Follow-up study to the LNG and storage strategy

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EXECUTIVE SUMMARY

The infrastructure priorities of the EU's LNG and Underground Gas Storage Strategy were tested under normal and security of supply (SOS) scenarios under high and low global LNG supply, and high and low gas demand projections. Based on these modelling runs, most of the projects provide satisfactory results in terms of utilization, either under regular or in SOS scenarios or in both. The most robust results are with pipelines in the Baltics, to IGB and IBS. Croatian LNG is very sensitive to global LNG supply and European demand development, although the benefits of the project are inevitable in SOS. The pipeline projects on the Iberian Peninsula did not show good results in any of the scenarios tested.

Utilization of LNG terminals

LNG terminal utilization in Europe varies widely. Based on the modelling results, in 2016 utilization is low (0-36%), with Italian and Greek terminals showing the highest figures and some development in terms of utilization by 2020 in Lithuania and Poland, while other terminals stay even or decrease due to the low demand levels across Europe and the market share strategy employed by Gazprom. Yearly utilization figures show a substantial increase from 2020 to 2025 because EU production is falling and there is more available competitive LNG on the global market. Lithuanian, Polish and Portuguese terminals double their utilization figure and Turkey triples. The terminals in Belgium, France, and the UK in North West Europe start to receive more cargoes when the global LNG supply is high, and it is the only scenario where the Dutch terminal shows a more significant utilization (25%). High LNG supply is also beneficial for the Turkish, Polish and Croatian LNG terminals, but the others (GR, ES, PT, IT, MT) are not responsive to such scenario. This is partly due to low interconnectivity and the isolated nature of these markets (GR, PT, MT) but also due to the lack of price disparity between neighbouring markets (IT, ES). Even in the high LNG supply scenario when the yearly European utilization rates of the terminals are up to 45%, there is no serious congestion (the Lithuanian and Turkish terminals are only close to the threshold).

Peak utilization of LNG terminals in high demand months does not lead to monthly congestion on any terminal in the reference 2020, and only the Lithuanian LNG terminal becomes congested in 2025. In the alternative high demand - high LNG supply reference in January, Belgian, Italian, Polish, Turkish an British terminals become congested. UK terminals show a 7% higher utilizatrion in January when the Rough underground gas storage is assumed to be closed down, but this increase in January is not visible on the yearly utilization of UK LNG terminals.

LNG can contribute to mitigate supply crisis problems with additional spot cargoes delivered to the closest terminal to the affected countries. LNG has a significant role in the modelled Northern route disruption, providing an additional ~17 TWh/month (~18% of the missing volumes) to the European supply, and in the African pipeline route disruption (~13 TWh/month, 38% of the missing volumes). It has limited contribution to mitigate supply disruptions in South-East Europe (SEE), as interconnectivity is still low in the Balkans (from the LNG terminal in Greece) and the planned LNG terminal in Croatia would need to reduce tariffs on cross border interconnectors to be able to benefit the region.

Utilization of storage facilities

Storage facilities play an important role in providing seasonal flexibility to the European market and under security of supply scenarios they contribute the most among the flexibility sources. Still, modelling results do not project an optimistic future for storages. The aggregate volume of gas stored is decreasing with time (7% in the EU28, and 3% in the entire modelled region) despite the current storage obligations in place in many countries.

While modelling results show an overall fall in storage use, storage sites in Bulgaria, Croatia, Italy, Poland and Ukraine show increasing utilization rates over the modelled period; others see decreasing utilization: the largest impact being on the Austrian, German and French storage use.

Regulatory interventions

A certain surplus capacity on the gas storage market is already facing financial troubles, and this year witnessed the first closure of a storage site in Ireland possibly with more to come. Modelled storage use is the highest in UK and in IR, which shows that the market is not willing to pay the cost of storage.[1]

Substantial surplus (unused) storage capacities were modelled by REKK, and even in the most extreme shock scenarios the infrastructure was capable to handle the crisis. Out of the approx. 1100 TWh working gas capacity available for EU28, around 600 TWh was used by the model and this amount was sufficient to handle even the most extreme supply and demand shocks. Other flexibility sources (especially long term contracts, LTCs) might also book storage capacity on a long-term basis that requires about 145 TWh of additional storage. Increasing competition of flexibility sources might outcompete some storage facilities, and this must be closely monitored, but we see no urgent risk on supply security in this regard.

To increase storage use storage obligations are in place in several Member States. Modelling results underpin the need for many of these obligations in the modelled security of supply scenarios. We also found, however, that these storage obligations are in some cases hindering cross border use of storage and worsen the business case for other countries' storage facilities where no storage obligations exist. For this reason, we have described an alternative regulatory solution in this study that could potentially replace storage obligations with EU-wide, VOLL-based firm and obligatory financial compensation for protected customers by suppliers.

Strategic storage stocks are not utilized in the modelled shock scenarios by the market and especially with the new infrastructure proposed by the LNG and Storage Strategy these strategic stocks can be turned into regular commercial storages with a regional use.

Based on modelled gas flows and infrastructure use in SoS scenarios, we see great potential in increased cooperation between Hungary, Serbia, Bulgaria, and Greece to optimize the allocation of additional sources from Hungarian storages and Greek LNG-import along this route. This would require the completion of the bi-directional BG-RS interconnector, which is an FID project with a target commissioning date of 2018. If the HU-SI interconnector is built and tariff issues are resolved, this cooperation could be extended to Croatia and Slovenia, further enhancing flexibility with the appearance of additional sources (Croatian LNG and storage) and supply routes. Another source of flexibility could be put into use if the removal of regulatory barriers would provide Bulgaria with access to Romanian storages. Finally, cooperation in the SEE region would be made complete with the involvement of Italy with a view of harmonizing the flows on TAP with the use of Italian storages.

Security of Supply

Under the modelled scenarios the European infrastructure can robustly serve the needs of the gas system even under the most extreme shocks. Modelling did not point to any

[1] For modelling purposes and due to lack of data on storage tariffs a uniform 1€/MWh is used fee for storage services, slightly below the modelled summer/winter spreread – except for those countries where published tariffs are lower than this figure (UA)

additional infrastructure need besides the ones described above. Price increase due to supply shocks remained modest, with a maximum of around 5 €/MWh increase for a 7 days period in the most extreme combined shock.

Regional price differences between South East Europe and North-West Europe are close to zero in 2020 and 2025 due to good interconnectivity. The price gap is more relevant between EU28 and the Energy Community Contracting Parties, the latter being 3.6 €/MWh more expensive than the EU28 by 2025. Turkey is showing very similar (modest) results to shocks, where the storage developments and the LNG terminals within Turkey provide the necessary flexibility to the Turkish market, and there is no significant flow between Turkey and the neighboring EU countries in SOS runs.

The study considered how liquidity, flexibility and transparency can be improved in European and global LNG markets. The LNG industry is in the process of substantial industry change, because of an oversupply crisis, new LNG technologies and the entry of substantial volumes of low cost US LNG.

Various preconditions are necessary for active trading markets to develop and there are separate indicators of a fully functioning trading market. Although many of the preconditions already exist and LNG is certainly becoming more flexible and liquid, LNG does not yet offer fully flexible, liquid and transparent trading markets.

Case studies of pipeline gas, oil and iron ore trading show that sophisticated trading markets develop when there is (in this order): 1) a crisis or dramatic change in the market, such as a supply overhang or new technology, 2) appropriate government action which sets the environment for markets to develop, and 3) the market is then left to itself to develop. While positive government intervention can drive markets forward, the wrong sort of government intervention can hold back or stop a trading market from developing.

The EU has already brought about important drivers for effective LNG trading markets to develop, including the ban on destination clauses and ship fuel regulations. The LNG industry considers that the industry is working fine and there is no need for further EU level intervention, nevertheless we have identified some areas for further development.

A standard contract is essential for active LNG trading, this will be developed by the industry though and there is little governments or the EU can do. The EU could help to set the environment for LNG hubs to develop where there is a combination of physical assets (large scale LNG storage and bunkering) and supporting paper based mechanisms (such as hub contract and fiscal incentives). LNG hubs would support liquid, flexible and transparent markets and could be developed in North West Europe, South West Europe or the Mediterranean. The EU can promote transparency with more information on terminal and LNG pricing, and for new market entrants (particularly new emerging market LNG buyers who have surplus LNG available for resale). There are also various ways in which the EU could engage in international cooperation and information sharing, including with other national buyers, emerging hubs (such as Singapore) and US agencies.

The study has shown that European LNG Import Terminals can accept LNG from virtually all of the current and proposed new LNG Export Terminals without the need for LNG blending to achieve a suitable specification.

There are however some issues that should be noted such as the UK being an exception with its narrower range for the gas network, hence blending facilities are provided at some terminals to handle LNG from some locations. Croatia and Lithuania also have certain composition restrictions even though the Wobbe Index values are compatible.

BACKGROUND

A consortium of Tractebel, REKK and Energy Markets Global was commissioned in December 2016 to carry out a follow up study to the LNG and storage strategy adopted by the European Commission in February 2016.

The kick off meeting was held in Brussels 24 January 2017 where Consultants presented their methodology, timeline, and division of tasks between consortium members to the Commission and invited stakeholders. Written comments were received from the Commission throughout February and various meetings were held with GSE and CEER to present the model (EGMM) and discuss the assumptions and data source to be used in course of modelling. Several interviews have been carried out with global players in the LNG industry to collect input for Tasks 8 and 9.

The Interim Report presented the methodology, the assumptions and data that is used for the modelling and the interim modelling results for Tasks 1 and 2, results for Task 3 and interim results for Task 8. Several comments were submitted by stakeholders on the Interim results, and in the follow up meetings, that were taken into account and addressed. The summary of comments is attached to this report in an Annex. The modelling exercise has been repeated with the updated input data that we received from stakeholders in the consultation phase.

Tractebel was responsible for Task 3 (gas quality issues), REKK for Tasks 1 and 2 (infrastructure modelling under security of supply conditions), Task 4, (assess the impact rules on access, capacity allocation and other regulatory aspects on infrastructure) Task 5, (identify potential regional cooperation mechanisms related to access to storage capacity on a regional level, and the circle of countries where this cooperation could most realistically take place in the most cost-efficient way) Task 6 (identify the barriers and limitations stemming from the specific storage measures and regimes in Member States) and EMG for Tasks 8 (Identify and assess the key issues regarding the liquidity and transparency of the global LNG market and the current level of development (including parallels and differences when it comes to oil markets)) and Task 9 (Identify and describe possible measures and initiatives (e.g. structured information exchange on LNG, etc) the EU can take as part of its energy dialogue with consumer, existing and potential supplier countries, international organizations and multilateral fora (such as the IEA, G7, G20, etc) to promote liquid and transparent global LNG markets). Task 7 (draw up potential directions for actions and specific actions that could be taken in order to address the barriers identified under tasks 4 and 6 above) is joint responsibility of REKK and EMG.

Tractebel is an Engineering Consultancy company, part of the Engie Group of companies working in the Energy Sector. They have significant experience in gas and LNG Projects from feasibility stage through to operations and are often involved in master planning of gas and power systems. For this study Tractebel have used their extensive knowledge of the development of LNG import and storage Projects to confirm LNG supply compatibility, general LNG storage costs and the basis for developers assessing their own LNG storage requirements.

The Regional Centre for Energy Policy Research (REKK) is an energy policy think tank based in Budapest, Hungary. A considerable methodological advantage of REKK for this project is that it has a wholesale regional gas market model covering Europe (EGMM). The model has been credited by several research and consultancy assignments to be a very useful tool to address broad regional questions, ranging from infrastructure cost benefit analysis, gas consumption and price forecasts to security of supply related issues. EGMM was further developed in March particularly to better reflect storage use and security of supply disruption scenarios: storage withdrawal curves per country and the possibility to define storage obligations are now built-in, security of supply scenarios as defined by this study are programmed. Geographically the model has been extended to include Turkey.

Energy Markets Global Limited (EMG) is an international consultancy, training and implementation company, operating in the energy sector. They are based in London, UK and operate throughout the world, particularly in emerging markets. For this project, EGM made use of their industry expertise and international range to: 1) construct a database of every LNG liquefaction project worldwide, making this the most up to date and accurate picture of the LNG supply scene in the world, which has informed our views on future LNG supplies availability; 2) conduct interviews with a range of LNG industry participants across the world, including Europe, South Asia, Singapore; 3) Prepare some case studies of trading in other relevant industries so as to inform the discussion about LNG; 4) analyse the market, commercial and legal issues around the LNG business, so as to draw conclusions on how global liquidity, transparency and flexibility can be further promotedto LNG.

INTRODUCTION

Since the European Commission published its EU strategy for liquefied natural gas and gas storage in February 2016, several aspects of the European gas market have gone through remarkable development. After years of decline and only modest growth in 2015, gas consumption of the EU28 picked up by a healthy 7% in 2016, according to Eurostat. Global LNG trade has continued its expansion, but as GIIGNL observed, supply growth of 7.5% last year was lower than expected. A significant run-up in European LNG imports has also failed to materialize, and the continent "did not function as a sink for the production increase in 2016."[2] Only three U.S. cargoes reached Europe last year, with Northwest Europe and Poland welcoming its first deliveries only in June 2017.

It is beyond doubt that LNG remains a very important flexibility tool for Europe, yet it may not become the game-changer as many expected. Its future role in Europe is determined not only by global supply and demand dynamics, but the level of competition and pricing strategies applied on the European markets themselves. Since the adoption of the strategy, Gazprom has moved to preserve its role as a traditional pipeline supplier by more flexible pricing and taking important steps towards the expansion of Nord Stream. In this follow-up study, we will reflect on these developments, and try to not only come up with realistic scenarios about the future role of LNG in Europe, but will also analyze what the EU could do toenable further market developments and diversification..

We have seen some storage-related developments as well. Ireland's Southwest Kinsale storage facility was closed in March 2017, and a decision has been made to close the UK's Rough facility. European storages continue to struggle under low summer-winter spreads, with some of them introducing new, TTF-based pricing formulas to increase filling levels. While questions remain about their commercial viability, some Member States make use of their security of supply value by imposing storage obligations on market players, or holding strategic stocks. The need for enhanced cross-border cooperation to remove regulatory barriers that prevent a more effective storage use seems to remain a valid point of the strategy both with a view of helping storage sites to stay in business, and for security of supply considerations.

Since the LNG and Storage strategy was adopted, a highly debated infrastructure proposal to build a second line of Nord Stream to bypass Ukraine has reached final investment decision according to the latest TYNDP. If built, this would certainly affect gas flows in Europe, and might have an affect on the strategy as well.

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[2] GIIGNL Annual Report 2017

And when it comes to security of supply, the way Europe's gas system coped with the challenges it faced this winter also worth highlighting (2016/17). January weather probably tested the "1 in 20 years" criteria of supply standards, and the European gas system was generally able to keep up with increased demand (although Greece was forced to curb gas-fired power generation). Prices on European gas exchanges have increased, but hikes similar to those observed on electricity markets were avoided.

The first part of the study is a modelling based analises with the aim to test the resilience of the European gas infrastructure to supply and demand shocks. In particular, the assessment of the added value of the new infrastructure proposed by the Strategy is tested and the potential need for upgrade and further new infrastructure is assessed. Special emphasis was given to South East Europe, but results are presented for other regions and for EU 28 as well. Impact of regulatory measures on storage use (storage obligations and strategic storage) are also tested by modelling.

The second part is an international analysis of the LNG markets based on qualitative and quantitative analysis, backed by several interviews.

The third part is a focusing on LNG quality issues from potential and future sources.

Regional scope of the study

The objective of the study is to elaborate on specific actions identified in the LNG and storage strategy in order to support their timely implementation. The assessment covers the internal EU market and global forces that influence it.

The Final Report provides our results for infrastructure assessment based on modelling, focusing on the need for storage and related infrastructure (e.g. reverse flow or interconnection upgrade) development given the projects already identified in the LNG and storage strategy.

The regional focus of the study is South East Europe, with a view on EU Member States, the Energy Community Contracting Parties and on Turkey. Throughout the study results are presented for six different, partly overlapping regions.

- "SEE" covers six EU Member States: Bulgaria, Croatia, Greece, Hungary, Romania, and Slovenia.
- "EnC" covers the Contracting Parties of the Energy Community in 2016: Albania, Bosnia and Herzegovina, FYROM Macedonia, Moldova, Serbia and Ukraine.
- "SEE+" covers the "SEE" EU Member States + the Energy Community Contracting Parties in 2016: Albania, Bosnia and Herzegovina, FYROM Macedonia, Moldova, Serbia and Ukraine.
- "SEE++TR" covers "SEE+" and Turkey
- "NWE" covers North-West Europe: Belgium, Germany, the Netherlands, and the United Kingdom,
- "EU 28" is included for comparison, however the name is slightly misleading as Cyprus is not modelled.

1. Modelling storage, transmission and LNG infrastructure use in Europe

1.1. Methodology

The following steps were taken to test the resilience of European gas infrastructure to supply shocks:

- Update of input data for latest available as of February 2017
- Model development to better represent storage market by (i) possibility to define in EGMM storage obligation by countries (ii) possibility to define strategic storage stocks, (iii) defining withdrawal curves for storage by country
- Agreement with Client and GSE on assumptions to be used for future reference scenarios and for missing data (esp. on storage tariff and long term storage contracts)
- Agreement on security of supply shocks to be modelled (demand and supply scenarios)
- Verifying the model on reference year 2016 without any supply shock
- Building the reference for 2020 and 2025
- Running supply shocks
- Running regulatory scenarios (obligation, strategic storage)
- Sensitivity runs (on demand, supply, key infrastructure) and further modelling is to be defined based on the interim results

The reference scenario uses the best estimates for supply and demand with the infrastructure envisioned by the LNG and storage strategy in place by the target year 2020. Two demand shock scenarios test the resilience of the European market to demand and supply shocks: (i) assuming 30% demand increase in January and (ii) 15 % demand increase in February when storage working gas level is low. Supply scenarios test a one month disruption on key infrastructure providing gas to the EU, focusing on South East Europe. The current storage obligation regime applied in certain countries is part of the supply and demand scenarios and of the reference as well. An additional scenario is dedicated to test the effect of releasing additional strategic stocks that are available in Europe (currently only in DK, ES, IT and HU) in all the demand and supply scenarios. When releasing strategic storage stocks, there is no restriction on trading gas in the market, not even in a supply disruption case, so additional supply can be distributed on a market basis in the modelling. This assumption however would need a regional strategic storage stock agreement, that is not in place today, and shall be discussed in the regulatory chapter.

In 2025 the infrastructure setup is the same, but the demand and supply pattern is changed: less domestic production is available in Europe and demand develops according to the Primes 2016 reference scenario, leading to a slight drop in demand while European import dependency increases.

The results presented in this report show the change in price and infrastructure utilisation during demand and supply shock scenarios, with a special emphasis on the use of storage and LNG, and transmission pipelines connecting the markets.

The modelling tool

EGMM is a competitive, dynamic, multi-market equilibrium model that simulates the operation of the wholesale natural gas market across the whole of Europe. It includes a supply-demand representation of 35 European countries, including gas storage and transportation linkages. Large external markets and LNG exporters are represented exogenously with market prices, long-term supply contracts and physical connections to Europe.

A crucial assumption in the EGMM is that all decision makers are price-takers. Consequently, given the input data, the model calculates the competitive market equilibrium for the modelled countries, where all arbitrage opportunities across time and space are therefore exhausted to the extent that storage facilities, transportation, infrastructure, and contractual conditions permit. As a result, the competitive equilibrium yields an efficient, welfare-maximizing outcome.

The timeframe of the model covers 12 consecutive months, starting in April. Market participants have perfect foresight over this period. Dynamic connections between months are introduced by the operation of gas storages and TOP constraints.

Storage units are found within 23 of the modelled countries. Each local market can contain any number of storage units, however their capacity is aggregated in a virtual capacity for each market. Each storage has an injection, a withdrawal (in GWh/day) and working gas capacity (in TWh) with associated fees. Withdrawal capacity differs month by month reflecting less availability of withdrawal capacity when working gas levels are low.

The use of storages in the model serves a dual purpose. First, in order to arbitrage price differences across months, traders decide in each month how much gas they want to inject into or withdraw from storages. As long as there is available capacity, as well as price differences between months exceeding the sum of storage fees and the foregone interest, the arbitrage opportunity will be present and traders will exploit it. Injections and withdrawals must be such that working gas capacity is never exceeded, intra-year inventory levels never drop below the predefined constraints, and year-end inventory levels are also met.

Second, storage obligations set by the national regulators are also built in the model. In some markets a predefined quantity of gas has to be filled into the storages by the beginning of October. Strategic storage stocks in Denmark, Hungary, Italy and Spain are also taken into account so that they can not be used during normal winter but only in gas crisis situations.

The value of storage consists of two parts in our model: one is the storage operators profit (the storage tariff multiplied by the amount of injected and withdrawn gas minus costs) plus the profit earned by traders on the price difference between summer and winter.

1.2. Storage market particularities and how they are reflected in the modelling

1.2.1. Storage products

EGMM models storage using bundled yearly products. Under the Third Energy Package, SSOs are legally obliged to provide bundled products, which comprise a ratio of injection, space and withdrawal capacity. This ratio varies according to the storage facility in question and is usually determined by the technical characteristics of the facility. As confirmed in the draft CEER report on barriers for gas storage product development[3], all 22 SSOs covered by CEER's questionnaire offer standard bundled products.

[3] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/CEER-ERGEG%20EVENTS/GAS/GST_Workshop_2017/Information/DRAFT%20CEER%20report%20on%20barriers%20for%20gas%20storage%20product%20development.pdf

The yearly product used by EGMM offers one injection and one withdrawal cycle each year; injection takes place between April and September, and withdrawal from October to March. Storage capacity is aggregated in a virtual capacity for each modelled country.

1.2.2. Storage withdrawal curves

Storage withdrawal capacity is highly dependent on the actual working gas level of UGS facilities. We have collected all available information on the 185 unique storage sites reported in GIE's database.[4] (See Annex 1)

We have seen that ENTSOG's data collection based on the data submission of storage operators gives almost the same results as REKK estimation.

Our preference is to use same data set as other modelling studies. For this reason, the country specific withdrawal curves were built into EGMM based on ENTSOG Winter Outlook report.[5]

1.2.3. Storage tariffs (negotiated tariffs)

With storage capacity aggregated as a virtual capacity for each modelled country, average tariffs of the yearly bundled products offered at the various facilities are applied in each market. Published regulated tariffs are, however, maximum values (tariff cap), and market tariffs can be substantially lower. Unfortunately, the lack of storage tariff transparency hinders the use of real infrastructure tariffs as they result from different auctioning processes that are considered to be a business secret. Another problem is that the auction design does not necessarily result in a uniform tariff for all users, with certain storage facilities using a "pay -as -you-bid" scheme. For modelling purposes, a maximum cap would be set on storage tariffs to 1 €/MWh (equal to the modelled winter-summer spread). This is because the function of market-based storage in EGMM is to arbitrage price differences across months, therefore the winter-summer spread can be regarded as a cap on storage services' market value. The tariff, however, cannot go below the marginal cost of operation, assumed in the modelling to be 0.5 €/MWh uniformly for all storages. In fact this is not the case for some storage sites and they struggle to cover their marginal costs, but it is beyond the scope of this study to analyse the individual financial situation of the storage operators.

Transmission tariffs to and from storage are also considered, but those tariffs are the regulated and published tariffs of the TSOs.

1.2.4. Long term booking of storages

A large part of storage capacity is currently booked for long-term (i.e. multiple years) in many countries, with no transparent data on the duration of these contracts, the volumes and price of these services. The assumption used in the study is therefore, that the difference of observed volumes in October 2016 and the modelled storage stocks in October (which consists of market based storage + storage obligation + strategic stocks) is due to long term booking of certain facilities.

[4] GIE Storage map, version December 2016. http://www.gie.eu/download/maps/2016/GSE%20Storage%20Map%20Database%202016%20-%20final.xlsx

[5] Winter Supply Outlook 2016/2017 & Winter Review 2015/2016, Annex A, Figure 8. UGS deliverability curve: In order to capture the influence of UGS inventory level on the withdrawal capacity, ENTSOG has used the deliverability curves made available by GSE. These curves represent a weighted average of the facilities (salt caverns, aquifers or depleted fields) of each area. ENTSOG curve does not consider storages in Turkey and Ukraine.

In addition, some of the storage capacity in facilities owned by Gazprom are also assumed to be long term bookings that are used to provide flexibility to the Russian LTCs.

The Latvian storage uniquely serves the needs of the Baltic countries and also provides flexible winter supply back to Russia. In 2016 its storage access rules were in derogation of EU law. Similarly Serbian TPA access rules and transparency for storage is limited, and the prevailing assumption is that full capacity of these storage facilities are used to provide flexibility to LTCs. Thus the capacity of these storages are also handled as long-term booked capacity and thus removed from the modelled market in the sense that their injection and withdrawal is not a function of the monthly gas price differentials, rather it is used when the Russian LTC price in a given market is favourable enough to call for increased quantities up to the maximum allowed by the flexibility clauses. For the Bergermeer storage 42% of the capacity is reserved to provide flexibility for LTCs with the rest available to the market according to the ownership structure of the facility. For the sake of simplification and due to unavailability of concrete data at the time of data collection, the working assumption for 5 storage sites in Austria and Germany where significant capacity is used to back the flexibility of Russian LTCs is also that the capacity is booked and used under long term agreements, while we are aware that these facilities operate under Third Energy Package rules and TPA[6]. in the model, they are filled to 100% by 1 October each year, and the entire quantity of mobile gas is withdrawn during the winter and so they are taken out of the market in the sense that injection and withdrawal is not a function of the modelled monthly gas price differential.

1.2.5. Storage obligation and strategic storage stocks

Storage obligations and strategic storage are taken into account in countries where such regimes exist. The quantity of gas that must be in storage because of regulatory requirements is calculated from data given as a percentage of total consumption in the study prepared by ref4e/mercados/e-bridge for the Commission entitled "The role of gas storage in internal market and in ensuring security of supply"[7]. Additional to that list more countries were included (Portugal, Turkey and Romania) where the existence of obligations from other sources can be confirmed.

Quantities under storage obligation is counted in storage by October 1 each year, but can be used by traders during the winter.

A different approach is used to model strategic storage stocks. Strategic storage is kept in storages under normal winter conditions, and is released administratively (e.g. a ministerial decree) only when a certain level of security of supply shock is affecting the market. Translated into the model, gas filed under strategic storage can only be used under certain SoS scenarios. Based on feedback from GSE, in Spain and in Denmark storegae obligations are treated as strategic stocks in the model, as opposed to their classification in the “Role of Storage” study.

The preservation of strategic storage stocks is costly, for example in Italy the current price is set at 63 €/MWh if it were to be released. In other countries it is not as clear how much the gas released from strategic stock would cost the consumers (in Hungary it is indexed to TTF prices in the days before the stock is released + a premium). The cost of parking gas for years without use must be somehow recovered, and rather than making assumptions that could vary considerably between countries and their respective

[6] New information was obtained after the input data collection process stating that 50% of Gazprom storages are used for ensuring LTC flexibility and the other 50% is available for TPA storage use. This may only affect modelling results in Serbia, where third party access to storage facility is not yet granted.
[7] https://ec.europa.eu/energy/sites/ener/files/documents/REPORT-Gas%20Storage-20150728.pdf

regulatory regimes, the model determines how much the market is willing to pay for this form of insurance.

Table 1. Storage obligations and strategic stocks as taken into account in EGMM

	Total mandatory storage obligation (TWh)	Total strategic storage (TWh)	Total mandatory storage (% of 2013 consumption)
BG	2.6	0	9
CZ	2.3	0	3
DK	0	2.3	5
ES	0	16.5	5
FR	85	0	18
HU[8]	19.54	8.74	31
IT	0	44.94	7
PL	9.3	0	5
PT	1.67	0	0.04
RO	19.78	0	0.18
TR	48.75	0	0.10

Source: REKK data collection based on "Role of Storage study"

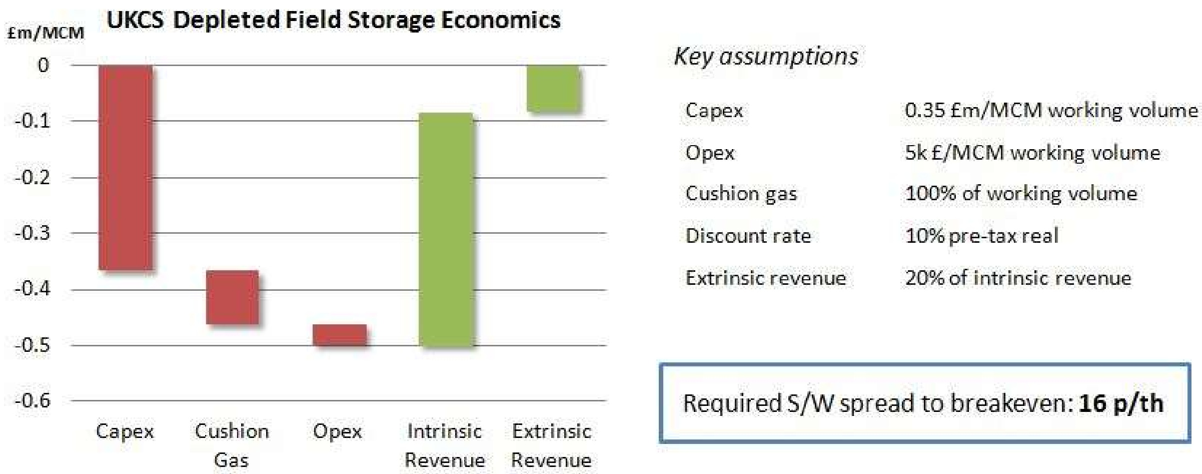
1.2.6. Value of storage

Modelling can explicitly capture the value of storage but is unable to differentiate between extrinsic and intrinsic value. Intrinsic value is monetised in the summer-winter seasonal spreads. Extrinsic value refers to the value of storage which can be gained from the flexibility of storage facility in response to the market developments. Modelling extrinsic value is not only technically but also theoretically challenging: the probabilistic nature of short-term market fluctuation and the expectation of traders active on the market should be factored in to model extrinsic value. It is possible to explicitly estimate extrinsic value using financial models, but this is clearly beyond the scope of our exercise.

Extrinsic value of storage is highly dependant on the type of storage: for less flexible facilities which are mainly utilised for seasonal operations (eg. depleted fields and aquifers), the value of storage is manifested in intrinsic value rather, while the more flexible facilities (salt caverns) tend to recover much higher part of their revenue from extrinsic value. Timera Energy suggested a 10-50% possible range for extrinsic value in total value of storage, depending on the type of facility.

[8] An amendment of 13/2015. (III.31) NFM regulation that comes into force in October 2017 raises the level of the strategic stocks in Hungary to 1200 mcm from the current level of 915 mcm.

Figure 1. Project economics for a generic UKCS depleted field storage facility



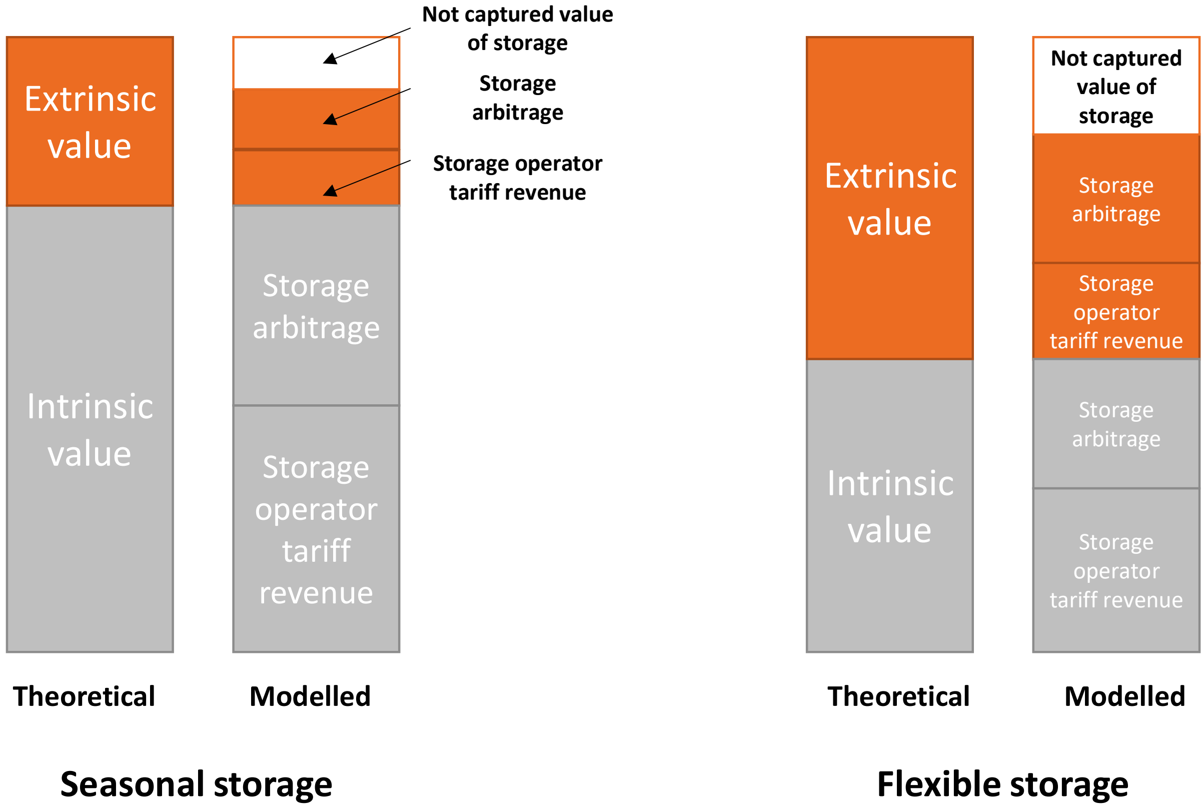
Source: http://www.timera-energy.com/the-challenges-of-investing-in-gas-storage/

More than 85% of working gas capacity is located in less flexible seasonal facilities, the remaining capacities are found in more flexible salt caverns.[9] Moreover, flexible salt cavern facilities are located in NWE, while this study focuses more on SEE. Although extrinsic value is a key for salt cavern facilities, it can be seen at first sight that these account for only a small part of the market, even though they are necessary to balance the short-term demand surges and daily flexibility needs.

Current modelling framework does not differentiate between extrinsic and intrinsic value, but between stakeholders (operators and traders). Extrinsic and intrinsic value may be realised by either the storage operator via tariffs or the trader using the storage via seasonal storage arbitrage.

[9] Based on GSE capacity map 2016 data.

Figure 2. Schematic representation of theoretical approach of extrinsic and intrinsic value of storage



Source: REKK

Modelling a normal scenario, traders possess perfect foresight: this means that reference scenario modelling captures only the intrinsic value of storage. However, when SOS scenarios are modelled, short spikes in demand or failing supply is introduced to the modelling scenario, unforeseen to market participants. This way we are creating a state of the world where the actual market outcomes are not foreseen by traders. Still, this is not the extrinsic value of storage but gives an indication of possible value of storage in SOS situations. It must be stressed that no probabilities are assigned to scenarios, so the results provide a quite high value and do not substitute for stochastic modelling at all.

1.2.7. LNG Storage

The inclusion of LNG storage capacity into the model was considered but ultimately withheld based on the expert opinion of Tractebel. (see Annex 7)

According to their expert understanding the storage capacity is fashioned only to suit the operational requirements of the terminal without any consideration for additional strategic long term supply risk scenarios. LNG storage costs are a significant component of the CAPEX for an import terminal and therefore Project developers will not sanction more storage capacity than they realistically need to maintain their contractual obligations.

Since the LNG storage capacity needed to fulfil peak send out requirements in the winter high season is more than required during the low season there is potentially spare LNG storage capacity available. However, the operators would typically amend the LNG Carrier shipping schedule to allow longer durations between unloading operations rather than hold spare LNG.

In addition to the normal onshore LNG import terminals, demand for FSRU (Floating Storage and Regasification Unit) import terminals is growing because they are much faster to commission and front-end CAPEX is much lower.

FSRUs have limited LNG storage capacity (up to around 170 000 m^3) and are normally associated with lower gas send out and/or fast track solutions when gas is urgently required; they provide no real option for longer term LNG storage.

Peak Shaving LNG facilities are sometimes used to store gas in the form of LNG for seasonal or peak loading, but their use for purely security of supply purposes would be less economically viable than adding to existing import terminals as the Peak Shaving facilities require liquefaction and vaporisation plant operation and maintenance in addition to the storage.

Many European LNG Import terminals are operating well below their throughput capacity and therefore have spare storage capacity that could be considered available forsecurity of supply purposes, but it is fully market dependent. But in the end, additional LNG storage at existing or new terminals is not to be considered economically viable for security of supplypurposes in the event of restricted pipeline gas availability scenarios.

1.3. Modelled LNG market assumptions

- LNG liquefaction capacity is assigned to producer countries (GWh/day).
- LNG shipping cost is distance based from February 2017.
- Spot LNG enters Europe at the market price of the receiving country, if the price is higher then their reservation price (including transmission cost, regasification cost and entry into the transmission system).
- LNG re-gas capacity is aggregated on country level.
- LNG regasification tariff is collected from LNG operator’s website.
- LNG transmission entry tariff is taken into account.
- LNG storages are considered to ensure LNG facilities send out capacity.
- Exempted, unused LNG re-gas capacity is available for the spot market for third party users.
- Overall investment levels into European LNG regas facilities are expected to be low, and in 2020 only the Krk LNG terminal is entering (108 GWh/day) and Greek LNG is extended (81 GWh/day)

1.4. Model validation on 2016

REKK’s EGMM model was updated with the latest available data from 2016, using Eurostat figures on demand and domestic production. Infrastructure capacities for interconnectors between countries are based on ENTSO-G’s latest capacity map, with LNG regasification capacity based on GIIGNL and storage capacity figures from GSE.

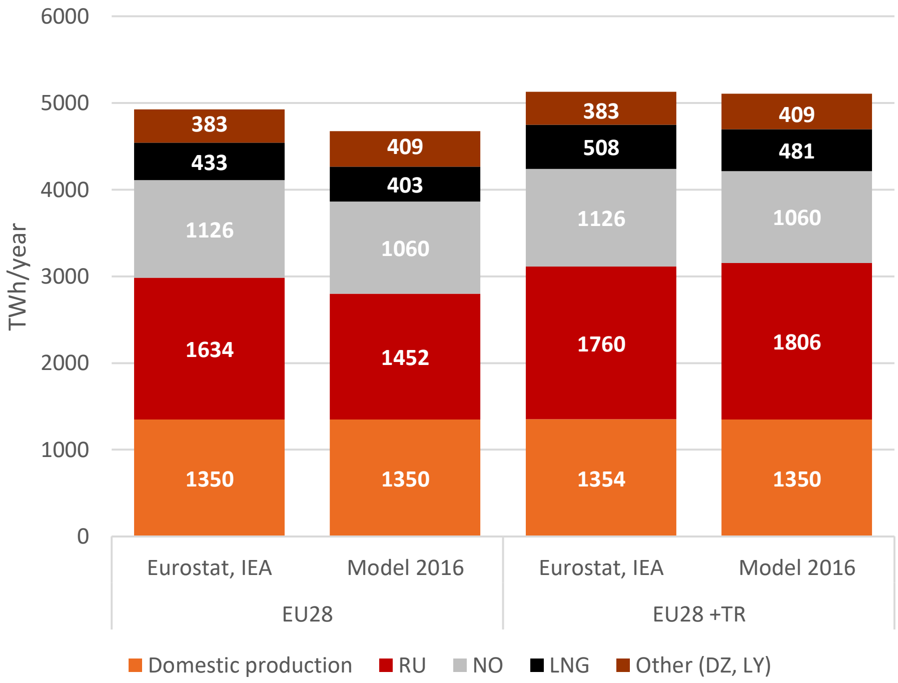
Transmission tariffs are based on published regulated entry-exit tariffs, storage tariffs are capped at 1 €/MWh and regasification tariffs are taken from LNG operators websites. Thank you to CEER and Members of GLE for providing latest tariff figures for requested facilities. In case of missing data for LNG terminals the average of other published tariffs was used.

If different LNG terminals within a country have different tariffs, the average tariff was used for aggregated capacity.[10]

REKK calculated LTC prices in 2016 based on foreign trade statistics published by Eurostat.[11]

To show that modelling accurately recreates actual flows in 2016, a validation trial model was carried out using 2016 data as published by Eurostat[12] and IEA.[13] To illustrate the results, flows across main pipelines and LNG terminals into Europe are aggregated at the EU28 and on EU28+Turkey level. For example, LNG flowing into the EU28 in 2016 was 433 TWh according to IEA Gas Trade Flows to Europe and the EGMM output was 403 TWh, a small different for a modelling exercise.

Figure 3. EGMM validation: modelled vs. actual 2016 supply structure (TWh)

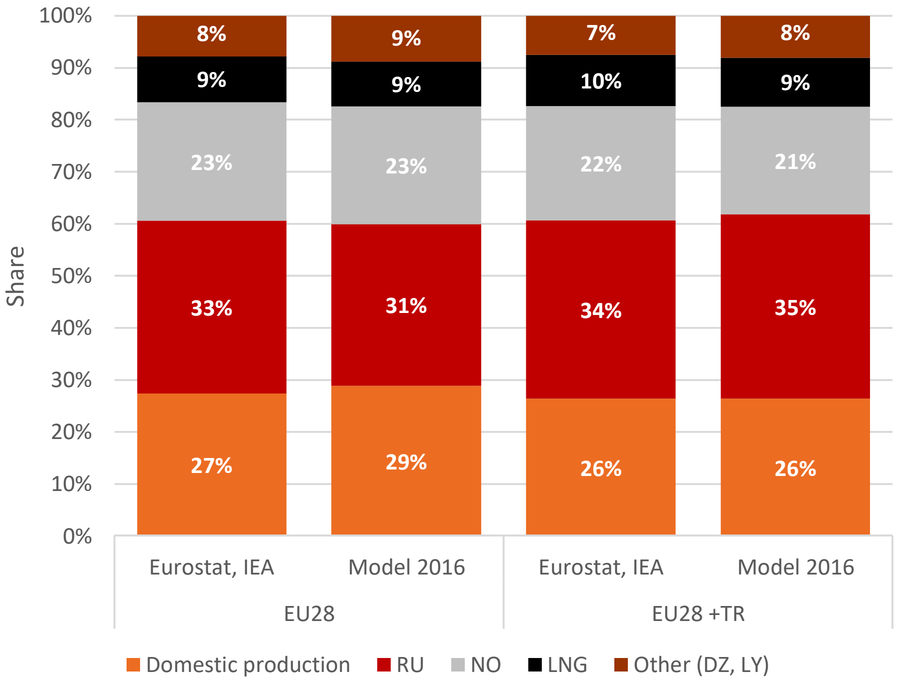


Source: REKK EGMM modelling

More importantly, the share of different supply sources is represented correctly in the model run for 2016.

[10] Modelling has to work with simplification. The approach is the same as how aggregated storage and in case there are more pipelines with different tariffs between two countries aggregated pipeline tariffs are considered in the modell.
[11] EU Trade since 1988 by CN8 (DS-016890)
[12] Supply, transformation and consumption of gas - annual data (nrg_103a)
[13] https://www.iea.org/gtf/

Figure 4. EGMM validation: modelled vs. actual 2016 supply structure (%)

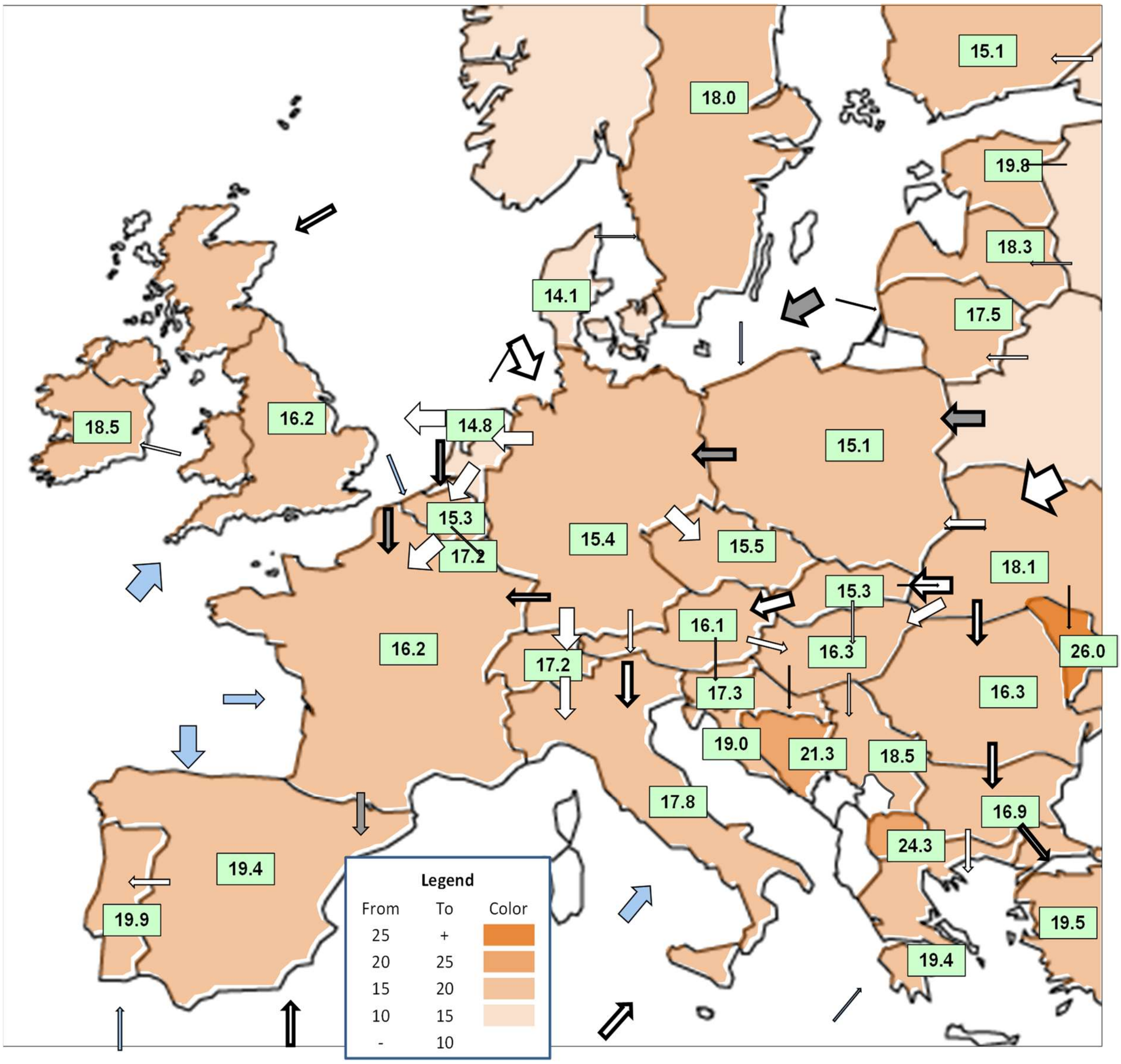


Source: REKK EGMM modelling

The modelled equilibrium results can be tested against actual 2016 wholesale gas prices in Europe for countries where with available transparent wholesale gas prices.

EU Quarterly Reports are used to compare the modelled gas wholesale prices that were used, available for: AT, BE, BG, CZ, DE, DK, EE, ES, FI, FR, GR, HU, IT, LT, LV, NL, PL, RO, SE, SI, SK and UK. The volume-weighted average of the EU Quarterly publication for 2016 was 16.26 €/MWh and 16.38 €/MWh from EGMM, a difference of less than 1%, proving the accuracy of the model.

Figure 5. EGMM modelled yearly average natural gas wholesale price, 2016 (€/MWh)



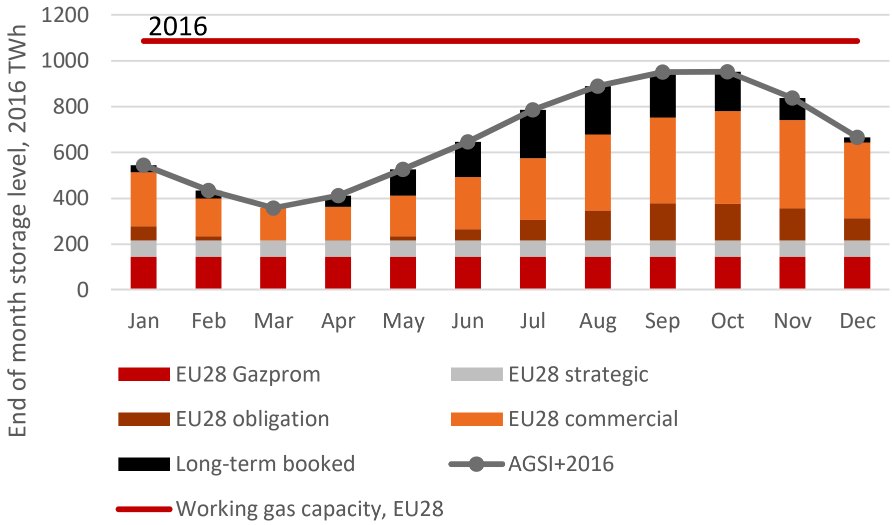
Blue arrows indicate LNG flows, white arrows indicate modelled gas flow on interconnectors, dark blue and green indicate congestion in at least one month

There is hardly any congestion across the European network in the 2016 reference case, and the 100% utilization of the infrastructure in at least one month is indicative of a price difference between two countries above the transmission tariff. Countries connected by white arrows never face a price differential larger than the transmission tariff.

In 2016 no serious bottlenecks could be identified on the European system. The highest yearly utilization is modelled in SEE on the HAG pipeline connecting Austria to Hungary and more broadly SEE to the Western markets (66%); for NWE there is congestion on the IP connecting Netherlands to the UK (50%) and to a lesser extent between France and Spain. Some congestion on the DE-AT interconnector is also an indication that access to the more liquid markets is utilized especially in winter months.

The following figure illustrates EGMM storage utilization levels in 2016. Strategic storage are continuously filled and only released in certain dedicated disruption scenarios - under normal conditions these stocks remain unchanged during the year, so does long-term gas stocks that provide flexibility to LTCs. An obligation to store gas is assumed as a percentage of consumption in countries where such an obligation exists. This obligatory storage stock has to be injected into the storages by 1 October, and can be used by traders throughout the winter. Commercial storage is booked on a market basis by traders (with a perfect foresight), and can be withdrawn when prices are high. While there is a substantial difference between modelled stock outputs and the actual storage stocks reported by AGSI+ of 171 TWh, it is assumed to be attributable to long term booked storage utilization, which due to lack of transparent data is impossible to verify.

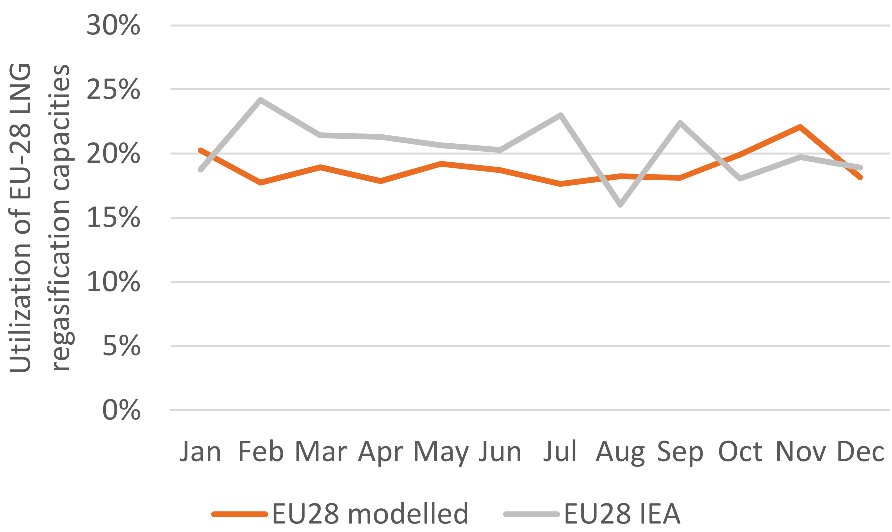
Figure 6. Storage utilisation in the EU-28, 2016



Source: REKK modelling and AGSI+

Average fill up level in October according to the model was 71% (780 TWh) in 2016 for the EU28, while AGSI+ reported 87% (951 TWh) over the same time period. Since REKK modelling is yearly, long-term bookings cannot be estimated endogeneously. Therefore it is assumed that volumes not captured by modelling are long-term bookings or volumes left in storage from the previous year due to a milder than expected winter.

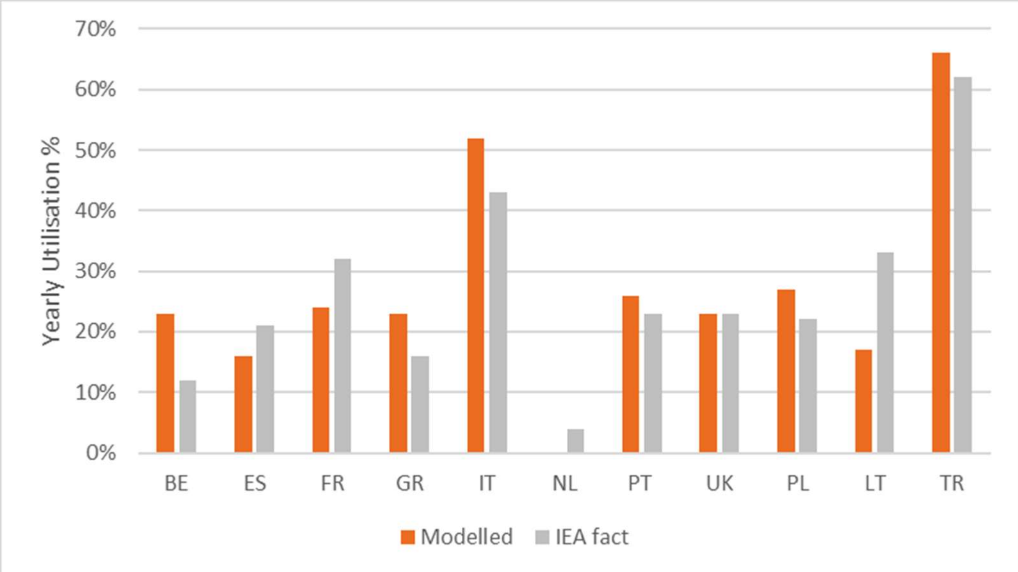
Figure 7. Monthly utilisation of EU-28 LNG regasification terminals, 2016

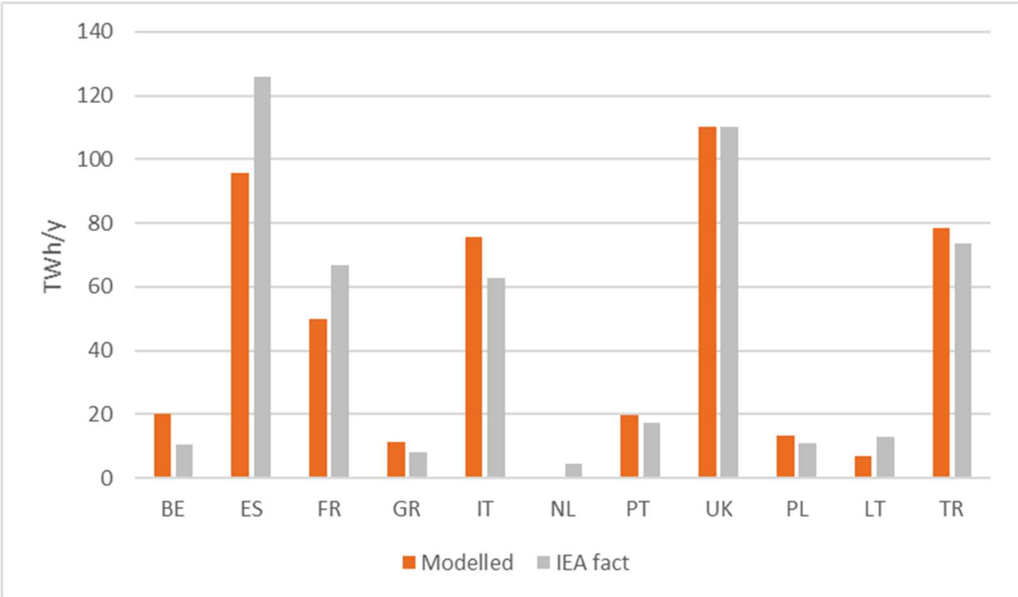


Source: REKK modelling and REKK based on IEA

Average monthly utilization of the LNG regasification capacities in Europe varies between 17 and 20 %. The volume-weighted modelled average annual utilization rate is 23%. Thus, modelled utilisation is represtnative of IEA reported data.

Figure 8. Modelled yearly utilisation of LNG terminals in 2016 (%) and yearly LNG flow by country in 2016 (TWh)





Soure: REKK EGMM modelling, IEA

1.5. Input data and modelling assumptions

The input data and sourcing for EGMM used for the 2020 and 2025 reference years are summarized in Annex 4.

Projected infrastructure development is an important assumption in the reference scenario. The agreed approach is to include existing infrastructure plus those with Final Investment Decision (FID) status according to the TYNDP 2017 and the LNG and Storage strategy (for the list of infrastructure see Annex 4).

TSO tariffs are taken at their actual (2017 January) level on IPs and for entry and exit into storage and LNG regas fees. The published storage fee on the operators' website is 0.5-1 €/MWh based on current summer/winter (S/W) spread, and on marginal cost for storage. The tariff for infrastructure use does not change within modelled years and between seasons. New transmission infrastructure is modelled with a uniform 1.5 €/MWh tariff (average tariff). LTC prices are harmonized with the forecasted oil price based on Primes 2016 reference scenario.

Those LTCs that expire are re-contracted to half of their annual contract quantity, at the same price reference (ie. contractual terms for pricing remain unchanged). In the 2020 reference the Russian-Slovenian, Russian-Greek and the Russian-Ukrainian contracts expire; by 2025 the Russian-Estonian, Russian- Macedonian, Russian-Polish, Russian-Hungarian and the Russian-Dutch contracts expire. Algerian LTCs to Italy and Spain are assumed to be expired by 2020 and 2025 respectively, but only in the sensitivity runs for the Algerian disruption scenario. The reduced level of LTCs allows for more spot trading and competition with new sources, also reflected by the increasing share of hub pricing in the LTC pricing mechanisms. New contracts are added by TAP in the 2020 reference: Azeri-Italian contract 80 TWh/yr, Azeri-Bulgarian contract 10 TWh/yr, and Azeri Greek contract 10 TWh/yr.

When Nord Stream 2 is included in the reference (2020 and 2025) the annual contract quantity is assumed to be the same with a new delivery route and delivery on the border of the receiving country.

Contract path assumptions with Nord Stream 2:

- Nord Stream 2 delivers LTCs to DE, NL, FR, AT, IT, CH, CZ, SK
- UA is transiting Trans Balkan (RO, BG, MK, GR, TR)
- HU (80% through UA, 20% through Nord Stream 2).
- RS (50% UA-HU-RS, 50% UA-RO-BG-RS)
- BiH (same as RS)
- MD (UA 100%)

Again, in the model only the delivery point will be changed for Russian LTCs if necessary but the price of gas paid by the buyer remains the same. Thus the potential difference in the transmission costs, higher or lower, are borne by the Russian party.

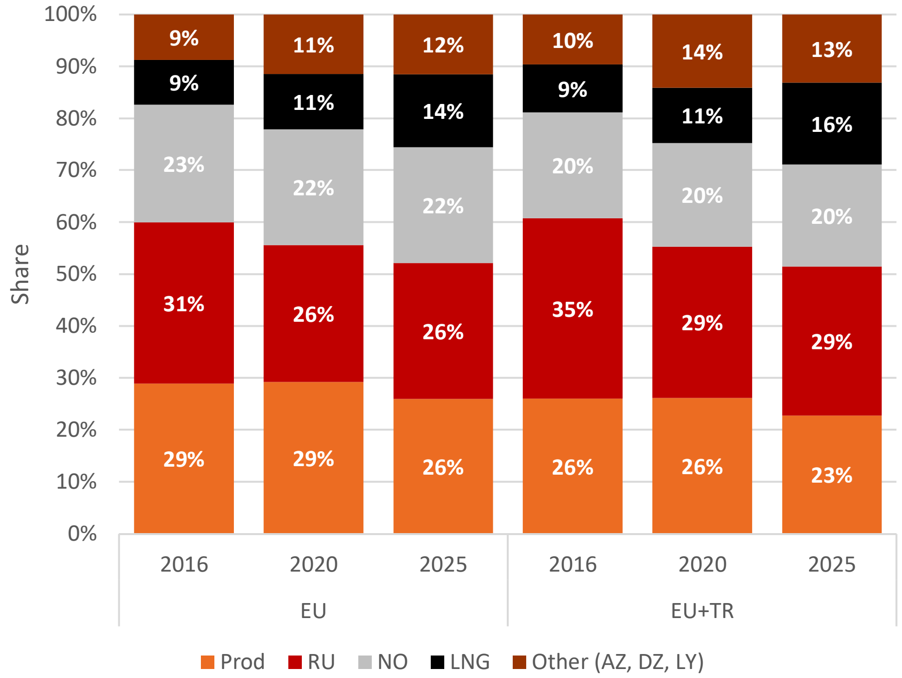
Supply assumptions:

- As indicated by the Primes 2016 reference scenario, domestic production is decreasing
- Norway has a production cap of 1078 TWh /yr (source: TYNDP 2017)
- Algeria is delivering to Europe only through LTCs.
- Russia pursues a market share strategy, meaning it will maintain its market share about at a level from 2016, willing to offer cheaper gas on a spot basis through Nord Stream 2 to undercut increased LNG inflow to Europe. Russia is trading predominately through the existing LTCs, however 10% of Nord Stream (1 and 2) capacity is reserved for spot trade and Russia is selling gas to Germany at a price competitive to Norwegian deliveries.
- LNG supply is available to Europe at large quantities but it is price dependent. The hypothetical maximum LNG flow into Europe according to EMG estimate is 1300 TWh in 2020 and up to 1700 TWh by 2025, but would not be reached in the reference because the price of other sources would be cheaper. In the sensitivities an alternative "High Europen demand and high global LNG supply" scenario tests also this extreme case.

1.6. Reference scenario for 2020 and 2025

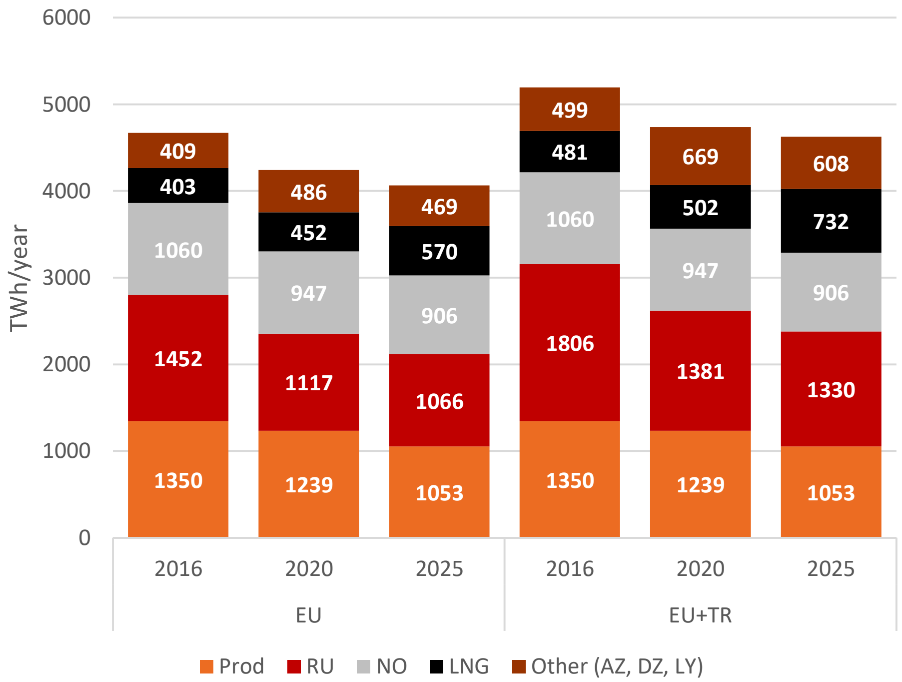
EGMM calculated an equilibrium for the reference years based on the assumptions and input data. Changes in infrastructure, demand and supply will be reflected in trade flows and modelled wholesale gas prices. Before testing the impact of supply and demand shocks for the reference years it is important to view the results under regular conditions.

Figure 9. Supply structure for 2016, 2020 and 2025 reference years (% of total)



Source: REKK modelling

Figure 10. Supply structure for 2016, 2020 and 2025 reference years (TWh/year)

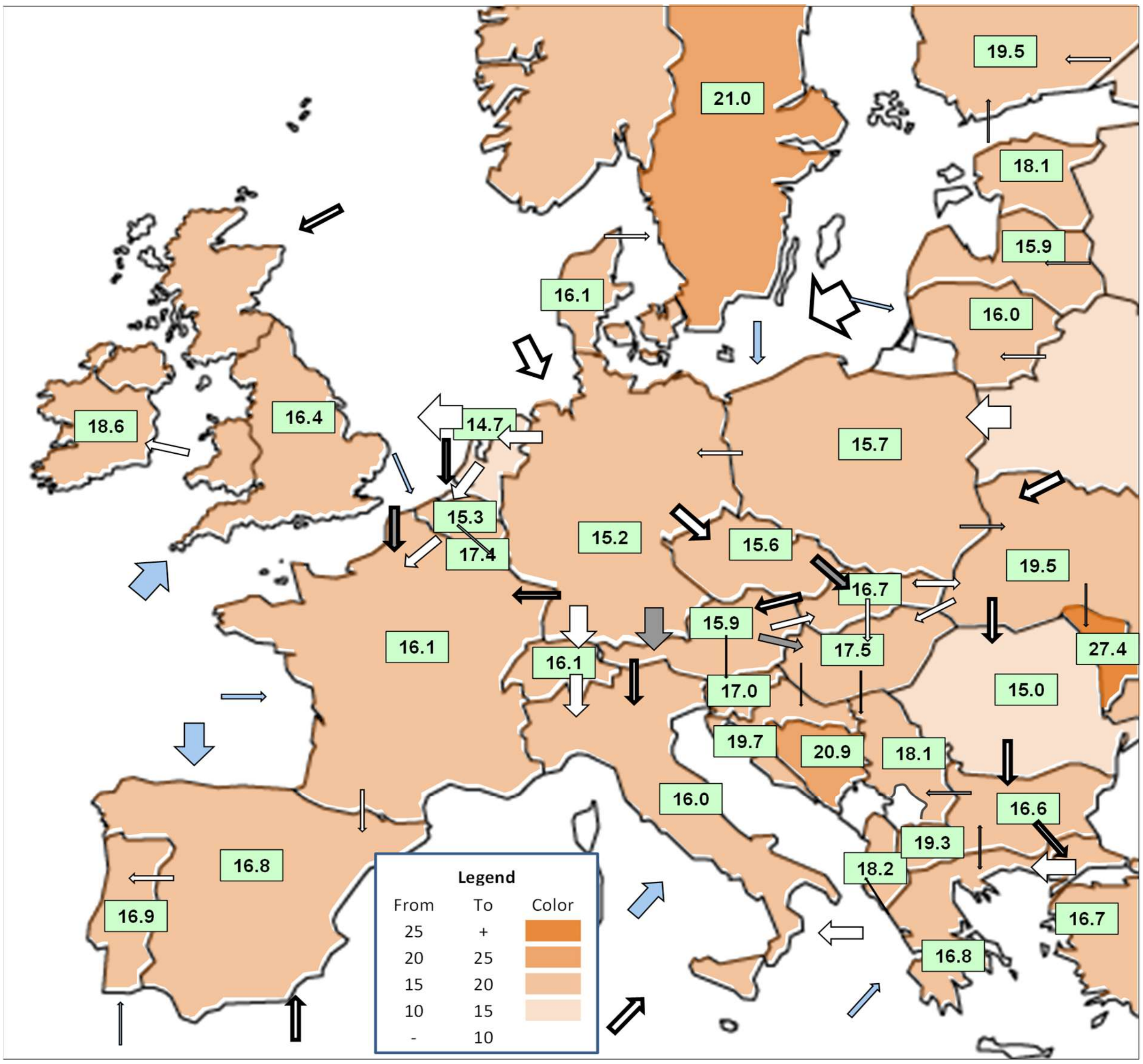


Source: REKK modelling

1.6.1. Prices

Domestic production in Europe leads to increased import dependence, inherently leading to higher prices. At the same time natural gas consumption is decreasing according to Primes 2016 reference forecast, adding downward pressure to prices. Moreover, increased LNG deliveries are creating a strong competition to the incumbent suppliers of the EU-28, who are willing to cut their prices in order to maintain market share. With the restructuring of certain Russian LTC contract routes to Nord Stream 2[14] the flow direction is also changing. The average fall in price across the EU28 compared to the 2016 reference is 2%. The difference between Ukrainian and German market price grows from 2.76 €/MWh to 4.35 €/MWh.

