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COVER NOTE

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Delegations will find attached document SWD(2016) 23 final.

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COMMISSION STAFF WORKING DOCUMENT
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COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS

on an EU strategy for liquefied natural gas and gas storage

{COM(2016) 49 final}

1. The role of gas in the EU

Natural gas currently represents around a quarter[1] of gross inland EU energy consumption. About 26 % of that gas is used in the power generation sector (including in combined heat and power plants) and 23% in industry. Most of the rest is used in the residential and services sectors (mainly for heat in buildings) which has the biggest share in gas consumption.[2]

Gas is expected to continue to play a vital role in the EU energy system for decades to come, as the EU meets its ambitious targets on greenhouse gas emissions, energy efficiency and renewables and makes the transition to a low-carbon economy.

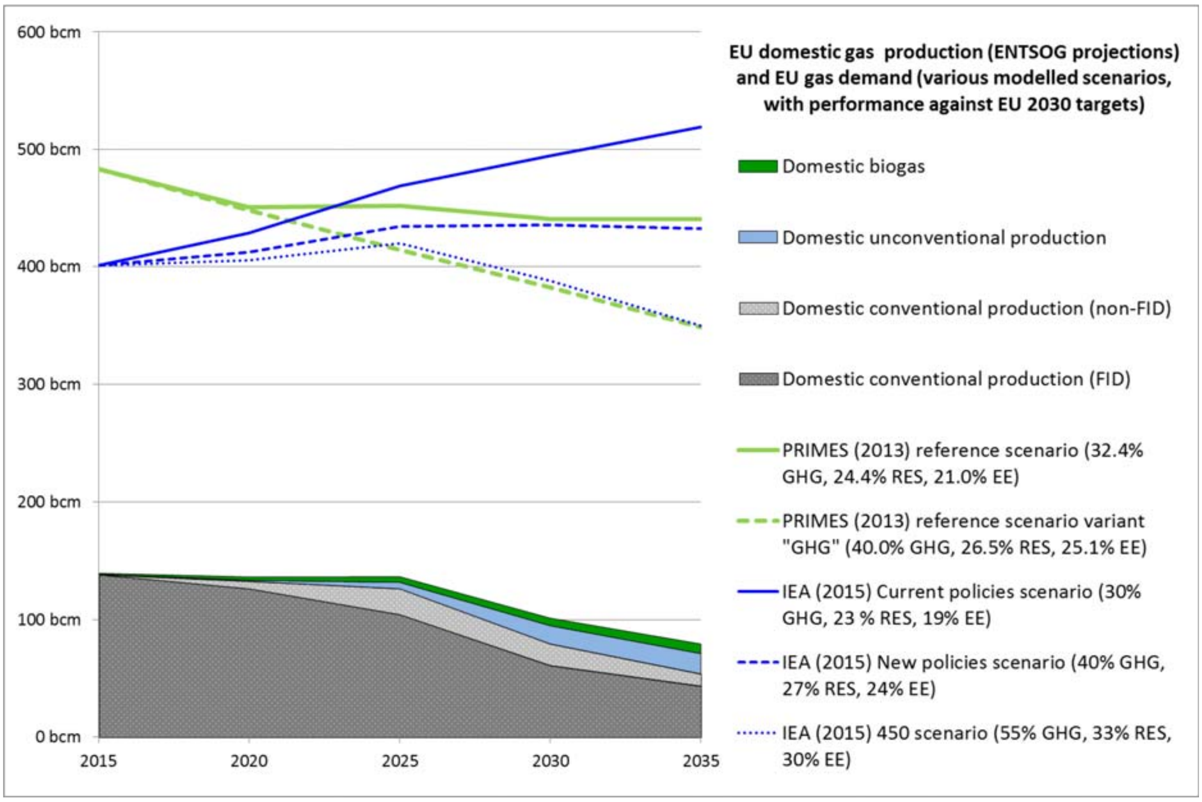
In the power generation sector, for example, recent years have seen a decline in the use of gas due to factors including low carbon prices, reflecting the surplus of allowances on the market following the economic crisis and coal-to-gas price ratios favourable to coal. In recent years reforms of the EU's Emissions Trading System (ETS) have been agreed, including the back-loading of 900 million allowances and the introduction of a Market Stability Reserve that will address the current imbalance between supply and demand for allowances. A higher carbon price, together with ongoing and future reforms of electricity and gas markets, as outlined in the Energy Union Framework Strategy, could contribute to making gas more competitive *vis-à-vis* other more carbon intensive fossil fuels. Gas will have an ongoing role in the medium term as a complement to renewable power generation and the use of carbon capture and storage (CCS) or carbon capture and utilisation (CCU) could see gas remain an important part of the power generation mix in the longer term.

Although energy efficiency policies are expected to dampen demand for heat overall, it is likely that natural gas will remain an important source of heat in industry and buildings over the medium term. It will also have a growing role as an alternative transport fuel, for example in maritime transport and heavy-duty vehicles (see below).

The precise level of future EU gas demand will however depend on many different factors, including fossil-fuel prices, carbon prices, future technology costs and the choices made by Member States and energy companies. Some illustrative projections based on different assumptions on these and other factors are shown in the graph below.

As can be seen, demand for imported gas under such projections remains broadly stable or increases, as domestic EU production declines. The need for infrastructure capacity can also be expected to remain at a high level, to ensure the deliverability of gas in periods of peak demand.

[1] Source: Eurostat. In 2013, gas represented 23,2 % of the EU's energy mix
[2] Source: Eurostat. Power generation 26,12 %, industry 23,4 % and residential and services 41,5% (2013)



2. International LNG markets

International LNG markets are set for major change, with substantial liquefaction capacity coming on stream in Australia and the United States in the period to 2020. Figure [1] is based on projects that are under construction or that have been the subject of final investment decisions and are therefore very likely to become operational.

The United States and Australia are set to become major players, alongside traditional suppliers such as Qatar, Nigeria, Algeria and Angola, and there is potential for significant supply from Canada, Tanzania, Mozambique, Iran, Iraq and Libya. The Eastern Mediterranean is also a promising future source of gas supply for the EU, with significant resources available in Cyprus, Egypt, Israel and Lebanon.

Abundant supply is expected to drive further integration of the Atlantic and Pacific basins and support the shift towards gas-on-gas pricing, shorter-term contracts, the use of spot markets and the rise of intermediaries such as portfolio players and traders. US projects can be expected to have a particular impact in this regard, with many providing purchasers with greater flexibility (e.g. destination-free contract terms). The Commission continues to promote free trade in energy and unconstrained access for EU companies to LNG supplies in the framework of negotiations on the Trans-Atlantic Trade and Investment Partnership and meetings of the EU—US Energy Council.

The overall picture for LNG importers such as the EU is therefore likely to be positive, at least in the short-to-medium term. LNG prices are expected to be lower than in recent years, possibly much lower, and EU imports are therefore likely to increase (as they have since late 2014). The exact level of future imports will depend on competition with pipeline supplies, but a larger and more liquid global market can be expected to bring benefits in terms of security and resilience, with more ships on the water at any one time and more supplier and consumer countries.

In the medium term (from the early 2020s onwards), as global LNG demand increases, the market is widely expected to tighten again, due to the cancellation or postponement, in the face of current low LNG prices, of new LNG liquefaction projects. But the long-term trend remains one of a move to a larger and more mature global commodity market with higher levels of liquidity and a growing number of suppliers.

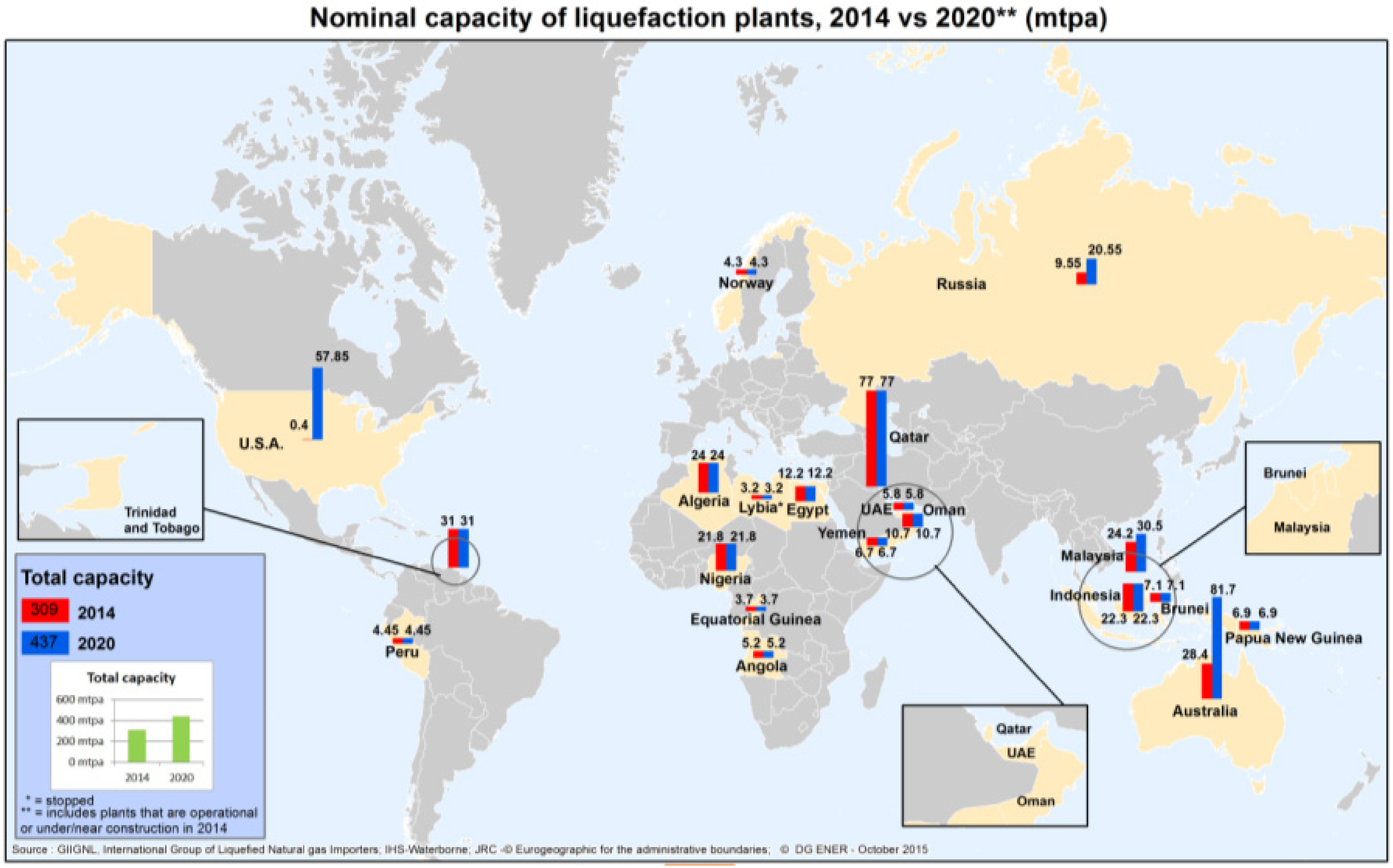


Figure 1: Current and new global liquefaction capacity (2014-2020)

3. Summary of the public consultation

In order better to understand stakeholders' views on the state and functioning of the global and European LNG markets, and their expectations as to what the EU could do, the Commission held a public consultation on the EU's LNG and gas storage strategy between 8 July and 30 September 2015.

