seven months of the year. The state-controlled PTT – with the backing of the Thai government – stepped up spot market purchases in response to the weak international price environment, mainly at the expense of domestic production, which, in turn, suffered a sharp 10% decline y-o-y in the first seven months.

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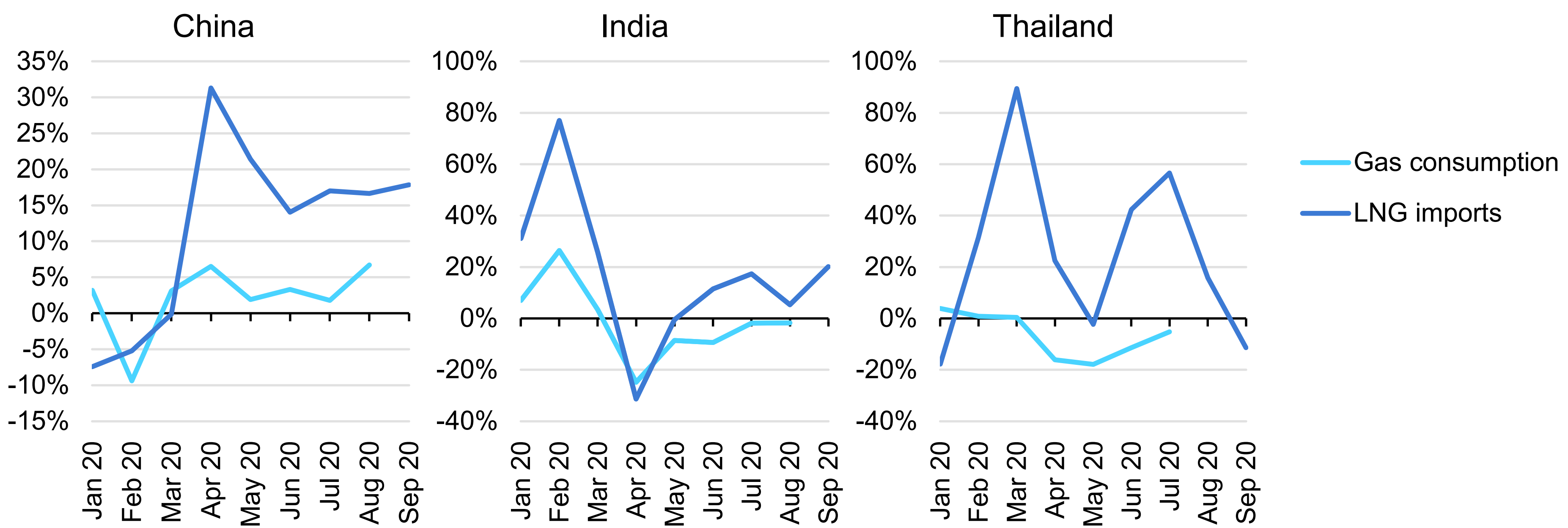
Strong LNG import growth continued amid a period of weak gas consumption growth in some Asian importing countries

Y-o-y change in gas consumption and LNG imports in selected countries in 2020 to date



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European gas supply: A balancing exercise

Europe played a key role in balancing out the global market in the first five months of 2020, by absorbing surplus volumes of LNG and accounting for close to 70% of net LNG trade growth. Consequently, the region's LNG imports grew by over one-fifth despite falling demand and at the expense of piped natural gas imports, which fell by over 20% during that period.

With the collapse of European spot gas prices to an historical low in May and June, and the transatlantic price spread between TTF and Henry Hub falling below zero, Europe's LNG imports started to decline in June, falling by 15% y-o-y that month. In Q3 the LNG influx into Europe decreased by 10% y-o-y, largely driven by lower imports into Belgium, Italy and Spain. Russia alone accounted for one-third of the gross decline in LNG supply in Q3 y-o-y, favouring Asian import markets, as the spread between Asian spot LNG price assessments and TTF widened to an average of USD 0.72/MBtu.

As a consequence of lower LNG inflow, the sharp fall in pipeline imports experienced in the first half of the year moderated in Q3, with overall pipeline imports decreasing by 12.5% and bringing total European imports down by 12% y-o-y in Q3.