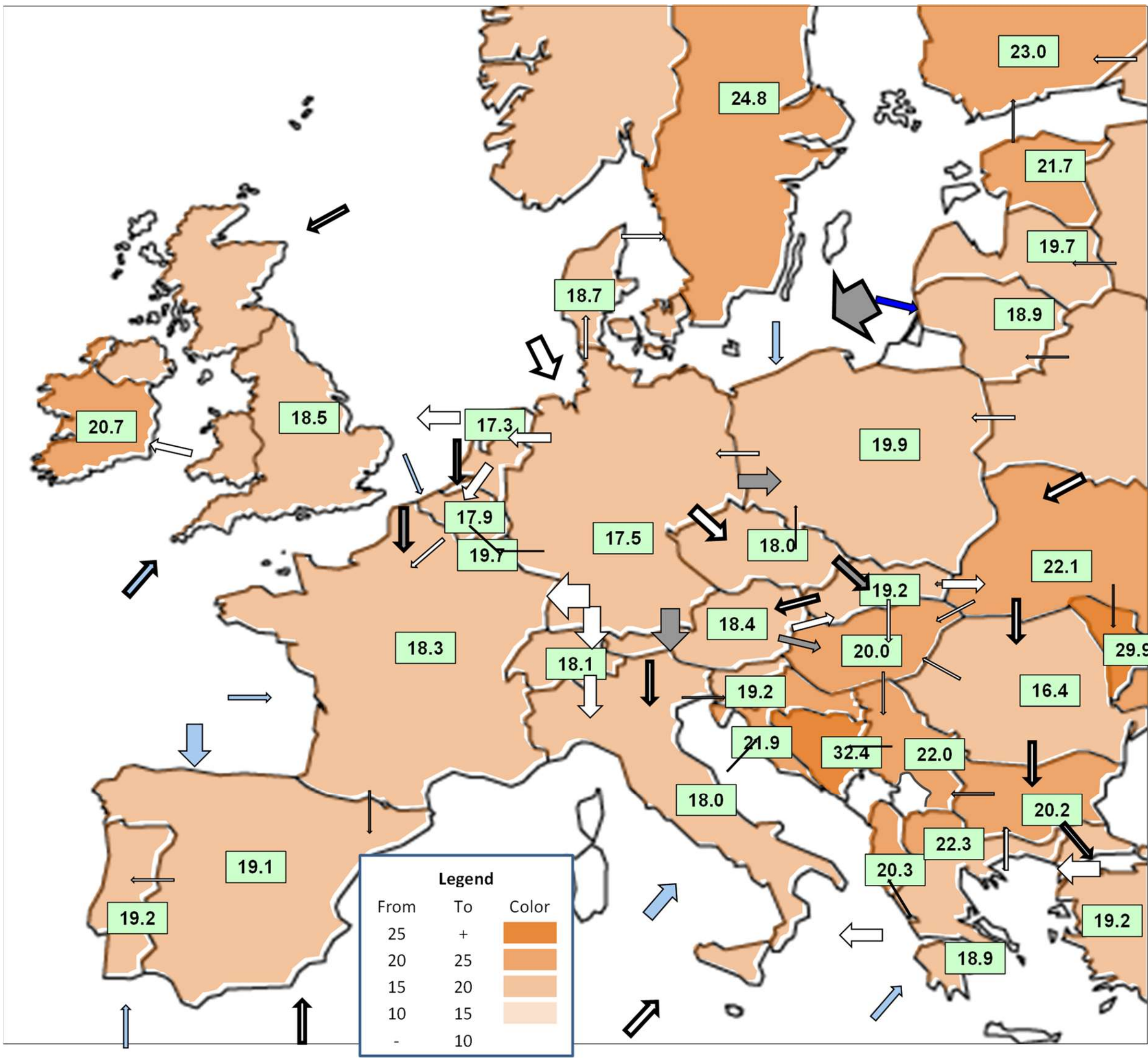
Figure 11. Modelled yearly natural gas wholesale prices in ref 2020 (€/MWh)



Source: REKK EGMM modelling

[14] For a detailed description of contract rerouting assumptions see the modelling assumptions chapter

Figure 12. Modelled yearly natural gas wholesale prices in ref 2025 (€/MWh)

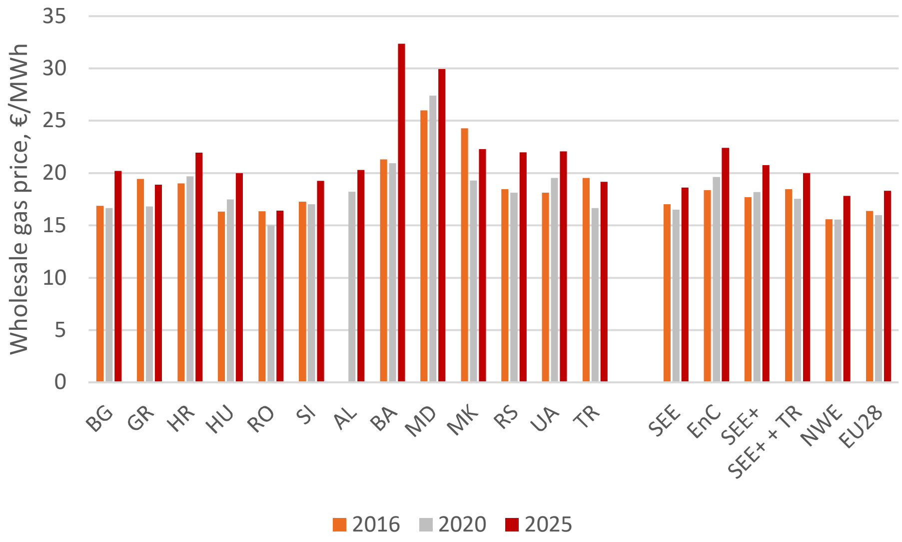


Source: REKK EGMM modelling

As domestic production is further reduced by 2025 and rising oil prices affect some LTCs, the yearly wholesale prices in Europe start to climb in all countries. Due to relatively low consumption levels compared to 2016 and the improved interconnectivity there is only a minor price difference between EU 28 (18.3 €/MWh weighted average in 2025) and in SEE (18.6 €/MWh in 2025). The difference between North West Europe and South East Europe falls from a 1.44 €/MWh difference in 2016 to 0.97 €/MWh in 2020 and 0.79 €/MWh in 2025. The spread between the EU Member States (EU 28) and the Energy Community Contracting Parties grows from 1.99 €/MWh in 2016 to 3.64 €/MWh in 2020 and 4.1 €/MWh in 2025, mainly due to price spikes in Bosnia where demand forecasts are not supported by pipeline investment, and interconnectivity relative to the EU 28 is still low. However, some new infrastructure like TAP, IGB, BG-RS and the Greek-Macedonian IP help these countries to join a lower priced region around the Greek LNG terminal.

For SEE and extended the SEE+ region, the price change is as follows between the reference years:

Figure 13. Modelled wholesale gas prices in 2016, 2020 and 2025, €/MWh



Source: REKK EGMM modelling

The high Bosnian price increase is associated with demand growth in Bosnia which is not supported by additional pipeline capacity build out. The other outlier is Moldova, where the price difference with neighbouring Romania signals a need for better interconnectivity. These decisions will be based on more detailed cost benefit analysis. For the rest of the countries the price differential is due to the tariffs variation, which is a known barrier to trade adressed by numerous studies[15].

1.6.2. Flows on the transmission system and congestions

Table 2. Physically congested interconnectors in 2020

Pipeline	Congested months	Annual utilisation (%)	Flow (TWh/year)
BE-LU	4	74%	10.3
NL-UK	5	72%	130.2
DE-AT	1	74%	98.3
DK-SE	2	60%	19.2
DE-FR	1	65%	137.6
CZ-SK	2	88%	223.5
AT-HU	5	80%	37.8
PL-UA	9	98%	16.3
BG-RS	2	80%	14.9
GR-MK_TAP	2	45%	4.1
DE-AT2	4	46%	24.2
LV-EE2	5	83%	12.8

Source: REKK EGMM modelling

[15] See REKK (2016): The preconditions for market integration compatible gas transmission tariffs in the CESEC region.
https://ec.europa.eu/energy/sites/ener/files/documents/Gas_transmission_tariff_CESEC_final_10_05_18.pdf

Table 3. Physically congested interconnectors in 2025

Pipeline	Congested months	Annual average utilisation (%)	Flow (TWh/year)
BE-LU	1	47%	6.5
DE-LU	3	36%	5.1
DE-AT	3	79%	104.3
IT-SI	7	84%	8.7
DK-SE	1	67%	21.6
DE-PL	8	100%	77.8
DE-FR	1	62%	130.5
CZ-PL	4	51%	5.2
CZ-SK	1	91%	232.0
AT-HU	2	74%	34.8
RS-BA	7	100%	5.2
SK-HU	1	36%	16.9
SK-UA	1	32%	48.3
BG-RS	2	87%	16.2
GR-MK_TAP	3	44%	4.0
DE-AT2	4	42%	22.2
DE-DK	1	51%	19.0
LV-EE2	7	94%	14.4

Source: REKK EGMM modelling

Although demand is not increasing, imports replacing declining porduction creates additional flows leading to more congestion on the intra EU IPs.

Most of the projects defined by the LNG and Storage strategy as 'high priority' proved to be valuable for market integration, even under normal circumstances. The Bulgarian-Serbian interconnector,TAP and the interconnector between Lithuania and Estonia are all utilized and even congested in some month of the reference. The reverse flows both from Slovakia and Poland are utilized to supply gas to Ukraine and get are congested during winter. The reverse flow from Hungary to Ukraine is not part of the model since it is only interruptable capacity and deliveries on that pipeline are not taken into account.

1.6.3. Storage use

Modelling suggests that the overall EU 28 storage level is decreasing in the coming years, with maximum working gas level of 730 TWh in 2020 and 731 TWh in 2025. This is mainly due to decreasing consumption.

Table 4. Modelled maximum yearly storage levels in 2016, 2020 and 2025, TWh

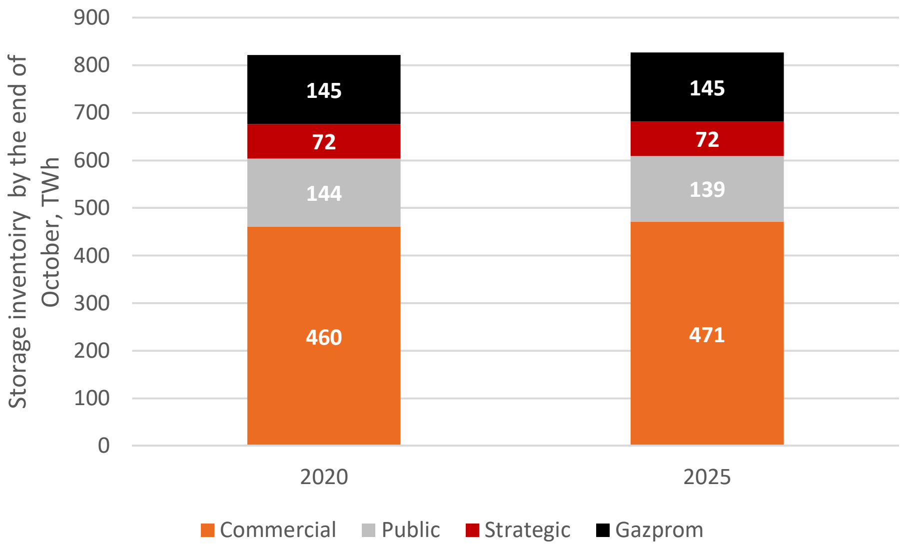
	2016	2020	2025
Modelled (EU28, without long-term bookings)	780	730	731

Source: REKK EGMM modelling

When looking at the structure of the storage stocks, it is important to highlight the increased volume of market based storage at the next chart. The slight increase in commercial storage from 2020 to 2025 may be explained by the modelled development of the winter-summer spread, which is forecasted to rise from 1.3 €/MWh in 2020 to 1.6 €/MWh in 2025, adding to commercial storage use. It is the result of the combined effect of decreasing European production and the expiry of many LTCs, since both narrow seasonal supply flexibility.

Storage obligation is a function of consumption, and with decreasing consumption in the reference, obligations also decrease. At the same time long-term booked stocks and strategic stocks remain constant.

Figure 14. Storage fill level in 2020, 2025 for EU 28



Source: REKK EGMM modelling

Table 5. Storage inventory by the end of October, TWh

	Stock level by 31 Oct, TWh			Stock level by 31 Oct, % of working gas capacity		
	2016	2020	2025	2016	2020	2025
AT	42.1	40.1	26.9	65%	62%	42%
BE	8.2	4.9	8.2	100%	59%	100%
BG	3.4	3.0	5.0	54%	48%	79%
CZ	32.3	21.7	29.9	77%	51%	71%
DE	194.7	178.5	180.6	68%	62%	63%
DK	12.3	10.9	12.3	100%	88%	100%
ES	31.2	29.8	27.8	100%	95%	89%
FR	114.3	87.1	86.3	85%	65%	64%
HR	1.1	1.1	4.6	20%	20%	84%
HU	43.5	45.3	42.0	65%	68%	63%
IE	2.5	2.5	2.5	100%	100%	100%
IT	142.4	156.5	151.8	74%	79%	76%
LV	25.5	25.5	25.5	100%	100%	100%
NL	27.4	25.5	25.5	54%	51%	51%
PL	14.1	12.8	18.6	43%	39%	57%
PT	3.0	2.4	2.0	84%	67%	56%
RO	24.3	24.3	23.2	74%	75%	71%
RS	5.0	5.0	5.0	100%	100%	100%
SE	0.1	0.1	0.1	100%	100%	100%
SK	7.2	7.2	7.2	20%	20%	20%
TR	21.9	45.0	31.1	79%	73%	51%
UA	130.3	142.1	146.8	37%	40%	42%
UK	50.8	50.8	50.8	100%	100%	100%

Source: REKK EGMM modelling

Rate of storage usage is a function of winter gas consumption and the availablility of other means of flexibility, including LNG, structure of supply contracts, domestic storage capacity, proximity to a liquid hub, transmission tariffs to neighboring countries, summer winter spread, etc. These are all built into the model, but one of the most important determinants, the storage tariff is not because the data is not publicly available. Instead the storage tariffs are included at a value close to the modelled summer winter spread. The interaction between these flexibility mechanisms make difficult to generalize country-level results, and this is not the aim of the study. For the most part, countries with direct access to an LNG terminal can more easiliy substitute the flexibility tools than others. It should also be noted that the storage facilities that have closed recently in the UK and Ireland would be utilized 100% according to modelling results, suggesting that their costs were too high for the market. In the model, they charged only 1 €/MWh for their services, by which 100% of their capacity would have been utilized.

Modelling does use short term capacity products currently. Assuming that traders tend to use more and more the short term booking possibilities facilitated by the implementation of the CAM and TAR network codes, in the time horizon modelled here (2020, 2025) the storage service might become more attractive to traders given that pipeline flexibility is more expensive in winter. For this reason the modelled results shall be taken as a conservative and rather pessimistic estimate.

1.6.4. LNG utilization

LNG terminal utilization rates vary widely between 0% and 88%. For EU 28 +TR, it grows from 19 % in 2016 to 23% in 2020 and 34% in 2025. The volume of LNG arriving in Europe (EU28) is 481 TWh in 2016, 502 TWh in 2020 and 732 TWh by 2025 - a modest progression limited by relatively low prices in Europe.

In the refrence scenario, the 2020 global LNG glut and the Russian market share strategy put downward pressure on prices. Only by 2025 do prices recover on the back of rising imports and the expiration of Russian LTCs (assumed to be renewed at 50%).

Table 6. Estimated LNG inflow to Europe in 2020 and 2025 (TWh)

Market	LNG import total modelled		
	2016	2020	2025
BE	20.0	20.0	20.0
IT	75.8	75.8	68.3
NL	0.0	0.0	0.0
PT	19.8	11.5	25.0
UK	110.0	119.3	219.9
HR	0.0	2.1	6.2
LT	6.7	19.1	36.9
ES	95.9	106.2	87.6
MT	0.0	3.6	3.4
GR	11.4	31.1	39.1
TR	78.4	50.6	162.7
FR	50.0	25.0	25.0
PL	13.2	38.2	38.2
Total	**481**	**502**	**732**

Source: REKK EGMM modelling

1.7. Security of supply simulation

1.7.1. Demand shock scenarios

The demand shock scenarios were designed in accordance with 994/2010 EU Regulation using two criteria:[16]

- extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years
- any period of exceptionally high gas demand over 30 days occurring with a statistical probability of once in 20 years;

Winter day natural gas consumption data was only available for five countries (AT, CZ, DE, HU, IT) from December 2012 – Februaty 2017, which allowed for analysis of 5 consecutive winters, one significantly colder than average (2016/2017) and four average temperatures. Since this still does not capture the coldest days in 20 years, a conservative approximation

[16] REGULATION (EU) No 994/2010 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC

was used in setting the consumption levels for these types of demand shocks. (For the detailed data analysis see Annex 2)

The following figure summarizes demand shock scenarios:

- to model the highest average consumption for 7 consecutive days a +30% demand increase is assumed for the month in January.
- to model peak consumption over a one-month period at the end of winter awe +15% demand increase is assumed for the month of February.

1.7.2. Supply shock definitions

The supply shock is simulated by the disruption of deliveries in January on the following pipeline infrastructure:

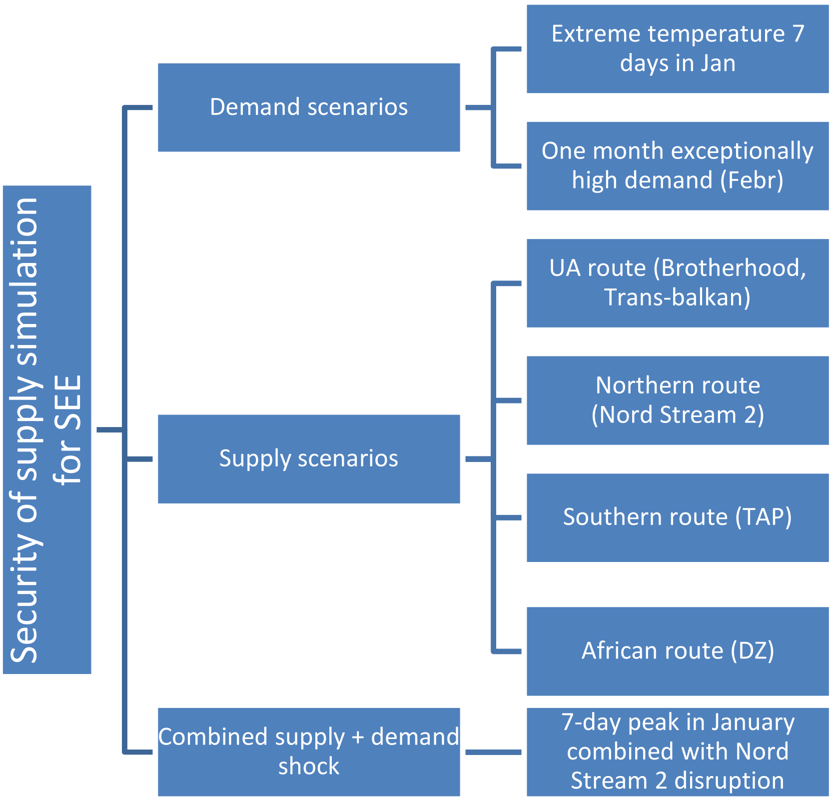
- Ukraine route: full supply cut on the Brotherhood and Trans-Balkan pipelines in January.
- Northern route: full supply cut on Nord Stream in January.
- Southern route: full supply cut on the Trans-Atlantic Pipeline (TAP) delivering Azeri gas through Turkey to the EU
- African route: full supply cut on Algerian supply delivering gas to Italy and to Spain (including transit through Lybia).

Simulated LNG infrastructure supply disruption was tested for GR and HR LNG terminals for the Interim Report, but based on stakeholder feedback this 'facility-based scenario' is not inconsequential compared to main pipeline sources, so an Algerian pipeline supply disruption was tested instead.

1.7.3. Combined demand and supply shock scenario

Disruption along key infrastructure might occur in very cold winter days. To test the resilience of the European gas infrastructure against such an extreme scenario, the maximum demand shock was combined with the maximum import infrastructure disruption scenario for the "7-day peak" scenario: a 30% increased in demand in January was and a 100% cut of supplies on Nord Stream 2. Additionally, the Ukrainian route is limited to delivery of Russian gas only to the Balkans.

Figure 15. Summary of security of supply simulation scenarios for Task1 and 2.



1.8. Results of modelling

1.8.1. How to read the results

The modelling was applied to the 2020 and 2025 reference years, testing two demand scenarios (7-day peak in January and 1-month peak in February) and four supply scenarios (cutting transit via UA, Nord Stream 2, TAP, Algerian supply), plus one combined demand and supply shock during a January peak. The price effect of the disruption scenario in January (compared to the reference January price) was recorded for each of the countries within the SEE and SEE+TR region while the regional volume weighted average price change in SoS is calculated for different regions to allow for comparison between them: NWE, EnC, SEE, SEE+, SEE+TR and EU 28. For illustration purposes we always use a map for 2020 and 2025, where colouring indicates the modelled price effect of a shock on countries affected.

During a shock, flexibility mechanisms like increased storage withdrawal, LNG offtake, increased pipeline flow or domestic production and demand reduction compete to offset the missing volumes, and the results will be illustrated in a chart.

European gas network resilience will be measured by the utilization of infrastructure during the disruptions.

- For LNG, the send-out capacity utilization is used as a proxy. This will be presented for all LNG receiving countries in January.
- For storage, the utilization of withdrawal capacity is included for each country. Those above 80% are considered fully utilized based on the withdrawal curve analysis.
- For transmission interconnection points (IPs), the monthly utilization figure for January is used. IPs with a 100% utilization are listed.

1.8.2. *Demand scenarios results*

The demand scenarios are tested with current storage regulation projected to 2020 and 2025 as described in Chapter 0.

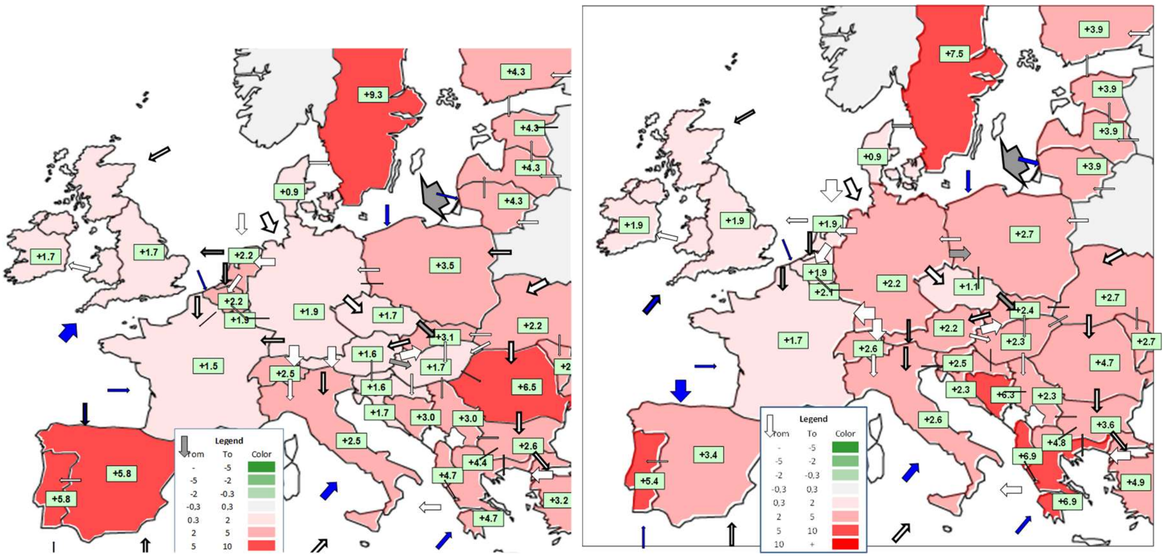
Two demand scenarios are tested

- the highest average consumption for 7 consecutive days ("7-day peak"): +30% increase in demand for all of January.
- a one-month-long consumption peak at the end of winter scenario ("one month peak"): +15% demand increase in February.

In the „one month peak", demand is expected to rise at the end of the heating season leaving storage facilities close to empty. Still the price effect of this scenario is smaller than that of the „7-day peak".

It is also important to note that LNG industry representatives interviewed as part of this study said LNG facilities would not be responsive on short notice for a 7-day demand peak scenario. For this reason additional LNG spot cargoes to Europe are constrained. LNG storage is not expected to be able to handle a 7-day peak demand scenario, nevertheless, in some cases could easily mitigate shorter time demand fluctuations. Morevover, the ability of the terminals to become adapted to sudden demand fluctuations depends on the ratio (storage/regasification capacity) and the stock level in the LNG tanks.(LNG storage capacities are listed in Annex 7. LNG Storage Capacity Definition.)

Figure 16. Price increase in a 7-day peak in January (€/MWh) on the left 2020, on the right 2025*

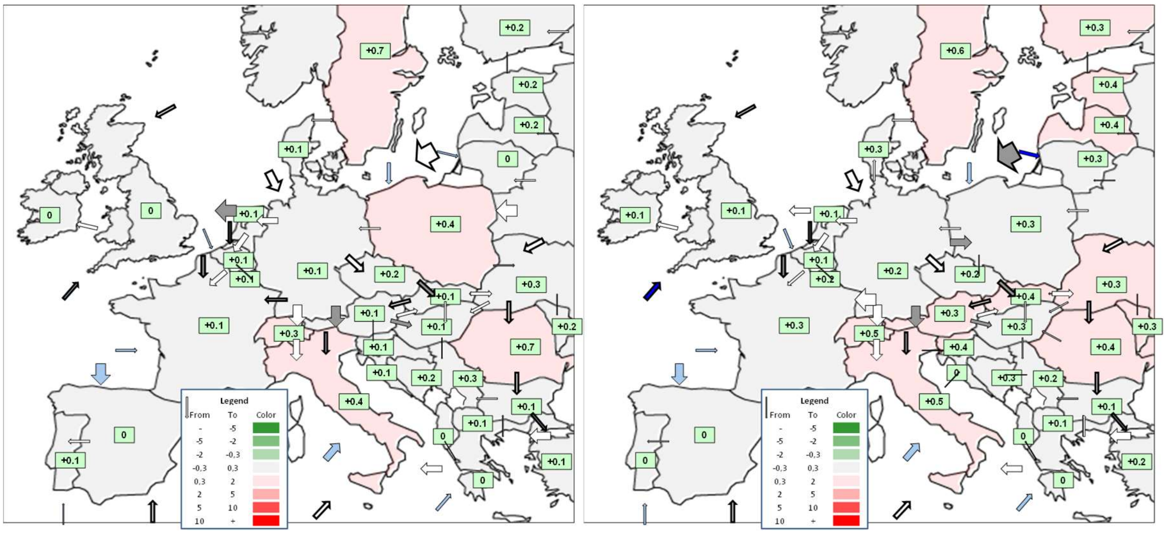


** compared to the reference case monthly January prices*

Source: REKK EGMM modelling

The sharp price increase in Spain, for example, is due to the fact that LNG can not be a source of flexibility on a short notice. However, when there is more time to react, as in the case of the February demand shock scenario, price effects is Spain are much milder with the addition of LNG flexibility.

Figure 17. Price increase in a one month peak in February (€/MWh) on the left 2020, on the right 2025*



** compared to the reference case monthly February prices*

Source: REKK EGMM modelling

In the reference case, SEE and NWE reach the same regional price level (considering volume-weighted average prices) and SEE+ and Energy Community contracting Parties are ~2€/MWh more expensive. An SoS demand scenario in January impacts the SEE region the most, with the price difference of the reference case (less than 0.5 €/MWh) rising to 2-2.5 €/MWh. For the 7-day peak scenario, Romania suffers the highest price increase (although Romanian started with lower than average in the reference because of domestic gas production).

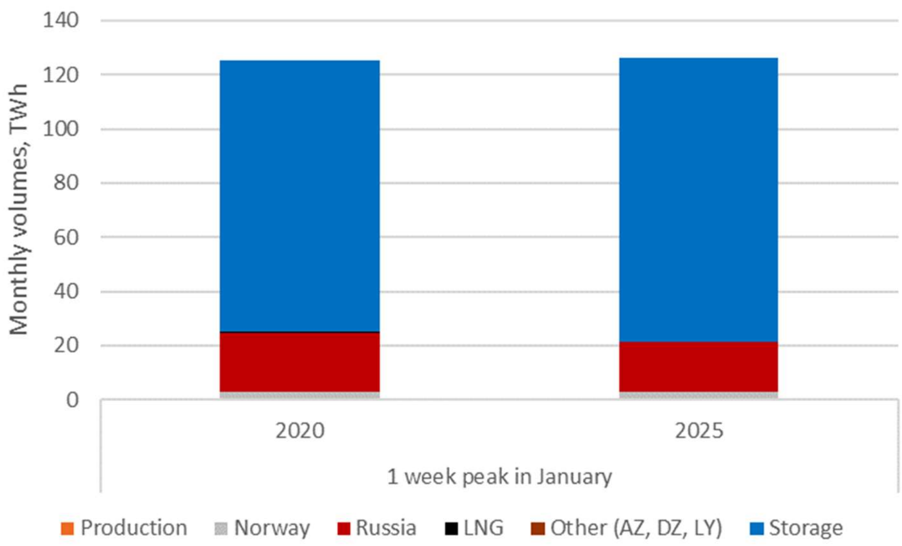
Table 7. Price increase in the demand shock scenarios in 2020 and 2025 compared to reference (€/MWh)

	2020				2025			
	REF JAN	7 day peak in January	REF FEB	1 month peak in February	REF JAN	7 day peak in January	REF FEB	1 month peak in February
AL	18.95	4.69	18.94	0.09	20.97	6.93	20.98	0.00
BA	21.20	3.02	21.18	1.91	37.66	6.31	37.56	3.58
BG	16.85	2.62	16.84	0.65	20.68	3.62	20.70	0.28
GR	17.45	4.69	17.44	0.09	19.47	6.93	19.48	0.00
HR	20.20	1.71	20.21	0.57	22.71	2.32	22.73	0.01
HU	17.49	1.71	17.50	0.57	20.00	2.32	20.01	1.12
MD	27.62	2.22	27.64	1.08	30.18	2.67	30.20	1.43
MK	19.78	4.36	19.77	0.65	23.61	4.79	23.62	0.28
RO	14.03	6.49	14.62	4.38	16.38	4.66	16.40	2.18
RS	18.37	3.02	18.35	1.91	22.18	2.32	22.20	1.12
SI	17.61	1.58	17.63	0.47	19.88	2.46	19.90	2.15
TR	16.93	3.22	16.94	0.65	19.55	4.85	19.56	1.24
UA	19.73	2.22	19.75	1.08	22.29	2.67	22.30	1.43
SEE	**16.32**	**3.81**	**16.55**	**1.91**	**18.84**	**3.78**	**18.86**	**1.26**
EnC	**19.82**	**2.31**	**19.83**	**1.12**	**22.59**	**2.73**	**22.64**	**1.41**
SEE+	**18.31**	**2.94**	**18.37**	**1.47**	**21.08**	**3.14**	**21.05**	**1.34**
SEE+TR	**17.80**	**3.04**	**17.83**	**1.15**	**20.43**	**3.87**	**20.41**	**1.30**
NWE	**16.28**	**1.91**	**16.31**	**0.51**	**18.56**	**2.01**	**18.59**	**0.97**
EU28	**16.57**	**2.45**	**16.58**	**0.84**	**18.97**	**2.35**	**18.94**	**1.23**

Source: REKK EGMM modelling

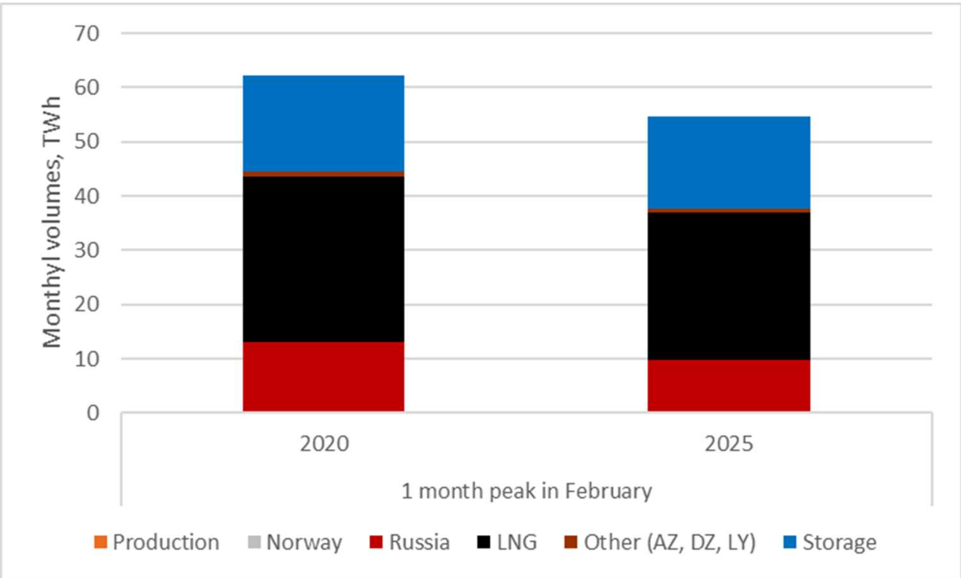
Without LNG flexibility in a 7-day demand shock scenario, storage provides most of the flexibility along with some increase in Russian deliveries. In this scenario, the role of storage is expected to grow from 2020 to 2025 as a result of declining European production and the expiry of Russian LTCs, which leads to diminishing LTC flexibility. Therefore, it is even more important in regions like SEE, - facing higher-than average price hikes in a demand shock scenario - to optimize storage use with enhanced cross-border cooperation as laid down in the Commission strategy.

Figure 18. Flexibility source in January "7-day peak"



Source: REKK EGMM modelling

Figure 19. Flexibility source in February "one month peak"



Source: REKK EGMM modelling

LNG regas terminals can provide additional flexibility under the „one-month scenario", and in 2020 LNG imports would more than double compared to the reference scenario (from 35 TWh to 73 TWh). The LNG terminal in Lithuania is 100% utilized, while the UK terminals are working close to their technical maximum capacity and there are additional spot LNG imports to Spanish, Greek, Croatian, Portugese and Turkish terminals as well. In 2025, it is a similar story.

Table 8. LNG utilization in the demand shock scenarios (TWh)

Terminal	2020				2025			
	REF JAN	7 day peak in January	REF FEB	1 month peak in February	REF JAN	7 day peak in January	REF FEB	1 month peak in February
BE	1.7	1.7	1.5	1.5	1.7	1.7	1.5	6.7
IT	6.4	6.4	5.8	5.8	5.8	5.8	5.2	5.2
NL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PT	0.8	0.8	0.7	1.0	1.8	1.8	2.0	2.5
UK	9.3	9.3	8.4	32.5	22.0	22.0	22.4	36.8
HR	0.0	0.0	0.0	0.7	0.0	0.0	0.0	1.2
LT	1.8	1.8	0.5	1.5	3.6	3.6	3.2	3.2
ES	11.9	12.3	10.4	14.2	9.8	9.8	8.5	11.9
MT	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
GR	3.7	3.6	3.2	3.8	3.2	3.2	2.8	4.3
TR	0.0	0.0	0.0	7.3	14.5	14.5	17.5	17.5
FR	2.1	2.1	1.9	1.9	2.1	2.1	1.9	1.9
PL	3.2	3.2	2.9	2.9	3.2	3.2	2.9	4.1
SEE	**2.7**	**2.7**	**2.4**	**3.0**	**2.4**	**2.4**	**2.1**	**3.5**
EnC	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
SEE+	**2.7**	**2.7**	**2.4**	**3.0**	**2.4**	**2.4**	**2.1**	**3.5**
SEE+TR	**1.1**	**1.1**	**1.0**	**5.6**	**9.6**	**9.6**	**11.3**	**11.8**
NWE	**5.9**	**5.9**	**5.3**	**19.5**	**13.3**	**13.3**	**13.5**	**23.2**
EU28	**6.4**	**6.5**	**5.7**	**11.4**	**8.2**	**8.2**	**7.8**	**12.0**

Source: REKK EGMM modelling

In 7 day peak in January shock, LNG volumes are constrained

Table 9. LNG utilization in the demand shock scenarios (%)

Terminal	2020				2025			
	REF JAN	7 day peak in January	REF FEB	1 month peak in February	REF JAN	7 day peak in January	REF FEB	1 month peak in February
BE	11%	11%	11%	11%	11%	11%	11%	46%
IT	36%	36%	36%	36%	32%	32%	32%	32%
NL	0%	0%	0%	0%	0%	0%	0%	0%
PT	11%	11%	11%	15%	26%	26%	32%	39%
UK	23%	23%	23%	88%	54%	54%	61%	100%
HR	0%	0%	0%	23%	0%	0%	0%	39%
LT	50%	50%	17%	47%	100%	100%	100%	100%
ES	20%	20%	20%	27%	17%	17%	16%	23%
MT	41%	41%	45%	52%	38%	38%	42%	49%
GR	37%	37%	35%	42%	33%	33%	32%	48%
TR	0%	0%	0%	42%	75%	75%	100%	100%
FR	6%	6%	6%	6%	6%	6%	6%	6%
PL	52%	52%	52%	52%	52%	52%	52%	73%
SEE	**28%**	**28%**	**27%**	**37%**	**25%**	**25%**	**24%**	**46%**
EnC	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
SEE+	**28%**	**28%**	**27%**	**37%**	**25%**	**25%**	**24%**	**46%**
SEE+TR	**11%**	**11%**	**11%**	**40%**	**54%**	**54%**	**69%**	**78%**
NWE	**16%**	**16%**	**16%**	**54%**	**34%**	**34%**	**38%**	**69%**
EU28	**19%**	**19%**	**18%**	**34%**	**25%**	**25%**	**26%**	**40%**

Source: REKK EGMM modelling

The increasing role of storage is confirmed by a comparison of January withdrawals in a demand shock scenario in 2020 and 2025. In EU28, modelled withdrawals only rise by 5

TWh, or little more than 1%, in the extended SEE region, however, the rise of 3 TWh is equivalent to almost 9%.

Table 9. Withdrawal (TWh) and utilization of available withdrawal capacities (%) in the "7-day peak"

	2020				2025			
	REF JAN		7 day peak in January		REF JAN		7 day peak in January	
Storage	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**
AT	8.9	40%	16.1	72%	7.3	33%	8.7	39%
BE	2.1	39%	4.9	93%	1.8	34%	5.3	100%
BG	0.5	34%	1.0	72%	1.4	100%	1.4	100%
CZ	2.9	16%	6.0	33%	5.0	27%	8.1	44%
DE	13.7	8%	18.2	10%	8.8	5%	20.2	11%
DK	2.3	50%	3.4	73%	3.5	74%	4.5	95%
ES	2.7	100%	2.7	100%	2.7	100%	2.7	100%
FR	20.2	28%	39.8	56%	17.3	24%	40.6	57%
HR	0.0	0%	0.0	0%	1.3	84%	1.6	100%
HU	9.4	45%	10.9	52%	7.7	37%	10.3	49%
IE	0.7	100%	0.7	100%	0.7	100%	0.7	100%
IT	25.9	38%	49.2	72%	25.0	37%	45.8	67%
LV*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
NL	0.0	0%	6.2	37%	0.0	0%	0.3	2%
PL	1.2	7%	5.2	33%	5.6	36%	12.2	77%
PT	0.3	12%	0.8	38%	0.5	21%	0.9	38%
RO	6.0	81%	7.3	98%	5.4	74%	6.3	85%
RS*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
SE	0.1	43%	0.1	43%	0.1	43%	0.1	43%
SK	0.0	0%	0.1	1%	0.0	0%	0.0	0%
TR	11.4	40%	22.3	78%	8.0	28%	17.4	61%
UA	20.6	40%	33.5	65%	22.1	43%	32.3	62%
UK	15.5	30%	39.9	78%	18.5	36%	41.8	81%
SEE	15.9	50%	19.3	61%	16.0	51%	19.6	62%
EnC	20.6	40%	33.5	65%	22.1	43%	32.3	62%
SEE+	36.5	44%	52.8	63%	38.0	46%	51.9	62%
SEE+TR	47.9	43%	75.1	67%	46.0	41%	69.3	62%
NWE	31.3	12%	69.1	27%	29.1	11%	67.5	27%
EU28	112.4	22%	212.6	42%	112.8	22%	211.3	42%

Source: REKK EGMM modelling

**Long term booked storage is not modelled to avoid double counting of flexibility*

In the one month demand shock scenario, flexibility provided by storages is called upon to a smaller extent, as there is more time to adjust by means of increased LNG-imports. In the EU28, we model only 109 TWh withdrawal in February 2020, which is almost 50% less than January withdrawals in the 7-day peak scenario. In 2025, the difference is even bigger (52%). The heavier reliance of the extended SEE region on storage is obvious in this scenario, too: February witdrawals are only less than 40% below January levels, and the gap does not widen from 2020 to 2025.

Table 10. Withdrawal (TWh) and utilization of available withdrawal capacities (%) in the one month peak scenario

	2020				2025			
	REF FEB		1 month peak in February		REF FEB		1 month peak in February	
Storage	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**
AT	6.9	31%	10.9	49%	1.4	6%	1.7	8%
BE	1.2	22%	1.2	22%	4.7	90%	4.7	90%
BG	0.4	29%	0.4	29%	0.4	29%	0.4	29%
CZ	2.3	12%	3.0	16%	4.2	23%	5.5	30%
DE	4.4	2%	4.4	2%	5.0	3%	5.0	3%
DK	2.1	44%	2.6	54%	1.9	39%	2.3	49%
ES	2.4	88%	2.4	88%	2.4	88%	2.4	88%
FR	19.5	27%	26.8	38%	16.7	24%	23.5	33%
HR	0.0	0%	0.0	0%	0.7	45%	0.7	45%
HU	7.9	38%	5.9	28%	8.0	38%	8.7	41%
IE	0.5	78%	0.5	78%	0.5	78%	0.5	78%
IT	23.9	35%	30.6	45%	21.6	32%	27.5	41%
LV*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
NL	0.0	0%	0.0	0%	0.0	0%	0.0	0%
PL	0.0	0%	0.0	0%	3.0	19%	4.5	29%
PT	0.2	7%	0.3	12%	0.0	0%	0.0	0%
RO	5.3	71%	5.9	79%	4.8	64%	4.8	64%
RS*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
SE	0.0	0%	0.0	0%	0.0	0%	0.0	0%
SK	0.0	0%	0.0	0%	0.0	0%	0.0	0%
TR	8.2	29%	8.3	29%	1.0	3%	8.1	28%
UA	14.4	28%	20.6	40%	16.0	31%	20.2	39%
UK	14.3	28%	14.3	28%	13.1	26%	13.1	26%
SEE	13.6	43%	12.2	39%	13.9	44%	14.6	46%
EnC	14.4	28%	20.6	40%	16.0	31%	20.2	39%
SEE+	28.0	34%	32.8	39%	29.9	36%	34.8	42%
SEE+TR	36.3	32%	41.1	37%	30.8	28%	43.0	38%
NWE	19.9	8%	19.9	8%	22.8	9%	22.8	9%
EU28	91.3	18%	109.0	22%	88.4	18%	105.4	21%

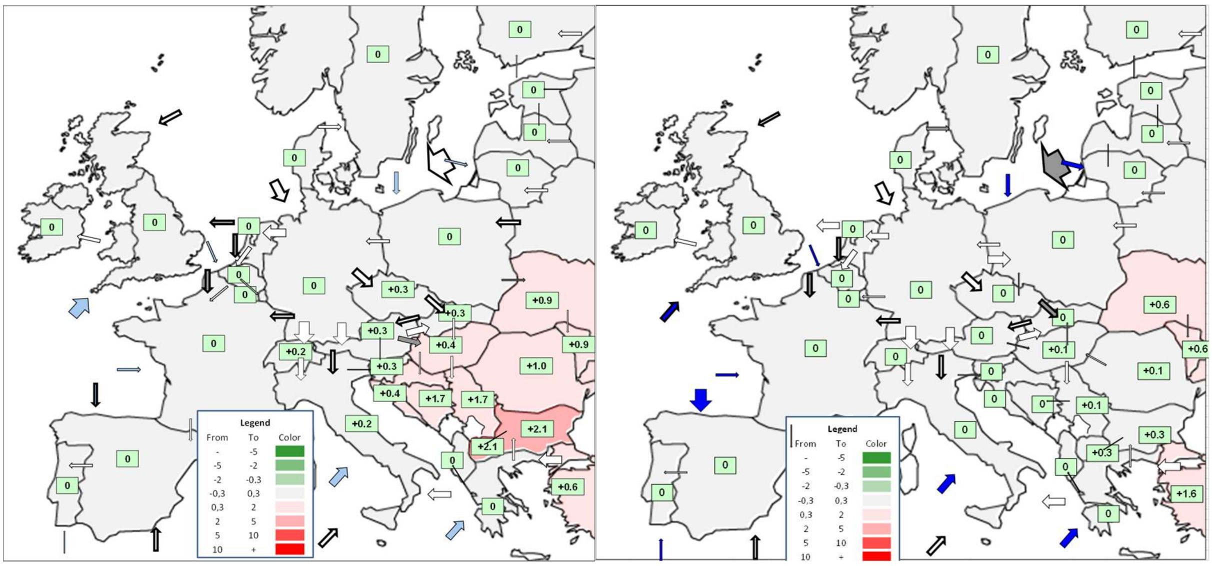
** Long term booked storage is not modelled to avoid double counting of flexibility*

1.8.3. Supply scenario results

1.8.3.1. Ukrainian route disruption

In the Ukrainian supply disruption scenario a full supply cut on the Brotherhood and Trans-Balkan pipelines in January occures.

Figure 20. January price change due to cut on the Ukrainian route on the left 2020, on the right 2025 (€/MWh)



Source: REKK EGMM modelling

A disruption on the Ukrainian route does not result in major price change in SEE or the EU 28 but BG and the EnC Contracting Parties are more affected the majority of Russian LTCs supplied by Nord Stream 2 in 2020.With the recontracting the risk of Russian supply disruption is shifted from South East Europe to Central and North West Europe and to the cut of Nord Stream 2.

The weighted price change for the SEE region is not far above the EU28 average price, but Energy Community contracting parties are 3 €/MWh above the EU28. This is not a security of supply related issue, however, as the same price difference was found under normal reference scenarios. The same trend holds for 2025. In 2020 Turkey is slightly better off than the Energy Community countries but in 2025 the disruption of the Ukrainian route would increase Turkish prices closer to the SEE+ level[17].

[17] Turkish Stream is not assumed in this scenario. Obviously Turkish Stream would mitigate the Ukrainian cut effect.

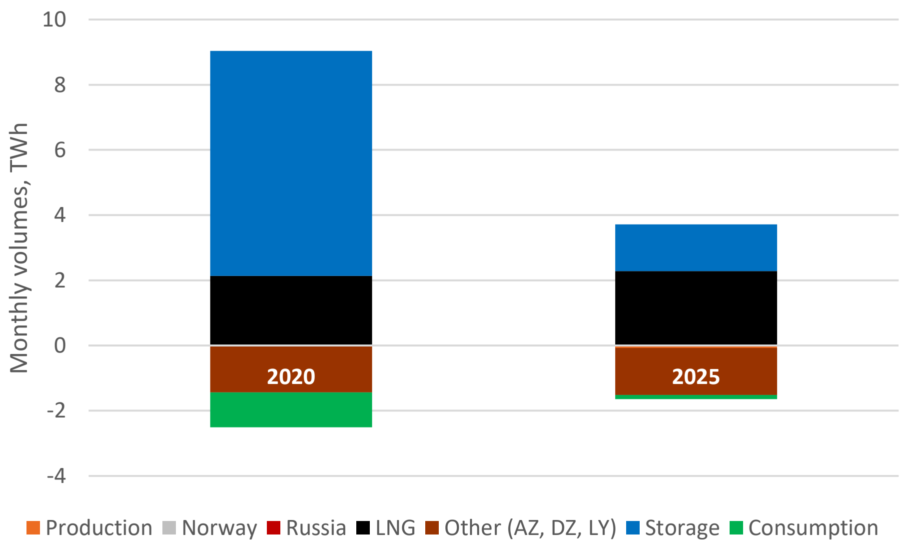
Table 11. January prices in a Ukrainian route disruption (€/MWh)

	2020		2025	
	REF JAN	UA cut price effect	REF JAN	UA cut price effect
AL	18.95	0.00	20.97	0.01
BA	21.20	1.74	37.66	0.00
BG	16.85	2.10	20.68	0.30
GR	17.45	0.00	19.47	0.01
HR	20.20	0.43	22.71	0.01
HU	17.49	0.43	20.00	0.14
MD	27.62	0.94	30.18	0.61
MK	19.78	2.10	23.61	0.30
RO	14.03	1.05	16.38	0.14
RS	18.37	1.74	22.18	0.14
SI	17.61	0.30	19.88	0.01
TR	16.93	0.61	19.55	1.63
UA	19.73	0.94	22.29	0.61
SEE	**16.32**	**0.73**	**18.84**	**0.13**
EnC	**19.82**	**1.01**	**22.59**	**0.57**
SEE+	**18.31**	**0.88**	**21.08**	**0.39**
SEE+TR	**17.80**	**0.78**	**20.43**	**0.91**
NWE	**16.28**	**0.00**	**18.56**	**0.01**
EU28	**16.57**	**0.10**	**18.97**	**0.01**

Source: REKK EGMM modelling

As shown in the chart below, a cut on this route requires far less adjustment in 2025 than in 2020. The main reason is the expiry of the Hungarian LTC. Lower overall demand levels also contribute to a smaller need of alternative supply. This latter factor helps explain the significant reduction of storage use, in contrast with the demand shock scenarios.

Figure 21. Flexibility source in a Ukrainian supply shock (TWh)



Source: REKK EGMM modelling

Increased utilization of storages and LNG terminals in Turkey and in Greece also help mitigating the crisis on a market basis. Turkisk LNG terminals supply the Turkish market only. In 2025, January LNG import of Greece increases by 2.3 TWh, and that of Turkey by 4.9 TWh.

Table 12. January LNG terminal utilization in the Ukrainian route disruption scenario (% of capacity)

Terminal	2020		2025	
	REF JAN	UA cut	REF JAN	UA cut
BE	11%	11%	11%	11%
IT	36%	36%	32%	32%
NL	0%	0%	0%	0%
PT	11%	11%	26%	26%
UK	23%	23%	54%	54%
HR	0%	0%	0%	0%
LT	50%	50%	100%	100%
ES	20%	20%	17%	17%
MT	41%	41%	38%	38%
GR	37%	59%	33%	56%
TR	0%	22%	75%	100%
FR	6%	6%	6%	6%
PL	52%	52%	52%	52%
SEE	**28%**	**44%**	**25%**	**42%**
EnC	**-**	**-**	**-**	**-**
SEE+	**28%**	**44%**	**25%**	**42%**
SEE+TR	**11%**	**31%**	**54%**	**77%**
NWE	**16%**	**16%**	**34%**	**34%**
EU28	**19%**	**20%**	**25%**	**26%**

Source: REKK EGMM modelling

Here the congested IPs already identified in the reference case remain so without additional congestion. Withdrawals in 2025 rise in Hungary (2.6 TWh, 33%), Italy (1.3 TWh, 5%), Turkey (5.8 TWh, 72%), and Ukraine (3 TWh, 14%), while Hungary imports more gas from Austria (0.2 TWh, 33%) and exports more to Serbia 1.5 TWh (136%). Bulgarian supply from Romania is cut completely (17.4 TWh), the interruption of flows on the UA-RO interconnector (17.7 TWh) leaves Bulgaria completely cut off (current regulation prevents spot trade on RO-BG).

Table 13. Withdrawal (TWh) and utilization (%) in the Ukrainian route disruption scenario (January)

	2020				2025			
	REF		UA cut		REF		UA cut	
Storage	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**
AT	8.9	40%	12.1	54%	7.3	33%	7.3	33%
BE	2.1	39%	2.1	39%	1.8	34%	1.8	34%
BG	0.5	34%	1.0	66%	1.4	100%	1.4	100%
CZ	2.9	16%	3.0	16%	5.0	27%	5.0	27%
DE	13.7	8%	13.7	8%	8.8	5%	6.3	4%
DK	2.3	50%	2.3	50%	3.5	74%	3.5	74%
ES	2.7	100%	2.7	100%	2.7	100%	2.7	100%
FR	20.2	28%	20.2	28%	17.3	24%	17.3	24%
HR	0.0	0%	0.0	0%	1.3	84%	1.3	84%
HU	9.4	45%	9.8	47%	7.7	37%	10.3	49%
IE	0.7	100%	0.7	100%	0.7	100%	0.7	100%
IT	25.9	38%	28.6	42%	25.0	37%	26.3	39%
LV*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
NL	0.0	0%	0.0	0%	0.0	0%	0.0	0%
PL	1.2	7%	1.2	7%	5.6	36%	5.6	36%
PT	0.3	12%	0.3	12%	0.5	21%	0.5	21%
RO	6.0	81%	6.0	81%	5.4	74%	5.4	74%
RS*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
SE	0.1	43%	0.1	43%	0.1	43%	0.1	43%
SK	0.0	0%	0.0	0%	0.0	0%	0.0	0%
TR	11.4	40%	20.8	73%	8.0	28%	13.8	48%
UA	20.6	40%	27.0	52%	22.1	43%	25.2	49%
UK	15.5	30%	15.5	30%	18.5	36%	18.5	36%
SEE	15.9	50%	16.8	53%	16.0	51%	18.5	59%
EnC	20.6	40%	27.0	52%	22.1	43%	25.2	49%
SEE+	36.5	44%	43.8	53%	38.0	46%	43.7	52%
SEE+TR	47.9	43%	64.6	58%	46.0	41%	57.5	51%
NWE	31.3	12%	31.3	12%	29.1	11%	26.7	11%
EU28	112.4	22%	119.3	24%	112.8	22%	114.2	23%

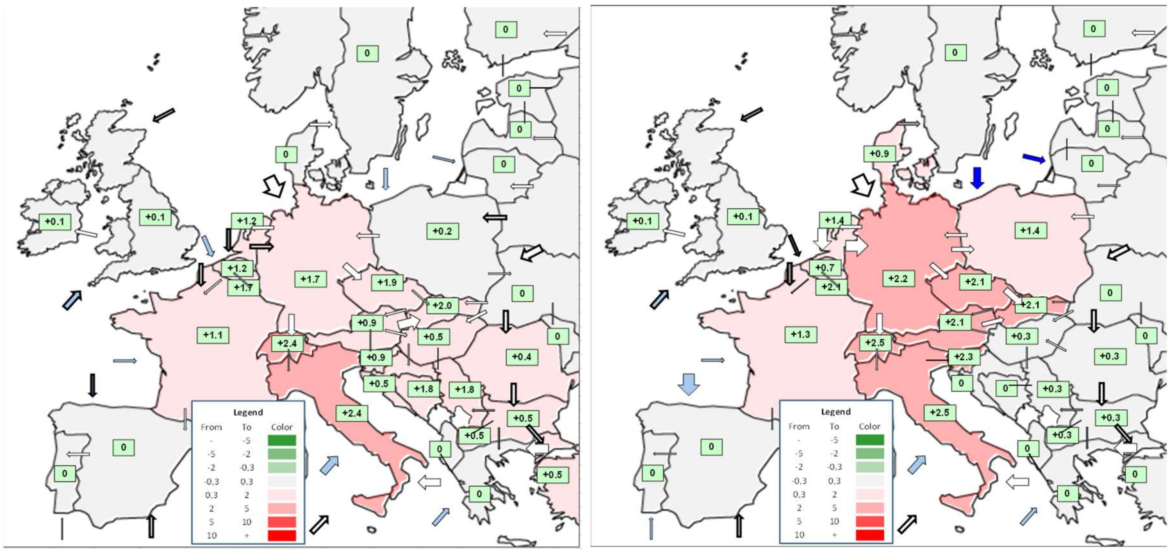
Source: REKK EGMM modelling

** Long term booked storage is not modelled to avoid double counting of flexibility*

1.8.3.2. Northern route disruption

Northern route is tested by cutting supplies on the full Nord Stream (including Nord Stream 2) in January.

Figure 22. Price change in January due to a 100% cut on the Nord Stream route; on the left 2020, on the right 2025 (€/MWh)



Source: REKK EGMM modelling

The change in Russian supply from the Ukrainian route to Nord Stream shifts the risk of a supply cut from South East Europe to Central and North West Europe. Thus it only has small upward weighted price effect in SEE of 0.4 €/MWh compared to 1.1€/MWh in the EU 28. However these results are affected by the restriction of spot traded Russian gas through Ukraine, which would otherwise provide some relief.[18]

Table 14. Prices in January in the Northern route disruption scenario €/MWh

	2020		2025	
	REF JAN	Nord Stream 2 cut price effect	REF JAN	Nord Stream 2 cut price effect
AL	18.95	0.05	20.97	0.01
BA	21.20	1.82	37.66	0.00
BG	16.85	0.50	20.68	0.28
GR	17.45	0.05	19.47	0.01
HR	20.20	0.51	22.71	0.01
HU	17.49	0.51	20.00	0.28
MD	27.62	0.00	30.18	0.00
MK	19.78	0.50	23.61	0.28
RO	14.03	0.36	16.38	0.28
RS	18.37	1.82	22.18	0.28
SI	17.61	0.86	19.88	2.34
TR	16.93	0.48	19.55	0.00
UA	19.73	0.00	22.29	0.00
SEE	**16.32**	**0.41**	**18.84**	**0.29**
EnC	**19.82**	**0.10**	**22.59**	**0.02**

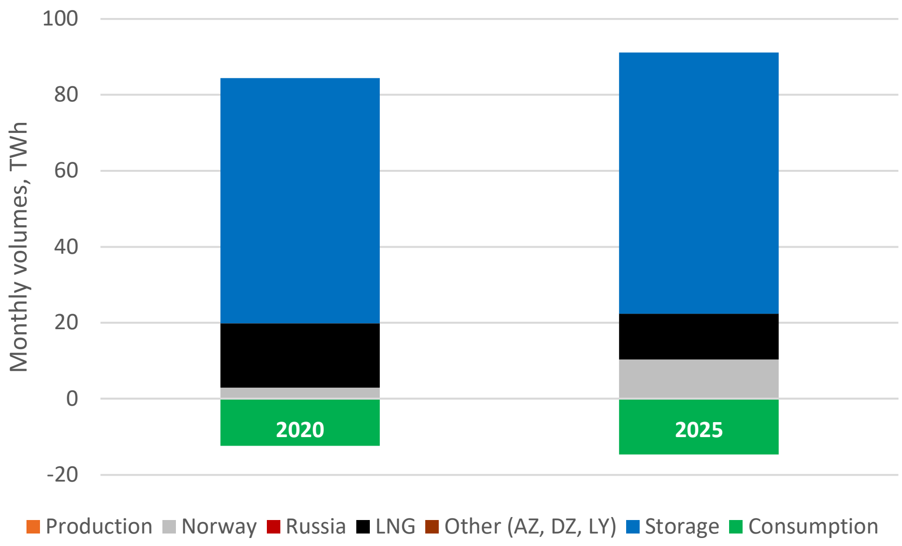
[18] The Hungarian LTC was not assumed to be re-contracted on Nord Stream before its expiry between 2020 and 2025.

SEE+	**18.31**	**0.23**	**21.08**	**0.13**
SEE+TR	**17.80**	**0.32**	**20.43**	**0.08**
NWE	**16.28**	**1.02**	**18.56**	**1.21**
EU28	**16.57**	**1.12**	**18.97**	**1.32**

Source: REKK EGMM modelling

Without spot flows via Ukraine, storage becomes a more important flexibility source in this scenario. Its role increases in 2025 when Russia is relying more heavily on Nord Stream deliveries, evidenced by higher withdrawal rates.

Figure 23. Supply source structure of additional missing volumes in a Northern route supply cut, 2020, 2025 (TWh)



Source: REKK EGMM modelling

The increased LNG flow to Europe finds its way to the markets where it is most needed. Modelling suggests that in case of price signals, spot cargos would be diverted from the Iberian Peninsula to Belgium in a Nord Stream disruption scenario. LNG inflow to Europe would result in a 27% average utilization of the terminals delivering additional 17 TWh LNG to Europe in January 2020. None of the terminals is congested in 2020. In 2025 the same pattern is visible with slightly higher numbers (additional 12 TWh LNG inflow and 31% average capacity utilization). The LNG terminal send-out capacity is fully utilized in Poland and in Lithuania (2025). On the other hand, utilization of LNG terminals in countries not hit by this shock scenario is very low or non-existent at all: in the Netherlands, France and in Croatia.

Table 15. January utilization of the LNG terminals in the Northern route disruption scenario 2020, 2025 (% of capacity)

Terminal	2020		2025	
	REF JAN	Nord Stream 2 cut	REF JAN	Nord Stream 2 cut
BE	11%	23%	11%	69%
ES	20%	20%	17%	17%
FR	6%	6%	6%	6%
GR	37%	37%	33%	33%
HR	0%	0%	0%	0%
IT	36%	36%	32%	32%
LT	50%	50%	100%	100%
MT	41%	41%	38%	38%
NL	0%	0%	0%	0%
PL	52%	52%	52%	100%
PT	11%	11%	26%	26%
TR	0%	0%	75%	78%
UK	23%	60%	54%	53%
SEE	**28%**	**28%**	**25%**	**25%**
EnC	**-**	**-**	**-**	**-**
SEE+	**28%**	**28%**	**25%**	**25%**
SEE+TR	**11%**	**11%**	**54%**	**56%**
NWE	**16%**	**40%**	**34%**	**47%**
EU28	**19%**	**27%**	**25%**	**31%**

Source: REKK EGMM modelling

An average 40% utilization of storage withdrawal capacity is modelled in January 2020; having full utilization only in 3 countries: Ireland, Bulgaria and Turkey. In 2025 the average utilization of storage withdrawal in a Nord Stream disruption scenario is 44%, having besides the ones in 2020 a 100% utilization of commercial storage in Spain as well. Commercial storages contribute to mitigating the supply crisis on a market basis. The volumes withdrawn in 2020 reference would increase by 50% in a Nord Stream 2 disruption scenario (from 78.8 TWh to 114.5 TWh) and by 77% in 2025. Most of the additional volumes are withdrawn from Austrian, German, Czech and Italian commercial storages. The obligatory stocks are also more intensively used, there is a 25% increase in withdrawal volumes in 2020 and 35% in 2025. Additional volumes are withdrawn from the French storages.

Table 16. Withdrawal volume (TWh) and rate (%) in the Northern route disruption scenario

	2020				2025			
	REF		Nord Stream 2 cut		REF		Nord Stream 2 cut	
Storage	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**
AT	8.9	40%	18.3	82%	7.3	33%	13.3	60%
BE	2.1	39%	3.2	61%	1.8	34%	5.3	100%
BG	0.5	34%	0.5	34%	1.4	100%	1.2	83%
CZ	2.9	16%	6.6	36%	5.0	27%	12.1	65%
DE	13.7	8%	24.9	14%	8.8	5%	27.5	15%
DK	2.3	50%	2.3	50%	3.5	74%	3.4	73%
ES	2.7	100%	2.7	100%	2.7	100%	2.7	100%
FR	20.2	28%	37.5	53%	17.3	24%	30.8	43%
HR	0.0	0%	0.0	0%	1.3	84%	1.3	84%
HU	9.4	45%	9.1	43%	7.7	37%	7.4	35%
IE	0.7	100%	0.7	100%	0.7	100%	0.7	100%
IT	25.9	38%	41.7	61%	25.0	37%	39.9	59%
LV*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
NL	0.0	0%	0.0	0%	0.0	0%	0.0	0%
PL	1.2	7%	1.2	7%	5.6	36%	5.6	36%
PT	0.3	12%	0.3	12%	0.5	21%	0.5	21%
RO	6.0	81%	5.9	80%	5.4	74%	5.4	74%
RS*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
SE	0.1	43%	0.1	43%	0.1	43%	0.1	43%
SK	0.0	0%	0.0	0%	0.0	0%	0.0	0%
TR	11.4	40%	10.9	38%	8.0	28%	7.3	26%
UA	20.6	40%	20.6	40%	22.1	43%	22.1	43%
UK	15.5	30%	21.8	42%	18.5	36%	24.2	47%
SEE	15.9	50%	15.5	49%	16.0	51%	15.4	49%
EnC	20.6	40%	20.6	40%	22.1	43%	22.1	43%
SEE+	36.5	44%	36.1	43%	38.0	46%	37.5	45%
SEE+TR	47.9	43%	47.0	42%	46.0	41%	44.8	40%
NWE	31.3	12%	49.9	20%	29.1	11%	57.0	23%
EU28	112.4	22%	176.9	35%	112.8	22%	181.5	36%

Source: REKK EGMM modelling

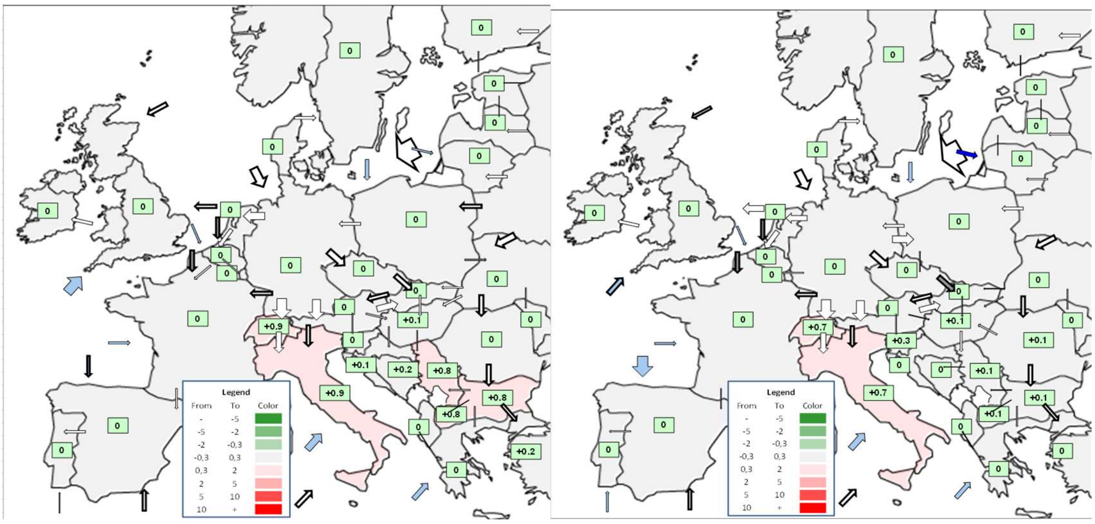
**Storages 100% long term booked to support LTC flexibility; not modelled to avoid double counting of flexibility*

Results demonstrate that earlier congestion (in the reference) disappears when Russian LTCs do not use the infrastructure.

1.8.3.3. Southern route disruption

The Southern route is tested by modelling a cut in the Trans-Atlantic Pipeline (TAP) that will deliver Azeri gas through Turkey to the EU.

Figure 24. January price change due to cut on the Southern route (TAP); on the left 2020, on the right 2025 (€/MWh)



Source: REKK EGMM modelling

A supply disruption on TAP has a less than 1 €/MWh price effect even in Italy, where most of these long term contracted volumes are arriving. In SEE the volume weighted price effect is only 0.1 €/MWh.

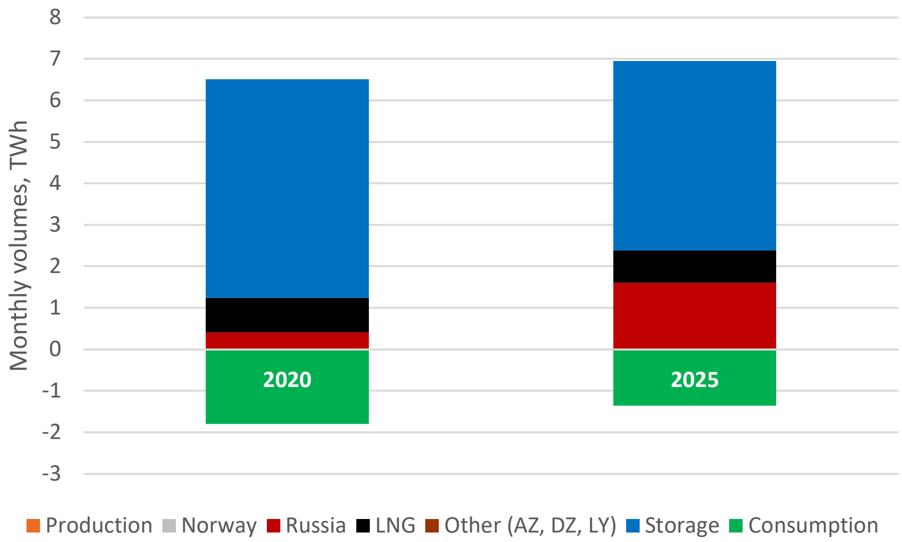
Table 17. January gas prices in the Southern route disruption scenario 2020, 2025 €/MWh

Market	2020		2025	
	REF JAN	TAP cut	STR	TAP cut
AL	19.0	0.0	21.0	0.0
BA	21.2	0.2	37.7	0.0
BG	16.9	0.8	20.7	0.1
GR	17.5	0.0	19.5	0.0
HR	20.2	0.1	22.7	0.0
HU	17.5	0.1	20.0	0.1
MD	27.6	0.0	30.2	0.0
MK	19.8	0.8	23.6	0.1
RO	14.0	0.0	16.4	0.1
RS	18.4	0.8	22.2	0.1
SI	17.6	0.0	19.9	0.3
TR	16.9	0.2	19.5	0.0
UA	19.7	0.0	22.3	0.0
SEE	**16.3**	**0.1**	**18.8**	**0.1**
EnC	**19.8**	**0.1**	**22.6**	**0.0**
SEE+	**18.3**	**0.1**	**21.1**	**0.0**
SEE+TR	**17.8**	**0.1**	**20.4**	**0.0**
NWE	**16.3**	**0.0**	**18.6**	**0.0**
EU28	**16.6**	**0.2**	**19.0**	**0.1**

Source: REKK EGMM modelling

Italy's is the most affected country, and its considerable storage capacity plays a key role as a flexibility source. In 2025, Russian supplies arriving via the Nord Stream from Germany to Italy are more impactful than in 2020.

Figure 25. Flexibility source used in a TAP supply cut (TWh)



Source: REKK EGMM modelling

In the Southern route disruption scenario the average utilization of LNG terminals in SEE in January grows from 28% to 34% in 2020 and from 25 to 31% in 2025. The increased use of the Greek LNG terminals can supply additional volumes to the region.

In 2025, Greek LNG imports grow by 0.8 TWh (26%) while Turkish import fall by 0.8 TWh (5%) because of the price differential. In 2025 additional Russian (LTC flexibility) supplies through the Trans-Balkan route contribute to the mitigation. Thus compared to the Ukrainian cut off, LNG plays a less significant role in substituting pipeline flows during a TAP cut off.

The lowest utilization rates of LNG terminals are in the countries further away: Netherland and France.Croatian LNG can also not help mitigating the crisis, because the there is very low interconnectivity on the Balkan, and LNG could not reach the affected countries (Bulgaria and Serbia are assumed to be connectected by the BG-RO interconnector, this is why Serbia is also hit by a TAP disruption.)

