Disclaimer

June 2022

The following product was concluded in September 2021, with an information cutoff date of August 2021, and thus does not reflect changes in the Iraq Kurdistan Region (IKR), in Iraq, or in the global market since that time.

Some notable developments have subsequently taken place in these markets, including **the Russian invasion of Ukraine and its impact on Europe** and the wider region's desire for gas diversification; **record-high world gas and LNG prices**; **the Iraqi Supreme Court's ruling on the unconstitutionality of the IKR's oil and gas sector**; **the establishment of the Kurdistan Region Oil and Gas Company (KROGC) and the Kurdistan Organisation for the Marketing of Oil (KOMO)**; **the cancellation of Genel's licenses for the Miran and Bina Bawi natural gas fields, and its resultant arbitration against the KRG**, and; **higher Turkey 2021 gas demand** (than reasonably estimated in this product due to low hydro output, but a continuing longer-term trend of replacement by renewables). With due consideration for these factors, we believe this product continues to present a reasonable outline of potential resources and opportunities for energy development in the IKR.

Conclusions herein may be revised pending additional data collection, formal review processes, and solicitation of comments by relevant stakeholders.

Qamar Energy

27 June, 2022

Opportunities to Strengthen the Natural Gas Sector in the Iraq Kurdistan Region: A Step Towards a Cleaner and More Secure Energy Future

September 8, 2021

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Disclaimer

The views and opinions of the report's authors do not necessarily state or reflect those of the Government of the United States, the U.S. Department of Energy's Office of International Affairs, or any agency thereof. Conclusions herein may be revised pending additional data collection, formal review processes, and solicitation of comments by relevant stakeholders. The information cutoff date for this product is August 2021 and it thus does not reflect changes in the Iraq Kurdistan Region (IKR), in Iraq, or in the global market since that time. We believe the study continues to present a reasonable outline of potential resources and opportunities for energy development in the IKR.

Study Objectives and Issue Statement

The project aims to deliver material analysis and robust conclusions on the Kurdish, Iraqi, and Turkish natural gas sectors, with the goal of strengthening the local Kurdish gas market and promoting U.S. strategic objectives: enabling Iraqi energy access and independence, improving environmental outcomes including reduction of carbon dioxide emissions, promoting U.S. investment in and trade with the Iraq Kurdistan Region, and limiting undesirable outside influence in Iraq and the Iraq Kurdistan Region.

Study Approach

1. Assess the natural gas and power production and demand outlook for the IKR, Federal Iraq, and Turkey, on a monthly and annualized basis from 2017 to 2040.
2. Describe key natural gas and power infrastructure, existing and planned.
3. Assess the opportunities for natural gas and power sales from the IKR to Federal Iraq and exports to Turkey.
4. Test different scenarios and commercial options for possible projects.
5. Recommend financing tools for adequate natural gas sector development in the IKR.

This study includes:

1. An impartial natural gas market analysis to enhance the physical and financial liquidity in the local Kurdish gas market, while establishing clear and transparent market rules for investors.
2. An assessment of the natural gas supply and demand balance in the IKR, Federal Iraq, and Turkey, to facilitate a functioning natural gas market in the IKR, in a manner that encourages the efficient, expedient and responsible development of natural resources.
3. Findings and recommendations based on information provided by the U.S. Department of Energy; the Kurdistan Regional Government Ministry of Natural Resources; key stakeholders, including upstream operators and downstream consumers in the Kurdish gas sector; and Qamar Energy's proprietary database on the IKR, Federal Iraq, and Turkey natural gas sectors.

Special Considerations:
The political, economic, and security environments in Iraq, including the IKR, create a unique and nuanced context and have been given particular consideration in weighing impacts on the region's natural gas market.

Methodology

1. Use proprietary Qamar Energy database of crude oil and natural gas fields, power projects, and natural gas infrastructure as per country of study by region and province.
2. Correlate natural gas demand, power demand, and industrial use to gross domestic product (GDP) and population growth parameters.
3. Model natural gas demand from the power and industrial sectors, considering all other generation, including planned and sanctioned oil, natural gas, hydropower, solar, wind, coal projects by region/province of each country.
4. Determine the natural gas available for export seasonally and at various times and balance against demand and existing/planned pipelines.
5. Recommend commercial tools and financing options based on conversations with key stakeholders in the IKR, Federal Iraq, and Turkey natural gas sectors.

Acronyms and Abbreviations

Terms	Definition for This Study
APICORP	Arab Petroleum Investment Corporation
BCM	Billion cubic meters
BGC	Basrah Gas Company
CCGT	Combined-cycle gas turbine
CO_2	Carbon dioxide
DG	Distributed generation / distributed generator
EEZ	Exclusive Economic Zone
EPC	Engineering, procurement, and construction
EXIST	Energy Exchange Istanbul
FI	Federal Iraq, i.e., Iraq excluding the IKR
GCC	Gulf Cooperation Council
GDP	Gross domestic product: The main measure of a country's economic activity
GE	General Electric
GHG	Greenhouse gas
GSA	Gas sales agreement
H_2S	Hydrogen sulfide, toxic and corrosive gas often found as a constituent of natural gas in reservoirs
IFC	International Finance Corporation
IKR	Iraq Kurdistan Region
IOC	International oil company
IPP	Independent power producer
IsDB	Islamic Development Bank
JBIC	Japan Bank for International Corporation
kb/d	Thousand (kilo) barrels per day
KRG	Kurdistan Regional Government
LNG	Liquefied natural gas
MMBtu	Million British thermal units
MNR	Ministry of Natural Resources (Kurdistan region)
Mt	Million metric tonnes
NAGGS	Northern Associated Gas Gathering System
OPEC	Organization of Petroleum Exporting Countries
Q	Quarter
PKK	Kurdistan Workers' Party
PPA	Power purchase agreement
PSA	Production Sharing Agreement – as used in the IKR
PSC	Production Sharing Contract – synonym for PSA
PUK	Patriotic Union of Kurdistan
SAGGS	Southern Associated Gas Gathering System
SOMO	State Oil & Marketing Organization
SPV	Special purpose vehicle
T&D	Transmission and distribution
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TCF	Trillion cubic feet
TPAO	Türkiye Petrolleri AO
TSA	Technical Services Agreement – as used in Federal Iraq
UAE	United Arab Emirates
US DFC	U.S. International Development Finance Corporation
y	Year

Glossary of Terms

Terms	Units	Definition for this Study
Average Demand	Gigawatts, megawatts (GW, MW)	The overall average demand for power within a country in a year. Average demand is always less than peak demand.
Gas Demand	Billion cubic meters (BCM)	The average monthly and/or annual demand for marketable (sales) gas across all sectors that consume gas, mainly power, industry, transport, residential (if applicable), and energy own use in a country. May or may not include gas exports (specified where relevant). May exceed actual gas consumption if some demand is unmet as a result of market, physical, or other barriers.
Gas for Industry Demand	BCM	The average monthly and/or annual demand for gas in the industry sector of a country. Industry includes shrinkage and natural gas liquid removal.
Gas for Power Demand	BCM	The average monthly and/or annual demand for gas in the electric power sector of a country.
Gas Supply	BCM	The average monthly and/or annual gas available to the demand sectors of a country. May or may not include gas imports (specified where relevant).
Generation	Terawatt-hours, gigawatt-hours, megawatt-hours (TWh, GWh, MWh)	The actual power generated over a period of time.
Generation Capacity	GW, MW	The total power generation capacity available to a country.
Peak Demand	GW, MW	The highest (peak) point of demand for power at any time within a country/region in a year. Peak demand occurs during the summer in summer-peak markets and in the winter in winter-peak markets.
Re-exports (gas)	BCM	Importing gas from one country for the purposes of exporting it to another country, or from one region within a country for the purposes of exporting it to another region within the same country.
Re-exports (power)	GWh, GW, MW	Importing power from one country for the purposes of exporting it to another country, or from one region within a country for the purposes of exporting it to another region within the same country.

Conversions:

1 BCM = 35.31 billion cubic feet (Bcf) = 0.735 million tonnes (Mt) of LNG = 34,121,416 million British thermal units (MMBtu)

At a Glance: Proposed Roadmap for the Kurdish Natural Gas Sector

Note: Some Milestones and steps will run concurrently.

STAGE 1: 2022 – 2023 ROADMAP

MILESTONE 1: Establishing Natural Gas Regulatory Framework

- **Step 1**: Conduct preparatory work and secure international development funding for establishing an MNR Natural Gas Directorate
- **Step 2**: Engage with financing institutions and other relevant stakeholders for the establishment of regulatory channels and mechanism/framework
- **Step 3**: Assess natural gas demand by engaging with the Ministry of Electricity, industrial customers and other relevant potential distributors and users
- **Step 4**: Conduct preparatory gas network design studies to assess transport, distribution, and export options, constraints and requirements
- **Step 5:** Select an appropriate, empowered and experienced Director for the Directorate, to report directly to the Minister of Natural Resources
- **Step 6**: Establish IKR oil and gas industry coordination group

MILESTONE 2: Establishing the MNR Natural Gas Directorate

- **Step 1**: Officially establish the MNR Natural Gas Directorate
- **Step 2**: Appoint the Gas Directorate Director
- **Step 3**: Initiate hiring suitable candidates to lead the technical, financial, commercial, and regulatory departments of the Directorate, assisted by national and suitable international experts
- **Step 4**: Training and capacity development workshops in the natural gas sector for less-experienced / junior staff
- **Step 5**: Roll-out the conclusions of initial demand assessment and gas network studies
- **Step 6**: Lead dialogue with and communicate the planned path of gas market reform and pricing to stakeholders

MILESTONE 3: Development of Associated Gas Capture Systems

- **Step 1**: Work with the involved oil companies to develop the engineering and commercial basis for associated gas capture systems from northern associated gas fields
- **Step 2**: Continue work to expand and/or develop priority non-associated fields, most of which have a timeline starting in 2022/23
- **Step 3**: Work with the involved oil companies to develop associated gas capture systems from southern associated gas fields, depending on demand assessment from power, industrial and distribution customers in the area

MILESTONE 4: Establishing Connecting Infrastructure

- **Step 1**: Connect the pipeline to Erbil on to the Duhok power plant
- **Step 2**: Rework the existing natural gas condensate Khor Mor-Jambur-Kirkuk pipeline to a natural gas pipeline to carry gas towards Kirkuk
- **Step 3**: Connect associated gas capture systems in the north to the Erbil-Duhok pipeline
- **Step 4**: Connect the associated gas capture systems in the south to the Khor Mor pipeline and potential distribution around Sulaymaniyah

STAGE 2: 2023-2024 – ONWARDS

MILESTONE 1: Establishing a Commercial Unit at the Directorate

- **Step 1**: Alongside other relevant stakeholders, the Director of the MNR Natural Gas Directorate could establish a dedicated Commercial Unit to assist in political reform
- **Step 2**: Establish infrastructure and gas buyer consortium(s)
- **Step 3**: Lead engagements with potential external (Federal Iraq, Turkey) customers
- **Step 4**: Enable financing agreements/arrangements, as well as GSAs with potential external offtakers before taking FID on building pipeline connections

MILESTONE 2: Commissioning Supporting Studies

- **Step 1**: The Directorate can commission a detailed grid design study to implement a gas-to-power option and provide requisite infrastructure to all power projects, as well as connections to potential external markets
- **Step 2**: Commission a sulfur handling study for storing, using and/or transporting excess sulfur from sour gas field developments
- **Step 3**: In parallel with Step 2, coordinate with other ministries and all relevant stakeholders to assess suitability of transporting sulfur
- **Step 4**: Establish commercial viability and practical feasibility of gas-to-power and sulfur transport options

MILESTONE 3: Political Advancements and Reform

- **Step 1**: Work with the KRG Cabinet and Ministry of Electricity to phase-out electricity/power subsidies
- **Step 2**: In parallel with Step 1, advance political dialogue with Baghdad that can assist in reform of the Federal Iraq power sector
- **Step 3**: Achieve political agreement with Baghdad to reach common interests, including, but not limited to, budget, revenue-sharing, security concerns, and crude oil exports

Executive Summary

Findings-in-Brief

Strengthening the natural gas sector in the Iraq Kurdistan Region (IKR) would facilitate:

- Cutting CO_2 emissions by more than 10 million metric tonnes per year (Mt/y) by reducing flaring, reducing fugitive methane emissions from infrastructure, and displacing oil-based power generation.
- Bolstering the regional economy by US$ 1.2 billion of direct revenues annually, while also improving industrial development, energy services, employment and standard of living for all Iraqi citizens.
- Enabling Iraqi energy independence, which would help deter negative influence from other actors in the region.
- Aligning the KRG and federal government, thereby improving Iraqi national governance.
- Balancing gas demand efficiently between summer and winter between Turkey, IKR and Federal Iraq.
- Building further positive regional economic relations between Iraq/IKR and Turkey.

At the foundation of a robust natural gas sector in IKR is a sufficient **market** and a **fair price structure**; this could be enabled by access to **financing to build infrastructure** and the establishment of a **Gas Directorate** within the Ministry of Natural Resources (MNR) that articulates and implements clear policy objectives aligned with pricing and markets.

Markets

- IKR fields have more than enough current reserves to meet projected demand from the power and industrial sectors through 2040; however current gas production must increase by ~6 BCM/y to meet current demand; absent adequate gas supply the KRG must either burn expensive and dirtier diesel or fuel oil or shed load, which becomes a political issue that can drive discontent and impede economic growth and development.
- Most of IKR's future growth in gas production is dependent on access to external markets and international finance; development can add ~23 BCM of external sales potential per year by 2035, with first marketable surplus appearing in 2024/25.
- Gas-to-power sales provides a supplemental market opportunity within IKR and externally; IKR has surplus electricity generation capacity but currently insufficient fuel supply leading to widespread use of fuel oil distributed generators; existing transmission lines connect IKR with Federal Iraq for possible future markets.
- Markets for IKR gas should be addressed in priority order, serving IKR first and drastically reducing flaring and fugitive methane emissions (onsite power generation, local power plants, industry, and reinjection for improved oil recovery) and then outwardly expanding to Federal Iraq and Turkey; sales to Federal Iraq potentially offer a bigger price margin than to Turkey but present political challenges.

Market structure

- A fair price structure incentivizes gas companies to invest in upstream and midstream assets *and* provides KRG with economic reimbursement for extraction of their resources.
- The cost to produce and gather natural gas varies widely depending on the field, with key factors including production levels, access to markets and the amount of H_2S in the gas.
    - If the pricing structure does not adequately address the actual production costs of their operations, those companies will not invest in gas capture and production or they may handle H_2S/sulfur in an environmentally detrimental way, let alone make the large additional investments required to reduce methane leakage and capture and use or store other greenhouse gasses.
    - Market-linked pricing is recommended, but existing production sharing contracts may need to be consensually amended to ensure that associated or other higher-cost gas development, capture , processing and utilization remains economically viable at the anticipated gas prices.
- A phased progression to market-based gas price is proposed in this study, beginning with a local IKR sales price aligned monthly to a regional benchmark, potentially the Turkish index or LNG price minus transport cost; ultimately a local gas exchange would be created where producers and consumers can buy and sell gas.
- Reform of the electricity sector and tariffs in both the IKR and Federal Iraq is recommended to allow the electricity sector to be a reliable commercial off-taker of gas.
- The KRG's issues with budget and bankability have to be addressed to ensure investors in gas are assured of being paid promptly and in full.

Financing and Infrastructure

- Financing gas developments in the IKR is difficult because of limited experience, limited creditworthiness of some prospective customers, and few financiers. International financial institutions, and export credit agencies may be options for the suggested phased approach that minimizes complexity and upfront expenditure to build market confidence and experience. International government and private sector finance institutions are beginning to demand greater attention to climate change mitigation measures and a focus on flared gas capture and other carbon emissions abatement measures when choosing new investments.
- Large infrastructure investments required to maximize the value of IKR gas resources include associated gas gathering in the northern area around Shaikan/Sarsang and southern area around Garmian, gas processing plants at major fields, sulfur storage or handling solutions for sour fields especially Bina Bawi and Miran, completion of the full south-north pipeline to Duhok and the Turkish border, and southern pipeline and reversible flow Chemchemal-Khor Mor (in case of major supplies to Federal Iraq).

Gas Directorate

- KRG is advised to set up a Gas Directorate within MNR, responsible for policy, strategy, regulation, enforcement, supply security and external affairs. The directorate would also develop internal expertise and negotiate sales agreements with export markets. The directorate can be led by an empowered and experienced Director, reporting directly to the Minister of Natural Resources, supported by a capable national and international team.
- MNR would benefit from establishing and leading a proposed Kurdistan Gas Consortium — a gas infrastructure SPV comprising MNR/KRG authorities, local IKR private sector, gas companies active in the IKR and/or new entrants, infrastructure investors, potentially including Turkish and/or Gulf Cooperation Council (GCC) entities.
- The consortium can include one or more large international private gas and infrastructure companies. Discussions with potential interested parties can begin in the near term.

Iraq Kurdistan Region Natural Gas Sector

The Iraq Kurdistan Region is endowed with a natural gas resource base, including both associated gas and non-associated gas resources, sufficient to produce approximately 40 billion cubic meters (BCM) per year of marketable (sales) natural gas by the mid-2030s.

Realizing maximum development of all potential resources will require designing policy and market structures that optimize all resources, all market opportunities, and implementation of maximum environmental protection measures. It is important to note at the outset of this study that getting the conditions exactly right will be exceedingly difficult and achieving this level of production growth is very challenging.

Current marketed natural gas production in the IKR (about 5.3 BCM/y) is limited to one non-associated gas field and one associated field. The former is Khor Mor, situated in the south of the Sulaymaniyah province of the IKR, and the latter is Khurmala, situated 35 kilometers southwest of Erbil, the capital of the IKR. Several other fields with large resources remain undeveloped because of technical and geological challenges (fractured carbonate reservoirs with hard-to-predict performance, need for expensive sour gas processing, and mountainous terrain), commercial and economic challenges, and unclear or contradictory corporate and government objectives.

Current local demand from the IKR's power and industry sectors is estimated at 11 BCM/y, of which half, or 5.3 BCM, is currently met by local production; the rest is unmet or met with liquid fuels. Demand is estimated to reach 15 BCM by 2030 and 21 BCM by 2040, with the largest contribution from the power sector (60% in 2030 and 52% in 2040). Industry also shows growing demand for natural gas—but at a slower rate, due to continued constraints posed by provision of subsidized fuel oil for cement, refining, and other industry uses. Fuel oil is also a significant source of pollutants, and supply is not always reliable. Gas production is constrained by the size of and access to the local market and external markets (Turkey and Federal Iraq), not by the resource base, with the caveat of the technical and cost challenges to field development mentioned above.

Current power generation capacity, characterized almost entirely by gas turbines, is sufficient to meet power demand in principle, but lacks natural gas fuel and suffers from high diesel costs ($460/tonne equating to $11/MMBtu). Some of the current power deficit is met by small diesel generators, but the rest must be shed (lost load), resulting in pervasive outages. There is potential for some electricity demand to be met by new hydropower and solar photovoltaic (PV) sources; a private 100 MW solar PV project is currently in early-stage development, and an independent power producer (IPP) project to develop 75 MW solar PV was recently tendered by the Kurdistan Regional Government (KRG) Ministry of Electricity.

Concerted development of natural gas resources would successfully close the gap between power demand and supply, but progress in recent years has slowed because of political and security problems, commercial disputes, challenges in prospective external sales markets (such as the Turkish market), the global collapse in oil and natural gas prices, and a protracted government financial deficit in the IKR. First steps towards remedying many of these challenges have resulted in positive momentum for resuming gas development in the early 2020s. For example, world energy prices have recovered significantly since March 2020, and government-to-government discussions with Federal Iraq have shown potential for sales of natural gas from the IKR. Large operators in the south of the IKR territory, such as Pearl Petroleum Corporation Limited (Pearl Petroleum), have weathered logistical disruptions, reduced demand, and lowered sales prices from the coronavirus pandemic. These entities are registering growth in natural gas production from their resources and moving ahead with further development plans to expand output.

This study has assessed a number of scenarios for gas supply and demand in the IKR and its accessible neighboring markets. These assessments find that, as early as 2023, if a pipeline connection is developed quickly, IKR producers can begin transferring small-scale supplies of Kurdish gas to Federal Iraq through existing infrastructure between Khor Mor and Kirkuk. An IKR–Federal Iraq trunkline has been proposed to enable greater supply; assuming the trunkline's construction and a large marketable natural gas surplus, these shipments can begin in 2025. Sales to

Turkey could be realized on a similar timeframe, contingent upon accessible demand within Turkey, the construction of infrastructure, the speed of field development within the IKR, and prioritization between the Federal Iraq and Turkish markets based on price competition, access, and/or policy preference. As these are complicating factors, the base case in this study shows gas sales to Turkey beginning by 2032, assuming a limited Turkish market and limited marketable natural gas surplus after supplies to Federal Iraq. Because of the lower demand in Federal Iraq in winter, a small marketable natural gas surplus is likely to emerge during the winter, starting in the early 2030s, which offers potential for developing a city gas network for residential heating usage between larger Kurdish cities.

A Roadmap for Development

Development of natural gas fields, particularly projects involving cross-border exports or technical complications such as sour gas or deep water, is often a lengthy process. Some fields have waited up to 30 years or more to be developed. However, some fields developed in recent years reached first production remarkably quickly; for example, Egypt's Zohr reached production two years from the date of discovery, even though the field is in deep water. Zohr did not involve exports and was able to use existing infrastructure within Egypt. Galkynysh in Turkmenistan—a giant, deep sour gas field that exports to China—began production within eight years of discovery but benefited from a large customer with access to finance and quickly growing gas demand. Shah Deniz in the Azerbaijan sector of the Caspian Sea exports to Georgia and Turkey, and the field reached first gas output within six years. For comparison, in the IKR, Topkhana, Miran, and Bina Bawi were discovered in 2011 and have not yet been developed.

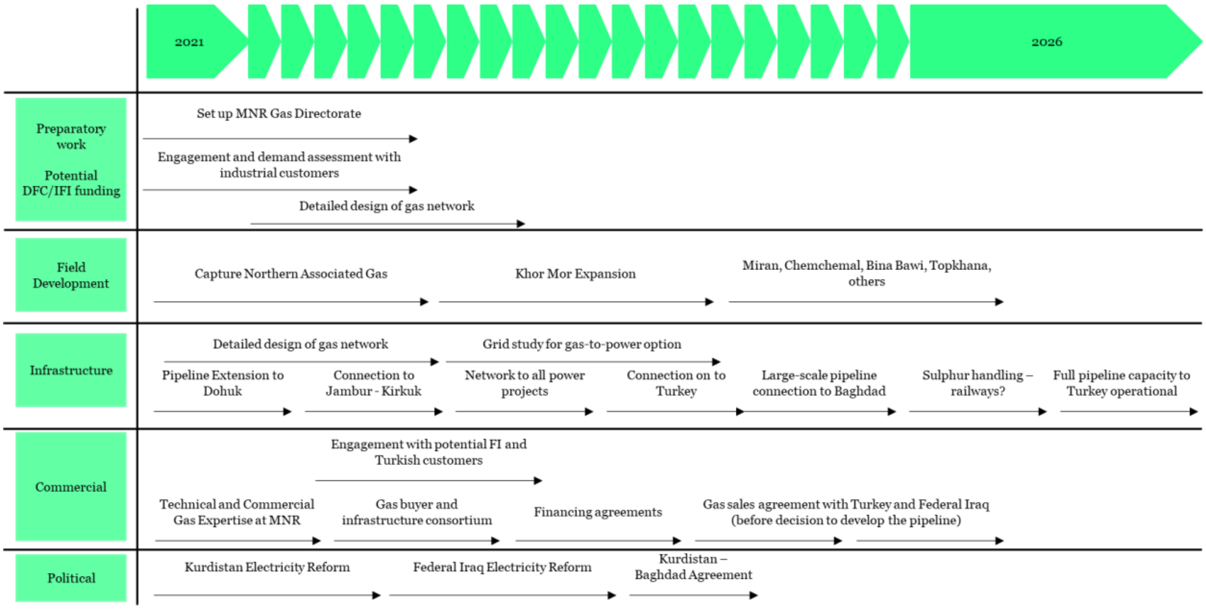


Figure 1 Illustrative chart of phased development of the Kurdish natural gas sector until 2026

Momentum on developing the natural gas sector in Kurdistan has been growing in recent years, owing to fitful progress on talks with Baghdad (for sales) and upstream operators on expanding production. If the IKR can allay lingering concerns with respect to assuring prompt payment from customers, the MNR is well-placed to introduce a phased development approach starting in 2021 with the support of all relevant stakeholders. Figure 66 in the main study summarizes a proposed phased development plan of the Kurdish natural gas sector until 2026, with major milestone developments concentrated between 2021 and late 2023. All of the tracks are essential and must be pursued in parallel to ensure rapid success.

- The first milestone track involves preparatory work and funding for establishing a regulatory institution/ system that is responsible for natural gas in the Ministry of Natural Resources, referred to as the MNR

Gas Directorate. The Directorate shall be responsible for engagement and demand assessment with potential industrial customers, as well as setting rules for the gas network. The Directorate should be led by an empowered and experienced Director, reporting directly to the Minister of Natural Resources, assisted by national and suitable international experts, and with a plan for training and capacity development in the gas sector for less-experienced staff.
- The second milestone track involves parallel efforts: developing associated gas capture from northern fields (the primary focus) and continuing work to expand and/or develop the priority non-associated fields, most of which we have assigned a timeline starting in 2022/2023.
- The third milestone track involves establishing infrastructure – starting with connecting the pipeline to Erbil and on to the Duhok power plant, connecting fields to nearby powerplants, and reworking the Jambur–Kirkuk pipeline to carry natural gas towards Kirkuk as soon as is feasible.
- In the fourth milestone track, from a commercial perspective, the MNR Directorate could establish a dedicated Technical and Commercial Unit, which could also assist in political reform, such as introducing phased-out subsidies, as a first step. The Unit would lead engagement with potential FI and Turkish customers, which could establish a gas buyer and infrastructure consortium. The consortium would enable financing agreements/arrangements, as well as GSAs with both FI and Turkey before a decision on building the pipeline connection(s) is finalized.

Assuming that a detailed planning study covering domestic supply and potential electricity interconnections has not been completed, now would also be the right time to commission a grid design study to evaluate the technical challenges and commercial opportunities for a power sales option. Surplus power would be generated by gas potentially supplemented with renewable energy. This study could also evaluate the technical and financing requirements to complete connections to Turkey and Baghdad. This sort of study can take a year or two if done correctly - but is a worthwhile investment to ensure that the MNR and Ministry of Electricity are considering all possible contingencies including maximizing planning for capturing and utilizing emissions and future uses of gas infrastructure to avoid stranded assets. International finance intuitions and donor countries often have funding that could be tapped for this sort of planning study.

Possibly later in the phased development approach, a railway network for transporting excess sulfur from sour gas field development could be considered; such a project would require complex coordination with other ministries and stakeholders. To be commercially viable, this railway would need to transport other cargo as well. This could include trade in industrial products such as cement or fertilizer, which could provide an additional source of gas demand. In the meantime, costs for trucking and/or disposal of sulfur would need to be included in planning for flared gas capture projects.

Assuming that the KRG places a priority on ensuring maximum flared gas and fugitive methane capture and utilization in the short-term, post-2022, development may concentrate around implementing additional infrastructure for further upstream non-associated gas development (some of which is already in process), with Khor Mor commissioning a new 2.5 BCM/y processing train in Q1 2023, which should increase overall production from the Khor Mor field to 7 BCM/y (assuming Phase 2 start-up). A second 2.5 BCM/y train will increase production to capacity, 9.5 BCM/y, by 2025. Development of other non-associated giant gas fields, including Chemchemal, Miran, Bina Bawi, and Topkhana, could also take place starting in 2024 or sooner. The planning for core infrastructure to serve all of these projects needs to start as soon as possible if it is to be ready for future field development.

External Markets for Kurdish Natural Gas

Assuming market conditions prior to September 2021, sales of Kurdish natural gas production in excess of local requirements to external markets, mainly Federal Iraq and Turkey, could result in gross external revenues to the KRG by 2032 of approximately US$ 4 billion annually, and net revenues (after costs and financing) of US$ 1.2 billion annually.

Federal Iraq

Natural gas demand in Federal Iraq is estimated to reach 60 BCM/y by 2030, mostly for power production, though with a growing share of industrial use. Development of natural gas capture projects and non-associated gas fields could help narrow the gap between natural gas demand and supply in Federal Iraq by the mid-2030s, but supplies of natural gas from other producers will continue to be required until at least 2040. IKR gas supplies can be the major contributor and can almost entirely replace Iranian imports, except during the summer months, when peak demand will necessitate a small volume of Iranian natural gas.

Iranian natural gas contract pricing to Federal Iraq is oil-linked and relatively expensive, while IKR supplies could be significantly cheaper. The lower pricing can offer some financial relief to the Federal Iraq Ministry of Electricity, which is currently not commercially self-supporting because of high transmission and distribution losses, non-payment of utility bills, and low tariffs.

Federal Iraq offers a market of 15-17 BCM/y in the 2030s, although small supplies via existing infrastructure (the Khor Mor-to-Jambur-to-Kirkuk condensate repurposed to a natural gas pipeline) could commence between 2023 and 2025, depending on the emergence of a surplus in Kurdish marketable gas. Larger supplies through a major pipeline to Kirkuk, or via the Diyala province towards Baghdad, could also begin in 2025. Kurdish natural gas could be highly cost-competitive in Federal Iraq, compared to the current alternatives: oil feedstock and expensive, unreliable Iranian contract gas. Politics and commercial matters permitting, Federal Iraq is here considered as the priority external market for IKR gas, given the lesser competition and higher prices than could be realized in the Turkish market (depending on the negotiating positions and strategies of the concerned parties).

Gas-to-power from the IKR to Federal Iraq is an additional supply option—one that does not preclude provision of natural gas supplies as well. The Kurdish electricity grid already supplies limited amounts of power to Kirkuk and could use the Kurdish generation capacity surplus to supply the Federal Iraq market via any or all of three new/expanded connections: to Mosul (the grid is currently connected to Mosul only by a 150 kV double circuit), to Kirkuk (the link to the current 400 kV single circuit could be expanded), and to Baghdad. In June 2021, the federal government approved an agreement from August 2020 to source 450 MW (with the potential to add a further 100-150 MW) of power from the Khurmala plant, with payment made in crude oil delivered to the Kalak refinery near Erbil. Another transmission line, from Khabat to Qaraqosh, will be introduced to connect Erbil to Mosul[1].

Turkey

Turkey is a large and well-supplied natural gas market of 46.9 BCM/y in 2020. It has very little domestic production, although this could change with the development of two recent Black Sea natural gas discoveries in the same block, Sakarya and North Sakarya (or Amasra). The country is currently supplied by pipeline imports from Russia, Azerbaijan, and Iran, and liquefied natural gas (LNG) imports from a variety of suppliers, including the United States, Qatar, Algeria, and Nigeria. There are potentially feasible near-term opportunities for new supplies to the Turkish gas market, as several Turkish natural gas import contracts are set to expire in the near future: 16 BCM in 2021, 20.4 BCM in the mid-2020s, and 9.6 BCM (from Iran) in 2026. Turkey's import routes were further diversified in the last few years by the Trans-Anatolian Natural Gas Pipeline (TANAP) from Azerbaijan via Georgia, which began operations in June 2018, and the TurkStream Pipeline from Russia under the Black Sea, which began deliveries in January 2020, as well as LNG import terminals.

Turkey has a well-developed and diversified power generation mix characterized by new additions such as coal/lignite, hydropower, solar, wind, and potentially nuclear[2], significantly reducing natural gas demand.

[1] Middle East Economic Survey, July 2nd 2021

[2] The four 1200 MW reactors of the Akkuyu nuclear plant are scheduled to come into service progressively between 2023-26.

Natural gas demand is set to decrease gradually to 37 BCM/y by 2030, before increasing again, assuming the Turkish government introduces a gradual phase-out of coal and new gas uses in alternative energy and industry (i.e., hydrogen). Peak demand for natural gas in Turkey is in the winter when it is used primarily for residential heating.

We estimate the available segment of Turkey's natural gas market for IKR gas at around 5–11 BCM. The relatively small available market segment is due to changes in both supply and demand: there are new sources of natural gas supply, and demand is lower than previously expected because of soft economic indicators and an increasingly diversified power generation mix. Nonetheless, IKR marketable natural gas could be highly cost-competitive in eastern Turkey (compared to Iranian sources) and cost-competitive in western Turkey (compared to Azerbaijani sources and to LNG, although IKR natural gas would probably not be cost-competitive with Russian natural gas).

Kurdish natural gas developments would have to be accelerated significantly to reach the 2026 Turkish market window, when several major contracts expire. Potential Kurdish natural gas exports to Turkey are highly dependent on existing and new competitors (such as large domestic gas from Sakarya and North Sakarya (Amasra)) in the Turkish natural gas market, and on future Turkish natural gas policy and strategic behavior.

Proposed Market Structure

The IKR requires a natural gas pricing scheme that is market-based and market-responsive, incentivizes upstream and midstream investment, and maximizes the retained value of the region's natural resources for the MNR and KRG. Proposed natural gas pricing could be a three-step process as the market and interconnections develop:

1. Sales within IKR: Netback from Turkish prices (LNG or index) to the IKR border, subtracting deemed transport costs
2. During external sales to Federal Iraq and/or Turkey: Netback from Federal Iraq and Turkey to the IKR border, subtracting deemed transport costs
3. Mature market: Move towards gas-on-gas, hub-based natural gas pricing

Supplies to Federal Iraq and/or Turkey will have to be competitive with both existing alternatives and potential new ones (such as large domestic production in Turkey from Sakarya and North Sakarya (Amasra)). To capture market share in Federal Iraq and Turkey, IKR natural gas is assumed to be sold in those territories at a moderate discount compared to existing suppliers. This depends on the relative strength of the IKR's negotiating position, and in the case of FI, to possible trade-offs against other issues such as the federal budget allocation.

With the development of accessible gas infrastructure and market, MNR would be more able to enforce existing rules preventing routine gas flaring and so reduce waste and pollution. Although routine flaring is generally discouraged, operators have historically been allowed to flare associated gas because of the lack of economically viable offtake solutions. Stricter enforcement of zero flaring rules prior to necessary reforms would be environmentally desirable but, on its own, would constrain oil production expansion and/or reduce current output because there would not be adequate economic incentive to build the necessary infrastructure to capture, process and utilize the gas produced with each barrel of oil

The joint development of processing and pipelines as part of associated gas development clusters should reduce the overall and unit costs of gas gathering and treatment. It is not recommended to differentiate pricing by associated and non-associated gas as this would result in administered pricing which is not reflective of market realities. Prices resulting from the above scheme should be high enough to incentivize operators to capture and sell their gas; prices would, in any case, cover at least part of the costs. Production shares, cost recovery, ring-fencing and other terms in the production sharing contracts can be adjusted by consensual negotiation to ensure acceptable economic returns for the investor at a given gas price, while maintaining a consistent price level and avoiding multi-tier or variable bilateral pricing. Achieving a commercially and environmentally viable solution for capturing and utilizing associated gas and fugitive methane emissions could also unlock additional social, political, and economic benefits.

For existing oil companies to invest in the capture, treatment and sale of their associated gas, they will need to be assured of prompt payment in full for the resulting gas supplies to cover the costs and return on investment of expensive new gas infrastructure. The proposed infrastructure consortium, by including both state and private investors, would create mutual incentives for investment and payment.

Proposed Natural Gas Infrastructure

Kurdish energy resources, both associated gas gathering and processing and major non-associated gas fields, can be efficiently and effectively developed in parallel. Suitable infrastructure should be developed across the IKR to serve the local market while also serving as the backbone for external sales. Proposed natural gas infrastructure includes:

- An associated natural gas gathering and processing node in northern IKR, around Shaikan
- An associated natural gas gathering and processing node in southern IKR, around Garmian
- Gas processing plants at major non-associated and associated gas fields
- Sulfur storage and/or handling solutions for sour gas fields, especially large non-associated gas fields such as Bina Bawi and Miran
- Expansion and extension of the existing south IKR to north IKR natural gas pipeline, to move natural gas from southern producing fields (such as Khor Mor) to Erbil and Duhok
- A southern pipeline, with reversible flow from Chemchemal to Khor Mor, and links to pipelines in Federal Iraq to supply Federal Iraq

The proposed natural gas infrastructure assumes a phased approach to minimize complexities and upfront financing requirements, while allowing time for building market confidence and domestic management experience. Phased development provides the flexibility to supply the local market while preparing for external sales, tying in new field developments when ready. This approach allows for switching supplies between Federal Iraq and Turkey based on seasonal demand. The list of developments is not prescriptive; fields may advance or fall back in priority or even not be developed at all if other fields make more rapid commercial progress or achieve lower production costs.

We assess that the priority domestic usage of Kurdish natural gas, i.e. the uses with the most immediate and highest economic and social value, would be in oil field facilities and for local power generation. Non-associated gas, once developed, can be directed first to power plants currently lacking in natural gas supply (Duhok, Baadre, Khabat, and other new plants); then to major industry (such as cement and refineries); then to gas reinjection for improved oil recovery; and then to cities (Sulaymaniyah, Erbil, Duhok, Zakho, Kalar, and other cities), depending on the market and economic viability.

Proposed Financing Structures

The proposed approach to securing financing entails developing a Kurdistan Gas Consortium, a gas infrastructure special purpose vehicle (SPV) comprising:

- The MNR and KRG authorities
- The local IKR private sector
- International oil companies (active in the IKR and/or new entrants)
- Infrastructure investors, potentially including Turkish and/or the Gulf Cooperation Council (GCC)

As most of the international companies active in the oil and gas sector in the IKR are small/mid-cap firms which are already heavily committed, it would be preferable if the consortium contained a strong and experienced large gas-sector player. This could be a leading international oil and gas company, or a midstream gas and infrastructure corporation. Discussions should be initiated with potential interested parties to gauge their requirements and opinions on how such a consortium should be structured.

The consortium could then secure financing from a variety of financing institutions, and/or export credit agencies assuming the overall enterprise, financing and ownership structure is in compliance with current policies. These potentially include the U.S. Development Finance Corporation, U.S. Ex-Im Bank, the UAE's Etihad Credit Insurance—which supported General Electric's (GE's) rehabilitation of power generation in Federal Iraq—and others. While complicated to assemble, a broad consortium would cover all the key requirements for a comprehensive gas infrastructure and market development, maximize stakeholder buy-in, and minimize risk to participants.

The consortium's mandate will include all finances, contracts for construction, and operatorship of the main natural gas processing and transmission network within the IKR and external links to Turkey and/or Federal Iraq. Ownership stakes could vary between different major segments of the system. Investors in the consortium would have capacity rights based on their ownership stake for transport of their entitlement gas (their share under a PSC) or purchased/sales gas and could book additional capacity if required. Others (non-equity owners) would be able to use the system by booking capacity and paying a transparent, non-discriminatory tariff.

Institutional Development

We recommend the MNR consider setting up a Gas Directorate, responsible for:

- The MNR's role in the Kurdish Gas Consortium
- Coordinating gas sales agreements (GSAs) with Turkey and/or Federal Iraq
- Directing policy, strategy, regulation, enforcement, supply security, and external affairs
- Developing internal capabilities with the assistance of partners

Urgent need for Energy Sector Reforms

The electricity ministries in both the IKR and Federal Iraq are not currently commercially self-sustaining, making it impossible for them to contract natural gas supplies without a government budgetary allocation and/or guarantee. This study recommends power sector reform in both the IKR and Federal Iraq using phased programs to cut non-payment issues, reduce transmission and distribution losses, and raise tariffs towards at least cost-recovery levels, including the minimum required return on capital. Other positive impacts of such programs include boosting energy efficiency and environmental performance, improving social equity by reducing the implied subsidy to high consumers, incentivizing the expansion of renewable generation, improving service levels and reliability, and reducing the burden on the government budget.

1 The Natural Gas Sector in the Iraq Kurdistan Region

1.1 Natural Gas Fields

The Iraq Kurdistan Region (IKR) contains oil and natural gas exploration and development blocks spread over the provinces of Duhok, Erbil, and Sulaymaniyah. In the north of the IKR are Shaikan, Atrush, Sarta, Sarsang and Ain Sifni, containing oil fields with associated gas, and Khurmala, another notable oil field also containing associated gas, as well as the more recent Baeshiqa discovery with associated gas. In the south are several notable non-associated gas fields: Bina Bawi, Taq Taq, Chemchemal, Miran, Topkhana, Kurdamir, and Khor Mor. Only Khurmala and Khor Mor (current capacity 4.3 BCM/y) are currently producing marketed gas; gas from the Peshkabir field in the Duhok province is reinjected in the nearby Tawke field for improved oil recovery. Otherwise, associated gas not used in oil field operations is flared.

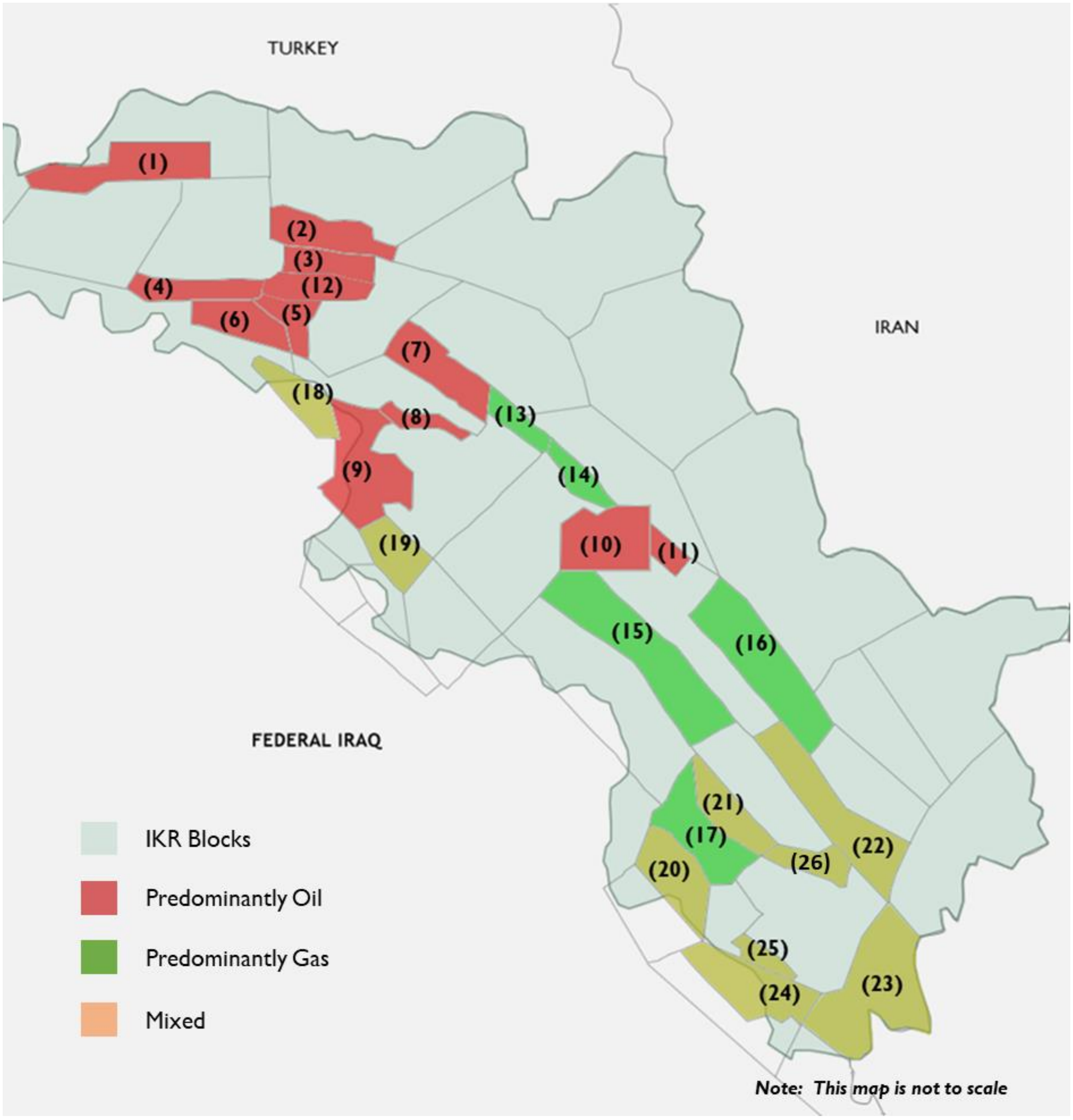


Figure 1 Oil and gas exploration and development blocks in the IKR[3]

Major Predominantly Oil Blocks		Major Predominantly Gas Blocks		Major Mixed (O&G) Blocks	
(1)	Tawke	(13)	Pirmam	(18)	Baeshiqa
(2)	Sarsang	(14)	Bina Bawi	(19)	Khurmala
(3)	Atrush	(15)	Chemchemal	(20)	Taza
(4)	Al Qosh	(16)	Miran	(21)	Topkhana
(5)	Ain Sifni	(17)	Khor Mor	(22)	Qara Dagh
(6)	Jabal Kand			(23)	Chia Surkh
(7)	Sarta			(24)	Shakal
(8)	Erbil			(25)	Garmian
(9)	Hawler			(26)	Kurdamir
(10)	Taq Taq				
(11)	Khalakan				
(12)	Shaikan				

Table 1 Only one non-associated IKR gas field is currently producing, with gas capture from one associated gas field and reinjection from one other field (* = operator)

Field	Type of Gas	Partners	Stake	Status	Current Reserves (TCF)	Current Output (BCM/y)
Khor Mor	Non-Associated	Pearl Petroleum*	100%	Producing	9.4	4.33
Chemchemal	Non-Associated	Pearl Petroleum*	100%	Development	6.6	Not producing
Bina Bawi	Non-Associated	Genel Energy*	100%	Development	4.9	Not producing
Miran	Non-Associated	Genel Energy*	100%	Development	3.5	Not producing
Topkhana	Non-Associated	Repsol (in process of completing sale)	80%/20%	Development	1.6	Not producing
Shaikan	Associated	Gulf Keystone Petroleum*, MOL	80%/20%	Producing	<0.3	Associated gas is flared
Khurmala	Associated	KAR Group*	100%	Producing	3.6	0.92
Kurdamir	Associated	Western Zagros*, KRG	80%/20%	Development	2.3	Not producing
Pirmam	Non-Associated	ExxonMobil*, TEC	80%/20%	Exploration	0.88	Not producing
Peshkabir	Associated	DNO, Genel	75%/25%	Producing		Reinjected in Tawke field for

3 Source: Based on information provided by the KRG Ministry of Natural Resources

Field	Type of Gas	Partners	Stake	Status	Current Reserves (TCF)	Current Output (BCM/y)
						improved oil recovery

Geologically, the IKR lies within the Zagros fold belt, with its oil and gas fields mostly in elongate doubly plunging anticlines, trending northwest–southeast (swinging round to east–west in northernmost IKR), and associated more complicated fault-related traps. Typical natural gas reservoirs vary significantly from north to south IKR (Figure 3 and Figure 4). Northern IKR is characterized by heavy and light oil in the Tertiary, Jurassic, and Cretaceous reservoirs, and typically light oil and sour gas in deeper Jurassic and Triassic. Southern IKR features light oil and typically sweeter gas in the Tertiary (Oligo-Miocene) and Cretaceous reservoirs. Almost all non-associated natural gas in the IKR is in the south, in Sulaymaniyah. The reservoirs are fractured carbonates with variable matrix porosity and permeability, creating challenges for drilling, production, and reserves estimation. The gas is often condensate-rich and variably sour (containing toxic, corrosive hydrogen sulfide [H_2S]). Some of the fields also contain oil, either in the shallower reservoirs or as an oil leg under gas caps.

The southernmost field is the Khor Mor gas field, operated by Pearl Petroleum. Khor Mor spans an area of 98 square kilometers (km^2) and currently produces 4.3 BCM/y of natural gas. Remaining reserves at the field, as of 2020, are 9.4 trillion cubic feet (TCF). North of Khor Mor lies the Pearl Petroleum-owned Chemchemal gas field, with estimated reserves of 6.6 TCF and production potential of 6.2 BCM/y by 2040 (Phase 1 and Phase 2 combined).

Northeast of Khor Mor, in the Zagros fold belt, lies the Topkhana gas-condensate field, originally operated by Repsol. It has recoverable resources of 1.6 TCF and is currently not producing; Repsol is in the process of selling its stake in the field (80%) and exiting the IKR. The Topkhana field is geologically linked to the Kurdamir field; Repsol sold its 40% stake in Kurdamir to partner Western Zagros in 2020.[4]

To the northwest of Khor Mor and Topkhana lies the Genel Energy-owned, non-producing non-associated gas field of Miran. Miran spans an area of 761 km^2 and has estimated recoverable resources of 3.5 TCF. West of Chemchemal and northwest of Miran lies Bina Bawi, another Genel Energy-owned, non-producing non-associated gas field. Bina Bawi has an area of 240 km^2 and estimated recoverable resources of 4.9 TCF. Immediately northwest of Bina Bawi is Pirmam, currently operated by ExxonMobil, with a reported 0.88 TCF of gas resources. Miran, Bina Bawi, and Pirmam all contain significantly sour gas.

Some significant associated gas lies in the north of the IKR. The Khurmala oilfield, which is 100% operated by the Kurdish KAR Group, has 3.6 TCF of associated gas resources and is currently producing 0.9 BCM/year of natural gas. The Shaikan oil field, operated by Gulf Keystone Petroleum, has <0.3 TCF of associated gas, which is produced from heavy oil production. The field is expected to be a contributor to the proposed northern associated gas gathering system, which will feed field and processing use and meet domestic requirements in the area, with any surplus directed to the planned Duhok–Zakho–Turkey pipeline for potential export to Turkey.

[4] https://www.mees.com/2020/2/28/corporate/krg-repsol-exits-kurdamir/59941e20-5a2f-11ea-a35c-2b49d057161a

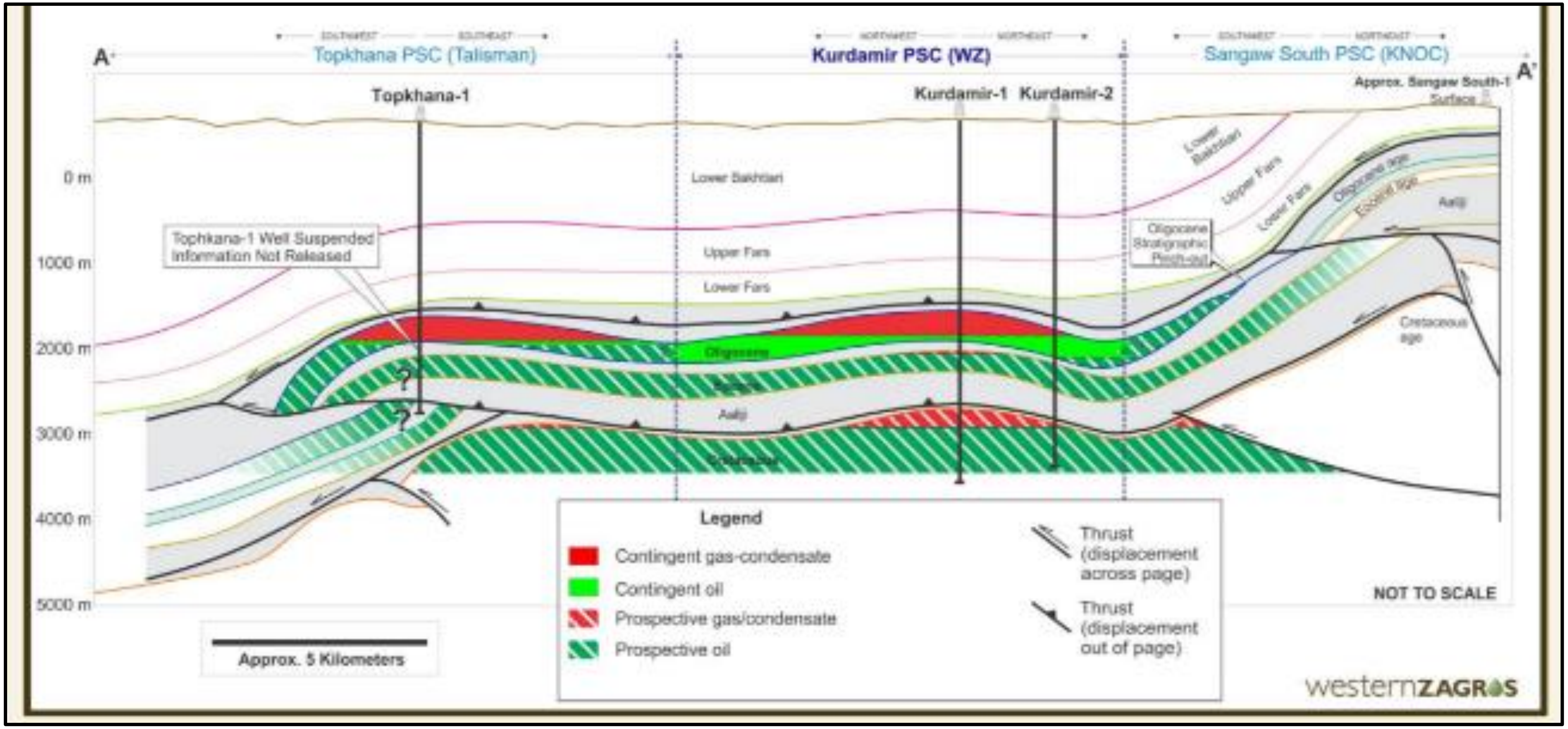


Figure 2 Example of KRG field geology - Kurdamir-Topkhana (south IKR)

Oil with gas caps in the Oligocene and Cretaceous

1.2 Natural Gas and Electric Power Generation Infrastructure

1.2.1 Natural Gas Infrastructure

Existing natural gas infrastructure in the IKR is limited to one natural gas processing plant at Khor Mor, gas gathering and processing for associated gas at Khurmala, gas capture at Peshkabir for reinjection at Tawke, and two existing natural gas pipelines. A handful of gas power projects exist, with more than sufficient capacity to meet IKR's power demand, in principle, but they are currently operating below capacity because of lack of natural gas and lack of funding for pricier, dirtier, and less efficient liquid fuel (crude, fuel oil, and diesel) required to run the plants until gas delivery infrastructure is built. Past proposals to build gas processing plants to capture and treat associated gas in the northern and southern IKR were assigned to Chinese and Indian contractors, but the plants have not been built.

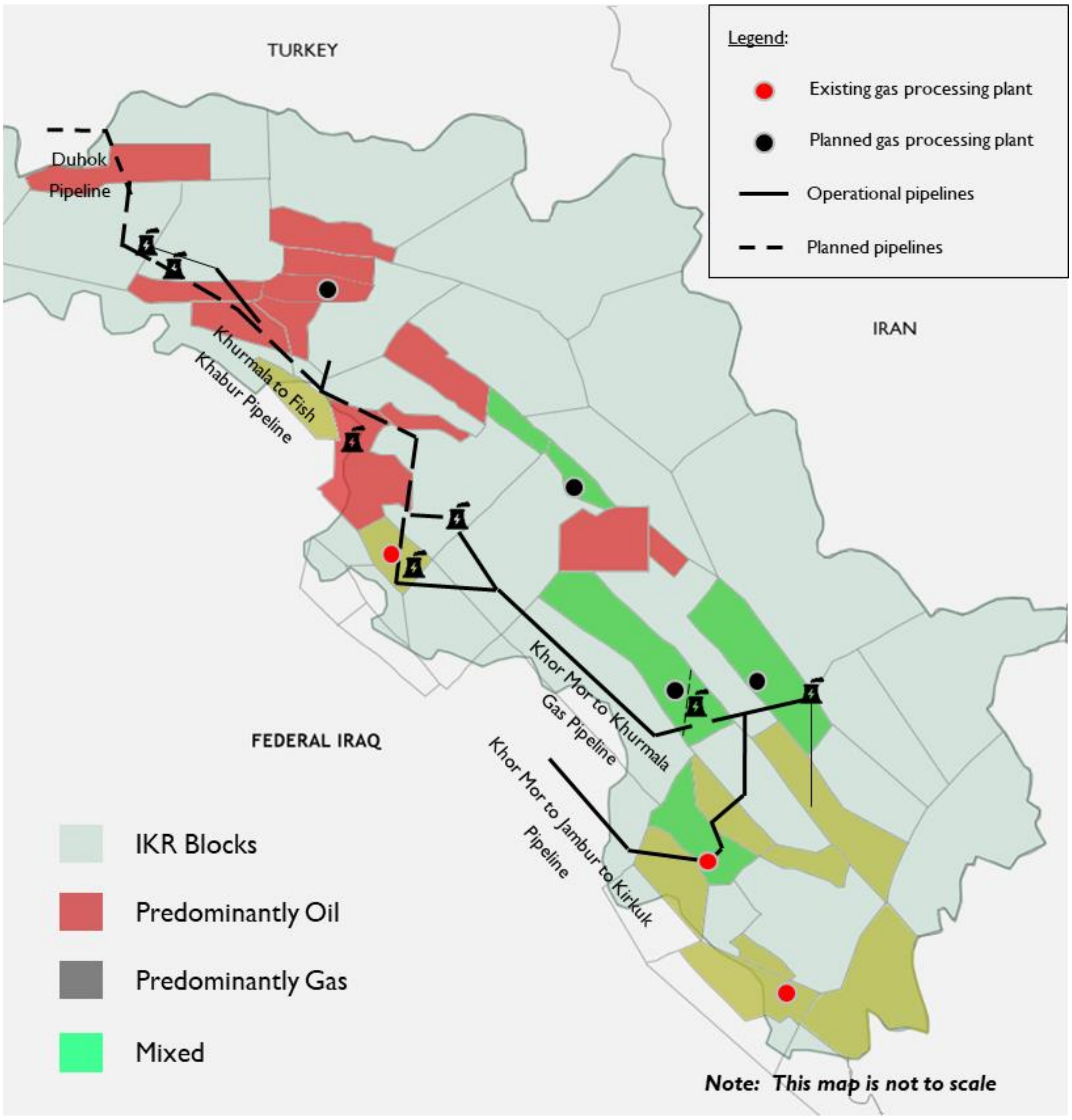


Figure 3 Natural gas processing plants, power plants, and pipelines in the IKR[5]

If development plans for the predominantly non-associated gas fields move forward, five new natural gas processing plants would be built as production commences at their linked fields. These include the Miran Natural Gas Processing Plant, with nameplate capacity of 5.7 BCM/y; the Bina Bawi Natural Gas Processing Plant, with nameplate capacity of 6.2 BCM/y; the Khor Mor Phase-2 Natural Gas Processing Plant, with nameplate capacity of 5 BCM/y; the Chemchemal Natural Gas Processing Plant, with nameplate capacity of 1.5 BCM/y; and the Topkhana Natural Gas Processing Plant, with nameplate capacity of 1.8 BCM/y.

Because first production from these fields (apart from Khor Mor Phase-2) is not yet decided, this study assumes these natural gas processing plants will come online as production commences.

The Khor Mor natural gas processing plant is currently the only operational natural gas processing plant in the IKR, other than the separation and processing units for associated gas at Khurmala. The Khor Mor plant has an original capacity of 3.1 BCM/y, expanded to accommodate additional production from Khor Mor Phase-1, and can now process up to 4.3 BCM/y of natural gas. All gas processed by the Khor Mor plant is used within the IKR for power generation. The plant also produces 15,000barrels per day (b/d) of natural gas condensate and 1,000 Mt/d of liquified petroleum gas (LPG), which are sold to the KRG and local traders, respectively.

A new 2.5 BCM/y processing train is expected to be commissioned by Q1 2023, which should increase overall production from the Khor Mor field to 7 BCM/y (assuming Phase-2 start-up). A second 2.5 BCM/y train should increase production capacity to 9.5 BCM/y by 2025.

Two main natural gas pipelines currently exist in Kurdistan. One of these is the Khor Mor-to-Khurmala pipeline, which carries natural gas from Khor Mor to local power plants at Chemchemal and Sulaymaniyah and on to Khurmala, from whence it supplies Erbil. The other pipeline is a relatively small, 20-inch gas condensate pipeline that runs between Khor Mor and Jambur near Kirkuk; this line previously transported Khor Mor gas condensate. There are ongoing talks with the Federal Iraq government to supply small volumes of Kurdish gas to Federal Iraq by repurposing the Khor Mor-Jambur–Kirkuk pipeline to carry natural gas. The pipeline could have a capacity of about 0.4 BCM/y, even though theoretically it could carry slightly higher volumes[6]. We believe the capacity is probably degraded due to age (~30 years) and corrosion. The IKR has one additional small pipeline, which runs from the Summail gas field to the Duhok power plant, intended to supply up to 1.2 BCM/y. However, this pipeline is not in operation, as the Summail field has ceased production.

1.2.2 Power Generation

Current gas power infrastructure in the IKR is characterized by four combined-cycle gas turbine (CCGT) power plants and three open-cycle or simple-cycle gas turbine power plants.

Table 2 Current main gas/oil power plants in IKR

Plant	Type	Capacity (MW)	Fuel	Required Gas (BCM)	Current Status
Duhok	Combined Cycle	1500	Natural Gas	2.18	Operating marginally on diesel

[5] Oil and gas exploration and development blocks shown on the map in gray outline have recently been updated by the KRG and are provided here for orientation purposes only
[6] Pearl Petroleum assesses its capacity at 0.85 BCM

Baadre	Open Cycle	150	Natural Gas, Oil	0.36	Operating on diesel
Khabat	Open Cycle	150	Natural Gas, Oil	0.36	Operating on diesel/ fuel oil
Garmian	Open Cycle (?)	165	Natural Gas, Oil	0.40	
Erbil	Combined Cycle	1500	Natural Gas	2.18	Operating on natural gas
Khurmala	Combined Cycle	930	Natural Gas	1.35	Operating on natural gas
Chemchemal	Combined Cycle	1500	Natural Gas	2.18	Operating on natural gas
Bazian	Open Cycle	500	Natural Gas, Oil	1.21	Operating on gas from Khor Mor supplemented with some diesel

Kurdistan's gas power generation capacity is estimated to increase to over 10 GW by 2040, with anticipated commissioning of new combined-cycle gas power plants near Erbil, Sulaymaniyah, and Duhok. Currently, there is 531 MW of diesel- and fuel-oil-based, utility-scale capacity that could potentially be replaced with natural-gas-based capacity. New hydroelectric dams have been planned but have made limited progress. The current assumption is that the following hydropower developments will not be commissioned within the study timeline: the Bawanoor run-of-river (32 MW), Mergasor run-of-river (37.6 MW), Bakerman (52.5 MW), Delga (97 MW), Taq Taq (270–400 MW), Mandawa (764 MW), and Bekhme (1500 MW) dams[7]. Obstacles include lack of finance, uncertain water availability, and community opposition. However, if these dams were constructed, they would also substantially reduce the gas demand for power and change the volume and timing of gas or power that would be available for sales outside of the IKR. Solar PV has significant potential, even though its use is very limited currently. However, a 100 MW private solar PV project is currently in early-stage development, and recently a 75 MW solar PV IPP project was tendered by the KRG Ministry of Electricity[8]. Wind power may also have potential in limited areas, though the mountainous terrain may make installation challenging[9].

1.2.3 Economic and Climate Benefit of Natural Gas Use for Power Generation

In the near term, ~1.2 GW of diesel-based distributed capacity in Kurdistan could be replaced with gas generation, potentially from capturing associated northern gas production to fuel smaller local gas turbines as well as large centralized power plants. Diesel-based capacity is currently made up of mostly private generators across both Kurdistan and FI, with an estimated operational cost at market prices of US$ 5 billion annually. In the IKR, 1.2 GW of diesel capacity generated 2.4 TWh of power in 2020, which could be replaced with generation from 0.56 BCM/y of natural gas, resulting in potential annual fuel savings of US$ 300 million in the IKR. Similarly, 7.9 GW of diesel generators in FI, generating 15.8 TWh in 2020, could be replaced with ~3.6 BCM/y of natural gas, saving US$ 1.9 billion (calculated at diesel prices of US$ 460/tonne, which is equivalent to $11/MMBtu, and gas prices of US$ 4/MMBtu). The replacement of diesel with natural gas would save about 1 Mt/year of CO_2-equivalent (CO_2e)

[7] Ahmad-Rashid, Khalid (2017), 'Present and Future for Hydropower Developments in Kurdistan' Energy Procedia 112, p632-639, https://www.savethetigris.org/wp-content/uploads/2020/07/Damming-the-Kurdistan-Region-of-Iraq-1.pdf.
[8] https://shafaq.com/ar/Kurdistan/Kurdistan-Region-launches-a-project-to-produce-75-megawatts-of-solar-energy
[9] https://globalwindatlas.info/

greenhouse gas emissions in the IKR and 6.2 Mt/y in FI[10], with annual carbon social costs valued at US$ 51 million in the IKR and US$ 315 million in FI, using US$ 51/ton CO_2e[11]. This reduction is almost 5% of Iraq's total CO_2 emissions from fossil fuel combustion in 2019[12]. Note that these calculations assume no difference in technical transmission and distribution losses between distributed diesel generation and larger-scale gas-fired generation, which is overly optimistic until the grid is improved.