3.1. Statistics

A high number of responses (137 in total)[3] was received, from stakeholders along the entire value-chain (see Figure 2), from LNG producers to buyers, terminal and underground storage operators, thereby providing a representative sample and a wide range of opinion. The biggest proportion came from industry (55 %) and associations (27 %), but public authorities (11 %), NGOs (4 %), researchers and citizens (4 %) also made their voices heard.

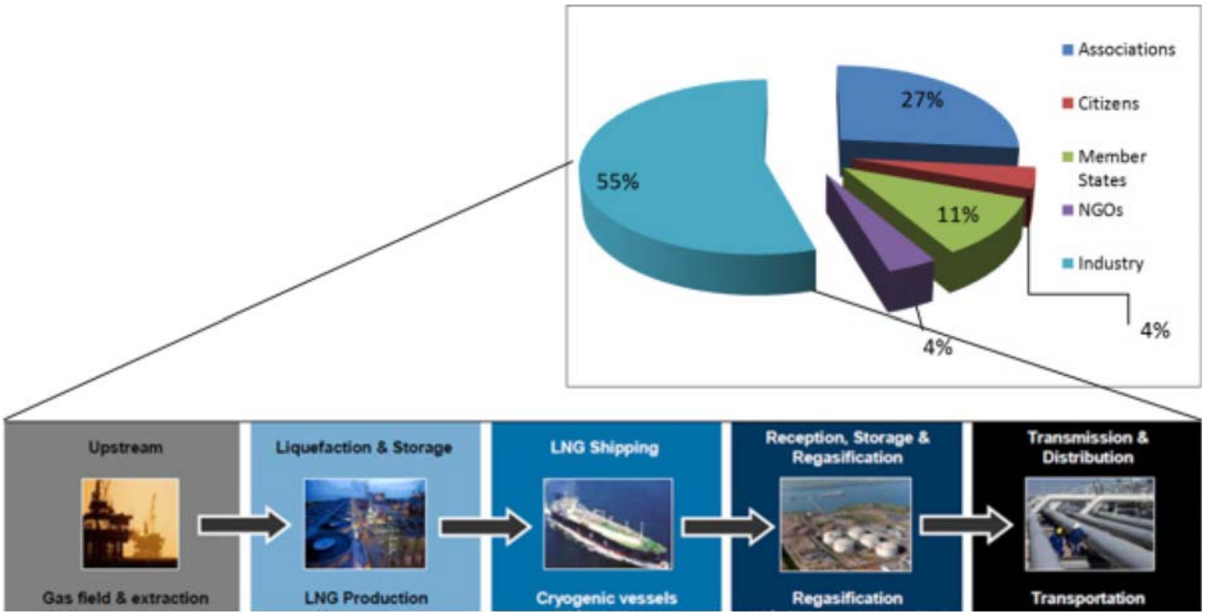


Figure 2: Responses to the public consultation by stakeholder group

There were contributions from most Member States (see Figure 3) and from several non-EU countries (including the Energy Community, Bosnia Herzegovina, Ukraine, Norway and the USA).

[3] All individual submissions are available here: https://ec.europa.eu/energy/en/consultations/consultation-eu-strategy-liquefied-natural-gas-and-gas-storage.

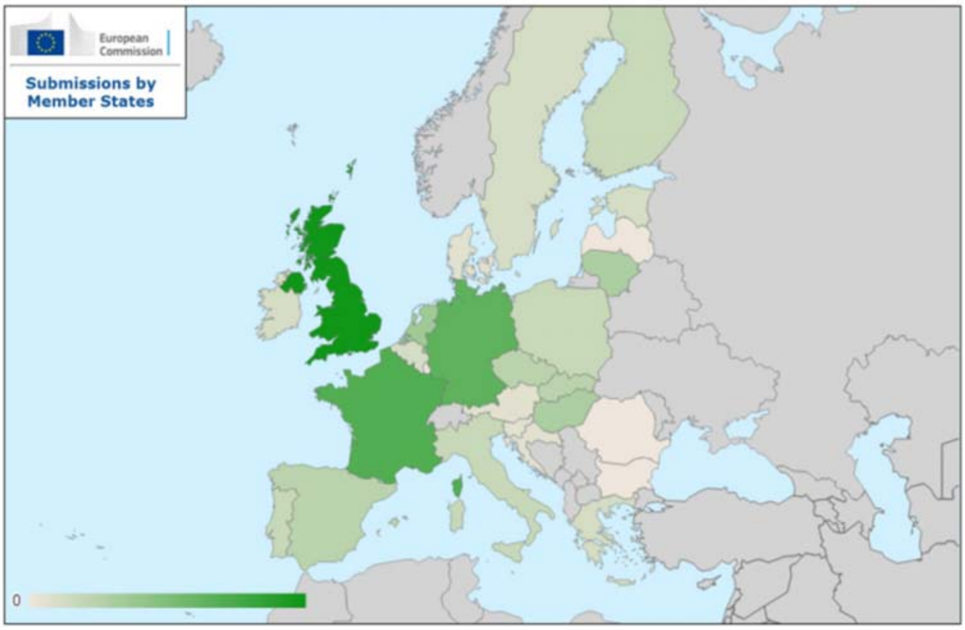


Figure 3: Responses to the public consultation by country of origin

3.2. Summary of views

Stakeholders' views can be summarised around the following topics:

Role of gas

There was a general view among stakeholders, in particular industry and market players, that the EU should develop an **understanding or vision on the future role of gas**. This should be coherent across policy areas and clearly communicated to the market, and is a pre-requisite for a stable investment environment. Some stakeholders went further, saying that the EU should favour gas and stress its vital role in the future, thus sending a strong security-of-demand signal and making the EU more attractive as a market for gas/LNG.

Optimal level/share of LNG

On whether an optimal level or share of LNG in the gas mix exists or can be quantified, an overwhelming majority responded that this would be determined by the market (i.e. price) and would vary from country to country depending on many factors, including price (LNG vs pipeline sources), degrees of diversification and interconnectivity, availability of domestic production and storage, etc. The few respondents expressing divergent views suggested that the issues should be approached from an infrastructure or regional perspective (e.g. what is the minimum required level of LNG-related regional infrastructure? what theoretical proportion of LNG could this allow for?) or that LNG capacity should not be less than the capacity of a country's main pipeline or 50 % of its overall pipeline capacity.

Assumptions (global context and EU regional situation)

As regards the assessment of the global context and the current situation in the EU's regions, most assumptions were accepted as generally right:

(1) The current EU LNG regasification capacity is overall sufficient but there are still Member States that do not have access to this source.

(2) Most regasification capacity is in north-west Europe and the Iberian Peninsula; in recent years, relatively low utilization rate has been observed at these terminals;

(3) There is limited access to LNG in central- and south-east Europe, especially due to lack of interconnectivity;

(4) The floating storage and regasification unit in Lithuania considerably contributed to the improvement of the security of supply situation in the Baltic region;

(5) The international LNG market is expected to show significant growth over the short- to medium term.

The majority of stakeholders responding to this particular question saw the low utilisation of LNG terminals as normal given the level of world LNG prices, and characteristic of the LNG value-chain, where global liquefaction capacity is approximately half that of regasification[4]. Global LNG prices after 2010 (as a consequence of the Fukushima event) pushed Asian LNG prices up that attracted cargos away from Europe to the Far East. For Europe (described as a market of last resort for LNG), cheaper gas was available through pipelines that could easily replace the volumes previously covered by LNG.

In that respect, it was also stressed that low utilisation of a terminal did not mean it was a stranded asset. This in particular is the case for exempted terminals where the investors hold long-term capacity at the terminal and thereby bear the cost of low utilization, or at least, mitigate the risk of the investment itself.

Some respondents pointed to the lack of a clear reference to the potential in the eastern Mediterranean and questioned some specific assumptions, e.g. that the Iberian Peninsula and all countries in central-eastern Europe are vulnerable in terms of access to sufficiently diversified sources.

Infrastructure and the question of stranded assets

Most respondents agreed that existing infrastructure must be better exploited through effective implementation of the Third Package and network codes, and by better interconnection between Member States and markets, including on the basis of reverse flow capabilities where needed. Where new (LNG or other) infrastructure is needed, investments need to be subject to a cost/benefit analysis to limit the risk of stranded assets. This applies equally where the main driver for investment is security of supply. (See also *No 'one size fits all'* below).

Barriers

[4] Source: IGU World LNG report 2014, global liquefaction was 301 mtpa, regasification 724 mtpa.

While in general many stakeholders (in particular, regulatory authorities and terminal operators) argued that there were no real barriers to LNG reaching the EU market, several respondents (especially traders and LNG producers) identified some **potential improvements**. There is also a marked difference between western and eastern Europe. Most functioning LNG terminals are in western Europe, where markets are considered to be well interconnected and sufficiently liquid, while central-eastern and south-east Europe are still lagging behind. Here, the main barrier identified was the **lack of infrastructure/interconnectivity and market depth** and therefore of **access to liquid hubs**. This was also mentioned as an issue in relation to the Iberian Peninsula.

Potential improvements were identified in the western markets, where exempted and regulated terminals co-exist and are in effect competing, but none were highlighted as needing further EU intervention, as existing legislation (with stronger enforcement and regulatory oversight) was considered sufficient to ensure a level playing-field.

The main issues identified related to **transparency**, in particular as regards ‘use it or lose it’ procedures to prevent abuse of primary capacity-holder status and allow **secondary markets** to function effectively. Respondents also highlighted the wide diversity of such procedures at the various terminals, which makes it more difficult for new players to enter the market.

The gas sector and its needs are changing rapidly, partly due to technological developments, and market players – and rules – need to adapt accordingly. The availability of more **innovative/flexible products** at terminals (e.g. separate storage services, etc.) and a supportive regulatory framework allowing for this were highlighted as a potential improvement to the current situation.

