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Title

Lebanese Natural Gas Exportation Pathways Economic and Geopolitical Assessment.

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Acknowledgment

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Background

The political instability in the Eastern Mediterranean region had developed in an unpredictable way in the last decade. In addition to the Arab-Israeli conflict, the so called "Arab Spring" presented new geopolitical mechanisms with the recent strategic ambition of Iran and Turkey, the civil war in Syria, the strong comeback of Russia, all coincides with a regression of the United States after being the only player in the region for more than two decades before. In this regional Chaos, the gas discoveries in the Levant Basin are considered an additional conflict base that starts to show on top. In a 2010 report, the U.S. Geological Survey (USGS) estimated that the Levant Basin has mean probable undiscovered oil resources of 1.7 billion barrels and, more significantly, mean probable undiscovered natural gas resources of 122 trillion cubic feet (tcf)[1]. The basin is covered mainly by the Exclusive Economic Zone (EEZ) of Palestinian occupied territory, Lebanon, Cyprus, and Syria.

Seismic studies conducted in 2010 of the Lebanese Coast suggest gas reserves could be in the range of 25 tcf[2]. Although these estimates could be considered optimistic, recent successes in the gas discoveries in Cyprus and Israel[3] raised the expectations that Lebanon can be a gas exporter even in a pessimistic scenario. So a country that had always suffered from a deteriorated energy security because of the lack of access to resources and critical infrastructure is on the threshold of becoming a Gas exporter.

Purpose of the Study

A country that stands on the edge of discovering natural resources as natural gas should study his exploitation and export options deeply before making any step that may have implications on his strategy on the long term. The question here is complex and should be treated from different edges. Any choice may face administrative, legal, political, security, geopolitical, commercial and technical challenges.

In the case of Lebanon, the Lebanese government has struggled on the administrative level to initiate its exploration plan after delineating the discovering blocks in its Exclusive Economic Zone. Then it succeeded finally to complete the first licensing round, where five out of the ten offshore blocks were open for bidding, and Block4 and Block9 were awarded to the consortium Total-Eni-Novatek. Since that date, no major steps were done except for the first drilling tests in Block4 in 2019 for which no clear results appear to date. These administrative steps are just the

[1] U.S. Geological Survey (USGS), "Assessment of Undiscovered Oil and Gas Resources of the Levant Basin Province, Eastern Mediterranean," *World Petroleum Resources Project*, (2010).

[2] Daily Stars, "Bassil Signs $470m Contract for Power Plant," *The Daily Stars*2013.

[3] **NB: The use of the word Israel in this study does not imply any recognition of its right to use resources in the occupied Palestinian territories**

start of a Gas Master plan that the government should work on and that should mainly study the monetizing of gas between domestic consumption and exportation. The government should also study the implication of any exportation option.

Besides Lebanon has a legal and political challenge related to the conflict of its maritime borders. Lebanon has only agreed its western maritime borders with Cyprus while the southern and the northern borders are still not agreed. The northern borders should be defined with Syria, however no actions are initiated in this sense yet due to the war in Syria and the perturbed relations between the two countries since 2005. The southern borders with the Israeli regime seems to be complicated. A disputed zone of 860 km claimed by Lebanon and Israel which may hold large quantities of gas especially after the Israeli discoveries just near it such as the well of Karish. Lebanon from its side has licensed block number 9, which includes a part located under the disputed zone. In 2020, after a long journey of discussion with the American government, Lebanon has started indirect negotiations with the Israeli regime over the delimitation of the disputed borders. The complexity of negotiating and the security challenge posed by this dispute because of the maintained state of war between Lebanon and Israel, create a serious obstacle to the development of discovered gas resources of Lebanon. This legal issue and its security implications will not be discussed in this thesis since it needs a separated research and has been discussed adequately by other authors.

This study will give a general overview of the geopolitical challenges of exportation of Lebanese natural gas and will discuss in details the technical and commercial challenges of the exportation routes. Technical challenges are discussed via analyzing the possible infrastructure and studying its financial feasibility. In addition, the commercial challenges will be discussed by analyzing the possible markets and the competitiveness of the Lebanese gas in these markets.

This study seeks to provide an independent analysis for the exportation options. It will serve as a foundation for a basic understanding by Lebanese decision makers, the business community, and the international and the local stake holders about strategic options for exporting the Lebanese natural gas.

Problem Description

This project assumes that the size of Lebanon's gas reserves is much larger than the domestic demand and therefore gas exportation would be the next question on the Lebanese gas agenda. Thus choosing the appropriate export infrastructure is an important prerequisite for the success of Lebanon in managing his gas resources. In order to choose the ultimate exportation pathway, some main considerations should be taken into account:

1- Lebanon is in extreme need to achieve a maximum profit from its gas reserves vis-a-vis his critical economic situation, thus gas should be used as an economical lever at the first place.

2- Lebanon location in this extremely volatile divided region presents the main factor to be considered. Any decision may have political implications, and could be interpreted as an alignment with one side against another.
3- The persisted state of war with Israel, thus any decision should avoid all sorts of direct or indirect coordination with Israel.
4- The fractionalized Lebanese political elite and its susceptibility to the influence of regional and international players may complicate the decision making process.

These considerations complicate the decision making process. This thesis should provide the appropriate context and guidelines for the best solution regarding these considerations. The problematic will be then reformed in the following question:

What is the solution that provides the best economical profit with the least geopolitical risk?

Hypothesis

Technically the exportation pathways can be summarized by the following options:

1- Building Liquefied natural Gas (LNG) plant on the Lebanese shore and export gas through maritime shipment.
2- Exporting through Pipelines to regional or global markets (This option include several pipeline scenarios discussed later on in this thesis)

The decision-making process of choosing of one of these options should be built on two main guiding contexts:

1. The economic feasibility and the attractiveness of each exportation pathway.
   - Is this option feasible according to the estimated gas reserve?
   - If yes what are the gas prices that Lebanon should consider to make this option profitable?
   - What is the rank of these prices according to the future gas market and are they competitive?
   - Does the option require long term or short term contracts?
   - Does the option require any coordination or partnership with other countries?
   - What are the political and security consequences that could be results from these partnerships?
2. The geopolitical implications of this exportation pathway.

Methods and Sources

Collecting available and published data about the gas reserves gas production gas consumption and gas trade will allow to draw the natural gas profile for each country in this region. This would lead to defining the region in the perspective of gas graphs and numbers independently from any political issue.

Then the geopolitical overview is presented via a narrative method, through which main events showing the alliances in the region in the last decade are followed and discussed.

The economic study is based on Discounted Cash Flow, or DCF techniques. These methodologies are used for assessing the "economic merit" of large-scale, capital-intensive projects, and are a ubiquitous analysis tool across the financial and commercial sectors. A feature of the DCF approach that makes it particularly attractive for use in this project is its ability to enable the "apples-to-apples" comparison of projects with, among other things, differing capital scales, risk characteristics, and timelines to delivery.

The thesis depends on a wide variety of resources starting from webpages that provide the historical data for natural gas, news websites that cited the main events, official reports issued by ministries and agencies concerned with natural gas in each country, to journal articles that analyze from authors perspectives.

Thesis overview

The thesis is divided into two main chapters. The first chapter entitled "the regional natural gas profile", through which the natural gas profile for the important countries in the region are explored by studying their reserves, production, consumption and natural gas infrastructure. This will allow to classify them as potential markets, potential collaborators or potential competitors. The chapter is divided to six sections. In the first five sections, the gas profile for Jordan, Turkey, Egypt, Israel and Cyprus are presented; while the sixth section presents a natural gas geopolitical over view of the whole region.

The second chapter presents a detailed economical study for each of the exportation options deduced in chapter one. The most realistic assumptions about the project sizing, the capital expenditure, and the operating costs of each project are reached. Depending on Discounted Cash Flow method, the Breakeven Prices (BEP) of each project is calculated and these projects are classified from the minimum to the maximum BEP. Finally, these prices will be examined in each market versus the existing and potential competitor prices.

Chapter One: The Regional Natural Gas profile

Introduction

Lebanon has the option to export the gas via offshore routes or onshore routes through Syria. The Targeted markets are few in the neighborhood countries “namely Jordan”. The location of Lebanon may play a positive role with its proximity to Europe and to the Suez Canal as route to export liquefied natural gas to Asian markets. Each one of these options require a special infrastructure and may require collaboration with some countries or may compete with the interests of other countries in the region.

The geostrategic interests of international and regional powers in the Lebanese gas are yet to be shaped according to size of the reserves and the role that such reserves can play. Thus, a study of the regional gas profile is essential in this stage to define the main factors that Lebanon should consider when proposing any exportation scenario. This regional analysis will help to predict the political pressure that any proposed scenario can impact on Lebanon. This is crucial, especially when considering that the competition between Lebanese political elites has the potential to direct the development agendas of the government. The competition among parties may be a reflection of competition between regional and international power agendas. Any proposed solution should provide the minimum level of the political elite’s cohesion or Lebanon will suffer from extra delays. Lessons should be taken from the discovering stage.

The discoveries of natural gas in the eastern Mediterranean has grabbed the attention of countries and researchers in the last few years. Every main political event or action is now linked to the conflict over the Mediterranean natural gas. Thus, the discovery forms an additional matter of dispute in a region that has been known historically for its fragile peace. The discovery open up new prospects for every country in the region, some of which wants to reach its energy security, others count on gas as a lever for their struggling economics, others are more ambitiously looking to be a gas hub, and all of them looks at it as a game changer that may apply new political alliances or new conflict tensions. The proximity of this gas source to Europe, the world’s leading natural gas consumption region, has also gave gas discovery an international aspect.

In front of this complicated situation one should search in deep the interests of each country. These interests can’t be always presumed from the political positions or the official speeches. One should analyze the numbers and markets of natural gas in each country. The natural gas reserves, the domestic consumption, gas production and gas trade are important parameters that shape exactly the gas profile of each country. Upon this gas profile the political position can be interpreted and a geopolitical image of the whole region can be drawn.

Jordan Natural Gas Profile

The kingdom of Jordan could be considered one of the poorest neighbors of Lebanon in energy resources and had always been dependent on imports to satisfy its energy demands. Thus studying the natural gas profile of Jordan is crucial to determine the possibility of having a neighbor market for the Lebanese gas, especially that this market can be reached with a minimum transportation fees which can enlarge the margin of profit. To study the natural gas profile of Jordan, figures provided by different references are used, knowing that these figures can differ slightly from one reference to another, but all give the same overall conclusion.

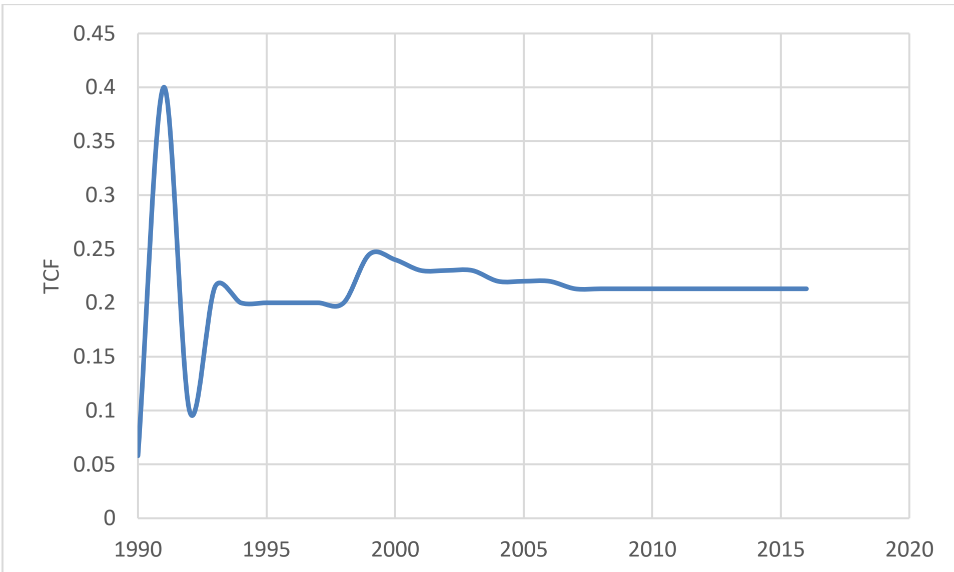

Figure 1 : Jordan natural gas reserve evolution in from 1990.[4]

As shown in Figure 1, the Kingdom of Jordan has a about 0.213 tcf gas reserve, mainly in Al Risha natural gas field where the country has started production in the early 90's. This field mainly supply the demand of a neighbor Al Risha power plant 350 km east of Amman, close to the border with Iraq. However this gas reserve is far from being sufficient to satisfy the domestic demand of the natural gas.

As shown in Figure 2 and Figure 3, until the early 2000's the country settles for the domestic natural gas production and natural gas played a minor role in the overall energy mix of the country. Then Jordan started to rely more on natural gas as a relatively cheap and clean source of energy when it started importing natural gas from Egypt via the Arab Gas Pipeline. This increase in the use of the natural gas has reached its peak in 2009. Then a dramatic decrease started after a shortage in the Egyptian gas supplies. Due to the political instability and the sabotage of the pipe line the imported quantities reached a minimum in 2012. This was followed by a shortage in gas production in Egypt and the produced quantities were totally consumed in the domestic Egyptian market. The pipeline was halted in 2015. During this period the shortage of natural gas was met with imports of diesel and heavy oil. Then in 2015 Jordan started to import Liquefied Natural Gas via the Golar Eskimo, a floating storage and regasification unit (FSRU), located at the Red Sea port of Aqaba.

[4] World meters, "Jordan Natural Gas," *worldometers.info*, (2020).

