September 2020

The Renewal of Turkey's Long Term Contracts: Natural gas market transition or 'business as usual'?

1. Introduction

Turkey's energy sector has been severely impacted by COVID-19. Demand for power decreased by 4.5% in the first five months, gas consumption in the industry sector fell by 16% and in the residential sector by 2%. The most affected months were April and May when natural gas demand fell by 20.6% (in April) and by 24.2% (in May). The power generation sector suffered the most with consumption falling by almost 46% in April and May.[1] The country witnessed a rebound in June and July, however there were still effects on private consumption, which tend to be more long lasting. The economic downturn led to the annual inflation rate accelerating from 11.39% to 12.62% in May.[2] The pandemic has also had negative impacts on Turkey's trade and financial flows. The annualized surplus of 1.1% of the gross domestic product (GDP) in the fourth quarter of 2019 declined to 0.2% of GDP by the first quarter of 2020, and the current account was projected to have dropped further to an estimated deficit of 1.6% in the second quarter.[3]

The situation created by the pandemic coincided with the time when Turkey was making the necessary market preparations for the impending renegotiation of long-term gas sales contracts with its current suppliers. The measures have been directed to structural changes in the market and its long-awaited liberalisation through freeing it from long-term contracts (LTCs), oil-linked prices, Take or Pay (ToP) obligations and destination clauses. The current market situation created by the pandemic, with the gas price falling below US$2/mmBtu in the major European liquid hubs and a surplus of both LNG and pipeline gas elsewhere in the world, will only accelerate this transition to a free, open, and transparent market. Turkey has long been unhappy with the high prices it pays for gas, relative to the rest of Europe, and wants to move away from the linkage to oil and oil products. It has traditionally purchased gas on long-term, oil-price-related contracts and the government has taken all the price-related risk by subsidizing the BOTAŞ gas price for the population, justifying it with security of supply.

Turkey's new, present natural gas strategy is timely and coincides with the situation that all LTCs with the current pipeline suppliers will expire in the 2020s. In 2021 alone, 16 bcm/year of LTCs will expire, of which 8 bcm/year is Gazprom gas, half imported by BOTAŞ, and the other half by seven private sector importers. Consequently, the year 2021 is expected to be crucial in terms of market restructuring, with the new contracts expected to have more flexible and competitive terms, as has long been anticipated. Gazprom has already suffered from the situation of low spot gas prices and decreasing sales volumes as a result of demand stagnation; it has already lost 30% Turkish market share since 2017.

[1] Energy Market Regulation Authority's (EMRA) Monthly Reports (2020), https://www.epdk.gov.tr/Detay/Icerik/3-0-95/dogal-gazaylik-sektor-raporu
[2] Turkey Report by Turkish Bank BBVA'
[3] "Turkey Economic Monitor: Adjusting the Sails", The World Bank, https://www.worldbank.org/en/country/turkey/publication/economic-monitor

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Changing market structures and liberalisation have had an impact on the development of spot markets and benchmarks in Europe and across the whole network of European gas hubs, with some of them becoming truly liquid. This process has changed the European gas market, causing it to function more on the basis of supply–demand economics rather than oil price fluctuations.[4] In Europe this process started in the mid-2000s and has been successfully finalized in most European regions, but it needs to be mentioned that it has not been successful in the countries adjacent to Turkey, i.e. southeast Europe.[5] Although liberalisation has not been successful there, the EU countries in the region – especially Bulgaria – have achieved hub prices through the DG COMP proceedings against Gazprom. Gazprom tried to escape reducing prices but reluctantly agreed to change its prices when Bulgaria threatened to take it back to the Commission.[6] As spot and contract prices diverged significantly in Europe and elsewhere, customers for Russian gas in Turkey began to demand an end to oil-linked pricing. The trend away from oil-linked pricing in Europe and, more gradually, in Asia has led to the emergence of a significant divergence between spot and contract prices in 2019.[7] This prompted BOTAŞ and private-sector companies to demand that Gazprom link the gas price to the TTF hub price. However, Gazprom refused to make any changes in the price formulations in the long-term contracts and this issue has been left for renegotiation in the extension of contracts for 8 bcm/year that expire in 2021.

Turkey has long been observing these developments and has a clear position that natural gas prices in Turkey do not reflect pure economic market fundamentals and that there must be a change toward short- and mid-term contracts, gas-to-gas indexation, and flexibility in contractual terms. Current long-term contracts with its pipeline and LNG suppliers have prevented such changes, although it has made some spot LNG purchases, and so far Turkey has failed to achieve better contractual conditions, as most European countries and companies did. Oil indexation, which still exists in Turkey's natural gas pricing, destination clauses, and ToP, have hindered the ability of BOTAŞ and private sector importers to re-export unwanted volumes to neighbouring markets when faced with falling demand, high stocks and limited gas storage. ToP and oil indexation have made supply less responsive to demand shocks and falling prices, but have also long delayed liberalisation in this, Europe's second biggest natural gas market.

This situation has resulted in premium prices in the Turkish natural gas market, with BOTAŞ and private sector importers paying gas bills 20% higher than those paid by Gazprom customers in Europe. Now, when the LTCs with Gazprom, Azerbaijan Gas Supply Company (AGSC)[8] and Iran's National Iranian Gas Company (NIGC) expire in the 2020s, beginning with the first 16 bcm/year of gas contracts in 2021, Turkey is keen to change the old-fashioned LTC terms in the upcoming renegotiations for renewed contracts.[9]

Turkey feels confident in adopting an assertive position in negotiations with Gazprom and other suppliers because it has significantly strengthened its position thanks to the strategy of doubling the daily entry-point gas send out capacity. This has included increasing LNG import capacity but also decreasing import demand by significantly increasing the share of domestically produced energy such as coal, lignite, wind, solar, and hydro. This policy has borne fruit; the country produced 66% of its electricity from local and renewable resources in the first five months of 2020, and 62.08% from January through July this year, according to the data from the Energy and Natural Resources Ministry. Turkey is approaching its goal of producing almost 66% of its electricity from local and renewable sources

[4] The comprehensive price study review conducted by the International Gas Union (IGU) in 2014 determines the proportion of gas in the wholesale market sold under a variety of pricing categories, (IGU 2015), http://members.igu.org/old/IGU%20Events/wgc/wgc-2015/committee-reports-with-tnematic-sessions/igu-gaspricereport-2015-final.pdf

[5] For analysis of the market liberalisation process in Europe see Stern J., "The dynamics of a liberalised European gas market" (2014), pp. 53-57, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/12/NG-94.pdf

[6] Shlapentoch, D.,"Gazprom concedes defeat in Bulgaria" in Natural Gas World Magazine, VOL 5, Issue 9, 11 May 2020

[7] For details on prices see Stern, J. and Imsirovic, A. (2020), A Comparative History of Oil and Gas Markets and Prices: Is 2020 just an extreme cyclical event or an acceleration of the energy transition? https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/04/Insight-68-A-Comparative-History-of-Oil-and-Gas-Markets-and-Prices.pdf

[8] AGSC is a marketing arm of the Shah Deniz consortium

[9] Deputy Energy Minister Alparslan Bayraktar's Zoom presentation at a webinar organised by the Bosphorus Energy Club held on 8th July

annually,[10] thereby reaping the fruits of long-term investments in renewable energy deployment.[11] May 20th was a historic day, because 94% of the country's electricity was generated from domestic sources.[12] Turkey wants to become self-sufficient in energy, and domestically produced energy can help to wean the country from natural gas import dependence and inflexible LTCs. The following sections of this paper will try to analyse how realistic this objective is: it is a key factor in deciding on the duration of the renewed contracts.

This paper focuses on the position of Turkey in the renegotiation of the expiring contracts; its strengths and weaknesses in defending its position; and the reasons for the confidence of Turkey and BOTAŞ, in their negotiating positions with Gazprom, AGSC, and NIGC. It also reviews the implications of the revision of the contracts and possible longer-term perspectives for the positions of Gazprom, Azerbaijan, and Iran in the Turkish domestic natural gas market. It further analyses the consequences of the changes for regional markets, especially Turkey's role as a transit country, and future gas exports from Turkey as a hub.

Market liberalisation: European experience

In Europe natural gas market liberalisation started post-2008, and was accompanied by financial pain for the incumbents due to the increase in third party access, which caused increased competition and consequently the decline of the market power of state incumbents.[13] OIES has published a series of papers on market transition in Continental Europe including the transition to hub prices, a summary of which can be found in the work of Stern and Rogers.[14] The gradual shift from oil-price-related contracts to gas-to-gas indexation; development of new pricing mechanisms; various hub benchmarks; and spot markets dominated by short-term contracts have created flexible contractual terms and competitive prices which, in turn, have secured natural gas (including LNG) supplies at low prices from various affordable sources. With the rapid development of hubs, the painful transition (often via international arbitration) from oil-linked to hub pricing has been accompanied by lengthy legal disputes and international arbitration.[15]

It needs also to be noted that in the southeast European market much of this has not yet happened, even for EU members. European Union member Bulgaria has achieved hub prices through competition law, not through liberalisation and there is still no market hub in SE Europe.

Lack of liberalisation in the Turkish gas market

To create a competitive market, to ensure supply security and to reduce the role of the state in gas sector, the Energy Market Regulation Authority (EMRA) first presented the Natural Gas Market Law (NGML) No. 4646 in 2001.[16] This was a fundamental step on the way to establishing a liberalised natural gas market in Turkey. In the last 19 years the transition to an open market has, however, been extremely slow. The first release of supply contracts by BOTAŞ only occurred between the end of 2007 and Q1 2009 with an annual total volume of 4 bcm, and in 2011 with a further annual volume of 6 bcm. A comprehensive revision of the Law was carried out in May 2013 and the new draft with amendments to the NGML has been prepared. This was expected to be approved by Parliament in 2014, to be followed

[10] Over 62% of Turkey's power produced from local, renewable resources in 2020, https://www.dailysabah.com/business/energy/over-62-of-turkeys-power-produced-from-local-renewable-resources-in-2020
[11] https://www.dailysabah.com/business/energy/66-of-turkeys-electricity-produced-from-local-renewable-resources-in-first-5-months
[12] Deputy Energy Minister Alparslan Bayraktar, 8th July
[13] OIES has published a series of papers on this topic since 2005. For a summary see Stern, J. and Rogers, H.V. (2014), *The Dynamics of a Liberalised European Gas Market: key determinants of hub prices and roles and risks of major players*, OIES Paper NG94.
[14] Stern, J and Rogers, H. `The Transition of Hub-Based Gas Pricing in Continental Europe', in Stern, J. ed. *The Pricing of Internationally Traded Gas*, OIES/OUP: 2012, Chapter 4. Stern, J. and Rogers, H. `The Evolution of European Gas Pricing Mechanisms', in Hafner, M. and Tagliapetra, S. *The European Gas Markets: Challenges and Opportunities*, Palgrave/Macmillan: 2017, Chapter 15.
[15] Ibid.
[16] In the paper on *"Natural gas in the Turkish domestic energy market: policies and challenges"* (2014), this author analyses NGML provisions in detail. See pp 46-50, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/02/NG-82.pdf

by the legal unbundling of BOTAŞ, which was included in the 2001 Law, but this has still not been realised and approved by the Parliament.

It was expected that legal unbundling would happen within the framework of a competitive, financially strong, stable and transparent natural gas market, and ensure the establishment of independent natural gas market regulation and supervision.

Another important issue in full liberalisation of the natural gas market is ownership and unbundling – splitting BOTAŞ's activities into different legal entities, each with its own accounts and third party access. According to the NGML, BOTAŞ's import, wholesale, transport, storage and distribution activities were supposed to be split into 3 legal entities by 2015: transportation, LNG and storage operations, and importation. In the Transitional Provision Article 2 of the NGML, the split of BOTAŞ was scheduled for 2009[17], but this never happened. BOTAŞ was required to tender at least 10% of its existing contractual obligations each year until it reached the 20% share by 2009.[18] One of the main reasons why NGML was not fully implemented is that the government viewed BOTAŞ as a strategic player and wanted to ensure supply security by implementing its existing contractual obligations, which provide long-term gas supplies. The political leadership of Turkey has been using its 'national champion' for not only natural gas issues, but also political relations with the suppliers, specifically with Russia.

The 2001 legal framework of the NGML has not been implemented and market-opening objectives have not been achieved.[19] It needs to be stressed that without a truly liberalised natural gas market with non-discriminatory TPA to domestic and international pipelines connecting Turkey with Europe (TANAP, TurkStream), it will be impossible to establish a liquid gas hub with price discovery. Given the numerous structural, commercial and political barriers to be overcome,[20] it will be difficult to convince Gazprom and other suppliers to accept market or hub prices unless they are forced to do so by some other form of gas to gas competition. Gazprom has fought market pricing through the arbitration courts in Europe and will do the same in Turkey. The suppliers' position with regard to pricing change could be that since there is no liberalisation and no market hub, it is impossible to establish a market price in Turkey. In addition, BOTAŞ may choose (or be required by government) to subsidise its customers by reducing their prices, but there is no reason for suppliers to subsidise Turkish customers.

