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Expansion of the Southern Gas Corridor pipelines and future supplies to Europe

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Introduction

In July 2022, European Commission President Ursula Van der Layer and Energy Commissioner Kadri Simpson visited Baku to meet President Aliyev and signed a Memorandum of Understanding on the export of an extra 10 bcma of gas from Azerbaijan to Europe starting from 2027, thereby confirming Azerbaijan as "a crucial, reliable and trustworthy energy partner".[1] The European Commission's RePowerEU plan aims at a massive and immediate reduction of EU consumption of Russian gas, and claims a realistic possibility of phasing out dependence on imported Russian fossil fuels, including oil, gas and coal, well before 2030.[2] This initiative envisages imports of gas from alternative sources such as the MENA region, LNG and gas from Azerbaijan, along with other measures. Since the end of 2021, Azerbaijan has been exporting gas from the giant Shah Deniz stage 2 (SD2) natural gas and condensate field to Greece, Bulgaria and Italy via the Southern Gas Corridor (SGC) and the aggregated annual contract quantity (ACQ) is 10 bcma. (In 2022 11.4 bcm was actually delivered, to help the purchasers deal with the ongoing gas crisis).[3]

The export of an extra 10 bcma of gas, making 20 bcma in total, to Europe by 2027 requires immediate work on segments of the SGC. The first action is a decision on the expansion of the Trans Adriatic Pipeline (TAP) which needs to be done this year, depending on the results of the two "open seasons", in January and the second half of 2023. Depending on the extent of the interest from potential European buyers, further decisions need to be taken regarding expansion of the Trans-Anatolian Natural Gas Pipeline (TANAP) and South Caucasus Pipeline (SCP). Finally, depending on the capacity booked in the TAP pipeline, which will be the gas volume to be purchased by European customer companies, gas supply contracts will need to be signed. This is conditional on the final investment decisions (FID) related to the upstream projects being signed. The last and most important stage is the FID on the gas fields to be developed to increase production for export.

This paper aims, first, to identify whether Azerbaijan has the potential to produce an additional 10 bcma in 5–6 years' time and, if yes, which fields this gas will come from. Second, the paper looks into the cost of expanding the entire value chain and the possible source(s) of financing and evaluates whether the projects are commercially viable. Third, the paper investigates gas demand in Azerbaijan and provides a demand growth projection to assess whether domestic demand could eat into production growth. In the same section, an assessment is made of the country's renewable energy (solar and wind) production potential and how that could potentially offset natural gas in the electricity generation sector by 2030. Finally, the paper provides a comparative analysis of the Turkish market compared with the European country markets to which the gas will flow: Greece, Italy, Romania, Bulgaria, Hungary, Slovenia, North Macedonia, Serbia, Bosnia and Herzegovina (B&H) and Croatia. These countries have already shown great interest in buying gas from Azerbaijan and are therefore relevant to the perspectives of the gas suppliers and Azerbaijan's interest.

This paper would be incomplete if it did not also include a look into the possibility of Turkmen gas exports to Türkiye and Europe via the SGC and an assessment of the extent to which construction of the Trans-Caspian Gas Pipeline (TCGP) is realistic in the current circumstances. The final section summarizes the findings and presents the conclusions.

[1] Statement by President von der Leyen with Azerbaijani President Aliyev, https://ec.europa.eu/commission/presscorner/detail/da/statement_22_4583
[2] REPowerEU: Joint European action for more affordable, secure and sustainable energy, https://ec.europa.eu/commission/presscorner/detail/en/ip_22_1511
[3] Ministry of Energy of Azerbaijan, https://minenergy.gov.az/uploads/Hesabatlar/son-Hesabat%20NK%202022_v6.pdf

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1. Upstream project development – where will the gas come from?

The fields that we will be assessing in this section are proved and producing resources. Once FID is taken to increase production after new exploration wells have been drilled and more data is available, it is quite possible to see incremental production in 5-6 years. It is necessary to look at existing fields for which Production Sharing Agreements (PSAs) are already in place and further development of deeper layers is needed to increase gas production. Fields such as **Shah Deniz Deep, Absheron Stage 1 and 2, ACG Deep** are currently in international consortia's production portfolios **and Ümid** is being developed by SOCAR. This group of reserves and resources comprises both (i) contracted gas and (ii) un-contracted gas, so-called 'free gas' that will show a growing surplus, potentially available for export.

We will not consider blocks where gas has been discovered but no wells have been drilled so that no accurate data is available to estimate resources. Any assumptions on data would be indicative. They are Babek, Shafaq-Asiman, Zafar-Mashal, Nakhchivan, Araz-Alov-Sharq, Dan-Ulduzu-Ashrafi, Inam.

1.1 Shah Deniz Full Field Development (SDFFD)

Shah Deniz has a great resource potential for further development. However it is important to mention that any incremental production and its commerciality will depend on the results of an exploration well which is planned to be drilled at the end of 2023. All present assumptions and production projections might be changed both in positive and negative ways, once the well has been drilled and data received. Therefore, all the information and analysis provided in this section are based on common knowledge and the author's assumptions and conclusions based on meetings with stakeholders.

The next stage of SDFFD, consists of two independent projects, which can add incremental gas and condensate volumes. SD Phases 1 & 2 gas production was 25.3 bcm in 2022. A compression project to keep production from SD1&2 at plateau is currently in the pre-Feed Stage. Furthermore, a total of 26 wells are planned as part of the project of which 21 have been drilled, 19 wells completed but only 15 are in production. By 2025-2026, all the wells will be drilled, increasing gas production.

The second project is exploration of p re-Fasila reservoirs. The consortium is currently drilling an exploration well - SDX-8 - targeting to reach the deeper horizons beneath the currently producing reservoirs in the eastern flank of the field to increase production.[4] If successful, the well will provide a clearer understanding of the drillability, producibility and resource potential of the field. This in its turn will allow the Shah Deniz partnership to further upgrade the ultimate resource potential in support of the plan for further development of the field.

It is most likely that in 2024, the consortium will decide in which priority order those 2 projects will progress. They can potentially add 1-1.5 bcm/year of gas according to a conservative scenario. It is expected that the FID for both projects will be taken in 2024 depending on exploration results.

1.2 Absheron Full Development

The Absheron field is currently under development by a joint venture of Total and SOCAR based on equal interests in Joint Operating Company Absheron. A final investment decision was approved in 2017, when it was planned that production of 1.5 bcm/year would start from the end of 2021 and be sold to SOCAR for the domestic market. The latest news on the project is that the Absheron Early Production System (EPS) is currently in the commissioning stage and is expected to start commercial ramp up production of 0.755 bcm in 2023. According to information obtained from the consortium, the plateau will be reached in 2024 with production of about 1.5 bcma, with a gradual natural decline starting in 2033 and tailing off until 2045 (Figure 1).

Full-field development (Phase 1) of the project envisages drilling exploration and development wells in deeper layers after the Absheron EPS comes on-stream. It is planned that the final investment decision

[4] https://www.bp.com/en_az/azerbaijan/home/news/press-releases/Shah-Deniz-spuds-a-new-exploration-well.html

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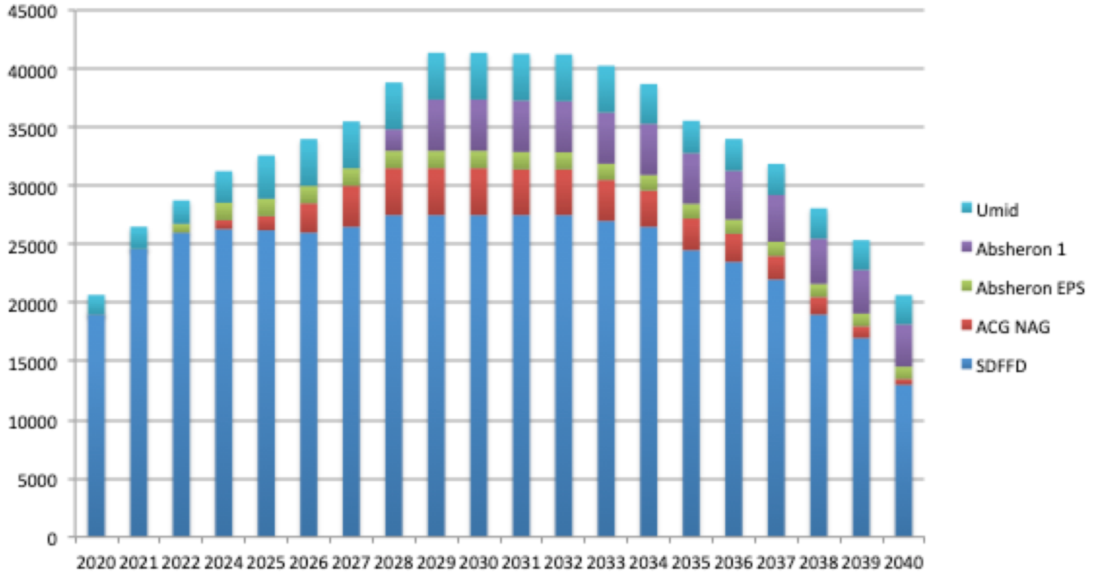
for Phase 1 will be taken by 2025 depending on exploration and appraisal well results, as well as marketing arrangements. The annual plateau level of production from phase 1 may add **4.3 bcma** starting from 2028-29 in addition to the initial 1.5 bcma (Figure1).

1.3 Azeri-Chirag-Guneshli Non-Associated-Gas (ACG NAG)

Both technical and commercial negotiations are ongoing and an appraisal well into the ACG Deep Gas reservoirs has already been drilled. The well provided data about the deep lying gas reservoirs beneath the currently producing oil field. ACG NAG (Deep and Shallow Gas reservoirs) future projected total recoverable volumes are around 155 bcm of gas. The full field development concept including production profiles and corresponding plateau level has not been published yet. Our estimate is that a full field development maximum gas production rate plateau of about 4 bcm/year gas can be achieved, not agreed yet since numbers of wells, facility tie in, etc. is on the evaluation stage. For 1 or 2 exploration and 2 development wells, the estimated CAPEX is around US$2 billion based on our calculations.

Figure 1: Gas production projection, mmcm



Source: Author's calculations

1.4 Ümid

The Ümid field was discovered in 2010 and was commissioned in 2012. One platform is operational and annual gas production from platform one (Umid-1) is 5.5 mmcm/d (1.98 bcma). Gas goes to the domestic market. It is planned that production will be more than doubled by 3Q 2026 with a second platform (Umid-2) drilling 3 exploitation and one exploration wells. Depending on drilling success, the plateau production level from Umid-1 and Umid-2 is foreseen to peak between 2024-2033 at 12 mmcm/day (4.3 bcma) of gas. The operation of the Ümid 1 and Ümid 2 platforms will allow for future tie-in of production from the Ümid-3 platform of probable resources which could maintain plateau production till 2036, after which a gradual tail off period will start (Figure 1).[5]

Future exploration and exploitation of the Babek structure, the continuation of Ümid, will largely depend on a decision by SOCAR whether to continue development of Ümid in an 80:20 consortium with Nobel Oil. Alternatively it could seek at this stage to attract an IOC with its experience, know-how and cash to deal with the geologically complex field. If an IOC takes over the technical operatorship and conducts

[5] Ibid.