The FSRU has been contracted for ten years with an option to terminate after five years and is connected to the Jordan Gas Transmission Pipeline.[5]

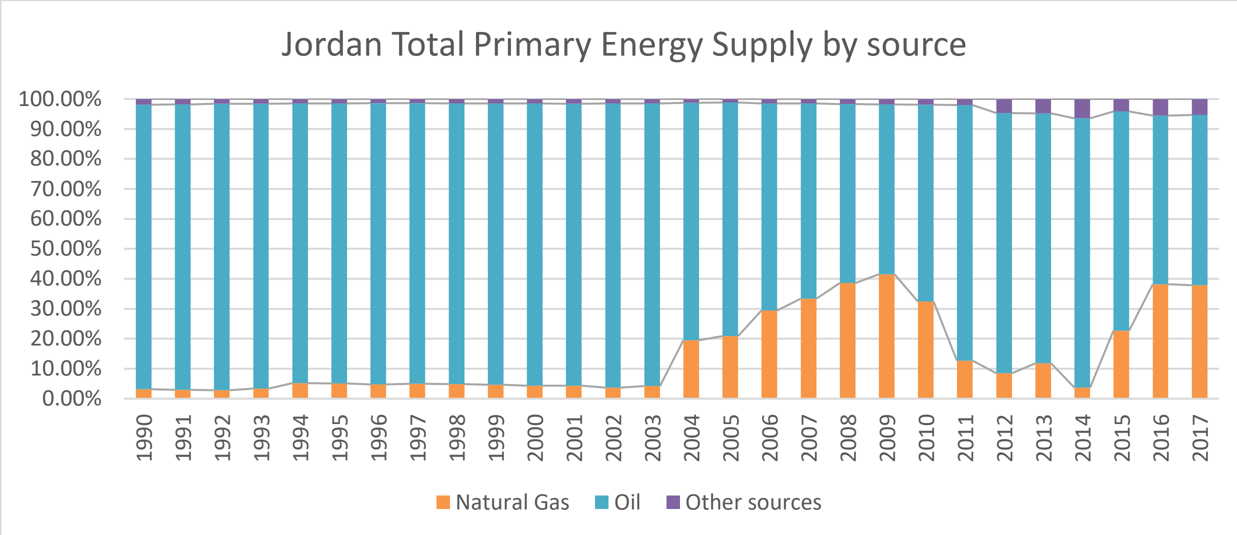

Figure 2 : Jordan Total Primary energy supply by source (graph produced by the author after collecting data from reference[6])

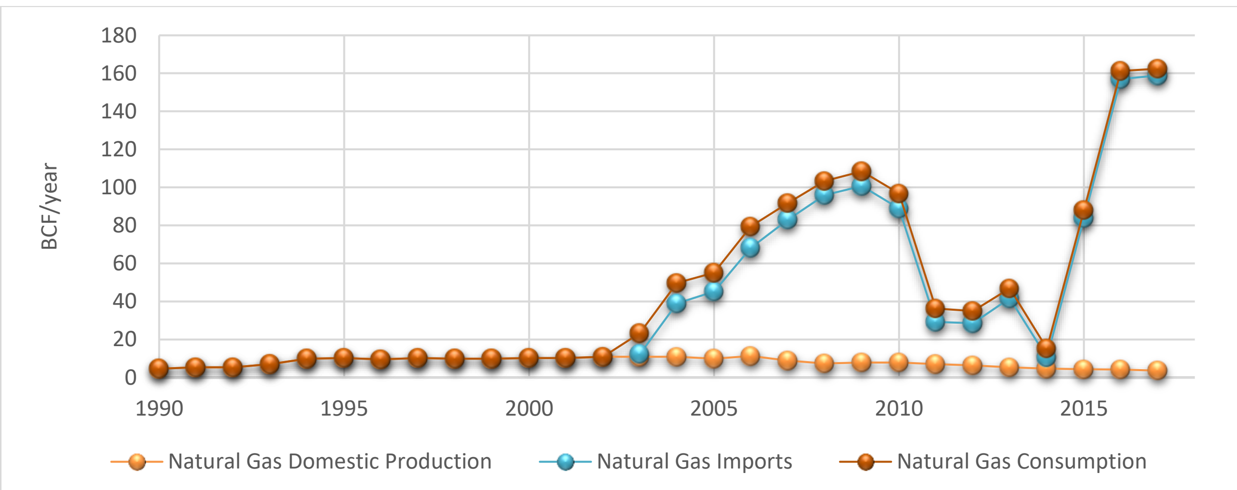

Figure 3 : Jordanian natural gas balance (figure produced by the user after collecting data from references[7,8,9,10]

[5] Offshore-energy, "Golar Eskimo Changes Hands" https://www.offshore-energy.biz/golar-eskimo-changes-hands/ (2020).

[6] iea.org, "Total Energy Supply (Tes) by Source, Jordan 1990-2018" https://www.iea.org/countries/Jordan (2020).

[7] CEIC data, "Jordan Natural Gas: Imports" https://www.ceicdata.com/en/indicator/jordan/natural-gas-imports (2020).

[8]TITI TUDORANCEA BULLETIN, "Jordan: Dry Natural Gas, Net Exports/Imports (-)" https://www.tititudorancea.com/z/ies_jordan_dry_natural_gas_net_exports_imports.htm (2020).

[9]Energy Charter, *Jordan Regular Review of Energy Efficiency Policies* (THE HASHEMITE KINGDOM OF JORDAN, 2010).

[10]The Ministry of Energy & Mineral Resources in Jordan, *Annual Report 2017* (2017).

Also in 2014, Jordan started importing small quantities of natural gas from Tamar gas field in Israel[11]. In late 2016, Jordan signed a contract with Leviathan natural gas field to import large quantities of natural gas, these imported quantities that started in the beginning of 2020 covers almost all the natural gas demand in Jordan.

So at the beginning of 2020, Jordan has signed several contracts to import natural gas. The original contract with Egypt was to import 250 mmscf per day which is equivalent to about 91 bcf per year. The contract with Tamar gas field consisted of receiving small volumes of 10-12 mmscf per day which is equivalent to 4 bcf per year. This contract was renewed in 2017 for 15 years till 2032. And finally, the large contract with Leviathan gas field with a quantity of 300000 MMBtu per day which is equivalent to about 106 bcf per year for a duration of 15 years started in 2020 and may continue until 2035. The summation of these quantities makes a total of about 200 bcf per year which is enough to cover the natural gas demand of the country and may be even stop importing LNG via the FSRU.

These imported quantities of natural gas can cover almost all the demand in the beginning of the 2020's, which may indicate that the Jordanian market is satisfied and no need for additional quantities. But as the earliest date to export the Lebanese gas will be after 2025, then a forecast for the Jordanian natural gas profile will allow to predict if the possibility of Jordan being a market for the Lebanese natural gas on the short term and the midterm.

In order to propose a forecast of the natural gas demand in Jordan, a forecast for the electricity demand is used because electricity generation is the main consumer of the natural gas in the country. Almost all power plants in Jordan operate on natural gas, from the largest one at Aqaba on the Red Sea Cost, to the second largest at al-Qantara, to the Rehab power station, to the Risha power plant to the independent power generation plants named IPP3 and IPP4.

Figure 4 shows how the fuel type profile of the electricity generation in Jordan was closely dependent on the natural gas profile of the country. After an increase in the early 2000's the country reached a peak of generating 90% of its electricity using natural gas in 2009, then decreased gradually to reach 7% in 2014. When Jordan started to import LNG via the FSRU in 2015 the dependence on natural gas increased again till it reached almost 90% in 2018. Although Jordan has ambitious plans to diversify its energy profile by depending on renewable energy and nuclear energy, but Natural gas will remain the largest fuel source for electricity generation. This reliance of electricity generation on natural gas can help in forecasting the natural gas demand depending on the forecast of the electricity demand.

[11] Eran Azran, "Israel's Tamar Gas Field Signs $500 Million Jordanian Export Deal," *Haaretz*2014.

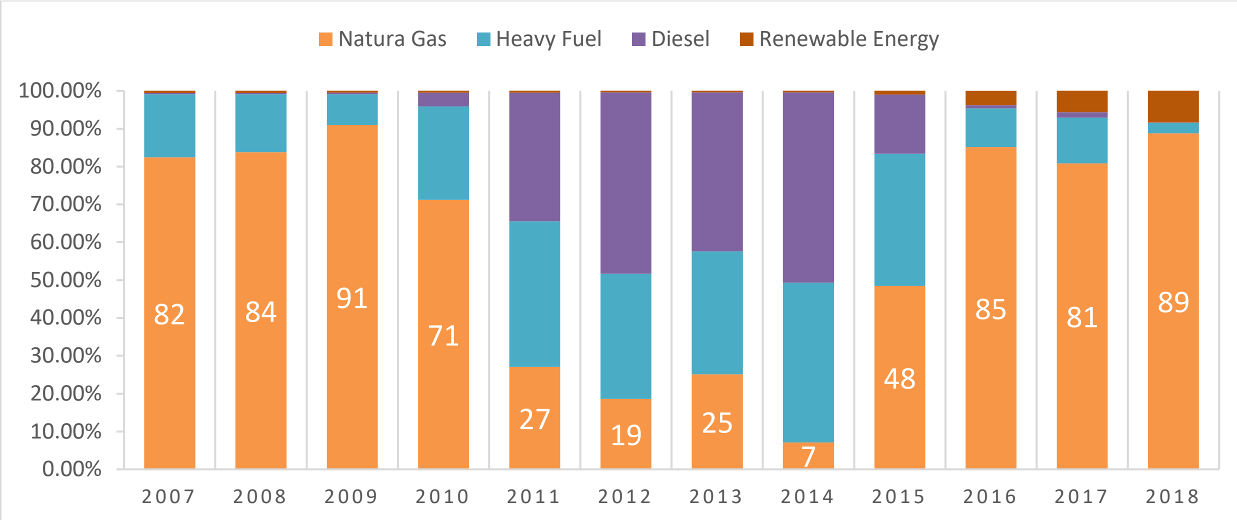

Figure 4 : Electrical Energy Production by Type of Fuel in Jordan[12,13]

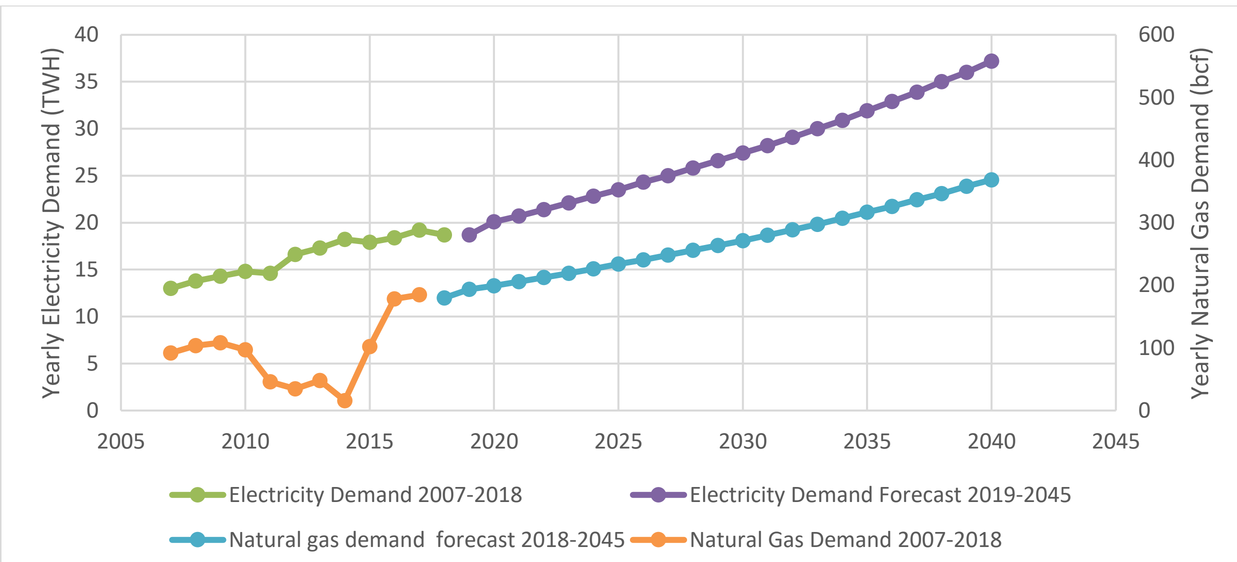

Figure 5 : Electricity and Natural Gas Demand Forecast in Jordan

According to the prediction of the National Electricity Production Company in Jordan NEPCO, Figure 5 shows that the electricity demand in Jordan will increase yearly on an average of 3%. This will almost double the electricity generation in the next 20 years. This will imply a parallel increase in the demand for natural gas, which may raise the consumption from about 200 bcf yearly in 2020 to 400 bcf yearly in 2040. With about 200 bcf yearly contracted imports in 2020, the gap between the imports and the consumption will increase in the coming 20 years.

With the technical interruptions that always face the natural gas deal with Egypt, and the political problems that face the Jordan natural gas deal with Israel, and in addition to the gap between the consumption and the imports shown in the forecast above, Jordan will always be a possible market

[12] National Electric Power Company in Jordan, (Annual Report 2015).
[13] National Electric Power Company in Jordan, *Annual Report 2018* (2018).

to purchase specific quantities of the Lebanese natural gas. Any gas exportation plans for Lebanon should keep Jordan on the top of its possible markets since it is the nearest possible market where gas transportation fees should be minimum, which will maximize the profit range of such an option.

Egypt Natural Gas Profile

The Egyptian gas history illustrates the constraints, barriers, and errors when a country starts its natural gas project without planning. The domestic demand driven by the growth of population and the rise of living standards, in addition to the poor considering of the geopolitical consequences of the choices, all result in a faltering gas march in Egypt.

Egypt has a long history of offshore gas exploration and production activities. Gas exploration in the Egyptian offshore started as early as the 1960s, and the first offshore discovery – the Abu Qir field – was made in 1969[14]. As shown in Figure 6, the Egyptian gas reserve has increased from 10 tcf in the1980's to 40 tcf in the 1990's and the exploration really scaled up after 2000.

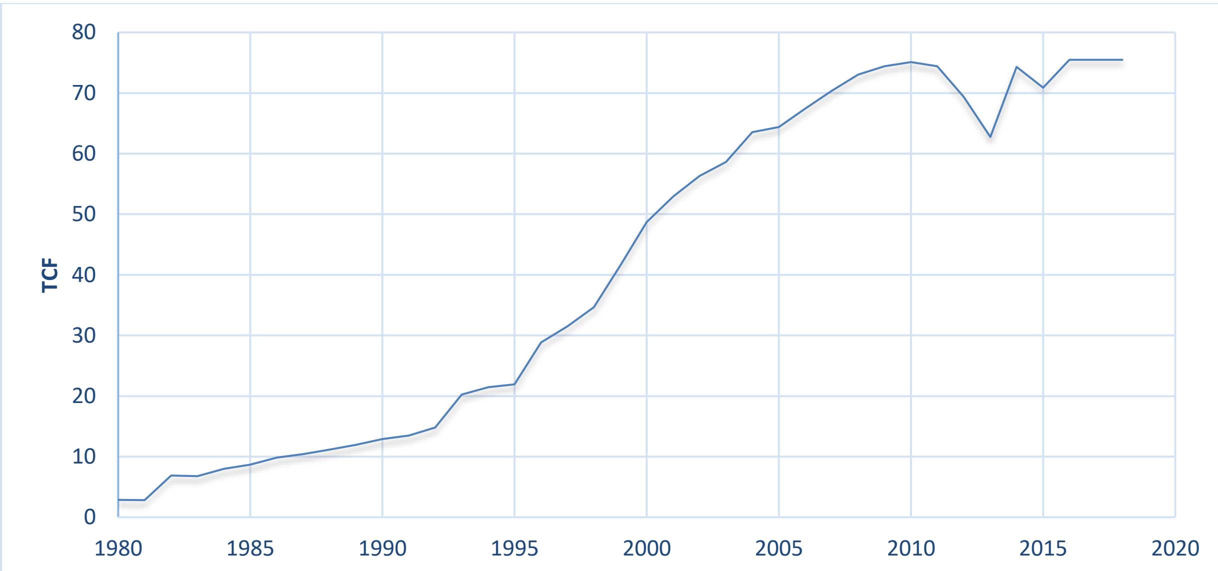

Figure 6 : Proved natural gas reserve history in Egypt1 1980-2019 (graph done by the author using data given by BP report[15])

Then a new stage in the country's gas profile started when the production started to exceed the consumption as shown in Figure 7. In the mid of 2000's, Egypt became a gas exporter after the development of its infrastructure to export the gas in the mid of 2000's.

This infrastructure is composed of two LNG plants in Damietta and Idku in addition to, two pipe lines which are the Arab Gas Pipeline and the El Arish-Ashkelon Pipeline. The Damietta LNG plant located 60 km west of Port Said has one train with a total capacity of 7.56 bcm/year[16]. The Idku LNG plant located 50km east of Alexandria has two trains with a total capacity of 11.48 bcm/year[17]. Thus Egypt has a total liquefaction capacity of 19 bcm/year. El Arish –Ashkelon Pipeline a 100 km offshore natural gas pipeline channels the Egyptian gas to Israel. The pipeline

[14] Simone Tagliapietra, *Energy Relations in the Euro-Mediterranean a Political Economy Perspective* (Palgrave Macmillan, 2017).
[15] British Petroleum, *Bp Satistitical Review* (2020).
[16] Gulfoilandgas.com, http://www.gulfoilandgas.com/webpro1/projects/PROJECT01.asp?id=100001&ctid=EG.
[17] egyptianlng.com, https://www.egyptianlng.com/Pages/About/Home.aspx.

was announced in 2005 and entered into operation in 2008, with a physical complete capacity of 9 bcm/year. The pipeline reached its maximum actual capacity in 2010 with 7.5 bcm/year supplying Israel with half of its consumption. During Mubarak's regime, the project was exposed to may internal criticisms on the ground of the low pricing compared to the global bench mark. These objections continued after the revolution of 25 January in 2011, until Egypt unilaterally halted its gas supply to Israel and since then the pipeline has sat idle.