2021 will be an important year for restructuring the country's domestic natural gas market by, to some extent, liberalising it and bringing long-needed "flexibility and competitiveness".[21] This would require changing the terms of LTCs to reflect supply–demand fundamentals to achieve a market price. The Turkish government reasons for the almost two-decade delay in natural gas market liberalization are clear:

- the existence of long-term sales contracts with all suppliers which include oil-indexed pricing, and destination clauses[22]
- government desire to control the market for economic, political and strategic reasons, which have prevented Turkish companies from trading freely outside the country.

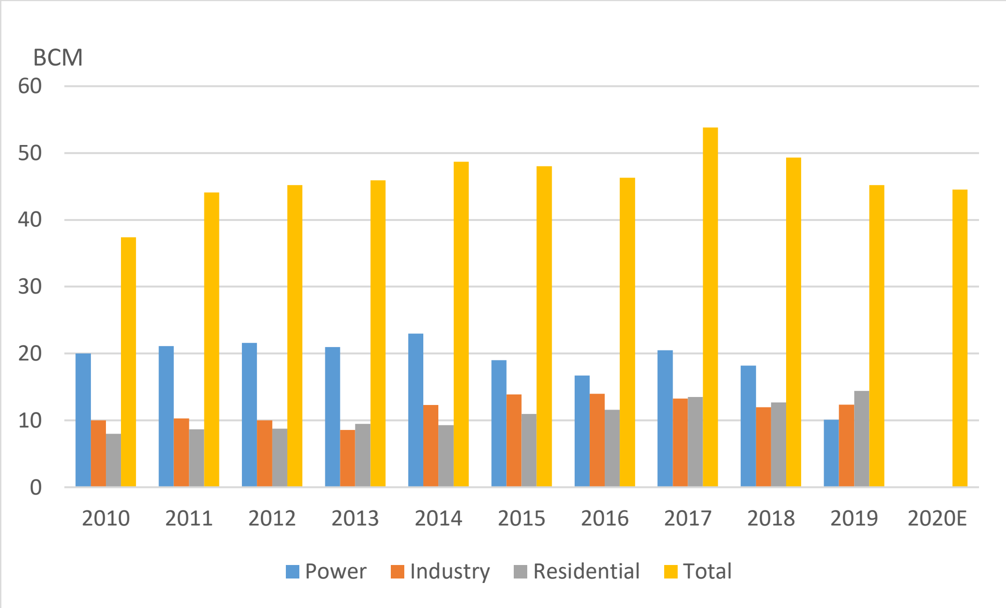
These have been the main obstacles to the development of a liberalised and competitive gas market, which has continued to be dominated by state incumbent BOTAŞ with a 97% import share in 2019.[23]

[17] Ibid.
[18] For alternative analysis on NGML see IEA's Turkey Report (2016), pp 15-17, https://webstore.iea.org/download/direct/328?fileName=EnergyPoliciesofIEACountriesTurkey.pdf
[19] IEA's Turkey Report (2016),
[20] European traded gas hubs: a decade of change, Heather, P., (2019), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/07/European-traded-gas-hubs-a-decade-of-change-Insight-55.pdf
[21] Deputy Energy Minister Alparslan Bayraktar's speech at a webinar: https://www.atlanticcouncil.org/event/impact-of-covid-19-on-the-global-energy-sector-and-reflections-on-turkey/
[22] Destination clauses exist in LTCs with all the suppliers except the Shah Deniz 1 contract.
[23] EMRA Annual Natural Gas Market Report (2019), https://www.epdk.gov.tr/Detay/Icerik/3-0-94/dogal-gazyillik-sektor-raporu

2. Demand projection

Turkey's gas demand has been declining since 2015, except for the short rebound in 2017. This decline has averaged 4%/year (Figure 1) and it is expected that this downward trend or very modest growth, will continue, depending on a number of factors. Turkey's gas demand is highly temperature sensitive and any deviations from seasonal norms in winter and summer directly affect natural gas consumption, especially in the power generation and residential sectors. Residential sector consumption increases significantly during cold winter weather, further driven by the expansion of the reach of the gas transmission and distribution network to 40 additional regions in the last two years and now serving 550 cities in total.[24] The network now exceeds 162,000 kilometres and supplies 81% of the population.

Figure 1: Turkey's gas demand 2010–2020E



Source: Energy Market Regulation Authority (EMRA), 2020 – author's estimate

In the industrial sector, gas consumption was growing strongly up to 2017 and has since plateaued owing to the depreciation of the Turkish lira and a strained economy with modest GDP growth. The steepest decline was in the biggest gas-consuming sector, power generation, for several reasons. Heavy seasonal rain resulted in massive growth in hydroelectric generation (hydro), squeezing out generation from natural gas and, to some extent, hard coal and lignite in 2019. The Turkish government also has a long-standing policy aim of reducing the share of gas in this sector,[25] which has resulted in the natural gas share in power generation more than halving, from 50% in 2015 to 19% in 2019.[26] The government support mechanism of providing feed-in tariffs and purchase guarantees to increase the share of renewables in the electricity production mix will continue in the foreseeable future, but in the long run, increasing renewables deployment will require more flexibility and therefore gas will be an important offset fuel and supply security provider.

Power generation & renewables

Coal-fired utilities have maintained a price advantage against gas-fired units since August 2018, when BOTAŞ amended its domestic pricing scheme to reflect the increase in its gas import costs. The BOTAŞ average import cost of Russian gas, was around $250/mcm ($6.71/Mmbtu) for the first quarter of 2020

[24] "Total inflow to Turkish gas system down 6.33 pct in 2019", Hurriyet Daily News, https://www.hurriyetdailynews.com/total-inflow-to-turkish-gas-system-down-6-33-pct-in-2019-150586
[25] Rzayeva, G., "Turkey's gas demand decline: reasons and consequences" (2017), OIES, https://www.oxfordenergy.org/publications/turkeys-gas-demand-decline-reasons-consequences/?v=79cba1185463
[26] EMRA Natural Gas Market Report 2019

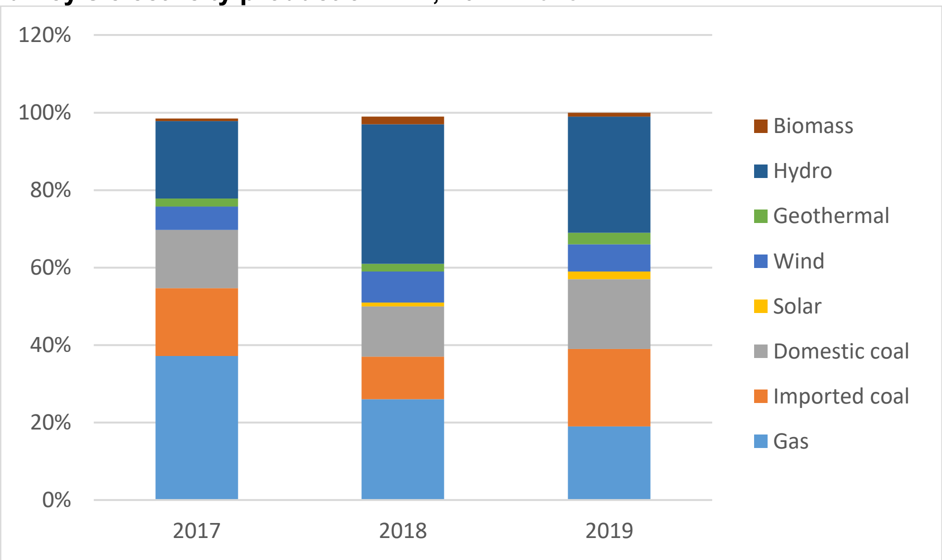
and, fell in the second quarter to around $230/mcm. Even so, in the absence of a carbon price, gas is likely to remain uncompetitive with coal for power generation, as long as the BOTAŞ regulated tariff for utilities reflects import costs and there is no substantial decrease in import prices.

Turkey's combined cycle gas turbine (CCGT) operators are unable to generate at a profit because gas prices for the electricity production sector are higher than for any other sector. Operators have to sell electricity at below cost and struggle to service their long-term loans.[27] Under such financial pressure, the operators must switch to alternative fuels, where switching is technically possible, such as domestically produced coal/lignite, renewables, hydroelectricity in season, which requires additional investments, or spot LNG purchases if the price is below the pipeline gas price. Cheaper LNG and alternative fuels can enable electricity producers to bring the cost of electricity production down and remain afloat.

As Figure 2 shows, the share of natural gas in electricity production fell significantly from 38.1% in 2017 to 19% in 2019.[28] The dominant factor in 2019 was the massive growth in hydro generation. This has squeezed out generation from gas and, to some extent, from imported coal (Figure 3). State-owned hydraulic works administration DSI is planning to bring 1.7GW of hydroelectric capacity on line in 2020.

The Turkish government has been successful in promoting the growth of renewable energy by introducing the support mechanism discussed above, including feed-in tariffs and long-term purchase guarantees. As a result, the share of renewables, plus hydro, in electricity generation has grown from 20% to 44%; the 2023 target of 30% was achieved as early as in August 2018. The government is now aiming to achieve its next ambitious target of increasing the share of renewables to 50% in the next four to five years by reducing imports of natural gas and coal, depending on the "dark and spark spreads" - measures of the profitability of coal- and gas-fired power generation. The government's objective is to install 27 gigawatts (GW) of renewable energy capacity other than hydropower by 2023, of which 20 GW is expected to be wind energy,[29] but this target looks unrealistic. Most of the tenders awarded in 2017-2018 did not make any progress.

Figure 2: Turkey's electricity production mix, 2017–2019



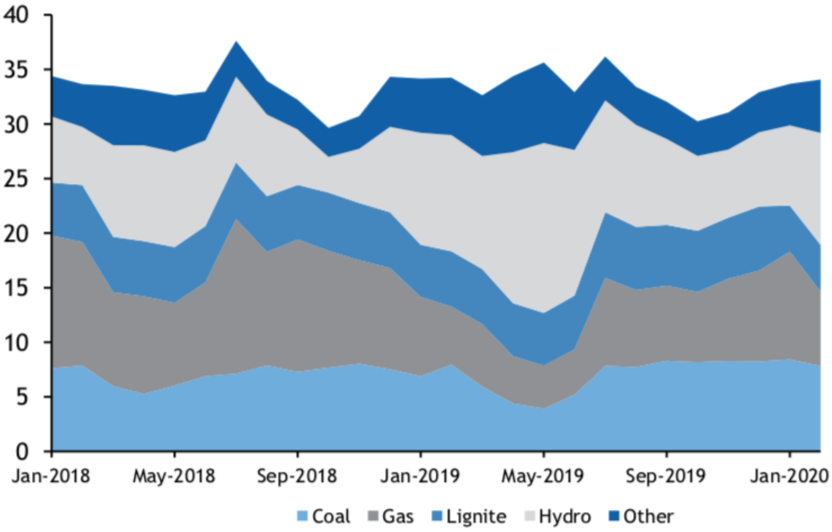
Source: EMRA

[27] Turkish operator Yeni Elektrik suspended output at its 865MW Yeni Elektrik CCGT plant after a court declared it bankrupt in February 2020. The plant is expected to remain offline until a financial settlement can be reached.
Energy and construction conglomerate Enka, which owns Turkey's largest gas-fired units — the 1.54GW Gebze and 1.52GW Izmir facilities — has idled its fleet this year, having kept the units offline in 2019 in response to low spot prices, which the firm said are still too low to allow a restart. Source: Argus

[28] From 70,000 GW to almost 40,000 GW in just one year.

[29] Turkish wind farm to more than triple generation capacity with EBRD loan, EBRD, https://www.ebrd.com/news/2020/turkish-wind-farm-to-more-than-triple-generation-capacity-with-ebrd-loan.html

Figure 3: Turkey's power generation mix, GW



Source: Argus

The share of solar and wind in the power generation mix has now reached 5,000 GW, 9% of the total mix. The Turkish Renewable Energy Resources Support Mechanism, YEKDEM, offers a feed-in tariff of $0.073 per kilowatt-hour (kWh) for wind and hydropower projects, $0.105 for geothermal facilities, and $0.133 for solar energy and biomass geothermal plants.[30] However, the scheme will end in 2020 and work is ongoing to introduce a more up-to-date and efficient replacement - mini-YEKA. Details of the new scheme to replace Yekdem have not been announced yet, but the government is working on a draft law to extend the mechanism with a lower guaranteed purchase price than in the current scheme. The government is also planning to widen the scope of the Yeka scheme by including smaller scale projects to attract more investors. The government policy is not only driven by the political and strategic consideration of lessening import dependence on Russia, but also by Turkey's extremely high energy import bill, which in 2019 was $41.1 billion. One thousand MW of installed solar energy capacity will replace $110 million of imported natural gas[31] assuming an average gas price of $230/mcm. Further increasing the share of renewables, including hydro, will lead directly to a further reduction of gas usage in this sector.

Gas demand in 2020 and the impact of Covid-19

At the beginning of 2020, EMRA projected gas demand in Turkey to be 52.3 bcm in 2020, a significant growth from 45.2 bcm in 2019, but this projection did not take account of the impact of the COVID-19 pandemic. It is now likely that gas consumption will not be higher than last year, and may fall to 43-44 bcm, because of the lockdown of most industry owing to COVID-19 during March-May and a fall in gas burning in the power generation sector in March to June. In January consumption was 6% higher yoy and in February it was 11.39% higher [32] and there was an increase in hydro reservoir levels. Then however demand fell, by 9.7% in March, 20.57% in April and 25% in May (Figure 5).