Table 3 Benefits of replacing diesel distributed generation with natural gas

	IKR	**FI**
Distributed diesel generation (GW)	1.2	7.9
Distributed generation in 2020 (TWh)	2.4	15.8
Gas required to replace distributed generation (BCM/year)	0.56	3.6
Savings from diesel replacement with gas (US$ million/year)	300	1900
CO_2 reduction from diesel replacement with gas (Mt/year)	1	6.2
CO_2 social cost saving (US$ million/year at $51/tonne)	51	315

[10] Emissions factors from https://www.epa.gov/sites/production/files/2021-04/documents/emission-factors_apr2021.pdf
[11] https://blogs.ei.columbia.edu/2021/04/01/social-cost-of-carbon/
[12] CO_2 emissions from BP Statistical Review of World Energy 2020

1.3 Natural Gas Balance

Production of marketable natural gas in the IKR could potentially increase eight times above 2020 production levels by 2040, if the most commercially mature and attractive natural gas resources are developed. These projects could add approximately 23 BCM/y of external sales potential, driven by concerted field development in the Sulaymaniyah and Erbil governorates, between 2025 and 2040. The growth in IKR natural gas production depends on access to suitable external markets and guarantees of sales gas purchase and payment from those markets. However, obtaining such guarantees also depends on making a convincing case that the IKR's natural gas resources and required infrastructure will be developed in a timely and predictable fashion, that volumes will be competitively priced in the relevant end markets, and that supply will be reliable and in line with contractual commitments over the duration of sales contracts, likely up to 20–25 years.

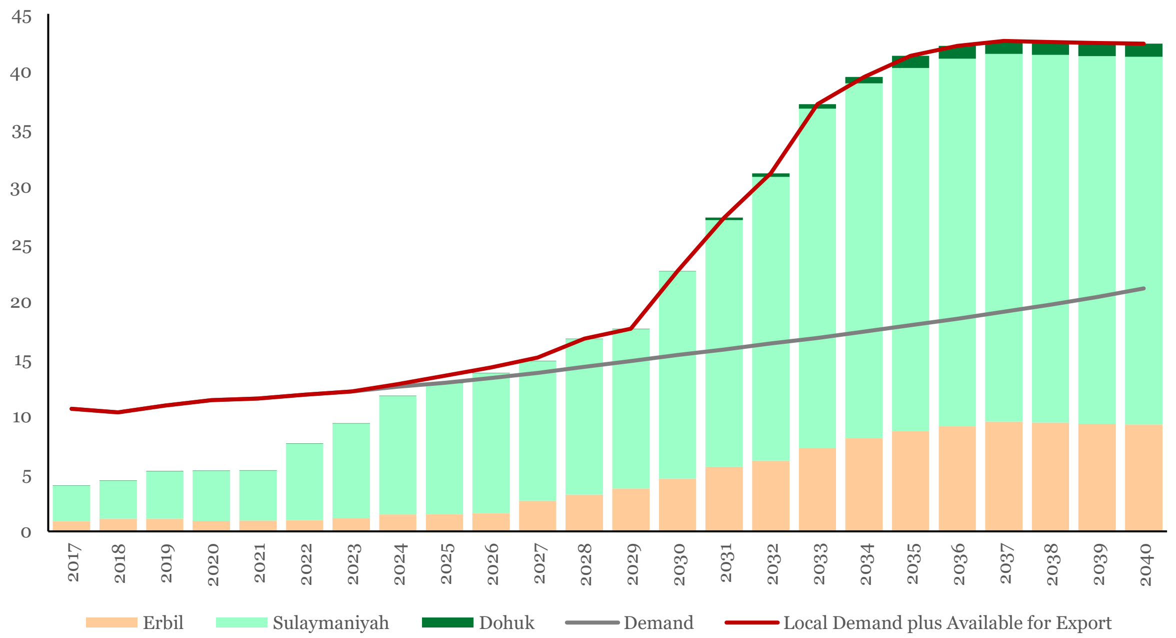


Figure 4 Kurdistan's natural gas production forecast until 2040, BCM/y

Gas resources in the IKR vary widely by province/governorate. The majority of Kurdistan's future non-associated natural gas production is projected to come from fields in the Sulaymaniyah province, as it is the site of some of Kurdistan's largest known natural gas fields. Duhok is expected to remain in deficit owing to a lack of adequate producing and prospective local fields. The lack of natural gas and lack of funds to buy adequate diesel fuel have resulted in a low capacity utilization of the Duhok power plant, and continued power cuts and blackouts. Completing the pipeline from Khor Mor to Duhok (via Erbil) could enable the use of local associated natural gas as well as gas from the south. Additional gas field development in Sulaymaniyah would support the completion of a large diameter natural gas pipeline to Duhok and address the deficit there. A sufficiently large surplus from fully functional fields in Sulaymaniyah would allow for natural gas sales to the nearest market outside of the IKR (i.e., FI via pipeline to Kirkuk and/or the Baghdad area).

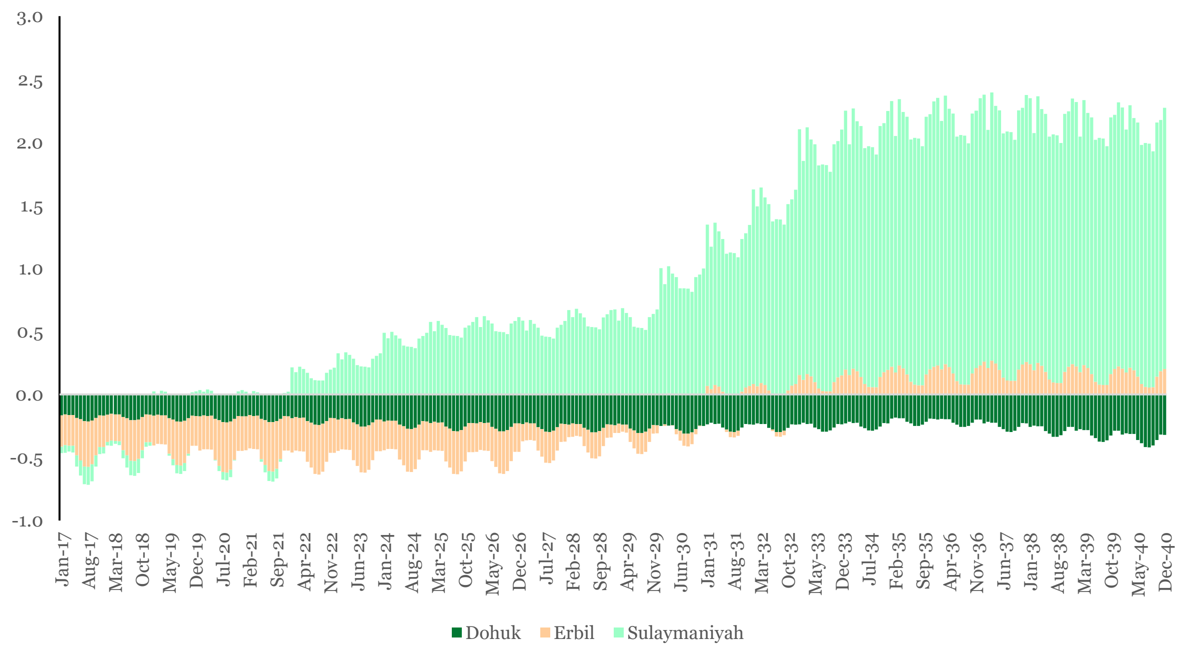


Figure 5 Kurdistan's natural gas balance forecast by province, monthly, until 2040, BCM/m

Sulaymaniyah's role in the natural gas balance is projected to be driven by strong development of non-associated natural gas production. The potential in the southern IKR will increase the need for close cooperation between Erbil and Sulaymaniyah. Local gas demand/consumption currently remains unmet from the level of natural gas production and lack of requisite infrastructure, but development of the assets in Sulaymaniyah and Erbil governorates could help the IKR fully meet its own demand around 2025 and begin selling to markets outside of its jurisdiction.

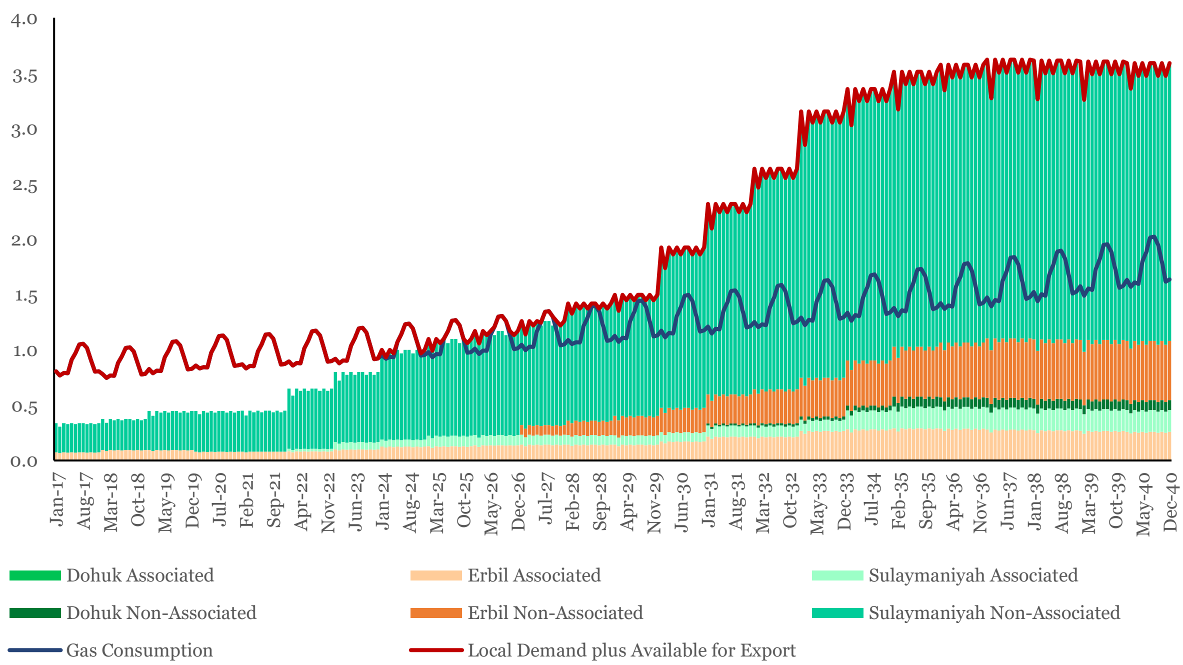


Figure 6 Kurdistan's natural gas production forecast, monthly, until 2040, BCM/m

Kurdistan could ultimately sell approximately 23 BCM/y of natural gas to FI and Turkey, assuming successful commissioning of required infrastructure (i.e., natural gas processing plants and pipelines) and full, environmentally sound development of all known commercially viable resources. These figures incorporate full-scale production from Miran and Bina Bawi natural gas fields, which require the installation of sour gas processing facilities. Planned developments include these installations, as natural gas from both fields is high in H_2S, which has to be removed to meet safe specifications for pipelines and end-users. The chart in Figure 8 is illustrative and not prescriptive; the actual timing and level of production and the fields involved may vary depending on:

- Corporate plans
- The speed of government approvals
- Infrastructure construction
- Sales contract negotiations
- Unforeseen geological, technical, or logistical challenges in field development
- Competitive positions of different assets
- Potential future discoveries or reserves additions

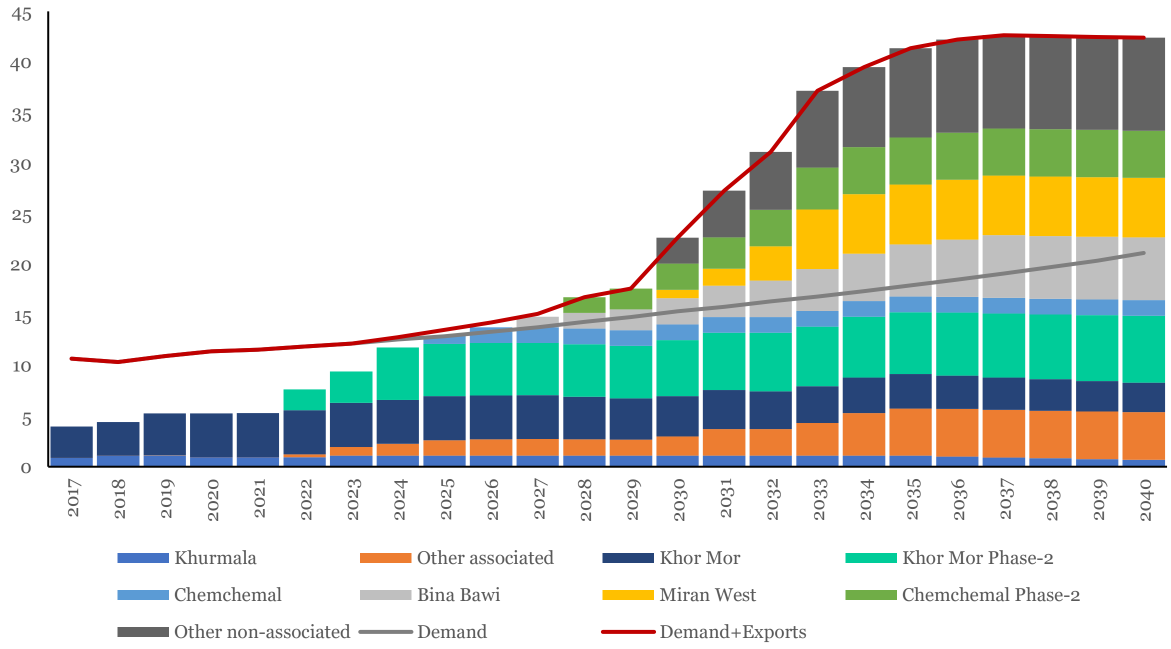


Figure 7 Kurdistan's natural gas production profile by asset until 2040, BCM/y

The rise in natural gas production can coincide with the existing surplus natural-gas-powered generation, which can then successfully run at 90% or more capacity as required. This offers two benefits: (1) meeting the IKR's internal electricity demand and (2) potentially sending surplus generated power to FI. The surplus could be delivered through one or more of three main routes: direct to Mosul, direct to Kirkuk, or through Diyala to Baghdad. The preferred route(s) would depend on the state of the power grid within the IKR and FI and the location of the largest or most urgent deficits within FI.

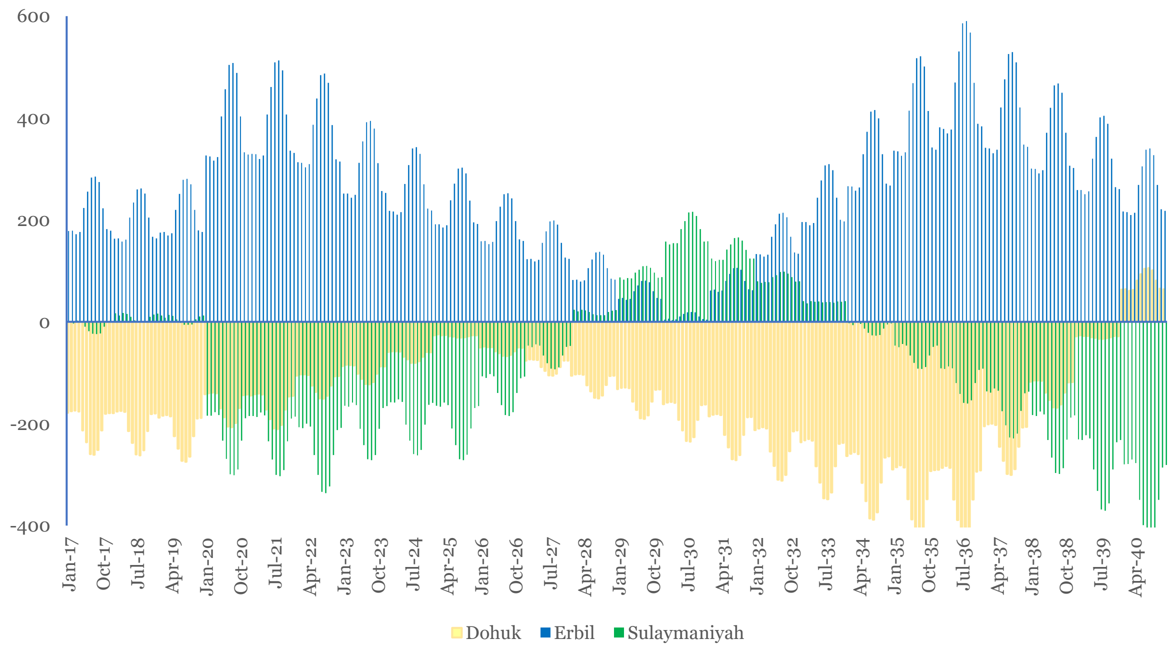


Figure 8 Kurdistan's power balance, monthly, until 2040, GWh

Kurdistan's daily power demand is characterized by a typical double peak; there is one peak in the afternoon and one in the evening. Seasonal demand variation is less than in FI, as Kurdistan has relatively cold winters (necessitating heating) and milder summers. These factors would allow the IKR to send surplus off-peak power to FI, which has a persistent power deficit at most times. In July 2020, the FI Ministry of Electricity unveiled a plan to begin taking in 450 MW of power from the IKR and 200 MW from Turkey to plug the existing power deficit. In addition, extra generation capacity in the IKR could be commissioned with the primary purpose of supplying FI and boosting the country's generating capacity. The ready availability of gas and the more stable investment environment could make this an attractive option. The IKR can send either gas or additional power or both to FI once infrastructure is built or strengthened and depending on the relative economic benefit.

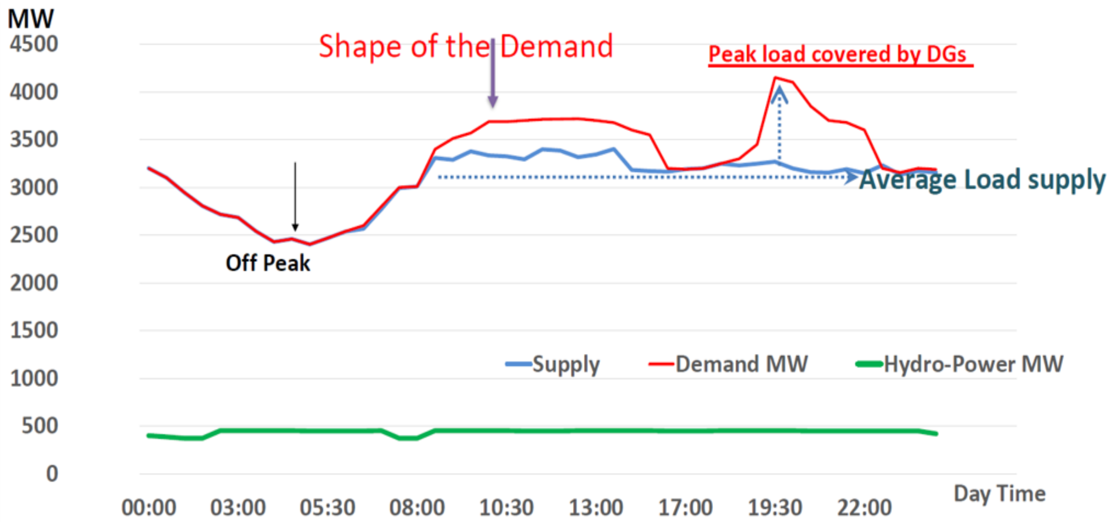


Figure 9 Kurdistan's daily power demand load, MW [DGs = distributed generators][13]

[13] Hama-Ameen Hasan, Iraq Petroleum CWC, October 21, 2020

Natural-gas-based power capacity is projected to account for 88% of the IKR's overall power generation capacity by 2040, with the remaining constituted by hydropower, solar PV, and some diesel. Capacity can therefore successfully meet not only the IKR's own peak demand but also demand for sales to FI.

Solar PV development up to 2040 has only been given limited weight in this study because of the sector's slow progress in the IKR—and in Iraq in general. However, as noted, some recent project proposals may signal a more rapid solar PV development in the IKR. Flexible gas generation with solar would offer a lower-cost power system with reduced greenhouse gas emissions. More rapid solar development would, to some extent, lower the projected demand for natural gas for power in the region; it would also increase a potential surplus of power for export at times, especially in the spring and fall, and bring forward the date at which a gas surplus would be available. However, incorporating solar would not have a dramatic impact on long-term natural gas volumes for external sales, as these are constrained by the demand in the end-user market rather than by reserves within the IKR.

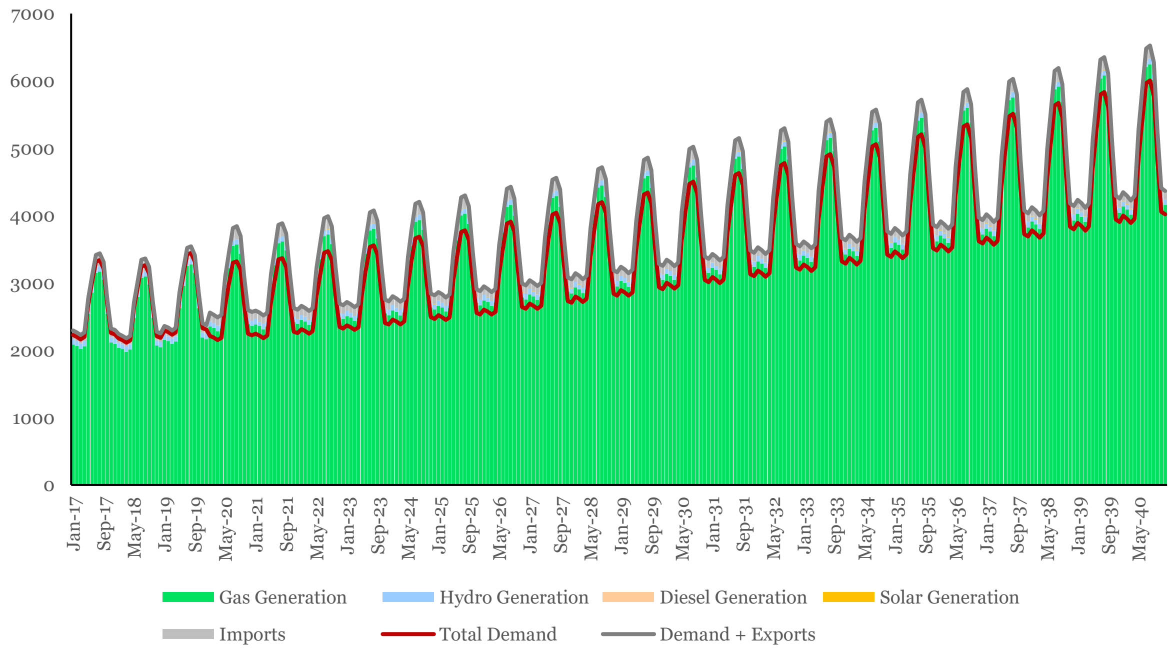


Figure 10 Kurdistan's projected power demand profile by generation method, monthly, until 2040, GWh

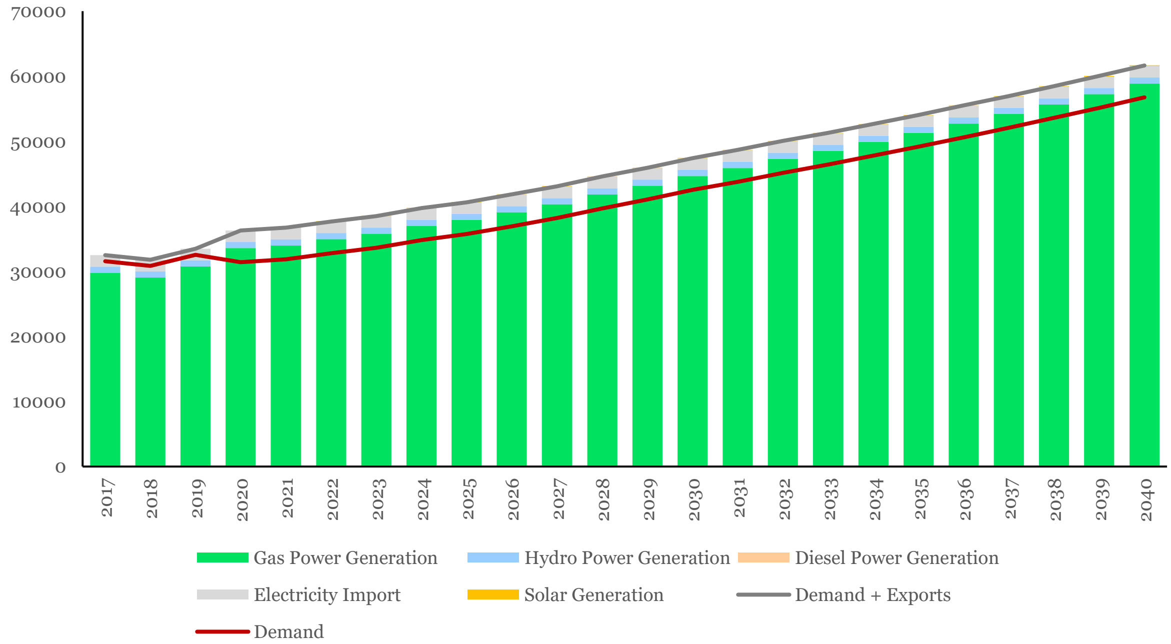


Figure 11 Kurdistan's projected power demand profile by generation method, annual, until 2040, GWh

2 Prospective Natural Gas Markets outside of the Iraq Kurdistan Region

2.1 Federal Iraq

2.1.1 Natural Gas Infrastructure

Federal Iraq has a chronic deficit of marketable natural gas, necessitating imports of natural gas from Iran. Even with these imports, FI faces continuing shortages. Demand for natural gas is projected to increase by 5% annually through 2040, requiring additional natural gas capture from associated field production and development of non-associated natural gas fields (such as Akkas in the Anbar province and Mansuriyah in the Diyala province). If more gas were available from the IKR it could displace more expensive and polluting liquid fuels and/or gas supplies from Iran as soon as the infrastructure was complete. In the short term (until at least 2025), FI will remain reliant on supply from Iran due to delayed implementation of gas projects and infrastructure in the south combined with demand growth, exposing FI to relatively high prices, political pressure, risks from U.S. sanctions, and unreliable supply, as witnessed in 2020. An increase in federal natural gas production, alongside supplies of IKR natural gas, could allow Iraq to plug its natural gas deficit, although smaller amounts of Iranian (or other) supplies may still be required during peak summer demand.

Iraq’s gas infrastructure is further detailed in Section 9 (Annex).

Figure 12 Select Major natural gas pipeline infrastructure in Iraq

Table 4 Main Iraq natural gas pipelines

Region	Pipelines	Annual Capacity	Status
Federal Iraq	Iran – Baghdad	12.8 BCM	Operational
	Iran – Basra	6.6 BCM	Operational
	Iraq – Jordan	3.1 BCM	Proposed, not implemented
	Basra – Kuwait	4.1 BCM	Existing, not operational
	Basra – Baghdad		Operational
	Kirkuk – Baiji – Baghdad		Operational
	Baiji – Mosul		Operational
	Baiji – Mosul – Qayyarah power plant	1.3 BCM	Operational (February 2021)
	Strategic (Basra – Haditha – Baiji)	3.1 BCM	Partially Operational
IKR Existing	Khor Mor – Khurmala	3.4 BCM	Existing
	Khor Mor -Jambur – Kirkuk	0.4 BCM[14]	Existing, not operational
IKR Planned/Proposed	Erbil – Duhok	-	Not implemented
	Kurdistan – Federal Iraq	20 BCM	Not implemented
	Kurdistan – Turkey	20-30 BCM	Not implemented

For several years, FI has had plans to expand natural-gas-fired power capacity to reliably meet peak demand. Currently, there are plans for 10 new gas-based power plants, which could achieve commissioning within the next seven years. These are mainly concentrated in FI's less-served provinces such as Anbar, Diyala, and Salah al-Din, although the 1.5 GW Besmaya expansion in Baghdad is important. In addition, GE is tasked with rehabilitating 2.7 GW of existing capacity at the Quds, Khairat, Baghdad South, Hilla, Mussayab, Haidariya, and Karbala plants.[15]

[14] Pearl Petroleum assesses its capacity at 0.85 BCM
[15] https://www.thenationalnews.com/business/energy/ge-reaches-financial-close-on-iraqi-power-sector-overhaul-1.1201213

Table 5 Planned gas-fired power plants in FI

Power Project	Technology	Location	Capacity	Secondary Fuel Source	Daily Gas Demand	Commission	EPC / Developer
Samawa Power Project	4 GE-9 Gas + 4 HRSG + 1 Steam	Muthanna	750 MW	Heavy Fuel Oil	3.3 MCM/d	Open cycle operational CC by 2023	ENKA (Turkey) and GE (United States)
Nasiriyah Power Project	4 GE-9 Gas + 4 HRSG + 1 Steam	Dhi Qar	750 MW	-	3.3 MCM/d	Open cycle operational CC by 2023	ENKA (Turkey) and GE (United States)
Baiji Power Project	3 CC Turbine x 507 MW	Salah al-Din	1,521 MW	Heavy Fuel Oil	6.7 MCM/d	2024	Orascom Construction (Egypt) and Siemens (Germany)
Baiji Power Project (re-built)	4 Siemens STG5-2000E Gas Turbines + revamp of existing 6 Gas Turbine	Salah al-Din	1,600 MW	-	7.2 MCM/d	2024	
Anbar Power Project	4 GT26 Gas + 4 HRSG + 2 Steam	Anbar	1,642 MW	-	6.1 MCM/d	2025	METKA (Greece)
Dibis Power Project	1 CC Turbine x 169 MW	Kirkuk	507 MW	Heavy Fuel Oil	2.2 MCM/d	2025	BLUE & P (Iran)
Al Qaim Power Project	2 GE-9 Gas x 125 MW	Anbar	250 MW	-	1.8 MCM/d	2025	LANCO Infrastructure (India)
Al Shemal Power Project	4 GE-9 Gas + 4 HRSG + 1 Steam	Nineveh	1,400 MW	Heavy Fuel Oil	6.1 MCM/d	2027	Energoprojekt ENTEL (Serbia)
Mansuriyah Power Project	1 GT13E2 Turbine	Diyala	728 MW	-	3.1 MCM/d	2027	Alstom (France) and METKA (Greece)
Akkas Power Project	4 OC Turbine x 30 MW	Anbar	120 MW	-	1 MCM/d	2028	-
Besmaya Expansion	4 x 9F 265 MW gas turbines + 2 x 250 MW steam turbines	Baghdad	1,500 MW			2021	GE/Mass Holding

Federal Iraq has hot summers with high requirements for air conditioning, so power demand has a high summer daytime peak (Figure 15). Note that this chart is based on simulated, not actual, data for 2010, but the approximate shape is believed to be representative. Power demand doubles from nighttime to midday and remains high until about 21:00. Similarly, seasonal demand is estimated to double from a low in March–April to a high in August. (Winter has slightly higher demand than spring, as some heating is required in the colder months.)

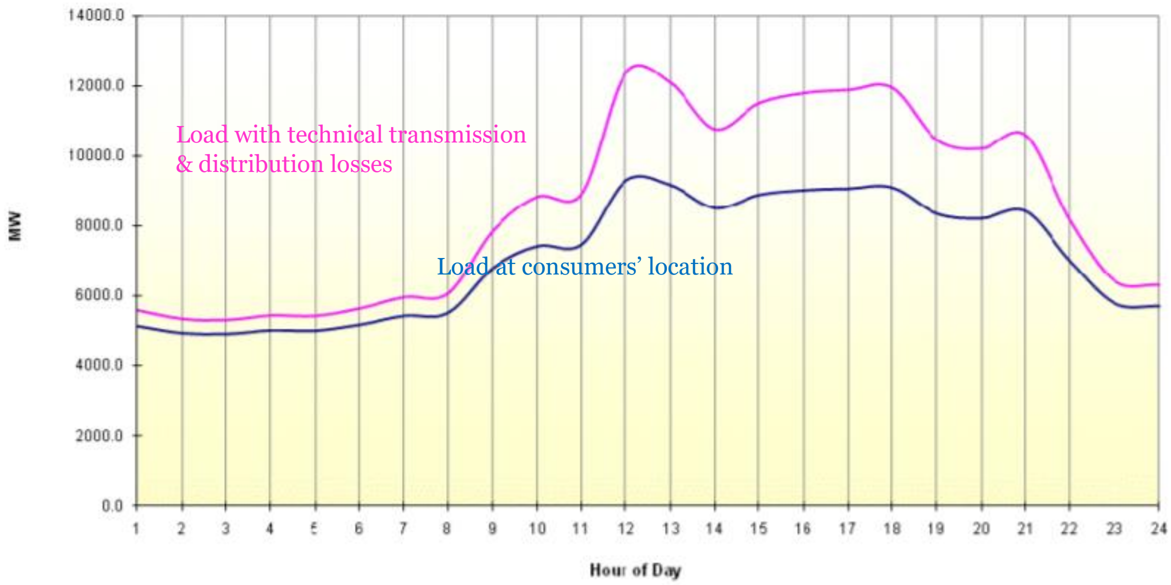


Figure 13 Simulated summer daily electricity demand in FI in 2010[16]

The FI power sector suffers from a number of severe structural weaknesses. These have negative impacts on the supply of service, and the financial performance of the sector.

1. **Lack of Maintenance**
   Lack of maintenance of the generation, transmission, and distribution systems, leads to effective capacity well below nameplate. In summer 2019, peak generation was about 19 GW—significantly lower than both nameplate generation capacity (about 30.3 GW) and estimated peak (unconstrained) demand (~26 GW). This underperformance is exacerbated by an outdated grid, which suffers from congestion, instability/wide frequency fluctuations, frequent technical faults nationwide, and a need for repairs (in former ISIS-controlled areas, the infrastructure has been subject to sabotage and significant battle damage). These factors lead to pervasive power cuts and to the use of expensive and inefficient neighborhood generators, which supply about 20% of demand. Users in the top bracket of the state tariff system pay an average of about 0.8 US¢/kWh, while local generators charge 8–17 US¢/kWh[17].

2. **Lack of fuel for Power Plants**
   Many plants lack both sufficient gas supply and connections. As a result, the plants either go without fuel or burn heavy fuel or crude, which reduces efficiency, escalates pollution, and increases maintenance and cleaning requirements. Even though this fuel is supplied at subsidized rates by the Ministry of Oil, it incurs a heavy opportunity cost versus potential exports and resulting maintenance outages.

3. **High Transmission and Distribution Losses**
   Such losses are from 40%–50%, compared to a world average of ~8%. Much of this is "non-technical losses", i.e., power theft, unauthorized connections, and non-billing. About two-thirds of generated power is not paid for, and customers who do pay cover only about 10% of the real cost of provision. There has been strong partisan and social resistance to improving metering and billing, even when accompanied with better service.

4. **Lack of Sector Funding**

[16] https://www.iraq-jccme.jp/pdf/archives/electricity-master-plan.pdf
[17] http://library.fes.de/pdf-files/bueros/amman/16449.pdf; https://blogs.lse.ac.uk/mec/2020/03/24/iraqs-power-conundrum-how-to-secure-reliable-electricity-while-achieving-energy-independence/

Because of the high losses and low tariffs and collections, the Ministry of Electricity is almost entirely reliant on budget transfers to fund its activities. In 2018, Iraqis paid an estimated US$ 4 billion to small neighborhood generators, equivalent to the Ministry's entire capital budget[18]; in 2018, the capital budget was US$ 4 billion. The 2018 operating budget was US$ 4.45 billion[19] — and this amount is not representative of the full cost of provision, as the fuel inputs are subsidized. Iraq's budget is, in any case, severely constrained. This contributes to a vicious circle of underinvestment, poor power provision, low economic growth, and social unrest, which then constrain electricity reform.

To address some of these challenges, the Ministry of Electricity would need to commit to large gas purchases while avoiding the frequent payment problems that have affected supplies from Iran (issues resulting from U.S. sanctions and Iraqi financial shortages). To achieve these objectives, the Ministry would have to be either (1) backed by further government guarantees and/or (2) substantially reformed. The use of gas in place of oil does provide savings that can partly cover the purchase cost. However, other actions would also be necessary[20], such as:

- Rationalizing the role of small generator operators, and diminishing their incentive to block reform.
- Offering consumers a bargain of better electricity service (and savings on generator charges) in return for higher tariffs and full payment.
- Re-investing savings in improving generation uptime and efficiency, rehabilitating generation capacity, reducing network losses, and introducing highly cost-competitive renewable energy.
- Putting the Ministry on a credible path to being independent of federal budget transfers, i.e., able to cover its own operating and fuel costs and, eventually, capital costs too, including an appropriate return on capital to investors.

POWER SECTOR ECONOMICS IN FEDERAL IRAQ

- Electricity procurement costs in Federal Iraq, including fuel and generation capital costs, but excluding transmission and distribution costs and losses, can be approximately summarized as:
  - Electricity imports from Iran: estimated price of US¢ 7–12/kWh
  - Generation from imported Iranian gas: estimated cost of ~ US¢ 7–10.7/kWh
  - Generation from gas at a price of $5/MMBtu: estimated cost of ~ US¢ 6/kWh
  - Generation from crude oil at the opportunity cost of US$ 60/bbl: estimated cost of US¢ 11/kWh
  - Distributed generation from diesel at US¢ 18–31/kWh (at opportunity cost of diesel; subsidized fuel is provided to generator operators)

- Ministry of Electricity tariffs range from US¢ 0.68–8.2/kWh, with most residential consumption charged at the lower end. Considering transmission and distribution costs and the very high level of losses, it can be seen that the Ministry incurs a heavy deficit for every kilowatt-hour supplied, even for those consumers who pay their bills. Non-payment is very high, further worsening the situation. Consumers may feel justified in not paying, given the poor service and the high fees they pay to distributed generator operators.

- For comparison, these generator operators charge about US¢ 60–120/kWh[19] and are able to enforce payment. Distributed generators supply about 20% of residential demand but make up most of the average household's bill.

[18] https://agsiw.org/iraqs-electricity-challenges-mount-as-oil-revenue-slows-to-a-trickle/
[19] https://www.researchgate.net/publication/338203074_Iraq's_electricity_tariff_reform
[20] http://library.fes.de/pdf-files/bueros/amman/16923.pdf

2.1.2 Natural Gas Balance

FI's natural gas production and demand balance is characterized by high levels of flaring and an ongoing natural gas deficit that necessitates Iranian natural gas imports. The supply–demand gap is expected to shrink by 2040, assuming that known natural gas resources are developed, especially non-associated gas fields like Akkas and Mansuriyah, and gas capture plans are enacted. However, even if known projects are implemented on schedule, the supply–demand gap probably will not disappear.

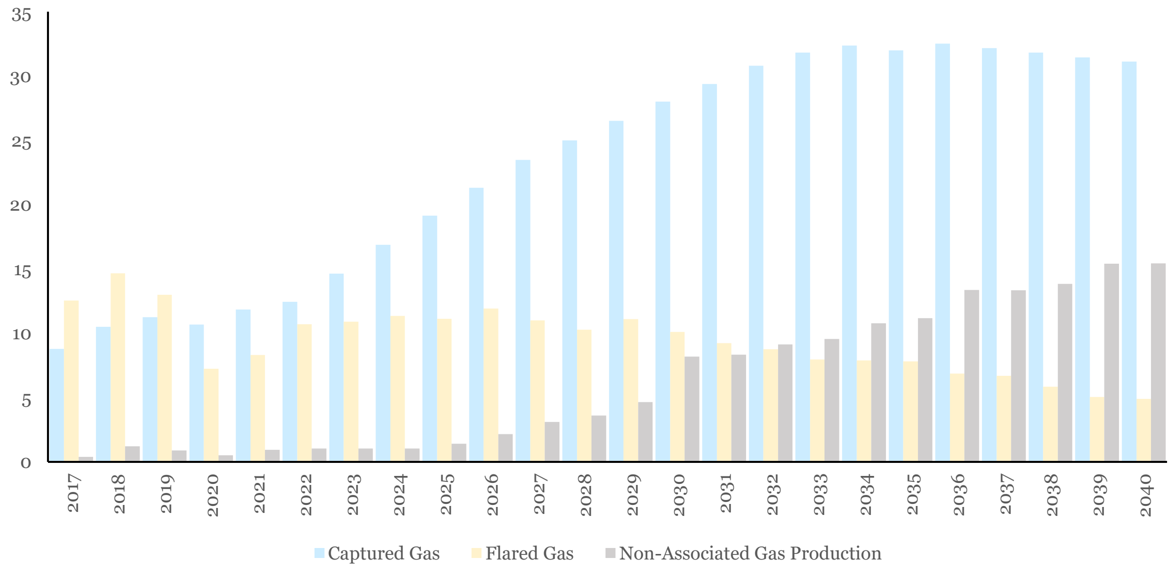


Figure 14 FI's natural gas production profile until 2040, showing captured and flared gas volumes, BCM/y

Supplies of marketable Kurdish natural gas plus additional development of FI's non-associated and associated gas could narrow the gap considerably, and perhaps even close it, save for the summer peak period. During these times, we estimate that FI would probably still require some external imports, likely from Iran, to meet demand fully. Nonetheless, this approach would significantly lessen FI's reliance on Iran for energy.

Current natural gas production in FI is almost entirely made up of captured gas processed by the Basrah Gas Company and a handful of smaller associated gas capture and processing projects in the south. Non-associated gas production is solely from the Siba natural gas field, located close to the border with Kuwait. The Siba field currently produces 0.52 BCM/y.

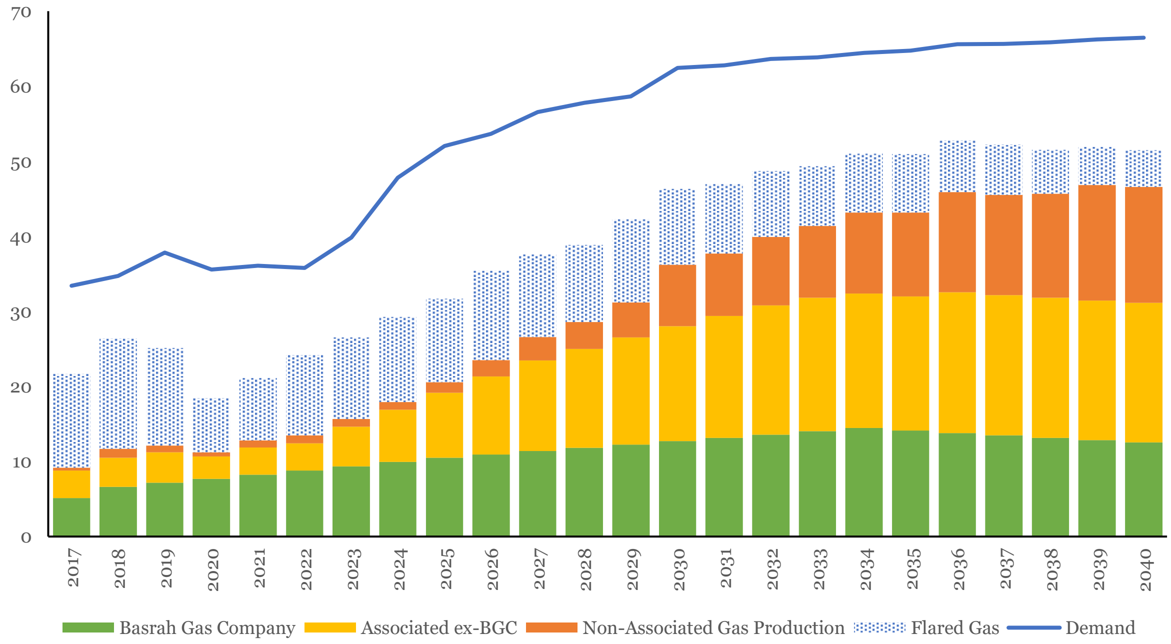


Figure 15 FI's projected natural gas production profile, including demand, until 2040, BCM/y

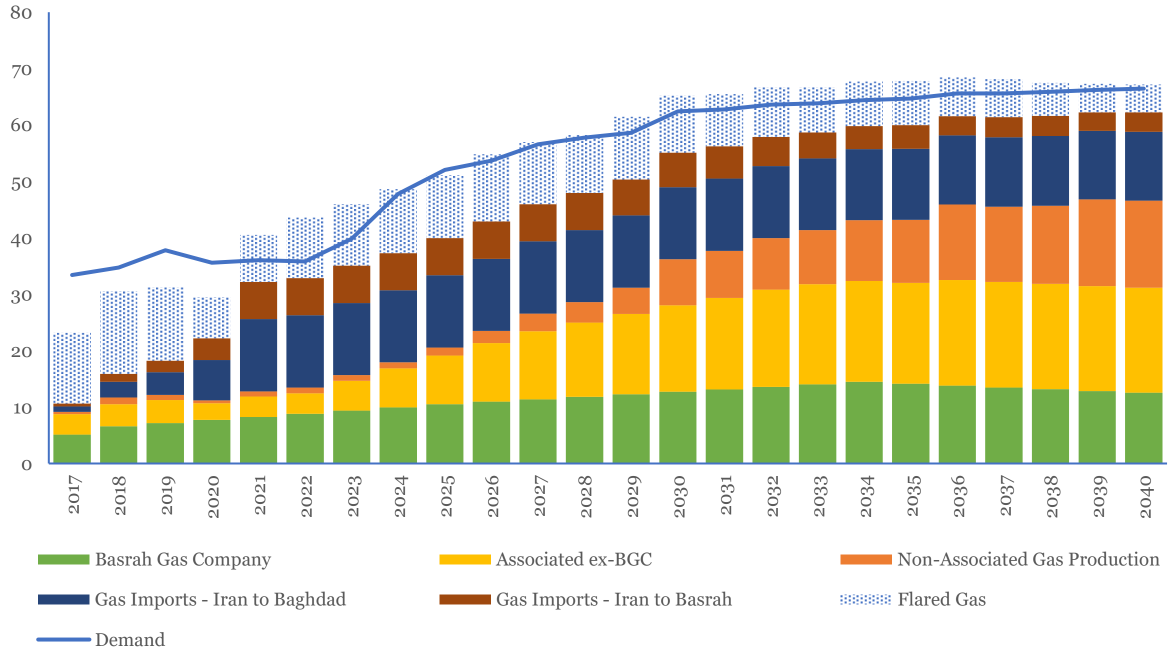


Figure 16 FI's projected natural gas production profile, including demand, and Iranian imports until 2040, BCM/y

Even with some continuing Iranian natural gas supplies, we believe FI will continue to have a natural gas deficit that presents a significant long term market opportunity for gas from the IKR. Remaining flared gas and fugitive methane emissions could be captured to close the supply–demand gap, but this approach would require fast-track, concerted development and/or expansion of capture projects. Alternatively, local gas supply in FI could be increased through yet-to-be-developed non-associated natural gas projects (such as Mansuriyah, Akkas, and the Bid Round-5 fields), in addition to new exploration over the longer term, but demand growth (including more provision of gas to industry), anticipated delays, and substitution for more costly liquid fuels and Iranian imports should still leave ample space for IKR imports for years to come.

In March 2021, Iraq reached preliminary agreement with Total (now TotalEnergies) for a number of projects, including two phases of gas capture of 600 Mcf/d each (12.4 BCM/year total). These efforts aim to capture Ratawi gas by the end of 2023 by establishing a complex at Ratawi to gather gas from the Ratawi, West Qurna-2, Majnoon, Luhais, and Tuba fields.[21] In April 2021, Sinopec of China was awarded a contract to develop the Mansuriyah non-associated field, with a short-term target of 50 Mcf/d (0.52 BCM/y) and a long-term target of 300 Mcf/d (3.1 BCM/y)[22]. These solutions should be pursued, but it should be recognized that Iraq has already faced major challenges and delays in developing these projects, and even quite optimistic assumptions about their success do not entirely meet the projected supply deficit. LNG imports via Basra have also been considered. However, these may be relatively expensive at times and would require new infrastructure in a crowded and insecure maritime area. Furthermore, this approach would deliver gas into the Basra area, which already has a surplus; more pipeline capacity would be required to move the gas to central and northern Iraq.

Natural gas from the IKR is potentially a timely, secure, and reasonably priced source of supply. Initial deliveries via Jambur could begin by 2025, when the first surplus of Kurdish gas appears, or sooner if an agreement on price and marketing can be reached with Pearl, and the FI and KRG Ministries. There are, in addition, potential infrastructure synergies that could be realized. For instance, a pipeline from the IKR through Diyala to the Baghdad area could also carry gas supplies from the Bid Round-5 fields and Mansuriyah.

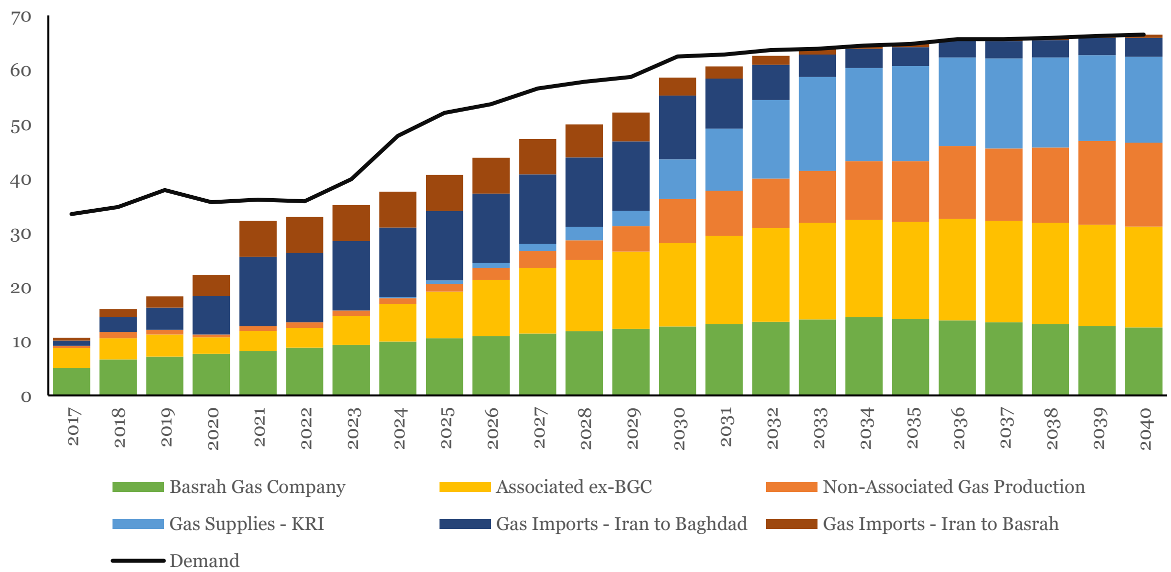


Figure 17 FI's natural gas profile, including demand and Kurdish supplies, until 2040, BCM/y

The introduction of natural gas supplies from Kurdistan into FI under the base case (see Section 3.2 below) could result in almost complete phasing out of up to 6.6 BCM/y of Iranian natural gas imports via Basra, and imports via Diyala into Baghdad would decrease to a quarter of current full capacity (12.8 BCM/y) for summer peak demand. These results offer the benefit of significantly lessening FI's reliance on Iran for energy security, as well as eliminating expensive payments to the National Iranian Gas Company. This approach would also support the development of a Kurdish natural gas sector that can supply timely, reliable, and significantly cheaper gas to the FI natural gas network.

Under the current environment of a severe natural gas and power deficit, developing a new source of natural gas supplies has taken on newfound importance for the FI Ministry of Electricity. The Ministry may be open to purchasing natural gas from the IKR, especially considering the risk of sanctions and the high cost of such purchases from Iran.

[21] https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/032921-iraq-total-agree-to-work-jointly-on-associated-gas-solar-power-projects
[22] https://www.iraqoilreport.com/news/iraq-awards-mansuriya-gas-field-boosting-hopes-for-domestic-gas-sector-43668/

Iran's supplies have historically been patchy, and only a fraction of their total capacity, owing to a host of different issues. Most prominent is FI's chronic inability to meet payments on time. Other challenges include lack of funds and banking problems related to U.S. sanctions, which result in shutoffs on the Iranian side; domestic shortages in Iran, especially during the winter season; and poor receiving and connecting infrastructure that impacts the reliability of supplies. In December 2020, Iran halted all supplies to FI for two weeks, in response to Baghdad's inability to pay previous outstanding debts (which are as high as US$ 6 billion, by some accounts), plunging the south of the country into an acute power crisis. Supplies resumed in January 2021, but the historic problems highlight the uncertainty of relying on Iran for energy security. Iranian gas exports to Turkey have experienced similar problems of lack of delivery in winter.

Iran's natural gas delivery price is relatively expensive by regional standards, in contrast to potentially much cheaper gas from the IKR. In 2020, delivery prices from Iran, which are linked to oil prices, stood at an estimated US$ 4.7/MMBtu. If FI continues to import from Iran, nominal prices are projected to increase to US$ 6/MMBtu by 2030 and to US$ 7.4/MMBtu by 2040 because of the concurrent projected increase in oil prices (Brent crude at US$ 50/bbl in 2027 and increasing 2% annually thereafter). The rise in Brent prices during 2021 to over $70/bbl will have driven up the gas price payable to Iran.

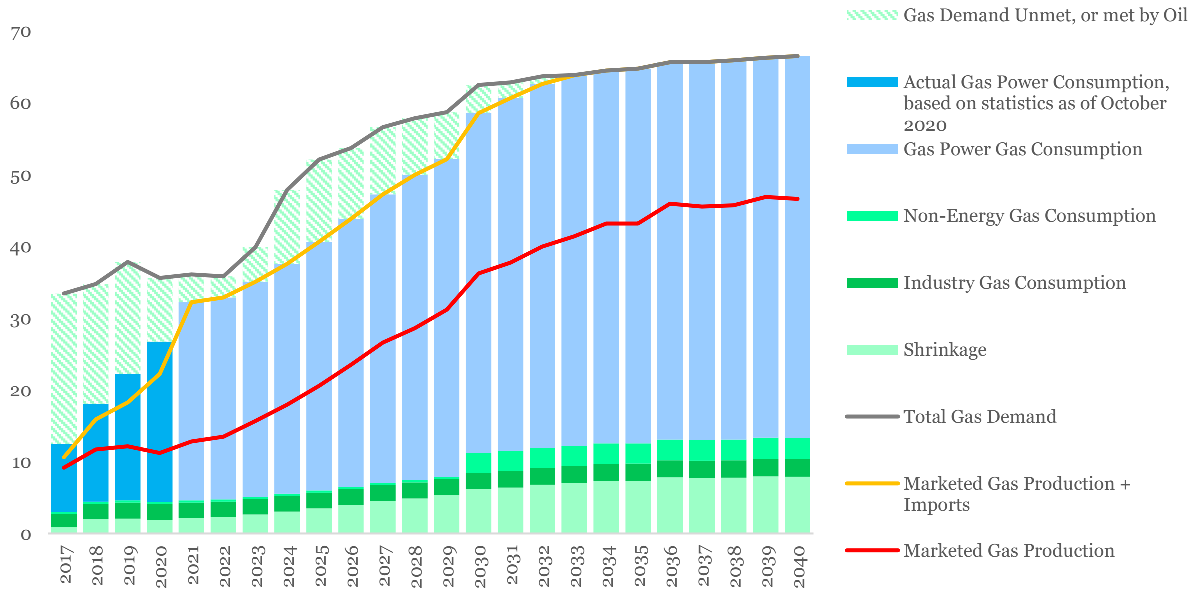


Figure 18 FI natural gas demand and supply, including imports, until 2040, BCM/y

Figure 20 shows FI's natural gas demand and supply balance under the base case (see Section 3.2). The power sector is by far the largest consumer of natural gas, as natural-gas-fired power capacity will significantly increase (Figure 21), with industry registering some significant growth from 2030 onwards as the 2.45 BCM/y Nebras Petrochemical Complex in Basra is assumed to come online. There are significant risks to realization of the Nebras project, which has been in negotiation since 2012[23] and will require large quantities of ethane extraction from Iraq's gas production. On the other hand, there is upside potential for more industrial gas growth than included here, even in more basic domestic-targeted facilities such as brickmaking, cement, glass, metal working and food processing. Marketed natural gas consumption, even with full development of non-associated and associated gas, will remain significantly short of meeting FI's demand on its own, meaning that FI will remain an importing market in the long term. Note that Figure 46 (see Section 3.3) shows FI's gas balance if supplies from the IKR are not accessed.

[23] https://www.hellenicshippingnews.com/iraq-to-speed-up-plans-for-8-bil-nebras-petchem-project-with-shell-oil-ministry/

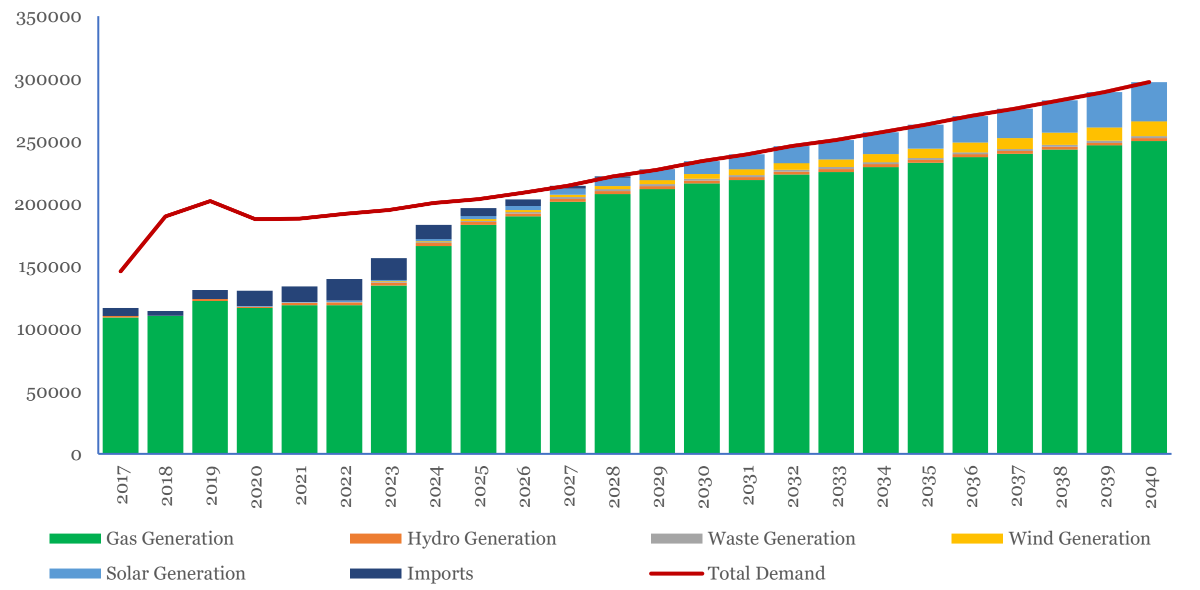


Figure 19 FI's projected power generation mix until 2040, TWh[24]

Natural gas-based power plants are projected to account for 85% of the generation mix by 2040 but will require gas imports (or burn oil) to meet demand. Power imports from Iran, Turkey, and the IKR are expected to continue until the medium term.

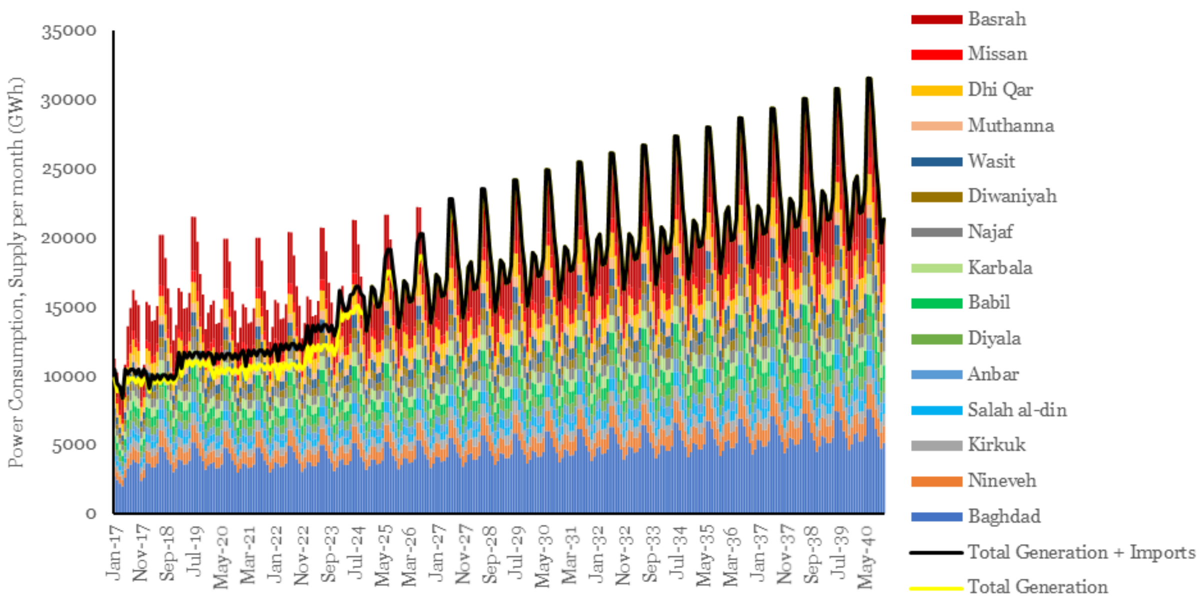


Figure 20 Electricity demand (GWh/m) per province by month. Power imports will help FI meet peak demand in the medium term.

[24] Because of lack of sufficient gas and connecting infrastructure, a large part of "Gas Generation" is met with oil, including fuel oil, diesel, and some crude oil.

2.2 Turkey

2.2.1 Natural Gas Infrastructure

This study divides Turkey into distinct natural gas zones based on the main sources of natural gas supply. Marketable Kurdish natural gas would enter Turkey through the southeast, a zone where it competes primarily with Iranian supplies. This could change as the current natural gas network is further developed and made more flexible with expanding storage capacity, offering another viable outlet for Kurdish gas in the long term, if required.

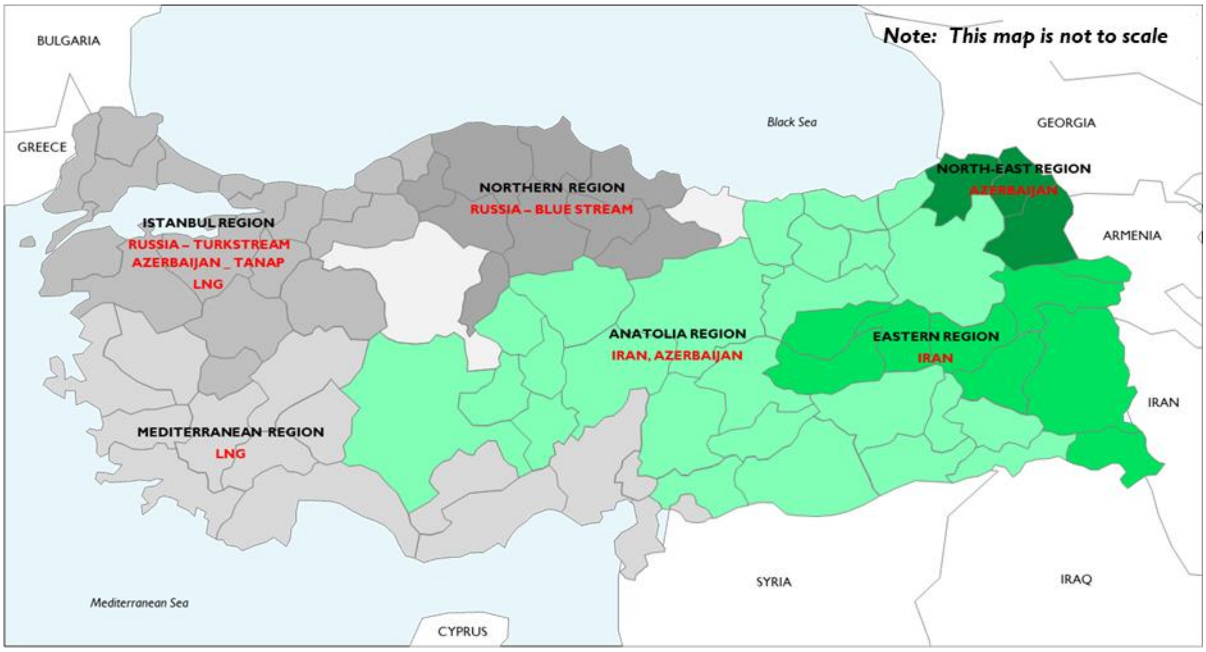


Figure 21 Turkey's natural gas zones and primary source of supply in each

Turkey is a large and well-supplied natural gas market of 46.9-48 BCM in 2020[25], with very minor domestic production, although this could change with the development of the two recent Black Sea natural gas discoveries, Sakarya and North Sakarya (Amasra). It is currently supplied by pipeline imports from Russia, Azerbaijan, and Iran, and LNG imports from a variety of suppliers, including Qatar, Australia, Nigeria, and Malaysia. Turkish natural gas import contracts representing 16 BCM/y are set to expire in 2021, followed by contracts for 20.4 BCM/y in the mid-2020s and 9.6 BCM/y (Iran) in 2026[26], opening a sizeable window for supplies from new sources. Turkey's import routes are diversified by the new Trans-Anatolian Natural Gas Pipeline (TANAP) from Azerbaijan via Georgia, which began operations in June 2018, and the TurkStream Pipeline from Russia under the Black Sea, which began deliveries in January 2020, as well as LNG import terminals. TANAP feeds on to the Trans-Adriatic Pipeline (TAP) to Greece, Albania, and Italy, while TurkStream also supplies the Balkans. Turkey has had ambitions to transform itself into a gas hub that could buy and sell gas from multiple sources. In September 2018, a spot gas market (Continuous Trading Platform) was launched via the Turkish Independent Energy Exchange (EXIST)[27]. Although liquidity is low, the market has developed, and prices appear reasonably in line with Turkey's main sources of supply.