The Arab Gas pipeline is a 1200 km linking Egypt to Jordan, Syria, Lebanon, and projected to reach Turkey. It has a capacity of 10 bcm/year, and gas flows through it reaching Jordan in 2003 and Syria in 2008 then Lebanon in 2009. After several attacks on the line in Sinai Peninsula the flow of gas was interrupted in March 2012. After that, the pipeline remained idle until September 2018 when Egypt resumed exporting some gas quantities to Jordan according to the 15 years contract signed between them in 2004. The initial agreement says that Egypt must supply Jordan with 250m scf/day valued at $2.5 per one million British Thermal Units (BTU)[18]. But this contract was subject to several changes in prices and quantities. Even more the quantities were also perturbed and stopped and resumed several times since September 2018 to date.

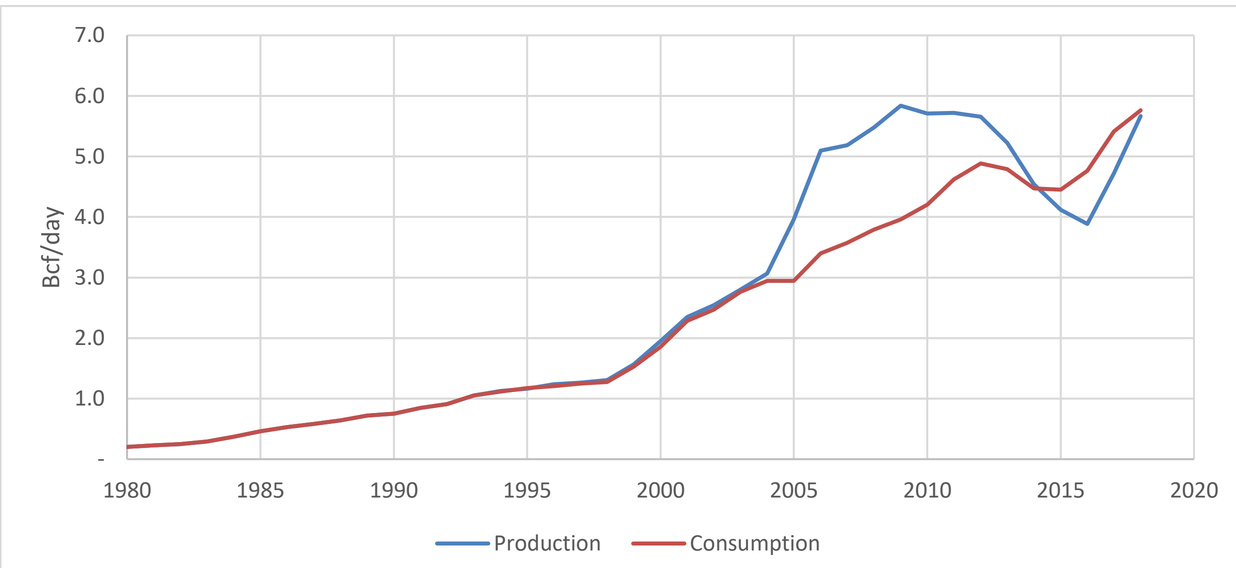

Figure 7 : Production vs. Consumption of Natural Gas in Egypt 1980-2019 (graph done by the author using data given by BP report[19])

As shown in Figure 8 and Figure 7 the exports peaked in 2006. However, since 2011 the production has dramatically decreased. The country's gas production has been severely affected by the so called "Arab spring" when the political instability has blocked the upstream investments. Egypt's LNG exports decreased dramatically from about 15 bcm /year in 2006 to almost zero in 2014, leaving the countries exportation facilities completely idle. In the following years Egypt was

[18] Mohamed Adel, "Egas Cuts Gas Exports to Jordan to 140 Scf/Day," *Daily News Egypt*2020.
[19] British Petroleum.

obliged to import gas to cover its domestic needs; this has been done through a floating storage and regasification unit installed off the red sea.

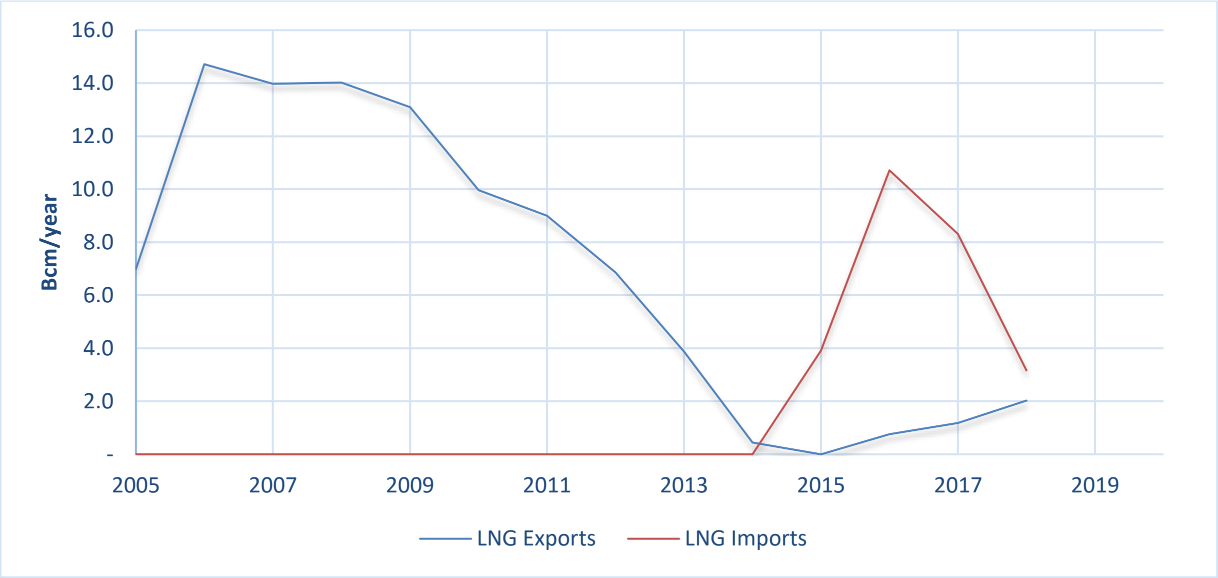

Figure 8 : LNG Imports Vs LNG Exports in Egypt 2005-2018 (graph done by the author using data given by BP report[20])

Because of the increase in gas consumption and the decrease in gas production Egypt has turned to become a net gas importer in 2015. Since then the country is trying to regain the balance of its gas market. Therefore, it started implementing policies to accelerate upstream developments. These policies helped the country to develop several gas fields which reversed the slope of its production curve.

At the end of August 2015, Italy's Eni announced that it had made a world class supergiant gas discovery at its Zohr Prospect, in the deep waters of Egypt[21]. The field could hold a potential of 30 trillion cubic feet of lean gas in place. On 20 December 2017, ENI indicated that it had produced its first gas from the Zohr field[22]. Zohr field is planned to reach a maximum production of 2.7 bcf/day. Another discovery was announced later on whish is the West Nile Delta (WND) development project. According to BP, the WND project will develop 5 trillion cubic feet (tcf) of gas resources with a maximum production level of about 1.5 bcf/d, and has the potential to maintain its production levels to 2030 and beyond[23,24]. Also as new discoveries one can consider, Nooros a Nile Delta offshore field, started in 2017 and is currently producing over 1 billion cubic

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[20] Ibid.

[21] ENI, "Eni Discovers a Supergiant Gas Field in the Egyptian Offshore, the Largest Ever Found in the Mediterranean Sea," (2015).

[22] ENI, "Eni Begins Producing from Zohr, the Largest Ever Discovery of Gas in the Mediterranean Sea," (2017).

[23] BP Press Release, "Bp Announces Start of Production from West Nile Delta Development Achieving First Gas Eight Months Ahead of Schedule and Production 20 Percent above Plan," (2017).

[24] BP Press Release, "Bp Finalises Deal to Develop Egypt's West Nile Delta Gas Fields," (2015).

feet a day[25], Atoll field which started producing 350 million cubic feet a day (Mcf/d) in the end of 2017[26], and Burullus Phase 9B which is expected to produce 390 million cubic meters of natural gas per day in Q1 of 2020.[27] Based on the summation of these values and estimation of the development and reduction of production in these fields a forecast of the production is given in Figure 9. The production ranges from 6 bcf/day in 2018 to reach up to 8 bcf/day in 2022 then decrease again to 6 bcf/day in 2027.

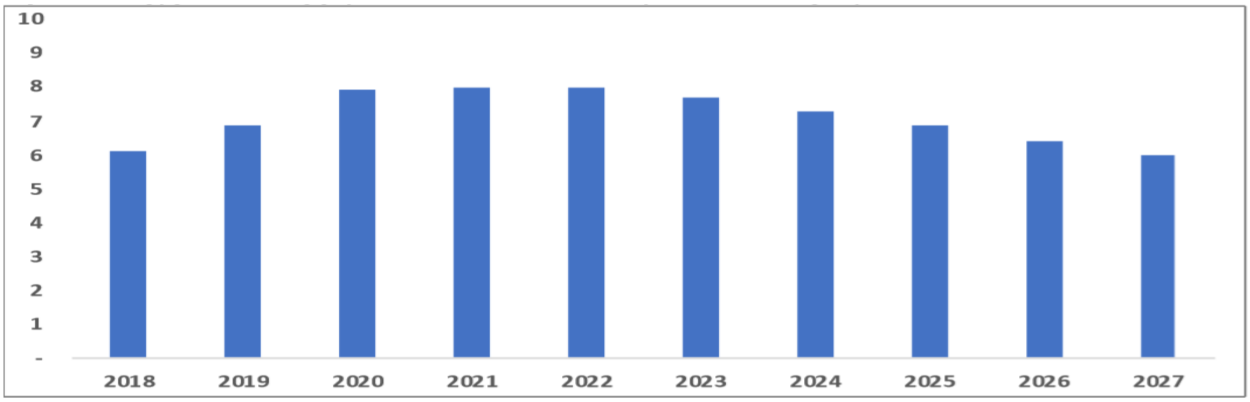

Figure 9 : Egypt gas production forecast scenario[28]

On the other hand, the consumption profile stays a crucial issue in determining the market balance of Natural Gas in Egypt. As Figure 7 shows the consumption profile vs. the production profile of natural gas and how the consumption of natural gas grows rapidly in Egypt, Figure 10 shows that in the last 30 years Egypt consumption of total primary energy had tripled and that natural gas exceeds 50 % of the total energy consumption in the last. Figure 11 shows that the power sector is the main consumer of natural gas among other sectors and it constitutes around 62 % of the total consumption in 2016.

[25]Ali Abdelaty, "Italy's Eni Says Egypt Nooros Gas Field Producing 900mln Cubic Feet Per Day," *Reuters*2016.
[26] BP Press Release, "Bp Begins Production from Egypt's Atoll Gas Field Seven Months Ahead of Schedule," (2018).
[27] egyptoil-gas.com, "Rashpetco, Burullus Gas Complete 9b Phase" https://egyptoil-gas.com/news/rashpetco-burullus-gas-completes-drilling-9b-phase/ (accessed 9/12/2020).
[28] Mostefa Ouki, "Egypt - a Return to a Balanced Gas Market?," *Oxford Institute for Energy Studies*, (2018).

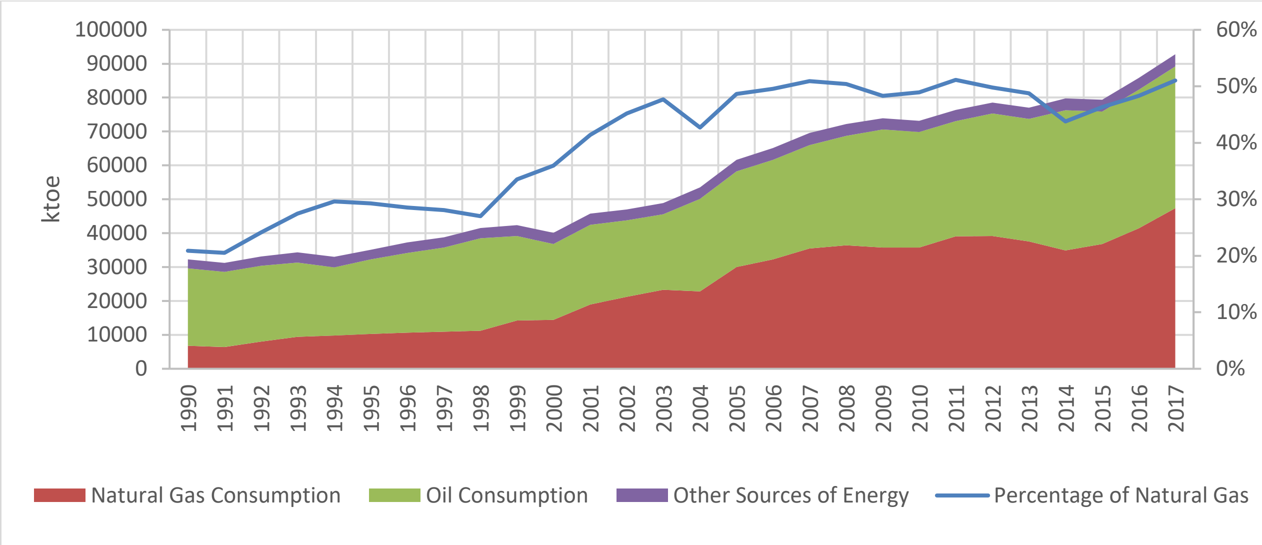

Figure 10 : Egypt Total primary energy consumption per source and percentage of Natural gas 1990-2017[29]

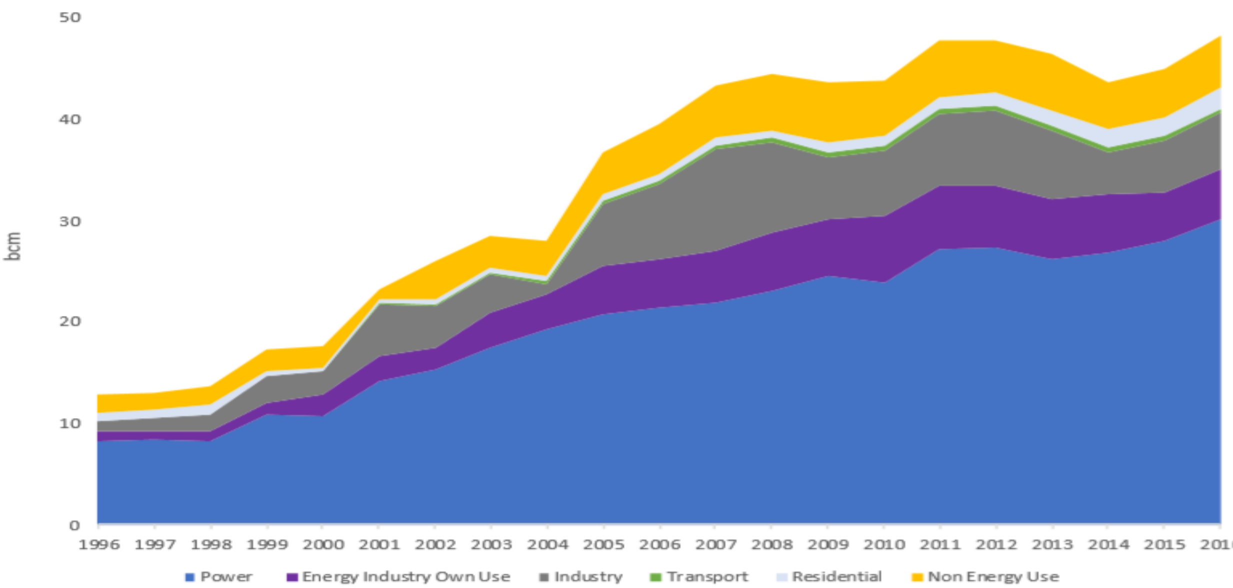

Figure 11 : Natural gas consumption by sector 1996-2016 source IEA2017

Thus any future balance of natural gas in Egypt will heavily depend on the growth of the power sector. Figure 12 shows how Egypt had increased its installed capacity for electricity generation from 29 GW in 2012 to more than 55 GW in 2018. In the years 2017 & 2018 the installed capacity for electricity generation has increased by around 38 %. This jump should lead to a sharp increase in the natural gas in the following years until 2020 then a normal increase of natural gas consumption of a rate of around 3% yearly can be applied to forecast the consumption profile of natural gas in Egypt. This scenario is applied to propose the consumption profile given in Figure 13.