In addition, the issue of **gas quality** was raised by several stakeholders, who pointed out that an over-narrow common Wobbe Index[5] range would exclude part of the current LNG supply and some potential new imports.

A few stakeholders identified further barriers (more in the context of specific markets) relating to:

- **tariff regime** in general (too often changing or does not incentivise LNG entry) or as regards a **failure of transmission tariffs to reflect costs**, **tariff pancaking**[6], etc.;
- more technical issues, such as **odorisation** or **minimum output rates**; and
- access to sufficient or affordable **storage capacity**, e.g. effective third-party access (TPA), storage obligations or full LNG storage, etc.

Current legislation

[5] The Wobbe index indicates the interchangeability of a fuel gas; it relates heating characteristics of blended fuel gases

[6] When a transportation service is using more than one transmission system and the total amount paid by the user for such service is not justified by the services rendered individually by each of the transmission operators implied

In general, the vast majority of respondents found existing legislation sufficient to overcome barriers and called for full, and better, implementation of the Third Energy Package and the associated network codes, the Gas Security of Supply (SoS) Regulation[7] and the TEN-E[8]. An industry association highlighted the importance in general also of competition rules to ensure non-discriminatory access to infrastructure and functioning of the gas market.

No 'one size fits all'

It was widely accepted that **regionally tailored** approaches and support may be appropriate in specific cases where the interconnectivity and liquidity of markets are still poor and there is dependence on a single supplier. Most respondents felt that this applied in general to the **Baltic** region and **south-east Europe**, with some national characteristics. It was recommended that floating storage and regasification unit (**FSRU**) technology be considered for these regions, where additional LNG infrastructure may be needed and where this would mainly serve security-of-supply purposes. Special value was attached to regional cooperation on matters of infrastructure development, as this would also reduce the risk of stranded assets.

However, any targeted intervention should be determined case by case after careful consideration of costs, benefits and market specificities, and be non-discriminatory, minimise market distortion and not hamper market development.

Voluntary demand aggregation

Most respondents cautioned against the idea of voluntary demand aggregation. Some stakeholders saw potential for demand aggregation, but strictly in crisis situations. The few who supported the concept were mainly from the eastern European countries, where markets and individual demand volumes are smaller and there is no access to a liquid regional gas hub.

The main message of those opposing the idea was that such practices should not be politically driven and agreed by governments, as they could also lead to restrictions on competition. However, if market participants saw the need, they should be allowed to bundle demand (e.g. to reach sufficient volume for an LNG cargo), subject to trade and competition rules, in order to improve their market position and bargaining power *vis-à-vis* suppliers.

Technological developments and other uses of LNG; sustainability

Most stakeholders see an important role for LNG in transport, as a replacement for oil, in particular in maritime and heavy-duty road vehicles, as a path towards decarbonising the transport sector. Tax regimes (e.g. fuel tax), available engine technology and standards (especially on gas quality) were mentioned as potential areas for action to eliminate barriers to further penetration. Current legislation (several respondents mentioned the Alternative Fuels Infrastructure Directive[9] and TEN-T[10]) is expected largely to address these issues. Some

[7] Regulation (EU) No 994/2010
[8] Regulation (EU) No 347/2013
[9] Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure

respondents from the Baltic states and Finland called for their inclusion in the LNG Blue Corridors programme[11].

Several stakeholders mentioned the potential of exploiting LNG ‘cold’ (cold waste recovery at terminals), which could provide further economic and environmental benefits.

A few respondents referred to a need to address methane leakage through infrastructure and technology improvements.

Storage

Most stakeholders agreed that storage faces increased competition from other sources of flexibility. Storage operators should therefore **offer a wider range of products** that are more flexible and responsive to the needs of the market, transparent and competitively priced. This may require adjustments in Member States’ legal frameworks. Stakeholders called for a **level playing-field** for all flexibility products, including storage, and for such new services to be allowed to develop.

Further major **barriers** concerned regional cooperation and **cross-border trade.** It was widely accepted that it makes sense to take a **regional approach** to increasing the role of storage in ensuring security of supply. Reference was made to aspects such as infrastructure development, cross-border access to storage capacity and rules for using storage in crisis situations. Many contributors referred to the Gas SoS Regulation, in particular preventive action and emergency plans, which should include storage-related measures and agreements on their use on a regional scale.

Respondents expressed partly contrasting views on measures obliging suppliers and traders to ensure that **minimum volumes** are stored at certain times (storage obligations) and to hold strategic stocks. While several stakeholders felt that these were clearly necessary to secure gas supply, others underlined their potential for distorting markets and their detrimental effects in terms of hampering the enhanced regional use of storage.

Several stakeholders pointed to transport **tariffs for stored gas** as a potential barrier, referring to current discussions, in the context of tariff network code development, on ensuring a cost-related framework.

On questions regarding **the market’s ability to ensure security of supply**, that is whether there is a market failure, many respondents (in particular, suppliers and parties active on developed and liquid markets) highlighted the key role of functioning markets. Most storage operators and stakeholders from central and eastern Europe stressed, however, that market players do not take sufficient account of low-risk/high-impact events and called for proposals on tools to ensure preparedness for crisis situations.

[10] Regulation (EU) No 1315/2013 of the European Parliament and of the Council of 11 December 2013 on Union guidelines for the development of the trans-European transport network
[11] Funded through the 7th RTD framework programme

Individual respondents proposed various tools to allow gas storage to improve security of supply and ensure that sufficient volumes are stored. These include market-based measures (auctions, etc.) and non-market measures (e.g. storage obligations and strategic storage). One respondent proposed that a '**toolbox**' be developed, i.e. a set of measures to address specific situations in the Member States, accompanied by a case-by-case assessment on the basis of transparent pre-determined criteria.

Several stakeholders recalled that required volumes of stored gas and consequently storage capacity can depend on many variables, including the degree of interconnectivity, the liquidity of the market, the availability of alternative sources of flexibility and the proportion of overall demand that protected customers account for. National and regional calculations should factor in all these aspects. Accordingly, it seems that **required storage capacity cannot be calculated *ex ante*** with sufficient reliability (about half of the respondents expressed this opinion), but should be determined by market forces.

A majority of stakeholders preferred **market-based measures** and called for caution in proposing more interventionist solutions, such as storage obligations (minimum filling levels) or earmarking volumes as strategic reserves. As regards potential measures and policy options, contributors generally accepted that '**no one size fits all**'. Where the market is not well developed or there is a lack of confidence in its ability to ensure security of supply, tailor-made solutions could be pursued.

4. Existing LNG infrastructure in the EU

Large-scale regasification capacity in the EU in 2015 was 195 bcm/year, with 23 bcm/year under construction; it will reach 213 bcm/year by 2019.[12] Planned projects[13] could result in an additional 146 bcm/year. Overall, therefore, the EU's LNG import capacity is clearly sufficient, taking into account annual gas consumption of 400-500 bcm/year in recent years. This also means, however, that utilisation rates for terminals across Europe have been relatively low; The average rate of LNG terminal utilisation in Europe (of total installed capacity) has decreased since 2010, from 53% to 25% in 2013, and in 2014 just 19% of the total send out capacity was used[14] (compared with a global average of 33 %[15]). This was a result of high LNG prices in Asian markets and competition with pipeline gas. Also see section 3.2 for more details on the low utilisation rate of EU terminals.

At the same time, there are Member States in the EU that do not have access to LNG as an additional source of diversification due to missing infrastructure (interconnections, reverse flow or potentially an LNG import terminal closer to demand). Please see section 8 for more details on modelling results of the impact of the current and future gas infrastructure on potential LNG penetration.

[12] Source: GLE LNG Map & Investment Database 2015.
[13] Non-FID (final investment decision) projects.
[14] Source: GIE
[15] Source: IGU World LNG report 2014;

Access regimes

In Europe, regulated and exempted LNG terminals co-exist (see Table 1); of the 22 LNG (onshore or FSRU) facilities in operation, 15 are regulated, six are exempted and one has hybrid TPA arrangements. With increasing interconnectivity, these terminals are in effect competing on the same market. While regulated terminals offer TPA, access at exempted terminals is negotiated directly between the owner and the shippers. National regulatory authorities are responsible for monitoring the effective functioning of anti-hoarding mechanisms and congestion management procedures.

Case study: Impact on security of supply and competition - the Klaipėda FSRU

Until recently, gas prices in Lithuania were among the highest in the EU, in spite of its geographical proximity to its historical supplier. The Government commissioned the Klaipėda FSRU, which began operations in December 2014. Access to LNG on the global markets now acts as a price cap (at levels similar to those on competitive EU gas markets). The terminal has been instrumental in negotiating a significant (around 20 %) reduction in the gas prices offered by Gazprom.

Table 1: LNG terminals in the EU[16]

Country	Name of installation	Type	TPA regime	Nominal annual capacity (billion m^3(N)/year)	LNG storage capacity (1000 m^3 LNG)
Belgium	Zeebrugge LNG Terminal	large onshore	regulated	9.0	380
Finland	Tahkoluoto/Pori LNG Terminal (under construction)	small-scale	off-grid	0.1	30
Finland	Rauma LNG terminal (under construction)	small-scale	off-grid		10
Finland	Tornio Manga LNG terminal (under construction)	small-scale	off-grid		50
Finland	Hamina-Kotka LNG terminal (under construction)	small-scale	off-grid		30
France	Fos-Tonkin LNG Terminal	large onshore	regulated	3.4	150
France	Montoir-de-Bretagne LNG Terminal	large onshore	regulated	10.0	360
France	Fos Cavaou LNG Terminal	large onshore	regulated	8.3	330
France	Dunkerque LNG Terminal (under construction)	large onshore	exempted	13.0	570
Greece	Revithoussa LNG Terminal	large onshore	regulated	5.0	130
Italy	Panigaglia LNG terminal	large onshore	regulated	3.4	100
Italy	Porto Levante LNG terminal	large off-shore	hybrid	7.6	250
Italy	FSRU OLT Offshore LNG Toscana	FSRU	exempted	3.8	135
Lithuania	FSRU Independence	FSRU	regulated	4.0	170
Netherlands	Gate terminal, Rotterdam	large onshore	exempted	12.0	540
Poland	Swinoujscie LNG Terminal (under construction)	large onshore	regulated	5.0	320
Portugal	Sines LNG Terminal	large onshore	regulated	7.9	390
Spain	Barcelona LNG Terminal	large onshore	regulated	17.1	760
Spain	Huelva LNG Terminal	large onshore	regulated	11.8	620
Spain	Cartagena LNG Terminal	large onshore	regulated	11.8	587
Spain	Bilbao LNG terminal	large onshore	regulated	8.8	450
Spain	Sagunto LNG terminal	large onshore	regulated	8.8	600
Spain	Mugardos LNG Terminal	large onshore	regulated	3.6	300
Spain	Gijón (Musel) LNG terminal	large onshore	regulated	7.0	300
Spain	Tenerife (Arico-Granadilla) LNG terminal (under construction)	large onshore	regulated	1.3	150
Spain	Gran Canaria (Arinaga) LNG terminal (under construction)	large onshore	regulated	1.3	150
Sweden	Nynäshamn LNG terminal	small-scale	off-grid	0.5	20
Sweden	Lysekil LNG Terminal	small-scale	off-grid	0.3	30
United Kingdom	Isle of Grain LNG terminal	large onshore	exempted	19.5	1 000
United Kingdom	Teesside LNG port	Gasport for FSRUs	exempted	4.2	0
United Kingdom	Milford Haven — Dragon LNG terminal	large onshore	exempted	7.6	320
United Kingdom	Milford Haven — South Hook LNG terminal	large onshore	exempted	21.0	775

[16] Source: GIE LNG Map Dataset, May 2015 version. Projects in the planning phase (i.e. for which no final investment decision has been taken) are not included.