Table 18. LNG terminal utilization rates during the Southern route disruption scenario (%)

Terminal	2020		2025	
	REF JAN	TAP cut	REF JAN	TAP cut
BE	11%	11%	11%	11%
ES	20%	20%	17%	17%
FR	6%	6%	6%	6%
GR	37%	45%	33%	41%
HR	0%	0%	0%	0%
IT	36%	36%	32%	32%
LT	50%	50%	100%	100%
MT	41%	41%	38%	38%
NL	0%	0%	0%	0%
PL	52%	52%	52%	52%
PT	11%	11%	26%	26%
TR	0%	0%	75%	71%
UK	23%	23%	54%	54%
SEE	**28%**	**34%**	**25%**	**31%**
EnC	**-**	**-**	**-**	**-**
SEE+	**28%**	**34%**	**25%**	**31%**
SEE+TR	**11%**	**14%**	**54%**	**55%**
NWE	**16%**	**16%**	**34%**	**34%**
EU28	**19%**	**20%**	**25%**	**25%**

Source: REKK EGMM modelling

The TAP disruption related additional withdrawal is supplied mainly by Italy.

In 2025 storage withdrawal increases in Hungary (0.8 TWh, 10%) and Italy (4.6 TWh, 18%). As far as pipeline flows, the cut of TAP stops all Italian export to Slovenia and Slovenian exports to Croatia.[19] Slovenia, in turn, increases its import from Austria by 76%. Hungarian exports to Serbia increase by 75%, fully compensating for the 55% delcine in Serbian imports from Bulgaria resulting the full cut of gas flows on the GR-BG route. It is important to note that a regulatory barriers prevents any increase in flows on the Trans-Balkan pipeline between Romania and Bulgaria even though it is not congested (utilization is 79% both in the reference and in the supply cut scenario).

The number of congested IPs does not grow 2020 from 2020 to 2025. However there is close to 100% utilization (above 85%) in January on the following IPs: DE-FR, BG-TR, RO-BG (new IBR), RU-DE, IR-TR.

[19] Although SI-HR flows are not significant in the reference scenario either.

Table 19. Withdrawal volume (TWh) and rate (%) in the Southern route disruption scenario

	2020				2025			
	REF		TAP cut		REF		TAP cut	
Storage	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**
AT	8.9	40%	8.9	40%	7.3	33%	8.1	36%
BE	2.1	39%	2.1	39%	1.8	34%	1.8	34%
BG	0.5	34%	0.5	34%	1.4	100%	1.4	100%
CZ	2.9	16%	2.9	16%	5.0	27%	5.0	27%
DE	13.7	8%	13.7	8%	8.8	5%	7.2	4%
DK	2.3	50%	2.3	50%	3.5	74%	3.5	74%
ES	2.7	100%	2.7	100%	2.7	100%	2.7	100%
FR	20.2	28%	20.2	28%	17.3	24%	17.3	24%
HR	0.0	0%	0.0	0%	1.3	84%	1.3	84%
HU	9.4	45%	9.4	44%	7.7	37%	8.5	40%
IE	0.7	100%	0.7	100%	0.7	100%	0.7	100%
IT	25.9	38%	31.2	46%	25.0	37%	29.6	44%
LV*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
NL	0.0	0%	0.0	0%	0.0	0%	0.0	0%
PL	1.2	7%	1.2	7%	5.6	36%	5.6	36%
PT	0.3	12%	0.3	12%	0.5	21%	0.5	21%
RO	6.0	81%	6.0	81%	5.4	74%	5.4	74%
RS*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
SE	0.1	43%	0.1	43%	0.1	43%	0.1	43%
SK	0.0	0%	0.0	0%	0.0	0%	0.0	0%
TR	11.4	40%	9.7	34%	8.0	28%	7.3	26%
UA	20.6	40%	20.6	40%	22.1	43%	22.1	43%
UK	15.5	30%	15.5	30%	18.5	36%	18.5	36%
SEE	15.9	50%	15.8	50%	16.0	51%	16.7	53%
EnC	20.6	40%	20.6	40%	22.1	43%	22.1	43%
SEE+	36.5	44%	36.4	44%	38.0	46%	38.8	47%
SEE+TR	47.9	43%	46.2	41%	46.0	41%	46.2	41%
NWE	31.3	12%	31.3	12%	29.1	11%	27.5	11%
EU28	112.4	22%	117.7	23%	112.8	22%	117.4	23%

Source: REKK EGMM modelling

** Long term booked storage is not modelled to avoid double counting*

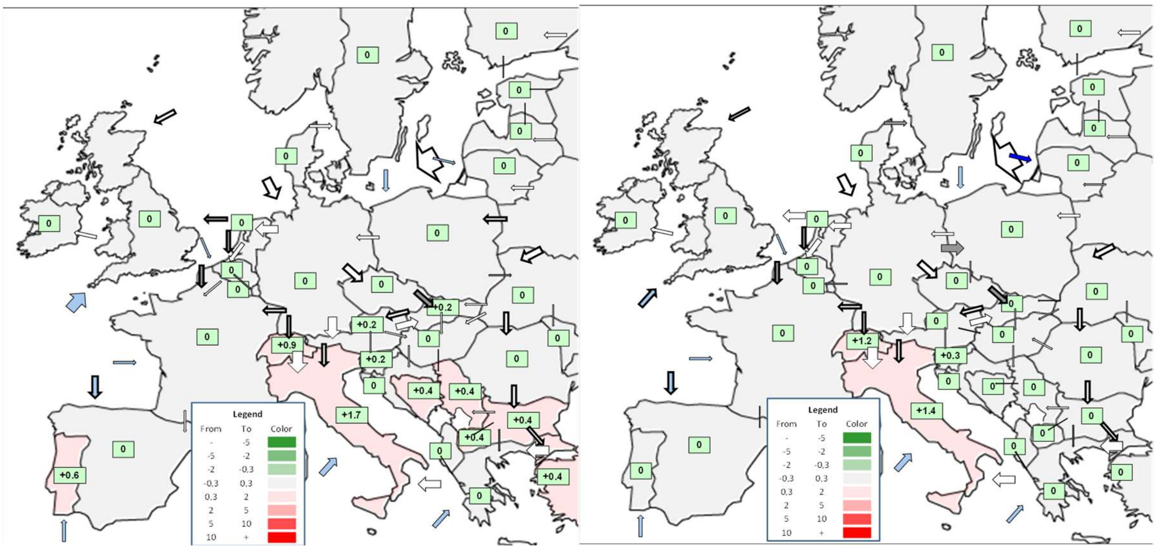
1.8.3.4. Algerian disruption scenario

In this scenario, pipeline gas flows of Algerian origin (some of them through Lybia) to Italy and Spain are cut in January. We must highlight that the following results are the ones testing the drop of Algerian pipeline LTC deliveries.

As we were informed that the Spanish contract will expire by 2022 and the Italian contract by 2019 and the missing volumes will be partly or fully replaced by Russian or Norvegian supplies, that would inflate the effects of any supply disruption from Algerain pipeline LTC supply.

To test the extreme, we did not count on the expiry of these contracts when modelling 2020 and 2025. Hence results shall be read as maximum demages caused by an Algerian cut.

Figure 26. Price change compared to the normal scenario due to a 100% cut of Algerian supplies in January; on the left 2020, on the right 2025 (€/MWh)



Source: REKK EGMM modelling

Italian wholesale prices increase by 1.7 €/MWh in 2020 and 1.4 €/MWh in 2025. In 2020, some countries of the SEE region and Turkey experience moderate price increases of up to 0.4 €/MWh. Outside of the region, Portugal and Switzerland are affected in 2020. In 2025, only Italy, Slovenia and Switzerland face higher prices.

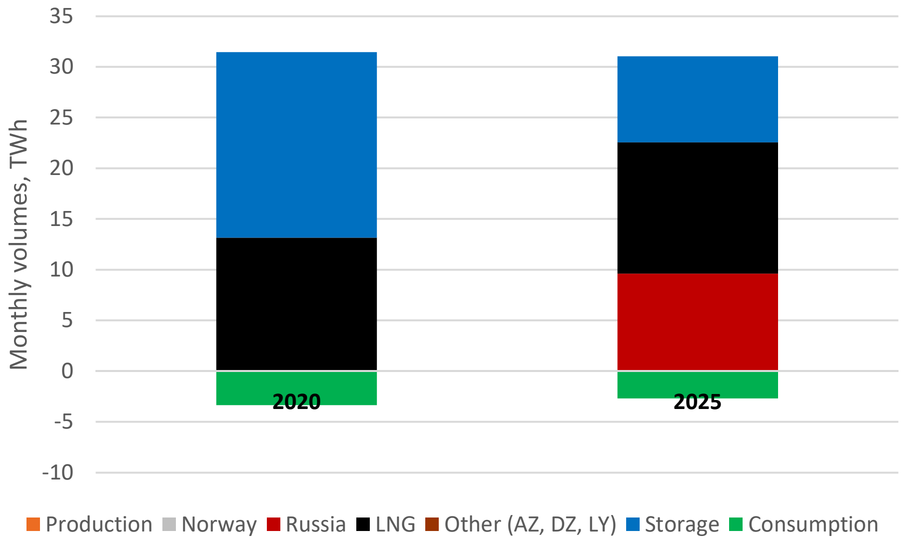
Table 20. Modelled gas prices in January in the Algerian disruption scenario 2020, 2025 €/MWh

Market	2020		2025	
	REF JAN	North Africa cut	REF JAN	North Africa cut
AL	19.0	0.0	21.0	0.0
BA	21.2	0.4	37.7	0.0
BG	16.9	0.4	20.7	0.0
GR	17.5	0.0	19.5	0.0
HR	20.2	0.0	22.7	0.0
HU	17.5	0.0	20.0	0.0
MD	27.6	0.0	30.2	0.0
MK	19.8	0.4	23.6	0.0
RO	14.0	0.0	16.4	0.0
RS	18.4	0.4	22.2	0.0
SI	17.6	0.2	19.9	0.3
TR	16.9	0.4	19.5	0.0
UA	19.7	0.0	22.3	0.0
SEE	**16.3**	**0.0**	**18.8**	**0.0**
EnC	**19.8**	**0.0**	**22.6**	**0.0**
SEE+	**18.3**	**0.0**	**21.1**	**0.0**
SEE+TR	**17.8**	**0.2**	**20.4**	**0.0**
NWE	**16.3**	**0.0**	**18.6**	**0.0**
EU28	**16.6**	**0.3**	**19.0**	**0.2**

Source: REKK EGMM modelling

Similar to the scenario involving the cut of TAP, flexibility provided by Italian storages play a huge role in adjusting the source structure in 2020, with the contribution of LNG also significant. Russian deliveries on Nord Stream, however, become competitive by 2025.

Figure 27. Supply source structure of additional missing volumes in a TAP supply cut, 2020, 2025 (TWh)



Source: REKK EGMM modelling

With an Algerian supply cut, Italy loses 20 TWh of pipeline import in 2025. These losses, interestingly, are not compensated by any increase of LNG import from other sources, resulting in a 11% cut in LNG inflow, with Greek LNG import also remaining constant. Utilization of Spanish LNG terminals, however, more than doubles in both 2020 and 2025, providing an alternative supply source for the Iberian peninsula. The biggest jump in terminal utilization can be observed in Portugal in 2020, with a rate of 39% as opposed to 11% in the reference scenario. In the North African cut scenario in 2025, Portugal terminals are even more utilized at 42%, but by 2025 we model a significant increase of terminal utilization in the reference scenario as well.

Table 21. January utilization of the LNG terminals in the North African route disruption scenario 2020, 2025 (% of capacity)

Terminal	2020		2025	
	REF JAN	North Africa cut	REF JAN	North Africa cut
BE	11%	11%	11%	11%
ES	20%	42%	17%	38%
FR	6%	6%	6%	6%
GR	37%	37%	33%	33%
HR	0%	0%	0%	0%
IT	36%	28%	32%	28%
LT	50%	50%	100%	100%
MT	41%	41%	38%	38%
NL	0%	0%	0%	0%
PL	52%	52%	52%	52%
PT	11%	39%	26%	42%
TR	0%	0%	75%	78%
UK	23%	23%	54%	54%
SEE	**28%**	**28%**	**25%**	**25%**
EnC	**-**	**-**	**-**	**-**
SEE+	**28%**	**28%**	**25%**	**25%**
SEE+TR	**11%**	**11%**	**54%**	**56%**
NWE	**16%**	**16%**	**34%**	**34%**
EU28	**19%**	**25%**	**25%**	**31%**

Source: REKK EGMM modelling

Storage withdrawals are up in Germany, in Portugal and in Italy in 2020; in 2025, with Portugal relying more on LNG and Germany on Russian import, only in Italy (13.3 TWh, 53%) and, to a lesser extent, Austria (0.9 TWh, 12%). Looking at pipeline flows in 2025, similar to the case when TAP is cut, they stop on the IT-SI-HR route, and Slovenia's import from Austria increase by the same 0.9 TWh (876%). Italian import from Switzerland increases by 4 TWh (83%); increased gas flows on the RU-DE-CH route confirm that Russian supplies substitute those of Algeria. It seems that - in line with the observed price developments - the effects of an Algerian supply cut do not spill over to other countries of the SEE region from Italy and Slovenia in 2025, as their import needs are covered from the rest of Europe.

Table 22. Withdrawal of gas volumes from storages (TWh) and utilization of available withdrawal capacities (%) in January 2020, 2025, in the Algerian route disruption scenario

	2020				2025			
	REF JAN		North Africa cut		REF JAN		North Africa cut	
Storage	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**
AT	8.9	40%	8.8	40%	7.3	33%	8.2	37%
BE	2.1	39%	2.1	39%	1.8	34%	1.8	34%
BG	0.5	34%	0.5	34%	1.4	100%	1.4	100%
CZ	2.9	16%	2.9	16%	5.0	27%	5.0	27%
DE	13.7	8%	17.9	10%	8.8	5%	3.1	2%
DK	2.3	50%	2.3	50%	3.5	74%	3.5	74%
ES	2.7	100%	2.7	100%	2.7	100%	2.7	100%
FR	20.2	28%	20.2	28%	17.3	24%	17.3	24%
HR	0.0	0%	0.0	0%	1.3	84%	1.3	84%
HU	9.4	45%	9.4	45%	7.7	37%	7.7	37%
IE	0.7	100%	0.7	100%	0.7	100%	0.7	100%
IT	25.9	38%	39.8	59%	25.0	37%	38.3	56%
LV*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
NL	0.0	0%	0.0	0%	0.0	0%	0.0	0%
PL	1.2	7%	1.2	7%	5.6	36%	5.6	36%
PT	0.3	12%	0.5	24%	0.5	21%	0.5	21%
RO	6.0	81%	6.0	81%	5.4	74%	5.4	74%
RS*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
SE	0.1	43%	0.1	43%	0.1	43%	0.1	43%
SK	0.0	0%	0.0	0%	0.0	0%	0.0	0%
TR	11.4	40%	11.0	38%	8.0	28%	7.4	26%
UA	20.6	40%	20.6	40%	22.1	43%	22.1	43%
UK	15.5	30%	15.5	30%	18.5	36%	18.5	36%
SEE	**15.9**	**50%**	**15.9**	**50%**	**16.0**	**51%**	**16.0**	**51%**
EnC	**20.6**	**40%**	**20.6**	**40%**	**22.1**	**43%**	**22.1**	**43%**
SEE+	**36.5**	**44%**	**36.5**	**44%**	**38.0**	**46%**	**38.1**	**46%**
SEE+TR	**47.9**	**43%**	**47.5**	**42%**	**46.0**	**41%**	**45.4**	**41%**
NWE	**31.3**	**12%**	**35.4**	**14%**	**29.1**	**11%**	**23.4**	**9%**
EU28	**112.4**	**22%**	**130.7**	**26%**	**112.8**	**22%**	**121.3**	**24%**

** Storages 100% long term booked to support Russain LTC flexibility; not modelled to avoid double counting of flexibility*

Summary of the supply scenarios

The effect of different supply cut scenarios vary in magnitude. The risk of Russian supply cut shifts from the Ukrainian route to the Northern Route, if the Ukrainian route is not kept operational. Due to rerouting of Russian contracts to Nord Stream and not using the Ukrainian transit route as a backup transmission route, the Northern route disruption scenario hits Europe most.

Mitigation of the crisis in all cases is largely due to increased storage withdrawals. LNG can also contribute to mitigation, however only from the 2nd week on. The price effect of the supply related SoS scenarios is relatively minor except for the Nord Stream case, hence the extent of demand response is the largest in this scenario.

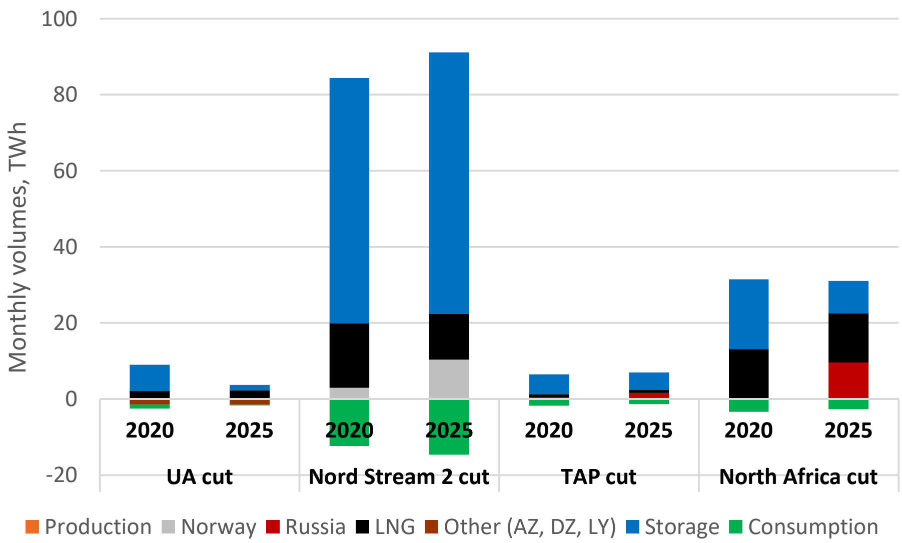
For NW Europe LNG plays an important role (after the first week) but this does not extend to SEE because of the high price with added transportation cost, not as a result of any congestion. LNG can best support regions that are close to the landing points, so entry closer to the region is more of a use.

January price increses due to the supply cut scenarios vary between zero (Algerian cut) to 0.7 €/MWh (Ukrainian cut) for SEE, and zero (Algerian and Ukrainian cuts) to 1.2 €/MWh (Nord Stream cut) for NWE. Price effects are generally milder in 2025 than in 2020 because LNG is a larger part of overall consumption. The only exceptions are NWE prices in case of a Nord Stream cut: as this route is gaining importance in supplying Russian gas and providing flexibility in the region, its disruption in 2025 results in bigger price hikes than in 2020. For SEE, however, the reverse is true, while in the case of a Ukrainian cut – to which SEE is most sensitive – the average price hike of 0.7 €/MWh in 2020 diminishes to only 0.1 €/MWh by 2025.

The small price spread between the two regions shows that the infrastructure is largely resilient to supply shocks. New infrastructure listed in the LNG and Storage strategy is only partly utilized, and the ability of HR LNG to serve the regional market is limited because the tariff on the HR-HU IP is still prohibitively high. (see more in the chapter focusing on infrastructure use)

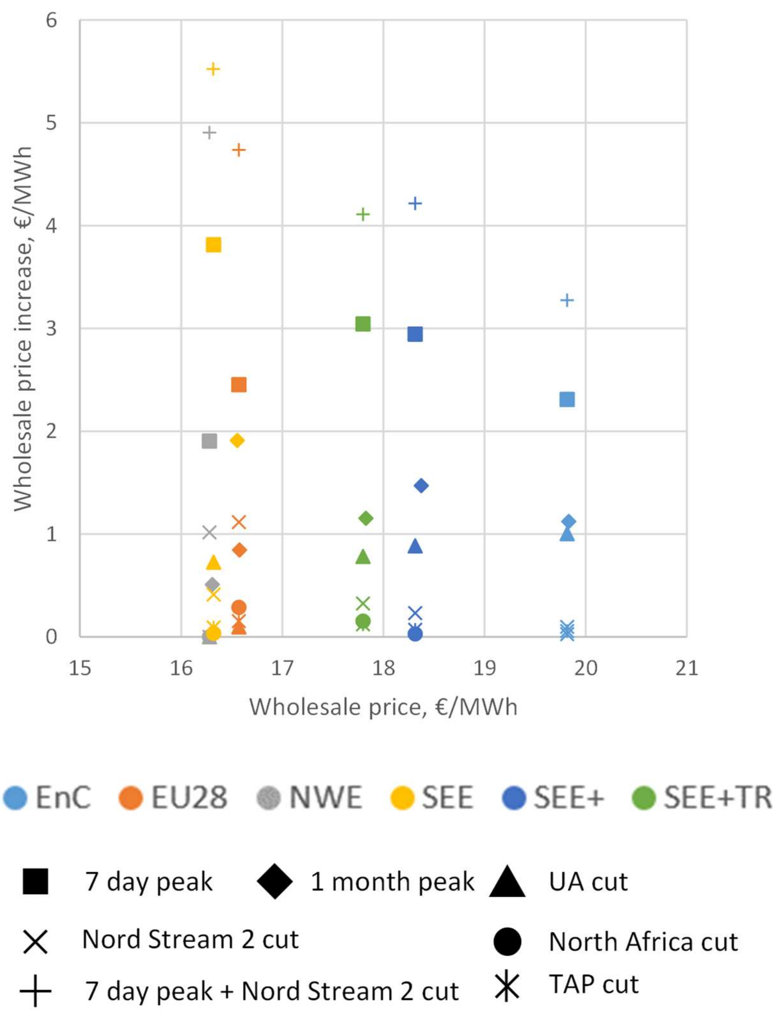
Energy Community countries are less integrated and therefore exhibit slightly higher prices both under demand and supply scenario circumstances. They are only sensitive to a Ukrainian cut, the effects of which are less in 2025 (0.6 €/MWh) than in 2020 (1 €/MWh).

Figure 28. Comparison of supply cut scenarios



Source: REKK EGMM modelling

Figure 29. Comparison of absolute prices and shock effects for the major regions, €/MWh



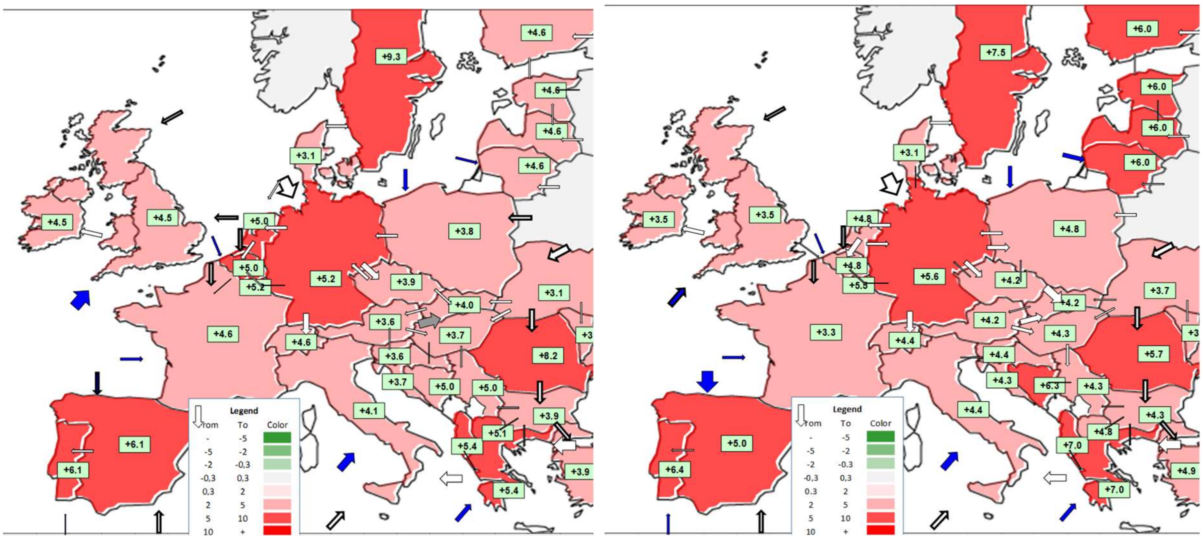
Source: REKK EGMM modelling

Regional price differences between South East Europe and North-West Europe are close to zero in 2020 and 2025 due to good interconnectivity. The price gap is more relevant between EU28 and the Energy Community Contracting Parties, the latter being 3.6 €/MWh more expensive than the EU28 by 2025. Turkey is showing very similar (modest) results to the Energy Community Contracting Parties.

1.8.4. Combined scenario results

This scenario tests a combined demand and supply shock, a 30% increase in January demand (7-day peak demand scenario) with a Northern Route cut.

Figure 30. January price change in a Northern route in a „7 day peak" scenario" on the left 2020, on the right 2025 (€/MWh)



Source: REKK EGMM modelling

As expected, price effects are quite significant throughout Europe, equalling more than the sum of the two scenarios independently. The 'multiplier' effect is stronger for NWE than SEE because it is already much more sensitive to a Nord Stream cut, but prices in SEE increase more in the demand shock scenario, whereas the combined effect is greater: an average increase of 5.5 €/MWh in 2020 and 5.1 €/MWh in 2025 compared to 4.9 and 4.7 €/MWh for NWE.

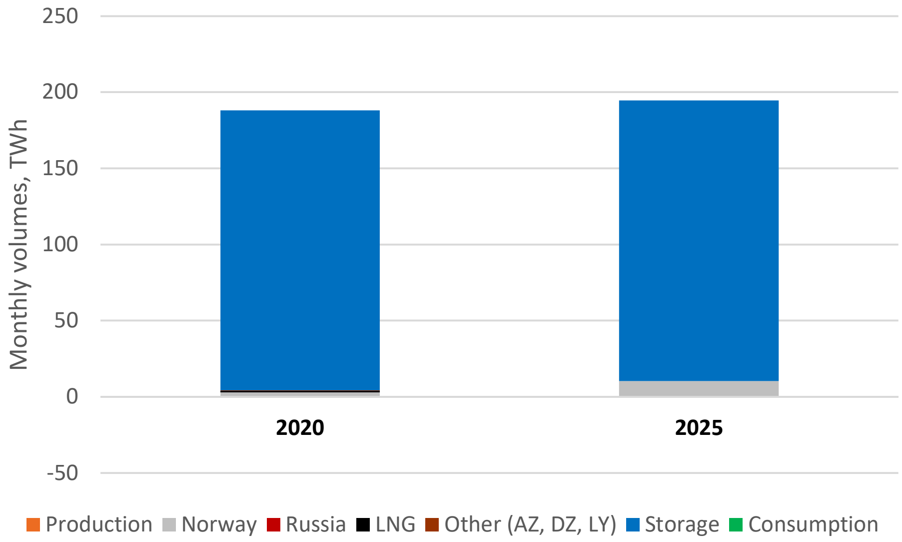
Table 23. Price outputs in the Combined Scenario €/MWh

	2020		2025	
Market	**REF JAN**	**Nord Stream 2 cut + January peak**	**REF JAN**	**Nord Stream 2 cut + January peak**
AL	19.0	5.4	21.0	7.0
BA	21.2	5.0	37.7	6.3
BG	16.9	3.9	20.7	4.3
GR	17.5	5.4	19.5	7.0
HR	20.2	3.7	22.7	4.3
HU	17.5	3.7	20.0	4.3
MD	27.6	3.1	30.2	3.7
MK	19.8	5.1	23.6	4.8
RO	14.0	8.2	16.4	5.7
RS	18.4	5.0	22.2	4.3
SI	17.6	3.6	19.9	4.4
TR	16.9	3.9	19.5	4.9
UA	19.7	3.1	22.3	3.7
SEE	**16.3**	**5.5**	**18.8**	**5.1**
EnC	**19.8**	**3.3**	**22.6**	**3.8**
SEE+	**18.3**	**4.2**	**21.1**	**4.3**
SEE+TR	**17.8**	**4.1**	**20.4**	**4.5**
NWE	**16.3**	**4.9**	**18.6**	**4.7**
EU28	**16.6**	**4.7**	**19.0**	**4.5**

Source: REKK EGMM modelling

With LNG unresponsive in the event of a 7-day demand peak and the source of Russian pipeline flexibility also cut with Nord Stream, Europe becomes extremely reliant on storage with a small amount of additional pipeline supply available from Norway. In this instance (and very extreme case), the combined supply and demand shock can only be mitigated where storage obligations are in place.

Figure 31. Flexibility source in the Combined Scenario (TWh)



Source: REKK EGMM modelling

In this case the average January utilization of storage withdrawal capacity increases significantly throughout Europe, from 22% in the reference to 59% in both 2020 and 2025. In NWE, the very low utilization (12%) in the reference increases to 43%, with almost all storage facilities working close to their maximum capacity.

Table 24. Withdrawal volume (TWh) and rate (%) in Combined Scenario

	2020				2025			
	REF		Nord Stream 2 cut + Janury peak		REF		Nord Stream 2 cut + Janury peak	
Storage	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**	**TWh**	**%**
AT	8.9	40%	21.1	94%	7.3	33%	18.5	83%
BE	2.1	39%	4.9	93%	1.8	34%	5.3	100%
BG	0.5	34%	1.3	90%	1.4	100%	1.4	100%
CZ	2.9	16%	13.0	70%	5.0	27%	17.9	97%
DE	13.7	8%	56.8	32%	8.8	5%	52.4	29%
DK	2.3	50%	4.7	100%	3.5	74%	4.7	100%
ES	2.7	100%	2.7	100%	2.7	100%	2.7	100%
FR	20.2	28%	53.3	75%	17.3	24%	52.8	74%
HR	0.0	0%	1.1	70%	1.3	84%	1.6	100%
HU	9.4	45%	11.9	57%	7.7	37%	10.3	49%
IE	0.7	100%	0.7	100%	0.7	100%	0.7	100%
IT	25.9	38%	63.4	93%	25.0	37%	60.7	89%
LV*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
NL	0.0	0%	6.2	37%	0.0	0%	6.2	37%
PL	1.2	7%	5.8	37%	5.6	36%	13.1	83%
PT	0.3	12%	0.8	38%	0.5	21%	0.9	38%
RO	6.0	81%	7.3	98%	5.4	74%	5.9	80%
RS*	0.0	0%	0.0	0%	0.0	0%	0.0	0%
SE	0.1	43%	0.1	43%	0.1	43%	0.1	43%
SK	0.0	0%	1.4	10%	0.0	0%	0.0	0%
TR	11.4	40%	22.3	78%	8.0	28%	17.4	61%
UA	20.6	40%	32.0	62%	22.1	43%	30.8	60%
UK	15.5	30%	39.9	78%	18.5	36%	41.8	81%
SEE	15.9	50%	21.6	69%	16.0	51%	19.3	61%
EnC	20.6	40%	32.0	62%	22.1	43%	30.8	60%
SEE+	36.5	44%	53.6	64%	38.0	46%	50.1	60%
SEE+TR	47.9	43%	75.9	68%	46.0	41%	67.5	60%
NWE	31.3	12%	107.7	43%	29.1	11%	105.6	42%
EU28	112.4	22%	296.4	59%	112.8	22%	296.9	59%

Source: REKK EGMM modelling

**Long term booked storage is not modelled to avoid double counting*

1.9. Effects of regulation on the storage market

The value of storage has been challenged in recent years by many factors.

- The working gas volume of European storage infrastructure is 1500 TWh, or 27% of 2016 consumption. Consumption has been in steady decline over the last decade and although stabilizing in the past two years, this has left surplus capacity on the market.
- The summer/winter spread is narrowing and neighboring country prices are converging.

- Improved interconnectivity in Europe not only enabled price convergence between countries, but provided pipeline flexibility.
- With increased hub liquidity, the development of risk hedging and financial tools compete with the traditional storage service.
- LNG competes directly in the longer run as a flexibility tool.

In North-West Europe storage operators responded by offering new services that are more competitive. In Central and South-East Europe they are further away from liquid hubs and less exposed to competition but still face decreasing injection volumes.

Governments impose storage regulation to ensure stocks are available for immediate response in a security of supply scenario, (see Table 1) understandable given the region's import dependency and the geopolitics of gas. But these measures should not unduly distort competition or the effective functioning of the internal market. Territorial restrictions can be particularly disproportionate or discriminatory, often raising legal concerns.

It can be argued that the market under values storage as far as its contribution to security of supply. Storage operators claim that the market is not willing to pay for the storage services even at marginal cost. Indeed, since traders use summer-winter spread as a benchmark for the value of storage, lower spreads have forced storage operators to lower their fees at close to or even below their marginal costs.

There is no way to know (given the publicly available information) which storage facilities might close down if these conditions persist in the near future. In some parts of Europe the storage capacity is overbuilt and further erosion of demand could clear the market.

In addition to the long term summer-winter-spread, traders are able to use storage to capitalize on shorter periods of price volatility (daily, weekly, monthly, quarterly, yearly), and the value differs depending on the direction of gas prices. At recent price levels (2016/17), natural gas storage operators assume an additional margin for traders derived from the extrinsic value of about 0.20 €/MWh – 0.50 €/MWh depending on the storage product (faster or slower cycle rate). This additional margin cannot be captured by modelling.

The European response was to lower storage transmission entry and exit fees, and this has been even part of the tariff network code which has now entered into force. Although there is a valid argument that this measure discriminates against pipeline flexibility in favour of storage flexibility, it may be less market distorting than storage obligations.

CEER regulatory studies assert that for some countries, like France and Poland, storage obligations hinder cross-border storage use. Additional administrative barriers to cross-border cooperation such as requiring obligations are met using national storage sites or giving special rights to governments, TSOs or SSOs for allocating gas in storage in the event of a supply emergency, or restricting cross-border gas flows in such a scenario further limit these possibilities. Even without them, obligations can lead to a suboptimal storage level below what the market would dictate.[20]

At the same time, obligations can promise higher storage levels in countries where security of supply is valued more highly, with governments able to pass the extra costs onto market participants. Another risk of market distortion, however, arises if market participants other than those protected by the measure are forced to bear these extra costs.

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[20] As observed by ref4e/mercados/e-bridge "The role of gas storage in internal market and in ensuring security of supply"

Strategic storage stocks are currently implemented by four countries in Europe. This type of security insurance is potentially more distortive to the market under exceptionally high demand or a supply cut since they are released by ministers on regulated prices. If these prices are expected to be relatively low, traders will not be incentivised to prepare for SoS scenarios by storing adequate quantities themselves. This again raises the issue that the market may not recognize the full insurance value of storage. On the other hand, one could argue that strategic stocks are less distortive than storage obligations because until they are released they are not part of the market and, therefore, do not change the patterns of commercial storage activities.

For any country, both storage obligations and strategic stocks increase available gas quantities in SoS situations compared to the market outcome, which can result in welfare gains in such an instance. Regional cooperation, however, has the potential to create more welfare gains through the optimisation of storage use. First, cross-border cooperation requires the abolishment of some administrative barriers to foster efficiency gains by the market. Second, if Member States were still to value security of supply more than the market, they can establish an obligation or strategic stock regime that builds on the efficiency gains that a larger geographic area with more supply and infrastructue presents.

The next chapters present the modelling results for storage obligations and strategic stocks and will endeavour to determine which countries could cooperate on the use of storage in supply disruption cases in the SEE region.

Methodology

Two alternative regulatory scenarios are applied and tested with all scenarios:

- The "no storage obligation" regime is a deregulation scenario under which current obligations providing security of supply for protected consumers is lifted. This scenario tests how the market would use the available flexibility tools without any distortive country specific regulatory intervention.
- The "strategic storage" includes existing "storage obligations" and strategic storage stocks that are available in Europe (currently only in DK, ES, IT and HU). In this case, the obligatory storage stocks are used throughout the whole heating season, but strategic stocks are released in January only if the supply/demand shock occurs.

The "no storage obligation" scenario will be tested under normal (without shock) circumstances to determine how much gas is stored in Europe without any regulatory intervention on a market basis. The welfare effect change of consumers and various stakeholders in the gas industry in this scenario can be monetized.

The welfare effect measures the difference between the „with current storage obligation" monthly price change in January minus the „with currents storage obligation + with release of strategic storage stocks." Countries with a positive value benefit from regional cooperation and use of storage.

1.9.1. Storage obligation

1.9.1.1. Storage obligation in reference case

Supply disruptions are very rare not the business as usual case in a gas market.

Costs associated with market distortion are difficult to monetize, but on a European level the welfare loss attributed to a non-efficient system can be measured by modelling.

This section investigates European storage utilization in the absence of storage obligations, measuring changes in the utilization of storage facilities within the different Member States.

For the EU28, storage obligations add some 37 TWh of annual injection in 2025, equating to 11% more gas in storages in October than without the obligations. In SEE, the combined injection of countries with storage facilities (Bulgaria, Croatia, Hungary, Italy, and Romania) is 35% higher.

1.9.1.2. Storage related regulatory scenarios combined with supply shock scenarios

Table 25. Modelled total storage injections in 2025, TWh

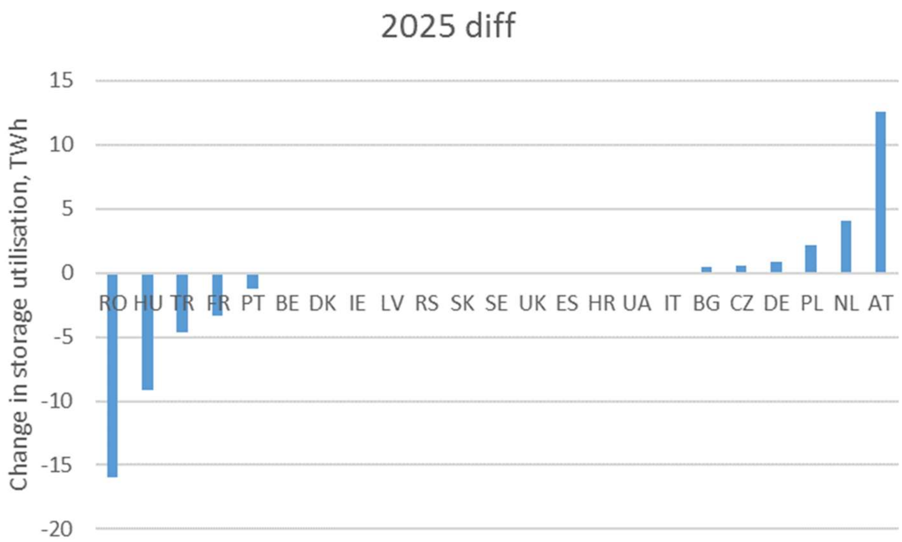
Storage	Without obligations	With obligations	Difference
AT	26.5	14.0	-12.5
BE	6.5	6.5	0.0
BG	4.2	4.2	0.0
CZ	18.2	18.2	0.0
DE	47.5	46.6	-0.9
DK	8.0	8.0	0.0
ES	8.4	8.4	0.0
FR	56.0	74.1	18.1
HR	3.5	3.5	0.0
HU	12.4	27.2	14.9
IE	2.0	2.0	0.0
IT	76.2	76.1	-0.1
LV*	0.0	0.0	0.0
NL	4.0	0.0	-4.0
PL	14.3	14.2	-0.1
PT	1.5	2.4	0.9
RO	0.8	20.9	20.1
RS*	0.0	0.0	0.0
SE	0.1	0.1	0.0
SK	0.0	0.0	0.0
TR	20.4	28.8	8.4
UA	76.6	76.5	0.0
UK	40.6	40.6	0.0
SEE	20.8	55.8	35.0
EnC	76.6	76.5	0.0
SEE+	97.4	132.4	35.0
SEE+TR	117.8	161.1	43.4
NWE	98.7	93.8	-4.9
EU28	330.6	367.1	36.5

Source: REKK EGMM modelling

**Long term booked storage is not modelled to avoid double counting*

Without storage obligations there would be only a slight decrease in modelled prices, and the location of storage activity shifts from east to west, meaning more storage in Austria, Germany and the Netherlands.

Figure 32. Change modelled storage fill level by the end of October, TWh, 2025



Source: REKK EGMM modelling

Storage obligations have a crowding-out effect, with commercial storage activity 100 TWh higher without storage obligations. Also storage in other countries were used than the obliged ones, which means that the market itself would store most of the stocks (althogether 157 TWh under storage obligation in 2025 including Turkey) without any intervention but probably in a slightly different manner: to other storage sites than.

Table 26. Modelled commercial storage use in 2025 (TWh)

Storage	Without obligations	With obligations	Difference
AT	26.5	14.0	-12.5
BE	6.6	6.6	0.0
BG	4.2	1.9	-2.3
CZ	18.2	15.6	-2.6
DE	47.5	46.6	-0.9
DK	8.0	8.0	0.0
ES	8.4	8.4	0.0
FR	56.0	0.3	-55.6
HR	3.5	3.5	0.0
HU	12.4	0.3	-12.1
IE	2.0	2.0	0.0
IT	76.2	76.1	-0.1
LV*	0.0	0.0	0.0
NL	4.0	0.0	-4.0
PL	14.3	3.6	-10.7
PT	1.5	0.8	-0.7
RO	0.8	0.0	-0.8
RS*	0.0	0.0	0.0
SE	0.1	0.1	0.0
SK	0.0	0.0	0.0
TR	20.4	9.5	-10.8
UA	76.6	76.5	0.0
UK	40.7	40.7	0.0

SEE	20.8	5.8	-15.1
EnC	76.6	76.5	0.0
SEE+	97.4	82.3	-15.1
SEE+TR	117.7	91.8	-26.0
NWE	98.7	93.8	-4.9
EU28	330.6	228.4	-102.2

Source: REKK EGMM modelling

**Long term booked storage is not modelled to avoid double counting*

The next table shows the difference between modelled January prices in the different supply and demand scenarios with and without obligations. Green colored cells indicate that deregulation would bring lower prices in the given SOS shock, while red cells indicate higher prices.

Deregulation leads to massive redistribution of welfare at the EU 28 level. The small decrease in price benefits consumers (about 200 million €/yr in the 2020 reference), with storage operation revenues and storage arbitrage revenues rising by about the same amout (206 million €/year in 2020 out of which the larger amount). The total welfare at the EU 28 level would not change much (3.4 million €/yr) because other stakeholders, mostly producers and LNG offtakers would lose money. In 2025, consumers surplus reaches 14 million €/year.

One possible conclusion is that obligatory storage regimes diminish the business case for storage operators in other countries. In the next chapter the model will test whether this regulatory storage redistribution improves security in case of supply shocks.

Table 27. Price effect of shocks in no obligation minus the with obligation scenarios, 2020 €/MWh

	UA cut	Nord Stream 2 cut	TAP cut	North Africa cut	February peak	January peak
AL	0.00	0.00	0.00	0.00	0.00	-1.56
AT	-0.01	-0.14	-0.02	-0.07	-0.02	-0.22
BA	1.12	0.31	-0.21	-0.33	0.02	0.93
BE	-0.11	-0.29	-0.11	-0.11	-0.11	-0.13
BG*	0.77	0.01	0.45	0.07	0.03	0.50
CH	-0.01	-0.14	0.00	0.00	-0.02	-0.14
CZ*	-0.29	-0.32	-0.02	-0.02	-0.02	-0.08
DE	-0.01	-0.34	-0.01	0.00	-0.02	-0.49
DK*	-0.02	-0.02	-0.02	-0.02	-0.02	-0.21
EE	0.00	0.00	0.00	0.00	0.00	-0.49
ES*	0.00	0.00	0.00	0.00	0.00	0.12
FI	0.00	0.00	0.00	0.00	0.00	-0.49
FR*	0.35	0.00	0.35	0.35	0.35	0.11
GR	0.00	0.00	0.00	0.00	0.00	-1.56
HR	0.09	0.00	0.05	0.19	0.13	-0.11
HU*	1.22	0.31	0.05	0.19	0.13	0.93
IE	0.01	0.00	0.01	0.01	0.01	-0.13
IT*	-0.01	-0.14	0.00	-0.07	-0.02	-0.12
LT	0.00	0.00	0.00	0.00	0.00	-0.49
LU	-0.01	-0.34	-0.01	0.00	-0.02	-0.13
LV	0.00	0.00	0.00	0.00	0.00	-0.49
MD	-0.01	-0.02	-0.02	-0.02	-0.02	0.15
MK	0.77	0.01	0.45	0.07	0.03	-1.25
MT	0.00	0.00	0.00	0.00	0.00	1.22
NL	-0.11	-0.34	-0.11	-0.11	-0.11	-0.13
PL*	0.18	0.02	0.18	0.18	0.18	-0.49
PT*	0.01	0.00	0.01	0.00	0.01	0.12
RO*	2.26	1.90	2.27	2.27	2.27	0.53
RS	1.12	0.31	0.45	0.07	0.02	0.93
SE	0.00	0.00	0.00	0.00	0.00	0.00
SI	-0.01	-0.14	-0.02	-0.07	-0.02	-0.22
SK	-0.01	-0.32	-0.02	-0.07	-0.02	-0.17
TR*	0.00	-0.02	0.10	0.07	0.00	-1.56
UA	-0.01	-0.02	-0.02	-0.02	-0.02	0.15
UK	0.01	0.00	0.01	0.01	0.01	-0.13

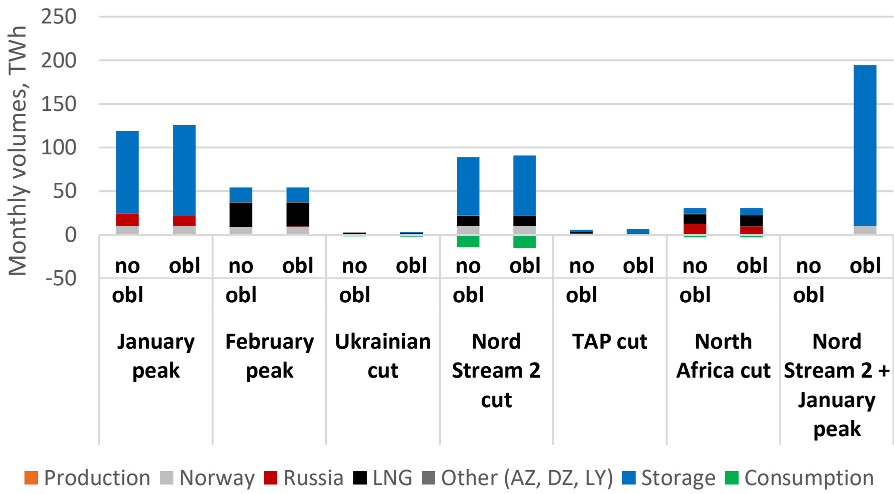
Source: REKK EGMM modelling

** denotes existing strategic storage or storage obligation*

As expected, there is overlap between the "red" countries and countries that impose storage obligations on traders. These countries - Bulgaria, France, Hungary, Poland, Portugal, Spain, Romania and Turkey – have a higher risk of a supply crisis which justifies the additional cost of the storage obligation investment into security. Storage obligations in the Czech Republic, Denmark and in Italy were not supported by our modelling, however risks outside the scope of this study might be relevant.

The following chart shows the shift in flexibility measures applied in the different shock scenario without storage obligations. The vast majority of the missing volumes are covered by the same instruments with or without the obligation.

Figure 33. Comparison of supply structure change with obligation and no obligation (2025)



Source: REKK EGMM modelling

1.9.2. Strategic storage

Three supply cut scenarios are modelled in combination with the relase of strategic stocks: a January cut of the Ukrainaian route, a cut in TAP, and an Algerian cut. In the SEE region, Italy and Hungary keep strategic stocks. In the following table the capacity data is summarized and the modelling provides the highest price at which the market absorbes their full quantity if they are released. Spain is included in the table because an Algerian supply cut can result in the release of Spanish strategic stocks.[21]

The goal is to assess the effect of such a release on gas flows to better understand the potential scope of regional cooperation or solidarity as defined in Gas SoS Regulation. The hypothesis is that with the release of strategic stocks extra available gas will duplicate flow patterns from Chapter 1.8.3., verifying interdependencies that could form the basis of regional cooperation mechanisms. The resulting market prices will of course be distorted, but no conclusions regarding prices will be made.

It is important to note that with the full release of strategic stocks in the January-March period this full period will be modelled and assessed, not only January. As the SoS Regulation prohibits any administrative restriction on cross-border gas flows, strategic stock release is not restricted to the country where the stock was held.

[21] When the Ukrainan route is cut, only the effect of the release of the Hungarian strategic stock is modelled since other countries with strategic stocks (Italy, Spain and Denmark) will not be seriously affected. For similar reasons, only the Italian stocks are released with a cut on TAP, and Italian and Spanish stocks in case of an Algerian cut.

Table 28. The use of strategic stocks in SoS scenarios

	WG capacity (TWh)	Withdrawal in SoS*					
		Ukrainian cut		Cut on TAP		Algerian cut	
		Quantity (TWh)	Price (EUR/MWh)	Quantity (TWh)	Price (EUR/MWh)	Quantity (TWh)	Price (EUR/MWh)
HU	8.7	8.7	19.5	0	-	0	-
IT	44.9	0	-	44.9	14	44.9	17
ES	16.5			0	-	5.4	17
*in Jan.-March							

Source: REKK EGMM modelling

If Hungarian strategic stocks are released during a Ukrainian cut, Croatian LNG imports for January-March decrease by 1.4 TWh (86%), to 0.2 TWh. This is much lower than the 1 TWh imported in the reference scenario, without any supply cut. Croatia increases pipeline imports from Hungary to account for the fall in LNG imports, which jumps from zero to 1.4 TWh during the three-month period. Hungary increases exports to Ukraine by 0.4 TWh (20%) and Serbia by 0.2 TWh (3.6%) while imports from Austria decline by 6.5 TWh (83%). Serbia substitutes 0.2 TWh imports from Bulgaria, stemming from a decrease in gas flows on the TR-GR-BG route, with Hungary.

If Italy's strategic stocks are released during a cut on TAP, 3-month Croatian LNG imports (from 1.9 TWh) and storage withdrawals (2 TWh) fall to zero. Turkish LNG imports also drops to zero (from 44 TWh), while Greece increases by 1.5 TWh (16.6%) and Italy by 1.9 TWh (11%). Italy starts to export to Slovenia (2.6 TWh), and Slovenia to Croatia (0.1 TWh). Slovenian imports from Austria decrease by 2.3 TWh (85%). Hungary, however, imports 7 TWh more (282%) from Austria, and its imports from Slovakia also rises significantly (1.4 TWh, 43%). As it starts exporting to Croatia (3.2 TWh), Serbian exports decrease by 2.5 TWh (55%). Italy's import from Switzerland comes to a complete halt (a fall of 15.6 TWh).

If a cut on the Algerian supply route triggers the release of Italian and some Spanish strategic stock, Croatian LNG imports fall to zero (from 1.1 TWh) in the January-March period. Italy starts to export to Slovenia (2.5 TWh, at full capacity), and Slovenia to Croatia (0.1 TWh). Italy also exports 15.4 TWh to Austria (pushing out 11 TWh Austrian imports from Germany), while Austrian exports to Hungary increase by 5.2 TWh (208%). Hungary, in turn, starts to export to Ukraine (1.9 TWh), and increases exports to Croatia by 1.2 TWh (169%) and to Serbia by 0.4 TWh (12%). Bulgarian exports to Serbia decrease by 0.2 TWh (6.7%), easing the congestion on the BG-RS interconnector, and Romanian exports to Hungary grow by 0.9 TWh (14.5%).

1.9.3. Assessing results for regional cooperation

Based on the modelling results presented in Chapters 1.8.3. and 1.9.2., the following conclusions regarding regional interdependency and possible cooperation between the countries in SoS scenarios can be reached:

- Hungarian exports to Serbia generally increase in parallel with increased Hungarian storage use.
- The HU-RS route is made even more important by congestions on the planned BG-RS interconnector. Increased Hungarian export to Serbia may ease these congestions.
- Since Bulgaria cannot intensify its storage use in SoS situations due to technical constraints, it is helped indirectly by HU-RS flows: if Serbia can substitute some of its Bulgarian imports from Hungary, Bulgaria requires less imports from Greece.

- Greece, in turn, needs less flexibility with LNG-imports if Bulgaria is less dependent on its supplies.
- The above points highlight the potential for increased cooperation between **Hungary, Serbia, Bulgaria and Greece** in optimizing the allocation of Hungarian storage and Greek LNG along this route. It would require the completion of the bi-directional BG-RS interconnector, which is an FID project with a target commissioning date of 2018.
- The IT-SI interconnector is congested in the reference scenario and flows are cut in both the TAP and the Algerian SoS scenario. Although Slovenia can increase imports from Austria, it can also make use of Hungarian storage if the HU-SI interconnector is built. The importance of this development is recognized by the EU as a Project of Common Interest (PCI).[22]
- SI-HR, HR-SI, HU-HR, and HR-HU interconnectors are conspicuously underutilized in both the reference and in SoS scenarios. Croatian LNG imports are also low and inflexible to supply shocks. These rigidities are due to tariff issues.
- If HU-SI is built and tariff issues are resolved, the proposed cooperation between Hungary, Serbia, Bulgaria and Greece could be extended to **Croatia and Slovenia**. This would further enhance flexibility with the emergence of additional sources (Croatian LNG and storage) and supply routes. For example, Hungary could increase exports to Serbia with access to Croatian LNG, and both Hungarian storage and Croatian LNG could play a collective role when the IT-SI-HR route is cut or congested.
- Italian storage has limited ability to become a more integral part of a regional cooperation scheme because of the small capacity of the IT-SI interconnector. Increased withdrawals from Italian storage can only have an impact on Hungary and Slovenia by reducing Italian import from Austria. A more direct cooperation between **Italy and Greece**, however, could be based on harmonizing flows across TAP with Italian storage use, e.g. Italy providing virtual backhaul by decreasing its import need with more withdrawals if neccessary.
- Under our modelling assumptions, Romanian storage does not contribute to mitigating the effects of supply cuts on a regional level. As we have noted, flows from Romania to Bulgaria are not allowed to increase even if the GR-BG route is cut due to regulatory issues, and in the Ukrainian SoS scenario RO-BG flows come to a complete halt. Removing regulatory barriers and forging better cooperation between **Romania and Bulgaria** would be beneficial for the entire region, as Bulgarian access to Romanian storage would free up sources on the HU-RS-BG-GR route, further enhancing flexibility.

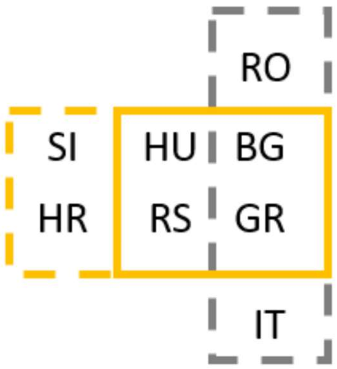
To summarize, Hungary, Serbia, Bulgaria and Greece are identified as a central corridor for cooperation in South-East Europe. Although Serbia is not an EU Member State, its central location and obvious dependence on supplies from Hungary makes it an important partner in any strategy aiming to optimize regional storage use. This corridor could be further reinforced with the involvement of Croatia and Slovenia in the South-West, and Romania in the North-East. Italy may also cooperate in enhanced regional cooperation by linking flows on TAP with Italian storage use.

The essential prerequisites for this cooperation to flourish include the completion of the Serbian-Bulgarian interconnector and the removal of regulatory barriers on the Trans-Balkan pipeline. This has already been targeted by the Action Plans of the Central and South-Eastern European Gas Connectivity (CESEC) High Level Group (dated July 2015,

[22] We have not included the HU-SI route in our scenarios as the project has not reached FID status yet.

and September 2016). Additional regulatory barriers to regional cooperation applied by some SEE countries in SoS scenarios will be covered in the following section.

Figure 34. Scheme of proposed regional cooperation



1.9.4. Establishing a regional cooperation mechanism

Any cooperation mechanism with the goal of optimizing the use of flexibility tools such as gas storage and LNG-import requires the free flow of gas across borders in SoS situations. Moreover, traders need to be sure that all the gas they put into storage will be available in case of an emergency; storage access regimes that give special rights to governments, TSOs or SSOs for the allocatiion of gas in storage under such scenarios discourages market-based usage and potentially disrupts cross-border cooperation. In the SEE region, the following rules explicitly contradict to these principles:

Croatia

The SSO is authorized to reject injection or withdrawal, taking into consideration public service obligations *(from the Storage Code published by Storage System Operator Podzemno skladište plina)*

Bulgaria

In the event of gas shortage Bulgartransgaz has full disposal of gas storage to satisfy the minimum required quantities under the nominations of the household consumers, gas distribution companies, district heating companies and other vulnerable consumers *(from RULES FOR ACCESS TO CHIREN UNDERGROUND GAS STORAGE published by Bulgartransgaz)*

Hungary

In a gas supply emergency, the government can restrict cross-border transportation of gas produced or stored in Hungary *(Gas Act, Article 97/A)*

Serbia

In a gas supply emergency, the government can restrict gas exports *(Energy Law, Article 319)*

These restrictions, along with tariff barriers targeted by the CESEC Action Plans, should be reconsidered in the framework of establishing a regional cooperation mechanism under the new Gas Security of Supply Regulation that includes relevant actions in the Preventive

Action and Emergency Plans, as well as with bilateral arrangements reflecting the solidarity principle.

If traders do not need to face these barriers in conceiving prepartions for SoS situations, they will better manage their risks by offering contracts that guarantee different levels of security of supply for their customers. Consumers that are not protected under the solidarity principle of the revised SoS Regulation will thus be able to set an appropriate level of security of supply for themselves through market-based mechanisms, e.g. choosing between firm and interruptible contracts as offered by traders.

Therefore, we fully agree with the CEER position that non-discriminatory access to storage facilities should be respected in SoS situations. Allowing non-discriminatory rules for storage access in emergency situations enhances the value of storage to the market and contributes to market participants realising the insurance value of storage.[23]

We expect that removing administrative and tariff barriers alone would awake market-based regional cooperation resulting in a more efficient use of storage. Additional benefits may include increased competition between traders, the emergence of sourcing portfolios that better reflect the risk profiles of consumers, and an incentive to further develop storage products.

Any centrally planned regional cooperation mechanism should therefore only focus on the continuous supply to protected costumers and ensure a cost-effective use of flexibility provided with both storage and LNG. If the prerequisites of a market-based, more efficient regional storage platform are fulfilled, even the abolishment of storage obligations may be considered. But first, a regulatory framework that ensures that regulators know how much of stored gas is "earmarked" by traders for their protected customers is needed.

With these considerations in mind, a cooperation mechanism could be established through the following steps, in line with the process of preparing the risk assessments and preventive action plans in the new Gas SoS Regulation:

1. A joint assessment of the supply standard that determines the gas quantities that need to be covered for protected costumers in the case of a supply cut in each country of the cooperating region.

2. For each supply cut scenario, an agreement on pre-defined supply routes that are expected to minimize the cost of supply, taking into account the geographical and technical availability of storage and LNG, and infrastructural constraints (including possible congestion in SoS scenarios). This could be based on an EU-wide disruption simulation with expanded analysis as part of the common and national risk assessments stipulated by the new Regulation.

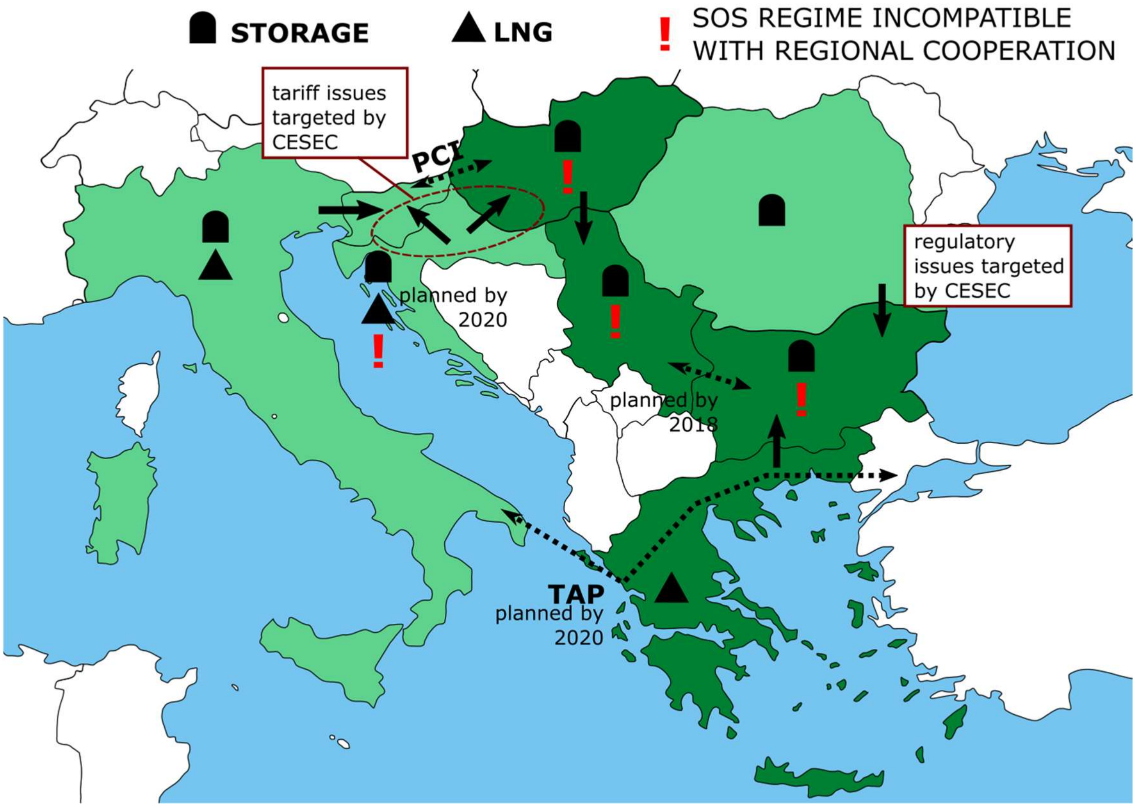
3. As part of the risk assessments, evaluating the expected effect of the removal of administrative and tariff barriers on storage levels that serve the purpose of supplying protected customers.

4. In case a possible shortfall is discovered in any supply cut scenario, a decision on cross-border preventive measures could be made by the relevant authorities of the cooperating region. Although our modelling suggests that market-based solutions are most likely to be able to ensure the continuous supply of protected customers, a solidarity situation, as in the Gas SoS Regulation, would assume that there is so little gas in the EU gas system that some MSs are not able to serve even their household customers. If the risk assessment reveals that this is a possible threat in any country of the cooperation region, preventive measures may include the setting

[23] CEER (2015): CEER Final Vision on Regulatory Arrangements for the Gas Storage Market

up of joint strategic stocks. These stocks could be distributed among the storage facilities of the cooperating countries according to the pre-defined supply routes and discovered shortfalls.

Figure 35. Opportunities and obstacles in regional cooperation in SEE



Source: REKK

1.9.5. Alternative regulatory solution to replace storage obligation

We have demonstrated that storage obligations are distortive to the European gas flexibility market. They arbitrarily redistribute welfare and tend to crowd out commercial storage. They also favour national solutions over promoting a better overall utilization of European UGS assets[24]. Storage obligations, combined with insignificant supplier liabilities in case of customer restrictions, distort supply security related risk perception of suppliers.

Strategic storage schemes further deteriorate gas supply security related risk perception of suppliers and lead to underutilization of commercial storage.

To correct the above inefficiencies, we propose **to replace storage obligation with the EU-wide introduction of a VOLL-based firm and obligatory financial compensation scheme that**

- can ensure that customer welfare is protected even when customer restrictions are unavoidable and implemented;
- send the proper incentive for suppliers to optimally utilize commercial storage;
- will contribute to the elimination of legal barriers to cross-border gas trading during gas supply security incidents.

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[24] We are not aware of a particular case when any of the eleven national storage obligation requirements is met by cross-border storage transactions.

Regulatory proposal

The proposal is that in each case a supplier can't physically meet its supply contract, it is obliged to pay a firm monetary compensation[25] to its customers that equals the quantity of non-supplied gas times the Value of Lost Load (ENS*VOLL). This will ensure that though customers will suffer a physical supply cut due to the inability of some suppliers to meet their contracts, the monetary compensation will keep customers' welfare unchanged compared to a no-supply-cut situation.[26] At the same time suppliers will face the full potential financial risk of non-compliance with their contracts. This might encourage suppliers to optimize their risk management through booking sufficient commercial storage, insurance or other means.

In case when some suppliers are unable to meet their contracts during a crisis but there is strategic storage present in a MS, the release of strategic stock can save customers from a physical supply cut and ensure their welfare is unchanged compared to a no-supply-cut situation. In this case final customers should pay the normal contracted price for gas during the crisis (supplied from the strategic stock). However, those suppliers that were unable to supply the contracted quantity for end customers should pay the strategic storage operator, instead of the final customer, the above financial compensation (ENS*VOLL).[27] This solution will ensure that suppliers will face the full potential financial risk of non-compliance with their contracts even when a strategic storage asset provides a physical insurance for gas crisis situations. Optimum risk management incentives for suppliers are retained in this case. Note that such a regulation will make strategic stock keeping obsolete and help transforming strategic storage to commercial storage in longer term.

Preconditions

To implement such a regulatory scheme, NRAs should produce reliable VOLL estimates for their respective (protected) customers.

The consistent, EU-wide implementation of such a scheme could encourage the fast development of financial products to help suppliers to mitigate their increased financial risk efficiently.

Coverage

The scheme can cover all customers or protected customers only. We are on the view that non-protected customers can more easily manage their financial compensation through contracting than protected customers. Thus, the scheme is primarily proposed to cover protected customers and related suppliers only but can also apply to all gas customers.

Likely impacts by stakeholders

Customer welfare will be protected in gas crisis situations regardless whether they suffer a physical supply cut (no strategic storage but financial compensation) or not (supply ensured from strategic stock and no extra compensation).

Suppliers' distorted risk management incentives under storage obligation and strategic storage schemes will be mitigated, incentives for optimal risk management restored. The financial market will help in efficient risk mitigation. Additional costs of risk management

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[25] No *vis major* argument should apply.
[26] This is the consequence of the definition of VOLL: the minimum monetary compensation needed to make customers indifferent for losing some gas supply.
[27] While this amount is most probably far exceeding the strategic storage operator's cost of refilling its UGS asset, the remaining revenue can be redistributed to gas customers or paid into the general budget.

will be passed through to final customers. At the same time, the costs associated with the present, inefficient risk management schemes will be cancelled.

A specific risk for suppliers under the proposed obligatory financial compensation scheme would be related to cross-border access to their stored gas. If e.g. a MS would apply a regulation to restrict cross-border trade during a crisis[28], the supplier should anyway be obliged to pay compensation for restricted customers at home (no *vis major*). If such a case happened, it would most likely conclude in litigations against the MS that applied cross-border trade restrictions by the supplier or its insurance company. Such litigations (or the risk of them) could encourage member states to remove such regulatory provisions from their respective national regulations.

Storage operators will lose local capacity bookings due to storage obligations but gain increased commercial bookings, local and cross-border.

1.10. New infrastructure utilization

The LNG and storage strategy identifies key pieces of infrastructure that have been selected as projects of common interest (PCIs) and identified by the relevant regional high level groups (such as CESEC, BEMIP and South-West Europe) as key priorities. These projects (listed below) were part of the reference scenario to test whether they are needed during demand and supply shocks.

Table 29. List of infrastructure identified by the LNG and storage strategy to be of key importance

Name	Maximum flow GWh/d	Date of commissioning	Basis to include into reference for 2020
HR-LNG	108	2020	LNG strategy
RO-HU (BRUA)	126	2020	LNG strategy
HU-RO (BRUA)	77	2020	LNG strategy
FI-EE	79	2019	LNG strategy
EE-FI	79	2019	LNG strategy
PL-LT (GIPL)	51	2019	LNG strategy
LT-PL (GIPL)	51	2019	LNG strategy
LT-LV	52	2019	LNG strategy
EE-LV	105	2019	LNG strategy
LV-EE	42	2019	LNG strategy
ES-PT	85	2021	LNG strategy
PT-ES	70	2021	LNG strategy
ES-FR	110	2021	LNG strategy
FR-ES	120	2021	LNG strategy
GR-BG	90	2018	LNG Strategy with FID
GR-BG	151	2021	LNG Strategy with FID
BG-RS	51	2018	LNG Strategy with FID
RS-BG	51	2018	LNG Strategy with FID

This chapter summarizes utilization of these pieces of infrastructure within the different modelling scenarios. The results are presented here also for the sensitivity scenarios (higher : TYNDP blue, and lower : EUCO 30 demand ; and higher and lower global LNG supply) The alternative scenarios are presented in the sensitivity chapter below.

Croatian LNG terminal

[28] Regardless this breaches EU law.

2020 results: The yearly utilization of the Croatian LNG terminal is 5% in the 2020 reference scenario (without supply or demand shocks), which can reach 24% when global LNG is well supplied but can go down to 0% when LNG market is tight.

Storage obligations have a negative effect on the utilization, and without these obligations utilization would rise by 3% (both in the reference and in the supply shock scenarios). With demand shocks storage utilization reaches 11%, and with supply shocks 14%.

2025 results: Yearly utilization of Croatian LNG is 16% in the reference which can rise to 23-30% with high global LNG supply, depending on the European demand developments, but in tight LNG market scenarios it can reach 0% again.

Storage obligation has less effect on the utilization in 2025 (+1%) since obligations are decreasing in volume by time (see chapter on storage obligations).

Demand and supply shocks increase the utilization up to 18-19%, and the terminal is never congested in any scenario.

Without Nord Stream 2, utilization of the terminal is 24% without shocks (2025). Nord Stream 2 has no effect on the utilization of the terminal in the 2020 reference.

Comment : A smaller FSRU carries higher utilization rates than onshore, so the low utilization is partly due to high regas tariffs (3 €/MWh) and high transmission tariffs on the evacuation pipeline, that combine to reduce the regional use of the facility. The HR_LNG is aimed to serve diversification purposes and as such it could serve as a bargaining tool and increase the negotiation power of European traders towards the dominant pipeline supplier in the region. As such, the project is risky for investors because of uncertainty in the global LNG market, the volumes and subsequent prices that would be available to Europe. The project has little chance to be implemented on a market basis, and thus is dependent on the CEF grant it was awarded in 2017.

Romanian-Hungarian interconnector

This pipeline is not utilized in 2020 and reaches 30% in the 2025 reference, dropping to 27% with high global LNG supply. This project is especially sensitive to Romanian gas demand developments; when demand is high in Romania (TYNDP blue) no gas is exported on on a market basis. With a EUCO 30 demand projection, the utilization is between 18-23% depending on global LNG supply.