[29] iea.com, "Total Energy Supply (Tes) by Source, Egypt 1990-2018" https://www.iea.org/countries/egypt (accessed 9/12/2020).

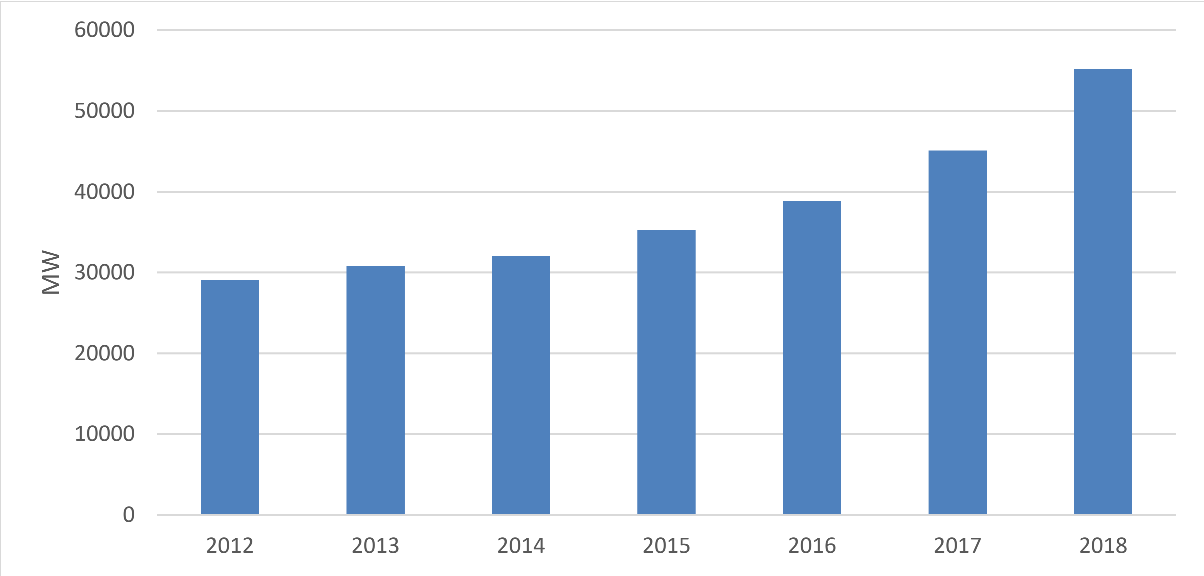

Figure 12 : Installed capacity of electricity generation in Egypt 2012-2018 [30]- [31]

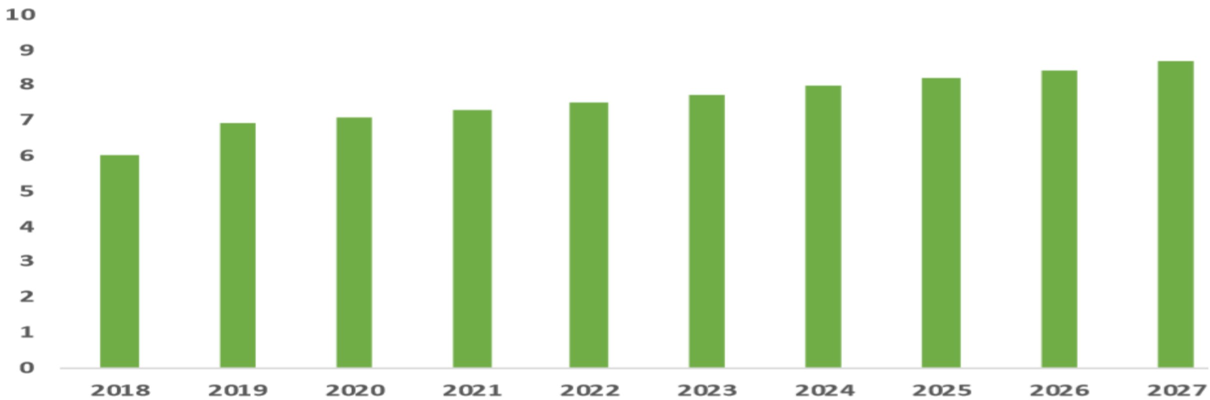

Figure 13 : Natural gas consumption forecast in Egypt (bcf/day)[32]

After comparing the forecast of the natural gas production in Figure 9 and the forecast of the natural gas consumption in Figure 13, one can conclude that Egypt will have to focus on balancing its gas market in the few coming years. The government will concentrate more on covering the shortage in its natural gas demand profile and quantities of natural gas for export will be very little if existed.

As discussed earlier Egypt has natural gas exportation facilities with a large capacity, 19 bcm/year of LNG, 7.5 bcm/year via Al-Arish Eshkon pipeline, and 10 bcm/year via the Arab Gas Pipe line. All these exportation facilities would become out of service if the country will not find enough quantities for exportation. Therefore the government is promoting the option that Egypt can play the role of a regional gas hub in order to optimize the use of their exportation facilities especially the LNG plants. In other words while the country is trying to balance between its domestic

[30] Egyptian Electricity Holding Company, *Annual Report 2017/2018* (2018).
[31] Egyptian Electricity Holding Company, *Annual Report 2015/2016* (2016).
[32] Ouki, "Egypt - a Return to a Balanced Gas Market?."

production and consumption, it is trying also to import additional gas quantities in order to export them again via its LNG plants. This option has been attractive for all the regional countries that has new gas discoveries and face a problem to build their own exportation facilities, especially for Cyprus and Israel.

In September 2018 Cyprus and Egypt signed an agreement to construct an offshore natural gas pipeline to transport the Cypriot gas from Aphrodite field to Egypt to be exported via the Idku LNG facility.[33] The planned pipeline capacity is 8 bcm/year.[34] After all the idea of this pipeline is challenged with the plan of east-med pipeline, the project which is signed in January 2020 as an agreement between Cyprus, Israel and Greece to export the east Mediterranean gas directly to Europe via an offshore pipeline instead of exporting it as LNG via the Egypt.

On the other hand Egypt signed a deal with Israel to export the gas from Tamar and leviathan gas field via the offshore pipeline between the two countries[35]. In January 2020 the exportation has started. A private firm in Egypt, Delphinus Holdings, will purchase 85 bcm of gas, worth an estimated $19.5 billion, from Israel's Leviathan and Tamar offshore fields over 15 years. Gas from Leviathan will be supplied to Delphinus at a rate of 2.1 bcm per year, rising to 4.7 bcm per year by the second half of 2022, according to Delek.[36]

[33] George Psyllides, "Cyprus, Egypt Sign Gas Pipeline Agreement," *Cyprus Mail*2018.

[35] David Wainer and Yaacov Benmeleh, "Israel-Egypt $15 Billion Gas Deal Boosts Energy Hub Prospects," *Bloomberg*2018.

[36]Aidan Lewis and Ari Rabinovitch, "Update 2-Israel Starts Exporting Natural Gas to Egypt under Landmark Deal," *Reuters*2020.

Turkey Natural Gas Profile

In the last decade Turkey emerged as an unavoidable regional power after the dramatic changes in its internal and external policies. Natural gas is a key factor in shaping the role of Turkey as an emerging power which has a strong economy and a decisive regional role. With a unique geographical position between two continents, Turkey is located on the crossroad between main natural gas suppliers in Caucasus, central Asia and Middle East on one hand and the European Union as a great natural gas consumer on the other hand. This location has motivated the Turkish ambition to become a natural gas hub or at least a transit country which can promote its position on the geopolitical map. Besides, the great economic growth of the Turkish economy, and its large dependence on imported energy and mainly natural gas, have risen the energy security policy to the top of the country's interests. Therefore studying the natural gas profile of Turkey should be addressed from two points; Turkey as a huge natural gas consumer, and Turkey as a potential natural gas transit hub.

The rapid economic growth of Turkey in the last two decades had boosted its consumption of energy. As shown in Figure 14, the energy consumed in Turkey quasi doubled in the last two decades. Also in the same figure it can be noticed that the main sources of energy in Turkey are coal, oil, natural gas, and other renewables. The role of each energy source has also changed by time.

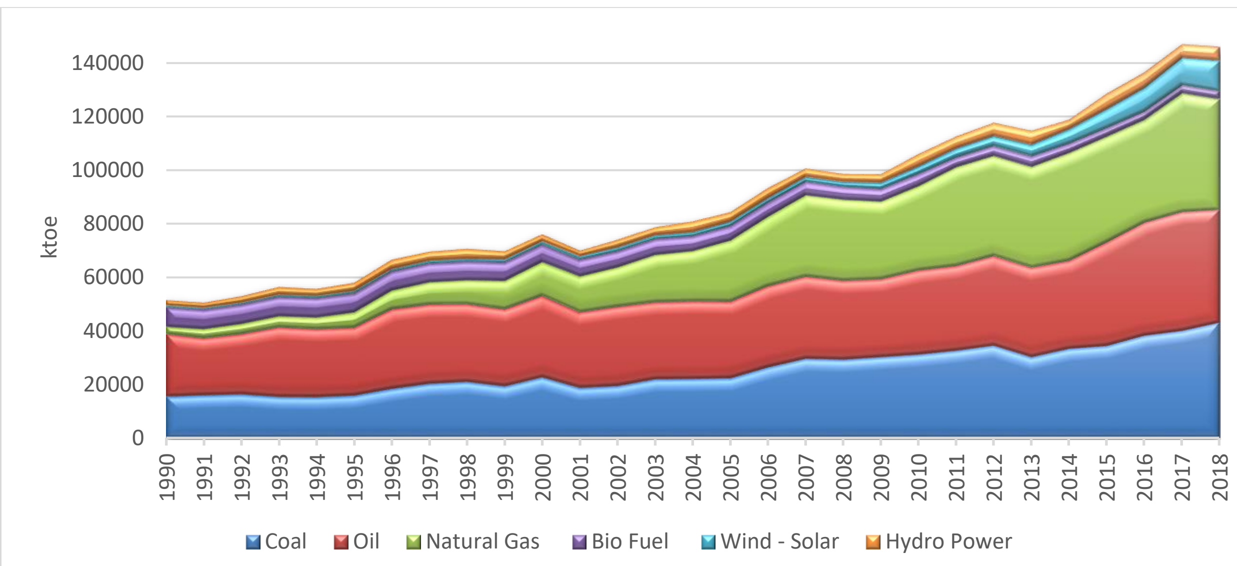

Figure 14 : Total Primary Energy Supply by source in Turkey in the last three decades[37]

Figure 15 shows that Turkey is always depending on domestically produced lignite coal to cover about 30% of its energy need. The portion of oil has decreased from about 45% in 1996 to about 30% in 2017. Also the portion of renewable sources has decreased. While the dependence on

[37] International Energy Agency, "Turkey Key Energy Statistics, 2018" https://www.iea.org/countries/turkey (accessed 9/5/2020).

natural gas has increased from about 6% in the beginning of the 90's to reach one third of the total country consumption in the last decade.

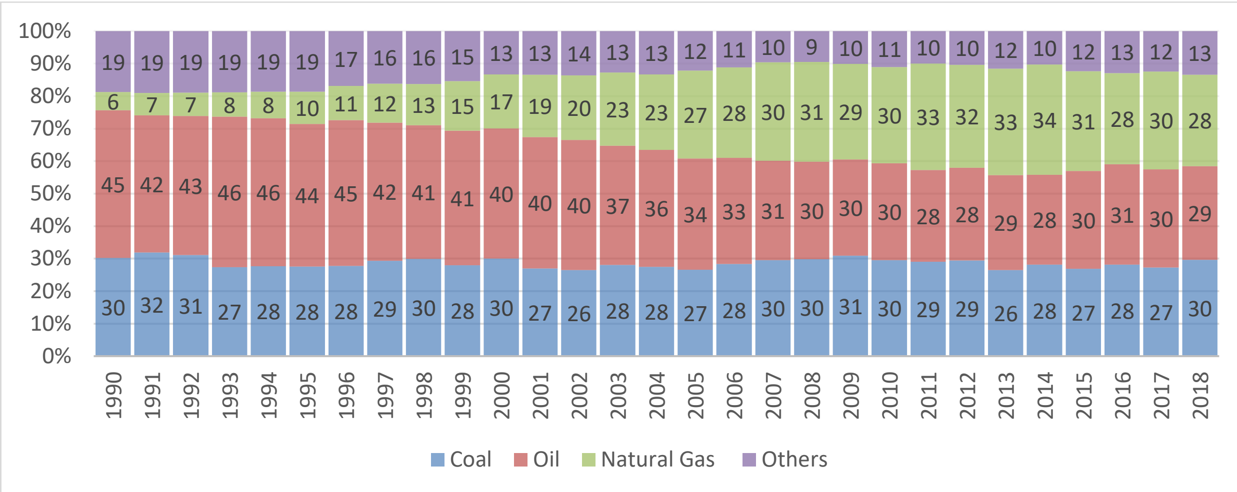

Figure 15 : Percentage of each energy source in the Turkish Total primary energy supply.

Turkey imports two thirds of its energy demand and almost all its natural gas demand. Until the end of the last decade, the proven natural gas reserves in Turkey was almost negligible in comparison with the consumed quantities as shown in Figure 16. In august 2020, Turkish President Recep Tayyip Erdogan has announced the discovery of a large natural gas reserves off the Black Sea coast. The Sakarya field in the Black Sea is estimated to hold 320 bcm size equivalent to about 11 tcf. The Turkish president announce later that the production from this field will start in 2023. Although it seems as an exaggerated ambition but if achieved it is expected to provide Turkey with 7% of its Natural gas needs.

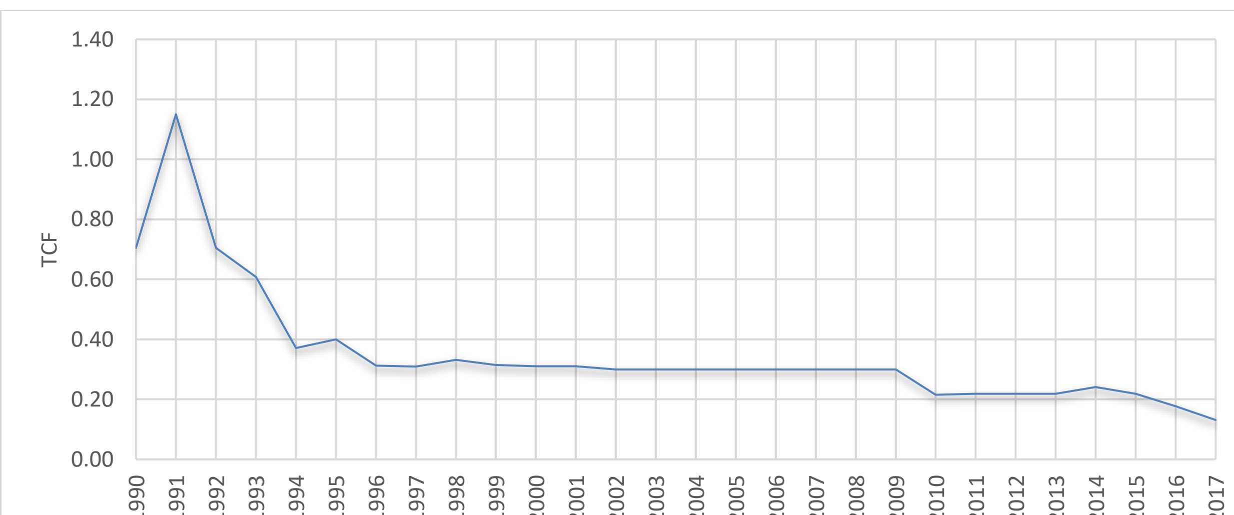

Figure 16 : Turkey Natural Gas Proven Reserve[38]

[38] World meters, "Turkey Natural Gas" https://www.worldometers.info/gas/turkey-natural-gas/ (accessed 9/5/2020).