- After plummeting by 28% in H1 2020, North African flows increased by 6.5% y-o-y in Q3, primarily driven by higher export volumes from Algeria to Italy via the Transmed pipeline.
- Russian exports to Europe remained down throughout Q3, declining by 18% y-o-y. Whilst both Nord Stream and transit through Belarus were running above 90% utilisation levels, net exports via Ukraine to the European Union halved. This is partly due to the increased use of virtual reverse flows (or backhaul) on the interconnection points between Ukraine and the European Union. Some of those reverse flows contributed to the substantial increase of net storage injections in Ukraine (up by 14% y-o-y) and might contribute to higher exit flows from Ukraine to the European Union during Q4.

European production decreased by 9% in H1 2020. Norwegian flows, falling by over 7% in H1 2020, returned to positive growth in August and increased by 16% y-o-y in Q3. Deliveries rose primarily to Germany and the Netherlands by an impressive 22% y-o-y. Growth has been particularly spectacular in September, with Norwegian flows up by 57% y-o-y, albeit from a very low base – last year's September deliveries represented a 15-year low due to both planned maintenance and unexpected outages.

Non-Norwegian domestic production fell by 13% in the first eight months of 2020 y-o-y and is expected to continue to decline in 2021 by over 7%. This is primarily driven by the gradual phase-out of the Groningen field in the Netherlands and the temporary stop of the Tyra field in Denmark.

The prospect of progressive demand recovery in Europe (with a 4% y-o-y increase in 2021), combined with further decline in domestic production, results in anticipated growth in total natural gas imports of 6% in 2021. This additional supply requirement will primarily benefit traditional pipeline suppliers – including Russia – and provide support for a continuing strong LNG influx in a context of abundant supply. In 2021 these are expected to reach just below the record-breaking levels of 2019. Moreover, the commercial start-up of the TAP pipeline system connecting Italy to the Southern corridor in Q4 2020 should allow Azeri supplies to further ramp up in 2021 by an initial 4-6 bcm.

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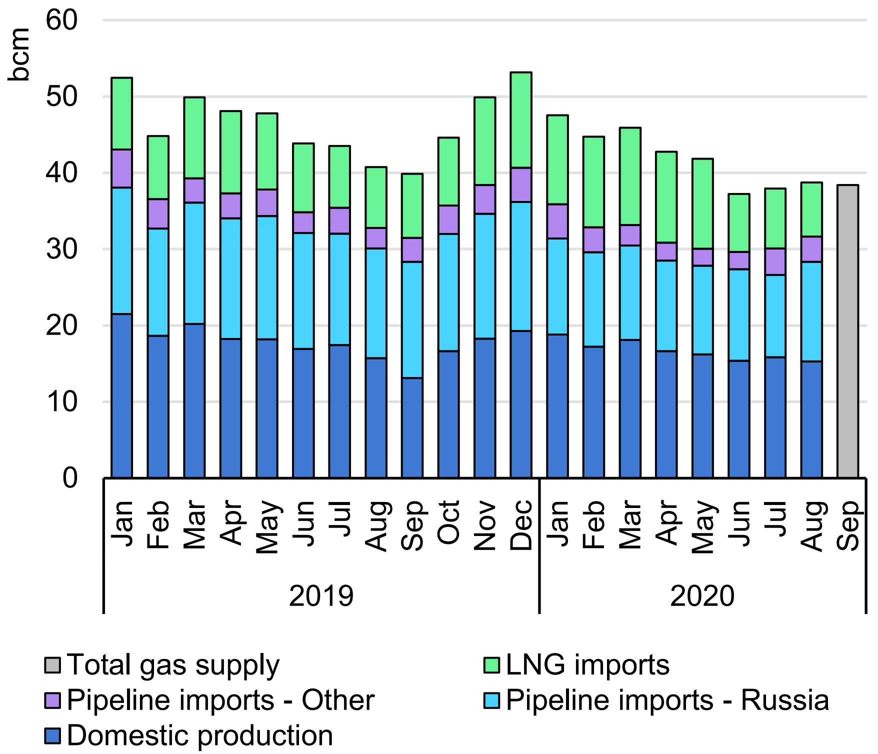
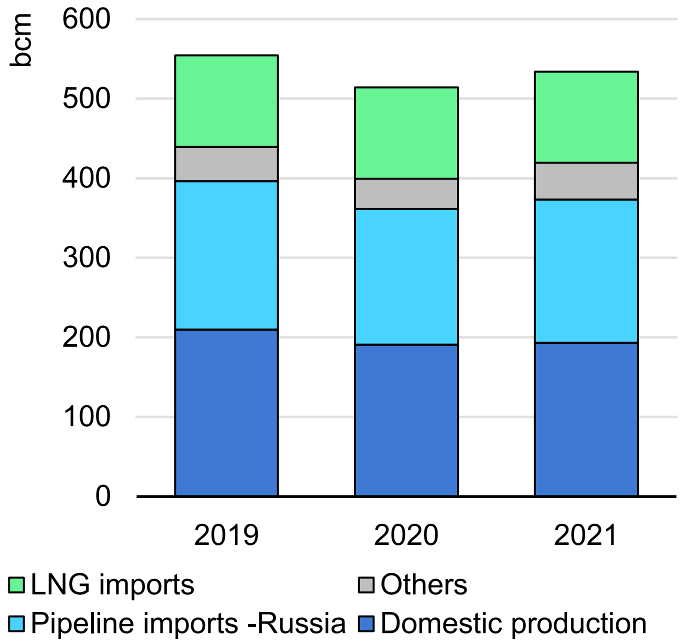
European imports are expected to rebound in 2021 amidst falling domestic production and recovering gas demand