Demand and supply shocks do not have any effect on the utilization of this pipeline and it is never congested under any scenario.

Without Nord Stream 2, the utilization would be 33%.

There is no flow from Hungary to Romania in the reference, only some minor flows (3%) in the high demand scenario in 2020.

This project is an extension of an already existing IP between Hungary and Romania, and the results presented here are very conservative in the sense that new offshore gas fields are not part of our reference scenario. Utilization figures can be higher if the offshore fields are developed and come online. A high tariff on the Romanian transmission exit point has already been identified by previous studies as a barrier to trade, and this is an issue that must continue to be monitored.

Estonia-Finland interconnector (Balticonnector)

The pipeline has a stable 32% utilization in the 2020 reference and supply shock scenarios, and demand shocks increase the utilization by 1-2%.

The 2025 the reference utilization is 32% and 27% for the EUCO 30 reference demand run; with high LNG supply this can reach 30% and with low LNG supply down to 18%. In the TYNDP blue scenario, flows are reversed and go from Finland to Estonia, at 5% utilization with the reference demand shock, 9% when a tight LNG market is assumed, and 1% if global LNG supply is high. This is a result of a convergence in demand forecast for the four Baltic countries (EE, FI, LT, LV) to about 50 TWh in the TYNDP blue scenario and 70 TWh in the EUCO 30, which is much closer to the Primes reference 74 TWh.

Utilization of this pipeline is not sensitive to supply or demand shocks or Nord Stream 2.

Comment: This assessment does not substitute for a proper CBA analysis, however the results suggests that this pipeline is a realisitc project under any circumstances.

Poland-Lithuania interconnector (GIPL)

In 2020 the reference utilization is 0%, only used in the 7-day peak and the combined 7-day peak + Nord Stream 2 disruption scenarios. In 2025 it reaches 15% from Lithuania to Poland but in January, the flow reverses and is utilized at 70% from Poland to Lithuania as a result of a relative change in prices. Under reference conditions prices are close in the two countries, but with the demand shock Lithuanian prices are higher than Polish prices in January. The results are slightly misleading because the model does not allow for additional spot Russian flows above the maximum LTCs on the pipelines connecting Russia to the Baltic countries.

In the 2025 reference yearly utilization of the pipeline is 21% from Poland to Lithuania. The direction of flows depend on global LNG dynamics; with high global LNG supply it is from LT to PL, in low global LNG supply it reverses. In the TYNDP blue scenario utilization reaches 100% and the pipeline is congested throughout the year.

Nord Stream 2 would increase pipeline utilization to 33% (LT to PL).

Comment: Although this analysis does not substitute for a proper CBA analysis, the flexibility of a bidirectional pipeline on the Lithuanian - Polish border seems to be beneficial from the security of supply point of view for both countries, given the uncertainty of global gas market developments.

Lithuania-Latvia interconnector extension

The pipeline shows very low utilization, 0% in the 2020 reference and 7% in 2025. This figure does not change significantly in the supply and demand shocks, however in the 7-day peak scenario January utilization is up to 88% in 2020 and 94% in 2025.

Comment: this pipeline serves peak demand purposes.

Latvian- Estonian interconnector

The pipeline is highly utilized in all modelled scenarios between 83 % to 95%, and in January 100%.

Comment: Results strongly support the need for this pipeline.

Portugal-Spain 3rd interconnector

This pipeline shows no flow in any of the scenarios, except for the EUCO 30 with low global LNG supply scenario, when it reaches 26% from Spain to Portugal.

Comment: EGMM does not model domestic bottlenecks. The strong interconnections between the Spanish and the Portuguese gas system might justify the need for this project for reasons that are not captured by our modelling.

France-Spain interconnector (Midcat)

This pipeline enters in 2025. There is no flow on the pipeline in the reference in 2025 with the high LNG supply scenario. It is utilized only in the France to Spain direction in January in the low LNG scenario and in the 7-day peak (when spot LNG cannot reach Spain within 1 week), but then 100% in January.

Comment: It would require a detailed CBA to decide whether the investment is warranted or other mitigation measures for the peak demand (e.g. demand response) might be more efficient.

Interconnector Bulgaria-Serbia (IBS)

This project has a high utilization in almost all modelled scenarios. In the reference, yearly utilization is 80% in 2020 and 87% in 2025 from Bulgaria to Serbia. The high utilization is partly due to an artificial recontracting of the Russian LTC from the original route (UA-HU-RS) to a new route (UA-RO-BG-RS[29]). Without any recontracting of the Russian LTC the pipeline would still be used up to 42% for spot trade, indicating solid market demand for the project that opens competition in Serbia (Azeri gas and LNG from Greece through Bulgaria). The need for the pipeline is even more straightforward in a non-cooperative supply shock scenario, assuming that the HU-RS border is closed to spot trades and storage in Hungary are not accessible in a supply disruption case.

In high LNG scenarios and in demand shock scenarios the utilization of the pipeline can reach 72-100%.

Comment: There is no flow from Serbia to Bulgaria even in the Southern supply disruption scenario. As Serbian storage is not working under TPA, there is no cross border storage use in the modelled scenario, yet the possibility for cooperation can not be excluded: during the implementation of the project parties can agree on cooperation and use of the storage facility according to TPA access rules.

Interconnector Greece-Bulgaria (IGB)

The yearly reference utilization rate of the pipeline is 27% in 2020 and 35% in 2025, and up to 81-100% in the Ukrainian disruption scenarios in January.

In the 2025 utilization is higher when more LNG is available on the global market (42%) and ifdemand is higher (TYNDP blue scenario – up to 49%). The maximum yearly utilization is about 57% if both demand and LNG supply are high.

Comment: the pipeline serves market integration and security of supply purposes with robust results even if global LNG supply is tight or demand development is modest.

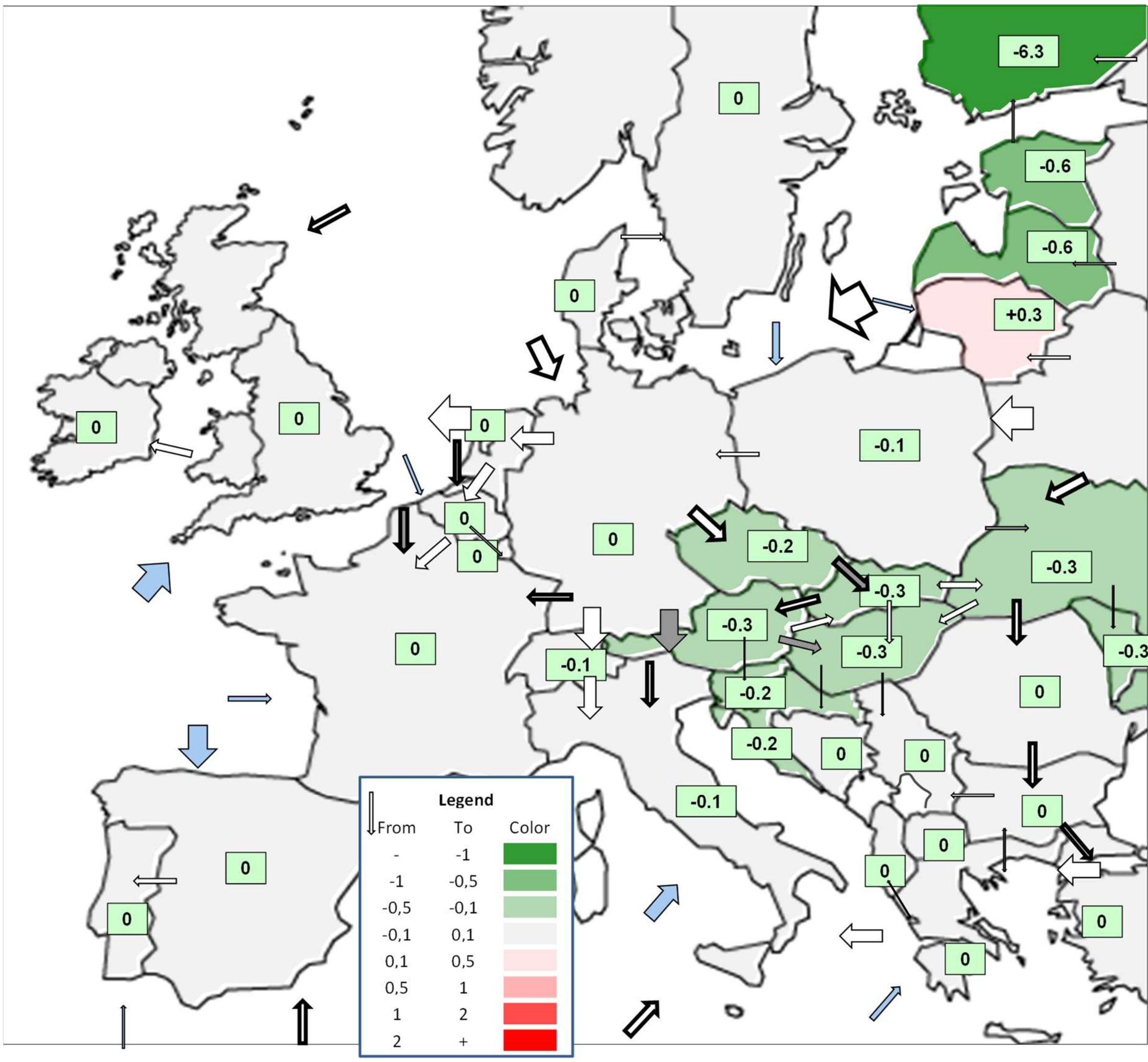
The combined effect of infrastructure proposed by the LNG and Storage Strategy

To test the need for the proposed projects a sensitivity run was tested using only projects with an FID according to the latest (2017) TYNDP, meaning that Nord Stream 2 and TAP would be built, and only IGB and IBS from amongst the other projects Croatian LNG is also included in light of its CEF funding. The following chart indicates the loss of market

[29] Results would be the same with a new route on the planned Turkish Steam (TR-BG-RS), which was not modelled

integration benefits by depicting the price decrease that does not occur because the projects were not implemented.

Figure 36. Yearly average wholesale price difference caused by LNG storage strategy projects in 2020, €/MWh



Green coloured countries would benefit from the projects while red colour countries receive higher prices.

Without the projects the EU 28 volume weighted price would be 0.07 €/MWh higher than with the projects in 2020, and the most effected countries are the Baltic countries (Latvia and Finland), some Balkan countries (Bosnia and Croatia) and some countries in CEE (Hungary, Slovenia, Czech Republic) and Ukraine. Romania is the most adversely affected, with total welfare change 56 million €/year gain in 2020 and 130 million €/year in 2025, although this does not incorporate the security of supply benefit. Considering the investment costs related to these projects and the scarce resources, attention should be focused on the projects with more utilization (see chapter above).

Summary of result:

The infrastructure priorities of the LNG and Storage Strategy were tested under normal and security of supply scenarios under high and low global LNG supply, and high and low and gas demand projections. Most of the projects provide satisfactory results in terms of utilization, either under regular or in SOS scenarios or in both. The most robust results are with pipelines in the Baltics, to IGB and IBS. Croatian LNG is very sensitive to global LNG supply and European demand development, although the benefits of the project are inevitable in SOS. The pipeline projects on the Iberian Peninsula did not show good results in any of the scenarios tested.

1.11. Utilisation of existing LNG terminals and storages

1.11.1. Utilization of LNG terminals

LNG terminal utilization in Europe varies widely. In 2016 utilization is low (0-36%), with Italian and Greek terminals showing the highest figures and some development in terms by 2020 of utilization in Lithuania and Poland, while other terminals stay even or decrease due to the low demand levels across Europe and the market share strategy employed by Gazprom. Yearly utilization figures show a substantial increase from 2020 to 2025 because EU production is falling and there is more available competitive LNG on the global market. Lithuanian, Polish and Portuguese terminals double their utilization figure and Turkey triples. The terminals in North West Europe start to receive more cargoes when the global LNG supply is high, in Belgium, France, and the UK, and it is the only scenario where the Dutch terminal is utilized (25%). High LNG supply is also beneficial for the Turkish, Polish and Croatian LNG terminals, but the others (GR, ES, PT, IT, MT) are not repsonsive. This is partly due to low interconnectivity and the isolated nature of these markets (GR, PT, MT) but also due to the lack of price disparity between neighbouring markets (IT, ES). Even in the high LNG supply scenario when the yearly European utilization rates of the terminals are up to 45%, there is no serious congestion on the yeary level (the Lithuanian and Turkish terminals are only close to the threshold).

Peak utilization of LNG terminals in high demand months does not lead to monthly congestion on any terminal in the reference 2020, and only the LT LNG terminal becomes congested in 2025. In the alternative high demand, high LNG supply reference in January Belgian, Italian, Polish, Turkish an British terminals become congested. UK terminals are 7% more utilized in January when Rough storage is assumed to be closed down, but this increase in January is not visible on the yearly utilization of UK LNG terminals.

LNG can contribute to mitigate supply crisis problems with additional spot cargoes delivered to the closest terminal to the affected countries. LNG has a significant role in the modelled Northern route disruption, providing an additional ~17 TWh/month (~18% of the missing volumes) to the European supply, and in the African pipeline route disruption (~13 TWh/month, 38% of the missing volumes). It has limited contribution to mitigate supply disruptions in SEE, as interconnectivity is still low in the Balkans (LNG terminal in Greece) and the planned LNG terminal in Croatia would need to reduce tariffs on cross border interconnectors to be able to benefit the region.

1.11.2. Utilization of storage facilities

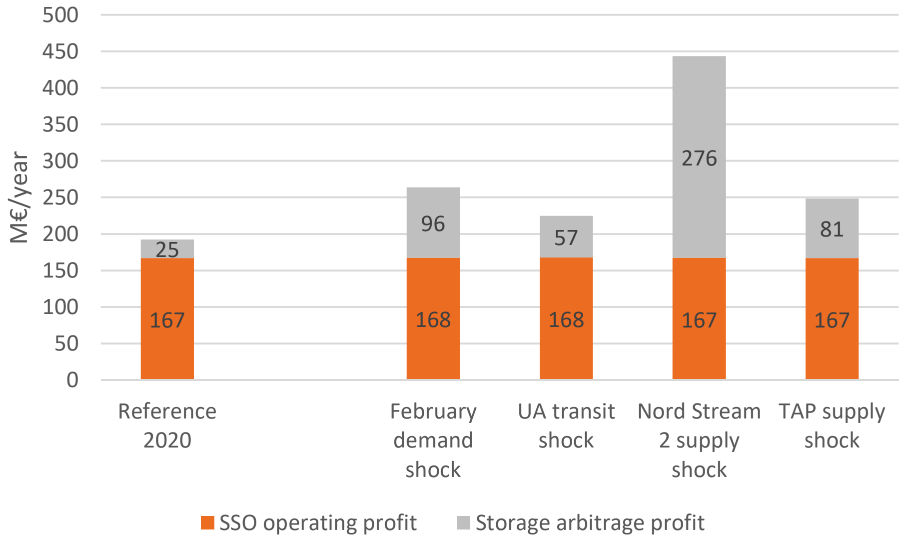
Storage facilities play an important role in providing seasonal flexibility to the European market and under security of supply scenarios they contribute the most among the flexibility sources. Still, modelling results do not project an optimistic future for storages. The aggregate volume of gas stored is decreasing with time (7% in the EU28, and 3% in the entire modelled region) despite the current storage obligations in place in many countries.

While overall storage use is falling, storage sites are utilized more in Bulgaria, Croatia, Italy and Poland and Ukraine. Others are less utilized:the largest volumes missing from the Austrian, German and French storage.

A certain surplus capacity on the market is already facing financial troubles, and this year witnessed the first closure of a storage site in Ireland possibly with more to come. Modelled storage use is the highest in UK and in IR, which shows that the market is not willing to pay the cost of storage.[30]

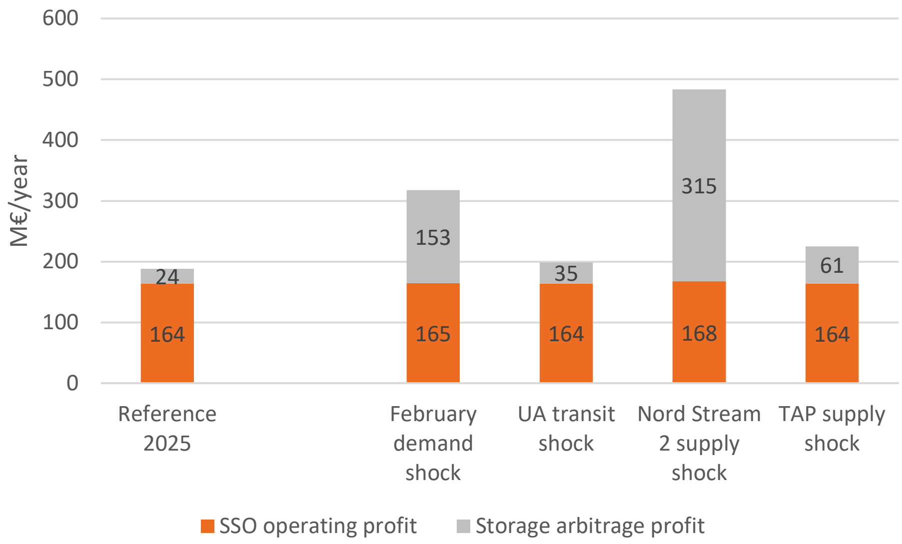
Modelling outcomes for 2020 indicate the highest possible value for storage in extreme cases. In the 2020 reference case, the storage infrastructure is under-utilised as other sources of flexibility (pipeline, LNG) are offering cheaper alternatives for seasonal demand. In case of an unforeseen 1 month demand shock in February (modelled as a 15% demand increase throughout Europe) storage arbitrage is increased from ~25 M€ to ~96 M€ in the EU-28. The reason for this increase in revenues is the fact that the unforeseen demand surge causes a price hike, making already stored gas volumes more valuable. Level of stored gas remains unchanged. Supply shocks cause a 57-276 M€ storage arbitrage. Modelling 2025, a somewhat wider range of 35-315 M€ is estimated. Probability of these scenarios is not assessed.

Figure 37. Modelled value of storage by storage operator profit and storage arbitrage in the EU-28, 2020



[30] For modelling purposes and due to lack of data on storage tariffs a uniform 1€/MWh is used fee for storage services, slightly below the modelled summer/winter spread – except for those countries where published tariffs are lower than this figure (UA)

Figure 38. Modelled value of storage by storage operator profit and storage arbitrage in the EU-28, 2025



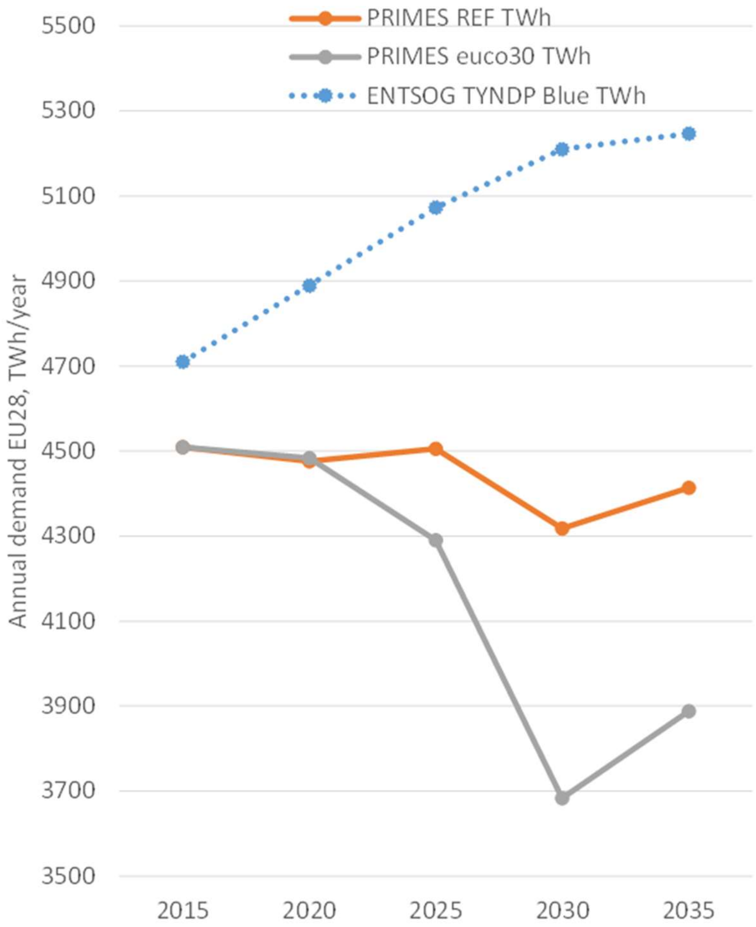
However, storage provides a great value for market players and consumers alike by smoothing the price levels between summer and winter prices. Were there less storages available, summer and winter spreads would be considerably higher, which would certainly increase the profit of operators still active on the market.

1.12. Sensitivity runs

The reference scenario for 2020 and 2025 are based on assumptions agreed upon during the first phase of the study, described in detail earlier in this report. At the same time, we forecasting gas demand for Europe and global LNG supply that would finally reach Europe depends on many factors that cannot be accounted for in a model.

The current trends and the outlook of the global LNG market are described in the LNG market trends chapter. The sensitivity analysis is based on the scenarios defined by Energy Markets Global, assuming demand to be above and below the Primes reference and LNG arriving to Europe that in the reference. The high demand scenario is based on the ENTSOG TYNDP blue scenario, while low demand is based on Primes EUCO 30 demand forecast. Since there is no difference between Primes reference and the EUCO 30 demand forecast curve for 2020 (see Figure 39), we do the sensitivity analysis for the 2025 modelled year.

Figure 39. Demand forecasts for Europe up to 2030 (TWh/yr))



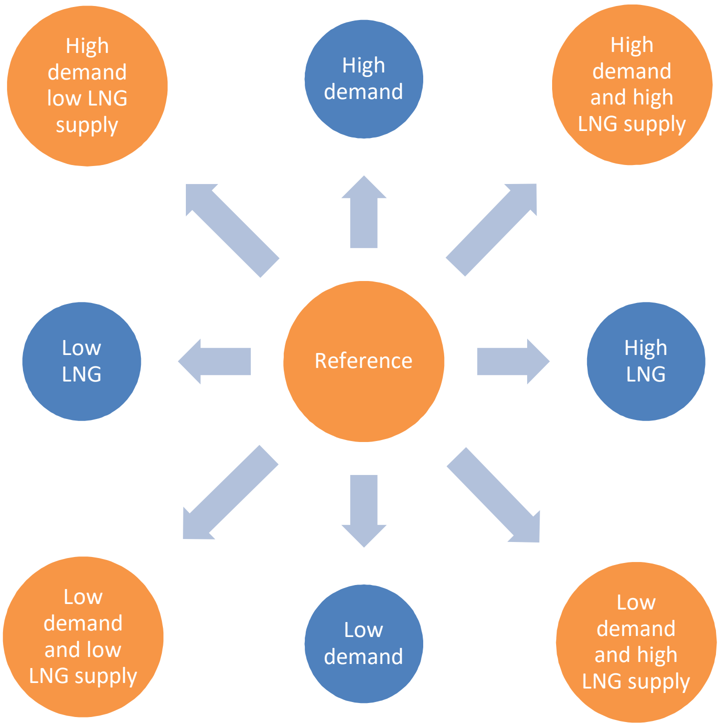
Source: PRIMES, ENTSOG TYNDP and EGMM assumptions

We also tested for more and less LNG supplied to Europe compared to our reference to reflect the unpredictable development of global gas demand centres. At times the price Europe is willing to pay might not be competitive enough to attract LNG, and this depends on demand developments in other regions of the world. This is represented by high and low LNG scenarios.

A low LNG scenario in the modelling assumes that by 2025 global demand for LNG has grown and prices in Asia are high. (25€/MWh). The high LNG scenario means that LNG prices in Asia are low (17 €/MWh)

The sensitivity runs are depicted on the chart below:

Figure 40. Schematic representation of sensitivity runs

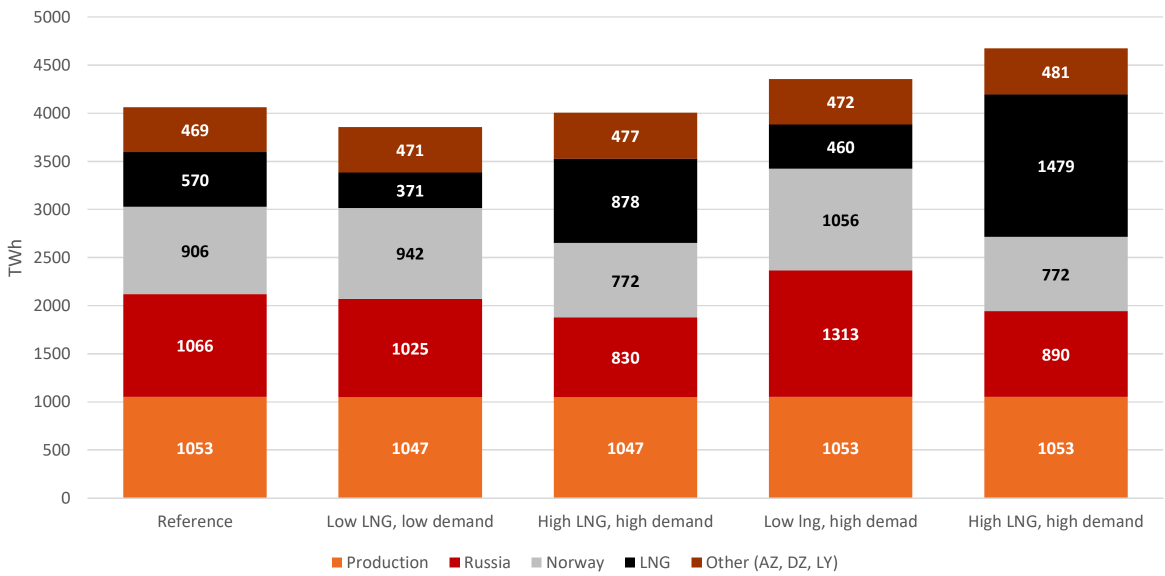


Source: REKK

In the 2025 reference scenario, 569 TWh LNG would reach Europe. This is well below the 1100 TWh that is available for Europe on the global market according to the outlook of Energy Markets Global because prices in Europe are lower and served more by pipeline (Russia, Norway, Algeria).

The supply structure of the alternative reference scenarios is illustrated on the chart below:

Figure 41. Supply structure of the alternative scenarios (2025)



Source: REKK EGMM modelling

The scenarios are introduced by comparing the following outputs of the modell:

- the EU 28 volume weighted yearly average gas prices (in €/MWh)
- the LNG inflow to EU 28 (in TWh)
- storage inventory in EU28 (in TWh)

Table 30. Volume-weighted average yearly wholesale price in the sensitivity reference scenarios, €/MWh

Price EU 28 (€/MWh)	low LNG	ref LNG	high LNG
high D	20.5	19.0	17.4
ref D	18.9	18.3	17.0
low D	18.5	18.0	16.7

Source: REKK EGMM modelling

The European (EU 28) volume weighted average price is driven by the European demand and is is dependent on the global LNG supply. As expected, the lowest price in Europe emerges when demand is low and supply is high. The Europen volume weighted average price would increase with demand as the TYNDP blue scenario forecasts under a tight LNG market, and the difference between the two is 20%. Further detail is provided in Annex 5.

Table 31. Yearly LNG to EU-28 in sensitivity reference scenarios, TWh/year

LNG inflow EU 28 (TWh/yr)	low LNG	ref LNG	high LNG
high D	460.1	854.8	1479.4
ref D	379.2	569.5	1044.8
low D	371.4	494.8	878.0

Source: REKK EGMM modelling

Assuming the same price level for all suppliers to Europe except for the LNG traders (they price against Asian LNG market price), LNG demand in Asia (and the price Asia is willing to pay) heavily influences the amount of LNG reaching Europe. The maximum modelled inflow (in a high European demand and high LNG supply scenario) is four times higher than the minimum inflow (with EUCO 30 demand and tight LNG market).

Table 32. Storage inventory in EU28 in sensitivity reference scenarios, TWh/year

Storage inventory in EU28 (TWh/yr)	low LNG	ref LNG	high LNG
high D	801.0	749.4	711.2
ref D	700.0	730.8	705.1
low D	738.8	754.3	708.2

Source: REKK EGMM modelling

The storage inventory varies close to the reference level, at most 10% more and at least 4% lower. All high LNG supply scenarios work against storage utilization as a competing source of flexibility.

The alternative scenarios depict possible future developments and their effect on the European market. The next tables show how the modelled security of supply outcomes would change in the alternative future reference scenarios. The Northern route disruption scenario was used to test the robustness of the results.

Table 33. Volume-weighted January wholesale price effect in the sensitivity Northern route disruption scenarios, €/MWh

Price EU 28 (€/MWh)	low LNG	ref LNG	high LNG
high D	2.9	0.8	1.0
ref D	3.9	1.3	0.9
low D	2.2	0.7	0.8

Source: REKK EGMM modelling

The difference between the January SoS price increase and the reference modelled scenario (1.3 €/MWh) and the same SoS modelled price increase compared to the alternative scenarios shows that results are more sensitve to the LNG supply and less sensitive to the European demand assumtions.

Table 34. January additional LNG inflow to EU-28 in sensitivity Northern route disruption scenarios, TWh/month

LNG inflow EU 28 (TWh/month)	low LNG	ref LNG	high LNG
high D	8.7	25.8	6.2
ref D	4.0	12.0	12.8
low D	0.1	3.5	30.1

Source: REKK EGMM modelling

Monthly LNG importd in SoS scenario is mainly driven by price signals in Europe and the amount of global spot LNG available globally. Europe can attract an additional 0.1 to 30 TWh LNG in a monthly shock, a large variation of which determining factors lay beyond the scope and influence of European regulation. In the 2025 reference case 53 TWh of LNG enters the EU 28 in January, an increase of 12 TWh. This 22% increase would fall in the low demand low LNG supply scenario to almost zero and could reach 37% in the low demand high LNG scenario.

Table 35. Storage withdrawal in EU28 in sensitivity Northern route disruption scenarios, TWh/month

Storage inventory in EU28 (TWh/month)	low LNG	ref LNG	high LNG
high D	72.4	71.3	60.0
ref D	69.7	68.7	54.1
low D	63.2	68.7	33.8

Source: REKK EGMM modelling

Storage withdrawal is not sensitive in the shock senarios, and only challenged by a low European gas demand combined with high LNG supply, where LNG could outcompete storage.

Sensitivity to key infrastructure

To test the sensitivity of results to key infrastructure, we selected the polictically highly debated project, the Nord Stream 2 project. We tested the results of the highest demand (TYNDP blue) and reference demand scenarios for 2020 and 2025 – and modelled them without building Nord Stream 2 and without rerouting the Russian contracts.

Table 36. Sensitivity of results to key infrastructure - Nord Stream 2

	2020	2025
Price difference no Nord Stream 2- with Nord Stream 2 EU 28	€/MWh	€/MWh
high D	-2%	-8%
ref D	1%	2%
LNG inflow EU 28	TWh/yr	TWh/yr
high D	24%	49%
ref D	4%	9%
Storage stock EU 28 max	TWh	TWh
high D	-1%	-10%
ref D	-3%	-8%

Source: REKK EGMM modelling

Without Nord Stream 2 in a high demand scenario the yearly weighted average price increase in the EU 28 is 8% higher than with Nord Stream 2, but 2% less in the reference demand scenario for 2025. The difference is even smaller for 2020 (-1% to 2%). This means that Nord Stream 2 might bring on a European level slight price increase but also slight price decrease depending on other factors (EU demand and LNG supply to Europe). The regional price effect is different in North West and in South East Europe. The price effect of key infrastructure on a European scale is within 10%, and is significantly smaller than the other determining factors (demand and LNG supply) described above. LNG inflow to Europe is higher if Nord Stream 2 is not built, and the difference is intuitively larger when higher European demand is assumed (up to 49% in a high demand scenario for 2025). The storage withdrawal is slightly smaller without Nord Stream 2, but storage withdrawal results are more robust, results are within a 10% threshold.

Comparing results of supply scenarios would be misleading as in the Nord Stream 2 building reference the Northern route disruption has the highest effect on security of supply and diminishes the effect of the Ukrainian route disruption. In the without Nord Stream 2 scenario the highest risk scenario is the Ukrainian route cut, that can not be directly compared to each other.

Conclusion: Our results on modelled price effects of supply shocks are most sensitive to the global (spot) LNG supply and to a lesser extent European gas demand. The existence of Nord Stream 2 is less decisive than the previous two factors; the current European network is capable of transmitting gas from different sources under different stress scenarios with or without that project as well.

2. Liquidity, Flexibility and Transparency in LNG

This section covers Task Eight and addresses the key issues regarding liquidity, flexibility and transparency of the global LNG market. It considers:

- Characteristics of trading markets, liquidity, transparency and flexibility;
- The current state of the LNG business globally and as it affects Europe, covering:
  - Supply, markets, costs, pricing, contracting;
- Alternatives and scenarios for future development and commercial arrangements;
- The main drivers for liquidity, transparency and flexibility in the LNG business.

The approach and methodology for how we will carry out the analysis and reach our conclusions for this section is:

- Review and analysis of publicly available data and information sources, including:
  - IEA, OIES, GIE; GIIGNL; and others;
- Interviews with key players in the industry, face to face or by telephone;
- Preparation of case studies:
  - Comparisons with liberalisation of pipeline gas markets in Europe;
  - The development of and current state of oil trading;
  - The development of iron ore trading;
- Construction of an inhouse detailed database with analysis of every LNG liquefaction plant globally up to May 2017 (existing, under construction, under FID, speculative projects), providing the most up to date analysis of the LNG liquefaction and supply position.

In the Annexes to this Task 8, we include:

Current state of the LNG Industry: A full description of the current state of the LNG industry globally, covering:

- **Overview of Current Trends:** Current state of the LNG industry globally;
- **New LNG Technology and Markets:** New LNG technologies and the new markets they are creating;
- **LNG Costs:** Analysis of the cost structure of LNG projects and the value chain;
- **Methodology for Analysis of Future LNG Supplies:** How we estimate global LNG supplies;
- **Analysis by LNG Liquefaction Project:** An analysis of LNG available for Europe from detailed study of every liquefaction plant around the world;
- **Asia LNG Market and Supply:** Moderation of the global supply analysis by consideration of Asian LNG markets;
- **Decline in Existing Production:** A note that declines in existing production as well as demand increases could affect volumes of supply becoming available;

Contracts: Descriptions of petroleum and LNG contracts:

- **Oil, Gas and LNG Contracts:** Overview of oil, gas and LNG contracts;

- **Gas Sales Agreement:** Contractual terms in typical GSAs;
- **LNG Sale and Purchase Agreement:** Typical contractual terms in LNG SPAs and how they differ from GSAs;
- **Other LNG Agreements:** Overview of the range of LNG agreements;
- **Main Differences for LNG Contracts:** The main differences between LNG contracts and other types of petroleum contract;
- Two template LNG contracts:
    - **GIIGNL LNG Template Contract;**
    - **AIPN LNG Template Contract.**

2.1. Scenarios for LNG Supply Available for Europe

In order to understand how the global LNG industry could develop over the next ten years we have prepared a set of four scenarios. These scenarios are descriptions of future positions. They are not predictions but are plausible "what-if" analyses. The scenarios do not show all possible outcomes for the global LNG industry. They are not intended to do that. What they do instead is to show a set of possible futures which are sufficiently different that they can test policies and strategies to ensure they are sufficiently robust under all the possible scenarios.

It is reasonably feasible to makes estimates of liquefaction capacity, through an analysis and consideration of each liquefaction plant and potential project. Estimating demand for LNG is much more complicated and so a scenario approach has value in trying to understand the future of the global LNG industry.

There are many PESTLE (Political, Economic, Social, Technological, Legal, Environmental) factors affecting the LNG industry globally but we consider the two most important key drivers to be:

- Levels of demand;
- Levels of supply.

We have plotted these two key drivers on a two by two chart to generate four scenarios for how the LNG industry globally could develop over the next ten years, taking as a starting point the reference case volumes described above. These are shown in the following figure and then each scenario is described.

The volumes of LNG which are likely under each scenario are those we predict would be available for Europe. These volumes are based on the historic assumption that Europe is a demand centre of last resort, after volumes are supplied to Asia because of the higher prices and the higher volume contracts on offer in Asia. What Europe consumes will be different from what is on offer and the market will balance itself at a market defined price level. Unlike oil, LNG does not float around the oceans in mobile storage looking for a destination. All LNG cargoes finds a buyer. So LNG markets balance with producers producing a little less or buyers (somewhere in the world) buying a little more and the market price enables the market to balance.

In an excess supply situation where there is more LNG available than market to consume it, the market will most probably balance by producers reducing their production for LNG. As is discussed further below, the USA is the highest marginal cost LNG producer, and as the (very large) marginal supplier, US LNG will most likely be reduced in over supply situations and increased in supply shortage situations.

Volumes of LNG available are based on Energy Markets Global analysis of liquefaction plants around the world plus IEA estimates of gas and LNG demand and Atlantic Council estimates of LNG prices[31], moderated according to each scenario.

Many Asian contracts were signed during previous periods of much higher LNG prices. Many of these contracts are now coming up for renewal and the buyers are pushing for much lower prices. In addition, for many projects which were negotiated on higher prices but not yet contracted, buyers are now seeking price renegotiations and price reopeners. Chinese LNG import contracts have tended to be higher priced than others in the region and Qatar has benefited historically from high priced exports to Asia. With the renewal and/or renegotiation of many Asian LNG contracts, there will be pressure from buyers for lower prices.

While Asian LNG long-term contracts, as well as short-term and spot contracts, will see downward pressure on prices, Asian prices on average will still remain higher than European prices. Ultimately, LNG prices globally will be set (or at least influenced) by US Henry Hub prices (different scenarios test whether emerging markets, who are price takers, accept or reject the international pricing of LNG). The shorter transport distances to European markets and the influence of Russian pipeline gas supplies will keep European gas prices lower than Asian prices, where LNG dominates and where transport costs from the US Gulf coast will be higher. Asian LNG prices may also be influenced by Asian LNG developments, including supply and demand in the region, and by any potential emerging LNG hubs in Singapore, Japan or Shanghai. Asian prices therefore are likely to be influenced by Asian market developments as well as by Henry Hub.

In the final analysis, economic theory states that the marginal supplier sets the marginal (spot) price. This is most likely to be the USA in the current circumstances.

The EEGM is based on a reference case, with LNG volumes available for Europe based on our reference case estimates (which is described in Annex 8). Four scenarios are developed below around the reference case (so five cases in total are considered). The EEGM describes the modelling output from the scenarios in Annex 5.

Implications for the EEGM Reference Case:

- Volumes available for Europe:
    - 2020: 87 mt (~1300 TWh);
    - 2025: 113 mt (~1700 TWh);
- Prices, Europe LNG:
    - 2020: $6.50 (~26 €/MWh)
    - 2025: $7-8 (~28-32 €/MWh)

[31] Atlantic Council, Global Energy Center, US Liquefied Natural Gas Exports Outlook, 31 May 2017

Table 37. Four Scenarios for 10 Year Future of Global LNG Industry

	Low Supply	High Supply
High Demand	"Emerging Markets" FSRUs produce high emerging market demand Robust market growth in China and emerging markets Declining exports from traditional LNG producers LNG price up to $10/mmbtu	"Steady As She Goes" Some limited new liquefaction Existing production as now IEA global demand estimates LNG price around $7-8
Low Demand	"Boom and Bust" No new liquefaction is being built currently built beyond those currently under construction Supply shortage builds up Prices rise in early 2020s Substantial new liquefaction capacity is then brought onstream leading to substantial price falls By 2025 and a long period after, price falls to marginal cost, around $3-5/mmbtu	"Chinese Shale" Chinese demand for LNG falls substantially Additional Asian volumes released Large supply overhang A period of turmoil LNG price collapse to marginal cost, around $3-5/mmbtu US LNG exports virtually cease after a period of uncertainty China embarks on a national gas industrialisation strategy and eventually Chinese demand for LNG and imports return (but after 2025)

Source: Energy Markets Global 2017

Steady As She Goes Case:

High LNG Supply / High Demand:

Of the scenarios, this one reflects most forecasts for the future of the global LNG industry more closely than the others. The industry generally perceives a global LNG over supply now and building up until around 2022. While much of the global LNG industry assumes this supply overhang will largely have disappeared by 2025, this scenario assumes the supply overhang will continue.

Until 2025, this scenario, our "Steady as She Goes" Case is in line with most industry forecasts for global LNG, namely:

- US producers in the Gulf of Mexico become the game changer, US LNG supply soon becomes the largest supply source in the world, US pricing (Henry Hub plus a markup) and US contracts prevail;

- A small number of new LNG liquefaction projects are constructed, mostly coming from the USA Gulf of Mexico;
- Existing production sources (Algeria and Qatar) continue as now;
- Existing Australian LNG liquefaction projects are completed, no new Australian projects go ahead but all Australian LNG production remains within the Asian region;
- Global demand for LNG is in line with IEA forecasts;
- The market balances at a slightly higher price in Europe than now, at around $7-8/mmbtu (just above the approximate price which can lead to a netback to US Henry Hub of around $3/mmbtu).

There are some important sensitivities in this case, which are that:

- The global demand for LNG could be much higher than forecast, particularly from emerging markets and new technologies (such as the drive for clean energy for shipping fuels and road transport); and/or
- Existing production could decline and decline much faster that currently forecast.

These two sensitivities are tested in the other scenarios.

Emerging Markets

Low LNG Supply / High Demand:

Higher global demand for LNG than forecast combined with larger production declines from existing fields than forecast lead to an excess of demand over supply. In the "Emerging Markets" scenario, the different global LNG industry is largely set by the behaviour of emerging markets. Whilst it can be argued that historically, emerging markets behaved in a separate manner from larger mature markets, under this scenario, the very large growth of gas demand in emerging markets has a global impact. The characteristics of this scenario are:

- FSRUs prove very successful. The low cost, low credit risk and increased flexibility (an FSRU can be towed away in the event of any substantial problem with the host government) make them very popular with investors and host governments alike. Gas demand in emerging markets is substantially higher than forecast;
- It is very difficult to put a figure on what this increased demand could be. Most of the additional demand from FSRUs is in the Middle East and Africa (and to a lesser extent in parts of Latin America). The IEA forecast 656 bcm consumption by 2021 for the Middle East (2.3% annual growth rate, 505 bcm) and Africa (3.4%, 151 bcm). These assumed growth rates could easily be exceeded with the right regulatory and market signals in place (Chinese gas demand is forecast to increase by 9.1% over the same period);
- At the same time, gas production in some traditional LNG producer nations declines and at a faster rate than predicted. Algeria is probably the most exposed country to a fast declining gas production. In order to maintain oil production, increasingly gas has had to be used to reinject to maintain oil wellhead pressure. In common with many emerging markets in gas producer countries, domestic gas consumption is increasing at a very high rate (see the bullet points above in this scenario). Algerian gas exports (pipeline plus LNG) fell from 43 bcm in 2014 to 41 bcm in 2015[32];
- Qatar is another case where there is a risk of less gas available for exports. Although Qatar has now lifted the moratorium on exports from the onshore gas fields and

[32] BP Annual Review of World Energy, June 2016

new offshore discoveries have been made in Qatar, nevertheless there remains a potential risk of declining Qatari gas production in the future. Qatar has had operational problems with the onshore field which may possibly affect production in the future;

- These two events in emerging markets (higher emerging market demand especially in Africa and Middle East combined with reducing production from traditional LNG producers) lead to an excess of demand over supply. Instead of the supply overhang that is generally accepted in the industry now, the opposite happens;
- LNG and gas prices rise, perhaps to $10/mmbtu for LNG delivered to Europe (this would provide strong price signals for new liquefaction projects to go ahead);
- Existing US producers step up and further US liquefaction projects receive FID and by 2025 there is increased US LNG supply in the market, available for emerging markets, traditional Asian buyers and also for Europe (depending on where the best price can be obtained).

Chinese Shale

High LNG Supply / Low Demand:

In this scenario, there are very high volumes of LNG available on the global market combined with a low demand (or at least a demand profile that does not rise to meet the much higher volumes of gas available) so there is a much higher supply overhang than now.

China has been developing shale resources in recent years and small volumes are currently being produced in China. BP and Petronas have shown recent interest in Chinese shale and signed the first Chinese shale gas PSC in March 2016.

Under this scenario, this is just the start of a massive growth in Chinese shale gas. By the early 2020s China needs substantially less imported gas (pipeline or LNG). China stops buying any LNG and makes much of the existing contracted purchase volumes of LNG available on international spot markets.

In order to absorb the domestic gas volumes available, China also embarks on a substantial state managed gas led industrialisation of the country. The move away from coal to gas fired power generation intensifies and the transport infrastructure is enhanced, with a large number of infill projects around the country. This industrialisation takes time however and by the end of the time horizon of this study (2025), there is still a large excess of Chinese gas supply over Chinese gas demand. The Chinese gas market balances through China turning away (or reselling in secondary markets) LNG imports.

The key features of the "Chinese Shale" scenario and the consequences are:

- Large additional volumes of Asian LNG are available for global markets (up to 55 bcm (approximately 38 mt) which are the Chinese contracted LNG imports by 2025);
- Other emerging markets do not grow sufficiently quickly to absorb the excess LNG volumes. The promise of FSRUs as a vehicle for rapid gas demand growth in emerging markets remain largely unfulfilled. For various national market and regulatory reasons markets do not grow and imported gas does not find a home in domestic markets;
- There is a price collapse with LNG prices falling to the marginal cost of production, liquefaction, shipping and regasification. As most costs are sunk fixed costs, the marginal costs are very low indeed. The delivered price of LNG to global markets, including Europe, falls to perhaps $3-5/mmbtu;

- All liquefaction projects which have not already passed FID cease and there is no new liquefaction construction;
- US LNG exports are curtailed. Because of the nature of US LNG exports, namely that they buy gas at Henry Hub, gas production is not tied to an LNG scheme. This means that US LNG has a high marginal cost (the Henry Hub price). In this scenario, existing US liquefaction facilities cannot buy at Henry Hub and make a margin on global sales prices. Some US liquefaction facilities continue operating, pricing liquefaction and shipping on a marginal cost basis only (which is virtually zero) for a while, others mothball their operations. While US LNG exports are curtailed, other countries continue LNG liquefaction (because most country LNG projects have a gas production tied to an LNG scheme, making marginal costs much lower than the US);
- Because of the fall in US production, the net position on global LNG supplies does not change much (reduced US supplies offset the high volumes of Asian supplies). Eventually (but after 2025), Chinese demand will also increase to match the increased supplies and China imports LNG and pipeline gas again;
- The reduction in US supplies offsets the combination of lower than expected gas demand growth in emerging markets and the release of large volumes of Asian LNG from Chinese contrats;
- The the swing supplier, the USA, reduces LNG exports to balance global LNG markets. There is nevertheless considerable upheaval in the period 2020-2025, characterised (at least initially) by substantially increased volumes of LNG. This leads eventually to a boom and bust cycle, as described in the last scenario.

Boom and Bust

Low LNG Supply / Low Demand:

Either as a consequence of the current forecast supply overhang continuing (Steady As She Goes Case scenario) or the Chinese Shale scenario, there is a boom and bust scenario.

Currently (first half of 2017), no new onshore LNG liquefaction projects are being approved for FID (some Floating LNG production facilities are still being approved). In this scenario, this situation continues leading to a shortfall in infrastructure later. The characteristics of this scenario are:

- Those liquefaction projects with FID are completed and go into operation;
- No new liquefaction projects are taken forward (not in USA nor anywhere else), none of the speculative projects are completed;
- The same supplies are available after 2020 with no new investment into additional liquefaction capacity. At the same time, the global market grows substantially in the period to 2020. Chinese demand picks up again and FSRUs are successful in developing emerging markets;
- By the early 2020s, the current oversupply position has turned to an LNG supply shortage. As a consequence of the supply shortfall, prices rise substantially, perhaps up to $10/mmbtu in the years around 2020-22. Prices do not rise to the extent of the period to 2014 in the aftermath of Fukushima and the indexation to very high oil prices. We do not see a return to high oil prices and the major buyer countries (such as Japan) are not expected to produce such demand pressures again. Nevertheless, the shortfall in supply, combined with robust growth in China and in emerging markets (Africa and Middle East especially) will lead to price rises;
- On the back of high LNG prices, there is a rush to complete more liquefaction projects. This is probably still not enough for new Australian liquefaction capacity to be built but various projects elsewhere will go ahead, such as East Africa. The largest number of new liquefaction projects proceeding though will be again in the

US Gulf of Mexico. Existing US producers and liquefaction facilities also increase their operations;

- The difference in this scenario from the "Emerging Markets" described above is that the boom (high prices) lasts a very short time and leads to a consequent bust. The price rises come at a time when renewable energy has become a mainstream energy source. Buyer nations are no longer prepared to tolerate high prices for petroleum products (this includes the main Asian buyers as well as Europe) at the same time as renewable energy sources are now available at competitive prices. Buyer demand for LNG falls dramatically in developed countries (Japan, South Korea, China as well, Europe) from 2022 on;
- 2025 will see a substantial amount of liquefaction capacity with reduced demand for LNG globally, especially in mature markets. The supply overhang this time is likely to last for a substantial period (ten years or more) because mature markets will already have diversified into large scale renewable energy power generation. LNG prices will fall to the marginal cost of supply ($3-5/mmbtu) and remain low for a substantial period.

Europe is in a fortunate position of already having considerable diversity of gas and LNG supplies. Under all of the scenarios as well as the reference case, there will be enough LNG for Europe, provided that European buyers pay the price. European buyers are credit worthy and are large buyers so European buyers are attractive to LNG sellers. The determinant will be price only and we have estimated a maximum price of $10/mmbtu. Security of supply will be maintained.

In terms of meeting the EU objectives of increasing liquidity, flexibility and transparency in LNG, it is a little more complicated. The analysis and conclusions as developed through this report are that markets develop when there is a crisis, usually caused by an oversupply. It will be easier therefore to introduce or to realise measures for liquidity, flexibility and transparency in an oversupply scenario than in a tight market scenario.

In that case, the Emerging Markets scenario will be the most difficult for the EU to operate under, in terms of securing LNG supplies, in the high prices which will be demanded and in the restrictive practices that may be put in place or maintained by LNG suppliers. Dialogue with emerging markets to understand their LNG and energy needs and buying profiles will be useful actions for the EU. In addition, the EU could encourage measures towards more liquidity and flexibility now, before any potential supply crunch under the Emerging Markets scenario comes about. The sorts of measures are described further on in this report.

2.2. Characteristics of Energy Trading Markets

2.2.1. Preconditions for Trading

Economic theory[33] also dictates some preconditions that need to be in place before trading can take place:

- **Homogeneous commodity:** There must be a single commodity or it must be possible to specify a standard grade and to measure deviations from that grade. This condition is necessary if futures trading can take place based on a standardised contract. With some commodities, there may be two or more standard contracts, frequently however trading tends to concentrate onto one contract. Discounts and premia are fixed by the exchange to correspond to grades of the commodity below and above the standard grade. If delivery of a non-standard grade is made then

[33] For example: The Theory of Futures Trading, B A Goss, 1972, Routledge Publishing

this discount or premium is applied to the price of the contract at that time (maturity);

- **Rigidities in production:** Rigid production can give rise to spot market commitments, either long or short, and once such a commitment exists it can be avoided only at considerable cost to the party concerned;
- **Fluctuations in commodity price:** The price of the commodity must fluctuate or be expected to fluctuate, so that persons with a spot market commitment face a price risk, which can lead to speculation (below);
- **Physical delivery:** Physical delivery of the commodity must be possible under the contract. If this condition is fulfilled then theoretically the price of a future at maturity will equal the spot price at that date, that is maturity basis will be zero because it will be a matter of indifference to a buyer of the actual commodity whether he purchases the commodity spot or purchases a future at maturity and obtains delivery;
- **Storage:** Storage of the commodity must be possible. In the absence of this condition, arbitrage would not be possible, as there would be no necessary relationship between spot and futures prices before maturity;
- **Liquidity:** Sufficient liquid funds must be available to facilitate market settlement;
- **Speculation:** There must be a speculative element present, either net short or net long, to take up the balance of open positions.

All of these preconditions apply to LNG, so the preconditions for active LNG trading already exist, in theory. There is one precondition which does not fully apply though, which is the existence of a standard contract. While oil trading globally takes place around a standardised contract, this does not exist (or not yet) for LNG. We see no particular reason why a standard contract cannot be applied for all LNG trading but this has not happened yet. On the other hand, the terms in LNG contracts are pretty standard and are similar to those found in most other energy supply contracts. This topic is discussed further below.

We have identified a further number of conditions that could be expected for trading to develop in a LNG:

1. **Many suppliers:** Many alternative producers willing and able to supply;
2. **Many customers:** Many alternative buyers;
3. **Customer pressure:** Pressure from customers for improved prices or service;
4. **Timing of Industry restructuring:** Some sort of external crisis, such as a time of supply surplus or excess capacity which acts as a catalyst for industry restructuring is key;
5. **Appropriate regulatory reform:** Appropriate and effective regulation can enhance flexibility, liquidity and transparency but inappropriate regulation can hold back markets;
6. **Standard contract:** In traded markets generally, a standard contract to trade from is essential;
7. **Price publication service:** Indicative trading market prices are needed for trading markets to develop;
8. **Storage infrastructure:** Availability of gas storage to enhance volume flexibility;
9. **Other infrastructure:** Availability of other physical facilities, such as ship to ship bunkering;
10. **Diversity of supplies:** Low reliance on a dominant single source of supply;
11. **Flexibility of supply:** Medium term responsiveness of supply to price movements;
12. **Weather variations:** Pronounced seasonality in demand, with possibly two peaks;
13. **Maturity of networks:** Mature industries with heavily depreciated networks or terminals, such that risks have been significantly reduced;

14. **Capacity constraints:** Absence of capacity bottlenecks;

The first three preconditions we consider to be fundamental to the development of any active trading market:

1. Many suppliers;
2. Many customers;
3. Customer pressure;
4. Timing of industry restructuring;

As any economics textbook will confirm, competitive markets require many buyers and sellers. A liquid market can be defined as one which is deep enough that the price is not significantly affected by a large new volume of supply or purchase.

1. Many Suppliers: There are many suppliers of natural gas and LNG globally and of those supplying Europe. There are least 16 countries (excluding Angola, Egypt, Libya and Yemen) currently producing and supplying LNG out of 34 liquefaction terminals. In 2015 in Europe six countries imported just under 50 bcm of gas by LNG[34]. Europe is in a very benign position in terms of the diversity of supply options for gas (pipeline or LNG) to come to Europe.

2. Many Customers: There are also clearly many customers globally and in Europe for gas and for LNG in particular. The IEA[35] list 101 regasification terminals worldwide, excluding the USA, and 23 in Europe including Turkey, with a nominal capacity for European regasification of 342.7 mcm/yr of LNG (210.8 bcm/yr of natural gas in gaseous state).

3. Customer Pressure: Customer pressure from infrastructure customers, terminal users and major buyers (shippers) exists and is growing for improved buyer commercial terms for LNG, with more flexibility in delivery and pricing. There is little evidence that customer pressure in Europe has been growing for LNG reforms but there is pressure for improved buyer terms. LNG is just another form of natural gas, which has to compete with pipeline natural gas to reach customers in Europe. There has been very considerable progress in achieving competitive wholesale and retail markets for pipeline natural gas throughout the EU, which has put pressure on LNG suppliers to Europe to match. Access to regasification terminals may be a barrier to a more competitive LNG business but in this area as well there has been little observed buyer pressure for reform. However, buyers are looking for improved commercial terms and the EU is providing customer pressure (at EU and national level). The development of a Buyer Forum is another sign of customer pressure for more flexible LNG supplies.

4. Timing of Industry Restructuring: With the expected oversupply situation looming with LNG supplies globally and in Europe, there is the opportunity to introduce LNG market liberalisation, to the benefit of buyers and consumers. It is much easier to introduce regulatory reforms at a time of supply surplus or excess capacity. That was observed to have been the situation with pipeline gas supplies, oil trading and it is expected to be the case with LNG as well.

The most important preconditions for active trading therefore already exist for LNG. The first two apply without a doubt. Customer pressure is building for more flexible buyer terms. The other key precondition which we have identified, timing of industry

[34] Natural Gas Information, Table 25: World LNG terminals, IEA 2016
[35] Natural Gas Information, Table 27: World LNG terminals, IEA 2016

restructuring, also applies now, with the changes now under way in the global LNG industry.

On a fundamental basis therefore, the preconditions already exist for active LNG trading to start.

The next eight preconditions can be said to apply to LNG now, to a greater or lesser extent:

5. Appropriate regulatory reform;
6. Standard contract;
7. Price publication service;
8. Storage infrastructure;
9. Other infrastructure;
10. Diversity of supplies;
11. Flexibility of supply;
12. Weather variations;

5. Appropriate Regulatory Reform: Following on from the Timing of Industry Restructuring, the type of restructuring is also very important. The case studies show that inappropriate and restrictive regulation can delay or stop a trading environment and significantly reduce liquidity and flexibility. Appropriate regulation, as well as targeted fiscal reform, on the other hand, encourages trading on and leads to significantly increased flexibility, liquidity and transparency. Sometimes very little regulation, if any at all, is needed to set an environment conducive for a trading market to take off. Light touch regulation or even government direction through some simple signals alone is often sufficient to prompt the market in the right direction. Often though, it has been observed that government does play an important role in starting or stopping the development of a trading market.

6. Standard contract: In traded markets generally, a standard contract has been considered to be an essential precondition for trading to take off. Although there are templates available, there is not yet in operation a standard contract for LNG. It will be difficult to see LNG trading really take off until there is a standard contract for traders to use, recognised and used throughout the industry, covering spot and short-term trades at least (long-term contracts may still be individually negotiated).

7. Price Publication Service: Trading markets need to know the range of prices and a price publication service is essential. Trading markets cannot take off without some sort of indicative price publication service in operation. An indicative range of prices and the volume of trades is published, not usually exact prices attributable to particular players. A number of LNG price publication services already exist but the issue remains as to how much more LNG price publication is needed. Price publication also has to be informative enough to enable price discovery but within a range of uncertainty so that traders can operate. Price publication in Europe of potentially commercially sensitive information also has to comply with EU competition law.

8. Storage Infrastructure: Sufficient LNG storage is an important part of increasing volume flexibility and liquidity at regasification (and also liquefaction) terminals. As has been noted above, LNG storage should be considered a necessary part of the LNG facilities. It is therefore operational storage and an intrinsic part of effective LNG operations. LNG storage therefore should not be included within SoS or other types of storage to help in general or emergency gas market flexibility.

9. Other Infrastructure: The case studies, particularly the oil trading case study, show that appropriate infrastructure is a key part of an effective trading market. As well as LNG storage, discussed above, other infrastructure that can help LNG trading to develop include facilities to enable bunkering and ship to ship transfers, and access to large high pressure transportation pipelines to enable easy access to gas market hubs. Large volume LNG storage, bunkering and access to downstream markets provide an attractive physical combination that can enable an LNG trading hub to develop (in addition to the other factors described above).

10. Diversity of Supplies: Having supplies from several different sources is important and is applicable to LNG. It is difficult to introduce competition when there is a single dominant source of supply (in the pipeline gas industry in Europe, it has proved more difficult to extend downstream effective trading and gas competition in Ukraine and in Turkey for example, largely because of the dominance of a single source of gas supply from Russia). In Eastern Europe, some LNG terminals have been built which acted in effect as competition to Russian pipeline gas, the presence of an LNG terminal affected the terms (price especially) under which Russian pipeline gas was subsequently supplied;

11. Flexibility of Supply: Medium term responsiveness of supply to price movements means that large price movements lead to changes in supply. While any effective trading hub has to be large enough that it can absorb any single large supply without significant price movements, the hub also has to be responsive to regional or global trends. If supply or price changes significantly, the hub should be sufficiently flexible and responsive that price or supply reacts in turn. Supply should be expected to respond flexibly to pricing or other market signals.

12. Weather Variations: Weather variations was one of the main original reasons for LNG imports to be started. Traditionally, apart from the three key countries who imported LNG for baseload gas supplies (Japan, South Korea, Spain), most importing countries, all of which were in the northern hemisphere, imported LNG as one of a hierarchy of means to meet peak demand.

The final two preconditions however pose more of a challenge for the introduction of trading markets into LNG:

13. Maturity of infrastructure;
14. Capacity constraints.

13. Maturity of Infrastructure: In comparison with pipeline gas, LNG is a relatively recent industry which means that liquefaction and regasification facilities are on average newer. This means that the capital costs have not been fully depreciated. In order for LNG liquefaction or regasification projects to obtain financing, they need long term contracts and committed buyers for a long period of time. Many of the LNG import facilities in Europe have obtained derogations from the full impact of the EU regulatory packages (the third package). These derogations by their nature are time limited and they will expire in time. But the capital intensive nature of the business and the need for assets to be fully or substantially depreciated before the risks can be assumed which are typically associated with a trading position;

14. Capacity Constraints: Partly as a consequence of Maturity of Infrastructure above, the nature of the derogations which EU regasification terminals have been able to negotiate means that TPA is partly or completely restricted. This could in theory lead to capacity constraints and lack of access to third parties without an effective TPA regime. Nevertheless, utilisation is low and there have not been any problems observed in a cargo obtaining access to a terminal. While this applies to NW Europe there are more concerns over access to E and SE European terminals.

2.2.2. Types of Energy Commodity Trading Market

In this report the length of contracts or trades are defined as:

- Spot: Immediate or very short-term trade;
- Short-term: Up to four years;
- Long-term: More than four.

Energy commodity trading markets may be broadly divided into four types:

- Spot;
- Forward;
- Futures; and
- Derivatives.

Spot: Spot markets are very short-term physical markets for the prompt delivery of gas.

Forward: Forward markets are for trading a commodity for delivery in the future at a price agreed now. Trades can range from one month to several years forward. Both spot and forward markets are generally traded over-the-counter (OTC), with bilateral deals done over the telephone, under standard contracts, although electronic internet-based trading is also now developing. The forward market is the informal over-the-counter financial market by which contracts for future delivery are entered into.

Futures: Standardised forward contracts are called futures contracts and traded on a futures exchange. Futures are similar to forwards except that they are mainly used for financial trading, and are traded on regulated exchanges such as the ICE (in the UK) or NYMEX (in the USA). Futures markets guarantee anonymity for the traders as the deal is effectively done through the exchange.

Derivatives: Derivatives are financial markets that are derived from other markets. The two main types of derivatives are options (which give the holder the right to buy and sell at a certain price in the underlying market) and financial swaps (which exchange a floating price for a fixed price).

Although energy trading markets can be characterised as having these types of trade, they are not all yet to be found in LNG. Spot trades certainly take place in LNG, with cargoes regularly diverted because of a higher spot price elsewhere but futures and derivatives trading have yet to take off.

2.2.3. Main Characteristics of Trading Markets

The development of spot, forward, futures markets and derivatives are key characteristics of highly developed energy trading markets. Other characteristics include the following:

1. **Standard contract:** A standard contract is an essential part of an active trading market and is considered a precondition for real trading to take off, as discussed above. Participants need to be able to quickly and easily agree essential terms (price, quantity, delivery time and place), knowing that other contractual elements are already covered;
2. **Price publication service:** A price publication service is also considered a precondition for trading to take off as well as being a characteristic of a developed trading market. Trading markets need to know the range of prices and a price publication service is essential;
3. **Spot and futures price indexation:** Use of price indices from futures markets and/or price reporting services as escalators in longer term contracts, thereby increasing their importance above their physical share of the total market;
4. **Supportive regulatory and fiscal framework:** Experience shows that successful trading markets benefit from a supportive regulatory framework. The right sort of

government and regulatory involvement is important to the development and functioning of a trading platform. A supportive fiscal framework is also important. On the other hand bad government interventions can reduce or destroy an effective trading market. Supportive regulatory or fiscal actions for LNG would be the sorts of measures described at the end of this report and could include tax and other incentives to encourage traders, transparency and clear rules of access to terminals (exempt and regulated), tariff structures to encourage LNG hub type activities, for example;

5. **Entry of new players:** Entry of new, strongly capitalised and committed players into the market;
6. **Increased contract flexibility:** Removal of take-or-pay clauses on contracts and considerably increased flexibility;
7. **Shorter-term and smaller contracts:** A trend towards shorter term contracts, away from the more traditional longer term take-or-pay contracts;
8. **Resale and secondary markets:** The churn rate, where a commodity is sold a number of times before it reaches the final end user, which means that secondary trading markets emerge to facilitate that resale trading;
9. **Capacity trading:** Ability to trade facility entry and exit capacity (regasification, pipeline and storage).

The LNG industry is starting to see some of these characteristics. In recent years, new players have entered the LNG business globally, including commodity trading companies such as Trafigura, Vitol, Glencore and others.

The industry globally has also seen a move towards shorter term contracts. South Korea was one of the leaders in moving towards shorter term contracts although China when it entered the LNG import market reversed the trend, reverting to long term contracts. Generally speaking, the pattern seems to be that new national buyers in LNG tend to be risk averse and prefer a majority of long term contracts. As they become more established and confident they increase the proportion of short term and spot cargoes. China as a new player took perhaps a cautious approach initially and engaged in relatively high priced long term LNG contracts. China may also have been influenced by the experience of South Korea. In the early 2000s, South Korea (a mature and experienced LNG buyer) started a policy of buying cargoes on short term contracts of up to five years. While this was a bold progressive move, unfortunately South Korea was caught short when spot prices rose dramatically from 2005 to 2015. Despite these two experiences though, there may be observed a general global trend towards shorter term contracts.

Reselling of surplus cargoes has emerged and is likely to become increasingly a feature of global LNG markets. Take-or-pay contracts are becoming more flexible although there is still some way to go in that regard. The other characteristics have not yet emerged to any significant degree in the LNG industry:

- Standard contract;
- Capacity trading;
- Spot and futures indexation.

Regarding capacity trading, access is provided for third parties to regulated terminals. For exempt terminals, third parties who want access can contact one of the existing capacity holders. While there is access to terminals and there is a certain amount of secondary trading to gain that access, this does not count as a full capacity trading environment. There is not yet an active capacity secondary market where third parties can go to the market to obtain access to a terminal (rather than ringing round each of the existing capacity holders). Gaining access to an LNG terminal is very different from gaining access to capacity on the UK-Belgium Interconnector (for example), where there are active trading markets in commodity, capacity and equity in the Interconnector company.

2.2.4. Drivers for Liquidity

In conclusion, a liquid trading market can be defined as one which is deep enough that the price is not significantly affected by a large volume trade.

Out of the discussion above of the preconditions for trading in general, preconditions for LNG trading and characteristics of developed energy trading markets, the most important elements of and drivers for active LNG trading markets, which lead to liquidity, flexibility and transparency, can be defined as:

1. Many sellers or suppliers;
2. Many buyers or customers;
3. Industry crisis (particularly of excess supply, which acts as a catalyst for change);
4. Supportive regulatory and fiscal framework;
5. Standard contract;
6. Price publication service (of indicative prices, price ranges and trading volumes);
7. Storage infrastructure;
8. Other infrastructure;
9. Diversity of supply;
10. Entry of new players.

These will then lead to the growth in the other indicators of an active LNG trading market:

11. Increased contract flexibility;
12. Shorter-term and smaller contracts;
13. Resale and secondary markets;
14. Capacity trading.

Swaps:

Swaps are a useful tool in other types of trade. They allow parties to save shipping or transportation costs, to gain access to new markets and to optimise their positions. Swaps have been successfully used in various pipeline gas trades. In theory, swaps should be a useful tool for enhanced liquidity in LNG. In practice though, it has not yet been possible to iron out all the inherent differences in LNG scheduling. There are various reasons for this:

- **Scheduling:** The fact that LNG comes in cargoes rather than a flow and has to be scheduled very precisely, whereby two separate cargoes in a swap both need to be scheduled in advance, has (so far) made LNG swaps difficult.

  A swap can be a location swap (a delivery in one location swapped for a delivery at a different location but at the same time) or a time swap (a delivery now swapped for a delivery in the future but at the same location). LNG swaps have to be both location and time swaps at the same time, making it that bit more complicated;

- Differences in vessels (difference in size of vessel, capacity and terminals which can accept them);

- Differences in terminal specifications;
- Differences in gas quality and specifications;
- Limited communications between different LNG buyers;
- Instances where there is inflexibility in contracts (destination restrictive clauses or volume inflexibility).

Regardless of the reasons, very few successful LNG swaps have actually taken place to date and they have not, at least not yet, proved a useful tool for LNG.

2.2.5. Barriers to Liquidity

Market liquidity is linked to increases in trade without negatively affecting the prices, minimising price variability, and reducing the gaps between buying and selling prices[36]. Despite some growth in spot trading, the current LNG market remains a relatively illiquid market dominated by long term contracts with rigid contractual terms. The barriers to liquidity in LNG market can be narrowed down to:

1. Concentration of players;
2. LNG trading suitability; and
3. Rigidity of contractual terms[37].

1. **Concentration of players:** One of the key barriers to liquidity in the LNG market has been the limited number of market players who can afford the large infrastructure investments such as liquefaction and transportation, and the large trading volumes (minimum of one cargo). The limited number of market players include both sellers and buyers. New players are now entering the LNG industry and the concentration among the established incumbents will lessen over time. With the new LNG supply coming onstream, predominantly from the USA and Australia, competition is increasing among the market players. Technological innovations are also allowing more players to access the market.

2. **LNG trading suitability:** Variations in the quality of LNG in terms of calorific value equivalents may be a barrier and makes the development of a trading market that bit more difficult. With the introduction of standardisation of physical LNG trading, the liquidity could eventually improve through the development of multiple indices and convergence to a single LNG index. Variations in quality (as discussed separately in the LNG quality section) do not pose much of a physical barrier but may hinder trading in some circumstances.

3. **Rigidity of contractual terms:** Destination clauses have been a barrier to liquidity because they limit trading activity in a competitive market. Destination clauses that are tantamount to territorial restrictions, limiting the possibility for EU importers to move LNG across Europe, may infringe competition rules and may be illegal. They are in the process of being removed from European and Japanese contracts. Restrictive contractual terms such as destination clauses are expected to face growing pressure from LNG buyers globally. Other rigid terms which are facing pressure from customers include pricing flexibility and renegotiations, and flexibility in delivery terms (increased flexibility in take-or-pay contracts).