Figure 17 shows the consumption vs the production of natural gas in Turkey over the last three decades. It is clear that the production is negligible and that Turkey depends totally on importing natural gas. Turkish gas consumption increased rapidly in the 2000's and almost tripled between 2000 and 2014 then it stabilized for two years before hitting a new upper record in 2017 and finally it decreased steadily in the last two years of the last decade.

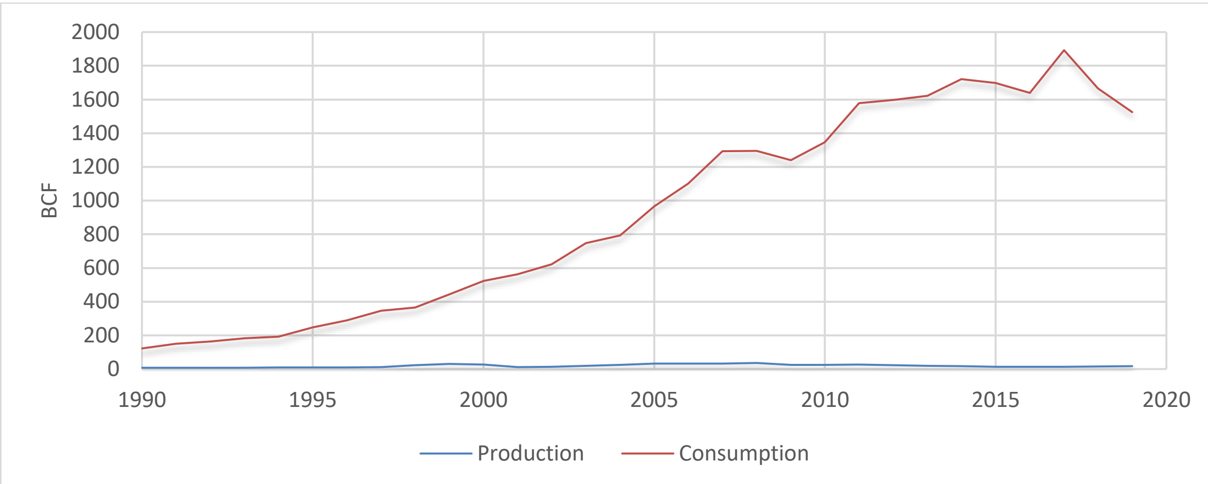

Figure 17 : Natural Gas production Vs Consumption Profile in Turkey[39,40,41]

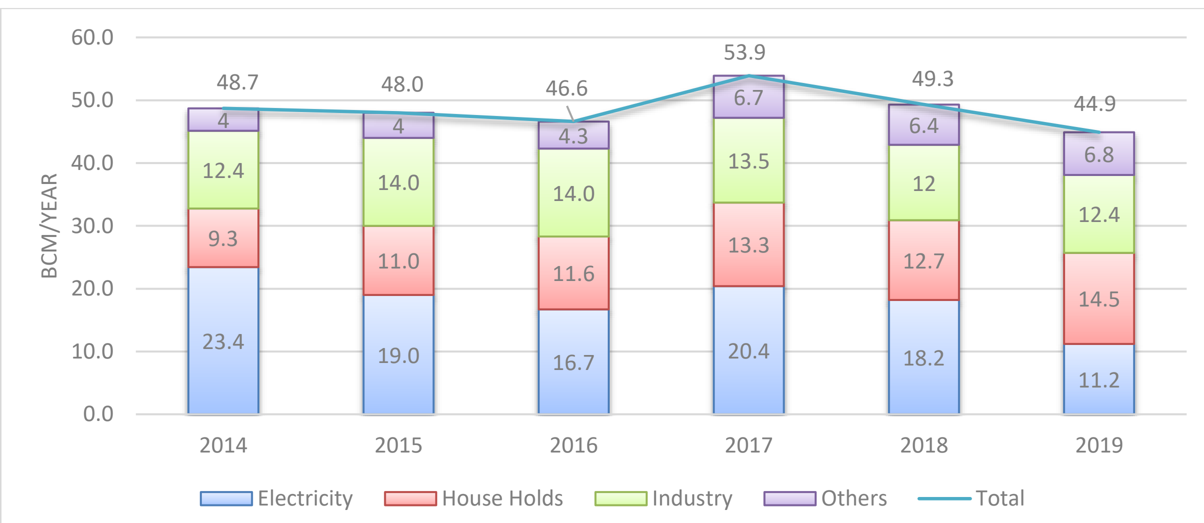

Figure 18 : Annual Comparison of Sectoral Consumption of Natural Gas in Turkey[42,43]

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[39] Ibid.

[40] Statista.com, "Natural Gas Consumption of Turkey 2005-2019" https://www.statista.com/statistics/703684/natural-gas-consumption-turkey/.

[41] CEIC data, "Turkey Natural Gas: Annual: Production" https://www.ceicdata.com/en/turkey/energy-statistics-natural-gas/natural-gas-annual-production#:~:text=Turkey's%20Natural%20Gas%3A%20Annual%3A%20Production,Cub%20m%20mn%20for%202018. (accessed 9/8/2020).

[42] EMRA, *Turkish Natural Gas Market Report 2017* (ENERGY MARKET REGULATORY AUTHORITY, 2018).

[43] GAZBIR, *2019 Natural Gas Distribution Sector Report* (2019).

Gas consumption in Turkey is mainly divided on three main sectors, gas fired electrical power, industry and households. The high reliance on imported gas and the huge increase in gas consumption pushed the Turkish government to rethink its energy policies. Turkey took serious decisions to reduce the portion of imported natural gas from the energy mix of the country. In its published energy strategy in 2009[44], Turkey stated clearly the aim of responding to the growing electricity demand while avoiding increasing dependence on imported fuels. Instead, the country counts on fully utilizing its indigenous hard coal and lignite reserves, hydro and other renewable resources such as wind and solar energy to meet the demand growth in a sustainable manner. Integration of nuclear energy into the Turkish energy mix will also be one of the main tools. The same objective was also announced in vision 2023 published in 2010 where it is specified that Turkey should rely on renewables to cover 30% of the electricity demand and on coal to cover another 30% and 10% by nuclear power and the rest may be covered by imported gas. The effect of these policies appears in Figure 18 and Figure 19 where it can be seen how the amount of gas used in electricity generation has decreased starting from 2014 to be to reach almost half of the value of 2014 in 2019. This decrease of gas consumption in the electricity sector has decreased the total gas consumption of the country.

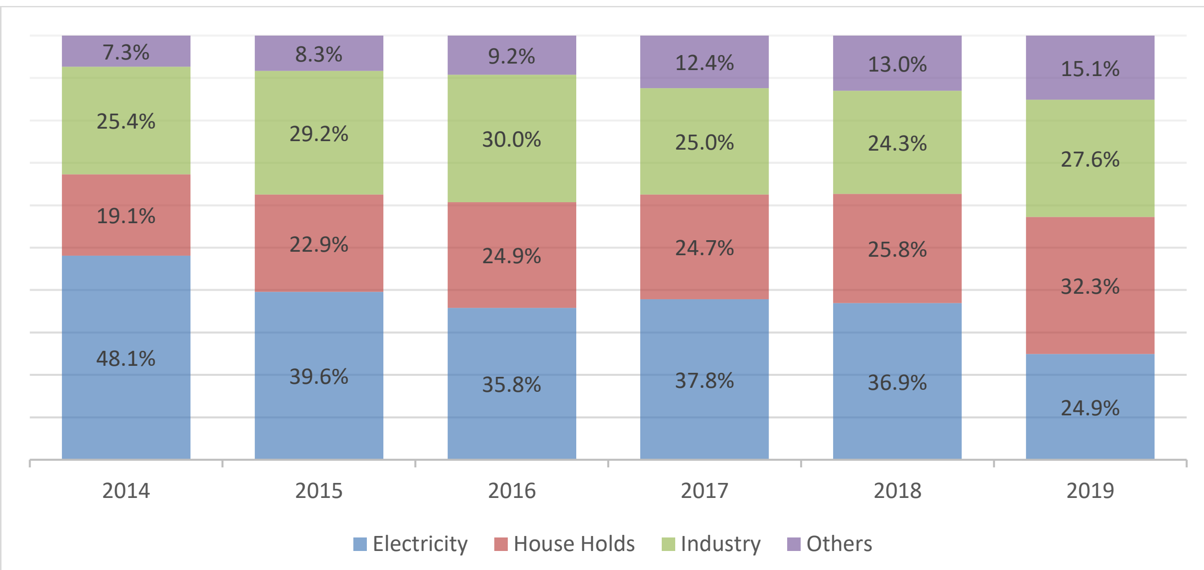

Figure 19 : Percentage of each consumption sector in the total natural gas consumption profile of Turkey.

Unlike the electricity sector the consumption of natural gas in residential households is increasing due to the increase in population and to the extension of the gas residential distribution network. As shown. As shown in Figure 20, the population of Turkey is increasing in a rate of 1% yearly, while the distribution network is growing rapidly to cover about 80% of the population. That led to a growth in the number of subscribers on in the network and obviously an increase of the natural gas residential end users which reached 66% of the total population in the end of 2019. Thus the residential sector consumption has increased from about 19% in 2014 to reach almost one third of

[44] REPUBLIC of TURKEY, *Turkey's Energy Strategy* 2009.

the total gas consumption of the country in 2019. The growth of consumption in this sector will continue in the next decade with the growth of population and the advances in the distribution network to cover new provinces.

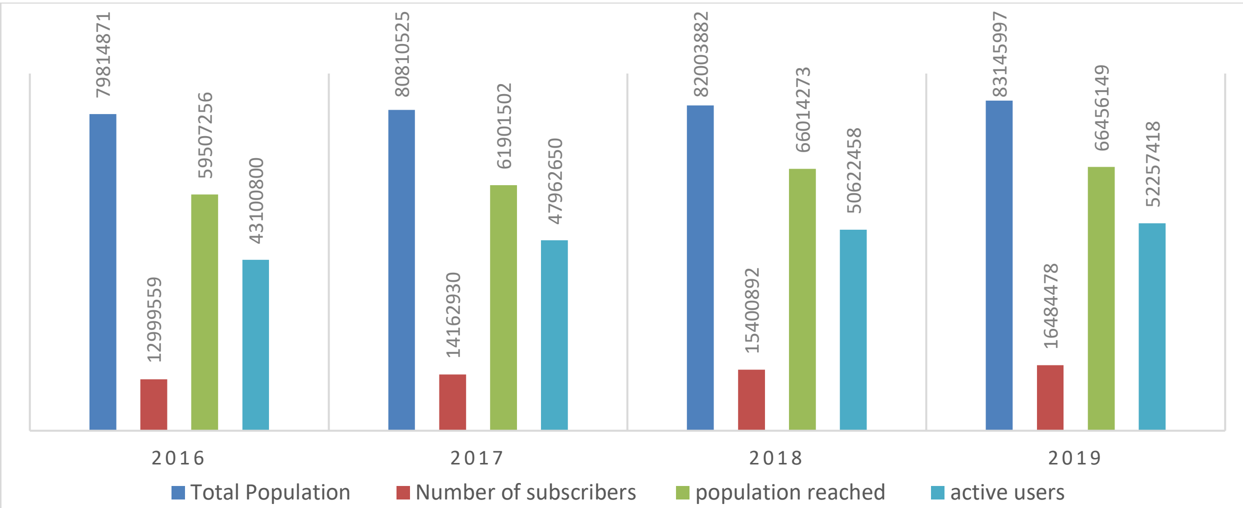

Figure 20 : Evolution of residential active subscribers and users in Turkey 2016-2019[45,46]

Industry is the third natural gas consumer sector, the growth of consumption in this sector is related to the country's GDP and the external and internal political stability. In the beginning of the last decade, according to the projection of gas consumption growth that time, Turkey was expected to reach very high consumption rates by the end of 2030. An OIES paper in 2014 predicts that the gas demand in Turkey would 67–70 bcm/year by 2030, contradicting BOTAŞ forecast in 2012 that projected demand would reach 81 bcm/year[47]. These changes in the gas consumption driver sectors in the last decade has changed the forecast projections of the Turkish gas consumption for the next decade. Razyeva in 2017[48] expected that the gas consumption in Turkey in 2030 will not exceed 62 bcm/year. As he justified that the growth in residential and industrial sectors will be neutralized by the decrease in the gas demand for electricity sector.

Turkish natural gas consumption is almost totally imported. Turkey import natural gas from several sources via pipelines and LNG. The main portion is imported due to long term contracts with Russia through the Blue Stream and Trans-Balkan lines, from Azerbaijan through the Baku-Tbilisi-Erzurum line, and from Iran through the Tabriz-Dogubayazit route. Also Turkey has two long term contracts to import LNG from Algeria and Nigeria, while the shortage is covered by midterm contracts and spot LNG. The characteristics of these contracts are detailed in Table 1. Figure 21 and Figure 22 shows that Russia has been always the main exporter of natural gas to

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[45] GAZBIR, *Natural Gas Distribution Sector Report* (2018).

[46] GAZBIR, *2019 Natural Gas Distribution Sector Report*.

[47] Gulmira Rzayeva, "Natural Gas in Turkey Domestic Energy Market : Policies and Challenges," *The Oxford Institute For Energy Studies*, (2014).

[48] Gulmira Rzayeva, "Turkey's Gas Demand Decline: Reasons and Consequences," *The Oxford Institute For Energy Studies*, (2017).

Turkey with a ratio between 50% and 60% of the total Turkey's imports except in 2019 where the Russian gas imports to Turkey has hit a minimum with 15 bcm and only 33%. Besides, Turkey has increased its LNG imports to benefit from low LNG prices in 2019 to cover the shortage of natural gas with spot LNG. Imports from Iran have been stable with some perturbations in supply especially in peak seasons. Imports from Azerbigan have been stable. The increase detected in 2019 is related to the arrival of the first imports from Shah Deniz 2 (2 bcm in 2018, 4 bcm in 2019)[49] .

Agreements	Volumes (bcm/y)	Date of signature	Duration (years)	Date effective	Expiry Date	Status
Algeria (LNG)	4	14-Apr-88	20	1994	Oct-24	In operation. Renewed and capacity increase to 5.4 bcm/year
Nigeria (LNG)	1.2	9-Nov-95	22	1999	Oct-21	In operation
Iran	9.6	8-Aug-96	25	2001	Jul-26	In operation
Russian Fed. (Blue Stream)	16	15-Dec-97	25	2003	End of 2028	In operation
Russian Fed. (Trans Balkan)	8	18-Feb-98	23	1998	End of 2021	In operation
Turkmenistan	16	21-May-99	30	-		
Azerbaijan (SD Phase-I)	6.6	12-Mar-01	15	2007	Apr-21	In operation
Azerbaijan (SD Phase-II)	6	25-Oct-11	15	2018	2033	In operation
Azerbaijan BIL	0.15	2011	35	2011	2046	In operation

Table 1 : Turkish Natural gas Purchase Contracts[50].

[49] Rasana Gasimova, "Socar: Tap to Be Commission by Late 2020" https://www.azernews.az/oil_and_gas/161795.html.

