INSTITUTE OF ENERGY
FOR SOUTH-EAST EUROPE

Prospects for the Establishment of Gas Trading Hubs in SE Europe

IENE Working Paper No28

Athens, June 2020

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Authors:

Dimitris Mezartasoglou, *Head of Research IENE*

Costis Stambolis, *Executive Director IENE*

Institute of Energy for SE Europe (IENE)
3, Alexandrou Soutsou, 106 71 Athens, Greece
tel: +0030 210 3628457, 3640278 fax: +0030 210 3646144
web: www.iene.gr, www.iene.eu e-mail: secretariat@iene.gr

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June 2020

This Working Paper summarizes the findings and conclusions of IENE's Study on the "Prospects for the Establishment of Gas Trading Hubs in SE Europe" (IENE Study M49) which was carried out in the second half of 2019.

This IENE Study Project was financially supported by a number of companies and organizations whose valuable contribution and support is acknowledged herewith with great thanks. The following companies acted as sponsors of the Study:

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Executive Summary

The European gas sector is facing major challenges affecting the way natural gas is traded and priced. Oil indexation is the dominant pricing mechanism, but is currently under increasing pressure as trading is gradually shifting to indexation on hub market prices. Gas hubs are virtual or physical locations where buyers and sellers of gas can meet and exchange gas volumes. In other words, gas hubs are marketplaces for natural gas.

The Institute of Energy for South-East Europe (IENE) took the initiative and carried out a research project, based on an earlier IENE study M19 (September 2014) on "The Outlook for a Natural Gas Trading Hub in SE Europe" **(1)**, in order to examine the conditions and prospects for establishing a gas hub in SE Europe. At present, there is neither a market mechanism to buy or sell gas in an efficient manner in the SE European region, nor a price discovery mechanism to determine spot prices, and gas exchange is based on bilateral agreements.

Today, there are 14 gas trading hubs operating across Europe. According to the International Gas Union, gas-on-gas competition in Europe increased from 15% in 2005 – when oil price escalation was 78% - to 76% in 2018 – when oil price escalation had declined to 24% **(2)**. Liquidity is increasing in European trading hubs, while the European Union aims at further increasing of liquidity, in the context of the completion of an integrated and interconnected internal energy market. The integration is expected to increase the energy market effectiveness, create a single European gas and electricity market, contribute in keeping prices at low levels, as well as increase security of supply. Trade between EU member states will become more flexible and thus, possible curtailments of Russian supplies will have less impact on the European gas market.

Oil-indexed prices have been associated mainly with long-term contracts while hub prices have been associated with spot or short-term contracts. Oil-indexed long-term contracts prevailed in the gas sector because they were considered to ensure investment security for the producer as well as security of supply for the consumer. On the other hand, a gas price mechanism which reflects the market value of the product should be considered as a natural evolution for the pricing of a commodity. Indeed, long-term contracts with prices linked to a gas market would ensure a price level reflecting the balance of supply and demand of the product in addition to security of supply.

Europe sees an important opportunity to meet its energy needs by developing the Southern Gas Corridor, at the core of which are gas supplies from the Caspian area (including Azerbaijan and most likely in the far future from Turkmenistan, Kazakhstan and Iran) and possibly from the Middle East (Iraq). The SE European countries (i.e. Greece, Croatia, Bulgaria, Romania, Turkey and Serbia) have well established gas markets, with supplies coming primarily through imports from Russia and, in the case of Turkey, from Iran and Azerbaijan also. Greece and Turkey, which have well developed LNG import and storage terminals, also import from Algeria, Nigeria, Qatar and other LNG spot markets. Two countries have a significant proportion of their demand met from domestic supplies (i.e. Croatia and Romania) and three others cover small percentage shares from domestic gas (i.e. Bulgaria, Serbia and Turkey).

According to IENE forecasts, some marginal gas quantities will become available after 2020 in the SE European region, which could be traded and therefore, as far as trading is concerned, the need will emerge for market prices to be determined. Turkey is already a major gas importer from Russia, Iran and Azerbaijan. In the future, Turkey is likely to get gas from Iraq. In addition, LNG will be another important player in the market, as there are plans for new LNG import terminals in the region. Already, one FSRU[1] is planned to be based in Alexandroupolis in Northern Greece, with the prospect of feeding gas quantities into the Greek and Bulgarian natural gas systems, among others. The Trans-Anatolian Pipeline or TANAP, already in operation since June 12, 2018, will be connected to Greece through the Trans-Adriatic Pipeline (TAP) pipeline, which is now under construction and about 91% completed as of October 2019. In addition to Azeri gas, TAP could be used to transport North African gas to Southern Europe and Turkey via reverse flow. There will also be a connection between Greece and Bulgaria and Bulgaria to Turkey via new interconnector pipelines. The immediate result of all of this is that there will be certain gas quantities available for trading outside long-term contracts. Consequently, the establishment of a natural gas trading hub initially to enable trading between Greece, Bulgaria and Turkey, will ensure the determination of market prices through the exchange of marginal gas volumes.

A hub can be a physical point, at which several pipelines come together (e.g. Zeebrugge) or it can be a virtual (balancing) point inside a pipeline system (like the NBP). In other words, a *physical hub* is an actual transit location or physical point where gas pipelines meet and natural gas is traded. Physical hubs can serve as transit points for the transportation of natural gas, as well as storage facilities. Nonetheless, a hub does not need to be a physical intersection of pipelines.

A *virtual hub* is a trading platform for the financial transaction of natural gas, where a wide number of participants have access. Physical hubs are implemented at a specific location where natural gas must imperatively be transported to. However, in

[1] A Floating Storage Regasification Unit (FSRU) is a special type of vessel which is used form transporting LNG.

the case of virtual hubs, the trading platform serves a trans-regional zone or an entire country. Therefore, the traded gas can be injected into any point on a trans-regional or national grid regardless of the point of extraction. The obvious advantage of virtual hubs is that all gas which has paid a fee for access into the network can be traded, while at physical hubs, only gas physically passing at a precise location can be traded and this entails higher risks.

Virtual trading hubs, such as NBP or TTF, do not yet exist in Southern and Eastern Europe. The region is now starting to warm up to the prospect of a liquid market where long-term contracts and spot or short-term trading are combined. The establishment and functioning of a gas trading hub requires a deregulated gas market, which is not the case today in most countries of SE Europe.

However, one could argue that the operation of a physical transit regional hub, such as the Belgian Zeebrugge, could also be possible, due to the flexibility resulting from the operation of the existing and planned interconnections in the region. The region could serve as a transit route for carrying Azerbaijani gas to smaller hubs that are planned in the region, as well as the Central European Gas Hub in Austria. Like the Zeebrugge, a hub where pipelines physically meet, a regional hub storage and LNG facilities, as well as pipeline connections, could become a possible balancing point for both storage and transportation.

A virtual hub would offer even greater flexibility, because – as it has already been mentioned – in virtual hubs, the eligible gas for trading is all the gas which has paid a fee for access into the network. Especially when moving towards an entry-exit system – which is required by EU regulation for member states - virtual hubs are more suitable for gas trading.

The establishment of a regional natural gas hub is expected to facilitate the wholesale trading of natural gas between participants in SE Europe. Essentially, it will allow gas supply and demand to meet in a marketplace by providing a platform for physical and/or financial transaction. It will enable competitive markets to function, even though it will probably have an administrative role in the beginning of its operation.

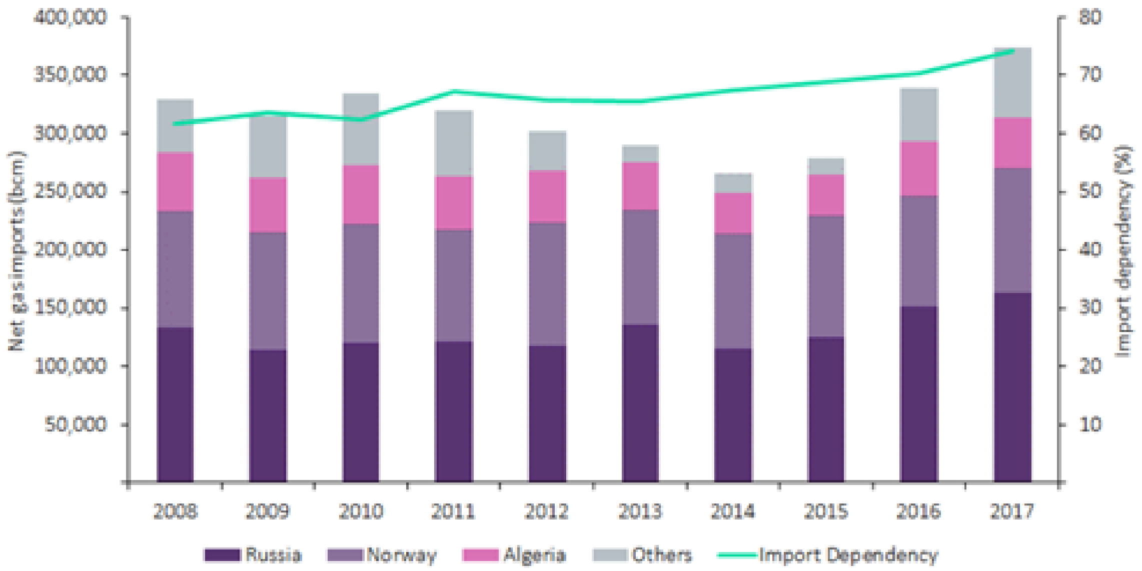
An important issue to be addressed is where the gas hub will be based. Increased supply optionality and infrastructure development are prerequisites for creating a market in the region. At the moment, there are several new pipeline connections planned in SE Europe, as well as FSRU and underground gas storage facilities, with Greece, Bulgaria and Turkey having expressed a high interest in establishing a regional gas hub.

Storage will also play an important role in providing physical gas flexibility. The role of gas storage is critical as it can serve as an important flexibility tool and may affect the location of the hub, if physical. If the hub operates as a physical hub, it is possible that the TAP/IGB/IGT junction can serve as a physical hub. In this respect, the creation of an underground gas storage facility in South Kavala is key, especially if Greece is to take a lead role in this initial stage.

Introduction – Raison d' être

Europe's dependence on imported natural gas has grown over the past 10 years. Based on Eurostat's data, gas demand in the EU rose by 5% in 2017, compared to the previous year and the increase was mainly driven by increased gas-fired electricity generation. The EU imported 76% of gas in order to cover its needs, mainly from Russia, Norway and Algeria, while LNG imports stood at 12% higher in 2017 than in 2016. Domestic production continued to decline and reached 24% of EU consumption.

Figure 1: European Union: Net Gas Imports (Left Axis) and Import Dependency (Right Axis), 2008-2017



Source: Eurostat

In 2017, the total EU hub-traded volumes were around 3% lower (i.e. 44,500 TWh or 4,555 bcm), compared to 2016, which is explained by lower price volatility at the largest gas hubs (i.e. TTF, NBP and NGC). However, other hubs saw an increase in trade. Gas prices also recovered from lower values in 2016, e.g. North West Europe (NWE) hubs' day-ahead prices were 20% higher than in 2016. In 2017, hub price purchases accounted for around 70% of supplies across Europe, with differences between regions. **(3)**

European gas wholesale markets continued to show increasing levels of convergence in 2017, in terms of gas hub prices (although to a lower extent for the latter due to the absence of hubs in a number of EU member states). More specifically, gas hubs in northwest Europe registered the highest price convergence in the EU, because of similar market fundamentals, ease of access for upstream suppliers, stable increase in hub trading, relatively lower-priced cost of transportation capacity and surpluses of long-term contracted capacity and commodity. Price integration in the Central and Eastern European region has improved in recent years, while Mediterranean hubs showed lower convergence. This is due, among other things, to lower interconnection capacity levels, the pancaking of transportation tariffs and weaker hub functioning.

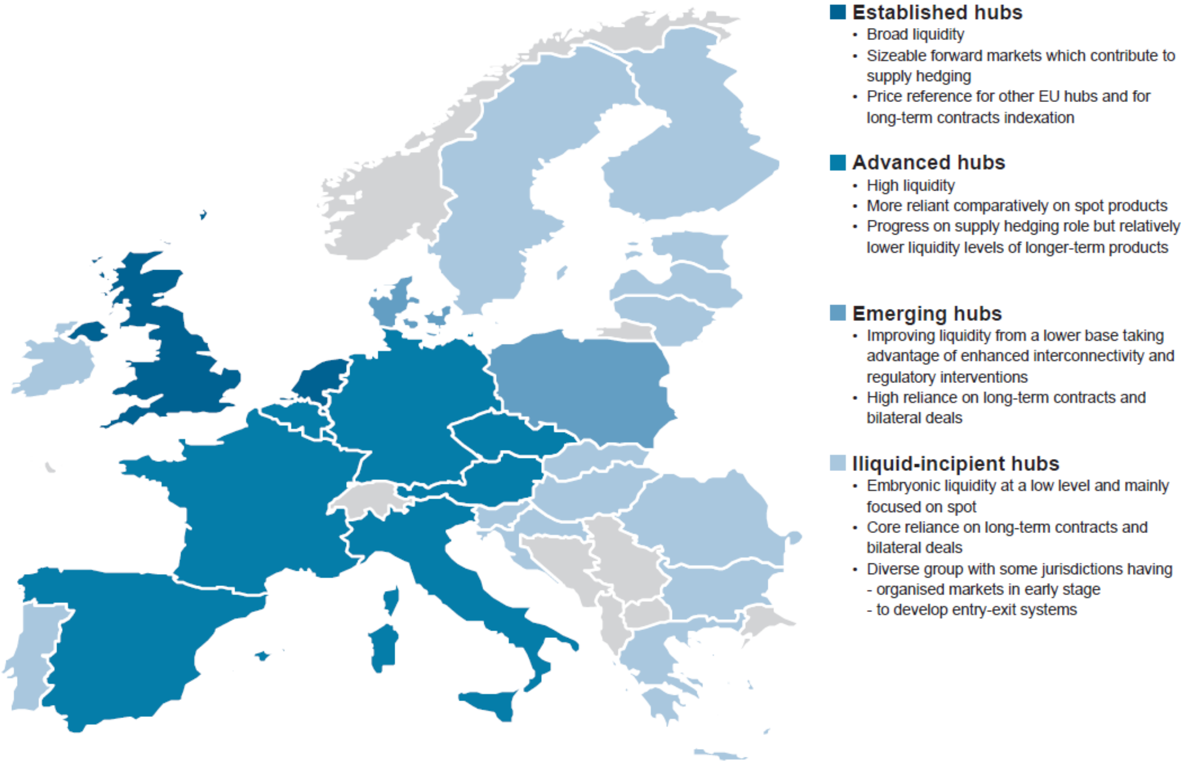
Britain's National Balancing Point (NBP) and the Dutch Title Transfer Facility (TTF) continue to be the EU's best functioning gas hubs. TTF and NBP distinguish themselves from the other hubs mainly because of the higher development of their forward markets (e.g. traded volumes on the curve, longer trading horizon, tighter bid-ask spreads). Over the last two years, TTF has overtaken NBP both in volumes traded and in its role as price-setter in Europe.