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exploration and exploitation works, it is possible that gas production from the Babek structure will come online sooner, depending on the results of an exploration well. Either way, given that no accurate data is available on the Babek field, it is not included in the gas production projection for export in 2027.

Summary

According to the analysis above based on the information obtained from the four project consortia on the current status of the projects, our projection is that SDFFS, ACG NAG and Ümid may add about 9.5 bmca of incremental gas production for export by 2027. Absheron Phase 1 will reach plateau in 2029-2030 and can potentially add about 4 bcma on top of the existing 1.5 bcma from the Absheron EPS from 2024 for domestic consumption (Figure 1).

1.5 Cost of upstream projects

As gas for the next stage of export will come from the four fields as described above, and as nothing has been decided at this stage, before binding agreements have been signed with the potential buyers and exploration wells drilled, it is not known what the main source of financing to develop the fields will be.

Clearly, the FID for the upstream projects mentioned above is conditional on securing LTCs and markets for agreed durations. According to our calculations, based on projected CAPEX for all the segments of the value chain (as described in the following sections), LTCs of from 10 to 15 years are required in order to ensure pay back for the investments, given the geological complexity and approximate estimated cost of the fields as well as expansion of the pipelines.

Table 1 assumes a 10 bcma capacity requirement for potential European buyers. On this basis, according to our calculations, the SOCAR share of investment in new upstream development, is about US$3.84 billion.

Table 1: The shares of stakeholders

	Upstream				Pipelines		
Companies' shares, %	**SD Deep**	**ACG NAG**	**Absheron**	**Umid**	**SCP**	**TANAP**	**TAP**
Socar/AZE gov	21.02	25	50	80	20.02	58	20
Botas						30	
Total			50				
Nobel Oil				20			
BP	29.99	30.37			29.99	12	20
TPAO	19	5.73			19		
Snam							20
Fuxys							19
Enegas							16
Axpo							5
Lukoil	19.99				19.99		
Inpex		9.31					
MOL		9.57					
Exxon		6.79					
ONGC		2.31					
Itochu		3.65					
Equinor		7.27					
Nioc	10						

Source: Project consortia

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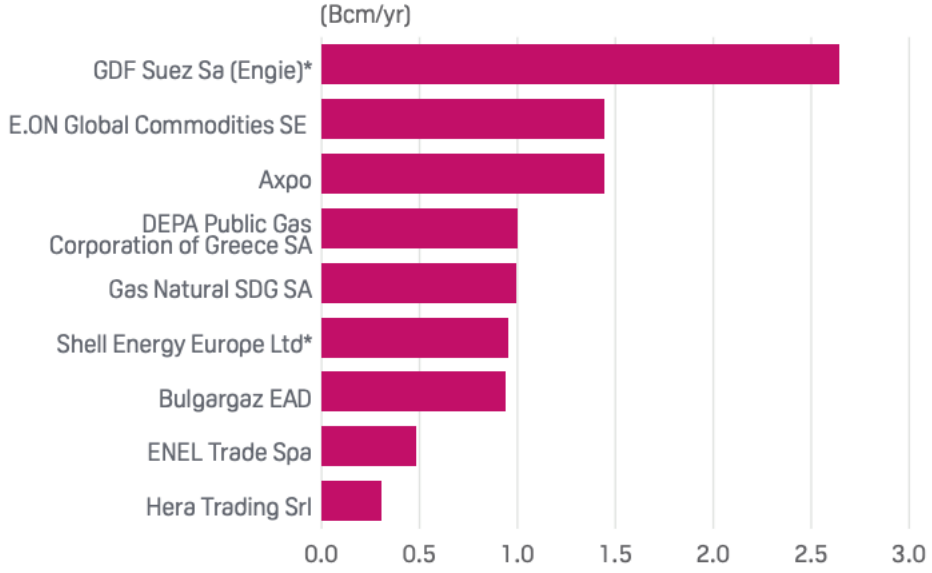
2. Expansion of the segments of the SGC system

Expansion of the capacity of the Southern Gas Corridor pipelines – SCP, TANAP and TAP – will be required to transport the extra 10 bcma from 2027 if the TAP booking phases this year indicate there is third-party demand for additional capacity.

2.1 Trans Adriatic Pipeline

TAP forms the last part of the transportation chain, and takes gas from the Greece–Türkiye border to the interconnection with the Snam transmission system in Italy, and hence to the PSV gas hub, the delivery point under most EU gas supply agreements (GSA) with the Azerbaijan Gas Supply Company (AGSC) (Figure 2).

Figure 2: Shah Deniz 2 gas buyers – volumes destined to Italy, Greece, Bulgaria



Source: S&P Global Platts, https://www.spglobal.com/commodityinsights/plattscontent/_assets/_files/en/specialreports/naturalgas/turning-on-tap-a-shift-in-the-european-gas-landscape.pdf
*In 2019, Shell bought part of GDF's volumes but did not reveal the percentage purchased.

The whole process of funding will start with and depend on TAP capacity booking, as TAP is directly linked to the market. This pipeline passes through the territories of Greece, Albania and Italy, and is therefore subject to EU regulation. As a result, auctions are required for potential buyers to book capacity and this provides an understanding of the demand for extra gas sourced from Azerbaijan.

There will be two phases of the capacity-booking auction for TAP in 2023. The initial, binding bid for the first level of expansion took place on 22 January and allocated 1.2 bcma of incremental capacity.[6] New contracts have already been signed for allocation of TAP capacity from 2026, and the 1.2 bcma of incremental capacity is allocated through long-term contracts starting in that year. To achieve this, TAP will add one compressor unit (ca. 15 MW) to the existing compressor station at Kipoi, Greece, and will upgrade the facilities there.[7] The second, binding open season is expected in the second half of 2023 and this will help test the market requirements in a gradual process of building up capacity expansion

[6] TAP to trigger first level of capacity expansion, https://report.az/en/energy/tap-announces-first-binding-bidding-phase-results-for-gas-pipeline-expansion/
[7] https://en.trend.az/business/energy/3714611.html, Trans Adriatic Pipeline (TAP) AG is pleased to confirm that following the completion of the first binding bidding phase of the 2021 Market Test, the Company will trigger the first level of capacity expansion, https://www.tap-ag.com/news/news-stories/tap-triggers-the-first-level-of-capacity-expansion

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year-on-year to a total additional capacity of 10 bcma by 2027.[8] That is to say, the companies which have shown an interest in buying gas via TAP and intend to submit their bids to book capacity have to take their decisions in 2023 in order to be able to import gas by 2027. TAP needs at least four years to build compressor stations after receiving the concrete capacity bookings from interested parties'.

Therefore, depending on the results of potential European buyers' volume bookings in 2023, the upstream project shareholders will agree to produce the amount of gas requested and consequently take the relevant investment decision(s). In the event that the total requirement is much less than 10 bcma, the TAP consortium has the right to decide that the lower level of volume requirement does not economically justify financing the expansion. In this case, no expansion of the entire SGC system would be realized and no extra gas will be shipped to the European market.

Extra gas production in Azerbaijan for export to Europe will also largely depend on a third-party access exemption. TAP has an exemption from certain aspects of the EU regime for a period of 25 years from the start of commercial operations, granted by Commission Decision of 16 May 2013 on the exemption of the Trans Adriatic Pipeline from the requirements on third party access, tariff regulation and ownership unbundling laid down in the third package of EU gas regulation.[9]

TAP has an initial capacity of 10 bcma, and is expandable up to 20 bcma, by the addition of compression capacity. However, the TAP exemption applies only to the initial capacity. This means that the first 10 bcma of capacity is exclusively reserved for Shah Deniz 2 gas, but any capacity above that will be subject to the full range of EU rules on third party access, tariff regulation and ownership unbundling, and will be available to third parties. Consequently, in the event that TAP is not exempted from third party access for the extra 10 bcma capacity, gas suppliers from Azerbaijan may receive only 20% of the capacity allocation, 2 bcma. This would make the entire SGC expansion initiative unfeasible.

According to TAP's calculation, the cost of the full (10 bcma) expansion will be €1.6 billion (Tables 1&2) and Italian entry tariffs at Melendugno will vary depending on the extent of the expansion, ranging from €2.15/yr/m³/d in a limited (1.2 bcma) expansion scenario to €2.12/yr/m³/d plus a mandatory premium of €3.80/yr/m³/d if there is a full expansion and a Snam network upgrade is required.[10] In Greece, there will also be a requirement to upgrade the DEPA gas transmission system to transport more gas to Greece and from there to neighbouring countries.

2.2 South Caucasus Pipeline[11]

The market test of TAP will be an important factor for TANAP and SCP pipeline capacity expansion. Whatever the demand request that is submitted by potential buyers, that will be the capacity to which TANAP and SCP will be expanded.

There are two SCP pipelines: one of 42-inch diameter and the second, SCP Expansion (SCPX) of 48 inch, giving a total capacity of approximately 24 bcma. The pipelines are designed in a way that capacity can be expanded up to 31 bcma[12] with the help of looping once the investment decision is taken. Two options for expansion are currently being considered. The first option would increase capacity by 3.5 bcma with a total investment of US$1 billion. This option envisages less gas production and export in the event that the TAP market test shows less demand interest. The second option is the full expansion of 10 bcma with a total investment of US$2.5 billion (Tables 1&2).

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[8] https://www.tap-ag.com/news/news-stories/tap-triggers-the-first-level-of-capacity-expansion
[9] https://energy.ec.europa.eu/system/files/2015-01/2013_tap_decision_en_0.pdf
[10] Tap details gas capacity expansion plan, Argus, https://www.argusmedia.com/en/news/2214707-tap-details-gas-capacity-expansion-plan
[11] Gas from Stage 1 of the Shah Deniz contract area is transported in the South Caucasus Pipeline and delivered to buyers in Azerbaijan, Georgia and Türkiye. First gas (Stage 1) flowed in 2006. SCP is owned by the South Caucasus Pipeline Company Limited (SCPC) which is a project company of the Shah Deniz consortium. Stage 2 of the Shah Deniz project also included an expansion of SCP.
[12] https://www.sgc.az/en/project/scp

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Two shippers, AGSC and SOCAR, have executed GTAs for the SD2 buyers for transportation services in SCP. All new GTAs with SCP will be conditional on a positive FID for the upstream projects. Any future expansions might not result in an increase in tariff for the initial shippers.

2.3 Trans Anatolian Pipeline[13]

The current capacity of TANAP, the continuation the SCP pipeline, is 16 bcma. Through this pipeline, the Shah Deniz consortium transports 6 bcma of gas to Türkiye and a contracted 10 bcma to Europe.[14] It is planned that TANAP capacity will be expanded to up to the 31 bcma required for transporting the extra 10 bcma by installing five compressor stations. Transportation charges in TANAP are calculated on a 100% capacity charge basis (that is, 100% "send or pay"), subject to certain permitted deductions and pro-rated for distance. The initial tariff over the base maximum distance (known as the TANAP System Unit Tariff) is agreed at US$107/mmcm, escalated annually from 2018 at 1% per annum. Other exit points attract lower tariffs, pro-rated on a distance basis.