[25] Lower figure from Energy Market Regulatory Authority of Turkey (EMRA) and higher figure from Joint Organisations Data Initiative (JODI)
[26] https://www.oxfordenergy.org/publications/the-renewal-of-turkeys-long-term-contracts-natural-gas-market-transition-or-business-as-usual/
[27] https://iicec.sabanciuniv.edu/sites/iicec.sabanciuniv.edu/files/iicec_energy_and_climate_research_paper_the_missing_piece_in_the_turkeys_gas_hub_ambitions_2.pdf

The country has an extensive natural gas grid, including lines that run up to within 1 km of the Iraqi border. Existing Turkish infrastructure constraints do not allow for easy movement of natural gas from west to east, although eastern gas flows westwards are easier. Current natural gas storage capacity is 3.4 BCM, which has to be further expanded to improve supply security and balance seasonal fluctuations. With available Kurdish gas, Turkey could successfully replace some LNG and Iranian gas, as Kurdistan is a potentially cheaper option.

However, even under an optimistic scenario, it is difficult for Turkey to import more than 11 BCM/y of natural gas from the IKR. Challenges include limitations of the Turkish natural gas grid and supporting infrastructure, as well as existing natural gas supply contracts, especially from Azerbaijan and Russia. These two countries provide superior gas coverage across the breadth of Turkey, reliable infrastructure, and attractive economics (especially from Azerbaijan). These two suppliers would also be likely to respond competitively to a new source in the Turkish market by lowering their prices.

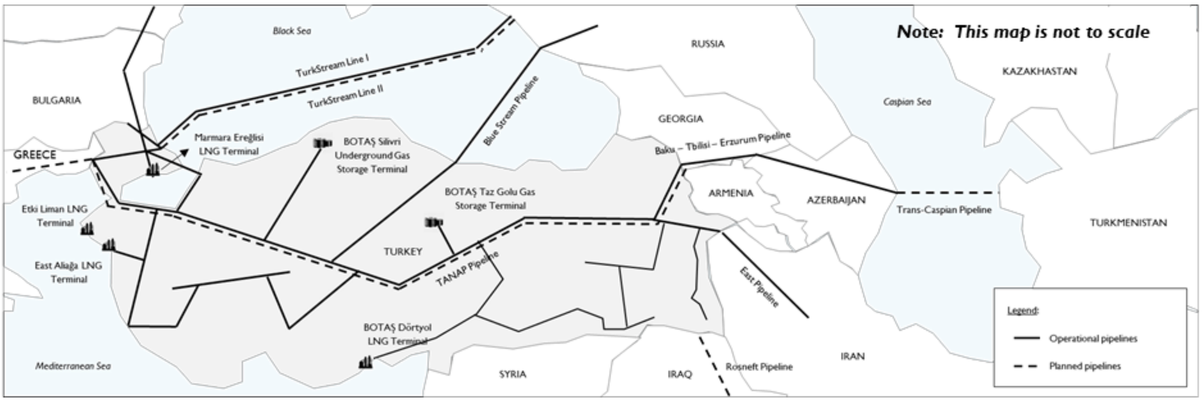


Figure 22 Major natural gas infrastructure in Turkey, including cross-border natural gas pipelines and LNG terminals

Table 6 Turkey's main international natural gas import pipelines

Status	Existing Pipelines	Commissioning	Annual Capacity
Operational	Trans-Balkan Pipeline (Western Route)	1987	26.8 BCM[28]
	TANAP	Q2 2018	16.4 BCM
	Blue Stream	Q4 2005	16.4 BCM
	Tabriz – Ankara	Q3 2001	14.4 BCM
Under Development or Proposed	TurkStream II – Balkans	2020	31 BCM
	Rosneft Pipeline: Kurdistan – Turkey	2025	30 BCM

Current domestic marketable natural gas production in Turkey is very minor — about 0.45 BCM/y, mainly from the Istanbul, Kırklareli, and Tekirdağ provinces—and is connected to the natural gas distribution lines in those provinces. In August 2020, Turkey announced that the Tuna-1 well in Turkey's Exclusive Economic Zone (EEZ) in the Black Sea had discovered the Sakarya field, with upgraded resources of 405 BCM. The field was appraised by the Türkali-1 well in November 2020. The main reservoir was shown to be Pliocene–Miocene sands at three levels between 3,000 and 4,775 meters' reservoir depth. These sands are typically thinly bedded and fine-grained, hard to evaluate, and not of very high reservoir quality, despite having good porosity; these characteristics could affect development economics. The discovery is in 2,014 meters of water depth, 170 kilometers from the port of

[28] Also serves south-east European countries

Zonguldak. Turkey plans to start producing in 2023 at 5–10 BCM/y, reaching 15 BCM/y by 2025. However, this timeline appears unrealistically fast, given the technical and commercial challenges that have held up developments in neighboring fields in the Black Sea sectors of Bulgaria and Romania. In addition, national oil company Türkiye Petrolleri AO (TPAO) has no experience in deepwater natural gas development and may need international partners, pushing estimated first production to 2025, with a plateau of 20 BCM/y by 2027. The cost of production also has to be determined and will have to be reasonably competitive with prices from Turkey's existing suppliers.

These concerns will also inform the development of the June 2021 discovered North Sakarya (Amasra) natural gas field, part of the same block in which Sakarya was discovered, and with a gas resource base of 135 BCM in the Amasra-1 well. TPAO has said that North Sakarya (Amasra) will be tied into existing plans to develop Sakarya, which has an ambitious 2023 start-up target. However, similar to Sakarya, first production might actually commence only in 2025, with a plateau of 6 BCM/y within 2 years.

Turkey is banking on both fields' success to strengthen the country's hand in negotiations with top pipeline exporters in renewing long-term contracts (many of which are expiring this year, as previously noted).

If more commercial discoveries are made in the region of Sakarya and North Sakarya (Amasra), Turkey's net natural gas import requirements would decline significantly, potentially allowing for exports to Southeast Europe, although such a scenario is speculative at this point.

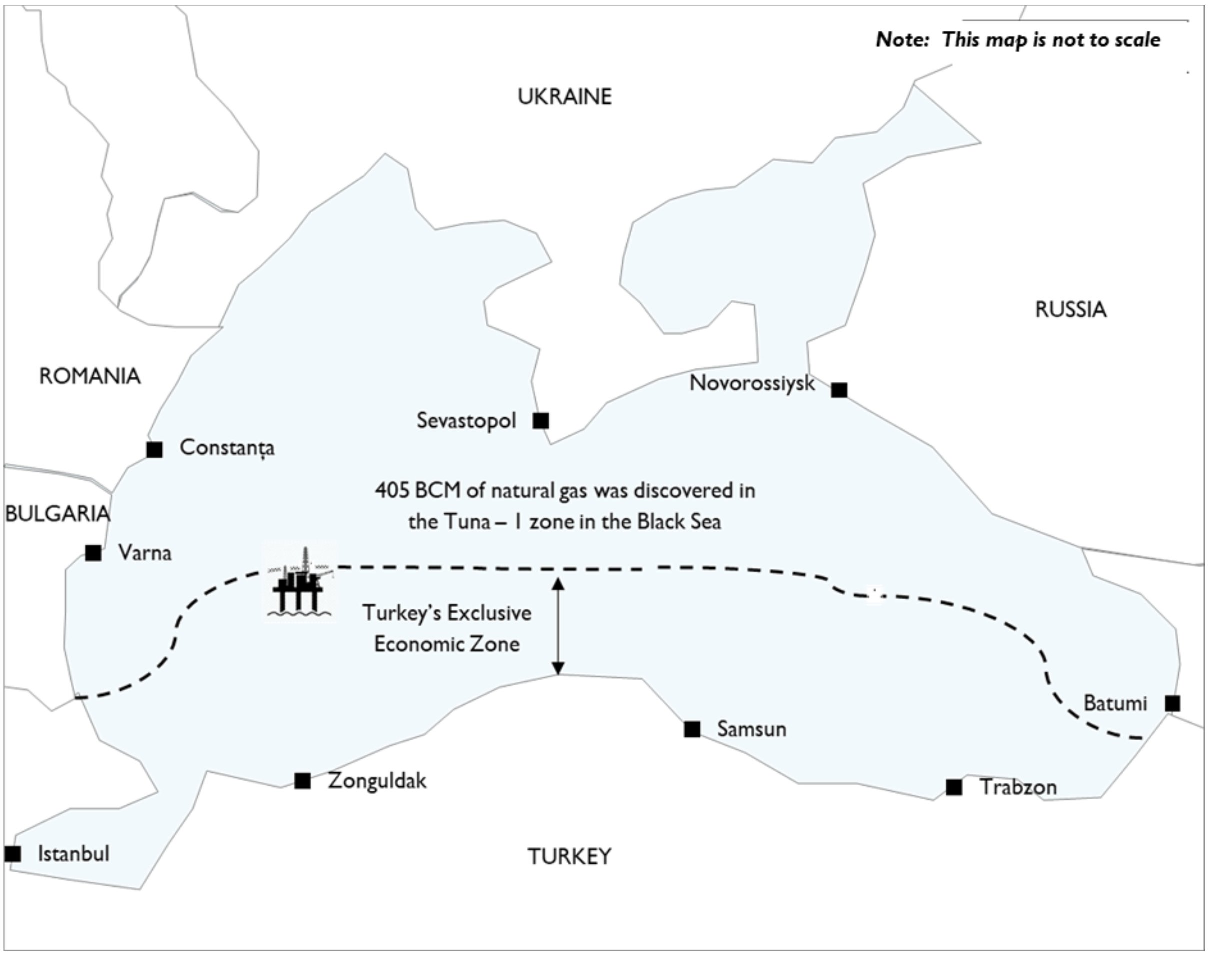


Figure 23 Location of the Sakarya field

2.2.2 Natural Gas Contracts

Agreements representing 16 BCM of natural gas sales to Turkey are set to expire in 2021, followed by agreements for 20.4 BCM in 2024–2025 and 9.6 BCM (Iran) in 2026. These expiring contracts could represent an opportunity for the IKR or FI, but it will be a challenge to replace other relatively reliable suppliers, as the countries would need to develop the needed gas production and infrastructure in time for the contract renewal window. Renewal or replacement of these contracts will involve aggressive negotiation by the main Turkish gas off-taker, BOTAŞ, on the following:

1. Formulation of natural gas prices: Oil-indexed natural gas pricing structures were agreed to before the emergence of other natural gas pricing mechanisms, which has led to natural gas import prices that are about 20%–25% higher than the average European import price.
2. Long-term contracts: BOTAŞ has signed long-term, off-take contracts (20 to 36 years) without flexibility on renegotiations, a point it will contend strongly during negotiations in 2021.
3. Take-or-pay obligations: Current contracts are subject to an 80% minimum off-take obligation, making it difficult to switch to supply sources with lower prices or better contractual terms without incurring sizeable penalty fees prior to expiry.
4. Elimination of final destination clauses: Turkey is aiming to become one of the world's next physical/virtual natural gas trading hubs, with free and open trade with its neighbors, requiring the elimination of final destination clauses in existing and new contracts.

Table 7 Turkey's natural gas import contracts with expiry dates

Natural Gas Supplier	Importer	Actual Off-Take	Pricing Structure	Contract Maturity
Azerbaijan Gas Supply Company (Baku–Tbilisi–Kars–Erzurum pipeline)	BOTAŞ Petroleum Pipeline Corporation, Turkey	6.6 BCM	Oil-indexed pricing under long-term contracts	April 2021
Nigeria LNG		1.3 BCM		October 2021
Gazprom (TurkStream pipeline)		4 BCM		December 2021
Gazprom (TurkStream pipeline)	Private companies	4 BCM		December 2021
Sonatrach, Algeria (LNG)	BOTAŞ Petroleum Pipeline Corporation, Turkey	4.4 BCM	Oil-indexed, Arab Crude Reference Basket	October 2024
Gazprom (TurkStream pipeline)		16 BCM	Oil-indexed pricing under long-term contracts	December 2025
National Iranian Gas Company		9.6 BCM		July 2026
Azerbaijan Gas Supply Company (TANAP)		6 BCM		June 2033
Gazprom (TurkStream pipeline)	Private companies	6 BCM		December 2042

The window of opportunity to provide new natural gas supplies opens in late 2025–2026, making IKR gas a real potential contender to replace higher-priced alternatives, especially supplies from Iran. Uncontracted demand is estimated to be 10–30 BCM/y by that time, but that market is currently heavily contested by Russia, Iran, Azerbaijan, and LNG from various suppliers. If Sakarya natural gas enters the commercial sphere, this supply source could play a highly significant role. Post-2030, the outlook for Turkish gas demand is quite optimistic, despite rapid growth in renewables; there will be limited or no new nuclear after the under-construction Akkuyu plant, an aggressive coal phase-out can be anticipated to come into force (in line with growing pressure on climate policy), and there is potential for growth in new gas-using sectors such as hydrogen. The largest opportunity for Kurdish gas in

Turkey would therefore be displacing natural gas imports from Iran, while at the same time meeting new demand. However, there are various scenarios that would reduce gas demand in Turkey, creating an even more competitive situation with fewer opportunities for the IKR or FI. These scenarios involve slower economic growth, retention of coal, more nuclear power, or lack of development of new gas-using industry. The opportunities diminish further if IKR/FI supplies are not developed rapidly enough to meet one of the contract expiry windows.

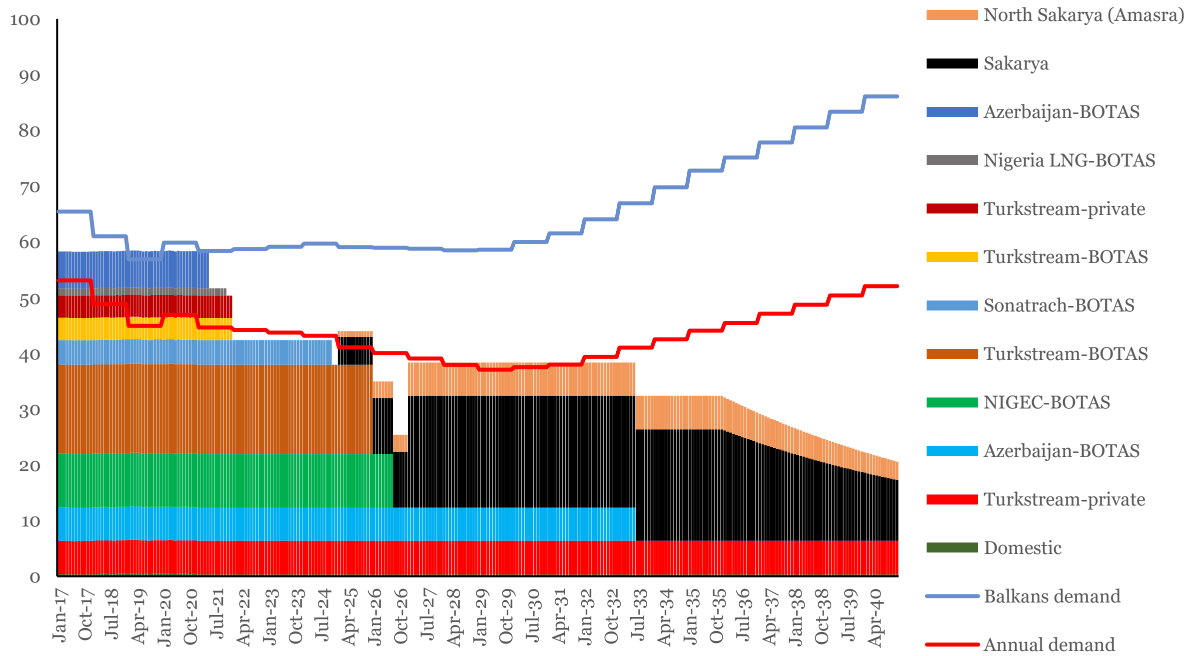


Figure 24 Turkey demand for natural gas, contracted, annualized, BCM

The Balkans have additional demand potential, but the market is highly competitive and relatively distant for IKR exports. Most of the Southeast European natural gas market is fragmented and dominated by Russian natural gas, while the largest market, Romania, is nearly self-sufficient and has its own offshore gas development plans[29]. TurkStream II will replace the Trans-Balkan pipeline through Ukraine as the main route for Russian supplies, while additional gas from TANAP/TAP and LNG via Krk (Croatia) and Alexandropoulos (Greece) will increase competition. New gas might be needed as demand grows from replacing coal/lignite and converting smaller markets to natural gas (Albania, Kosovo, North Macedonia, Montenegro), pushing import requirements to 20 BCM in 2026 and 34 BCM by 2040.

However, Kurdish natural gas will struggle to compete directly, given the long transport distances (hence higher delivered costs), dominance of incumbent suppliers, and Turkey's own natural gas hub ambitions. IKR gas could be purchased by Turkey for resale as part of its gas hub plans, which would simplify the marketing task for the IKR and its companies, but Turkish entities would then presumably retain most of the margin. TAP recently offered expanded capacity with three options of 4.4 BCM/y, 7.1 BCM/y and 10 BCM/y, but found no firm takers[30]. Securing long-term contracts for gas imports from European buyers to underpin long-distance pipeline construction or expansion is difficult given concerns over the future of gas in the European energy mix.

[29] For example, 1 BCM/y from Black Sea Oil & Gas, and 42–82 BCM resources in the Neptun Deep field, to be sold by ExxonMobil to Romgaz, https://www.blackseaog.com/about-us/at-a-glance/
[30] https://www.atlanticcouncil.org/blogs/energysource/tap-and-the-southern-gas-corridor-challenges-to-expansion/

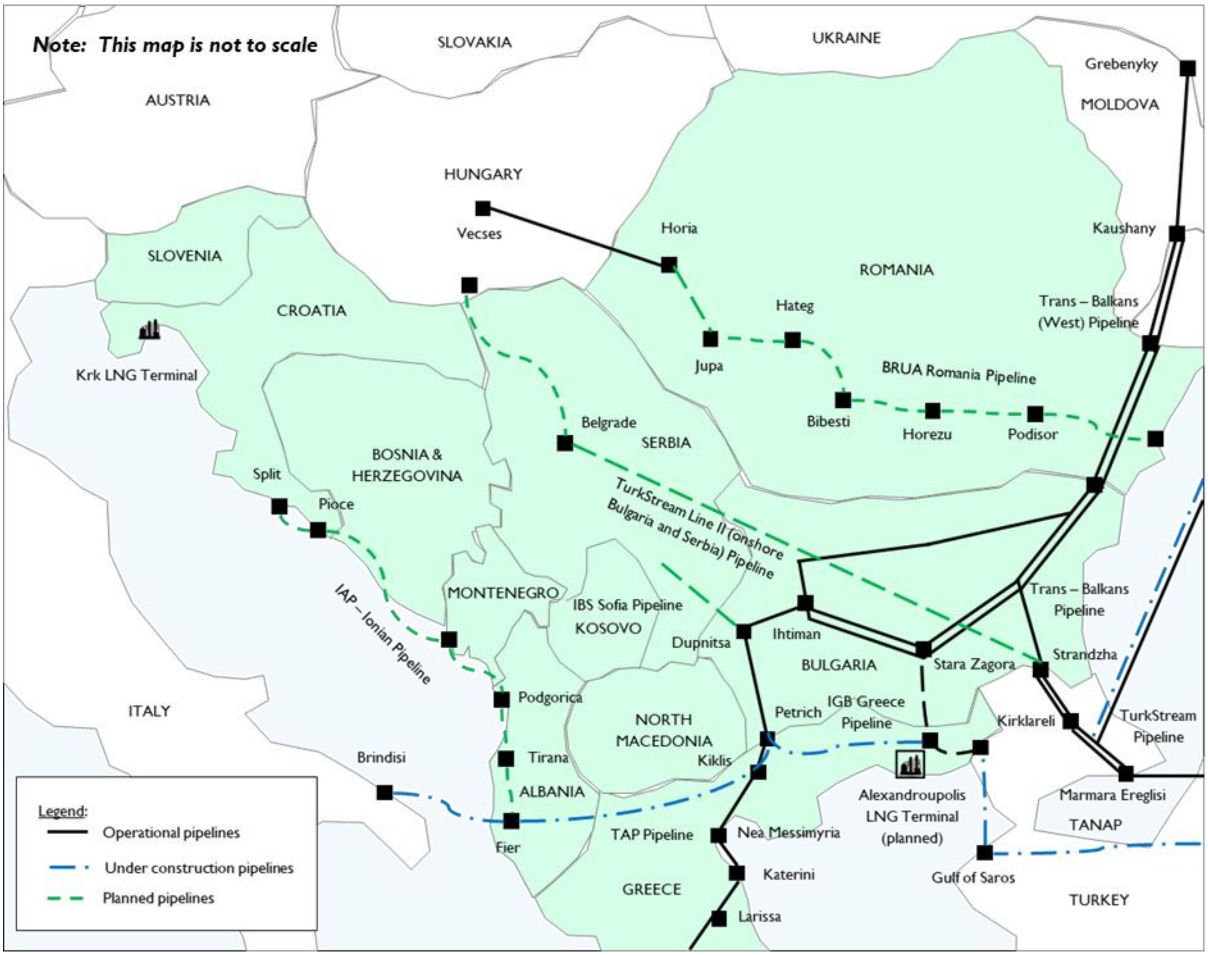


Figure 25 Major natural gas pipelines and LNG terminals in Southeast Europe

2.2.3 Natural Gas Pricing

Table 7 shows the current and 2026 forecast natural gas prices in the Turkish market. Iranian and Azerbaijani natural gas are by far the most expensive. However, Azerbaijan has no other ready market and, when its contract is up for negotiation in April 2021, could be motivated to reduce prices to make supplies more attractive. Oil-indexed prices in 2020 were based on Brent crude prices of US$ 41.76 per barrel and are based on a Brent crude price future of US$ 49.97 per barrel in 2026. US LNG prices to Turkey are based on Henry Hub prices of US$ 1.97 per MMBtu in 2020 and US$ 2.61 per MMBtu in 2026, using the typical long-term contractual relation of Free-on-Board LNG price = (Henry Hub x 1.15) + 3, plus US$ 1/MMBtu for shipping and US$ 0.6/MMBtu for regasification. Note that new U.S. contractual models might somewhat reduce this price. Changes in any of these assumed prices would affect mid-term competitiveness but will be considered and adjusted for when contracts are renewed or renegotiated.

Table 8 Estimated Turkish natural gas supply costs

Natural Gas Supply Contract	Oil-linked (% to Brent)	Tariff from border (US$/MMBtu)	Liquefaction (US$/MMBtu)	Shipping (US$/MMBtu)	Regasification (US$/MMBtu)	Final Price (US$/MMBtu)	
						2020	2026
Spot LNG	-	-	-	-	0.6	4.43	6.45
US LNG to Turkey (Henry Hub-based)	-	-	3.00	1.00	0.6	6.87	7.60
Iran to Turkey	13.6%	N/A	-	-	-	5.68	6.80
Gazprom (Russia) to Turkey	11%	0.73	-	-	-	5.32	6.23
Azerbaijan (TANAP) to Turkey	8%	2.42	-	-	-	5.76	6.72
IKR to Turkey border	-	Border Cost to Turkey	-	-	-	-	3.19
IKR to Istanbul	-	Border Cost to Turkey + Zakho to Istanbul	-	-	-	-	5.59

IKR gas could be substantially cheaper than Iranian gas in eastern Turkey, the IKR's prime market. IKR gas could also be price-competitive with supplies from the Azerbaijan TANAP in western Turkey if Turkey's gas grid is made more flexible to carry Kurdish natural gas from east to west. Figure 28 illustrates the estimated and forecast delivered natural gas costs across Turkey in 2020 and 2027. Note that BOTAŞ tariffs are not based on distance but on exit and entry fees, and as such IKR supplies could be assessed as more competitive in western Turkey than shown here. However, for the purposes of this analysis, it has been assumed that BOTAŞ would take these costs into account when comparing import options.

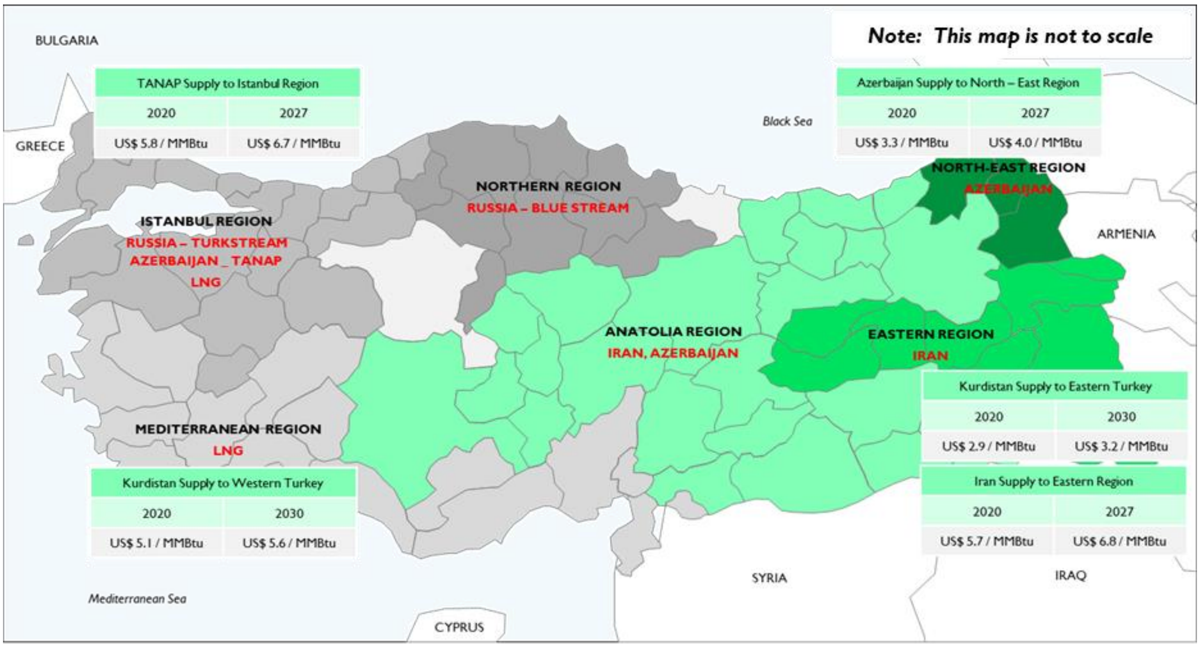


Figure 26 Estimated and forecast delivered natural gas costs across Turkey

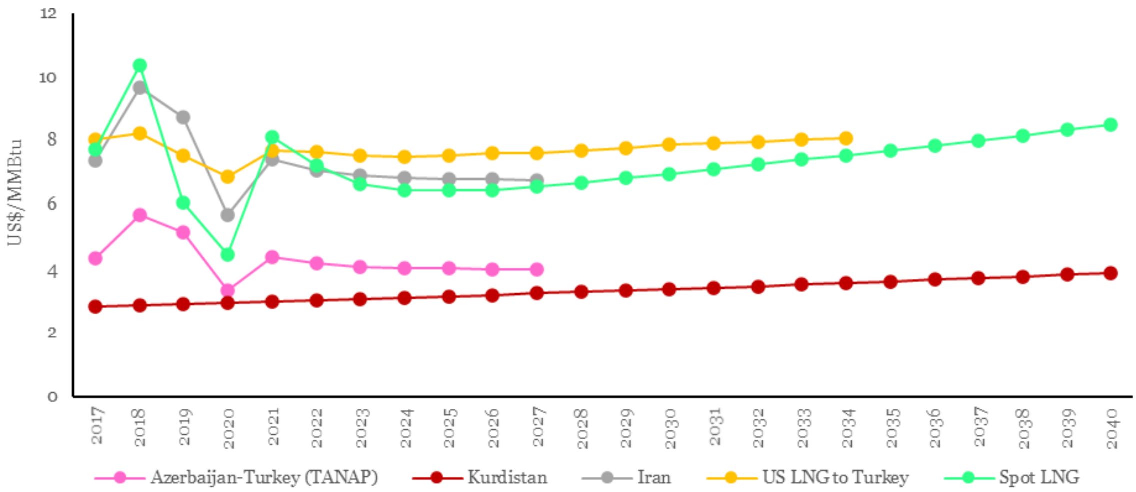


Figure 27 Natural gas delivered costs to eastern Turkey, US$/MMBtu

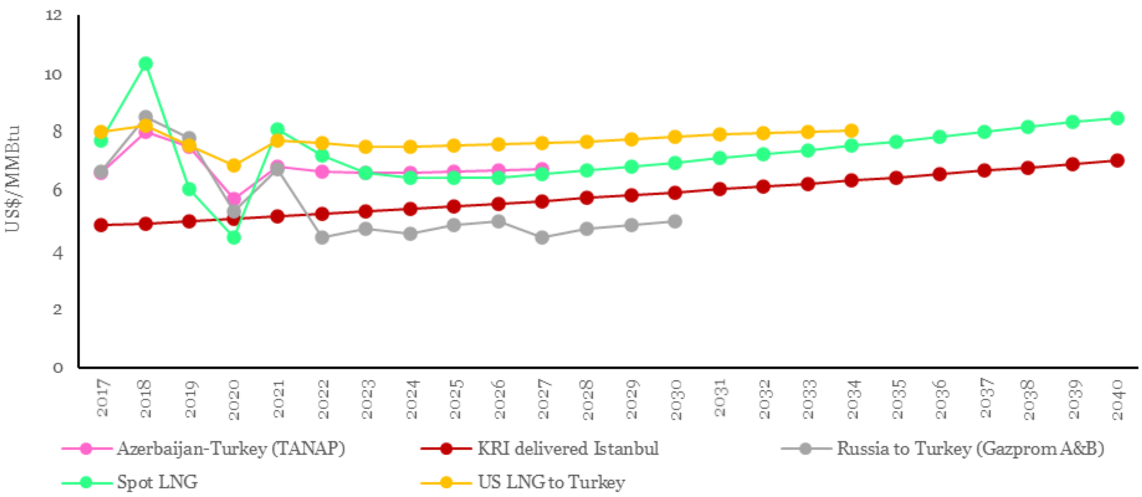


Figure 28 Natural gas delivered costs to Istanbul, US$/MMBtu

The price that IKR suppliers would be able to realize in negotiations therefore lies somewhere between their production and transport cost, as a lower bound, and the marginal competing supplier after renegotiation, as an upper bound. The larger the volume of IKR gas to be sold, the more competitive (i.e., lower) prices will have to be to outcompete incumbent suppliers. Natural gas from the IKR could be competitive against TANAP and U.S. LNG, but potential sales could be undercut by cheaper supplies from Gazprom, which has the ability to cut its prices, restricting the available Turkish market size for IKR gas. However, although price is very important to Turkey, the competition is not purely price-based. Diversification, reliable supply, and possibly political factors (to some extent) play a part. To underpin field development and pipeline construction within the IKR, developers will likely need long-term contracts with relatively high take-or-pay levels, which conflicts with the Turkish authorities' objectives in new supply contracting. On the other hand, the diversification benefits from IKR gas, the relatively positive relations between Ankara and Erbil, the politically unthreatening position of the IKR with respect to Turkey, and the presence of the state-owned Turkish Energy Company (TEC) in some upstream projects in the IKR are supportive factors.

2.2.4 Natural Gas Balance

Turkey's natural gas demand will enter a transitionary period of decline as the country diversifies its energy mix with renewable energy (mostly hydropower, solar, and wind), nuclear, and coal. It has dropped since 2017, although it was up somewhat in 2020 and early 2021, due mostly to drought constraining hydroelectric generation. By 2030, natural gas demand for power is projected to fall to low levels, before picking up in 2032 as coal is retired and new uses appear in the industrial and other natural gas sectors, such as hydrogen. By 2040, the power, residential, commercial, and industrial sectors will account for 60% of Turkey's total natural gas demand.

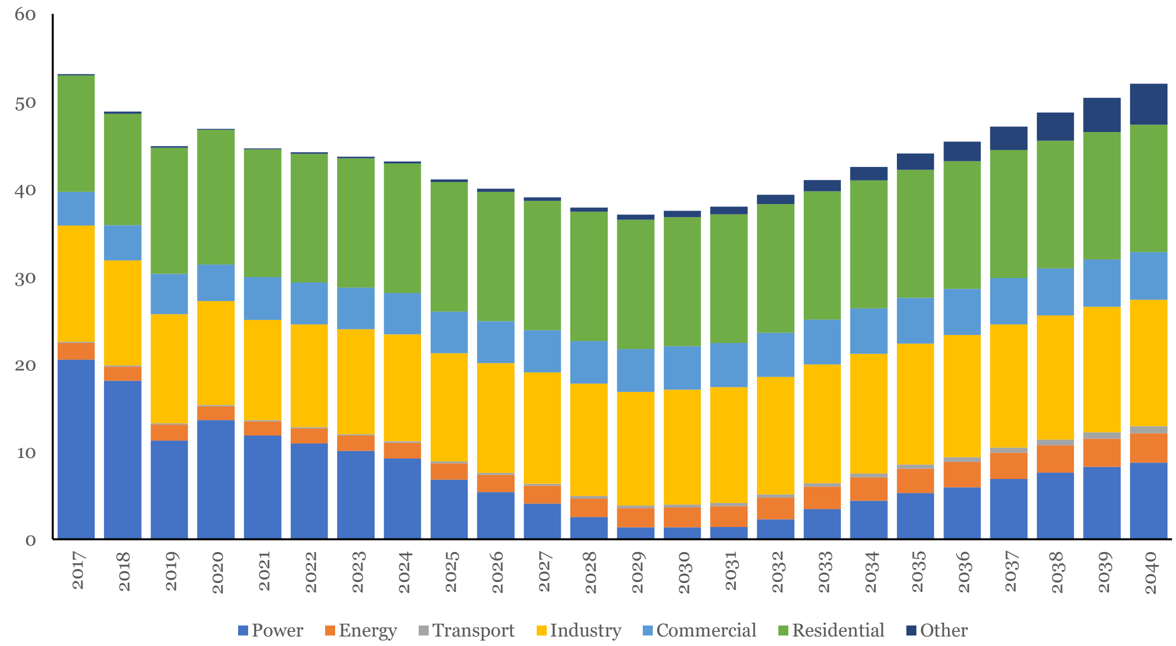


Figure 29 Turkey natural gas demand until 2040, BCM/y

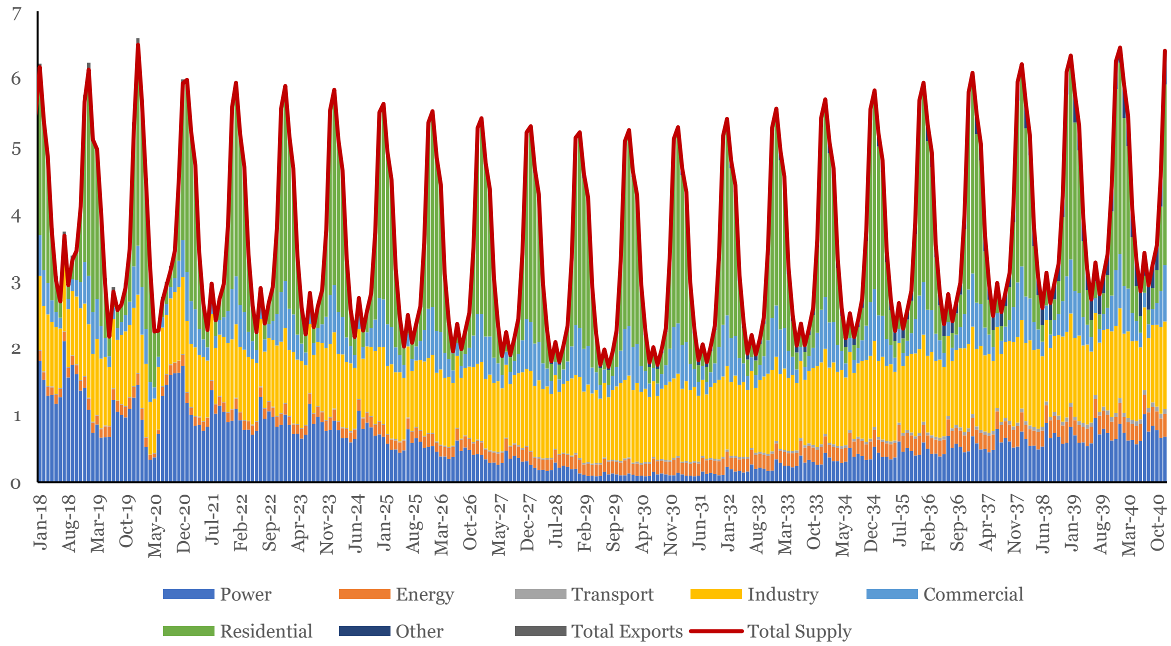


Figure 30 Turkey natural gas demand, monthly, until 2040, BCM/m

Peak natural gas demand is projected to increase only marginally between 2020 and 2040. Turkey's natural gas grid has been extended to almost all provinces, meaning that not many new sources of demand exist in the short to medium term. From 2034 onwards, industrial demand is projected to increase for new industries and alternative fuels (such as hydrogen and other synthetic fuels). Commercial natural gas demand, meanwhile, is expected to remain flattish, owing to efficiency gains and soft economic indicators.

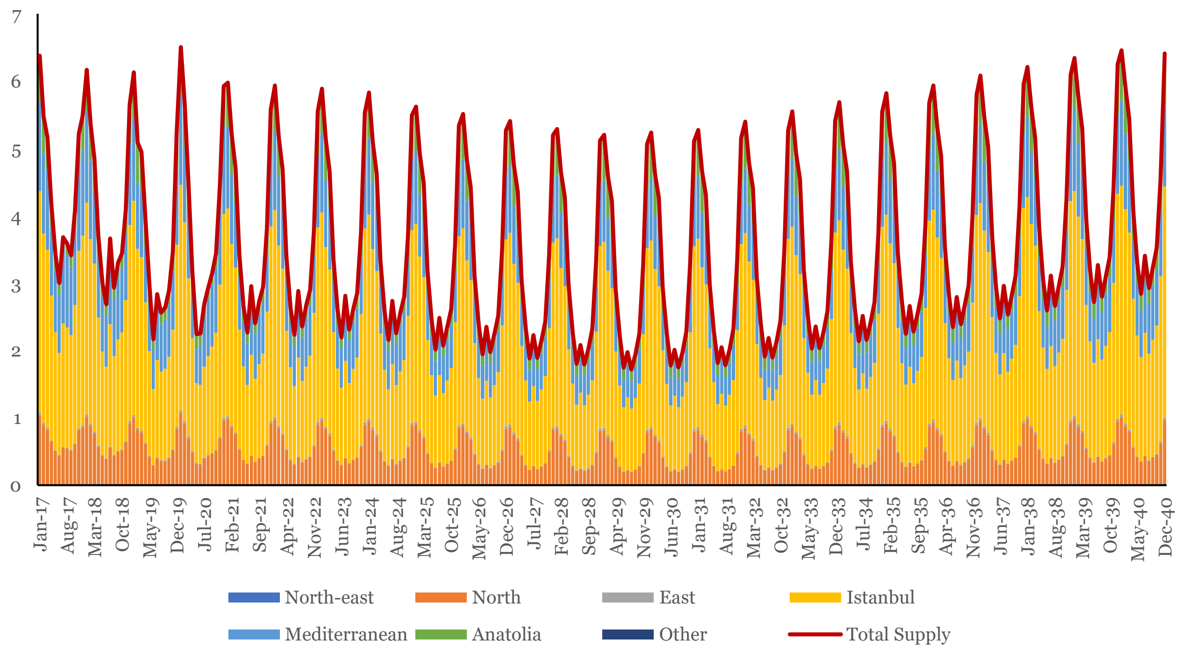


Figure 31 Turkey natural gas demand by region, monthly, until 2040, BCM/m

The Istanbul area will remain the highest consumer of natural gas in Turkey until 2040. Kurdish gas could be cost-competitive against Azerbaijan TANAP in Istanbul, although the area is situated far from potential IKR exports. Istanbul will continue relying on TurkStream for Russian gas, even if overall demand does not rise much. Eastern Turkey and the Mediterranean regions, meanwhile, could benefit from natural gas from Kurdistan, depending on the timely development of a Kurdistan–Turkey pipeline. Initial exports could begin when the Erbil–Duhok pipeline is completed and extended to the border, where BOTAŞ has already constructed a pipeline within Turkey. However, all the IKR's internal demand must be met before supplies are exported to Turkey. Large-scale flows to Turkey could begin in 2027, if gas supply talks between FI and Kurdistan are not productive, or in 2032, if the IKR–FI talks bear fruit and Kurdistan prioritizes flows to FI (starting in 2025). This timeline must be adhered to if suppliers in the IKR are to hit the 2026 window of contract expiry.

3 Developing the IKR Natural Gas Sector: Political, Technical, and Commercial Considerations

Table 9 Summary of key barriers to development

Barriers	Notes and Comments
Political	▪ Lack of clear lines of authority and empowered leadership in the Ministry of Natural Resources prior to the appointment of Minister Atroshi in January 2021. ▪ Political rivalries within and between the Patriotic Union of Kurdistan (PUK) and the Kurdistan Democratic Party (KDP). ▪ Outcome/sustainability of discussions/agreements with federal Iraqi government on budget, revenue-sharing, and crude oil exports. ▪ Turkey's unclear regional political intentions. ▪ Uncertainty due to the direction of sanctions policy and U.S.–Iranian negotiations (although future U.S. sanctions on Iranian gas exports could benefit Kurdistan). ▪ Security threats from ISIS, Iran-aligned militias and (both inside Turkey and IKR) from PKK ▪ Local community protests, political interference and corruption. ▪ Political deadlock and vested interests in FI.
Technical	▪ Mountainous terrain, causing challenges for pipeline routing and field development. ▪ High occurrence of sour gas with many fields having hydrogen sulfide >10%, requiring costly treatment and sulfur disposal, storage, or export. ▪ Relatively small associated gas production from most fields, limiting economies of scale. ▪ Fractured carbonate reservoirs, making drilling and production/reserves evaluation challenging.
Commercial	▪ Insufficient creditworthiness of buyers, notably the Ministry of Electricity (federal) and Ministry of Electricity (KRG), because of low tariffs and collections; Iraq requires risk mitigation schemes from external institutions, that could support payment guarantees and ensure parties comply with their obligations. ▪ International oil companies (IOCs) have competing interests and plans in terms of export markets and infrastructure options. ▪ Low currently offered gas prices, and/or contract terms, that do not incentivize development of flared gas capture projects, new investment in fugitive methane prevention and green house gas emissions reduction, and shared core infrastructure. ▪ Insufficient financial resources for MNR to play envisaged role of a midstream aggregator. ▪ Unclear role and intentions of Rosneft on planned pipeline to Turkey, although this agreement lapses in mid-2022. ▪ Continued economic downturn brought on by COVID-19 and depressed oil prices.

3.1 Political Dynamics

The development of the natural gas sector in Kurdistan is exposed to various internal and external political and regulatory risks, many of which are derived from internal disagreements within the IKR, between the IKR and Baghdad, and between the IKR and neighboring countries that enjoy positive trade relations with the IKR, but are also wary of promoting Kurdish autonomy across the region.

Politics Internal to the IKR and Iraq

The IKR political structure is largely dominated by two rival parties, the Kurdistan Democratic Party (KDP) and the Patriotic Union of Kurdistan (PUK). The Kurdistan Regional Government consists of a tenuous coalition between KDP, PUK, and third-party Goran, but the KDP has had a lock on many key positions in the KRG and in Erbil and Duhok governorates, while PUK controls Sulaymaniyah. Rivalries between the three governing partners and other smaller parties hinders a united Kurdish stance on many issues, including oil and gas development. This situation has had impacts on the formation of the KRG coalition government and the respective appointments in the executive cabinet, and has often politicized appointments in the MNR, which is led by a KDP affiliated appointee, and other institutions.

After the First Gulf War of 1990–1991, the Iraqi Kurdistan area was able to establish a degree of autonomy from Baghdad. Following the U.S.-led invasion of Iraq and the overthrow of Saddam Hussein in 2003, the Kurdistan region negotiated an autonomous government within a federal structure. However, relations with the federal government have been tense and conflicted, owing to disputes over important topics: the status of Kirkuk and other contested territories; control over oil and gas developments, exports, and revenues; and the share of the federal budget received by the KRG.

To secure its autonomy and develop its economy, the KRG has increased its regional and international profile through political, socio-economic, trade, and investment partnerships. In addition to the internal political structure, the IKR's external and regional political profile features (1) a mixed relationship with Turkey that juxtaposes a constructive trade and economic relationship with a challenging political and security relationship centered around Ankara's opposition to increased autonomy for Kurdish regions in Turkey and the continued presence of Turkey-focused Kurdish separatist organizations (including the PKK) in the IKR; (2) positive relations with the United States and European countries and reliance on their political, military, and economic support; (3) cautious engagement with Russia and China in some economic aspects; and (4) wariness of the increasing influence of Iran in FI, but constructive engagement with Iran in some areas, particularly trade with the IKR.

Independence Referendum

In September 2017, the KRG held a controversial advisory referendum on independence that amplified political tensions with the national government. The referendum was carried out despite requests from the governments of the United States, Iraq, and external actors to delay or cancel it. Around 72% of eligible voters participated in the referendum, of whom ~92% voted "Yes." The referendum was held across IKR and in other areas that were under the control of Kurdish forces. These areas included territorially disputed areas between the KRG and the central government of FI, such as the city of Kirkuk, the adjacent crude-oil-rich areas, and parts of the Ninewa governorate.

Following the referendum, the central government of FI imposed a ban on international flights to the IKR. In October 2017, Prime Minister Haider Al Abadi ordered Iraqi forces to return to the disputed territories that had been under KRG control prior to the Islamic State's 2014 advance. Much of the crude-oil-rich governorate of Kirkuk that has been long claimed by the KRG returned to the control of the central government. The central government of FI removed the international flight ban in 2018 following an agreement on border control, customs, and security at the airports in the IKR. October 2017 remains a flashpoint between the KDP and PUK, who continue to blame each other for the KRG's losing control of Kirkuk.

The referendum delayed the long overdue legislative elections at the Kurdistan National Assembly, which were eventually held in September 2018.

Legislative Elections

Table 10 Kurdistan region's legislative elections summary

Kurdistan Region's Legislative Elections (September 2018)	
Coalition Party	**Seats Won**
Kurdistan Democratic Party	45
Patriotic Union of Kurdistan	21
Change (Goran) Movement	12
New Generation	8
Komal	7
Reform List	-
Kurdistan Islamic Union	5
Azadi List	1
Modern Coalition	1
Turkmen Parties	5
Christian Parties	5
Armenian Independents	1

The KDP won a plurality of the vote with 45 seats out of 111 seats, followed by the PUK with 21 seats, and the remaining split between the smaller opposition parties. Following the election, KDP leader Masrour Barzani (son of former president Masoud Barzani) was appointed the prime minister of the IKR, and his cousin Nechirvan Barzani was appointed the president of the IKR.

Following the elections, factions within the PUK differed over the KRG cabinet formation, in addition to the KDP and PUK's differences on the regional level. One of the settlements achieved between the KDP and PUK was the appointment of Barham Salih, a PUK member and former KRG prime minister, as candidate for the FI National Presidency, traditionally held by a Kurd.

In March 2019, the KDP and PUK leaders announced a four-year political agreement that led to the establishment of the KRG cabinet, set joint positions on the national cabinet, and led to agreements on the governorship of Kirkuk.

In January 2021, Dr. Kamal Mohammed Atroshi was confirmed as the Minister of Natural Resources in the KRG cabinet, following a parliamentary vote of a majority 81 out of 111 votes. Those who did not vote for him included opposition party members from Komal, Kurdistan Islamic Union, the New Generation party, and some members of the PUK. They called for reforms in the crude oil sector, including revising crude oil contracts and disclosing production, exports, and revenue data. Atroshi had been serving as an advisor to KRG PM Masrour Barzani.

Prior to the appointment of Dr. Atroshi, Prime Minister Masrour Barzani was the functioning and acting Minister of Natural Resources since his government's establishment in July 2019. The former long-running minister, Dr. Ashti Hawrami, had continued as an adviser to the prime minister, but his involvement in the oil sector and his availability were increasingly limited, and many industry insiders complained of the lack of transparency and opaque contracts during Ashti's tenure.

Relationship with Federal Government

Central features of the KRG's relationship with the central government in FI are disagreements and periodic discussions on national budget allocation, hydrocarbon exports, and revenue sharing.

Iraq's hydrocarbon sector is an uneven geographic distribution of crude oil and natural gas resources, and the legacy of communal favoritism practiced under Saddam Hussein has created a lasting concern among Kurds and Iraqis regarding equitable distribution of revenues. These disputes continue to shape sectarian violence and have negatively affected Iraq over the last two decades. The dispute on budget allocations, hydrocarbon exports, and revenue-sharing generally enjoys bipartisan agreement between the KDP and PUK in the IKR, though the PUK has sought to exploit Erbil-Baghdad disputes to undermine the KDP.

The KRG and the federal government often disagree on the principles and mechanisms by and through which Iraq's crude oil revenues are to be collected and distributed. What is required is an equitable and mutually acceptable system of sharing that is fundamental to the IKR's and FI's future political and economic stability.

Article 112 of the Iraq's constitution requires the government to distribute revenues:

> *"…in a fair manner in proportion to the population distribution in all parts of the country, specifying an allotment for a specified period for the damaged regions which were unjustly deprived of them by the former regime, and the regions that were damaged afterwards in a way that ensures balanced development in different areas of the country, and this shall be regulated by a law."*

Budget

On March 31, 2021, Iraq's Parliament passed the country's 2021 budget, preserving the currency devaluation (~23%) and outlining a significant deficit of US$ 19.5 billion (calculated on the devalued currency, which makes the 2021 budget deficit the largest dinar-denominated deficit in recent history; the 2019 budget contained the largest dollar-denominated deficit, of US$ 23.3 billion). The budget includes provisions for normalizing the IKR's contribution to federal revenues, in addition to restructuring its debts owed to trading houses and international oil companies.

In addition, Kurdistan is to receive a 7.4% share of the national budget if it transfers 250 kb/d of crude oil exports to FI's State Oil & Marketing Organization (SOMO); otherwise, FI shall subtract the value of these exports from the IKR's allocation. Prior to 2018, the KRG was allocated 17%, less deductions for sovereign expenses, though disagreements were frequent on the calculation of this amount and how much was actually transferred.

Table 11 Iraq budget breakdown

Federal Iraq, Draft Budget, 2021	Amount
Spending Budget	US$ 89.7 B
Deficit	US$ 19.5 B
Crude Oil Revenue (allegedly calculated on a 10-month calendar)	US$ 47.5 B
Kurdistan Allocation (assuming 250,000 b/d crude not transferred to SOMO)	US$ 6.6 B
% of national spending budget	7.4%

Table *12* 2021 budget breakdown to KRG

2021 Budget Breakdown to KRG	At Budget Price of US$ 45/b	At February Iraq OSP of US$ 60.3/b
KRG Monthly Oil Revenues from 460 kb/d Exports	US$ 621 M	US$ 832 M
Transfer of Monthly Revenues from 250 kb/d Oil to SOMO	US$ 337.5 M	US$ 450 M
Monthly Payments to KRG Oil Sector	US$ 358 M	US$ 358 M
Remaining Revenue with KRG	-US$ 74.5 M	US$ 24 M
Budget Transfer from Federal Iraq	US$ 550 M	US$ 550 M
Payment to Kurdish Civil Servants	US$ 440 M	US$ 440 M
Net Profit to KRG, Monthly	US$ 35.5 M	US$ 134 M

Relations External to the IKR and Iraq

The development of the IKR's natural gas sector is also exposed to its mixed external and regional relationships with Turkey and Iran. Historically, Turkey has sought to limit Kurdish influence and identity across Turkey, because of concerns relating to Turkish territorial integrity and political stability. The PKK is a Turkey-based, Marxist–Leninist separatist movement that emerged in the 1970s and sought to challenge traditional Turkish Kurdish tribal hierarchies. For more than 30 years, the PKK has engaged in on-and-off conflict with the government of Turkey and with fellow Kurds in Turkey, in addition to developing links with other Kurdish groups in Iraq, Syria, Iran, and Europe.

However, Turkey is the KRG's largest regional trading partner and an external source of investment, particularly as consumer and transport hub for crude oil extracted from Kurdish-controlled territories. Turkey's economic linkages and political relations with the KRG provide Turkey with leverage to better manage its efforts to mitigate conflict and reach a greater political accommodation with the wider Kurdish community.

For several years, Turkey has aided the KRG efforts to export crude oil through Turkey without the approval of the central government in FI, which is another factor causing uncertainty for developers and impacting relations with FI and Turkey as the parties resolve an ongoing legal dispute.

In addition to this, the development of the IKR's natural gas sector is related to the future of Iranian supply of natural gas to Turkey and FI. In June 2020, government officials from the United States and Iraq resumed a high-level strategic dialogue pursuant to the 2008 United States–Iraq Strategic Framework Agreement, which addressed security, economic, stabilization, and cultural exchange concerns.

One of the features of the dialogue was helping Iraq become energy self-sufficient. The Trump Administration repeatedly extended waivers of U.S. sanctions to allow Iraq to purchase electricity from Iran. However, the issue remains an irritant until Iraq completes plans to become more energy-independent and diversifies its energy partners.

Turkey and FI are the two main potential customers for natural gas sales and exports from Iran. In recent times, Turkey has made significant shifts in diversifying its natural gas imports from Iran by increasing LNG and natural gas imports through cross-border pipelines from Azerbaijan and Russia.

In March 2020, a cross-border natural gas pipeline from Iran to Turkey was attacked, which disabled its operations. Turkey did not rush to repair the pipeline, indicating that natural gas imports from Iran may not be critical under the current economic and supply conditions. In contrast to Turkey, FI imports from Iran are vital to maintaining the current levels of electricity supply.

Substituting imports of natural gas from Iran with those from the IKR offers Turkey and Iraq long-term economic and geopolitical benefits. Although not sanctioned directly, Iraq faces problems, as noted, in paying for Iranian gas due to banking-related sanctions.

3.2 Technical Considerations

The technical considerations in developing the IKR's natural gas sector are mostly related to its geography and geology and to the composition of the IKR's natural gas, which is mostly sour.

The IKR comprises mostly the governorates of Erbil, Sulaymaniyah, Duhok, and Halabja, which was split from Sulaymaniyah in March 2014. The IKR borders Syria to the west; Iran to the east, separated by the highest parts of the Zagros Mountains within the IKR; and Turkey to the north, where fertile plains meet the Taurus Mountains. The IKR is traversed by the Sirwan river, the Tigris, the Great Zab, and the Little Zab. The most prominent geographic feature is the mountainous terrain, which increases the difficulty and cost of developing a natural gas pipeline from the region to Turkey or FI. The mountains across the IKR have an average height of about 8,000 feet (~2,400 meters), which increases to 10,000–11,000 feet (3,000–3,300 meters) across different regions. The highest point is Mt. Halgurd in north central IKR, with a height of 12,251 feet (3,734 meters). The typically northwest–southeast trending mountain ridges are often separated by deep gorges. The southern IKR (Garmian area) is less mountainous but features heavily eroded badlands.

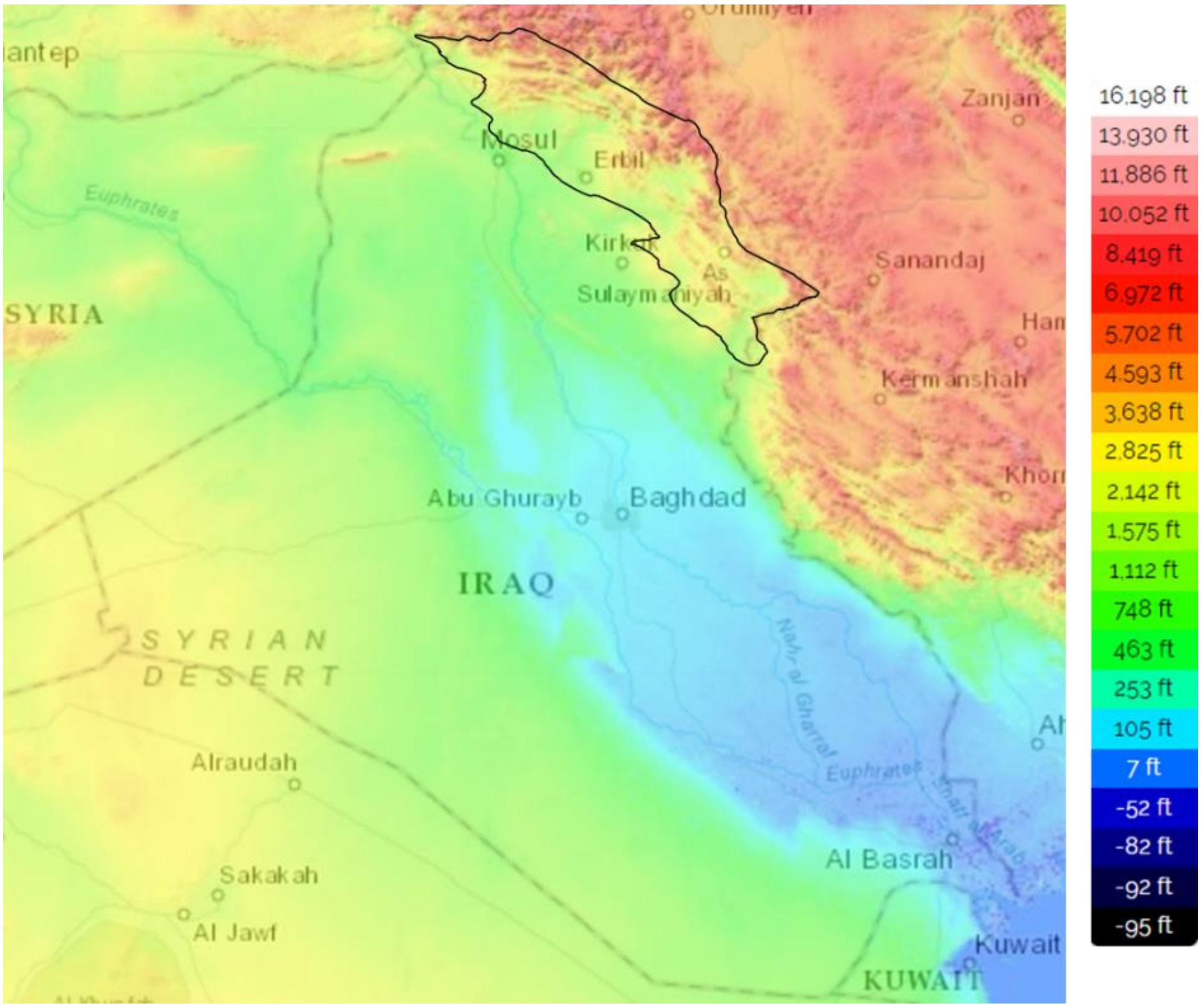


Figure 32 IKR and Federal Iraq topography

A key feature of much of the IKR's natural gas resources is high levels of hydrogen sulfide (H_2S) that makes the natural gas "sour." H_2S is a poisonous and corrosive gas that must be chemically treated and removed if present in levels greater than 4–10 parts per million (ppm).

Many of the IKR's natural gas fields have significant H_2S levels, at ~10% (or 100,000 ppm). Miran and Bina Bawi contain natural gas with H_2S levels reaching up to 160,000 ppm. On the other hand, Khor Mor, Topkhana and Kurdamir contain gas with relatively low levels of H_2S.

The main issues that sour gas causes for development in the IKR are:

1. Safety concerns of piping raw sour gas over mountainous and populated terrain to central processing units, as noted in the discussion of the Northern Associated Gas system. Processing gas at each individual field would raise costs;
2. Significantly higher costs for gas production and treatment due to requirements for corrosion-resistant alloys, processing, safety systems, and sulfur handling/removal;

3. Logistical and market issues of storing and/or exporting large quantities of elemental sulfur produced as a by-product of sweetening the gas.

The cost increase of sour gas production compared to sweet gas depends on the exact level of H_2S, the pressure of the wellhead fluids, the presence of other contaminants such as CO_2 and mercaptans, the size of the facility, the local situation and safety requirements, and the options for sulfur evacuation. Engineering studies suggest sour gas sweetening for low levels of H_2S (50 ppm) may add about $0.40/MMBtu to production costs[31]. Higher levels of H_2S can raise capital costs by 40% for oil and up to 70% for gas, because of the requirement for treating facilities, high levels of health and safety precautions, and for corrosion-resistant duplex or super-duplex steel alloys. Production costs from the Shah field in Abu Dhabi (23% H_2S, 10% CO_2) have been quoted as $5-6 / MMBtu[32], and $6/MMBtu for Kidan in Saudi Arabia (35% H_2S, 10% CO_2). [33] These are not exact comparisons to the IKR's sour gas fields, but are indicative of some of the challenges.

Table 13 Hydrogen sulfide and carbon dioxide in major Kurdistan natural gas fields[34]

Natural Gas Field	Area	Hydrogen Sulfide (ppm)	Carbon Dioxide (ppm)
Khor Mor	98 km²	100	NA
Miran	761 km²	12,000–20,000	40,000
Bina Bawi	240 km²		NA
Khurmala	360 km²	72,000	NA
Taq Taq	640 km²	130	NA
Pirmam		180,000	NA
Kurdamir		6,000	NA

Natural gas with substantial levels of H_2S requires costly treatment to comply to an acceptable specification for pipeline supply (no more than 4–10 ppm), in contrast to "sweet" natural gas with low levels of H_2S. H_2S poses serious safety risks (caused by leaks) to personnel and nearby communities, with well control incidents in some IKR fields causing serious concerns.

A common method of treating sour natural gas is through the Claus Process, which desulfurizes natural gas and recovers solid elemental sulfur.

[31] https://central.bac-lac.gc.ca/.item?id=MR50040&op=pdf&app=Library&oclc_number=710885018, allowing for subsequent inflation
[32] https://ppiaf.org/documents/5485/download
[33] https://www.meed.com/shell-to-pull-out-of-saudi-gas-joint-venture/, https://www.energyintel.com/pages/eig_article.aspx?DocId=687578, https://www.earthdoc.org/docserver/fulltext/2214-4609/287/1191375.pdf
[34] Company reports; https://pubs.geoscienceworld.org/geoarabia/article-pdf/20/2/181/4568154/mackertich.pdf

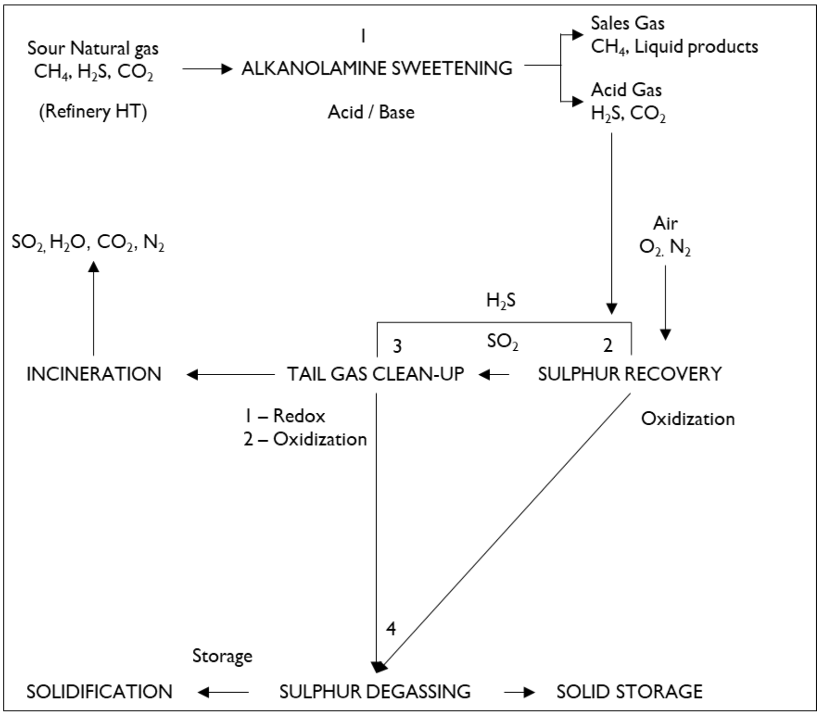


Figure 33 The Claus Process: natural gas sulfur treatment

The Claus Process is also used to treat by-products of gases that contain H_2S derived from refining crude oil, gasification, and industrial gases. Claus sulfur plants can achieve high recovery efficiencies, typically recovering 95%–98% of the hydrogen sulfide feed-stream.