The difference between better functioning hubs and those without transparent trading venues continues to increase. Map 1 presents a classification of gas hubs. The groupings reflect the results of the ACER Gas Target Model (AGTM) metrics analysed in its Market Monitoring Report (MMR)[2]. While there are notable positive developments in the Iberian and Baltic regions, those EU member states where a trading venue with a transparent price mechanism is either absent or not visible during many trading days of the year continue to fall behind better performers. These EU member states will find it harder to catch up as the difference becomes bigger and bigger. The Energy Community Contracting Parties[3] still show very limited hub trading activity.

[2] https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202018%20-%20Gas%20Wholesale%20Markets%20Volume.pdf

[3] Currently, the Energy Community has nine Contracting Parties, including Albania, Bosnia and Herzegovina, Kosovo, North Macedonia, Georgia, Moldova, Montenegro, Serbia and Ukraine.

Map 1: Ranking of EU Hubs Based on Monitoring Results - 2018



Source: ACER

The present Working Paper aims to examine the role of a gas trading hub in SE Europe, to identify the conditions and requirements for its creation which will initially operate as a regional balancing point and eventually as a fully-fletched gas trading hub, as well as to analyze the economic and political implications of the trading activity of the hub for the SE European countries.

European Gas Trading Hubs

During the last decades, there have been important changes in the European natural gas markets. European gas hubs are young and less developed compared to US gas hubs. The Henry Hub in Louisiana sets the benchmark price for the entire North American trading area, which is the most liquid gas market in the world. Currently, the European gas market is characterized by long-term contractual arrangements with gas producers (often outside of the EU), for the delivery of specific gas volumes at specified points on natural gas transmission networks. Since deregulation in the mid-1990s and as a result of the gradual opening of gas markets in several European countries, trading has started gaining ground and spot markets have developed. However, long-term contracts are still the dominant feature. The number of participants and traded volumes are increasing along with the traditional OTC volumes.

The European Union promoted the establishment of virtual (regional) trading hubs in order to achieve the integration of its natural gas markets. According to the old market regime, the ownership exchange of natural gas is arranged in a bilateral fashion between the buyer and the supplier using long-term contracts. Market experience shows this market model will gradually be replaced by wholesale markets where sellers and buyers make short to medium-term deals through trading hubs. These deals now include futures, swaps, and even a few options.

The new market model does not include the creation of a single European regulator. To the contrary, its philosophy is to build on the existing contractual, regulatory and operational arrangements of national TSOs and regulators and facilitate the efficient use of cross-border capacity with transparent price formation, which will encourage greater participation in trading and increase liquidity.

The National Balancing Point (NBP) in the UK is the oldest and most liquid gas hub in Europe (1996). Due to gas liberalization policies carried forward by the European Union and mergers between different gas hubs (for example, between France and Germany), market pricing of gas contracts has become increasingly important in continental Europe, particularly since the pipelines connecting UK's NBP to Belgium's Zeebrugge hub and to the Dutch Title Transfer Facility (TTF) started operation. During the previous decade, market pricing was launched in the rest of Europe through interconnecting pipelines, while new gas hubs were created.

Table 1: Evolution of European Gas Traded Hubs (as of 2018)

Gas Traded Hubs	Date
NBP	National Balancing Point; Great Britain; 1996
ZEE/ZTP	Zeebrugge Hub/Zeebrugge Trading Point; Belgium; 2000/2012
TTF	Title Transfer Facility; Netherlands; 2003
PSV	Punto di Scambio Virtuale; Italy; 2003
PEG (N,S,T)/TRS/TRF	Points d' Echange de Gaz (Nord, Ouest, Est, Sud, TIGF); France: 2004 PEG Nord (merger of PEGs N,O,E); France: 2009 Trading Region South (covering PEG Sud and TIGF); France: 2015 Trading Region France (covering PEG Nord, Sud and TIGF); France: 2018
AOC/PVB	Almacenamiento Operativo Comercial/Punto Virtual de Balance; Spain; 2004/2015
GTF/ETF	GasTransfer Facility/Electronic Transfer Facility; Denmark; 2004
CEGH/VTP	Central European Gas Hub/Virtual Trading Point; Austria; 2005/2013
GPL	Gaspool; Germany; 2009
NCG	NetConnect Germany; Germany; 2009
MGP	Magyar Gázkiegyenlítési Ponton; Hungary; 2010
VOB	Virtuální Obchodní Bod; Czech Republic; 2011
VPGS	Virtual Point Gaz-System; Poland; 2014
SK (VOB)	Slovenskom Virtuálnom Obchodnom Bode; SK; 2016

Source: Heather, P. (4)

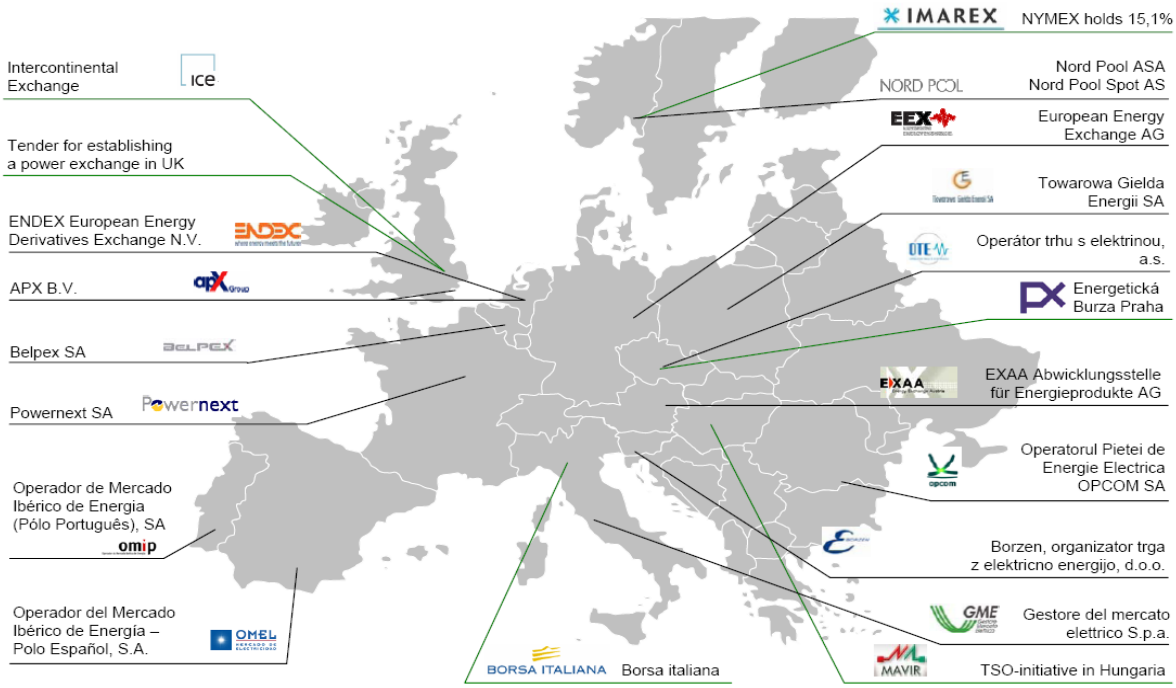
Map 2: European Gas Regions, Markets and Hubs (as of 2018)

Source: Heather, P.

European Energy Exchanges

The list of power markets in Europe is large. It is composed of a group of regional power markets, which are more or less physically connected. These markets operate under the umbrella of the Electricity Regional Initiative launched back in 2006 and introduced the transition into a single, integrated energy market. Each of the 7 regions is monitored by a different entity and a vital part of their unification work is to help establish wholesale markets for electricity.

Map 3: Energy Exchanges Across Europe



Source: EUROPEX

The most relevant exchanges operating in these regions (and which increasingly overlap their products) are organized in an Association called the EUROPEX, i.e. the Association of European Energy Exchanges, which currently has 26 members.

The Role of Gas Exchanges in Promoting Gas Trade

There was a sharp increase in gas exchange trading post-financial crisis, especially in Anglo-Saxon countries from 2010 onwards, due to these markets being more financially secure than the OTC markets. Nevertheless, the gas exchanges are complementary to the OTC market and offer an alternative route to market for market participants, having very different modes of trading, different cash flow implications and of course, a different risk profile.

Being regulated markets, gas exchanges are obliged to make public the price and volume data which promotes price transparency and discovery and therefore, the ability to know the price of gas now for immediate delivery and in the future (up to six years ahead on ICE NBP and five years for ICE-Endex TTF). The data are publicly and easily accessible, either on the gas exchanges' own websites or disseminated through price reporting agency screens. Gas exchange trading allows for the ability to easily separate the price function from the physical supply function thereby providing a facility for managing price risk through a secure and regulated market, whilst keeping the physical flows separate.

As well as allowing for hedging and trading, the gas exchanges can also be a marketplace for the buying and selling of, usually, marginal quantities of physical gas and are in many countries the vehicle used for the balancing requirements of that hub. However, the main role and function of gas exchanges is that they are complementary to the OTC markets and assist in the development of gas trading hubs in a secure and regulated environment.

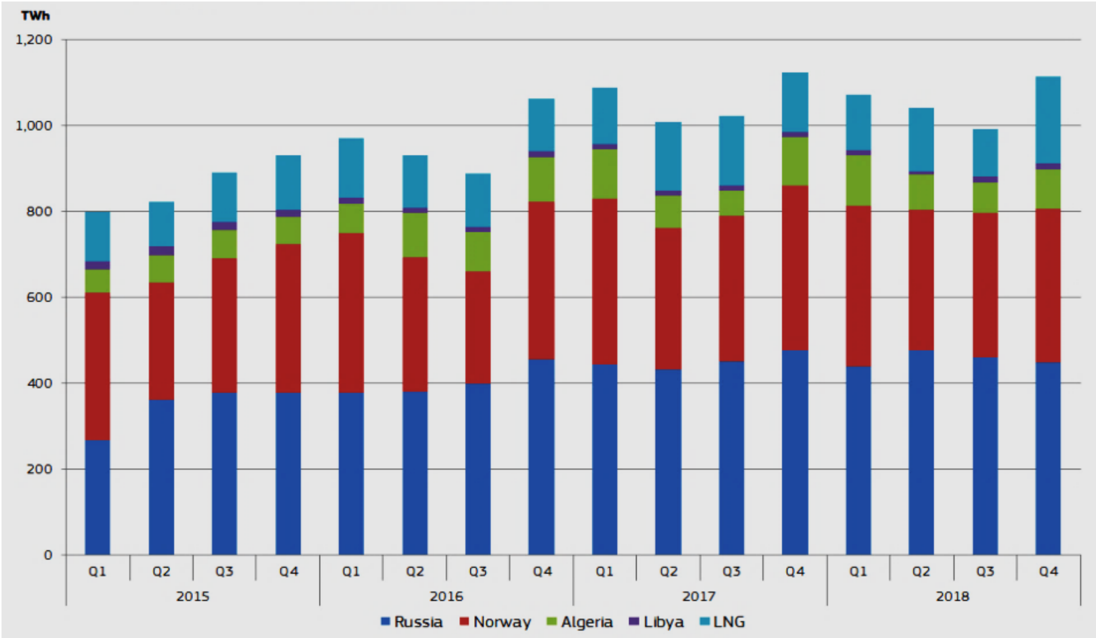
Potential Suppliers of European Gas Market and Their Role in Ensuring Market Liquidity

According to the Quarterly Report on European Gas Markets, published by the European Commission, net imports of EU gas rose by 8% in the fourth quarter of 2018, compared to Q4 2017. Imports from Russia decreased by 6% y-y, while Norwegian imports also went down by 4%. Imports from Algeria decreased by 17%, while those from Libya rose by 10%. At the same time, LNG imports reached the highest over the last five years and ensured 18% of the total extra-EU gas imports. In Q4 2018, the total net EU gas import was 100 bcm, while in 2018, it amounted to 363 bcm, up by 3% (by 10 bcm), compared to 2017.

Russian pipeline supplies remained the main source of EU imports, covering 40% of extra-EU imports in Q4 2018, down by 2%, compared to the same period of 2017, and the lowest since Q1 2016. It was followed by Norwegian pipeline imports (32%), LNG imports (18%) and pipeline supplies from North Africa (10%). The EU's estimated gas import bill rose to around €28 billion in Q4 2018, 30% more than a year earlier. In 2018, the EU import gas bill is estimated to €90 billion, up from €75 billion in 2017, primarily owing to increasing import gas prices, compared to 2017, based on data provided by the European Commission.

EU LNG imports showed a huge increase in Q4 2018, up by 59% in y-y comparison. After a summer period with very low LNG send-outs, shrinking price premiums of the Asian LNG markets enabled more cargos to arrive in Europe in Q4 2018. Increasing LNG imports resulted in a shift of supply sources, as the share of Qatar and Nigeria in total extra-EU imports dropped from the previous quarter (to 22% and to 14%), while Russia became the second most important LNG source (17%) and the share of the US quadrupled, reaching 12% in Q4 2018.