[36] Peter R. Hartley, 'The Future of Long-Term LNG Contracts' (2015) 36 The Energy Journal.
[37] Tsueno Miyamoto and others, *Developing Liquidity in the LNG Market - Asia's Challenges and Outlook* (1st edn, KPMG 2017)

2.2.6. Drivers for LNG Industry Growth

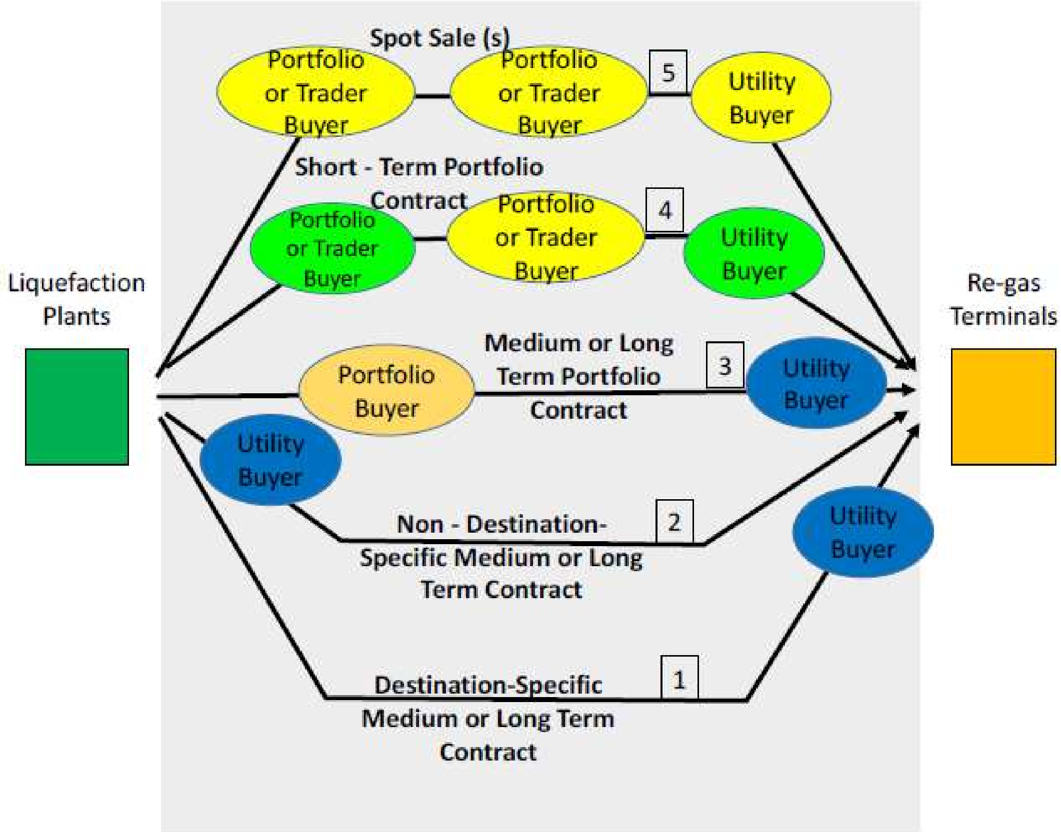
Key drivers of LNG industry growth which have been identified include[38]:

1. **Global economic growth:** Global economic growth will advance LNG consumption in Europe and Asia;
2. **Energy efficiency:** The environmental concerns of major economies have pushed for greater energy efficiency regulations and major economies are adding cleaner fuel into their energy mix;
3. **Excess Capacity:** The additional capacity coming online from the USA and Australia will put more pressure on an already saturated market, with implications for LNG projects, prices, and demand;
4. **New markets and new end users:** Additional supplies of LNG will need more regasification infrastructure in new markets. Historically, most supplies are absorbed by Asian countries. In addition to developing new markets, LNG will be consumed by users other than utilities or utility scale power generation. New end users can include transportation such as shipping, trains, and trucks;
5. **Market liquidity:** With the LNG trade traditionally dominated by long term contracts, liquidity would result in increases in trading opportunities as new supply and demand hubs lead to additional potential routes and increasing market participation.

The figure below shows a simplified illustration of different routes or channels for connecting to the market. Attempting to define the volumes of LNG in any one specific channel is challenging due to the potential for double counting cargo re-sales. The matrix of possibilities expands when one considers that for 2016 there were 18 active LNG supplier countries and 35 importing countries.

[38] John England and Andrew Slaughter, LNG at the Crossroads: Identifying Key Drivers and Questions for an Industry in Flux (1st edn, Deloitte Center for Energy Solutions 2014)

Figure 42. Different Routes for Bringing LNG to Market



Source: Howard Rogers, 'Does The Portfolio Business Model Spell The End Of Long-Term Oil-Indexed LNG Contracts?'

2.3. LNG Industry Structure and Major Players

Traditionally, the LNG industry globally had a very simple industry structure:

1. Producers, usually IOCs and their liquefaction plant;
2. Shipping companies, usually the shipping arm of the same IOC;
3. Buyers, usually large state owned national companies.

The industry operated on long-term contracts with very little flexibility for the buyer. Because of their monopoly control over liquefation and shipping, it was very difficult, if not impossible for third parties to move their gas through the LNG system. The authors of this part of the report (EMG) have an example of this when, in the mid 2000s, they attempted to supply gas from an independent producer in Nigeria (one of the world's largest LNG producers) to a large Spanish industrial buyer. EMG were able to arrange for delivery of gas to the liquefaction plant but were not able to gain access to LNG shipping from the liquefaction plant.

Restrictions by suppliers, such as destination clauses were also common. Destination clauses are now well on the way to being removed in the EEA. Destination clauses that limit, directly or indirectly, the possibility for EU importers to move the LNG across Europe, may constitute infringements of EU competition law and lead to antitrust liability.

In recent years, the LNG industry globally has changed and many new types of player have emerged. Brief profiles of the different types of company and their business model are described in this section.

Producers: The traditional producers still remain. These include the IOCs who are active in gas (such as *Shell* or *Chevron* for example), independent gas producers and NOCs with large gas portfolios (Qatar especially). They produce gas and deliver to the liquefaction plant. Their involvement in the LNG chain stops at the liquefaction plant (apart from those who are also aggregators or potfolio players).

Liquefaction Terminals: These are usually set up by consortia. Each consortium typically consists of producers who want an exit for their gas. A recent trend is for established large or national buyers to be part of a consortium. Sabine Pass in Cameron Parish, Louisiana, USA, for example, has in the consortium constructing Trains 3, 4 and 5, *Shell* (formerly BG Group), *Gas Natural Fenosa*, *Total*, *Centrica* (UK largest gas buyer and retailer), *KOGAS* (South Korean national buyer and pipeline transporter) and *GAIL* (Indian national buyer).

Aggregators / Portfolio Players: Most of the IOCs who are strong in gas are also aggregators or portfolio players. There are also other large companies. These companies are large enough and have enough resources that they have many sources of LNG and many customers. They can therefore buy LNG and put into their general portfolio, from which they can deliver to customers almost anywhere. They should be able to offer considerable flexibility to customers although the industry globally has not seen that much flexibility from them so far. Because they are large companies with numerous LNG purchase and buyer interests, on different contractual flexibility terms, there are regularly large volumes in play. In addition, aggregators can buy from and sell into spot markets. Buyers require LNG of the right specification to be delivered as scheduled but they do not mind where it comes from. Aggregators therefore have considerable flexibility and probably more than they are currently offering buyers (although without knowing the details of their operations which are not public, it is difficult to know for certain just how much flexibility they can really offer).

Large IOCs are in this group and some large utility buyers or suppliers. They include Shell (with BG), Chevron, Gas Natural Fenosa, RAO Gazprom, Centrica, for example.

These types of LNG industry player are the traditional companies, very large and established. They have a traditional approach to the industry. It is from this group that any resistence to change or a new industry model is likely to come. Traditionally, they offered very inflexible contracts (100% firm supply) but as the industry has opened up, this group are offering more flexible contracts, to 80% and possibly to 70% take or pay flexibility. They also prefer long-term contracts. They are adapting to the changing world and this group would be happy with a world with about 70% long-term contract and 30% short-term and spot (of which 5-10% is really spot). Considering the portfolio nature of their operations and the inherent flexibility in their LNG supplies, it may be possible that they can actually offer much more flexibility than they have been prepared to offer to date. Tradition may be keeping them to a certain model though.

Shipping Companies: Traditionally there were a few large LNG shipping fleets (Shell having the largest) and a larger group of smaller ship owners. Often these smaller owners would charter out their vessels to one of the larger shipping companies. When BG (which became one of the largest LNG companies until it was acquired by Shell in 2016) first entered the LNG business in the mid 1990s, it did so by buying two LNG vessels and immediately chartering them out, as a way of gaining a toehold in the industry. Over the last decade or so, the traditional shipping companies have been replaced by new entrants. The largest LNG shipping companies now include *Teekay LNG* (80 vessels from none in 2004), *Shell Transport and Shipping* (40 vessels), *Qatar Gas Transport*, *Maran Gas Maritime* and many others. Many of the ships belong to producers or aggregators (such as Shell and Qatar). Others are independently owned and available for charter, either on contract (long or short term) or on a spot basis.

New US companies: The world is starting to see the entry of new US LNG exporters. Although these companies may be new to the world and are bringing contractual flexibility and pricing novelty (Henry Hub pricing), their operations can be considered as standard within the USA.

Project Developers: A new breed of LNG project development company have entered the LNG industry. *Höegh* and *Golar LNG* are two examples. They are independent owners and operators and make use of their maritime expertise and technologies. They operate at all levels of the value chain but are particularly active in the new technologies of FSRUs and FLNGVs. As such many of their clients are with the new sets of buyers in emerging markets. Because they are technology solution providers, they are unaffected by LNG price movements (unlike the producers and aggregators).

Traditional Buyers: Traditional buyers include large national or utility buyers from Asian countries, such as *Kogas*, *Tokyo Gas*, *Osaka Gas*, *GAIL*. They have been buying LNG for many years and know the busines. Increasingly Asian traditional buyers are buying spot or short-term cargoes. Nevertheless, many of these buyers have equity in liquefaction plants. They have equity LNG which protects their security of supply but because of the over contracted position, they are putting most of their equity LNG back onto the secondary market. The larger and traditional buyers generally have good credit, including European ones. Although European buyers may seek lower LNG prices than Asian buyers, their generally good credit rating to some extent offsets the lower prices being sought.

Emerging Market National Buyers: These are new entrants to the global LNG market, often introduced through one or more FSRUs which they have recently acquired. There are a large and fast growing number of these buyers, which are national state owned companies in developing countries new to LNG, for example Middle Eastern and South East Asian buyers, including India, Egypt, Jordan, Pakistan, UAE (Dubai), Indonesia, Malaysia, Thailand, also South American and Caribbean buyers, for example. African buyers include most of the countries down the west coast of Africa. Nigeria (a major LNG exporter) may also become an LNG buyer with projects in development to ship LNG from the Niger Delta to Lagos as an alternative to pipeline gas supplies.

Many of the new national buyers (in addition to the traditional buyers) have over contracted LNG and are looking to resell volumes. As they are new to the industry and as, on the whole, they are largely government companies, they are risk averse, taking to 60-70% of LNG supplies on long-term contracts. Although emerging market buyers have poor credit ratings and normally would not be able to acquire LNG, the advent of FSRUs has changed the industry. A poor credit rated emerging market (South Asian or African for example) can now buy an FSRU for $50m or charter one for less, and which can be towed away in the event of a default, from sellers who are over supplied and keen to sell their gas. Credit from normally uncredit worthy customers increasingly is not now an issue.

Traders: Another very important group of companies who have started entering the LNG business are the pure traders. The largest ones include *Trafigura*, *Vitol* and *Glencore*. Unlike the producers and aggregators who prefer a long-term steady business on long-term contracts, the traders are purely short term and are completely commercial. They have no physical assets stake in the industry. They operate purely on a spot basis and any shipping or assets they may get involved in are on a charter basis. These are global companies with a history in commodities trading (coal, oil, solid minerals). As purely commercial traders, these trading companies bring a new business culture to LNG. Some have had concerns over particular transactions raised with national regulatory authorities from time to time. As well as the large well known traders there are also smaller trading companies operating in LNG, brokers in reality. There is concern among some national and portfolio buyers over the credit worthiness of some of the smaller traders and some of them are avoided.

The LNG industry therefore now has a large number of players with different business models and different objectives from the industry. A common characteristic though is that they tend to be large corporate players. Unlike pipeline gas or oil companies, there seems to be little room for smaller companies in the LNG business worldwide.

2.4. Case Study: Lessons from Liberalisation of Pipeline Gas Industry

2.4.1. Regulatory and Legislative Push

Note: References in the following discussion to the British gas market refer to the gas market reforms as they affected the mainland of Britain (mainland England, Wales and Scotland), excluding the islands (so Britain not Great Britain) and excluding Northern Ireland, so they refer to mainland Britain, not Great Britain and not the United Kingdom.

There can be some lessons from the early liberalisation of the British gas market which may inform how the global LNG industry could develop. The comparisons are not with the British gas industry as it is now but with the early stages of liberalisation before regulation was imposed.

Attempts by the Conservative British government to liberalise the British gas industry began in 1982 with the first of many Acts of Parliament (Oil and Gas (Enterprise) Act, 1982). The Gas Act 1986 allowed for the corporatisation of the Gas Boards into British Gas plc and its subsequent privatisation, through a stock market flotation in December 1986. Despite the privatisation, competition was slow to develop, indeed a competitive multi-player market was not the initial declared intention of the government.

Competition started to emerge through consumer pressure. Sheffield Forgemasters (an industrial customer) complained about discriminatory pricing and in 1988 a referral was made to the Monopolies and Mergers Commission (now the Competition Commission). The result was a regulatory ruling for published price schedules and restrictions into British Gas gas purchases (restricted to 90% of new gas on offer), so as to encourage third party owned gas into the market.

In 1991, the Office of Fair Trading (OFT) reported on an investigation into the gas market and ordered a gas release programme (realised through auctions of British Gas held gas), market share undertakings by British Gas and the separation of transport and trading (initially through Chinese walls and an internal separation). The OFT conducted another review into progress in 1993. From this point, in 1991, a gas trading market began, with gas traders entering the market and a spot market first developing.

The final shock for the old British Gas came in 1995 when gas trading was developing in earnest. A gas supply overhang was building up, leading to a price collapse on the spot market. From September 1994 to May 1995, the spot price fell from over 20 p/th (pence per therm) to 8 p/th. British Gas meanwhile was trapped in the long term take or pay contracts with an average price of 18 p/th. British Gas faced the twin problems of losing money on every therm of gas it sold combined with a fall in market share of the contestable industrial market from 95% to 45% in the four months from December 1994 to April 1995 (Source: Energy Markets Global). This take or pay problem in a soft price market was the main driver for the restructuring of British Gas into Centrica plc and BG plc.

The most important driver towards competitive trading probably was a new Act of Parliament, the Gas Act 1995. This set out the new legislation for the retail and wholesale competitive gas market that we now see in the UK and indeed across the EU. Clare Spottiswoode, the UK gas regulator (DG of Ofgas, now Ofgem) at the time, saw that a supply overhang was building up in the gas industry and saw this as a golden opportunity to force through liberalisation. She therefore put considerable efforts into drafting and steering through Parliament the Gas Act 1995[39].

[39] Source: Private discussions between Energy Markets personnel and Clare Spottiswoode

The final piece of the regulatory transformation came in 1996 when the Network Code was introduced, which set out a set of rules for allowing third party access and daily balancing. A Network Code was a requirement on British Gas by the Gas Act 1995 and so was (and is) a regulatory instrument but it was developed not by the regulatory institution (Office of Gas and Electricity Markets, Ofgem) but by a "Shippers Forum", a collaboration among the users of the gas transport system.

2.4.2. Informal Start to Gas Trading

The area of interest is what happened between the start of a meaningful gas trading market in 1991 until the Network Code was introduced in 1996. While not at all the Wild West, this was an unregulated period where, in effect, British Gas as the major incumbent company, took up the slack from traders' activities while the trading market emerged, until the market became too big and a formal structure had to be put in place.

The spot and forwards trading markets began in a very informal way. The "trading circle" (the relatively small network of trading entities that began gas trading) included different types of trading company. There were marketing arms of the oil and gas producers, also merchant banks, regional electricity companies, trading houses and independents.

From about 1995, many more participants joined, lured into the market by the certainty given in the Gas Act (1995) that full competition was imminent. From less than 15 traders in 1995, there were over 50 two years later, and more than 200 licensed traders by around 1999 (although not all were active).

Very little equipment was needed in these early days, essentially all that was needed was a telephone connection, so some companies operated from residential terraced houses and even from caravans. Individuals would ring round their contacts, buy a strip of gas, then ring round other contacts and sell it on. Some of these informal marketers contacted industrial and large commercial companies and sold to them. They operated in what was called "cherry picking", picking customers who they knew were paying a much higher price to the incumbent, British Gas, than the new players could acquire on the emerging spot market. There was no attempt to balance inputs or outputs, while the third party access market was informal and relatively small, the transport arm of the incumbent British Gas was able to absorb the balancing costs and risks.

2.4.3. Gas Traders

Of the traders[40], Enron and Accord in particular introduced American trading methods, namely aggressive market making and price disclosure. These are both very important components to enabling the beginnings of a true traded market. Market making is where a trader will simultaneously quote both an offer and a bid price (the bid is the highest price a buyer is prepared to pay, in contrast to the ask or offer price from the seller). Price disclosure, usually through a trade publication, allows for greater transparency and therefore for confidence in trading that commodity. The varied mix of participants entering the market with their different trading agendas and risk appetites helped to greatly increase liquidity, thereby attracting further players.

Following the collapse of Enron in the autumn of 2001, there was considerable restructuring of the gas trading market in Britain, with American companies pulling out and European ones coming in. During the upheaval, from around 2002 to 2005, trading volumes and liquidity fell. By 2010, many financial companies had entered the gas trading market,

[40] The following discussion of traders, churn rate and network code is largely taken from: Patrick Heather, the Evolution and Functioning of the Traded Gas Market in Britain, OIES, August 2010

including banks, financial institutions, hedge funds, investment and pension funds. Gas and electricity trading in spot and forwards trades became another financial product.

2.4.4. Churn Rate

A measure of a market's liquidity and depth is the so-called "churn rate". This is a measure of the number of times a parcel or strip of the relevant commodity is traded and re-traded between its initial sale by the producer and final purchase by a consumer. There are several ways in which this number or ratio is calculated, depending on the statistics available, the overall transparency of the market in question and the specific methodology chosen by the compiler. However, as a rule of thumb, markets are generally deemed to have reached maturity when the trading churn is in excess of 10.

In the British gas market, churn rates reached a peak of 21 times in 2001 before easing off in the post Enron/TXU collapse, with the churn falling to around just eight times in 2005. However, as the market recovered, so did the churn rate, and by August 2007 it was back at around the 20 times mark.

2.4.5. Network Code and NBP

The development of the network code was fundamentally important to the development of the modern British gas business. It is not considered relevant to the global LNG business so we will not discuss the history of the network code here, except for two features which are considered relevant for LNG:

1. National Balancing Point (NBP)

The National Balancing Point (NBP) is a virtual point or location created by the Network Code in order to promote the balancing mechanism detailed in the Code. The Network Code, National Balancing Point and the Entry/Exit gas transmission pricing structure were all initially designed within British Gas (led by the Chief Economist). The NBP is the point where shippers nominate their buys and sells and where National Grid balances the system. Although the NBP was created purely in order to allow system balancing, it rapidly evolved as a trading point and price setting point as well. Traders had confidence in buying and selling gas on a standardised basis at the most liquid point in the system. The NBP rapidly evolved as a leading virtual gas hub.

In the early days (before the network code), gas was mostly traded at the Entry Points, commonly known as "at the beach". A trading point, whether at the beach or the NBP, was very important to the development of the gas trading business.

2. Standard Contract

Trading was encouraged by the use of a standardised contract. It came about following pressure from traders to have a common standardised trading contract and it was set up by an industry working party around six months after the introduction of the Network Code.

The standardised contract is known as the "Short Term Flat NBP Trading Terms & Conditions", or NBP-97. The NBP was used as the basis for the standardised NBP-97 contract, which became the cornerstone of the British OTC traded market and also the delivery point for the ICE natural gas futures contract. It is a relatively simple contract.

The NBP-97 contract is very short, only eight pages, yet it covers all aspects needed to trade gas at the NBP, including practical issues (definitions, confirmation procedure, trade nominations, contract price, billing and payments) and a few necessary legal clauses. The NBP-97 contract is always for delivery of gas only at the NBP, so traders only have to define the period of delivery, the quantity and the price, knowing that the location is in the British grid and the quality of the gas is within NTS specifications.

As well as standardised billing and payment terms, the contract also has three very important features that enabled trading to develop and continue to be successful:

1. Participants are "kept whole", meaning that volumes delivered are guaranteed to equal volumes traded. This is an important concept which distinguishes the NBP-97 from upstream contracts, which have an element of swing or volume optionality included, and from trading at continental European hubs where volumes traded are not guaranteed and may be pro-rated depending on actual physical flows on that particular day;

2. Quantities traded are "flat", meaning that the volumes traded are delivered at a constant flow rate throughout the delivery period. There is no interruption or volume tolerance permitted, again unlike upstream contracts which may be subject to take-or-pay clauses, swing rights or other daily variances in quantity;

3. Thirdly, there is very limited Force Majeure. There is no relief from the obligation to deliver or take gas from the NTS. An upstream field shut down or exit point problem does not constitute Force Majeure. The only Force Majeure allowed is an event beyond the control of the affected party, resulting in the inability to get a trade nomination into the system, and even then reasonable endeavours are required to overcome the Force Majeure, such as making a telephone call or sending a facsimile. This is unique to trading at the NBP and confers confidence on traders. The payment terms are clear and straightforward, allowing for VAT to be paid only on the net delivered volumes of gas, meaning that speculative traders who balance their books before contract expiry are not liable to VAT payments. Suppliers' invoices are to be paid by the 20th of the month following delivery (M+1). Most participants have netting agreements which will allow for just one invoice and payment per month.

The presence of a trading point (virtual or physical) and a simple standardised contract that can be easily used by traders were two fundamental criteria to gas trading in Britain.

2.4.6. Price Transparency

Price disclosure was the other key necessary part of the emerging gas trading market. The Heren Index was another entrepreneurial response to the developing market. It was started by a journalist who saw a market opportunity and started in a very simple way, yet over time it became the price setting index around which NBP trades were calculated and settlements made.

Patrick Heren had been publishing some occasional spot gas prices since January 1994, monthly through European Gas Markets, or weekly via newswires. Until the winter of 1994, they were of some minor interest to participants in Britain's newly liberalised gas industry, but not vital. Few then understood that accurate and timely price reports were essential for competitive markets to function.

However, the entry of Accord Energy, a 50:50 joint venture between British Gas and US Natural Gas Clearinghouse, signalled that at least one company was prepared to make a market, and some of the oil companies, such as BP and Texaco, began to assign experienced professionals to the British market.

From the 1994 winter, trading started to pick up, from one or two deals a month being discovered, the team were starting to discover three or four a week. British gas prices were also becoming more consistent (around 19p/th), although there was a lot of confusion about what contracts participants were actually trading. On the whole, traders seemed to be trading months or quarters, but some were reporting flat gas and some were reporting flexible delivery: the favourite was 135/90 (135% daily swing, 90% take-or-pay).

Traders were starting to ask for a volume weighted gas index. The emerging gas trade did not have long to wait. Accord Energy had privileged access to the British Gas Morecambe Bay fields, designed for high swing and capable of meeting 20% of UK peak day demand. They began to sell increasing volumes into the market, feeding the widespread demand for gas to compete on the industrial market with their own 50% shareholder British Gas.

As the 1994 winter drew on, prices came under pressure and the requirement for more regular pricing information from market participants increased. One question, which remains pertinent, was whether the market needed a price assessment or a transaction based index. Large producers generally preferred an index, while traders preferred an assessment, provided it was accurate. In early March 1995, the situation became urgent: prices were sliding as temperatures rose, and the market needed more transparency. Where a few months earlier prices had been much the same from month to month, by this time now they were changing weekly.

Patrick Heren then took the decision in March 1995 to launch the Heren Index and European Spot Gas Markets (ESGM).

Pricing assessments were offered through bid-offer assessments. At this stage, a year before the introduction of the network code, there was no virtual National Balancing Point (NBP), and gas was physically delivered and traded at the beach before entering the National Transmission System. There were six beach terminals, and the index began with a table showing all six, though in truth there was only ever price information for the two most important ones, Bacton and St Fergus.

In addition to the pricing assessment, an index was launched of forward month deals, requiring a minimum of at least ten qualifying transactions. In the event, eleven trades for April delivery were discovered, with a volume-weighted average of 14.1 p/th.

Very little was done to prepare the market, other than casual remarks to market participants. Email was in its infancy and they did not have a website. The first two page report was faxed, manually faxed by Patrick Heren to the 400 or so numbers on the contact list.

The impact of a price index for the whole market was profound. There was a lot of confusion at first. Some people were astonished by the prices reported (14 p/th and falling): "I've just paid 18 p/th for 300 000 therms" was one irate response. As the spot price fell below 9p/th, subscriptions rolled in[41].

The Patrick Heren Index became a fundamental part of the British gas trading environment but as with the gas trading itself, it started in a very small and somewhat haphazard way.

2.4.7. Lessons for LNG

The reason for describing the earliest days of the initial start of the British gas trading business is that there are some important lessons that may be learned and applied to the LNG trading business, also now in its infancy. Some key lessons are:

1. **Market Led:** Perhaps the most important lesson, is that the market developed by itself. It was a bit chaotic initially but it soon settled into a structure;

2. **Legislative and Regulatory Drive:** Although the market developed by itself, and in ways which had not been predicted by anyone beforehand, the market would not have taken off without the political vision to drive through the necessary legislative and regulatory enabling environment. Without the vision to

[41] Patrick Heren, Guest article: The birth of the ESGM and the Heren Index, ICIS, 20 March

realise that there was an opportunity to make a market and the drive to then make that happen, the market would never have taken off;

3. **Information and Price Discovery:** Transparency of information is key for trading markets to develop, in particular pricing information. Traders need this and the market took off when pricing information was made available;

4. **Price Setting Point:** Whether one or more physical points such as the entry point facilities (the beach) or a virtual point (the NBP), trading markets need a place where they can make their trades and agree a price for delivery to/from that point. An LNG hub would offer an obvious price setting point for LNG;

5. **Standardised Contract:** A standardised contract is necessary, and not just a standard contract, but a simplified one that traders can use. All terms are included in the standard contract so that the trader only needs to negotiate the price, volume, delivery point and delivery time;

6. **Churn Rate:** While not a precondition for a trading market, the existence of a churn rate, where a commodity is resold several times before reaching the end user, is a good indication of an active trading market;

7. **Entry of New Players:** The entry of new companies, buyers and sellers, brings new business models and dynamics into the industry, and is an important part of making a market. These can be pure new entrants but often a JV of a new entrant (such as a US trading or LNG company) with a dynamic incumbent can bring the benefits of a new business model combined with the experience of players already established in the market.

These factors described above are all very relevant to LNG. It can be said that the experience of the British gas trading business has shown these to be generic indicators of an active trading market. Although the five factors described above describe active trading markets, none of them can be said to apply to LNG. LNG cannot yet be said to be operating as an active trading market.

There are some other aspects of the onshore British gas trading experience which are different from and which do not apply to the situation of LNG:

1. **Balancing:** Order and structure came into the British gas market with the network code, as it became necessary to have a balancing regime (and a daily rather than a monthly one was chosen). The lack of a network code put all the pressure on the gas transporter to balance and after the market became over a certain size it was no longer feasible for the incumbent transporter to continue alone with this function.

   It is not clear though that balancing is an issue for the LNG business. The LNG business is structured fundamentally differently, principally because LNG comes in cargoes rather than as a flow. It is not a matter of ensuring a balance between inputs and outputs (necessary for a pipeline system) but instead, LNG needs to ensure that there is continuous and confirmed reception for the cargos at those specific intermittent times when they are delivered.

2. **National Regulator:** Britain benefited from a single government and a single regulator, in a stable country operating under rule of law. The same applies across Europe with national regulatory authorities and the European Commission acting as the single legislative authority (the third package).

   Again, this does not apply to LNG. LNG is a global business (oil is also a global business and that is discussed in the next section below) and it is very difficult to see how it can be globally regulated. In time, it could be imagined that the market could coalesce around a standardised contract (as oil trading has) but it is difficult (at least at the moment) to envisage a single governmental or regulatory authority to cover the global LNG industry, one that the EU, USA, Australia, Russia, Qatar, Yemen and all the other national players could agree to submit to. LNG will not have a single regulatory or government authority driving change across the industry and enabling a market, not in the same way as a national regulator (or supra-national one like the European Commission).

3. **Point to Point versus Network:** This point is a little more controversial. The British onshore pipeline gas operates in a network, a grid. The British network code was designed for a network, not for a point to point system. The EU took that argument and applied it to the rest of the EU, seeing that the EU is also a complex network of interconnecting gas pipelines.

   Historically, LNG has operated as a point to point operation. A full LNG ship with a single cargo departed from a single fixed liquefaction point and went straight to a single fixed regasification point where it discharged the entire cargo. That is a point to point system and not a network. This was only reinforced by the restrictive nature of destination clauses in many LNG contracts.

   This analysis is a little contentious though because perhaps LNG can become at least a little more like a network. To the extent that destination clauses are gradually eliminated there may be more flexibility for trading LNG to different regasification terminals. The reality of LNG is a physical one, that is it comes in cargoes not in a flow, so perhaps there will always be restrictions in how it moves and it will essentially always operate basically on a point to point basis.

   There are two other points though which are reducing the point to point nature of LNG.

   - One is that there is a growing list of markets which are considering LNG on the basis of a "milk round", that is where a single LNG tanker drops off part only of its cargo at a number of small regasification terminals on a round (as the milk float used to and occasionally still does, dropping off milk bottles at residential homes). Examples of potential LNG milk rounds include isolated settlements around Europe, such as Scottish islands or Norway, the Caribbean, Philippines and perhaps down the west coast of Africa;

   - The new technologies associated with ship to ship bunkering means that LNG can now be collected from other ships or terminals, part filled. This means that LNG does not have to be collected from a single liquefaction point at the start of its journey but can be collected from different points en-route. LNG bunkering is most apparent in the low countries ports of Belgium and the Netherlands, also in the Baltic and it may develop in the Mediterranean. The development of Singapore as an LNG hub is also an important development in this regard.

   Although LNG has historically been a point to point business, there are indications therefore that this is now breaking down and is starting to operate in more of a network fashion, which could be a driver towards enabling LNG trading.

4. **Gas on Gas versus Oil Index Linked Pricing:** The final point in this section is another slightly controversial point. When the British gas market liberalised, it benefited from the trading ethos of the City of London and was boosted (at least in the early days until the collapse of Enron) by US traders. From the start therefore, the British gas market liberalisation was led by the Anglo-Saxon trading ethos. Although sharp, aggressive and cut throat (called by some "red in tooth and claw"),

in the early days at least (before network codes and lawyers became involved) traders operated under the old City of London ethos of "my word is my bond", so contracts were not necessary and an agreement over the telephone was all that was needed. The resulting culture was an Anglo-Saxon trading culture, based on gas on gas competition and hub pricing.

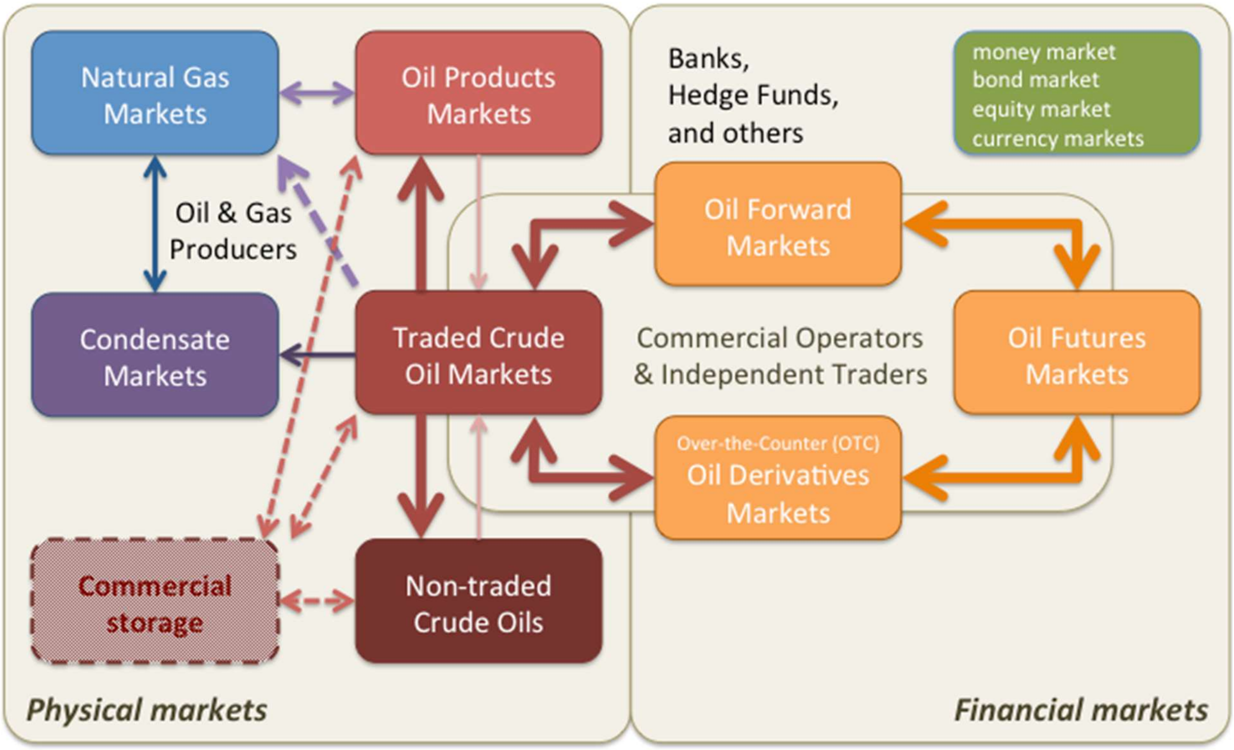
It has been argued[42] that the UK is therefore more geared towards LNG suppliers' pricing. This is different from the continental Europe situation where gas supplies are more linked to pipeline conditions and long term contracts linked to oil pricing (the EON-Gazprom contracts for example). The future therefore could be influenced by both hub priced LNG (US Henry Hub, UK NBP or NL TTF) and oil indexed German border prices.

2.5. Case Study: Oil Trading Markets

2.5.1. Oil Trading

The transportation of physical oil is done through pipeline and tankers while the trading component is supported by advanced financial markets. Financial arrangements contain term contracts and spot trades. Both buyers and sellers can choose to hedge prices by employing financial derivatives such as futures and options. The international oil market for physical oil trade is the biggest balancing market globally. The trading of oil based financial contracts constitute of the biggest commodities paper markets globally. The figure below shows the interactions between physical and financial markets:

Figure 43: Interaction between Physical and Financial Markets



Source: Cape Otway Associates, The Global Oil Market, 2016

The crude oil market is the main driver in setting the direction of influence to other product markets. The crude oil market also interacts with the natural gas and condensate markets.

[42] Patrick Heather, the Evolution and Functioning of the Traded Gas Market in Britain, OIES, August 2010, 6.3 The role of LNG, pp. 31-32

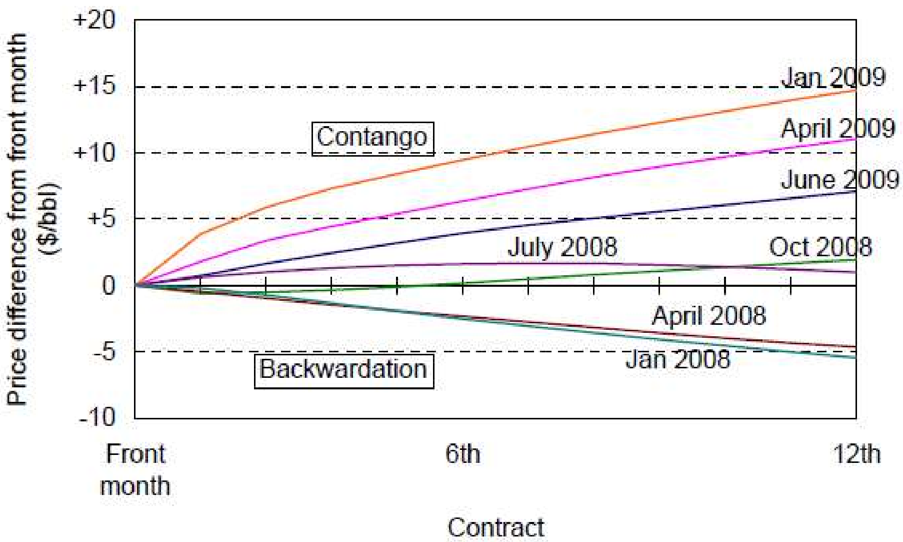
Similarly, oil forward markets, oil futures markets, and over-the-counter (OTC) derivatives markets interact with money markets, bond markets, currency markets, and equity markets[43].

The function of physical storage is not just limited to the logistics chain but it also plays an important role in connecting the physical market with the financial (or paper) markets. The economics and financing of physical storage is responsible for linking spot and future prices. Oil traders are constantly searching for opportunities to arbitrage oil prices based on a multitude of factors such as the forward curve (also known as forward price curve, which is the current price for a commodity in a specific location on a particular date in the future), oil storage cost, transportation to storage facilities, and interest rates.

The connection of physical and financial markets is missing in LNG now. It could develop in time and the example of Singapore (discussed elsewhere in this report) where the government is taking active steps to build such a market, in competition with other Asian countries, is an important development.

The forward curve is explained through the difference between the spot price and futures prices at any given time. If the market condition results in a situation where the futures price is greater than the spot price then the condition is called 'contango'. Alternatively, if the future price is less than the spot price then the forward curve is in 'backwardation'.

Figure 44. Changes in Forward Curves



Akira Yanagisawa, 'Usefulness of The Forward Curve In Forecasting Oil Prices', 2009, IEEJ

Market conditions under contango promote the buildup of physical oil stocks. In such a scenario, the standard trading strategy is to buy spot and sell futures for a set targeted return. In the case of backwardation, the standard response is by selling spot and purchasing futures. When the market expects future prices to be higher than spot prices then contango occurs. Backwardation occurs when carrying stocks has a financial cost (interest rate). The forward price signals in paper markets play an important role in enabling risk management proficiencies that were not available before the development of paper markets[44].

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[43] Cape Otway Associates, 'The Global Oil Market' (2016)
[44] Cape Otway Associates, 'The Global Oil Market' (2016)

Table 38. Timeline of Oil Market Development

TIMELINE	1859	1882	1911	1933	1970	1983	1987…
Period:	*1859-1882*	*1882-1911*	*1911-1933*	*1933-1973*	*1974-1983*	*1983-1987*	*1987-present*
Era	*Innovation and consolidation*	*Standard Oil Trust*	*[Transition period]*	*'Seven Sisters'*	*OPEC pricing*	*[Transition period]*	*Global market*
Pricing system	*Refiners play the key role*	*Monopoly*	*Oligopoly*	*Posted prices controlled by the companies*	*Posted prices controlled by the export countries*	*Netback pricing*	*Reference pricing against benchmark crudes*
Key landmarks	*1850s: Discovery, applications stimulate demand, competition between suppliers, then consolidation and control 1857: first oil concession in the United States. 'Rock oil' for lamp fuel. Rail rates key. Pipelines displace rail: refineries relocate to ports. 1871: Standard Oil alliance in response to price collapse*	*1882: Trust structure used for centralized management of companies 1890: Sherman Antitrust Act 1899: Standard Oil Company (New Jersey) created, which becomes the parent company; Standard Oil controlled 90 to 95% of all the oil refined in the United States 1911: Supreme Court divides Standard Oil*	*1914-18: WW1 Oil price volatility: 1915: $0.64 ($14.93 in 2015$) 1920: $3.07 ($36.30 in 2015$) 1933: $0.67 ($12.25 in 2015$) 1920: Interest rates peak at 5% 1929: Stock market crash; The Great Depression persists to 1939 1931: Bank of England abandons the gold standard 1933: first contract to drill for oil in Saudi Arabia secured by SOCAL*	*1938: first commercial oil in Saudi Arabia produced by SOCAL 1939-45: WW2 1950s: post-war consumer boom and widespread car ownership 1961: ENI CEO Mattei secures Italy-USSR oil trade agreement 1970: "Seven Sisters" control 85% of world's petroleum reserves 1971: President Nixon closed the gold window*	*1973: Arab Oil Embargo 1973: US President Nixon—EPPA 1978: Iranian Revolution 1980: Iran-Iraq war 1980: "Seven Sisters" control less than 25% of reserves 1981: Interest rates peak—10y Treasuries >15% President Reagan decontrols United States oil prices (28 Jan) 1983: OPEC abandons the idea of production cuts to support prices*	*1983: UK PM Thatcher's 'Big bang' financial deregulation 1983: launch of WTI NYMEX contract (March) 'paper barrels' 1984: Shell formalizes 15-day 'dated Brent' OTC establishing it as a reference price 1985: Saudi Arabia switches to netback pricing 1986: price collapse, netback pricing abandoned 1987: stock market crash, completion of BP privatization*	*1988: IPE futures market launched in London 1989: IPE put and call options market launched 1991: Soviet Union dissolved 2008: oil price peak, collapse, and rebound 2010-14 2010-15: shale oil revolution, Brent-WTI spread opens 2012: US EIA adopts Brent over WTI for its AEO 2014: major price collapse begins 2016: Saudi Arabia fights for oil market share*
Key supplier	*United States*	*United States*	*United States*	*Saudi Arabia & the Middle East*	*Saudi Arabia & OPEC*	*Soviet Union, North Sea*	*New entrant: US shale oil*

Source: Cape Otway Associates, 'The Global Oil Market' (2016)

2.5.2. History of Oil Trading Markets

Until the 1970s, the main channel for oil supply was among and between the major oil companies. Petroleum products flowed within the integrated system, and each IOC or NOC had its own source of crude oil supply as well as the refinery with the capacity to refine it. Out of this integrated system, the petroleum product would only flow if either released due to imbalances between refinery output and market demand or refined independently of it, which formed the basis for spot trading.

Spot trading transactions were in limited volumes and were collectively around 5%[45] of the total oil trade, while the remaining 95% was based on contracts specifying prices and quantities over relatively long periods of time. Spot trading was conducted in a very simple manner. Most of the transactions for spot trades were based on personal trust and in the form of un-invoiced exchanges. In 1979 the spot market showed signs of a slow increase in market share thought to represent about 10% of physical crude sales. By 1982, the size of the spot market had grown to more than 50% but by 2007 the size of crude market was generally estimated to represent around 35% to 40%[46] of the physical sales of crude oil. Historically, major IOCs or NOCs such as Saudi Aramco still primarily pursued long-term contracts, but they have recently been playing the spot market, selling from month to month to try to capture some of the major buyer's short-term demand.[47]

Since the 1970s, the trading of Petroleum products has not only developed into one of the largest worldwide commodity markets but has turned into an increasingly complex business. In the last two decades, both the contract period and the price have become much more flexible. Spot cargos can be traded more than 50 times, involve hundreds of millions of dollars and are carried out by sale and purchase agreements containing numerous safeguard measures. Recently though, things have been changing in the

[45] The New Global Oil Market, Understanding issues in the World Economy, Pg 51
[46] Perspective, Economic Analysis review 2007, Volume 17, Pg 8.
[47] CNBC, Opec big three battle for oil market share until the bitter end, 22-11-2016

industry, particularly following a High Court decision, Proton Energy group SA vs Orlean Lietuva [2013], where the dispute centred upon whether a negotiation only between seller and buyers gave rise to a contract.[48] The interlinkages between spot trading, futures markets and contract sales have changed the nature of the petroleum business from its traditional straight forward production-oriented approach to a complex portfolio management environment.

This could develop for LNG in time and these tools would increase liquidity, flexibility and transparency in LNG. These market mechanisms will be developed by the market though, once the commercial environment is in place, and not through government or regulatory interventions.

2.5.3. Stages of Market Development

Contractual and spot trading have come a long way in the petroleum industry, although they have been around since the establishment of the industry itself. Today the spot or futures market is normally taken to refer to spot trading in Rotterdam, New York Harbour, and a few other centres. The Contractual and Spot trading in these markets have been established only in the past few decades and developed in four distinct stages.

1. Residual Market

The 1950s was the era of inter trading among the oil majors, as they had direct contracts among themselves, and where no opportunity was given to the outsiders to enter the club other than the major producers and consumer, a similar situation to what has been experienced in the early stages of development of the LNG market. Each of the Seven Sisters (the major IOCs) was vertically integrated and had control of both upstream operations (exploration, development and production of oil)[49] having their own supplies of crude oil and the capacity to refine it to feed their retail networks.

Most of the companies faced issues in matching refinery outputs with retail demand for various products. Companies with storage facilities and shipment managed by selling their product in different markets but companies with no facilities would quite often balance by swapping with other products or selling and buying some product in the spot market. Contracts specifying prices and quantities over a relatively a long period were the basis of oil trade resulting in 95% of transactions taking place on the basis of long term contracts. Petroleum products outside this closed system, either released due to imbalances between refinery output and market demand, or refined independently of it, constituted the basis and primary function of the spot market, which was limited to 5% of the total trade, thus making it a residual trade during the 1950s and 1960s.[50]

2. Marginal Market

In the 1973 and 1974 oil crises, manipulation of oil prices and supplies by the oil exporting countries came at a most inopportune time for the West, where the governments of oil producing countries had taken over the production of crude oil and contracts were signed between the major companies.

The spot market began to play a marginal role, the market slowly developed and over time became significant trading as supposed to the insignificant trading of the residual market. Jeannette Walls, a famous writer, one wrote "*Sometimes you need a little crisis to get your adrenaline flowing and help you realise your potential*". The significance of spot trading started to play a marginal role in the price setting for petroleum products as oppose to

[48] Clyde & Co, Do we have a deal? Contract formation in oil trading, Oct 2013
[49] (Danielsen, 1982)
[50] World Bank, New Era of Petroleum Trading, Pg 11

following contract prices (usually a little above or below the contract price) without significantly affecting those prices.

The oil companies started to refine the crude supplied by oil exporting countries in their own refineries to resell to third party customers including some independent and government owned companies in consuming countries. Thus, the major companies were central to contract trading but the independent companies bought some of their requirements from the large companies and relied heavily on the spot market. The independents were smaller trading companies (smaller than the seven sisters who dominated the oil business until then). Government (OPEC) producers started selling to these independents (private and government owned) who then resold to a small number of consumers.

This case does not completely transfer to LNG because LNG customers require substantial infrastructure, infrastructure which cannot be transported to another place, whereas oil is much easier to transport to different markets after it is refined. Independent companies in LNG are much more connected with the infrastructure than oil traders are. LNG companies, at least so far, are much larger and the small oil traders are not to be found in LNG, at least not yet.

Once the spot market started to play a marginal role, it started to show its effect. From 1975 to 1978 low spot prices were used as indicators of soft market conditions by both the petroleum industry and consumer countries to set price control policies. The market increased after 1979 when it was demonstrated that it could play its role in both soft and tight market conditions.

3. Major Market

The spot market had a long journey to win its share in the market. Despite influencing the price control policies by both industry players and governments of consuming countries, its share remained trivial during the second stage of market development. It was only after some years that in 1983 several factors came together and started to influence and contribute to the rapid share of the market. Trade then started to grow visibly.

The two years after 1983 were critical for the industry. Spot and spot related transactions started to show their influence in the market. Their market share as compared to contracts went up by 75% in two decades of competition with long term contracts. By 1985 spot related transactions were 80-90% of international trade.[51] The dynamics for this market change were due to:

I. Excess Refining Capacity:

Refining capacity within the industry started to increase and excess capacity became available to refine crude and supply different kinds of petroleum product to the market. Market dependence on the integrated system of majors broke down from the 1960s and refiners started to fight for their survival. The refining industry used the most economical ways to procure crude and supply the market. The industry started to mature and came to a point where refineries tried to increase their throughput to the point where the price of a marginal barrel covered the marginal operating cost. This situation started to put pressure on the crude oil industry where everyone was looking for a bargain. Spot started to gain market share because of declining flexible spot prices as compared to rigid contract prices.

II. New Market Suppliers (other than the Majors):

As the monopoly of the previous integrated system of the major oil companies (such as the seven sisters) came to an end, new upstream suppliers started entering the market

[51] World Bank, New Era of Petroleum Trading, Pg 4

and it became common practice to refine for the spot market. Small traders were buying refined products from and selling into the spot market. That was despite the old tradition of the oil majors where only the imbalanced product from refinery and market demand would end up in the spot market. Majors such as OPEC began to lose their market share, which brought panic into the industry and players began to engage in the so called "spot related" transactions to recapture lost market share. The new market rules brought an opportunity and opened a new era of different spot related trades such as barter trades, variable price contracts and netback pricing deals.

III. Petroleum Future Markets:

The next phase of market development was the growth in petroleum futures in response to instability in spot markets. A variety of derivatives instruments started to take shape which allowed traders to lock in or hedge a price for oil deliveries in the future[52], including the introduction of New York Cotton Exchange and a Bunker C and gas oil contract on the New York Mercantile Exchange (NYMEX). Traders started to develop and use oil derivatives instruments and the regulatory authorities then entered to regulate the emerging market.

The first-generation petroleum industry contracts started to fade away into obscurity. The main reason behind this was the failure of petroleum prices to fluctuate as expected. After the 1973 crisis, the USA, through its Energy Policy and Conservation Act (1975), limited the annual increase in the crude oil price. This led to a failure of market development for futures and spot, out of which, only heating oil and heavy fuel oil contracts were exempted.

The second generation of petroleum futures started with the introduction of a heating oil and heavy fuel contract on the New York Mercantile Exchange (NYMEX) in November 1978. These contracts which were not regulated under the Energy Policy Act and became a great success on the exchange, in turn encouraging other exchanges such as the Chicago Board of Trade and the International Petroleum Exchange of London to introduce other futures related to the petroleum industry. [53]

Following the success of heating and heavy oil market contracts, crude oil contracts (COC) were introduced in 1983 to trading floors. The contracts expanded the interaction between the futures and spot market and brought trust into futures trading. Traders started to take contracts trading seriously and they soon became a price signalling channel for crude oil, especially in the USA.

Spot markets started to bring a change into the markets and spot trading became popular among buyers and sellers. It was not limited to independent oil companies as majors also became involved in active trading and many state-owned oil companies, oil majors and OPEC producers started to increase their share of the spot market and involvement in spot or spot-related transactions. Because of the drive in the spot trade, the markets became more fluid and a larger number of entities (on both sides of the trade) started to take more interest in learning how to use the crude spot market.

2.5.4. Development of the Rotterdam Market

In the early petroleum market development, the petroleum spot market was known as the "Rotterdam Market". It is the birth place for petroleum spot trading and became popular due to its extensive petroleum storage and distribution facilities and oil production. Since then Rotterdam has always been the most active spot market for Europe as well as for World spot markets. It has import and export of large quantities of spot crude and products, with a deep water port plus independent and easy access to the hinterland markets in Western Europe as well as overseas.

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[52] Platts, The Structure of Global Oil Markets, June 2010
[53] World Bank, New Era of Petroleum Trading, Pg. 5

The Rotterdam development grew side by side with the development of the petroleum industry itself. Its geographic position made it a particularly attractive centre for oil trading. It first became significant to the oil trade in the early 1960s with discoveries in Africa, especially Libyan crude supplies by US independents. The African supplies represented an extensive source of low price crude oil, outside the majors' closed system[54]. At that time Europe was at the phase of developing its capacity for independent refining and trading of petroleum products, when the limitation of US market imports barred by import quotas diverted African crude towards European markets which in turn dramatically contributed to the development of Rotterdam port.

The Rotterdam port development was booted into a second stage of development with the 1973 and 1974 oil embargo and continued until 1978. The recession and high petroleum prices with depressed demand left the Rotterdam market with excess capacity in all its operations.[55] Market demand shifted towards lighter products and refineries were run at low utilisation rates. Operators disposed the surplus crude into the Rotterdam market and trust started building in its independence as a free market. Other European countries in the region started to shape their domestic control price policies based on the Rotterdam market.

Oil producing countries started to observe Rotterdam as the only valid reference point for the supply and demand balancing. The third stage of development began when it became a recognised indicator of global oil demand and supply. As oil prices moved towards their peak in 1978 ($40/bbl), actual trading at Rotterdam became very thin, but nevertheless, OPEC and non-OPEC producers began to use information from the Rotterdam market to set increases in prices, and justified the increase by the growth in market demand exhibited by Rotterdam prices.

Oil importing countries became concerned about the high oil prices at the Rotterdam market affecting the world economy. In 1979 at the Tokyo Summit the six major industrial oil importing countries, including the USA, Japan and large European countries tried to moderate Rotterdam market activity. The European Commission played its executive role and began scrutiny of the Rotterdam market. It carried out a process under the name of "checkrun" by reintroducing the register of spot transactions that had been carried out for six months in 1978. In 1979 to 1980 a new register was introduced by the name of "Comma" (Commission Market Analysis) with voluntary participation of the industry to have a deeper understanding of the Rotterdam market's structure and operations.

The EC pushed to formalise the establishment of a trading floor for oil by organising a second examination by experts from various parts of the industry, called the "Bourse Group". Both examinations came back with the results that the Rotterdam market was more or less a free market for petroleum.

Such a register could be a good idea for LNG once spot trading was sufficiently established. At the moment, spot in LNG is in its early stages.

Today, Rotterdam remains Europe's premier oil port and refinery centre and one of the most important trading centres of the world. Much of the oil traded on the spot market is either in storage at Rotterdam or on board a tanker heading that way. The market, whatever its true location, acts as a kind of buffer for oil companies, which cannot always precisely match their available supplies with the needs of the markets they serve.[56]

[54] Changing Nature of Crude Oil Market
[55] World Bank, New Era of Petroleum Trading
[56] Rotterdam Oil Brokers Defend Volatile Market

2.5.5. Development of the Brent Market

Brent has functioned as a leading global benchmark for the crude oils produced in the Atlantic Basin, and low-sulphur or sweet crude oils. The Brent market was formally called a trading club. At the start, there were a limited number of participants and no membership requirement except the ability to enter the actual deals based on identity and reputation among the traders, who knew each other. The development of Brent was initially due to coincidence during 1981-1982 by the willingness of a number of oil companies to sell their equity oil into the spot market to minimise tax labilities and sell crude oil in advance of production in order to avoid the risk associated with falling oil prices.

Another reason for the Brent market development was the interest among traders to sell short. It was due to expectations that oil prices would fall and the trader would be able to buy product back from the market to fulfil his obligations at a lower price than what he had sold it before.

The Brent market became the industry's own market as opposed to other markets seen as belonging to commodity traders. Brent started to serve futures markets as an un-institutionalised and unregulated market, which included trades which were not really intended for end users but to be closed before the date of delivery. It became an important bench mark for crude oil prices in reflecting the demand and supply conditions of crude oil.

The crude oils under Brent include most grades produced in Nigeria, Angola, and US Gulf Coast (USGC) sweet crude oils. Brent is effective as a pricing basis because of its exchangeability for the refineries in the USGC, US East Coast, and NW Europe. The Brent field is located in the United Kingdom Continental Shelf (UKCS) of the North Sea and transported to the terminal at Sullom Voe (Shetland Islands) – namesake for the futures and options market of Brent. The crude oil trading based on Brent is actually based on Dated Brent, a cargo shipment within the next 10-21 days. This is despite the fact that Dated Brent itself is not an actual spot market, instead a short-term forward market influenced by contracts for differences (CFDs) derived from the forward curve of Brent futures and short-dated cash market options. It is nevertheless still the benchmark used to price approximately 65% of crude oil trades [57].

A dated forward market would be a good idea for LNG as that more realistically reflects the scheduling and the delivery of a cargo at a terminal after some weeks. It would be up to the market though to develop such types of trade.

2.5.6. The Singapore Market

Singapore is an ideal location for an oil trading hub and it has transformed its economy into an energy trading hub within a few decades. Its centrality at the crossroads of Asia and the flow of Middle East product into the Pacific Asian markets made it the second largest petroleum port next to Rotterdam.

Singapore did not have its own crude but its free economy and excellent telecommunications and other infrastructure contributed to make it an ideally suited port to respond to changes in the Pacific Asian oil market and transformed it into the "Houston of Asia"[58]. Singapore built five refineries in the 1960s and 1970s and established a free trade zone for petroleum products which gave it the edge to become a leading petroleum market in the region.

The oil shocks of the 1970's affected the Singapore market negatively as it did the world. The first oil shock reduced oil accessibility to Singaporean refineries as oil importing

[57] Intercontinental Exchange "ICE" Crude Oil
[58] Doshi 1989

countries made security of supply a top priority and major oil importing countries such as Japan withdrew their refining contracts from Singapore. The Singaporean role in supplying oil products in the region was diminished but it had already emerged as an oil trading hub in Asia. After the second oil shock and the recession in 1985, the oil industry in Singapore shrunk but its contribution to the economy was stable as it made efforts to revive its oil industry.

To secure supply for its refineries and recover its position in the petroleum industry, Singapore adopted different strategies to position itself in the oil trading market. It introduced the Approved Oil Trader (AOT) scheme, introduced in 1989, which gave a concessionary a 10% tax rate on trading activities and lower operating costs, which worked as a strong pull factor, attracting many trading firms to open their offices in Singapore.[59]

Singapore had another benefit in that its exchange floor operation hours overlapped with the USA and Europe. By the time the US exchange floor closes, the Singapore exchange floor opens and by the time Singapore exchange floor closes, the European exchange floor opens. Singapore can be connected throughout 24 hours. Its multiculturalism and better living conditions with no language barriers as compared to Japan helped it to become one of the biggest oil trading hubs in Asia.

2.5.7. The Western Texas Intermediate (WTI) Market

The Western Texas Intermediate (WTI) is a mid-continent pipeline market for crude oil where it runs continuously at almost constant rates. Historically, the crude oil industry in the USA started in western Pennsylvania, eastern Ohio and in Canada in southern Ontario. Nevertheless, the industries soon discovered much greater sources of crude oil elsewhere. In the USA, the industry initially flourished in Southern California, superseded by discoveries along the US Gulf Coast, Oklahoma, and then West and East Texas. The early importance of Oklahoma, and the demand for long-distance pipelines to refining centres in the Midwest, gave rise to a pipeline terminal at Cushing. Once crude oil discoveries were made in the Permian Basin of West Texas and New Mexico in the 1920s, pipelines were connected to Cushing and refining centres along the US Gulf Coast. The crude from the Gulf Coast is shipped to the north to connect to this pipeline system, along with Canadian crude moving south. The combination of the pipelines network and storage tanks at Cushing established WTI at Cushing as a natural benchmark price for US pipeline crude oil. The US pipeline market rotates around the pipeline scheduling considerations, the period after the 25th day of the previous month and before the beginning of the following month is the scheduling period. The crude oil priced for the following month's delivery flows is supplied at that price in the next month. The fixed price act as the foundation for swaps against crude oil priced in the daily market[60].

In the 1970s Saudi/Arab Light crude (S-ALC) was the marker crude against which values of lower or higher quality oils could be set but by the beginning of the 1980s WTI started to gain the trust of the market as a marker against Saudi Light crude and was viewed in the industry as a "free" crude and its price movements. The WTI of the USA, the UK's Brent Blend, and Dubai's Fateh crude became the new commercial marker crudes as their prices reflected market conditions more realistically[61]. The perception among the traders was that the Arab Light crude was not traded in any significant volume in the spot market, and spot prices for the S-ALC were just following the old prices, with nothing other than a repetition of its prices. S-ALC production was much higher than Brent or WTI but it was mostly sold on long term contracts rather than spot. In addition, WTI and Brent were extensively traded (up to 30 mm b/d) on the futures and forward markets.

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[59] Chang, Y. Energy Community Trading in Singapore, Chap 2
[60] Intercontinental Exchange "ICE" Crude Oil
[61] World Bank, New Era of Petroleum Trading

WTI started to bring more clarity to world oil markets but it was unlikely to be the world's largest market indicator since physical supplies were all landlocked. The US mid-continent pipeline system was one of the drawbacks to the WTI market but reflected US buyers thinking, something very similar to Henry hub for Gas.

2.5.8. Conclusions

The history of crude oil trading shows that markets react when they are hit by crises, when development takes place much quicker than at any other time. Not all markets perform positively though and every market is effected by its own geographical and regulatory position and the availability of product.

Crises:

An example can be taken of Rotterdam which after the crude crises in 1970s became a major hub for crude trading not only for Europe but the world. It could have struggled after the oil crises but it benefited from the significant discoveries in Africa, especially Libyan crude supplies by US independents. As it had access to extensive African sources of low price crude oil, outside of the majors' closed system, it helped in the development of the Rotterdam market.

In comparison, the Singaporean market which went into crisis after the 1970 shocks, did not have major discoveries near to its refineries and suffered huge cuts when countries such as Japan were effected by oil shortages and security of supply became a priority for them. These led to Singapore's role becoming diminished and it had to adopt different policies, promoted by the Singaporean government, to emerge as an oil trading hub in Asia and transform itself into a financial and business hub.

Regulatory Regimes:

This case study also shows that unnecessary regulatory regimes at certain times may affect markets negatively and can become an obstacle in market development. The US case shows that its Energy Policy and Conservation Act (1975) limited the annual increase in the crude oil price, led to failure of market development for futures and spot in the US and kept the market from development for a decade until that barrier was removed.

On the other hand, appropriate regulatory intervention is a very important driver for market development. Singapore shows with the Approved Oil Trader (AOT) scheme that a positive regulatory and fiscal environment can bring positive change into a market and can encourage traders to find new methods to make markets more accessible and increase regional trade.

Infrastructure:

The availability of proper Infrastructure is another component which motivates traders and builds trust in markets. Markets such as Rotterdam, WTI and Singapore all developed on the basis of having proper infrastructure. A free market as well as excellent infrastructure, communication system and connectivity to the world made them ideally suited to respond to changes in the oil market.

Something very similar is needed in the LNG trading world, namely infrastructure in the region which can create hubs for trading LNG and make spot trading more accessible for new traders other than just the major incumbent players.

2.6. Case Study: Development of Trading in Iron Ore

2.6.1. History of Iron Ore Trading

The recent development of markets for commodities such as coal and iron ore can be compared with oil trading, pipeline natural gas and LNG. Similarly to LNG, the iron ore market faced challenges of lagging in development of a liquid market but it has experienced accelerated development in recent years. The traditional iron ore market has commonalities with the current LNG market, such as East Asia being the demand centre and a lack of transparency with the pricing system. Prices were based on long term contracts and through bilateral negotiations[62].

The iron ore spot market started in the early 2000s. Demand was driven by Chinese steel manufacturers expanding iron ore acquisition in the spot market. On the supply front, the market was driven by Indian producers trading more of their products in the spot market. This eventually resulted in the growth of the iron ore spot market. With added liquidity in the spot market, the price reporting frequency evolved from monthly to daily, and finally gained the confidence of the market as price indices. As shown in the figure below, the collapse in spot iron ore prices brought on by declining demand due to the recession was a turning point in further advancing market liquidity. With spot iron ore prices dipping below the benchmark price, the established steel makers shifted to spot price based trading from benchmark price based trading. Simultaneously, established iron ore producers such as BHP and Vale conveyed their backing for spot prices, validating the growth in iron ore spot market liquidity.

Figure 45. Iron Ore Market Formation

Tsueno Miyamoto and others, Developing Liquidity in the LNG Market - Asia's Challenges and Outlook (1st edn, KPMG 2017)

2.6.2. Lessons for LNG Market Development

The iron ore market formation process can also be seen as providing lessons for the current LNG market development. The current condition of the LNG market needs to be compared and examined with respect to:

1. Growth of spot trading;
2. Development of spot price indices;
3. Emergence of financial trading;
4. Collapse of the traditional pricing system; and
5. The development of liquidity in futures market.

Growth of spot trading: Trading in LNG is dominated by long-term contracts with mostly Japanese and Korean players. In recent years, a new wave of LNG importers have entered the market through short-term contracts and spot trading. The expansion of LNG spot trading looks similar to China's expansion into spot trading in the iron ore market. Similar

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[62] Tsueno Miyamoto and others, *Developing Liquidity in the LNG Market - Asia's Challenges and Outlook* (1st edn, KPMG 2017)

signs have been seen recently in the LNG market by the Japan Fair Trade Commission (JFTC) announcing a ban on the destination clause or restriction on buyers in the LNG contracts, which takes LNG one step nearer to spot market trading.[63]

Development of spot price indices: The LNG market has seen a positive development of spot indices such as DES Japan and SLInG. LNG market players will have to closely follow the developments in order to discover which price index will come to dominate the Asian trade, as well as their relation to Henry Hub and NW European hub price indices.

Emergence of financial trading: In the current market, liquidity in swaps on spot LNG prices is yet to be established but the swap trading through exchange such as JOE and the SGX is anticipated to develop further.

Collapse of the traditional pricing system: The developments in the pricing systems needs to be evaluated on the demand and supply front. On the demand front, the policy shift by JERA, Japan's largest LNG importer, to reduce the ratio of long-term contracts by 2030 and to cover the decrease by short-term and spot contracts which will eventually improve flexibility in procurement, will affect the traditional pricing system. Similarly, Japanese players need to respond to the Power and Gas Systems Reform by increasingly utilising spot trading to improve flexibility in LNG procurement. Additionally, the commencement of North American LNG exports to Japan based on Henry Hub prices will also lead to a shift from the traditional oil indexed pricing system. On the supply front, the completion of large LNG projects is leading to a supply surplus and the suppliers may find themselves in a circumstance that compels them to move to spot price based trading[64].

Development of liquidity in futures markets: The creation of futures markets such as JOE's futures market based on the DES Japan index and the SGX's futures market based on the SLInG index, are positive developments but none of the markets have (yet) secured sufficient trading volumes to be considered liquid markets.

The above description of the current LNG market condition shows the recent developments in the LNG market with respect to the growth of spot trading, the development of spot prices, and the emergence of financial trading, all of which suggest that market formation is in the developmental stage. However, the traditional pricing system still dominates the current LNG market and the market is still far from being liquid. With the policy shift in Japan, the world's largest LNG consumer, there is a possibility of the move being a catalyst to move away from the traditional pricing system.

2.7. Results of Interviews with LNG Industry

2.7.1. Introduction

As part of the research for this study, we carried out a series of interviews with a selection of industry participants across the LNG industry, including from: gas producers, regasification terminals, LNG lawyers and industry experts. The interviews were carried out on the basis of Chatham House Rules, that is the names of the interviewees' organisations are made public in this report and the interview comments are made public, but all comments are unattributable, so no comment can be related to any of the participants. In addition, some participants agreed to have their comments made public but on the basis of complete anonymity, so the name of the organisation is not disclosed in this study.

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[63] Natural Gas World, Japan Bans Destination Clauses in New LNG Contracts, 28 June 17
[64] Tsueno Miyamoto and others, *Developing Liquidity in the LNG Market - Asia's Challenges and Outlook* (1st edn, KPMG 2017).

A questionnaire was circulated to each participant in advance of the interview but this was treated as the basis for discussion rather than as a questionnaire to be completed. The survey questions are provided in Annex 10.

2.7.2. Results of Interviews

The following description summarises and reflects the comments and views of the participants in the survey, described under each of the topics within the survey.

2.7.3. Organisations Interviewed

The participating organisations in the survey of industry opinion are shown as follows (there are also some organisations who requested their contact details to remain confidential):

- Producers:
    1. Shell Group – Europe Gas and Electricity Markets;
    2. Shell Group – Global Gas and LNG
    3. International Association of Oil and Gas Producers;

- Facility operators:
    4. Isle of Grain LNG;
    5. Cheniere Energy;

- Buyers:
    6. A national LNG buyer;
    7. A national LNG buyer;

- Institutions:
    8. International Association of Oil and Gas Producers (IOGP);
    9. European Federation of Energy Traders (EFET);
    10. Eurogas;

- Advisors:
    11. A leading LNG legal firm, UK;
    12. A leading LNG legal firm, Singapore;
    13. Navigant, consultancy;
    14. An energy and strategy consultancy;

In summary, the view of the LNG industry in Europe is that the LNG industry is working fine and any minor problems can and are being addressed by the industry itself. There is a belief that the gas storage market is overregulated and a concern that this may be repeated in LNG. While not specifying what they mean by over regulation, the industry would be concerned with price regulation, publication of prices and other commercially confidential information, stringent rules of access to exempted terminals, subsidies to LNG infrastructure (would could distort the market and provide competition to exempted terminals), regulations restricting new FSRUs.

Liquidity is improving by itself but the key barriers to further liquidity, flexibility and transparency, as identified by the LNG industry, are:

- In a global situation of oversupply of LNG, the low prices offered by Europe are not encouraging new liquefaction projects to be developed to meet potential supply shortages from around 2025 (although the credit worthiness of European customers offsets that and there is currently more than enough LNG to meet Europe’s needs);

- The nature of LNG, whereby because it comes in discrete cargoes which have to be scheduled weeks in advance (rather than a pipeline flow) plus the boiloff of LNG means that it is not economic for LNG to be kept in storage for long periods of time;
- Access to gas storage at regasification terminals;
- Transparency of information and pricing at regulated regasification terminals;
- Lack of liquidity at the market or market hub downstream from the terminal;
- Some minor concerns over LNG qualities and the extent to which some terminals can accept some LNG specifications.

2.7.3.1. Views on Global LNG Developments:

LNG supply: Most of the industry thinks there is an LNG supply overhang which will last to the early 2020s (2020-2022). Nevertheless there is a need to plan now for more liquefaction capacity to be ready from 2022. Most of the major producers have taken industry standard forecasts (such as Wood Mackenzie or IEA for example) and added their own interpretation. The Shell view (for example) is that there will be a 30% growth in global LNG production in the period 2016-40, with massive increases in demand, especially in India and China.