The term of the TANAP–AGSC GTA runs until the expiry or termination of the Shah Deniz Exploration Development and Production Sharing Agreement (EDPSA) or until the annual booked capacity is reduced to zero, whichever is earlier. Consequently, for Shah Deniz gas, a new GTA between TANAP and AGSC is not required. For gas coming from other fields, new GTAs with the relevant consortia will need to be executed. All GTAs will be conditional until the upstream projects' FIDs are confirmed. They will become unconditional only on approval of the Absheron FFD, ACG NAG and Ümid fields' FIDs. The tariffs for the existing shippers to transport extra volumes according to new GTAs with TANAP may be different from the tariffs for any new shippers. Any future expansions may not result in an increase in tariff for the initial shippers. It is likely that this model will be mirrored in the SGC expansion.

Table 2: The expansion of the SGC segments

Pipelines	Capacity	Transportation tariff	Status
SCP	7.5bcma	Base $40/100km/1mmcm tariffs are escalated at 1 January each year by 2.5%	Operational
SCPx	24bcma	Base $49.8/100km/1mmcm tariffs are escalated at 1 January each year by 2.5%	Operational
SCPfx	31bcma	To be defined	To be expanded
TANAP	16bcma	Base $107/$76/100km/1mmcm escalated annually from 2018 at 1%	Operational
TANAPx	31bcma	To be defined	To be expanded
TAP	10bcma	€60/100 km/1mmcm	Operational
TAPx	20bcma	To be defined	To be expanded

Source: Pipeline consortia

[13] TANAP is a mainly 56-in. pipeline (48-in.' from Eskişehir to Tr-GR border) extending for 1,783 km from a single Entry Point at the interconnection with SCP at the Georgia/Türkiye border, to the furthest Exit Point at the interconnection with TAP at the Türkiye /Greece border. Additional Exit Points are in Türkiye at Eskişehir (around 190 km SE of Istanbul) and in Thrace. The Shah Deniz consortium, through its gas sales vehicle AGSC, is an Initial Shipper in TANAP (for 10.5 bcma at plateau), as is BOTAŞ (6 bcma) and SOCAR.

[14] In 2022, exports exceeded ACQ and reached 11.4 bcma.

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It needs to be mentioned that with the expansion of all the three pipelines along the value chain, legally the shareholders, who are the members of the consortia, all have the right to refuse to invest further in the expansion and to give up their shares partly or fully to a new or existing shareholder to avoid extra capex. In the event that this happens, the companies that decline to participate in the expansion will retain their shares and revenues from shipping via the old pipelines (in the SD case).

2.4 Possible hydrogen transportation

Hydrogen transportation via the Southern Gas Corridor is a recommendation of the European Commission but it is not a requirement. As TAP is a European project, the pipeline will need to be technically capable to support hydrogen blending. The consortium is conducting research on possible blending from 1% to 100% and will present a report in 2024 which will evaluate technical and financial aspects. According to preliminary studies technical modification and big investments will not be needed for 2% blending. However, starting from 10%, technical modifications and investment will be needed. As the SGC was removed from the EU PCI list of projects, all the investments will need to come from the pipeline owners. Another question is the source of hydrogen. Azerbaijan does not have any potential to produce hydrogen in the short and mid-term. It has started investing in renewable, solar and wind, (this will be discussed in detail in the section on domestic demand), and hydrogen production is technically possible in the long term. However, the financial viability of green hydrogen production and its transportation is yet to be evaluated by the investors.

3. Financing scheme and source of funding

SOCAR and the government of Azerbaijan will separately finance their share in each upstream and pipeline project and the IOCs (BP, Total etc) will take care of financing based on each company's shares of interest in the projects. The whole financing process for SOCAR could be similar to the financing of SD2 and the first stage of the SGC, i.e each partner will be committed to finance capital expenditures related to the upstream projects and expansion of midstream projects based on its share of interest using various financial instruments described below.

As illustrated in Table 1, we estimate that Azerbaijan's total net financing requirements in connection with its capital expenditure commitments under the whole value chain described above will be approximately US$7 billion (US$3.84 for upstream projects and US$3.162 for pipelines expansion) of the total US$18.51 investment required for full (10bcma) expansion, which is expected to be incurred between 2024 and 2027. It is expected that part of this amount will be borrowed from international banks and part will come from the government in the form of bonds due to SOFAZ (the State Oil Fund of Azerbaijan) and equity. After the gas starts flowing to market, the revenue from the project will also contribute to CAPEX.

The source of financing of the SGC1 included the following scheme:[15]

a) **The issue of Notes**: Southern Gas Corridor CJSC[16] authorised the issue of US$ Guaranteed Notes, which were sold in offshore transactions. The main Guarantor of Notes is the government of Azerbaijan which agreed to irrevocably and unconditionally guarantee

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[15] From closed presentation of the managing director of SGC CJS at the 7th Ministerial Meeting of the Southern Gas Corridor Advisory Council in Baku in February 2019.

[16] "Southern Gas Corridor" Closed Joint-Stock Company was established with the purpose of consolidating, managing and financing the State's interests in the Projects (SGC segments). SGC was founded on 31 March 2014 by the State (the Ministry of Economy of Azerbaijan) (51%) and SOCAR (49%). All of SOCAR's participating interests in the Projects were transferred to SGC, which undertook onward financing of these participating interests (the completion of the transfer of 14.35% stakes in Shah Deniz and South Caucasus Pipeline projects will take place in 2023 subject to the fulfillment of certain conditions precedent). For the organisational structure of Southern Gas Corridor CJSC see: https://www.sgc.az/en/about

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to each holder of a Note, the due and punctual payment of all sums from time to time payable by the SGC CJSC in respect of it.

b) **Equity:** In accordance with the Presidential Decree, the Ministry of Economy finances the Government's share of the equity contributions through funds received for that purpose from SOFAZ. Pursuant to the State Commission Resolution, SOCAR's portion of the equity contributions is paid as follows: a portion is financed from the revenues received from the 10% interests held by SOCAR's affiliates in the Shah Deniz PSA and SCPC, and the remaining portion is provided by the Ministry of Finance to SOCAR from the State Budget.

c) **Bonds (due to SOFAZ):** In accordance with the Presidential Decree dated 25 February 2014, SOFAZ was instructed to finance SOCAR's acquisitions of interests in the Projects. Accordingly, in 2014 SOCAR issued 10-year bonds to SOFAZ in the aggregate amount of US$ 2,517 million.

d) **Revenues from the projects**

e) **Additional debt:** In the case of the SGC1, the Asian Development Bank was the only private bank which agreed to give a guarantee, and only for the upstream segment (Shah Deniz 2) (subject to a certain interest fee). Based on this guarantee SOCAR attracted commercial loans from various international banks and loans from development finance institutions. For the pipeline projects SOCAR attracted commercial loans from the international banks under the government guarantee.

It is most likely that the SGC financing scheme for stage 2 will be the same as for SGC stage 1.

3.1 Risk factors to be considered by the international banks

The international banks will strictly consider all the risk factors and uncertainties that may affect the ability of SOCAR (money borrower) to fulfil its obligations of repaying the Notes and the Guarantor's (the Government of Azerbaijan) ability to fulfil its obligations under the Guarantee. Clearly, there are economic and political risks, such as SOCAR's revenues and profitability and Azerbaijan's economy and the state budget which are dependent on condensate and natural gas prices. Despite current high levels the prices are historically volatile and are affected by a variety of factors beyond the borrower's control, as well as production levels.

Perhaps the major risk for the expansion of the SGC is the European natural gas market and the EU's decorbanisation policy. International initiatives to address climate change, such as policy and regulatory actions to reduce greenhouse gas emissions, could affect the SGC Expansion (and consequently SOCAR) by affecting the balance of demand for and supply of various types of fuels, in particular natural gas and renewable energy. The current energy crisis in Europe may be tackled by 2027 and the European buyers may not be willing to conclude long-term contracts or extend their sales and purchase agreements.

3.2 Key strength to be considered by the international banks

SOCAR's first tranche of borrowing has been successfully handled. It appears that SGC and SD2 are more profitable than expected because of high gas prices in the European market in 2H 2021 and 2022. The Asian Development Bank's (ADB's) assessment is that the project's overall contribution to private sector development and ADB's strategic development objectives is satisfactory. "Most outcome and output targets in the design and monitoring framework have been achieved".[17]

However, it will not be easy to attract commercial loans for the proposed gas production and transportation projects, as some banks (e.g., the European Investment Bank and the European Bank for Reconstruction and Development) have changed their lending strategies to limit investment to green projects only and have stopped lending money for fossil fuel projects. Other banks will have

[17] https://www.adb.org/sites/default/files/project-documents/48330/48330-001-xarr-en.pdf

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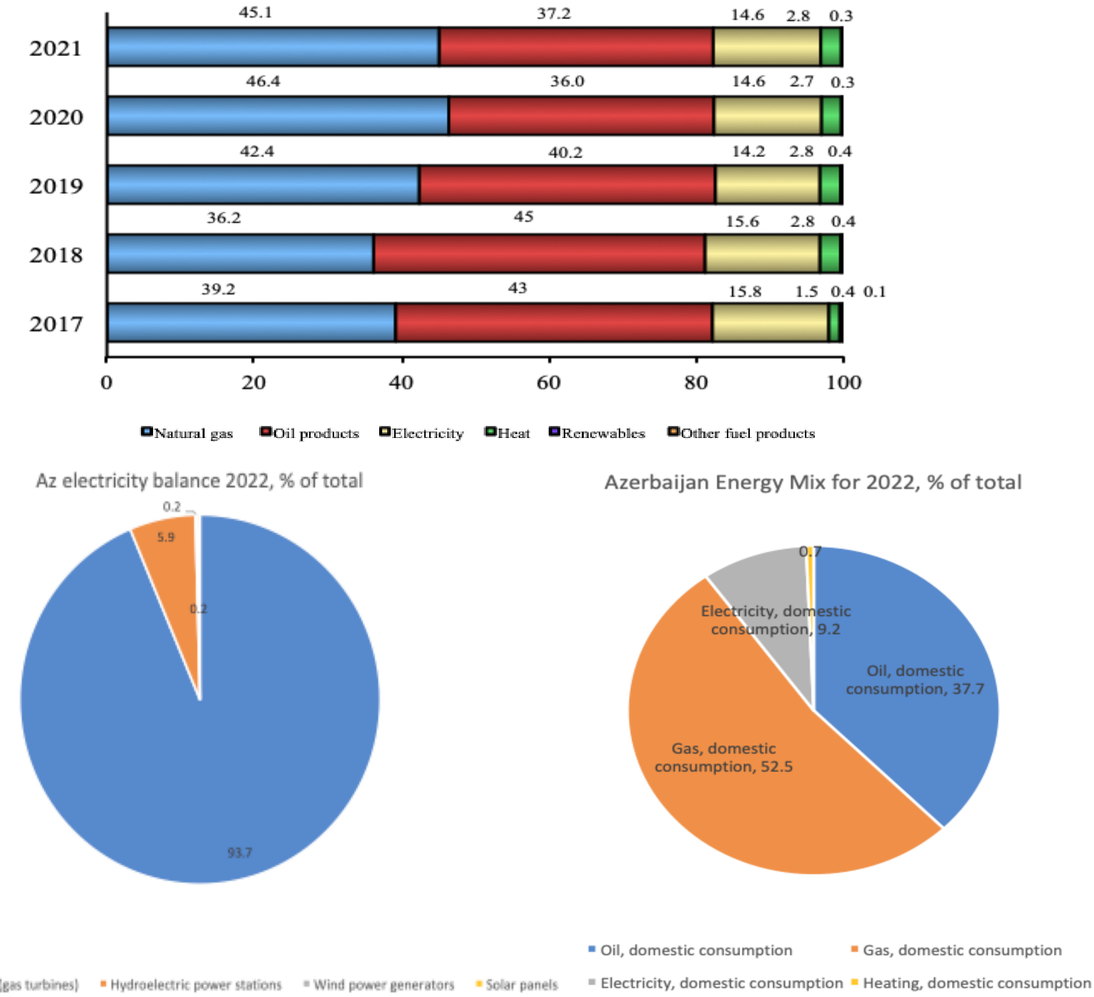
requirements for a green component in pipeline projects and guarantees that infrastructure projects will not lead to stranded assets in the long-run, should they be capable of transporting only natural gas. Incremental hydrogen blending is one of the requirements the banks will have and this would mean extra spending for SOCAR and other shareholders due to the necessity of technical modification of the pipelines.