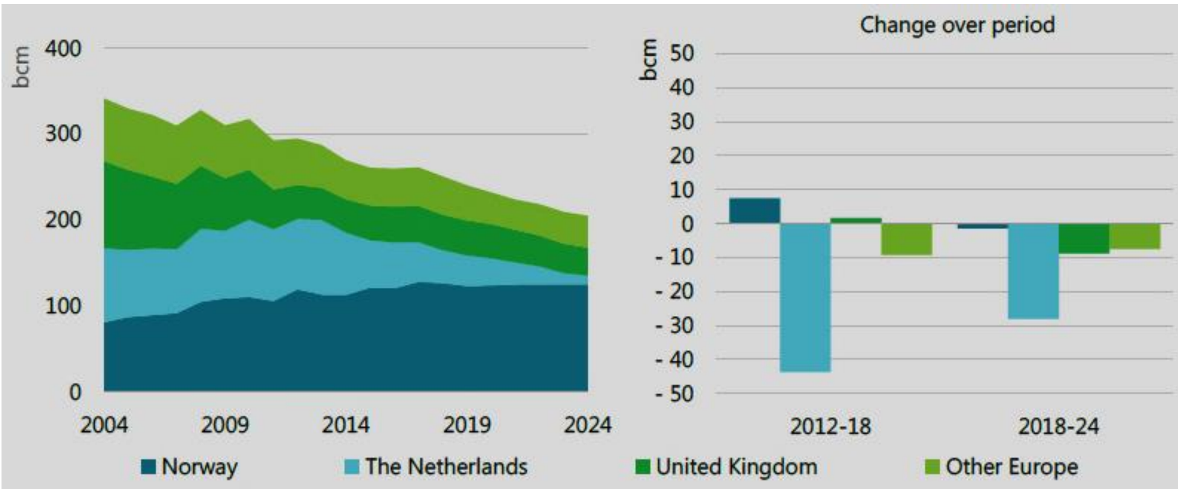
Figure 2: EU Natural Gas Imports by Country, 2015-2018



Source: European Commission, Quarterly Report on European Gas Markets (Vol. 11)

According to IEA's 2019 Gas Report **(5)**, gas production in Europe is expected to decrease at a rate of 3.5% per year by 2024, meaning that approximately 45 bcm of domestic gas supply will be lost. This is largely driven by the decision of the Dutch government to phase out the giant Groningen field by 2030 at the latest. As shown in Figure 3, the Netherlands accounts for over 60% of the decline in European gas supply by 2024.

Figure 3: Gas Production in Europe, 2004-2024



Source: IEA

Falling UK production is the second source of European production decline (18% of the region's decrease between 2018 and 2024). Production in other European countries, such as Denmark, Germany and Italy, is also expected to decline, and to be counterbalanced by production increases in Romania by 2024. Norwegian gas production, the largest contributor to European domestic supply, is expected to remain stable to 2024. Given that European gas demand is expected to remain stable over the next five years, declining domestic supply will further increase European gas import needs. Another consequence is the loss of some flexibility and timeliness associated with domestic production, which will foster the importance of other sources of supply flexibility such as gas storage, interconnectors and demand-side response.

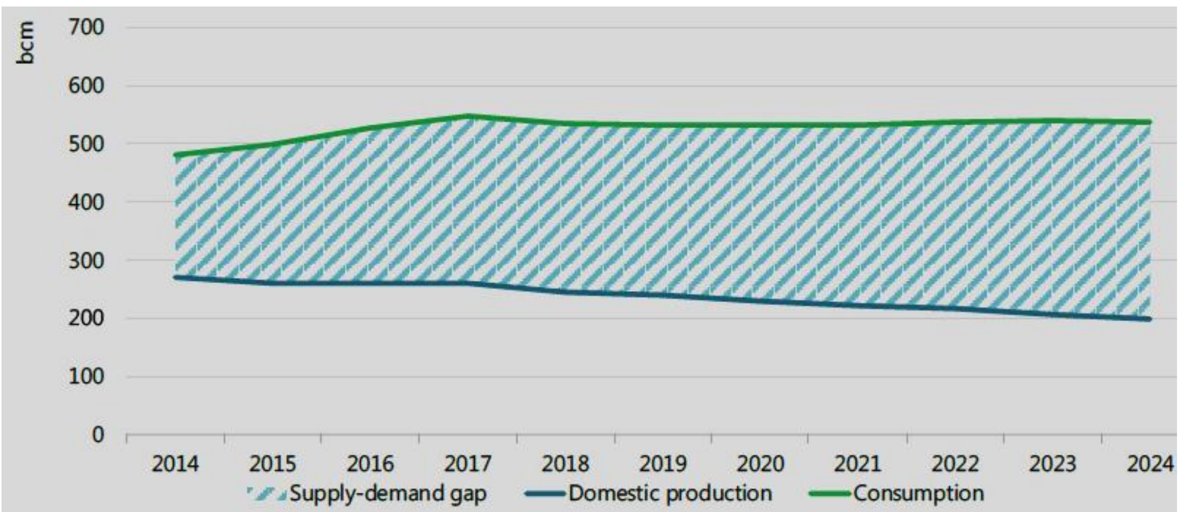
All in all, natural gas is a vital component of the EU energy mix and will undoubtedly continue to play an important role in EU's energy strategy. As already mentioned, energy security concerns have been expressed about possible curtailment in Russian gas supplies. The EU is currently looking to diversify supply and attract non-Russian gas in order to compensate for the EU production decline.

The internal European energy market is undergoing many changes, as the EU seeks to complete its integration and liberalization. The integration is expected to increase the energy market effectiveness, create a single European gas and electricity market, contribute in keeping prices at low levels, as well as increase security of supply. Trade between EU member states will become more flexible and thus, possible curtailments of Russian supplies will have less impact on the European gas market.

A Widening Supply-Demand Gap

As IEA points out, European gas import requirements are expected to increase by almost 50 bcm/y by 2024 to reach 336 bcm/y (see Figure 4). Whilst European gas consumption is set to remain almost flat, domestic production is set to fall at an average rate of 3.5% per year, primarily driven by the Groningen phase-out in the Netherlands and declining production in the North Sea.

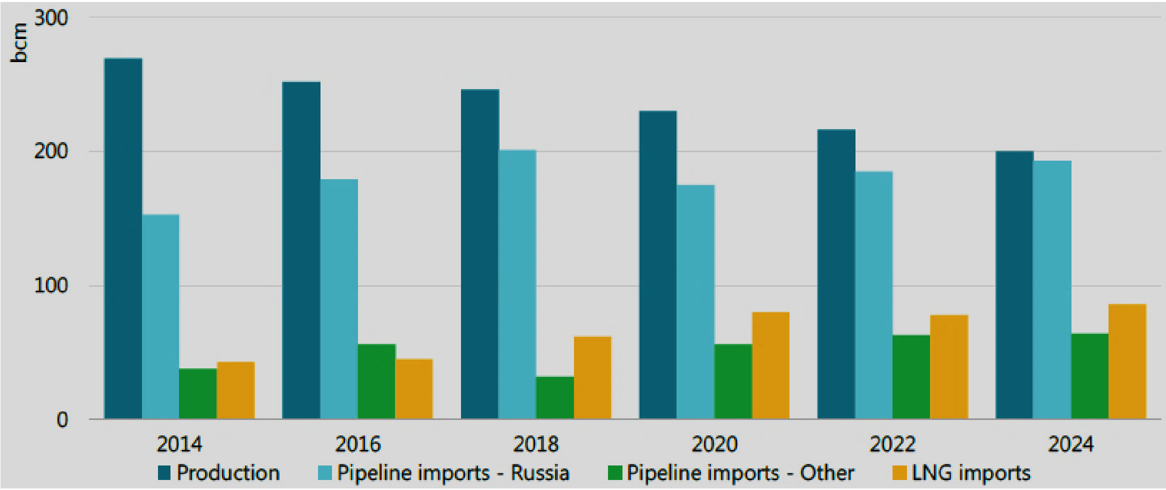
Figure 4: Gas Supply-Demand Gap in Europe, 2014-2024



Source: IEA

Incremental import requirements will be met by a variety of supply sources, including new pipeline gas imported through the Southern Gas Corridor, additional LNG volumes from an increasingly flexible global gas market and from traditional suppliers such as Russia (see Figure 5). Because of this diversification, the market share of Russian pipeline gas is expected to decline from its 2018 record high of 37% to a range of 33-36% by 2024.

Figure 5: Gas Balance in Europe, 2014-2024



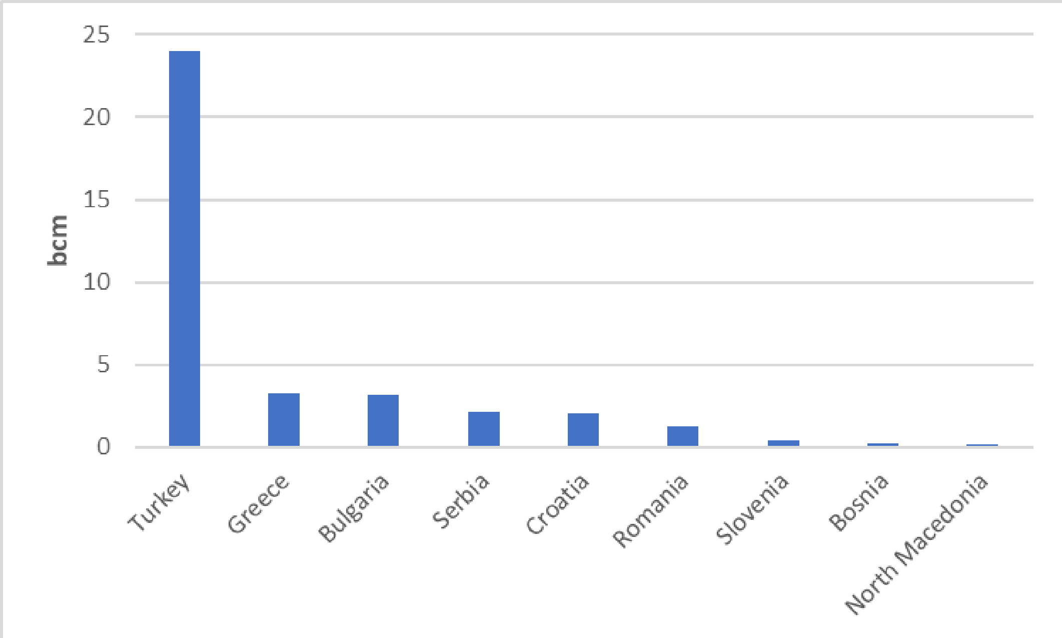
Source: IEA

SE Europe as a Gas Transit Region

Europe sees an important opportunity to meet its energy needs by developing the Southern Gas Corridor, at the core of which are gas supplies from the Caspian area (including Azerbaijan and most likely in the far future from Turkmenistan, Kazakhstan and Iran) and possibly from the Middle East (i.e. Iraq). According to the current state of play in SE Europe, forecasts predict that the demand will grow up to 2025 at a rate of 1% each year.

Six of the SE European countries (i.e. Greece, Croatia, Bulgaria, Romania, Turkey and Serbia) already use natural gas, having well established markets, with supplies coming primarily through imports from Russia (see Figure 6) and, in the case of Turkey, from Iran and Azerbaijan also. Greece and Turkey, which have well developed LNG import and storage terminals, also import from Algeria, Nigeria, Qatar and other LNG spot markets. Two countries have a significant proportion of their demand met from domestic supplies (i.e. Croatia, Romania) and three others cover small percentage shares from domestic gas (i.e. Bulgaria, Serbia, Turkey). In projecting future demand for gas in the region, one of the main issues is the extent to which availability of gas would make possible the displacement of other fuels in various categories of demand, such as power generation and residential, commercial and industrial applications. Relative prices and competing fuels lie at the heart of analysis, although potential growth in demand for gas will also be driven by other factors, including environmental aspects and national policies.

Figure 6: Russia's Gas Supplies to Selected SEE Countries (bcm), 2018



Source: Gazprom Export (6)

It is generally assumed that the natural gas sector will grow faster in the SE European region mainly because the main driver for gas consumption growth is power generation which is emerging as one of the faster developing sectors of the broader SE European energy market. While each single SEE gas market is relatively small, a regional approach provides a sound basis for development. Romania is the biggest gas producer of the region with 9.5 bcm annual production (2018), while the consumption of the SE region (excluding Turkey) is around 22.7 bcm (2018). The three most gas dependent countries of the SE European region are Turkey, Bulgaria and Greece. Indigenous gas production in SE Europe (excluding Turkey), at 12.9 bcm/year, is sufficient to cover around half of current gas demand. However, not all countries in the region are gas consumers. This is especially true in Western Balkans which in the vast majority of their geographical expanse do not have any gas infrastructure.

Planned Major Gas Infrastructure Projects in SE Europe

Natural gas pipelines have been a hot topic lately in the European energy agenda, a region heavily dependent on Russian gas supply. For instance, Bulgaria and Greece launched the construction of the €220 million Interconnector Greece-Bulgaria, while Serbia's energy minister said his country plans to build a natural gas pipeline connecting Belgrade to Banja Luka in Bosnia. The present Working Paper will attempt to chart progress made so far in all different gas infrastructure projects in SE Europe, but also discuss the serious challenges which lie ahead.

Based on data of October 2019, 90.5% of the **Trans Adriatic Pipeline (TAP)** project has been completed **(7)**, while 10% of the respective offshore part of the pipeline under the Adriatic Sea has also been constructed. The overall construction phase of the project is expected to be completed in the second half of 2019, as Italian Prime Minister Giuseppe Conte has given the green light for the completion of the TAP pipeline, expressing his support after many months of negotiations and constant concern over the objections of the Italian side. TAP is a project worth a total of €4.5 billion. The TAP pipeline will transport Caspian natural gas to Europe, connecting with the Trans Anatolian Pipeline (TANAP) at the Greek-Turkish border crossing Northern Greece, Albania and the Adriatic Sea before coming ashore in Southern Italy to connect to the Italian natural gas network.