Gas-fired generation in March fell to an all-time low, as higher hydro and coal output pushed gas to the lowest level in the power mix. Gas burn in April to June – peak hydro months - remained below the record lows experienced in the second quarter of 2019, with reduced maintenance at coal-fired plants and an improving hydro outlook. Output at gas-fired plants averaged 3.7 GW from March 11–12, down

[30] Clean energy generation receives TL 2.8B in incentives in January, Daily Sabah, https://www.dailysabah.com/energy/2020/02/19/clean-energy-generation-receives-tl-28b-in-incentives-in-january

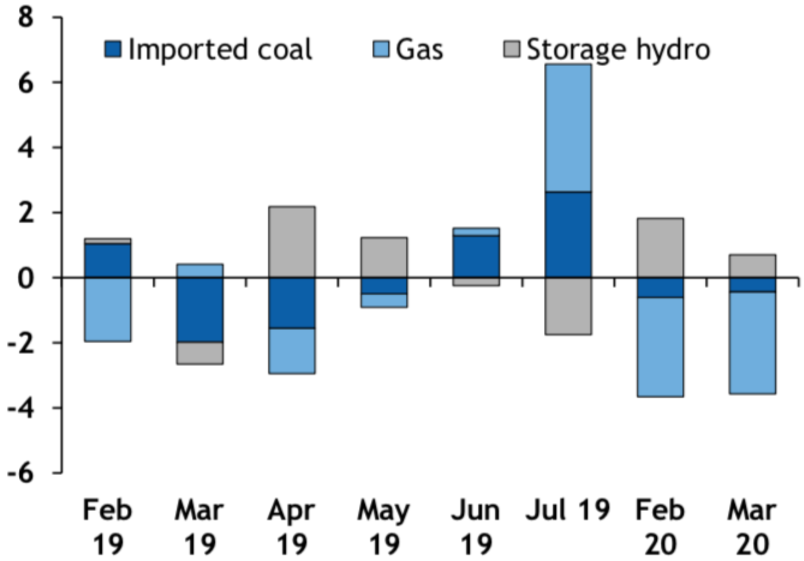
[31] Solar is key in reducing Turkey's gas imports, https://www.hurriyetdailynews.com/solar-is-key-in-reducing-turkish-gas-imports-152228

[32] EMRA Monthly Report

from 6.8 GW in February and 5.7 GW a year earlier.[33] This was below the record monthly low of 3.9 GW in May last year (Figure 4).

Storage hydro output averaged 8.2 GW in March, up from 7.5 GW in February and 6.8 GW a year earlier. At the same time, run-of-river generation rose to 3.9 GW from 2.7 GW a month earlier and 3.5 GW at the same time in 2019.[34]

Figure 4: Month-by-month variations in the Turkish power mix, GW



Source: Argus

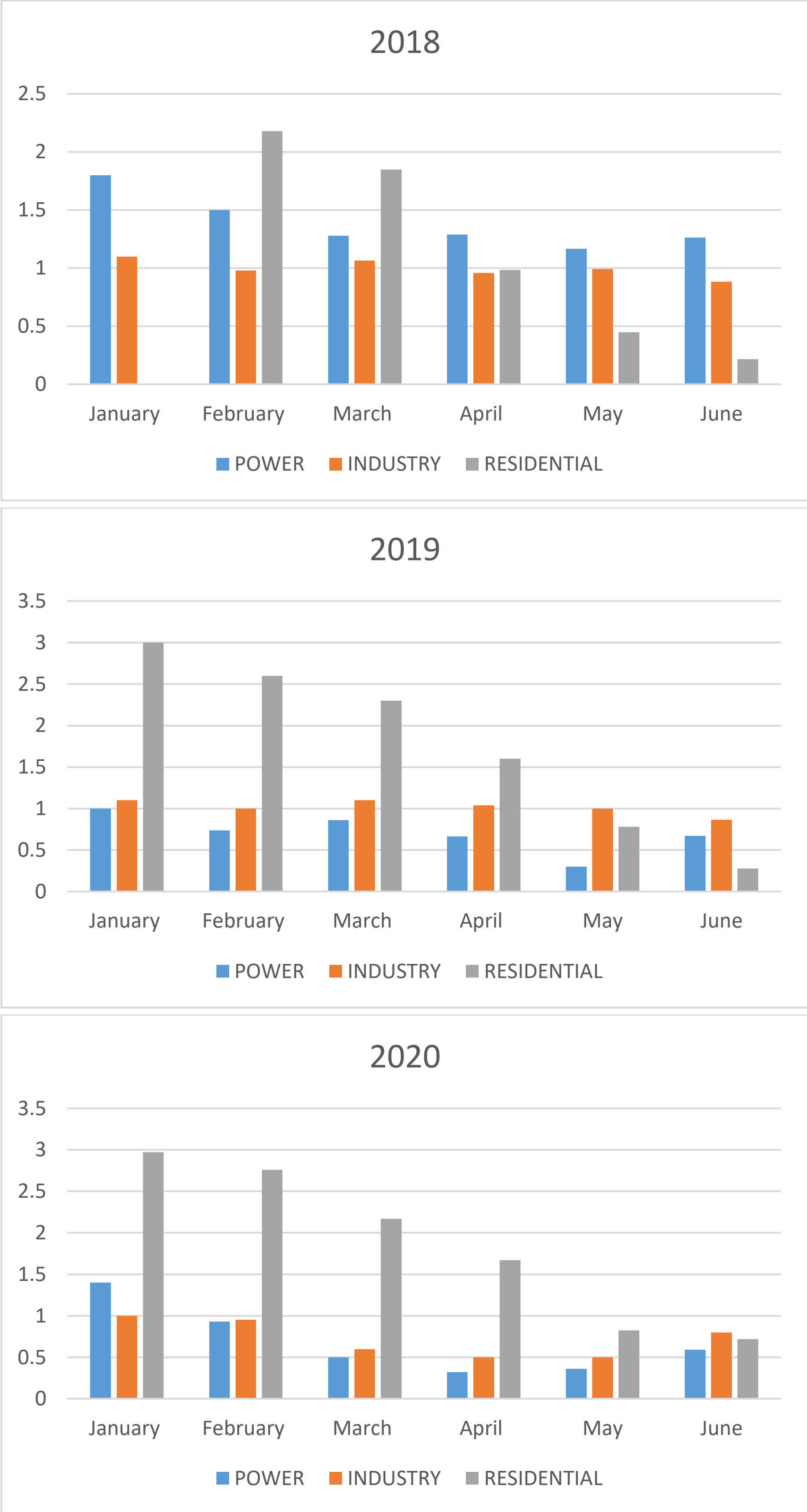
In June 2020 gas-fired generation significantly rebounded with gas consumption up by 14%. Forward power price assessments suggest that the economics are still unfavourable for gas-fired plants, although the average gas import price may fall to around USD 180/mcm. Gas burn in power generation also broadly depends on hydro storage capacity, which offsets gas, as was the case last year. Hydropower output could potentially displace around 260MW of thermal generation from the base load on a yoy basis, assuming a 35% utilisation rate for 2020 and flat overall power demand. However, the impact of Covid-19 had almost completely petered out in June (for gas burn for power) as industrial and commercial activity returned to full capacity, with power demand reaching a near parity with the June 2019 level, almost 5GW higher than in April-May. Gas burn on 1-28 June already reached 32TWh (higher on the year) and has seen further support from lower hydro and wind output (Figure 5).

All Turkey's gas import contracts are oil-indexed, so that oil prices on international markets are a key factor in Turkey's imported gas prices and the country's regulated tariffs. Crude price changes are reflected in gas prices with a six- to nine-month lag, implying that the effects of lower oil prices may be reflected in the fourth quarter. The recent steep drop in oil prices will not translate to a similar level of decrease in the price BOTAŞ pays for Russian gas later this year, as the long-term agreement has clauses that soften the impact of oil prices falling below $50/bbl. Nevertheless, the lower price in the first quarter of 2020 is expected to slightly affect the Turkish imported gas price in the fourth quarter. CCGT operators will try to offset expensive gas with cheaper options such as spot LNG, thereby reducing generation costs. The spot LNG import price for Turkey has been, on average, more than $150/mcm, lower than the imported pipeline gas price.

[33] Power Exchange Exit data, daily, weekly and monthly reports, EPIAS, https://www.epias.com.tr/wp-content/uploads/2020/04/epias-bulten-02.04.2020.pdf

[34] EPIAS daily report, https://www.epias.com.tr/wpcontent/uploads/2020/04/epias-bulten-02.04.2020.pdf

Figure 5: Turkey's monthly gas demand 2018–2020, bcm



Source: EMRA

The residential sector showed modest growth owing to increased gas usage in the first three to four months of the lockdown to prevent the spread of COVID-19, although the lockdown was not nationwide, (Figure 5). However, demand may rise in this sector starting in November when temperatures usually fall, and also because of the possible low gas price that is expected as a result of the current low crude oil price.

The industrial sector may show stagnation in gas consumption for most of this year for the same reason, the lockdown, as well as because of the high gas price expected for most of this year. In line with overall output, production from most gas-intensive manufacturing sectors decreased year on year in March through May. It is most likely that annual consumption will be below the 2019 level of 12.35 bcm.

In sum, it is projected that gas consumption in the power generation sector in 2020 could be around 9–10 bcm; in the residential sector 14–16 bcm; and in the industrial sector 9 bcm. Total demand in 2020 may be in the range 43 to 44 bcm, depending on the price of imported natural gas toward the end of the year and hydro power production levels.

Natural gas demand projection to 2030

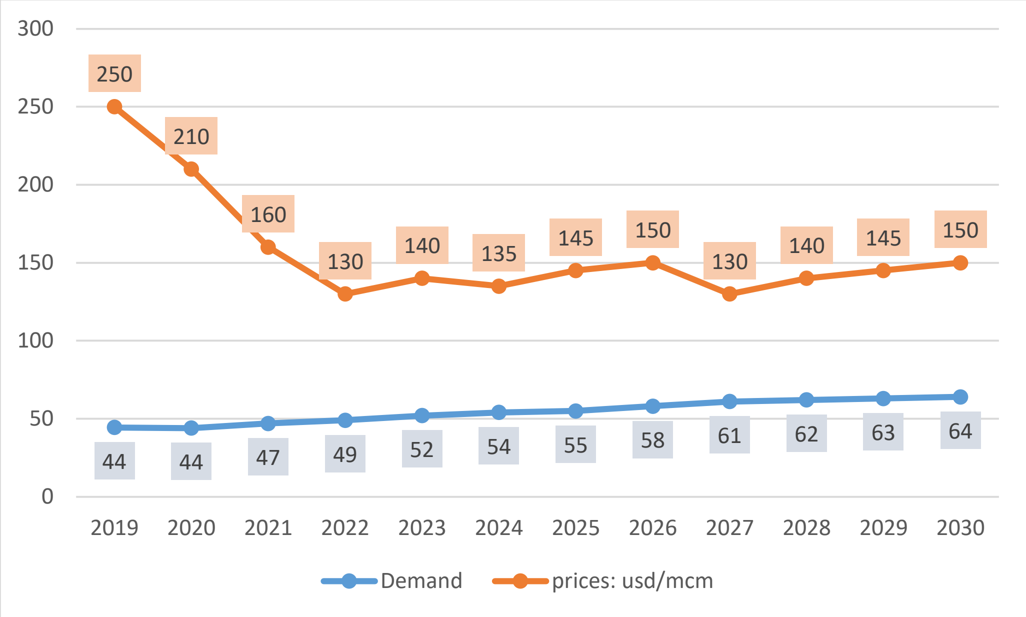
For the last five years, Turkey has been preparing for the next round of negotiations for gas supply contract renewal with a policy of reducing the share of natural gas in the power generation sector, the biggest gas consumer, and building up gas receiving infrastructure and daily send-out capacity. Declining natural gas demand will strengthen the negotiating position of BOTAŞ and the private sector and encourage the negotiators on the other side of the table to be more flexible. This policy will continue until the oil-linked gas price formulae in the long-term contracts are changed and gas prices more accurately reflect the supply and demand dynamics, rather than oil and oil products prices. This is realistic but conditional on whether the market is liberalised.

Turkey's gas demand will change depending on imported natural gas prices and the outcome of the impending renegotiation of gas contracts, which expire in the 2020s. In the following sections we analyse in detail the possible changes of contractual terms, including the price and price formulae changes. Any change in imported natural gas prices will significantly affect gas demand in Turkey. Almost 20.5 bcm/year of gas contracts expire by 2024, of which 16 bcm/year will run down by the end of 2021 (Table 1). With lower gas prices, as is most likely to be the case in the current circumstances, gas demand may react accordingly and increase. The private companies will be able to import gas at a lower price and, finally, make some profit selling it on the domestic market.