5. EU gas storage facilities and storage infrastructure

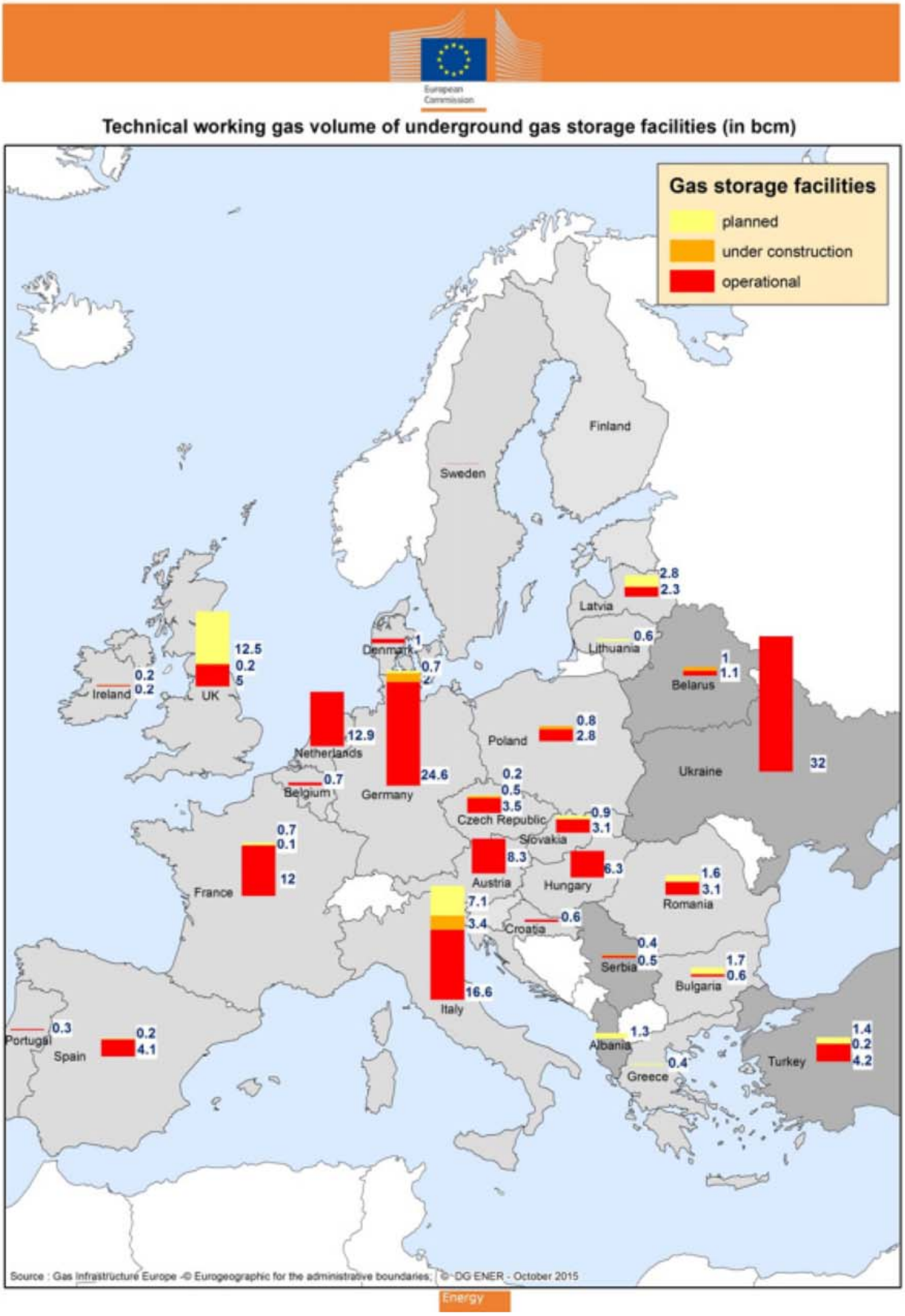


Figure 4

Available capacity in countries with storage ranges from 10 % to over 100 % of average winter demand. Eight Member States could meet 50 % or more of their peak demand by drawing on their storage; Austria and Germany could cover all of their peak demand.

In central and south-east Europe, substantial storage capacity is available but unevenly distributed across countries. As the only functioning gas storage facility in the Baltic states, the Inčukalns Underground Gas Storage Facility in Latvia ensures the stability of natural gas supply in the region. The geology of the area could theoretically permit a tenfold increase in existing storage capacity. In general, greater interconnectivity and regional cooperation could result in a better and more efficient use of storage.

Geological conditions in certain non-EU countries may allow for additional storage capacity, from which the EU could benefit if demand for storage products made investments in such sites and related transmission infrastructure commercially attractive.

6. Tools for optimising the role of storage in ensuring security of gas supply

Member States policies' for optimising the use of gas storage differ considerably and range from a fully market driven approach to non-market based instruments as strategic reserves or storage obligations at certain points of time. The following overview summarises the characteristics of direct government interventions in the storage sector to earmark and withhold gas for unexpected demand-supply imbalances.

6.1. Non-market-based instruments

Overview of existing options with direct relevance for storage

	Storage obligation	*Strategic storage*
Principle	Fixed volume of gas secured for winter season. Determined on the basis of demand from protected customers in certain weather conditions.	Fixed volume of gas stored permanently. Determined upfront or based on specific criteria (import, sales and import infrastructure capacity) under certain weather conditions.
Governance	Suppliers contract directly with storage system operators (SSO).	Governmental body. Suppliers and/or shippers contract directly with SSO.
Storage use	Storage 'in the market' throughout the winter period, but in practice use may be determined by the need to comply with the supply standard.	Storage held 'out of the market' unless its use is allowed by the government.
Outstanding issues	Market intervention depends on the level of obligation set. The SoS risk coverage (peak, volume) may depend on the level of obligation set by the Member State. Use of stored gas does not depend on	Market intervention is usually significant, depending on volume. High protection comes with high costs ('insurance fee'). Release of strategic storage volumes dependent on Member

	Member State's decision.	State's decision. Clear criteria needed for use to avoid interference with commercial storage.
Context of application	Higher import dependency.	Higher import dependency.

Storage obligation (minimum storage requirements)

The effectiveness of a gas system in ensuring security of supply depends on storage capacity and storage filling levels. If the storage facilities do not contain sufficient volumes, an unusually severe winter combined with technical problems could lead to substantial supply shortages that could not be made up for straight away, even if gas imports were increased.

A certain proportion of the stored gas stays in the reservoir ('cushion gas') to ensure a minimum pressure for physical extraction of the gas. The 'working gas' is the maximum remaining volume available for withdrawal. The withdrawal rate in storage facilities with high filling levels has proven to be relatively stable, so the impact of low filling levels is usually felt at the end of the winter. In particular, it starts to flatten out when a low level (which is different for each storage facility, depending on its 'withdrawal profile') has been reached.

In the scenarios that have been examined, the gas supply situation in November appears to be largely uncritical. Except in the event of a political conflict resulting in a total disruption of gas supplies, shortages were identified only for the month of February. These were due less to increased demand in this period than to lower withdrawal rates, which underlines the importance of storage filling levels.

Storage obligations can be introduced instead of, or as well as, strategic reserves, which permanently withdraw certain volumes from the market. They involve requiring market participants to place and hold a certain volume of gas not permanently in storage but only at specific times so as to guarantee that sufficient volumes are available for emergency situations, e.g. demand spikes due to cold spells. Unlike strategic reserves, storage obligations are effective already ahead of a crisis.

Considerations for storage obligations

General principle	Supplier for protected customers and institutions of public interest (e.g. police, hospitals) has to put an amount of gas in storage for the winter.		
Fixing of volume to be stored	Percentage of winter demand.	Percentage of demand for coldest period (month), plus withdrawal capacity.	Percentage of annual demand.
Duration	Heating period (winter). Note: if duration exceeds winter period, the measure will be considered as strategic storage.		
Beneficiary	Protected customers only.	Protected customers and public institutions.	Protected customers, public institutions and key sectors.
Location	Gas to be stored in the Member State.	Gas can be stored outside Member State if transport	Specific storage site(s), e.g. close to point of

		capacity is secured.	consumption (option not used in Europe to date).
Use of stored gas	Minimum volumes kept in stock for winter season.	Freedom to use gas during season.	
Cost allocation	Individual costs of supplier.		

Strategic storage

The key element of a strategic reserve is that a certain proportion of stored gas is set aside from general market mechanisms, to be used only in specific scenarios outside the general market. The gas in the reserve cannot be traded and may be used only in the event of a supply crisis.

Reserves are considered an appropriate tool to improve security of supply, but organisational and practical questions still need to be answered. Apart from determining the volumes to be stored, their location, triggers and procedures for their release and their impact on markets, Member States need to entrust an entity with the management of the reserve, or create one for that purpose.