Once built, TAP will provide important new energy supplies to SE Europe very much needed to power its homes and industries as the region transitions to a low-carbon future. Natural gas is the cleanest fossil fuel and will continue to play an important role in Europe's future energy mix helping to replace more carbon intensive sources of energy. It will also increase energy security by diversifying EU's energy supplies. For instance, on completion, TAP will provide an estimated 33% of Bulgaria's gas needs, 20% of Greece and approximately 10.5% of Italy. **(8)**

It is worth noting that the TAP AG, a company established to plan, develop and build the TAP pipeline, and the Greek National Gas System Operator (DESFA) signed an agreement on the maintenance of Greek section of the TAP pipeline, which was ratified by the competent Regulatory Authority for Energy (RAE) on December 12, 2018, while the TAP and the TANAP successfully completed their connection in early November 2018 with the final "golden weld", which physically connected the two pipelines. It is worth noting that the TANAP is already in operation since June 12, 2018.

The **Turkish Stream**, with its onshore leg still under construction, will supply Russian gas to Turkey via the Black Sea and is expected to be operational by the end of this year upon completion of the construction of its onshore part on Turkish territory. The Turkish Stream project consists of two lines across the Black Sea, the first of which will serve Turkey with a capacity of 15.75 bcm, while the second line, of the same capacity, is planned to serve Europe. Each pipeline is 930 kilometers in length, laid at depths reaching 2,200 meters. The project is the biggest-diameter offshore gas pipeline in the world laid at such depths. The deep-sea pipe-laying was carried out by Pioneering Spirit, the world's biggest gas pipeline laying vessel.

On November 19, 2018, Istanbul hosted the ceremony of completion of the construction of the offshore section of the Turkish Stream. The seabed section is 910 km long and the land section will run 180 km into Turkey. The project is estimated at a total of €11.4 billion. **(9)**

On December 21, 2018, Bulgartransgaz, Bulgaria's gas transmission and storage system operator, launched a public procurement procedure for the construction of the so-called Bulgarian section of Turkish Stream. During the following day, the country's Energy Regulator gave permission for the state-owned company to start pre-selling the pipeline capacity, the funds from which will be used to finance the project. The Bulgarian part of the Turkish Stream envisages over 480 km of gas pipeline and two new compressor stations at Provadia and Rasovo. **(10)**

In May 2019, Russian Gazprom confirmed that the first quantities of gas – estimated at 15.75 bcm per year – will be fed through the Turkish Stream pipeline to Turkey by December 31. More specifically, the pipeline will be ready for testing in November, while the goal is to launch commercial operations in the last ten days of December, according to Mr. Vitaly Markelov, the vice-president of Gazprom. It is planned that the second leg of the Turkish Stream pipeline will feed the SE European market after 2021, with an additional quantity of 15.75 bcm. This quantity will more than offset the quantities delivered to Bulgaria, Greece, Turkey and North Macedonia via the Trans Balkan pipeline, the future of which remains uncertain. **(11)**

One more project under construction is the **Interconnector Greece-Bulgaria (IGB)** which consists of a cross-border and bi-directional gas pipeline, connecting the Greek gas network with the Bulgarian gas network. The annual capacity of the gas pipeline is foreseen to be up to 5 bcm, with an initial capacity of 3 bcm. The IGB inauguration ceremony took place in Bulgaria's Kirkovo on May 22, 2019. On October 10, 2019, an inter-governmental agreement was signed in Sofia by the two countries' energy ministers. Earlier in May, ICGB AD, the company that will construct, own and operate the IGB, has chosen following a tender Greece's J&P AVAX as EPC contractor **(12).** As Mrs. Corina Creţu, European Commissioner for Regional Policy, recently announced, about €33 million of EU funds are expected to be used in order to finance part of the construction of the IGB project.

At first glance, the biggest obstacles to the construction of the **East Med pipeline**, which consists of an offshore and onshore pipeline that will connect the East Mediterranean gas resources to the European system, are related to the pricing issues, the ability to ensure adequate gas volumes for exports as well as technical challenges. In November 2018, Israel's Energy Minister Mr. Yuval Steinitz attempted to ease fears about construction issues and suggested that East Med can be completed by 2025 **(13)**. Also, Greece's Energy Minister Mr. George Stathakis said in

December 2018 that the East Med pipeline is "technically and economically viable", enjoys the support of all the other countries involved as well as the European Commission and would allow Israel and Cyprus to transport their proven hydrocarbon reserves as well as Greece's potential reserves to the European market. Studies conducted so far indicate that the project's construction cost could reach €8 billion, while it is currently classified as a Project of Common Interest (PCI) by the EU. **(14)**

The East Med pipeline will be able to carry roughly 8 bcm/y. It is worth noting that the leaders of Greece, Cyprus and Israel met in Jerusalem on March 21, 2019 during the 6th Trilateral Greece-Cyprus-Israel Summit, which was also attended by the US Secretary of State Mr. Mike Pompeo, and agreed upon the significance of the pipeline. The presence of Mr. Pompeo signaled the full support of the US to the cooperation between Greece, Cyprus and Israel, as the US administration is committed in promoting energy security in SE Europe.

In addition, the **Vertical Corridor** emerges as a broad gas interconnectivity concept of all countries concerned, including Greece, Turkey, Bulgaria, North Macedonia, Serbia, Romania and Hungary. The Vertical Corridor concept does not concern a single pipeline project, but involves rather a gas system that will connect the existing national gas grids and other gas infrastructure in order to enhance energy security and ensure liquidity. Initially, the Vertical Corridor will be used to transport some 3-5 bcm per year but later could transfer some 8 bcm.

In May 2015, IENE completed an initial study on "The Vertical Corridor - From the Aegean to the Baltic", which attempted an all-round investigation of the existing and prospective gas infrastructure of the SEE region and its relevance to the development of the Vertical Corridor system of gas pipelines, as agreed at political level in November 2014 by Greece, Bulgaria and Romania. This IENE study provides a detailed analysis at both technical and economic level of the main parameters involved for the implementation of what appears to be a very challenging project. As it became clear from the study, the construction of new components for this system will require minimal work, whether pipelines, compressor stations, branches or metering stations since at the same time serve the needs of local gas networks **(15)**. The broad concept of the Vertical Corridor being to facilitate the movement of gas from north to south and vice-versa by enhancing the use of existing infrastructure in all countries concerned and by constructing layovers where necessary.

On September 28, 2017, Bulgaria, Romania, Hungary and Austria signed a memorandum of understanding to proceed with implementation of BRUA gas link project that seems to replace the afrorementioned Vertical Corridor. Under the memorandum, all countries have agreed on a reverse-flow gas interconnection.

Romania has issued a building permit for the BRUA project on its territory and has conducted procedures for assigning the construction works **(16)**. The pipeline will have a total length of 528 km and its Romanian section is expected to be completed by the end of 2020.

In addition, Romania's gas TSO Transgaz secured a €50 million loan from the European Investment Bank (EIB) in order to finance the first stage of the BRUA project, which is expected to link the Black Sea gas fields with Austria. The amount refers to the disbursement of the first tranche, as the total amount will be in the region of €150 million.

On June 5, 2019, Romania's President Mr. Klaus Iohannis emphasized the importance of the actual implementation of the projects launched at the Three Seas Initiative Summit that took place in 2018 in Bucharest and indicated that the BRUA gas pipeline could be one of the steps through which Romania can become the main security provider in the region. **(17)**

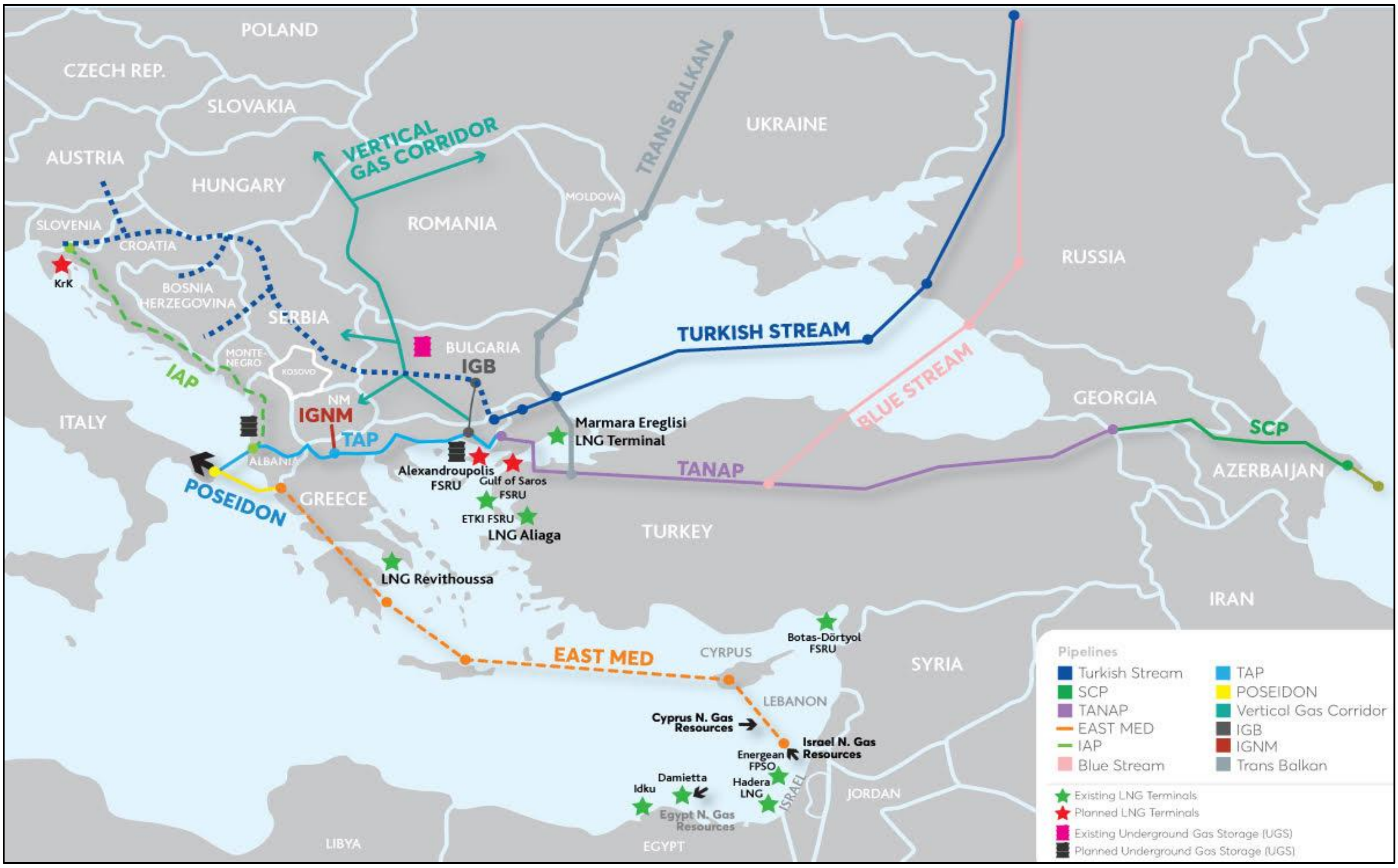
Map 4: BRUA Corridor

Source: European Commission

In addition, there are some very important planned gas infrastructure projects in SE Europe, including the **Interconnector Greece-North Macedonia**, which will enhance the diversification of North Macedonia's gas supplies as the country is solely dependent on the Trans Balkan Pipeline as well as Greece's **underground gas storage project in the depleted gas field in South Kavala**, which is expected to "collaborate" with both the planned FSRU in Alexandroupolis and the existing LNG terminal at Revithoussa, Greece's sole LNG terminal that completed its expansion in November 2018.

In parallel and in view of several new projects under development in the region, it is time to **redefine the South Corridor**, as this has already been suggested by IENE, by including these planned and new potential gas supply sources and routes. Therefore, an **Expanded South Corridor**, as shown in Map 5, may be considered and defined as such, to include all major gas trunk pipelines and LNG terminals.

Map 5: The Expanded South Corridor



NB.: The TANAP has been completed, while TAP, Turkish Stream, BRUA and IGB are under construction. The IAP, the IGI Poseidon in connection with East Med pipeline and the Vertical Corridor and the IGF are still in the study phase. Blue Stream and Trans Balkan are existing pipelines.

Source: IENE

The Role of LNG in SE Europe

It appears that LNG prospects in SE Europe and the East Mediterranean in particular, are far better placed than they were five years ago with new projects getting ready to progress and LNG clearly emerging as a fuel of choice for several industrial consumer groups helped by lower prices and increased availability.

In SE Europe, LNG seems to be a realistic alternative fuel as it increases security of supply through multiple and independent supply sources, provides the opportunity for new LNG suppliers (e.g. Australia, US, etc.) to export gas to the region, enhances pricing flexibility and safer gas transportation and can also support underperforming gas pipeline projects. It is worth noting that on December 30, 2018, Greece's Revithoussa LNG terminal, following an agreement between Cheniere and DEPA, welcomed the first US LNG cargo at its newly build 3rd tank of 95.000-m3 storage capacity. Thus, the Revithoussa LNG terminal opens up the way for new prospects in gas supply by differentiating energy sources and enhancing security of supply in SE Europe, enabling Greece to become a gas hub for the wider region.

On May 30, 2019, Greece's Public Power Corporation (PPC) held a tender for the purchase of 130,000 cubic meters of LNG with five providers submitting bids and with the best offer tabled by Shell. The LNG will be stored at the Revithoussa terminal. The quantity is expected to be consumed within July 2019 by the power utility's units. According to a PPC press release, the net benefit for the utility amounts to €11 million, when compared to the average contract price for similar LNG portfolios. **(18)**

It is thus anticipated that the SE European region will play a significant role in expanding LNG trade in Europe by 2020 through the construction and operation of several new LNG regasification projects such as the FSRU unit that is planned to be located offshore in Alexandroupolis, in Northern Greece, with the prospect of feeding gas quantities into the Greek, Bulgarian, Serbian and Turkish gas systems, among others.