[50] Ole Gunnar Austvik and Gülmira Rzayeva, "Turkey in the Geopolitics of Natural Gas," *Harvard Kennedy School Mossavar-Rahmani Center for Business & Government* M-RCBG Associate Working Paper Series | No. 66, (2016).

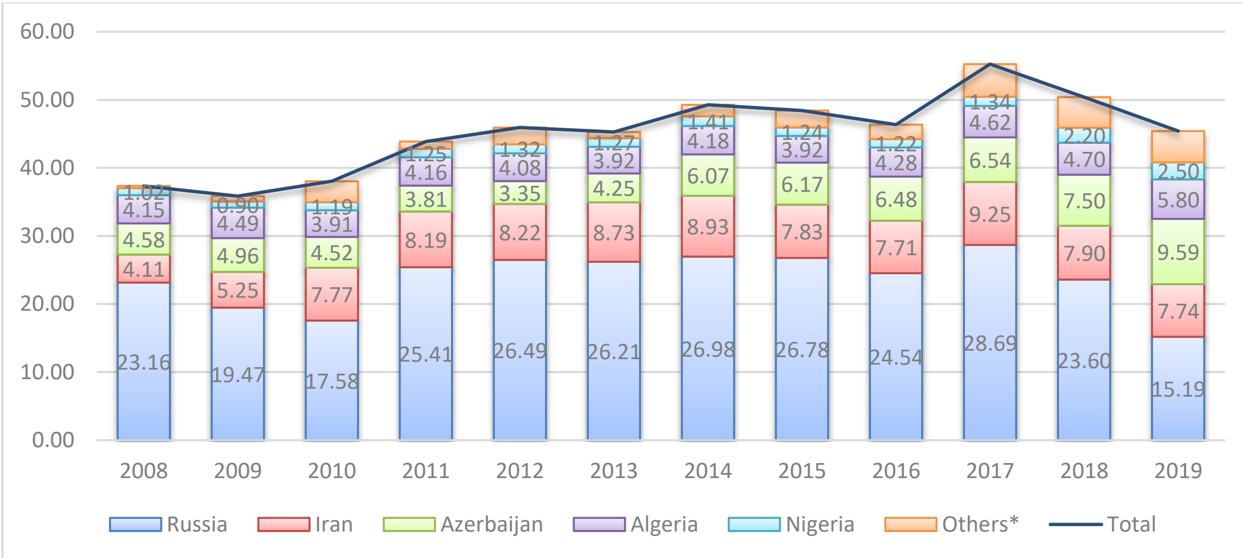

Figure 21 : Natural gas imports to Turkey by country of origin between 2008 and 2019 [51,52,53]

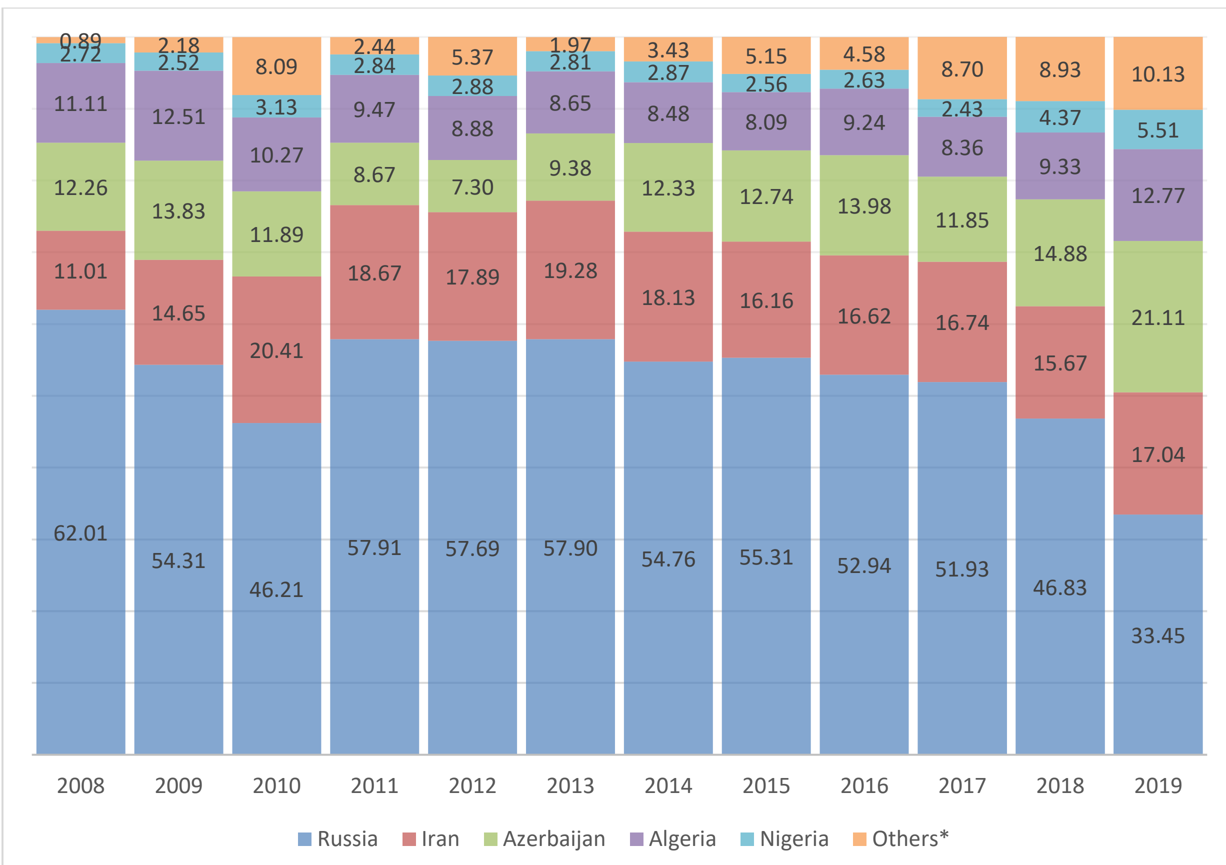

Figure 22 : Percentage of each source in the Turkish natural gas imports 2008-2019.

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[51] EMRA.

[52] British Petroleum, *Bp Statistical Review* (2019).

[53] British Petroleum, *Bp Satistitical Review*

Till the end of the last decade Turkey did not export large quantities on the way of its ambition of becoming a natural gas transit country. Turkey has started natural gas export to Greece with the completion of Turkey-Greece Natural Gas Interconnector 2007. But since then the exported quantities ranged between 1% and 2% of the imported quantities. This is mainly because almost all the imported quantities were consumed locally. However, this figure is about to change by the beginning of the new decade. Shah Denis 2 added 16 bcm of natural gas per annum from which 6 bcm started to supply Turkey from 2018 while the other 10 bcm will flow to the European consumers via Trans Anatolian pipeline (TANAP) that cross the Turkish territory then via the Trans Adriatic Pipeline (TAP). According to Vitaly Baylarbayov, the Azerbaijani state energy company SOCAR's deputy vice president for investment and marketing, TAP will start to carry gas to European markets as by the end of 2020. He noted also that a contract of 25 years has been signed to supply Turkey with 8 bcm and Bulgaria and Greece with one bcm each.

Another large step for Turkey on the road of being a transit country was in January 2020 when Turkey announced the launch of the Turk stream project with Russia. Turk stream replace the project called south stream which was initially planned to transmit the Russian gas to south Europe under the black sea. In 2016 after military clash between Russia and Turkey on the Syrian borders the two sides made the deal to build the Turk stream pipeline. The Turk Stream project will consist of two parallel pipelines with a total capacity of 31.5 bcm per year (15.75 bcm each)[54]. One is projected to fulfill the Turkish domestic gas demand and mainly to replace the Trans Balkan pipeline in a way that the Russian gas would bypass Ukraine. And the other is projected to feed southeastern and central European markets via Bulgaria, Serbia, and Hungary. Gazprom began gas deliveries to some markets via Turk Stream in January 2020 using partially completed and existing infrastructure[55]. The second stage of the project (Turk stream 2 or the European part) which will take the gas from the Turkish borders into Europe is not ready yet. Bulgarian officials estimate completion, by mid-2020, of around 295 miles of the pipeline that crosses the country and connects to Serbian infrastructure. Serbia's 250-mile segment of pipeline is reportedly complete. In June 2019, Serbia and Hungary reached an agreement to construct trans-border infrastructure; at the time, Hungarian officials stated that construction would begin in mid-2020[56]. But this part of the project is threatened by the American sanctions[57] because it would deepen Europe's reliance on Russian natural gas, and reduce Ukraine's role as a transit state.

For the next decade, comparison between the demand forecast with the supply contracts signed to date shows that most long term contracts will expire in 2020's. Figure 23 shows the demand forecast estimated by (Rzayeva, 2017)[58] which is the most recent and modest forecast of demand that takes into account all the new updates of the demand drivers. Moreover, it shows only the

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[54] Turkstream.info, "The Turkstream Pipeline" turkstream.info/project/.

[55] Sarah E. Garding et al., "Turkstream: Russia's Newest Gas Pipeline to Europe," *Congressional Research Service*, (2020).

[56] Ibid.

[57] Matthew Lee, "Us Warns Firms About Sanctions for Work on Russian Pipelines," *The washington post*2020.

[58] Rzayeva, "Turkey's Gas Demand Decline: Reasons and Consequences."

published contracted quantities to date where no clear data is published about the contracted quantity via Turk stream which is already in operation. Turk stream is expected to replace Trans Balkan and have a capacity to supply Turkey with 15 bcm/year. Turkey will not have large challenges in the renewal of most of these long term contracts especially with Azerbaijan where the two countries are on good relations. For Iran, the renewal will be an interest for both sides because Iran needs to export its gas. Russia can deliver gas to Turkey with the full load of Turk stream. So with taking these renewals into account a large part of the gap will diminish as shown in Figure 24 and the rest can be covered with LNG mid contracts and spot LNG. Then Turkey will not have a supply energy security issue but this doesn't deny that Turkey has the interest to diversify its natural gas sources portfolio and break the full dependence on Russia and Iran. Moreover Turkey will always welcome new quantities discovered in the eastern Mediterranean to pass through it and not directly to Europe. The thing that can reinforce its position as a transit gas hub for the European Union.

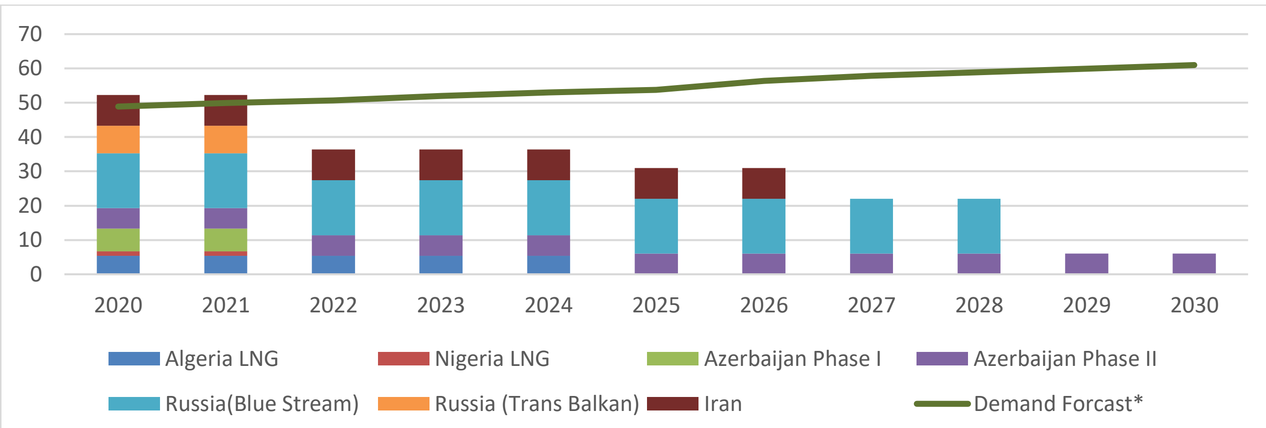

Figure 23 : Forecast of demand vs contracted quantities of natural gas in Turkey 2020-2030

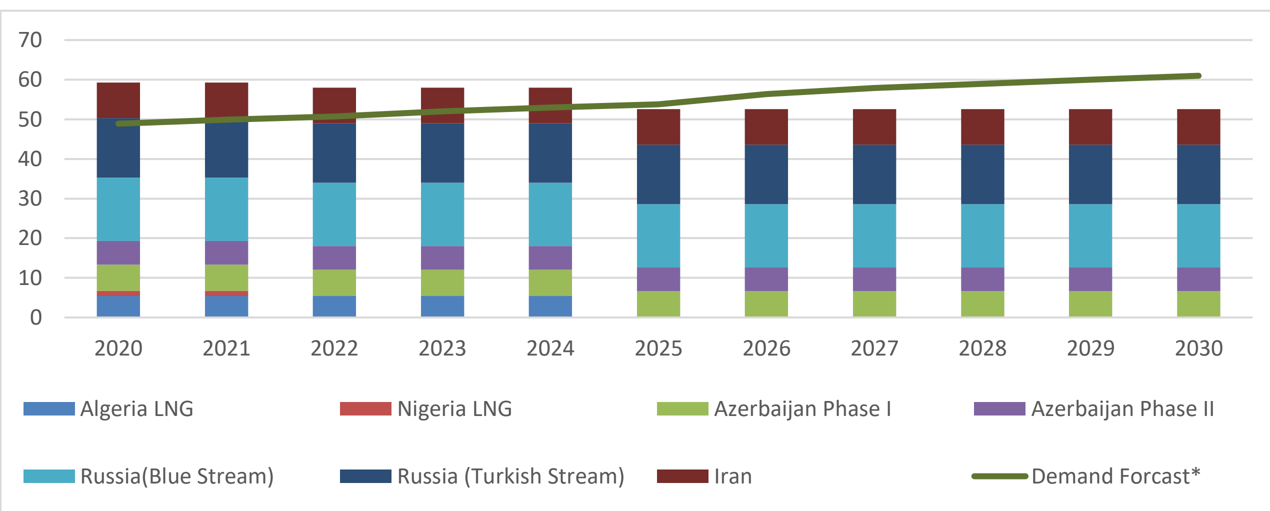

Figure 24 : Forecast of demand vs contracted and renewed quantities of natural gas in Turkey 2020-2030

Israel Natural Gas Profile

In the middle of the last century, few years after occupying palastine, the israelian regime has started to look for hydrocarbon reserves in the occupied land. No significant discoveries have been noted until 1999 with the discovery of the first offshore natural gas discovery called Noa. Few monthes later in 2000, a second discovery was announced with a relatively large natural gas field called Mari-B which contained a reserve of 25 bcm. This was considered a turning point for the energy profile of the country. To that date natural gas was not used resources in the energy profile of the country as shown in Figure 24.