Imported gas prices will continue to be among the most important factors influencing gas demand in all sectors but, clearly, other factors will remain significant, including temperature; wet or dry weather, which increases hydro availability; the government support mechanism for renewables and domestically produced lignite; and the policy of decreasing Turkey's dependence on Russian gas imports for political and strategic considerations. Turkey's plans to build nuclear power plants may weigh on its long-term gas demand. Construction began at the 4.8GW Akkuyu plant in early 2019 — the first unit is expected to come on line in 2023 with full commissioning by 2026 but delays are highly probable.

However, prices, low or high, are the main incentive for all the energy policies initiated by the government and the main driver for changes in gas burning in the power generation sector. Figures 6 and 7 show gas demand projections correlated with our assumptions on possible price changes in the renewed contracts.

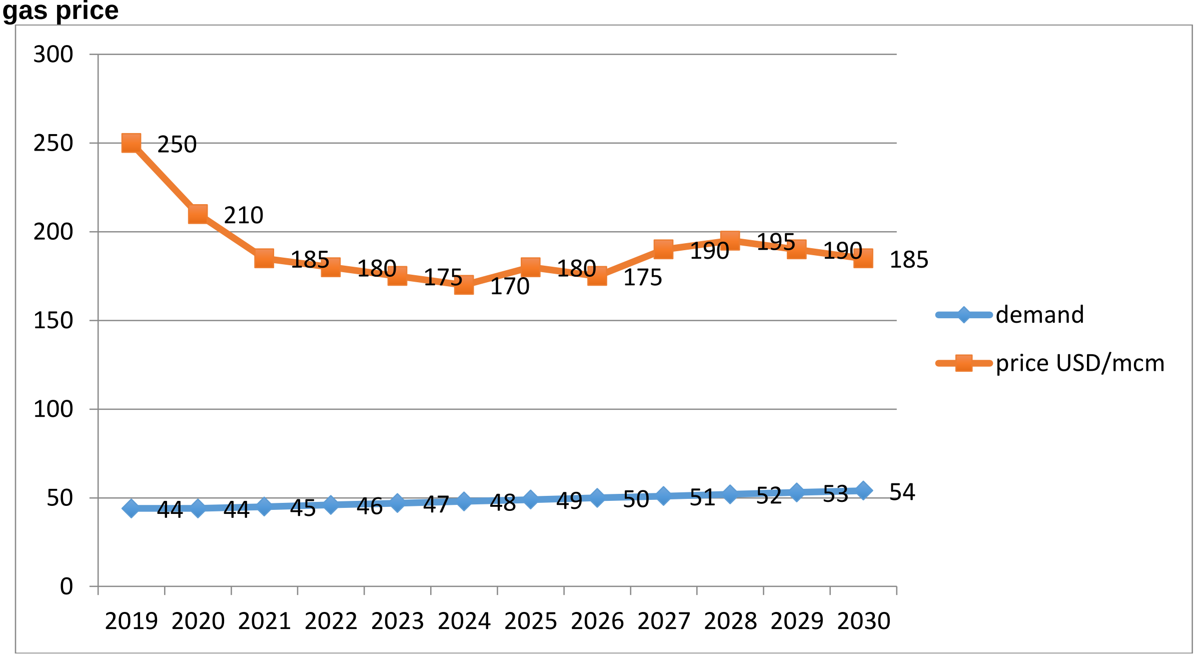
Figure 6: Scenario 1, correlation of natural gas demand (bcm) and lower average gas prices



Source: Argus (for 2019), EMRA, author's estimate

In Scenario 1, we assume that Turkey will be able to negotiate better prices and change the pricing mechanism to hub indexation, where imported gas prices will be defined by the supply–demand dynamic and market conditions as explained in detail in the following sections. In this case, lower than current prices for imported pipeline gas will be inevitable and Turkey's natural gas prices will be close to European hub prices. This means that they may go as low as US$130/mcm, from the average of between US$225 and US$235 in 2Q 2020. There is no doubt that this will affect consumption, as the economics will be favourable for burning gas in CCGT, the spark spread will be positive, imported coal may be substituted with gas, private sector importers will be able to take contracted volumes, and households will be able to afford to burn more gas for heating purposes.

Figure 7: Scenario 2, correlation of natural gas demand (bcm) and unrevised imported average gas price



Source: Argus (for 2019), EMRA, authors estimate

In the second scenario, we project demand in the event that, in the re-negotiation of the long-term contracts, Turkey fails to negotiate better terms, such as lower prices and changes in the price formula to link prices to the market-defined hub price. Prices remain almost unchanged, i.e., 20–30% higher than average European hub prices, but with a slight decrease in the late 2020s as a result of the current low oil prices. In this scenario, gas demand will either stagnate or fall. By 2030, demand may reach around 54-55 bcm/year, depending on government policy and seasonal temperature. This scenario is highly unlikely for the reasons described in the following sections.

3. Renewal of BOTAŞ LTCs: Time for change?

The year 2021 will be a crucial turning point for the Turkish natural gas market as, in this year alone, 16 bcm/year of long-term contracts with Turkey's existing suppliers expire (Table 1).

Most of these LTCs were concluded in the era of peak oil-indexed long-term contracts in the 1980s and 1990s. Since then, owing to restrictions on contract term review, Turkish companies have had no chance to renegotiate. Nevertheless, it remains to be seen whether Turkish decision-makers will embrace the opportunity presented by contract expiration; how quickly liberalisation could develop in future; and whether additional structural and regulatory measures would be needed. One thing is clear – Turkey will not accept the same old-fashioned long-term sales contracts, with oil price indexation and burdensome ToP, in the new contracts.[35]

Table 1: Turkey's natural gas import contracts

Supplier	Importer	ACQ, bcm/year	Contract base	Contract end
AGSC1, BTE	BOTAŞ	6.600	Oil products	April 2021
NLNG	BOTAŞ	1.338	Oil products	October 2021
Gazprom A, TS	BOTAŞ	4.000	Oil products	December 2021
Gazprom B, TS	Private	4.000	Oil products	December 2021
Sonatrach	BOTAŞ	4.444	Arab crude basket	October 2024
Gazprom BS	BOTAŞ	16.000	Oil products	December 2025
NIGC	BOTAŞ	9.600	Oil products	July 2026
AGSC2, TANAP	BOTAŞ	6.000	Oil products	June 2033
Gazprom C, TS	Private	6.000	Oil products	December 2042

Source: EMRA, various sources

The current situation with the contracts and clauses that BOTAŞ is keen to renegotiate

a) ***Formation of prices**:* All BOTAŞ's and private importers' LTCs are linked to oil product prices, which fluctuate in response to oil market prices with a 6–9 month lag. Since the BOTAŞ LTCs with its pipeline and LNG suppliers were signed in the 1980s, 1990s, and early 2000s, the natural gas market has gone through an unprecedented transformation. Turkey, as a result of lack of gas market liberalisation, has not created a supply/demand price discovery mechanism enabling it to import gas at a price reflecting true market fundamentals, that is, supply/demand dynamics, rather than being based on the oil products price on the international market. Oil-linked price formation in the BOTAŞ contracts with all its suppliers has remained the main reason for high import prices over the years; prices have been 20–25% higher than the European average gas price. In 1H 2020 LTC prices were 100–120% higher than the European average and 150–160% higher than the spot price of LNG imported by BOTAŞ (Figure 8). BOTAŞ has already been enjoying extremely low prices linked to the Dutch TTF hub, with a discount of $2/MMBtu[36] in its short-term spot LNG contracts from January to July, and is keen

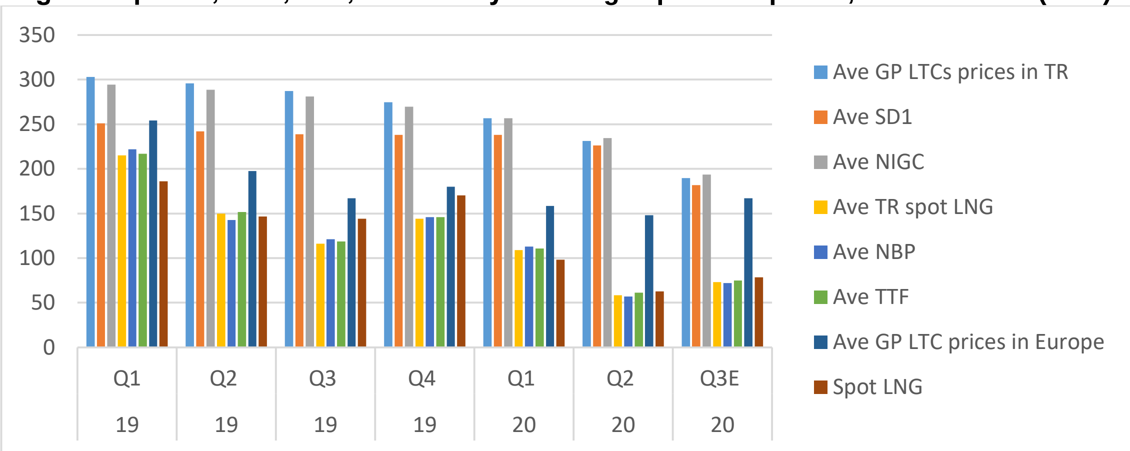
[35] Bayraktar

[36] Özdil, E. "How Turkey benefits from global LNG glut" (2020), https://www.atlanticcouncil.org/blogs/turkeysource/how-turkey-benefits-from-global-lng-glut/

to apply the same pricing mechanism to its impending renegotiated pipeline contracts with all its suppliers.

The immediate impact of price decoupling in Turkish LTCs will be a significant downward shift in prices for as long as a supply surplus and low gas prices persist. This shift will inevitably push exporter companies to attempt to improve their position through different negotiation tactics.

Figure 8: BOTAŞ imported average LTC prices from all suppliers versus Gazprom European average LTC prices, NBP, TTF, and Turkey's average spot LNG prices, 2019–1H2020 (USD)



Source: Argus

In 2019, the average Gazprom export price to Turkey remained quite high at US$290/mcm; higher than the SD1 and NIOC gas export prices, but lower than the price of SD2 gas imported via TANAP.[37] In all four quarters of 2019, the average Russian gas price for BOTAŞ remained high not only relative to other suppliers, but also relative to Gazprom's European LTC prices and average hub prices in Europe (Figure 8).

When oil prices were low in April and May 2020, Turkish gas importers, both state-owned BOTAŞ and the private sector, failed to benefit as the long-term agreements with Russia had clauses that softened the impact if oil prices fell **below $50/bbl**, clauses that BOTAŞ would now want to eliminate along with other terms. The present situation is that movements in oil and oil products prices between US$50/bbl and US$-30/bbl, will have the same impact on final Gazprom export prices to Turkey with a 6-month lag. Therefore, we assume that the average Gazprom gas export price for BOTAŞ will fall from around US$230/mcm[38] in Q1 2020 to around US$185–167/mcm for the rest of this year (Figure 8).

Shah Deniz Phase 1: BOTAŞ signed an LTC with the Azerbaijan Gas Supply Company (AGSC), a marketing arm of the Shah Deniz consortium, in 2001, and this contract also expires in April 2021. Similar to the Gazprom contract, the AGSC 1 contract price formula is linked to a price basket of various oil products and payment is made every three months. When determining the basic price for payment, the formula use the average of the product prices over the past six months. Neither side has ever experienced any major price dispute since gas trade relations were established, except for the year 2010, when oil and gas prices in the international market were the highest and the SD1 gas price for Turkey was rather symbolic. The Azerbaijani side requested a price review not least because of Turkey's various attempts to open the border with Armenia that was closed because of the occupation of 20% of the Azerbaijani territory of Nagorno-Karabakh and seven surrounding regions by Armenian military forces, a conflict that remains ongoing.

[37] SD2 gas price for Turkey is the highest owing to the high TANAP transportation fee – around US$76/mcm per 100 km
[38] Argus

The AGSC1 gas price was, for most of 2018 and 2019, lowest relative to other suppliers to Turkey and 15% lower than the Gazprom price. AGSC1 prices will drop further starting from October this year as a result of the low oil prices in April and May. As the AGCS contract with BOTAŞ does not have a clause which softens the impact of the oil price falling to an extreme low, for the rest of the year and Q1 2021 the SD1 gas price for BOTAŞ will remain low, at around US$130–150/mcm (Figure 8).

NIGC: The Iranian LTC was signed in 1996 and expires in July 2026. Iranian gas prices had always been highest for Turkey, above US$500/mcm, until 2016, when the price dispute arbitrator ruled in favor of BOTAŞ, which received US$800 million in retrospective payments from NIGC. In the price formula, the gas price is linked to a basket of oil products and this is reflected in gas prices with a nine-month lag. The Iranian gas price for Turkey last year was 5–10% lower than Gazprom's and will be around US$145-160 in the fourth quarter of 2020 according to our calculations.

b) ***Long-term sale contracts****:* BOTAŞ signed 20–36 year contracts in the past because it sought to ensure secure long-term gas supplies into the Turkish natural gas market that LTCs would provide for decades to come, without a need to renew them. This was the classic monopoly position throughout Europe which has now changed fundamentally everywhere except in SE Europe and Turkey. At the time it signed the long term contracts the entire European market pricing mechanism, established in the 1970s, was (largely) based on oil product indexation and no hub indexation had yet developed. In addition, BOTAŞ did not want to leave any part of the market open to spot supplies negotiated either by itself or possibly by private companies in the future. Both the LNG and pipeline gas markets then were volatile and the prices and availability of gas via pipelines in the region and via spot LNG were uncertain. For these reasons, BOTAŞ contracted all the required gas volumes with a portfolio management strategy in mind.