For lean acid gas streams, the recovery typically ranges from 93% for two-stage units up to 96% for three-stage units. For richer acid gas streams, the recovery typically ranges from 95% for two-stage units up to 97% for three-stage units.

For facilities where higher sulfur recovery levels are required, the Claus plant is usually equipped with a tail gas clean-up unit to either extend the Claus reaction or capture the unconverted sulfur compounds and recycle them to the Claus plant.

New sour natural gas technologies and expertise are increasingly available across the United States, Canada, the United Arab Emirates, and Kazakhstan. An example of this is Royal Dutch Shell's Catalysts & Technologies, which offers a portfolio of innovative sulfur recovery technologies that cater to the full range of sulfur removal capacities that can be integrated as part of a complex natural gas cleaning line-up. In addition to technologies that utilize the Claus Process, the technologies offered by Royal Dutch Shell include other sulfur recovery systems and processes, such as Claus Off-Gas Treatment (SCOT), sulfur degassing, and the THIOPAQ O&G process, which integrates natural gas purification with sulfur recovery in a single unit. With relation to US companies, Exterran provides flexible sour gas processing solutions for already operating gas processing plants. These include the Recycle Split Vapor (RSV) retrofit, which allows plants to be modified to achieve ultra-high ethane and propane recoveries. Exterran has already provided an Iraq company with their RSV offering to manage extremely high H_2S content of natural gas for a gas plant, yielding butane, propane, and gasoline, in addition to addressing the H_2S content. Honeywell UOP tackles acid gas (a mix of H_2S and CO_2) removal through its proprietary UOP Separex™ membrane systems, the UOP Amine Guard™ FS process, UOP Benfield™ process, UOP SeparALLTM process, UOP Selectox™ process and other adsorbent technologies for bulk or selective H_2S and CO_2 removal. Baker Hughes offers Petrosweet H_2S scavenger solutions, that remove H_2S and other mercaptans efficiently through water-soluble, triazine-based scavengers and oil-based amine systems to lower CAPEX and replacement costs by keeping systems sweet. US upstream companies including ExxonMobil, Chevron and Occidental have been involved in major sour gas developments such as Tengiz and Kashagan (Kazakhstan) and Shah (Abu Dhabi). Other technological alternatives under development include reinjection of acid gas into a suitable reservoir, which might be difficult in the IKR given the fractured formations; the decomposition of H_2S to hydrogen, an emerging clean fuel[35]; and the combustion of H_2S for energy with the corrosive SO_2 gas product being reinjected into the sour gas reservoir.

With many international oil companies specializing in H_2S treatment through various technologies and processes, there is room for deeper collaboration between the MNR and the main IOCs working on sour gas fields in the IKR. This includes selecting appropriate technologies, setting safety regulations, and developing common infrastructure. The treatment of sour gas will produce large quantities of sulfur. As an illustration, 10 BCM/y of sour gas production with 20,000 ppm H_2S would yield 290,000 metric tonnes per year of solid sulfur. The UAE, the world's largest sulfur exporter, produces more than 6 million metric tonnes per year. Sulfur is a low-value or even money-losing by-product, whose price in Mediterranean markets rose fromt about US$ 60/metric tonne in late 2020 to $200-300/metric tonne in mid-2021[36], and used for producing sulfuric acid, fertilizers, preservatives, vulcanized rubber, and other applications. Unwanted sulfur can be stored in the open, but with risks of causing contamination and fires. Export would be preferable, most likely to Turkey, but the volumes produced by a future IKR sour gas industry would likely be too large for transport by trucking. The logistics of sulfur storage and transport, either in hot liquid form or as solid blocks, are complicated and have been discussed in the case of Kuwait, a more straightforward case given proximity to ports across relatively short distances of flat terrain[37].

In Abu Dhabi in the UAE, sulfur is moved by rail to ports. Plans for a railway in the IKR were announced in 2019 but are at an early stage. For comparison:

- At prices of about $60/metric tonne, 290,000 metric tonnes of sulfur export would earn about US$ 17M per year, rising to about $60M per year at $200/metric tonne.
- At current Turkish rail tariffs,[38] transport of sulfur over 600 km from the Turkish border to the port of Ceyhan would cost about $15/metric tonne, excluding the cost of rail within the IKR, and costs are shared with other goods transport.
- The UAE's 264 km Stage One of the Etihad railway, which carries 7.2 million metric tonnes of sulfur annually over mostly flat desert, required financing of $1.28 billion. Including operating and financing costs, that suggests at least $25/metric tonne of sulfur transported over 25 years.

Therefore, unless prices are sustained at mid-2021 high levels over an extended period, the revenues from sulfur alone are unlikely to cover the cost of such a railway, and plans would need additional economic justification in terms of other freight, cargoes, and passengers. A thorough business plan would include connections to other points within the IKR and possibly FI.

3.3 Commercial Considerations for Development

Selected commercial considerations/challenges for developing the natural gas sector in IKR include (1) uncertainty caused by the lack of movement on the existing agreement with Rosneft to construct a natural gas pipeline to Turkey; (2) FI's insufficient creditworthiness, which increases the risk exposure and profile of a proposed natural gas pipeline from IKR to FI; and (3) the payment risk incurred due to the weak "bankability" of power purchase agreements in FI and the KRG's weak financial capacity.

Rosneft Project

In 2017, Rosneft entered a deal to develop natural gas reserves in the IKR and construct a 30 BCM/year natural gas export pipeline from the IKR to Turkey. The pipeline would run parallel to the existing crude oil pipeline that

[35] https://www.sciencedirect.com/science/article/abs/pii/S0360319918332129
[36] https://www.argusmedia.com/en/blog/2021/june/30/sulphur-prices-in-the-mediterranean-pricing-peak-reached
[37] https://onepetro.org/SPEKOGS/proceedings-abstract/17KOGS/2-17KOGS/D021S002R002/195000
[38] http://documents1.worldbank.org/curated/en/223371593828212937/pdf/Turkey-Rail-Logistics-Improvement-Project.pdf

stretches from near Erbil to the border between the IKR and Turkey. The terms in the framework agreement for the natural gas pipeline between Rosneft and the MNR are unclear, but it is understood that the agreement expires in summer 2022.

Rosneft's strategic motives to develop the natural gas pipeline in IKR could be (1) to protect its compatriot Gazprom's market share in the Turkish market by stalling natural gas from IKR; (2) to challenge Gazprom's market share in the Turkish market, as part of competitive behavior within the Russian political-business scene; and/or (3) to acquire another point of economic leverage vs. Turkey, to be played at a time and in a way of Moscow's choosing. Elements of all three motivations may be present making it uncertain Rosneft plans to proceed with the project.

Rosneft has agreed to invest billions of dollars in the IKR's crude oil projects since 2016, including securing a majority stake (60%) in the region's crude oil pipeline for US$ 1.8 billion, with local firm KAR Group holding the remaining 40%. In addition to the natural gas pipeline, since 2017, Rosneft has spent US$ 400 million on five exploration blocks and US$ 1.2 billion on crude oil purchases.

However, Rosneft's plans for the natural gas pipeline have stalled, and the scale has changed, with the company planning a phased development of 3 BCM/year exports initially, in contrast to the originally planned first phase of 10–12 BCM/year. It is believed that the Rosneft pipeline agreement is an "option," expiring summer 2022, which would not prevent other developers from advancing their proposals, especially as Rosneft has not made tangible progress more than three years after concluding the agreement.

FI economic challenges/creditworthiness

The development of the IKR's natural gas sector is dependent on commercial financing – specifically the risk mitigation mechanisms utilized by an investor–developer consortium to mitigate the projects risks. FI does not generally follow the same model of development. Recent economic challenges from fluctuating oil prices have led to concerns about creditworthiness and long-term ability or willingness to pay for gas or power supplies on a commercial basis – a concern that could apply both to the IKR and FI. FI's long-term credit rating is affected by the country's high debt-to-revenue ratio, which stands at 222%, combined with a liquidity-to-GDP ratio of 9.9%.

In the short term to medium term, Moody's has rated FI's overall credit profile as "Caa1," which is assessed to be of poor standing and is subject to an exceedingly high credit risk. This is combined with a "Ba2" rating for economic strength, given that FI continues to balance its size and ample natural resource endowment against volatile economic growth, inadequate infrastructure, and the economy's lack of diversification and competitiveness; a "Caa3" for institutions and governance strength, which reflects significant institutional challenges and very low policy effectiveness; a "Ba3" for fiscal strength, which reflects a very high fiscal vulnerability to a decrease in crude oil prices and an increasing debt burden; and a "Caa" for susceptibility to event risk that is driven by high levels of political risk.

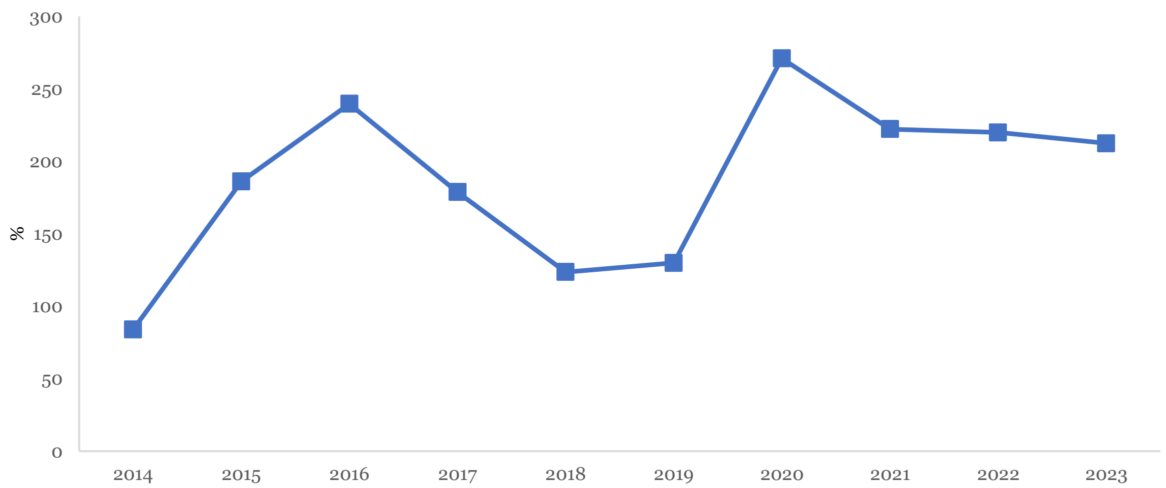


Figure 34 Long-term + short debt to revenue in FI, %

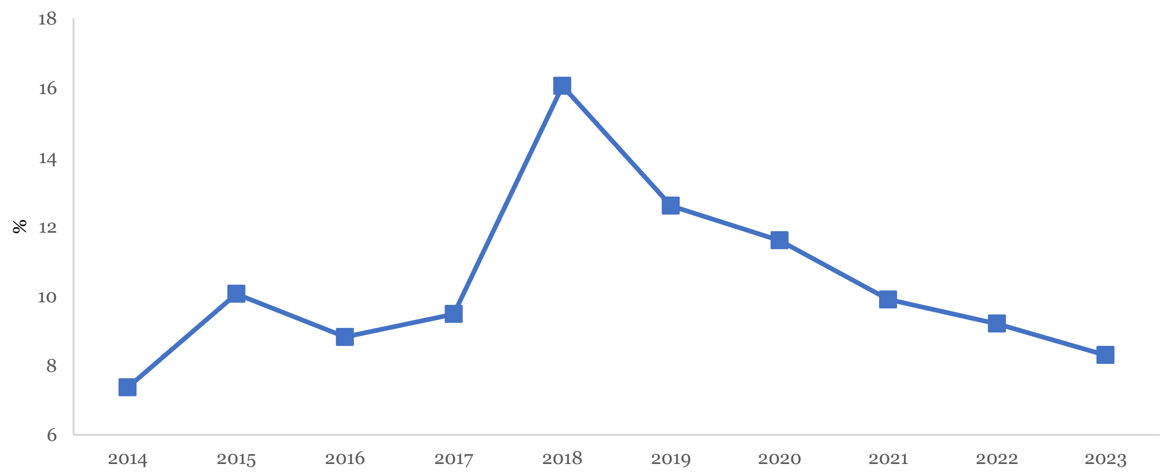


Figure 35 Liquid assets to GDP in FI, %

There are points to reflect on beyond the FI's insufficient creditworthiness: (1) on the World Bank's Governance Indicators, FI stands on the 10th percentile in terms of "regulatory quality," and (2) FI ranks 172/190 on the World Bank's Ease of Doing Business Ranking, 2020.

Should a prospective investor–developer consortium in the IKR decide to engage in a gas sales agreement from the IKR to FI, the investment, risk, and capital raising profile from equity and debt financiers would be dependent on the bankability of the power purchase agreement (PPA) the consortium enters.

International development and financial institutions such as the U.S. International Development Finance Corporation (US DFC) expect to enter into long-term off-take agreements with a creditworthy off-taker that is bankable with a sufficient financing tenor and enables repayment of debt financing through adequate and predictable revenue streams.

A PPA is assessed to be bankable if it provides a significant degree of purchase obligation from the off-taker that reduces payment risk. In addition, the PPA must clearly define how and when pre-agreed tariffs are paid, how extraordinary circumstances are mitigated, under what circumstances the project can be terminated, and how changes in taxes, local laws, and foreign exchange risk are mitigated.

If a prospective investor–developer consortium in the IKR decides to engage in gas sales to FI, the consortium is likely to be exposed to a significant payment risk. International financial institutions can provide financing instruments that mitigate non-payment risk for projects.

4 Base Case Scenario

4.1 Methodology and Assumptions for the Base Case

The base export and development scenario (hereafter referred to as the Base Case is based on a combination of upstream production estimates, anticipated infrastructure commissioning (pipelines and processing facilities), and natural gas demand factors in the IKR, FI, and Turkey. The Base Case has been developed from the information provided by the KRG Ministry of Natural Resources, key upstream operators in Kurdistan's natural gas sector, industry experts, the US Department of Energy, and analyses and review of third-party information sources, as well as publicly available information from the relevant government bodies in the IKR, FI, and Turkey.

The Base Case, along with the next four scenarios (see Section 5.1), assumes, as a constant, a steady pace of development of Kurdistan's natural gas resources, as per reasonable upstream development timelines. For fields without public development plans, we have analyzed credible third-party sources and, where available, communications with the companies concerned, to arrive at a reasonable commissioning estimate. Therefore, all scenarios are based on the following production timeline of Kurdistan's natural gas resources. This scenario is not intended as prescriptive or a recommendation; the timing of development depends on the results of further appraisal and detailed development planning, company decisions and financing capacity, government approvals, construction of infrastructure, signature of sales contracts, and other factors. The optimal sequencing of development and production levels may vary from that given here. Additional discoveries could also enter the development sequence, and/or reserves revisions could allow for higher or lower production from fields in this table.

Table 14 Upstream production estimates for **all** development and export scenarios, except Alternate Scenario V, VI, VII, BCM/y

Field	Type	Province	2020	2025	2030	2040
Khurmala	Associated	Erbil	0.92	1.10	1.10	0.68
Other[39]	Associated	IKR	0.02	1.53	1.90	4.71
Khor Mor	Non-associated	Sulaymaniyah	4.33	4.34	3.96	2.92
Khor Mor Phase-2	Non-associated	Sulaymaniyah		5.17	5.55	6.59
Chemchemal	Non-associated	Sulaymaniyah		0.78	1.55	1.55
Chemchemal Phase-2	Non-associated	Sulaymaniyah			2.59	4.66
Bina Bawi	Non-associated	Erbil			2.59	6.20
Miran West	Non-associated	Sulaymaniyah			0.84	5.89
Other[40]	Non-associated	IKR			2.56	9.19
Total	Associated		0.94	2.63	3.00	5.39
	Non-associated		4.33	10.28	19.64	37.00
	All		5.27	12.91	22.64	42.40

Kurdistan's natural gas demand is kept constant across all 8 scenarios. In 2020, estimated natural gas demand in Kurdistan was 11.41 BCM, comprising 7.68 BCM from the gas power sector and 3.73 BCM from the industry sector. Total gas sales that year were 5.27 BCM, resulting in a deficit of 6.14 BCM. By 2025, however, the natural gas

[39] Primarily Shaikan, Sarsang, and Kurdamir block associated gas
[40] Primarily Benenan, Topkhana, Kurdamir and Taza

balance in Kurdistan flips into a surplus, supporting potential for external sales. By 2040, growth in industry leads to an industrial demand of 10.1 BCM, supporting the IKR's plans for diversification into heavy industry, cement, fertilizers, and petrochemicals. Table 10 shows Kurdistan's natural gas demand used as constant across all development and export scenarios.

Minor use of gas in residential/commercial and transport applications is also possible but would not affect the overall conclusions. It is likely that only the major cities would be connected. The ten largest cities in the IKR have a combined population of about 3.35 million[41]; using typical Turkish benchmarks of 20–122 m^3/person/year commercial gas and 55–159 m^3/year residential gas, IKR consumption would likely be in the range of 0.07 BCM/y commercial and 0.18 BCM/y residential, which would require only a modest increase in production to satisfy. However, the provision of city gas would have positive social, economic, and environmental effects. Replacing electric heating with natural gas in winter would also slightly increase the gas surplus for export, as well as easing the load on the electricity grid, since gas used directly for heating is more efficient than generating power for heating (a modern gas heater has at least 78% efficiency, while combined-cycle generation plus transmission and distribution losses has efficiency of delivered heat around 32-47%). To the extent that gas provision replaces LPG, kerosene, or wood for heating, it would of course increase gas demand.

Table 15 Natural gas demand estimates for **all** development and export scenarios, BCM/y

Sector	2020	2025	2030	2040
Gas Power Demand	7.68	8.20	9.16	11.02
Industry Gas Demand	3.73	4.70	6.19	10.10
Total Gas Demand	**11.41**	**12.90**	**15.35**	**21.12**

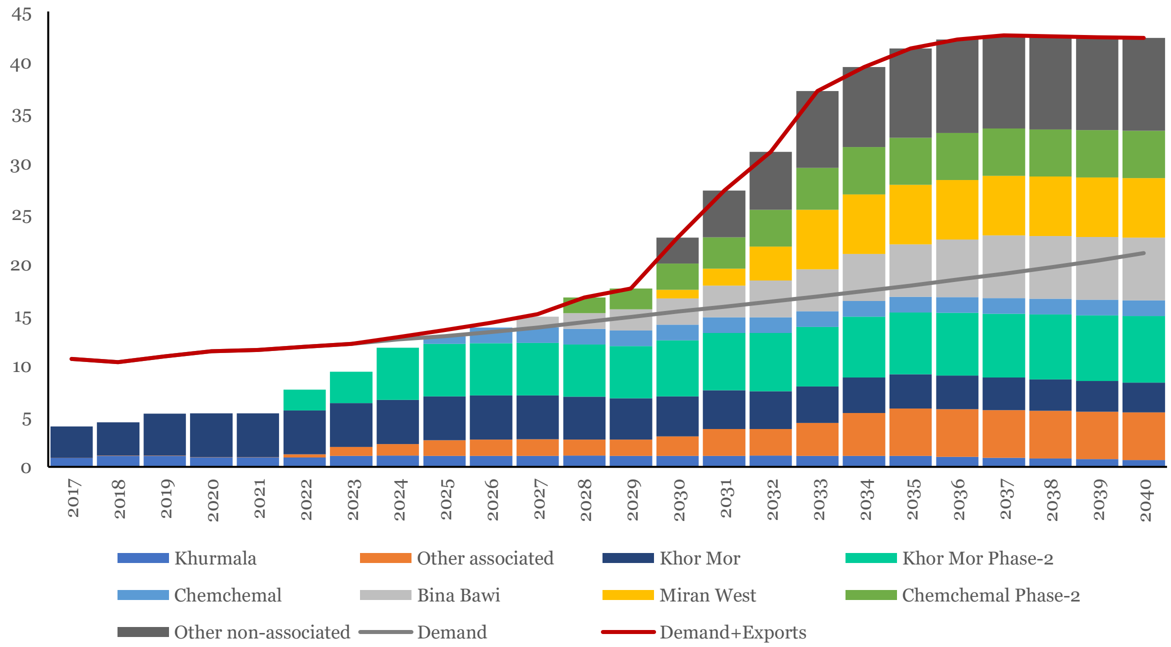


Figure 36 Upstream production and natural gas demand estimates for **all** development and export scenarios, except Alternate Scenario V, VI, VII, BCM/y

Therefore, the second assumption for **all** scenarios is the consistent estimate for natural gas demand in Kurdistan. The first assumption for **all** scenarios, except Alternate Scenario V, VI, and VII, is the consistent estimate for natural gas production in Kurdistan.

[41] UN; KRG

The third assumption for the Base Case is the commissioning (or repurposing) of the 0.4 BCM Khor Mor-Jambur–Kirkuk gas condensate pipeline to carry minor supplies of Kurdish natural gas to the FI market via Kirkuk. The existing natural gas grid in northern Kurdistan runs only to Erbil. Connection to the Turkish pipeline system, which is built within Turkey close to the border, requires commissioning of the Erbil–Duhok pipeline with a further extension to Zakho and on to the border, forming the backbone of the Turkey export pipeline in the future. The existing Khor Mor–Jambur and Jambur–Kirkuk condensate pipelines can be (or according to some sources, already has been) repurposed, easily and relatively inexpensively, into a natural gas pipeline from the Khor Mor area into FI (distribution lines further north or south are constrained – and additional testing and repair might be required to enable sustained operations). The Khor Mor-Jambur–Kirkuk natural gas pipeline is assumed therefore to have been repurposed to allow deliveries by 2025. Talks to this end with the FI government have been progressing positively, according to Crescent Petroleum, operator of the Khor Mor natural gas field and a participant in Pearl Petroleum.

Based on the third assumption, limited supplies of Kurdish natural gas to FI can commence soon with full volumes entering this pipeline around 2025 when more gas is available.

The fourth assumption for the Base Case is the commissioning of a 20 BCM/y capacity natural gas pipeline from Kurdistan to FI to supply surplus Kurdish natural gas to FI. The pipeline could come online by 2025, when an IKR natural gas surplus first appears in the Kurdish natural gas balance. The commissioning of the main IKR–FI pipeline by 2025 seems possible for four reasons: (1) within both the FI government and the MNR, there are compelling reasons for reaching an arrangement to trade energy with each other, (2) FI has a chronic natural gas deficit, (3) the U.S. continues to pressure Baghdad to wean FI off Iranian natural gas and power supplies, and (4) there is financing potential from the U.S., as IKR–FI pipelines would support U.S. energy policy for Iraq and has positive environmental, geopolitical, and social impacts.

The Base Case could include two possible routes for such a pipeline from the Khor Mor area: south through Diyala towards Baghdad, potentially connecting to the Mansuriyah field and to the fields awarded in FI's Bid Round-5; or northwest towards Kirkuk, connecting to the federal northern gas pipeline system and to Baghdad via Baiji from the northwest. In either case, it is assumed that the federal pipelines would be rehabilitated and expanded as required to accommodate the new volumes. Depending on the route, the gas would supply the power plants around Kirkuk, Mosul and Baiji, and the Baiji refinery, or the power plants in and around Baghdad, the Doura refinery, and the industrial area of Taji north of Baghdad.

The fifth assumption for the Base Case is the commissioning of the Sakarya gas fields in Turkey. Turkey currently plans to start producing from Sakarya in 2023 at 5–10 BCM/y, reaching 15 BCM/y by 2025. However, the Base Case assumes a less aggressive timeline that has first production from both fields coming online in 2025 (which seems probable if a fast-track development campaign, currently under way, obtains sufficient reservoir information to inform the master development plan). This assumption has an important impact on the volumes of gas imports required by Turkey.

The final assumption for the Base Case is the commissioning of the IKR–Turkey natural gas pipeline by 2027. The Erbil-Duhok section is assumed to be completed earlier to supply the Duhok power plant. Technically, the connection to Turkey could be completed earlier (within 15 months of an investment decision), but in the Base Case, the IKR does not have surplus gas for export until later. There is a logic to over-building the pipeline to prepare for an extension to Turkey and larger future volumes, but this would require additional financing without assurance that the extra capacity would be utilized. Small summer surpluses could be delivered on a spot basis, but it makes more sense to direct these to FI given its summer peak demand rather than Turkey where demand peaks in the winter. There are incentives for commissioning the Erbil-Duhok-Turkey pipeline over the longer term. Post-2030, the IKR will have a significant winter natural gas surplus remaining, even after delivery to FI. A common user pipeline/trunkline with reversible flows would support both supplies to Turkey in the winter and additional supplies to

FI in the summer. Commissioning of the IKR-Turkey pipeline is estimated for 2027, once the Erbil–Duhok connection is completed to carry marketable surplus natural gas from the southern IKR to Duhok.

Table 16 Key assumptions for the Base Case scenario, excluding constant assumptions for all scenarios

Key Assumptions		Capacity	Commission	Online	Balance	2021	2040
1	IKR Gas Production					5.3 BCM	42.4 BCM
2	IKR Gas Balance					-6.3 BCM	
3	Minor IKR–FI supplies to Kirkuk	0.4 BCM	2025	Yes			
4	Turkey Pipeline	15–30 BCM	2027	Yes			
5	Sakarya Fields (Turkey)	26 BCM	2025	Yes			
6	IKR–FI Pipeline	20 BCM	2025	Yes			
7	Supplies to FI					0.0 BCM	15.8 BCM
8	Exports to Turkey					0.0 BCM	5.3 BCM

Note that one variation on the Base Case could be "gas by wire," i.e., the development of gas-fired generation (possibly supplemented with renewable) capacity in the IKR with the primary intention to sell electricity to FI via expanded and new transmission. This would obviously affect the electricity sectors of both the IKR and FI, but directionally, the effect on the gas market would be the same: IKR gas production would expand, electricity provision to FI would increase, and FI would have far less need for other (non-IKR) gas imports. The choice of gas-by-wire versus gas pipeline sales depends on various factors, including existing infrastructure, the presence of unused generating capacity, relative transmission costs, and the timing of FI's power versus gas deficits. Currently, if FI completes planned power generation roughly on time, the country would have sufficient generating capacity by around 2025–2026 to meet demand, but the gas deficit is forecast to continue for substantially longer. Given the magnitude of transmission and distribution losses in the FI power grid, it might actually be more difficult to mitigate energy deficits in FI through trade in power vice gas - barring significant reform of the sector and improvement in operating practices and maintenance.

Pipeline costs (capital and operating) to deliver gas from the southern IKR to Baghdad, a distance of about 200 km, are estimated at US$ 0.23/MMBtu, equivalent to US¢ 0.20/kWh of electricity if used in a power plant with 40% thermal efficiency. If the pipeline is used on average at only 60% of maximum capacity, this cost rises to US¢ 0.33/kWh. Electricity transmission costs for a 400 kV line (roughly 400 MW), plus a substation, over the same distance are estimated at US¢ 0.76–1.2/kWh, including 7% line losses and assuming 60% utilization, depending on terrain[42]. Therefore, electricity transmission is estimated to be about 2–4 times more expensive than the equivalent pipeline transport of gas. However, electricity transmission may enable higher sales prices if electricity is priced against Iranian imports. As noted earlier, it is estimated that FI pays US¢ 7–12/kWh for electricity imports from Iran versus US¢ 7–10.7/kWh for generation using imported Iranian gas. At the upper limit, the additional margin of US¢ 1.3/kWh would more than cover the higher cost of the electricity transmission line. In addition, of course, shorter-distance tie-ins to the existing FI grid around Kirkuk or Mosul would incur lower costs.

[42] Using costs from https://openjicareport.jica.go.jp/pdf/12151825_03.pdf, https://iopscience.iop.org/article/10.1088/1757-899X/881/1/012044/pdf

Table 17 Potential Transmission Costs between IKR and Baghdad

Transmission Costs	IKR to Baghdad
Pipeline Cost (Capital & Operating) to deliver natural gas	US$ 0.23/MMBtu
Cost of gas transmission if used for electricity generation in FI at 40% thermal efficiency	US¢ 0.20/kWh
Cost of gas transmission if pipeline used at average 60% of maximum capacity	US¢ 0.33/kWh
Electricity transmission costs at 60% line utilization	US¢ 0.76-1.2/kWh

4.2 Base Case: Rising IKR Output Will Enable Two Export Markets

The Base Case allows for the successful development of two separate external markets for Kurdish surplus marketable natural gas: a primary summer market (FI) and a secondary winter market (Turkey). The projections assume a steadily increasing rate of gas consumption in the IKR power sector as new CCGTs are commissioned near Sulaymaniyah, Erbil, and Duhok. Projections of industry gas consumption growth assume that, as subsidies on delivered fuel oil are repealed, cement and refineries will switch to natural gas feedstocks, starting in the medium term (2025 onwards).

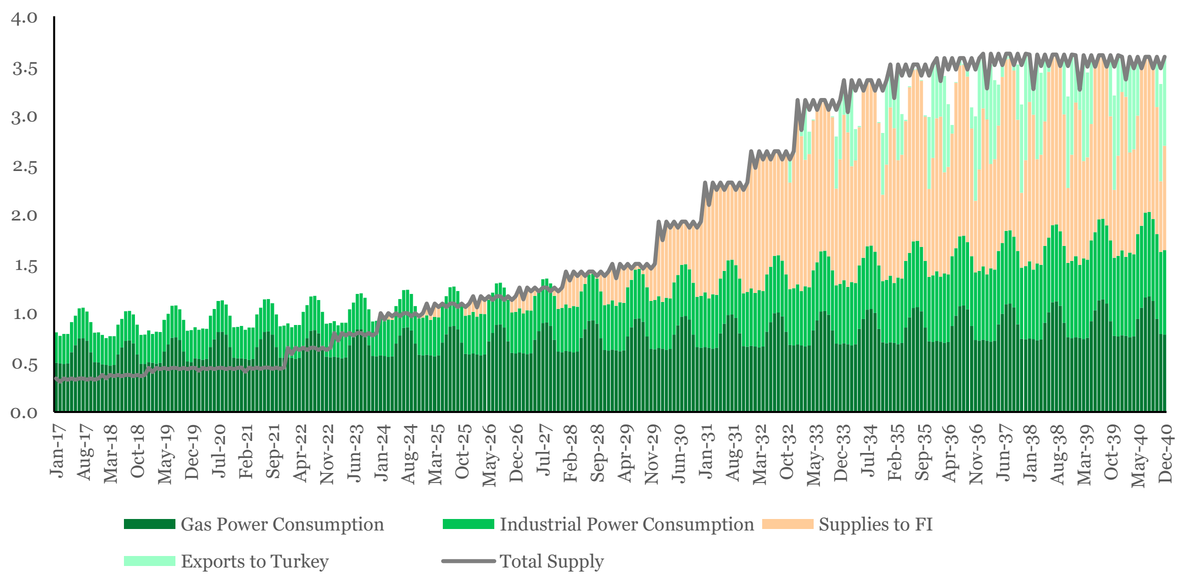


Figure 37 Kurdistan natural gas sector balance under the Base Case Scenario, BCM/m

Under the current rate of projected gas project development, a pipeline from the IKR to Turkey could be justified and commissioned by 2027. An Erbil–Duhok pipeline (to carry natural gas to meet rising power demand in the northern areas) will have to be constructed first to serve as the backbone of any exports to Turkey. However, because the priority market will be FI, and the timelines for development resulting in adequate volumes of surplus gas are long, Kurdistan might miss the 2026 market window for Turkey and may need to wait until at least 2032 for a new opportunity to market sizeable volumes of gas in Turkey. Regardless, the available Turkish market is secondary for this scenario, with Kurdish natural gas exports to Turkey still projected to average 5.3 BCM by 2040.

A winter surplus will be available between 2034 and 2037, even with full contracted sales to both Turkey and FI, if all known material resources are developed. Even with some surplus capacity to accommodate maintenance or interruptions, this overage will mandate policy allowing for flexible production and/or the construction of natural gas storage. Some volumes could be directed to local consumption (such as city gas for commercial and residential use), but this strategy would require concerted development of a city gas system with links between the major centers of demand and production/distribution nodes. Development of compressed natural gas or small-scale LNG could also be considered to supply transport and remote consumers.

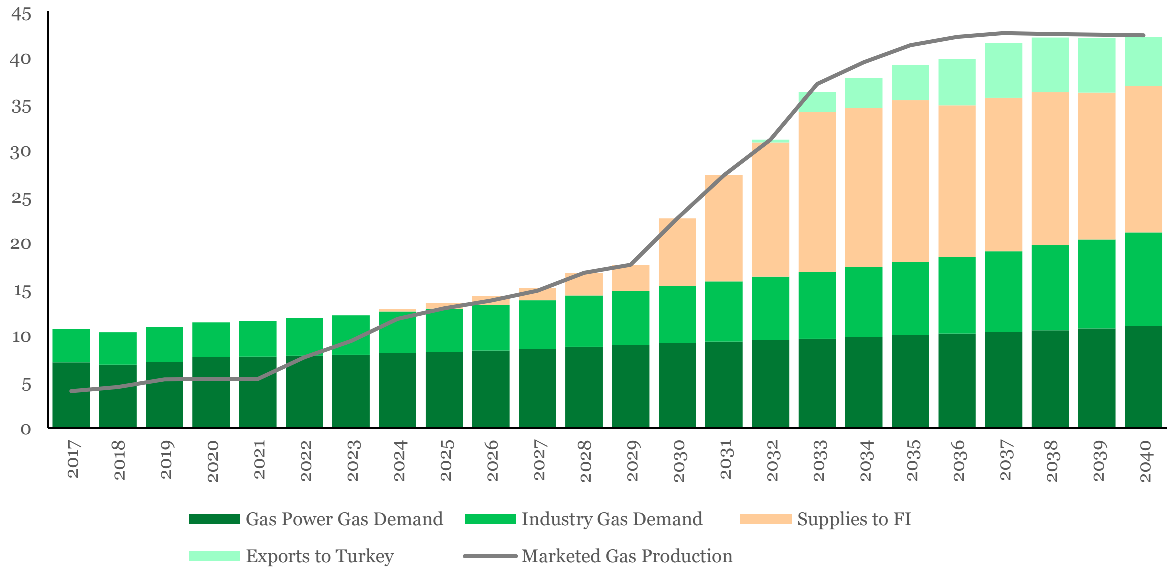


Figure 38 Kurdistan natural gas sector balance under the Base Case scenario, BCM/y: A small surplus emerges between 2035 and 2037

4.3 Base Case: IKR Gas to Federal Iraq Could Almost Eliminate Iranian Gas

Under the Base Case, major supplies of Kurdish marketable natural gas to FI via the 20 BCM/y proposed natural gas pipeline could begin in 2025. Although it will not necessarily reduce the amount of Iranian natural gas FI will continue to require until at least 2030, due to the magnitude of the power deficit in FI, the IKR supply will markedly narrow the gas deficit. From 2030 onwards, rising Kurdish natural gas flows could successfully start squeezing out Iranian gas sales via Basra; the need for Iranian sales could be nearly eliminated by 2033. Until 2040, FI will continue to receive relatively minor volumes of Iranian natural gas via Baghdad (the major 12.8 BCM/y Iran natural gas pipeline culminates in Baghdad). These small-volume sales will remain necessary to meet FI's high peak summer demand.

The Base Case assumes that Iran is able to successfully send full contracted gas volumes to Iraq until 2030, though Iran rarely supplies contracted volumes over a full year.

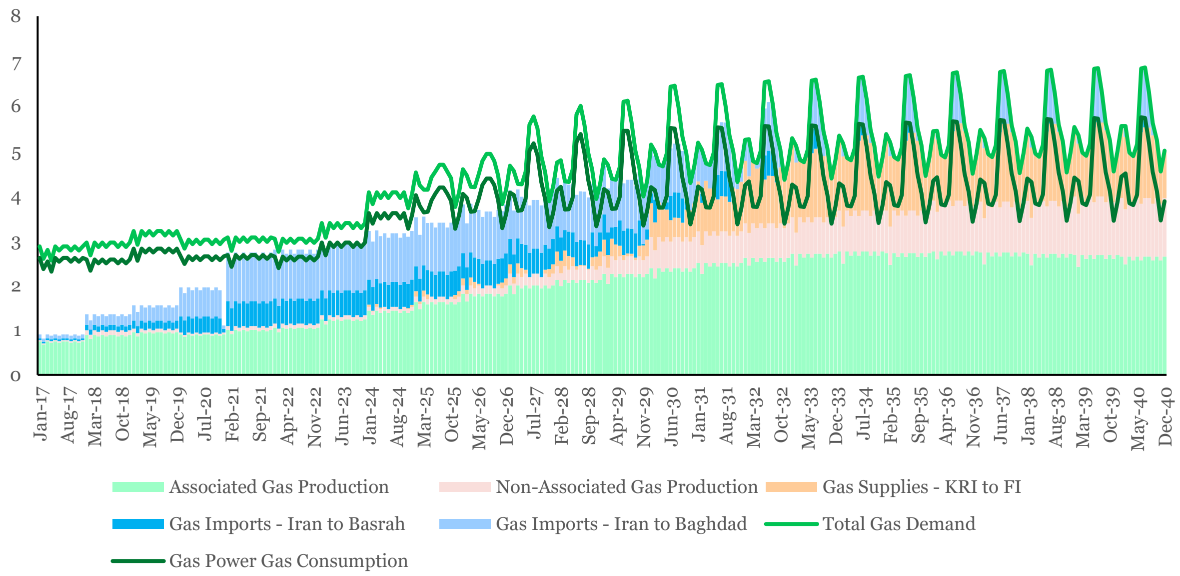


Figure 39 FI natural gas supply balance under the Base Case scenario, BCM/m

Supplies of Kurdish natural gas to the FI market can begin in 2023, thanks to the 0.4 BCM Khor Mor-Jambur-Kirkuk connection. While beginning this trade would send a strong signal that the KRG and Baghdad can work together on gas trade, this volume will not be sufficient to make a significant difference to FI's natural gas supply and demand balance. Even when major supplies start around 2025, the gas deficit in FI will continue to increase as new power generation capacity comes online in FI and peak demand grows, necessitating higher supplies. By 2033, however, we estimate that FI could succeed in eliminating its natural gas deficit fully, though with at least some imports. Domestic production will probably remain too low to meet demand (even though several non-associated gas and captured gas projects are fully developed) particularly during peak periods.

Iran's natural gas exports to FI were slashed in December 2020, but news coverage[43] mentioned these resumed at "full volumes" in January 2021. Periodic outages during peak periods or due to nonpayment add to uncertainty and argue for the need to reduce reliance on imports from Iran more generally. The Base Case assumes full delivery will continue going forward. As Figure 38 shows, even with full delivery, a certain amount of gas power demand will remain unmet, or will be met with fuel oil/diesel, until at least 2031. Note that "shrinkage" in this chart refers to removal of NGLs from the production stream. FI's associated gas volumes are also restricted currently, and may be in the future, by compliance with OPEC+ oil production cuts. FI's non-cyclic demand sectors (e.g., industry and non-energy gas consumption) are assumed to be less accommodating and flexible than the gas power sector, which can be modulated relatively easily to switch between gas and oil fuel. The gas power sector therefore plays a key role in balancing demand in FI. Given FI's highly seasonal demand patterns, with power generation for air conditioning peaking in the summer, flexible imports/gas purchases are essential to match demand, along with the ability to vary production from FI's own non-associated gas fields as and when they are developed.

[43] https://www.reuters.com/article/us-iraq-gas-iran/iran-to-resume-gas-flows-to-iraq-after-agreement-on-unpaid-bills-iraq-ministry-says-idINKBN2931RH

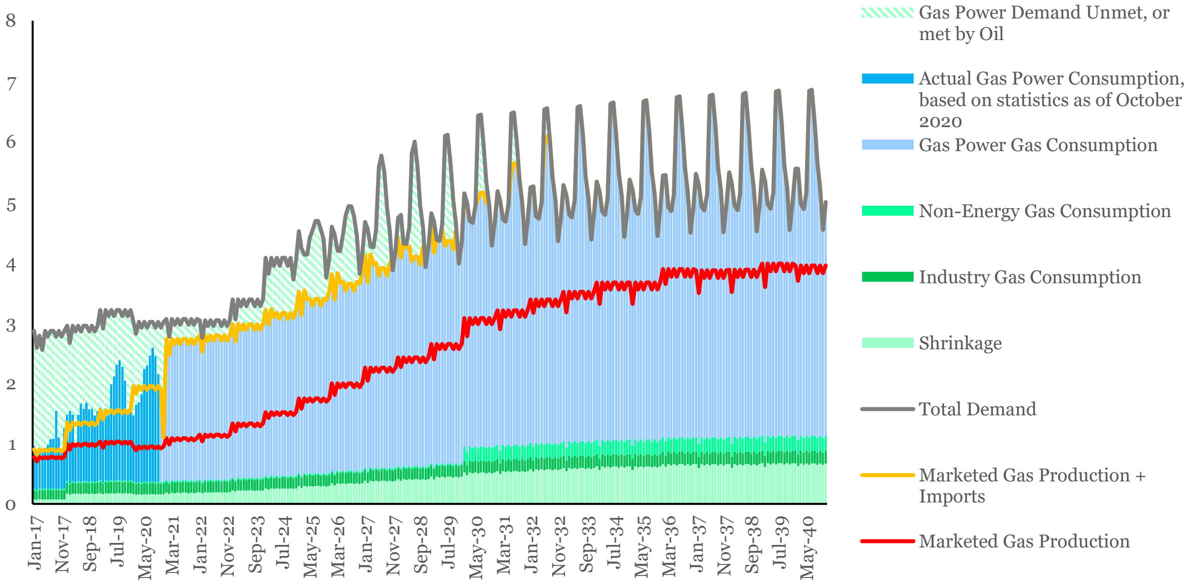


Figure 40 FI natural gas demand balance under the Base Case scenario, BCM/m[44]

4.4 Base Case: Kurdish Gas to Turkey Will Be Constrained by Supplies to Federal Iraq

Turkey will continue requiring Russian, Iranian, and LNG gas, even if a IKR–Turkey agreement is established and enacted. As noted above, a market window for Kurdish gas into Turkey will open by 2026–2027, assuming the successful completion of the Erbil–Duhok connection under the Base Case and the further connection to the Turkish border. However, even with this infrastructure in place, large volumes of Kurdish gas are not expected to be available until 2032, as the IKR will prioritize gas supplies to its own domestic sector first and in our estimation would be advised to focus on the FI market second due to timing, proximity and the existing need for gas to supply gaps in FI supply. Turkey will therefore have to continue acquiring gas from existing sources. However, required volumes are expected to be lower, as Turkey's own domestic gas production (from the Sakarya fields) should increase, and demand in the late 2020s and early 2030s will most likely flatten due to soft economic indicators and competing power generation methods and suppliers in Turkey.

The first IKR deliveries of gas to Turkey are expected to commence in late 2032, and at marginal volumes, before increasing to a final market of 5.3 BCM, annualized, in 2040.

[44] Historic discrepancy in import figures and consumption figures attributed to inaccuracies in reporting of FI and Iran data

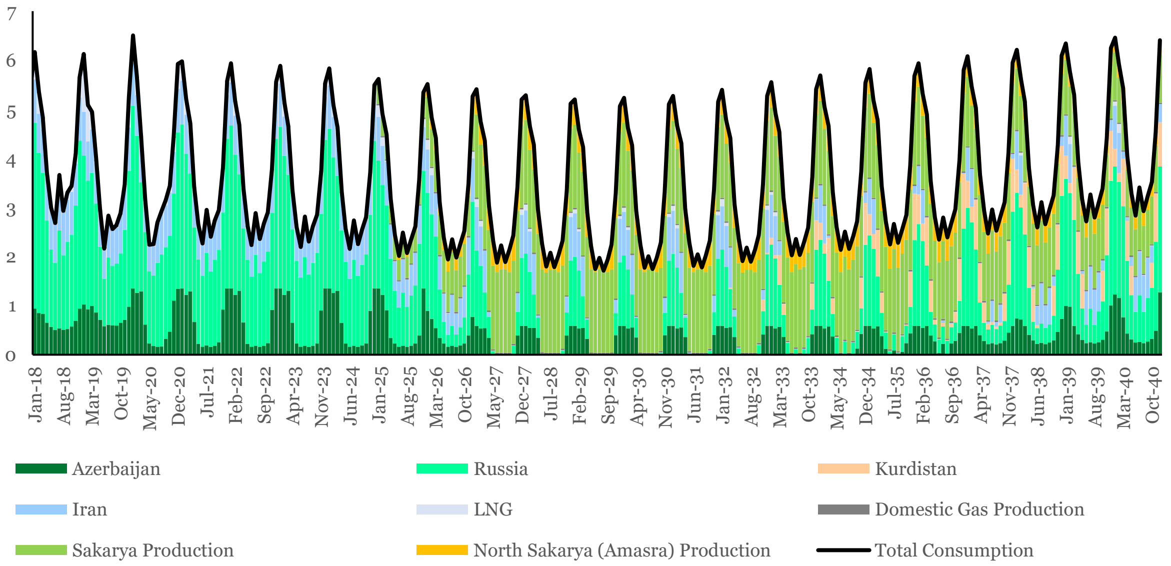


Figure 41 Turkey's natural gas supply balance under the Base Case scenario, BCM/m[45]

4.5 Base Case: In the Immediate Term, IKR Can Increase Captured Gas to Support Domestic Needs and Potentially Supplies to Federal Iraq in the Future

Although bulk external markets are generally not accessible until at least 2025, the local Kurdistan market requires significant additional volumes to meet demand in the immediate near term. The IKR can utilize the expansion of oil production from its northern oilfields to increase marketable natural gas output and achieve the environmental benefit of reduced flaring. Currently, most associated gas in Kurdistan is flared, even though a waiver for this is required from the MNR, because terms are not in place to ensure companies are compensated for the additional expense of capturing relatively small volumes of gas. In July 2021, the MNR sent a letter to field operators instructing them to halt flaring gas within 18 months[46].

Capturing flared natural gas from the Atrush, Shaikan, Swara Tika (Sarsang block), and Ain Sifni fields could feed a proposed Northern Associated Gas Gathering System (NAGGS) that would jointly process the sour gas from these fields, thereby saving costs. Projected associated natural gas production could reach ~0.2 BCM/y (or 187 Mscf/d) after oil production expansion plans, with Shaikan, Swara Tika, and Atrush being the main contributors. The individual companies would still need to receive adequate gas sales revenues to cover the cost of delivering the expensive-to-treat gas to this processing hub in a safe and environmentally sound manner.

Table 18 Associated gas volumes from Ain Sifni, Shaikan, Atrush, and Swara Tika, including planned oil production expansions

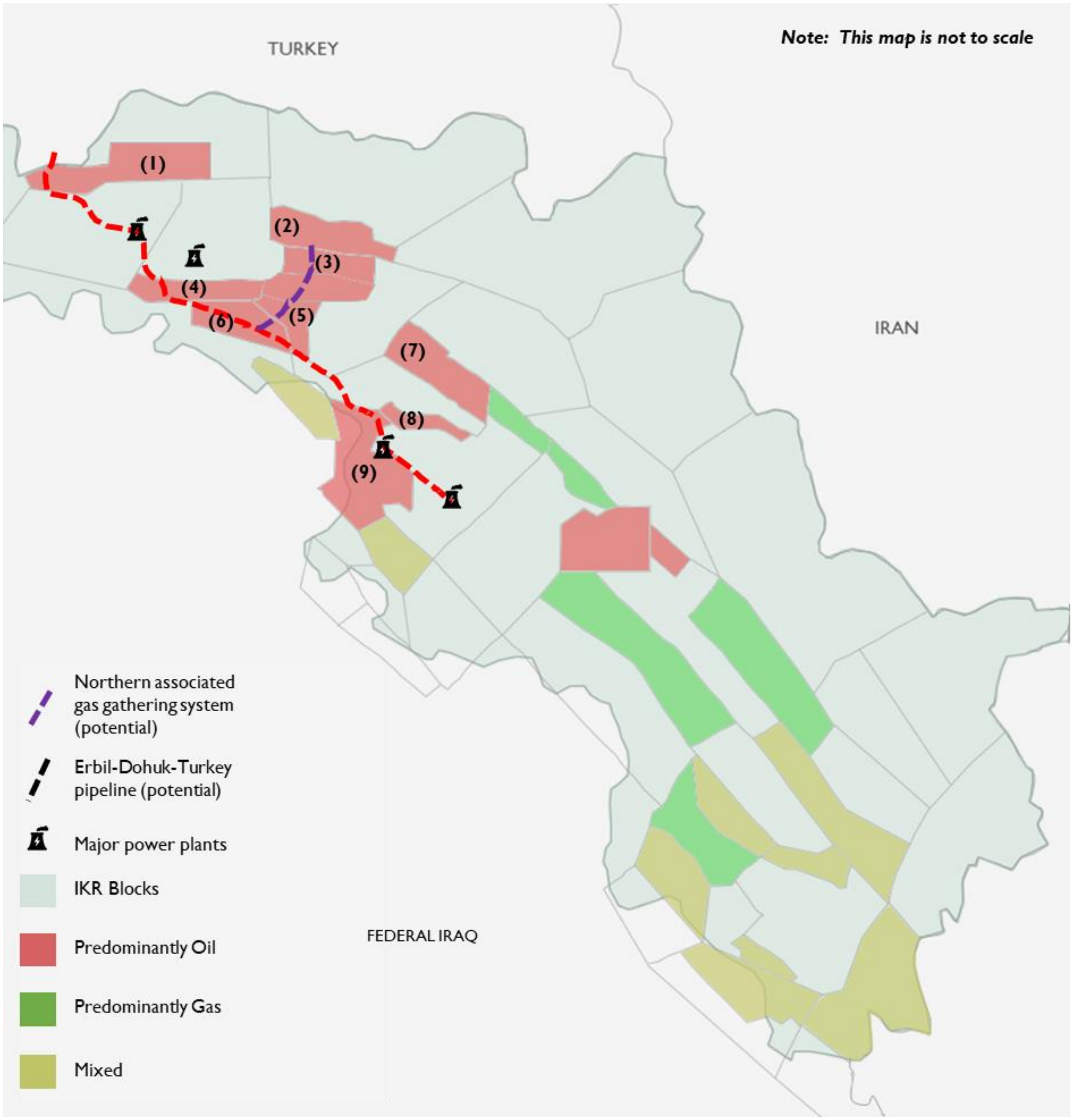
Field	Output		H_2S Level
	Mcf/d	Mm^3/y	
Ain Sifni/Simrit	5	52	12%–15%
Shaikan	25, increasing up to 50	258-517	Sour
Atrush	12–22	124–227	-
Swara Tika (Sarsang block)	25, increasing up to 100	258–1,034	2%–6%

[45] Chart shows only imports and production actually used within Turkey, not imports that are re-exported or production that is exported

[46] https://www.iraqoilreport.com/news/kurdistan-gives-oil-companies-18-month-deadline-to-end-gas-flaring-43931/

Captured volumes can provide supply to local oilfields for in-field use; for reinjection for improved oil recovery (where technically possible, such as is currently used in DNO's Tawke oilfield); and for power generation, such as in the Baadre power plant near Ain Sifni (capacity 150 MW, currently running on diesel or fuel oil), which requires ~0.3 BCM/y of natural gas. Any remaining surplus can be fed to the proposed Erbil–Duhok–Turkey pipeline for the Duhok power plant or export. This requires coordination between the MNR and the operators of the fields but is recommended as a near-term project to reduce flaring, unlock additional oil production, and improve local power supply.

The major technical challenge to this proposal is the high levels of H_2S in much of the associated gas. Piping sour gas over mountainous terrain and through populated areas poses significant safety risks. Technical solutions should be sought to this issue, including drying of the gas to avoid corrosion[47], the use of corrosion-resistant alloys (CRA), safety and alert systems, blending with lower-H_2S gas, and any possible pre-processing on site to reduce H_2S levels prior to central gathering.



47 e.g. https://onepetro.org/SPEADIP/proceedings-abstract/14ADIP/3-14ADIP/D031S061R001/210178

Figure 42 Proposed NAGGS under the Base Case for near-term Kurdish associated gas production growth

Major Predominantly Oil Blocks	
(1)	Tawke
(2)	Sarsang
(3)	Atrush
(4)	Al Qosh
(5)	Ain Sifni
(6)	Jabal Kand
(7)	Sarta
(8)	Erbil
(9)	Hawler
(12)	Shaikan

4.6 Base Case: Required Schematic Nodes and Gas Flows from South IKR and North IKR

Realizing the Base Case scenario will require a ~12 BCM/y natural gas pipeline running from Khor Mor, to Chemchemal, to Khurmala, to Kalak, to Duhok, to the Turkish border. This pipeline would be able to transport southern IKR gas north for future Turkish exports and meeting northern demand, while having a reversible section between Khor Mor and Chemchemal to allow the flexibility to switch between flows to FI in the summer and to Turkey in the winter.

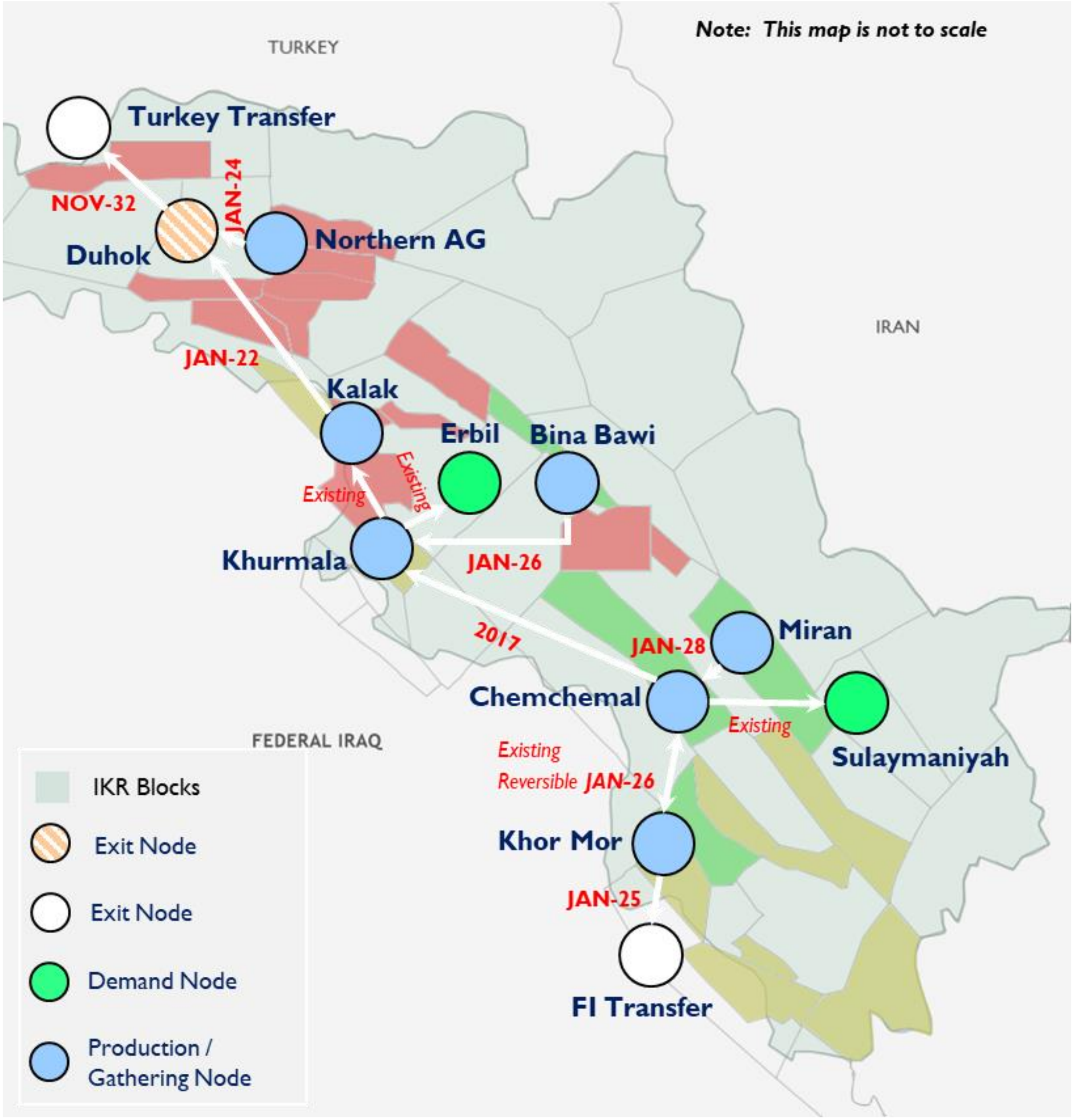


Figure 43 Required gas nodes for Base Case scenario and required in-service dates (schematic)[48]

Table 19 Schematic nodes of Base Case Kurdish gas system

Pipeline	Max. annual capacity (BCM)	Max. annual reverse capacity (BCM)
Khor Mor → FI	20.8	
Khor Mor → Chemchemal	9.9	6.6
Miran → Chemchemal	6.0	
Chemchemal → Sulaymaniyah	9.1	
Chemchemal → Khurmala	11.9	
Bina Bawi → Khurmala	6.3	
Khurmala → Erbil	8.8	

[48] Oil and gas exploration and development blocks shown on the map in gray outline have been updated by the KRG and are provided here for orientation purposes only

Pipeline	Max. annual capacity (BCM)	Max. annual reverse capacity (BCM)
Khurmala → Kalak	11.9	1.5
Kalak → Duhok	12.6	0.7
Northern AG (Shaikan) → Duhok	5.3	
Duhok → Turkey	13.9	

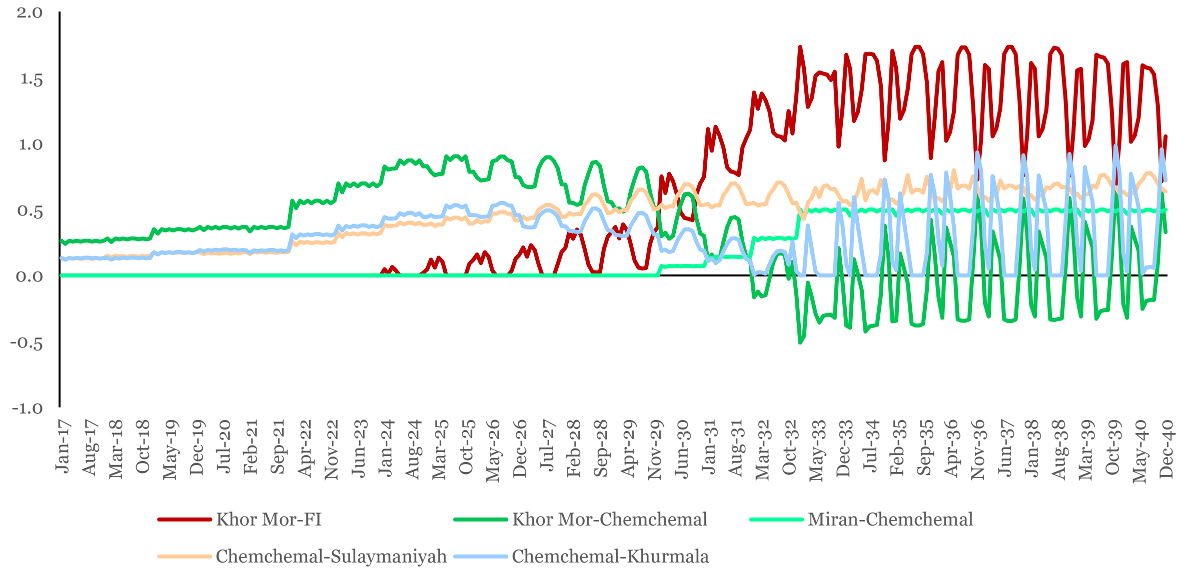


Figure 44 Monthly gas flows from the southern part of the Kurdish gas system under Base Case scenario (negatives indicate flowing in reverse direction). BCM/m

Khor Mor–Chemchemal–Sulaymaniyah/Khurmala flows could increase between 2022 and 2025 to meet local demand. Overall natural gas flows to FI from Khor Mor can begin to ramp up in 2025, mostly in the summer, while Khor Mor–Chemchemal flows could be reversed to feed FI as well.

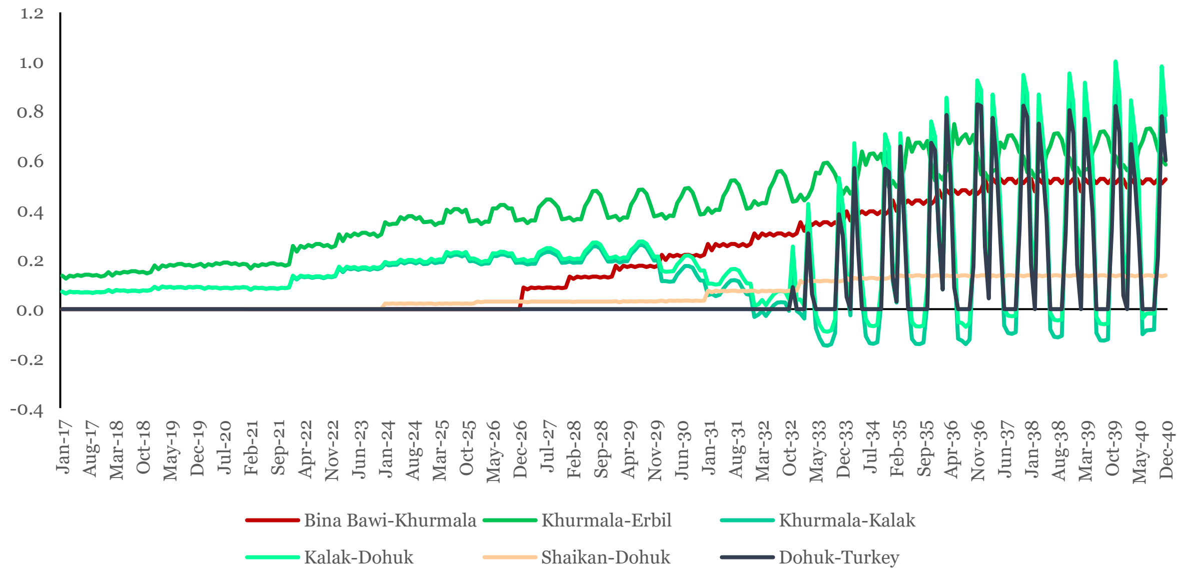


Figure 45 Monthly gas flows from the northern part of the Kurdish gas system under Base Case scenario (negatives indicate flowing in reverse direction), BCM/m

Kalak–Duhok and Shaikan–Duhok flows could increase in the mid-2030s to export to Turkey, mostly in the winter season. Some reverse flow, mainly from Khurmala–Kalak, will take place in summer to meet demand in Erbil, southern Kurdistan, and FI (this requirement is small and could be avoided by slightly increasing production capacity in the southern IKR or by switching some power generation to the northern IKR.)

5 Opportunities and Challenges: Realizing the Base Case

5.1 Connecting Natural Gas Infrastructure

For the Base Case scenario to materialize, several challenges need to be addressed for each stakeholder involved in the future Kurdish natural gas market. The KRG would need to get policy and stakeholder engagement exactly right over a broad range of issues to ensure full development of gas resources in an economically and environmentally sustainable manner. The main countries/territories involved in the Base Case scenario are the IKR, FI, and Turkey, with Iran and potential/speculative other future markets playing a supporting role.

In Kurdistan, the main stakeholders involved in the natural gas sector are the KRG (specifically the MNR and Ministry of Electricity), upstream operators, gas power plant operators and developers (IPPs), industry, and minor city gas users (residential and commercial).

Fully developing the natural gas sector over the long-run requires a balanced approach across users to quickly minimize flaring and build up markets. Such a balanced approach can include:

1. **Maximizing use of Associated Gas**
   Maximizing use of associated gas in oil-field operations, for replacing diesel used to generate in-field power, and where appropriate, for injection for improved/enhanced oil recovery (EOR), as currently underway in Tawke. Where technically feasible, EOR can have a high value by increasing oil sales, particularly as the older IKR oil-fields mature. Remuneration for this use of gas can come from ensuring compensation is allowed within the oil field development contracts to cover additional costs. The IKR benefits from decreased pollution and increased oil sales or access to additional power supplies.
2. **Facilitation of Local Sales of Natural Gas**
   Local sales of natural gas can be facilitated to:
   - The gas power sector, including currently below-capacity power plants (such as the Duhok power plant) and planned future power plants.
   - The existing industrial sector, starting with oil refining and cement in the immediate term (replacing subsidized fuel oil with natural gas), then possibly metals, chemicals, glass, ceramics, bricks, and light industry, such as food processing and paper.
   - Potential new gas-using industries, such as fertilizers (ammonia, urea), mines, metal smelting, plastics and hydrogen.

3. **Development of potential City Gas networks**
   Developing potential city gas networks can meet residential and commercial demand for heating and cooking.

4. **Resolution of Existing Challenges**
   Resolving existing challenges can help realize the full development of the IKR's natural gas sector. Primary concerns that need initial addressal include:
   - Subsidy Reform: Subsidies (rates set well below cost recovery) and non-payment of electricity bills together have made the KRG's Ministry of Electricity financially non-self-supporting and a significant drain on the region's budget.