There are different views as to what will happen after the early 2020s. The majority view is that additional liquefaction capacity will be needed from around 2023.

One view is that an additional 50 mtpa will be needed by 2025, in addition to liquefaction capacity currently under construction or where FID has already been taken. The view is that because no new projects are going forward now, by around 2025 there will be an LNG shortage and consequent increases in prices, the actual price depending on the number of new projects developed by then.

One major organisation however takes a very different view and believes the supply overhang could last out to 2030 (as a result of the impact of low carbon initiatives and the competition to gas from renewable energy). This will mean low prices for the foreseeable future. This is more in line with our own view.

The different views over LNG supply and price forecasts are reflected in the scenarios presented in this report.

Some of the industry players believe there will be a significant decline in gas production from traditional producers, which (over time) will reduce the current oversupply position.

US LNG Production: Forecasts of the volumes of US LNG available for Europe range from 70 mpta (Wood Mackenzie) to 85 mpta by 2020. Because of the low prices offered in European markets, Europe is unlikely on its own to underpin much new LNG investment. Those projects which have reached FID will go ahead however. The very substantial volumes from US projects which have reached FID and the over-contracted position of Asian markets nevertheless means considerable volumes of US LNG will be available for Europe. The US government is supportive of the LNG export projects and the USA is forecast to become the largest LNG producer globally.

LNG Demand: LNG markets are growing rapidly. While traditional LNG markets (Japan, South Korea, China more recently, Europe) are showing much slower growth than before or even slightly declining markets, these are counter-balanced by rapidly growing new LNG markets in emerging markets, including Africa, Middle East and India. Buyer countries have over contracted LNG for at least the next three years, including China, India and South Korea.

There are different views as to how these new LNG markets will develop, with no clear industry view. A high demand growth view is based on a rapid uptake of FSRUs. Due to the low initial cost of FSRUs and because they can be towed away, they bring much lower credit risk than fixed onshore regasification plants. This means that emerging market buyers have much easier access to credit to buy these FSRUs than they had before. FSRUs do have some disadvantages, namely that they have to be towed away approximately every five years for turnaround maintenance. Emerging market buyers though have tended to overlook the disadvantages and are taking up FSRUs at a fast rate.

An alternative view, one of low LNG demand growth among emerging markets, is based on the view that emerging markets will not accept the international pricing that will go with LNG imports. Regulatory constraints (pricing in particular) and local alternative fuels in emerging markets may slow the rate of uptake of imported LNG. Many consumers in emerging markets have been used to price subsidies and governments would find the higher prices demanded by international LNG sellers politically challenging. However, the price falls in LNG since 2014 have made international LNG pricing now much easier for emerging market buyers. In some cases, the delivered international LNG price (or the netback for domestically produced LNG) is equal to or even lower than the domestic price. This is approximately the case in Nigeria now.

There is no consistent view of which of these two views will prevail but the extent to which emerging markets adopt LNG will be a key determinant of whether an LNG supply overhang will continue to 2025 and after or not.

National LNG Buyers: Those national buyers in emerging markets who we contacted are new to the LNG business and believe that they are still learning. Because of this and because of their national governmental nature, they are more comfortable buying LNG following direct government to government contacts, with each government nominating their credible company. They then buy following a tender process on long-term contracts. This approach provides payment and offtake assurance to the buyers. National government buyers contact producer nation governments from all over the world, including European ones. National buyers are also moving into spot and short-term contracting but in a smaller way, they tend to buy their base load needs on long-term contracts and top up secondary markets from spot and short-term trades.

Traditional LNG Buyers: The more traditional LNG buyer countries, such as Japan, South Korea, Taiwan, are increasingly buying short-term and spot cargoes, not long-term. The supply overhang means that sellers are increasingly having to sell to less credit worthy buyers in emerging markets. While Europe is considered the buyer of last resort because of the lower prices on offer, Europe is nevertheless attractive to LNG sellers because of the credibility of buyers. There is less credit risk with European buyers than with the new emerging market LNG buyers.

Buyers are also increasingly buying into production to assure their own LNG supplies. These include Japan, India, South Korea and China. In many of these cases, because they are over-contracted, these national buyers are currently reselling much of their LNG onto secondary markets or into aggregators' portfolios.

New LNG Markets: There are also new markets in LNG trucking, bunkered LNG and micro-LNG. Again, there are different views of how fast these markets will grow. They are developing in Europe (trucking LNG to off-grid markets, such as to off-grid industrial parks in Spain or Scandinavia). LNG bunkering could be expanded to the Mediterranean and to Asian markets.

Atlantic and Pacific Basins: Historically, LNG has tended to operate as two separate basins, Atlantic basin and Pacific basin (Asian markets). The industry view is that essentially there will remain differences between the two basins, although there will be some convergence and the two basins are now inter-related on price. Cargoes from Qatar, USA, Trinidad and Tobago, even Russia, are finding their way to both sets of market but the industry view is that pricing differences will remain. On the whole, Asian LNG will tend to be supplied to Asian markets and Atlantic Basin LNG to Atlantic markets.

An alternative view is that there will be a three-way split: 1) The USA will remain on Henry Hub pricing; 2) European pricing will be based off Russian pipeline pricing, influenced by US supplies; 3) Asia-Pacific will be priced off the emerging Singapore hub (or possibly a yet to develop China Shanghai hub) and Japan Crude Cocktail (JCC) or emerging Japan hub price.

LNG Prices: Historically, Asian prices were about one third higher than European prices. They rose to an unprecedented almost $17/mmbtu in Asian markets in 2014 but prices have settled since then. Prices are expected to return to the traditional level of an approximate maximum of one third premium of Asian over European LNG prices.

Some price convergence is expected in the future but there will remain price differences between Asian, US (Henry Hub) and European markets. Because of the lower prices in Europe, Europe will remain the market of last resort. LNG producers will want to sell into Asian markets first and only after into European markets.

LNG pricing in the future is expected to be based on Henry Hub, with a differential of Henry Hub plus something, as a result of the large volumes of LNG from the USA. Prices to Europe will be in a range of Henry Hub + liquefaction cost + transport to the NBP/TTF hub. That applies to NW Europe. This does not apply to E and SE Europe which are much less liquid and may still be priced according to Russian Gazprom prices.

Producers report that US suppliers need prices in a range of at least $6.50-7.50/mmbtu (providing a netback to Henry Hub of around $3/mmbtu) to break even. US LNG pricing is a fixed toll of $2.50-$3.50 + 15% of Henry Hub (to cover losses + US transport). The range of US pricing can be considered as lying between the US short run marginal cost (SRMC, Henry Hub +15%) to the long run marginal cost (LRMC, approximately $6.50-7.50/mmbtu), which is in the order of Henry Hub + $3-4.50/mmbtu. The high marginal cost of US LNG could mean that it will be the balancing supplier, albeit a very high volume one.

Because US LNG suppliers buy gas at Henry Hub prices, this makes the USA a high SRMC province, compared with other LNG liquefaction provinces. The SRMC for Qatar is effectively zero (marginal costs are covered from liquids production). The same applies to Australia (fixed capital costs are very high but they are sunk costs and marginal costs are very low). The LRMC for Australian LNG is very high but the SRMC is very low.

In Asia, already now and in the future, LNG prices set downstream gas market prices. Europe is different because of the strength of pipeline gas options. Europe is likely to see a competition between Russian pipeline gas and US LNG. The industry expects that Russia will make efforts to maintain its market share in European gas markets, although in particular years market share may go up or down. Russian contract prices are expected to be the main factor influencing gas hub prices, with US LNG prices also having an influence (although a lesser one). US companies and other LNG suppliers to Europe therefore largely expect to be price takers with the LNG price at the regasification terminal being a netback from the gas hub price.

New Technology: It was noted that most of the new LNG technology is coming from the USA and not so much from Europe, such as LNG ship fuelling and ship to ship bunkering.

NW European Hubs: NBP used to be the largest and most important European hub, by far, but it is becoming increasingly less so. TTF has increased in liquidity and may now have overtaken NBP in terms of liquidity (although on the other hand, there is more churn at NBP and an LNG cargo is churned 6-7 times before it comes into Grain LNG). Three reasons are identified for the growing popularity of TTF:

1. Proximity: TTF is close to European gas networks whereas gas supplies from NBP have to pass through the UK-Belgium Interconnector with a capacity of approximately 20 bcma;

2. Currency risk: TTF trades are in € which avoids the £/€ currency risk from trading at NBP (although global markets still index to £ at NBP and there are some € trades on offer at NBP);

3. Brexit: Although the extent of the Brexit effect is not yet clear, it is clear that Brexit does play some part in the increasing movement of European gas trades from NBP to TTF.

Emerging Singapore LNG Hub: Singapore has been at risk of gas supply shortages from pipeline gas supplies from Indonesia. The Singapore government then made the decision to increase liquidity and their security of gas supply by deliberately bringing about an LNG spot market, trading hub and price reference point. The Singapore hub is in development and it is not known how it will develop. Nevertheless, this is a case to watch.

Singapore benefits from already have large volumes of storage which means that cargoes can be dropped off and collected continuously. Although LNG cannot be stored long term because of effects of boiloff, when the storage is large enough plus it is continuously topped up and withdrawn, LNG storage can be provided effectively. Singapore has three tanks of around 230 000 cubic metres each. Ship to ship bunkering is also possible, with around 50 ships now converted from HSPO to LNG.

As well as the physical elements of the hub, work is also taking place with the Singapore Stock Exchange for a standard paper contract. In 2015, the Energy Market Authority (EMA) a statutory board under the Ministry of Trade and Industry in Singapore, announced that it is considering setting up a Secondary Gas Trading Market (SGTM) which will allow gas buyers and sellers to trade gas within Singapore, enabling domestic gas price discovery that reflects Singapore's demand and supply conditions.

These would be via the Singapore Exchange (SGX) as well as commodity price reporting agencies. The SGTM will also enhance Singapore's position as a hub for LNG and gas trading activities. It would also pave the way for the potential establishment of a gas forwards market to trade financial contracts for gas.

In addition, there have been tax changes leading to a global commodities tax regime. As a result, all the global gas and oil traders are based in Singapore.

The pricing regime is still being worked on. Platts is already quoting a Singapore spot price.

All the elements of a deliberately created LNG hub are coming together and are expected to be ready by around 2022-23, comprising:

- A physical hub with large volumes of LNG storage and ship to ship bunkering;
- A paper contract for traders to hedge against;
- Physical presence of traders, supported by a progressive commodities tax regime.

The Singapore LNG market is small and it remains to be seen how it will develop in competition with much larger potential Asian hubs, such as at Shanghai or Japan. Although it handles much larger volumes of pipeline gas and LNG, the Shanghai hub is not really a hub because of its heavily regulated nature, including regulated pricing, whereas Singapore is being deliberately created as a true liquid LNG trading hub.

Potential European Hubs: The main view from the industry is that LNG hubs are not needed in Europe. Market hubs exist at NBP and TTF. LNG hubs will develop at the supplier end, which means at the US Gulf Coast. An alternative view is that various places are developing in Europe which could possibly become physical LNG hubs. These include Rotterdam (Gate terminal), Zeebrugge, somewhere in the Baltics, the Mediterranean (Malta or Gibraltar possibly). These are all places where LNG bunkering could take place and where a hub may also develop.

2.7.3.2. Contractual Issues:

Unregulated LNG: Because LNG is a global (not a national or regional) industry, it is unregulated. The industry operates under contract, with most contracts under English law (the Laws of England and Wales). Enforcement of contractual terms can be difficult at times though. If a national buyer refuses to pay for example, there is in reality little the seller can do, even a national seller. This is not withstanding arbitral clauses and judgements in international courts according to the contract.

Much of the LNG industry is confidential and not open to public disclosure. While some agreements are online (such as the Cheniere tolling agreement on the FERC website), most LNG sale and purchase agreements remain confidential and not disclosed. Contractual terms are becoming more flexible though.

Standard contract: LNG contracts are generally like any other oil or gas contract, the main differences being with scheduling and offloading.

Some industry players want an industry standard LNG contract, others do not. There are various standard contracts available (such as GIIGLN, AIPN, EFET) but even though these have been developed by industry associations and industry members, on the whole they have not been taken up. There is little appetite in the industry for developing or taking on a new standard contract when a standard from a particular company will probably emerge. Just as oil trading grew around a standard producer contract, so the LNG industry in Europe will probably adopt the contract from one of the leading players, in other words, a US Gulf coast player, such as Cheniere or another US Gulf Coast player, or Shell.

A standard contract may emerge (or be imposed by a leading industry player) for spot and short-term trading but there is a view among some players that it may be more difficult to have a standard LNG contract generally, as there are too many different risks and prices available. Energy Markets Global are not convinced by this argument. While it is true that LNG does have particular differences around scheduling cargoes, other risks and pricing are not particularly different than for the oil industry.

Around 70% of LNG trades are on long term contracts, following lengthy contract negotiations. Around 30% are on short term and spot trades.

There will probably be a standard LNG contract in 20 years, possibly in 10 years but maybe not within 5 years. One view is that long term LNG contracts will remain dominant in the future. Another view is that once there is enough uncontracted flexible supply available, buyers may decide not to sign a term contract but to choose to rely on buying short-term or spot. There can then come a tipping point from buying on fixed long-term contracts to buying on flexible contracts.

Risk Allocation: There are two basic ways in which LNG can be supplied, *Free on Board* (FOB) and *Cost, Insurance and Freight* (CIF), which in the LNG industry is called *Delivered at Terminal* (DAT) or *Delivered at Place* (DAP). The terms DAT and DAP replace the former terms *Delivered Ex-Ship* (DES) terminology. Although many in the industry still refer to DES, the term was removed from INCOTERMS in January 2011.

Under FOB contracts, the buyer takes title and risk at the liquefaction facility and is responsible for shipping, insurance, unloading, regasification, duties and taxes, and other costs and responsibilities. Risk is transferred from seller to buyer at the ship's rail at the port of shipment (where the LNG is loaded onto the ship at the liquefaction plant);

Under DAT/DAP contracts, the seller retains title and risk until delivery and is responsible for the costs of transportation to the destination (insurance and freight). Title and risk are transferred at the port of destination when the LNG is made available for unloading to the buyer.

US liquefaction companies, such as Cheniere, are selling FOB and transferring risk to their buyers, who are generally portfolio or aggregator companies up to now. New buyers, such as national buyers in emerging markets, are buying DAT/DAP and are not taking on the transportation risk.

Traditionally, with long term contracts, buyers took volume risk and suppliers took price risk. The buyers committed to buy at often very inflexible terms, while prices were often indexed, usually to an oil price basket. With the supply overhang now, power is moving towards buyers, providing buyers with more options to pass volume and price risk towards sellers. Buyers are looking for increasing flexibility in delivery options as well as taking advantage of low spot prices. Buyers are looking for more volume flexibility in long-term contracts and are also gaining more flexibility through short-term and spot trades. Buying cargo by cargo on a spot basis provides the ultimate flexibility to a buyer although it carries the risk of price fluctuations and possibly of unavailability of a normally easily accessible LNG cargo

2.7.3.3. Flexibility:

LNG Terminals and Other Entry Points: There are some key differences between LNG regasification terminals and other gas or fuel entry points:

1. LNG comes in cargoes;
2. It is not possible to give 24 hours' notice under TPA rules for LNG;
3. LNG jetties operate differently from oil import jetties;
4. Using bulletin boards or use-it-or-lose-it provisions for LNG is difficult;
5. A full spot market is difficult with the requirements for precise scheduling for LNG;
6. LNG boils off so it cannot be kept waiting in storage as oil can;
7. Safety issues – squeezing an LNG cargo into a terminal just because there is a slot available is not so easy.

The question is whether these differences mean that LNG is fundamentally different from pipeline gas or oil so that traded markets cannot develop, or that these differences can be overcome.

One viewpoint is that LNG is fundamentally different and will always remain so, meaning that full trading markets cannot develop with LNG. Some producers and liquefaction facilities keep to this view and would like the traditional long-term inflexible contract model to remain.

An alternative view is that it may take a little longer to bring about but LNG can be traded. The entry of US LNG with its more flexible contract terms will be a key driver. Standard contracts and a liquid market downstream of the regasification terminal are considered as essential for LNG trading.

Cargo Flexibility: Traditionally, there was very little flexibility in LNG contracts, with 100% delivery. Upward and downward tolerances have now been introduced, with tolerances down to 80%. Producers report that buyers are looking for further flexibility to 70-80%. Some producers and portfolio players state they could provide 70-140% flexibility (although US Gulf Coast producers are offering 0-100% flexibility). It is not clear to Energy Markets Global why portfolio players cannot offer much more flexibility than they are currently proposing to offer (considering the large very portfolio nature of their businesses).

Terminal access: The general industry view regarding access to regasification terminals is:

- There are no particular problems with terminal access;
- Liquidity (or barriers) comes from the market hub behind the terminal, not with the terminal itself;
- LNG cargoes need access to storage;
- Gas storage suffers from too much regulation, this should not be repeated for LNG;
- Exempted regasification terminals (those that have obtained derogations) should have the right to operate terminals as they wish.

A common view expressed is that there are no particular problems with access to LNG regasification terminals. Liquidity is not provided by the terminal but by the market hub behind it and downstream from the terminal. In NW Europe, where there are liquid markets, no industry players who we interviewed identified any problems in obtaining access. Cargo holders can obtain access through a regulated terminal or through secondary markets for an exempted terminal (through contacting one of the existing capacity holders). Generally and particularly at present (first half 2017) there is plenty of spare capacity at terminals and cargo holders are able to access that capacity. Utilisation in NW Europe is close to zero. In addition, there is competition between terminals and the access from the terminals to liquid markets in NW Europe.

Where barriers exist, they are in access to hubs behind the terminal. While there is market liquidity in NW Europe, concerns were expressed over access to markets in E and SE Europe, such as Poland or Greece, where trading cannot take place due to insufficient market liquidity.

There may be some specific problems identified connected with specific terminals, such as for example, use-it-or-lose-it regime at Grain, or regasification pricing in Spanish terminals. The industry view is that these specific problems should be looked at on a terminal by terminal basis.

Much of the industry consider that exempted regasification terminals should not be regulated, with no need for regulated TPA to regasification terminals, because competition already exists and private investors should be allowed to enjoy their own capacity rights.

New infrastructure should not be subsidised as that distorts markets. There should be much more emphasis on improving markets rather than regulating LNG access.

Liquidity: Liquidity is defined as a transparent price marker that can absorb significant volumes without significant price differences. NW Europe (NBP and TTF) qualifies but much of E and SE Europe does not.

The industry view in general is that liquidity is enhanced by improving liquidity at the hubs downstream of the regasification terminal and not at the terminal itself. Gas markets built from hubs are considered more resilient than markets built on infrastructure. This is because hubs are market based where traders buy and sell gas and set prices. Infrastructure on the other hand depends on the ability of the owner to predict the market and where the infrastructure is built or subsidised by government, the market may be distorted. This is the industry view although there are examples of where infrastructure creates the market and draws trade to it.

Europe is in fact well placed with considerable options for diversity of supply, in comparison with other regions around the world.

There was a case where an LNG regasification terminal was built and immediately a big price discount was offered by RAO Gazprom. The LNG terminal then became a hedge against Gazprom prices and not a physical need in its own right.

One view is that the LNG industry provides flexibility but not liquidity. An alternative view is the opposite, that traditionally the LNG industry has been very inflexible (but this is now changing) and the increasing volumes of LNG becoming available now will provide much more liquidity. The industry view is that liquidity in European LNG supplies will be provided at the US Gulf Coast supplier end.

A consistent complaint was that the emphasis should be into fully implementing the third package and ensure a functioning market. This should take precedence over increased investment and over introducing regulation into new areas, such as into currently unregulated LNG.

There need to be buyers and sellers for a market. For example, Vitol (a trader) had offered spot cargoes in Japan but they were not taken up. Lack of an active market behind the terminal and lack of TPA through the terminal stopped LNG trading developing in Japan.

US Flexibility: Cheniere is offering flexibility through:

- No destination restrictions. 87% of Cheniere LNG are destination free;
- Diversion rights, which implicitly follows on from the no destination clause;
- 100% fully flexible, with 0-100% geographic and volume flexibility. Buyers can nominate gas flows down to 0;
- There remains though a commitment on the fixed liquefaction fee, so in effect buyers are still liable for a 100% capacity charge, and based on current Henry Hub prices, buyers are still liable for around 50% of their costs;
- Cheniere retain the right to resell volumes from any unused capacity and keep the income.

Transparency: Transparency and more information is considered a good thing in general, with no general complaints against increased transparency. Differences however emerged over the details.

LNG has tended to be a close, clubby and fairly secretive business, although this is changing now with new players (buyers and sellers) entering the business. Picking up short term contract cargoes is much easier now. New companies have entered such as Golar LNG or Höegh LNG.

Although information is not publicly available, those in the business (aggregators, traders, utilities) know where cargoes are. There are several confidential systems which provide details of every cargo in the world at any time. These systems provide physical details of cargoes (source, destination, location) but do not provide contractual details or price. They therefore have a limited use and many pieces of information remain unknown.

National buyers in emerging markets take a difficult view on access to information. Their view is that while shipping companies and producers have a lot of data and they do not share all of it with buyers. National buyers see a benefit in more transparency of information. They would value a bulletin board and in general wish for more information on trading opportunities and mechanisms. National buyers' concerns are over flexibility and price. They are not receiving clear enough price trend signals from Henry Hub and NBP.

LNG Buyers' Club: An LNG Buyers' Club has been established, including China and India. Some of the members of the Buyers' Club, who have over-contracted LNG, are national buyers and new to the LNG business. Some of them need help in understanding and benefiting from global LNG trading.

Industry Players: LNG trading is made up of different types of player:

- Those who balance physically – physical buyers, physical sellers;
- Speculative traders, such as Vitol, Trafigura, Glencore for example;
- Portfolio players, who use the market to balance their portfolio, including Shell, Total, BP, Gas Natural Fenosa for example:
    - Those who are long – upstream producers;
    - Those who are short – downstream consumers;
- Utility and National Buyers.

Some buyers have good credit, including European ones. There is concern among some national and portfolio buyers though over the credit worthiness of some traders and they are avoided.

Price Publication: Interviewees were asked about their views on the publication of key terms in LNG contracts, particularly the price.

For access to terminals, the view was that there should be regulation for the publication of key terms, especially prices, for access to regulated terminals but there was not such a view about exempted terminals.

Non-European based LNG players are in favour of price publication for sales into Europe, however all members of the European LNG industry who were interviewed did not agree to publishing LNG prices, for various reasons:

- Publishing prices is anti-competitive;
- It would discourage LNG trade;
- Pricing transparency in any case is provided by the publication of hub prices;

The view from much of the industry is that a bulletin board or screen based system would be difficult to implement and may be commercially sensitive.

Pricing agencies publish the number of trades and the range of pricing, not the exact price of each trade and name of the trader. ICIS Heren, Platts, Argus, Waterborne Commodity Intelligence (HIS), Rim are examples of trade publications which provide LNG market information. Price discovery is workable but regulated price disclosure would be resisted by most of the players.

National buyers have a different view however and see insufficient information provided from the existing systems. They would like a published information service for contract terms and prices, so that they can see benchmarks and also to aid them in placing cargoes into European markets. These are cargoes which they have overcontracted for and are looking to resell into secondary markets. National buyers from emerging markets would like help in selling their overcontracted cargoes into European markets.

LNG Quality: There are considered to be some issues with different specifications of LNG being received at different terminals. South Hook (Wales) for example is specifically geared towards Qatar LNG. Nevertheless, it is easy to blend gas with nitrogen. A problem can appear at certain terminals which do not have access to nitrogen. This can be an operational constraint but is not a trading issue. In summary, terminals can take any gas and there are measures to treat any out of specification LNG. These come at a cost though and not all terminals or traders are keen to do that.

Storage: The industry view is that storage is suffering from too much regulation and this should not be repeated with LNG. The industry view is that it is better to leave LNG unregulated than to overregulate.

Successful markets have a lot of storage flexibility, for example in NW Europe which is innovative, open and with consultative approaches to customers. In other markets it is different, for example in Poland and the Czech Republic where storage is protected with obligations. Problems were highlighted with France and Italy as well.

It should be possible to use storage from a different country, with cross-border storage. Often storage is not allowed to compete with storage in a different country.

The measures some countries take to meet security of supply storage obligations are favourable to national infrastructure or national TSOs, rather than taking a regional (cross-border) approach. Implementation of the Security of Supply Directive at national level is patchy, for example, Poland have security of supply requirements but they act at a national level (not making use of storage in neighbouring countries).

Government and EU Actions:

Actions EU can Take: The majority (but not exclusive) view around the industry is that there is little that the EU can do, at an EU level. More could be done at a national level. Areas where governmental or EU action can be taken include:

- Improve transparency of terminal access at regulated terminals;
- Implement the third package;
- Promote hubs over infrastructure options;
- Improve infrastructure (regasification, storage, transport) and network codes in SW, E and SE Europe;
- Sharing some information on buyers;
- Create a Singapore style physical and paper LNG hub in NW Europe;
- Recognise that markets are the best solution and solutions should be market based;

National buyers consider that the EU can help in sharing information on buyers of LNG in Europe and contacts for buyers, sellers and resellers of spot, short-term and long-term LNG.

The industry sees a difference in access between NW Europe, and E and SE Europe, where barriers are seen to exist. The EU can support the development of LNG import infrastructure (regasification terminal, storage and transportation pipelines) where there is little available now, such as at Bulgaria, Northern Greece or Croatia, for example.

An alternative view is that there is a lot more that the EU can do, including:

1. Impose a transparency obligation, that all sales to Europe are under price transparency;

2. A specification for Europe and standard terms on a standardised MSA contract, for DAT/DAP (formerly DES) not FOB contracts;

3. Introduce options such as cargo by cargo deliveries vs firm delivery contracts, or contracts with an inflexible baseload and flexible higher priced supplies.

The first two of these ideas are not supported by any other European based industry player. While price ranges can be published, published prices of all sales is not supported. There is also no enthusiasm for an imposed standard contract. The industry view is that a standard contract will emerge from the industry (probably from one of the US Gulf players). The third proposal is something that should be offered by the industry and not imposed by regulation, however a dialogue at the EU level could promote the ideas of more diversity and flexibility in contractual offerings.

European Singapore Style Hub: It is possible that a physical LNG hub could be set up in Europe as is being done in Singapore. NW Europe offers some terminals which have the physical capacity to take on such a role. Additional work would have to be done to provide the supporting paper trading environment, such as an LNG hub contract and tax treatment as is offered in Singapore, whether that work is done at the industry, national or EU level.

2.7.4. Summary of Comments from the LNG Industry

The views of the industry regarding global LNG developments and how to introduce liquidity, flexibility and transparency into LNG into Europe can be summarised as follows:

Global Developments: The majority view is for a supply overhang until 2020-23 but views differ after that. Some consider the supply overhang will continue much longer, while others consider there may be a shortage of new liquefaction projects, leading to price increases from around 2023.

No Major Problem over European LNG Trading Market: Most of the industry stated that there is essentially no problem with the development of the LNG industry in Europe. Views ranged from an extreme that the EU has no role in becoming involved in an industry that is functioning well to a view that there are some minor issues but that these can and are being addressed by the industry.

There was a concern that gas storage is overregulated in Europe and the industry would rather no regulation than the danger of overregulating LNG.

The industry does not see the need for regulation or third party access rules for exempted regasification terminals. Because there is competition between terminals and for access to the hubs downstream of the terminals, regulation is only needed for regulated terminals, not for exempted ones.

Market Growing by Itself: As discussed above, the LNG market is developing by itself and will continue to do so. There are new entrants, more flexible contract terms, increasing use of hub based pricing and the introduction of US LNG will bring considerable market flexibility.

Hub Liquidity: Liquidity lies with the market hub downstream of the regasification terminal and not with the LNG trade or the terminal itself. Liquidity at hubs is considered to be very important to the development of gas markets. Efforts therefore should be put into improving access to hubs and hub liquidity, which should be pursued before additional infrastructure options.

The industry believes that trades are increasingly moving from NBP to TTF, and TTF may have overtaken NBP by now in terms of liquidity. Reasons identified for this are: 1) Reduced currency risk at TTF; 2) TTF is nearer to mainland European markets; and 3) Brexit effect.

LNG Hubs: On the whole, industry players are not seeing the need for LNG hubs in Europe. The general view is that any LNG hubs will probably develop at the US side of the Atlantic rather than in Europe. In general, the industry has not really considered the implications of the Singapore model and its applicability to Europe. Some industry players though do see the potential for physical and trading hubs to develop where there are large volumes of LNG storage and ship to ship bunkering.

NW Europe is different from E and SE Europe: LNG terminal access and the access to markets through hubs are considered to be working fairly well in NW Europe. This is considered to be very different though from the situation in E, S and SE Europe. Problems include: lack of liquid markets and hubs downstream of the regasification terminal, lack of access from the terminal to markets, lack of access to storage, overregulated storage.

Access to Storage: Several industry players stated that for LNG to be successful, there needs to be easy access to gas storage at the terminal.

Access to Terminals: While the industry was close to unanimous that there is essentially no problem with access to regasification terminals, a number of specific problems were recognised at specific terminals. There are areas therefore where access to terminals can be improved, for example, with use-it-or-lose-it, access pricing at Spanish terminals or obtaining accurate capacity information at certain terminals.

Fully Implement the Third Package: The industry considers that the EU should concentrate on improving the third package properly. In order to improve hub liquidity and access to markets, the third packaged needs to be completely implemented, particularly in E and SE Europe.

Price Transparency: The European based industry is completely opposed to price transparency except for the price ranges that are quoted by price publication services. One dissenting voice and non-European players on the other hand argued for regulation to ensure price publication and much more information to be made publicly available.

3. OPTIONS FOR HOW THE EU CAN FURTHER DEVELOP LNG

3.1. Conclusions

Some general conclusions can be drawn from the discussion of liquidity, flexibility and transparency in LNG, the case studies and the interviews with industry players, discussed in Task Eight above.

3.1.1. Measures and Drivers of Liquidity, Flexibility and Transparency

We have identified and considered various measures of liquidity, flexibility and transparency for LNG. In conclusion, a liquid trading market can be defined as one which is deep enough that the price is not significantly affected by a large volume trade.

Drivers for LNG Trading: We identified the most important elements of and drivers for an active trading market, which lead to liquidity, flexibility and transparency, as:

1. Many sellers or suppliers,
2. Many buyers or customers,
3. Industry crisis (particularly of excess supply, which acts as a catalyst for change);
4. Supportive regulatory and fiscal framework;
5. Standard contract;
6. Price publication service (of indicative prices, price ranges and trading volumes);
7. Storage infrastructure;
8. Other infrastructure;
9. Diversity of supply;
10. Entry of new players.

These will then lead to the growth in the other indicators of an active LNG trading market:

11. Increased contract flexibility;
12. Shorter-term and smaller contracts;
13. Resale and secondary markets;

14. Capacity trading.

Barriers to Liquidity: The main barriers to liquidity can be considered as:

- Concentration of players;
- LNG trading suitability;
- Rigid contractual terms.

3.1.2. How Trading Markets Develop

The case studies show a pattern and some common themes in how each commodity trading market developed. Successful trading markets develop from a combination of three factors, in this order:

1. A market crisis or other major driver for change;
2. Deliberate government action to create the environment for a market;
3. The market then develops by itself.

The case studies of trading markets (gas pipelines, oil, iron ore) show that in each case there was an initial market crisis, such as an oversupply situation building up. The government took advantage of that crisis to put in a new regulatory, fiscal or other framework which set out a favourable business environment. The market then developed by itself with little or no further government intervention.

3.1.3. Much is Already Happening with the LNG Market

These factors as described above apply to the case studies described above and to the LNG industry, globally and Europe. A supply overhang, new technology, new business models and a certain amount of luck have led to the new LNG world that is now emerging. These make up the crisis and the drivers now driving change.

Supply Overhang: Most of the industry believes there is an excess of LNG supply over demand, with this situation lasting until the early 2020s. In this report, we have presented our own analysis and views, under different scenarios, of how much LNG will be available for Europe and under what price ranges.

New Technology: Several new pieces of technology are now coming together which are driving change in the LNG industry. These are discussed in Annex 8 to this report and include:

- The shale gas revolution in the USA, producing large volumes of low cost gas;
- Ship to ship LNG bunkering technology;
- LNG powered shipping;
- LNG trucks which are driving new markets for LNG;
- Floating Storage and Regasification Units (FSRUs) which have reduced the cost of LNG regasification from over $1bn to as low as $50m, which is driving rapid growth in new markets for LNG in emerging markets;
- Floating LNG (FLNG) vessels are also now entering the market and are considerably lowering the cost of liquefaction. An FLNG project recently (June 2017) received FID in Mozambique.

New business models: New players are entering the industry. From a traditional industry structure of International Oil and Gas Companies (IOCs) producing for national buyers under long term contracts, there are now also portfolio players, traders, new national buyers, utility buyers, brokers and other independents entering the industry. With these new suppliers, buyers and middlemen entering the industry, there is a move to more flexible contract terms and new business models for developing LNG.

For example, technology based players like Golar and Höegh LNG are using their maritime technology skills to develop FSRUs for new emerging market buyers. Also, the pure trading companies such as Trafigura and Vitol are taking no physical infrastructure positions at all but are purely contracting vessels, buying and selling LNG, with a short term trading outlook and who are likely to be key drivers towards spot markets.

Luck: It was fortuitous that the USA had built a large number of LNG import regasification terminals. Converting a regasification to a liquefaction plant is much lower cost than building a greenfield liquefaction plant. There is a certain amount of luck involved that the USA is now able to offer large volumes of low cost gas through low cost liquefaction facilities and making use of the more flexible US commercial models.

These developments as described above are the drivers which are now setting the scene for a revolutionary new global LNG industry. These are the drivers driving the "crisis" and industry restructuring currently under way. These are just the first stage though. For a trading market to develop, governments still need to put in place the favourable business environment to allow these new opportunities to develop.

3.1.4. The EU has Already Done Much with LNG

The EU has already had a beneficial impact into the LNG business through several important regulatory interventions, including:

Ship fuelling regulations: The EU regulation regarding ship fuel[65], establishes limits on the maximum sulphur content of gas oils, heavy fuel oil in land-based applications and marine fuels. This single regulation is leading to a phasing out of and is a major driver for the move towards LNG for ship fuel. One simple regulation is a major driver for LNG ship refuelling, ship to ship bunkering, LNG storage and ports to provide these facilities, which in due course could lead to the growth of physical LNG hubs (discussed in more detail further below).

No Destination Clause: Destination clauses are contrary to EU internal market and competition rules, and are contrary to the Treaty establishing the EU[66]. Destination clauses are therefore banned in pipeline gas and LNG contracts for all supplies to any EEA country. This regulation has forced more flexibility in contracts. The EU-Japan Memorandum of Cooperation[67], signed on 28 June 2017 which also mentions more flexible LNG contracts through avoiding destination clauses, is a further regulatory driver for more flexible LNG contracting globally, not just to the EU.

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[65] EU Directive 2005/33/EC on Marine Fuel Oils. Other instruments regulating fuels include EU Directive 2014/94/EU on the deployment of alternative fuels infrastructure; IMO Marine Environment Protection Committee London regulation of 27 October 2016, 2020 global sulphur limit, placed a global cap on sulfphur in fuel oil in ships of 0.5% m/m from 1 January 2020; MARPOL Emission Control Areas regulations; the EC White Paper of 28 March 2011 on Roadmap to a single European Transport Area – Towards a Competitive and Resource Efficient Transport System

[66] Treaty on the Functioning of the European Union, Protocols, Annexes, Declarations annexed to the Final Act of the Intergovernmental Conference which adopted the Treaty of Lisbon, 13 December 2007

[67] EU-Japan Memorandum of Cooperation on the global LNG market, Council of the EU, Brussels 28 June 2017, 10534/17

Regulated Regasification Terminals: Another important area is regarding improved access to regasification terminals in the EU. This is an area which needs more work and which is discussed elsewhere. Nevertheless, the moves the EU and MS have already taken to improve access to LNG terminals are helping to set the business environment for LNG.

There are some further measures the EU can take to improve the business environment for LNG and these are detailed further below.

3.2. Recommendations

3.2.1. What Governments Can and Cannot Do

Despite the views of much of the industry that there is nothing wrong with the operation of LNG in Europe, we do nevertheless have some recommendations for how the EU could improve liquidity, flexibility and transparency in LNG. An important lesson from the case studies is that trading markets emerge as a result of (in this order):

1. Some crisis or dramatic market change;
2. Government action to set a supportive business environment;
3. Market players who then enter.

Governments (and the European Commission) have an important but limited role in this development of markets. In terms of government actions, there are three types of market making activity:

1. Actions which can only be carried out by the market;
2. Areas where governments can set the environment within which a market operates;
3. Areas where government can take direct action.

Government and EU level activities therefore will be most successful when they set the framework for a market to develop. Governments and the EU do have an important role to play in driving markets. Good regulation and setting a good legal, regulatory and fiscal framework is often an essential part of a market development but bad regulation can slow down or finish off an emerging market but. Business and markets themselves are essential but left completely to itself, there is a high likelihood that incumbent market players would attempt to block new entrants and hold the market back.

The EU has already undertaken some important initiatives to improve the market position of LNG but we have identified a few further actions which can further improve liquidity, flexibility and transparency in LNG for Europe. Our recommendations cover the following areas:

- Essential actions by the market alone:
    - Contracts;

- Actions where the EU can set the enviromment:
    - LNG hubs;
    - International cooperation;

- Areas where the EU can take direct action:
    - Transparency:
        - LNG prices;
        - Information for new market entrants;
        - Terminal pricing;
    - Terminal access.

3.2.2. Essential Actions by the Market Alone

1. Contracts:

A standard contract, at least for spot and possibly short-term contracts, is essential for the development of LNG trading. There is very little if anything though that the EU can do to bring one about. Even though there are several standard contract templates around, they have not really been adopted by the industry. The case studies show that the standard contract is usually taken by the industry from the leading company. A US or Shell/BG contract will probably emerge as the industry standard contract. The EU will not be able to successfully impose one of its own making. The EU role will be limited to monitoring and encouraging the emergence of an industry led standard. Rules of access (network code) for regulated LNG terminals can offer transparent and non-discriminatory access to regasification capacity and a standard terminal contract would refer to those rules of access.

Recommendations:

- Monitor progress towards an industry standard LNG spot and short-term contract;
- Encourage progress towards an industry standard LNG spot and short-term contract;
- Investigate how the industry could be encouraged to introduce more contractual options for LNG supply, such as options for cargo by cargo deliveries (interruptible contracts in effect) vs firm delivery contracts, or contracts with an inflexible baseload and flexible higher priced supplies.

3.2.3. Actions Where the EU Can Set the Environment

2. LNG Hubs:

Hubs are physical or virtual places where product (gas or LNG for example) arrives from different directions, is wheeled through the hub and then sent off again in other directions. It is where different physical or trading routes come together. Hubs become places where traders can buy and sell wholesale (large volumes), and are places where market prices are set.

Hubs can bring liquidity to a market because of the large volumes of product and the large number of buyers and sellers they attract. The gas market in NW Europe has been relaxed about the imminent closure of Rough gas storage in the UK and the decline in the Groningen gas field, the two large gas storage sites in NW Europe. The market does not seem to consider strategic gas storage to be necessary in NW Europe because of the presence of the hubs which bring liquidity.

There is far less liquidity at hubs in E and SE Europe and there is far more concentration on regulated strategic gas storage there.

With the large volumes of US LNG becoming available, NW European hubs will be closely linked with US hubs. Hubs in Asia have yet to really emerge and it remains to be seen how much they will resemble the US/NWE hubs. The Shanghai hub, although it deals with very large volumes of gas, cannot really be called a hub because of its regulated nature. Singapore is still in development and, in comparison with the volumes into China or Japan, is very small. Nevertheless, the developments at Singapore and elsewhere should be monitored carefully.

Much of the LNG industry in Europe does not see the need or desirability for LNG hubs. This is not fully convincing. At least one LNG hub is emerging offshore at the US Gulf Coast so there is no intrinsic reason against LNG hubs. The argument is that Europe (NW Europe at least) already has liquid onshore hubs and so there is no need for a further offshore hub. This argument should apply to the USA as well, which does have onshore hubs and also an emerging offshore LNG hub.

Ultimately an LNG hub will emerge in Europe if the market sees a need for it, combined with an enabling environment (regulatory, fiscal or other) provided at a national or EU level. In this context, we believe that the emerging LNG hub in Singapore could provide pointers to Europe.

As LNG becomes increasingly used as ship fuel, physical places offering ship LNG fuelling facilities will become increasingly important and will become more widespread.

Places with the physical benefits of large volumes of LNG storage and the opportunities for ship to ship bunkering provide potential sites for LNG hubs. These physical characteristics can then be enhanced by paper products, such as a hub contract or tariffs that facilitate storage. These physical and virtual LNG hubs could then develop hub and storage type services, depending on what the market would want and put a value on. An LNG hub based on physical storage and easy transfer (to storage or to ships) could offer various services, such as (for example) parking (short term storage), lending (short term sales out of the LNG storage), long term storage (possible when the storage is large enough and there is enough liquidity at the LNG storage), daily balancing and possibly some strategic storage services. The frequent use of an LNG facility can also provide opportunities to sell the surplus "heat" and "cold" from liquefaction and regasification.

It is the combination of LNG regasification and flexible use of LNG storage that can allow these new hub based services to develop. These services would increase liquidity generally, flexibility of services and transparency at the hub. They could also become price setting points.

Some of the large ports in NW Europe could provide an obvious first set of potential hubs to investigate but there may be parts of the SW Europe and the Mediterranean which also have potential and which would improve LNG and gas liquidity in the Mediterranean.

Recommendations:

- Initiate or extend links at the EU level with Singapore;
- Investigate lessons to be learned from the emerging Singapore LNG hub and how they could be implemented in Europe, particularly concerning:
  - Physical assets such as bunkering and storage;
  - Virtual services such as a hub contract;
  - Governmental support, such as tax changes or targeted regulation;
- Identify potential LNG hub points in Europe, based on physical advantages (such as bunkering and ship to ship refuelling facilities, substantial LNG storage) and with governments likely to put in a regulatory and fiscal framework supportive of hub developments.

3. International Cooperation:

International cooperation or information sharing can be sought with different organisations and governments, including:

- Gas Buyer's Forum;
- National buyers;

- Singapore hub and other hub developments;
- US DOE and FERC.

Gas Buyer's Forum:

The EU is not a member of the gas Buyers' Forum and it may be problematic to become one. The EU has been pushing competitive markets and may find it difficult to join what may be considered as an anti-competitive organisation. Nevertheless, the EU and other buyers would benefit from ideas sharing and some information sharing. The recent EU-Japan cooperation on LNG is a good example of what could be achieved.

Ideas which could be shared could include, for example, hub developments, flexibility measures, Asian pricing (whether oil index linked or a move towards Henry Hub plus pricing), move from long-term to short-term and spot contracts, and how to provide useful market information for buyers from other regions.

USA:

With the USA set to deliver such large volumes of US LNG to Europe and indeed to become the major global LNG player, the EU should have close links with the relevant US authorities, such as the Department of Environment (DOE) and Federal Energy Regulatory Commission (FERC).

A general assumption is that the US Gulf Coast producers, liquefaction companies and suppliers will bring the type of flexibility and liquidity that the EU is looking for. The companies concerned though will only do that by accident, their primary concern is to make a profit for their shareholders. US private companies may (perhaps) bring some practices which reduce competition.

It will be important therefore to maintain close links with the US authorities. Price publication is an example. As has been described above, the European gas industry (including US companies hoping to sell LNG into Europe) have all be very clear in their opposition to price publication. The US DOE however already publishes the prices and names of every LNG cargo[68]. We are not clear why a practice which is so universally opposed by the industry in Europe, is already standard practice in the USA. Indeed, for every single US cargo, the cargo price is public knowledge and the transport cost is public, yet the industry does not want the delivered price in Europe (LNG + transport) to be published.

Close cooperation and coordination between the EU and US authorities should be in place to address pricing and many other issues regarding the development of a global LNG market in the interests of the EU and the USA.

Singapore Hub and Other Hubs:

As is discussed above, the potential developments with a Singapore LNG hub are worth following, and whether the lessons for the combination of physical, paper based and fiscal incentives are successful in delivering increased liquidity, flexibility and transparency in LNG.

The EU should also maintain close links with and monitor developments in other potential Asian hub areas, such as in Japan. Japan indeed may learn lessons from the European

[68] US DOE, Fossil Energy, Office of Oil & Natural Gas, LNG Monthly; an example page from YTD – through May 2017 is shown in Annex 11

experience in how to increase access of LNG to hubs and markets, thereby increasing liquidity, flexibility and transparency to Asian LNG markets.

National buyers:

Either through the Gas Buyer's Forum, another forum, or directly, the EU could initiate exchanges of information with certain major large buyers of LNG in emerging markets. There are two key reasons for doing this:

1. Providing assistance in developing their LNG commercial arrangements, which helps to increase liquidity, flexibility and transparency generally;

2. Provides information on European and other markets, so helping new entrants to the LNG business to provide more gas into secondary markets, thereby enhancing liquidity generally.

Recommendations:

- Investigate how to have an involvement with the Buyers' Forum short of full membership, such as an observer status or such like;

- Initiate or enhance links at EU level with other international market players, including:
    - US DOE and/or FERC;
    - Singapore hub and other hubs;
    - National buyers in emerging markets.

3.2.4. Actions Where the EU Can Take Direct Action

4. Transparency:

Transparency in general is a good thing and should be encouraged. Against this is the need to preserve essential commercial confidentiality plus the need for a certain ambiguity among pricing and trading positions. We have identified three areas for improving transparency of information:

- LNG Prices:

This is the most difficult area in terms of improving transparency. Pricing information is essential for the development of a liquid hub and LNG pricing information should be available. One proposal is for the EU to regulate that all LNG cargoes into Europe should publish key contract information, in particular the LNG price paid. The European industry is strongly against this and points out that for trading to take place the range of pricing is needed, not the actual price paid. Existing price information services in other petroleum products publish the range of prices and the number of trades. The US DOE however already publishes LNG contract prices per cargo (discussed further below). Any price regulation moves adopted in Europe need to be compliant with EU competition rules.

The range of LNG prices into Europe should be published, on a daily, weekly or monthly basis. This should be carried out by private price publication companies, not by the EU itself. LNG price publication services are already on offer in the market, so the EU does not necessarily need to do anything more except monitor the quality of LNG pricing information put into the market.

- New market entrants:

While much of the incumbent industry established in Europe is very clear that the LNG market is generally working well, there are new entrants who are less sanguine. These are companies and governments new to the LNG trading business who are far from confident in their abilities to understand the market. There are many national buyers of LNG who have contracted for more than they need and are looking for secondary markets to resell into. These national buyers and resellers complain that they would like to sell LNG into Europe but do now know how to. They could resell to aggregators or portfolio companies or they could be helped to sell into European markets. These national resellers are also generally more comfortable dealing with other governments than with large commercial operators;

- Terminal pricing:

Several market players have expressed concerns over access pricing and available capacity information at regulated terminals.

Recommendations:

- LNG Prices: Monitor LNG price information services available commercially, to ensure sufficient coverage and to avoid any pricing distortions or manipulation (which some other price benchmarks have been accused of);
- LNG Pricing: Take up any issues or ideas initially with commercial price publication services directly rather than through regulation;
- New Market Entrants: Investigate what type of and how some basic information can be made available at an EU level to help new entrants to understand:
    - LNG price ranges;
    - General contractual terms (those that can be made public);
    - Terminal access regimes;
    - LNG and gas markets in Europe and how to access them;
    - European LNG buyers (basic requirements and contact details);
- Terminal Pricing: Improve information transparency on a regulated terminal by terminal basis.

5. Terminal Access:

At a time when there is close to zero capacity utilisation at regasification terminals, it is difficult to argue there are fundamental barriers to third party access. There are no spot cargoes floating around unable to find a terminal to enter. Nevertheless, there are some areas of concern, which can be addressed on a terminal by terminal basis. The argument put forward by the industry that the exempted terminals (those that have obtained derogations) should be free from any form of regulation is not fully convincing. Where barriers to TPA are found, they should be addressed, regardless of the type of terminal. Many exempted terminals have derogations from implementing all aspects of the Third Package. Those derogations must be kept to but after the derogations are ended, the terminals should expect to have to offer TPA on an acceptable basis.

Recommendations:

- Resolve any problems of access on a terminal by terminal basis;
- Identify where there are problems in access to terminals (regulated and exempted);
- Improve transparency of information, particularly regarding pricing and capacities;

- Regulated terminals: Ensure clearer published pricing and capacities, through EU level regulation if necessary;

- Exempted terminals:

    - Respect the derogations for those terminals which have them;

    - Consider how to bring exempted terminals into a transparency system;

    - This could be perhaps on a "negotiated TPA" basis, so exempted terminals are allowed to propose their own solutions to problems of access which have been identified, taking account of the needs to improve access and transparency of information, particularly for new market entrants, combined with the need to schedule well in advance (often up to four weeks in advance);

4. ANALYSIS OF LNG QUALITY FROM EXISTING AND POTENTIAL FUTURE SOURCES

Analysis of LNG quality from existing and potential future sources (Worldwide large scale liquefaction terminals) and gas quality standards in Member States with LNG terminals, if considered necessary assess the ability to blend at these terminals and costs associated with the adaptation of the gas quality at the terminals.

4.1. Methodology

Tractebel has produced a table of large scale LNG liquefaction/Export Terminals worldwide noting their location, capacity and the associated known or likely LNG compositions (refer to Annex 6).

This list includes current, under construction, and future Export Terminals that could potentially be online by 2025.

Where LNG composition data is not yet available Tractebel has made an assessment of whether the likely Wobbe index range will be compatible for direct use in the European Member States (LNG is a clean fuel due to the processes during liquefaction therefore the limiting factor for use in Europe is the Wobbe index range).

The European Association for the Streamlining of Energy Exchange – gas (EASEE-gas) has proposed a gas quality specification range which specifies a range for the Gross Wobbe Index between 13.60 and 15.81 kWh/m³. The Gross Wobbe Index for typical LNG is situated between 14 and 15 kWh/m³ and therefore is well within the EASEE-gas limits.

Tractebel has then reviewed the LNG composition data for existing and future LNG import terminals in Europe (refer to Annex 6) and assessed if there are any major compatibility issues with the listed LNG Export terminals (refer to Annex 6).

Tractebel has reviewed data on the GIE map for gas specification aspects and checked compatibility with Export LNG composition ranges.

A note regarding LNG storage capacity development is also included in the report (refer to Annex 7).

4.2. Conclusions

The tables and figures in the Annexes show that European LNG Import Terminals can accept LNG from virtually all of the current and proposed new LNG Export Terminals without the need for LNG blending to achieve a suitable specification. As noted the UK is an exception with its narrower range for the gas network, hence blending facilities are provided at some terminals to handle LNG from some locations.

Note that the conclusions are applicable for FSRU based LNG import terminals as well as onshore based terminals.

4.3. Additional Notes

The following points are of note

The Sabine Pass LNG export terminal is located in Louisiana, USA and has come online recently (2016). Although at this point the typical composition of the LNG output is not available to Tractebel, it is likely to comply with the acceptance criteria for European import terminals since cargos were transferred to Spain, Italy and Portugal in the last year.

Since the Wobbe Index value range required in the UK national grid is narrower compared to other EU markets, restrictions regarding gas quality are applicable for pipeline gas transfers from the European mainland (Belgium and Norway) to the United Kingdom.

The Croatia natural gas quality specification is similar to the EASEE-gas spec; however it contains more parameters to fulfil such as: the CH_4, C_2H_6, C_3H_8+ and N_2 content. The main constraint of the Croatia NG spec is the ethane (C_2H_6) content, which is limited to max 7 mol%; therefore theoretically some LNG origins would not be allowed (for example Australia, Algeria, Libya, Peru). Possibly these restrictions have a historical nature since the sole gas supply source for Croatia in the past was Russian and the Croatia NG spec could be based on that typical gas composition.

The Lithuanian natural gas quality specification is similar to the EASEE-gas spec; however it contains more parameters to fulfil such as the CH_4, C_2H_6, C_3H_8 and sum of C_2H_6 and C_3H_8 content. All these constraints imply that theoretically many LNG origins would not be allowed (for example Australia, Algeria, Brunei, Oman, Libya, Peru, Indonesia, Malaysia, Nigeria, Qatar). These additional gas quality requirements are established in the legal acts of the Republic of Lithuania and therefore must be met, according to the LNG terminal owner Klaipedos Nafta, thus setting some restrictions.

ANNEX 1. ANALYSIS OF STORAGE WITHDRAWAL CURVES

Storage withdrawal capacity is highly dependent on the actual working gas level of UGS facilities. We have collected all available information on the 185 unique storage sites reported in GIE's database.[69] Storages are voluntarily reporting storage withdrawal and injection curves on their website following the recommendations of GIE transparency platform. Data collection involved checking the storage access rules and any documents related to storage access as well as the technical parameters of the facility. If no information on storage curve was found, a targeted search for "curve" and "withdrawal curve" was performed on the site of the storage. However, only half of the facilities (89 of 185) published a characteristic withdrawal curve, accounting for ~59% of the total withdrawal capacity.

Table 39. Total storage capacity by type and storage capacity with a characteristic withdrawal curve

	Storage type				Total
	Depleted field	Aquifer	Salt cavern	Other	
Total technical capacity (TWh)	1152	219	181	51	1603
Storage curve published (TWh)	615	166	111	51	943
Share of data of total capacity	53%	76%	61%	100%	59%

Source: REKK based on storage operator's sites

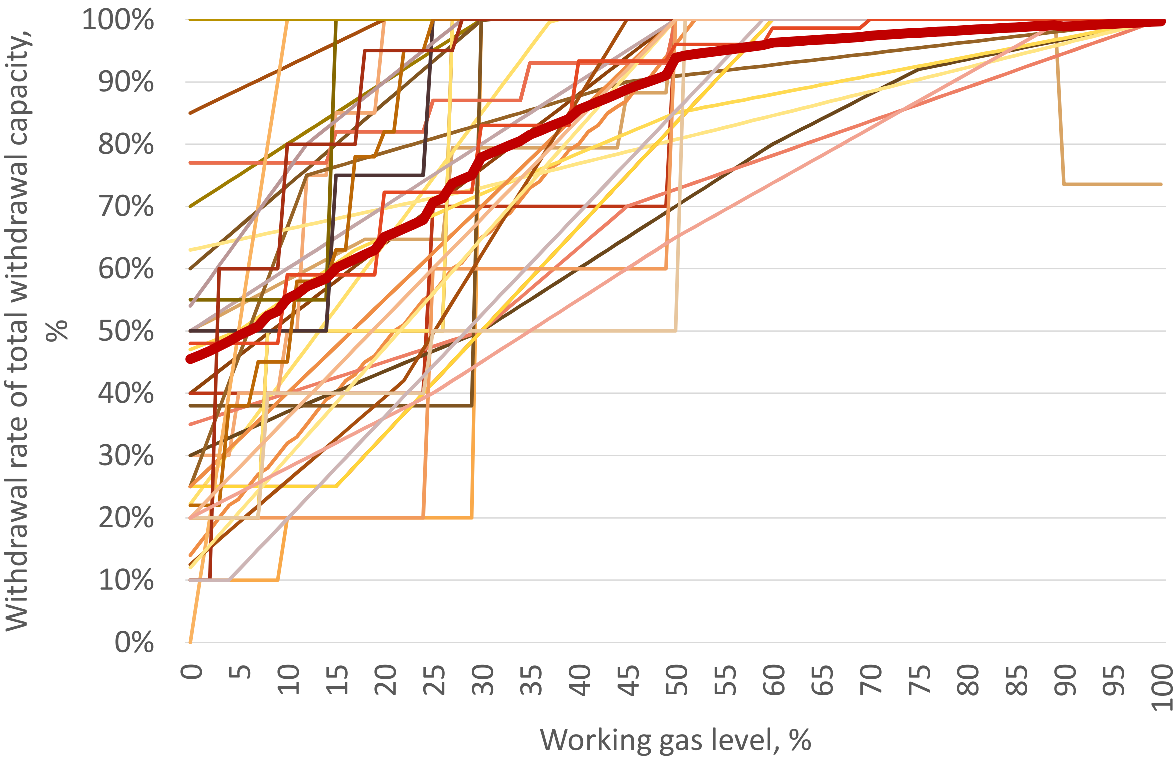
Most missing data can be found in the depleted field type of storages, which account for the majority of UGS capacities. By location, most storage data is missing for Italy and the Netherlands. The storage curves for the Ukrainian storages was kindly reported by Ukrtransgaz.[70]

This sample data fits well with the total storage capacity reported by GIE, although depleted fields are somewhat under-represented in our sample while other types of storages are over-represented.

The withdrawal curves represent the available withdrawal capacity at a certain working gas level. We plotted all storages and constructed a joint European storage curve based on our sample, by calculating a simple weighted average of working gas capacity. The thick red curve represents this simple weighted average. The aggregated curve suggests that at 50% working gas capacity, 90% of withdrawal is available. However, at 20% of working gas capacity this falls to somewhere slightly above 60% of withdrawal capacity. If the working gas level is close to zero, still around 45% is available for withdrawal.

[69] GIE Storage map, version December 2016. http://www.gie.eu/download/maps/2016/GSE%20Storage%20Map%20Database%202016%20-%20final.xlsx
[70] Ukraine and SoS of the EU. Presentation of Sergiy Makogon Executive Director, Strategy and Business Development Member of the Board, Ukrtransgas 7th Central European Gas Congress 26-26 April 2016, Bratislava, Slovakia

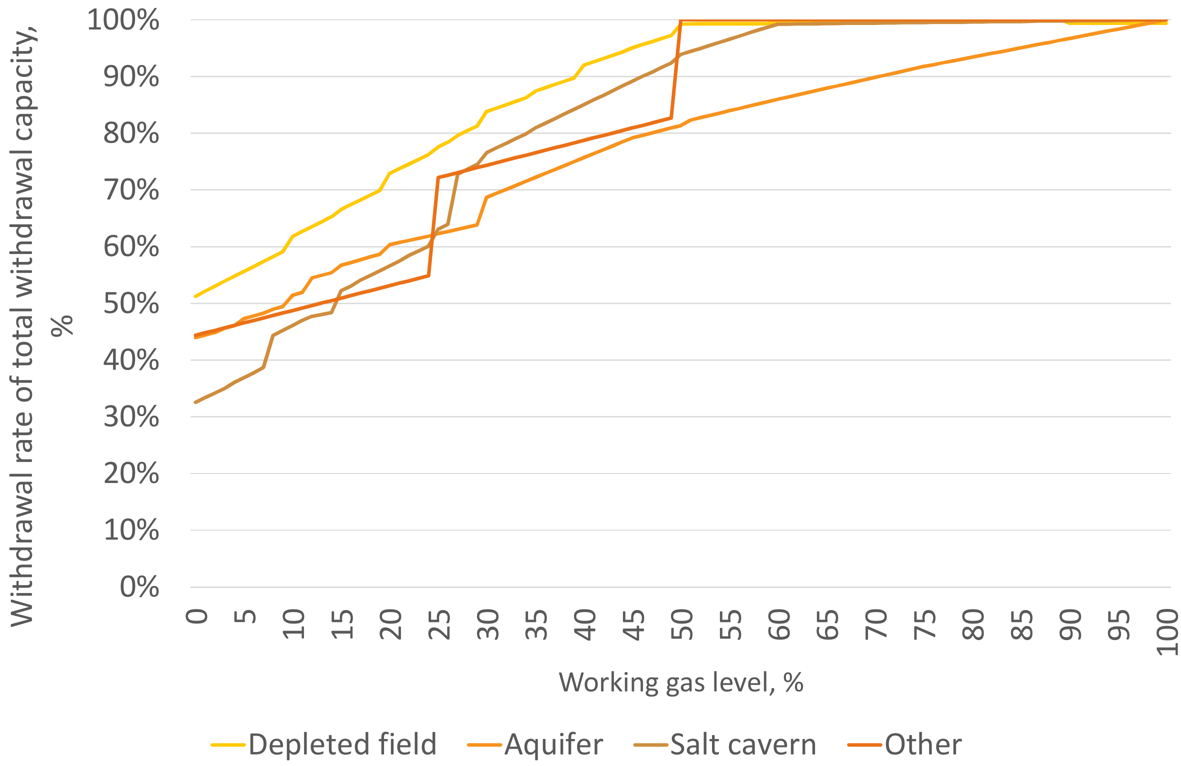
Figure 46. Unique storage curves and the aggregated withdrawal curve (bold red)



Source: REKK based on storage operator's sites

The same exercise can be done according to storage type as well. It can be observed that salt caverns and aquifers have more limited available withdrawal rates than depleted fields. In markets with more aquifers and salt caverns (eg France) low deliverability at low working gas levels is much more of a threat than in markets with bigger share of depleted fields.

Figure 47. Withdrawal curves by type of storage

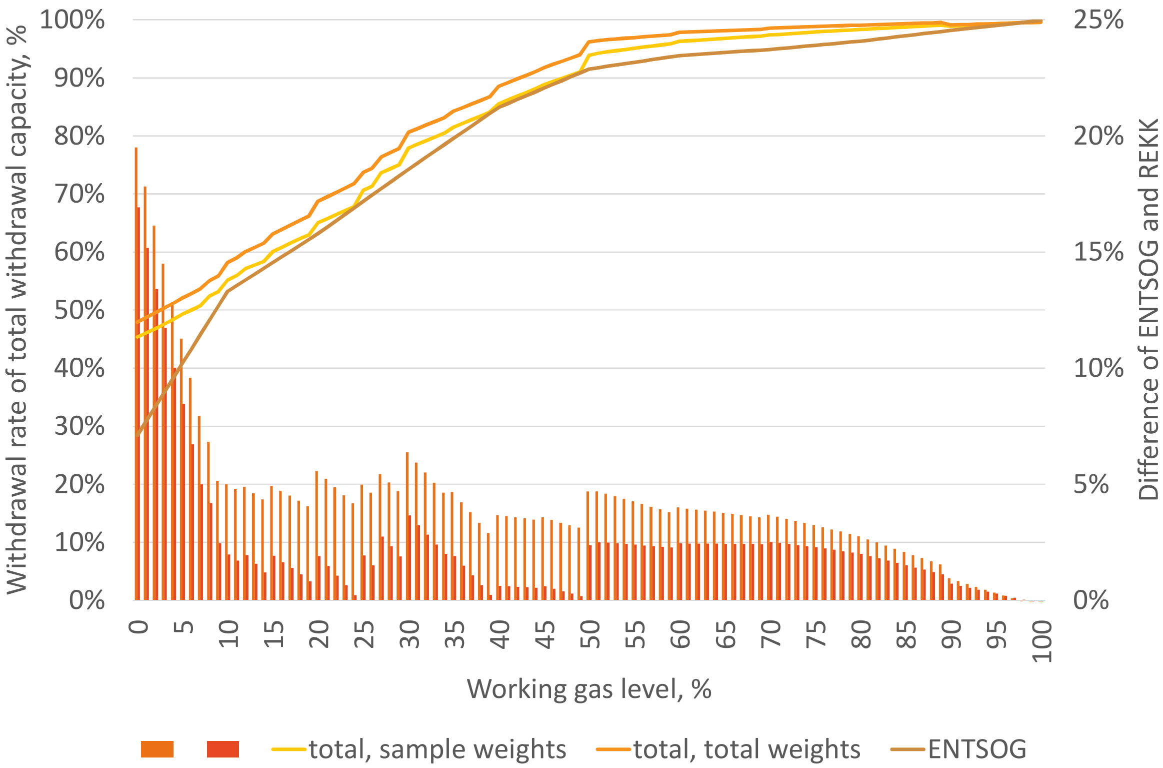


Source: REKK based on storage operator's sites

ENTSOG[71] has also published withdrawal curves on a country-by-country basis, but the specific coverage of this data collection is unknown. An aggregated European curve based on ENTSOG data was plotted and compared to that of REKK. In the 50%-100% working gas level, REKK data shows storage performing at 2-5 percentage points better than ENTSOG, but in the lowest fill-up levels the difference comes more striking: according to ENTSOG numbers, 28% of withdrawal capacity is available, while REKK's estimation suggests 45-48% availability of withdrawal capacity even at low fill-up rates.

[71] Winter Supply Outlook 2016/2017 & Winter Review 2015/2016, Annex A, Figure 8. UGS deliverability curve: In order to capture the influence of UGS inventory level on the withdrawal capacity, ENTSOG has used the deliverability curves made available by GSE. These curves represent a weighted average of the facilities (salt caverns, aquifers or depleted fields) of each area. ENTSOG curve does not consider storages in Turkey and Ukraine.

Figure 48. REKK estimate and ENTSOG withdrawal curve



Source: REKK based on ENTSOG and storage operator's sites

Annex 2. Demand scenario background calculation

The demand shock scenarios in our modelling were set in accordance with the 994/2010 EU Regulation[72]. This contains two cases:

- extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years
- any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years;

To arrive to demand shock input data daily consumption data for the longest possible time was needed. The Commission provided daily consumption data for the analysis.

As data was only available from 2012 December to 2017 February, natural gas consumption of winter days was observed for this period, in five countries (AT, CZ, DE, HU, IT). This allows data from 5 consecutive winters to be included in the analysis, one with significantly cold weather (2016/2017), and 4 with average temperatures. It still may not capture the coldest days in 20 years, so a conservative approximation was used in setting the consumption levels for these types of demand shocks.

Where data was not available (e.g. last few weeks of February 2017) the average of the four earlier winters was used. From this data average winter consumption and average December, January and February consumption was calculated for all the five countries.

Table 40. Average daily natural gas consumption (per country and per month)

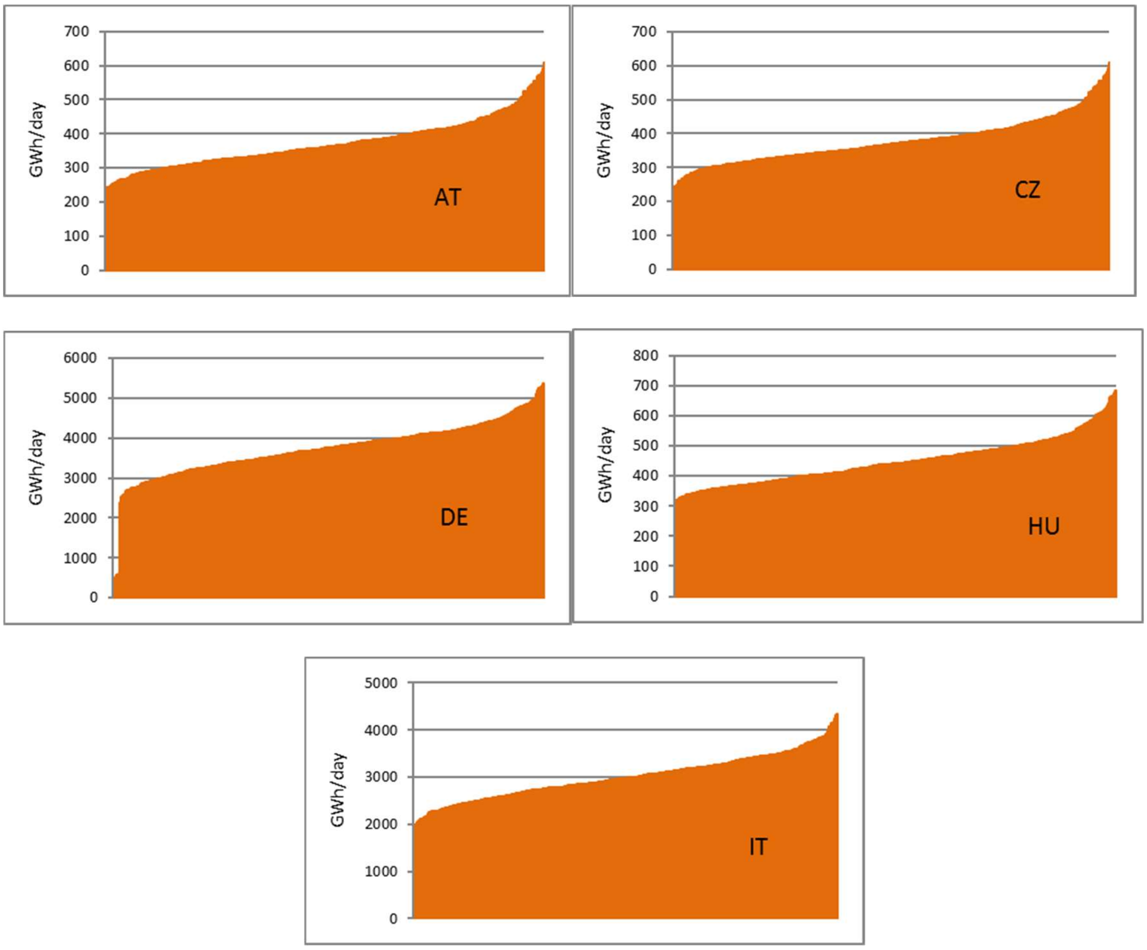
(Gwh/day)	AT	CZ	DE	HU	IT
Winter average	372	375	3729	449	3003
Dec. average	358	354	3491	439	2920
Jan. average	404	406	4003	492	3158
Feb. average	351	363	3689	412	2926

Source: REKK calculation based on data received from the European Commission

In addition to these average values the distribution of the consumption is an important consideration. To see how frequent extreme peaks are, curves mimicking load duration curves in electricity markets were created across the whole period. From this it can be observed that extremes in low and high consumption are relatively rare in all the five observed countries.

[72] REGULATION (EU) No 994/2010 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC

Figure 49. "Load duration curves" in the analysed countries



Source: REKK calculation based on data received from the European Commission

In order to build a 7-day peak consumption scenario, the maximum of the average consumption of 7 consecutive days was calculated for the whole period and compared to average daily winter consumption for each country.

Table 41. Ratio of the maximum of the average consumption of 7 consecutive days and average daily winter consumption

	AT	CZ	DE	HU	IT
max7 / winter average	153%	138%	136%	148%	135%

Source: REKK calculation based on data received from the European Commission

The highest peaks were observed in the 2016/2017 winter for all countries, in line with the logic that European peaks (such as cold spells) usually appear at the same time in the different countries. ENTSO-G comes to the same conclusion in Winter Supply Outlook 2016/2017, calculating the EU Peak Simultaneity indicator. To see if these peaks emanate from the volatility within winter (between the 3 different months) we also calculated the maximum of average consumption of 7 consecutive days in December, January and February, and compared these values to the average daily consumption in the given months in the observed period. This ratio reflects more precisely what happens in a demand shock situation: increase in consumption is important relative to the expected consumption level of the given month, not to the average winter consumption level.