Since then, the gas market has undergone tremendous changes, especially in the neighbouring European market, and LTCs, even those of the traditional supplier, Gazprom, have been gradually replaced with short-term contracts that provide a great deal of flexibility. The argument that oil-linked gas prices was the most appropriate mechanism, and that no other mechanism was available, has long been seen as irrational as a result of the transformation of most world gas markets (except for Asia).[39]

Long-term purchase contracts with Turkey's suppliers denied BOTAŞ any flexibility to renegotiate unwanted clauses in the contracts described in this section, other than price discounts, as there is no term review for those clauses in the agreements. Furthermore, because of the existing LTCs, Turkey was not in a position to buy gas from potential new pipeline gas suppliers if such an opportunity arose, as should have been possible given the market over-supply in recent years. The Energy Ministry officials have repeatedly said that Turkey will not under any circumstances sign long-term contracts with existing suppliers and all new contracts will be short in duration.[40] Interestingly, however, this strategy may change for political considerations, given that BOTAŞ signed a 15-year sales agreement to import Shah Deniz 2 gas from Azerbaijan via TANAP in 2013.

c) ***ToP*****:** A minimum purchase commitment has been one of the most painful terms of the contracts for Turkish supply, especially for private sector importers, for the last five years owing to the fall in gas demand. BOTAŞ contracts have been subject to an 80% minimum offtake obligation applied with a five-year make-up period, making it impossible to manoeuvre between the choice of supply sources offering lower prices and better contractual terms.

[39] For detailed analyses on price development see Stern, J. & Imsirovic, A. "A Comparative History of Oil and Gas. Markets and Prices: is 2020 just an extreme cyclical event or an acceleration of the energy transition?", OIES (2020), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/04/Insight-68-A-Comparative-History-of-Oil-and-Gas-Markets-and-Prices.pdf
[40] Bayraktar

BOTAŞ has so far managed to take nearly all the gas implied by its long-term gas contract ToP obligations at oil-linked prices. Private sector importers have, however been forced to take volumes at much higher prices than those from various sources based on short-term spot contracts. Subsidies from the state and a market which is not liberalized have enabled BOTAŞ to take unwanted volumes (because of demand fluctuations and a general decline of demand) at higher prices and sell them in the domestic market at a lower price, thus depriving the market of price competition. This is what European utilities were unable to do because their markets had been liberalised; they were unable to continue to pay oil-linked prices because their competitors were offering significantly lower hub prices. They therefore had to change their contracts to hub pricing or risk going out of business.[41] As BOTAŞ had an obligation to take at least 80% of the ACQ, to avoid oversupply it postponed TPA not only for pipeline imports (except for just 10 bcm of gas contracts released in 2007, 2009 and 2011 via auctions), but also for long-term and spot LNG imports for many years. This in turn severely delayed the market liberalisation process, the law on which was passed as early as 2001.

As Figure 9 shows, BOTAŞ performed quite well for the last 5 years by importing around 80% of ACQ from Gazprom, except in 2019 when it imported only 13.6 bcm, 73% of ToP. Then, in the first half of 2020 the volume of BOTAŞ gas purchased from Russia fell significantly, by 64% yoy, to around 19% of total Gazprom ACQ, sharply increasing imports from Azerbaijan as Shah Deniz 2 shipments ramped up along with spot LNG (Figure 9).

d) ***Destination clause:*** Despite the discussions on the ambitious target of Turkey becoming, in a best-case scenario, a physical and virtual natural gas trading centre and, in the worse-case scenario, a liquid hub similar to European hubs, it has not been possible to realise this ambition so far, not least owing to the destination clauses in BOTAŞ's contracts with all suppliers except for the SD1 contract. This has prevented Turkey from free and open trade with its neighbouring countries. It is impossible to create a liquid hub, and even difficult to create a trading centre, in a market which is not liberalised and is dominated by a state-owned company which is able to control the market and keep out players that it does not like or might pose a threat to its position. The process of elimination of final destination clauses in new and existing European contracts because they did not comply with European Competition Law and enabled first-order discrimination started as early as 2002.[42]

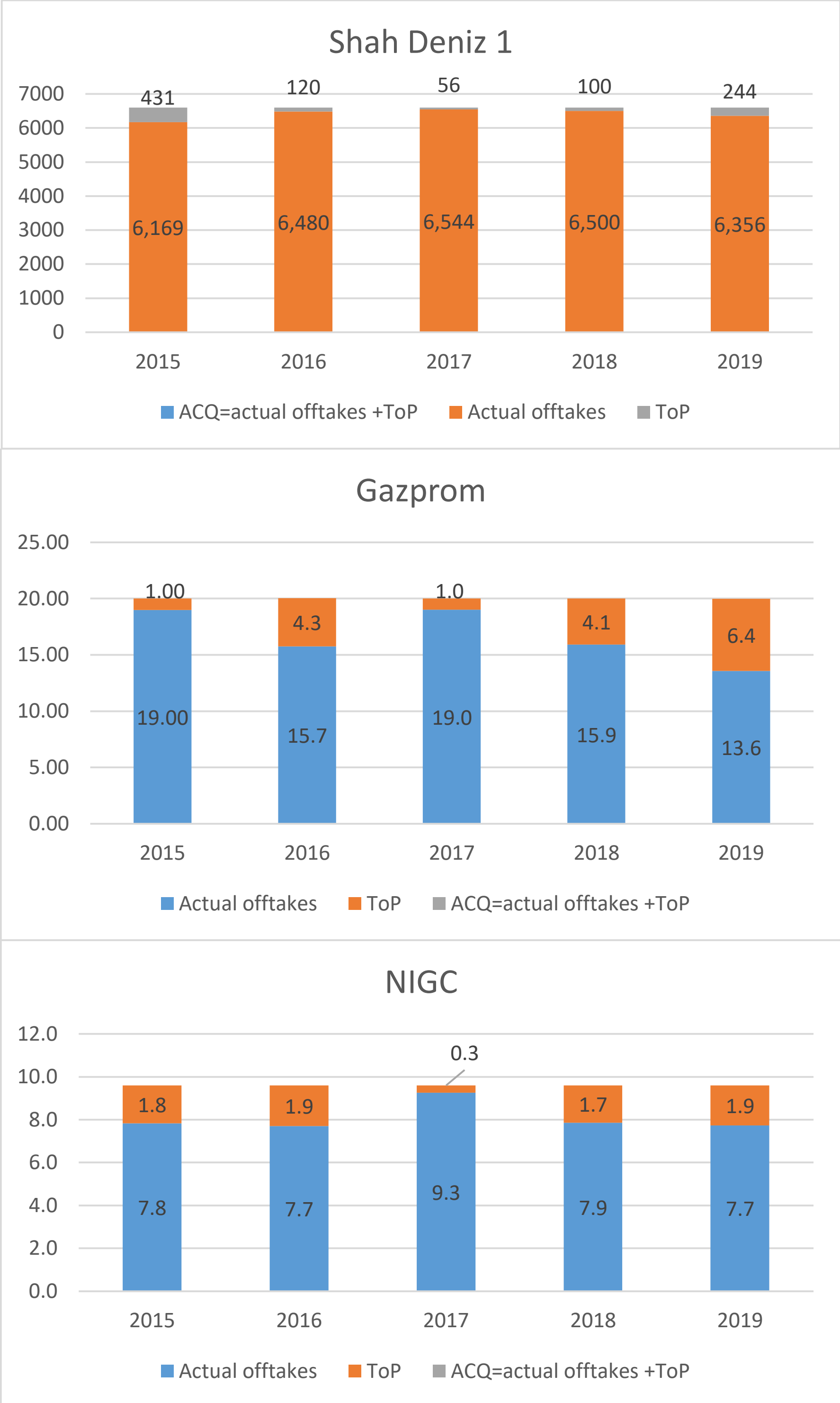
BOTAŞ, or any private sector company that holds an export license from EMRA, have not been able to re-export[43] unwanted gas, and thus benefit from trade opportunities, because of re-export restrictions in the contracts. This has made BOTAŞ's situation even more difficult, especially in low-demand periods and has also restricted regional price competition between the spot and contractual prices paid by traders, foreign producers, state incumbents and other market participants. Clearly, in a competitive market, the BOTAŞ netback margin would have been very low or negative given its high gas import prices plus transportation costs to potential markets. The clause has also had a role in delaying the market liberalisation process by preventing private companies from trading gas outside the country. Elimination of the clause, coupled with changes in gas pricing formulas, could boost trading activities in the Turkish virtual trading platform EPIAS, thereby expanding its activities outside Turkey and perhaps helping it to become a regional price benchmark.

[41] Stern and Rogers (2012). `The Transition of Hub-Based Gas Pricing in Continental Europe', in Stern, J. ed. *The Pricing of Internationally Traded Gas*, OIES/OUP: 2012, Chapter 4. Stern, J. and Rogers, H. `The Evolution of European Gas Pricing Mechanisms', in Hafner, M. and Tagliapetra, S. *The European Gas Markets: Challenges and Opportunities*, Palgrave/Macmillan: 2017, Chapter 15.

[42] Finon, Dominique (2002), "Integration of European Gas Markets: Nascent competition on a Diversity of Models", Cahier de Recherche 31, IEPE.

[43] Since 2007 BOTAŞ re-exporting SD1 gas to Greece. In 2019 BOTAŞ exported 762.6 mcm of gas, 13% growth yoy. Source: EMRA

Figure 9: BOTAŞ ACQ, actual offtakes, volumes not taken under ToP 2015–2019, mcm[44]



Source: EMRA

[44] As for 2020 the data shows only 1 half of the year, the ToP figures are indicative.
Azerbaijan ACQ, actual offtakes and ToP shows only Shah Deniz phase 1 and does not include Phase 2

BOTAŞ's bargaining leverage in negotiations with suppliers

Turkey has been thoroughly preparing for the historic event of contract renewal for the last five years. Its position is not equal to those who will be sitting on the opposite side of the table and it will try to obtain maximum advantage from its strengths. The strengths that Turkey has created over the years and that could secure the upper hand in the upcoming negotiations include:

-First, no demand pressure as a result of bringing the share of natural gas in power generation down significantly and the ability to replace imported natural gas with domestically produced energy such as wind and solar, hydro, and lignite. As described in the section on demand projection, in 2020 Turkey's gas demand is projected to grow modestly or stagnate relative to 2019 as a result of the impact of COVID-19; a relatively dry winter and reduced hydro-power output; and the phase-out of coal-fired plant. Spot LNG was the option of choice this winter as Turkey significantly increased its imports, and it is most likely that LNG will cover the growth of demand even in off-peak seasons.

-Second, Turkey has expanded daily entry-point sendout capacity in its mid-stream infrastructure, including LNG re-gasification terminals.

-Third, historic low LNG prices have enabled Turkey to benefit from substituting a significant share of Russian gas in 2019 and H1 2020.

LNG imports: Perhaps the strongest factor, which matches the flexibility and competitiveness narrative that the Turkish decision-makers have frequently referred to, and that will significantly play into BOTAŞ's hands, is the technical ability to import almost 90% of its total current gas consumption via spot LNG. In order to neutralize any potential risks of possible cut-offs of Russian gas after the downing of a Russian SU-15 jet, Turkey invested billions of US dollars in the expansion of re-gasification capacity, both floating and onshore. It increased LNG receiving facility capacity from 65.4 mcm/d (23.5 bcm/year) in 2017 to 94 mcm/d (33.84 bcm/year) in 2020. With the expansion of the Aliaga LNG terminal capacity, the country's total regasification capacity will reach almost 49 bcm/year (136 mcm/d) in 2021,[45] 110% of total Turkish gas demand in 2019.

Turkey became the second biggest LNG importer in Europe and the eighth in the world in 2019[46] owing to the low spot LNG price and a glut in the world market. If, in previous years, LNG was for Turkey only a marginal supply source to meet peak demand, in 1H2020 it was the second biggest supply source for Turkey after the gas from both phases of the Shah Deniz field, with the country importing it throughout the year (Figures 10 and 12). The lion's share of imported LNG came from the U.S.A. For Q1 2020, U.S. LNG cargoes into Turkey were 1.8 million tonnes, an increase of 44% relative to 2019, when U.S. exports to Turkey were 814,000 tonnes for the full year.[47] The biggest surge in U.S. volumes was in February, when the U.S.A. delivered 742,00 tonnes into Turkey's four terminals. This volume eclipsed other supplying nations and was nearly double the LNG delivered from Algeria or Qatar that month, about 400,000 and 430,000 tonnes, respectively[48] (Figure 10).