Regarding the Alexandroupolis FSRU, Gastrade, the promoter of the project, is close to launching a binding second-round market test for annual capacity reservations, seen taking place within the next few weeks **(19)**. The company has requested the approval of market-test guidelines and regulations from Greece's Regulatory Authority for Energy (RAE). Once this stage has been completed, participants will receive a series of related documents covering issues such as capacity reservation and guarantees. Pricing policy is among the matters that have been discussed between Gastrade and RAE in the lead-up. Gastrade has opted for a flexible pricing policy, promising users a range of choices on aspects such as LNG quantities, products and commitment durations. Binding second-round market test participants will be given approximately two months to make their capacity reservations for the LNG terminal, sources have estimated. The market test's first round, a non-binding stage, was completed on December 31, 2018. Twenty firms based in various parts of the wider region, as well as major international gas traders, expressed interest for annual capacity reservations totaling 12.2 bcm, which exceeded the project's planned regasification capacity of 5.5 bcm.

One further FSRU project in Greece is now in the planning stage and it is promoted by Motor Oil Hellas, a major refining and oil marketing group. This latest FSRU project, which received its approval by RAE on March 5, 2019, is to be located offshore in the Agioi Theodoroi area, near Motor Oil's refinery **(20)**. The capacity of the FSRU tank will be 135,000-170,000 m^3, while its regasification capacity peak is expected to be 470,000 Nm^3/h.

Cyprus provides an interesting LNG paradox. In August 2019, the country selected contractors (led by consortium of JV China Petroleum Pipeline Engineering Co Ltd, AKTOR S.A. and METRON S.A., with Hudong-Zhonghua Shipbuilding Co. Ltd and Wilhelmsen Ship Management Limited) as preferred bidders to develop a 2.5 bcm/y FSRU to be located offshore in Vasilikos Bay, near Limassol, along with jetty mooring and pipeline infrastructure. The c. €300 million investment costs are being met by the EU with grants of €105.8 million (from CEF) and €10 million (from the European Energy Programme for Recovery or EEPR) with the remainder from the participants in the import terminal. A separate Expression of Interest process has been launched for LNG supply to the project, the results of which are expected by the end of 2019. Concurrently, Cyprus has revived discussions around plans to develop an LNG export project (either onshore or floating) to monetise recent gas discoveries in Cyprus' EEZ – notably the 2011 discovery of the Aphrodite gas field, as well as more recent discoveries named Calypso and Glaucos-1. **(21)**

Turkey's first FRSU terminal in Aliağa (i.e. ETKI FSRU), north of the port city of Izmir on the country's Aegean coast, launched operations in December 2016. The 145,000 m^3 LNG storage capacity vessel is operated by the Turkish construction companies Kolin and Kalyon with a 20 mcm of send-out capacity per day. In addition, the Botas-Dörtyol FSRU, the world's largest FSRU in operation in the Turkish port of Dörtyol, a district in the southern province of Hatay, started its operation in February 2018 as the country's second FSRU terminal. The FSRU has an LNG storage capacity of 263,000 cubic meters and has re-shipment and gas transfer capabilities, with a regas discharge capacity of 540 mcm per day. Turkey has also two land-based LNG terminals (i.e. Aliaga and Marmara Ereglisi). Thus, Greece and Turkey are the only countries in the broader Black Sea-SE European region which at present possess LNG gasification terminals which are well linked and integrated into their national gas systems (see Map 6).

Map 6: LNG Terminals in SE Europe

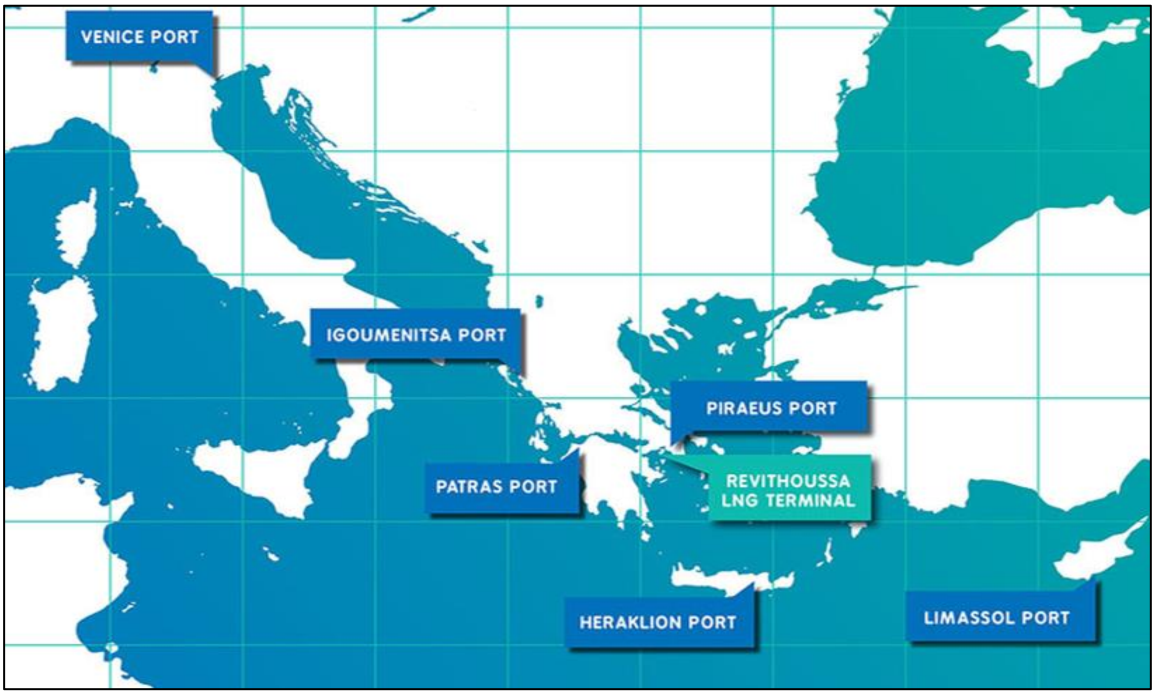
Source: IENE

There is also a very important LNG bunkering project in SE Europe, known as Poseidon II LNG Bunkering Project, which is a continuation of Poseidon Med and the Archipelago LNG projects, which all together are part of the Global Project aiming to take all the necessary steps towards adoption of LNG as marine fuel in East Mediterranean Sea, while making Greece an international marine bunkering and distribution LNG hub in SE Europe. The Action will build on the achievements of the aforementioned projects as well as on the results of Poseidon Med I, which delivered the Master Plan for LNG as a marine fuel in the Mediterranean region. The major objective of the project is to contribute in reducing negative impacts of heavy fuel oil used for power generation and to facilitate the implementation of the requirements of a number of EU Directives regarding alternative fuels for a sustainable future in the shipping industry as well as the distribution of LNG in six main ports (i.e. Piraeus, Patra, Heraklion, Igoumenitsa, Limassol and Venice), as Map 7 illustrates.

Poseidon Med II, with Greece's Public Gas Corporation (DEPA) being its coordinator, is financed by the Connecting Europe Facility (CEF), a key EU funding instrument that supports trans-European networks and infrastructures in the sectors of energy, transport and telecommunications. This project will last for 5 years with the participation of 26 companies from three EU member states (i.e. Greece, Cyprus and Italy). The start date of this Action was June 2015 and the end date is December

2020. Its estimated total cost is roughly €53 million and the percentage of EU support is 50% (i.e. €26.6 million) (22). In this context, Greece's DEPA received government approval on July 30, 2019 to build a small-scale LNG terminal at the port of Patras in western Greece. The development is part of a plan by Athens and the European Commission to make Greece into an LNG bunkering hub for southeastern Europe. The Patras facility, scheduled to come online at the end of 2020, will have a storage capacity of 3 mcm.

Map 7: Poseidon Med II LNG Bunkering Project



Source: DEPA

Table 2 shows the gas production and consumption in SE Europe in 2008, 2018 and 2025 (estimated), highlighting the low gas production and the need for the SEE countries to import increased natural gas volumes. What is evident is the substantial contribution of Turkey in total gas consumption in SE Europe, which is expected to increase further by 2025, corresponding to more than 63% of the total, based on IENE's estimates. Turkey is the region's major gas consumer and importer by far and its interest in natural gas is strong both as a potential producer but also as a transit country to European markets. On the transit side, virtually all of the various gas pipeline projects, which plan to transport Caspian gas to the European markets, involve Turkey as a transit country (e.g. TANAP and Turkish Stream).

Table 2: Natural Gas Production and Consumption in SE Europe (2008, 2018 and 2025e)

Country	2008		2018		2025e	
	Gas production (bcm/y)	Gas consumption (bcm/y)	Gas production (bcm/y)	Gas consumption (bcm/y)	Gas production (bcm/y)	Gas consumption (bcm/y)
Albania	0.02	0.02	0.1	0.09	0.01	0.22
Bosnia and Herzegovina	0.0	0.31	0.0	0.24	0.0	0.45
Bulgaria	0.31	3.5	0.01	3.04	0.21	4.3
Croatia	2.03	3.1	1.28	2.48	1.52	3.3
North Macedonia	0.0	0.05	0.0	0.18	0.0	0.6
Greece	0.0	4.25	0.1	4.87	0.0	6.0
Kosovo	0.0	0.0	0.0	0.0	0.0	0.0
Montenegro	0.0	0.0	0.0	0.0	0.0	0.0
Romania	11.2	16.9	10.26	11.97	10.02	14.1
Serbia	0.25	1.92	0.45	2.93	0.51	2.8
Slovenia	0.0	0.51	0.0	0.8	0.0	1.07
Turkey	1.03	36.9	0.51	49.64	0.73	56.0
Total	**14.84**	**67.46**	**12.71**	**76.60**	**13.00**	**88.84**

Sources: IENE, IEA, 10-year Development Plans of gas TSOs

What's Next

Attention is now focused on three major gas pipeline projects in SE Europe; two of them currently under construction (i.e. TAP and Turkish Stream) and one at an advanced design stage (i.e. East Med).

Even though several intergovernmental agreements were recently reached between the countries that are now interested in the **East Med pipeline project** (i.e. Greece, Israel, Italy and the Republic of Cyprus), there is no guarantee that the project will be on track soon. This, of course, does not mean that the East Med pipeline project should be re-examined or abandoned, since its existence on paper only helps strengthen a wider strategic alliance among the countries of the East Mediterranean region (including Egypt), which comes against Turkey's growing unease and expansioning aspirations in the region. In this context, the East Med pipeline project will remain for a long time a purely "political" project, with the prospect of being implemented if and only if there is a strong interest from one or more investors in order to create a well-funded consortium as well as the necessary conditions for the gas supply and distribution from the under-development gas fields of the East Mediterranean region can be met.

Regarding **Turkish Stream**, Bulgaria and Serbia have already proceeded to build the infrastructure for receiving gas since Russian Energy Minister Alexander Novak announced on July 26, 2019 that the second leg of the Turkish Stream pipeline will go through Bulgaria, Serbia and Hungary and not through Greece. More specifically, Bulgaria plans to complete the construction of the Balkan Stream, an offshoot of the Turkish Stream through Bulgaria to Serbia, by early 2020, Russia's Industry and Trade Minister Denis Manturov recently announced. Serbia has taken delivery of the pipes that will be used to construct its section of the Turkish Stream to carry Russian gas to Europe, the country's energy minister announced on May 21, 2019. Roughly 7,000 tonnes of pipes arrived on May 20 with some 50,000 tonnes more are expected to be delivered by December when the project is scheduled to be completed. **(23)**

Furthermore, Serbia plans to build a gas pipeline connecting Belgrade to Banja Luka, the main city of neighbouring Bosnia's Serb Republic entity, Serbia's energy minister added. The Belgrade-Banja Luka link will branch out from the gas transmission pipeline that Serbia is building from the border with Bulgaria to its border with Hungary as part of the Turkish Stream project of Russia's Gazprom.

In Serbia, the project for building a pipeline from the border with Bulgaria to the border with Hungary is carried out by Novi Sad-based Gastrans, a wholly-owned subsidiary of Swiss-based South Stream Serbia, according to data from Serbia's commercial register. Gazprom owns a 51% stake in South Stream Serbia, while state-owned Srbijagas holds the remaining 49%, according to Gazprom data. **(24)**

On June 14, 2019, Hungarian Minister of Foreign Affairs and Trade Mr. Péter Szijjártó and Serbia's Minister of Mining and Energy Mr. Aleksandar Antic signed an agreement on building a gas pipeline as a part of the Turkish Stream. Mr. Antic said that the construction works in Serbia are going on in three phases, and the pipeline from the border with Bulgaria to the boundary with Hungary will be finished by mid-December this year, while the Hungarian Minister said his country's part would be completed by the end of 2021. **(25)**

According to Mr. Stambolis **(26)**, plans for the expansion of Turkish Stream to Europe via the hub at the Greek-Turkish border seems to be in limbo. After 2019, Greece will be forced to increase its gas imports from Turkey via the Interconnector Greece-Turkey, which has been in operation since 2007 and has a sufficient capacity of 5.0 bcm, but no more than 1.5 bcm is expected to be used per annum over the next years. As of January 1, 2020, Greece may have to buy gas quantities of Turkish basket at significantly higher prices, if Gazprom stops gas flows through Trans Balkan pipeline, as it is anticipated. Alternatively, Greece will end up importing Russian gas from Bulgaria's system.

Both Romania's Transgaz and Bulgaria's Bulgartransgaz derive significant revenues from transit of Russian gas through the Trans Balkan pipeline. For Transgaz, over the last 6 years, between 18%-20% of its total operating revenues came from transit operations. However, for Bulgartransgaz the revenue is very substantial, around 60% for the last 4 years. The reason for the disparity seems to be that Transgaz operates a much larger system handling larger domestic volumes and transit distance is much shorter. The Romanian market is almost four times the size of the Bulgarian one (11 bcm vs 3 bcm), and transit is only 200 km across Romania. **(27)**

With total proven reserves of 1.3 tcm, Azerbaijan is not considered as the country that will solve the problem of European energy supply (with the Eastern Mediterranean region possessing three times more reserves). However, Azerbaijan's export capacity, through the **SCP-TANAP-TAP system** and its gas treatment plants, will very soon become a reference point for the entire Caspian region, as part of a wider attempt to exploit export capacities of the neighbouring countries.