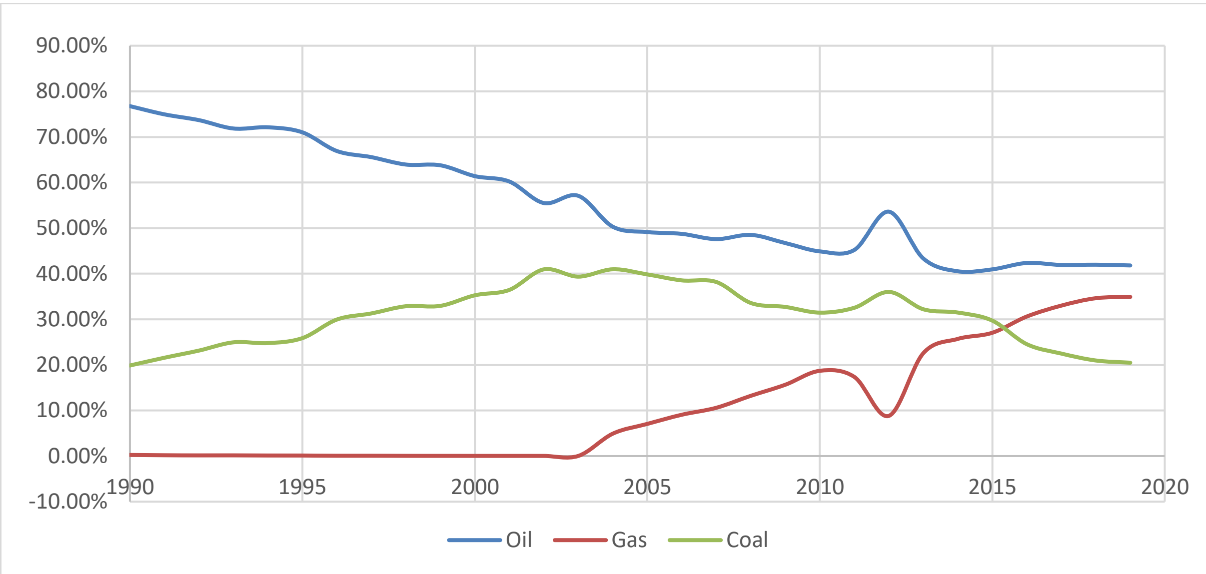

Figure 25 : Percentage of each energy source in the total primary energy supply in Israel in the last three decades[59]

The production in Mari –B started in 2004, despite its limited size it played a major role in Israel strategy to transit from heavy fuels to clean burning electricity production[60]. From that date natural gas had progressively become a main source in the energy profile of the country by increasing from less than 1% in 2003 to reach more than one third of the total energy consumption in 2018. Then starting 2004, the gas consumption increase steadily and electricity generation is the main consumer beside a relatively small portion for the industry. In fact, the industrial sector started progressively to rely on natural gas as shown in Figure 26. This increase in the domestic demand was covered by various supply sources. Mari-B first was the only source for natural gas then in 2008 Israel started importing natural gas from Egypt through the Eastern Mediterranean Gas pipeline "EMG". In 2010 the Egyptian gas imports covered about 40% from the Israeli Domestic demand, but this supply was perturbed after the so called Egyptian revolution and due to the dramatic change in the Egyptian gas profile which turned Egypt into a gas importer.

[59] iea.com, "Total Energy Supply (Tes) by Source, Israel 1990-2019" https://www.iea.org/countries/israel (accessed 9/19/2020).
[60] David Wurmser, *The Geopolitics of Israel's Offshore Gas Reserves* (2013).

One year before, the energy sector in Israel had its second huge turning by the discovery of the huge gas field called Tamar in the beginning of 2009 with a reserve of 282 bcm.

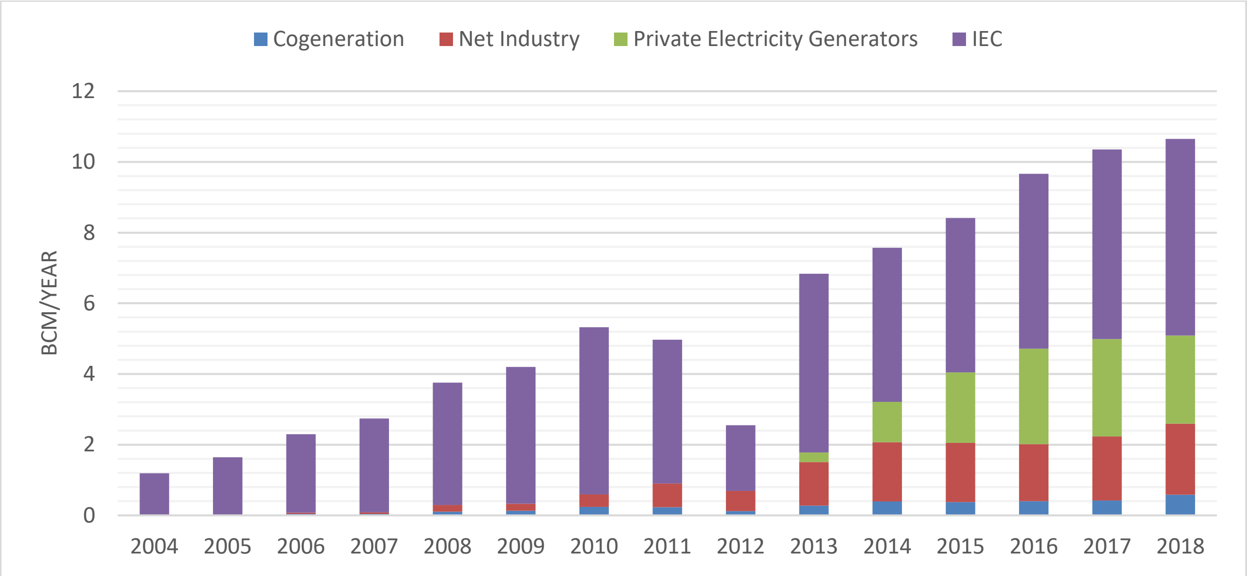

Figure 26: Natural Gas consumption by sector in Israel 2004-2018[61]

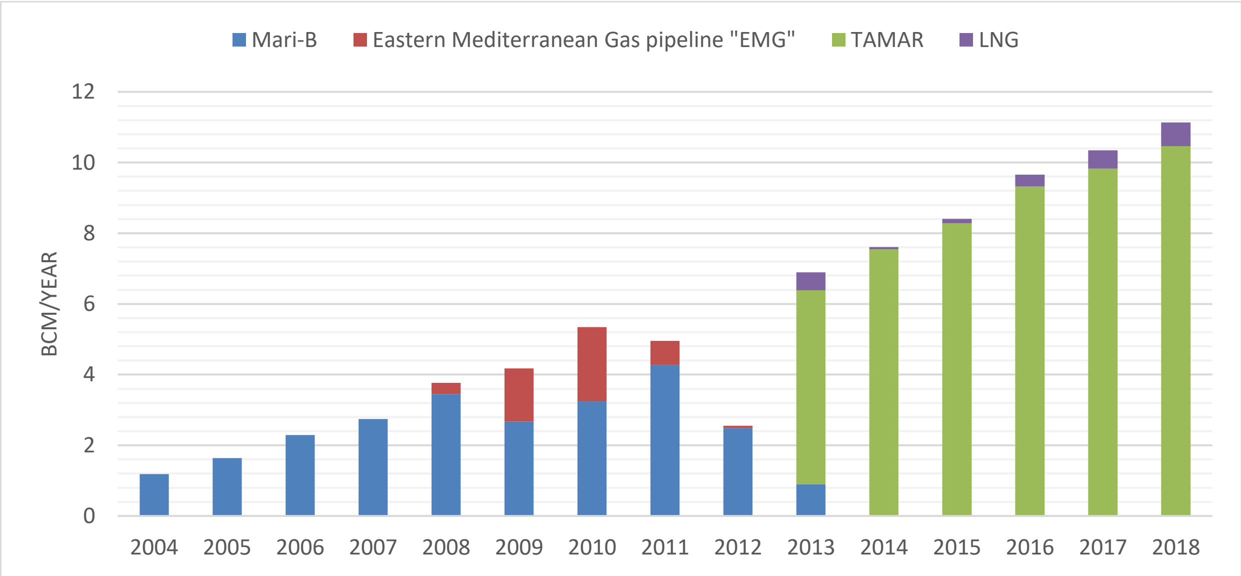

Figure 27 : Natural Gas supply by source in Israel 2004-2018[62]

As shown in Figure 27 the production from Tamar has started 4 years after its discovery and it intervene to cover almost all the domestic demand from 2013 to 2019. Only small shortages between Tamar supply and domestic demand was covered by importing small LNG quantities. In 2019, the Tamar reservoir provided about 10.48 bcm, close to 93 percent of the total supply for the consumption which reached 11.25 bcm[63].

[61] Ministry of Energy Israel, *Israel's Energy Sector Review for 2018* (2018).

[62] Ibid.

[63] Sujata Ashwarya, "Natural Gas Discoveries and Israel's Energy Security," *Georgetown Journal of International Affairs*, (2020).

Thus at the end of the last decade, Israel had succeeded to balance its natural gas domestic demand with its natural gas production, moreover it was ready to become a gas exporter. Israel proven gas reserves ranges between 26 and 30 tcf (750 to 950 bcm). The main large discovery was the giant reserve called Leviathan, two years after the discovery of Tamar, with a reserve more than 500 bcm. Then further discoveries had followed as the reserve of Karish, Shimshon, and Tanin etc. These fields are shown on the map in Figure 28.

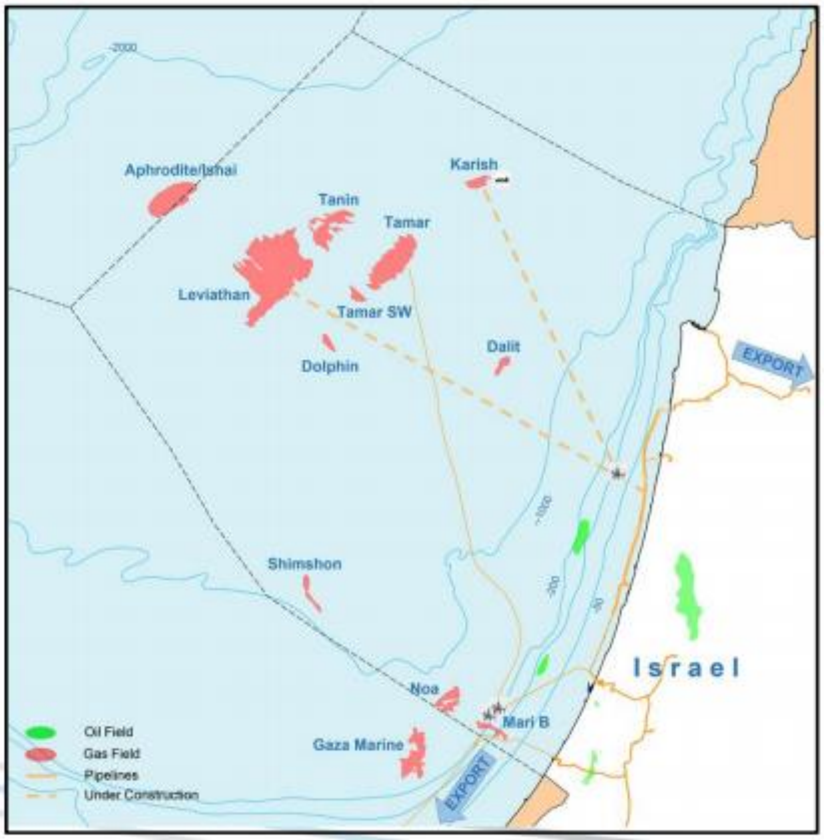

Figure 28 : The Discovered Offshore gas fields as published by the ministry of energy in Israel [64](Note that the northern boundary of the EEZ is disputed with Lebanon and the figure represents the Israeli version of the borders).

As published by recent report of the ministry of energy in Israel the estimated sizes of the remaining Natural gas fields is about 900 bcm as shown in Table 2. The production from Leviathan has started at the last day of 2019. It has the capacity to produce about 12 bcm/year and was expected to 9.3 bcm in 2020 and 10.8 bcm in 2021 but these estimates reduced due to the decrease in demand in the era of covid-19 to become 7 bcm in 2020 and 8.9 bcm in 2021[65]. This will add 70 to 80 percent to the gas production, the added quantities will be exported.

Small gas exports from Israel's Tamar field to Jordan began in 2017 under a deal signed in 2014 to supply 1.8 bcm over a period of 15 years to Jordan's Arab Potash Company and the Jordan

[64] Ministry of Energy Israel, "Oil & Gas Opportunities Offshore Israel," in *Global Appex 2019* (London: 2019).
[65] kallanishenergy.com, "Israel's Leviathan Gas Field Production Hit by Declining Demand" https://www.kallanishenergy.com/2020/07/21/israels-leviathan-gas-field-production-hit-by-declining-demand/ (accessed 9/24/2020).

Bromine Company[66]. But this is equivalent to 0.12 bcm/year which is considered negligible to the contracted deals with Jordan and Egypt signed later on.

Supplier		Reservoir size (BCM)	Status
Active reservoirs	Tamar	282	Correct for the end of 2018 – 232 BCM remaining
	LNG	Dependent on demand	
	Total existing reservoirs	+310	
Future reservoirs	Leviathan	500	Active end of 2019
	Karish	32	Active in 2021
	Dalit	14	Unknown
	Shimshon	15	Company returned the license
	Tanin	35	Active in 2021
	Total future	596	

Table 2 : The state of reserves of natural gas reservoirs in Israel in 2018 [67]

As published on the site of the ministry of energy in Israel, the contracted quantities to Egypt and Jordan are listed in Table 3. In January 2020 the exportation to Egypt has started. A private firm in Egypt, Dolphinus Holdings, will purchase 85 billion cubic meters (bcm) of gas, worth an estimated $19.5 billion, from Israel's Leviathan and Tamar offshore fields over 15 years. Gas from Leviathan will be supplied to Dolphinus at a rate of 2.1 bcm per year, rising to 4.7 bcm per year by the second half of 2022, according to Delek.[68] Also Israel has begun pumping the first supplies of Israeli gas to Jordan's National Electricity Company (NEPCO) in the beginning of 2020. These agreed exporting quantities has the sum of almost 8.8 bcm/year, added to the forecast of the domestic gas demand may give an idea about the natural gas profile of Israel in the next decade.

Figure 29 shows the forecast of natural gas production forecast in Israel published in global data, the forecast takes into account the production from leviathan in 2020 then Karish at the end of 2021 then the rest of projected wells developments. Besides the figure shows the demand forecast as projected by the ministry of energy in Israel and the contracted export quantities with Egypt and Jordan. These forecast shows that Israel can cover all the demanded quantities and it will have surplus quantities that increase to reach about 10 bcm/year at themed of 2020's. This obliges Israel to look for new exportation destinations in the near future. Therefore, Israel look forward to expand the natural gas exportation deals with Egypt which has large LNG facilities that can operate on Israeli gas. Moreover Israel has the ambition to export gas to Europe. In February 2020, Israel has signed a deal and an agreement with Cyprus and Greece to construct an offshore pipeline to export natural gas from Greece and Israel to Europe, the pipeline is called EASTMED.

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[66] Stuart Elliott, "Jordan's Lawmakers Approve Draft Law to Ban Israeli Gas Imports" https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/012020-jordans-lawmakers-approve-draft-law-to-ban-israeli-gas-imports-reports.
[67] Ministry of Energy Israel.
[68] Lewis and Rabinovitch.