Monthly European natural gas supply, 2019-20



European gas supply by source, 2019-21



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Global gas benchmark prices recorded strong gains in Q3 2020...

After plummeting to decade lows across all major gas-consuming regions in Q2 during the lockdowns, natural gas spot prices recorded strong gains in the third quarter, supported by supply adjustments and recovering demand.

In the United States Henry Hub spot prices averaged at USD 2/MBtu in Q3, 17% higher in Q3 compared with Q2. Prices rose to above last year's levels for the first time at the end of August, reaching a nine-month high of USD 2.57/MBtu. Strong gains during July and August were supported by strong gas burn in the power sector due to exceptionally hot temperatures. This trend has been reversed in September, with Henry Hub spot prices falling by 17% month-on-month to an average of USD 1.9/MBtu, as gas-fired generation declined on lower electricity consumption. Strong demand swings translated into extremely high volatility of close to 200%, the highest on record for a September month.

In Europe natural gas spot prices on the TTF averaged at USD 2.7/MBtu in Q3, increasing by over 50% compared to their average price level during Q2 – albeit 20% lower than a year before. Strong demand recovery in Q3 (up 3% y-o-y) was driven by the ongoing coal-to-gas switching in the power sector, coupled with reduced LNG inflows (down 10% y-o-y) from an adjusting global gas market. This provided support to the European spot price increase. In September TTF prices were trading on average 23% above last year's September price levels.

Asian LNG spot prices followed a similar trajectory, with a Q3 average price 63% above Q2 levels at USD 3.6/MBtu, but 24% below last year's price levels. LNG supply adjustments and unexpected outages at several LNG liquefaction facilities continued to provide support to price recovery during August, combined with renewed buying interest from China and emerging Asian markets. Asian spot prices reached USD 5/MBtu by end of September for the first time since January.

The strengthening of prices has been accompanied by a substantial recovery in inter-regional price spreads. The TTF–Henry Hub spread collapsed to below zero in May and averaged USD -0.1/MBtu between May and July. This in turn triggered supply adjustments in the form of LNG cargo cancellations, which supported recovery in spot prices in Asia and Europe during August and contributed to the widening of inter-regional price spreads again. The TTF–Henry Hub spread gradually recovered to an average of USD 1.6/MBtu in September. Similarly, the spread between Asian LNG spot prices and Henry Hub rose from below USD 0.5/MBtu in May to USD 2.4/MBtu.

The forward curve (as of 1 October 2020) suggests a continued price recovery during Q4, with both Henry Hub and TTF Q4 contracts trading respectively 7% and 10% above last year's spot levels. Based on this assessment, Henry Hub would reach an average of USD 2/MBtu and TTF USD 3/MBtu in 2020, or down 20% and 33% y-o-y respectively. This would represent the lowest annual average for TTF since it was established in 2003 and the lowest annual average for Henry Hub since 1995. The forward curve as of 1 October suggests price recovery in 2021, with TTF returning to above 2019 levels (increasing by 57% y-o-y) and Henry Hub rising by 40% to USD 2.9/MBtu, its highest level since 2018.