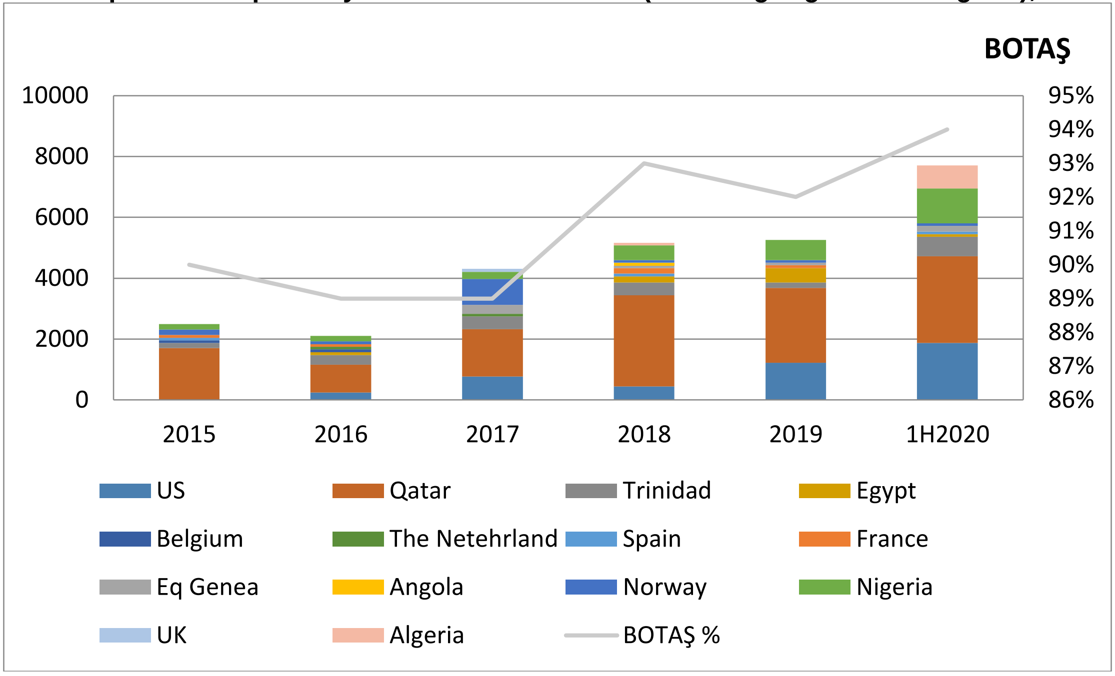
[45] For detailed analysis of infrastructure capacity expansion in Turkey see Rzayeva G. paper "Gas supply changes in Turkey", pp. 8-9, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/01/Gas-Supply-Changes-in-Turkey-Insight-24.pdf pp. 14-16

[46] Turkey second-largest LNG market in Europe (2019), https://www.dailysabah.com/energy/2019/10/17/turkey-second-largest-lng-market-in-europe

[47] ICIS

[48] Ibid.

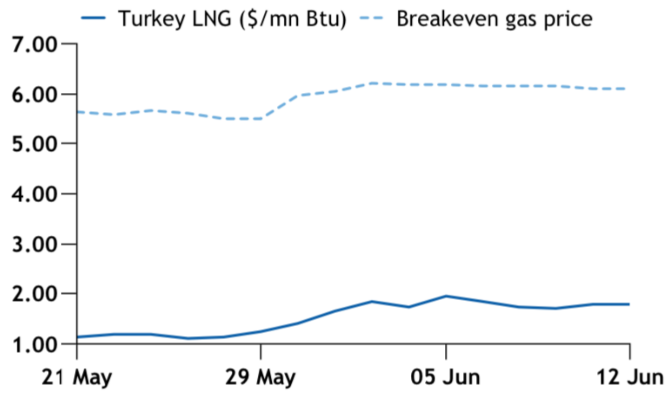
Figure 10: Spot LNG imports by source 2015–H1 2020 (including Nigeria and Algeria), mcm



Source: EMRA

As the spot LNG price for BOTAŞ is linked to the TTF hub, with a US$2/MMBtu discount, and given the historic low prices in the hub at most times of this year,[49] the spot LNG import price for Turkey was around US$1.10–1.20/MMBtu throughout May and $1.50–2/MMBtu[50] in June 2020[51] (Figure 11); a price that is more than six times lower than Russian and Iranian imported gas prices.

Figure 11: Turkish LNG and gas switching prices[52]



Source: Argus European Natural Gas

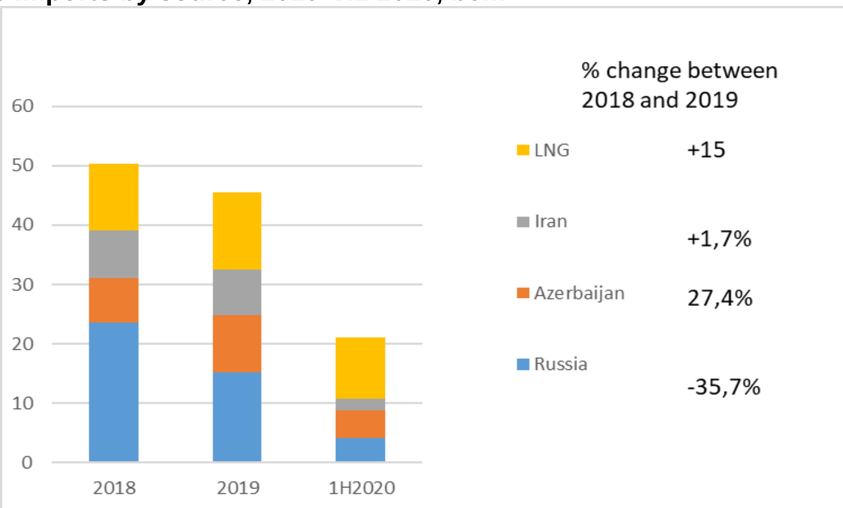
However, the surplus of LNG in the first five months of 2020, which was a big factor behind the fall of TTF spot prices below US$2/MMBtu, started to decline from mid-May till mid-July, owing to U.S. LNG shut-ins and the recovery of Asian demand. This was the reason for a sharp decline of LNG imports

[49] For details on the prices in European hubs see Fulwood, M. "$2 gas in Europe is here: who will blink first?" & "$2 Gas in Europe (Part III): Down, Down, Deeper and Down", OIES (2020), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/03/2-gas-in-Europe-is-here-who-will-blink-first.pdf
[50] Terminal and regasification charges add around US$0.5/MMBtu
[51] The average lowest netback standard freight cost for Turkey in June was spot LNG delivered from Russia – US$1/MMBtu, and the average highest was from Algeria – US$1.85/MMBtu. These prices do not take into account return leg and charter fuel costs. Source: Argus
[52] Assumes 50% efficient CCGT

into the European market during mid-May to mid-July, which points to TTF prices rising across H2 2020. This implies that Turkey's spot LNG import prices will be slightly above US$2/MMBtu for Q3 2020 and between US$2.2–3/MMBtu for Q4 2020.[53]

As a result of great divergence between Russian gas and spot LNG prices, Gazprom lost significant market share in Turkey to spot LNG as well as to increasing imports of Shah Deniz Phase 2 gas, which started flowing to Turkey in July 2018; Russia was unable or unwilling to compete with the price of LNG sourced from the U.S.A. and elsewhere (Figure 12). This is despite the existing three pipelines – BlueStream and TurkStream 1 and 2 – with a capacity of 48 bcm/year.

Figure 12: Gas imports by source, 2019–H1 2020, bcm



Source: EMRA

Turkey also has an opportunity to import spot LNG and re-export it to Europe, although BOTAŞ restricts private companies'[54] access to LNG-receiving terminals and facilities. For these purposes, and also to create a free, liquid and more liberalized market, in 2018 the Turkish government created a virtual gas trading centre – Epias – in which Turkish and foreign traders trade electricity and gas on a that-day, day-ahead, week-ahead and month-ahead basis.

Possible scenarios for the outcome of negotiations and the position of the exporters

What is certain is that contractual decoupling from oil prices will inevitably bring imported gas prices down significantly, given the current low European hub prices, but there is no doubt that this will be an unwelcome development for the majority of the sellers of gas to Turkey. For them, accepting Turkey's condition of price decoupling and bringing ToP commitments down from the current 80% to around 50–60% should mean significant financial losses. However, as is clear from the rhetoric of Turkish officials, Ankara will take a hard bargaining stance with a "take-it-or-leave-it" negotiation strategy. Current market circumstances play into Turkey's hands, and under no circumstances will Ankara soften its position. The old-fashioned contractual terms have become untenable. The Turkish deputy energy minister's statement that, if the current gas suppliers will not accept Turkey's fair terms, the country will potentially welcome new pipeline and LNG suppliers,[55] is a confirmation of this logic. However, there is a major weakness in Turkey's negotiating position, which it created itself: without a liberalised market, or unless there is a physical connection to European hubs which make a connection to hub prices convincing,

[53] According to Argus, BOTAŞ awarded some of the summer cargoes it sought through a tender closing in early June, possibly at a 5-10¢/MMBtu premium to the TTF

[54] In 2019 BOTAŞ accounted for 94% of spot LNG imports with only Egegaz also importing LNG. None of the other 54 companies holding LNG import licenses have been allowed to book capacity in the re-gas terminals because of the over-supply problem.

[55] Turkey's Deputy Energy Minister Alparslan Bayraktar: https://www.atlanticcouncil.org/event/impact-of-covid-19-on-the-global-energy-sector-and-reflections-on-turkey/

BOTAŞ' options may simply be to say that pipeline gas will need to compete with LNG on price or it will not be purchased. This would push Turkey towards purchasing the majority of its gas on a spot or short term basis.

Gazprom is probably the exporter that will suffer the most from the contract renewal. It has already lost significant market share in Turkey, which has led not only to financial losses but also to losing its position as the biggest gas supplier to Azerbaijan and becoming only the third biggest supplier. Even the newly launched Turk Stream did not change this situation. By agreeing to provide concessions, Gazprom's financial losses will be enormous and painful, because Turkey is its highest-premium market in Europe, and its most profitable.

On the other hand, however, there might be an opportunity for Gazprom in this "crisis." By agreeing on a transition away from a formal contractual oil product price linkage, lower Gazprom export prices may become competitive with not only the other pipeline suppliers' gas prices, but also with spot LNG prices, which are likely to use more or less the same price formula. BOTAŞ and private sector importers may, in this case, increase its imports from Russia via Turk Stream and increase the market share of Gazprom from the current level.

Another possible scenario is that Gazprom may apply an approach similar to that it has already used in Europe by supplying substantial volumes of gas to Turkey via the spot market, either directly or via private companies in Turkey in which it has an ownership interest. This will be possible when and if EPIAŞ delivers a convincing spot market with a supply/demand price. It is obvious that, in the case of Turkey, Gazprom will be unable to apply a volume-over-value strategy, as it has been doing in Europe, because of the fall in demand. However, the situation may change with market liberalisation and the elimination of destination clauses.

Shah Deniz Phase 1 gas exporters are in a slightly better position than Gazprom. This is because the SD1 field is in natural decline. It started producing in late 2006 and reached its plateau level in 2010; the field's geological tail-off period should begin in 2024–2025. During the tail-off period, production levels may decrease by around 2 bcm/year or more, depending on well productivity.[56] This leads us to assume that there might not be sufficient gas to extend the contract with BOTAŞ, which expires in April 2021, to continue to provide 6.6 bcm/year on an LTC basis. Our assumption is that both sides should be interested in extension of this LTC, the Turkish side because it has been, to date, the cheapest pipeline gas for BOTAŞ; and the SD consortium because it will continue to benefit financially from all the remaining gas, even if the price will be substantially lower. In any case, as the shareholders of Phase 1 and Phase 2 are the same companies, any financial losses from Phase 1 can be balanced from Phase 2, the LTC of which will expire in 2033. Remarkably, this LTC, signed in 2013, also has almost entirely oil-price indexation and 100% ToP. Our prediction is that a short-term contract might be signed for a reduced volume of gas from SD1 for three to a maximum of five years. Another, less likely, scenario is that any remaining volume from the tail-off period may be purchased by SOCAR for the domestic market and/or exported into Turkey via the "SOCAR Turkey" company.

Iran's NIGC LTC will remain in a difficult position until it expires in 2026. As the gas price under this contract was lower than Gazprom's but higher than SD1, it was BOTAŞ's second choice for imports. In the event, if first SD1 and then Gazprom gas prices are reduced significantly as a result of market pricing, the Iranian gas price will become the highest for quite a long time. It is not difficult to predict that the price of around US$200/mcm, compared with hub indexed prices at least half that value, cannot be BOTAŞ's first choice for imports. BOTAŞ may prefer to substitute this gas with spot LNG or Russian gas imports. Nevertheless, ToP will oblige BOTAŞ to import at least 80% of the annual contract volume. NIGC may be forced by circumstances to offer a discount to be able to remain competitive.

[56] For details of gas production projection for Azerbaijan see the chapter on "Outlook for gas production in Azerbaijan and future supplies: prospects to 2040" in "The Southern Gas Corridor and its Importance for South-East Europe in the New Era of Energy Transition", ed. Dr K. Andriosopoulos and G. Rzayeva (2020), https://www.bp.com/content/dam/bp/country-sites/en_az/azerbaijan/home/pdfs/e-books/sgc_book_final.pdf?fbclid=IwAR3zQmLrbO7FGtWkdwbzKT4YHmkM5-LiKqao2cdqxsCH5My6ViC4SCU3ZyE

Nigerian LNG: This 1.3 bcm LTC expires in April 2021, and, again, it is most likely that it will be extended based on short-term spot LNG import contracts.