- Subsidies for Fuel Oil: Subsidies for fuel oil to industry make it hard for gas to compete.
  - Many stakeholders of domestic energy companies also have a presence in other sectors, such as cement, potentially supporting the uptake of natural gas.
- Infrastructure: Lack of gas infrastructure for sales to industry, available and future power generation, and, in the future, city gas, challenges the development of the natural gas sector.
- Regulatory Structure: Lack of a well-functioning regulatory and market structure.
  - Unrealistically low natural gas prices and terms offered to producers, which makes production uneconomic.

In FI, the main stakeholders involved in the natural gas sector are the federal government, the Ministries of Oil and Electricity, associated gas capture operators such as the Basrah Gas Company and the Ratawi Gas Hub (once awarded), and other upstream operators. Currently, discussions are under way between Kurdistan and FI for the sales of natural gas and electricity (450 MW) from Kurdistan to FI, but successful facilitation of these discussions will need several issues addressed, as discussed below.

Similar to IKR, FI faces non-payment of electricity bills and crippling subsidies, which have made the federal Ministry of Electricity financially non-self-supporting. The near total reliance on oil revenues makes budget revenues unstable, and complicates planning and payment for expensive large long-lead time projects that do not generate net revenue. FI must also contend with the "generator mafia," characterized by influential political figures who oppose natural gas and power sector reforms. In addition, Iran uses its political influence to maintain its natural gas and power exports to Iraq and perpetuate the latter's dependency on Iran and its exports. If Iran feels threatened by IKR gas entering FI, there is potential for competitive Iranian price cuts that could undermine the IKR's full entrance into the market. Iran can also put pressure on key officials and politicians to block the required decisions and investments for IKR gas supplies. Finally, the FI gas transmission and distribution network is currently insufficient for widescale and reliable delivery to all main consumption sites. In certain parts of the country, it is also vulnerable to sabotage.

In Turkey, the main stakeholders are the Ministry of Energy and Natural Resources, BOTAŞ Petroleum Pipeline Corporation, Türkiye Petrolleri AO (TPAO), the Energy Market Regulatory Authority, private buyers and traders of gas, and industrial users. Turkey has been the focus for most of the IKR's plans for natural gas sales to a foreign market. Russia's state-controlled oil company, Rosneft, has committed to fund and build a cross-border pipeline from Kurdistan to Turkey, with an export capacity of 30 BCM/y, but this project has been slow-moving. Kurdistan faces several challenges if it is to break into the market in Turkey. Turkey has a highly competitive natural gas market with numerous supply sources. Turkey also approaches such agreements strategically, using a "wait and see" approach before finalizing any commitment or plan for natural gas imports, including those from the IKR. Russia and Rosneft also demonstrate strategic behavior in the region, and both Russia and Iran could move forward with competitive natural gas price cuts to undermine the IKR's efforts to enter the Turkish market. In addition, Rosneft seems to be stalling on pipeline development and is now aiming at a phased development of a lower-capacity project: 3 BCM/y, down from the original first phase of 10–12 BCM/y. Rosneft's option on the pipeline is understood to expire in summer 2022, so the company has limited time remaining to progress its plans.

For the Base Case, other interested parties in Kurdistan's natural gas sector are Iran and prospective future markets; for example, Iraq as a whole (including Kurdistan) could eventually produce sufficient surplus to export through renovations to the non-operational pipeline through Basra to Kuwait, making Kuwait a potential market – either through direct links or gas swaps with southern Iraq. In Iran, natural gas sales to FI (mainly into Baghdad and Basra) will continue in the near term through the connecting National Gas Pipeline, as will electricity sales through connecting transmission and distribution grids. However, Iran remains an unreliable player for Iraq's energy security, as Iran is exposed to U.S. sanctions. In addition, Iran has been inconsistent in supply, as the country has been experiencing winter gas shortages, curtailing domestic use, and technical troubles at transport and receiving nodes.

5.2 Federal Iraq and Turkey Export Markets Attractiveness Matrix

Table 20 Federal Iraq and Turkey export markets' attractiveness for Kurdish gas (matrix)

Highly Attractive	Attractive, with some challenges	Moderate Attractiveness, significant challenges	Poor Attractiveness, serious challenges

Destination	Feasibility	Economics	Competition	Materiality
KRI Power				
KRI Industry (cement)				
KRI Industry (other)				
KRI city gas				
Federal Iraq				
Turkey - East				
Turkey - West				
SE Europe				
Other Markets				

The Turkey export market is highly material, but the practically accessible market for Kurdish gas is limited.

6 Developing a Roadmap for Gas Market Development

6.1 Long Development Timelines for International Gas Projects

Development of large gas fields, particularly involving cross-border exports or technical complications such as sour gas or deep water, is typically a lengthy process. Generally speaking, gas fields discovered more recently, such as the Zohr field in Egypt, the Tamar and Leviathan fields in Israel, and Pluto in Australia, have reached initial production quicker than others discovered pre-2000s due to their unique circumstances. These recent discoveries benefited from superior available technology (e.g. for sour gas and deepwater), better fiscal terms, inter-country and intra-country advancements on revenue-sharing and contract models, and improved handling of expiring PSAs. Delays to final investment decisions can occur for a host of reasons, including technical issues, lack of capital, limited infrastructural and technological capabilities, and political disagreements.

As Figure 65 shows, from a selection of notable projects, some fields have waited up to 30 years or more to be developed. However, some fields reached first production remarkably quickly when the investment environment, partner expectation alignment, and timing was particularly primed for success; for example, Egypt's Zohr reached production two years from the date of discovery, even though the field is in deep water which typically adds to costs and development time internationally. The Zohr Field development partners did not need to rely on exports for financing and project success and were able to use existing infrastructure within Egypt. Galkynysh in Turkmenistan—a giant, deep sour gas field that exports to China—began production within eight years of discovery, facilitated by access to a large market and a partner that assured prompt payment. Shah Deniz in the Azerbaijan sector of the Caspian Sea exports to Georgia and Turkey, and the field reached first gas output within six years, because the market was available in Turkey for the gas at the right time, and the project was led by a strong international oil company (BP), including other key stakeholders (TPAO and Azerbaijan state oil company SOCAR) in its consortium. For comparison, in the IKR, Topkhana, Miran, and Bina Bawi were discovered in 2011 and have not yet been developed.

Gas development in the IKR would benefit from developing a deeper understanding as to why some of these projects were able to overcome commercial and technical barriers and move to production more quickly than others through conversations with companies and counterparts in other countries. Some key lessons have been highlighted in the brief case studies above, and learnings for commercial structure and financing have been included in the following discussion.

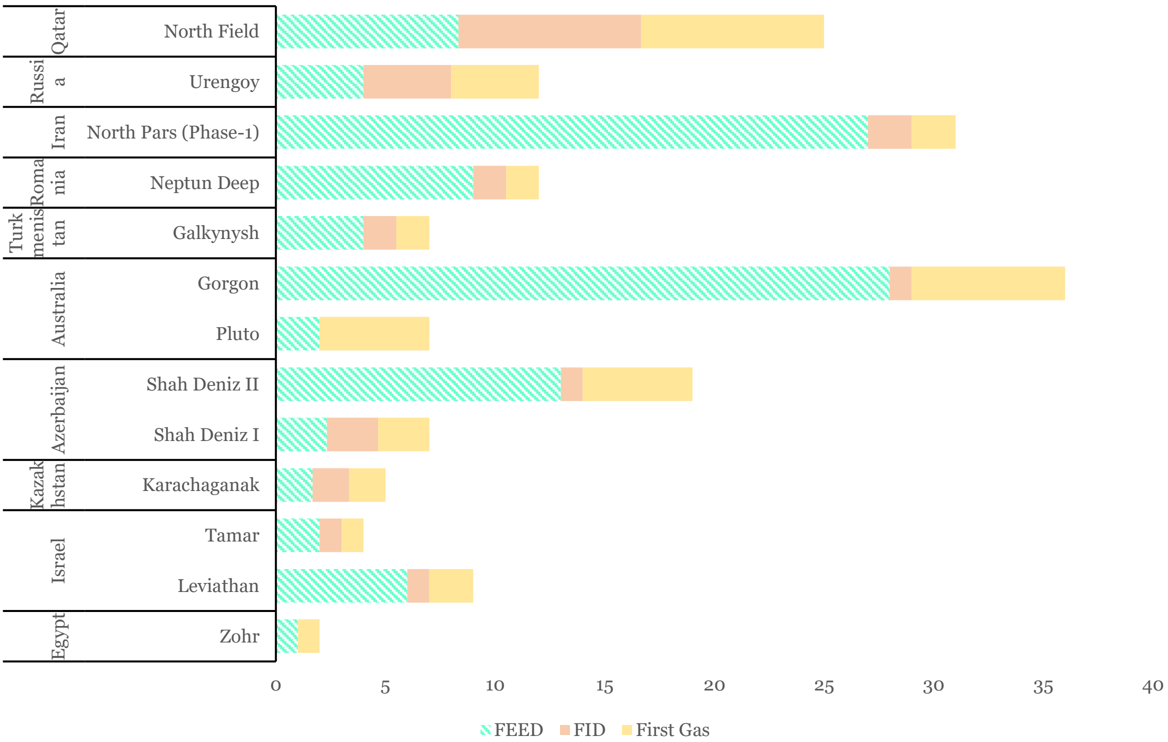


Figure 46 Global gas projects' development timelines, in number of years taken to reach first gas after the year of discovery

6.2 Phased Development Approach

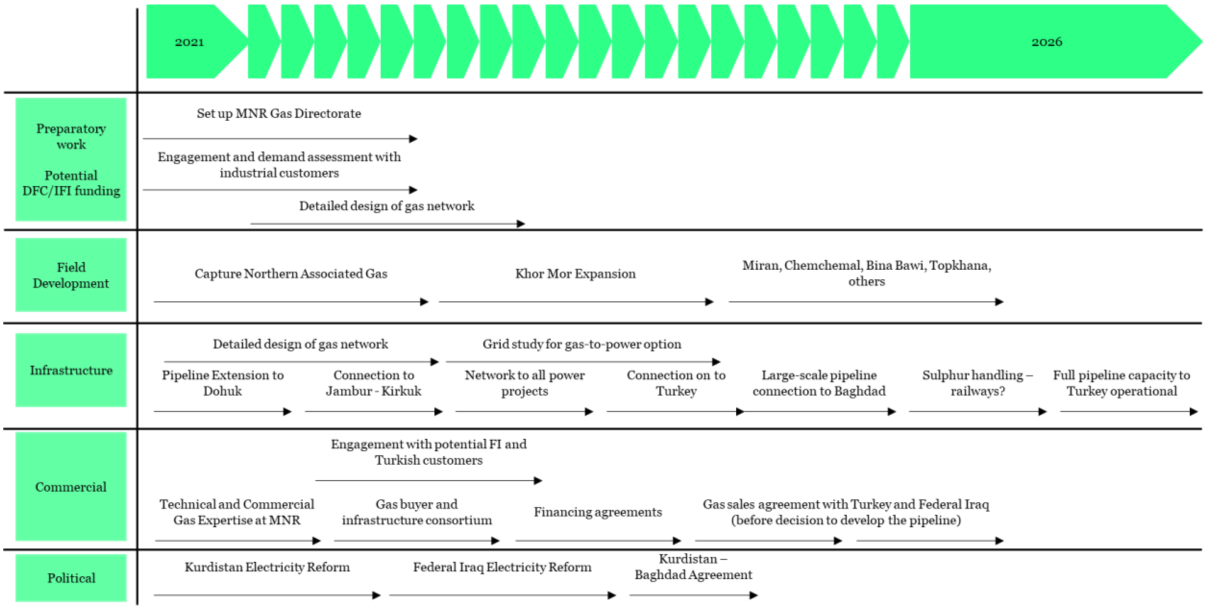


Figure 47 Proposed phased development of the Kurdish natural gas sector until 2026

Momentum on developing the natural gas sector in Kurdistan has been growing, owing to higher oil and gas prices, talks with FI (for sales) and talks with upstream operators on expanding production and capturing flared gas. The MNR should be thinking through a phased development approach starting in 2022 with the support of all relevant stakeholders which this study should help to facilitate/inform Figure 66 summarizes a proposed phased development plan of the Kurdish natural gas sector until 2026, with several key developments concentrated between 2021 and late 2023. These efforts must be pursued concurrently to maximize the potential for successfully developing the KRG gas sector, so that delays in one area do not hold up others.

- The first milestone involves staffing, capacity building, and funding for establishing a regulatory institution responsible for natural gas in the MNR, this could take the form of an MNR Gas Directorate. The Directorate would be responsible for government engagement with and demand assessment of potential customers, as well as the permitting and approval of a detailed gas network. The Directorate should be led by an empowered and experienced Director, reporting directly to the Minister of Natural Resources, assisted by local and international experts, and the directorate should formulate a plan for training and capacity development in gas sector issues for less-experienced staff.
- The second milestone involves parallel efforts to develop gas:
    - Developing associated gas capture from northern fields (the primary focus).
    - Continuing work to expand and/or develop the priority non-associated fields, most of which we assess to have a timeline starting in 2022/2023.
- The third milestone involves establishing the infrastructure connecting the pipeline to Erbil on to the Duhok power plant as soon as possible and reworking the Khor Mor-Jambur–Kirkuk pipeline to carry natural gas towards Kirkuk (possibly within the next year or two).
- In the fourth milestone, the MNR Directorate could establish a dedicated Technical and Commercial Unit, which could formulate technical, economic, and political arguments for reform, and begin introducing phased-out subsidies, as a first step. The Unit would lead engagement with potential FI and Turkish customers, which could establish a gas buyer and infrastructure consortium. The consortium would enable financing agreements/arrangements, as well as gas sales agreements (GSAs) with both FI and Turkey before a decision on building the larger bulk pipeline connection(s) to them is finalized.

This would also be the right time to commission a grid design study to determine the relative technical and economic feasibility of a gas-to-power option. This study would recommend new infrastructure required to connect all power projects with each other and plan for infrastructure required to get power and gas connections to Turkey and Baghdad under way.

Possibly later in the phased development approach, a railway network for transporting excess sulfur from sour gas field development could be considered; such a project would require complex coordination with other ministries and stakeholders. To be commercially viable, this railway would need to transport other cargo as well. This could include gas-derived industrial products such as cement, which would provide an additional source of gas demand. In the meantime the MNR will need to study the viability of alternatives such as onsite storage or trucking.

Post-2022, and assuming that the Gas Directorate is up and running, and most flared gas capture projects are proceeding, longer-term development will concentrate around the upstream, with Pearl hoping to commission a new 2.5 BCM/y processing train at Khor Mor in Q1 2023, which should increase overall production from the Khor Mor field to 7 BCM/y (assuming Phase 2 start-up). A second 2.5 BCM/y train should increase production to capacity to 9.5 BCM/y by 2025. Production from development of other non-associated gas fields, including Chemchemal, Miran, Bina Bawi, and Topkhana, could then be phased in beginning in 2024.

6.3 Upstream Development

6.3.1 Capturing Associated Gas

Proposed expansion of oil production from existing oilfields in Kurdistan will lead to increases in associated gas production from both the north and south. As outlined above, the NAGGS would gather associated gas primarily from Swara Tika (Sarsang block), Atrush, Shaikan, and Ain Sifni and feed it into the main pipeline, which will serve Baadre, Duhok, and potential exports to Turkey. A Southern Associated Gas Gathering System (SAGGS), meanwhile, would gather gas from the Kurdamir and Sarqala fields and, if developed later, also from Chia Surkh, Shakal, and Pulkhana fields. Southern gas could be delivered north for users in Kurdistan and infrastructure could also be built connecting to FI to take maximum advantage of commercial opportunities as production expands. Associated gas production from Kurdistan could reach ~4.8 BCM/y by 2040, a sizeable amount, of which the Erbil governorate would contribute 3 BCM/y and the Sulaymaniyah governorate would contribute 1.8 BCM/y. An initial step has been to capture and utilize flared gas in the region for power generation with the construction of a 165 MW power plant by Aggreko in the Garmian area running on associated gas from the Sarqala field[49]. Based on production of 35 kbbl/day and an estimated gas-oil ratio, the field may be producing about 50 Mcf/d (0.5 BCM/y) of associated gas of which about 40 Mcf/d (0.4 BCM/y) would be required to run the power plant at full capacity.

Most northern associated gas is sour, so a joint processing plant for final sweetening would save costs. However, this has to overcome the technical and safety challenges of piping sour gas over mountainous and populated areas. It may be necessary to build local processing plants at each field to make the gas safer for transportation. The companies would require assurances from the MNR that gas processing projects would be treated as valid costs for the purposes of cost recovery within the PSA agreements and that a high enough price would be agreed for the gas to ensure that processing it is economical. Southern associated gas is sweeter, so individual processing units may be less costly and thus easier to finance. Initially, captured SAGGS gas in excess of the requirements of the Garmian power plant could go to Sulaymaniyah industry (cement, refineries) and potentially be used as city gas (if the system is developed), with surplus feeding into the IKR–FI pipeline and future IKR-Turkey pipeline. successful development of natural gas projects will require close coordination and effective communication between the MNR and all operators concerned. Proclamations demanding action prior to engaging with the IOCs that may not be covered by development contracts should be avoided.

[49] https://www.iraqoilreport.com/news/sarqala-power-plant-highlights-krg-progress-on-gas-flaring-43748/

In the near term, capturing associated gas as soon as feasible would be highly recommended, as successful projects would reduce flaring, unlock additional oil production, and improve local power and industry supply.

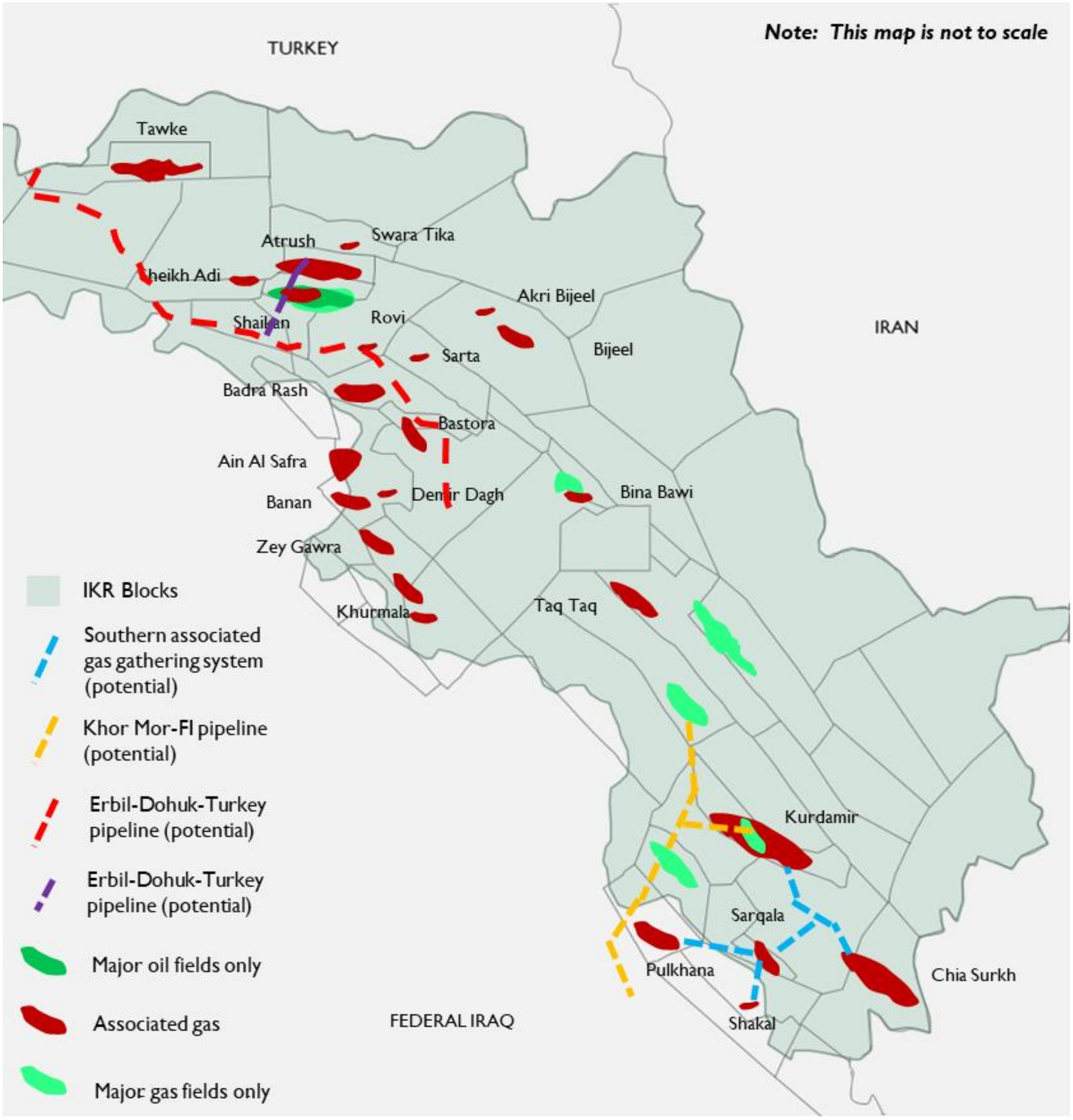


Figure 48 Proposed associated gas gathering systems for IKR associated gas[50]

[50] Oil and gas exploration and development blocks shown on the map in gray outline have been updated by the KRG and are provided here for orientation purposes only

6.3.2 Studying Potential City Gas Model

Additional natural gas, either associated gas or surplus from non-associated production, could potentially feed a city gas system, plans for which were first proposed by Crescent Petroleum in 2008. However, required gas volumes would be rather small and unlikely to impact the overall Kurdish natural gas supply and demand balance significantly. City gas consumption for heating would likely be more concentrated in northern IKR areas, but per-capita demand will be much lower than in Iran and Turkey, which are significantly colder in winter. Therefore, city gas consumption around Erbil and other northern areas will begin at the low end of the consumption spectrum, taking time to develop/grow.

City gas requirements for the ten largest cities in the IKR are estimated as ~0.07 BCM and for residential are 0.18 BCM, calculated from Turkish examples as commercial consumption from 20–122 m³/person/year and residential from 55–159 m³/person/year. While relatively small, a city gas system would have several positive economic, social, and environmental benefits, such as creating jobs and eliminating more polluting fuels used for heating and cooking. Distribution of small-scale LNG or CNG by truck or (if constructed) rail to population centers and industrial users is another potential use of modest volumes in a practical and flexible way both prior to more extensive infrastructure development and to reach more remote consumers.

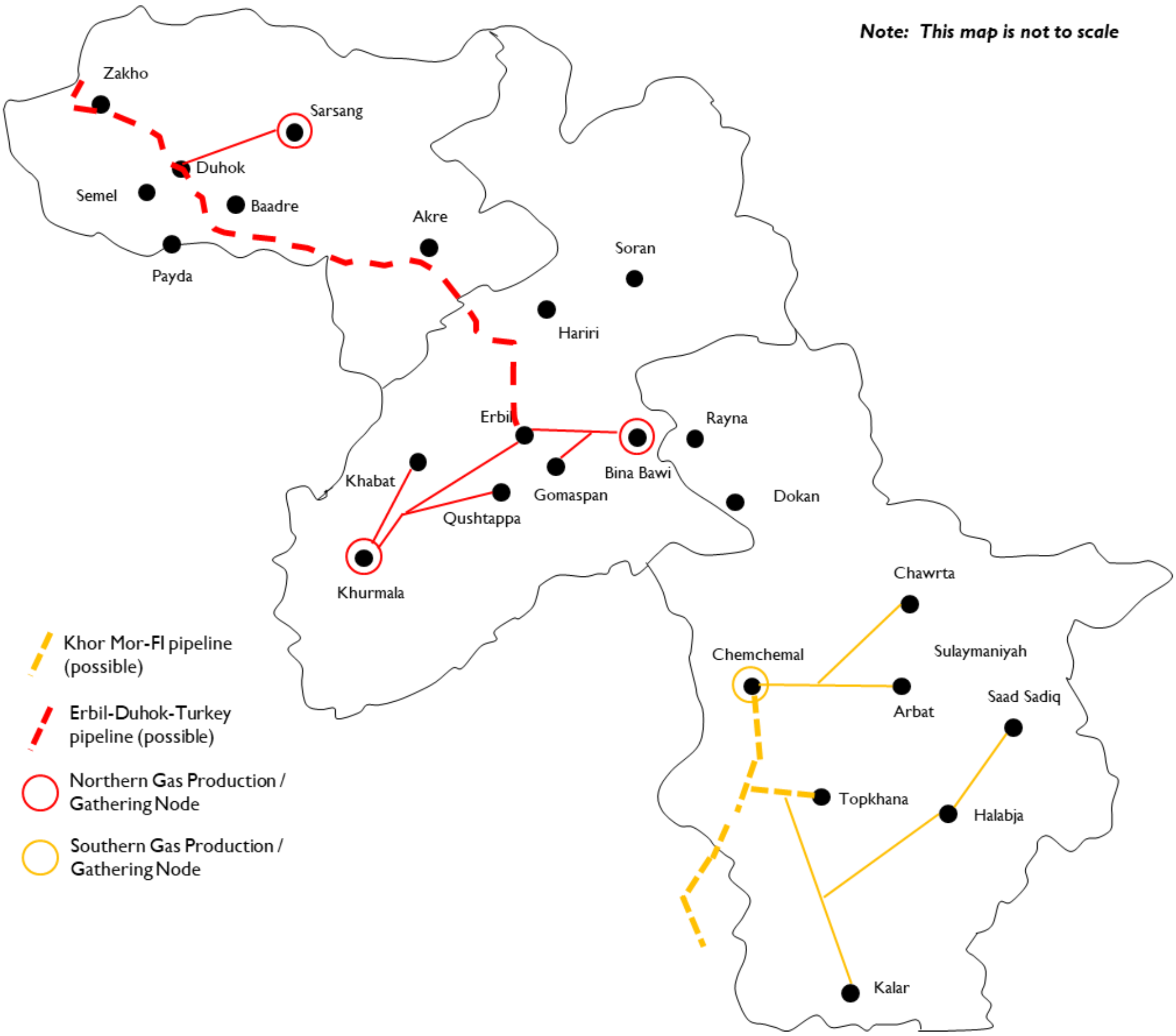


Figure 49 Potential gas gathering and distribution model for Kurdistan (schematic)

6.4 Infrastructure Development

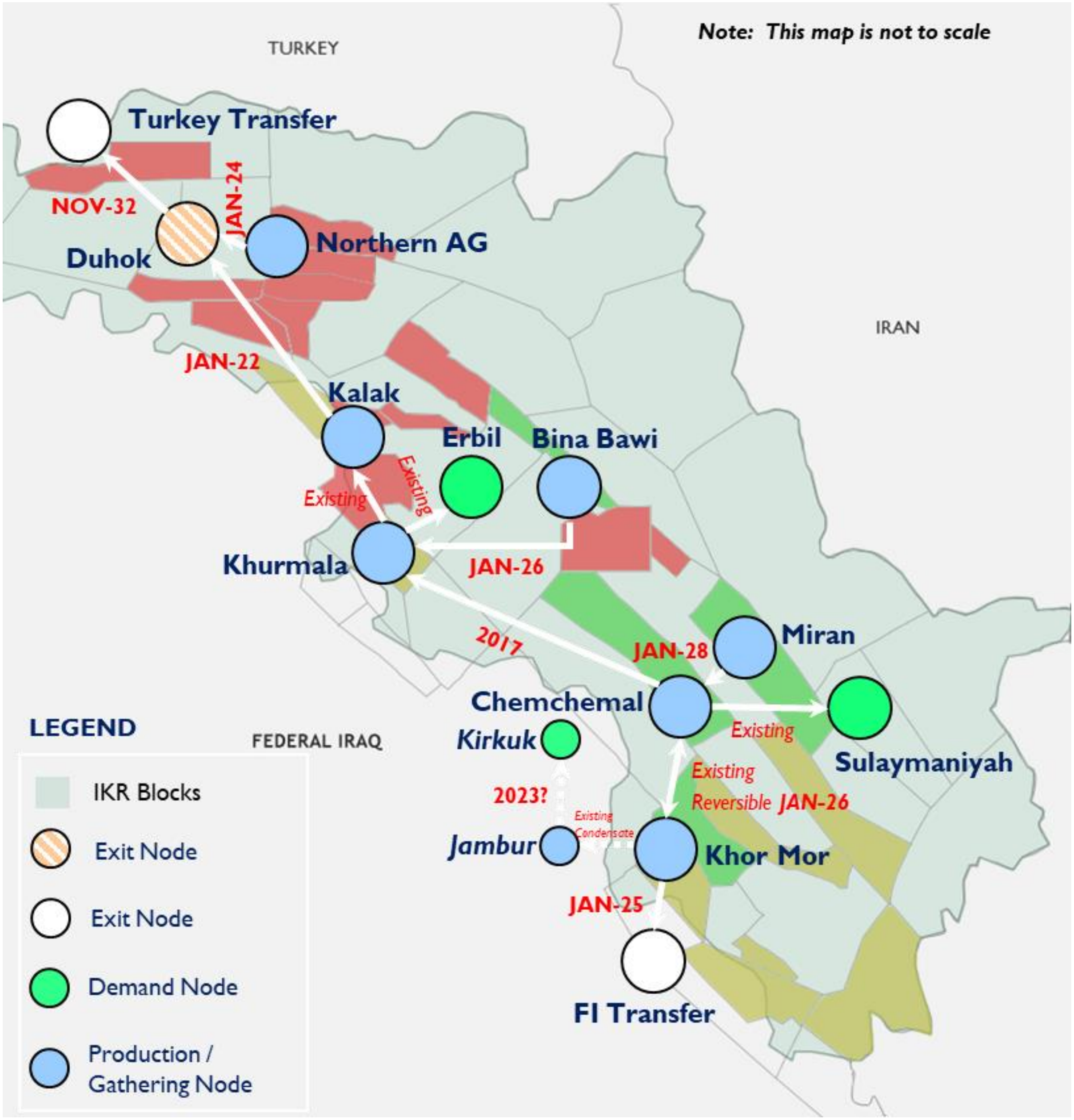


Figure 50 Possible (1) Khor Mor-Jambur–Kirkuk connection schematic; (2) Duhok connection/pipeline schematic; (3) Possible domestic natural gas pipeline to FI schematic; (4) Possible natural gas pipeline to Turkey schematic, and required in-service dates[51]

6.4.1 Planning for Current flexibility and Future Exports to Turkey

Even though our analysis indicates that exports to Turkey are second in priority to exports to FI, the Duhok pipeline will serve as the backbone for meeting gas power and industry demand in northern Kurdistan, as well as sales of natural gas to Turkey. Construction of the system requires planning and short-term decisions on final investment

[51] Oil and gas exploration and development blocks shown on the map in gray outline have been updated by the KRG and are provided here for orientation purposes only

and pipeline size and capacity. Currently, the government's vision is to create a common-use pipeline to be a highway for all gas producers in Kurdistan and all gas users, while also supporting exports. This could require a 20–30 BCM/y pipeline, but because Turkey's exports under the Base Case will be relatively limited (as the accessible market there is assessed to be small), a 48" diameter 10 BCM/y pipeline could be expanded to 20 BCM/y by adding compression as industry consumption grows and production comes online from later-to-be-developed natural gas fields (e.g., Bina Bawi and Miran).

Another option could be a potential 56" pipeline all the way to the border with Turkey. The pipeline on the Turkish side has already been completed. A 56" pipeline would significantly reduce capacity constraints if exports or flows from north to south in the IKR turn out to be higher than assessed, but would be costlier to build and maintain, and utilization might be low.

The Jambur pipeline from Khor Mor to Kirkuk could quickly begin initial small-volume sales to FI, but a sustained surplus above IKR needs that could be sent to FI will not appear until 2025. There are also plans for a pipeline to Duhok for the Duhok power plant and Turkey exports, and we suggest a possible connection from the Chemchemal area to Kirkuk/Baghdad for feeding larger sales into FI. A flexible system with multiple pathways could accommodate market shifts and seasonal demand difference such as summer sales to FI and winter exports to Turkey. The discussion and graphics below outline some possible phased approaches and related timelines for building out infrastructure based on the assumptions and analysis feeding into the base case. In general, the system will need to plan for flexible supply to the KRG, FI, and Turkey in the long run to take advantage of shifting market opportunities and seasonal demand variations.

6.4.2 Khor Mor-Jambur–Kirkuk Connection

The existing 20" pipeline between Khor Mor and Jambur, most recently used for transporting condensate, could be repurposed to transport sales gas (initially unprocessed gas) from Khor Mor to Jambur and then to Kirkuk (FI). Initial flow in the pipeline is pending final agreement on sales terms some work may have been done to prepare the pipeline in the event of an agreement between all three parties, Baghdad, Erbil, and the operators of the field, the Pearl consortium. Volumes could increase through this pipeline as the expansion of Khor Mor proceeds and more gas becomes available for sale to FI.

The short-term agreement for unprocessed gas could be superseded by the expansion plan at Khor Mor if the deal is not approved soon. Currently, the Khor Mor Phase 1 expansion plan -2.5 BCM/y - includes rerouting the existing condensate pipeline within the site perimeter of the field to run just north of the Khor Mor expansion area. This will involve cutting the 20" Jambur pipeline and removing the parts of the pipeline that are within the Khor Mor expansion site. Conversations with concerned stakeholders in the project have indicated positive potential exists to use the rerouting of this pipeline to feed additional future sales gas into FI via Kirkuk. The gas would feed power plants in the Kirkuk area and could be transported onwards through the existing federal gas transmission system. Initial gas flows could precede the expansion and final processing could occur at Kirkuk because wells in the Khor Mor field are currently producing below capacity while awaiting arrival of the new processing trains and the Jambur – Kirkuk section of the pipeline and the Kirkuk processing plant have surplus capacity.

6.4.3 Domestic Natural Gas Pipeline to Federal Iraq

Here we suggest a couple of pipeline options the IKR could consider for transferring sales gas to FI. Running the main pipeline south of Khor Mor into FI is the most direct option; the IKR might be able to use some of the capacity in the existing pipeline from Iran, and the Khor Mor natural gas field has good expansion potential. The pipeline could connect to other gas fields in the Diyala province awarded to Crescent in FI's Bid Round-5 (Injana, Khashm Al Ahmar, Gilabat, Qumar) and on to the Baghdad area as well as a allowing for other gas production to be delivered south as production increases at other IKR fields

However, the Diyala province remains prone to ISIS/militant attacks, which poses a risk to the pipeline's uninterrupted functioning. Baghdad already imports Iranian gas through Diyala, which could potentially become a sensitive issue over Kurdish versus Iranian gas. On the other hand, cheaper IKR gas could displace at least some Iranian gas and use the same infrastructure if Iraq were to decide to reduce pricier Iranian imports in favor of cheaper gas from the IKR,

Another option is connecting the Chemchemal field and other producing fields to Kirkuk, which would require a larger connection to the FI gas grid at Kirkuk and rehabilitation/expansion of existing lines from Kirkuk to Mosul and Baghdad, therefore more work with risks for potential delays. Connecting the larger fields directly to Kirkuk would connect up more potential demand and might allow for maximum flexibility within the system depending on the outcome of demand and supply studies and agreements for gas sales to FI from the IKR fields. It would rebalance the Iraqi gas system from its heavy reliance on southern production and central imports. Either or both of these options would need to be completed in time to accommodate FI sales after IKR needs are satisfied around 2025.

6.4.4 Cross-Border Pipeline to Turkey

The backbone of the Turkish export system via Kurdistan could be a 12 BCM/y pipeline that runs from Khor Mor through to Chemchemal, Khurmala, Kalak, Duhok, and Turkey. The Duhok pipeline, as explained above, should be sufficiently sized to enable Turkish exports.

Khurmala has additional gas that can be captured, enabling it to potentially become a larger production/gathering sales gas node to support the main trunkline towards Kalak, Duhok, and Zakho. A 48" pipeline that is designed to be expandable should be sufficient to carry natural gas to the Duhok power plant, which will consume about 2.18 BCM/y at 1500 MW capacity, plus 5.0 BCM/y exports to Turkey in the future under the Base Case.

Additional expansion by adding new compression capacity to the 48" line could also be suitable if scenario AS1 materializes, which could mean increasing sales gas for Turkey to 10 BCM/y. The pipeline in Turkish territory has already been completed to near the IKR border. The capacity of the Turkish system to accommodate the proposed gas volumes in the sequence outlined above, including any required modifications or expansions, will need to be analyzed and confirmed by all parties.

6.4.5 Gas-to-Power Sales

Figure 51 outlines the present situation of Kurdistan's power system. The transmission and distribution system consists of 132 kV transmission lines, sometimes twinned, that carry power to the 33/11 kV distribution side at each point to cities with large power demand, such as Duhok, Erbil, and Sulaymaniyah. The existing connection with exports to FI runs to Kirkuk. Imports from Iran arrive around Saad Sadiq near Sulaymaniyah, and from Turkey to Zakho.

Additional higher-voltage connections at 400 kV (~400–500 MW per line) could include Kirkuk expansion, lines to Baghdad, and lines to Mosul, as part of its post-ISIS recovery.

An alternative or complement to gas sales to FI is to generate power from gas (and potentially renewables) within the IKR and send electricity to FI. As noted, IKR already sells moderate amounts of electricity to FI. In June 2021, the federal government approved an agreement from August 2020 to source 450 MW (with the potential to add a further 100-150 MW) of power from the Khurmala plant, with payment made in crude oil delivered to the Kalak refinery. Another transmission line, from Khabat to Qaraqosh, will be introduced to connect Erbil to Mosul[52]. It would be preferable for future electricity sales arrangements to be paid in cash rather than barter to improve transparency and allow the cash to be available for remunerating IOCs and IPP developers.

[52] Middle East Economic Survey, July 2nd 2021

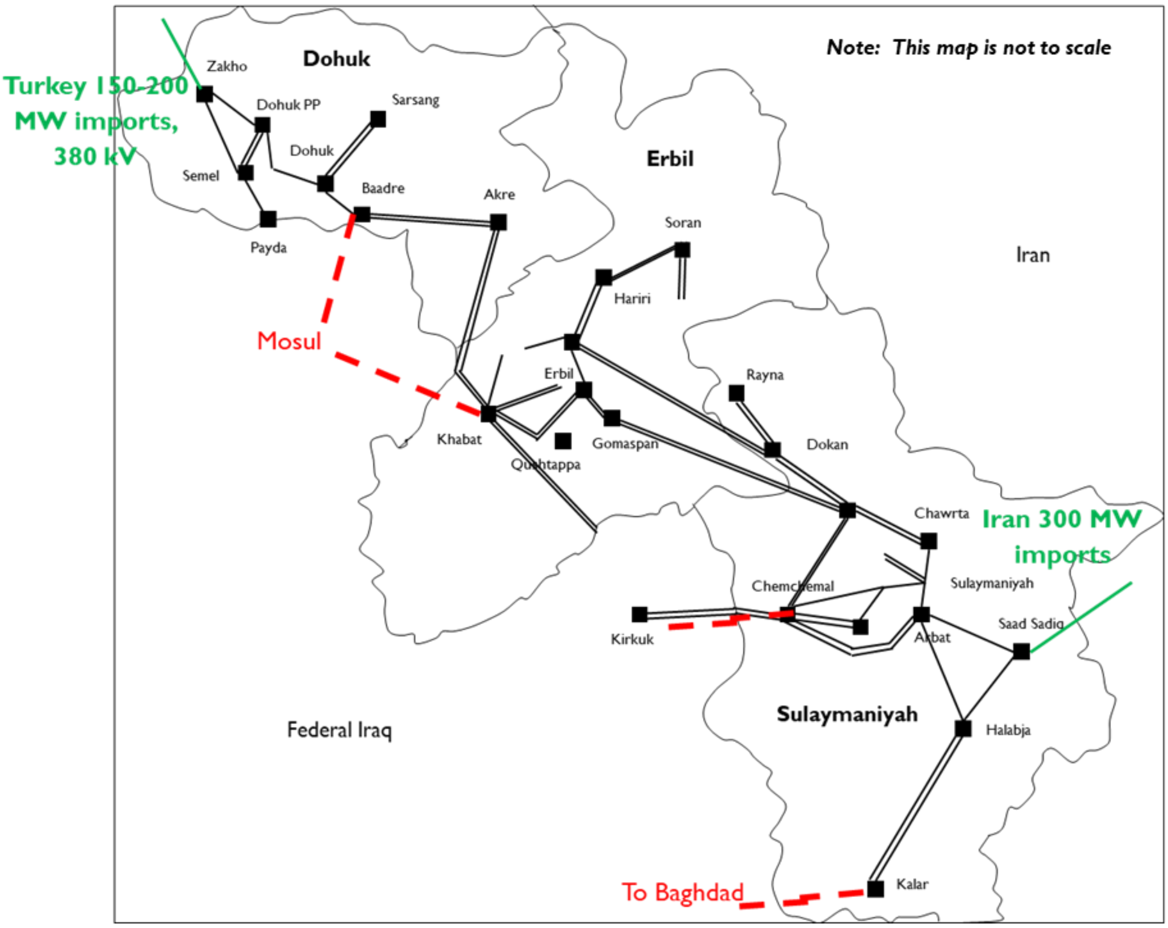


Figure 51 Potential grid extensions from Kurdistan to FI (schematic)

Advantages	Disadvantages
Greater flexibility – power available for IKR or FI as needed	Higher overall delivered cost of energy
Potentially earlier start to deliveries	Power lines vulnerable to sabotage
Potentially greater commercial / payment security	Higher up-front investment from IKR
More local economic development in IKR	Higher system energy losses
Can be a relatively low-cost initial step	May distract from gas sales opportunities and/or reduce critical mass of gas for pipelines
Potentially higher sales price	Cannot serve FI industrial gas demand

The gas-to-power sales option is not mutually exclusive with gas sales, as FI has both a gas and a power deficit and the IKR could transfer either gas or power depending on market conditions and need. Power sales would need assurance of the condition of the relevant parts of the FI grid to receive them and operate reliably. The commercial issues would be similar, requiring suitable payment assurance from the federal Ministry of Electricity. The up-front investment would be increased given the need for a power plant as well as gas field development; however this may be offset by avoiding the cost and long-term commitment on a gas pipeline, depending how much use can be made of the existing federal electricity grid.

Generally, we believe the demand for gas to fuel existing generation is likely to be more enduring than the need for additional power flows to FI. Gas-to-power sales largely through existing infrastructure can be a quick and relatively easy first step to establish the principle. Both gas and power sales could play a role, but more study is required.

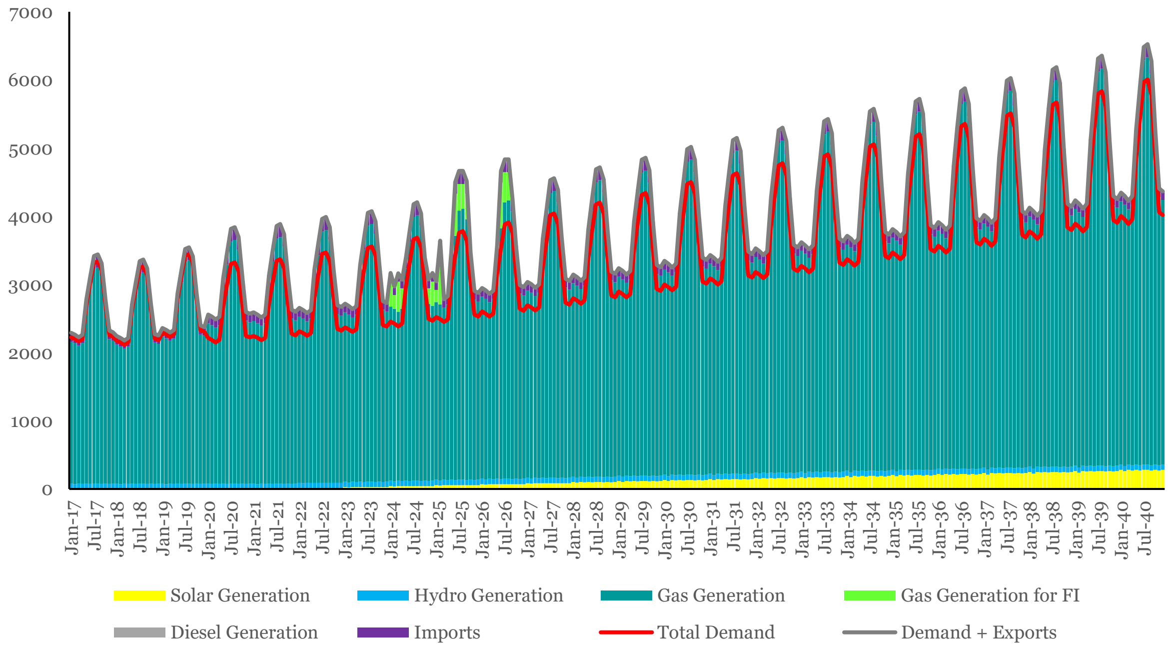


Figure 52 IKR's monthly power generation with FI gas-to-power sales option, if natural gas developments are greatly accelerated, GWh/m

Figure 52 depicts the IKR's monthly power generation under a potential gas-to-power sales option to Federal Iraq. Under the Base Case, Figure 13, IKR does not have to send power supplies to Federal Iraq, because:

1. If all planned projects are completed, FI could have sufficient power generation capacity to meet its own demand from 2026 onwards.;
2. If power sales to FI are prioritised over gas sales to Turkey, surplus natural gas in the IKR, after gas sales to FI, appears only around the 2030/31 window. At this point FI has no need for power supplies from the IKR as its own capacity can utilize the gas supplies it is receiving from the IKR (and Iran) to meet internal demand

If IKR gas developments, however, are accelerated aggressively, wherein fields like Miran West, Chemchemal, Chemchemal Phase-2, and Topkhana are commissioned much earlier than under the Base Case, the first surplus gas appears in 2024. The IKR can direct this surplus gas for the development of new power generation in the IKR (additional to what it requires for its own demand) to be supplied to the Federal Iraq market. Supplies end from 2026 onwards, as Federal Iraq is projected by then to have sufficient existing and planned power generation capacity to meet demand (from natural gas supplies from the IKR and ongoing supplies from Iran). But given the high uncertainty over FI electricity supply and demand, it is quite plausible that IKR electricity sales could continue after 2026, at least in summer.

Table 21 Commissioning Dates for IKR Natural Gas Developments under potential Gas-to-Power Sales to FI Option

Field	Commissioning Date under Base Case	Commissioning Date under Gas-to-Power
Benenan	2034	2030
Bina Bawi	2027	2025
Miran West	2030	2027
Chemchemal	2025	2022
Chemchemal Phase-	2028	2022
Topkhana	2030	2025

Under the Base Case, FI has adequate power generation capacity before it has sufficient gas; therefore the gas-to-power option only works on its own rather than as a complement to gas sales for a short time. A cheap connection using existing power generation capacity in the IKR is workable to meet this window of demand, but it might not be as economical to construct new power plants in the IKR solely to serve the power market in FI. Conversely, if FI has adequate power being supplied from the IKR, this could in fact slow down its own generation expansion plans. If more grid connections can be installed at low cost, then this does create a valuable option to use IKR power plants at closer to maximum capacity, which could continue after 2026 if FI is slow in building up its own generation.

7 Financing Considerations

7.1 Phased Development of the Natural Gas Sector: Financing Considerations

The development of natural gas infrastructure in the IKR is dependent on the availability of financing under appropriate structures from local and international companies, regional and international development financial institutions, and commercial banks across the Middle East and Turkey.

As part of this study, the U.S. International Development Finance Corporation (US DFC), World Bank/International Finance Corporation (IFC), Islamic Development Bank (IsDB), Arab Petroleum Investment Corporation (APICORP), and Japan Bank for International Corporation (JBIC) were consulted and are noted as potential sources of development finance based on their past interest and track record of extending financing facilities on various infrastructure projects in the IKR and FI. This assumes that the gas project is in compliance with current United States and international policies calling for more ambitious efforts to reduce or eliminate methane emissions and mitigate the effects of climate change.

Table 22 Selected financing options for natural gas projects in the IKR

International and Regional Development Financing Institution	Country	Assets Under Management (as of December 31, 2020)	Financing Products	Ratings
United States Development Finance Corporation	United States	US$ 12bn	▪ Debt Financing ▪ Equity Investments ▪ Investment Funds ▪ Political Risk Insurance	Moody's: Aaa S&P: AAA Fitch: AAA
The World Bank/International Finance Corporation	United States	US$ 98bn	▪ Long – term Loans ▪ Syndicated Loans ▪ Equity and Quasi-Equity Finance ▪ Securitized Products: Guarantees, Risk Sharing Facilities	Moody's: Aaa S&P: AAA
Islamic Development Bank	Saudi Arabia	US$ 32bn	▪ PPP – Project Financing ▪ Private Sector Financing ▪ Trade Financing	Moody's: Aaa S&P: AAA Fitch: AAA
Arab Petroleum Investment Corporation	Saudi Arabia	US$ 7bn	▪ Specialized equity investments across the energy sector in the Middle East (inc. Iraq)	Moody's: Aa2 Fitch: AA
Japan Bank for International Cooperation	Japan	US$ 159bn	▪ Overseas Investment Loans ▪ Import Loans ▪ Guarantees ▪ Equity Contributions	Moody's: A1 S&P: A+

These international development financial institutions offer a range of facilities, which include *inter alia* debt financing, equity investments, import loans, and political risk insurance through various financing structures. It may be harder in the near future to get financing for projects to develop non-associated gas that does not abate its carbon dioxide emissions. This makes it more critical to ensure that terms offered to the companies are adequate to cover the cost of methane abatement, carbon capture utilization and storage technologies and other environmentally sound practices that may be desired by the IKR and FI governments.

A prospective option for financing natural gas infrastructure projects in the IKR would include a debt financing facility (or an investment loan) that is provided to one or more of the following:

- An investment and development consortium
- A foreign company (Japanese, in the case of the JBIC, or US, in the case of the US DFC)
- A business joint venture
- A foreign government entity
- A IKR/FI local financial institution with an equity stake in such a project or that provides financing for such a project

The debt financing facility could be offered as part of a financing syndicate, which would consist of more than one financing institution. The use of DFC here is illustrative and should not be taken as support for any specific gas project.

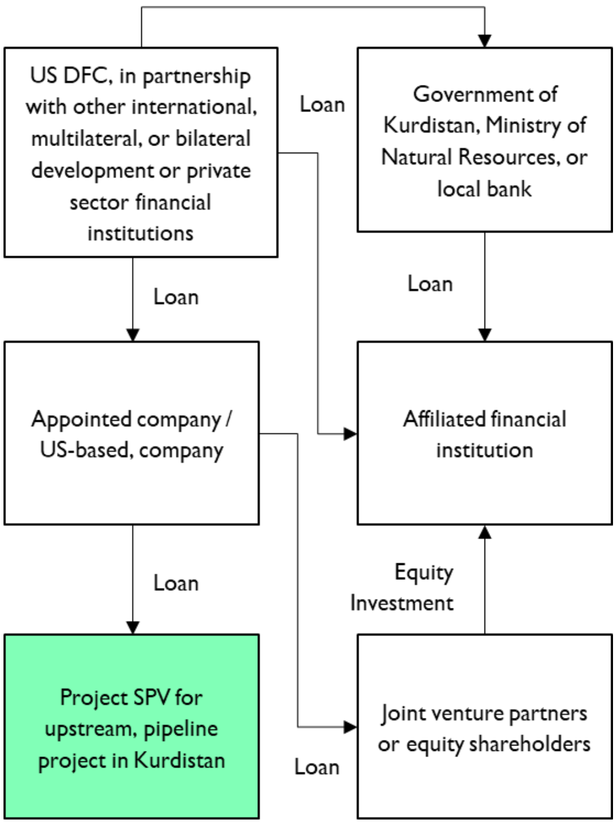


Figure 53 Indicative example of US DFC's debt financing structure

When determining the debt financing facility offered by a development financial institution, the institution would first appraise the financing requirement for a prospective natural gas infrastructure project in the IKR and analyze climate change and social and environmental factors. The appraisal takes into account the amount of financing required; the currency in which the financing is offered/requested; interest rates; repayment period and method; and securities, guarantees, and collateral required to secure the financing. The financing amount typically does not exceed the value of a contract associated with the infrastructure project. The funds are applied to meet financial needs for undertaking a specific operation or develop the long-term operations of the project and are disbursed when an actual financing need arises. The financing amount can be provided in currencies other than US dollars

(US$), such as euros and Japanese yen. The debt financing facility carries a fixed or floating interest rate, determined at the time of application. The repayment period is determined by taking into account the period required for recouping investment; the repayment schedule is typically flexible, includes a grace period, and is dependent on the expected rate of return of the individual project. Thus, the terms and conditions of the debt financing facility offered are subject to the development financial institution's assessment of the securities and guarantees presented.

In addition to debt finance, IKR natural gas infrastructure project financing will need to include equity investments, which can include a capital injection in the infrastructure project (asset-level), a capital injection in the investment and development consortium that operates the infrastructure project (corporate-level), or a capital injection in an investment fund that owns and operates the infrastructure project.

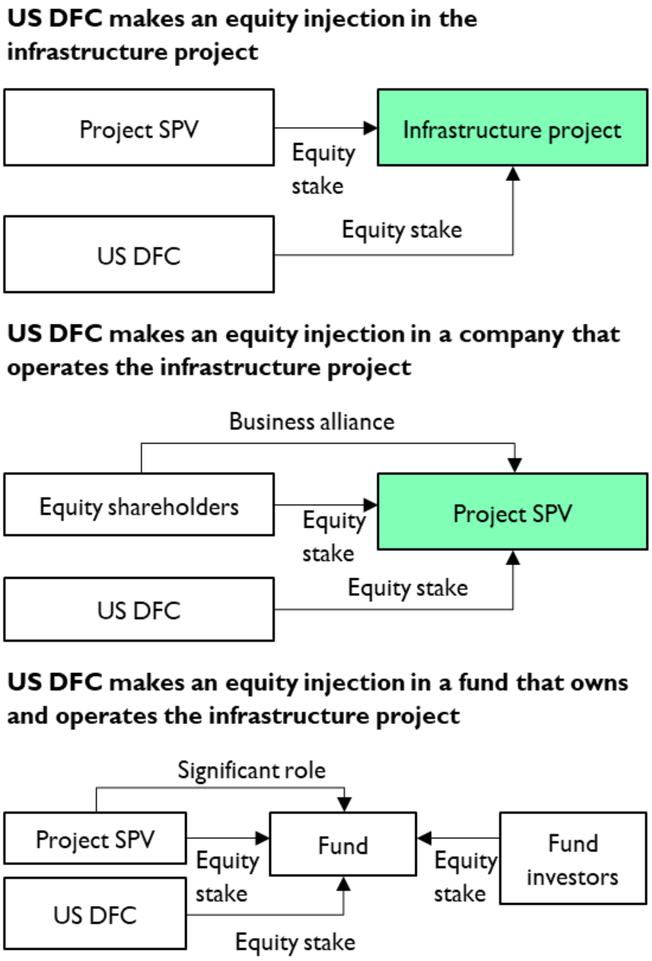


Figure 54 Indicative example of US DFC's equity financing structure

An equity stake acquired by a development financial institution in exchange for a capital injection could be a majority stake (≥51%) or a minority stake (≤49%) of the total equity valuation of the project. Some development financial institutions, such as JBIC, operate an investment strategy in which equity contributions are <50% of the total investment (i.e., the institution will not become the largest shareholder through add-on equity contributions). Before determining equity participation, the financial institution will issue an equity investment term sheet that sets exit conditions and the institution's degree of involvement in daily operations and management.

In addition to financing the development of infrastructure, development financial institutions extend import loans to finance operations. Such loans are typically limited to strategically important commodities such as crude oil, natural gas, minerals, and other natural resources.

An import loan financing agreement typically includes a loan amount that is equal to the value of the import contract. The funds are disbursed when the activity requiring financing takes place. The agreement identifies the loan interest rate being offered, a periodic repayment period that is dependent on the repayment method (which is usually a sum of principal plus interest), and import guarantees that are subject to the coverage and guarantee period.

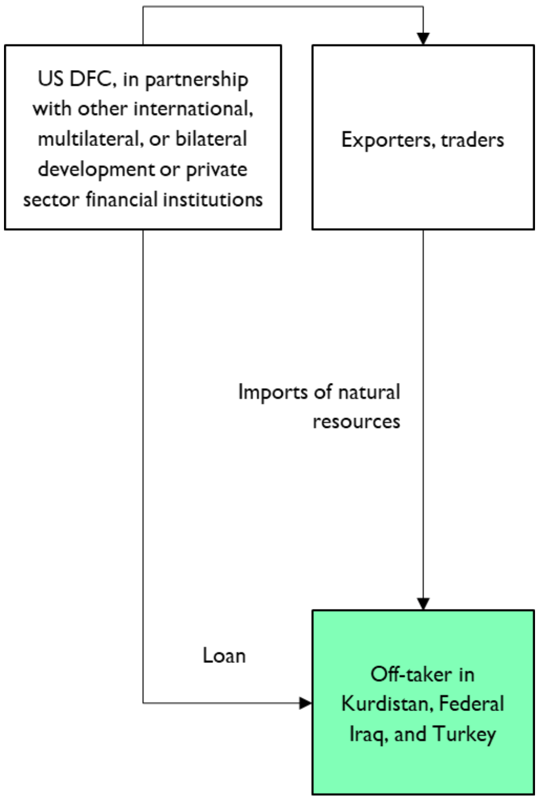


Figure 55 Indicative example of US DFC's import loan structure

The US DFC has financed natural gas infrastructure projects in the IKR in the past. Based in Washington, DC, the US DFC is a development financial institution of the U.S. federal government, responsible for providing and facilitating financing for private development projects in lower-income and middle-income countries. The US DFC operates under a portfolio of investments with total assets under management of US$ 12 billion. As of December 31, 2019, 28% of the institution's committed capital was allocated to South America, 27% to Africa, and 10% to the Middle East.

The US DFC operates under three strategic objectives:

- Maximizing development impact by mobilizing private sector investment to advance development in emerging markets that prioritize low- to middle-income countries
- Driving private capital in sectors and industries that are strategic to US foreign policy, in addition to bringing new capital to emerging market development
- Managing taxpayer risk with the private sector and qualifying sovereign entities through co-financing and structuring of private capital in areas of strategic interest

The US DFC achieves its strategic objectives through an investment strategy that prioritizes private sector projects in lower-income and middle-income countries. The strategy includes offering a range of financing products:

- Debt financing that involves direct loans and guarantees of up to US$ 1 billion over an investment horizon of 25 years, targeting small and medium-sized businesses.
- Equity investments in companies and projects committed to creating developmental impact.

- Investment funds in emerging market private equity to help address the shortfall of investment capital.
- Political risk insurance aimed at increasing underwriting capacity through coverage of up to US$ 1 billion against foreign exchange risk and political risk.
- Technical development services, which include feasibility studies and technical assistance programs to accelerate project identification and preparation for additional financing.

The financial institution's structured financing terms for a prospective IKR natural gas infrastructure project could include a debt financing package of up to ~US$ 1 billion, with an additional allocation through other co-lenders for larger financing requirements over a tenor of 5–25 years, with a maximum of 30 years, depending on the type of project and the debt servicing.

In addition to the structured financing terms, the US DFC offers various types of political risk insurance coverage: currency inconvertibility, expropriation, political violence, reinsurance, and breach of contract for capital markets.

Table 23 US DFC's political risk insurance

Types of Risk Coverage	Additional Details
Currency Inconvertibility	Protects conversion and transfer of earnings, returns of capital, principal and interest payments, technical assistance fees, and similar remittances
Expropriation	Protects against acts of expropriation and other forms of government interferences, such as nationalization, confiscation, abrogation, repudiation, imposition of confiscatory taxes, and confiscation of funds or assets
Bid, Performance, Advance Payment, and Other Guaranty Coverages	Guarantees are usually in the form of irrevocable, on-demand, standby letters of credit
Political Violence	Protects against assets and income losses due to war, hostile national or international forces, revolution, civil war, terrorism, and sabotage
Reinsurance	Additional underwriting capacity and support development in countries where investors have difficulty obtaining political risk insurance
Breach of Contract for Capital Markets	Political risk insurance supports US capital market financing structures that catalyze private capital in emerging markets

An example of US DFC's track record in the IKR is its financing of Pearl Petroleum, a consortium of Dana Gas, Crescent Petroleum, OMV, MOL, and RWE involved in the production and development of the Khor Mor and Chemchemal fields. Pearl Petroleum was established in 2009 and is one of the largest private investors in the hydrocarbons sector in the IKR.

In December 2020, the US DFC approved US$ 250 million in facility debt financing as part of a total all-source funding package of US$ 625 million. The proceeds are to be used by Pearl Petroleum to finance the development, construction, and operation of a 250 MCF/day natural gas processing facility and the associated infrastructure, and the drilling of up to 5 wells in the Khor Mor field. The processed natural gas will be provided to underutilized natural-gas-based power plants in the IKR. This loan was in process during the transition from the Trump Administration to the Biden Administration and was allowed to proceed. It may be more difficult to get this sort of DFC financing approved in the near future unless the project includes plans for fully abating carbon emissions or is dedicated to capturing flared gas or fugitive methane emissions.

The financial institution's debt financing facility was based on a policy review that assessed the economic and social viability of the project to:

- Have a highly developmental impact on FI through the construction and operation of a natural gas processing facility that will supply IKR power projects
- Improve power capacity utilization and mitigate the lack of available input natural gas, which limits power generation
- Reduce the region's frequent blackouts through an increased natural gas supply that is also critical for reliable electricity generation
- Support the use of natural gas over diesel fuel and crude oil for electricity generation, thereby generating power generation cost savings and lowering carbon dioxide emissions

US DFC is one of a number of development financial institutions that have financed a range of infrastructure through investment loans, equity contributions, and project financing facilities across FI and the wider Middle East. These organizations include the World Bank/IFC, IsDB, APICORP, and JBIC.

Based in Washington, DC, the World Bank/IFC is an international financial institution that offers investment, advisory, and asset-management services to encourage private sector development across less developed countries. One of the IFC's most recent financing mandates involved an investment loan of US$ 35 million to Lafarge to support the development of a cement facility in Karbala, FI, that would produce 2.3 million metric tonnes per year. The investment loan was part of a follow-on financing commitment to an investment the IFC made in 2010 to support a Lafarge endeavor: development of 2 cement production facilities in Iraq, including the one located near Karbala.

Table 24 Selected FI projects financed by the IFC

Target	Year	Country, Region	IFC's Contribution	Project Sponsor	Use of Proceeds
Karbala Cement Manufacturing Limited	2016	Iraq, Karbala	Investment loan of US$ 35M	Lafarge	Completion of the rehabilitation program of the cement plant operated by Karbala Cement Manufacturing Limited
MGES Power	2015	Iraq, Kurdistan Region	Equity and debt investment of US$ 250M	Mass Energy Group Holding Limited	Support in the development of the CCGT expansion of Sulaymaniyah Power Projects, as well as indirect support to the development of the Bismayah Power Project
Gulftainer Company Limited	2012	Iraq, Basrah	Investment loan of US$ 30M (total financing of US$ 48M)	Gulftainer Company Limited	Development and operation of a 750,000 m² bonded dry port north of Umm Qasr port, which is expected to serve container traffic at the port, and transport and logistics needs of the oil and gas industry in Southern Iraq

Based in Jeddah, Saudi Arabia, IsDB is a multilateral development financial institution that specializes in Islamic financing facilities across its 57 shareholding member states, of which Iraq is a member country. The largest single shareholder of IsDB is Saudi Arabia.

IsDB provides a range of financing facilities that cover project financing, loans, and technical assistance to projects and entities operating in the agriculture, infrastructure, energy, industrial, education, and healthcare sectors. The Institution also provides equity investment and lines of financing for financial institution sector development across IsDB member countries. To date, 78% of IsDB financings in Iraq have gone to the transport sector, 10% to education, 10% to health, and 2% to the industry and mining sectors.

The financial institution's mandates are typically co-financed with other development financial institutions, which include, but are not limited to, the Asian Development Bank, European Bank for Reconstruction and Development, World Bank, JBIC, and Japan International Cooperation Agency.

In 2016, IsDB contributed US$ 217 million as part of a US$ 1 billion financing package with the World Bank, the government of Iraq, and other partners to fund the construction of the Expressway No. 1 highway, which is a major trade corridor connecting Iraq to its neighboring countries. Upon completion, the 1,300 km highway will pass through the capital city of Baghdad and help enhance trade flow and regional linkages between the GCC countries and other Levant countries.

Table 25 Selected projects financed by IsDB in the Middle East

Project	Sponsors	Total Financing	IsDB's Commitment	Co-financiers with IsDB	Use of Proceeds
UAE: DEWA 800 MW solar PV power project	Shuaa Energy Phase II	US$ 924M	US$ 110M	Abu Dhabi Islamic Bank, Natixis, National Bank of Abu Dhabi, Union National Bank and First Gulf Bank	Installation of energy generation capacity using solar PV technology
Uzbekistan: Reconstruction and expansion of sewerage	Government of Uzbekistan	US$ 61M	US$ 58M	Government of Uzbekistan	Increased wastewater treatment capacity, sewerage network upgrade work
Senegal: Railways project	Government of Senegal	US$ 61M	US$ 38M	Government of Senegal	Upgrade and rehabilitation of households with access to potable water supply and electricity systems
Turkey: 10 high-speed train sets	Government of Turkey	EUR 246M	EUR 312M	Government of Turkey	Annual capacity increase at maritime ports

The Arab Petroleum Investment Corporation (APICORP), based in Dammam, Saudi Arabia, is an energy-focused multilateral development financial institution that offers a diversified set of corporate banking and investment solutions. The financial institution has financed a range of projects and assets in the energy value chain across the Middle East.