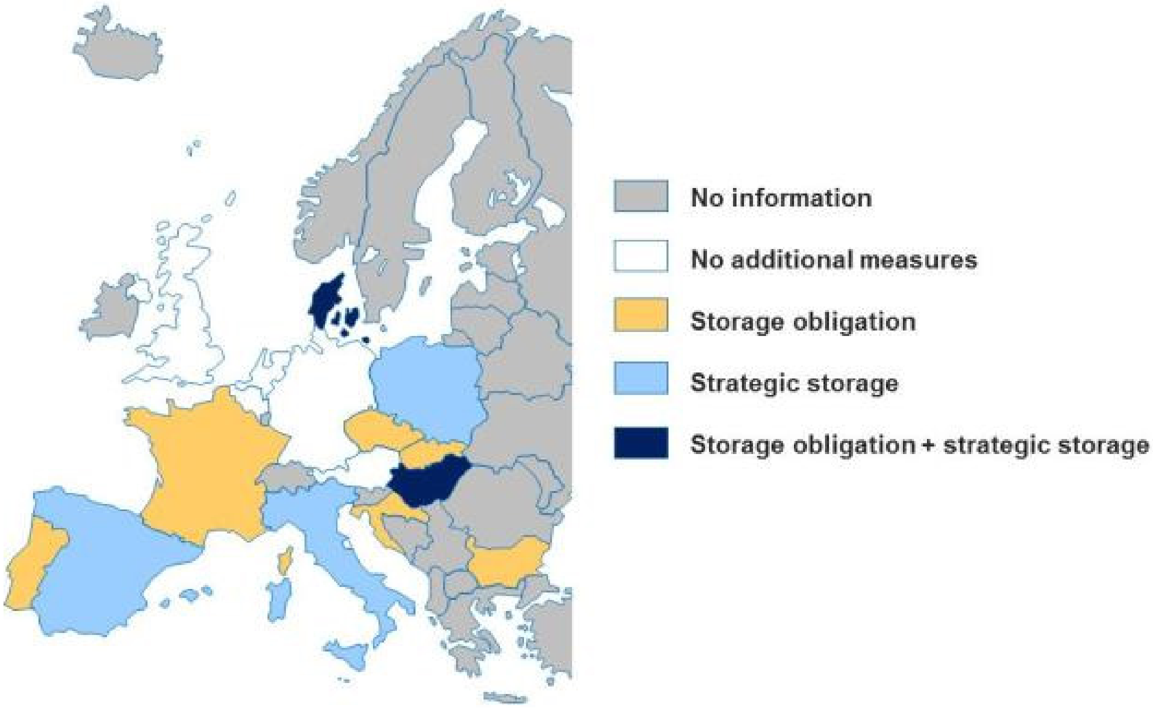
Emergency gas stocks are physical stockpiles of natural gas that are not available to the market under normal conditions. Like oil stocks, they can be owned by the government or held by the industry on the basis of government-imposed stockholding obligations. They are held to protect consumers against non-market risks, i.e. risks that the market cannot cover under normal conditions and so fall outside the reliability standards of the gas market.

Considerations for strategic storage

General principle	A fixed volume of gas has to be kept in storage permanently as a strategic reserve. Obligation not only for winter season (unlike 'storage obligation').		
Fixing of volume to be stored	On the basis of demand from specific customer group.	On the basis of the Member State's average demand for a specific period (20 or 30 days).	On the basis of gas imports to the Member State (securing supply from abroad).
Duration	Entire year		
Beneficiary	Protected customers and public institutions.	No specific beneficiary.	
Who stores gas?	Supplier obliged to store.	Storage consortium or specific institution.	Transmission system operator (TSO) stores
Location	Gas to be stored in the Member State.	Gas can be stored outside Member State if transport capacity is secured.	Specific storage site(s), e.g. close to point of consumption.
Use of stored gas	Authority (government or NRA) defines use in the event of crisis		

	(defined event).		
Cost allocation	Individual costs of supplier (for individual bookings) or consortium.		State-funded (for TSO booking).

6.2. Storage-related requirements and policies across Europe



Source: GSE, CEER and Ascari

Member States can use a wide range of tools for gas storage, including regulatory intervention and market-based instruments. Their choice will depend *inter alia* on the organisation of market, the energy mix and the availability of alternative flexibility mechanisms to compensate for disruptions. Additional security-of-supply instruments may be necessary to prepare for severe large-scale events (e.g. cutting-off of a major supply source, a coordinated attack on strategic gas infrastructure, etc.).

It appears that the market may in general underestimate the security and resilience benefits of stored gas, since these accrue to a broad range of stakeholders other than the companies bearing the costs of storage, i.e. those operating on the storage market. Suppliers, households and the public and private sectors all benefit in the event of major supply disruption. Therefore, some of the benefits of gas storage, notably its insurance value, may be considered a public good, which the market may not fully reflect in the value it attaches to its financing. Depending on the regulatory framework, strategic reserves and storage obligations in Member States may help to internalise the costs and benefits of storage.

Both strategic storage and storage obligations should be subject to strict conditions so as to avoid unnecessary costs to the gas system that would reduce the overall competitiveness of gas *vis-à-vis* other fuels.

To ensure full transparency and cooperation across borders and allow Member States to prepare appropriate measures in terms of impact on security of supply, such non-market instruments should be explained in detail in regional risk assessments, preventive action plans and emergency plans, as proposed under the revised SoS Regulation. Closure of storage sites could be avoided, e.g. by ensuring a level playing-field between competing flexibility instruments, *inter alia* through appropriate transport tariffs. Tariffs should reflect the costs of storage facilities and may also take into account the gas security benefits they provide.

7. PCIs contributing to the development of the gas market for LNG and gas storage

A subset of projects of common interest (PCIs), as identified in the second list of 2015 PCIs, serves in particular the purpose of the LNG and storage strategy.

Central East South Europe Gas Connectivity group (CESEC)

The CESEC group identified six key priority projects that specifically improve LNG access for all countries in the region, along two main corridors:

i. the LNG regasification facility at Krk, together with the evacuation pipeline towards Hungary, would bring a new source of gas to Croatia and its neighbours, from west to east; and

ii. the Greece-Bulgaria and Bulgaria-Serbia interconnectors, with further reinforcement of the Bulgarian system and reverse flow capability for the Romanian network, would allow Greek LNG and Trans-Adriatic Pipeline (TAP) gas from the Caspian to reach Bulgaria and countries further north.

These projects will also enable cross-border access to existing storage capacities in the region. Additional projects could further improve security of supply in the region, depending on the needs of the market and progress with other key projects.[17]

Baltic Energy Market Interconnection Plan (BEMIP) group

The BEMIP group identified nine key priority projects that specifically contribute to LNG and storage access in the region. These will connect the Baltic states and Finland to the European network (via an interconnector between Finland and Estonia, grid reinforcement between the Baltic states and an interconnector between Poland and Lithuania). Once interconnected, the enhanced Inčukalns underground gas storage facility will make storage services available to the entire regional market. Additional LNG import capacity could be added in the Baltic Sea region countries through new terminals in Sweden or Estonia (Paldiski or Tallinn) or at the existing Świnoujście terminal in Poland.

South West Europe high-level group

The Iberian Peninsula already has extensive access to LNG, in addition to supplies from Algeria. However, as mentioned in the Madrid Declaration of March 2015, specific projects in the region would serve to eliminate bottlenecks, connect regional markets and maximise the diversification of the EU's gas portfolio. A scalable MidCat project (between Spain and France) and the subsequent development of the 3rd Portugal-Spain interconnection would

[17] LNG terminal in northern Greece (to be developed if there is local market demand), offshore Romanian gas to the grid and further enhancements of the Romanian system, and a Croatia-Serbia interconnector.

make this a reality.[18] Other projects seen as enablers of the eastern axis, such as reinforcement of France's domestic gas transmission, have been identified in the second PCI list.

Other EU projects

In addition, analysis has consistently highlighted Ireland as lacking diversity of supply and Cyprus and Malta as being 'energy islands'. The PCI process includes projects that would address these vulnerabilities and work is ongoing to determine the most economic solutions (which may or may not involve new LNG infrastructure).

Detailed information on relevant PCIs

The table below sets out basic information (technical characteristics and implementation timeline) on the projects referred to in the strategy. The total cost of the projects implies possible investment needs of around €5 billion, but it should be borne in mind that:

- initial cost estimates are typically optimistic and real costs can easily be 15-20 % above project promoters' current estimates; and
- depending on project and design choices (e.g. whether an Estonian LNG project goes ahead and, if so, which of the two currently proposed variants will be constructed), the total investment figure could also be lower; the same applies to the LNG terminal in Krk, where three different developmental stages/options are proposed.

[18] A ministerial meeting of the high-level group adopted an implementation plan in January 2016 and EU co-funding under the Connecting Europe Facility has been allocated to studies for the scalable MidCat.

Name of project (PCI number)	How the project contributes to Energy Union objectives	Location and type / technology used	Implementation status (expected commissioning date)
Interconnector between Estonia and Finland [currently known as "Balticconnector"] (8.1.1)	The project will end the gas isolation of Finland, provide access to Klaipeda LNG terminal and, after completion of GIPL, further diversify gas sources, routes and counterparts. Overall, it will increase the security of gas supply of both Finland and Estonia by integrating markets in the eastern Baltic region.	**Location**: From Inkoo (west of Helsinki (FI)) to Paldiski (west of Tallinn (EE)) — routing based on the TEN-E G122/04 Balticconnector study **Technology:** New 80 km bidirectional offshore pipeline (Inkoo-Paldiski, DN500, 80 bar), plus 50 km onshore pipeline in EE (Kiili-Paldiski, DN 700, 55 bar) and 20 km onshore pipeline in FI (Siuntio-Inkoo, DN500, 80 bar), including metering and compressor stations at both ends with nominal capacity of 7.2 mcm/day. Capacity can be increased to 11 mcm/day if network capacity in EE and FI is increased. The power of each compressor station is about 10 MW. Of offshore pipeline, 50 km are expected to be part of the FI transmission system and 30 km part of the EE transmission system.	Design and permitting (2020)
EITHER: Paldiski LNG (EE) (8.1.2.2) **OR** Tallinn LNG (EE) (8.1.2.3)	Either project would provide the Baltic states and Finland with further diversification.	**Location**: New onshore LNG terminal near Paldiski, Harju county (EE), including a reloading facility for bunkering and truck-loading bays. **Technology:** Stage I will have a storage capacity of 160 000 cm LNG with a send-out capacity of 3.84 mcm/day; second stage can increase the storage capacity to total of 320 000 cm LNG and send-out capacity to 14 mcm/day, subject to market demand.	Design and permitting (2019 (Stage I))
		Location: Muuga Harbour, near Tallinn (EE) . **Technology:** New conventional onshore LNG terminal near Tallinn, at Muuga Harbour (including reloading facilities for ships and barges, bio-methane and/or methane-rich gas receiving, network injection facility, truck-loading bay), with send-out capacity of 4 bcm/year and further potential up to 8 bcm/year. LNG storage capacity is up to 320 000 cm and the ship size on existing berth is 230 m (LOA), with an extension possibility to the second berth (also existing) with ship size of 350 m (LOA). The terminal is capable of handling any LNG tanker that can pass through the Danish Straits	Design and permitting (2017 (Phase I); 2019 (Phase II))
Enhancement of Latvia-Lithuania interconnection (8.2.1)	The project will further increase gas transportation capacities from the Klaipeda (LT) LNG terminal and from other EU markets (once GIPL will be commissioned) to Latvia, Estonia and, after completion of Balticconnector, Finland.	**Location**: Riga to Iecava (LV) and Iecava to the Lithuanian border; Kiemenai station (LT) **Technology:** Construction of new 50 km parallel pipeline from Riga to Iecava (LV) and new 43 km parallel pipeline from Iecava to the Lithuanian border, with capacity of 12 mcm/day (onshore); upgrade of a gas metering station in Kiemenai (LT).	Planned (2021)