It is clear that Turkish importers' preference is to have short-term contracts to secure flexibility and a more frequent review of terms. The worst-case scenario for the exporters is that BOTAŞ will be able to conclude short-term spot contracts to meet all its demand. With the development of a domestic gas price index under the EPIAS[57] electricity and gas trading platform, BOTAŞ will be able to conclude spot gas purchase contracts with the current suppliers and trade the gas on the spot market, a development that may threaten the security of supply provided by the LTCs. However, this development may create a long-awaited opportunity for private sector companies to utilize surplus pipeline capacity via various trading structures such as physical cross-border swaps. To legally support the function of a free and open spot market in Turkey, last year the EMRA promulgated a law on "Procedures and principles regarding the determination of spot pipe gas import volume and application method."[58] EMRA is responsible for maintaining a transparent, free and open tendering mechanism for announcing free capacity in the pipeline infrastructure to private companies. Because of oversupply to the Turkish market resulting from falling demand and ToP obligations, it currently seems unlikely that the private companies will show great interest. The expiration of LTCs may nevertheless create additional private sector trading opportunities.

Whether it is BOTAŞ that will renew the contracts or private sector importers is not known at this stage as there are legal obstacles for BOTAŞ. According to NGML 4646, BOTAŞ cannot sign new contracts until it imports less than 20% of total Turkish consumption, except for LNG, and must release surplus contracts to the private sector. However, the experience of BOTAŞ signing the new SD2 6 bcm/year LTC sales contract in 2013, and the 5+5 year extension of the Sonatrach contract, which expired in 2014, show that Ankara can quite often create exceptions for strategic reasons, possibly through amendments to the law.

4. Private sector future gas imports and contract renewal

It has long been the case that the seven private sector importers[59] of Russian gas have been struggling with high import prices, resulting in significant losses in the domestic market. Turkish private importers traditionally bought gas from Russia on 25-year contracts, where pricing, as with BOTAŞ LTCs, is related to oil products, with a minimum ToP level set at 80% of the ACQ level with a make-up period of five years. In the case of the private companies the minimum offtake volume is 8 bcm/year of gas out of a 10 bcm/year ACQ. Pricing in the original contracts is the same as in Gazprom's contracts with BOTAŞ while BOTAŞ subsidizes its competing sales, a major obstacle to the development of a true market. It is typical in this kind of contract that "Seller takes the Price Risks" and "Buyer takes the Volume Risks",[60] but in the case of the private company imports, the importers have been taking both the price and the volume risks. The seller, in this case Gazprom, mitigates his volume risks with a ToP clause and price risk by adjusting the price to an average of oil product prices with a 6 month lag.[61] The private sector buyers take all the price risks because of: a) oil price volatility in the international markets, b) exposure to the national currency's depreciation and volatility, and c) domestic prices lower than imported gas prices.

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[57] From 2021 at the latest, EPIAS will launch weekly gas contract trading open to and annual, quarterly and monthly contracts. As well as in increase in the product portfolio, liquidity in the EPIAS gas trading platform is also increasing. In June 2020, Nearly 238 million m^3 of gas were traded over this platform in June 2020, a new monthly record.

[58] Law is available in Turkish: https://www.resmigazete.gov.tr/eskiler/2019/09/20190919-13.pdf

[59] Akfel, Avrasiya Gaz, Bati Hatti, Bosphorus, Enerco, Kibar, Shell

[60] For the explanation of these terms see Stern, J. & Rogers, H. "The Dynamic of Liberalised European Gas Market", OIES (2014), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/12/NG-94.pdf and Stern, J.P. (ed.) (2012). The Pricing of Internationally Traded Gas, Oxford: OIES/OUP. https://www.oxfordenergy.org/shop/the-pricing-of-internationally-traded-gas-ed-jonathan-p-stern/ Stern, J.P. (2012a). `The Pricing of Internationally Traded Gas: an historical survey', in Stern (2012), Chapter 2, http://www.oxfordenergy.org/shop/the-pricing-of-internationally-traded-gas-ed-jonathan-p-stern/

[61] Ibid.

The private companies face the risks of falling demand and having to sell gas to wholesalers in Turkey at less than the import cost. During the last two years the Turkish lira has depreciated significantly against the US dollar, which has caused import costs to soar above the tariff at which the gas could be sold. The companies could not accept selling the gas on the domestic market on this basis because, unlike BOTAŞ, they are not public companies and their gas prices are not subsidised. Their inability to absorb large contract volumes is also as a result of the seasonality of demand. The peak demand period is usually from December to March, when demand may reach up to 6.4 bcm/month, as seen in 2017, and the low demand period is from March through November, when consumption falls as low as 2.4 bcm/month.[62] The importing companies are unable to sell gas during the summer months and have to import significantly less.

The average imported Russian gas price for these companies in Q2 2020 was about $228/mcm,[63] whereas spot gas on Turkey's Energy Exchange Istanbul (EXIST)[64] was trading at approximately $200/mcm on May 4th 2020.[65] The difference between imported and domestic prices is a loss for the importing private companies. These companies are struggling with financial difficulties. The high import price, modest demand growth, and steep increases in LNG imports in 2019 and 1H 2020 due to the extremely low prices have caused private sector importers to significantly reduce their annual offtake volumes from an aggregate annual contract quantity of 10 bcm to 1.323 bcm in 2019, while the total import in 2018 was 7.35 bcm[66] (Table 2).

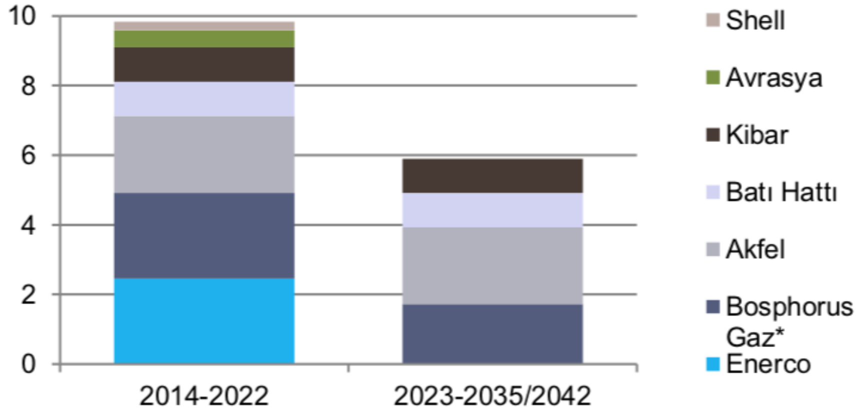
Table 2: Turkey's private sector importers - contract terms and imported volume, 2019

Supplier	Importer	ACQ, bcm/y	Contract Base	Contract End	Imports in 2019, bcm
Gazprom	Enerco Enerji	2.5	Oil products	2021	0
Gazprom	Avrasiya Gaz	0.5	Oil products	2021	0
Gazprom	Shell	0.25	Oil products	2021	0.043
Gazprom	Bosphorus Gaz1	0.75	Oil products	2021	0.186
Gazprom	Bati Hatti	1	Oil products	2036	0.017
Gazprom	Akfel	2.25	Oil products	2043	1.063
Gazprom	Bosphorus Gaz 2	1.75	Oil products	2043	
Gazprom	Kibar	1	Oil products	2043	0.014
	Total	**10**			**Total: 1.323**
Gazprom	BOTAS	4	Oil products	2021	

Source: EMRA

[62] EMRA 2019 Natural Gas Market Report, https://www.epdk.gov.tr/Detay/Icerik/3-0-94/yillik-sektor-raporu
[63] ICIS
[64] According to Heather, P. this hub is not liquid and barely gas traded. See ''European Traded Gas Hubs: the supremacy of TTF" (2020), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/05/European-Traded-gas-hubs-the-supremacy-of-TTF.pdf
[65] https://www.aa.com.tr/en/energy/electricity/spot-market-natural-gas-prices-for-monday-may-4/29172
[66] EMRA

Figure 13: Contracts in place 2014–2035/2042 (bcm/year)



Source: IBS
*Gazprom subsidiary until 2018

Since 2015, the seven private companies have demanded a price reduction from Gazprom and a possible change in the price formulation as the situation has created and maintained a significant disadvantage for them. In 2015, they agreed a 10.25% discount, which was supposed to be valid until 2016. However, the importers considered the discount to be perpetual and did not pay the increased bill for January 2016. In response, Gazprom cut their bids for gas supply by the amount of non-payment.[67] A preliminary agreement was reached, with a price reduction to be backdated to the start of 2015. However, the agreement was not signed as relations between Turkey and Russia soured in late 2015 and Russia made the price reduction conditional upon the signing of an intergovernmental agreement for the 31 bcm/year TurkStream pipeline project. Separately, five private Turkish importers have been in arbitration with Gazprom since February 2017 over gas prices for that year. Eventually Gazprom extended the 10.25% discount to 2016, but the Arbitration courts have decided this did not continue into 2017, leaving private sector importers with a $400 million bill.

This situation created difficulties with some Turkish wholesale companies that were reluctant to renew contracts with private sector importers for 2018. The problem was that private sector importers were selling gas to wholesale marketers at prices that anticipated a 10.25% price reduction from Gazprom. The importers held back-to-back long-term sale contracts with wholesalers covering the period January 2017 to September 2018, which would result in retroactive payments of $160 million, including clauses that the marketers would pay more if the importers do not receive the discount.[68] The situation is exacerbated by the fact that contractual prices are denominated in foreign currencies, which means that any exchange rate-related fluctuations are passed through from importers to wholesalers. That is, under their long-term agreements, importers have the right to transfer their responsibility for payment to Gazprom for the imported gas to their customers, based on the back-to-back terms embedded in the agreements.[69]

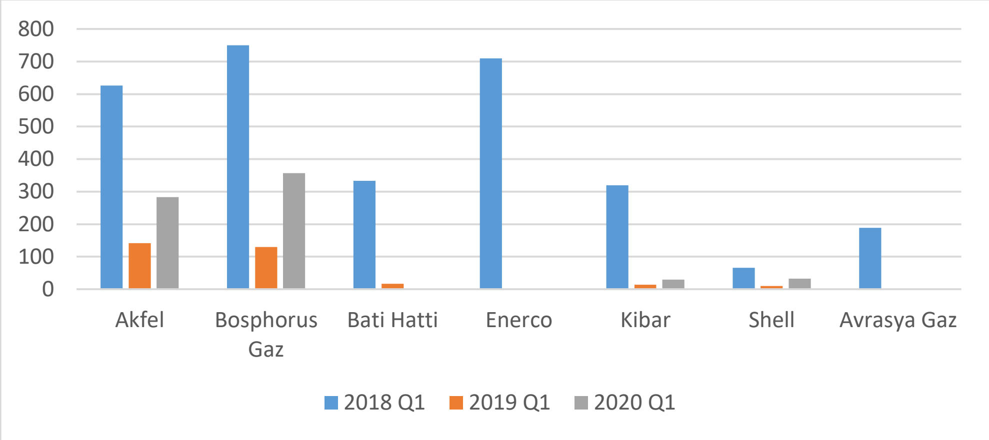
As a result, gas imports from Gazprom by private companies fell by 80%, reducing Gazprom's market share in Turkey from 55% in 2015 to only 33.6% in 2019.[70] Although Gazprom won the arbitration case and received short-term benefits, in a longer-term perspective, it made a strategic loss. While a long-term Gazprom goal was to increase its market share in Turkey and to be competitive with traditional and potential new suppliers (spot LNG, Shah Deniz phase 2 gas, gas from Iraq, EastMed, etc.), the disagreement on price discount did Gazprom's competitors a huge favour. In a relatively short period

[67] «Газпром» уходит с рынка Турции (2017), https://www.kommersant.ru/doc/3319128
[68] For detailed analysis on this issue see Rzayeva, G. Gas Supply Changes in Turkey (2018) p.7-9, OIES, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/01/Gas-Supply-Changes-in-Turkey-Insight-24.pdf
[69] Akfel Gaz and Enerco Energy have this right under the LTC terms
[70] EMRA 2019 Annual Natural Gas Market Report

of time this resulted in an increase of gas supply from Azerbaijan of almost 30% and a doubling of the spot LNG share.[71]

Figure 14 shows the seven companies' imports for Q1 2018-2020.