Table 26 Selected projects financed by APICORP in the Middle East

Target	Country	APICORP's Commitment	Project Sponsor	Use of Proceeds
Yellow Door Energy	United Arab Emirates	US$ 50M Revolving Construction Facility	Yellow Door Energy	The aim was development of solar PV projects in the MENA region, with a key emphasis on projects in Jordan and Pakistan.
Al Fanar	Saudi Arabia	US$ 75M, 5-year Murabaha Financing Facility	Al Fanar	The loan was granted in support of Al Fanar's renewable energy projects, including a key 720 MW wind energy project in Spain.
Al Khorayef United Holding	Kuwait	24% Equity Stake for an undisclosed amount	Al Khorayef United Holding	Al Khorayef United Holding is a Kuwait-based oil and gas services and facilities management company. APICORP views the strategic acquisition in the Kuwaiti energy sector as a key enabler that will encourage further private sector investments.
Egyptian Methanex Methanol Company (E-METHANEX)	Egypt	17% Equity Stake for an undisclosed amount	Egyptian Methanex Methanol Company	E-METHANEX is a joint venture between Egyptian Petrochemical Holding Company, Egyptian Natural Gas Holding Company, Egyptian National Gas Company, and Canada's Methanex Corporation, specializing in methanol industry supply, distribution, and marketing.
Al Dur Power and Water Company	Bahrain	US$ 113M in Equity and Investment Loans	Al Dur 2 IPP	The aim was development of a 1,500 MW, Al Dur 2 IPP, natural-gas-based power project.
Sonatrach	Algeria	2 Investment Loans of US$ 250M	Sonatrach Petroleum Investment Corporation	APICORP funded the maintenance of a refinery that Sonatrach acquired in Sicily, Italy. A secondary aim was to purchase feedstock for the refinery from Saudi Aramco.

JBIC is a Tokyo-based, policy-focused public financial institution and export credit agency that conducts lending, investment, and guarantee operations that complement other Japanese private sector financial institutions. The institution offers various financing options for the energy infrastructure projects through overseas investment loans, import loans, guarantees, and equity contributions, with total assets under management of US$ 159 billion. As of March 31, 2019, 9% of JBIC capital is deployed in the Middle East.

JBIC has financed various projects in the energy sector across the Middle East. Its most notable transaction in FI was on March 30, 2017, when it extended a US$ 193 million buyer's credit facility to the FI government. The facility was co-financed with the Bank of Tokyo–Mitsubishi and the Sumitomo Mitsui Banking Corporation, under a total co-financing amount of US$ 322 million. The proceeds of the financing were used to finance the Iraq Ministry of Electricity's purchase of a set of substation facilities from Toyota Tsusho Corporation for development and construction of substations at 16 domestic sites.

Table 27 Selected projects financed by JBIC in the Middle East

Project	Year	Counterparty	Total Amount	JBIC's Commitment	Co-financiers with JBIC	Use of Proceeds
UAE: Fujairah F3 Natural Gas-Fired Combined-Cycle Power Project	2020	Fujairah Power Company	US$ 941M	US$ 470M	Mizuho Bank, Sumitomo Mitsui Banking Corp, Sumitomo Mitsui Trust, BNP Paribas, and Standard Chartered Bank	FPC will build, own, and operate a 2,400 MW natural-gas-fired combined-cycle power project in Fujairah.
UAE: Hamriyah Natural Gas-Fired Combined-Cycle Power Project	2019	Sharjah Hamriyah Independent Power Company	US$ 1.1bn	US$ 555M	Sumitomo Mitsui Banking Corp, Sumitomo Mitsui Trust, Norinchukin Bank, Société Générale, and Standard Chartered	SHIPCO will build, own, and operate a 1,800 MW gas-fired combined-cycle power project in Sharjah.
Iraq: Buyer's Credit for Government of Iraq	2017	Government of Iraq	US$ 322M	US$ 193M	Bank of Tokyo-Mitsubishi and Sumitomo Mitsui Banking Corp	JBIC financed the Ministry of Electricity's purchase of a set of substation facilities to construct substations at 16 sites.
Qatar: Project Financing for Barzan Gas Project	2011	Barzan Gas Company Limited	US$ 1.2bn	US$ 600M	Sumitomo Mitsui Banking Corp, Bank of Tokyo-Mitsubishi, Mizuho Bank, ANZ Group, and HSBC	The aims were drilling offshore gas fields in Qatar's North Field, transporting the extracted gas, and producing fuel gas for power generation.
Egypt: Loan for Project Supporting Egypt's Natural Gas Development	2008	Egyptian Offshore Drilling Company	US$ 500M	-	HSBC	JBIC financed EODC procurement of equipment for developing offshore gas fields in Egyptian waters.

In addition to US DFC, IFC, IsDB, APICORP, and JBIC, other regional and international development financial institutions have indicated an interest or have a track record of financing and developing projects in FI or the region. Like DFC, European institutions might be less likely to offer financing for gas projects in the future unless the climate change mitigation benefit is clear These institutions include the European Bank for Reconstruction and Development, European Investment Bank, KfW Group (KFW) of Germany, and the Asian Infrastructure Investment Bank, in addition to various regional commercial banks and Middle Eastern sovereign wealth funds. The involvement of some of these institutions, particularly the European ones, in IKR gas projects may be limited or prevented by a policy to avoid fossil fuel investments, even though IKR gas could have a substantial positive environmental impact by displacing the use of diesel, fuel oil, and crude oil, as well as a positive developmental effect.

Table 28 Development financial institutions

Name	Type of Financial Institution	Country	Assets Under Management
Zirrat Bank	Commercial Bank	Turkey	US$ 91bn
Finansbank			US$ 90bn
IsBank			US$ 80bn
Garanti Bank			US$ 80bn
National Commercial Bank	Commercial Bank	Saudi Arabia	US$ 117bn
Al Rajhi Corporation			US$ 90bn
SAMBA			US$ 62bn
Riyadh Bank			US$ 58bn
First Abu Dhabi Bank	Commercial Bank	United Arab Emirates	US$ 180bn
Emirates NBD			US$ 121bn
ADCB			US$ 70bn
Qatar National Bank	Commercial Bank	Qatar	US$ 197bn
Qatar Islamic Bank			US$ 35bn
Commercial Bank of Qatar			US$ 35bn
Al Ahli United Bank	Commercial Bank	Kuwait	US4 108bn
National Bank of Kuwait			US$ 77bn
Kuwait Finance House			US$ 54bn
Kuwait Investment Authority	Sovereign Wealth Fund	Kuwait	US$ 592bn
SAMA Foreign Holding		Saudi Arabia	US$ 494bn
Qatar Investment Authority		Qatar	US$ 320bn
Public Investment Fund		Saudi Arabia	US$ 230bn
Mubadala		United Arab Emirates	US$ 225bn
Investment Corporation of Dubai			US$ 229bn
Emirates Investment Authority			US$ 45bn
State General Reserve Fund		Oman	US$ 25bn

When considering investment in IKR/FI natural gas infrastructure projects, financial institutions must consider the state of the national economy. FI's economy is estimated to have contracted in 2020 in response to lower crude oil prices and the spread of COVID-19. This has reversed the trend on decreasing public debt and has added pressure on the exchange rate and central bank reserves. Higher oil prices have begun to undo some of the financial distress experienced in 2020, but it will take time to recover. Weaker crude oil prices, fiscal budget, cuts to economic growth programs, and slow implementation of structural reforms are all risks to the economic and investment outlook. Thus, the outlook for FI is highly uncertain and is dependent on the changing of global crude oil markets, how the country to responds to the COVID-19 pandemic, and the economic reform process. The World Bank projects that if conditions ease, economic growth will return to 2%–7% between 2021 and 2022, with the non-oil economy bouncing back to an average of 4% growth in 2021–2022.

Despite the improving economic outlook, there are other challenges to the business and investment environment in the IKR and FI: security, corruption, and an unequipped banking system.

While the security environment remains volatile, attacks on officials and institutions occur regularly. A weak federal government that is rife with bitter sectarian and political fights, combined with weak security services, has allowed militia and insurgent groups to assert themselves time and again. FI continues to remain a high-risk place to invest, with a significant probability of renewed violence and political instability. In contrast to FI, the security situation in the IKR has been much more stable in recent years; however, threats remain.

As in other developing economies, corruption in Iraq remains high. According to Transparency International's Corruption Perception Index (2020), Iraq ranks 160th out of 170 countries in terms of public sector corruption, based on the lack of transparency in government regulations, government involvement in bribery and favored tenders, misuse of public funds, a weak judicial system, and the public sector's ineffectiveness in tackling corruption.

If FI and the IKR are to attract greater foreign investments, domestic banking sector reforms are imperative. Although the banking sector has the potential to grow, owing to massive oil and gas revenues, the domestic banking infrastructures and operations are limited. Iraq has only 51 banks, with 7 state-owned banks holding 89% of the country's bank deposits. These state-owned banks are inefficient and ridden with bad debts and old losses.

Despite the weak economic and investment climate, commercial banks in FI have two notable financings: Citibank Corporation's financing of Basrah Gas Company (BGC) and Deutsche Bank's financing of Behzan's (Bazian's) natural-gas-fired power project in the IKR.

BGC is a 25-year incorporated joint venture between Iraq's South Gas Company, with an equity stake of 51%; Shell, with an equity stake of 44%; and Mitsubishi Corporation, with 5%. It is one of the world's largest natural gas flare reduction projects. BGC's operations focus on capturing and processing associated gas from 3 oil fields in the south of Iraq: Rumaila, West Qurna 1, and Zubair. In 2019, Citibank extended a US$ 50 million credit facility to BGC, which will be used for working capital support and for the growth of natural gas production and exports. As part of the financing facility, BGC and CitiBank also implemented a cash management model to meet the BGC's needs to pay local and international suppliers reliably within the time schedules required through partnership with domestic banks in FI.

The Behzan (Bazian) Power Project is a 750 MW combined-cycle power project consisting of 500 MW of simple-cycle gas turbines and 250 MW steam turbines. The project, which was commissioned in Q4 2016, is located 25 km from Sulaymaniyah and is being developed by a IKR-based conglomerate, Qaiwan Group. The company operates a portfolio of assets and businesses across various sectors. Qaiwan Group's oil business segment is involved across various stages of the petroleum value chain, and its power business segment is involved in the construction of the Behzan (Bazian) Power Project, on which the company entered into a 15-year PPA with the Ministry of Electricity of the Kurdistan Region in Q4 2013 to finance, build, own, operate, and maintain the power project in Sulaymaniyah.

In 2016, a financing syndicate consisting of Deutsche Bank and Lebanon-based BankMed extended an 8-year buyer credit facility of US$ 75 million to Qaiwan Group to refinance part of the Bazian Power Project. The total financing package consists of an additional US$ 30 million in commercial loans arranged by General Electric, which were issued previously in 2015.

However, the Deutsche Bank and BankMed financing of the Bazian Power Project highlighted key challenges incurred by IKR infrastructure developers. These obstacles include scarcity of finance, given the limited risk appetite exhibited by international and GCC-based financing institutions; restrictive policies of export credit agencies;

eligibility to acquire senior unsecured financing; and political and security risks.

Table 29 Complexities in long-term financing of the Behzan (Bazian) Power Project

Scarcity of Finance	▪ Qaiwan Group's capital raising of the project incurred a limited pool of regional financing options, given the limited risk appetite exhibited by international and GCC-based financing institutions. ▪ One of the most attractive options for Qaiwan Group consisted of leveraging supply contracts with international turbine manufacturers and acquiring support from export credit agencies from their respective countries.
Restrictive Policies Export Credit Agencies	▪ Export credit agencies operate with a limited and restrictive set of policies for Iraq and, in many cases, no provisions for the Iraq Kurdistan Region. ▪ Official credit policies mainly consist of approving loans to local corporates that are backed by a sovereign Iraqi guarantee or an acceptable, state-owned Iraqi bank guarantee. ▪ Guarantees are complicated to attain for projects in Kurdistan, given the underlying political complexity.
Time Pressures	▪ The PPA was signed and entered into with the off-taker under strict deadline in terms of project completion. ▪ As part of adhering to the project completion timeline – Qaiwan Group had to timely conduct and conclude the selection of an engineering, procurement, and construction (EPC) contractor and technology suppliers.
Senior Unsecured Financing	▪ Qaiwan Group's eligibility to secure a senior unsecured financing structure was largely attributed to its ability to operate a sound balance sheet structure and profitable (cash-generating) business.
Refinancing	▪ As part of the financing structure, Qaiwan Group negotiated to a re-financing provision, i.e., instead of disbursing the loan by effecting payments to the selected turbine suppliers, export credit agencies would approve that Qaiwan financing requirement for the project before the loan would be available. Once finalized, that loan would be used to refinance payments made by Qaiwan to selected turbine suppliers.

Political and Security Risk	▪ At the time of financing, meeting lender requirements became increasingly complicated because of the challenging political and security risks in Iraq that resulted from:
	  ▪ ISIS invasion of Iraqi territory
	  ▪ Military conflict between the Kurdish army and ISIS
	  ▪ Dispute between the government of Kurdistan and the central government of Iraq on oil exports and revenue sharing
	  ▪ An uncertain global energy market, given the fall of crude oil prices at the end of 2014, which added to great pressure on the region's financial situation

7.2 Phased Development of the Natural Gas Sector: Natural Gas Pricing

The IKR has various options to price its local natural gas sales but has shown inclination for the Regulation – Cost of Service (RCS) method, which is the main system used across the Middle East. For example, in 2019, 75% of natural gas sales in the Middle East (~410 BCM) were based on RCS contracts, mainly across Saudi Arabia, the UAE, Bahrain, and Oman.

The RCS method of natural gas pricing involves fixing a well-head or field-fence price on each producing field, based on development and operating costs, plus return on capital. The final price to the consumer is a combination of the production, processing, and transport costs, which can be simpler than deregulated pricing mechanisms. If the IKR has accurate information on each field's production costs, RCS could extract maximum rent for the IKR, but this pricing method is not always reflective of the broader regional and international market realities. It might also be prone to incentives for "gold-plating" and over-investment into projects. Also, if offered prices are low, an RCS mechanism would deter development interest, owing to lack of return on investment.

Table 30 Pricing mechanisms for natural gas pipelines from Kurdistan to Turkey or FI

Mechanism	Abbreviation	Description
Oil Price Escalation	OPE	Price is linked, typically through a base price and an escalation clause to crude oil or oil products.
Gas-on-Gas Competition	GOG	Price is determined by market demand and supply. It is traded over physical or virtual regional/national trading hubs over a period of time (daily or more frequently, monthly, quarterly, or annually).
Bilateral Monopoly	BIM	Price is determined through bilateral negotiations and agreements between a large seller and/or large buyer. Prices are typically fixed over a period of time.
Netback from Final Product	NET	The cost of delivery is determined by the price received by the buyer for the final product.
Regulation – Cost of Service	RCS	Prices are structured to cover the cost of delivery plus recovery of investments and a "negotiable" price premium based on an investment rate of return.
Regulation – Below Cost	RBC	Prices are deliberately set below the average cost of production and delivery, subjected to state subsidy or grant.

RCS and other regulated mechanisms (Table 33) are characteristic of strong government control, where natural gas price formation closely follows government policy objectives. RCS is often a precursor to the development of a de-regulated gas-on-gas competition market, as in Europe. This method is still widely used throughout the Middle East, Southeastern Europe, and Central Asia.

Another potential mechanism is oil price escalation or indexation, under which natural gas prices are based on oil prices multiplied by a specific factor, plus fixed transport (pipeline, or in the case of LNG, shipping) costs. The mechanism is linked to competing fuels such as crude oil, gas oil, or fuel oil, usually through a base price and an escalation clause. For example, Qatar prices much of its LNG exports on an OPE mechanism to Asia, linked to the Brent crude benchmark, and inclusive of a fixed factor. Iran's sales contracts to Turkey and Iraq are understood to be based on oil-price escalation, as is BGC's sales of processed gas to the Iraqi state. Such an arrangement will be better aligned with existing natural gas sales contracts to Turkey and FI, but it poses the risk of falling out of line with market realities and becoming inflexible to seasonal variations in demand patterns.

A third mechanism could be gas-on-gas competition, with natural gas prices determined by supply and demand traded in physical and/or virtual hubs.[53] Numerous producers and buyers compete in an open market with ready access to transport capacity, providing incentives for both producers and consumers. The mechanism is significantly more transparent than RCS and OPE, best aligned with market realities, and is reflective of seasonal variations or unexpected changes in demand patterns.

The global average of natural gas sales is overwhelmingly characterised by GOG pricing mechanisms, making GOG the basis for developing a sophisticated natural gas market in regions with large resources. Notable GOG indices include hubs such as Henry Hub (US), TTF (Netherlands), NBP (UK), and the JKM (Asia–Pacific LNG). Turkey has

[53] Institute of Energy for South-East Europe, "The Outlook for a Natural Gas Trading Hub in SE Europe", September 2014, https://www.depa.gr/wp-content/uploads/2018/12/The20Outlook20for20A20Natural20Gas20Trading20Hub20in20SE20Europe_FINAL

also launched a GOG hub, EXIST. This method currently might be out of touch with IKR aims and realities. For example, the IKR has too few producers and large buyers to enable a competitive market today. Also, prices are much more volatile than in other mechanisms, which can result in a windfall of profits or losses for low-cost and high-cost producers.

For the IKR, the preferred end state would be a GOG-driven natural gas market, but only after intermediate challenges are dealt with, including the development of open-access infrastructure, and the emergence of several large-scale buyers and sellers.

Table 31 Potential gas pricing methods in the IKR context

Method	Description	Pro	Con
Regulation – Cost of Service	Each field receives a fixed well-head or field-fence price based on development and operating costs, plus return on capital. Price to consumers is based on production, processing, and transport costs.	• Simple in theory • Can extract maximum rent for KRG	• Not adapted to market realities • Incentives for 'gold-plating' and over-investment • Does not encourage developments if prices set too low. • Requires sophisticated understanding of reasonable development costs for various types of fields.
Oil Price Escalation	Price is based on oil prices multiplied by a factor, plus fixed transport (pipeline) costs.	• Related to price of competing fuels in power and industry • Aligned with existing gas sales contracts to Turkey and federal Iraq	• Can become out of line with market realities • Does not allow for seasonal variations
Gas-on-Gas Competition	Numerous producers and buyers compete in an open market with ready access to transport capacity.	• Best aligned with market realities • Incentives for producers and consumers • Transparent • Reflects seasonal variations • Basis for developing a sophisticated market (futures, hub prices, etc.)	• Can give windfall profits to companies with lower-cost fields • Too few producers and large buyers in IKR for a competitive market today • Prices can be volatile

In the case of gas sales to Turkey and/or FI, the IKR or companies negotiating such sales will need to price their gas competitively. This could be based on oil price escalation, as done by other sellers to these markets. This is probably most realistic for FI, although in the case of Turkey, there could also be the option of using LNG prices, a link to European gas hub prices, or the traded Turkish gas index on EXIST.

7.3 Phased Development of the Natural Gas Sector: Margins from IKR Natural Gas Sales to Turkey versus Federal Iraq

IKR natural gas sales into Turkey offer a smaller margin than sales into FI (assuming a IKR natural gas sales price 10% lower than the Iranian natural gas price into FI and 10% lower than the lowest of LNG, TANAP (Azerbaijan), and Iran natural gas prices into Turkey). However, the smaller margin is contingent on Iran's competitive position and actions in response to sales from the IKR. Iran could very well lower its sales prices to both FI and Turkey to compete. It is also dependent on the state of negotiations between the federal government and KRG, which may include other issues such as the federal budget share and agreements on budget transfers if the gas sales contract is between the MNR and Baghdad rather than a commercial agreement with producers.

Alternatively, the IKR natural gas sales price could be assessed against the price of delivering processed FI natural gas to Baghdad (based on the BGC price formula), but BGC is not the marginal supplier, given that its prices are relatively low compared to the price of Iranian gas or liquid fuels, BGC costs are generally lower, but its output is not sufficient on its own to meet FI demand. Prices discussed with TotalEnergies for the Ratawi associated gas gathering project are understood to be similar to BGC prices. The Turkish natural gas hub (INDEX) could eventually be used as an option for benchmarking Kurdish natural gas prices, but the hub is new and currently not very liquid.

Figure 77 shows the potential margins available to the IKR from sales to the Turkey and FI markets until 2040. The cost of supply from the IKR has been determined based on the existing arrangement reached with Genel Energy for the Miran and Bina Bawi fields.[54] In this case, Genel would supply raw gas for US$ 1.20/Mcf (approximately US$ 1.60/MMBtu, after removal of non-hydrocarbon gases), and a KRG-established midstream company would process and transport it, with an estimated midstream capital cost of US$ 2.5 billion for 10 BCM/y of processed gas, giving an estimated processing cost of US$ 1.03/Mcf (approximately US$ 1/MMBtu). Note that fields with a higher condensate/NGL content and/or lower H_2S content, such as Khor Mor, Chemchemal, and Kurdamir-Topkhana, would likely incur lower production costs.

The sales price to Turkey has been calculated at a 10% discount to the lowest price between global LNG spot prices, Iran's natural gas price to Turkey, and Azerbaijan's natural gas price to Turkey via TANAP. Both the LNG and TANAP prices exclude regional border costs, i.e., the tariff of transporting natural gas from the IKR to Turkey. 2027 LNG prices are forecast at US$ 6.58/MMBtu, while the TANAP price to Turkey is forecast at US$ 6.77/MMBtu, including border costs to Turkey. Iran's natural gas price to Turkey is forecast at US$ 6.78/MMBtu. A 10% discount to the lowest of the three (spot LNG), minus pipeline costs from the Turkey-Iraq border, results in a potential netback sales price of US$ 3.64/MMBtu to Turkey. Note that it is understood that BOTAŞ network tariffs do not vary by distance/location, but it is nevertheless expected that the company would do an internal evaluation of the costs to move imported gas to the point of consumption when negotiating gas purchase contracts.

Similarly, the netback sales price to FI has been calculated at a 10% discount to the Iranian sales price to Iraq, delivered to Baghdad. This results in a potential IKR 2027 sales price of US$ 5.1/MMBtu. This is higher than the cost of delivering Basrah Gas Company supplies to Baghdad, or the price understood to have been agreed with TotalEnergies for the Ratawi gas gathering project, around US$ 3.5/MMBtu[55]. Since the FI in this case is a net importer, the higher price for IKR supplies could be economically justified as still cheaper than other alternatives.

[54] https://genelenergy.com/wp-content/uploads/2020/08/genel-eneergy-2015-annual-report-final.pdf
[55] International Energy Agency, personal communication

Against the IKR's border supply costs, this results in a margin of US$ 1.87/MMBtu from natural gas sales to FI, compared to a margin of only US$ 0.41/MMBtu from natural gas sales to Turkey. However, if the FI would demand a price comparable to that for its own domestic production, the margin for the IKR would be reduced significantly, to about $0.30/MMBtu, less than that to Turkey but still positive.

Under the Base Case scenario, this results in net revenues (after all costs) of US$ 1.7 billion annually from sales to FI, and just under US$ 0.2 billion from sales to Turkey.

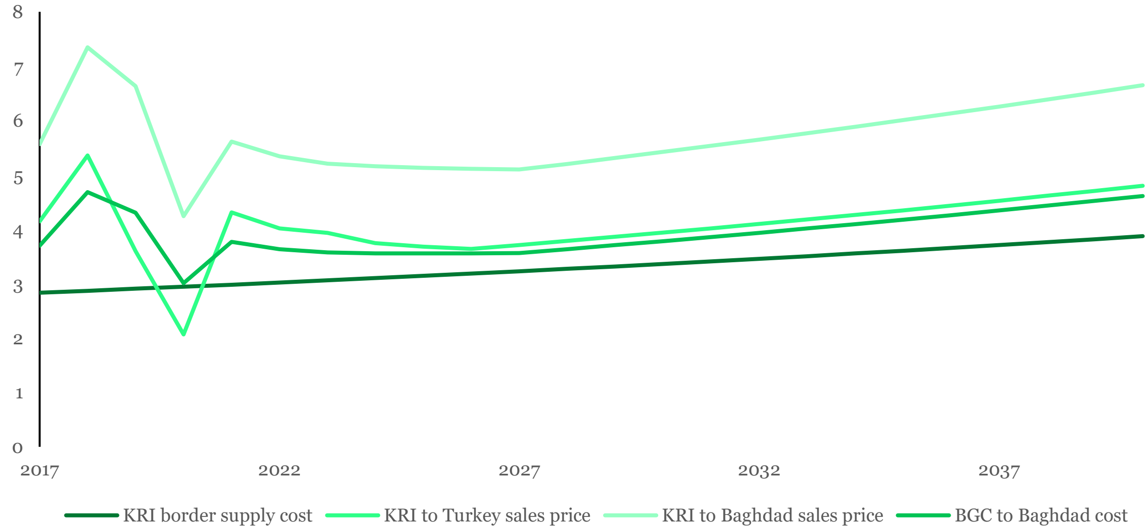


Figure 56 Natural gas sales price from the IKR, US$/MMBtu

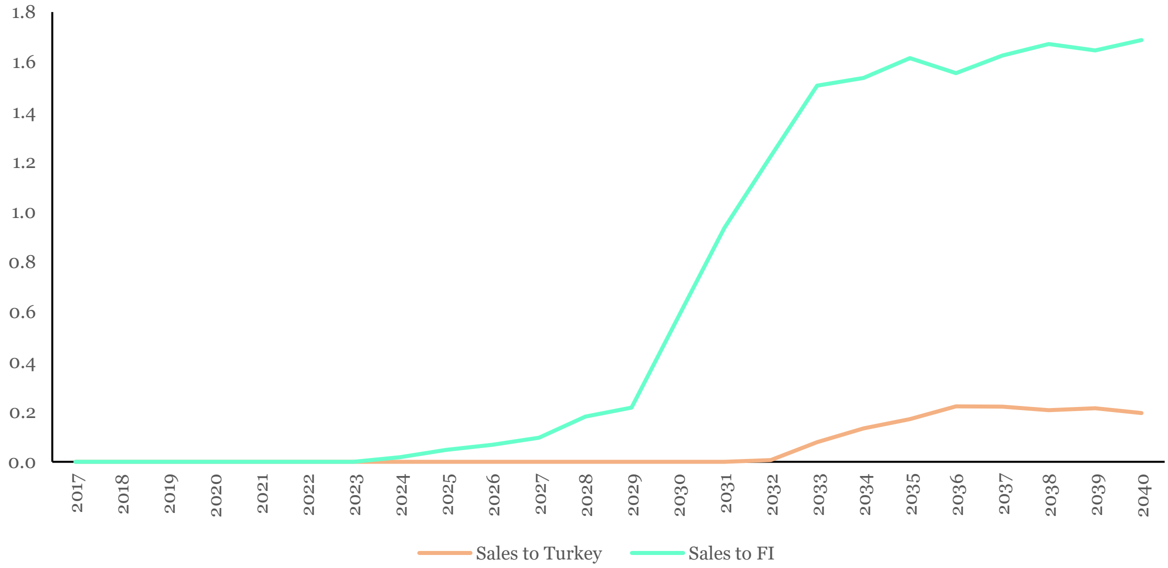


Figure 57 Potential annual net revenues from gas supplies to FI and Turkey under the Base Case, US$ billion

Small-scale supplies to FI through the Khor Mor-Jambur–Kirkuk connection could result in ~US$ 40 million/year net revenues, and these deliveries can start well before exports to Turkey. Costs depicted in Figure 77 are net of pipeline and upstream costs. However, achievable prices could be reduced by competitive price-cutting by Iran or other players. This would benefit FI and Turkey, particularly in the case of FI, given the relatively high prices paid to Iran in the absence of alternatives.

7.4 Phased Development of the Natural Gas Sector: Indicative Project Structure for Gas Pipeline Company to Federal Iraq and Turkey

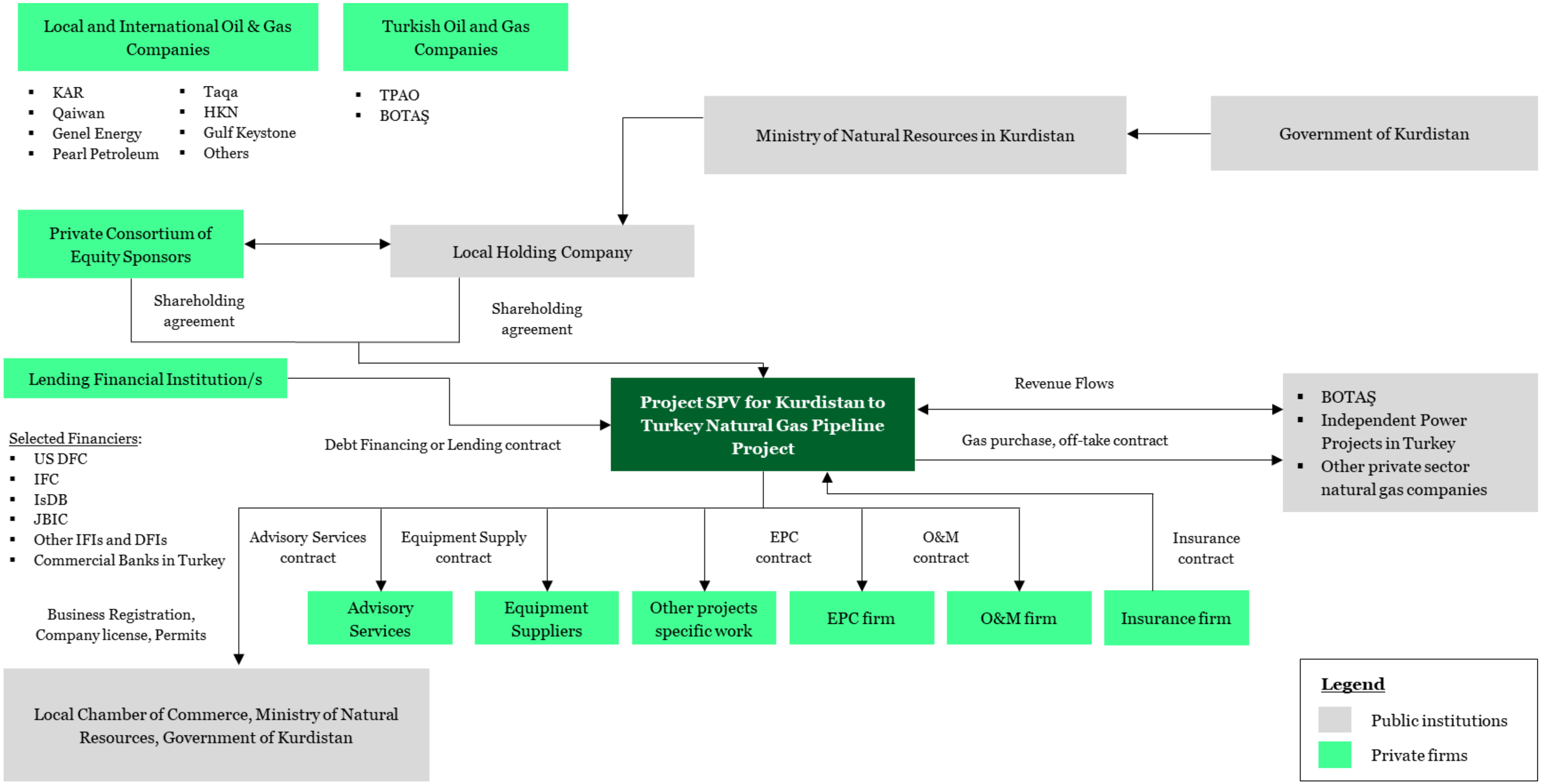


Figure 58 Indicative project structure for gas pipeline to Turkey

Figure 79 depicts an indicative project structure for a natural gas pipeline from the IKR to FI. A local holding company under the MNR can enter into a shareholding agreement with a private consortium of equity sponsors, including local and international oil and gas companies operating in the IKR, as well as other IOCs operating in FI, to establish a similar SPV for the FI natural gas pipeline. Debt financing can be established through leading financial institutions, while the local Chamber of Commerce in the IKR would work with the SPV to contract advisory, equipment supply, EPC, O&M, and insurance contracts with private firms. The gas purchase contract(s) would then be established with the Ministry of Electricity in Iraq, which would pay the SPV directly for the IKR's natural gas supply. As currently constituted, this would require a federal government guarantee, given the Ministry of Electricity's weak financial situation. Meanwhile, IOCs operating in Kurdistan, which will utilize the pipeline to transport their gas to FI, will pay the SPV an agreed tariff based on contractual supply/usage of the pipeline. IOCs which invest in the pipeline would receive preferential rights for a proportional share of throughput for their production in IKR, subject to booking.

Similarly, Figure 80 (next page) depicts an indicative project structure for a natural gas pipeline from the IKR to FI. A local holding company under the MNR can enter into a shareholding agreement with a private consortium of equity sponsors, including local and international oil and gas companies operating in the IKR, as well as other IOCs operating in FI, to establish a similar SPV for the FI natural gas pipeline. Similar to the indicative project structure for the natural gas pipeline to Turkey, debt financing can be established through leading financial institutions, while the local Chamber of Commerce in the IKR would work with the SPV to contract advisory, equipment supply, EPC, O&M, and insurance contracts with private firms. The gas purchase contract(s) would then be established with the Ministry of Electricity in Iraq, which would pay the SPV directly for the IKR's natural gas supply. IOCs which invest in the pipeline would receive preferential rights for a proportional share of throughput for their production in IKR, subject to booking.

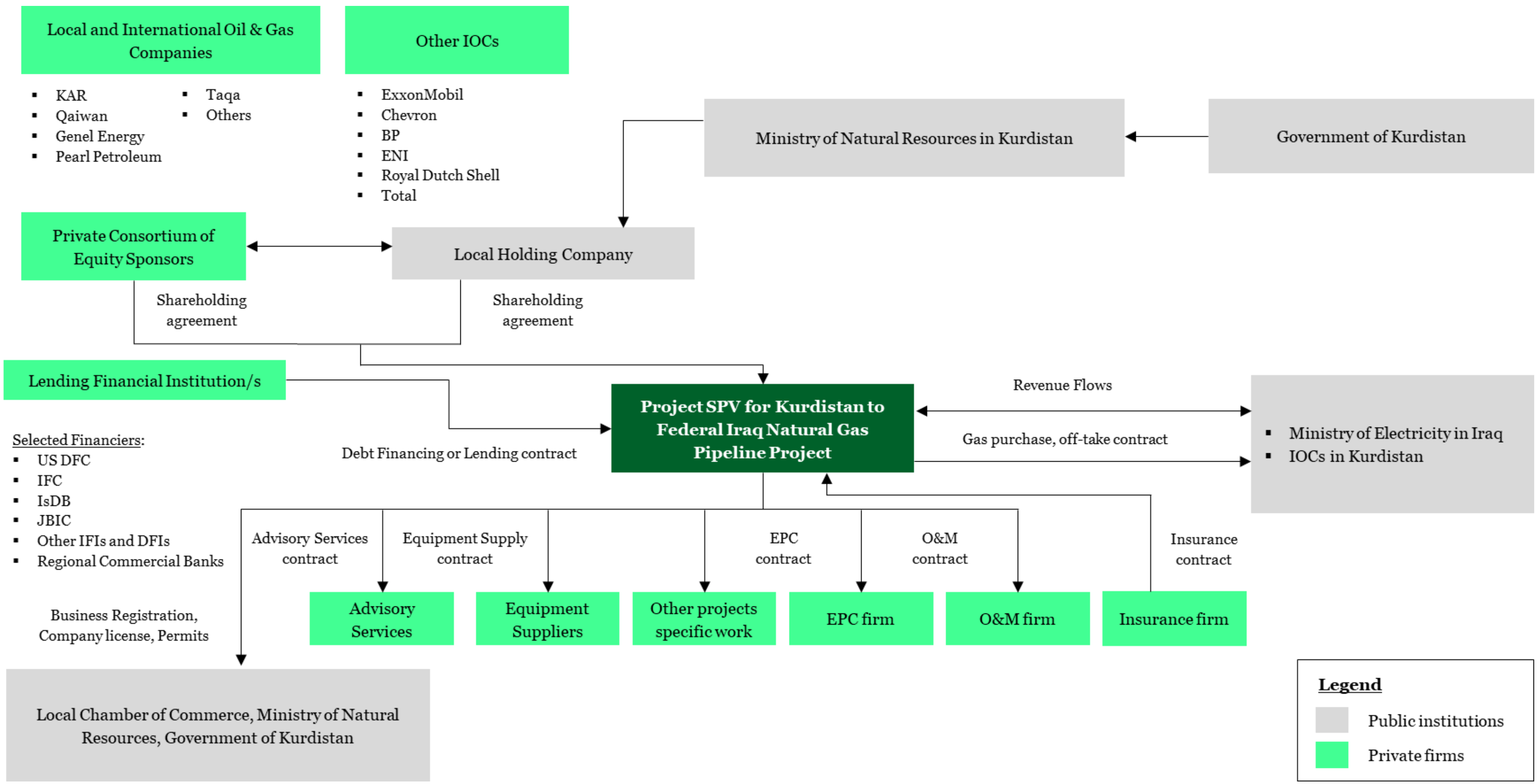


Figure 59 Indicative project structure for gas pipeline to FI

7.5 Phased Development of the Natural Gas Sector: Project Structure Scenarios

7.5.1 SPV Constructs Gas Pipeline, Upstream Users Pay a Tariff

Under the first project structure scenario, the SPV would construct and finance the natural gas pipeline, while upstream users will pay a tariff for utilizing the pipeline for transporting their gas as sales. Alternatively, upstream companies could sell the gas at the field fence (entry point into the pipeline) and end-users could pay the tariff, or intermediaries/traders could buy, transport and sell the gas, paying the appropriate transport tariff. The SPV shall enter into a natural gas sales agreement with upstream, local, and/or international oil and gas companies that market their own natural gas output and have entered into supply agreements with end users in FI and/or Turkey. These upstream IOCs will pay the SPV an agreed tariff based on the contractual supply/usage of the pipeline.

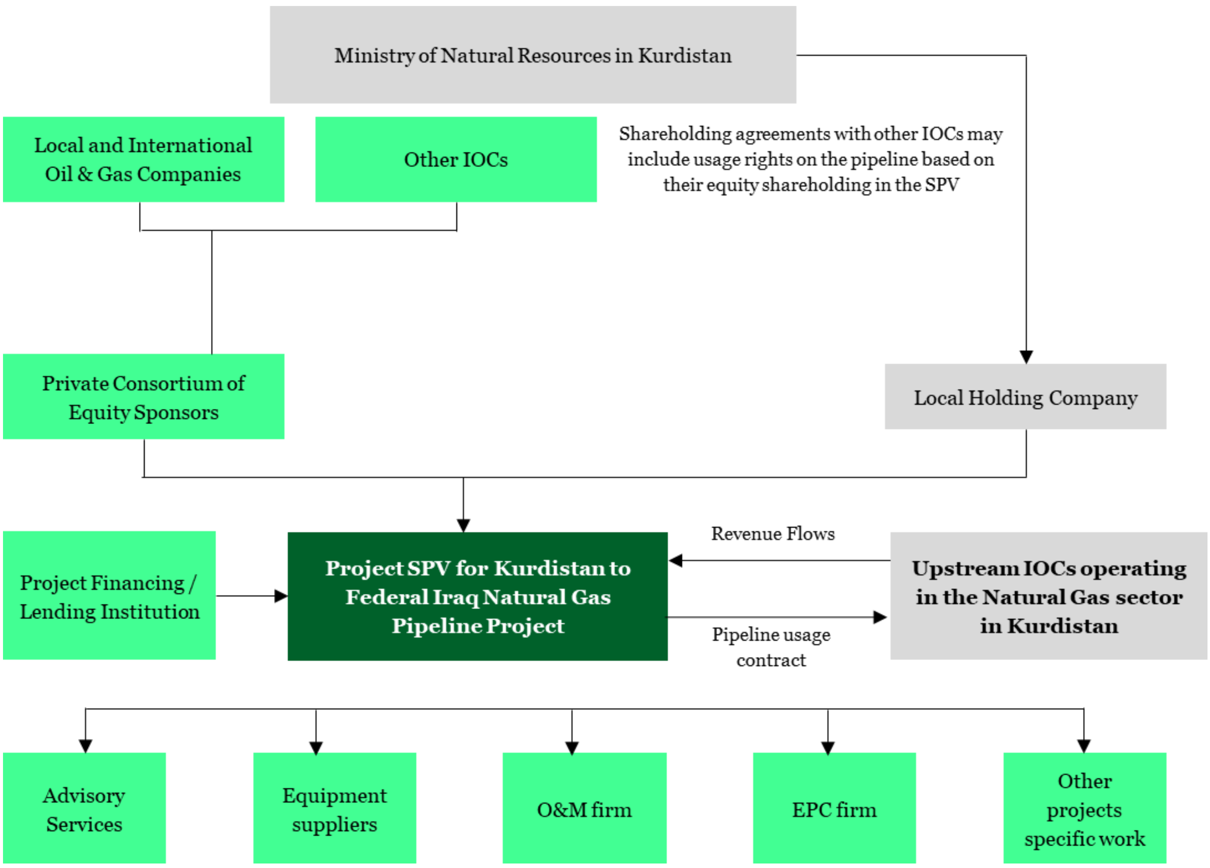


Figure 60 Project Structure Scenario 1: SPV constructs gas pipeline, upstream users pay a tariff

7.5.2 SPV Constructs Gas Pipeline, Acts as Gas Aggregator

Under the second project structure scenario, the project SPV constructs and finances the natural gas pipeline to FI from Kurdistan. The SPV enters into gas purchase agreements with local or international oil and gas companies operating in the IKR. The SPV will sell the natural gas through the pipeline to end users in FI through a medium-term/long-term natural gas supply agreement.

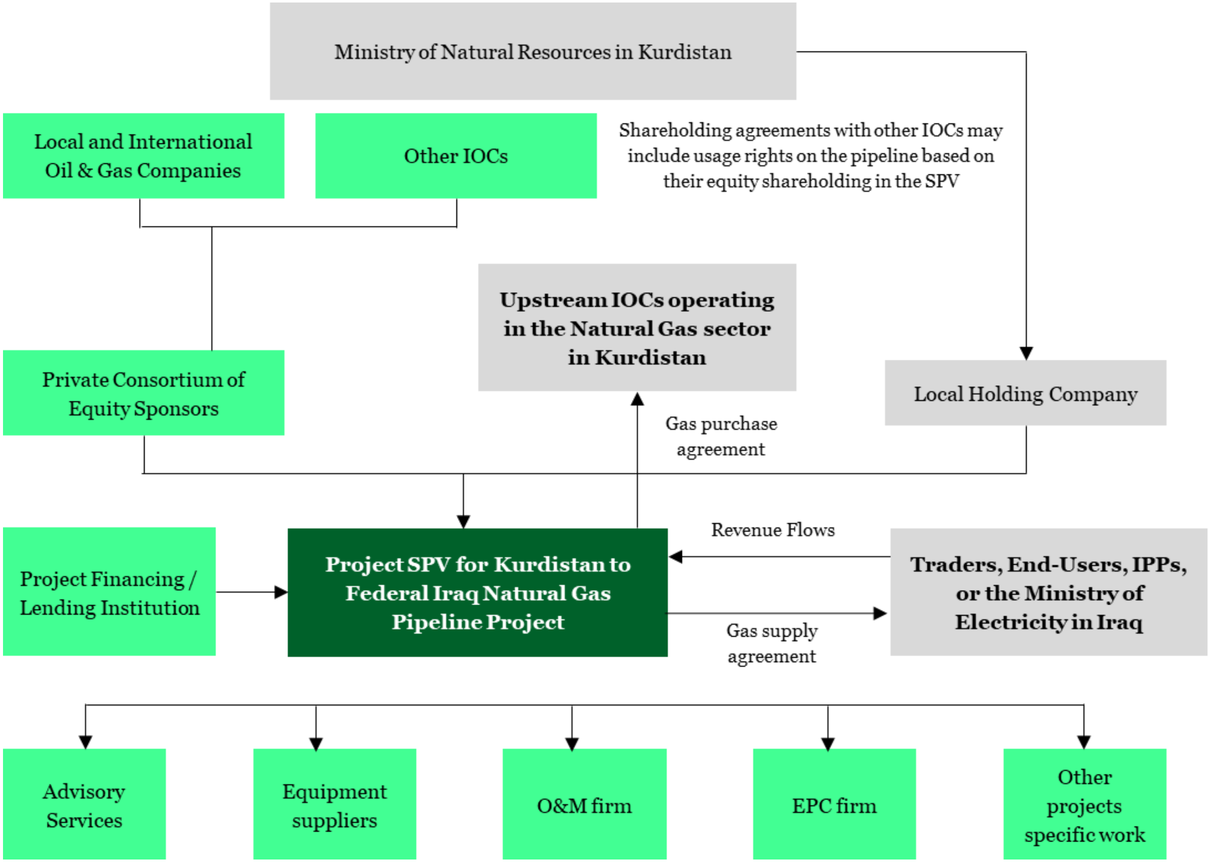


Figure 61 Project Structure Scenario 2: SPV constructs gas pipeline, acts as a gas aggregator

7.5.3 SPV constructs gas pipeline, with a separate gas aggregator

Under the third project structure, the project SPV constructs and finances the natural gas pipeline from IKR to Federal Iraq. A separate gas aggregator purchases natural gas from upstream producers in the IKR, and then enters into a supply agreement with buyers in FI. The aggregator concludes a pipeline usage agreement with the SPV, including volumes. Note that this arrangement could co-exist with some gas producers in IKR who market their gas direct (not to the aggregator) and have separate pipeline usage agreements with the SPV, and indeed could be shareholders in the SPV.

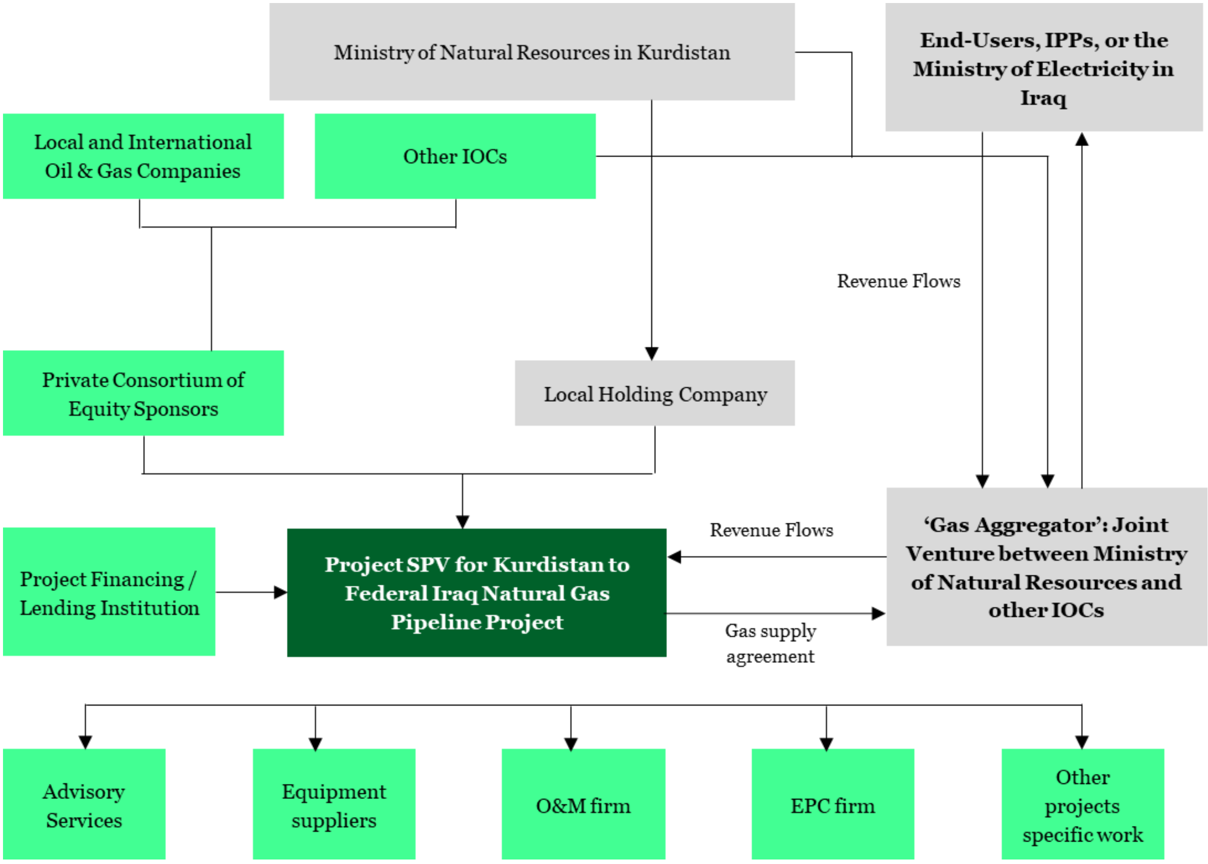


Figure 62 Project Structure Scenario 3: SPV constructs gas pipeline, with a separate gas aggregator

8 Regulatory Considerations

Several other comparable and/or neighbouring jurisdictions to the IKR have been selected to show how their gas and power sectors are organized (see Section **Error! Reference source not found.**), namely Norway, Azerbaijan, Oman, Abu Dhabi (UAE) and Turkey. The Section shows the structure of governance (the roles of the ministry of oil/energy, a regulator if any, and the national oil and gas company if any), oil and gas production, domestic and international gas pipelines and sales, electricity generation and sales, and the setting of domestic gas and electricity prices. These examples are used to illustrate and inform particular aspects of the IKR's situation described in the following sections. For example, Azerbaijan is also an effectively landlocked entity with a few large gas fields, a sizeable domestic market, and important export pipelines.

8.1 Phased Structure of the Natural Gas Sector in Comparable Regions

Norway is the largest gas producer in Europe and a leading exporter of pipeline gas and LNG. It has a strong independent regulatory structure, and a leading role for its national oil company, Equinor, alongside numerous domestic and international oil and gas companies active in the upstream and midstream. The offshore pipeline network is co-owned by state and private companies. Very little gas is used domestically, but exports are at international prices and producing companies are free to market their gas.

Regulators	Exploration & Production	Liquefaction & Storage	Gas Utilities	Electric Utilities
Ministry of Petroleum and Energy (MPE) is responsible for overseeing the country's energy resources. Sets strategy and policy. **Norwegian Petroleum Directorate (NPD)** counsels the MPE, regulates E&P activities	**Equinor** dominates natural gas exploration and production in Norway. Equinor also operates the LNG export terminal and liquefaction facility at Melkøya, Norway, near Hammerfest.		**GASSCO** state-owned operator for Norway's natural gas pipeline network, including the network of international pipelines and receiving terminals that exports Norway's natural gas to the UK and continental Europe	**Statnett** owns and operates the electricity grid and is responsible for ensuring the reliability and efficiency of the electric grid and for balancing electricity supply and demand
	A number of international oil and natural gas companies, including ExxonMobil, ConocoPhillips, Total, Shell, and Eni, have a sizable presence in the natural gas and oil sectors in partnership with Equinor		**Gassled** is the unincorporated JV owning the offshore gas transmission system, including Norwegian state, IOC and investor shareholders	

Figure 63 Structure of the natural gas sector in Norway

Azerbaijan exports gas by pipeline to Georgia, Turkey and on to south-eastern Europe and Italy. It is a land-locked country (apart from its access to the Caspian Sea, not connected to world oceans). Its national oil company, SOCAR, plays an important role in gas exports alongside BP and other international oil company partners. Setting of gas and electricity tariffs is being transferred to a new regulatory authority.

Regulators	Exploration & Production	Liquefaction & Storage	Gas Utilities	Electric Utilities
Ministry of Energy (MOE) is responsible for overseeing the country's energy resources. Sets strategy and policy. **Energy Regulatory Agency (ERA)** is under the MOE, and under establishment by the decree of 2017, currently in inter-ministerial consultations.	**SOCAR is the national oil company.** It operates fields on its own account and also partners with IOCs in production and in pipelines. Most oil and gas production is by IOCs under production-sharing agreements (PSAs).		The main **gas export pipelines** are built and owned by consortia of SOCAR with IOCs, including BTE (SOCAR 16.67%) and TANAP (SOCAR 51%).	**Azerenerji** is state-owned and owns and operates electricity generation and transmission, although regional distribution networks are being privatized.
Tariff Council is responsible for the setting of all regulated prices. This function for energy is to be transferred to the ERA. Electricity tariffs by law have to cover costs. Gas transport costs and prices are regulated and are currently $1.25/Mcf wholesale, $2/Mcf to power producers.	Leading international oil companies in partnership with SOCAR include BP, Lukoil, Equinor, Total, TPAO, Petronas and others.		**Azerigaz** is owned by SOCAR and distributes gas within Azerbaijan. SOCAR's **Gas Export Department** receives gas produced at the ACG and Shah Deniz fields and markets Azerbaijan's gas internationally.	

Figure 64 Structure of the natural gas sector in Azerbaijan

Oman is an important non-OPEC oil producer with capacity of about 1 million bbl/day, and also a significant exporter of LNG. Gas production and exports are carried out by partnerships of the state with international companies. Domestic gas prices are regulated while domestic gas infrastructure is government-owned.

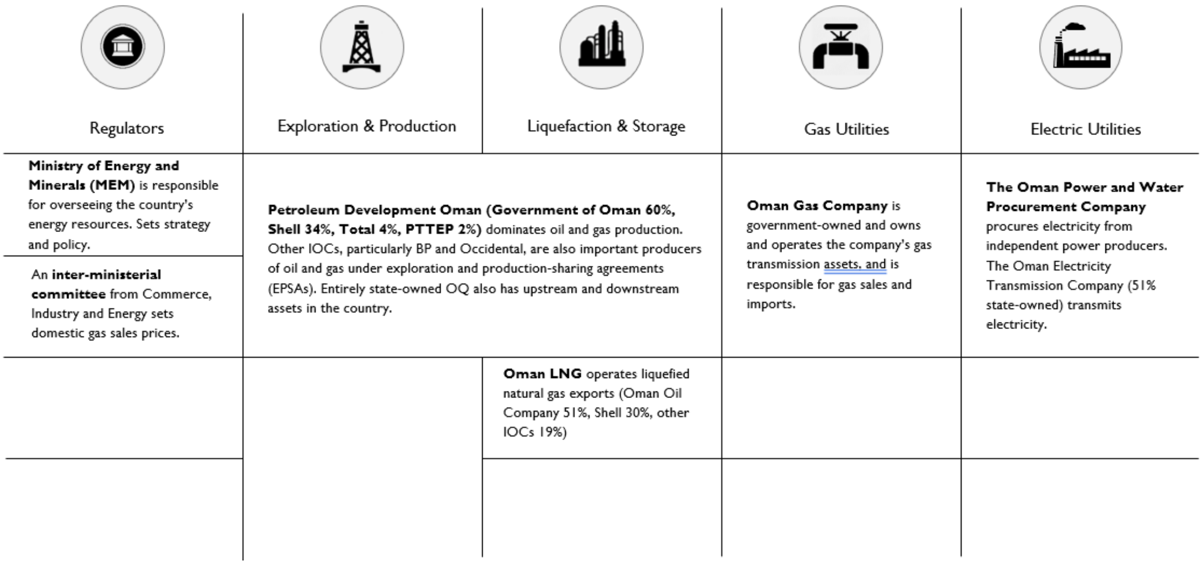


Figure 65 Structure of the natural gas sector in Oman

Abu Dhabi is the dominant oil- and gas-producing emirate in the UAE under its federal structure. The national oil company ADNOC handles oil and gas production and exports in partnership with numerous international companies. It also recently sold a stake in its gas pipelines to international investors. Another state-private venture, Dolphin Energy, imports and also distributes gas. Domestic gas prices are regulated by the Supreme Economic Council, while the Ministry of Energy and Infrastructure handles federal-level energy policy.

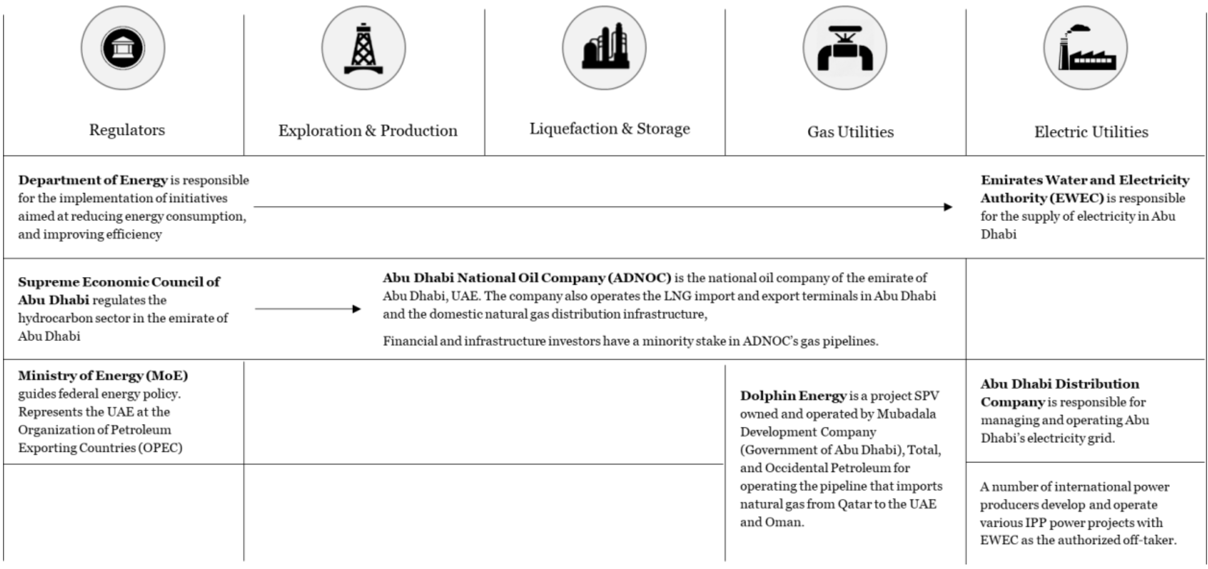


Figure 66 Structure of the natural gas sector in Abu Dhabi, UAE

Turkey is currently a very minor gas producer but an important gas market and transit country. It has an independent market regulator which sets gas and power prices, and a state-owned gas pipeline company. It has recently introduced a traded gas market though this so far only makes up a small share of sales. Its new Black Sea gas discoveries, if commercial, will be developed by state oil firm TPAO, possibly with international partners.

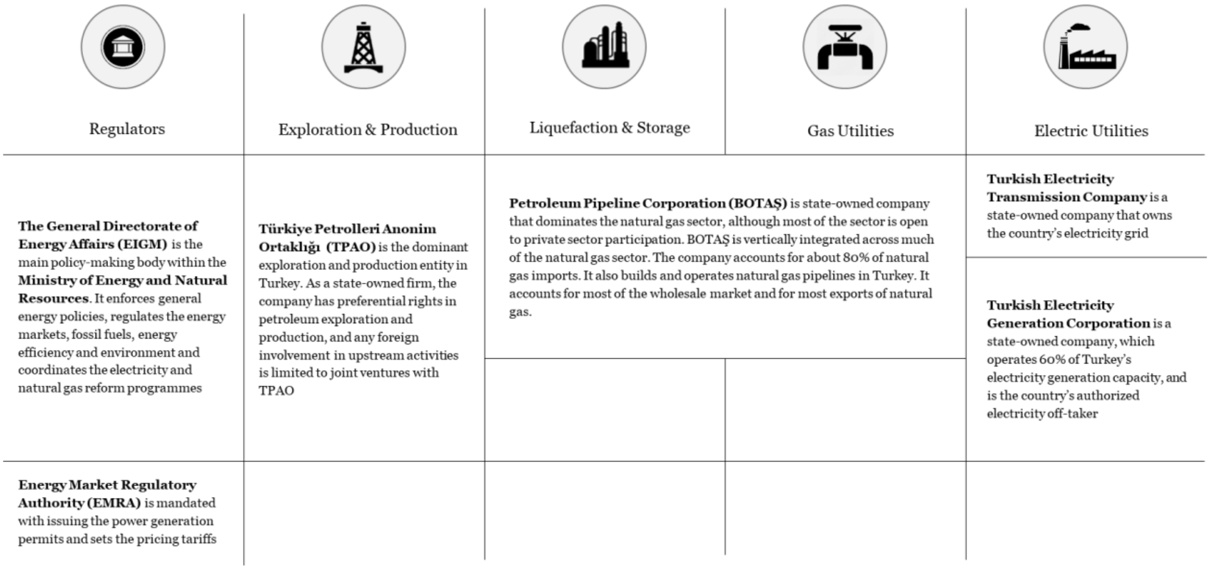


Figure 67 Structure of the natural gas sector in Turkey

These countries' situations vary in various ways from the IKR's, but illustrate possible frameworks that the IKR can consider for the structure of its gas and electricity markets. For example, they cover land-locked states seeking to export gas; gas exporting countries with a mix of international oil company and state involvement; federal structures; and gas market reform to meet changing circumstances and customer demands. Key elements are consistency and professionalism of regulation and tariff-setting; a growing reliance on market-based mechanisms; and strong government-private partnerships in gas infrastructure.

8.2 Natural Gas Sales Agreements to Federal Iraq and Turkey

The development of a natural gas pipeline from the IKR to FI and/or Turkey is dependent on the nature of the natural gas sales agreement, which will document the sale and purchase of a specified quantity of natural gas to Turkey and/or FI.

A standard natural gas sales agreement (GSA) is a contractual agreement between a single seller and a single buyer, usually with a long-term economic horizon, which is drafted from a neutral point of view. In the case of a GSA based on a single field or group of fields, the agreement provisions for deliveries of natural gas through a pipeline system where the seller dedicates an agreed and specified quantity of natural gas produced from its interest in the natural gas field(s) to the buyer.

However, given the long-term economic horizon of GSAs, they will be exposed to various project financing risks, which include commercial and technological changes. Hence, a GSA relating to a natural gas pipeline to Turkey and/or Iraq has to be structured and drafted to mitigate such risks. In addition, this also provides upstream natural gas producers in Kurdistan assurance in allocating a proportion of their production from the natural gas fields to the pipeline and securing necessary capital allocations to develop the fields.

A GSA could be a fixed term-based supply agreement with varying degrees of quantity and delivery time flexibility. A standardized GSA is referred to as a "Term Agreement," which provisions for a short-term sale and purchase of natural gas, typically over a 1–5 year period, or a longer-term arrangement up to 20–25 years. In contrast to a term agreement, a "Supply-Based Agreement" allows for a degree of flexibility in terms of the source of natural gas, such that a seller commits to delivering natural gas to the buyer without any commitment to the source of natural gas (or natural gas field). In a supply-based agreement, both parties agree in advance on the quantity and delivery of natural gas, and the seller must adhere to those terms.

In terms of flexible options, another consideration could be a "Depletion-Based Agreement," which differs from a supply-based agreement in that a seller commits to delivery of natural gas to the buyer based on an unspecified amount of economically recoverable reserves from a nominated natural gas field. These contracts are typically enforced based on the economic and technical life of the natural gas field, where the scope of agreement is limited by the natural gas reserves remaining at the field.

And finally, counterparties on a natural gas pipeline from Kurdistan to FI and/or Turkey may choose to implement a "Hybrid Supply Agreement," which allows for the nomination of specific natural gas field(s) as a source of supply for a fixed or variable period. If the aggregator model is followed, the GSA could be based on the total reserves available to the aggregator. If sales agreements are made by individual companies, the GSA would most likely be based on a proportion of the reserves entitlement of that company in the IKR.

Table 32 Selected GSAs to FI and Turkey

Selected Natural Gas Sales Agreement	Additional Details
Term Agreements	▪ Term agreements provide for the sale and purchase of natural gas over a specified period of time and are generally classified as either short-term (1–5 years) or long-term (~20–25 years—but may also include much longer terms).
Supply-Based Agreements	▪ In a supply-based agreement, the seller commits to undertake and deliver a specified quantity of natural gas to the buyer with a degree of flexibility in terms of the source of supply. The degree of flexibility is a negotiated item and a broad right that may entitle the seller to source natural gas to other locations.
Depletion-Based Agreements	▪ Depletion-based agreements are based on an unspecified amount of economically recoverable reserves from a nominated natural gas field. In reality, the depletion-based agreements will remain in place for the economic and technical life of the natural gas field, where the scope of the agreement is limited by the reserves remaining at the natural gas field.
Hybrid Supply Agreements	▪ Undertaking entities may also implement a hybrid supply agreement and depletion agreement under which a particular natural field is nominated as the single source of supply for an aggregate volume of natural gas or for a fixed period of time.

Furthermore, the economic viability of the aforementioned GSA agreements is dependent on key contractual clauses, which include, but are not limited to, gas quality specifications, delivery times, quantities (daily, annual), nominations, take-or-pay clauses, quantity shortfalls, make-up in case of failure/delays to payments, periodic price reviews, force majeure conditions, and dispute resolution provisions.