In contrast with spot benchmarks, oil-indexed gas prices have weakened through to Q3, as oil prices, which have averaged below USD 50/barrel since March, are filtering through the price-setting reference period of the contracts, usually with a lag of three to six months. The predominance of oil-indexed contracts in the import portfolios of Asian LNG buyers is reflected in the evolution of the weighted average LNG import price of China, Japan and Korea. This decreased by over 25% y-o-y in June-August 2020, to below USD 7/MBtu – still almost twice the price level of spot LNG during that period. The current forward curve suggests that oil-indexed prices could further weaken in Q4 into a range of USD 6-7/MBtu.

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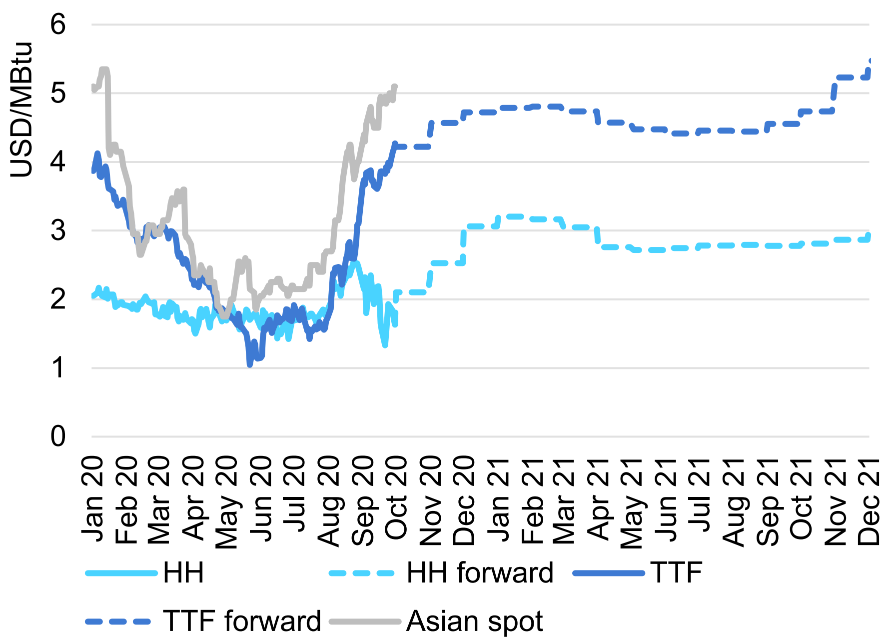
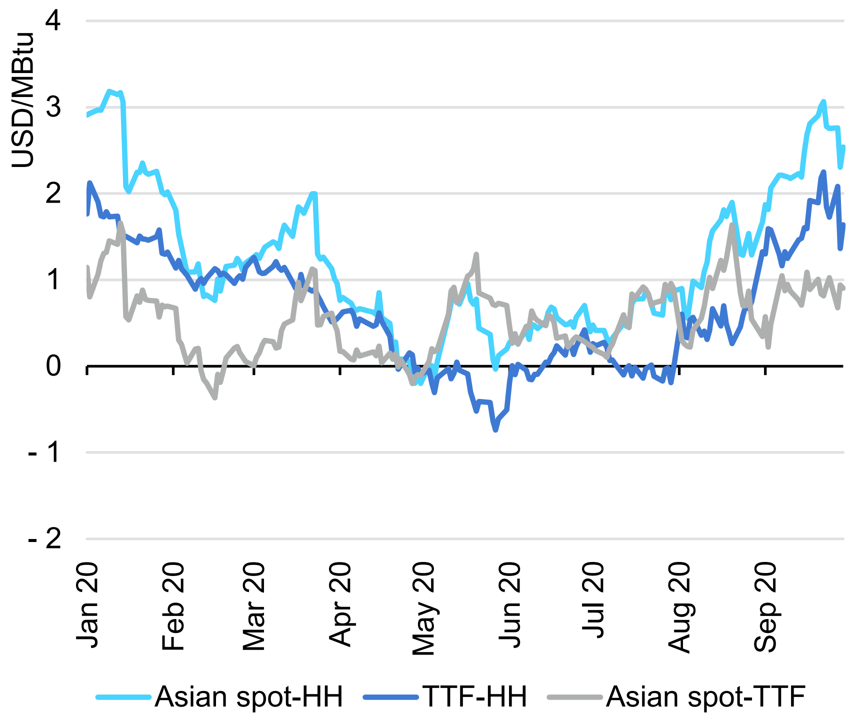
...followed by recovery in inter-regional price spreads

Evolution of main spot and forward gas prices

US Henry Hub, European TTF and Asian LNG spot index



Evolution of inter-regional price spreads



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Sources: IEA analysis based on CME (2020), Henry Hub natural gas futures quotes and Dutch TTF Natural Gas Month Futures Settlements; EIA (2020), Henry Hub Natural Gas Spot Price; ICIS (2020), ICIS LNG Edge (subscription required); Powernext (2020), Spot market data.