4. Azerbaijan gas demand projection and renewable energy production capacity

4.1 The country's gas balance

Natural gas is the main source of energy in Azerbaijan's energy mix and the predominant fuel in the power generation sector. In 2022, natural gas provided almost 94% of the total electricity generation mix and 52.5% of the total energy mix (Figure 3).

Figure 3: Final consumption of energy products (%)



Source: State Statistical Committee of Azerbaijan, MoE (2022)

Natural gas demand was almost flat from 2012 till 2018, showing slight growth in 2015, an increase of 7% in 2016, and then a decline of 10% for two consecutive years before starting to grow in the last four years. This is due to a state programme of increasing subsidies in the sector in an attempt to increase the export of non-oil-sector products.

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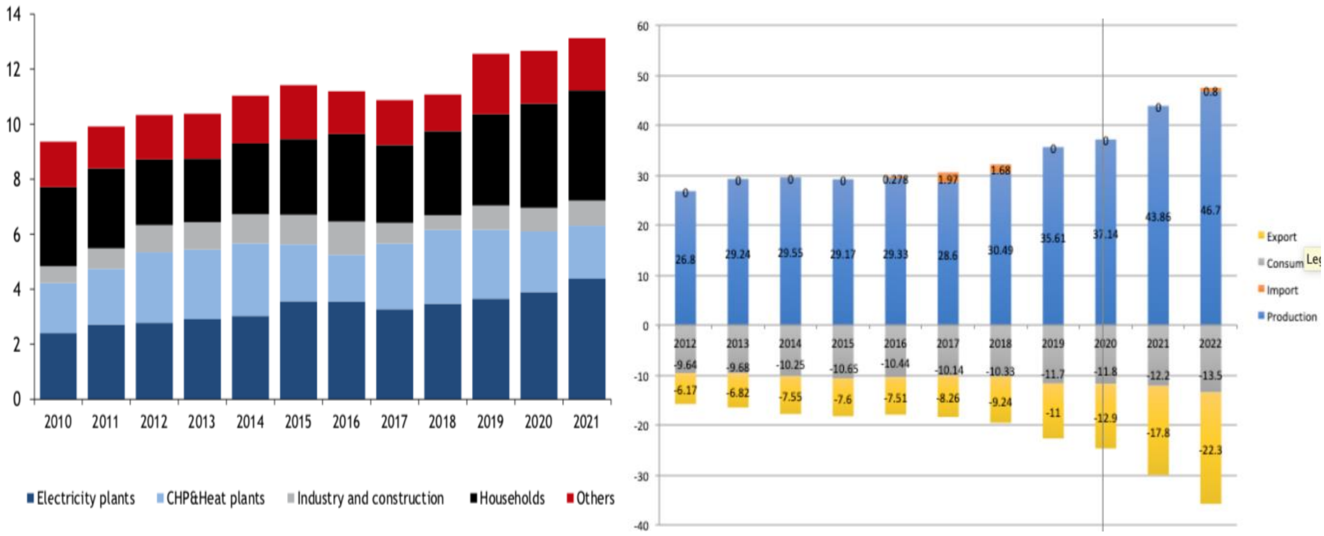
The residential sector in Azerbaijan is the second biggest gas consumer after the electricity generation sector with a share of about 30% (Figure 4). Natural gas is the predominant fuel for heating in this sector, constituting approximately 90%, with small shares for wood, LPG and diesel. Residential natural gas demand has high seasonal dependence because it is typically temperature sensitive. The lowest gas consumption months in this sector are May to September, the warmest months of the year.
Any future incremental demand increase in the domestic market will be covered using renewable energy in the power generation sector, as described below, and from 2023 by gas from the Absheron field, which will add about 1.5 bcma to the domestic gas supply portfolio.

Figure 4: Azerbaijan gas balance and gas consumption by sector, bcm



Source: Argus, MoE, State Statistical Committee

As shown in Figure 4 on the right hand side, gas production was increased by 6.2%, export by 25.2% and consumption by 10% in 2022. The demand growth did not affect exports negatively. Gas for export comes from the fields that are under PSA with international consortia, which is dedicated for export.

About 3-3.5 bcma of gas is delivered from SD 1& 2 for the domestic market. 7.8 bcma comes from the fields in the SOCAR production portfolio, 3 bcma of petroleum gas comes from BP's ACG field and is delivered free to SOCAR under a PSA, a total of 13.8-14.3 bcma for the domestic market.

4.2 Demand projection

This report considers several factors that have historically affected gas demand in Azerbaijan, still influence demand change and most likely will continue to do so in the long-run. They include:

- the prospects for SOCAR's gas production portfolio;
- supply contracts and imported gas price;
- the power generation mix; and
- financial support mechanisms for renewable energy.

These all constitute drivers and constraints, challenges and opportunities for the Azerbaijani electricity and natural gas sectors. Uncertainties in the first two drivers may affect gas demand growth, as it is most likely that production from the SOCAR gas production portfolio will decrease. The SOCAR/Azneft gas production portfolio comprises volumes from mature natural gas fields that have been producing for decades but which are now in decline (Gum Deniz-Bahar, Bahar 2, Bulla Deniz, Harazire-Duvanni, Oil Rocks, Guneshli, etc.). All the gas produced is consumed in the domestic market. There are several oil fields with substantial associated gas reserves, such as Azeri-Chirag-Guneshli and Shallow Water

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Guneshli. Significant quantities of associated gas are present in other offshore reserves such as Oil Rocks, although much of this gas is used operationally or re-injected to enhance oil recovery.

To replace some volumes of gas from these fields, SOCAR will need to import more gas from Turkmenistan. It has been agreed to double the current ACQ of 2 bcma. SOCAR will also receive more gas from the international consortia operating in the country (SD 1 and 2, Absheron FFD and ACG, both oil and NAG) and inject more renewable generation into the grid to offset about 1 bcma of gas in the power generation sector.

Production from SOCAR's gas portfolio has been declining over the last 10 years and this has led SOCAR to buy more gas from international consortia operating in the country as well as to import gas from Turkmenistan via Iran. The imports raise the cost of gas for SOCAR and create a difference between the cost of gas and the price at which SOCAR sells it to the domestic market, including Azerenegy.[18] Gas imported from Turkmenistan in 2022 cost US$129,37/mmcm,[19] whereas the gas price for the population was US$70.6. Although the difference in price has been subsidised by the government, any gas and electricity price increase in the domestic market in the future will be a great incentive for consumers to save energy, leading to greater efficiency, as happened from 2015 (when the Tariff Council increased gas prices and introduced differential tariffs) until 2019, when demand stagnated or slightly decreased. This resulted in an efficiency-based demand reduction of about 5–10%, mainly from residential and industrial end-users.

Consequently, drastic demand growth is not expected in the next 5–7 years, and it is projected that demand will only increase from the current 13.5 to 15–16 bcma, mainly because of the deployment of the huge potential of renewable energy (solar and wind) over these years. About 1 bcma of gas will be offset in the power generation sector from 2030. Moreover, gas supply to the liberated territories that had been under Armenian occupation for 28 years will not add significantly to demand growth, as the internally displaced population will be relocated to their homes in the Karabagh economic zone of Azerbaijan and the national population will be the same as when they lived elsewhere in Azerbaijan. Additionally, most of the liberated areas are planned to be green zones,[20] producing and consuming renewable energy.

If domestic gas demand rises, it will be met by imports from Turkmenistan under SOCAR gas purchase agreements with international consortia in accordance with PSAs (ACG PSA allows SOCAR to take associated gas free of charge). It is assumed that Azerbaijan may renew its short-term contract with Turkmenistan and continue importing Turkmen gas via Iran, when and if necessary, as it will be increasing Azeri export volumes. The volume could be 1–4 bcma, as the parties signed an MoU in June 2022 to double imports to 4 bcma. As shown in Figure 5, considering all the MoUs and agreements in place, planned or announced, it is assumed that sufficient gas will remain for domestic customers after increased exports and re-injection.

[18] Current natural gas price for electricity producing companies is 165 AZN/mmcm (91.7Euro). See Tariff Council of Azerbaijan Rebublic data gas prices for all the sectors of Economy and households: http://www.tariffcouncil.gov.az/?/az/content/66/
[19] Azerbaijan imported more than 857 million cubic meters of gas from Turkmenistan for 110 million USD in 2022, https://turkmenportal.com/en/blog/58359/azerbaijan-imported-more-than-857-million-cubic-meters-of-gas-from-turkmenistan-for-110-million-usd-in2022
[20] Azerbaijan approves action plan for green energy zone in liberated areas, https://en.trend.az/azerbaijan/politics/3612576.html

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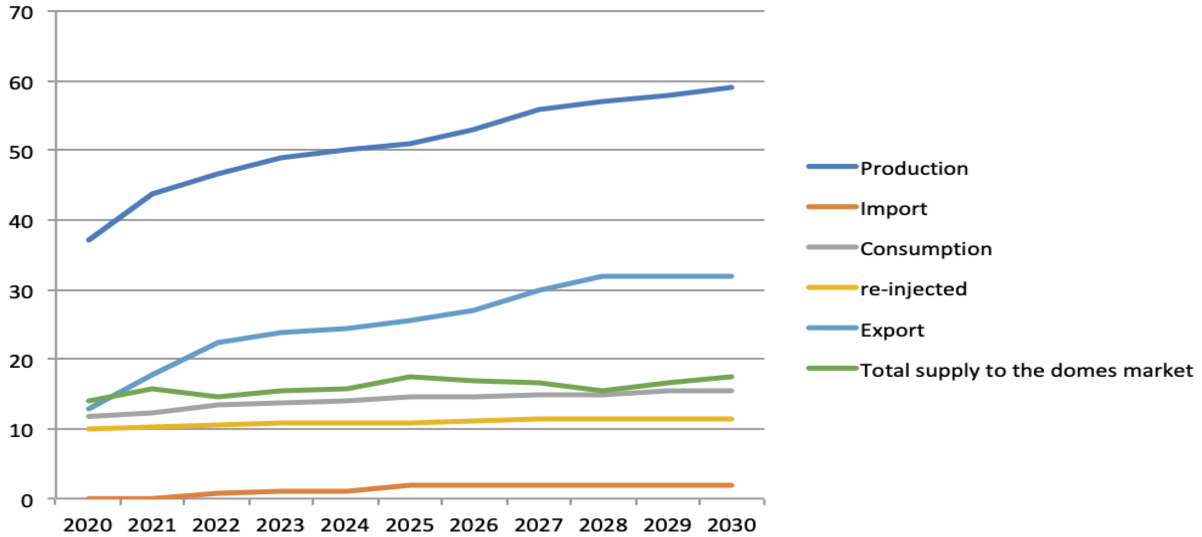
Figure 5: Gas remaining for the domestic market vs. gas consumption*



Source: State Statistical Committee; MoE; author estimates, 2023–2030

*Total production plus import – re-injected gas (non-commercial) – minus exports = total domestic supply. Consumption is supplied from total domestic supplies. The difference between the total domestic supply and consumption is injected into underground gas storage.