Table 3: Major Gas Pipeline Projects Under Construction in SE Europe

Project	Shareholders	Length	Cost	Capacity
TAP	BP (20%), SOCAR (20%), Snam S.p.A (20%), Fluxys (19%), Enagás (16%) and Axpo (5%)	878 km	€4.5 billion	10.0-20.0 bcm/y
IGB	BEH (50%), IGI Poseidon (50%)	182 km	€220 million	3.0-5.0 bcm/y
Turkish Stream	Gazprom, BOTAS	1,100 km	€11.4 billion	31.5 bcm/y*
Bulgaria-Romania-Hungary-Austria (BRUA)	Bulgartransgaz, Transgaz, FGSZ, Eustream, GCA	500 km	€500 million	6 bcm/y

*This amount corresponds to the first two strings of the pipeline with an additional 31.5 bcm foreseen when strings 3 and 4 will be constructed and become operational.

Sources: IENE and involved energy companies

Following the landmark energy agreement signed between the Caspian Sea countries of Russia, Azerbaijan, Iran, Kazakhstan and Turkmenistan in August 2018 **(28)**, Turkmenistan and Iran are already in negotiations with Baku for the exploitation of Azerbaijan's gas network in order to export large quantities of gas through Turkey to European markets. With Azerbaijan and Turkmenistan currently discussing the transportation of limited gas quantities (i.e. 3-5 bcm) through the existing underwater pipeline network and through the construction of the planned Trans Caspian Pipeline (see Map 8). Thus, Azerbaijan is anticipated to play an important role as a major hub for the transportation and promotion of natural gas from the wider Caspian region to the West **(29)**. On July 1, 2019, TAP launched a market test to allow natural gas shippers to express interest and potentially secure access to new, long-term capacity in TAP. The market test includes two phases: (a) non-binding phase, as of July 1, 2019 and (b) binding phase, which is expected to start in Q2 2020 at the earliest. The results of the non-binding first-round market test, concerning a possible capacity boost of the TAP pipeline, justify an increase from 10 bcm to 20 bcm. Procedures for the second-round market test, whose result will determine whether a pipeline capacity increase will be carried out, and if so, its extent, are already underway.

Map 8: Trans-Caspian Gas Pipeline and the Caspian Sea Region

Source: Financial Times

Over the last 10-12 years, we have seen the emergence of a number of projects involving the construction of major, and smaller, gas pipelines across SE Europe. Most of these projects have evolved around the so-called South Corridor. Some of these projects, grand in formulation and ambitious in terms of deliverable gas volumes, have collapsed (e.g. the Nabucco pipeline), while others have been mothballed (e.g. the ITGI). Other grandiose schemes, such as the South Stream, although strictly speaking outside the remit of the South Corridor, but of relative importance, have been cancelled and pushed aside mostly due to political considerations, part of the never-ending East-West (read USA/EU-Russia) wrangle.

At the same time, entirely new projects have come about, of smaller scale but of great strategic value, such as the BRUA pipeline, and the various interconnection projects in the East Balkans (e.g. Interconnector Greece-Bulgaria and Interconnector Greece-North Macedonia[4]). There are also relatively new highly challenging projects

[4] Greece's DESFA is preparing to launch a market test for the development of a Greek-North Macedonian gas pipeline interconnection running from Nea Mesimvria, on Thessaloniki's western outskirts, to Gevgelija, in the neighboring country's southeast. Windows International Hellas, an enterprise controlled by Russian entrepreneur Leonid Lebedev, which, in the past, has expressed interest for a rival project, has yet to emerge with any new action. An alternative project from Windows International Hellas would be developed as an independent gas system, whereas DESFA's proposal is planned to be incorporated into the national gas grid. RAE approved both project plans at the beginning of this year following two years of processing and consideration. However, DESFA was asked to conduct a market test as the cost of the project, if developed by the operator, would, as a national

such as the East Med pipeline or the FSRU in Alexandroupolis which add a totally new dimension to the region's energy capabilities and help enhance its role as a vital energy bridge between East and Southeast and the Western European markets. The latest developments on gas infrastructure projects in SE Europe bring closer to reality the concept of an integrated Expanded South Corridor.

The Role of Central European Gas Hub (CEGH) As A Benchmark and Pivot for Promoting Gas Trading in SE Europe

For more than 13 years, Central European Gas Hub (CEGH), which is located in Vienna (Austria), has been a reliable fixture in the gas trading landscape. As the operator of the Virtual Trading Point (VTP), CEGH offers international gas traders a gateway for trading in the entry/exit zone of the Austrian market. In 2018, CEGH achieved a total trading volume of 659 TWh of natural gas and ranks among the most important gas hubs in Continental Europe.

The dedicated link between commercial transaction and physical settlement has always been crucial for successful trade. Through its connection to the important transit pipelines and storage systems, CEGH is the most attractive gas market in Central and Eastern Europe. The distribution station at Baumgarten (see Map 9) is the most eastern distribution node in Europe. Plus, the direct connection of storage facilities to the CEGH VTP contributes to additional flexibility and makes gas trading in Austria even more attractive.

Map 9: Baumgarten Station

Source: Gas Connect Austria

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grid project, be passed on to users. The project, budgeted at €48.7 million and planned to stretch 120 km for a 3 bcm capacity, is seen as a source-diversifying initiative.

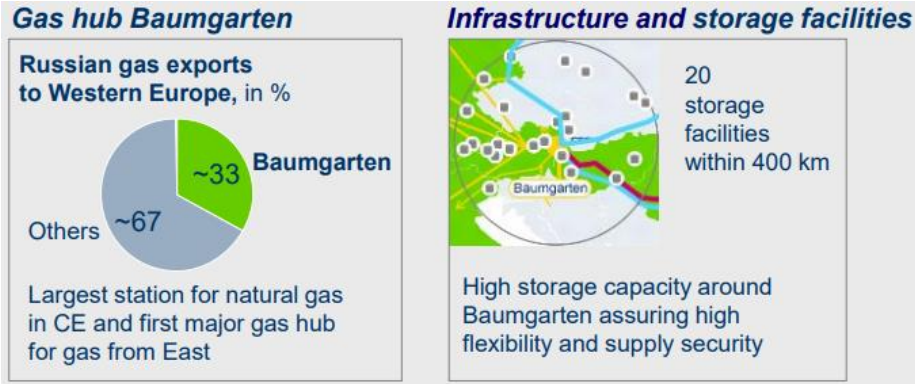
As already analysed, the shareholders of Central European Gas Hub AG are OMV Gas & Power GmbH with a stake of 65%, Wiener Boerse AG with a stake of 20% and Slovak Eustream a.s. with a stake of 15%. OMV Gas Storage GmbH operates gas storage facilities in Austria for more than 50 years. With a total working gas volume of approx. 25 TWh, OMV Gas Storage GmbH is among the leading European storage providers. In addition to the storage facilities in Austria, OMV Gas Storage Germany GmbH has a salt cavern storage facility in Germany (Etzel) since 2012, which is connected to the Dutch and German market areas. The storage facilities of OMV Gas Storage GmbH are integrated to a storage pool and connected to the Austrian Market Area East. Registered clients have the possibility to trade on the Virtual Trading Point CEGH (VTP). **(30)**

Map 10: The Storage Facilities of OMV Gas Storage GmbH in Austria

Source: OMV

Since 2016, the Austrian and the Czech CEGH Spot and Futures contracts have been listed on the pan-European PEGAS platform under the Powernext rulebook and exchange license. This gives international traders comfortable access to comprehensive trading, clearing and settlement services on multiple markets. Traded volumes in 2017 almost tripled – a clear indicator that the cooperation was more than just a step in the right direction. In 2018, volumes continued to grow and reached an all-time high of 133 TWh.

Figure 7: Current Status of CEGH-VTP



Source: CEGH

According to EFET, CEGH has one of the highest gas hub score ratings and has developed into the most important trading hub for the CEE region, with the CEGHIX being a recognized reference price for the wider region. With its tailor-made nomination-platform as well as many additional services, CEGH actively engages with the trading community and continually develops new customer-oriented offerings.

CEGH serves as a gateway between East and West and is therefore the most interesting trading platform for SE European gas markets. In recent years, more and more traders have used CEGH as a trading hub between West and East, reflecting the needs of Eastern European countries to import gas from the West.

Taking into consideration all the aforementioned data and information as well as the fact that there is not a single gas trading hub east and south east of Vienna, CEGH could act as a pivot for organizing gas trading in this region as more and more gas flows are expected in SE Europe upon completion of major gas infrastructure projects (e.g. TAP, IGB, Alexandroupolis FSRU, etc.). In addition, if we take into account CEGH's strategic location, among important gas transit routes, with the existence of substantial gas storage facilities, we can easily understand its significance.

Is There a Need for a Benchmark Gas Hub Price in SE Europe?

In the European continental gas markets, TTF is the only pricing benchmark, while other hubs are priced as spreads with TTF prices. Although many hubs are more or less successful, only two of them, NBP and TTF, are benchmark hubs. Although the Netherlands' TTF is developed after NBP, it became the benchmark to which prices in European end-consumer contracts are pegged. TTF has developed quickly and steadily in the past few years and is considered a success story. Today, NBP is the £ benchmark for gas in the British Isles and some LNG supplies, while TTF has become the € benchmark hub for North West European gas supplies. Both are being widely used for risk management.

In SE Europe, there is neither a market mechanism to buy or sell gas in an efficient manner, nor a pricing mechanism to determine spot prices. Gas exchange is still based on long-term bilateral agreements. The lack of established market conditions hampers development and increases the potential for these markets to be coerced by dominant players. The development of regional gas trading hubs can prove critical to overcoming such inefficiencies.

A key element of such hubs is pricing indices that more readily reflect regional supply and demand fundamentals (compared to the traditional oil indexation), while facilitating both financial and physical hedging for buyers. Trading hubs can help prevent the emergence of dominant market players keen to dictate their terms or serve political interests. In fact, under the energy hub trading framework, players become more inter-dependent; hence, the former can foster cooperation, economic and political stability in a region and limit conflicts.

Regarding SE Europe, the question that needs to be addressed is whether the emerging gas trading hubs of Bulgaria, Romania, Ukraine, Greece and Turkey can build a spot gas market individually or even regionally, offering benchmark prices or their prices should be pegged to TTF, for instance. The answer to this question requires more time as the country that will be able to be first in securing relevant investments in its energy infrastructure and interconnectors will be able to become the key player in the regional gas trading zone.

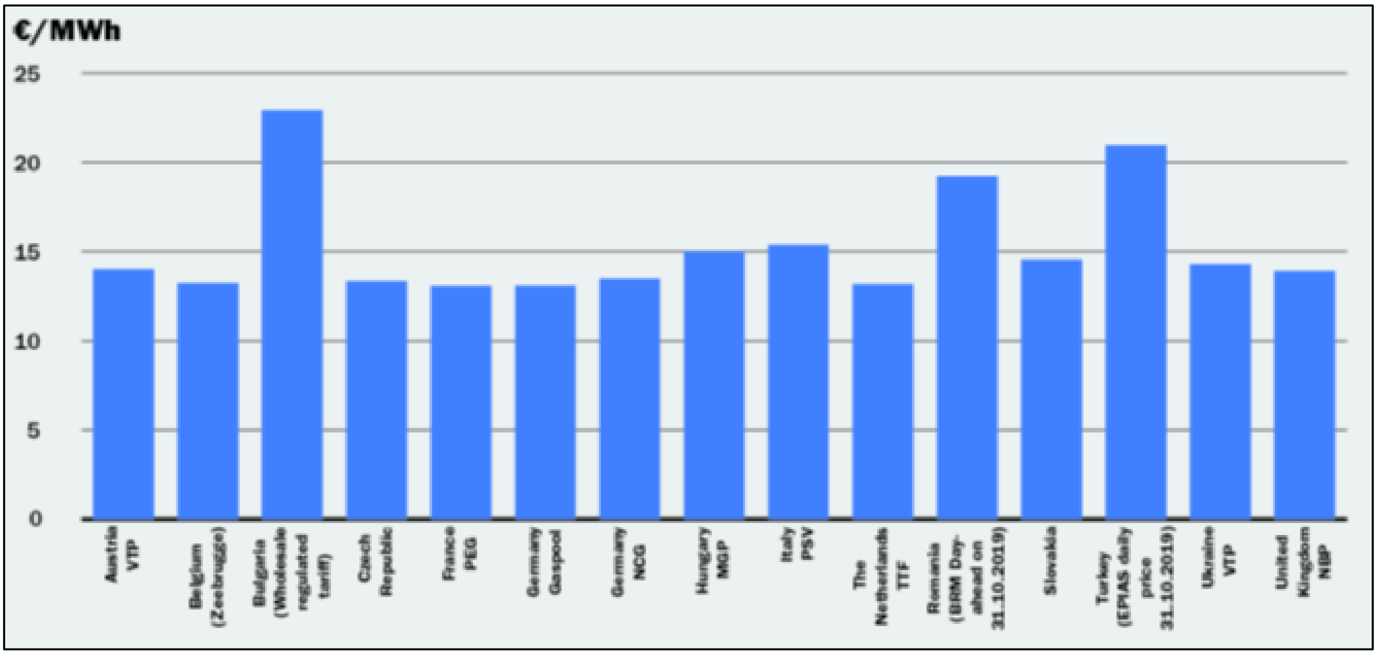
On closer examination, neither TANAP nor Turkish Stream are likely to boost liquidity and support the formation of a reference price in SE Europe. Turkey will be importing Azeri gas via TANAP at a price indexed to the Russian imports and volumes will only be delivered to BOTAS. Since Turkish imports are oil-indexed, BOTAS has no flexibility in setting a market price, being entirely exposed to fluctuations in crude futures. It is not known how Russian gas exported via Turkish Stream will be priced, but considering the region traditionally buys at oil-indexed prices and that there are no liquid gas trading hubs in proximity, it is possible Gazprom will continue the practice in countries such as Bulgaria. Romania, which is not dependent on Russian gas due to its own resources, may start developing its own reference price, although if it continues to block cross-border trading, the benchmark would not have much regional significance.