Name of project (PCI number)	How the project contributes to Energy Union objectives	Location and type / technology used	Implementation status (expected commissioning date)
Enhancement of Estonia-Latvia interconnection (8.2.2)	The project will enable gas to flow from north to south, i.e. from Finland and Estonia to Latvia and Lithuania.	**Location**: Viljandimaa, Karksi, Puiatu (EE) **Technology:** Upgrade of an onshore pipeline to a capacity of 10 mcm/day. The power of the compressor station(s) is 35 MW.	Design and permitting (2019)
Poland-Lithuania interconnection [GIPL] (8.5)	The project is a game-changer in the eastern Baltic region. It will end the gas isolation of the Baltic states and, after completion of Balticconnector, also of Finland. It will provide the region with access to diversified sources of gas (including LNG) from central Europe.	**Location**: Rembelszczyzna (PL) — Jauniunai (LT) **Technology:** New onshore, bi-directional pipeline with a total length of 534 km (177 km in LT and 357 km in PL) and capacity of 2.4 bcm/year in the direction PL->LT and up to 1.7 bcm/year in the direction LT->PL. The capacity in the direction PL->LT may be extended up to 4.1 bcm/year in the second stage of project development.	Design and permitting (2019)
Enhancement of Inčukalns Underground Gas Storage (8.2.4)	Inčukalns (LV) is the only UGS in the eastern Baltic region that (once the necessary transmission capacity is provided) could provide services to Poland, Lithuania, Latvia, Estonia and Finland.	**Location**: Vidzeme, 45 km from Riga (LV) **Technology:** Upgrade and extension of an aquifer storage facility with the following technical characteristics: - current working gas volume: 2 300 mcm; after extension 2 635-2 835 mcm; - current withdrawal capacity: up to 28-30 mcm/day; after modernisation (expected): 34-35 mcm/day; - current injection capacity: 17 mcm/day; after modernisation: 21-22 mcm/day; - cycling rate: 1 time/year (seasonal storage).	FID (Stage 1) (Stage 1 & 2: 2022; Stage 3: 2027)
Interconnector Greece-Bulgaria [IGB] between Komotini (EL) - Stara Zagora (BG) (6.8.1.)	Key route (together with the interconnection point Sidirokastro-Kulata) to carry gas, e.g. from TAP and Greek LNG, to Bulgaria and further north.	**Location:** Between Komotini (EL) and Stara Zagora (BG). **Technology:** New 185 km onshore pipeline with a capacity of approximately 13.7 mcm/day. The power of the compressor station(s) is approximately 20 MW.	Permitting (2018)

Name of project (PCI number)	How the project contributes to Energy Union objectives	Location and type / technology used	Implementation status (expected commissioning date)
PCI Gas interconnection Bulgaria — Serbia [currently known as "IBS"] (6.10.)	Crucial diversification and security of supply link for Serbia.	**Location:** Sofia district, from Sofia to Kalotina (BG), and then through Dimitrovgrad to Nis (RS) **Technology:** New 150 km onshore pipeline with a capacity of 1.8 bcm/year connecting the Bulgarian and Serbian gas systems.	Feasibility studies(2018) Design of the BG section
Necessary rehabilitation, modernisation and expansion of the Bulgarian transmission system (6.8.2)	Specific system reinforcement to ensure that gas can flow in and out of Bulgaria across its existing and planned interconnectors with Greece, Serbia and Romania.	**Location:** Existing gas transmission infrastructure in Bulgaria **Technology:** Activities relating to the overall rehabilitation, modernisation, reinforcement and expansion of the existing gas transmission infrastructure in Bulgaria (modernisation and rehabilitation of compressor stations, inspections, repair and replacement of sections; expansion and modernisation of the existing network).	Feasibility studies/Front End Engineering Design (FEED)/permitting (2020)
Phased Romanian system reinforcement (on the Bulgaria-Romania-Hungary-Austria corridor (6.24.2)	System reinforcements to ensure that existing and planned bidirectional interconnectors with Bulgaria and Hungary are integrated into the regional market. The project will allow cross-border capacity to reach 1.5 bcm/year to Bulgaria and 1.75 bcm to Hungary.	**Location**: Podișor-Corbu-Hurezani-Hațeg-Recaș-Horia Pipeline **Technology:** New 478 km onshore bidirectional pipeline on the Podișor-Corbu-Hurezani-Hațeg-Recaș route, with a transmission capacity towards Bulgaria of 1.5 bcm/year and towards Hungary of 1.75 bcm/year. Compressor stations in Podișor, Bibesti and Jupa are also included.	Design (FEED) (2019)
Phased development of an LNG terminal in Krk (HR) (6.5.1)	The worldwide LNG market can provide opportunities for diversification and security of supply to Croatia and the broader CESEC region.	**Location:** Omišalj, on the island of Krk (HR) **Technology:** LNG terminal based on a migration concept: 1st phase: LNG Regasification Vessel — installation of receipt of LNGRV, with the corresponding annual send-out capacity of 1-2 bcm/year; 2nd phase: Floating Storage Unit — storing LNG on a vessel; — onshore regasification — a segment of the future LNG terminal, with corresponding send-out capacity of 2-3 bcm/year; 3rd phase: LNG terminal onshore, with corresponding send-out capacity of 4-6 bcm/year.	Feasibility/FEED/permitting (2019)

Name of project (PCI number)	How the project contributes to Energy Union objectives	Location and type / technology used	Implementation status (expected commissioning date)
Zlobin — Bosiljevo — Sisak — Kozarac — Slobodnica (HR) (6.5.2)	Gas from the LNG terminal in Croatia needs to be brought to market, including beyond Croatia.	**Location:** Zlobin via Bosiljevo, Sisak, the Kozarac gas node to Slobodnica (CZ) **Technology:** Construction of new, upgrade and extension of existing pipelines with a total length of 308 km, as follows: - Zlobin — Bosiljevo pipeline (58 km); - Bosiljevo — Sisak pipeline (100 km); - Sisak — Kozarac pipeline (22 km); - Kozarac — Slobodnica pipeline (128 km). The capacity is 30 mcm/day	Feasibility/FEED/permitting (2019)

8. LNG penetration and impact of selected PCIs

The analysis considers four scenarios to assess the potential penetration[19] of LNG in the EU. In order to be able to measure this, a theoretical approach was taken based on an assumption that LNG and domestic production are the only available supply sources to cover total demand on an average winter day. The total demand is the sum of daily final gas demand (i.e., from households, commercial activities and industry) and demand for electricity generation[20]. Storage and pipeline imports are not considered. Prices and other types of technical or economic barrier are disregarded.

The scenarios are as follows:

1. LNG is used to cover only the national final gas demand of the Member State with an operating terminal (Figure 5);
2. A cooperative approach is taken, whereby Member States with LNG capacity exceeding national gas demand share the surplus with neighbouring countries with sufficient interconnection capacity (Figure 6);
3. New up-coming LNG terminals and a set of relevant PCIs identified by the current strategy (Figure 7) are taken into account with LNG supply still being used locally; and
4. A cooperative approach is taken, using the new infrastructures referred to in the third scenario (Figure 8).

Member States cooperate by covering only a proportion of their national demand themselves and leaving the surplus supply available for neighbouring countries. The proportion is calculated by dividing the total available[21] extra LNG capacity in a given region (i.e. a group of Member States linked by cross-border points) by regional aggregated gas demand, once domestic production is discounted. The transfer of LNG supply among Member States is constrained by aggregate capacity at cross-border points. The intensity of LNG use is quantified using the 'LNG supply index', calculated as the percentage of national gas demand covered by available LNG capacity. Maximum daily LNG capacity and the capacities at cross-border interconnection points on the primary market are set using 2014 data published by ENTSOG[22] and Gas LNG Europe[23]. Final gas demand is determined under average winter conditions and Scenario A in ENTSOG's *Ten-year Network Development Plan 2015.*[24] Demand for electricity generation is derived from 'peak demand for power generation' (Vision

[19] i.e., the proportion of total supply that LNG could account for on an average winter day.
[20] The definitions used in the ENTSOG Ten-Year Network Development Plan are applied here.
[21] Available capacity is not total national surplus capacity, but the part of it that could be potentially sent to a neighboring Member State through the interconnection points.
[22] http://www.entsog.eu/maps/transmission-capacity-map
[23] http://www.gie.eu/index.php/maps-data/lng-map. For Greece, the value declared in the national Risk Assessment is applied.
[24] http://www.entsog.eu/publications/tyndp#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2015.

3 scenario) and rescaled for the average winter[25]. National production is based on the ENTSOG plan.