4.3 Renewable energy production

In the last two years, Azerbaijan started aggressively investing in renewable energy and has attracted hundreds of millions of dollars of foreign investment for wind and solar energy production. The share of wind and solar installed capacity as of now is 3.5% (45.9 MW) and 5.1% (66.1 MW) respectively, and it is planned to increase this to 1,500 MW by 2030 (approximately 50% solar and 50% wind). Wind will replace 687 million m3 of gas/year, solar will replace 558 million m3, 1045 million m3 in total,[21] in the domestic gas market. 1.045 bcma will replace gas in the power generation sector. Azerbaijan is targeting 30% solar and wind in the country's energy mix by 2030.

Azerbaijan has signed 20 different agreements with 14 companies from different countries to produce, develop and export solar and wind power starting from 2023 and, in the longer run, green hydrogen.

In the second stage of green energy generation, about 10 GW in total, all to be generated by Masdar and including green hydrogen production, is envisaged from 2030. Of this, it is planned to export approximately 3 GW to Romania and Hungary via Georgia and Black Sea optical fibre links. The timeline for green energy export to Europe is not yet determined.[22] This would be a third transportation corridor from Azerbaijan to Europe after the Baku–Tbilisi–Ceyhan oil pipeline and the SGC, and will be on the same scale of energy transportation. Green energy export will help maintain Azerbaijan as a relevant energy exporter beyond 2040, when SD 2's 20-year long-term gas supply contracts will expire. Azerbaijan may remain an energy exporter beyond 2050, when many countries in Europe have pledged to reach their net-zero targets.

[21] This information obtained from State Agency of Renewable Energy Sources under the Ministry of Energy of the Republic of Azerbaijan (AREA)

[22] On December 17, 2022, the "Agreement on strategic partnership in the field of green energy development and transmission between the Governments of the Republic of Azerbaijan, Georgia, Romania and Hungary" was signed in Bucharest. https://area.gov.az/az/page/beynelxalq-emekdasliq/beynelxalq-muqavileler/azerbaycan-gurcustan-ruminiya-ve-macaristan-hokumetleri-arasinda-yasil-enerji-sahesinde-strateji-terefdasliga-dair-sazis

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5. The Turkish market versus the European market – comparative advantages and disadvantages for Azerbaijan

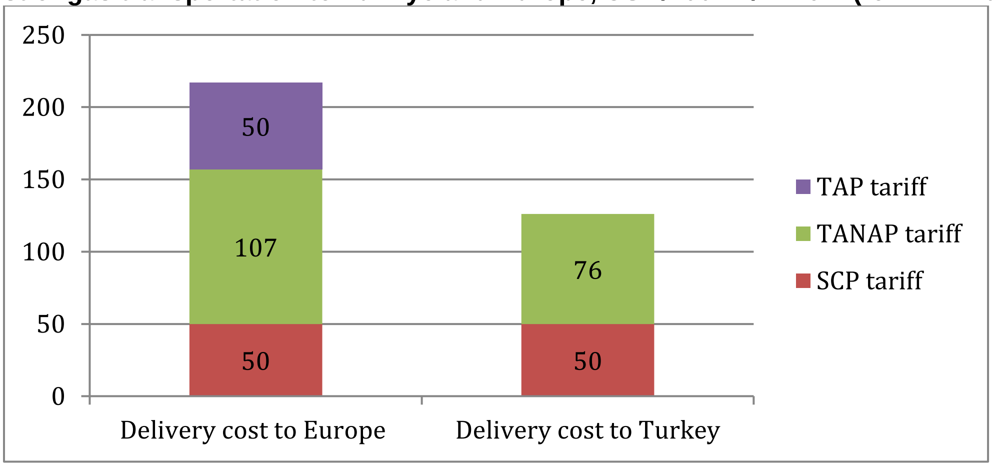
5.1 Türkiye versus Europe – a comparative analysis

5.1.1 Türkiye

It is important to consider which gas market is commercially more profitable for the exporters in Azerbaijan; the project developers have choices. It is highly unlikely that exporting all the available gas to Türkiye or alternatively to a hub that Türkiye is discussing setting up with Gazprom, is a preferable choice for the exporters and for Baku, for strategic but also economic reasons in the long-run. It is apparent that differences in distance between gas transportation from Azerbaijan to Türkiye or the European market will lead to different transportation costs and consequently different rates of return for the entire value chain. Depending on the choice of destination, there may be new shippers, and shipping tariffs for them may be different from those for the SD2 gas buyers. New shippers may emerge in the event that potential buyers of extra gas from Azerbaijan want to offtake their gas at a delivery point other than their market, i.e., on the Türkiye–Greece border or somewhere in Türkiye.

There also might be a new commercial structure for each of the three pipelines that will define the new tariffs, and a new economic model will be needed to calculate the new tariffs for the extra gas shipments. It is assumed that the tariffs will not be much higher, or may even be the same as the old ones, at least for SCPX and TANAPX, because the shippers will be the pipeline owners, as is the case for SD2 gas shipments. It is assumed that the TAP shipping tariff may change, as the gas seller companies will deliver the gas on the Turkish-Greek border at the Komotini offtake point if the gas is for the Greek, Bulgarian or any other market that will import gas via Greece (North Macedonia, Serbia and Hungary); or at the PSV offtake point if the gas is to be sold in the Italian market. As it is not known at this stage whether the tariff will change, or to what extent, the overall cost of shipments to Türkiye (for the domestic market) and Europe will be calculated assuming the old tariffs for SD2 gas.

Figure 6: Cost of gas transportation to Türkiye and Europe, USD/100km/mmcm (for TAP-Euro)



Source: Pipeline consortia

The transportation cost for SD2 gas for Türkiye via SCP and TAP is about US$130. It needs to be mentioned that TANAP transportation has two different tariffs: US$76 for Türkiye's BOTAŞ (for the Turkish market) and US$107 for European shippers, which reflects the shorter distance to the offtake point in Türkiye, at Eskishehir (Figure 6).

The transportation tariff via the entire value chain to Greece is US$207, onward transport to Bulgaria adds €55, making the total US$262 (at the current exchange rate) (Figure 6). Consequently, the shippers using SCP and TANAP, which in the case of SD2 are the same as the gas producer companies, will pay less for transportation and thus decrease their cost and almost double their rate of

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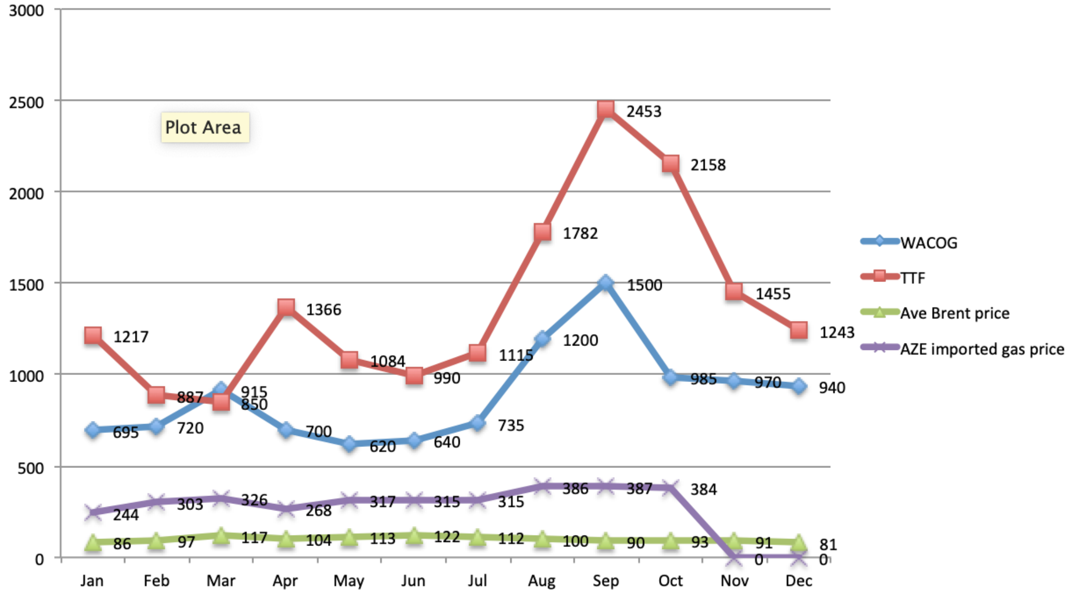
return if the gas price in say Greece and Türkiye is the same (this will largely depend on pricing in new contracts).

In 2022, the minimum average imported cost of gas in Türkiye occurred in May at US$620/thousand m^3, and the maximum was in September at US$1,782/thousand m^3 (Figure 7), reflecting the TTF hub prices and oil prices with a six-month lag, according to calculations based on the contractual pricing and contracted volumes. Gas imported from Gazprom is 70% linked to TTF prices and 30% to oil prices, whereas gas imported from both phases of Azerbaijan's SD field and from Iran is 100% oil and oil products price indexed. Of the total 62 bcm annual contract quantity (ACQ) as of 2022, 57% is oil linked (43.5 bcma) and 43 per cent hub indexed (TTF and Henry Hub); this includes spot LNG (18.75 bcma).[23]

Figure 7: Weighted average cost of gas imported to Türkiye, and TTF and average Brent prices, 2022 (USD/Mmcm for gas, USD/barrel for Brent)



Source: ICE, author's calculation for Türkiye's imported price based on oil and TTF prices, Azerbaijan State Custom Committee for imported gas prices from SD 1 & 2[24]

As shown in Figure 7, the average price for imported gas in Türkiye mirrors the TTF price with a difference of about 60-70%. The Turkish import price is currently lower than the TTF price owing to oil price indexation in LTCs.

According to Article 7.8 of the 2013 TANAP Host Government Agreement (HGA) between Türkiye and Azerbaijan, "The States expressly agree that all volumes of Gas belonging to the Republic of Azerbaijan and planned to be shipped via the TANAP System in excess of an initial volume of sixteen (16) billion cubic meters per Year will first be offered to buyers in the Republic of Turkey".[25] That is to say, extra gas can be exported to Europe only in the event that Türkiye declines to buy additional volumes. Depending on the pricing and other contractual conditions under which new gas sellers would want to sell gas to Türkiye, the current situation in the market supports the assumption that Türkiye will need as much gas as Azerbaijan can offer in the future. Türkiye's natural gas demand is largely affected by three major factors: temperature, hydrological conditions and the price of imported coal and natural gas. In the power sector, imported gas is required if hydro reservoir levels are low or if the cost of imported

[23] For detailed analysis on cotracts renewals and pricing see G. Rzayeva, "Turkey's Supply Demand Balance and Renewal of LTCs", 2022, (pp. 21-23), https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2022/04/Insight-113-Turkeys-supply-demand-balance-and-renewal-of-its-LTCs.pdf

[24] https://www.stat.gov.az/source/trade/az/bulleten/2022/f_trade_12_2022.zip

[25] https://www.tanap.com/store/file/TANAP_Hukumetlerarasi_Anlasma.pdf, p.7

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coal is higher than gas.[26] If Türkiye has access to relatively cheap gas, gas usage in the power sector could increase, mainly replacing imported coal. In the industrial sector, cheap gas is vital for ramping up production and exports, which are vital for the economy and balancing the budget deficit.