Thanks to its active cross-border buying, Ukraine could start a border price that may act as a benchmark for the region. If Ukraine succeeds in ramping up production and reforms its domestic sector, which represents more than 60% of demand, its chances to launch a reference price would increase. However, the development of a Ukrainian reference price would depend on its commitment to continuing the reform process. Hungary, on the other hand, is one of the more promising central European countries in terms of establishing a market, looking to boost its regional connections and encourage competitive trading. The extra sources of gas that would be brought to the market, as well as the opening up of numerous bidirectional interconnections, are likely to contribute towards that. **(31)**

It is worth noting that Italy was for the first time ever a net exporter of gas in June 2018. The political will in Italy to see a strong PSV gas hub that can be a marker price for Mediterranean gas has resulted in significant changes to its market structure, especially since 2014. This has resulted in a PSV hub that progressed from "poor" to "active"; from a total traded volume of 282 TWh in 2013 to 944 TWh in 2017. Although the PSV hub is not perfect and still has further to go on the road to maturity, it could become the reference hub for southern Europe, giving the pricing signals to attract LNG and possibly become, in time, a supply route for gas into northern Europe.

From a pricing perspective, the SE European region currently carries a premium of anything between €9.00-€14.00/MWh ($2.98/MMBTu–$4.6/MMBtu) over western Europe. In Bulgaria's and Turkey's case, this is because they operate regulated end-consumer tariffs, which reflect the price of Russian oil-indexed gas imports. As for Romania, the government reversed the liberalization process this year, capping end-consumer tariffs and introducing an import obligation despite reduced interconnection capacity with neighboring markets. The high costs paid by these countries for natural gas makes it even more imperative for them to open up their borders and allow LNG to reach their markets, while LNG companies should be attracted to sell to this premium region at a time of globally reduced profits.

Figure 8: November '19 Gas Prices Across European Markets



Sources: ICIS, BRM, EPIAS, EWRC

As already analysed, several SEE countries have expressed their interest in order to develop gas trading hubs. Although there is an increasing liquidity of some gas hubs, mainly in Northwest Europe, this does not stand for the SEE countries; thus, they also face difficulties in developing benchmark prices. Without clear benchmark prices in the region, neither LNG nor pipeline gas suppliers will have sufficient information for price discovering to allow gas to flow from the cheapest areas to the more expensive ones, neither in the medium term nor in the short term. Implementing the Gas Target Model in the EU member states of SE Europe is thus essential to provide price signals to appeal to LNG when needed. Moreover, the traditional indexation of the long-term LNG contracts to oil (derivatives) is being substituted, specifically for spot trading with hub reference price or index. This could also be used in the future for long-term contract indexation.

Economic Implications From the Operation of A Gas Trading Hub in SE Europe – A Discussion

The setting up and operation of one or more regional gas trading hubs will undoubtedly have some economic implications for the countries involved. However, the precise impact of an operating gas trading hub on market conditions is hard to predict and even harder to quantify. The reason is the introduction of a completely new approach, together with a new and inclusive price-setting regime into a market where none existed before; other than bilateral agreements based on strict oil-indexed contracts. These bilateral arrangements still determine, to a large extent, gas prices in SE Europe (e.g. Bulgaria, Serbia, Romania, Greece and Turkey), which is predominantly supplied via pipelines. In the case of Greece and Turkey, there is a certain differentiation, since both countries satisfy about 10-20% of their needs from LNG imports, which are priced differently, although oil is still used as the basis.

On the other hand, it is relatively easy to categorize the economic parameters involved that should be taken into consideration in the ensuing discussion. These can be summarised as follows:

(a). The existing gas infrastructure and the current gas traded volumes
(b). The minimum level of new investment required in gas infrastructure work to enable the availability of adequate gas quantities to be traded through the hub
(c). The origin of gas to be supplied and to be traded through the hub, together with recent price history (i.e. average quarterly prices over the last five years)
(d). The anticipated volume of gas to be traded through the hub and the forecasted churn ratio.

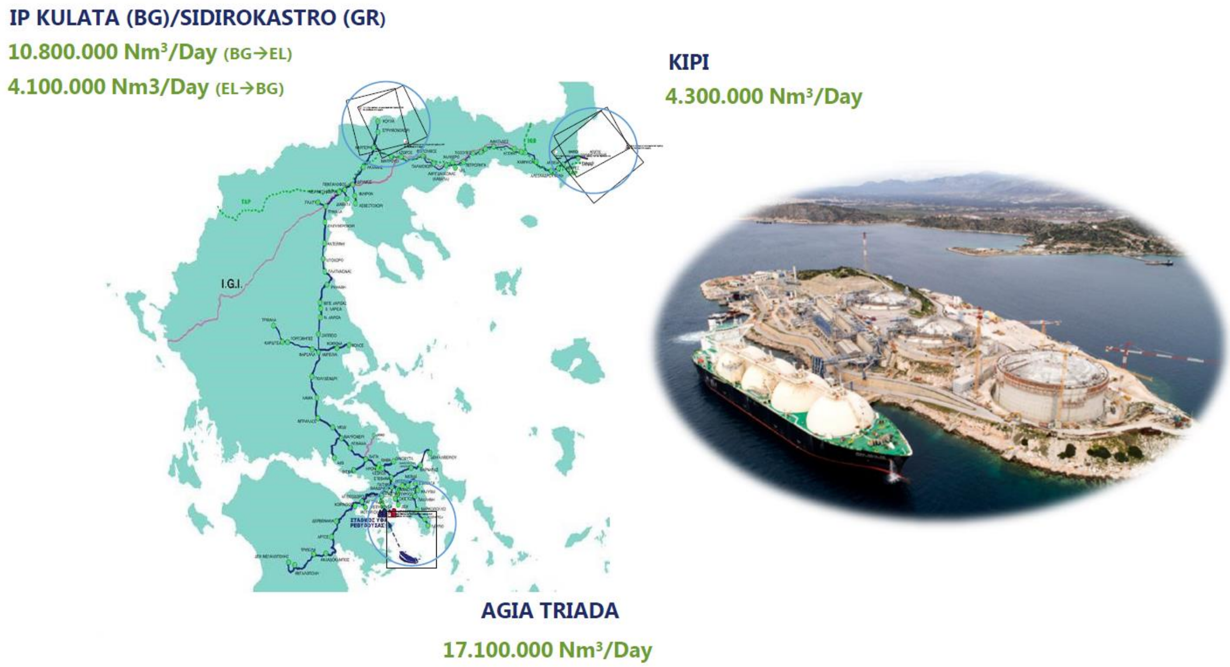
In the operation of a gas trading hub, the existing infrastructure is of great importance. In the case of Greece, the National Natural Gas System (NNGS) comprises the National Natural Gas Transmission System (NNGTS) and the LNG terminal on the island of Revithoussa. The transmission system consists of one main, high-pressure pipeline 512 km long and high-pressure line branches that total 975 km in length (see Map 11). There is no strategic gas storage in Greece, and commercial stocks are only held at the site of the LNG terminal. DESFA is the owner and operator of the NNGS.

Greece’s NNGTS has three entry points: two at the north and north-eastern borders (Sidirokastro and Kipi), connecting Greece with the Bulgarian and Turkish gas networks, and one in southern Greece (Agia Triada), linked to the LNG terminal. The quantities flowing through Sidirokastro represent 58% of the imported gas and the interconnector with Bulgaria has been able to operate an interruptible reverse ("virtual reverse") flow since 2013, while a firm reverse ("physical reverse") flow capability in the order of 0.36 bcm per year was first provided in 2017 and was upgraded to 2.1 bcm/y since January 2020; thus, enhancing the security of supply. Since 2017, the available capacity is auctioned, complying with EU regulations for cross-border trading, allowing more market players to participate and literally giving space for competition and eventually leading to market liberalization. The interconnector with Bulgaria allows for gas flows from Russia via Romania, Moldova and Ukraine.

At the borders with Turkey lies another entry point at Kipi and this Greek-Turkish interconnector brings gas mainly from the Middle East and the Caspian region into Greece. This point currently represents 15% of the imported gas or approximately 0.75 bcm and is capable of transmitting larger quantities, almost double. Today, there is only one agreement in place between BOTAS and DEPA for contracted quantities and until 2018 there was no other agreement of any other company with BOTAS. There are ongoing efforts signing an Interconnection Agreement between DESFA and BOTAS.

The third entry point is the only LNG terminal in Greece, in the islet of Revithoussa near Piraeus, which now represents 27% of the imported gas quantities and it is anticipated to increase its contribution in the near future.

Map 11: Greece's National Natural Gas System



Source: DESFA

In order to discuss the economic implications from the operation of a proposed fully-fledged regional gas trading hub based in **Greece**, a number of assumptions need to be made in terms of geography, infrastructure and cost, prospective gas supplies and their origin and anticipated trading conditions. These assumptions are summarized as follows:

(1) In terms of geography, the trading will initially take place between market participants in Greece, Bulgaria, Romania and Turkey.

(2) In order for cross-border trading to evolve, the following infrastructure should be in place:

I. The Greek-Bulgarian Interconnector (IGB)

II. The TANAP-TAP pipeline system, linking Turkey, Greece, Albania and Italy

III. The gas interconnection between Greece and North Macedonia (IGNM)

IV. The underground gas storage facility in South Kavala

V. At least one floating LNG storage and gasification unit (FSRU), such as the Alexandroupolis FSRU or the Motor Oil FSRU in Agioi Theodoroi

The cumulative cost for these projects, based on company information can be estimated as follows:

Table 4: Cost of Planned Gas Infrastructure Projects

Natural Gas Project	Cost
IGB	€220 million
TANAP	€805 million (with TANAP's cost corresponding only to Turkey's European ground route)
IGNM	€50 million
TAP	€4.5 billion
South Kavala UGS	€350 million
Alexandroupolis FSRU	€380 million
Total	€6.305 million

Source: IENE

We must point out that the above cost estimate is specific to the nascent regional gas trading hubs in Greece and Turkey and is not characteristic of infrastructure costs in general for the setting up of gas trading hubs. It so happens that all the above infrastructure components are in various stages of development, with all corresponding projects slated for completion and full operation by 2022.

(3) The origin of natural gas will be as follows:
   I. **For pipeline gas:** This will originate in Azerbaijan, through the TANAP-TAP system and in Russia through the Turkish Stream.
   II. **For LNG:** Qatar, Nigeria, Algeria, Norway, US, East Med, etc.

(4) In view of currently available information concerning gas volumes corresponding to long-term contracts through the TANAP-TAP system, the existing capacity of the pipelines involved (i.e. IGB, IGT) and gas demand projections for 2030, one could safely assume that some 1.0 bcm of gas will become available for trading as early as 2021, rising to 2.0 and possibly to 3.0 bcm and more by 2025. In addition to that, one should take into consideration a realistic churn ratio of, let's say, 1.0 to 2.0; however, hard this may be to predict. Given the experience of European trading hubs, churn ratios may vary from 1 up to 20.

(5) Additional gas quantities for trading at the Hellenic Trading Point up to 3.0 bcm could become available from other sources such as Russian gas (via Turkish Stream), from Turkey's system (Turkish basket) and LNG until 2025.

On the basis of the aforementioned assumptions, a number of possible scenarios have been worked out for available gas trading quantities and churn ratios based on current prices in the region as follows:

Table 5: Scenarios for Trading Activity in the Regional Gas Trading Hub

Gas volume physically delivered (bcm)	Churn Ratios	Traded gas volume (bcm)	Traded value* (in million €)
1	1.5	1.5	334
	2	2	446
	2.5	2.5	557
	3	3	668
	4	4	891
	5	5	1,114
2	1.5	3	668
	2	4	892
	2.5	5	1,114
	3	6	1,336
	4	8	1,782
	5	10	2,228
3	1.5	4.5	1,002
	2	6	1,338
	2.5	7.5	1,671
	3	9	2,004
	4	12	2,673
	5	15	3,342
4	1.5	6	1,336
	2	8	1,784
	2.5	10	2,228
	3	12	2,672
	4	16	3,564
	5	20	4,456
5	1.5	7.5	1,670
	2	10	2,230
	2.5	12.5	2,785
	3	15	3,340
	4	20	4,455
	5	25	5,570

*Based on the average 2018 gas price of $245.50 per 1,000 cubic meters for Gazprom gas deliveries in SE Europe (exchange rate: US$1=€0.907620).

Source: IENE

From the data presented above, especially that concerning infrastructure investment and the anticipated volume of gas trade, it becomes clear that the setting up of the specific gas trading hub – which in the first phase will connect Greece, Bulgaria and Turkey – requires major infrastructure investment of the order of €6.3 billion[5], while it will be generating substantial financial turnovers on a yearly basis. Starting from a modest €334 million and rising to €5.6 billion, depending on available quantities and participating traders.

Of course, the actual economic and financial implications from the emergence and operation of a regional gas trading hub are far broader than the strict numbers, as shown above. The completion of the extensive gas transmission infrastructure now planned in Greece, Turkey and Bulgaria, among others, will inevitably have a positive

[5] One should point out that from the above stated total investment, 88% is already committed and almost fully paid.

impact on investment and industrial activity in sectors such as building construction, manufacturing, transport and storage, consulting, legal services, financial intermediation, etc. In addition, the sheer availability of gas in large parts of the border areas in the above countries will lead to increased peripheral gas demand from the domestic, commercial, agricultural and industrial sectors.

The operation of a proposed fully-fledged regional gas trading hub based in **Turkey** can also be feasible, as analysed in IENE's 2014 study. The development of gas infrastructure projects in Turkey, including existing, under construction and planned domestic and cross-border pipelines (e.g. Turkish Stream and the TANAP-TAP system), existing and planned underground gas storage facilities and existing and planned LNG terminals and FSRUs will have a positive impact on the country's economy and will facilitate increasing gas flows available for trading activities. As already analysed, the Energy Stock Exchange Istanbul (EPİAŞ[6]) launched its spot gas trade system on the energy stock exchange in September 2018, in a bid to further liberalize the gas market. This development is undoubtedly of vital importance in its attempt to emerge as a regional gas trading hub and highlights its substantial progress as Turkey and Greece are the frontrunners in establishing gas trading hubs, according to the latest EFET's 2019 Gas Hub Benchmarking Study, as shown in Figure 11.