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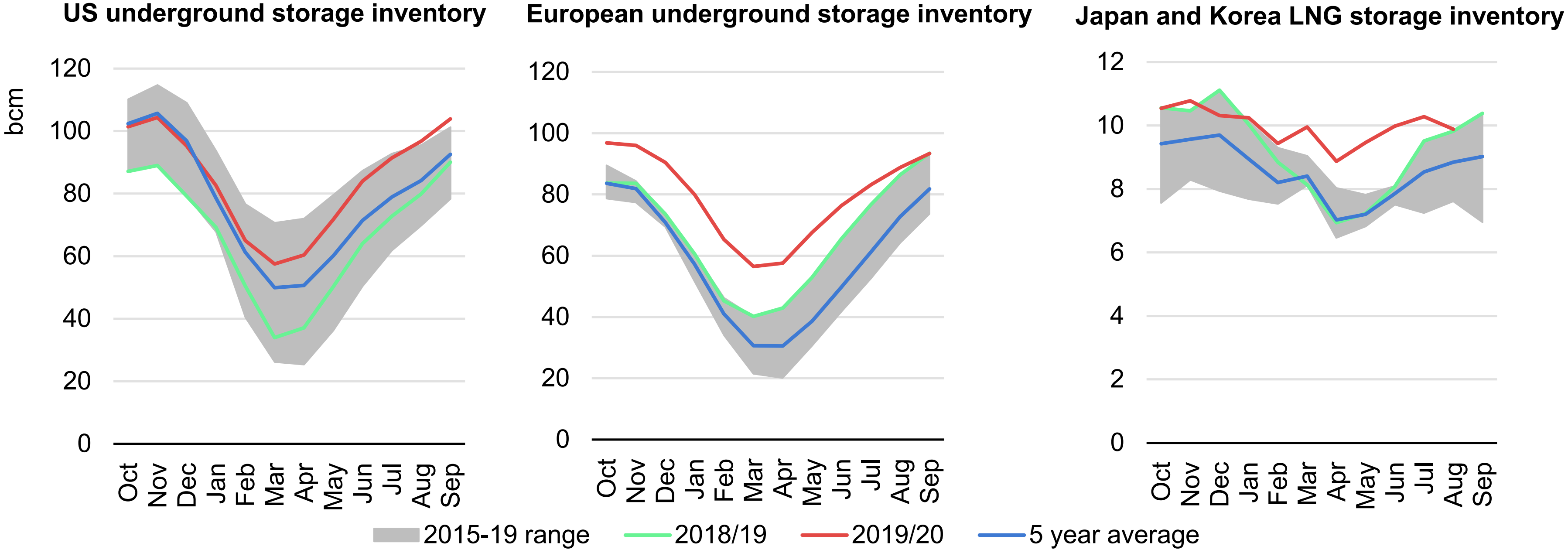
Underground storage inventories start the heating season at a five-year record in spite of slower summer injection

Supported by high opening stocks at the end of the 2019/20 winter, and despite the clear slowdown in net injections during Q3 2020, storage inventories in the United States and Europe stood at 14% and 12% above their respective five-year averages in September. In the United States net injections totalled close to 20 bcm in Q3, 26% below the levels of last year, as declining production reduced injection needs. In Europe net injections decreased by almost 40% in Q3 y-o-y, as lower LNG influx coincided with recovery in demand, weighing on the rate of injections. Moreover, net injections into Ukraine's storage facilities (not included in the figure below) rose by 14%, supported by either physical or virtual (backhaul) reverse flows from Europe. In spite of this slower injection rate throughout the summer, European underground storage was 95% full at the beginning of October, just below last year's record-breaking fill levels. LNG storage in Japan and Korea averaged 20% above their five-year average from May to August, which together with lower demand weighed on LNG importation needs.



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Sources: IEA analysis based on EIA (2020), Weekly working gas in underground storage; GIE (2020), AGSI+ database; IEA (2020), Monthly Gas Data Service (subscription required).