Türkiye has been aggressively pushing its exports for the past few years in order to take advantage of the depreciated lira, which makes Turkish products more competitive overseas. In 2022, Türkiye recorded a 13% increase in exports to US$254 billion,[27] above the targeted US$250 billion. The new target of the Turkish government is to increase exports by 10% p.a. to reach US$300 billion in two years, placing the country among the top 10 countries for exports in the longer term.[28] This will also help to reduce the budget deficit and balance the import/export ratio. With these ambitious economic plans, Türkiye will need to increase its imports of cheap gas when, and from where, it is possible; and Azerbaijan seems to be the most economically preferable option.

Today, Azerbaijani gas is the cheapest imported gas for Türkiye owing to the pricing mechanism in LTCs (Figure 7). However, it is clear that the whole expansion of the SGC project to double the export volumes is designed for the European market. Azerbaijan can get loans from international banks and secure the FID in further development of the gas fields with the international consortia (SD, Absheron, and ACG) only if this gas is sold in Europe. As this is a term of the HGA, it is the Turkish and Azerbaijani governments (Ministries of Energy) will negotiate on this issue as part of the expansion process and come to an agreement before the precise demand in the European market is defined after the final TAP auction by the end of this year. It is hard to predict the outcome of the negotiations, however, given the extremely good political relations and unprecedentedly close ties between the two countries, it is quite possible that Ankara and Baku will come to an agreement. Turkiye would most likely want to continue gas imports from Azerbaijan after 2024 when the SD1 mid-term gas supply contract expires. The solution might be that SD1 concludes a new open-ended short-term contract for smaller volumes (reserves remaining in SD1 until complete tail off) and/or increase re-export of the Turkmen gas that Azerbaijan imports via Iran based on spot contracts. These would be small volumes of about 1-2 bcma.

As explained in Section 2, new and existing gas sellers will be involved in the expansion of gas production projects and exports in Azerbaijan, and therefore the pricing mechanism for Türkiye may not be the same as in the SD LTCs. The new suppliers may include Total (Absheron), TPAO, Mol, Inpex and Equinor (ACG NAG) who may want to have more market-oriented pricing linked to hubs in Europe such as TTF or, at least, to regional hubs such as PSV, the Balkan Gas Hub in Bulgaria (which is not liquid enough), or even Exist in Türkiye (also not liquid). This means that the gas price for Türkiye might not significantly differ from that for Europe. The other option, which Türkiye may opt for, is that, without any linkage to a gas hub, the gas price could be determined by offers in the trading market.

5.1.2 Türkiye's hub plans

With the current, unprecedented high natural gas prices on European hubs, any reference to European liquid hubs in the Turkish LTCs has become unpopular or even undesirable for decision makers. A historically high weighted-average cost of imported gas price pushed Ankara to start working on a local hub concept to which it could link its imported gas price in the future. For that, more gas from various sources needs to be traded on Turkish soil. This has been prevented for many years by the monopoly of Botaş and the unliberalized market, with only minor and restrictive roles for private companies.[29]

[26] "Turkey's Supply Demand Balance and Renewal of LTCs", 2022, https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2022/04/Insight-113-Turkeys-supply-demand-balance-and-renewal-of-its-LTCs.pdf

[27] https://www.ft.com/content/6bdcecc4-67f2-4747-89b0-ebf89f31af18

[28] Turkish exporters eager to step up pace for $300B sales in 2 years, https://www.dailysabah.com/business/economy/turkish-exporters-eager-to-step-up-pace-for-300b-sales-in-2-years

[29] For market liberalisation process and obstacles see "The Renewal of Turkey's Long Term Contracts: Natural gas market transition or 'business as usual'?", G. Rzayeva, 2020, (pp. 3-4; 26) https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2020/09/Insight-72-The-Renewal-of-Turkey%E2%80%99s-Long-Term-Contracts.pdf

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Russian president Vladimir Putin's suggestion that Russia and Türkiye create a joint gas hub from which Türkiye could re-export Russian gas to Europe answered Türkiye's plans to set up its own liquid gas hub with the possibility of providing the price reference for LTCs in the future. Whatever type of hub this will be, any virtual or physical trading centre, in order to become liquid and credible, must have a high churn rate with a large number of private companies having access to; gas from various sources; import–export infrastructure; a gas transmission system; LNG import facilities; gas storages; and so on. Türkiye is not there yet, as BOTAŞ controls more than 95% of market share, including import and export contracts, and infrastructure, and 100% of the gas transmission system. However, over the past 3–4 years, some important work has been done.

Although at this stage it is not known what this gas hub will look like and how it will operate, it can be assumed that almost 16 bcma of gas from Russia will flow via the second string of TurkStream (TS) at the Stradzha–Malkoclar 2 entry point to European customers in Bulgaria, Romania, Serbia, Hungary, Greece, Macedonia, B&H, etc. The capacity of this pipeline is almost fully utilized at the moment. The 2 bcma Türkiye–Greece interconnector can also be used to transport Russian gas to Europe via Türkiye. Additionally, reverse flow through the Trans-Balkan Pipeline can potentially add 15 bcma, if available when and if the hub is operational. Depending on the number of countries, including current and former Gazprom customers in this region and beyond, the maximum 33 bcma of existing capacity, (of which 15 bcma of the TS is utilized), does not seem to be sufficient to divert Nord Stream gas export volumes and/or exports via Ukraine to Türkiye.

Turkish Minister of Energy and Natural Resources Fatih Dönmez has suggested that future extra volumes of gas available for export in Azerbaijan and/or Turkmenistan, and potentially in Iraq, could also be transported via this possible physical hub.[30] However, given that 14.4 bcma is currently being transported by Gazprom to Greece, Serbia and Hungary, and that third party access is also required, the question is how it would be possible to transport potentially 10 bcma of Azerbaijani gas, a minimum 10 bcma of Turkmen gas when and if transported westward, and Russian gas once the hub is operational through the remaining 18.6 bcma capacity of the three pipelines?

Consequently, Ankara would like to receive any extra Azerbaijani volumes for export to this hub and re-export it to customers in Europe. This would also be in line with the TANAP HGA signed between the two countries. However, this would not be acceptable for Azerbaijan which, from the beginning, has invested a great deal, politically and financially, in the construction of the entire value chain up to the end users in order to participate in all segments. By being a gas supplier to those European countries, Baku increases its political weight in the region as well as benefitting financially, especially now, given high gas prices.

This is particularly important now, when the European countries are divided into two groups, with one group supporting Azerbaijan's fight for the liberation of its lands from Armenian occupation and the withdrawal of Armenian military forces from its internationally recognized territories (the UK, SEE and Central European countries); and another group criticising it in line with their weakened interest in the region after the 2020 war (France, Germany and Benelux countries). Clearly, the policy of direct gas sales to customers exposes the supplier to the financial risks of a volatile market and changing prices, but Baku has chosen this option of gas transportation up to the customer's door, with all the risks involved, and will continue to do so because it will double its gas supplies to Europe. Therefore, Azerbaijan will opt for direct export to customers in Europe over exports via the planned hub, if it is created by 2027.

5.2 Southeast Europe and Central European markets

The European countries interested in buying Azerbaijani gas include existing customers in Greece, Bulgaria and Italy, and potential new customers in Hungary, Croatia, Serbia, North Macedonia, B&H, Romania, Slovenia and Albania. The heads of these countries have met President Aliyev in Baku or in

[30] Turkish Energy Minister on possibilities of expanding country's role as gas hub, https://www.azernews.az/region/202005.html

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their own capitals and asked to increase gas imports from Azerbaijan.[31] They or their energy ministers also took part in the 9th Ministerial Meeting of the Southern Gas Corridor Advisory Council and the First Green Energy Advisory Council Meeting held on 3 February in Baku.[32] Together, these countries form the Southeast Europe and Central European region, which is becoming increasingly important as they seek to increase pipeline gas and LNG import capacity significantly in an attempt to diversify away from Russian supplies. Connectivity with other suppliers, and interconnectivity within the region, have improved immeasurably, and will continue to do so as other projects are developed over the next 4–5 years.[33] The region has been investing in becoming a transit region for gas coming from various sources, having constructed LNG terminals, mainly in Greece and Italy, and international pipelines, such as TAP and TurkStream, for moving gas further to the other member states. This region has also built strong interconnectivity with Türkiye and has, in total, 41.62 bcma of technical interconnection capacity with Bulgaria and Greece.[34]

Thanks to the new pipeline and LNG projects that countries started to build from 2010, the region has managed to partly move away from reliance on Gazprom and will be able to fully replace Russian gas in 2–3 years with a mix of LNG and pipeline gas,[35] perhaps with the exception of Hungary. The aggregated natural gas consumption of the region was almost 30 bcm in 2022, excluding Italy, plus 69 bcm of Italian imports last year (Figure 8).[36] The region's countries are significantly reliant on coal in their energy mix and produce around 20% of the EU's coal and lignite. The main producers, Serbia, Greece, B&H, Bulgaria and Romania, all have plans to reduce their coal production and consumption, and to substitute it with natural gas and renewable energy, in line with the EU's decarbonisation objectives. Gas demand may therefore increase and, given that this regional market was heavily dependent on Russian gas, and that these countries are planning to completely end that dependence, LNG and gas import requirements from alternative sources such as Azerbaijan may increase significantly.

[31] Four countries offer help to boost Azeri gas supply to Europe, https://www.reuters.com/business/energy/four-countries-offer-help-boost-azeri-gas-supply-europe-2022-09-30/ ; European nations ask EC to finance gas supplies from Azerbaijan to guarantee future sources, https://www.azernews.az/nation/205479.html

[32] https://energy.ec.europa.eu/news/southern-gas-corridor-advisory-council-9th-ministerial-meeting-and-green-energy-advisory-council-1st-2023-02-03_en#:~:text=The%209th%20Ministerial%20meeting,Azerbaijan%20and%20the%20European%20Union.