Table 33 Selected terms and conditions of GSAs to FI and Turkey

Selected Terms and Conditions of the Natural Gas Sales Agreement (GSA)	Additional Details
Delivery	• The seller must make gas available to the buyer at an agreed delivery point. Risk and title in the gas generally passes from the seller to the buyer at the delivery point.
Quantities	• Often heavily negotiated, the quantities provisions define the scope of the seller's principal obligations under the GSA. • The parties are expected to decide on the degree of quantity flexibility to be afforded by the buyer. • The buyer will want as much flexibility as possible to enable it to manage its downstream obligations. • The seller will want to minimize the level of flexibility so it can effectively manage its upstream risk, its inventory, and its supply obligations under other GSAs. • The seller will also seek to pass on the cost of building in any quantity flexibility and limit its exposure for failing to supply. • Quantities are typically expressed in terms of the Annual Contract Quantity (ACQ) and Daily Contract Quantity (DCQ). These can be fixed or can vary over time. There may also be minimum seasonal or monthly quantities to ensure a buyer does not reduce their offtake too much during low-demand periods.
Nominations	• Given that the parties generally agree on a range for the contract quantity of gas that the seller is obliged to deliver to the buyer, the GSA will also contain detailed procedures for the buyer to nominate the actual quantities it wants and can take delivery of on any day.
Take-or-Pay/Undertake	• The GSA provisions will determine a buyer's obligation to "take-or-pay" a stated quantity of the ACQ, which may be around 80%. If not taken, the buyer has to pay but can then lift the paid-for quantities in future years ("make-up gas") subject to achieving the ACQ for those years. • Despite industry norms regarding take-or-pay clauses, the parties to a GSA must also consider the local law position regarding the enforceability of such an obligation. In some jurisdictions, a take-or-pay clause that creates contractual and economic imbalance to the detriment of one party may well be unenforceable.
Make-up or Carry Forward	• If a buyer has paid for and not taken certain quantities of gas under a take-or-pay obligation, make-up rights entitle the buyer to nominate and receive those quantities of gas at a later time during the term of the GSA. • If the buyer has paid for and taken delivery of a quantity of gas in excess of the annual take-or-pay quantity, then buyer may accrue carry-forward credits, which may be set off against take-or-pay obligations in later years.
Shortfall, Under Delivery, or Deliver-to-Pay	• The seller under a GSA must compensate the buyer to the extent that the seller fails to deliver the nominated quantity of gas (known as a "shortfall" or "under-delivery") unless the seller's failure is excused by certain circumstances. • To mitigate strict exposure to liability for shortfall, the GSA may include additional relief from seller's obligations, such as force majeure, failure to deliver due to buyer's acts or omissions, permissible non-delivery, or aggregated nominations.
Price Review	• In a long-term GSA, parties will include a price formula that attempts to ensure that the commercial terms remain competitive, for both buyer and seller, for several decades. This price formula may be fixed, escalated, linked to crude oil or oil products, linked to other gas price indices or a gas hub, or a combination of these. • Under specified circumstances (for instance, an unforeseen change in the market), and/or at specified time intervals, either party may have the right to request a price review, which, if mutual agreement cannot be reached, may be resolved by expert determination or arbitration
Specification	• This covers the quality / composition of the gas, including the maximum quantity of water, CO_2 and H_2S, the heating value, the range of shares of methane, ethane and other hydrocarbons, and other such factors, and the ranges they may be allowed to vary within.

	• Gas falling outside the specified quality range may be rejected by the buyer or the buyer may be entitled to compensation.

Under a supply-based agreement, since the seller commits to supply of natural gas without any commitment to the source of natural gas, contractual clauses do not highlight the natural gas field as the source of supply, and seller is free to supply natural gas from any of the natural gas fields open to them. They may also enter into a different natural gas supply agreement from the same or different fields. In addition, the quantities of natural gas available for supply by the seller are pre-agreed and fixed over a period of time, with limited provisions for termination.

However, under a depletion-based agreement, contractual clauses on the agreement specify an exclusively dedicated natural gas field, with a fixed quantity of delivery over a specified period of time, after which they are reassessed each year as the production capacity changes.

Hence, the development of a natural gas pipeline from the IKR to FI and/or Turkey will involve a GSA that is structured and drafted to mitigate the associated risks. Gas buyers in Turkey are likely to be relatively creditworthy. Gas buyers in the IKR itself or in FI are likely to be less creditworthy, and in the case of FI, a sovereign guarantee is likely to be required, with various provisions in case of non-payment.

8.3 MNR Can Benefit from a Gas Directorate

As part of a successful natural gas market design and the subsequent development of the natural gas infrastructure in Kurdistan, the Ministry of Natural Resources would benefit from establishing a Natural Gas Directorate, which would oversee and regulate the infrastructure and supply of natural gas, and assess market opportunities for Kurdish natural gas locally and in Turkey and FI.

The prospective structure of the natural gas directorate would be headed by the Minister of Natural Resources, who would oversee the primary executive tier of the directorate, consisting of an executive director, general counsel, and general secretary. They would collectively oversee, direct, and provide legal counsel to the minister on the executive, administrative, and official operations of the directorate and the overall natural gas sector in Kurdistan.

The prospective structure of the natural gas directorate in Kurdistan then could contain a secondary executive tier of the directors, who oversee specific administrative and official operations of the directorate: natural gas policy research, analysis, and enforcement; market regulations; review of technical and economic feasibilities of new and ongoing natural gas projects and assets; infrastructure security; and consistent/reliable supply of natural gas.

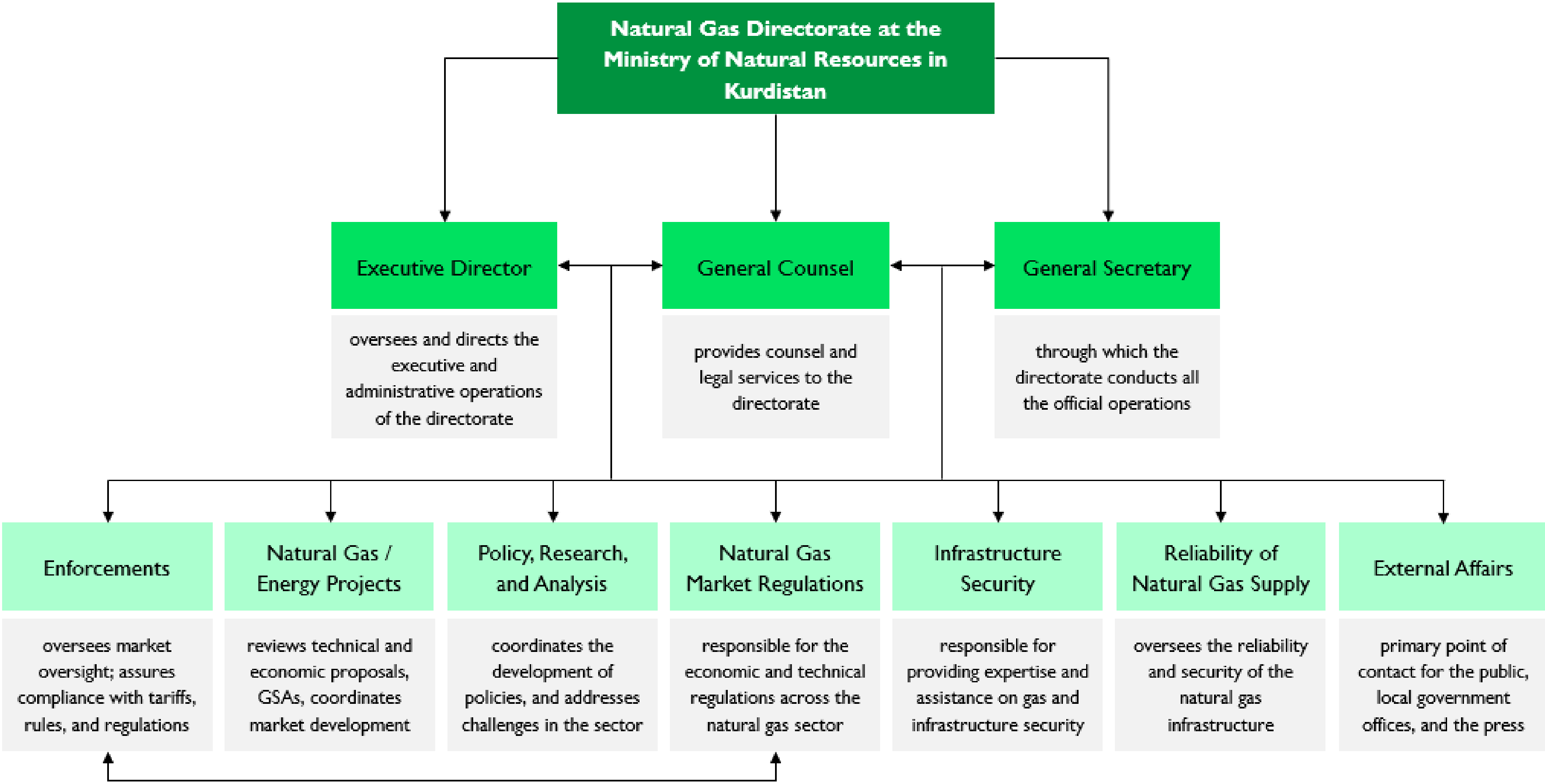


Figure 68 Indicative structure of the Gas Directorate in the IKR

8.4 Suggested Pricing and Market Model for the IKR

A phased approach to gas pricing within the IKR is suggested (Table 39). This is intended to achieve five objectives:

- Incentivize economically efficient gas development and production
- Maximize the returns to the KRG from gas sales, consistent with providing adequate returns to investors
- Ensure gas consumers in the IKR can purchase gas at reasonable and competitive prices
- Align IKR gas prices with regional and world markets
- Allow the IKR gas market to expand and mature at a realistic pace

Table 34 Suggested phasing of pricing and market model for the IKR

Proposed Phase	Additional Details

Phase 0 (Start-up Phase)	• The first steps would be to:
	  ○ Set up the MNR's natural gas directorate, led by a strong and experienced Director, with a capable team
	  ○ Where necessary, renegotiate PSCs to give the contractor the right to process and market their gas within the IKR, with suitably adjusted production shares and cost recovery provisions to preserve the fair risk/reward balance
	• Simultaneously, the MNR can also establish a Kurdish Gas Consortium to finance and manage the construction of infrastructure (pipelines and processing plants)
	• Discussions can be initiated with a number of large international gas and infrastructure companies who may be capable of leading the private-sector role in the consortium
	• Depending on the chosen contractual model, the Kurdish Gas Consortium could negotiate GSAs with Turkey and FI, and enter into gas purchase agreements with producers in the IKR to satisfy the GSAs with Turkey and/or FI; or, the Gas Directorate may coordinate sales negotiations to avoid price competition between IKR sellers
	• The oil companies active in the IKR would be permitted to set up an industry association to allow sharing of best practices and coordination on common goals, with appropriate provisions on confidentiality and competition

Phase 1, before sales to FI or Turkey	• The directorate could set a local IKR sales price monthly at the delivered LNG price to Turkey (for example, as assessed by Argus), minus a deemed transport cost from the IKR border to western Turkey (or could use netback from INDEX Turkish hub price, if deemed sufficiently liquid and mature) • Price paid to IKR producers is the sales price minus the regulated transport cost for use of the consortium's infrastructure • Large gas buyers in the IKR (such as IPPs, industry, city gas distributors) can contract directly with producers at an agreed price • The Gas Directorate leads negotiations with oil companies present in the IKR to ensure the price determined above is sufficient to cover the required investments for gas gathering and treatment, and reaches agreement on adjustments to their production sharing contracts as required

Phase 2, after commencement of sales to FI and/or Turkey	• Sales price to FI and/or Turkey is set by negotiation, but would be expected to be based on a moderate discount to competing suppliers in those markets or equivalent to the Turkish INDEX hub if that has become sufficiently liquid • Local IKR sales price is set weekly or monthly at the lower of the IKR border netback to FI and/or Turkey (minus transport costs within those markets) • Price paid to IKR producers is the sales price minus the regulated transport cost for use of the consortium's infrastructure
Phase 3, after market has developed sufficiently	• Creation of local natural gas exchange where producers and consumers can buy and sell gas

8.4.1 Terms of Current Major Gas Sales Agreements in the IKR

Currently, the Pearl Petroleum contract is not public, but it is understood that it has the right to market its gas production independently of the MNR/KRG. Genel and DNO had previously reached agreement to sell gas production from the Summail field, and Genel had reached agreement to sell gas from the Miran and Bina Bawi fields, to KRG entities. The Talisman (subsequently Repsol) contract for Topkhana gives the contractor the right to market gas, but it is understood that Repsol eventually withdrew because of an inability to reach acceptable terms with the MNR over gas sales.

Table 35 Examples of gas sales terms in the IKR

Field	Operator	Contract Terms / Gas Provisions
Bina Bawi and Miran	Genel (100%)	• Genel, sole contractor in both fields, is committed to delivering gas at contracted quantities for a 12-year period. ▪ Bina Bawi: ○ 2-year build up period, delivering 3.6–7.2 BCM/y (350–700 MMscf/d) ○ 10-year plateau period, delivering 7.2 BCM/y (700 MMscf/d) ▪ Miran ○ 2-year build-up period, delivering 2.6–5.1 BCM/y (250–500 MMscf/d) ○ 10-year plateau period, delivering 5.1 BCM/y (500 MMscf/d) • By end of the 10-year plateau period, Genel will supply gas equal to or less than the previous year, until end of development period (may be nominated by Genel itself) • KRG is to buy Genel's gas via a take-or-pay arrangement where it is obliged to buy 80% of the annual contract quantity • Genel to receive a fee of US$ 1.20 per thousand cubic feet for the raw gas delivered into the gas treatment facilities; this fee includes a provision for inflation adjustment • Genel's production sharing terms for gas are amended to zero royalty or capacity-building payment, 100% cost recovery ceiling, and profit share starting at 100% and decreasing via R-factor (ratio of cumulative revenues / cumulative costs) to 50%
Summail	DNO (40%), Genel (40%), and KRG (20%)	• In 2013, KRG signed a domestic gas sales agreement with DNO and Genel, which would supply up to an initial 1 BCM/y (100 MMscf/d) of gas from the Summail field to feed the 500 MW Sumel power plant • DNO and Genel's delivered gas volumes were priced at US$ 3/MMBtu, inflating over time to a maximum of US$ 4/MMBtu • Genel and DNO were to receive around $0.60 margin per Mcf of gas • However, the Summail field performed poorly and had to be shut down in 2015 because of declining production
Khor Mor and Chemchemal	Pearl Petroleum (Crescent Petroleum 35%, Dana Gas 35%, OMV 10%, MOL 10%, RWE 10%)	• The contractors committed to develop the Khor Mor and Chemchemal fields and to deliver gas free of charge to two power plants in the IKR[56] • The contractors were entitled to receive and sell liquid hydrocarbons (NGLs and condensate) from the gas production to cover their petroleum costs plus an agreed rate of return (18%) on investment • They were granted the right to market and sell any gas in excess of those power plants' requirements

[56] https://www.italaw.com/sites/default/files/case-documents/italaw10252.pdf, https://www.italaw.com/sites/default/files/case-documents/italaw10249_0.pdf

9 Annex

9.1 Alternate IKR Natural Gas Export and Development Scenarios

9.1.1 Summary of Scenarios

Scenario	Underlying Assumptions	Impact on Natural Gas Sales to Federal Iraq	Impact on Natural Gas Exports to Turkey	Implications
Base Case	• IKR-Turkey pipeline commissioned in 2027 • IKR-FI pipeline commissioned in 2025 • Khor Mor-Jambur-Kirkuk connection supplies Kurdish gas to Kirkuk • Sakarya fields (Sakarya and North Sakarya) in Turkey commissioned in 2025	• 2021 supplies: 0.0 BCM • First supplies: 2025, from Jambur connection, and from main IKR-FI supply pipeline • 2040 supplies: 15.8 BCM including 0.4 BCM from Khor Mor-Jambur-Kirkuk connection	• 2021 supplies: 0.0 BCM • First supplies: November 2032, due to limited Kurdish gas after meeting priority FI market • 2040 supplies: 5.3 BCM	• Requires fast-track development of d IKR gas projects so as not to lose a 4-year window to Turkish market (2027 pipeline commissioning, but first supplies only in 2032)
AS1: Main IKR-FI supply pipeline not commissioned	• IKR-Turkey pipeline commissioned in 2027 • IKR-FI pipeline not commissioned and IKR prioritizes exports to Turkish market (11.5 BCM) • Khor Mor-Jambur-Kirkuk connection supplies Kurdish gas to Kirkuk • Sakarya fields (Sakarya and North Sakarya) in Turkey commissioned in 2025	• 2021 supplies: 0.0 BCM • First supplies: 2025, from Jambur connection • 2040 supplies: 0.4 BCM from Khor Mor-Jambur-Kirkuk connection	• 2021 supplies: 0.0 BCM • First supplies: January 2027 • 2040 supplies: 11.5 BCM	• Base case pace of development of IKR gas projects is excessive for available 11.5 BCM Turkish market • Several IKR field developments would not be needed/could be delayed in case main IKR-FI pipeline is not commissioned • Major issue of FI market in chronic deficit until 2040
AS2: Turkey-IKR supply pipeline not commissioned	• IKR-Turkey pipeline not commissioned due to slow progress on GSA and lack of financing arrangements • IKR-FI pipeline commissioned in 2025 • Khor Mor-Jambur-Kirkuk connection supplies Kurdish gas to Kirkuk • Sakarya fields (Sakarya and North Sakarya) in Turkey commissioned in 2025	• 2021 supplies: 0.0 BCM • First supplies: 2025, from Jambur connection, and from main IKR-FI supply pipeline • 2040 supplies: 15.8 BCM including 0.4 BCM from Khor Mor-Jambur-Kirkuk connection	• 2021 supplies: 0.0 BCM • 2040 supplies: 0.0 BCM	• IKR can direct unused winter (Turkish market) natural gas to heavy industry/city gas – might be more willing to sell to industry that can afford natural gas rather than power plants • Need to address issue of subsidized fuels to industry (cement plants)
AS3: Turkey's Sakarya fields (Sakarya and North Sakarya) not commissioned	• IKR-Turkey pipeline commissioned in 2027 • IKR-FI pipeline commissioned in 2025 • Khor Mor-Jambur-Kirkuk connection supplies Kurdish gas to Kirkuk • Sakarya fields (Sakarya and North Sakarya) in	• 2021 supplies: 0.0 BCM • First supplies: 2025, from Jambur connection, and from main IKR-FI supply pipeline • 2040 supplies: 15.8 BCM including 0.4 BCM from Khor Mor-Jambur-Kirkuk connection	• 2021 supplies: 0.0 BCM • First supplies: November 2032, due to limited Kurdish gas after meeting priority FI market • 2040 supplies: 5.3 BCM	• Requires fast-track development of IKR gas projects so as not to lose a 4-year window to Turkish market (2027 pipeline commissioning, but first supplies only in 2032) • No significant impact on IKR gas volumes to Turkey as this is

Scenario	Underlying Assumptions	Impact on Natural Gas Sales to Federal Iraq	Impact on Natural Gas Exports to Turkey	Implications
	Turkey not commissioned			constrained by available supplies after deliveries locally and to FI • However, achievable price in Turkey could rise (depending on whether Sakarya gas would have been marginal supply or LNG/Azerbaijan) • Lack of development of Sakarya fields has no significant impact for IKR's priority market (FI)
AS4: Turkey's Sakarya fields and main IKR-FI supply pipeline not commissioned	• IKR-Turkey pipeline commissioned in 2027 • IKR-FI pipeline not commissioned and IKR prioritizes exports to Turkish market (11.5 BCM) • Khor Mor-Jambur-Kirkuk connection supplies Kurdish gas to Kirkuk • Sakarya fields (Sakarya and North Sakarya) in Turkey not commissioned	• 2021 supplies: 0.0 BCM • First supplies: 2025, from Jambur connection • 2040 supplies: 0.4 BCM from Khor Mor-Jambur-Kirkuk connection	• 2021 supplies: 0.0 BCM • First supplies: January 2027 • 2040 supplies: 11.5 BCM	• Base case pace of development of IKR gas projects is excessive for 11.5 BCM Turkish market • Several IKR field developments would not be needed/could be delayed in case main IKR-FI pipeline is not commissioned • Major issue of FI market in chronic deficit until 2040
AS5: IKR's Bina Bawi, Miran West non-associated gas fields delayed in commissioning	• IKR-Turkey pipeline commissioning delayed to 2032 • IKR-FI pipeline commissioning pushed to 2027/28 • Khor Mor-Jambur-Kirkuk connection supplies Kurdish gas to Kirkuk • Sakarya fields (Sakarya and North Sakarya) in Turkey commissioned in 2025	• 2021 supplies: 0.0 BCM • First supplies: 2025, from Jambur connection • Major supplies: 2027 • 2040 supplies: 12.3 BCM including 0.4 BCM from Khor Mor-Jambur-Kirkuk connection	• 2021 supplies: 0.0 BCM • First supplies: November 2034 • 2040 supplies: 1.3 BCM	• Base case pace of development of some IKR gas projects excluding Bina Bawi and Miran West (12.9 BCM capacity combined) • Topkhana assumed to be brought forward in development by 2 years • FI market will be in deficit throughout, but significantly narrower than AS4 • AS5 shows lack of available Kurdish gas for export until at least 2028, meaning many market windows will close
AS6: Low-case of Kurdish Gas Development – Miran West and Bina Bawi non-associated gas fields not commissioned	• Commissioning of Miran West and Bina Bawi pushed beyond 2040 due to technical complexities • IKR-Turkey pipeline not commissioned due to minor IKR gas surplus by 2026/7 • IKR-FI pipeline commissioning in 2025, but 10 BCM/y	• 2021 supplies: 0.0 BCM • First supplies: 2025, from Jambur connection • Major supplies: 2028 • 2040 supplies: 5.7 BCM including 0.4 BCM from Khor Mor-Jambur-Kirkuk connection	• 2021 supplies: 0.0 BCM • 2040 supplies: 0.0 BCM	• Delayed pace of development of IKR gas projects excluding Bina Bawi and Miran West (who come online only after 2040) • FI market will be in deficit throughout • AS6 shows lack of meaningful Kurdish gas surplus by 2027,

Scenario	Underlying Assumptions	Impact on Natural Gas Sales to Federal Iraq	Impact on Natural Gas Exports to Turkey	Implications
	• Khor Mor-Jambur-Kirkuk connection supplies Kurdish gas to Kirkuk • Sakarya fields (Sakarya and North Sakarya) in Turkey commissioned in 2025			meaning Turkish window will effectively be closed
AS7: High Case of Kurdish Gas Development – Chemchemal Phase-1 begins in 2023, Phase-2 in 2025	• Commissioning of Chemchemal fast-tracked, with Phase-1 coming online in 2023 and Phase-2 by 2025 • Additional Phase-3 assumed to come online by 2027 due to large reserves at field • Priority market for IKR gas is Turkey, IKR-Turkey pipeline commissioned in 2024 • IKR-FI pipeline commissioned in 2027 • Khor Mor-Jambur-Kirkuk connection supplies Kurdish gas to Kirkuk • Sakarya fields (Sakarya and North Sakarya) in Turkey commissioned in 2025	• 2021 supplies: 0.0 BCM • First supplies: 2025, from Jambur connection • Major supplies: 2027 • 2040 supplies: 5.2 BCM, including 0.4 BCM from Khor Mor-Jambur-Kirkuk connection	• 2021 supplies: 0.0 BCM • 2040 supplies: 11.5 BCM	• Base case pace of development for other fields except Chemchemal (which is fast-tracked) results in IKR gas surplus by 2024 • FI market can almost meet supply-demand gap with IKR gas, but small deficit will remain post-2038 • IKR able to enter Turkish market by 2024, 2 years prior the expiration of major Turkish natural gas supply contracts • Kurdish gas in Turkey eliminates Iranian gas to Turkey completely by 2031

9.1 Alternate Scenario I: Main IKR-FI Natural Gas Pipeline Not Commissioned

9.1.1 Methodology and Assumptions

The first two assumptions for **all** scenarios, except Alternate Scenario V, VI, and VII, are the constant estimates for natural gas production and natural gas demand in Kurdistan. Therefore, for Alternate Scenario I (hereafter referred to as AS1), Kurdistan's natural gas production and natural gas demand are the same as in the Base Case.

The next assumption for AS1 is the full commissioning (or repurposing) of the 0.4 BCM Khor Mor-Jambur–Kirkuk gas condensate pipeline to carry minor supplies of Kurdish natural gas to the FI market via Kirkuk. The Khor Mor-Jambur–Kirkuk gas condensate pipeline can be (or reportedly, already has been) repurposed, easily and relatively inexpensively, into a natural gas pipeline to carry unused natural gas (from the Khor Mor area) into FI (distribution lines further north are constrained). Therefore, AS1 assumes that the Khor Mor-Jambur–Kirkuk natural gas pipeline will be commissioned by 2025. Talks to this end with the FI government have been progressing positively, according to Crescent Petroleum, operator of the Khor Mor natural gas field and a participant in Pearl Petroleum.

Limited supplies of Kurdish natural gas to FI can commence soon if agreed by all parties and full flow in 2025 as available volumes increase.

The fourth assumption, and the one that differs from the Base Case, is the *non-commissioning* of the main Kurdistan to FI natural gas pipeline. This can happen for a host of reasons and is not entirely speculative, given the political history between the IKR and FI. While recent talks towards the development of such a pipeline have been positive, several factors could result in the IKR–FI natural gas pipeline being stalled or indefinitely delayed. These factors include the risks posed by insecurity, especially in the Diyala governorate, through which the pipeline would likely run; political wrangling; disputes between the central government and the semi-autonomous government; the high level of political patronage; and typical bureaucratic hold-ups that surround energy development plans in Iraq. In this non-commissioning scenario, therefore, Kurdistan prioritizes Turkey as its export market.

The fifth assumption is the same as that for the Base Case, i.e., the commissioning of the Sakarya gas fields in Turkey. AS1 assumes that the Sakarya fields will come online in 2025.

The final assumption is the commissioning of the IKR–Turkey natural gas pipeline by 2027, based on the project's rate of progress so far on the Kurdish side. Technically, the connection to Turkey could be completed earlier (within 15 months of an investment decision), but in AS1, the IKR does not have surplus gas for export until later. The existing natural gas grid in the northern IKR will not connect to a Turkey export pipeline without the commissioning of the Erbil–Duhok–Zakho pipeline, the backbone of the future Turkey export system. First sales to Turkey will begin successfully in 2027, roughly in time to meet the 2026 contract expiry window, and barring large sales to FI, Kurdistan can export 11.5 BCM of natural gas to Turkey by 2040.

Table 36 Key assumptions for AS1, excluding constant assumptions for all scenarios (Base Case)

Key Assumptions		Capacity of Pipelines/Major Fields	Commissioning Date	Online
1	Turkey Pipeline	15-30 BCM	2027	Yes
2	IKR-FI Pipeline	20 BCM	-	No
3	Minor IKR-FI Supplies to Kirkuk	0.4 BCM	2025	Yes
4	Sakarya Fields (Turkey)	26 BCM	2025	Yes
Natural Gas Balance under AS1				
			Balance in 2021	Balance in 2040
1	IKR Natural Gas Production		5.3 BCM	42.4 BCM
2	Supplies to FI		0.0 BCM	0.4 BCM (Minor supplies via Jambur)
3	Exports to Turkey		0.0 BCM	11.5 BCM
4	IKR Natural Gas Balance		-6.3 BCM	9.4 BCM

9.1.2 AS1: Lack of Main IKR–FI pipeline Will Result in >11 BCM Supplies to Turkey

In this scenario, even though small volumes of Kurdish natural gas continue flowing into FI through the 0.4 BCM Khor Mor–Jambur-Kirkuk connection, the lack of major sales to the FI market will allow Kurdistan to export over 11 BCM of its natural gas to Turkey. While the IKR could export significantly more, the Turkish market will remain limited by its own domestic limitations, existing contracts, competing suppliers, and constraints with the natural gas grid, particularly to western Turkey.

Figure 44 indicates the massive gas surplus the IKR will amass without sales to FI. This highlights that several Kurdistan field developments would not be needed, or could be delayed, as there is a lack of outlets for the surplus.

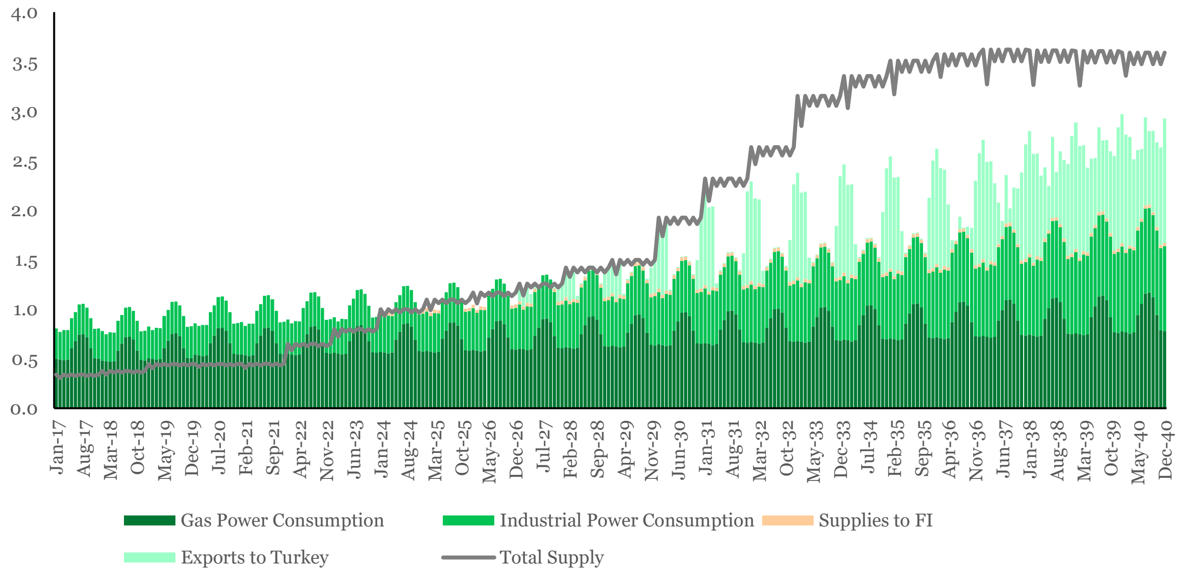


Figure 69 Kurdistan natural gas sector balance under AS1, BCM/m

9.1.3 AS1: Federal Iraq Will Continue Requiring Iranian Gas until 2040

Under AS1, the lack of commissioning of the main IKR–FI natural gas pipeline will put FI in an unavoidable long-term gas deficit, even with continued full-contract volumes of Iranian natural gas imports. This is clearly an undesirable scenario for major stakeholders, including the government of Iraq, the Ministry of Natural Resources in Kurdistan, and the United States. It will become near-impossible to wean FI off Iranian supplies, which will significantly heighten the political and financial influence Tehran will wield over Baghdad—a concern for both FI and the United States. Kurdistan will also be affected, as failing to reach agreement with FI over the natural gas pipeline will mean putting off development of the IKR's natural gas sector, which could disappoint potential investors and lessen routes/options for international financing and backing.

FI's own natural gas production could increase as the country brings online long-stalled non-associated gas projects, such as Akkas and Mansuriyah, and natural gas capture projects take off in earnest. Even under this optimistic scenario, however, FI will remain in chronic deficit. The country will require additional imports from elsewhere or run the risk of worsening protests and demonstrations, further destabilizing its political and governance structures.

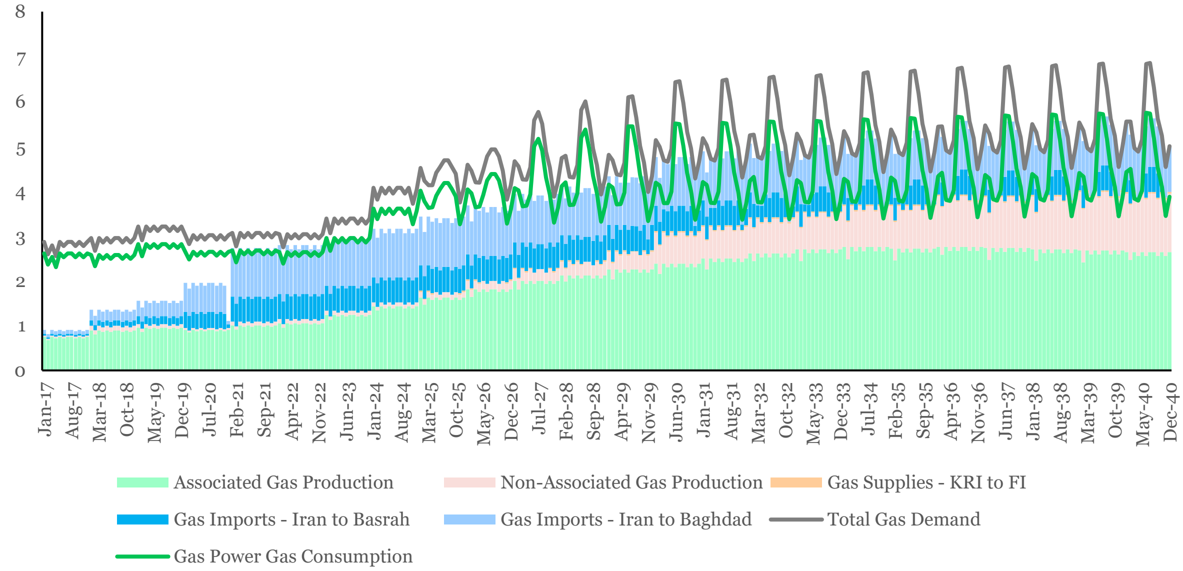


Figure 70 FI natural gas supply balance under AS1, BCM/m

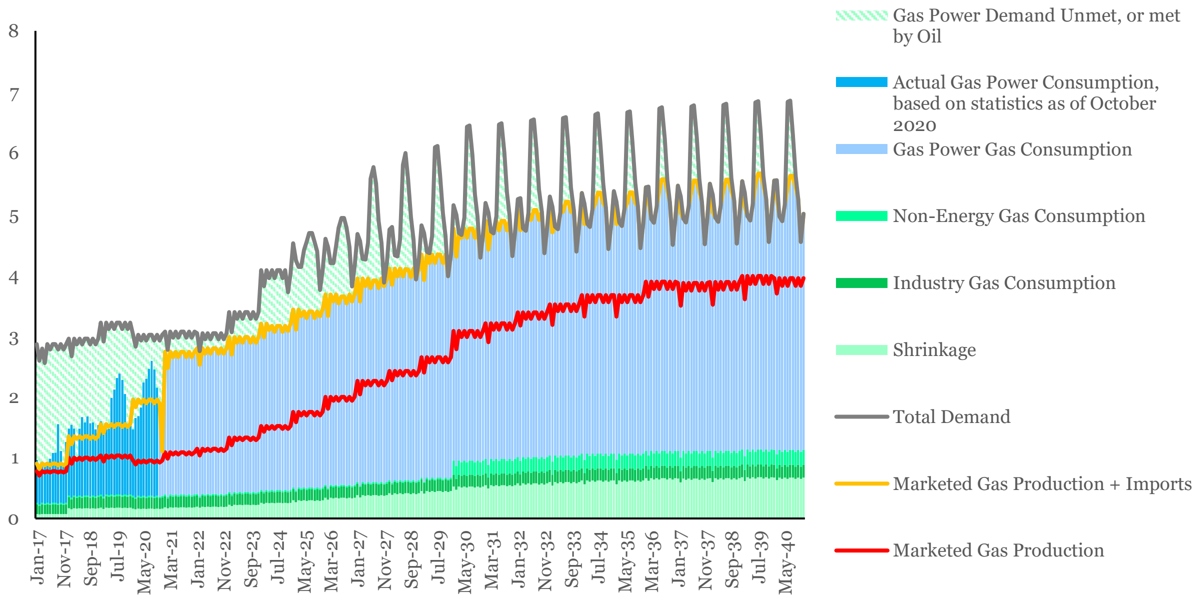


Figure 71 FI natural gas demand balance under AS1, BCM/m

Figure 46 shows that, under AS1, gas power demand remains chronically unmet until 2040, even though imports of natural gas from Iran continue at full contracted volumes.

9.1.4 AS1: Major Kurdish Gas to Turkey Will Help Displace Most Iranian Gas from the Turkish Market

With the Sakarya natural gas field commencing commercial production in 2025 and Kurdish natural gas entering Turkey in 2027, Turkey will be able to displace Iranian gas almost entirely. Required LNG and Russian gas imports also lessen. Replacing Iranian gas with Kurdish gas will be a positive for Turkey, owing to the lower price, greater reliability, and reduced political dependence.

First supply of Kurdish natural gas to Turkey begins in 2027, before expanding to 11.5 BCM in 2040.

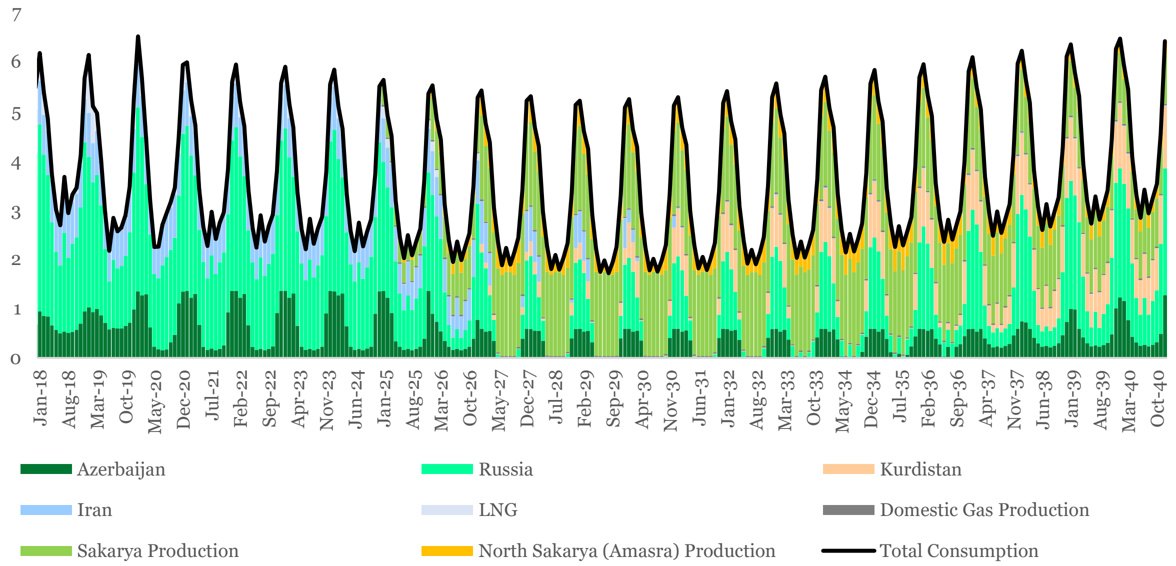


Figure 72 Turkey's natural gas supply balance under AS1, BCM/m[57]

[57] Chart shows only imports and production actually used within Turkey, not imports that are re-exported or production that is exported

9.1.5 AS1: Required Schematic Nodes and Gas Flows from South IKR and North IKR

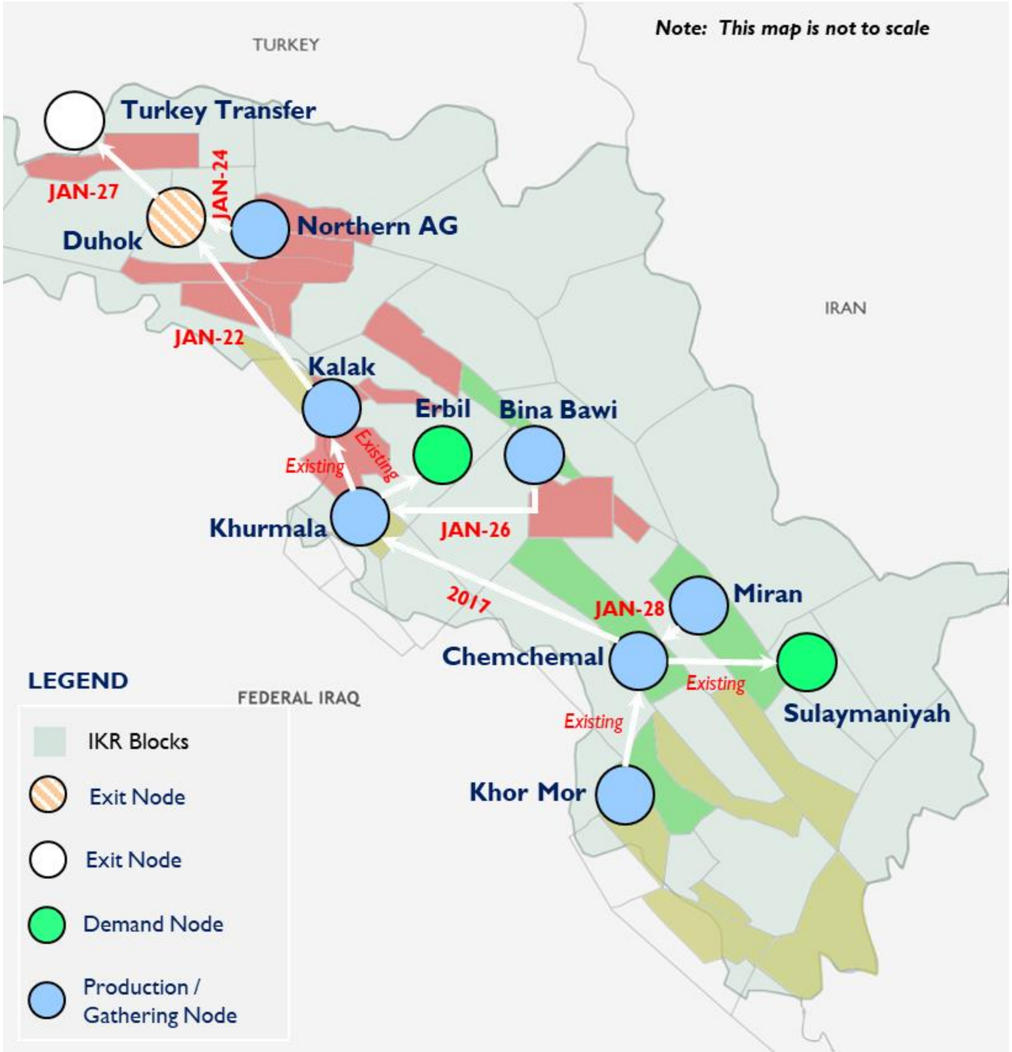


Figure 73 Required gas nodes for AS1 and required in-service dates (schematic)[58]

Table 37 Schematic nodes of AS1 Kurdish gas system

Pipeline	Max. annual capacity (BCM)	Max. annual reverse capacity (BCM)
Khor Mor → FI	**0.0**	
Khor Mor → Chemchemal	15.7	
Miran → Chemchemal	6.0	
Chemchemal → Sulaymaniyah	16.4	
Chemchemal → Khurmala	18.5	
Bina Bawi → Khurmala	6.3	
Khurmala → Erbil	15.3	
Khurmala → Kalak	16.7	
Kalak → Duhok	17.5	
Northern AG → Duhok	5.3	
Duhok → Turkey	14.9	

[58] Oil and gas exploration and development blocks shown on the map in gray outline have been updated by the KRG and are provided here for orientation purposes only

The backbone of the Kurdish natural gas system under AS1 is the ~15 BCM/y Khor Mor–Chemchemal–Khurmala–Kalak–Duhok–Turkey pipeline connection. As major supplies to FI are not foreseen under this scenario, no reversible pipeline sections are required.

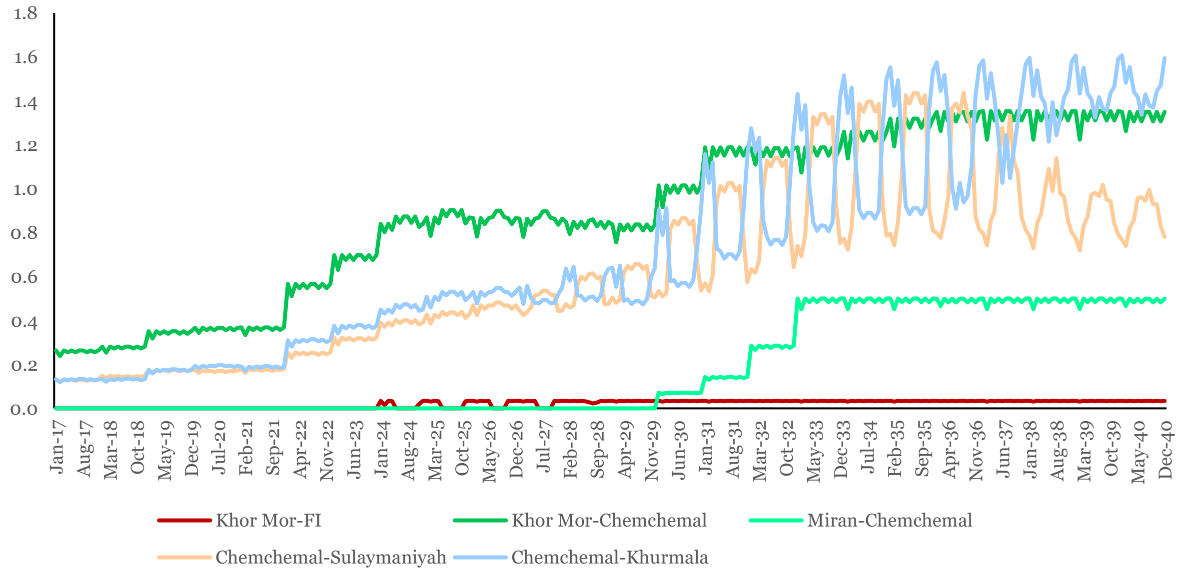


Figure 74 Gas flows from the southern part of the Kurdish gas system under AS1, BCM/m

Limited amounts of Kurdish natural gas will flow into FI through the Khor Mor–Jambur pipeline, shown in the Khor Mor–FI connection in Figure 49.

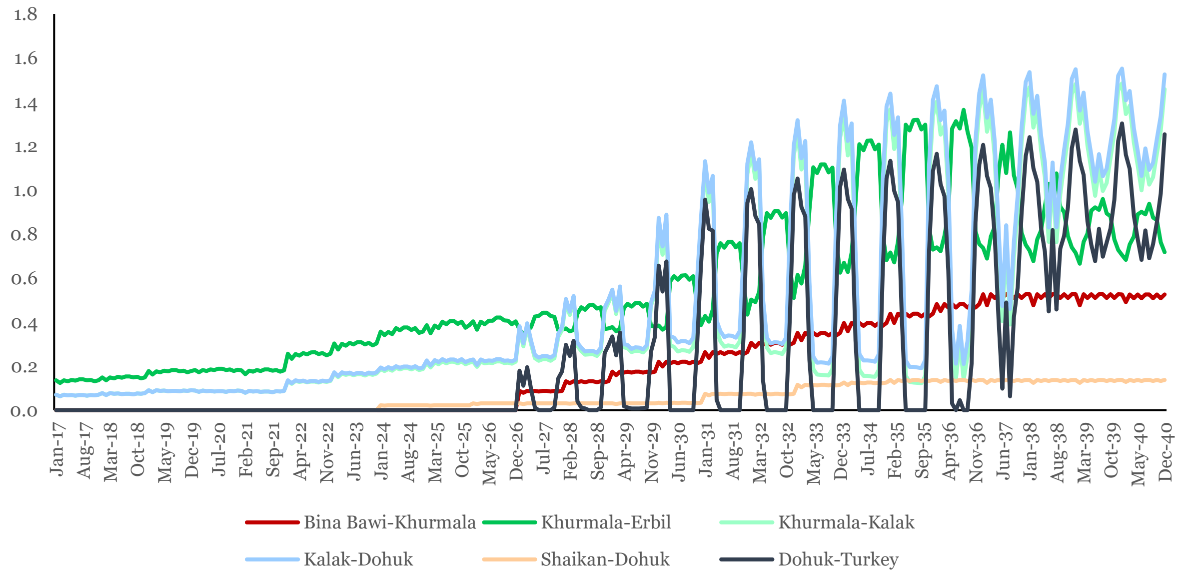


Figure 75 Gas flows from the northern part of the Kurdish gas system under AS1, BCM/m

9.2 Alternate Scenario II: IKR–Turkey Natural Gas Pipeline Not Commissioned

9.2.1 Methodology and Assumptions

The first two assumptions for **all** scenarios, except Alternate Scenario V, VI, and VII, are the constant estimates for natural gas production and natural gas demand in Kurdistan. Therefore, for Alternate Scenario II (hereafter referred to as AS2), Kurdistan's natural gas production and natural gas demand are the same as in the Base Case and AS1.

The next assumption for AS2 is the commissioning (or repurposing) of the 0.4 BCM Jambur–Kirkuk gas condensate pipeline to carry minor supplies of Kurdish natural gas to the FI market via Kirkuk. Limited supplies of Kurdish natural gas to FI can commence soon if agreed by all parties and full flow in 2025 as available volumes increase.

The fourth assumption for AS2 is the commissioning of a 20 BCM/y capacity natural gas pipeline from Kurdistan to FI to supply surplus Kurdish natural gas to FI. The pipeline could come online by 2025, when a IKR natural gas surplus first appears in the Kurdish natural gas balance. The commissioning of the main IKR–FI pipeline by 2025 seems probable for several reasons: (1) within both the FI government and the MNR, there are positive indicators for reaching an arrangement to supply near-term Kurdish gas surplus to FI, (2) FI has a chronic natural gas deficit, (3) the United States is continuing pressure to wean FI off Iranian natural gas and power supplies, and (4) there is financing potential from the international community, as a IKR–FI pipelines would support U.S. energy policy for Iraq, and have positive environmental and social effects.

The final assumption for AS2, which differs from the Base Case and AS1, is the non-commissioning of the IKR–Turkey natural gas pipeline. The major reasons for this assumption is the current slow progress on the GSA between the two countries, and the lack of financing arrangements and guarantees to establish the project successfully. Additional issues that might prevent this project from advancing are the high level of competition for the Turkish market, potential additional Black Sea gas discoveries, falling gas demand in Turkey due to alternative power generation, and possible political or security problems relating to the Kurdistan Workers' Party (PKK). In SA2, these issues remain unresolved in the medium to long term, resulting in non-approval of the pipeline.

Table 38 Key assumptions for AS2, excluding constant assumptions for all scenarios, Base Case & AS1

Key Assumptions		Capacity of Pipelines/Major Fields	Commissioning Date	Online
1	Turkey Pipeline	15-30 BCM	-	No
2	IKR-FI Pipeline	20 BCM	2025	Yes
3	Minor IKR-FI Supplies to Kirkuk	0.4 BCM	2025	Yes
4	Sakarya Fields (Turkey)	20 BCM	2025	Yes
Natural Gas Balance under AS2				
			Balance in 2021	Balance in 2040
1	IKR Natural Gas Production		5.3 BCM	42.4 BCM
2	Supplies to FI		0.0 BCM	15.8 BCM
3	Exports to Turkey		0.0 BCM	0.0 BCM
4	IKR Natural Gas Balance		-6.3 BCM	5.5 BCM

9.2.2 AS2: Lack of a IKR–Turkey Pipeline Will Have No Impact on the FI Market

The non-commissioning of the IKR–Turkey natural gas pipeline will make no difference to the FI gas market but will leave the IKR with a sizeable winter surplus, without readily available outlets given that FI's gas deficit is in summer. The surplus could necessitate efficient flexible production. Alternatively, MNR could direct unused natural gas to heavy industry or to a city gas system. Implementing city gas has been in talks since 2008, but it has not yet been developed, and the volumetric potential for city gas is quite limited.

Kurdistan might be more willing to sell to local industry who can afford the natural gas, rather than expand power generation capacity, but the country will first have to address the issue of subsidized fuels currently supplied to the industrial sector (chiefly cement plants). Several stakeholders in local oil and gas companies are also stakeholders in Kurdistan's cement factories and seem to favor replacing fuel oil with natural gas. One of these, Dynasty Petroleum, was seeking to acquire stakes in the Topkhana and Kurdamir fields although it appears that this has not proceeded due to lack of regulatory approval and legal issues.

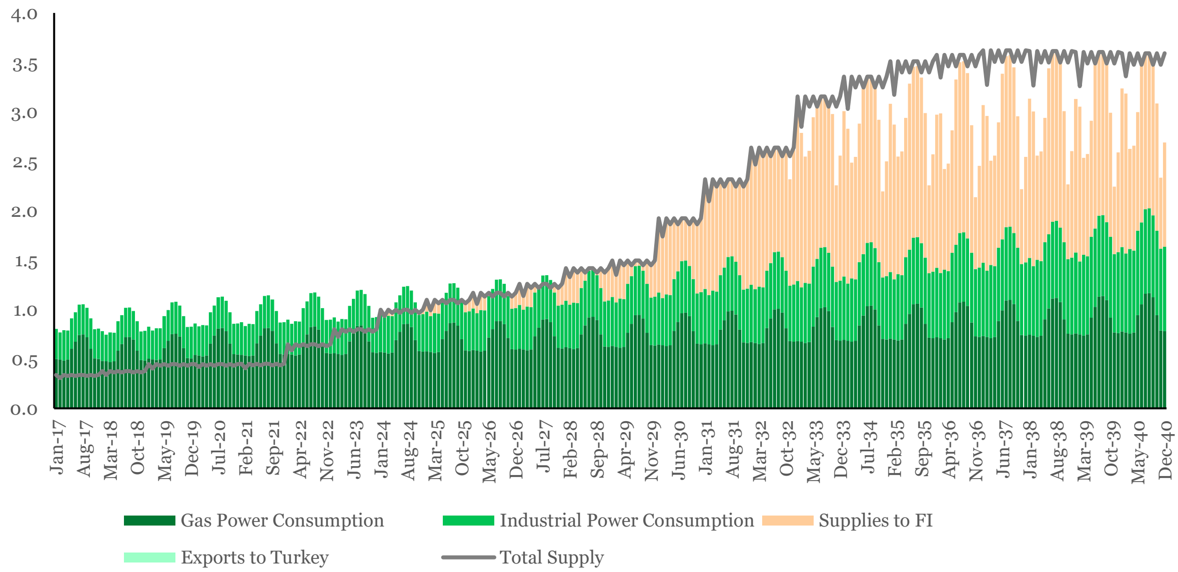


Figure 76 Kurdistan natural gas sector balance under AS2, BCM/m

9.2.3 AS2: Impending Turkey Deficit Will Be Met with LNG and Natural Gas Through TurkStream and from Iran, Closing the IKR's Window of Opportunity

The positive development of Sakarya beginning in 2025 reduces the amount of Russian gas required in the Turkish market, but supplies through TurkStream and from Iran, as well as LNG, will rise to make up for the unavailable Kurdish natural gas. This scenario might be a more expensive proposition for Turkey. The Iranian gas currently being fed into the Turkish market is expensive, and historically, Iran has been unwilling to negotiate prices.

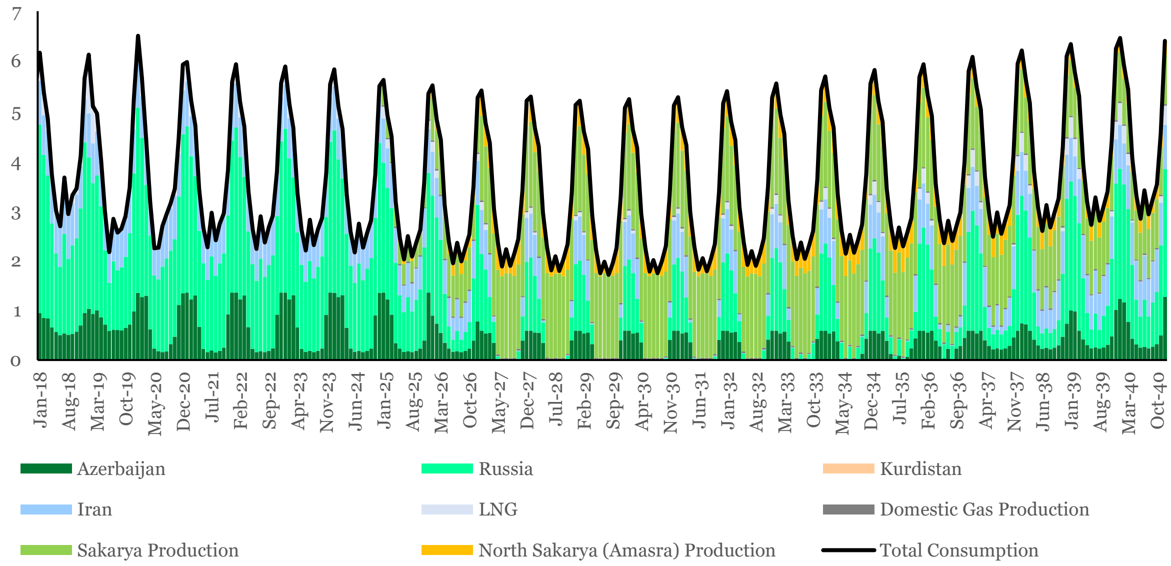


Figure 77 Turkey's natural gas supply balance under AS2, BCM/m[59]

9.3 Alternate Scenario III: Turkey's Sakarya Fields are Not Commissioned

9.3.1 Methodology and Assumptions

The first two assumptions for **all** scenarios, except Alternate Scenario V, VI, and VII, are the constant estimates for natural gas production and natural gas demand in Kurdistan. Therefore, for Alternate Scenario III (hereafter referred to as AS3), Kurdistan's natural gas production and natural gas demand are the same as in the Base Case, AS1, and AS2.

The next assumption for AS3 is the commissioning (or repurposing) of the 0.4 BCM Jambur–Kirkuk gas condensate pipeline.

The fourth assumption for AS3 is the commissioning of a 20 BCM/y capacity natural gas pipeline from Kurdistan to FI to supply surplus Kurdish natural gas to FI.

The fifth assumption for AS3, and the one that differs from the Base Case, AS1, and AS2, is the non-commissioning of the Sakarya and North Sakarya gas fields in Turkey. The main reasons for this are the fields' technically challenging nature and the potentially unattractive development economics.

The final assumption for AS3 is the commissioning of the IKR–Turkey natural gas pipeline by 2027. Technically, the connection to Turkey could be completed earlier (within 15 months of an investment decision), but in AS3, the IKR does not have surplus gas for export until later. The Erbil-Duhok section is assumed to be completed earlier to supply the Duhok power plant. The pipeline will be used to transport the remaining natural gas surplus (after supplies to FI). The existing natural gas grid in the northern IKR will not connect to a Turkey export pipeline without the commissioning of the Erbil–Duhok–Zakho pipeline, the backbone of the future Turkey export system. There is also potential for a common user pipeline/trunkline with reversible flows to support supplies to Turkey in the winter and additional supplies to FI in the summer. Commissioning is estimated for 2027, once the Erbil–Duhok connection is completed and available to carry marketable surplus natural gas from south Kurdistan to Duhok.

[59] Chart shows only imports and production actually used within Turkey, not imports that are re-exported or production that is exported

Table 39 Key assumptions for AS3, excluding constant assumptions for all scenarios, Base Case to AS2

Key Assumptions		Capacity of Pipelines/Major Fields	Commissioning Date	Online
1	Turkey Pipeline	15-30 BCM	2027	Yes
2	IKR-FI Pipeline	20 BCM	2025	Yes
3	Minor IKR-FI Supplies to Kirkuk	0.4 BCM	2025	Yes
4	Sakarya Fields (Turkey)	-	-	No
Natural Gas Balance under AS3				
			Balance in 2021	Balance in 2040
1	IKR Natural Gas Production		5.3 BCM	42.4 BCM
2	Supplies to FI		0.0 BCM	15.8 BCM
3	Exports to Turkey		0.0 BCM	5.3 BCM
4	IKR Natural Gas Balance		-6.3 BCM	

9.3.2 AS3: Even with Lack of Sakarya Gas, Supplies to FI Will Constrain IKR Supplies to Turkey

Non-commissioning of the Sakarya gas field translates into a larger need for Turkish gas imports. However, under the AS3 assumptions, FI is the priority market for the IKR. Therefore, IKR supplies will be delivered to FI first, constraining supplies Turkey. Turkey will therefore turn to other sources—mostly TurkStream and Iran—for the required natural gas to meet demand.

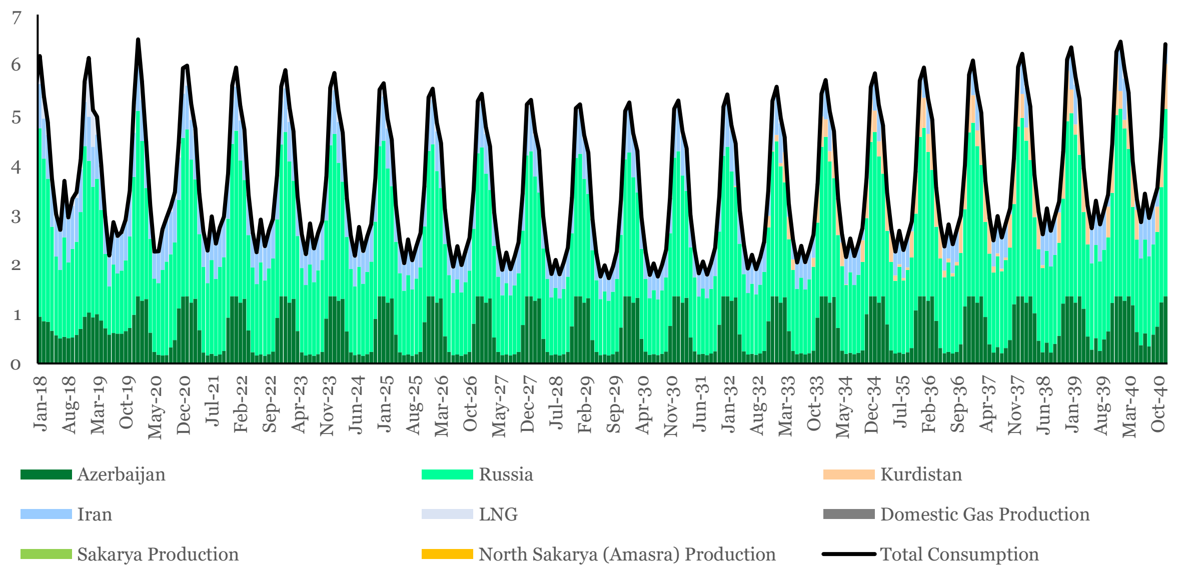


Figure 78 Turkey's natural gas supply balance under AS3, BCM/m[60]

[60] Chart shows only imports and production actually used within Turkey, not imports that are re-exported or production that is exported

9.4 Alternate Scenario IV: Neither Turkey's Sakarya Fields nor the IKR-FI Pipeline are Commissioned

9.4.1 Methodology and Assumptions

The first two assumptions for **all** scenarios, except Alternate Scenario V, VI, and VII, are the constant estimates for natural gas production and natural gas demand in Kurdistan. Therefore, for Alternate Scenario IV (hereafter referred to as AS4), Kurdistan's natural gas production and natural gas demand are the same as in the Base Case, AS1, AS2, and AS3.

The next assumption for AS4 is the commissioning (or repurposing) of the 0.4 BCM Jambur–Kirkuk gas condensate pipeline to carry minor supplies of Kurdish natural gas to the FI market via Kirkuk.

The fourth assumption is the *non-commissioning* of the main IKR–FI natural gas pipeline. This can happen for a host of reasons and is not entirely speculative, given the political history between the IKR and FI. While recent talks towards the development of such a pipeline have been positive, several factors could result in the IKR–FI natural gas pipeline being stalled or indefinitely delayed. These factors include the risks posed by insecurity, especially in the Diyala governorate, through which the pipeline would likely run; political wrangling; disputes between the central government and the semi-autonomous government; the high level of political patronage; and typical bureaucratic hold-ups that surround energy development plans in Iraq. In this non-commissioning scenario, therefore, Kurdistan prioritizes Turkey as its export market.

The fifth assumption for AS4, and the one that differs from the Base Case, AS1, and AS2, is the non-commissioning of the Sakarya gas fields in Turkey. The main reasons for this are the fields' technically challenging nature and the unattractive development economics.

The final assumption for AS4 is the commissioning of the IKR–Turkey natural gas pipeline by 2027, based on the project's rate of progress so far on the Kurdish side. The Erbil-Duhok section is assumed to be completed earlier to supply the Duhok power plant. The existing natural gas grid in the northern IKR will not connect to a Turkey export pipeline without the commissioning of the Erbil–Duhok–Zakho pipeline, the backbone of the future Turkey export system. First sales to Turkey will begin successfully in 2027, and without sales to FI, Kurdistan can export 11.5 BCM of natural gas to Turkey by 2040.