Table 42. Ratio of the maximum of the average consumption of 7 consecutive days in December, January and February, and average daily winter consumption in these months

		AT	CZ	DE	HU	IT
max7 / monthly average	Dec	129%	130%	130%	125%	128%
	Jan	141%	127%	127%	135%	128%
	Feb	143%	125%	115%	128%	120%

source: REKK calculation based on data received from the European Commission

As demonstrated in Table 3 these figures are lower, meaning compared to average monthly values, these week-long peaks are less significant than they are compared to winter average values.

Since our model only contains monthly consumption data, a possible 7 day peak could be realized by increasing the average monthly consumption for a selected month. With the exception of AT (an outlier), the observed countries' monthly ratios are around 130%. Thus for modelling the highest average consumption for 7 consecutive days we assume that +30% demand increase occurs for a whole month (this could serve as a „top estimate", or a "worse case scenario", that is in line with the above mentioned prudent approach). Since the highest values occur in January on average for the five countries, this is the month to be evaluated. Also ENTSO-G chooses January for its short-period (1-day) peak demand scenario in the above mentioned document.

For the second demand scenario, the one-month-long consumption peak, we assumed that a demand shock occurs at the end of winter. Although the highest 30-day-long consumption may occur in January, a demand shock in February might have a bigger effect, as storage levels may be lower by that time.

The average February consumption was calculated for all the observed countries in every year, and these values were compared to the overall average February consumptions. In all but one country the highest monthly consumption occurred in February of 2013 – once again a proof of simultaneous cold spells across Europe.

Table 43. Maximum ratio of February consumption in a given year and average February consumption

February	AT	CZ	DE	HU	IT
maximum February average consumption/5-years-average February consumption	111%	111%	109%	109%	114%

source: REKK calculation based on data received from the European Commission

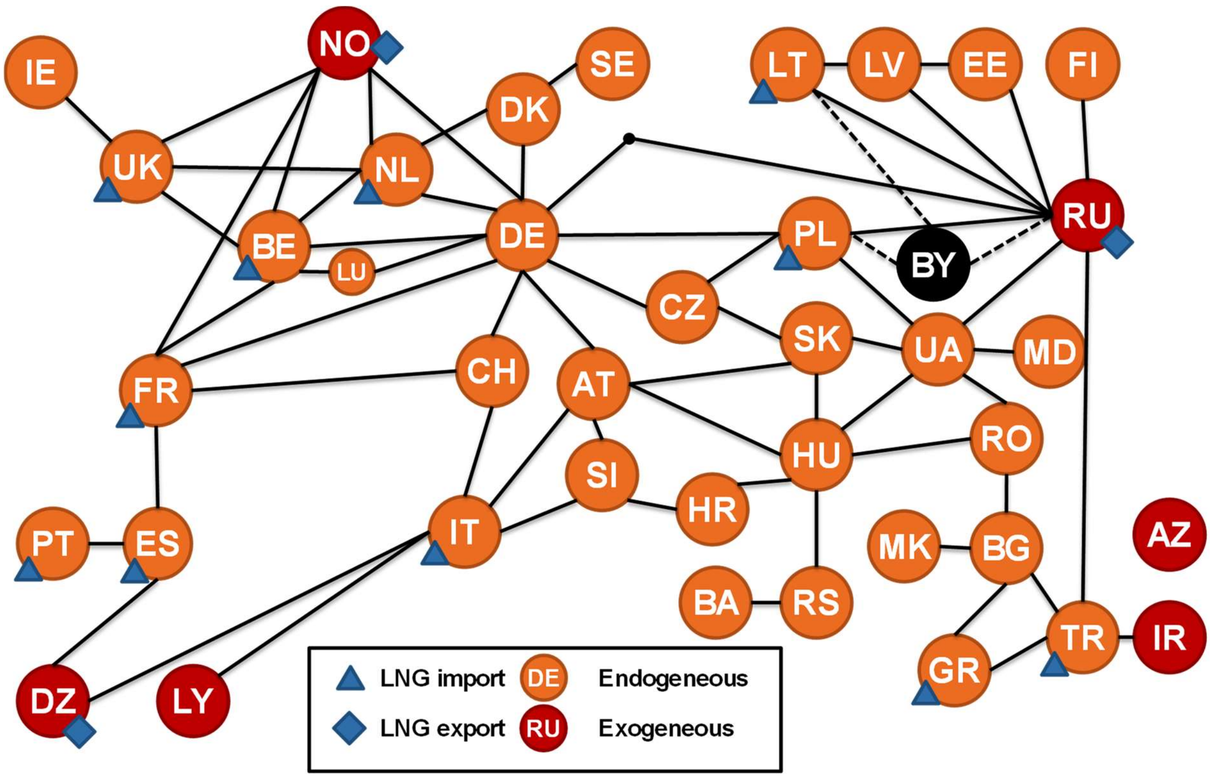
Following Table 4, the highest monthly peaks in case of February are around 10-15%. As a prudent estimate, we assume +15% demand increase in February in our 'one-month-long consumption peak at the end of winter scenario.' And, again, ENTSO-G observes a similar scenario with a 2-week cold spell in the period of 15-28 February.

ANNEX 3. EGMM MODEL DESCRIPTION

The EGMM is a competitive, dynamic, multi-market equilibrium model for natural gas production, trade, storage, and consumption in Europe. It explicitly includes a supply-demand representation of 35 European countries,[73] as well as their gas storages and transportation links to each other and to the outside world. The time frame of the model is 12 consecutive months, starting in April. Market participants have perfect foresight over this period.

REKK's European Gas Market Model has been developed to simulate the operation of an international wholesale natural gas market in whole Europe. The next figure shows the geographical scope of the model. Country codes denote the countries for which we have explicitly included the demand and supply side of the local market, as well as gas storages. Large external markets, such as Russia, Iran, Libya, Algeria and LNG exporters are represented by exogenously assumed market prices, long-term supply contracts and physical connections to Europe.

Figure 50. The geographical scope of the European Gas Market Model



Source: REKK

Given the input data, the model calculates a dynamic competitive market equilibrium for 35 European countries, and returns the market clearing prices, along with the production, consumption and trading quantities, storage utilization decisions and long-term contract deliveries.

Model calculations refer to 12 consecutive months, with a default setting of April-to-March.[74] Dynamic connections between months are introduced by the operation of gas storages ("you can only withdraw what you have injected previously") and take-or-pay (TOP) constraints (minimum and maximum deliveries are calculated over the entire 12-

[73] Countries covered are EU-27 (not including Cyprus), Energy Community Contracting Parties (Albania, Ukraine, Moldova, Serbia, FYR of Macedonia, Bosnia and Herzegovina), Switzerland and Turkey

[74] The start of the modeling year can be set to any other month.

month period, enabling contractual "make-up").The European Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) long-term take-or-pay (TOP) contracts; and (7) spot trading. We will describe each of them in detail below.

Local demand

Local *consumption* refers to the amount of gas consumed in each of the local markets in each month of the modelling year. It is, therefore, a quantity measure.[75] Local *demand*, on the other hand, is a functional relationship between the local market price and local consumption, similarly specified for each month of the modelling year.

Local demand functions are downward sloping, meaning that higher prices decrease the amount of gas that consumers want to use in a given period. For simplicity, we use a linear functional form, the consequence of which is that every time the market price increases, local monthly consumption is reduced by equal quantities (as opposed to equal percentages, for example).

The linearity and price responsiveness of local demand ensures that market clearing prices will always exist in the model. Regardless of how little supply there is in a local market, there will be a high enough price so that the quantity demanded will fall back to the level of quantity supplied, achieving market equilibrium.

Local supply

Local *production* is a similar quantity measure as local consumption, so the corresponding counterpart to local demand is local *supply*. Local supply shows the relationship between the local market price and the amount of gas that local producers are willing to pump into the system at that price.

In the model, each supply unit (company, field, or even well) has either a constant, or a linearly increasing marginal cost of production (measured in €/MWh). Supply units operate between minimum and maximum production constraints in each month, and an overall yearly maximum capacity.[76]

Any number of supply units can be defined for each month and each local market. As a result, local supply is represented by an increasing, stepwise linear function for which the number, size, and slope of steps is defined by the user.

Gas storage facilities

Gas storages are capable of storing natural gas from one period to another, arbitraging away large market price differences across periods. Their effect on the system's supply-demand balance can be positive or negative, depending on whether gas is withdrawn from, or injected into, the storage. Each local market can contain any number of storage units (companies or fields).

Storage units have a constant marginal cost of injection and (separately) of withdrawal. In each month, there are upper limits on total injections and total withdrawals. Storage fees are considered in a volumetric manner, which considers injection, withdrawal and working gas tariff items.

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[75] All quantities are measured in energy units within the model.

[76] Minimum production levels can be set to zero. If minimum levels are set too high, a market clearing equilibrium may require negative prices, but this practically never happens with realistic input data.

There are three additional constraints on storage operation: (1) working gas capacity; (2) starting inventory level; and (3) year-end inventory level. Injections and withdrawals must be such during the year that working gas capacity is never exceeded, intra-year inventory levels never drop below zero, and year-end inventory levels are met.

External markets and supply sources

Prices for external markets and supply sources are set exogenously (i.e. as input data) for each month, and they are assumed not to be influenced by any supply-demand development in the local markets. In case of LNG, the price is derived from the forecasted Japanese spot gas price, taking into account the cost of transportation to any possible LNG import terminal. As a consequence, the price levels set for outside markets are important determinants of their trading direction with Europe. When prices of the external markets are set relatively low, European countries are more likely to import from the outside markets, and vice versa.

Cross-border pipelines

Any two markets (local or outside) can be connected by any number of pipelines or LNG routes, which allow the transportation of natural gas from one market to the other. Connections between geographically non-neighbouring countries are also possible, which corresponds to the presence of dedicated transit routes.

Cross-border linkages are unidirectional, but physical reverse flow can easily be allowed for by adding a parallel connection that "points" into the other direction. Each linkage has a minimum and a maximum monthly transmission capacity, as well as a proportional transmission fee.

Virtual reverse flow ("backhaul") on unidirectional pipelines or LNG routes can also be allowed, or forbidden, separately for each connection and each month. The rationale for virtual reverse flow is the possibility to trade "against" the delivery of long-term take-or-pay contracts, by exploiting the fact that reducing a pre-arranged gas flow in the physical direction is the same commercial transaction as selling gas in the reverse direction.

Additional upper constraints can be placed on the sum of physical flows (or spot trading activity) of selected connections. This option is used, for example, to limit imports through LNG terminals, without specifying the source of the LNG shipment.

Furthermore, the model allows for constraining spot flows on infrastructure for interconnectors exempted / not under the jurisdiction of the European Regulation or booked long term by a major market player (e.g. Trans-Balkans pipeline).

LNG infrastructure

LNG infrastructure in the model consist of LNG liquefaction plants of exporting countries, LNG regasification plants of importing countries and the "virtual pipelines" connecting them. "Virtual pipelines" are needed to define for each possible transport route a specific transport price. LNG terminals capacity is aggregated for each country, which differs from the pipeline setup, where capacity constraints are set for all individual pipeline. LNG capacity constraints are set as a limit for the set of "virtual pipelines" pointing from all exporting countries to a given importing country, and as a limit on the set of pipelines pointing from all importing countries to a given exporting country.

Long-term take-or-pay (TOP) contracts

A take-or-pay contract is an agreement between an outside supply source and a local market concerning the delivery of natural gas into the latter. The structure of a TOP contract is the following:

Each contract has monthly and yearly minimum and maximum quantities, a delivery price, a point of delivery and a monthly proportional TOP-violation penalty. Maximum quantities (monthly or yearly) cannot be breached, and neither can the yearly minimum quantity. Deliveries can be reduced below the monthly minimum, in which case the monthly proportional TOP-violation penalty must be paid for the gas that was not delivered.

Any number of TOP-contracts can be in force between any two sources and destination markets. Monthly TOP-limits, prices, and penalties can be changed from one month to the next. Contract prices can be given exogenously, based on oil-indexed long term contract formulae.

The delivery routes (the set of pipelines from source to destination) must be specified as input data for each contract. It is possible to divide the delivered quantities among several parallel routes in pre-determined proportions, and routes can also be changed from one month to the next. The point of delivery may be set to any interconnector within the modelled system.

Spot trading

The final building block, spot trading, serves to arbitrage price differences across markets that are connected with a pipeline or an LNG route. Typically, if the price on the source-side of the connection exceeds the price on the destination-side by more than the proportional transmission fee, then spot trading will occur towards the high-priced market. Spot trading continues until either (1) the price difference drops to the level of the transmission fee, or (2) the physical capacity of the connection is reached.

Physical flows on pipelines and LNG routes equal the sum of long-term deliveries and spot trading. When virtual reverse flow is allowed, spot trading can become "negative" (backhaul), meaning that transactions go against the predominant contractual flow. Of course, backhaul can never exceed the contractual flow of the connection.

Equilibrium

The European Gas Market Model algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, respecting all the constraints detailed above.

In short, the equilibrium state (the "result") of the model can be described by a simple no-arbitrage condition across space and time.[77] However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders.[78]

Local consumers decide about gas utilization based on the market price. Consumers in each market within the region are represented by a linear monthly gas demand function that only depends on the contemporaneous local wholesale price of gas.

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[77] There is one, rather subtle, type of arbitrage which is treated as an externality, and hence not eliminated in the model. We assume that whenever long-term TOP contracts are (fully or partially) linked to an internal market price (such as the spot price in the Netherlands), the actors influencing that spot price have no regard to the effect of their behavior on the pricing of the TOP contract. In particular, reference market prices are not distorted downwards in order to cut the cost of long-term gas supplies from outside countries.

[78] We leave out storage operators, since injection and withdrawal fees are set exogenously, and stock changes are determined by traders.

Local producers have piecewise linear short-run cost functions, with upper and lower limits on monthly production and a separate upper constraint on yearly output. Local producers decide about their gas production level in the following way: if market prices in their country of operation are higher than unit production costs, then they produce gas at full capacity. If prices fall below costs, then production is cut back to the minimum level (possibly zero). Finally, if prices and costs are exactly equal, then producers choose some amount between the minimum and maximum levels, which is actually determined in a way to match the local demand for gas in that month.

Traders in the model are the ones performing the most complex optimization procedures. First, they decide about long-term contract deliveries in each month, based on contractual constraints (prices, TOP quantities, penalties) and local supply-demand conditions. Importers own long-term take-or-pay (TOP) contracts that are sourced from gas exporters in outside markets, most importantly from Russia, Norway, Algeria, and a number of LNG exporting countries. Each contract specifies a price, a delivery route, and a minimum and maximum delivered quantity per month and per year. The monthly minimum delivery constraint alone is flexible: it can be violated, but most of the undelivered gas must be paid for according to the TOP rules.

Second, traders also utilize storages to arbitrage price differences across months. For example, if market prices in January are relatively high, then they withdraw gas from storage in January and inject it back in a later month in such a way as to maximize the difference between the selling and the buying price. As long as there is available withdrawal, injection and working gas capacity, as well as price differences between months exceeding the sum of injection costs, withdrawal costs, and the foregone interest, the arbitrage opportunity will be present and traders will exploit it.[79,80]

Finally, traders also perform spot transactions, based on prices in each local and outside market and the available cross-border transmission capacities to and from those markets, including countries such as Russia, Turkey, Libya, Algeria or LNG markets, which are not explicitly included in the supply-demand equalization.

Besides the actors listed above, the EGMM considers infrastructure operators as well. Transmission System Operators (TSOs), Storage System Operators (SSOs) and LNG operators however are not active actors within our modelling framework. The infrastructure operators merely observe the gas flows utilising their infrastructure and earn revenues based on the utilisation. Since all actors exhibit price-taking behaviour, the equilibrium is welfare-maximising for all market participants.

Welfare analysis

The changes of socio-economic welfare are estimated with the net benefits (benefits minus cost) that the individual projects can bring to the analysed region. Total positive socio-economic welfare accounted for in the NPV of a modelled period (year) is calculated as the sum of welfare change of all market participants:

- Consumer surplus [to consumers]
- Producer surplus (or short-run profit, excluding fixed costs) [to producers]
- Profit on long-term take-or-pay contracts [to importers]

[79] Traders also have to make sure that storages are filled up to their pre-specified closing level at the end of the year, since we do not allow for year-to-year stock changes in the model.
[80] A similar intertemporal arbitrage can also be performed in markets without available storage capacity, as long as there are direct or indirect cross-border links to countries with gas storage capability. In this sense, flexibility services are truly international in the simulation.

- Congestion revenue on cross-border spot trading [to TSOs]
- Cross-border transportation profit (excluding fixed costs) [to TSOs]
- Storage operation profit (excluding fixed costs) [to SSOs]
- Profit on inter-temporal arbitrage via gas storage [to traders]
- Profit of LNG operators [to LNG operators]

Welfare change for each market participant is assigned with an equal weight of 1:1.

ANNEX 4. INPUT DATA TO MODELLING AND MAIN ASSUMPTIONS

Table 44. Input data used in EGMM and source of data

Input data	Unit	Source	Comment
Yearly gas demand	TWh/year	Primes 16 where available	For other countries TYNDP 16 Green evolution
Monthly demand	In % of yearly	Eurostat	Based on fact data from 2013-15
Production	TWh/year	Primes 16 where available	For other countries TYNDP 16
Pipeline Capacity	GWh/day	ENTSO-G capacity map 16	Future pipeline capacities based on PCI 2nd list
Pipeline Tariff on IP	€/MWh	REKK calculation; regulators websites as of 2017 Jan	Each IP is a sum of an Exit+entry component
Storage capacity	Working gas: TWh, Inj.. withdr: GWh/day	GSE	Data on each storage site – than aggregated on a country level
Storage tariff	€/MWh	Storage operators websites 2017 Jan	1 €/MWh cap will be used
LNG regas capacity	GWh/day	GIE	Aggregated on a country level
LNG regas tariff	GWh/day	Operators websites	Entry into pipeline network is taken into account – IT entry to TSO transmission reduced and also IT regas in a sensitivity
LNG liquefaction	GWh/day	GIIGNL 2016	Source is constrained by liquefaction capacity
LNG transport cost	€/MWh	REKK calculation	Distance based. takes into account ship rates and boil off cost
Long term contracts	ACQ: TWh/year. DCQ: GWh/day	REKK collection from press + Cedigaz	TOP. flexibility. except for gas islands Delivery point on borders. pricing based on foreign trade statistics. delivery routes predefined based on historical flows (IEA)

Source: REKK EGMM modelling

Infrastructure used in the 2020 and 2025 reference scenarios

Table 45. New infrastructure assumed for the reference scenarios 2020, 2025 based on ENTSOG TYNDP

Name	Maximum flow	Date of commissioning	Basis to include into reference for 2020
	GWh/d		
IT-CH	368	2018	FID
BG-RS	51	2018	FID
RS-BG	51	2018	FID
CH-FR	100	2018	FID
CH-DE	240	2018	FID
TR-GR2_TAP	350	2019	FID
RU-DE	3 798	2019	FID
GR-MK_TAP	25	2019	FID
AZ-TR_TANAP	490	2018	FID
GR-BG	90	2018	FID
GR-BG	151	2021	FID
GR-IT_TAP	334	2019	FID
SI-HR2	165	2019	FID
HR-SI	165	2019	FID
BG-RO	14	2016	FID
RO-BG2	14	2016	FID
IT-AT2	189	2018	FID
AT-DE2	36	2017	FID
DE-AT2	143	2017	FID
GR-LNG expansion	81	2017	FID
MT-LNG	24	2020	existing 2017

Source: REKK assumptions based on LNG Strategy

Table 46. New infrastructure assumed for the reference scenarios 2020, 2025 based on LNG and storage strategy

Name	Maximum flow	Date of commissioning	Basis to include into reference for 2020
	GWh/d		
HR-LNG	50	2020	LNG strategy
RO-HU (BRUA)	126	2020	LNG strategy
HU-RO (BRUA)	77	2020	LNG strategy
FI-EE	79	2019	LNG strategy
EE-FI	79	2019	LNG strategy
PL-LT (GIPL)	74	2019	LNG strategy
LT-PL (GIPL)	51	2019	LNG strategy
LT-LV	52	2019	LNG strategy
EE-LV	105	2019	LNG strategy
LV-EE	42	2019	LNG strategy
ES-PT	85	2021	LNG strategy
PT-ES	70	2021	LNG strategy
ES-FR	110	2021	LNG strategy
FR-ES	120	2021	LNG strategy

Source: REKK assumptions based on LNG Strategy

Capacities are from ENTSOG TYNDP 2017, except for HR LNG terminal (an FSRU is assumed)

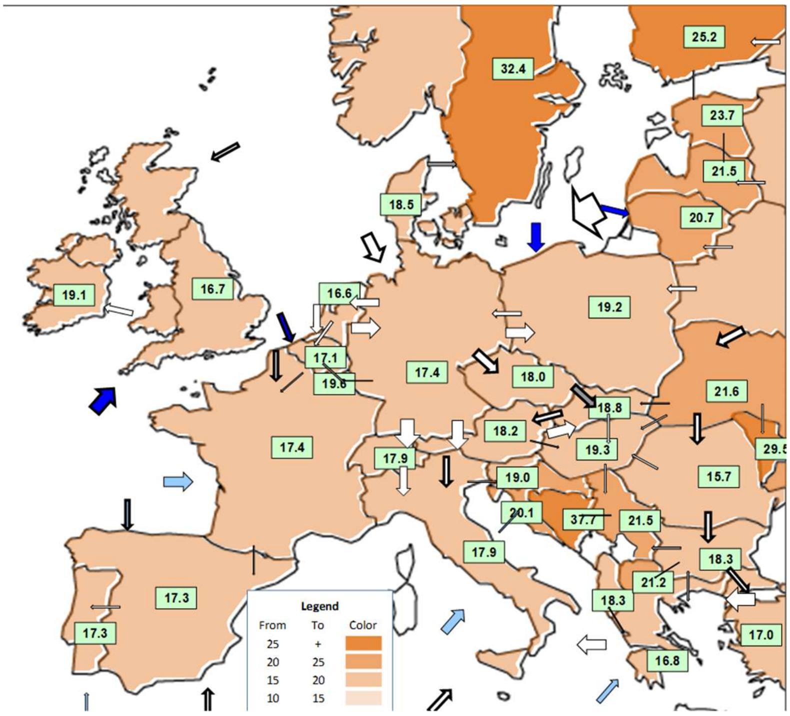
Table 47. New storage capacities assumed for the reference scenarios 2020, 2025

Storage facility	Market	Capacity			Commissioning
		Working gas	Injection	Withdrawal	
		TWh	GWh/d	GWh/d	
Tuz Gölü	TR	5	159	159	2017
Botas Tarsus	TR	11	319	319	2020
Silivri (Marmara)	TR	46	638	638	2020
Bordolano phase II	IT	7	109	185	2019

Source: REKK assumption based on ENTSOG TYNPD and GSE

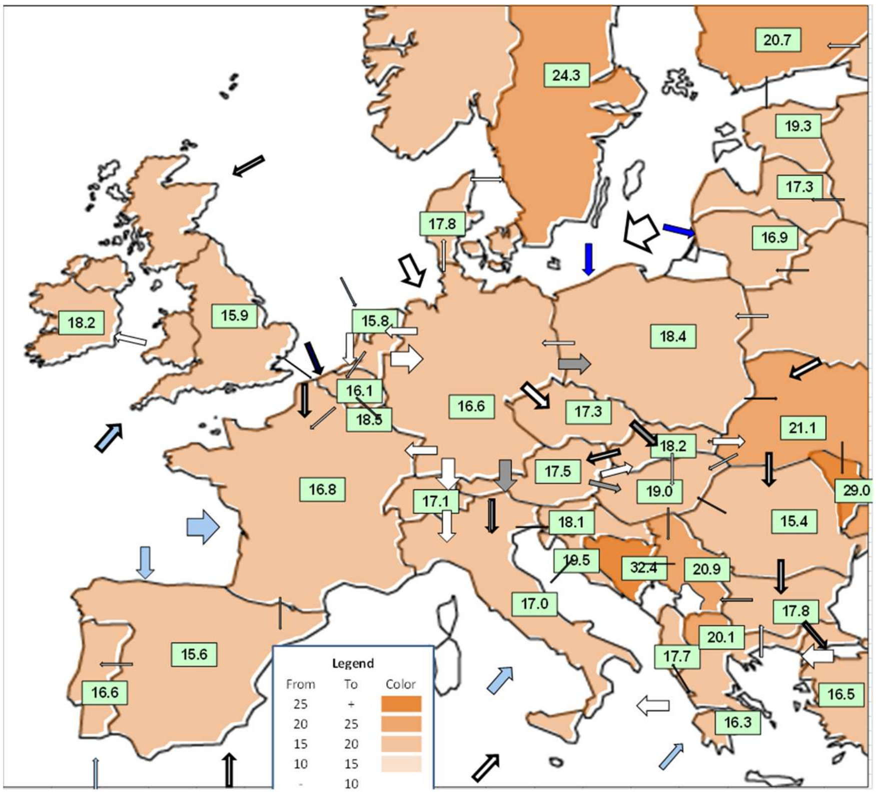
ANNEX 5. SENSITIVITY OF THE REFERENCE SCENARIOS

Figure 51. Modelled yearly wholesale price in the Primes reference demand and high LNG supply scenario 2025 (€/MWh)



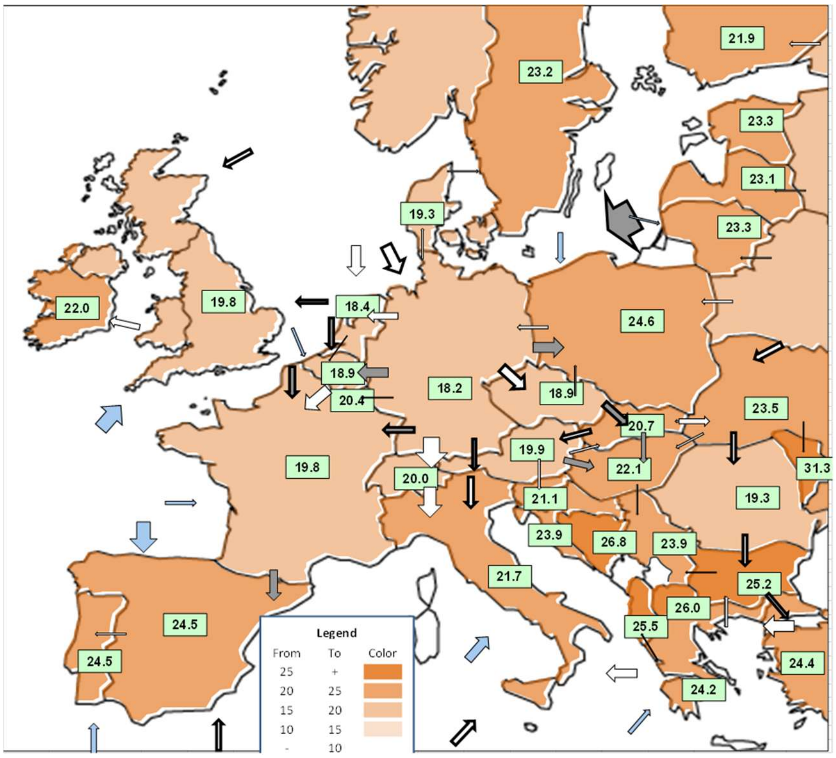
Source: REKK EGMM modelling

Figure 52. Modelled yearly wholesale price in the Primes EUCO30 demand and high LNG supply scenario 2025 (€/MWh)



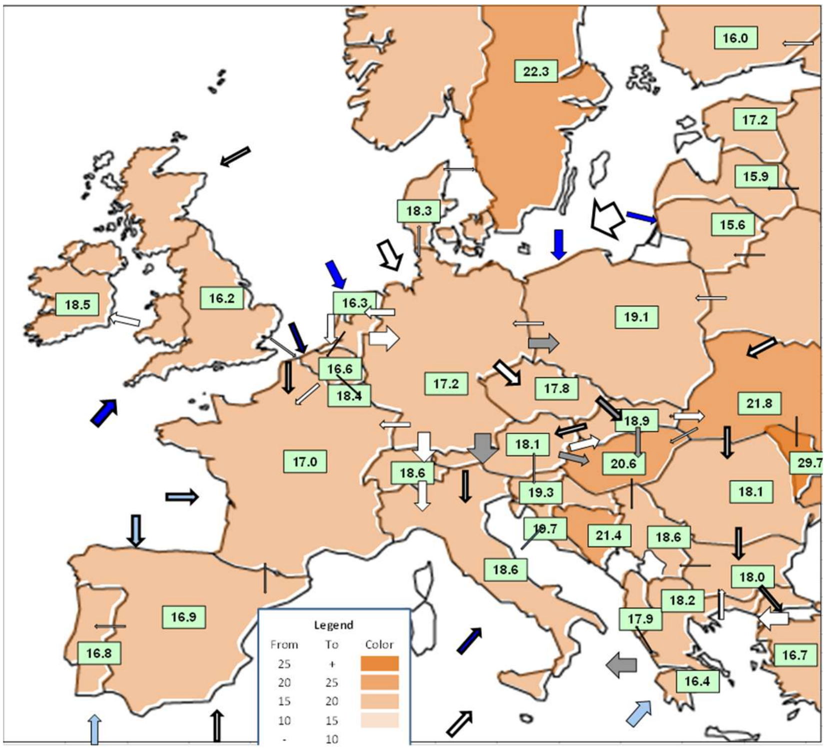
Source: REKK EGMM modelling

Figure 53. Modelled yearly wholesale price in the TYNDP blue demand and low LNG supply scenario 2025 (€/MWh)



Source: REKK EGMM modelling

Figure 54. Modelled yearly wholesale price in the TYNDP blue demand and high LNG supply scenario 2025 (€/MWh)



Source: REKK EGMM modelling

Table 48. Yearly regional prices in the alternative scenarios (€/MWh)

	ref	low_lng & low_demand	high_lng & low_demnd	low_lng & high_demand	high_lng & high_demand
AL	20.29	25.41	17.72	25.53	17.87
BA	32.36	32.36	32.36	26.76	21.41
BG	20.19	22.56	17.79	25.20	17.95
GR	18.89	24.03	16.29	24.15	16.45
HR	21.95	22.17	19.46	23.93	19.73
HU	20.00	20.09	19.01	22.10	20.65
MD	29.94	29.87	28.96	31.33	29.66
MK	22.28	26.23	20.12	26.05	18.25
RO	16.43	16.50	15.44	19.29	18.06
RS	21.98	22.30	20.89	23.93	18.58
SI	19.25	19.36	18.09	21.12	19.27
TR	19.16	24.23	16.54	24.40	16.72
UA	22.08	22.01	21.10	23.48	21.80
SEE	**18.62**	**19.36**	**17.09**	**21.68**	**18.78**
EnC	**22.41**	**22.43**	**21.41**	**23.72**	**21.81**
SEE+	**20.76**	**21.13**	**19.56**	**22.71**	**20.30**
SEE+TR	**20.00**	**22.54**	**18.09**	**23.46**	**18.62**
NWE	**17.83**	**17.95**	**16.18**	**18.84**	**16.61**
EU28	**18.31**	**18.45**	**16.70**	**20.55**	**17.39**

ANNEX 6. WOBBE INDEX REVIEW

WOBBE INDEX FOR EUROPEAN LNG IMPORT TERMINALS

The following table and figure indicates the Wobbe Index values established for the current European LNG Import Terminals:

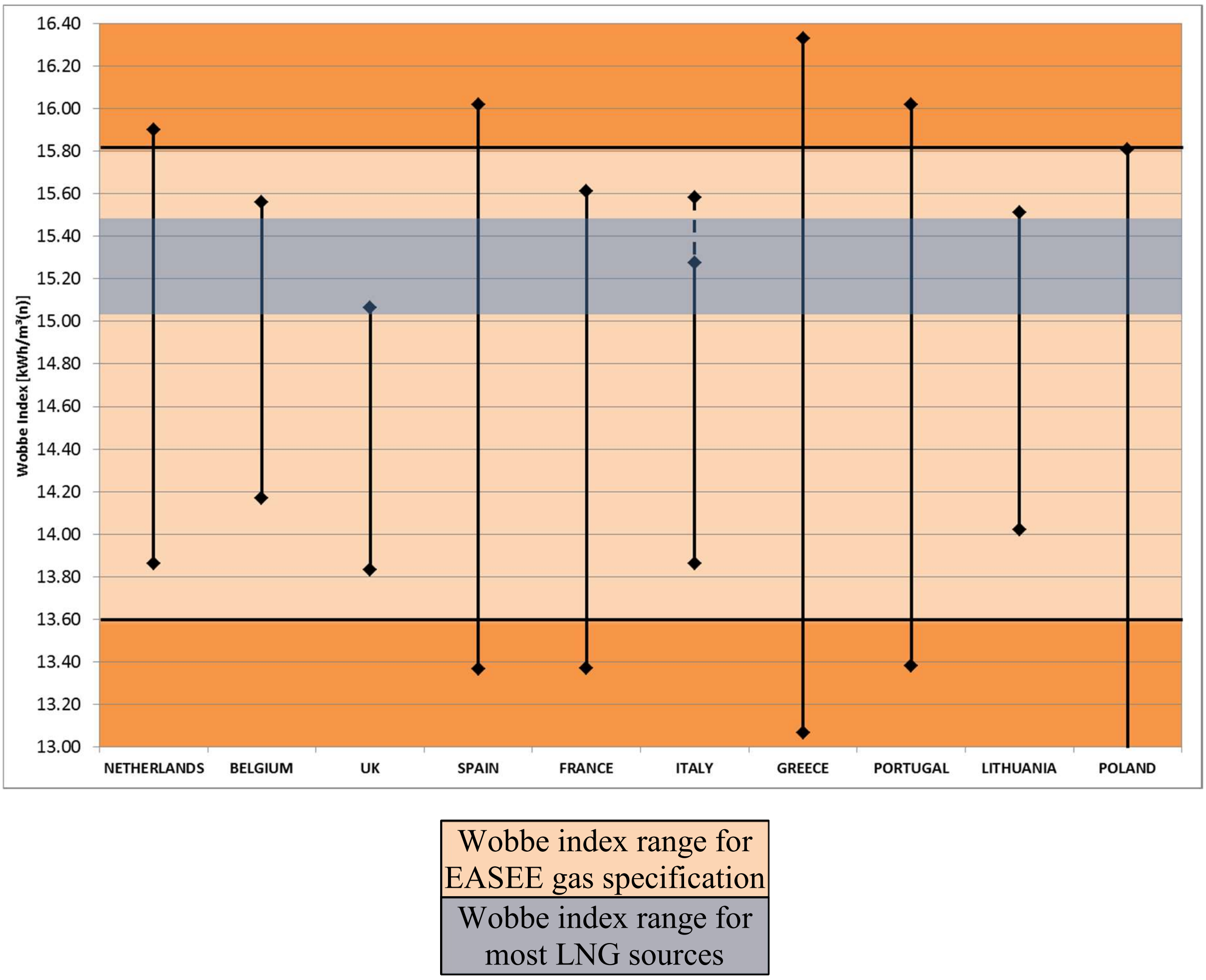
Table 49. Maximum and minimum Wobbe Index values for European LNG import terminals

Country	Terminal	Minimum Wobbe Index	Maximum Wobbe Index	LNG quality adjustment facilities present?	Source
		kWh/m³ (n)	kWh/m³(n)		
EASEE gas		*13.60*	*15.81*		
Belgium	Zeebrugge	14.17	15.56	Y	http://www.fluxys.com
UK	Isle of Grain	13.83 (*)	15.06 (*)	Y	http://www2.nationalgrid.com/uk
UK	South Hook LNG	13.83 (*)	15.06 (*)	Y	http://www2.nationalgrid.com/uk
UK	Dragon LNG	13.83 (*)	15.06 (*)	N	http://www2.nationalgrid.com/uk
Netherlands	Gate LNG	13.86	15.90	Y	http://gate.nl
Italy	Panigaglia	13.86	15.28 (**)	Y	http://www.gnlitalia.it
Italy	Porto Levante	13.86	15.28	N	http://www.adriaticlng.it
Greece	Revithoussa	13.07	16.33	N	http://www.desfa.gr
Portugal	Sines	13.38 (*)	16.02 (*)	N	https://www.ign.ren.pt
Poland	Swinoujscie	12.50 (*)	15.81 (*)	Y	http://en.gaz-system.pl
Lithuania	FSRU Klaipeda	14.02	15.51	N	http://www.golng.eu
Spain	Barcelona Huelva Cartagena Bilbao Sagunto Mugardos	13.37 (*)	16.02 (*)	N	http://www.enagas.es
France	Fos Tonkin	13.60	15.61	N	https://www.elengy.com
France	Montoir	13.60	15.61	N	https://www.elengy.com
France	Fos Cavaou	13.37	15.61	N	http://www.fosmax-lng.com

(*) LNG import quality requirements unknown → replaced by gas quality requirement of national grid

(**)Max. allowable value increased to 15.58 kWh/m³(n) due to availability of Wobbe Index correction

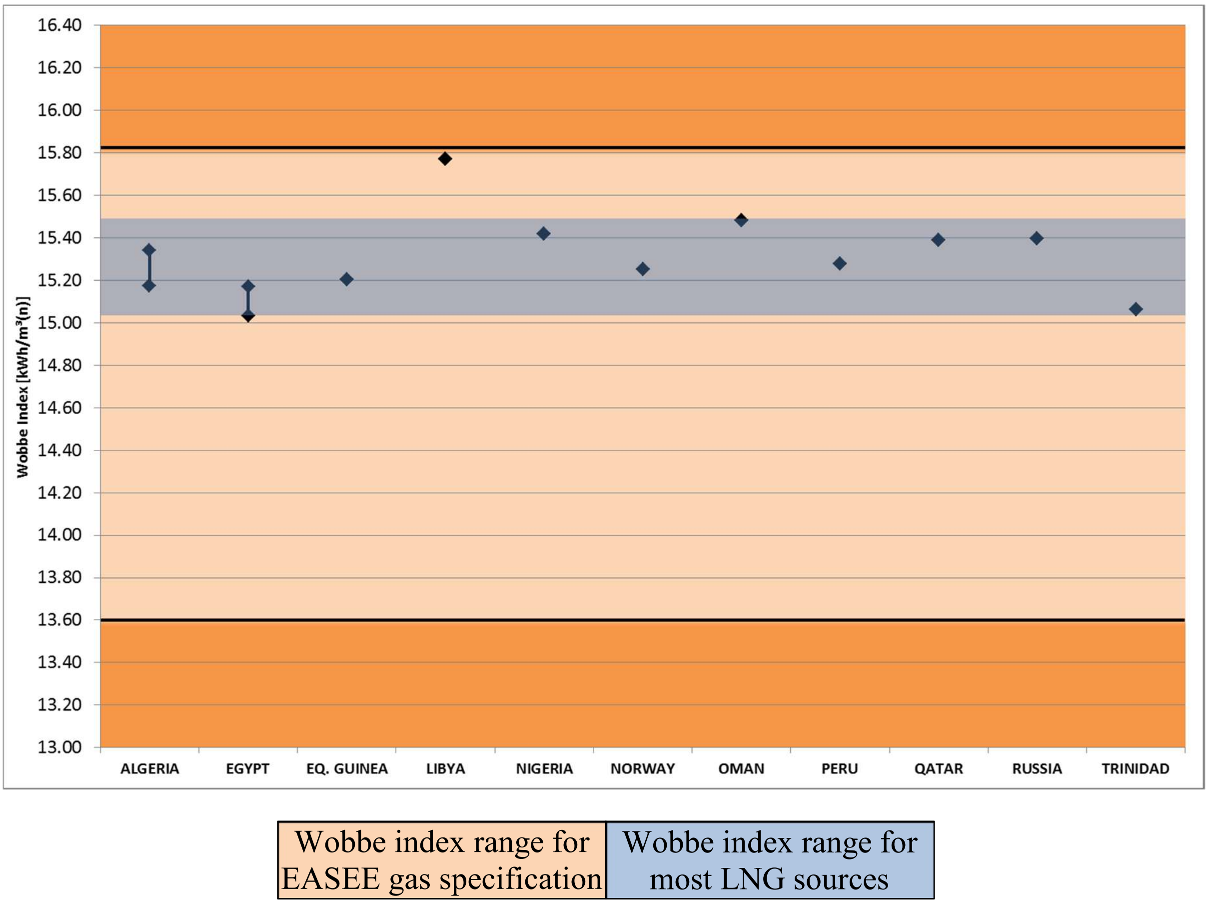
Figure 55. Wobbe index requirements at LNG import terminals in Europe



Wobbe Index values for LNG Export terminals servicing Europe

The following figure indicates the Wobbe Index values established for a range of LNG Export Terminals providing LNG to Europe: (Note that Libya is not currently exporting LNG)

Figure 56. Typical Wobbe index for sources of LNG supply to Europe



Conclusions

The table and figures depicted above indicate the following:

- Typical values of Wobbe Index of LNG sources supplying Europe are within the range of 15.0 to 15.5 kWh/m³(n), with the exception of Libyan LNG which is no longer exporting.
- EASEE gas upper limit of the Wobbe Index is adequate to cover most LNG sources (only exceptionally would an LNG cargo exceed this upper limit);
- The receiving terminals of all but one of the European countries currently importing LNG accept Wobbe Index values which are within the range of LNG sources currently supplying Europe, again with the exception of Libyan LNG;
- The Wobbe Index value range required in the UK national grid is narrower compared to other EU markets and is not in line with the Wobbe Index values of most LNG offered on the market. However, Isle of Grain LNG and South Hook LNG both have nitrogen ballasting facilities in order to blend a defined quality of LNG within UK national grid specification.

Annex 7. LNG Storage Capacity Definition

When a company decides to develop an LNG import terminal its main consideration is the throughput capacity of NG based on market assessment (volume of gas sales).

LNG storage capacity is calculated to provide a sufficient quantity of LNG to meet the NG demand in between LNG deliveries whilst maintaining a buffer to manage potential demand fluctuations (peak deliveries) and to provide some contingency/buffer storage if an LNG supply vessel is delayed.

Therefore in order to estimate likely LNG storage volumes required a shipping & storage study must be carried out in order to determine the optimal storage capacity for the LNG regasification terminal. As the storage and shipping represent an important part of the total project cost, an evaluation of the LNG transport and receiving system is an important tool to identify and eliminate excess capacities of the system. (Developers tend to prefer to minimise the LNG storage capacity of the terminal)

As noted above the storage capacity must be sufficient in order to provide a buffer between subsequent ship unloading operations while guaranteeing the gas send-out demand.

The NG send-out demand is defined on the basis of a market study and peak seasonal demand requirements.

The LNG supply volumes required depend on the number of vessel unloading operations and the frequency of vessel arrivals to meet the NG send out demand:

- Number of unloading operations depends on the number of ships, ships capacity, distance from loading port, real ship speed (which varies with sea conditions, wind direction/speed, machinery ageing, hull fouling, etc.)
- Potential irregularity of arrivals of ocean-going vessels due to random, scheduled or seasonal events: import terminal closure due to weather conditions, daylight travel restriction, difficult sea conditions, unscheduled liquefaction plant shutdown, vessel breakdown, port transit duration, etc.

A detailed LNG storage level calculation is based on successive volume balances, performed at the beginning and at the end of each unloading operation, leading to a daily tank inventory assessment which is then used to assess the minimum operational strategic storage capacity required.

The distribution range and the cumulated frequency of the strategic capacity calculated on a monthly basis can then be analysed in order to define the required storage capacity.

This storage capacity is concluded only to suit the operational requirements of the terminal, it does not consider any additional long term strategic LNG storage or major long term supply risk scenarios – LNG storage costs are a significant component of the CAPEX for an import terminal and therefore Project developers will not sanction more storage capacity than they realistically need to maintain their contractual obligations.

As a general rule it is usually recommended to provide a minimum of one week strategic LNG storage capacity over and above the required capacity to accommodate the send out requirements between normal ship arrivals.

Typically a 5BCMA import terminal would include 2 x 150 000 m^3 LNG tanks and these tanks would be valued at around €175-200m for a Project in Europe (2016 rates).

As the LNG storage capacity needed to fulfil peak send out requirements (say in winter)is more than required during the low season there is potentially spare LNG storage capacity available, however, the operators would then generally amend the LNG Carrier shipping schedule to give longer durations between unloading operations rather than hold more LNG than required.

As LNG within the storage tanks is subject to boil off due to heat influx the Boil Off Gas needs to be sent out into the pipeline or re-liquefied and this adds potential additional operational costs for LNG storage (in particular for low/zero send-out scenarios during ship unloading)

In addition to the normal onshore LNG import terminals a more recent trend to reduce the start-up time and front end CAPEX is the implementation of FSRU (Floating Storage and Regasification Unit) based import terminals.

However, these terminals have restricted LNG storage capacity (up to around 170 000 m^3) and are normally associated with lower gas send out demand or fast track solutions where gas is urgently required. They have no real option for longer term strategic LNG storage.

Peak Shaving LNG facilities are sometimes used to store gas in LNG form for seasonal or peak loading use but the implementation of these facilities purely for strategic storage purposes seems less economically viable than adding storage capacity to existing import terminals as the Peak Shaving facilities require liquefaction and vaporisation plant operation and maintenance in addition to the storage.

In general terms additional LNG storage being established at existing or new terminals purely for strategic storage in the event of restricted pipeline gas availability scenarios would not be considered economically viable for the operator (currently it is noted that many European LNG Import terminals are operating well below their throughput capacity and therefore have spare LNG storage capacity that could be considered as available for strategic storage but this capacity is fully market dependent).

ANNEX 8. CURRENT STATE OF THE LNG MARKET

Overview of Current Trends

The LNG market section provides an overview of the global LNG trade, our forecasts of the medium-term market (five and ten year projections, showing 2015, 2020 and 2025), and global price developments.

The overall share of natural gas in the energy mix accounts for roughly a quarter of global energy demand. The share of Liquefied Natural Gas (LNG) in the global natural gas supply accounts for approximately 10% but it has averaged an annual 6% growth from 2010 to 2014.[81] Global LNG trade grew to a record 263.6 million tonnes (mt), an increase of 18 mt (7.5%) over 2015. The market players contributing to growth included the United States (Gulf of Mexico), Malaysia and mainly from Australia, producing 15.4 of the 18 mt additional supply for 2016.[82] The growth numbers were robust but still lower than expected growth forecast due to delays and plant outages.

Global nominal liquefaction capacity stood at 339.7 mtpa at January 2017 and Qatar remained the largest LNG producing country (with 30.2% of total global LNG supply). Other additions to supply were the commencement of LNG production in the USA with Sabine Pass Trains One and Two coming online. Similarly, additional supply from Australia included the commencement of commercial operations by Gorgon LNG Trains One and Two, Australia Pacific LNG, coupled with the addition of new trains at Gladstone LNG and Queensland Curtis LNG. The proposed LNG capacity totalled 879 mpta at January 2017 but

[81] 'GIIGNL 2016 Annual Report' (Groupe International des Importateurs de Gaz Naturel Liquéfié (GIIGNL) 2016)
[82] 'GIIGNL 2017 Annual Report' (Groupe International des Importateurs de Gaz Naturel Liquéfié (GIIGNL) 2017)

activity levels were less than forecast due to anticipated market imbalances, low oil prices, and an uncertain long-term demand outlook.[83]

On the demand front, LNG demand growth was largely driven by China, India, and other emerging importers. As well as these, new market development for LNG took place in countries with limited indigenous production, such as Egypt, Pakistan, and countries with a preference for clean and flexible fuel for power generation, such as Jamaica and Malta (Note: Egypt is in a special category as it has changed from being an LNG exporter to an importer and may perhaps change again, Egypt is discussed in more detail elsewhere in this study). China led demand growth figures with an impressive 36.9% growth due to an increase in gas-fired power generation and industrial sector demand. The Indian LNG market has also grown considerably with imports increasing by over 30%, reaching 19 mt. Emerging LNG importers such as Egypt, Jordan, and Pakistan imported a combined 13.5 mt, growth dominated by Egypt which accounted for more than 50% (7.5 mt) of the combined increase. Simultaneously, the two largest LNG markets (Japan and South Korea) remained sluggish due to the restart of nuclear units, energy conservation efforts, and renewable power generation. Europe also showed subdued demand growth with a decline in imports from the UK (-26%), Belgium (-58%), and the Netherlands (-42%).

In other major development trends, Floating Storage Regasification Units (FSRUs) and LNG bunkering depicted positive signs in shaping the industry and taking the LNG industry forward. FSRU addition assists in expanding access to emerging markets and absorbing the extra supply. LNG is also playing a role as bunkering fuel for maritime transport which can reduce NOx and SOx emissions significantly. These trends are crucial for the development of LNG and increasing the share of LNG in the global energy mix.

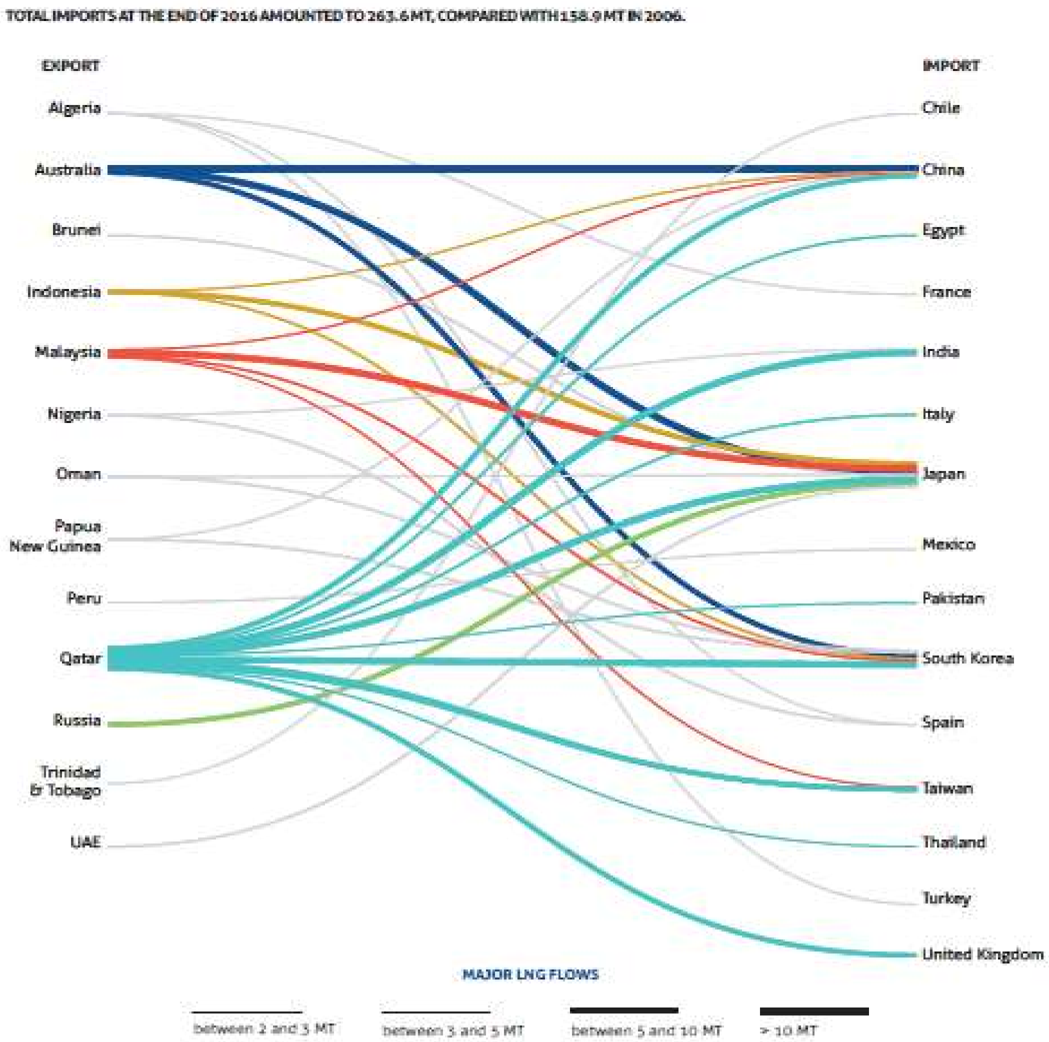
Current LNG Market

Global LNG trade recorded growth for the third consecutive year, reaching 263.6 mt, an increase of 18 mt (7.5%) from 2015. The increase of growth was driven by the continued addition in LNG supplies from Australia and the commencement of exports from US Gulf of Mexico. In addition, demand growth was marked by Asian economies; China, India, and Pakistan.

The figure below shows the total LNG market flow between countries in 2016. The total imports at end of 2016 amounted to 263.3 mt, compared with 158.9 mt in 2006. The majority of LNG exports originated from Qatar and Australia, with a combined share of approximately half of the total global LNG market. Qatar remained the largest supplier of LNG closely followed by Australia.

[83] International Gas Union, 'IGU 2017 World LNG Report' (International Gas Union (IGU) 2017)

Figure 57. Total LNG Market Flows



Source: Tsueno Miyamoto and others, Developing Liquidity in the LNG Market - Asia's Challenges and Outlook (1st edn, KPMG 2017)

European LNG imports year on year increased for the second consecutive year but high Pacific Basin prices during the last quarter of 2016 restricted imports from exceeding 0.6 mt. European LNG markets such as the UK, Belgium, and the Netherlands experienced a decline in LNG consumption due to a sizeable increase in gas supplies from both Russia and Norway. However, new markets such as Poland and Lithuania added a combination of 1.4 mt in 2016.

European LNG imports are determined by the inter-basin price differentials and, as noted above, demand was met from pipeline imports. LNG imports in Europe are competing with plentiful gas supply from Russia and Norway through well-integrated European gas networks. Gas-fired generation in Spain, Italy, and Greece could lead to increased LNG imports but in general, LNG market development in Europe will depend on gas price movements.[84]

Short and medium-term LNG trade reached 74.6 mt in 2016, accounting for 28% of total trade. Short and medium-term trades were initially driven by the power generation gap

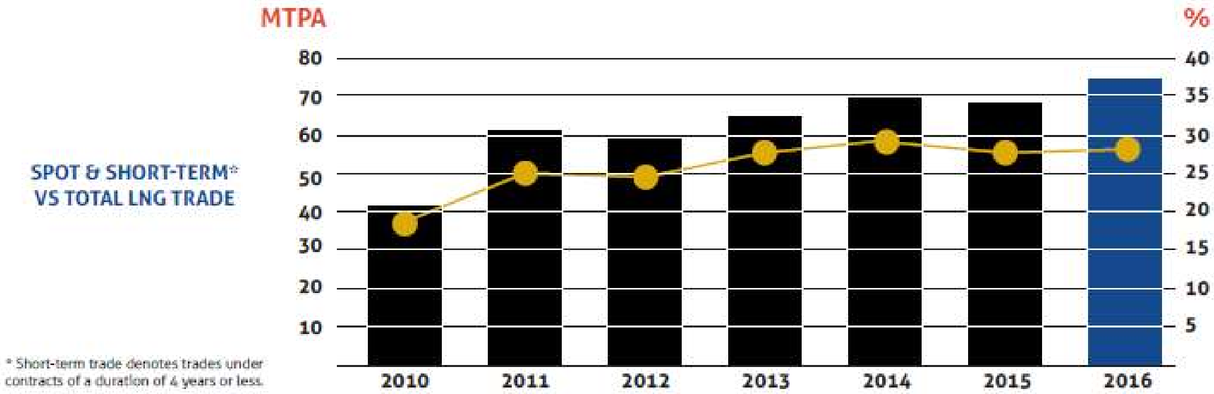
[84] International Gas Union, 'IGU 2017 World LNG Report' (International Gas Union (IGU) 2017)

due to the Fukushima crisis, which required commercial innovations. Since then the share of short and medium-term LNG trade has stayed relatively stagnant.

A reduction in short term purchases were due to weakening demand in markets that are highly dependent on spot and short-term volumes, for instance, in Brazil, traditionally a significant player in spot markets, as well as drops in short-term purchases in Japan and South Korea. In addition, emerging markets such as Pakistan and Malaysia began importing under long-term contracts in 2016.

In contrast, the growth in short-term LNG trade was driven by China, India, and Egypt, accounting for 30% of spot LNG trade in 2016. The figure below shows the short-term LNG trade compared with total LNG trade:[85]

Figure 58. Spot & Short-term vs. Total LNG Trade



Source : 'GIIGNL 2017 Annual Report' (Groupe International des Importateurs de Gaz Naturel Liquéfié (GIIGNL) 2017)

The short-term trade outlook looks positive due to new liquefaction plants coming online. The total new liquefaction capacity commencing commercial operations is expected to be over 45 mpta in 2017, 37% of which is uncontracted or contracted to Atlantic Basin aggregators. This uncontracted capacity indicates a trend towards greater flexibility in the LNG trade and is likely to result in an increase in destination-free volumes as new buyers and sellers enter the market. This trend is expected to grow at an accelerating rate in 2018 because half of new liquefaction capacity commencing operations will be located in the USA.

Global Prices

Due to increases in supply and weak demand, Asian and spot LNG prices declined steadily to $4.05/mmbtu in the first half of 2016. The second half of the year showed the opposite trend with supply disruptions and cold winters driving the prices up to $9.95/mmbtu by February 2017.

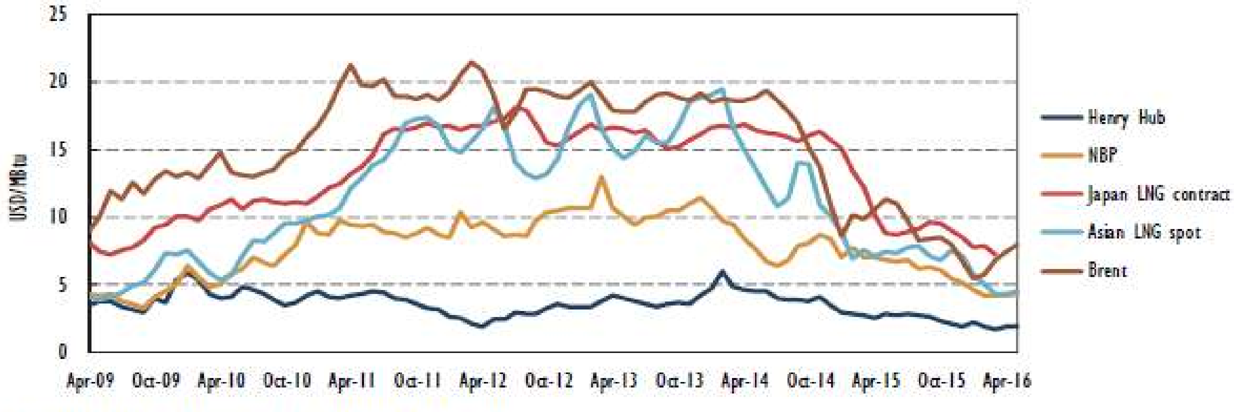
Similarly, in the UK, due to cold weather and storage constraints at the Rough gas storage facility, the National Balancing Point (NBP) also ended the year with prices increasing to $5.44/mmbtu. The continued decline in oil prices in the first half of the year led to low oil-indexed LNG contract prices.

Gas prices in North America are predominantly determined at liquid trading hubs, the most prominent of which is Henry Hub in Louisiana. In Europe, long-term contracts dominate the wholesale gas market. The pricing component of LNG long term contracts is gas hub

[85] 'GIIGNL 2017 Annual Report' (Groupe International des Importateurs de Gaz Naturel Liquéfié (GIIGNL) 2017)

based or oil linked, or a combination of both. In Asia, prices are fixed through oil linkages. Traditionally, oil linked prices in Asia and Europe decline with the decline in oil prices so that oil prices are crucial for the LNG market. With the decline in prices globally, the market moved nearer to price convergence, resulting in an average differential of $0.91/mmbtu between NBP and Northeast Asian spot prices in 2016.[86]

Figure 59. Gas Price Development



Note: NBP = National Balancing Point (United Kingdom).

Source: IEA Medium-Term Gas Market Report 2016

The price developments provide a good insight into fundamental changes in the LNG market. The contraction of price differentials between different trading regions lead to a price trend towards marginal transportation costs, a reflection of an oversupplied market with no region wanting to pull surplus cargoes. The convergence in prices and weaker demand have also led to a trading environment less conducive to growth in spot and short-term markets.[87]

LNG Supply

The LNG supply section provides a brief overview of the liquefaction plants, new proposed liquefaction plants, regasification terminals, FSRUs, and shipping fleets.

1. **Liquefaction Plants:**
   Global liquefaction capacity increased by 35 mpta between late 2015 and early 2017, to reach a total of 338.6 mpta. The increase in liquefaction capacity came through new projects such as Gorgon LNG, Australia Pacific LNG, and Sabine Pass LNG. Furthermore, the additional trains at Gladstone LNG, Queensland Curtis LNG, and Malaysia LNG also boosted capacity. Liquefaction capacity is expected to increase over the coming years with 114.6 mpta capacity under construction as of January 2017.
2. **Proposed Liquefaction Projects:**
   The shale revolution in the US and significant gas discoveries globally increased liquefaction capacity to 879 MTPA as of January 2017. The project economics will dictate the final decision on whether these capacities will be added to the supply. The proposed projects are faced with low demand which is well below the proposed increase in capacity. In addition, significant pipeline supply by Russia, Norway, and the USA have negative implications for the LNG project economics. Similarly, Egypt mayend up being an LNG exporter instead of importer once the Zohr field commences commercial gas production. The bulk of proposed capacity is located in the US Gulf of Mexico, Canada, East Africa, and Asia-Pacific.
3. **Regasification Terminals:**
   Total regasification capacity increased to 794.6 mpta by January 2017 with additional

[86] International Gas Union, 'IGU 2017 World LNG Report' (International Gas Union (IGU) 2017)
[87] IEA/OECD, *Medium-Term Gas Market Report 2016* (1st edn, OECD Publishing 2016).

capacity being delivered in developed markets such as China, Japan, France, India, Turkey, and South Korea. The development of new capacity coming online in developed markets is in contrast with 2015 when growth was driven by emerging markets such as Egypt, Jordan, and Pakistan. As of January 2017, 90.4 mpat of capacity were under construction with in aggregate eleven projects located in China and India. Other new entrants with regasification projects include Philippines, Bahrain, and Russia.

4. **Floating Storage Regasification Units (FSRUs):**
   Global FSRU capacity reached 83.0 mpta by January 2017 with new units introduced in the UAE (Abu Dhabi, 3.8 mpta) and Turkey (5.3 mpta). Other units were added in Colombia and Malta but commercial operations had not not commenced by January 2017. In addition, various FSRU projects are in the later stages of completion in Uruguay, Chile, Puerto Rico, and Russia. FSRU projects have a significant time advantage over other land-based infrastructure. For example, Turkey's offshore regasification terminal became operational within one year of the start of construction.
5. **Shipping Fleet:**
   As of January 2017, the total shipping fleets globally comprised of 439 vessels including conventional vessels, FSRUs, and floating storage units. A total of 31 vessels (including two FSRUs) were added to the shipping fleet in 2016, a 7% increase compared to 2015. Total shipping capacity amounted to 69.3 million cubic meters and total operational capacity (vessels in service) amounted to 64.7 million cubic meters by the end of 2016. The average spot charter rate for LNG carrier of 160 000 cubic meters declined from $36 038/day in 2015 to $33 528/day in 2016. The outlook for the LNG tanker market is expected to face downward pressure due to expected additions to the tanker supply. If all 53 LNG tankers are delivered according to schedule then there will be declining charter rates. With the increase in liquefaction capacity in both the Atlantic and Pacific Basin, the new capacity will hold the prices at par which will limit the need for cross-basin trade.

New LNG Technology and Markets

The LNG industry globally is now undergoing transformations in several areas, which are important drivers for change. New Technologies are having a dramatic impact, including:

Floating Liquefied Natural Gas: Traditionally, the costs of liquefaction plants are over $1bn. FLNG is a new technology and is still in development but it could also prove promising in terms of dramatically reducing the cost of liquefaction.

Floating Storage and Regasification Units (FSRUs): The costs of onshore regasification are in the order of several hundred million dollars. New FSRU technology has driven these costs down dramatically and an FSRU regasification plant can now be installed for as little as $50m. A further benefit is that because these are floating, they can be towed away, meaning much less credit risk for financiers (in the case of default the FSRU can be towed away). This means that new emerging markets can now enter into LNG imports, opening up large new markets globally for LNG. There are some disadvantages with FSRU, namely that they have to be towed away for about three months every five years for turnaround maintenance. This has not distracted new emerging market buyers from investing in this.

LNG Bunkering: LNG is available as a ship fuel and ships can be fuelled with LNG at ports with LNG bunkering facilities.

Ship to Ship LNG Refuelling: As well as ship refuelling from bunkers, ships can also be refuelled by transfer from other ships.

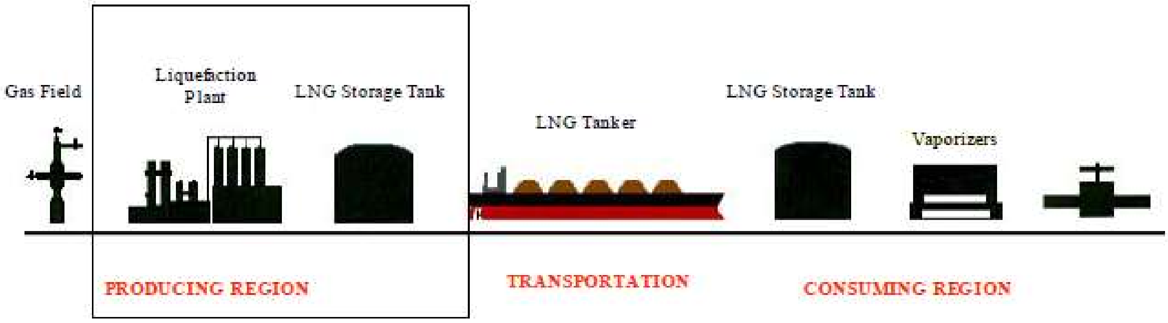
LNG Transport: LNG can also be transported by truck overland.

With the exception of FLNG, these all open up new markets for LNG, leading to potentially dramatic growth in the LNG industry.

LNG Costs

The complete economic evaluation of LNG should consider all the components of the LNG value chain because each element in the chain adds to the cost of financing. The figure below displays the LNG value chain and this report covers the cost drivers for liquefaction plants.

Figure 60. LNG Value Chain



Source: Heinz Kotzot and others, LNG liquefaction – not all plants are created equal

The primary cost drivers for liquefaction plant include (a) Project Scope and Complexity; (b) Construction Costs; (c) Equipment and Materials; (d) Engineering and Project Management; and (e) Owner's Costs. The table below shows the breakdown of cost by category for LNG projects:[88]

Table 50. Cost by Category for LNG Projects

Cost Category	%age of Total Cost
Construction	32
Equipment	30
Bulk Materials	20
Owner's Costs	10
Engineering & Project Management	8
TOTAL	100

Source: Brian Songhurst, 'LNG Plant Cost Escalation' (2014) OIES Paper: NG 83

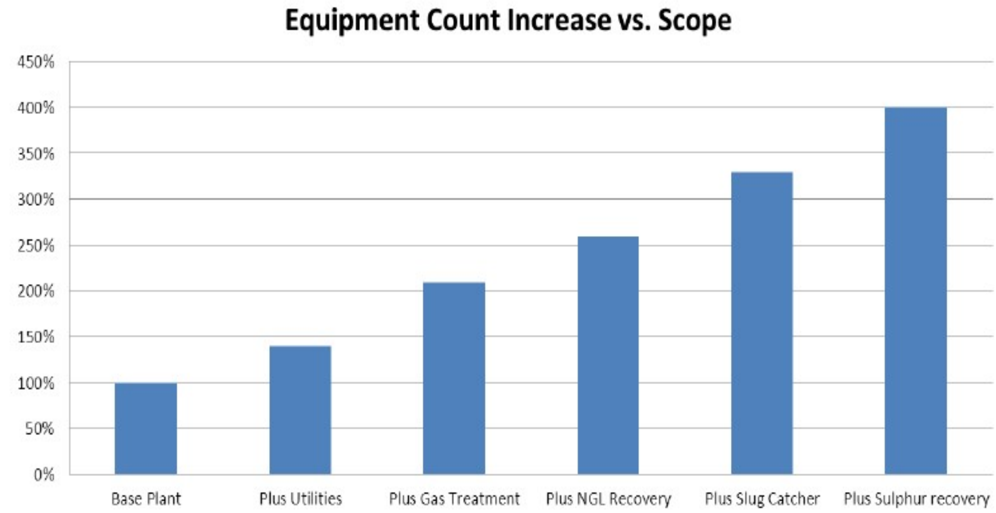
a) Project Scope and Complexity:

The project scope is a key determinant of the project costs. The plant scope and complexity may result in increasing costs by twofold or threefold for the same capacity. The project scope for a new complete facility (a 'grass roots' development) involves developing complete infrastructure – marine facilities, LNG & NGL storage tanks, a power station, construction camps etc., for the project. Whereas the addition of a liquefaction train to a facility is simply an extension of an existing project which employs most of the existing

[88] Brian Songhurst, 'LNG Plant Cost Escalation' (2014) OIES Paper: NG 83 The Oxford Institute of Energy Studies.

infrastructure already developed for the complete facility. The project scope is a crucial cost driver because the equipment count also increases considerably with the broadening of project scope. The figure below shows the increase in equipment count for variance in project scope, starting with base plant and ending with Sulphur recovery:

Figure 61. Equipment Count Increase vs. Project Scope



Source: Heinz Kotzot and others, LNG liquefaction – not all plants are created equal

The complexity of projects depends on various factors such as lack of infrastructure, remote infrastructure, multiple front-end engineering contracts (FEEDs), environmental and permitting issues. All of these factors can significantly increase costs[89].

a) **Construction Costs:**
The major drivers of construction cost is plant location, labour costs, and productivity. The construction cost can make up to 30% of the total project cost and for Australian projects, it may climb up to 50-60%. Plant location in remote areas with no infrastructure or marine facilities can also increase the cost significantly. Lastly, labour costs for a newly built liquefaction plant require a construction team of 6000-8000 for a period of 4 years, totalling up to 30 million site construction man hours.

b) **Equipment and Materials:**
The cost of equipment and material can contribute up to 30% of the total liquefaction project costs. In the main equipment section of the industry, there is limited competition with major equipment such as refrigeration compressors and their turbine drivers solely supplied by General Electric.

c) **Engineering and Project Management:**
The engineering and project management cost component generally represents 8% of capital expenditure of the project. The major contractors for the engineering and project management of a large-scale LNG plant are limited in number and are already part of the existing oil gas upstream, midstream, and downstream divisions.

d) **Owner's Costs:**
The owner's costs generally add up to 10% of the total project cost but it may vary from project to project, depending on the project scope and complexity. The major component of owner's cost comprises of the project team and support services to manage both commercial and technical aspect of the project, from project initiation to transferring to the operations department. For a major LNG project, the timescale is approximately 10 years from initial planning stage to operations.