[33] "South East Europe gas markets – reconfiguring supply flows and replacing Russian gas", J. Bowden, OIES, 2022, p.1, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/12/South-East-Europe-gas-markets-NG-177.pdf

[34] SEEGAZ Report: regional transmission routes, Energy Community, 2022, file:///Users/gulmirarzayeva/Downloads/Enc_SEEGAS_Report_2022.pdf

[35] For the detailed analysis on the regions's gas market see "South East Europe gas markets – reconfiguring supply flows and replacing Russian gas", J. Bowden, OIES, 2022, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/12/South-East-Europe-gas-markets-NG-177.pdf

[36] IEA, 2023. Gas Trade Flows. https://www.iea.org/data-and-statistics/data-product/gas-trade-flows

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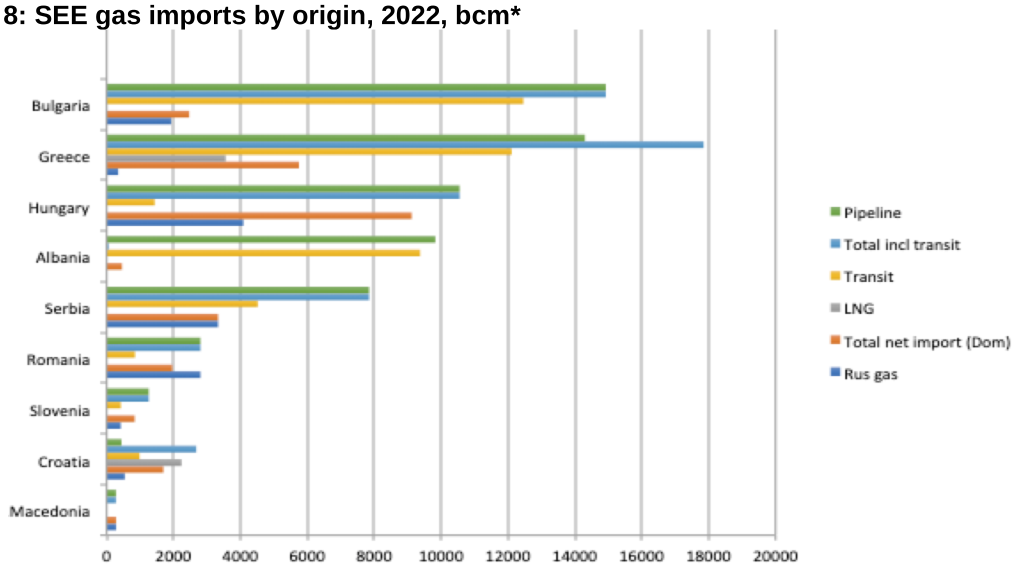
Figure 8: SEE gas imports by origin, 2022, bcm*



Source: IEA, 2023. Gas Trade Flows. https://www.iea.org/data-and-statistics/data-product/gas-trade-flows

***Bulgargaz** had its LTC supplies from Gazprom suspended in April 2022 when it refused to pay in rubles. Therefore, the volumes entering Bulgaria from Turkey are likely only transit volumes, destined for North Macedonia, Serbia, and Hungary. Since July 2022, the net imports into Bulgaria are smaller than the physical volume arriving in Bulgaria from Greece. Therefore, Bulgaria is likely no longer receiving Russian pipeline gas. Historically, Bulgaria imported 2-3 bcma of Russian pipeline gas.

Albania likely already receives only Azeri gas via TAP.

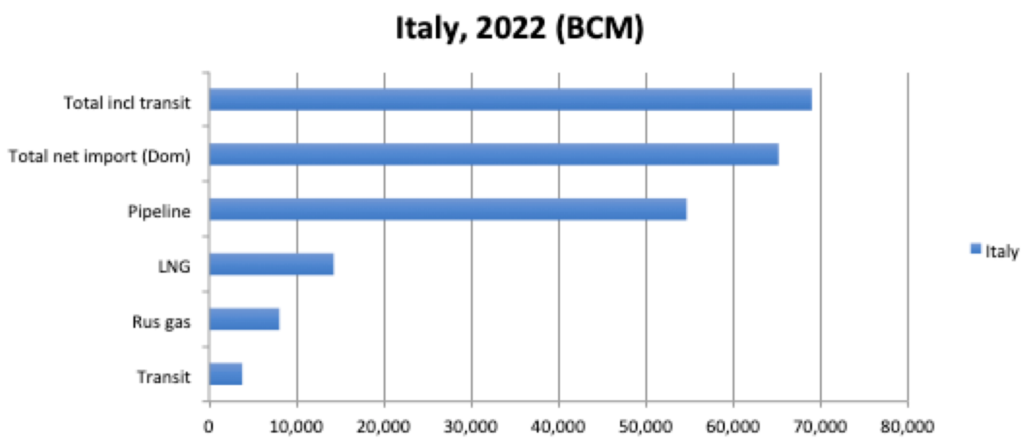
Historically, **Croatia** imported 1-2 bcma of pipeline gas that was likely Russian in origin. This fell to 0.5 bcm in 2021, and in 2022 Croatia was a net exporter of pipeline gas. It seems that Croatia is now importing very little, if any, Russian gas.

The volumes flowing into **Greece** from Bulgaria are likely Russian, delivered to Bulgaria via TS and Türkiye. Historically, Greece imported 2-3 bcma of Russian pipeline gas via Bulgaria. But the net flow between Greece and Bulgaria shifted in 2022, and now it is difficult to identify Russian pipeline volumes to Greece.

In 2022, only the volumes arriving in **Hungary** via Serbia are definitely Russian in origin.

The total pipeline imports to **N.Macedonia** are almost certainly Russian in origin. This is 0.2-0.4 bcma.

The total net pipeline imports to **Serbia and Romania** are almost certainly Russian in origin. This is 0.2-0.4 bcma and 1.5-2.5 respectively



***** Italy has replaced the lower volumes of Russian pipeline imports with more LNG, more pipeline imports via Switzerland, and lower demand. Historically, Italy imported 25-30 bcma of Russian pipeline gas into northern Italy from Austria. This fell to 8 bcm in 2022, and could soon fall close to zero depending on divercification of import portfolio.

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5.3 Possible marketing arrangements and gas supply agreements (GSA)

5.3.1 Joint selling arrangements

Joint sales and marketing through a single seller is not allowed in the EU market in accordance with European competition legislation as it is in breach of Article 81(1) EC and Article 51(3) of the European Economic Area Agreement.[37] When, in 2013, long-term gas supply contracts were signed with the European gas buyers, the marketing arm of the Shah Deniz consortium, Azerbaijan Gas Supply Company (AGSC), a single seller, was exempted from joint sales restrictions on the ground that, although it is a single consortium, there are seven shareholders, the Shah Deniz Gas Entitlement Holders, and each of these sells its gas via AGSC in proportion to its entitlement.

Clearly, the situation with the new suppliers in Azerbaijan will be different. This is because, unlike SD2, purchasers must now deal with at least two different upstream consortia (ACG and Ümid) with different shareholdings, and the aggregated around 10 bcma of gas will come from different upstream companies. This is in line with EC Competition Law but complicates gas sales to Europe via one marketing company. Consequently, marketing arrangements with the new projects will have to be different.

It is too early at this stage to discuss who will sell gas and how. The Shah Deniz extra volumes (1.5 bcma) will most likely be sold within the same scheme, via the AGSC, in which the gas producers are the same as the gas sellers. However, gas coming from the Absheron, ACG NAG and Ümid fields needs to be sold separately. The assumption is that there can be two options for gas sales. SOCAR may want to buy out all the gas volumes available for export – from Total in Absheron (50%), ACG NAG (various shareholders) and Nobel Oil (20%), in the event that these companies are willing to sell their gas at the extraction point – and sell it to the European customers as a single seller. For that, SOCAR will need an exemption from the EC, perhaps referring to the fact that there are two other gas producers and that SOCAR is not a sole producer and exporter. If Total and Nobel Oil refuse to sell their gas in Azerbaijan and want to participate in the entire value chain, gas sales will need to be realized separately, and each company will need to conclude separate supply contracts with buyers. This does not seem to be acceptable for Azerbaijan and would also complicate the process for the buyers. A more realistic option is to create another marketing company similar to AGSC and make joint sales with a possible exception granted by the EC referring to the fact that there are several producer companies.

5.3.2 Price determination

The parties, sellers and buyers, need to choose the most suitable pricing mechanism for their contracts, which is one of the most essential and sophisticated components of a long-term gas supply contract and also the most troublesome.[38] The pricing mechanism of the new contract will most likely be fully linked to a European gas hub/hubs because, over the years, the oil indexation in GSA and LNG sales and purchase agreements has largely been displaced by spot and hub indexation, primarily linked to the most liquid ones – TTF, NBP and PSV.[39] The Shah Deniz 2 EU Gas Sales Agreements with nine European buyers plus AGSC short-term sales (these are required to satisfy regulatory requirements in Italy) are all linked to the TTF and PSV hubs, and only the contract with Bulgargaz is linked to oil products.

It is possible that pricing for new contracts could be changed significantly and, for customers in SEE and Central Europe, price linkage might be with the regional hubs rather than the liquid TTF. This is because this region's gas market has been transformed into one with much improved interconnectivity, which is a good platform for replacing Russian gas imports in the near term[40] with substantial volumes of gas coming from alternative sources. Consequently, this will turn the region into an important transit region for Europe, with active cross-border trading within a broader regional setting. Accordingly, some

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[37] https://ec.europa.eu/competition/legislation/treaties/ec/art81_en.html

[38] A. Ason "international gas contracts", 2022, p.2, OIES, https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2022/11/International-Gas-Contracts.pdf

[39] Ibid.

[40] "South East Europe gas markets – reconfiguring supply flows and replacing Russian gas", J. Bowden, OIES, 2022.

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of the region's countries, such as Bulgaria, Romania, Greece and Hungary, might want to link their contract price to the trading hubs existing in their countries, although these hubs are not sufficiently liquid. This might be the Balkan Gas Hub in Bulgaria, BRM in Romania, the Hellenic Energy Exchange Natural Gas Trading Platform in Greece, CEEGEX and MGP in Hungary and VTR in Austria.

The growing interconnectivity of SEE and Central Europe might be a good basis for new price determination through links to local hub platforms if they become liquid enough in new contracts with gas suppliers in Azerbaijan. However, it must be mentioned that none of the trading platforms in those countries is liquid and there is little convergence with TTF due to local factors. For most of the time in day-ahead markets, the prices on, for example, BGS are 10–15% higher than on TTF[41] and, on the face of it, buyers may not be willing to have this hub as their price link. In any case, this will be determined based on the agreed contract terms on price determination.

5.3.3 Italy

The Italian market was increasingly converging on TTF but has, in the past year, diverged a little again (become cheaper), as have several of the western European markets due to local factors (ES, FR and IT in particular). The PSV hub is liquid and SD2 prices are linked to it. This hub is a good platform for sellers to link with for pricing for the Italian market.

New GSAs with European buyers could include transition mechanisms in their price clauses if both sides agree. Price transition mechanisms are widely experienced in international long-term gas supply contracts and provide mechanical criteria for the price formulae to be amended in a predetermined manner. For instance, buyers starting with single-hub pricing using, say, BGH, could for example switch to PSV if PSV satisfies the liquidity test set out in the GSAs, at which point the price formula will automatically be amended. Conversely, if BGH becomes more liquid in the future, then BGH will be referenced for determining the price formula. Another option that is also encountered in international GSC practice is amending the initial price automatically by reference to a liquid hub if such a hub emerges in any of the countries described.

5.3.4 Duration of the contracts

The economics and financing of new upstream gas projects and infrastructure has traditionally required long-duration contracts to secure borrowing from international banks. However in recent years, before the war in Ukraine and the ensuing energy crisis, this rationale had been changing and buyers preferred mid- and short-term contracts. The energy crisis and war have changed this pattern and securing additional supplies of non-Russian gas has re-focused buyers towards long-term contracts.[42]

The nine European buyers concluded 25-year gas supply contracts with the AGSC in 2013, a rare case for the European market at that time. This is because the entire value chain was based on new projects and it was necessary to secure investment borrowing and the economics of the entire project. Given that there are new upstream projects such as Absheron, ACG NAG, Ümid and new expansion of the existing pipeline, it is assumed that the duration of the new GSAs will be about 10-15 years. This reflects the potential size of investment and some indications given by the consortia that a protection from price risks will be afforded to sellers, which will also help to secure financing for these projects. With gas supplies there is usually up to a three-year build-up period and a 3-year tail-off period.