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Annex

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Summary table

World natural gas demand and production by region and key country (bcm)

	Demand				Production			
	2018	2019	2020	2021	2018	2019	2020	2021
Africa	157	159	157	160	244	243	232	243
Asia Pacific	824	849	848	893	627	655	645	671
of which China	*283*	*307*	*319*	*343*	*160*	*174*	*185*	*193*
Central and South America	153	150	141	143	185	177	145	154
Eurasia	666	661	617	648	932	952	863	932
of which Russia	*493*	*481*	*444*	*474*	*726*	*738*	*684*	*723*
Europe	536	541	514	534	246	227	204	203
Middle East	544	560	548	560	666	679	683	695
North America	1061	1087	1062	1077	1062	1146	1126	1120
of which United States	*854*	*883*	*866*	*875*	*868*	*956*	*944*	*927*
World	**3940**	**4008**	**3886**	**4014**	**3963**	**4078**	**3897**	**4020**

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Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other countries and territories.[1]

Asia Pacific – Australia, Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, Japan, Korea, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, the People's Republic of China,[2] the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other countries and territories.[3]

Central and South America – Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other countries and territories.[4]

Eurasia – Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, the Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Europe – Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[5,6] Czech Republic, Denmark, Estonia, Finland, the Former Yugoslav Republic of North Macedonia, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo,[7] Latvia, Lithuania, Luxembourg, Malta, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[5,6] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain and Sweden.

Middle East – Bahrain, the Islamic Republic of Iran, Iraq, Israel,[8] Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

North Africa – Algeria, Egypt, Libya, Morocco and Tunisia.

North America – Canada, Mexico and the United States.

[1] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda.

[2] Including Hong Kong.

[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.

[4] Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, St Lucia, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands.

[5] Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

[6] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

[7] The designation is without prejudice to positions on status, and is in line with the United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of Independence.

[8] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law

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Abbreviations and acronyms

CME	Chicago Mercantile Exchange (United States)
CNG	compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CPC	Chinese Petroleum Corporation
CQPGX	Chongqing Petroleum and Gas Exchange (China)
DQT	downward quantity tolerence
DUC	drilled but uncompleted
EGAT	Electricity Generating Authority of Thailand
EIA	Energy Information Administration (United States)
ENTSOE	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EPIAS	Enerji Piyasaları İşletme A.Ş (Turkey)
EPPO	EnergyPolicy and Planning Office (Thailand)
FID	final investment decision
FLNG	floating liquefied natural gas
FSRU	floating storage regasification unit
GIE	Gas Infrastructure Europe
HH	Henry Hub
ICIS	Independent Chemical Information Services
JGA	Japan Gas Association
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
LNG	liquefied natural gas
MME	Ministry of Mines and Energy (Brazil)
m-o-m	month-on-month
NBP	National Balancing Point (United Kingdom)
NCG	NetConnect Germany
NDRC	National Development and Reform Commission (China)
NIGC	National Iranian Gas Company
PPAC	Petroleum Planning & Analysis Cell (India)
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
ToP	take or pay
TTF	Title Transfer Facility (the Netherlands)
USD	United States dollar
y-o-y	year-on-year

Units of measure

bcf	billion cubic feet
bcm	billion cubic metres
mb/d	million barrels per day
TWh	terawatt-hour

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Acknowledgements, contributors and credits

This publication has been prepared by the Gas, Coal and Power Markets Division (GCP) of the International Energy Agency (IEA). The analysis was led and co-ordinated by Jean-Baptiste Dubreuil, Senior Natural Gas Analyst. Songho Jeon, Akos Losz, Gergely Molnár, Sean O'Brien, Tomoko Uesawa and Jean-Baptiste Dubreuil are the main authors. Sara Abd Alla and Antonio Erias Rodríguez provided essential research and statistical support. Keisuke Sadamori, Director of the IEA Energy Markets and Security (EMS) Directorate, and Peter Fraser, Head of GCP, provided expert guidance and advice.

Timely and comprehensive data from the Energy Data Centre were fundamental to the report. Special thanks go to Mathilde Daugy and Louis Chambeau for their support.

The IEA Communication and Digital Office (CDO) provided production and launch support. Particular thanks to Jad Mouawad and his team: Astrid Dumond, Merve Erdem, Grace Gordon, Katie Lazaro, Jethro Mullen, Rob Stone and Therese Walsh. Justin French-Brooks edited the report.

The report was made possible by assistance from Enagás, Mitsubishi Corporation, SK E&S and Tokyo Gas.

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Typeset in France by IEA – October 2020

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