Figure 14: Private sector company gas imports from Gazprom in Q1, 2018–2020, mmcm

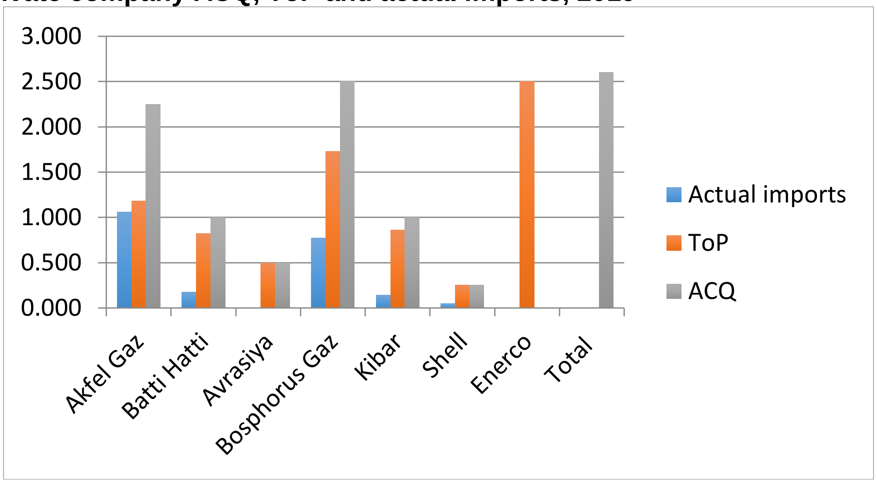


Source: EMRA

As Figure 15 shows, in 2019 the private sector's aggregated gas imports were almost 1.3 bcm, which is only 13% of the contractual volumes. All importers will face severe take-or-pay penalties for last year's gas undertake.[72]

Enerco and Avrasiya Gaz were not able to import any Russian gas during the whole of 2019,[73] and thus must pay ToP penalties over a five-year make-up period. For Bati Hatti and Kibar, imports fell steeply to only 10% of ACQ, imported during only one month of the year, January. Bosphorus Gaz imported in only two months, January and July, a total of only 15% of ACQ. Akfel imports were realized throughout the year, with each month showing 45% of the offtake volume, and Shell also imported every month at 30% of the ACQ volume (Table 2, Figure 15).[74]

Figure 15: Private company ACQ, ToP and actual imports, 2019



Source: EMRA

[71] According to Turkey's deputy Energy Minister Alparslan Bayraktar, the share of LNG in 2019 reached 28.3%, whereas in first four months of 2020 it was 44%, of which 40% was sourced from the US. Source: https://www.atlanticcouncil.org/event/impact-of-covid-19-on-the-global-energy-sector-and-reflections-on-turkey/

[72] Gazprom recently billed the private sector importers an estimated $38 million for failing to import their required minimum summer quantity of 37.5% of the contract total.

[73] EMRA

[74] Ibid.

Contractual terms that the seven companies want to change

Negotiations between Gazprom and the private sector importers have started this year for the extension of the LTC import contracts of 4 bcm/year that expire at the end of December 2021. It is not known at this stage whether all the companies will renew their contracts and be able to continue importing gas from Gazprom after 2021. From the companies' perspective, they will not be able to remain afloat if the same contractual terms and conditions remain in the renewed contracts and they continue to import gas from Russia. Consequently, like BOTAŞ, they are keen to re-negotiate the following terms in the LTCs:

a) the formation of prices, including the hub-indexed price formula.

b) More flexibility in off-take volumes, reducing compulsory offtakes from 80% of contractual levels to between 50% and 60%.

c) Elimination of the destination clause and flexibility in gas re-export westwards, mainly to Bulgaria, via the Malkoclar–Stradza pipeline, and Greece.

The Law on spot market regulation will create a good opportunity for private companies to trade with gas sourced elsewhere, including Russian pipeline gas, to profit when and if the prices are suitable. They also have an opportunity to import spot LNG and re-export it to Europe, although BOTAŞ restricts private company access[75] to LNG receiving terminals and facilities. But the question which arises, is how a law can create opportunities if BOTAŞ can stop other players from getting access to gas?

For the Turkish companies, security of supply is no longer a major issue as it was in the past when there were infrastructure constraints. Turkey has almost fully eliminated the physical capacity shortage through the expansion of LNG receiving terminal capacity and construction of three new floating storage regasification units. Newly contracted capacity from two international pipelines, TANAP and TurkStream, has solved Turkey's import constraints from Azerbaijan and possible transit risk in importing gas from Russia.[76] For Turkish private companies, competitive and flexible gas prices matter more than secure supplies, and this is what they intend to demand at the new round of negotiations with Gazprom.

The future of the contracts and the fate of Turk Stream

The position of these companies is not as strong as that of BOTAŞ and it is clear that they do not have as strong a relationship with Gazprom as BOTAŞ has. The first and most important reason is that these companies are operating in a monopolistic market. They do not enjoy the benefits of access to cheap spot LNG, price subsidisation in the domestic market, free and open domestic market access, a diverse import portfolio and access to international pipelines as well as LNG terminals. Although three of the seven private importers – Bosphorus, Enerco and Shell – have already received spot LNG import licences[77] and can legally import spot LNG at much lower than Gazprom LTC prices, this has not happened thus far due to BOTAŞ restrictions. And this is the contradiction at the heart of the whole price situation.

It is also clear that Gazprom has leverage against these companies as they will have to pay back millions of dollars in fines, in line with their ToP obligation, for failing to take annual contract quantities over the last three years, including the all-time minimum offtake of 1.3 bcm in 2019. It will almost be impossible to repay the debt, after many years of operational losses in the price-regulated market. Nevertheless, threatening to enforce payment of these debts seems to be the only instrument available to Gazprom Export to secure gas flows through Turk Stream and not leave it idle. Gazprom may use this leverage to persuade the private importers to renew their contracts.[78]

[75] In 2019 Botas accounted for 94% in spot LNG imports with only Egegaz importing 6%. The other companies holding LNG import licenses have not been allowed to book capacity in the re-gas terminals due to near-over supply problem.
[76] For detailed analysis of this issue, see Rzayeva, G., "Gas Supply Changes in Turkey", p.6, 15-18, OIES (2018), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/01/Gas-Supply-Changes-in-Turkey-Insight-24.pdf
[77] Emra report
[78] The private sector importers' signature is required for changing Gazprom's delivery point from Malkoçlar to Kıyıköy.

Our assumption is that Gazprom may encourage Bosphorus Gaz and perhaps Shell to renew their contracts with larger volumes by making concessions in the terms. The remaining companies, under the control of the State Deposit Insurance Fund (SDIF) are expected to be forced by Gazprom to renew their contracts in return for cancelling their existing ToP and Minimum Supply Quantity (MSQ) penalties. However, this scenario is only possible if the contractual terms are changed to reflect the market fundamentals described in the previous section, in a non-monopolistic market. This will be the only way for the private companies to continue their existence as gas importers from Russia and stay afloat. Gazprom's possible refusal to change contractual terms could result in a loss of market share of 10 bcm/year.

The future for Gazprom in the Turkish market seems even bleaker given the current natural gas prices elsewhere in the world, and especially in Europe, which make it impossible for Gazprom to attempt to maintain "business as usual."

5. Summary and conclusion: The future of the Turkish natural gas market

On the basis of the discussion above, this paper concludes that as long as the market is not liberalised and liquid national or regional trading hubs are absent, any changes in long-term contract terms will not adequately reflect the market dynamic. The government/BOTAŞ does not want to liberalise the gas market but it wants the benefits of market liberalisation: these aims cannot be reconciled. In Europe liberalisation progressed, too much LNG was developed, new players came in, the market became swamped with gas and extremely competitive and hub prices began to dominate.[79] European utilities with long term oil-linked price contracts could not compete with new players offering hub prices and long term contracts had to be changed.

Turkey's gas market will inevitably transition away from traditional LTCs linked to oil product prices. This has arguably already begun, as can be seen in the high level of spot-gas price indexation in short-term spot LNG contracts. Given BOTAŞ' dominance, subsidies to domestic customers, and no workable TPA, it is not possible to achieve any kind of hub/market price in Turkey. The alternative option, to achieve this through links to market hubs in Europe could be possible. However, for that to happen, it would need to be credible that BOTAŞ would refuse to purchase any pipeline gas at any price above TTF, as long as it can obtain all of its gas needs through LNG at that price. Although this has happened with the TTF-related price for LNG it is highly unlikely that it can act to force European market prices to be adopted for the whole of the Turkish market. The other option is for pipeline connections to be created (reverse flows on the Malkoclar-Stradja2 pipeline, Turkey-Greece pipeline, TANAP and TurkStream) which would allow Turkish buyers to access pipeline gas from the rest of Europe at hub prices.[80] That would force pipeline gas suppliers to accept European hub prices for their gas in long term contracts, but probably only after a major legal/contractual fight (as there was in Europe).

Given the changes that have begun in the Turkish natural gas market, as described in this paper, this country has made itself ready for serious structural changes and perhaps a new market design. For that, structural and institutional changes will also be needed and a new market design will not work unless and until this happens. The current gas surplus and several months of prices in the range US$2–3/MMBtu at the European gas hubs, it is entirely likely, will add to the other factors accelerating the transition from oil-linked to market pricing in Turkey. With the current unique gas market conditions in the world, not least the result of COVID-19, the transition away from oil-indexed prices and gas pricing mechanisms seems to be a natural and overdue evolution for the Turkish market in the wake of the expiration of the current contracts.

The impact of European and global dynamics in natural gas has made the existence of old-fashioned LTCs untenable in this particular market. This transition, if Turkey manages to negotiate favourable

[79] See Stern and Rogers (2012) and (2017). `The Transition of Hub-Based Gas Pricing in Continental Europe', in Stern, J. ed. *The Pricing of Internationally Traded Gas*, OIES/OUP: 2012, Chapter 4. Stern, J. and Rogers, H. `The Evolution of European Gas Pricing Mechanisms', in Hafner, M. and Tagliapetra, S. *The European Gas Markets: Challenges and Opportunities*, Palgrave/Macmillan: 2017, Chapter 15.

[80] This is essentially the strategy that Ukraine adopted

contractual terms as suggested in this paper, can be viewed as both a challenge and an opportunity. The transition from a monopoly, inflexible and uncompetitive market, not least created by the terms of the LTCs, to a spot market and competition may be unpredictable in terms of longer-term supply planning that reflects supply and demand conditions and is therefore volatile in terms of supply availability. Companies' trading books may become unbalanced, with a mismatch of long-term obligations and supplies. The apparent collapse of private-sector contracts has eliminated the cushion of comfortable supplies. All market players may face these risks, to which they will have to adapt.

There is no doubt that there are more opportunities than challenges. The European experience is perhaps a good example for this. The first and utmost benefit is that market prices reflected in the contracts would inevitably and immediately drag prices down significantly to something close to Turkey's spot LNG prices but not forever. This can be a short term phenomenon, based on short-term contracts or no contracts, and linked to TTF with a US$2 discount, which in Q1 and Q2 2020 was 150% lower than the average imported pipeline gas prices for the same period. Market liberalisation and the emergence of new private players will first of all take away the market risk and financial burden that BOTAŞ carries alone and share it evenly. BOTAŞ would need to give up its market dominance, which would mean shared risk equals shared reward. By developing national or even regional gas trading centres, and perhaps in the future gas hubs with price benchmarks, Turkey will be linked with the European gas hubs and the market, thereby creating more trading opportunities via various cross-border trading schemes. Enabling that, Turkey has developed one of the most advanced cross-border and domestic gas infrastructures in Europe and is capable of utilizing it appropriately, if and when contractual terms allow.

It is clear that Turkey's unshakable intention to drastically revise contractual terms is an unwelcome development for the suppliers. It seems that Gazprom will be the most affected exporter because, first, it is already in a weak position having already lost significant market power by virtue of its highest exported gas prices, which have been substituted by SD2 gas from Azerbaijan and spot LNG. Second, it has a strategy of non-concession in price discounts for private sector importers at the expense of market share. This has backfired for Gazprom, which is not only gradually losing its market power, but also its bargaining power in the negotiations. Further, any attempted manipulation of the gas price by implicit pressure imposed by Russia on Turkey is complicated by the multi-level relations between the countries, involving not only energy but also Turkey's presence in Syria and its international orientation. Third, at present, Turk Stream 1 seems likely to operate in 2020 with a throughput of only 4 bcm/year, well below its 15.75 bcm/year capacity, a factor which must be disturbing Gazprom. Given that two private companies – Avrasiya and Enerco – with total import portfolios of 3 bcm/year failed to import any Russian gas in 2019 and the first half of 2020, it is most likely that they will not be in a position to extend their contracts. This implies that Turk Stream may operate with even lower volumes after 2020.

To conclude, given the current Turkish natural gas conditions, real liberalisation can only be achieved by implementation of the provisions of NGML and market prices can be achieved via this route. Although the government is under time pressure to achieve these objectives before the LTCs expire, it will not be possible to fully liberalise the market in the short term. BOTAŞ may conclude a short-term contract with market prices with Gazprom and SD1 next year using its access to cheaper LNG. But it will have to fully liberalise the market gradually by the end of 2020s when all its LTCs with pipeline suppliers expire, leaving aside political and strategic considerations and driven by pure economic logic. An alternative option of accessing European market hubs via LNG and possibly pipeline gas, and for BOTAŞ to be prepared to go fully towards spot gas purchase, would contradict NGML, which envisages a reduction of BOTAŞ market share to 20% of total gas consumption. This can be achieved. The government has adopted a new Law on spot pipeline gas imports/exports by private companies. However, again, success is directly linked to market liberalisation and will not be possible without private company access to import/export infrastructure, which will catalyse significant changes in market structure.