[41] https://www.balkangashub.bg/en, for the Romanian market see: https://www.brm.ro/en/, https://www.opcom.ro/acasa/en; for the Hungarian market see: https://ceegex.hu/en/; for the TTF prices see, for example, the ICE: https://www.theice.com/products/27996665/Dutch-TTF-Gas-Futures/data?marketId=5508663

[42] A. Ason "international gas contracts", 2022, p.5, OIES.

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6. Export of Turkmen gas to Azerbaijan, Türkiye and Europe: Does TCP have a chance of finally being built?

Gas export from Turkmenistan to Europe through Azerbaijan and Türkiye via a Transcaspian pipeline has been on the table more than 30 years. Nevertheless, this project has not moved beyond discussions and numerous meetings of the interested parties – Turkmenistan, Azerbaijan, Türkiye and the EU. The opposition of Russia and Iran for mainly political and geopolitical reasons has been the main impediment to pipeline construction across the Caspian Sea.

Despite its vast natural gas resources, Turkmenistan has only one large, long-term gas market, China. Its gas supply contract with Gazprom expires in June 2024 while that with Azerbaijan is a relatively small open-ended contract. Depending on only one market makes Ashgabat's position weak in negotiations on contractual terms, and specifically when it comes to the gas price for Chinese buyers. In 2022, the average import gas price China paid for Turkmen gas was about US$240/mmcm,[43] much lower than the market price. Ashgabat has had geopolitical concerns about exporting its gas westward to Türkiye and especially to Europe and participating in the entire value chain to the market. Recent developments in the region after the war in Ukraine have changed the overall geopolitical situation in the Central Asian region. Perhaps it would be safe to say that the Kremlin has lost much of its grip on the region. Turkmen gas, although only a small amount, ended up in Türkiye last year. President Erdogan and President Aliyev's visit to Ashgabat and Awaza and the signing of numerous agreements in various areas, particularly trade, energy and transportation, are rather historic and unprecedented events. Ashgabat is interested in, and expecting – putting it in a phrase used on the Turkmenistan government website – "to form a coordinated and multi-option system for delivering energy resources to global markets".[44]

Türkiye is the party that is most interested in bringing in as much Turkmen gas as possible and passing it on to Europe. Ankara is trying to counterbalance the political environment in the region by strengthening its footprint in Turkmenistan and other Central Asian Turkic countries via cooperation in various international organizations, the most important one perhaps being the Organisation of Turkic States, and by strengthening bilateral relations. Türkiye needs cheap gas for its domestic market to boost exports of goods and services but also to benefit from the gas re-export business through the planned hub for Gazprom gas. Türkiye needs to blend Russian gas with gas coming from as many sources as possible, including Turkmenistan, to be able to present it to Europe as a mix of various gas supplies.

As for the position of Baku, President Aliyev has made it clear that if Ashgabat wants to sell its gas at the border, someone should take the responsibility of investing (not only financially but also politically) in infrastructure and transporting this gas to the market. However, it is not Azerbaijani gas, and Baku is very unlikely to take the responsibility for and pursue the construction of a Transcaspian Pipeline. It is equally clear that Ashgabat will not do so due to its geopolitical concerns, meaning that if Europe needs this gas, it would need to back the project politically, and European institutions should finance the pipeline, which implies a mismatch between the European and Turkmenistan approaches.

In technical terms, the pipeline construction could be accomplished in relatively short order. A 10 bcma Trans Caspian Connector project linking Turkmenistan's and Azerbaijan's offshore facilities with a 78-km pipeline, could be put in place at an estimated cost of approximately US$400–600 million within a few months of securing the necessary approvals of both countries and the necessary financing.[45] However, bringing even 10 bcma from Turkmenistan via the SGC is not possible at the moment and

[43] http://english.customs.gov.cn/statistics/Statistics?ColumnId=6

[44] В Национальной туристической зоне «Аваза» состоялся Первый трёхсторонний Саммит глав дружественных государств, https://turkmenistan.gov.tm/en/post/68690/v-nacionalnoj-turisticheskoj-zone-avaza-sostoyalsya-pervyj-tryohstoronnij-sammit-glav-druzhestvennyh-gosudarstv

[45] Europe and the Caspian: The gas supply conundrum, Atlantic Council, https://www.atlanticcouncil.org/blogs/energysource/europe-and-the-caspian-the-gas-supply-conundrum/#:~:text=In%20January%202022%2C%20a%20scheme,bcm%20between%20November%20and%20March.

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also does not look realistic after 2027 as this infrastructure capacity is limited to only Azerbaijani gas at the moment. The future expansion of the SGC for an additional 10 bcma of gas beyond 2027 will again be dedicated to gas sourced in Azerbaijan, as discussed throughout this paper. For the transportation of an additional 10 bcma or more of Turkmen gas, a new transportation system needs to be built, which would seem irrational at this time given the European plans to transition to low-carbon energy sources in the mid- to long-run. The cost would be enormous, similar to that of SGC construction – about US$15 billion – and transportation fees through the new system, including TCP, would add significantly to the overall cost of gas in, say, the Greek or Italian market. It would be even higher should this gas be further shipped to Central European markets. The only way to transport Turkmen gas in a westward direction at the moment is through Iran, or Azerbaijan via Iran, but the volumes will be limited to a maximum of 3–5 bcma, given the limited capacity of the Soviet-era interconnector between Iran and Azerbaijan and the pipeline between Iran and Türkiye.

Conclusion

This paper has attempted to answer three major questions: does Azerbaijan have enough gas resources and the production potential to double its exports to Europe by 2027? Will it be technically and financially possible to deliver the gas by 2027? And what are the major challenges and uncertainties in the market? The conclusion of this paper is that the gas is available underground and it is technically possible to produce and deliver the gas to the market by 2027 if there are demand commitments in the market and if the potential European buyers are committed to finalise bookings of capacity in the TAP as early as this year (2023). This will determine the extent of the total demand from potential consumers, and thus how much the pipeline capacities will need to be expanded and how much natural gas will need to be produced. This will also determine the size of the investment. Only the market can give the consortia shareholders the guarantees required for an FID. The first TAP bidding auction for an incremental 1.25 bcma of capacity expansion was finalised in January, and all the offered capacity is now committed, so that it appears that, by the end of this year, all the auction commitments for 10 bcma will be in place.

Gas demand in Azerbaijan will not grow at a fast enough pace to eat into the incremental gas production capacity and new gas is dedicated to export. Declining SOCAR gas production will be offset by about 1 bcma of gas that renewal (solar and wind) energy will replace by 2030 along with 1.4 bcma of gas production from Absheron EPS. Furthermore, the country has a swap supply contract with Turkmenistan delivered via Iran to import from 1 to 4 bcma, depending on the needs of the market.

However, securing the financing of the US$7 billion cost of expansion for the value chain will not be an easy task this time. For the members of international consortia undertaking the upstream projects, even the buyers' binding commitments to import gas from the new assets might not be convincing enough for them to go ahead with the FID. This is because there are too many uncertainties in the market, including the European decarbonisation policy, volatile prices and uncertainty in long-term demand. Nevertheless, they are clearly interested in a stable and long-term revenue stream, and desire to maintain good standing in the global financial community. Therefore, the members of the consortia would like to have long-term agreements of minimum 10–15 year duration given the size of investment and with relevant contractual terms that would strengthen their position in the market (ToP, pricing mechanism, etc.). If the 10 bcma of binding demand is defined by the end of this year, it is most likely that LTCs with the buyers in SEE and Central Europe will be signed, perhaps next year.

The new country markets that the gas producers in Azerbaijan will be entering from 2027 are not the same as was the case in 2013, when the SD2 LTCs with nine European buyers in Greece, Bulgaria, and Italy were signed. Back then it was a buyer's market with gas prices reasonably low and these countries were awash with Russian gas, with Bulgaria having been 96% reliant on Gazprom supplies. There were many risks, but they related to the financial profitability, and even viability, of the nearly US$40 billion SGC. However, the Brussels stance on diversifying the market away from a single major supplier, Gazprom, for supply security and political reasons, combined with the strong political support of Washington, prevailed.

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Today, gas prices are higher than in previous years. Even though it is getting toward summer, SEE and Central European countries are in dire need of gas from alternative sources to fully replace Russian gas, and it seems that this demand will be there for quite a long time. Even though in the new reality Europe is aiming to reduce gas consumption at a faster pace, as reflected in the REPowerEU document[46], it is most likely that this process will be slower in SEE and Central European markets because most of these countries are reliant on coal, and their primary goal is to replace coal with natural gas, in line with EU clean energy policy objectives. The heads of Romania, Hungary, Bulgaria, Slovenia, Serbia, Macedonia, Greece, Italy, and B&H expressed their strong interest in importing gas from Azerbaijan from 2027 at the 9th SGC Advisory Meeting in Baku on 3 February. In fact, it appeared that they were competing with each other for the 10 bcma, with each willing to obtain as much of it as possible. For example, in a side discussion this paper's author was told by an Italian representative at that meeting that Italy is ready to offtake all of the 10 bcma that will be available for export. Most of these nations are aiming to assume the role of a gateway or transit country for this gas to neighbouring European countries by investing in cross-border infrastructure.

The terms of the Host Governmental Agreement signed between Baku and Ankara is an important component of the SGC expansion. Ankara has a critical decision-making role in whether to take all the new gas or transit it further to Europe and benefit from transit fees. One thing is clear, that Turkiye will not be willing to import large amounts of new gas from Azerbaijan for a price linked to European liquid hubs, say TTF, and pay the same price as European customers because it simply will not be able to afford expensive gas. Given that the gas owners are consortia with IOCs as members, it is most likely that they will want pricing at European levels in new LTCs for Türkiye. As a result, Baku and Ankara are likely to come to an agreement to send this gas to Europe, as intended. Critically, though, the outcome all depends on whether binding commitments are signed this year after the auctions.

In geopolitical terms, it seems that the biggest beneficiary of the expansion of the Southern Corridor pipelines will be Azerbaijan, the clear leader and the only nation directly contributing gas to the SGC. As the sole supplier, it enjoys a higher level of influence over the pipeline's operations. It also benefits financially and strategically by becoming "a crucial trustworthy and reliable energy partner for the EU", as Ursula Van Der Layen said in Baku during her meeting with President Aliyev, going on to categorise the country as "friendly". Most of the countries to which gas from Azerbaijan is or will be flowing – Türkiye, Italy, Greece, Bulgaria, Albania, Hungary, Romania, Serbia, B&H, Slovenia, Croatia, Montenegro and North Macedonia – are NATO members and have chosen Azerbaijan to provide their energy supply security along with US LNG. There is strong participation by Türkiye as a transit country and the UK as the home of BP. This suggests that Baku is binding its economic and geopolitical security with the West, for whom stability in the South Caucasus should be a priority given the multibillion investments of western companies and banks for decades to come. This will continue after the long-term gas supply contracts expire, as a new phase of renewable energy supplies to Romania and Hungary will come into play beyond 2030-2040.

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[46] REPowerEU: Joint European action for more affordable, secure and sustainable energy, https://ec.europa.eu/commission/presscorner/detail/en/ip_22_1511

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