Table 40 Key assumptions for AS4, excluding constant assumptions for all scenarios, Base Case to AS3

Key Assumptions		Capacity of Pipelines/Major Fields	Commissioning Date	Online
1	Turkey Pipeline	15-30 BCM	2027	Yes
2	IKR-FI Pipeline	20 BCM	-	No
3	Minor IKR-FI Supplies to Kirkuk	0.4 BCM	2025	Yes
4	Sakarya Fields (Turkey)	-	-	No
Natural Gas Balance under AS4				
			Balance in 2021	Balance in 2040
1	IKR Natural Gas Production		5.3 BCM	42.4 BCM

2	Supplies to FI	0.0 BCM	0.4 BCM (Minor supplies via Jambur connection)
3	Exports to Turkey	0.0 BCM	11.5 BCM
4	IKR Natural Gas Balance	-6.3 BCM	9.4 BCM

9.4.2 AS4: If the IKR–FI Pipeline Is Not Commissioned and Sakarya Remains Undeveloped, the Turkish Market for IKR Gas Returns to 11.5 BCM

If the IKR–FI major pipeline is not commissioned and the Sakarya natural gas field in Turkey remains undeveloped, Kurdish natural gas supplies to Turkey reach 11.5 BCM/y (the maximum available market in Turkey), but Turkey will require more Russian gas going forward. The lack of access to the market in FI for Kurdish natural gas means Kurdistan can begin exporting its natural gas to Turkey in 2027.

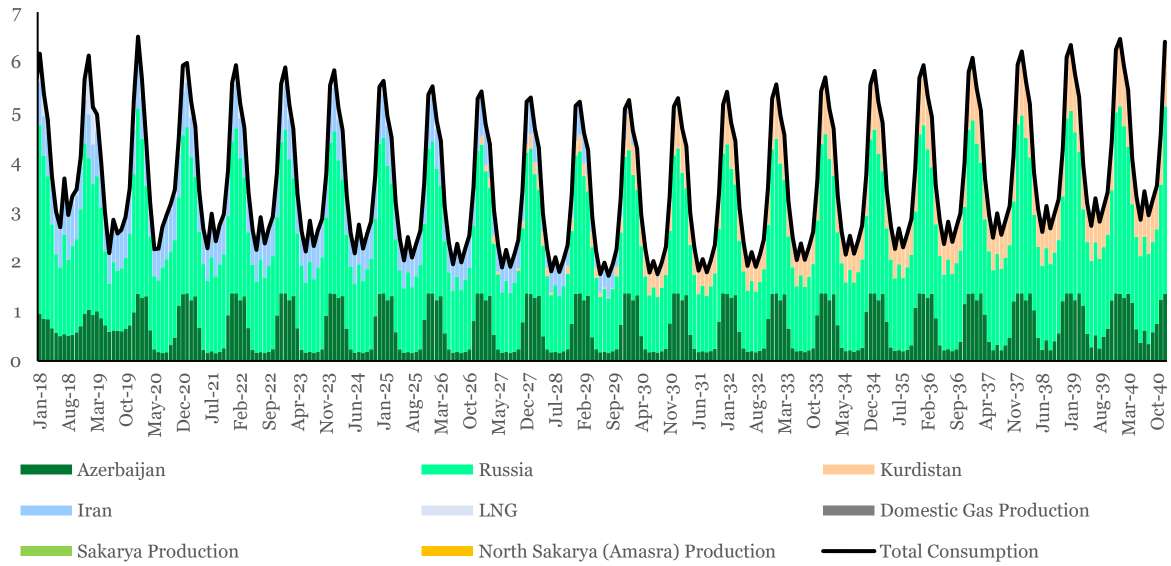


Figure 79 Turkey's natural gas supply balance under AS4, BCM/m[61]

9.5 Alternate Scenario V: Miran West and Bina Bawi Non-Associated Natural Gas Fields Commissioning Delayed

9.5.1 Methodology and Assumptions

The first assumption for Alternate Scenario V (hereafter referred to as AS5) is that the commissioning of the Miran West and Bina Bawi non-associated natural gas fields is delayed by up to 10 years. Likely reasons for delay include both fields' technical complexities and sour characteristics and the associated high cost of development and production. Another non-associated natural gas field, Topkhana, situated to the east of Khor Mor, would be commissioned sooner in AS5 (ultimately creating a surplus for external sales when all three fields are operational). Miran West and Bina Bawi would have a combined production capacity of 12 BCM, if developed according to the Base Case schedule, but in this scenario they are still in ramp-up in the late 2030s, while Topkhana has an overall production capacity of 3.7 BCM. Therefore, Topkhana is insufficient to compensate fully for the delayed development of the other two fields.

[61] Chart shows only imports and production actually used within Turkey, not imports that are re-exported or production that is exported

Table 41 Upstream production estimates for AS5, BCM/y

Field	Type	Province	2020	2025	2030	2040
Khurmala	Associated	Erbil	0.92	1.10	1.10	0.68
Other[62]	Associated	IKR	0.02	1.53	1.90	4.71
Khor Mor	Non-associated	Sulaymaniyah	4.33	4.34	3.96	2.92
Khor Mor Phase-2	Non-associated	Sulaymaniyah		5.17	5.55	6.59
Chemchemal	Non-associated	Sulaymaniyah		1.55	1.55	1.55
Chemchemal Phase-2	Non-associated	Sulaymaniyah			2.59	4.66
Bina Bawi	Non-associated	Erbil				3.62
Miran West	Non-associated	Sulaymaniyah				0.84
Other[63]	Non-associated	IKR			4.41	9.19
Total	Associated		0.94	2.63	3.00	5.39
	Non-associated		4.33	12.14	18.06	29.37
	All		5.27	14.76	21.06	34.76

The next assumption, natural gas demand in the IKR, is the same as in all other scenarios, Base Case to AS4.

The third assumption for AS5 is the commissioning (or repurposing) of the 0.4 BCM Jambur–Kirkuk gas condensate pipeline to carry minor supplies of Kurdish natural gas to the FI market via Kirkuk.

The fourth assumption for AS5 is the commissioning of a 20 BCM/y capacity natural gas pipeline from Kurdistan to FI to supply surplus Kurdish natural gas to FI. The pipeline could come online by 2025, when the first surplus of Kurdish natural gas appears in the Kurdish natural gas balance. Even though Miran West and Bina Bawi will be both delayed by 10 years in commissioning, the growth of production from Khor Mor and Kurdamir will play an essential role in creating a, even if initially quite small, marketable surplus to FI by 2025. This scenario would delay access to the Turkish market until 2034, which is significantly later than anticipated, based on current conversations with relevant stakeholders in the IKR. In AS5, the overall available market for IKR gas in Turkey is reduced to 1.3 BCM, displacing mainly some LNG and Iranian natural gas, and is nearly not large enough to establish the IKR as a significant regional natural gas player.

The fifth assumption for AS5 is the commissioning of the Sakarya gas fields in Turkey. Turkey currently plans to start producing in 2023 at 5–10 BCM/y, reaching 15 BCM/y by 2025. However, AS5 assumes a less aggressive timeline that has first production from the Sakarya fields coming online in 2025 (which seems probable if a fast-track development campaign, currently under way, obtains sufficient reservoir information to inform the master development plan).

The final assumption for AS5 is the commissioning of the IKR–Turkey natural gas pipeline. The commissioning would be pushed back to 2030 or later, as the IKR will likely not export volumes to Turkey before then (since the FI market is still considered to have priority). Commissioning is estimated once the Erbil–Duhok connection is completed to be able to carry marketable surplus natural gas from the southern IKR to Duhok.

Table 42 Key assumptions for AS5, excluding constant assumptions for IKR gas demand for scenarios Base Case to AS4

Key Assumptions	Capacity of Pipelines/Major Fields	Commissioning Date	Online

[62] Primarily Shaikan and Sarsang block associated gas
[63] Primarily Benenan, Topkhana, Kurdamir and Taza

1	Turkey Pipeline	15-30 BCM	2034	Yes
2	IKR-FI Pipeline	20 BCM	2025	Yes
3	Minor IKR-FI Supplies to Kirkuk	0.4 BCM	2025	Yes
4	Sakarya Fields (Turkey)	26 BCM	2025	Yes
Natural Gas Balance under AS5				
			Balance in 2021	Balance in 2040
1	IKR Natural Gas Production		5.3 BCM	34.8 BCM
2	Supplies to FI		0.0 BCM	12.3 BCM
3	Exports to Turkey		0.0 BCM	1.3 BCM
4	IKR Natural Gas Balance		-6.3 BCM	0.0 BCM

9.5.2 AS5: Slow-Moving Kurdish Gas Development Will Delay Export Markets

Under AS5, the delay in the commissioning of two major non-associated natural gas fields, Miran West and Bina Bawi, delays the realization of feasible external sales markets, FI and Turkey, to 2027/2028 and 2034, respectively.

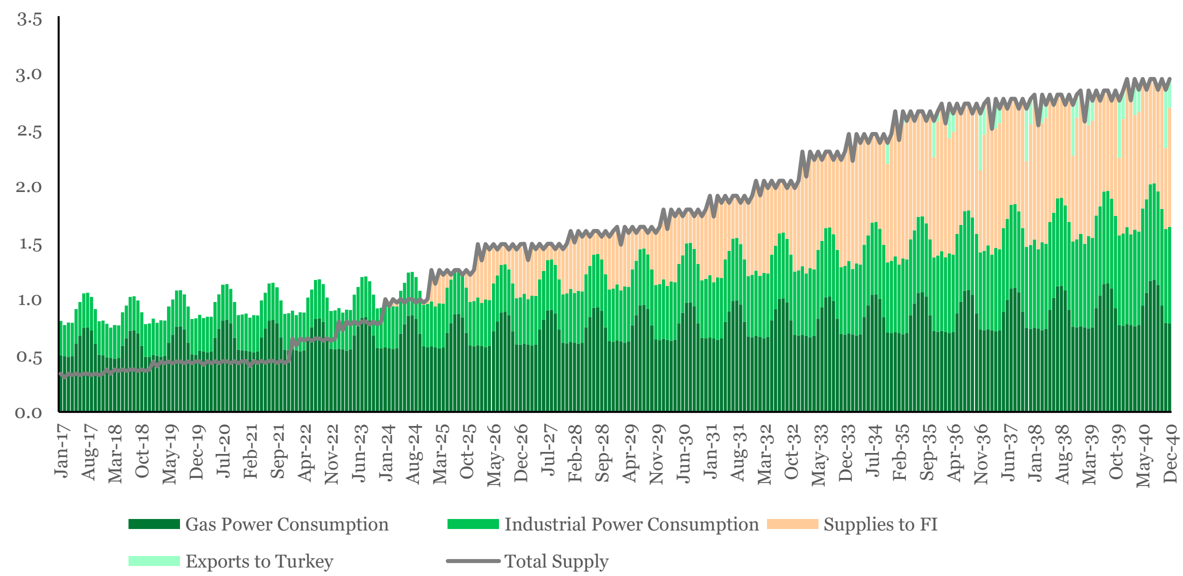


Figure 80 Kurdistan natural gas sector balance under AS5, BCM/m

Applying reasonable estimates for the development of other fields, the IKR will be able to begin some small marketable supplies of natural gas in 2025/26. The priority market will still be FI because the IKR will have missed the main contractual window in Turkey due to having only a small surplus. Holding advance discussions with Baghdad, starting now, can apply some competitive pressure on Turkey. Otherwise, Turkey can continue waiting and playing the various suppliers off against one another, as it has done for years. This is the scenario depicted in AS5, in which minor IKR supplies to Turkey do not begin until 2034, displacing only some LNG and Iranian gas entering Turkey.

9.5.3 AS5: Kurdish Gas to Federal Iraq Will Not Be Enough to Cover FI Deficit

Under AS5, major supplies of Kurdish marketable natural gas to FI via the 20 BCM/y proposed natural gas pipeline will not begin until 2027/2028, even though smaller supplies can commence in 2025. The delay in the commissioning of Miran West and Bina Bawi will reduce the surplus available for supplying natural gas to external markets, so FI will continue relying on Iranian gas (although the FI demand–supply gap will narrow by 2039, thanks to some Kurdish gas and continued imports from Iran).

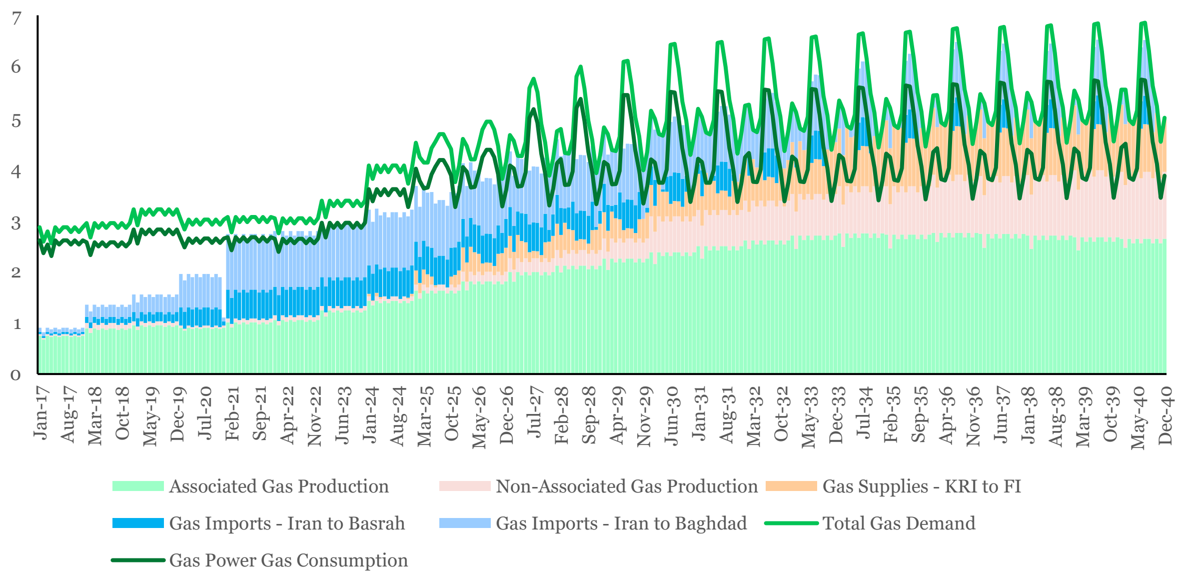


Figure 81 FI natural gas supply balance under AS5, BCM/m

9.5.4 AS5: Kurdish Gas to Turkey Will Be Very Minor, Not Starting Until 2034

The delay in the commissioning of Miran West and Bina Bawi will impact the momentum in developing the Erbil–Duhok connection, so the Turkish market for IKR gas will be available only when some surplus emerges after gas supplies to the IKR's own domestic sector and sales to FI. Turkey will therefore continue requiring Russian, Iranian, and LNG gas, although volumes will be somewhat lower because of Turkey's own rising domestic gas production (from the Sakarya fields) and flattening demand in the late 2020s and early 2030s (soft economic indicators and competing power generation methods).

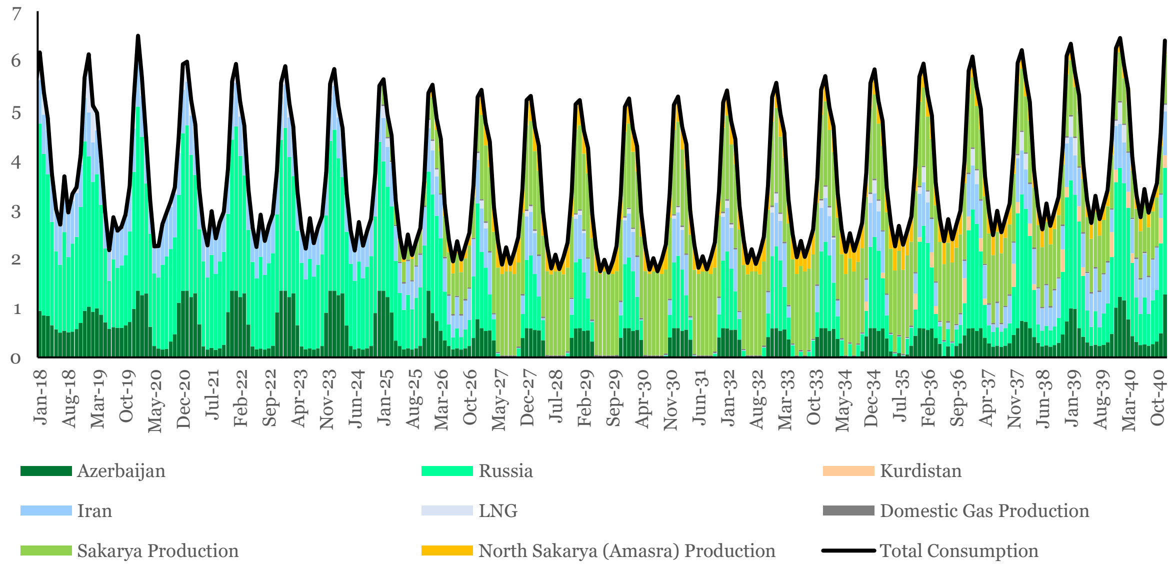


Figure 82 Turkey's natural gas supply balance under AS5, BCM/m[64]

9.6 Alternate Scenario VI: Low-Case of Kurdish Gas Development - Miran West and Bina Bawi not Commissioned

9.6.1 Methodology and Assumptions

The first assumption for Alternate Scenario VI (hereafter referred to as AS6) is that the commissioning of the Miran West and Bina Bawi non-associated natural gas fields is indefinitely delayed. While not ideal, the scenario is not implausible, as both fields have so far remained underdeveloped, and their technical complexities and sour characteristics lend to an associated high cost of development and production. Development could potentially take place in the long-term, but applying a 15 year delay in commission from estimates established in the Base Case puts the commissioning for both fields beyond 2040. Assuming another operator takes over from Repsol, Topkhana will become the only major non-associated gas field, other than Pearl Petroleum's assets, to output significant natural gas in the 2030s. AS6 also assumes that further reserves of Chemchemal apart from Phase-1 and Phase-2 are not developed.

Table 43 Upstream production estimates for AS6, BCM/y

Field	Type	Province	2020	2025	2030	2040
Khurmala	Associated	Erbil	0.92	1.10	1.10	0.68
Other[65]	Associated	IKR	0.02	1.53	1.90	4.71
Khor Mor	Non-associated	Sulaymaniyah	4.33	4.34	3.96	2.92
Khor Mor Phase-2	Non-associated	Sulaymaniyah		5.17	5.55	6.59
Chemchemal	Non-associated	Sulaymaniyah		1.55	1.55	1.55
Chemchemal Phase-2	Non-associated	Sulaymaniyah			2.59	4.66
Bina Bawi	Non-associated	Erbil				
Miran West	Non-associated	Sulaymaniyah				

[64] Chart shows only imports and production actually used within Turkey, not imports that are re-exported or production that is exported
[65] Primarily Shaikan, Sarsang, and Kurdamir associated gas

Field	Type	Province	2020	2025	2030	2040
Other[66]	Non-associated	IKR			1.85	5.65
Total	Associated		0.94	2.63	3.00	5.39
	Non-associated		4.33	10.28	15.5	21.37
	All		5.27	12.91	18.5	26.76

The next assumption, natural gas demand in the IKR, is the same as in all other scenarios, Base Case to AS5.

The third assumption for AS6 is the commissioning (or repurposing) of the 0.4 BCM Jambur–Kirkuk gas condensate pipeline to carry minor supplies of Kurdish natural gas to the FI market via Kirkuk.

The fourth assumption for AS6 is the commissioning of a major natural gas pipeline to FI. In previous scenarios, this was estimated to be 20 BCM/y, but with a bearish outlook on commissioning of Genel's assets, the marketable natural gas surplus available for export reaches about 8.8 BCM in 2035, and declines to 5.7 BCM in 2040, as the IKR's domestic demand grows and field developments and associated gas capture plans come to fruition in FI. Therefore AS6 ascertains a 10 BCM/y pipeline will be more than enough to carry Kurdish gas surplus to FI.

The fifth assumption for AS6 is the commissioning of the Sakarya gas fields in Turkey. Turkey currently plans to start producing in 2023 at 5–10 BCM/y, reaching 15 BCM/y by 2025. However, AS6 assumes a less aggressive timeline that has first production from the Sakarya fields coming online in 2025 (which seems probable if a fast-track development campaign, currently under way, obtains sufficient reservoir information to inform the master development plan).

The final assumption for AS6 is the commissioning of the IKR–Turkey natural gas pipeline. Because of the priority to the FI market, to whom supplies begin in 2025 at <1 BCM from the 10 BCM/y main and 0.4 BCM/y Jambur pipelines combined, the Turkish market is effectively closed to the IKR, who cannot develop a large enough surplus to support supplies to Turkey, as well as to FI. Even though theoretically the IKR could choose to prioritise the Turkish market over FI, the bearish outlook on natural gas developments will dampen the IKR's credibility as an alternate supplier to Turkey. Moreover, the main window for the IKR to enter Turkey starts in 2026/27. In 2027, under AS6, the IKR will have a marketable gas surplus of only 0.65 BCM, which is too minor to warrant any form of external sales agreement with Turkey. Therefore, under AS6, there is *no* commissioning of a IKR-Turkey natural gas pipeline.

Table 44 Key assumptions for AS6, excluding constant assumptions for IKR gas demand for scenarios Base Case to AS5

Key Assumptions		Capacity of Pipelines/Major Fields	Commissioning Date	Online
1	Turkey Pipeline	15-30 BCM	-	-
2	IKR-FI Pipeline	10 BCM	2025	Yes
3	Minor IKR-FI Supplies to Kirkuk	0.4 BCM	2025	Yes
4	Sakarya Fields (Turkey)	26 BCM	2025	Yes
Natural Gas Balance under AS6				
			Balance in 2021	Balance in 2040

[66] Primarily Benenan, Topkhana, and Taza

1	IKR Natural Gas Production	5.3 BCM	26.8 BCM
2	Supplies to FI	0.0 BCM	5.7 BCM
3	Exports to Turkey	0.0 BCM	0.0 BCM
4	IKR Natural Gas Balance	-6.3 BCM	0.0 BCM

9.6.2 AS6: No Commissioning of Miran West & Bina Bawi results in an export market of only 10 BCM/y to FI

Available Kurdish natural gas surplus will peak at 8.8 BCM in 2035, thereafter declining to 5.7 BCM in 2040, as the IKR's domestic demand grows. While a 10 BCM/y pipeline to FI could carry this surplus, supplies will initially take place only in winter months (2024-2029 window) due to lower demand in the IKR then. Summer months will not allow the IKR to supply FI, which itself runs into a natural gas deficit routinely during that time of the year. Post-2029, reliable and continued supplies of IKR gas can enter FI, covering both winter and summer months, while also meeting the IKR's internal demand. The chart below shows supplies exclusively to FI, as the bearish outlook on commissioning of Genel's assets effectively eliminates a Turkish market.

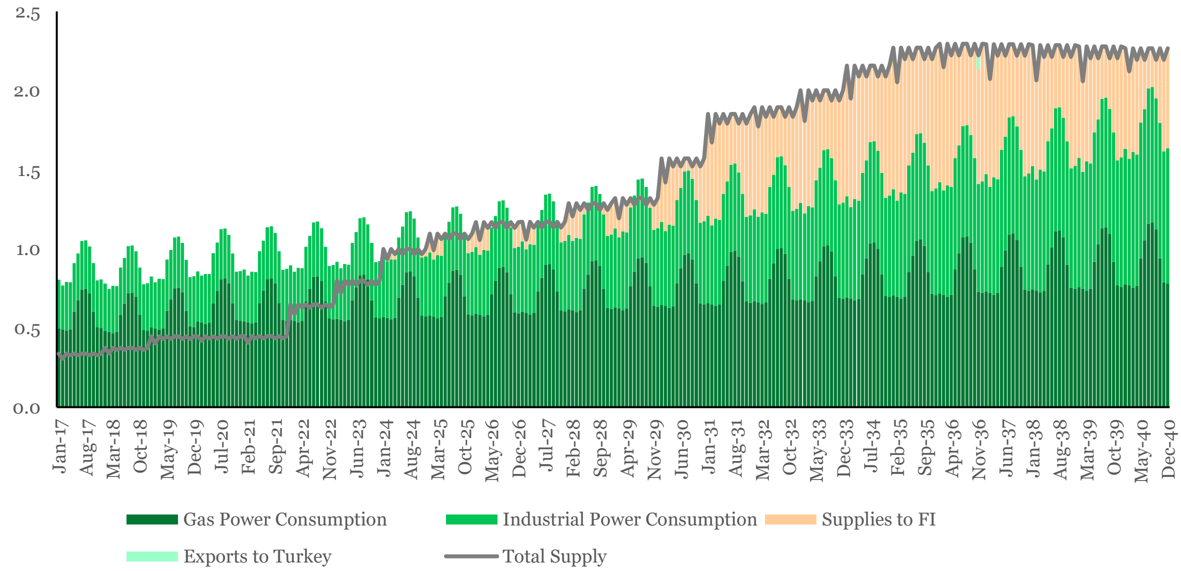


Figure 83 Kurdistan natural gas sector balance under AS6, BCM/m

9.6.3 AS6: Kurdish Gas to Federal Iraq Will be Insufficient to Cover FI Deficit

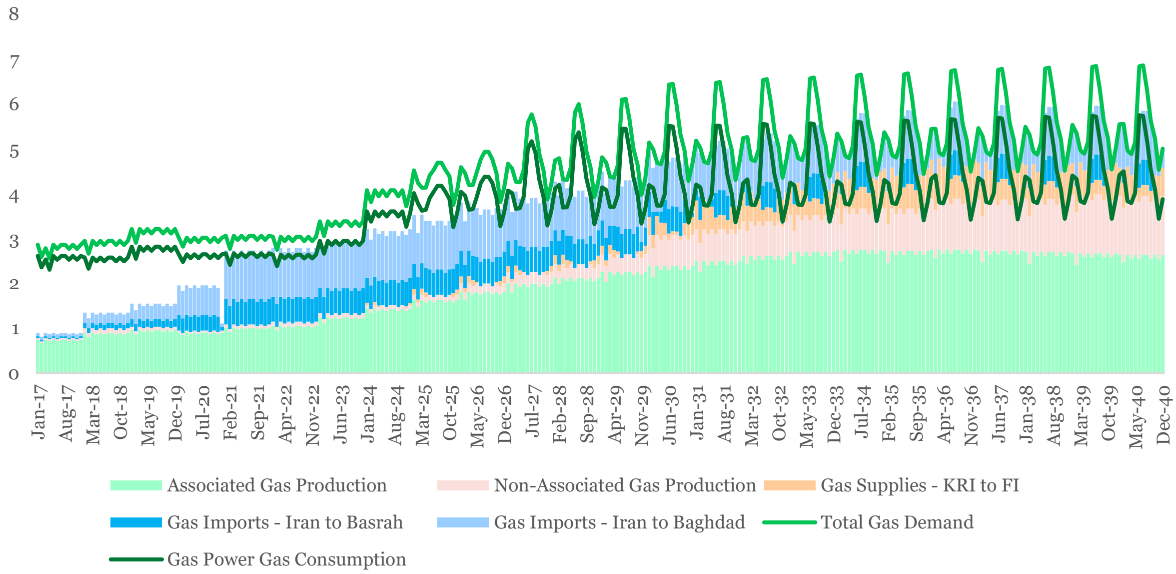


Figure 84 FI natural gas supply balance under AS6, BCM/m

9.6.4 AS6: Without Kurdish gas, Turkey will continue relying on other suppliers

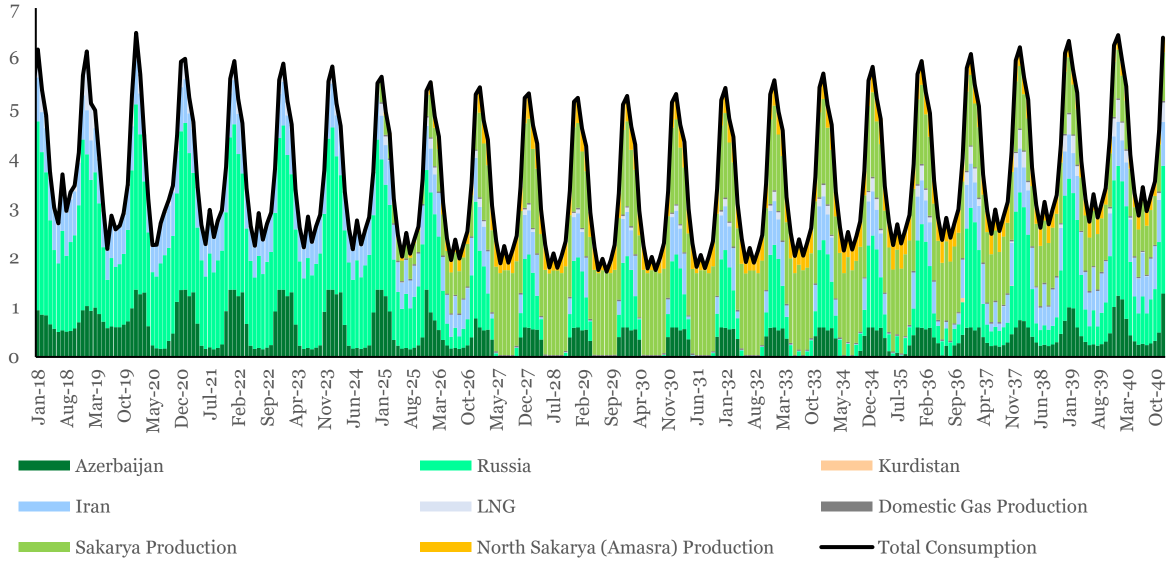


Figure 85 Turkey's natural gas supply balance under AS6, BCM/m[67]

[67] Chart shows only imports and production actually used within Turkey, not imports that are re-exported or production that is exported

9.7 Alternate Scenario VII: High-Case of Kurdish Gas Development – Chemchemal Phase-1 begins in 2023, Phase-2 in 2025

9.7.1 Methodology and Assumptions

The first assumption for Alternate Scenario VII (hereafter referred to as AS7) is the fast-track development of the Chemchemal natural gas field, which lends to the IKR amassing its first export surplus by 2024. Phase-1 of the field comes online by 2023, at a rate of 0.78 BCM/y, while Phase-2 comes online in 2025. Large reserves at the field result in an additional Phase-3, which is estimated to come online by 2027. By 2030, the Chemchemal field amasses 9.75 BCM/y of production.

Table 45 Upstream production estimates for AS7, BCM/y

Field	Type	Province	2020	2023	2025	2027	2030	2040
Khurmala	Associated	Erbil	0.92	1.10	1.10	1.10	1.10	0.68
Other[68]	Associated	IKR	0.02	0.87	1.53	1.64	1.90	4.71
Khor Mor	Non-associated	Sulaymaniyah	4.33	4.34	4.34	4.34	3.96	2.92
Khor Mor Phase-2	Non-associated	Sulaymaniyah		3.10	5.17	5.17	5.55	6.59
Chemchemal	Non-associated	Sulaymaniyah		0.78	1.55	1.55	1.55	1.55
Chemchemal Phase-2	Non-associated	Sulaymaniyah			1.55	2.59	2.59	4.66
Chemchemal Phase-3	Non-associated	Sulaymaniyah				0.71	3.54	3.54
Bina Bawi	Non-associated	Erbil				1.03	2.59	6.20
Miran West	Non-associated	Sulaymaniyah					0.84	5.89
Other[69]	Non-associated	IKR					1.85	5.65
Total	Associated		0.94		2.63		3.00	5.39
	Non-associated		4.33	8.22	12.61	15.39	24.02	37.00
	All		5.27	10.18	15.24	18.12	27.02	42.40

The next assumption, natural gas demand in the IKR, is the same as in all other scenarios, Base Case to AS6.

The third assumption for AS7 is the commissioning (or repurposing) of the 0.4 BCM Jambur–Kirkuk gas condensate pipeline to carry minor supplies of Kurdish natural gas to the FI market via Kirkuk.

The fourth assumption for AS7 is the commissioning of a major natural gas pipelines to Turkey and FI. In this scenario, the fast-track development of Chemchemal resources is supported by equally fast-tracked negotiations between Turkey and the IKR for completing the Kurdish side of the pipeline to connect to the Turkish border. Assuming development on the pipeline commences immediately, it would be possible to have it operational by 2024. Incremental volumes of Kurdish gas begin flowing through the pipeline to Turkey to meet its winter demand. Initially volumes in summer are minimal/shut-off due to Kurdistan's own high summer demand and low demand in Turkey. In this scenario, the Turkey market takes priority over the FI market, who begins receiving IKR supplies only in 2027. The success of the IKR-Turkey agreement cements the IKR's credibility as a cost-effective natural gas player, and talks with the FI result in the commissioning of a 20 BCM/y pipeline. Ultimately, the IKR can access a 13 BCM/y market in FI (in 2033, falling to 5.2 BCM by 2040 as the Turkish market grows and prioritises Kurdish gas over other suppliers), and an 11.5 BCM/y market in Turkey (in 2040) under this scenario.

[68] Primarily Shaikan, Sarsang, and Kurdamir associated gas
[69] Primarily Benenan, Topkhana, and Taza

The fifth assumption for AS7 is the commissioning of the Sakarya gas fields in Turkey. Turkey currently plans to start producing in 2023 at 5–10 BCM/y, reaching 15 BCM/y by 2025. However, like previous scenarios, AS7 assumes a less aggressive timeline that has first production from the Sakarya fields coming online in 2025 (which seems probable if a fast-track development campaign, currently under way, obtains sufficient reservoir information to inform the master development plan).

Table 46 Key assumptions for AS7, excluding constant assumptions for IKR gas demand for scenarios Base Case to AS6

Key Assumptions		Capacity of Pipelines/Major Fields	Commissioning Date	Online
1	Turkey Pipeline	15-30 BCM	2024	Yes
2	IKR-FI Pipeline	20 BCM	2027	Yes
3	Minor IKR-FI Supplies to Kirkuk	0.4 BCM	2025	Yes
4	Sakarya Fields (Turkey)	26 BCM	2025	Yes
Natural Gas Balance under AS7				
			Balance in 2021	Balance in 2040
1	IKR Natural Gas Production		5.3 BCM	42.4 BCM
2	Supplies to FI		0.0 BCM	5.2 BCM
3	Exports to Turkey		0.0 BCM	11.5 BCM
4	IKR Natural Gas Balance		-6.3 BCM	4.6 BCM

9.7.2 AS7: Fast-track development of Chemchemal results in an ~18 BCM/y export potential for IKR

Under AS7, the IKR develops an a marketable natural gas surplus by 2024, when the IKR-Turkey natural gas pipeline is commissioned. Exports to Turkey commence at a rate of 1.2 BCM/y in 2024, growing to 2.5 BCM/y by 2026 and ultimately 11.5 BCM/y in 2040. Supplies to FI commence in 2027 through a 20 BCM/y pipeline, peaking at 13 BCM/y by 2033. The increase in supplies to FI is due to lowering gas demand in Turkey during the early 2030s. However this begins reversing from 2033 onwards (as Turkish demand rises due to new generation and new gas use in industry), and the IKR re-prioritises the Turkish market over FI, resulting in a peak of 11.5 BCM/y of gas to Turkey in 2040. Even with an 18 BCM/y market, the IKR accrues additional surplus starting 2033 onwards, which could necessitate flexible production, storage solutions, or the development of a city gas network.

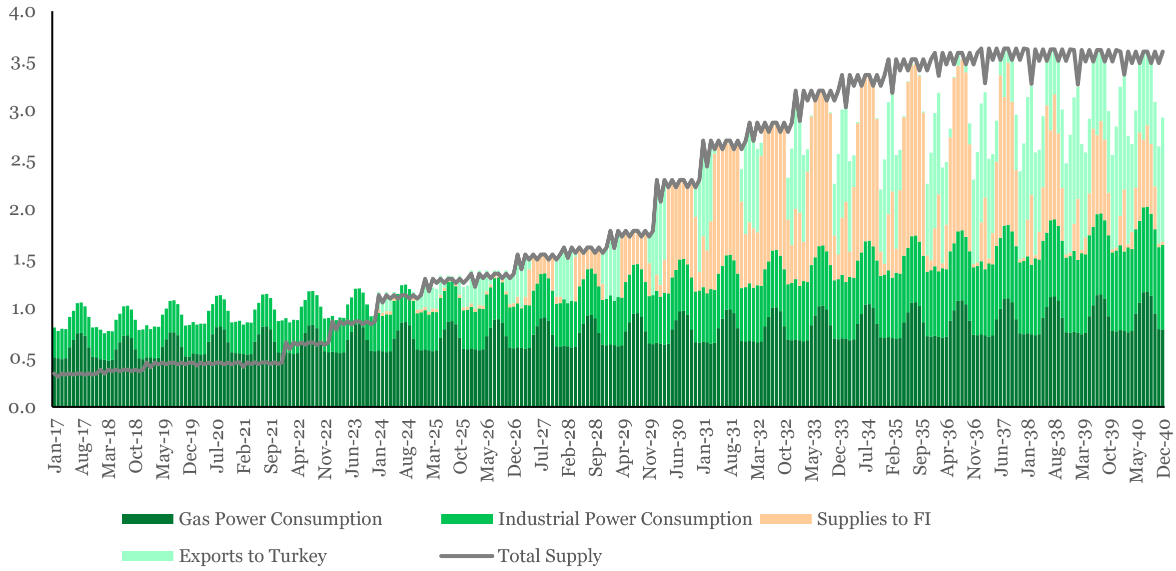


Figure 86 Kurdistan natural gas sector balance under AS7, BCM/m

9.7.3 AS7: Kurdish Gas to FI will close Supply-Demand Gap almost entirely, but a small Deficit will remain in 2040

Tapering of Kurdish supplies to the FI market as demand in Turkey rises results in FI restarting Iranian gas imports via Basrah to meet its demand (2038 onwards). FI manages to completely close off its supply-demand gap during the mid-2030s with IKR gas and eliminate natural gas imports from Iran via Basrah, but post-2038 begins registering a minor deficit once again, which could necessitate another supply solution. This could be either increased associated gas capture, discovery of new natural gas resources and development, more aggressive development of existing resources, or expansion of the Kirkuk-Jambur line to carry additional IKR gas (over the pipeline's 0.4 BCM/y capacity) to FI and close the deficit.

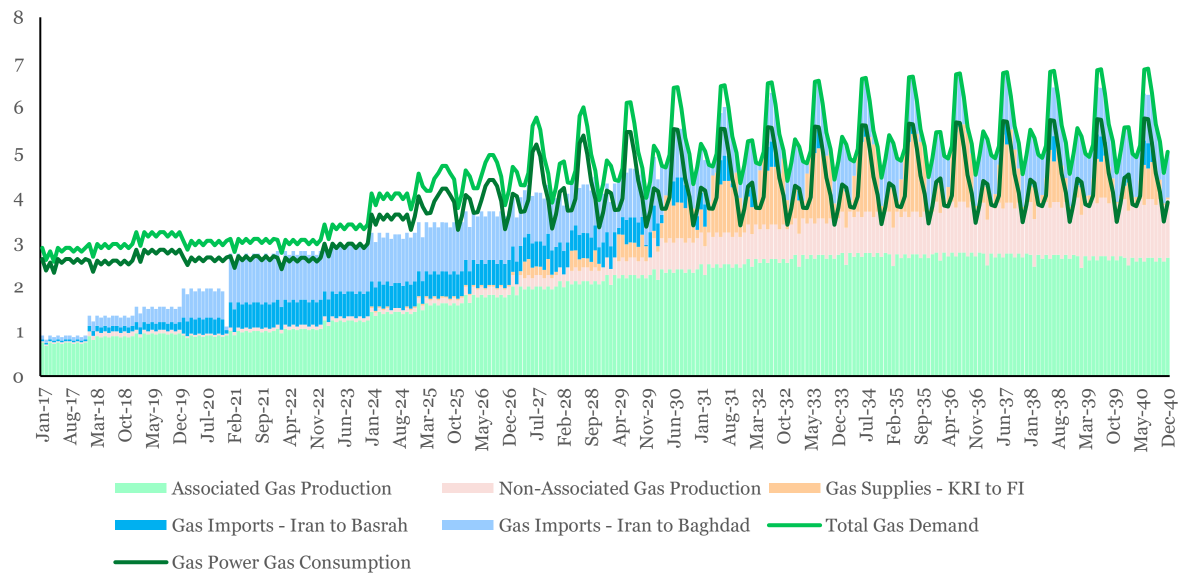


Figure 87 FI natural gas supply balance under AS7, BCM/m

9.7.4 AS7: IKR gas to Turkey begins flowing in 2024; Turkey eliminates reliance on Iranian gas completely by 2031

Under AS7, the IKR is able to enter the Turkish market by 2024, 2 years prior the expiration of Turkey's main natural gas supply contracts, which can establish the IKR as a credible natural gas player in a highly competitive market. Kurdish gas initially begins displacing Iranian gas, completely eliminating it by 2031, and also begins displacing Russian gas as production from Sakarya and North Sakarya (Asmara) commences.

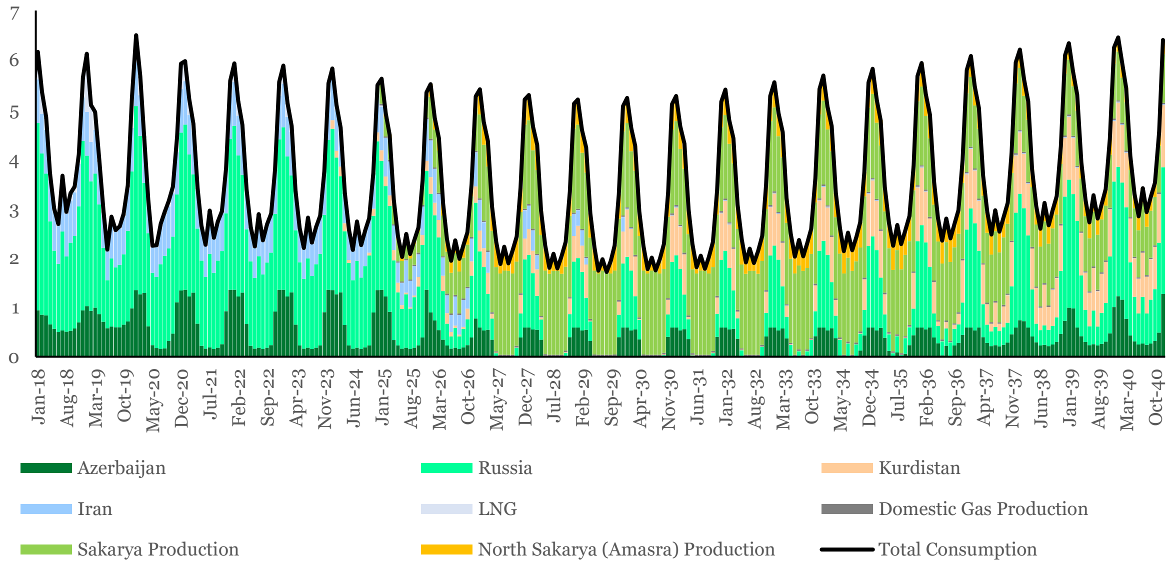


Figure 88 Turkey's natural gas supply balance under AS7, BCM/m[70]

[70] Chart shows only imports and production actually used within Turkey, not imports that are re-exported or production that is exported

9.8 Potential Annual Net Revenues from Gas Supplies to FI and Turkey, per Scenario

9.8.1 Potential Annual Net Revenues from Gas Supplies to FI and Turkey, AS1: Main IKR–FI Pipeline Not Commissioned

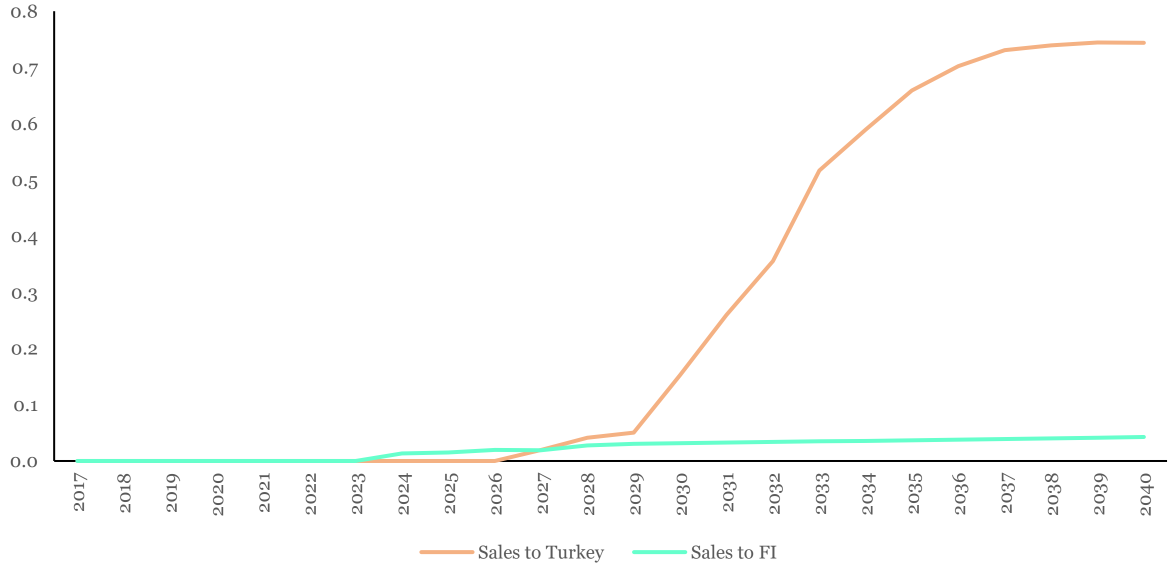


Figure 89 Potential annual net revenues from gas supplies to FI and Turkey, AS1, US$ B[71]

9.8.2 Potential Annual Net Revenues from Gas Supplies to FI and Turkey, AS2: Turkey–IKR Pipeline Not Commissioned

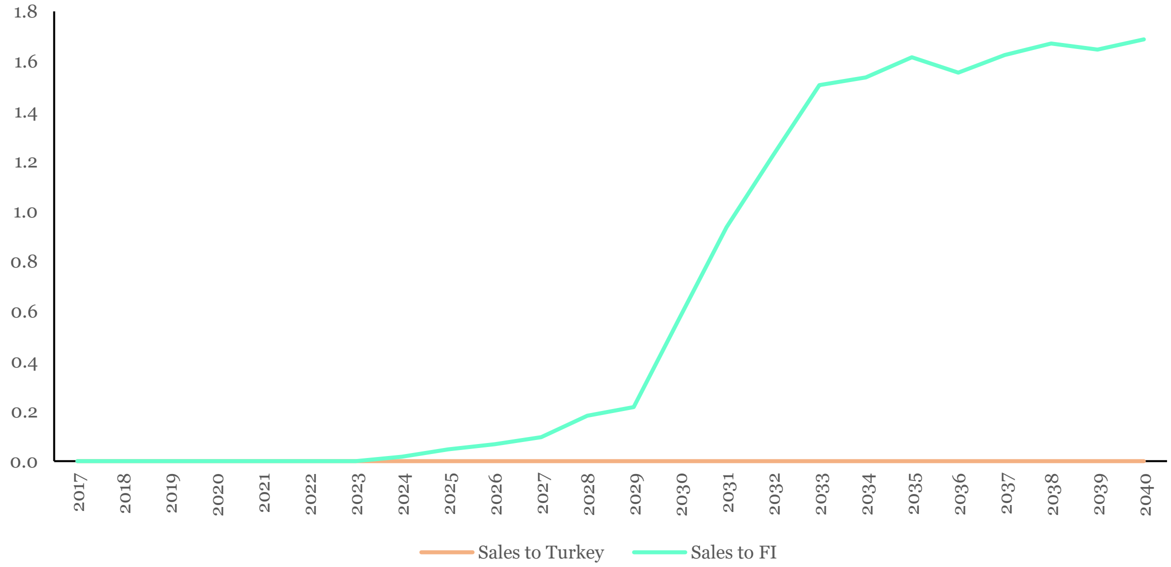


Figure 90 Potential annual net revenues from gas supplies to FI & Turkey, AS2, US$ B[72]

[71] Available Turkish market for IKR gas ~11.2 BCM/y; IKR sales to FI limited to volumes via Jambur–Kirkuk pipeline
[72] No impact on available FI market for IKR gas from non-commissioning of Turkey–IKR pipeline

9.8.3 Potential Annual Net Revenues from Gas Supplies to FI and Turkey, AS3: Sakarya Field Not Developed

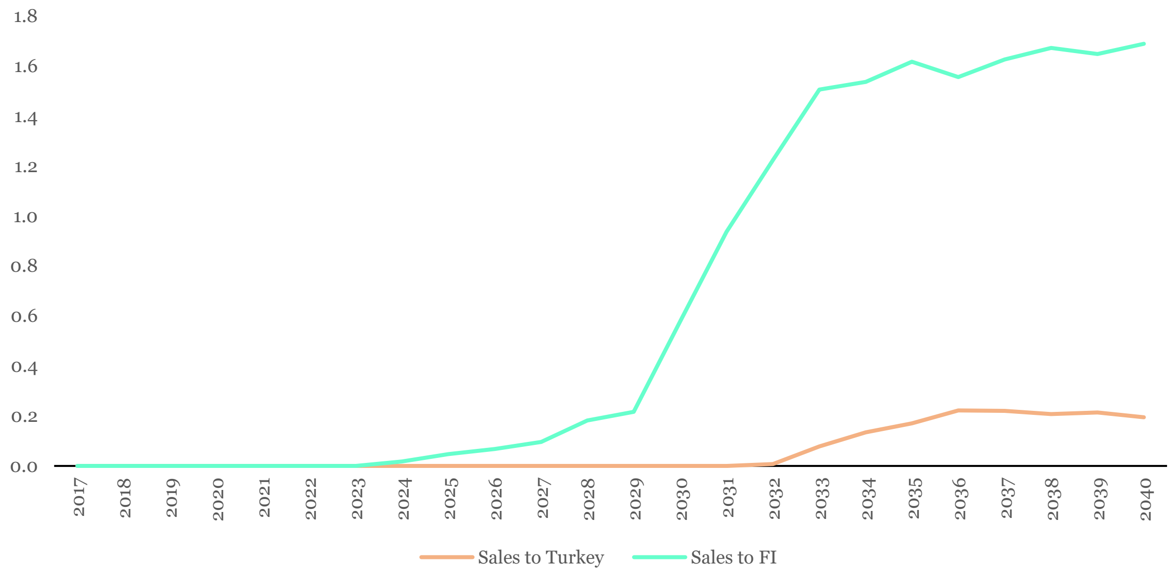


Figure 91 Potential annual net revenues from gas supplies to FI and Turkey, AS3, US$ B[73]

9.8.4 Potential Annual Net Revenues from Gas Supplies to FI and Turkey, AS4: Main IKR–FI Pipeline Not Commissioned, Sakarya Not Developed

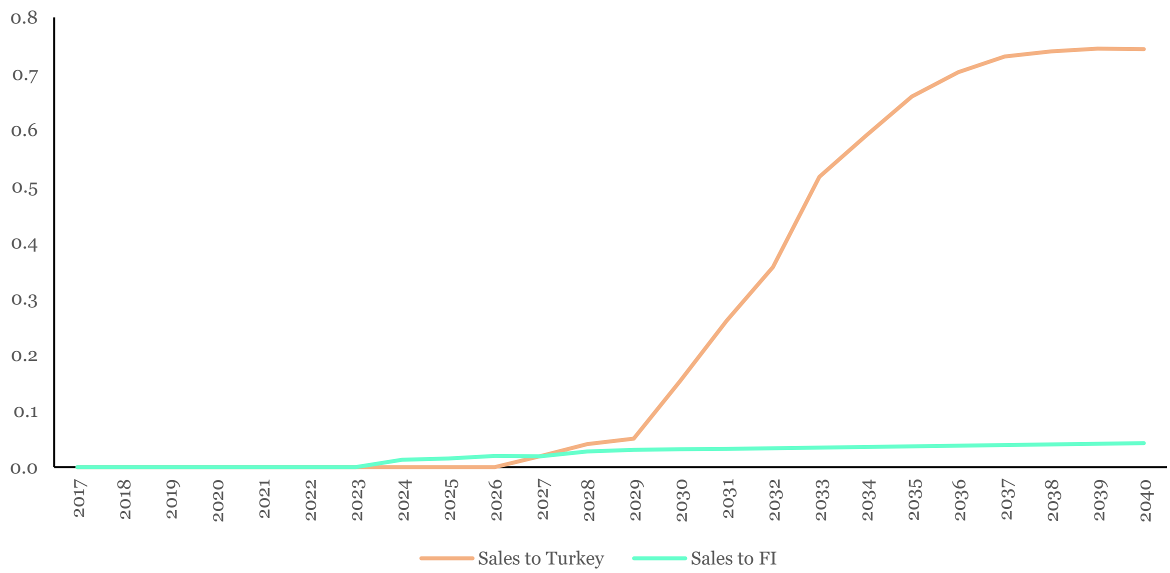


Figure 92 Potential annual net revenues from gas supplies to FI and Turkey, AS4, US$ B[74]

[73] Non-development of Sakarya has no impact on available market size in Turkey and FI for IKR gas
[74] Non-development of Sakarya and non-commissioning of main IKR–FI pipeline results in ~11.2 BCM/y available Turkish market for IKR gas

9.8.5 Potential Annual Net Revenues from Gas Supplies to FI and Turkey, AS5: Miran West and Bina Bawi Delayed in Commissioning

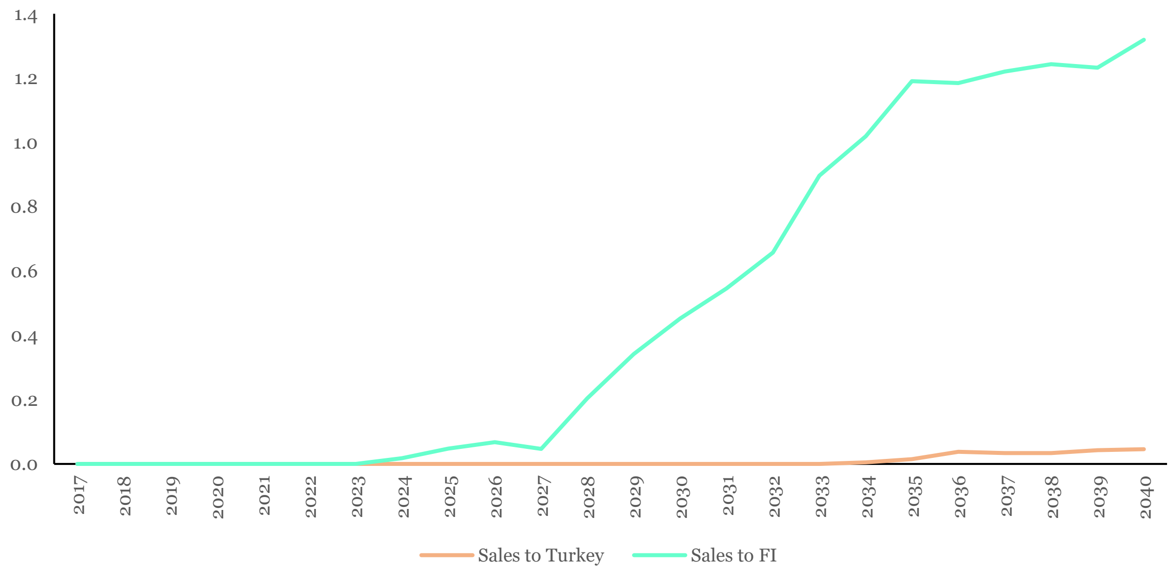


Figure 93 Potential annual net revenues from gas supplies to FI and Turkey, AS5, US$ B[75]

9.8.6 Potential Annual Net Revenues from Gas Supplies to FI and Turkey, AS6: Low-case of Kurdish Gas Development – Miran West & Bina Bawi not Commissioned

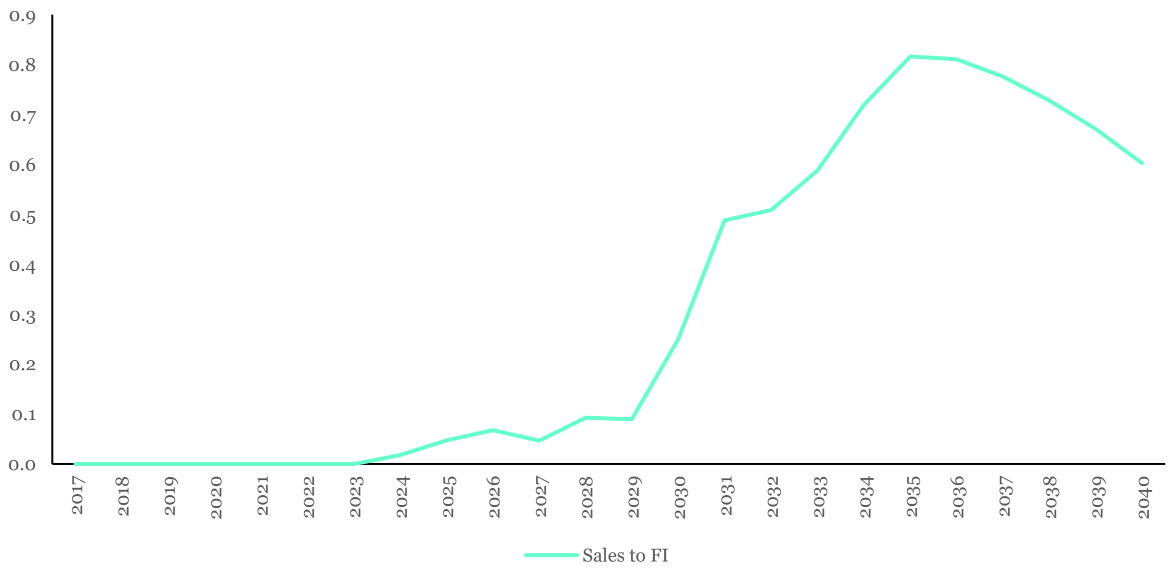


Figure 94 Potential annual net revenues from gas supplies to FI and Turkey, AS6, US$ B[76]

[75] Delayed commissioning of Miran West and Bina Bawi significantly constrain natural gas volumes to Turkey and resultant revenues

[76] No commissioning of Miran West and Bina Bawi result in no sales to Turkey and therefore no resultant revenues

9.8.7 Potential Annual Net Revenues from Gas Supplies to FI and Turkey, AS7: High-Case of Kurdish Gas Development – Chemchemal Phase-1 starts in 2023; Phase-2 in 2025

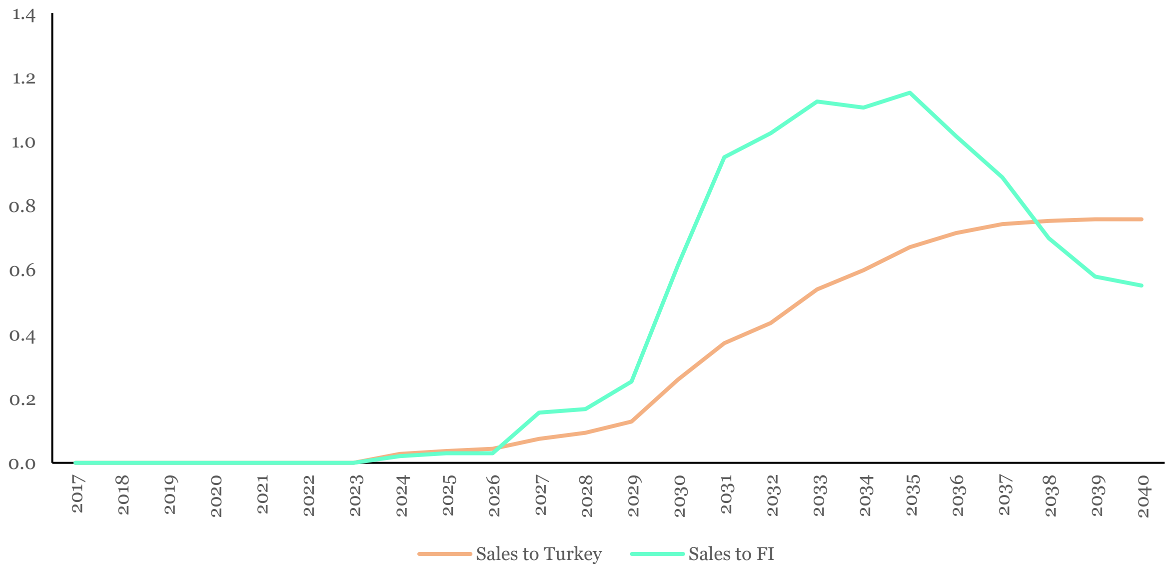


Figure 95 Potential annual net revenues from gas supplies to FI and Turkey, AS7, US$ B[77]

9.9 Federal Iraq Gas and Power Infrastructure

Table 47 FI natural gas infrastructure

Province	Non-Associated Gas Field		Natural Gas Processing Plants		Major Gas Power Plants		
	Name	Final Capacity (BCM)	Name	Capacity (BCM)	Name	Type	Design Capacity (MW)
Baghdad					South Baghdad 1	Open Cycle	612
					South Baghdad 2	Open Cycle	400
					Daura Plant	Open Cycle	150
					Quds Plant	Open Cycle	642
					Al-Rasheed Plant	Open Cycle	95
					Sadr Power Plant	Open Cycle	658
					Al-Taji Power Plant	Open Cycle	658
					Al-Taji New Plant	Open Cycle	160
					Basmaya IPP	Combined Cycle	3000
					South Baghdad	Steam Turbine	355
					Daura Steam	Steam Turbine	640
Nineveh					Nineveh Gas Plant	Open Cycle	750
					Mosul Plant	Open Cycle	240
Kirkuk			Kirkuk	5.54	Mulla Abdulla Old	Open Cycle	222

[77] Rising Turkish demand results in revenues from sales to Turkey crossing revenues from supplies to FI

Province	Non-Associated Gas Field		Natural Gas Processing Plants		Major Gas Power Plants		
	Name	Final Capacity (BCM)	Name	Capacity (BCM)	Name	Type	Design Capacity (MW)
					Mulla Abdulla New	Open Cycle	462
					Kirkuk (Taza) Plant	Open Cycle	617
Salah al-Din					Baiji	Open Cycle	636
					Baiji Thermal	Steam Turbine	1320
Anbar	Akkas	4.15					
Diyala	Mansuriyah	3.32					
Babil					Hilla Old	Open Cycle	125
					Hilla New	Open Cycle	250
					Al-Mussaib Plant	Combined Cycle	500
					Al-Khairat Plant	Combined Cycle	1250
					Al-Mussaib Thermal	Steam Turbine	1200
Karbala					Karbala Plant	Open Cycle	250
Najaf					Najaf 1	Open Cycle	1250
					Najaf 2	Open Cycle	250
					Najaf – Jabriya	Combined Cycle	402
					Haydariya	Combined Cycle	980
Diwaniyah					Diwaniyah Plant	Open Cycle	500
Wasit			Badra	1.60	Wasit Thermal	Steam Turbine	2540
Muthanna					Samawa Plant	Combined Cycle	500
Dhi Qar			Nasiriyah	0.52	Nasiriyah Thermal	Steam Turbine	840
					Nasiriyah Plant	Open Cycle	150
Missan			Halfaya	2.27	Amara Plant	Combined Cycle	500
					Bazurgan 1	Open Cycle	120
			Missan	1.03	Bazurgan 2	Open Cycle	120
					Al-Kahlaa Plant	Open Cycle	180
Basra	Siba	1.04	Nahr bin Omar	0.83	Al-Hartha	Steam Turbine	400
					Najibiya Thermal	Steam Turbine	145
			Majnoon	0.72	Asmida Plant	Open Cycle	14
					Rumaila	Combined Cycle	584
			North Rumaila	2.58	Shaat al-Basra	Open Cycle	1250
					Najibiya Plant	Open Cycle	500
			Khor al-Zubair	7.24	Shuaiba Plant	Open Cycle	66
					Rumaila IPP	Combined Cycle	1500
			Siba	1.14	Hartha IPP	Open Cycle	120
					Inma IPP	Open Cycle	64

9.10 Technical Specifications for IKR Natural Gas to FI/Turkey

Chemical Composition (As Mol %)			
Methane	(C_1)	Minimum	80%
Ethane	(C_2)	Maximum	6-12%
Propane	(C_2)	Maximum	4%
Butane	(C_4)	Maximum	1%
Pentane and other heavy hydrocarbons	(C_5^+)	Maximum	0.5%
Carbon dioxide	(CO_2)	Maximum	1%
Oxygen	(O_2)	Maximum	N/A
Nitrogen	(N_2)	Maximum	6%
Sulphur			
Hydrogen Sulfide	(H_2S)	Maximum	5 mg/m3
Mercaptan Sulfur		Maximum	15 mg/m3
Total Sulfur		Maximum	30 mg/m3
Gross Calorific Value			
Maximum		10500 kcal/m3	
Minimum		8500 kcal/m3	
Wobbe Index[78]			
Maximum		12.5 kcal/m3	
Minimum		11 kcal/m3	
Pressure – Summer		1200 PSI	
Pressure – Winter		1000 PSI	
Water Dew Point		Maximum	-10°C
Hydrocarbon Dew Point		Maximum	-7°C

[78] The Wobbe Index (WI) indicates the interchangeability of fuel gases such as natural gas, liquefied petroleum gas (LPG), and city gas, and is often defined in the specifications of natural gas supply and transport utilities