8.1. Scenario 1

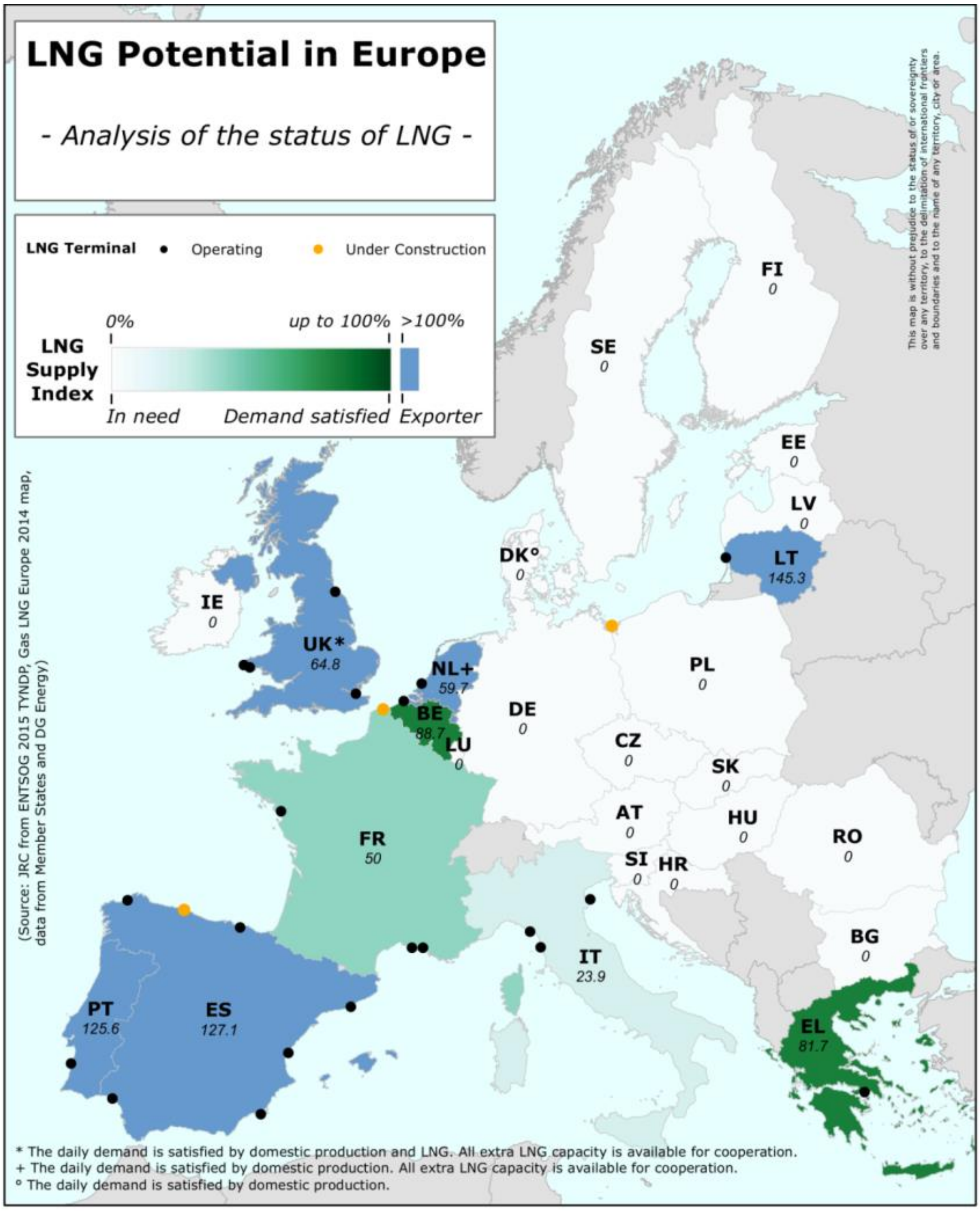


Figure 5 Current potential penetration of LNG in Member States with an operating terminal (assuming no cooperation between Member States)

[25] It has been assumed that the ratio between electricity demand and final gas demand for the peak condition is the same as for the average winter condition. This assumption could bias upward the demand for electricity in some Member States. JRC derived average winter consumption for electricity generation for Bulgaria from the Bulgarian Risk Assessment.

Current LNG penetration at national level shows that not all Member States with at least one LNG terminal could cover their national gas demand and have extra capacity to export (Figure 5).[26] France, Italy, Greece and Belgium do not have excess export capacity. Their available LNG capacity can partly cover national gas demand. The overall extra capacity of LNG in this scenario is substantial but not shared: 3.4 mcm in the Baltic region and 95.3 mcm in the rest of Europe for an average winter day.

Note: If a Member State has extra LNG capacity to export to other Member States, it is marked in blue to stress its role of potential exporter. Even in these cases, the LNG supply index may be lower than 100 %, as LNG may cover only part of its demand (the rest being covered by domestic production). This is the case with the UK, for example: when the LNG capacity is shared with other Member States, the surplus LNG is exported, while all domestic production is consumed locally. The LNG supply index therefore decreases as the exported amount is deducted.

8.2. Scenario 2

[26] The Netherlands is modelled in each scenario considering only the high calorific gas system.

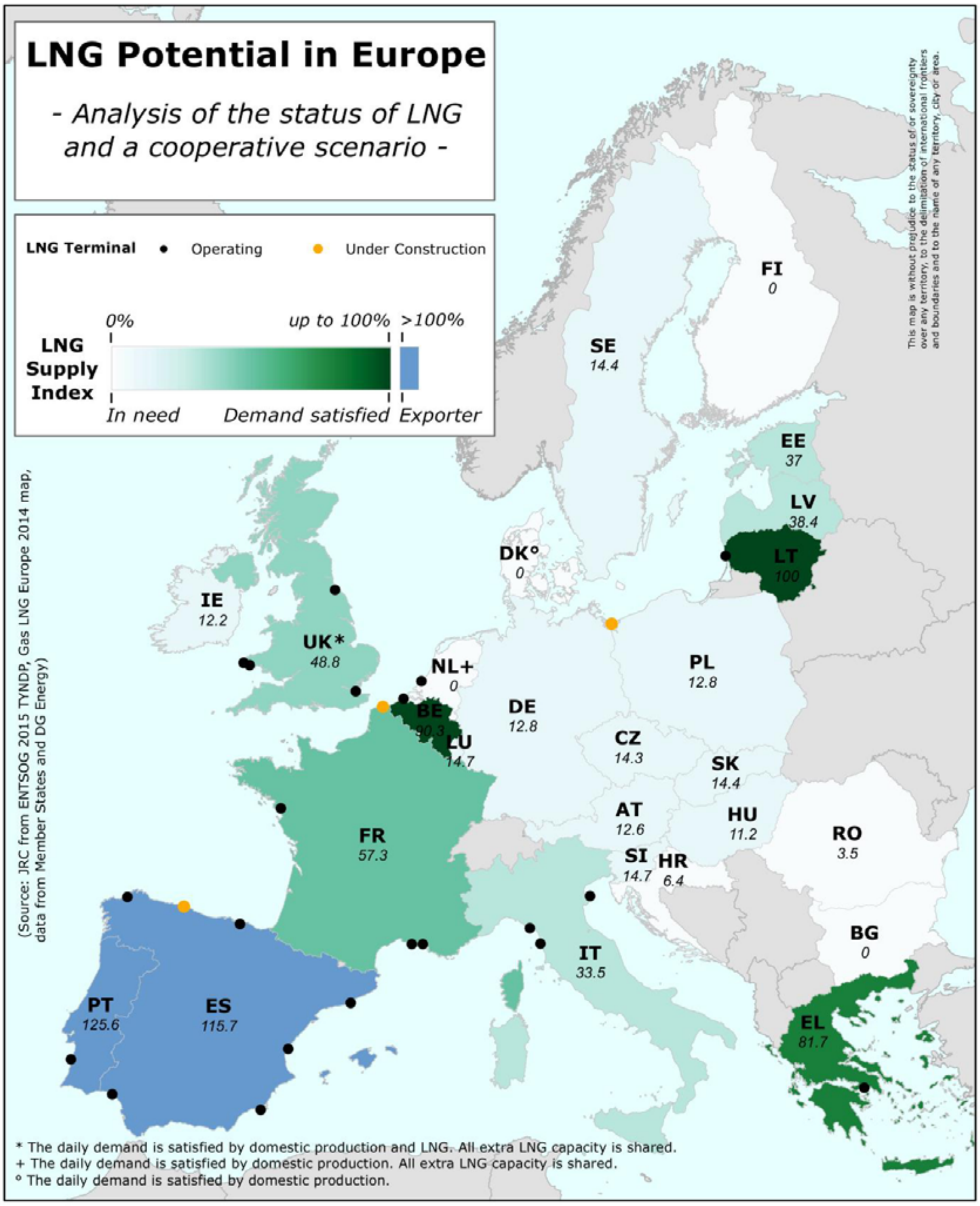


Figure 6 Potential LNG penetration under a cooperative approach with 39 % of demand for the Baltic Region and 15 % for the rest of Europe (excluding Bulgaria and Greece, which form an isolated region)

All Member States except Bulgaria and Finland[27] could benefit from cooperation, by using the extra available LNG capacity (Figure 6). The average national increase in the LNG supply index for Member States in need is 12 %, taking into account the constraints imposed by cross-border interconnection capacities. The intensity of cooperation is 39 % for the Baltic region and 15 % for the rest of Europe (excluding Bulgaria and Greece, which form an isolated region with no extra LNG available). The main export flows are from the UK and the Netherlands to central and south Europe, and from Spain to France. Lithuania can cooperate

[27] Finland has one small scale LNG liquefaction terminal, and 2 small-scale off-grid regasification terminals under construction

only with Latvia and Estonia, as the Baltic region is still isolated from the main grid. Greece cannot share with Bulgaria, and south-east Europe is in need of supply. The potential of the Iberian Peninsula is still underexploited because of the limited interconnection capacity with France and the absence of reverse-flow capacity from France to Germany and Belgium.

8.3. Scenario 3

If we factor in new upcoming LNG terminals and some relevant PCIs, the EU's LNG potential improves further (Figure 7). Overall extra capacity increases to 139 mcm for an average winter day. All Member States are connected to a single EU gas network. Estonia and Croatia become potential exporters. Poland is able to cover a third of its national demand. France increases its utilization. Cross-border capacities are increased in the South-East Corridor and in the Iberian Peninsula. The Baltic region is linked to the main EU grid and Croatia supplies central-eastern Europe.