[89] Brian Songhurst, 'LNG Plant Cost Escalation' (2014) OIES Paper: NG 83 The Oxford Institute of Energy Studies

Methodology for Analysis of Future LNG Supplies

To understand the LNG supply position and in order to estimate the volumes of LNG from around the world likely to be available for Europe in 2020 and 2025, we carried out a detailed analysis of the LNG supply position. We have prepared a database of every liquefaction facility throughout the world, giving key details on each facility. This database is recently updated (March 2017) and is therefore more update and comprehensive than any other such public data source. For each liquefaction facility, the information covers:

1. Location;
2. Project name;
3. Operators;
4. Design capacity in million tonnes, million cubic metres and GWh/day;
5. Date project built;
6. Current status (operating, under construction, speculative, cancelled);
7. FID taken or not;
8. Type (onshore or FLNG);
9. Gas supply field feeding the LNG liquefaction facility;
10. Production capacity (in million tonnes);
11. Capacity per year (in million cubic metres);
12. %age capacity;
13. Whether new capacity committed;
14. Number of trains in the facility;
15. Minimum million tonnes;
16. Maximum million tonnes;
17. Membership of OPEC;
18. Country or operators where production is supplied to;
19. Ownership;
20. Reason for delay or cancellation (for cancelled projects);
21. Supply to Europe (%age);
22. Supply to Europe (million tonnes);
23. Likelihood for project to proceed;
24. Capacity already contracted;
25. Uncontracted and available capacity.

From this database, we have consolidated the liquefaction plants into four categories:

1. Already operating;
2. FID already taken or under construction;
3. Speculative (projects under consideration but where FID has not yet been taken);
4. Cancelled (projects where a clear cancellation notice has been given).

We then carried out an analysis of all the LNG liquefaction projects to determine the volumes to be supplied to Europe. We have considered supplies to Europe under three spot dates: 2015, 2020 and 2025. The latest publicly available data are from 2016, based on 2015 data, so we have taken three spot dates with five year intervals.

In determining the volumes of LNG available for Europe from around the world, we have made the following assumptions:

2015:

As a start point, we have assumed LNG volumes supplied to Europe not as the actuals supplied to Europe in 2015 but the average of the five years 2010-2015. These are based on those plants actually operating in 2015.

Minimum supplies to Europe 2020 and 2025: The minimum volumes of LNG available for Europe in 2020 and 2025 are assumed to be the average supplies to Europe of the five years 2010-2015, based on actual operating plants.

Maximum supplies 2020: The maximum volumes of LNG available to Europe in 2020 are the sum of the minimum (average actual supplies 2015) plus all the supply from all the plants currently under construction. This is not very likely as most of the additional supply volumes will be supplied to Asian markets.

Maximum supplies 2025: The maximum volumes of LNG potentially available to Europe in 2025 are the sum of actual supplies in 2015, plus all volumes currently with FID or under construction, plus all speculative projects under development. This is an extreme maximum and not a realistic maximum. This is because the speculative category includes a large number of projects which are on hold. They are not actually officially cancelled but no project development work is taking place on them. These projects are delayed due to uncertainties over gas price or lack of contracted buyers. In reality, no LNG liquefaction project is proceeding to financing stage unless there are contracted commitments in place.

Our estimates of the most likely supply scenarios for Europe in 2020 and 2025 are therefore:

2020:

LNG volumes available to be supplied to Europe by 2020 include:

- The same volumes as supplied in the 2015 base year, namely the average of the previous five years from operating plants;
- Those projects for which construction has already started and which are expected to be operational by 2020;
- Pacific Basin supplies are excluded as they are assumed to supply Asia only;
- Of plants within the Atlantic Basin, the following further assumptions are made:
    - Supplies are made to owners (shareholders), Japanese buyers (for example) buy small shareholdings in a project but then commit to much larger proportions of outputs (50-70%);
    - The remaining (uncommitted) Atlantic Basin supplies are supplied 30% to Latin America and 70% to Europe (which was the approximate size of the South American LNG import market compared with Europe in 2015);
    - We assume Yamal LNG will be operational by end 2017, 70% of Yamal supply will be to Asia via the Arctic and 30% to Europe;

2025:

LNG volumes available to be supplied to Europe by 2025 include:

- The sum of the volumes for 2020, namely facilities operating in 2015 plus those under construction;
- A proportion of the speculative category, made up of:
    - East African region supplies (Mozambique and Yemen) are assumed to be supplied 20% to Europe.
    - 25% probability that those non-US in Atlantic Basin will proceed;
    - 75% probability for US converted Import Terminals and expansions of existing facilities;
    - 90% probability for US conversions with contracted buyers in place.

Analysis by LNG Liquefaction Project

There are certain individual LNG liquefaction projects which are worth highlighting.

Under Construction:

The following liquefaction plants are currently under construction or FID has already been taken:

Table 51. LNG Liquefaction Plants Under Construction

Country	Project Name	Design Capacity (million tonnes)	Volumes Assumed for Europe (%)	Volumes for Europe (million tonnes)
Australia	Ichthys LNG	8.4		
Australia	Prelude FLNG	3.6		
Canada	Woodfibre LNG	2.1		
Canada	Tilbury LNG	3.0		
Indonesia	Senkang LNG	0.5		
Indonesia	Tangguh	3.8		
Malaysia	Petronas Floating LNG	1.2		
Malaysia	Petronas Floating LNG 2	1.5		
Malaysia	Bintulu MLNG (Train) 9	3.6		
Mozambique	Cabo Delgado, ENI	3.4	20%	0.68
Russia	Yamal LNG	16.5	30%	4.95
USA	Sabine Pass Trains, 3, 4, 5	13.5	60%	8.10
USA	Cameron LNG	12.0	15%	1.80
USA	Freeport LNG	13.2	15%	1.98
USA	Dominion-Cove Point LNG	5.25	35%	1.84
USA	Corpus Christi LNG	9.0	65%	5.85
USA	Corpus Christi LNG	4.5	100%	4.50
USA	Elba Liquefication Project	2.5	70%	1.75
TOTAL		**104.15**		**31.45**

Source: Energy Markets Global 2017

We have assumed that all the Asian and Pacific Ocean projects will entirely supply the Asian market, with no volumes for Europe. The two Pacific Coast Canadian projects (Woodfibre and Tilbury) have had FID taken, construction has started but has been delayed. There is now some doubt as to whether these two projects will be completed before 2020. As they are dedicated to the Asian market under our assumptions however, the status of these two projects does not affect the results of our analysis.

Yamal LNG: Yamal LNG in Russia has received its first vessel as part of commissioning (March 2017), construction is ahead of schedule and operations are forecast to begin in September 2017. Europe is adequately served from Russia by pipeline gas and it is assumed that 70% of Yamal LNG will supply Asia, with 30% to Europe. This assumption is based on the makeup of the partners in the project (CNPC, Novatek and Total) and all the capacity has been sold under long term contracts.

US Plants: There are seven US LNG plants which are being converted from import regasification to export liquefaction. These are all on the Atlantic coast and are all currently under construction. As they are conversions from regasification plants the costs of construction are much less than for building a new onshore liquefaction plant. It can be assumed that these will all proceed.

Apart from Yamal LNG, all the new liquefaction capacity available for Europe is being constructed in the USA, making an additional 30.77 million tonnes LNG capacity available for Europe by 2020.

Speculative Projects:

The following liquefaction plants are in the speculative category or are where FID has not yet been taken:

Table 52. Atlantic Basin Speculative Liquefaction Projects

Country	Project Name	Design Capacity (million tonnes)	Design Capacity (GWh/Day)	Volumes for Europe (%)	Like-lihood to Proceed (%)	Volumes for Europe (million tonnes)
Canada	Atlantic Coast	4.5	187.97			
Canada	AC Phase 2	9.0	375.93			
Canada	Saguenay LNG	11.0	459.47			
Canada	Becancour	0.5	20.89			
Canada	Bear Head LNG	8.0	334.16			
Colombia	El Viajano LNG	0.5	20.89			
Russia	Sakhalin II	5.0	208.85			
Russia	Arctic LNG II	6.0	250.62			
Russia	Baltic LNG	10.0	417.70			
USA	Calcasieu Pass	10.0	417.70			
USA	Plaquemines	20.0	835.40			
USA	Monkey	12.0	501.24			
USA	Port Arthur LNG	13.5	563.90			
USA	Rio Grande	27.0	1127.79			
USA	Port Brownsville	4.0	167.08			
USA	Lousiana LNG	6.0	250.62			
USA	Annova LNG	6.0	250.62			
USA	Eagle LNG	1.0	41.77			
USA	G2 Cameron	14.0	584.78			
USA	CE FLNG	8.0	334.16			
USA	Gulf LNG	11.5	480.36			
USA	Live Oak LNG	5.0	208.85			
USA	Alturas LNG	1.5	62.66			
Equatorial Guinea	Fortuna FLNG	2.2	91.89	70%	25%	0.39
Mozambique	Anadarko-Dolphin	6.0	250.62	20%	25%	0.30
Nigeria	NLNG T 7	8.0	334.16	70%	25%	1.40
USA	Sabine Pass, 6	4.5	187.97	60%	90%	2.43
USA	Freeport LNG	5.0	208.85	10%	90%	0.45
USA	Corpus Christi	9.0	375.93	70%	75%	4.73
USA	Magnolia LNG	8.0	334.16	25%	90%	1.80
USA	Cameron-Expand	10.0	416.45	25%	75%	1.87
USA	Sabine-Golden P	15.6	651.61	70%	90%	9.83
USA	Driftwood LNG	26.0	1086.02	70%	0%	0.00
USA	Lake Charles	16.2	676.67	70%	0%	0.00
Yemen	Yemen LNG	6.7	279.86	20%	90%	1.21
TOTAL						**24.41**

Source: Energy Markets Global 2017

Of Atlantic Basin LNG projects which we have put in a speculative category, a large number are unlikely to go ahead. There are four Canadian projects, one Colombian, three Russian and 14 US projects undergoing appraisal. They are all on hold for various reasons, mostly because of low gas price or because they cannot find contracted buyers. It is assumed that none of these will be ready by 2025, if indeed they go ahead at all.

There is another group which are more likely to proceed, and which are described as follows:

Equatorial Guinea, Fortuna FLNG: This is an expansion from the existing facility in Equatorial Guinea. Nigeria has more or less missed the boat for increased LNG exports (discussed below) but Equatorial Guinea is in discussions with Nigeria to take Nigerian gas supply to feed the new FLNG facility. We have assumed that 70% of the output would go to European markets and we have conservatively given a 25% probability of this project being completed by 2025.

Mozambique: In the early years of this decade there emerged the potential for 2-4 multi-train LNG projects from East Africa, with developments in Mozambique and Tanzania both developing LNG projects from the Rovuma basin straddling the two countries. Mozambique started to pull ahead in terms of preparation. The Tanzanian LNG projects are now considered not likely to proceed. One of the Mozambique projects (ENI) reached FID in June 2017 and we conservatively give the remaining one a 25% probability of going ahead, with 20% of the gas destined for Europe.

Nigeria: In the early years of this decade, there were several LNG projects in development in Nigeria. After the successful completion of six trains, NLNG was seeking FID for Train Seven. In addition, Olokola (OK) LNG and Brass LNG were also proceeding. For various reasons, none of these projects were concluded. We consider that OK LNG and Brass LNG will not proceed and are in our cancelled category. NLNG Train Seven is more likely to proceed and we give a 25% probability of that proceeding, with 70% of the output destined for Europe.

Yemen LNG: Due to the civil war, Yemen LNG went offline in 2015. Although an operational facility, we have assigned this to the speculative category. We have assumed that Yemen LNG will become operational in the period 2020-2025. We have therefore given a 90% probability that Yemen will be operational by 2025, with 20% of supply to Europe.

These above projects in total will add only 19.6 million tonnes to global LNG supply and we assume just 2.13 million tonnes will come to Europe. So, whether assumptions are too optimistic or pessimistic, the African and Yemen speculative projects will not add much to LNG supply to Europe.

US Speculative Projects: This cannot be said for the remainder of the speculative projects. There are eight US projects in our speculative category which we consider more likely to proceed because they have already contracted buyers for most of the capacity:

- **Sabine Pass, Train 6:** FID has not yet been taken but environmental permitting is in process and is expected by end 2017. We see a 90% likelihood of Sabine Pass Train 6 being completed by 2025 with 60% of supplies available for Europe;
- **Freeport LNG:** This is an expansion to an existing project at Quintana Island and we assume a 90% probability of completing, but we assume only 10% of supplies for Europe because contracted buyers are in Japan;
- **Corpus Christi, Cameron Parish:** An expansion and we estimate 75% likelihood of proceeding;
- **Magnolia LNG:** FEED has been completed and there are contracted buyers in Asia, we assume a 90% probability of proceeding with 25% of output to Europe;
- **Cameron LNG Expansion:** We assume a 75% likelihood of proceeding with 25% of supply destined for Europe;
- **Sabine – Golden Pass:** This project is being led by Exxon and Qatar Petroleum, and given both companies ambitions to expand in LNG (particularly Qatar's strategy of diversifying away from Qatar based production), we believe there are some political drivers behind this project, making it very likely to proceed, so we therefore give it a 90% likelihood to proceed, with 70% of supply dedicated to Europe;
- **Driftwood LNG** and **Lake Charles LNG:** Although FEED has been completed, we do not believe there are the drivers behind these two projects as for the others previously described. We do not believe these two will be completed within the timescale of 2025.

Altogether we estimate 25 million tonnes from these speculative projects will be added to LNG supply for Europe by 2025, most of which, 23 million tonnes, will come from the USA.

We foresee very large volumes of US LNG coming to Europe over the next 5-10 years, 31 million tonnes currently under construction plus another 25 million tonnes not yet in FID stage, making a total 56 million tonnes (2339 GWh/Day) by 2025, a very significant volume.

Another factor to consider with the US projects is that while LNG prices globally have fallen (most dramatically in Japan), LNG prices are still higher internationally than Henry Hub US gas prices. Considering the relatively low costs of converting a US import to an export terminal (low in comparison with the costs of a new onshore greenfield liquefaction plant), and the higher prices US exporters will be able to find overseas compared with US Henry Hub pricing, the factors deterring LNG new liquefaction projects around the world are likely to have less on an impact on US gas exporters.

Algeria: We have discussed the very large volumes which we foresee coming from the USA but against that, the position of Algeria is likely to deteriorate. Engineers have been struggling to maintain wellhead pressures for some years. Algerian gas supplies are past their peak. In addition, the Algerian domestic market has been growing. In the future, Algeria will struggle to maintain current levels of export supplies or may see declines in gas production, unless there are policy and investment changes.

Following the analysis described above, our estimates of the most likely level for LNG supplies to Europe are set out in the table below. We estimate **87 mt** (1309 TWh) by **2020** and **113 mt** (1702 TWh) by **2025** is available for Europe. This is based on our estimate of the supply position of each individual LNG liquefaction project.

Asia LNG Market and Supply

This is not the whole story though. A key assumption in our above analysis has been that all Asian supply will service the Asian market. In addition, we have assumed that all those cargoes from Atlantic Basin producers contracted to Asian buyers will be delivered 100% to those Asian buyers. These assumptions assume that Asian markets will be able to absorb all the gas that is being thrown at it. This is unlikely to be the case however.

The IEA believe that the three top Asian importers (China, Japan and South Korea, who together account for over 55% of global LNG trade) have turned from a short position of around 40 bcm in 2011 to a long position of around 20 bcm in 2017-18[90]. This 20 bcm equates to around 14 million tonnes. In addition should be considered the 12 million tonnes of Australian LNG (Ichthys LNG and Prelude FLNG) that will be available from 2018 and there can be seen a supply overhang of some 26 million tonnes in Asia.

This additional supply will most likely lead to (1) Qatar LNG being diverted from Asian to European markets; and (2) US LNG that is contracted to Asian buyers will be released to secondary markets and marketed to Europe.

By 2025 therefore Europe could see some 113 million tonnes (1702 TWh) of LNG supply from Atlantic Basin suppliers plus an additional approximately 26 million tonnes (393 TWh) diverted from previous supply to Asian markets. These are very approximate figures because they do not take account of potential large increases in LNG demand from emerging markets in the Asia region.

[90] Gas Medium Term Market Report 2016, Market Analysis and Forecasts to 2021, IEA, Are LNG buyers over contracted, p.104

Decline in Existing Production

Another set of factors to consider is regarding declines in existing production. We have assumed that existing producers will not increase production but will be able to maintain their existing production for the time horizon of the next ten years.

It is not clear though that this is the case. Qatar will probably maintain existing production from the existing onshore fields and existing levels of LNG exports but this is far from certain. Even more uncertain is the extent to which Algeria will be able to maintain existing levels of exports. Well head pressures have been falling in Algeria for at least the last ten years and gas is increasingly being reinjected so as to maintain existing levels of oil production. Algeria may be prioritising oil production over gas production. In addition, domestic gas demand within Algeria is increasing significantly. There are therefore pressures on the ability of Algeria to maintain existing levels of gas exports to Europe. This is certainly the view of some of the industry participants to this study.

ANNEX 9. CONTRACTS

Introduction

There are certain similarities among many asset based businesses, such as:

- Requirements for considerable capital investment into fixed assets;
- Investments from a mixture of equity and long term loan financing;
- The large investments required mean that only very large companies can be involved;
- Investment returned to the investors plus a return over a long time (years or decades);
- Profit based on a rate of return on assets, often regulated by regulator or contract;
- Assets have to be built to handle peak periods of demand, meaning that on average some capacity is lying idle.

This applies to, for example, airports, hospitals, utilities (gas, water, electricity, telecommunications), pipeline companies, oil and gas production companies, and LNG businesses (liquefaction, regasification and shipping).

The similarities apply to contractual arrangements as well. This means that essentially, very similar terms and contractual approaches can be found in petroleum development, pipeline and LNG contracts for liquefaction and for regasification. This section will describe the similarities in contracts for LNG and gas projects, then discuss the key differences.

Oil, Gas and LNG Contracts

LNG and gas projects require different types of contract at different stages of the project development[91]. The four contractual structures that have been adopted comprise:

- Production Sharing Contracts (PSCs) or Production Sharing Agreements (PSAs);
- Joint ventures;
- Licences;
- Concession contracts;
- Service contracts.

LNG projects under licences include Qatar, Australia and USA. Those under PSCs/PSAs include Indonesia, Malaysia and Angola. Nigerian oil, gas and LNG projects are under JVs (although many oil and gas projects are increasingly moving to PSCs).

LNG contracts, as with other oil and gas contracts, involve different agreements over the process of the lengthy multi-year negotiations that are needed for such large capital investments. These are all documents developed in progression of detail as the negotiations develop. They include:

- Term sheet;
- Letter of Intent (LOI);
- Memorandum of Understanding (MOU);
- Heads of Agreement (HOA).

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[91] The following is partly taken from EMG proprietary work and from Understanding Natural Gas and LNG Options, November 2016 (reprinted February 2017), Power Africa, "Understanding" series, 3rd volume

Gas Sales Agreement

The Gas Sales Agreement (GSA) or Gas Sales and Purchase Agreement (GSPA) is a standard contract in the gas and power industries. Although there are many different types of GSA, reflecting the many different uses to which it is put, there are standard conditions which are found in most GSAs. These following terms are to be found in any standard GSA, whether gas or LNG:

- Table of Contents;

1. Definitions and Interpretation;
2. Duration, Start Date and Conditions;
3. Obligations;
4. Commitment – Take or Pay
5. Facilities;
6. Contractual gas issues:
    1. Gas Reserves;
    2. Gas Quantities;
    3. Commissioning Gas;
    4. Excess Gas;
    5. Take or Pay;
    6. Make Up Gas;
    7. Carry Forward Gas;
    8. Make Good Gas;
    9. Undertake Gas;
    10. Overtake Gas;
    11. Quality and Off-Specification Gas;
    12. Shortfall Gas;
    13. Nominations and Deliveries;
7. Contract Price;
8. Invoicing and Payment;

20. Other provisions:
    1. Title and Risk;
    2. Taxes;
    3. Buyer’s Guarantee;
    4. Seller’s Reservations;
    5. Measurement;
    6. Maintenance;
    7. Force Majeure;
    8. Relief of Hardship;
    9. Liabilities and Limitations;
    10. Transfers and Control;
    11. Termination;
    12. Confidentiality;
    13. Dispute Resolution:
        a. Arbitration;
        b. Expert Determination;
    14. Insurance;
    15. Exclusivity;
    16. Notices;
    17. Warranties and Representations
    18. Representatives;
    19. General;
    20. Applicable Law and Process;

- Schedules

The same basic format applies to Gas Transport Agreements (GTAs) as well, with certain modifications. The key commercial terms in a GTA are:

1. Parties to the contract - Gas Shipper, Transporter;
2. Delivery:
    a. Entry point, Exit point, Volumes;
    b. Quantities and Capacities;
3. Transporters and Shippers obligations;
4. Term and effectiveness;
5. Ship or Pay provisions;
6. Tariff – Capacity and Commodity payments;
7. Fuel supply- Conmingling, Allocation, Attribution;
8. Key legal provisions.

Commitment: In general terms, under and SPA the seller commits to sell and the buyer commits to buy. Commitment is an important issue, whether the buyer will take a firm take or pay commitment under which they are required to pay for supply even if they are unable to accept delivery, or a softer reasonable endeavours obligation.

Pricing: Pricing of gas to the liquefaction plant may depend on the structure of the LNG chain, whether it is integrated, merchant or tolling. The price may be indexed, may be fixed, with or without escalation, or may follow an external marker (hub pricing). If the structure of the LNG export project is integrated, there is generally not a transfer price between the upstream and the LNG plant for the gas feeding the plant. The domestic gas price may also be fixed and/or regulated or negotiated between buyers and sellers.

Payment: Gas sales for exported LNG are usually priced in US Dollars but domestic gas sales are usually priced in the local currency, which can give rise to currency fluctuation risks.

LNG Sale and Purchase Agreement (LNG SPA)

The LNG SPA is the cornerstone for the LNG project and brings the liquefaction plant to the regasification terminal. The LNG SPA has many features in common with any other type of gas project SPA, as described above. There are some peculiar features relevant to LNG SPAs though. The main points are:

Terminal: Probably the main difference between an LNG SPA and another type of SPA is in relation to mechanisms for delivering gas feedstock into the liquefaction facility and into the regasification terminal. The contractual difference between LNG and other petroleum contracts shows up most clearly in the provisions for terminal access.

Commitment and Take or Pay: As in any other SPA, the seller commits to sell and the buyer commits to buy. The elements of the commitment for an LNG SPA are term, transportation, volume, level of commitment and ability to divert LNG supplies.

LNG SPAs are almost always based on a take or pay commitment, where the buyer agrees to pay for the committed volume of LNG, even if it is not taken. In most TOP clauses, there is some flexibility, where the buyer can flex his requirements up or down by a certain amount and is allowed make up gas later. Historically, LNG TOP clauses however have been very restrictive, in effect allowing no (or hardly any) deviation from the contracted quantity. Where the SPA does provide for certain permitted changes to the committed volumes, the flexibility is quite small and for very specific reasons, such as for volumes not delivered due to force majeure, due to the seller's failure to make them available, or which are rejected for being off specification.

Some LNG SPAs now are starting to use a more traditional TOP structure where there is more flexibility in turning up or down volumes within a permitted range and with make up gas later allowed, where small take or pay banks are allowed. In these cases, the SPA can use a **Mitigation Mechanism**, whereby for cargos not taken by the buyer the seller can sell elsewhere, for example on a spot market. The seller then charges the buyer for any reduction in price between the contracted and the spot price, plus costs involved in the new sale. The buyer may still be liable to charges but these would be far less than the costs of meeting an inflexible TOP commitment.

Similarly, in a shortfall situation, where the seller does not deliver the full commitment, the seller can limit their exposure to something less than full damages. Often the seller will be responsible for a shortfall amount calculated as a negotiated percentage (15%-50%) of the value of LNG not delivered, with this amount paid either in cash or as a discount on the next volumes of LNG delivered.

Volume: The SPA specifies the volume of LNG that the seller must deliver, and the volume the buyer must take, each contract year, and provide a process for scheduling and delivering this volume in full cargo lots. As described above, there is sometimes some small flexibility in volume delivery but these are quite small and for specific reasons.

Term: Historically, LNG SPAs have been long-term contracts with terms of over 20 years. Together with firm commitments to buy from buyers, long-term contracts were demanded by the financiers and so have been a requirement on the seller and the buyer to justify the significant investments required. The majority of the throughput of the liquefaction plant needs to be tied into these long-term contracts to enable the developer to secure project finance. Long-term SPAs are needed to secure financing. Shorter term contracts (up to five years) are being secured for a small proportion of throughput and an LNG spot market is growing but long-term SPAs for the majority of volumes are needed to secure financing.

Transportation and Discharge: There are two basic ways in which LNG can be supplied:

- **Free On Board (FOB):** Where the buyer takes title and risk at the liquefaction facility and is responsible for transportation of the LNG. The buyer is responsible for shipping, insurance, unloading, regasification, duties and taxes, and other costs and responsibilities. Risk is transferred from seller to buyer at the ship's rail at the port of shipment (where the LNG is loaded onto the ship at the liquefaction plant);
- **Cost, Insurance and Freight (CIF):** Where the seller is responsible for delivering the LNG to the tanker at the liquefaction plant. The seller retains title and risk until delivery and is responsible for the costs of transportation to the destination (insurance and freight). Title and risk are transferred at the port of destination when the LNG is made available for unloading to the buyer. In the LNG industry, this CIF method is called **Delivered at Terminal (DAT)** or **Delivered at Place (DAP)**. The terms DAT and DAP replace the former terms **Delivered Ex-Ship (DES)** terminology. Although many in the industry still refer to DES, the term was removed from INCOTERMS in January 2011.

Destination and Cargo Diversions: Destination clauses in long-term LNG supply contracts forbid buyers from reselling a cargo outside the country where they are established. Traditionally, most LNG SPAs included restrictive destination clauses. These clauses specified the destination the cargo would go to and would not permit delivery to a different destination. Recent LNG SPAs contain the right to divert a cargo to a different market, particularly those to Europe where destination clauses are forbidden under EU Treaty.the Third Package of EU gas and electricity Directives have forbidden destination clauses. Cargo diversions are diverted for a number of reasons, often because the parties believe a better price can be obtained from diversion, but it could also be for other reasons, technical for example, such as if the receiving terminal is not able to receive the cargo for some reason. The party diverting the cargo (the seller) will have to bear the costs associated and compensate the buyer under a Mitigation Mechanism as described above.

The seller may still be liable to charges but the seller could take a commercial view that these charges are less than the additional revenue from the sale to a third party. Non-avoidable costs, such as receiving terminal costs, pipeline tariffs or consequential damages for missed natural gas sales, need to be covered. The two parties may also share in the additional profit from the diversion sale. US cargoes are already destination free and this new flexibility is likely to have a wider impact around the industry.

Price: LNG is priced through different price mechanisms. The main different approaches are between a reference market price (a hub price) and an indexed, usually indexed to some basket of oil prices.

Technical: Technical provisions in an LNG SPA include provisions on minimum and maximum specifications for LNG (including heating value and non-methane components), measurement and quality testing of LNG, LNG vessel specifications and requirements, receiving terminal specifications and requirements and provisions for nomination and scheduling of cargos. They also cover how LNG of different specifications can be accommodated in the receiver terminal storage tanks, whether blended or stored in separate tanks.

Miscellaneous: In addition to the key components as discussed above, an LNG SPA includes all the other provisions typically found in an SPA. They can include:

- Definitions and interpretation;
- Conditions precedent;
- Transfer of title and risk;
- Provisions for invoicing and payment;
- Currency of payment;
- Security for payment, including prepayment, standby letters of credit and parent company or corporate guarantees;
- Taxes, charges and liabilities;
- Force majeure;
- Confidentiality;
- Dispute resolution through international arbitration;
- Termination;
- Governing law.

Other LNG Agreements

There are other agreements that can make up an LNG project, depending on the structure selected. Although the details differ, these agreements apply to other oil and gas projects as well as LNG. They include:

Project Enabling Agreement: Unless specifically authorised by legislation or regulations, a liquefaction project will require some sort of project enabling agreement between the host government and the project sponsors, which describes in detail:

- The scope of the project to be undertaken;
- The legal tax regimes applicable, including any tax incentives or exemptions;
- Ownership of the project, including any reserved local ownership component;
- Governance and management;
- Fiscal requirements applicable;

- Local content requirements and procurement procedures applicable;
- Any government assistance including acquiring land, licenses and permissions;
- Any special local terms and provisions.

Shareholders Agreement: If an incorporated Special Purpose Vehicle (SPV) is to be used, the agreement of the shareholders regarding governance and management needs to be set out in a Shareholders Agreement. The Shareholders Agreement complements and expands on the Articles of Incorporation or other constitutional documents of the SPV.

EPC Contracts: The Engineering, Procurement, and Construction (EPC) contract(s) for construction of all assets, the upstream, liquefaction and regasification facilities will need to be negotiated and agreed.

Financing Agreements: Invariably, project financing is used and a large number of financing and security agreements need to be agreed.

The following are some examples of other agreements which specifically apply to LNG:

Transportation Contracts: Either the seller or the buyer need to contract for LNG shipping to transport from liquefaction to regasification. The party (seller or buyer) can either provide their own the LNG vessels or they can charter. In reality, even large LNG ship owners (such as Shell Shipping for example) themselves charter many of their vessels. When BG (before it was acquired by Shell) first entered the LNG business, it acquired two LNG ships and immediately chartered them out on long term agreements (the purpose of this was for BG to start to learn the LNG shipping business in a low risk manner). In the ownership model, an LNG shipbuilding agreement is required. If chartered, the ship charter typically is one of:

- Bareboat charter (charterer provides crew and fuel);
- Voyage charter (owner provides crew and fuel for a single voyage); or
- Time charter (owner provides crew and fuel for a set period of time).

Facilities Sharing Agreement (FSA): This applies to LNG complexes with multiple LNG trains and differing ownership between trains. When any new train is built, in addition to the cost of the train itself, the new entrants are required to enter into facilities sharing agreements. These provide for payment of their share of common facilities, such as LNG storage, power generation and LNG berths, for example.

Liquefaction Agreement: If a tolling structure is selected, the liquefaction tolling entity needs a contract outlining the services to be performed, the tolling fee structure for such services and other provisions regarding risks, etc. with the natural gas customer. This Liquefaction Agreement is also called a **Liquefaction Agreement** or **Tolling Agreement**.

Gas Feedstock Agreement: If a merchant structure is selected, the merchant liquefaction entity needs to purchase the natural gas to be liquefied in the liquefaction facility. The main issues in a gas feedstock agreement are:

- Transfer price for the gas, typically with the seller wanting a netback price and the liquefaction entity wanting a fixed price;
- Liability of the gas supplier for any shortfall in deliveries, with the gas supplier wanting to limit liability and the liquefaction entity wanting a passthrough of its LNG SPA liabilities.

Terminal Use Agreement: As discussed above, the need for provisions regarding access to terminals is the key distinguishing feature of the LNG business contractually. Terminal use agreements therefore are key in an LNG regasification project.

Main Differences for LNG Contracts

Following the analysis of contractual terms and from interviews with a number of industry players, the key features of LNG and LNG contracts which are restricting flexibility can be summarised:

LNG comes in Cargoes not in a Flow: Unlike with pipeline oil or gas contracts, LNG comes in cargoes not in a flow. Those who defend the generally more restrictive nature of LNG contracts argue the fact that is comes in discrete cargoes rather than a constant flow as the main difference. Scheduling cargoes into terminals, both receiving and delivering terminals, requires much more attention than with liquid oil or gaseous natural gas. Lead times are needed which have to be negotiated and incorporated into the SPA. Oil also comes in cargoes but it is much easier to wheel an oil cargo through a reception terminal than with LNG, which means there is considerable more expense involved with LNG.

Terminals: The cargo nature of LNG means that the biggest difference between an LNG SPA and another type of petroleum SPA is regarding terminals. There are many clauses related to terminal access which apply only to LNG.

It is true that the cargo nature of LNG and the need to schedule cargoes several weeks in advance is unique to LNG. Combined with the very capital intensive nature of LNG, this can lead to some inflexibility. While there is a point in this, we do not believe this really explains all of the inflexibility found in much of the LNG business.

Destination Clauses

There was, perhaps, in the early stages of the industry, a reason for putting destination clauses into LNG contracts. Because of the boil off nature of LNG, cargoes need to be in transit for as short a time as possible. Traditionally, buyers, sellers and financiers all needed to know that when a cargo left the liquefaction terminal, it would go directly to a regasification terminal without delay and with a guaranteed reception. In the early days of the LNG industry, when there was no spot market to send cargoes to, it perhaps made sense for both parties to agree to destination clauses so as to minimise risk and attract the project financing.

It is not so clear now though why destination clauses have been maintained, except perhaps for a certain inertia in the industry. According to EU competition rules, destination clauses are anti-competitive and for this reason they have already been removed from some contracts for LNG sales to Europe. They are now less prevalent for LNG sales in the Atlantic Basin because of regulatory action in Europe, which is likely to be supported by the generally more market oriented nature of US LNG sales. Destination clauses do continue to be applied though to many LNG SPAs in Asia and the Pacific Basin.

Inflexible Take or Pay Provisions

Traditionally, LNG contracts have allowed very little flexibility indeed. Take or Pay contracts do allow some flexibility. Even if there is a long term commitment to buy, take or pay contracts typically allow buyers and sellers some flexibility to turn up or down volumes within a range, with make up gas allowed to recover any deficit, or take or pay bank, later. LNG contracts traditionally have not allowed even that and have been very inflexible indeed. For much of the industry, moving to a traditional take or pay contract would in fact introduce more flexibility.

Because of the cargo nature of LNG and the complications around scheduling access to terminals, as discussed above, it has been more difficult to introduce supply flexibility into LNG compared with pipeline gas. An undersupply in a cargo is simply wasted capacity and is not as easy to make up.

Nevertheless, more flexibility can be and is being introduced now because of the increasing number of options for LNG sellers. These include:

- Spot cargo sales;
- Cheaper regasification through FSRUs;
- LNG storage;
- Ship to ship bunkering;
- Mini LNG, milk rounds and other small scale LNG sales.

These are all examples of how a seller has options other than solely a sale direct to the contracted buyer at the nominated destination point. It should be possible therefore to introduce more flexibility to LNG contracting through encouraging more flexibility in TOP terms.

Non-Standardised Contract

Another difference between the LNG industry and other energy businesses is the lack of a standardised contract. The argument is that oil trading benefits from the use of a single standardised contract and the lack of one has held back LNG trading. The case study of the UK pipeline gas industry liberalisation shows that NBP trading benefited hugely from the introduction of a single hub trading contract, and what is more, from a simple contract (it is just six pages, and basically it simply obligates parties to abide by the network code).

While it is certainly true that oil and gas trading have benefited from use of a single standardised contract, there are a couple of caveats to this.

One is that it is not actually correct that there is a single oil trading contract. Although they are very similar, in reality, each major producer tends to impose their own contract. Each of the major IOCs have their own oil trading contract which they impose. So for example, Brent, which is the main oil trading price marker, operates on the BP contract.

The second point is that, as has been shown above, there are similarities among all LNG contracts. The SPAs described above use a common set of terms and approaches.

In addition there are two standard template LNG contracts available, even if they are not commonly used throughout the industry. Model short term contracts have been produced and are available by:

- International Group of Liquefied Natural Gas Importers / Groupe International des Importateurs de Gaz Naturel Liquéfié (GIIGNL);
- Association of International Petroleum Negotiators (AIPN).

While both contract templates are international and can be applied anywhere in the world, the GIIGNL is more European and the AIPN is more American slanted.

Lack of National Regulatory Authority

An important difference between pipeline gas trading (such as at Henry Hub, NBP, TTF or others) and LNG trading is that pipeline gas trading hubs lie within national boundaries and jurisdictions and can be regulated. The UK gas market liberalisation shows that the regulatory push was fundamentally important for the emergence of the British gas trading model.

This cannot be done in the same way with LNG because LNG is a global business. Some parts of the LNG business can be regulated, such as terminal access (such as regulating

TPA to LNG regasification terminals) but the rest of the LNG business is outside any single national jurisdiction.

Unlike pipeline gas which is a national or regional business, the global nature of LNG means that many legislative or regulatory tools are not available.

GIIGNL LNG Template Contract

Although as has been discussed, there is no standard LNG contract in general use, two model contract templates are publicly available. While long term LNG contracts can be very long and detailed, requiring considerable negotiation and drafting, standard or template Master SPAs can become more relevant and useful for short term supplies, where an agreement can be reached for each single cargo. For short term agreements and single cargo loads, there is a need for a Master SPA that can be easily adapted for each situation. The GIIGNL publish two types of template contract for LNG deliveries, which are particularly applicable for short term agreements:

- Master FOB LNG Sales Agreement (buyer responsible for shipping);
- Master Ex-Ship LNG Sales Agreement (seller responsible for shipping);
- LNG custody transfer handbook, 5th edition 2017.

LNG Custody Transfer Handbook:

The LNG custody transfer handbook is not a model contract. It is more of a reference manual to assist with procedures and equipment to determine the energy quantity of LNG transferred between LNG ships and LNG terminals. It is sets out practical issues and requirements to guide and facilitate a skilled operator team to work out a suitable procedure for a specific LNG ship-shore custody transfer application.

The two template LNG sales agreements contain standard terms to be expected in an LNG sales and purchase agreement. The key clauses of the two GIIGNL LNG sales agreements are shown below and compared (the main differences in clauses are highlighted, which cover loading / unloading and seller’s/receiver’s facilities):

Table 53. Master FOB and Maseter Ex-Ship templates comparison

Master FOB LNG Sales Agreement:	Master Ex-Ship LNG Sales Agreement:
1. Definitions and interpretation	1. Definitions and interpretation
2. Sale and purchase	2. Sale and purchase
3. Quantity and loading schedule	**3. Quantity and unloading schedule**
4. Quality	4. Quality
5. Shipping and seller's facilities	**5. Shipping and receiving facilities**
6. Ship movement and loading	6. Ship movement and loading
7. Measurement, sampling and testing	7. Measurement, sampling and testing
8. Transfer of title and risk	8. Transfer of title and risk
9. Price and payment	9. Price and payment
10. Taxes and charges	10. Taxes and charges
11. Permissions and approvals	11. Permissions and approvals
12. Force majeure	12. Force majeure
13. Limitation of liability	13. Limitation of liability
14. Governing law and arbitration	14. Governing law and arbitration
15. Safety	15. Safety
16. Term	16. Term
17. General	17. General
18. Annexes:	18. Annexes:
a. Confirmation notice	a. Confirmation notice
b. Measurement and testing	b. Measurement and testing
c. Letter of credit	c. Letter of credit
d. Parent guarantee	d. Parent guarantee

Source: GIIGNL

Master FOB LNG Sales Agreement:

The following does not attempt to describe the agreement in full but it sets out some of the key features.

1. Definitions and Interpretation:

"Delivery Point" means the point of loading of LNG at the relevant Seller's facilities where the outlet flanges of the loading lines of the relevant LNG Vessel connect with the inlet flanges of the loading lines at the relevant Seller's Facilities.

"Title Transfer Point" means the point in international waters which is the last point where the LNG Vessel is outside the territorial waters of the country where the relevant loading port is situated.

"Full Cargo Lot" means a cargo of LNG that is the maximum quantity the relevant LNG Vessel can safely load and transport (within the operational tolerances established by the captain of the LNG Vessel and the operator of the Loading Port).

2. Sale and Purchase:

The seller agrees to sell and delivery, and the buyer agrees to buy and take delivery, one a "Confirmation Notice" has been signed by both parties in respect of a specific quantity of LNG. LNG shall be sold and purchased in "Full Cargo Lots" unless otherwise specified in the applicable Confirmation Notice

3. Quantity and Loading Schedule:

If a vessel arrives for loading within its agreed timeslot, it has priority over any other LNG vessels there.

If the buyer cannot take a cargo, parties use reasonable endeavours to reschedule, buyer paying reasonable costs. If parties are unable to reschedule, then the quantity not taken is a "Deficiency Quantity", which seller sells to a third party and buyer pays seller for any losses incurred (seller keeps any profits if third party sales at a higher price). If seller cannot sell, then buyer is liable for value of full amount as liquidated damages.

The same applies in reverse. If the seller is unable to or fails to deliver, the parties use reasonable endeavours to reschedule, seller paying reasonable costs. If the parties are unable to reschedule, then the buyer may refuse to accept the shipment and is paid liquidated damages of the "Cargo Underdelivery Amount" which is the amount of any losses from buying LNG from another source at a higher price, times a percentage (to be negotiated between the parties).

4. Quality:

LNG is to be delivered according to the "Specifications" laid out in the confirmation notice. If "Off Spec LNG" is to be delivered (having been tested), the buyer may reject it or if the buyer may agree to accept it, provided that the Master of the LNG vessel determines it can be transported. If the seller agrees to pay the "Estimated Treating Costs", the off spec LNG is delivered to the buyer. If the seller does not accept the estimated treating costs or if the buyer does not accept the off spec LNG, then the seller is liable for a cargo underdelivery amount.

5. Shipping and Seller's Facilities:

Under an FOB agreement, the buyer is responsible for maintaining the LNG vessel according to international standards and the seller has the right to inspect the buyer's shipping. The seller is responsible for maintaining the seller's facilities and the buyer has the right to inspect.

6. Ship Movement and Loading:

The buyer ensures the seller is notified of the LNG vessel's Estimated Time of Arrival ("ETA") upon departure and at regular intervals until arrival at the seller's facilities. The buyer's vessel is responsible for safe anchorage. The seller is responsible for transfer of the LNG to the vessel. The buyer is then responsible for the safe and expeditious departure of the vessel after it has been filled. The buyer may use a different vessel from that in the confirmation notice provided that the replacement vessel is compatible with the seller's facilities. "Used Laytime" is the time used in loading the vessel. If the used laytime exceeds that laid out in the confirmation notice, the seller pays demurrage charges to the buyer at the rate agreed in the confirmation notice. If there are delays, the seller shall also pay the buyer for boil off losses.

7. Measurement, Sampling and Testing:

The buyer shall install equipment for measuring the LNG, including the LNG Vessel's "Custody Transfer Measurement System" ("CTMS"). The seller measures before and after loading in accordance with the LNG custody transfer handbook and issues a "Loaded Volume Certificate" and a "Quality Certificate". Not less than one week before loading, an "independent surveyor" is appointed to witness the measurement, sampling and testing. If the parties fail to agree on the expert, either party can ask the International Chamber of Commerce's International Centre for Expertise to appoint the Expert.

8. Transfer of Title and Risk:

Title and risk in each cargo loaded under this Agreement pass from the Seller to the Buyer as the LNG passes the Delivery Point, at the seller's facilities. For supplies from the USA, title transfer takes place at the title transfer point (which is in international waters).

9. Price and Payment:

The "LNG Price" is as determined in the confirmation notice. The amount payable by the buyer is the LNG price times the quantity delivered. Payment is made a negotiated number of days after receipt of an invoice and is paid by bank transfer in US Dollars or Euros. If an invoice is disputed, the amount not in dispute is paid and the disputed amount paid once the dispute is resolved. Late payments attract interest at an agreed percentage plus LIBOR.

If the buyer does not have a credit rating of at least BBB+ or equivalent, the seller can request from the buyer either an irrevocable letter of credit or a parent company guarantee.

10. Taxes and Charges:

All taxes in the receiving facilities' country shall be borne by the buyer, except for taxes associated with the seller's premises in the receiving country. All taxes in the seller's country shall be borne by the seller, except for taxes associated with the buyer's premises in the dispatching facilities' country.

11. Permissions and Approvals:

Each party is responsible for obtaining their relevant permissions and approvals.

12. Force Majeure:

"Force Majeure" includes but is not limited to:

a) Compliance with an act, order or demand of authority or agency;
b) Natural events, Acts of God, shipwreck, navigational and maritime perils;
c) War, riot, civil war, piracy, blockade, insurrection, quarantine restriction;
d) A strike or any other kind of labour dispute;
e) Any circumstances relating to loading which affect the ability of the Seller to deliver;
f) Any circumstances relating to unloading or transportation, which affect the ability of the Buyer to receive, unload or use the LNG.

13. Limitation of Liability:

Liabilities of either Party are limited to direct costs, losses or damage. Neither Party is liable for any consequential losses.

14. Governing Law and Arbitration:

Governing law is in accordance with the laws of England and Wales.

Any "Dispute" which cannot be resolved in good faith within sixty days shall be finally settled by arbitration in accordance with Arbitration Rules then in force (such as with the ICC). Unless the parties agree on one arbitrator, there shall be three arbitrators, one each appointed by the buyer the seller pursuant to the rules, and the third appointed by the first two arbitrators. Any award shall be final and binding upon the parties concerned.

15. Safety:

The parties shall maintain high standards of safety in accordance with generally accepted standards prevailing in the LNG industry. The parties shall use reasonable endeavours to ensure their employees, agents, contractors and suppliers have due regard to safety and abide by the relevant regulations.

16. Term:

The Agreement is in force from the date first set out and remains in force until terminated by either party in accordance with this clause. Either party may terminate this Agreement by giving an agreed number of days' written notice to the other party. If a Confirmation Notice has been executed by the Parties and not fully performed, the termination only becomes effective once all obligations have been satisfied.

17. General:

This covers contact details and how information or notices are to be passed from one party to the other party. Neither party may assign their rights without written agreement from the other party.

Annexes:

Template form of notices are attached covering:

a) Confirmation notice;
b) Measurement and testing;
c) Letter of credit;
d) Parent guarantee.

Master Ex-Ship LNG Sales Agreement:

The template Ex-Ship agreement is similar to the FOB agreement. This section highlights the main differences between the two.

1. Definitions and Interpretation:

"Delivery Point" means the point of unloading of LNG at the relevant Receiving Facilities where the outlet flanges of the unloading lines of the relevant LNG Vessel connect with the inlet flanges of the receiving lines at the relevant Receiving Facilities.

3. Quantity and Unloading Schedule:

If a cargo arrives within its agreed timeslot, it has priority over any other LNG vessels there.

The terms relating to failure to receive or to deliver a cargo are the same as with the FOB agreement.

5. Shipping and Receiving Facilities:

The seller is responsible for the LNG vessel and its safe and effective operation. The buyer is responsible for maintaining the receiving facilities.

6. Ship Movement and Unloading:

The seller shall ensure that the LNG Vessel gives the buyer and the operator of the receiving facilities notice of its estimated time of arrival ("ETA") at regular intervals and on arrival.

7. Measurement, Sampling and Testing:

The seller shall install equipment for measuring the LNG, including the LNG Vessel's "Custody Transfer Measurement System" ("CTMS"). The seller notifies the buyer of measurement results and provides an "Unloaded Volume Certificate".

AIPN LNG Template Contract

The Association of International Petroleum Negotiators (AIPN) have also produced a model template Master LNG Sale and Purchase Agreement (Combined Buyer Delivery Sales and Seller Delivery Sales). The model contract consists of a standard set of articles:

1. Definitions and Interpretation;
2. Scope;
3. Term;
4. Sale and Purchase;
5. Quantities;
6. Quality;
7. Price;
8. Invoices and Payment;
9. Credit Support;
10. Taxes, Duties and Charges;
11. Measurement and Testing of LNG and Vaporized LNG;
12. Liabilities;
13. Force Majeure;
14. Notices;
15. Governing Law and Dispute Resolution;
16. Termination;
17. Amendment and Waiver;
18. Confidentiality;
19. Assignment;
20. Representations and Warranties;
21. Business Practices and Foreign Corrupt Practices Act;
22. Miscellaneous;

Exhibits:

a. Form of Confirmation Memorandum;
b. Seller's Facilities, Transportation and Loading – Buyer Delivery Sales;
c. Buyer's Facilities, Transportation and Unloading – Seller Delivery Sales;
d. Measurement and Testing Procedures;
e. E1: Letter of Credit;
e. E2: Guarantee;
f. Offshore Title Transfer.

Article 1. Definitions and Interpretation:

1.1 Definitions

1.2 Interpretation

1.3 Rounding

"Buyer Delivery Sale" means a sale where the title and risk of loss of LNG transfers from the Seller to the Buyer at a Delivery Point at the Loading Port and the Buyer is responsible for transporting and insuring LNG from the Loading Port to the Unloading Port.

"Confirmation Memorandum" means each document executed by a Seller and a Buyer substantially in the form contained in Exhibit A and incorporating the provisions of this MSA (as such provisions may be amended, deleted, or supplemented by such Confirmation Memorandum) to record the terms and conditions of a particular sale and purchase of LNG.

"Delivery Point" means: (1) in respect of a Seller Delivery Sale, the point at the Unloading Port at which the flange coupling of the LNG receiving line of Buyer's Facilities connects to the flange coupling of the LNG discharging line of the LNG Tanker; and (2) in respect of a Buyer Delivery Sale, the point at the Loading Port at which the flange coupling of the LNG loading line of Seller's Facilities connects to the flange coupling of the LNG loading line of the LNG Tanker.

"Seller Delivery Sale" means a sale where the title and risk of loss of LNG transfers from the Seller to the Buyer at a Delivery Point at the Unloading Port and the Seller is responsible for transporting and insuring LNG from the Loading Port to the Unloading Port.

"Title Transfer Point" is where title and risk is transferred from seller to buyer and is at the last point where the LNG tanker is entirely outside the territorial waters of the buyer's country.

Article 2. Scope:

2.1 Requirement for a Confirmation Memorandum

2.2 Buyer Delivery Sales and Seller Delivery Sales

2.3 Rights of Affiliate

A "Confirmation Memorandum" needs to be signed by both parties for sale and purchase of each cargo of LNG.

Article 3. Term:

3.1 Term of MSA
3.2 Term of Each Confirmation Memorandum
3.3 Certain Rights and Remedies

The Agreement remains in force until a) a certain date has been reached; and/or b) either party requests a termination according to a written notice.

Article 4. Sale and Purchase:

4.1 Seller's and Buyer's Obligation to Sell and Purchase
4.2 Source of Gas
4.3 Title and Risk of Loss

The seller shall sell and make available, and the buyer shall buy, take and pay for, or pay for if not taken, LNG in accordance with the terms and conditions of each Confirmation Memorandum. The gas must be supplied from the nominated gas supply field alone or from another gas supply source. An option is that gas supply is prohibited from countries under US sanctions. Title and risk transfers at the delivery point.

Article 5. Quantities:

5.1 Quantities
5.2 Buyer's Liability for Shortfall
5.3 Seller's Liability for Shortfall

The quantities supplied are those defined in the Confirmation Memorandum. If the buyer does not take the LNG, except for force majeure, seller not delivering or off spec gas, that is called "Buyer Shortfall Quantity". There are two alternatives: 1) the buyer pays for the

LNG and a "Mitigation Sale" is made to third parties by the seller on behalf of the buyer and the buyer is credited with the proceeds less reasonable seller costs; or 2) the buyer is liable for all liquidated damages (consequential losses).

On the other hand, any seller failure to deliver is a "Seller Shortfall Quantity". There are two alternatives again: 1) the buyer will buy the deficient shortfall quantity from a third party (a "Cover Purchase"), paid for by the seller plus the buyer's reasonable costs; or 2) the seller is liable for liquidated damages.

Article 6. Quality:

6.1 Specifications
6.2 Determining LNG Quality Specifications
6.3 Off-Spec LNG

This article covers "Quality Specifications" and off spec LNG. The buyer shall use reasonable endeavours to use off spec LNG but is entitled to reject all or part of it. If the buyer does accept the off spec gas the buyer shall notify the seller of expected consequential losses (in treating the gas). The seller then either consents to pay the buyer for: 1) buyer's losses; 2) the buyer's losses from treating the off spec gas; or 3) buyer's losses up to the "Off Spec Damages Cap". If the buyer declines off spec gas then the seller is deemed to failed to make LNG available.

Article 7. Price:

The contract price per mmbtu is set out in the Confirmation Memorandum for each cargo, even if the contract price includes a reference to a monthly index price.

Article 8. Invoices and Payment:

8.1 Delivery Invoices
8.2 Statements of LNG Not Taken, Not Made Available, or Not Delivered
8.3 Other Invoices
8.4 Provisional Invoices
8.5 Payment Due Dates
8.6 Payment Method and Currency
8.7 Disputed Invoices
8.8 Late Payment and Refunds
8.9 Access To Information
8.10 Netting of Invoices
8.11 Safe Harbor

The seller presents invoices showing the heating value (mmbtu), statements of LNG not taken or not delivered. A "Provisional Invoice" can be presented if the mmbtus cannot be obtained quickly. The due date for payment is 30 days after receipt of invoice.

Any amounts in dispute shall be notified and then: 1) pay the full amount and settle the disputed amount later; 2) pay the undisputed amount and the disputed amount after settlement; 3) pay the undisputed amount and deposit the disputed amount in an escrow account until the dispute is settled.

Interest is due on late payments, including payments in escrow accounts. Each party is entitled to examine the other party's accounting books. Payments are due in full without netting or offsetting. Alternative clauses can allow netting of payments.

The agreement constitutes a "Master Agreement" for purposes of the US bankruptcy code.

Article 9. Credit Support:

9.1 Credit Support - Buyer
9.2 Credit Support – Seller

Each party shall provide credit support to the other as required in the Confirmation Memorandum.

Article 10. Taxes, Duties and Charges:

10.1 Seller's Tax Obligations
10.2 Buyer's Tax Obligations
10.3 Tax Refunds
10.4 Procedure for Payment of Taxes

The seller shall indemnify the buyer against any taxes in the seller's country for activities related to the LNG shipments. Likewise, the buyer shall indemnify the seller against taxes in the buyer's country. An optional extra article refers to the US Internal Revenue Code.

Article 11. Measurement and Testing of LNG and Vaporized LNG:

Measurement and testing of LNG shall be conducted in accordance with the provisions of this agreement and exhibit.

Article 12. Liabilities:

12.1 Consequential Loss
12.2 Exclusive Remedies
12.3 No Express Remedy
12.4 Estimated Loss

Neither party is liable for any consequential losses of the other party, except for those expressly provided for in the agreement (such as for non delivery of LNG).

Article 13. Force Majeure:

13.1 Events of Force Majeure
13.2 Notice: Resumption of Normal Performance
13.3 Rights Upon Force Majeure

Force Majeure is defined as covering natural disasters, acts of war or other insurrection, contamination, industrial action, changes in law, acts or omissions of government. Force Majeure does not include attempts to seek better economic terms, changes in market or demand, events affecting unconnected facilities, changes in law that do not prevent performance but merely renders it more costly, certain government actions. Optional additional clauses that exclude Force Majeure cover government acts affecting the particular party alone (and not other businesses in the country), depletion of the gas supply area, damage to upstream facilities, damage to buyer's facilities.

Article 14. Notices:

14.1 Delivery

14.2 Notice Details

14.3 Change of Address

14.4 Acknowledgement of Certain Notices

Contact details and how to communicate official documents with the other party.

Article 15. Governing Law and Dispute Resolution:

15.1 Applicable Law

15.2 Dispute Resolution - Arbitration

15.3 Dispute Resolution – Initial Steps

15.4 Expert Determination

15.5 Confidentiality

15.6 Waiver Of Sovereign Immunity

The governing law is left blank, for the parties to agree.

Alternatives are provided for dispute resolution, firstly that disputes are settled 1) by the courts of the governing law country; or 2) by binding arbitration. Alternatives are then provided for how arbitration shall be settled, whether by the American Arbitration Association (AAA), International Chamber of Commerce (ICC), London Court of International Arbitration (LCIA), Singapore International Arbitration Centre (SIAC), United Nations Commission on International Trade (UNCITRAL) or other.

An optional provision covers the nationality of the arbitrator. Alternatives cover the scope of the arbitral tribunal to cover consequential losses or penalties.

Optional provisions cover the jurisdiction of the courts and parties' recourse to the Pre-arbitral Referee Procedure of the International Chamber of Commerce; whether several disputes can be consolidated into a single arbitration proceeding; and whether in the case of a question of law an application may be made to the the High Court of England.

The process for dispute resolution is described, beginning with a "Notice of Dispute", with an optional provision for space for negotiations among senior executives of the two parties.

Article 16. Termination:

16.1 Termination of MSA by Notice

16.2 Termination of Confirmation Memorandum for Cause

16.3 Effect of Termination

Each party has the right at any time to terminate, however this does not terminate a Confirmation Memorandum. Clauses then cover early termination of a Confirmation Memorandum for various causes, with various alternatives.

Article 17. Amendment and Waiver:

17.1 Amendment

17.2 Waiver

The agreement cannot be amended or waived except in writing signed by both parties.

Article 18. Confidentiality:

18.1 Obligations of Confidentiality

18.2 Permitted Disclosures

18.3 Required Disclosures

18.4 Press Releases

"Confidential Information" shall be kept confidential by both parties, except for permitted or required disclosures. No press releases may be made unless agreed by both parties in writing.

Article 19. Assignment:

19.1 Assignment with Prior Consent

19.2 Assignment of Rights for Security and Payment

No party may assign an agreement without the written consent of the other party, except in relation to payments.

Article 20. Representations and Warranties:

20.1 Governmental Approvals and Other Approvals

20.2 Corporate Good Standing and Validity

20.3 Warranty of Title

20.4 Other Warranties

Each party warrants that they will have obtained the necessary government approvals required for the Confirmation Memorandum. Each party also warrants that they are in good standing under the laws of the state of their incorporation. The seller warrants that he has good and marketable title to all LNG made available.

Article 21. Business Practices and Foreign Corrupt Practices Act:

21.1 No Violation of Applicable Law

21.2 Commercial Acts

21.3 No Brokers

21.4 Business Records

21.5 Contractors

21.6 Indemnification

21.7 Conflict of Laws

Each party agrees that it will not act in violation of any applicable law; take any action to put the other party in violation of a business practices law, including the OECD Convention on Combating Bribery of Foreign Public Officials in International Business Transactions and the US Foreign Corrupt Practices Act; or pay any bribes.

Each party agrees not to pay any fees, commissions or rebates to any person connected to the other party. Neither party shall use a broker, agent or other intermediary in connection with agreeing or performing any agreement.

Each party shall keep all records to confirm compliance with these articles and shall maintain adequate internal controls. Each party shall endeavour to ensure their contractor complies with these provisions.

Article 22. Miscellaneous:

22.1 Third Party Beneficiaries

22.2 Each Party To Bear its Own Costs

22.3 No Partnership

22.4 Entire Agreement; Confirmation Memoranda

22.5 Severability

22.6 Counterpart Execution

Neither the MSA nor a Confirmation Memorandum create any rights except as in this MSA. An optional provision stipulates that the agreement is not enforceable under the Contracts (Rights of Third Parties) Act 1999 by any third party. Each party is responsible for their own costs. Neither the MSA nor a Confirmation Memorandum create any relationship between the parties. This MSA constitutes the entire agreement between the parties. Upon execution, each Confirmation Memorandum and the MSA are the entire agreement between buyer and seller. The provisions are severable so if any portion is deemed invalid, the remainder shall survive.

The MSA then contains detailed Exhibits. These give further legal provisions, with optional provisions, relating to aspects of the MSA. The exhibits are:

Exhibit A. Form of the Confirmation Memorandum

Exhibit B. Seller's Facilities, Transportation and Loading – Buyer Delivery Sales

Exhibit C. Buyer's Facilities, Transportation and Unloading – Seller Delivery Sales

Exhibit D. Measurement and Testing Procedures

Exhibit E1. Bank Letter of Credit

Exhibit E2. Guarantee

Exhibit F1. Offshore Title Transfer for Seller Delivery Sale

Exhibit F2. Offshore Title Transfer for Seller Delivery Sale

ANNEX 10. LNG INDUSTRY PLAYERS - SURVEY QUESTIONNAIRE

Note: We are expecting a rather free flowing discussion, rather than a strict question and answer. The following therefore are guidelines to help the discussion and to make sure that the main points are covered. Some of the questions are not relevant for every organisation or may be confidential but please try and cover as much as possible.

Details of the organisation

1. Contact details
2. Who the organisation is, what they do, their role in the LNG chain
3. Current LNG activities
4. Forecast LNG activities
5. Corporate structure and ownership
    a. Who are the ultimate owners of your operation?
    b. Are you an independent player (you respond to market signals and follow business where you consider it best) or do/does your owner/s set out what you do?

Views on global LNG market development

6. Your views on developments in the global LNG market, on volumes, prices and costs
    a. Gas feedstock
    b. Liquefaction
    c. Shipping
    d. Regasification
    e. Gas markets
    f. New LNG markets (such as mini LNG regasification, LNG vehicles, LNG storage, LNG powered shipping and bunkering)
7. Your views on developments in your own local market, on volumes, prices and costs
    a. Gas feedstock
    b. Liquefaction
    c. Shipping
    d. Regasification
    e. Gas markets
    f. New LNG markets (such as mini LNG regasification, LNG vehicles, LNG storage, LNG powered shipping and bunkering)
8. Please provide as best you can forecasts for your own organisation's:
    a. Production
    b. Prices

Costs

9. Please provide as good an indication as you can of your cost structure:
    a. Now
    b. Forecast over the next five and ten years
10. What is your view of future LNG industry costs, in particular:
    a. Liquefaction
    b. Shipping

Contractual issues

11. Please provide (if possible) a template or example LNG supply contract
12. Please describe the main typical contract terms

Flexibility

Our client, the European Commission, is keen to find out how contractual terms, and in particular flexibility provisions, are likely to develop in the future.

13. Please describe in your opinion how contract terms are likely to develop
14. Will long term contracts remain dominant?
15. Is there likely to be a move towards more short term contracts (1-5 years)?
16. Could LNG spot markets develop? If so where?
17. In your opinion, are LNG markets likely to remain as essentially Pacific Basin and Atlantic Basin or will they converge:
    a. Convergence of contractual terms?
    b. Convergence of market destinations for LNG supplies?
    c. Convergence of pricing
18. Would your organisation or in your opinion the LNG industry benefit from an information service showing where LNG cargoes are available for delivery (an aide to spot trading)

Government actions

19. To what extent do you think can governments shape the future of the LNG business. Do governments play a role or is LNG essentially a business and governments follow what companies do?
20. What do you think the European Union could do (if anything), at government and at European Commission level, to promote the development of flexibility, liquidity and transparency in the LNG industry?

ANNEX 11. EXAMPLE PAGE FROM US DOE OF US LNG PUBLICATION

U.S. DEPARTMENT OF ENERGY | Fossil Energy

OFFICE OF OIL & NATURAL GAS

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(YTD – through May 2017)

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U.S. DEPARTMENT OF ENERGY | Fossil Energy

VESSEL-BORNE EXPORTS OF DOMESTICALLY-PRODUCED LIQUEFIED NATURAL GAS (LNG)

Table 2a

Date of Departure	Name of Exporter	Supplier	Docket Number	Docket Term	Country of Destination	Name of Tanker	Departure Terminal	Volume (Mcf of Natural Gas)	Price at Export Point $/MMBtu	Notes
1/1/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Japan	Maethane Lydon Volney	Sabine Pass LNG Terminal	3,111,137	$ 3.72	
1/2/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Spain	Sestao Knutsen	Sabine Pass LNG Terminal	2,946,374	$ 3.72	
1/4/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Mexico	Clean Ocean	Sabine Pass LNG Terminal	3,455,279	$ 7.52	[L]
1/5/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Malta	Gaslog Santiago	Sabine Pass LNG Terminal	867,346	$ 4.52	[*]
1/5/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Jordan	Gaslog Santiago	Sabine Pass LNG Terminal	2,428,613	$ 4.52	[*]
1/7/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Mexico	Cool Voyager	Sabine Pass LNG Terminal	3,428,332	$ 7.52	[L]
1/11/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	India	SCF Mitre	Sabine Pass LNG Terminal	3,622,568	$ 4.52	
1/15/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Spain	Rioja Knutsen	Sabine Pass LNG Terminal	3,644,042	$ 7.01	[L]
1/17/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Japan	Creole Spirit	Sabine Pass LNG Terminal	3,703,484	$ 7.52	[L]
1/18/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Mexico	Maran Gas Pericles	Sabine Pass LNG Terminal	3,025,173	$ 4.52	[*]
1/18/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Mexico	Maran Gas Pericles	Sabine Pass LNG Terminal	394,212	$ 7.52	[*] [L]
1/24/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	China	Maran Gas Achilles	Sabine Pass LNG Terminal	3,391,087	$ 4.52	
1/25/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Portugal	Golar Kelvin	Sabine Pass LNG Terminal	3,442,365	$ 7.01	[L]
1/26/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Mexico	Stena Crystal Sky	Sabine Pass LNG Terminal	3,706,516	$ 7.52	[L]
1/28/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Spain	Methane Spirit	Sabine Pass LNG Terminal	3,411,662	$ 7.00	[S] [C] [L]
1/29/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Japan	Maria Energy	Sabine Pass LNG Terminal	3,718,018	$ 7.52	[L]
1/31/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Jordan	Galea	Sabine Pass LNG Terminal	2,939,021	$ 7.52	[L]
2/2/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Portugal	Clean Ocean	Sabine Pass LNG Terminal	1,691,600	$ 6.90	[*] [L]
2/2/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Spain	Clean Ocean	Sabine Pass LNG Terminal	1,765,661	$ 6.90	[*] [L]
2/3/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Turkey	La Manchua Knutsen	Sabine Pass LNG Terminal	3,705,488	$ 6.39	[L]
2/5/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	India	Palu LNG	Sabine Pass LNG Terminal	3,399,239	$ 3.90	
2/9/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Mexico	Cool Voyager	Sabine Pass LNG Terminal	3,427,486	$ 7.07	[S] [C]
2/11/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Turkey	Oak Spirit	Sabine Pass LNG Terminal	3,696,872	$ 6.90	[L]
2/12/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	China	Maran Gas Amphipolis	Sabine Pass LNG Terminal	3,464,863	$ 3.90	
2/14/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Mexico	Rioja Knutsen	Sabine Pass LNG Terminal	3,606,218	$ 6.39	[L]
2/15/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Chile	Gemmata	Sabine Pass LNG Terminal	2,950,188	$ 6.90	[L]
2/17/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	China	Maran Gas Pericles	Sabine Pass LNG Terminal	3,444,825	$ 3.90	
2/20/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Mexico	Ribera del Duero	Sabine Pass LNG Terminal	3,667,863	$ 5.33	[S] [C]
2/20/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Kuwait	Golar Penguin	Sabine Pass LNG Terminal	3,378,113	$ 5.29	[S]
2/23/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Jordan	Madrid Spirit	Sabine Pass LNG Terminal	2,944,820	$ 3.90	
2/24/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Mexico	Stena Crystal Sky	Sabine Pass LNG Terminal	3,705,611	$ 5.89	[S] [C]
2/26/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Japan	Stena Clear Sky	Sabine Pass LNG Terminal	3,705,039	$ 6.90	[L]
2/28/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	China	Clean Planet	Sabine Pass LNG Terminal	3,428,365	$ 6.39	[L]
3/2/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	South Korea	Gaslog Gibraltar	Sabine Pass LNG Terminal	3,583,966	$ 3.02	
3/8/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Mexico	Cool Voyager	Sabine Pass LNG Terminal	3,404,694	$ 5.10	[S] [C]
3/9/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Jordan	Maran Gas Apollonia	Sabine Pass LNG Terminal	3,358,596	$ 3.02	
3/12/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Jordan	Golar Kelvin	Sabine Pass LNG Terminal	3,296,471	$ 5.51	[L]
3/15/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Pakistan	Gaslog Skagen	Sabine Pass LNG Terminal	3,165,927	$ 3.02	
3/17/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	South Korea	Clean Ocean	Sabine Pass LNG Terminal	3,457,554	$ 4.34	[S] [C]
3/19/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Turkey	Oak Spirit	Sabine Pass LNG Terminal	3,520,905	$ 4.42	[S]
3/20/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Dominican Republic	GDF Suez Point Fortin	Sabine Pass LNG Terminal	2,933,786	$ 5.37	[S]
3/22/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Thailand	Methane Alison Victoria	Sabine Pass LNG Terminal	3,112,643	$ 3.02	
3/24/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	15-171-LNG	Short-Term	Mexico	Creole Spirit	Sabine Pass LNG Terminal	3,707,229	$ 4.54	[S] [C]
3/26/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Mexico	Rioja Knutsen	Sabine Pass LNG Terminal	3,615,896	$ 5.51	[L]
3/30/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-111-LNG	Long-Term	Kuwait	Valencia Knutsen	Sabine Pass LNG Terminal	3,360,169	$ 3.02	
3/30/2017	Sabine Pass Liquefaction, LLC	Sabine Pass Liquefaction, LLC	10-85-LNG	Long-Term	Chile	Gallina	Sabine Pass LNG Terminal	2,951,103	$ 6.02	[L]

[S] **Spot** - a one-time transaction for near-term delivery of a specific quantity of LNG at a specific location. Prior to 2006, spot cargos could be included in either long-term or short-term authorization types.
[*] **Split cargo** - a single shipment of LNG where portions of the cargo have different transactional characteristics. For instance, a single cargo can have more than one buyer, supplier, price, unloading port, loading port, or DOE authorization.
[C] **Commissioning cargo** - pre-commercial cargo loaded while export facility operations are still undergoing final testing and inspection. Commissioning cargos may occur multiple times for the same facility as individual LNG trains enter service.
[L] **Liquefaction fees** - liquefaction fees have been included in the cargo's price. Export prices for cargos made pursuant to long-term sales and purchase agreements (SPA's) or contracts do not include liquefaction fees unless indicated.

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