In the case of the proposed regional gas hub, we believe it is premature to try and predict the evolution of a gas price regime after 2020-2021, once adequate gas quantities become available on a regional basis. What we can forecast though is that there is going to be strong demand for cross-border trade, as interviews with a number of local companies in all three countries reveal. Once the interconnections are in place and an effective gas exchange mechanism exists, such as the one that will be created by the proposed gas trading hub (i.e. Hellenic Trading Point), traders would be willing to buy available gas (i.e. marginal gas quantities) which will become available from main gas importers, by placing bids through the "hub" for both physical quantities and gas futures. Such trading activity will inevitably lead to the formation of a new climate of competitive prices, exerting pressure on traditional suppliers to revise their contract prices.

A lot will depend on gas volume availability, as the tendency will be for traditional suppliers to curtail the availability of extra gas quantities, so as to limit trading through the hub. In such a case and presuming that the hub has attracted a fair number of registered traders, the challenge will be for non-traditional or new suppliers to enter the picture and fill the gap by providing adequate gas quantities. This may happen from Turkey's side, where at times excess gas volumes are

[6] On July 27, 2018, EPİAŞ began publishing gas transmission data through its online transparency platform. It also started to share transport nomination, virtual trade, capacity, reserve, and actualization as well as stock amounts on a daily basis. More gas data and information are available at: https://www.epias.com.tr/en/

available within its gas grid and storage system, from the Shah Deniz consortium and its partners, who may decide to offer part of their allocated gas volumes to the open market (i.e. spot market), and from LNG suppliers through Greece's two LNG terminals (i.e. Revithoussa and one or two planned FSRUs).

The operation of the proposed regional gas trading hub is therefore predicted to have a positive effect on wholesale markets in all three countries by channeling needed gas volumes at competitive market rates. If we are to judge from the price history of selected European gas hubs, one should expect a marked differentiation from oil-indexed prices. This means that a significant portion of local gas supplies, in the range of 15% to 40% of yearly consumption for each country, could be priced at much reduced rates, which inevitably will lead to lower prices for consumers in the long term.

Figures 9 and 10 are the most appropriate when discussing the financial implications from the operation of a gas trading hub in our region, as they show the notable difference in prevailing prices between oil-indexed contracts and prices formed by gas-on-gas competition as well as EU gas import prices. Although it is difficult, at this stage, to predict market behaviour and its reflection on spot prices, once the above hub enters full operation, based on European hub operation experience, one could safely assume that spot prices determined through hub trading will be lower than oil-indexed ones. Of course, this is not the only positive financial implication arising from a hub operation. The attraction of sizeable tradable gas volumes and the trading activity arising from this will help to reassure markets in terms of gas availability and security of supply.

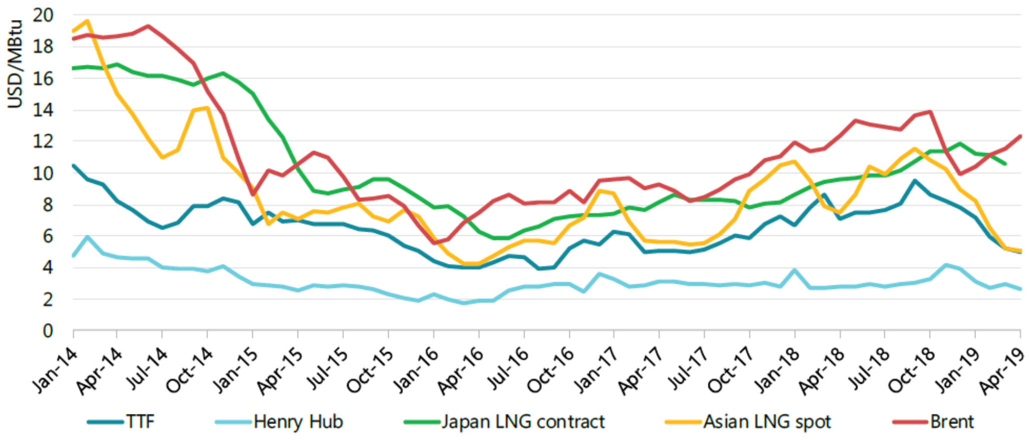
Figure 9: EU Natural Gas Import Price (US$/MMBtu), October 2015 – October 2019

Sources: World Bank, ycharts

After almost three years of decline from the end of 2013 to the first half of 2016, global gas prices increased in 2017 and 2018. Depending on the region, the 2017–2018 y-y average rate of growth varied between 6% and 38%. This has been partly driven by the strong increase in global gas demand, which grew by 4.6% – its highest growth rate since 2010, according to the IEA. Other factors contributing to the strengthening of gas prices were the rise in Brent crude prices, increasing y-y by 30%

in 2018 to an average of US$71 per barrel from US$55 per barrel in 2017 (see Figure 10). This supported gas prices both directly, via oil indexation in long-term contracts, and indirectly via the arbitrage mechanisms between spot purchases and optimisation of long-term contracts. Whilst gas markets are becoming increasingly interlinked, regional price-setting dynamics retain their dominance.

Figure 10: Crude Oil and Natural Gas Monthly Average Prices, 2014–2019



Sources: IEA, Bloomberg Finance LP, ICIS

Conclusions – Key Messages

The main conclusions and key messages of the study can be summarized as follows:

1. Over the last few years, the international gas market has evolved away from long-term take-or-pay contracts that are linked to oil prices and include trade restrictions from destination clauses. Instead the market now features shorter-term contracts without destination clauses and pricing based on the supply-demand dynamics of natural gas instead of oil-linked prices. In line with these developments, the volume of spot gas trade has also significantly increased.
2. There is a definite trend in European gas markets for gas volumes to be traded through gas hubs, several of which have been established and are operating successfully in many EU countries. **Already fourteen (14) such hubs are in operation and more are planned over the next few years.**
3. Gas trading hubs come under two broad categories:

   i. **physical gas trading hubs**, with import and export pipelines, connections with other physical hubs mainly via interconnectors, access to storage and gas title transfer among actors trading, and

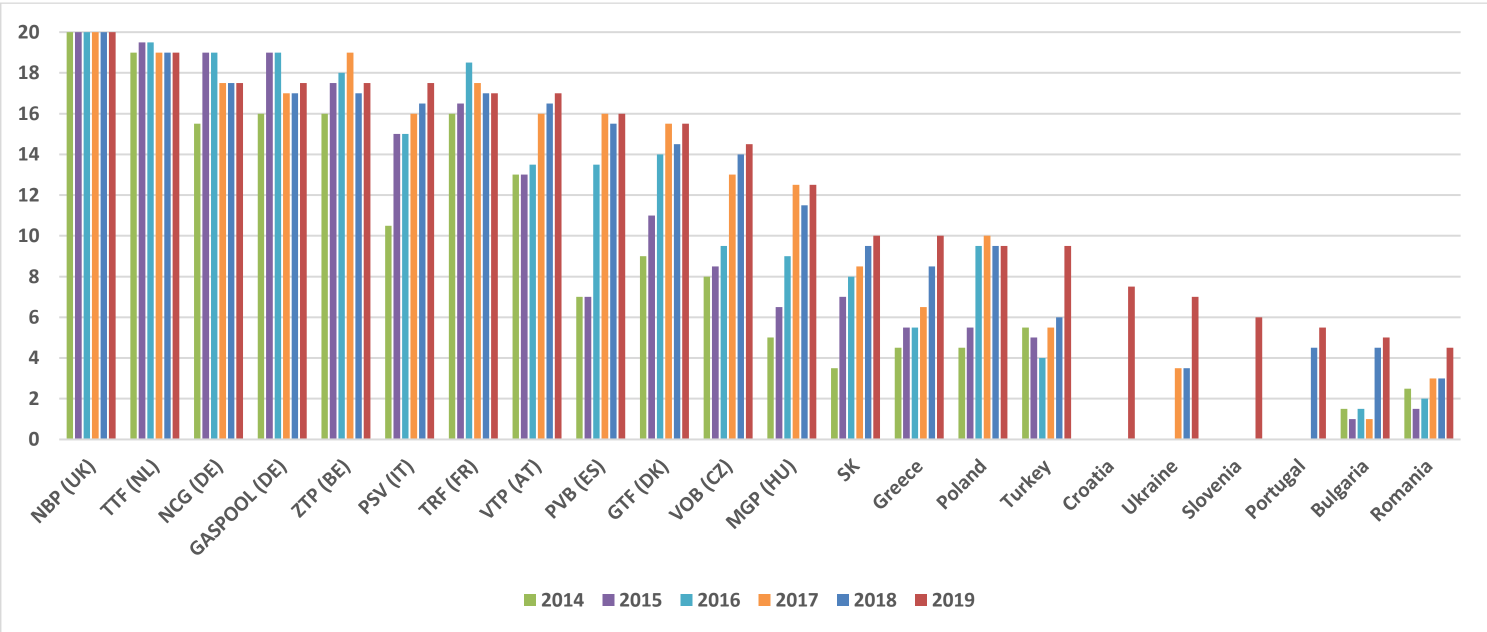
   ii. **commercial hubs with bilateral and broker-based trading**, a balancing mechanism that takes market-based price formation as a basis as well as exchange trading, futures and financial derivative transactions.

It should be noted that gas trading hubs are not necessarily limited to strict geographical boundaries as participants tend to trade gas volumes over extended boundaries. Therefore, the concept of gas trading hubs capable of serving the need of a wider region is fast gaining ground.

4. Historical records from the operation of European gas trading hubs over the last ten years show that spot prices for gas volumes traded through the hubs are markedly lower than corresponding prices for long-term oil-indexed contracts.
5. In view of pressing European gas market needs to meet demand from a diversified supply base and planned new transit routes and interconnectors in the SE European region, coupled with increased storage capacity and new LNG terminals, available gas volumes in the region are set to increase substantially in the medium term (2021-2025).
6. On January 1, 2020, the International Maritime Organisation (IMO) will implement a new regulation for a 0.50% global sulphur cap for marine fuels, known as “IMO 2020”. Both “IMO 2020” and the European Commission’s Sulphur Directive are predicted to increase the use of LNG as a marine fuel for ships in Europe and beyond. Despite a slow uptake of LNG-fuelled vessels, it is expected that over time the LNG industry will gain from “IMO 2020” and the Sulphur Directive, with European and SE European LNG import terminals seeing increased LNG bunkering (i.e. small-scale loading) activity.
7. On the basis of the current contracted gas volumes to be transited through SE Europe by 2021-2025, it appears that market liquidity will substantially increase over the next few years with a parallel rise of gas trading opportunities.
8. The satisfaction of future gas demand in SE Europe involves various routes, including the Southern Corridor, Turkish Stream, the East Mediterranean region and LNG terminals (land-based and FSRUs). However, future gas demand increases appear to be small, meaning that gas will need to move further westwards to find market and/or competitively force itself into Turkey. But transporting gas further north to larger markets in Europe looks hard, because greater distance means greater transportation costs and therefore lower netbacks.
9. SE Europe would be significantly exposed in the case of a transit disruption through Ukraine under high demand scenarios.
10. **Today, there is not one gas trading hub (or hubs) serving the needs of the SE European region. The Vienna-based CEGH is the nearest such hub which at present serves the needs of Central European countries. Vienna’s CEGH in view of its geographical position and trade volume and origin can play pivotal role in enhancing gas trading in SE Europe and also act as a benchmark (to the regional gas hub(s) to be developed).**

11. The background is already set for the planning and establishment of one or two or more gas trading hubs which will serve the needs of the broader SE European region enabling market participants in Greece, Bulgaria, Romania and Turkey to actively participate in gas trading activities.
12. Already the TSOs of the countries in the region, energy exchanges, key market players and other stakeholders are actively exploring the possibilities and prospects of establishing such gas trading hubs.
13. Setting up gas trading hubs in SE Europe should be a commercial rather than a political exercise, although governments should be fully informed of the process.
14. The EU's role through its existing legislation and Directives is crucial in ensuring suitable conditions (i.e. balancing points and virtual trading points) in the various country members of the region, which will enable free and competitive gas trading.
15. In order for one or more regional gas trading hubs to be established in the mid-term, market liquidity must increase considerably. For this to happen, a series of key gas infrastructure projects (e.g. TAP-TANAP system, IGB, South Kavala UGS, FSRUs) must be fully implemented, with construction and operation likely to converge in 2021.
16. **Already, there is a number of nascent gas trading hubs in SE Europe, which include those in Greece, Turkey, Bulgaria and Romania.** According to the EFET's Annual Scorecard 2019 (32), Greece is the frontrunner in SE Europe in its attempt to establish a regional gas trading hub, which is known as Hellenic Trading Point (HTP), as shown in Figure 11.

Figure 11: EFET's 2019 Gas Hub Benchmarking Study



Source: EFET

17. As the Groningen gas field in the Netherlands is planned to be closed by 2022, this is bound to affect TTF’s effectiveness as a key pricing benchmark. Hence, an opportunity arises for the emergence of new regional gas trading hubs, with CEGH being in a suitable location to take advantage of it.
18. The experience of numerous European gas trading hubs demonstrates that there are certain essential factors for gas hub development. Unbundling of vertically integration gas companies creates the necessary conditions for the emergence of market players. Market liberalization and pricing transition create the need of trade and liquidity. Hubs and the transition of gas pricing formation are interconnected. In addition, the liberalization and pricing transition requires political determination, and changes of cultures, regulations and governance practices.
19. This Working Paper (and the study) does not intend to promote the emergence of a specific gas trading hub in SE Europe and only attempts to shed light on the latest related developments. Inevitably, competition between gas hubs in the region will ensue and successful gas trading hubs will be able to attract business on account of their ability to provide cost-competitive and high-quality services.

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