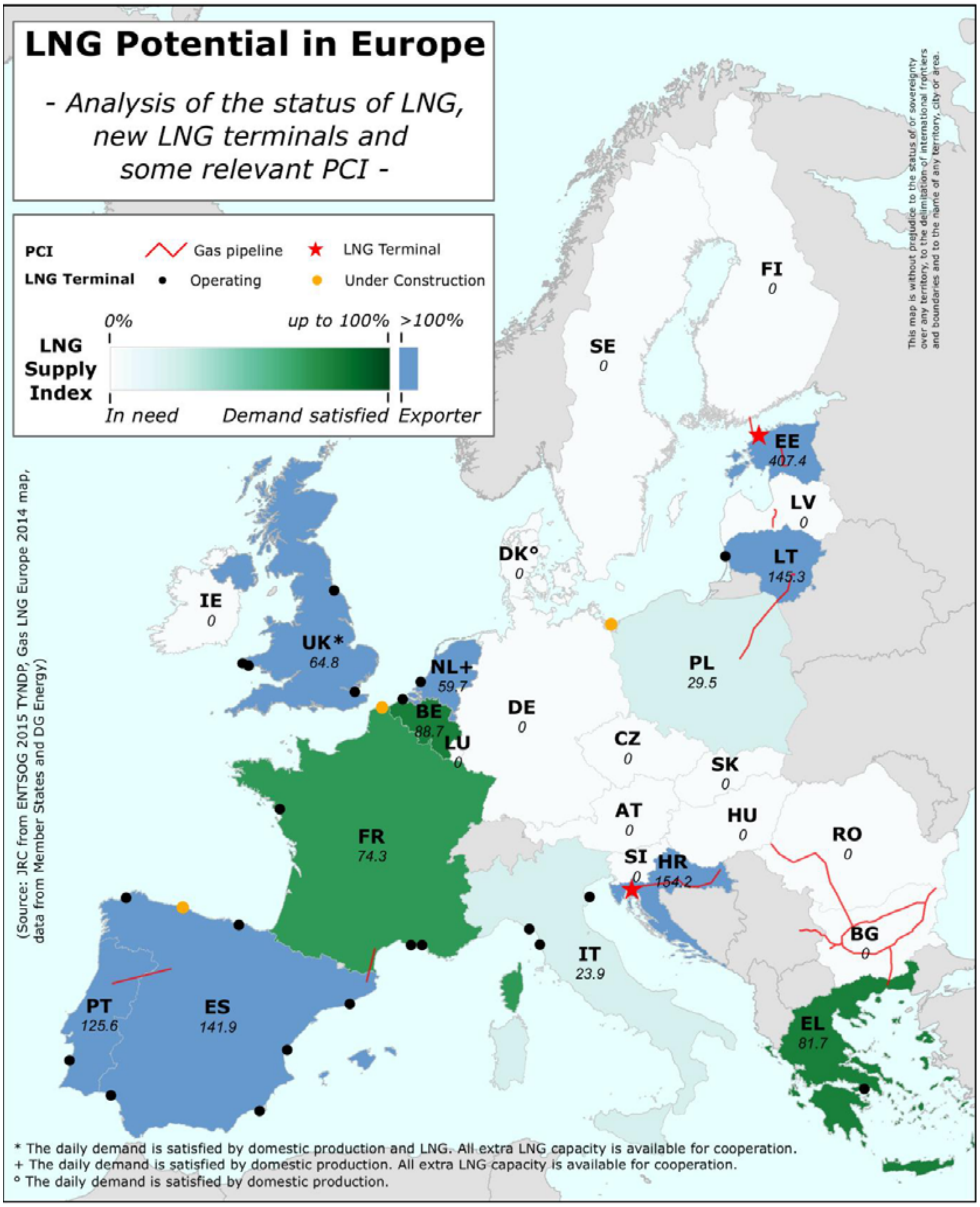


Figure 7 **Potential penetration of LNG after completion of relevant PCIs (including new LNG terminals and interconnections), without cooperation between countries**

8.4. Scenario 4

All Member States could benefit even more by cooperating and using the extra available LNG capacity (Figure 8). The average increase in the LNG supply index in Member States without LNG terminals is 19 %, taking into account the constraints imposed by cross-border interconnection capacities. The intensity of cooperation is 22% for all Member States in need, increasing the volume of LNG shared. There are new export flows from Estonia to the Baltic region, from Lithuania to Poland and from Croatia to Hungary and south-east Europe. In this scenario, Italy cannot completely cover its cooperative share of gas demand, falling 3 % short of its expected LNG supply index value.[28] Residual surplus supply coming from Spain to France is trapped due to the absence of reverse flow to Germany or Belgium and the capacity of the cross-border interconnection with Switzerland now acting as a bottleneck. Other extra LNG supply is available in the Baltic region because of the limited capacity of the new Poland – Lithuania interconnection, from Lithuania to Poland.

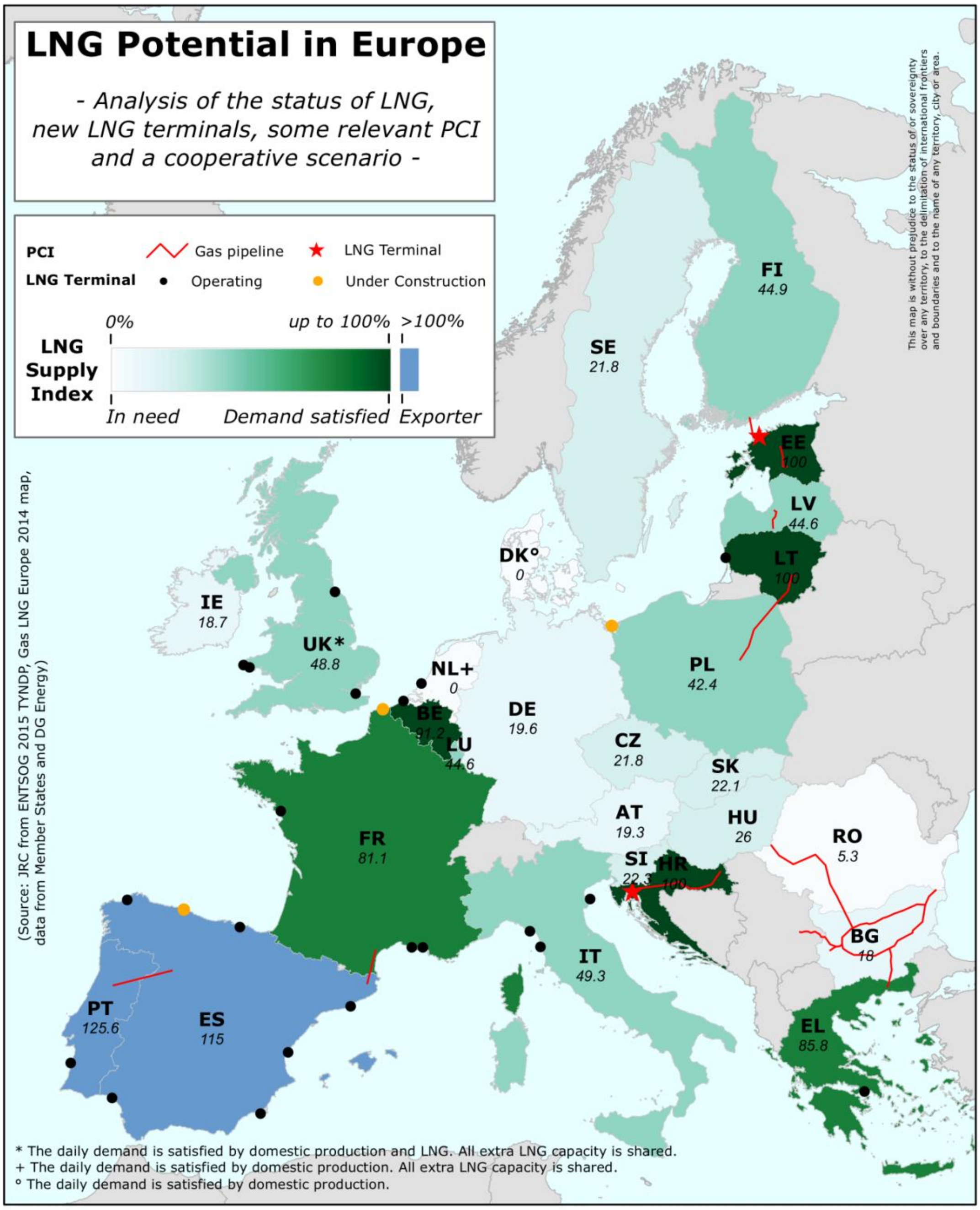


Figure 8 Potential penetration of LNG after completion of relevant PCIs and with cooperation between countries; 35% of demand is covered for Member States in need

[28] In other variants of this scenario, Slovakia and/or Greece are unable to achieve their targets if Italy does so. Slovakia can never fully achieve its target because of the limited capacity of the interconnection with Hungary. There are possible solutions whereby all the three fall a little short of their targets. We have taken this scenario to highlight the positive impact of the PCIs in the North-South Gas Corridor.

9. LNG as an alternative fuel in transport, heat and power

The use of LNG as an alternative fuel to diesel in heavy duty **road transport** such as lorries can contribute significantly to the reduction of pollutant emissions such as NOx, SOx and particulate matter (PM), and to noise. An extensive demonstration of the technology's feasibility is being carried out under the LNG Blue Corridors project[29].

The current LNG vehicle offer in the EU remains limited, due the lack of EURO VI compatible[30] high power lorries, but is expanding. Some vehicle manufacturers are already offering EURO VI lorries. Others have announced that they will start marketing them this year or next.

Demand for LNG from EU road transport fleet operators is increasing. The development of the necessary infrastructure is under way with significant support from the TEN-T CEF Programme.

The use of LNG in **maritime transport** permits the sector to meet the requirements for reducing the sulphur and nitrogen content in marine fuels in the Emission Control Areas. Figures for reductions in specific emissions are as follows[31]:

- NOx up to 90%
- SOx up to 95%
- PM[32] nearly 100%,

LNG use in shipping can also cut CO_2 emissions by up to 25%, and the use of LNG can therefore support the European Commission's ambition to cut emissions from the shipping sector by at least 40% from 2005 levels by 2050, and if feasible by 50%[33].

Essential to this are the technical works necessary to facilitate the use of LNG in a safe and interoperable way, which will be completed in international fora and within the EU to the timeframe set out in Directive 2014/94/EU on the deployment of alternative fuels infrastructure.

The work of the European Sustainable Shipping Forum, which was set up in 2013 by the European Commission and which harnesses the expertise of government and industry experts, will be crucial in this regard, in particular in the context of the development of international LNG bunkering standards covering safety, training, gas quality aspects, ship-supplier commercial relations, procedural/operational aspects, certification, standardisation and all other remaining legislative and operational gaps identified by the EC Study on the completion of an EU framework on LNG-fuelled ships and its relevant fuel provision infrastructure[34].

[29] http://lngbc.eu/
[30] http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32007R0715
[31] https://lngforshipping.eu/about-lng/environment-sustainability
[32] Particulate Matter
[33] COM(2011) 144 final: Roadmap to a Single European Transport Area - Towards a competitive and resource efficient transport system
[34] Study on the Completion of an EU framework on LNG-fuelled ships and its relevant fuel provision infrastructure: http://ted.europa.eu/udl?uri=TED:NOTICE:347013-2013:TEXT:EN:HTML&tabId=1

The use of LNG in transport is an option because of LNG's its high energy density, low pollutant emissions and lower greenhouse gas emissions,[35] however the overall GHG impact of LNG usage will be affected by any emissions ('slip') of methane during filling/bunkering and/or operation of engines, and this therefore needs to be minimised[36]. Similar considerations apply to the use of LNG in heat and power supply.

There is significant potential for GHG impacts to be further reduced through the use in LNG fuelled ships or lorries of liquid biomethane (and/or liquid synthetic gas produced from low carbon sources), for example through blending with LNG.

The overall environmental impacts of LNG facilities can also be reduced by, for example, combining regasification facilities with cooling warehouses or other large energy consumers who can make use of the excess cooling potential.

[35] Life cycle greenhouse gas intensity according to Directive 2015/652 is for diesel 95,1 gCO2eq./MJ, and for LNG 74,5.
[36] Methane slip is expected to be largely eliminated in the next generation of LNG-fuelled engines.