Country-Customer	Start-up Year	Source	Total Quantity, BCM
Jordan - Industrial facilities at the Dead Sea	2015	Tamar	1.9 (0.067 TCF)
Jordan - Industrial facilities at the Dead Sea.	2019	Tamar	1.24 (0.044 TCF)
Jordan - The National Electric Power Company NEPCO	2017	Leviathan	45 (1.59 TCF)
Egypt - Dolphinus Holdings Ltd.	2020	Leviathan	60 (2.12 TCF)
Egypt - Dolphinus Holdings Ltd.	2020	Tamar	25.3 (0.89TCF)

Table 3 : Natural gas exports already underway or agreed between Israel and Jordan and Egypt[69]

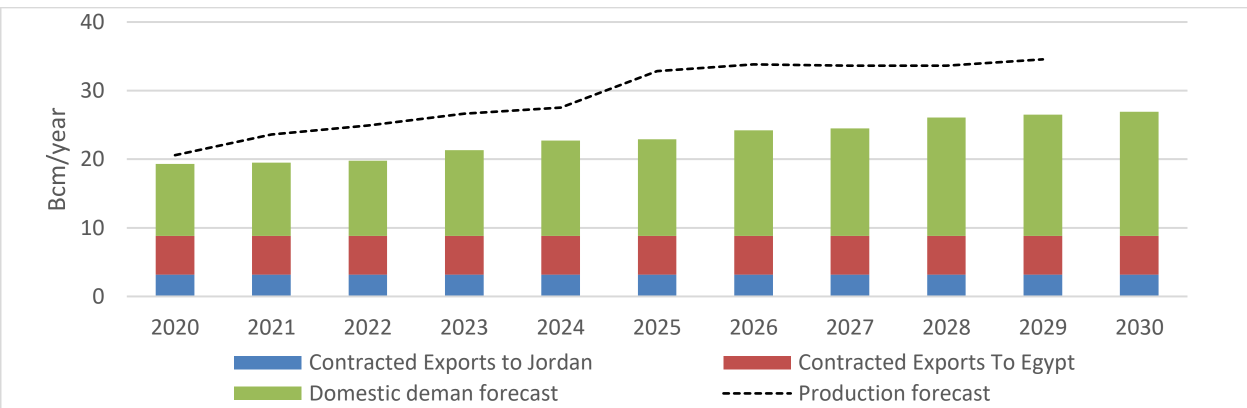

Figure 29 : Natural gas profile forecast in Israel 2020-2030[70,71]

[69] Ministry of Energy Israel, "Gas Markets Exports" http://www.energy-sea.gov.il/English-Site/Pages/Gas%20Markets/Israels-Export-Options.aspx (accessed 9/24/2020).
[70] globaldata.com, "Israel Will Emerge as Gas Exporter in Eastern Mediterranean Region by Mid-2020s" https://www.globaldata.com/israel-will-emerge-as-gas-exporter-in-eastern-mediterranean-region-by-mid-2020s-says-globaldata/ (accessed 9/23/2020).
[71] Ministry of Energy Israel, "Oil & Gas Opportunities Offshore Israel."

The Eastern Mediterranean (EastMed) Pipeline Project is anticipated to start offshore in Israeli economic waters and run 1,900 km offshore and onshore to reach the Greek mainland, via Cyprus and Crete, where it will connect with the Poseidon pipeline linking Greece with Italy. The countries aim to reach a final investment decision by 2022 and have the pipeline completed by 2025. While initially set to transport up to 10 bcm/year from 2025, the pipeline ultimately will have the capacity to transit up to 20 bcm/year of natural gas[72].

[72] Ministry of Energy Israel, "Gas Markets Exports".

Cyprus Natural Gas Profile

The gas discoveries in the Eastern Mediterranean has played a major role in the transformation of the energy sector in Cyprus. Some of the discoveries are located in Cyprus EEZ, large investments have been done in exploration, and production is estimated to begin in the next 5 years. In addition to its own gas discoveries the geographic location of Cyprus as an island in the Eastern Mediterranean and as the south east tip of the European union increase the strategic importance of Cyprus as a connecting node of the eastern Mediterranean gas with Europe.

The majority of the declared blocks in the EEZ of Cyprus has been licensed and the island has passed a long way on its exploration path. The first discovery was Aphrodite gas-field with estimate of 4.45 tcf, in 2011 by Noble Energy and Delek Group. The field is granted commercial in 2015 and Cyprus has granted its exploitation in 2019 to predict that the first production may begin in 2025. However, a part of Aphrodite field is in the EEZ declared by Israel, and the two countries have not reached a resolution on sharing the resources yet. This would affect the timeline to the production date[73]. The next discoveries were in 2017 when Total and Eni explored Onesiphoros west-1 in block 11 and declared it non-commercial with only 0.5 tcf[74]. In 2018 Eni announced the discovery of Calypso gas-field with promising quantities of about 6 tcf since it look geologically similar to the Zohr field off Egypt[75]. In 2019 ExxonMobil and Qatar Petroleum announced the discovery of the Glaucus gas-field estimated to hold 5 to 8 tcf of gas[76].

Nine years after the first natural gas discovery the country now sits on a reserve of about 15 tcf, but this did not affect yet the energy consumption profile of the country. Cyprus still depends totally on heavy fuels in its energy mix. On the contrary the discovery of natural gas played a role in the delay of introducing natural gas into the energy profile of the island. That's because the gas discovery lead to postpone previous plans of the country to build an FSRU unit to import LNG. In January 2020 Cyprus presented its Integrated National Energy and Climate Plan to the European Union in which Cyprus present its future plan for energy consumption and tendency to cleaner energy where natural gas will be a part of the primary energy profile. The plan presented two scenarios to project the primary energy supply till 2030, a scenario with existing measures and another with Planned Policies and Measures. In both scenarios Natural gas should present about 40% of the total energy supply of the country in 2030[77]. Figure 30 shows that in both scenarios the consumption of natural gas is projected to about 30 bcm/year from 2022 to 2030. But since the nearest production date is estimated to be in 2025, in July 2020 Cyprus announced the construction

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[73] NS Energy, "Aphrodite Gas Field" https://www.nsenergybusiness.com/projects/aphrodite-gas-field/#:~:text=The%20Aphrodite%20gas%20field%20is,Tcf)%20of%20recoverable%20gas%20reserves. (accessed 10/9/2020).

[74] subseaintel.com, "Onesiphoros West-1 'Non-Commercial' for Total" https://www.subseaintel.com/news/3912 (accessed 10/13/2020).

[75] reuters.com, "Eni/Total Find Natgas Off Cyprus in Field Close to Zohr" https://www.reuters.com/article/us-cyprus-natgas-idUSKBN1FS1G3 (accessed 10/13/2020).

[76]

[77] Theodoulos Mesimeris and George Partasides, *Cyprus' Integrated National Energy and Climate Plan for the Period 2021-2030* (2020).

of an FSRU terminal in Vassilikos port and the unit is planned to be operational in the end of 2022[78].

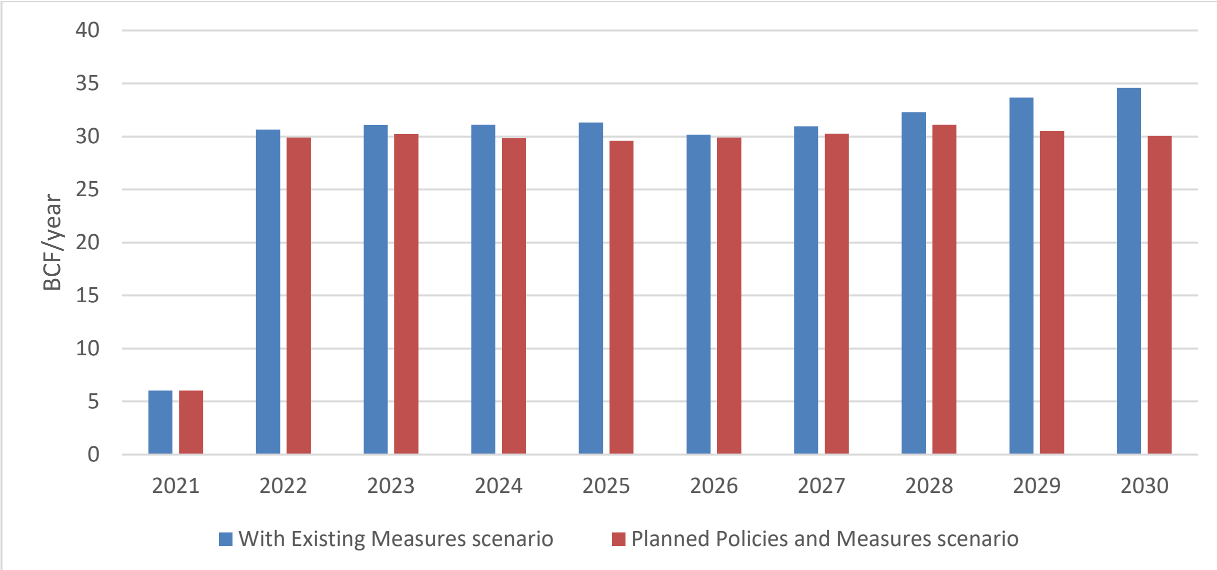

Figure 30 : Projected Natural gas consumption in Cyprus according to two scenarios until 2030

Although Cyprus has not started any natural gas production yet but the country has passed large steps on the way of planning its natural gas exportation routes in the future. As mentioned in the previous section, Cyprus is a part of EASTMED pipeline with Israel and Greece. The offshore pipeline will export natural gas to Europe from Israel and Cyprus. More over in September 2018, Cyprus and Egypt signed an agreement for the subsea natural gas pipeline from the Aphrodite field to Egypt liquefaction plants to be then exported to Europe as LNG[79].

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[78] Gary Lakes, "Cyprus Enters Lng Era with Fsru Groundbreaking at Vassilikos" https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/071020-cyprus-enters-lng-era-with-fsru-groundbreaking-at-vassilikos (accessed 10/15/2020).

[79] offshore-energy, "Cyprus, Egypt Ink Deal for Subsea Gas Pipeline" https://www.offshore-energy.biz/cyprus-egypt-ink-deal-for-subsea-gas-pipeline/ (accessed 10/15/2020).

Geopolitical Over View

The announcement of the discovery of natural gas in eastern Mediterranean occurred in the beginning of the last decade. Also in this decade, countries of the eastern Mediterranean and surrounding countries had witnessed major internal political and major geopolitical events and transformations. One can say that this region has been always a conflict zone while others try to relate every major political event with its trace on the natural gas plan. Both point of views may be right to a certain limit and can present counterarguments to the other one. This paragraph tries to draw a geopolitical overview in order to discover to which limits the two figures are interdependent, who the main players are, and how the overall geopolitical picture has developed in the last ten years.

Until recently most of the Eastern Mediterranean countries was considered poor in natural resources and if it exists it was far from covering the domestic needs. Thus the discovery was seen as internal economical booster for each one of them. Some countries look for achieving their energy security through these discoveries, others looks at the gas as a lever for their struggling economics while others have the ambition to be an energy hub to consolidate their position on the political map. These ambitions give the discovery an important national dimension for each of these countries.

Eastern Mediterranean region is located in the heart of the Middle East. The region that has been always arena for a regional and international players. The conflict has been always built on two pillars first the Palestinian issue and what the security of Israel presents for some international players, second the interest of international player in the hydrocarbon resources in the gulf region. Now natural gas enters as a new subject of conflict. Several regional players compete for control and influence over the region. As a first rank, Israel, Turkey, and Iran are the three major regional powers. After them one can notice a role for Egypt and Arab gulf countries. Thus the discovery of natural gas has a regional dimension on the agenda of each of these powers.

Beside these national and regional dimensions, the eastern Mediterranean gas has an international dimension due to its location close to Europe, one of the largest gas markets in the world. Although the discovered quantities till now cannot be considered as a game changer in the gas market but it seems that the discoveries are still modest with respect to the gas potential that the region holds. The discovered quantities till now are about 16.4 tcf in Israel, 9.2 tcf in Syria, and about 10 tcf in Cyprus, this gives the total of about 36 tcf which is modest if compared to Azerbaijan with 100 tcf for example[80]. However, the assessment performed by the United States Geological Survey in 2010[81] on the Levant Basin Province says that the basin contains around 122 tcf of natural gas to be discovered. If this is added to the 75 tcf proven reserves of gas in Egypt, it will become a game

[80] British Petroleum, *Bp Satistitical Review*

[81] U.S. Geological Survey (USGS), "Assessment of Undiscovered Oil and Gas Resources of the Levant Basin Province, Eastern Mediterranean."

changer when compared to 5.2 tcf[82] which represents the Russian exports of natural gas to Europe in 2019. From here, the gas in this region may play a role in the Russian European natural gas relations dilemma. As a consequence natural gas in the region attracted the attention of Russia, EU and the US.

This creates a complicated multidimensional geopolitical figure that needs first a careful dismantling of the interdependent components by identifying the obvious interest of each player. Then, the second step is to figure out how these interests intersect and contradict in the sake of drawing the whole geopolitical figure of the region. To do so, the next paragraphs will review the interest of each player alone, then review the major events that occurred in the last decade to form the actual situation.

Starting from the international dimension, the outer frame lines of the problem can be drawn. The geographic location of the eastern Mediterranean gas on the counter coast of the Mediterranean facing the European shores give it the potential to play a role in the European Russian natural gas dilemma. This role viewed by the European Union as an opportunity, is also viewed by Russia as a threat. This rapid overview paragraph, does not allow to detail the well-known Russian European gas problem, its baseline will only be used to build on. The baseline can be summarized by the interdependency between them.

Europe depends largely on the Russian natural gas imports which is considered as a threat of its energy security and it has been trying for decades to break this dependency by diversifying its natural gas portfolio. For the EU the energy supply is a security question. The question for the EU countries is whether they can have sufficient energy supplies, and how securing these supplies can reach the European market. EU plans to avoid strategic dependence on Russia, this tendency appeared clearly after several crisis in natural gas supplies due to Russian problems with the transit countries such as Ukraine and Belarus. The dependency on the Russian gas varies from one European country to another thus they didn't achieve a gas policy for the whole union. The thing that prevented the EU from reaching internal agreements on financing alternative pipeline projects. Southeast and Central Europe are almost exclusively dependent on Russian gas. Therefore the Mediterranean gas has an importance for these countries due to its proximity. As mentioned previously the discovered gas quantities till now might not be enough to achieve the desired independence but at least it could put pressure on the price of Russian pipeline gas. Therefore Europe will always be the ultimate destination for the Mediterranean gas.

On the other hand the Russian economy depends largely on the exports to Europe. Besides, Russia uses energy as a powerful tool to achieve its political and strategic influence. Any alternative source for natural gas in Europe is always seen by Russia as a threat. For this Russia has put major pressure on the natural gas from the Caspian Sea region to prevent any break of its gas dominance.

[82] Andres Mäe, "European (Energy) Security and Russian Natural Gas," *International Center for Defence and Security EESTI-Estonia*, (2020).

As the discovery of the eastern Mediterranean gas popped up, Russia tried to enter the region in several ways. The escalation of the military and political presence of Russia in Syria gave it and advanced site on the shore of the eastern Mediterranean. Besides the Russian companies tried to establish a foot hold in the gas profiles of all the countries of the region. In Cyprus, Russian companies Novatek and GPD Global resources had placed bids in the second round of licensing but were unsuccessful. In Israel, Gazprom wanted to have a stake in the Leviathan field but didn't succeed, also Gazprom signed a letter of intent with Tamar partners to export LNG but didn't materialize. In Syria, a Russian state control company has the exploration and production license in block 2. In Egypt, Rosneft acquired 30% stake in Zohr, and a Russian controlled investment fund, Letter One, inherited 35% in West-Nile Delta Project"[83]. In Lebanon, the Russian company Novatek owns 20 % of the consortium that is licensed for the exploration in blocks 4 and 9. Although the Russian aim behind these movements is not declared, but one can guess that Russia tries to have an influence on the direction, volumes, and prices of the natural gas that will be produced in the region.

After the EU and Russia that have direct relation with the issue, comes the US that may have also an indispensable role. The American companies may present a modest economic interest for the US in the region. The interest of the US is due to security reasons since Turkey is a part of NATO and Israel is a key ally. But the main interest may be to contain the Russian role in the region and to prevent the rise of any Russian hegemon in Eurasia.

Israel is one of the most powerful countries in the region, it passed large steps on the gas march all in discovering producing and even exporting. Israel does not show a will to transform its economy to depend on natural gas nor building big gas projects like LNG due to economic and security reasons. Also Israel doesn't aspire to become an energy hub. But the Israeli policy shows that Israel wonts to benefit from its gas to build strong economic relations with the surrounding countries. Thus from the early stages Israel started its talks with potential regional markets and succeeded to have exportation deals with Jordan and Egypt. Also it started talks with Cyprus and Turkey to construct common exportation infrastructure. These talks discussed constructing a common LNG in Cyprus, the project that have been abandoned later on. They discussed also a pipeline to Turkey that also has been abandoned. Finally Israel succeeded to reach a deal with Cyprus and Greece to build a huge pipe line project, the East med pipeline to export gas to Europe. Egypt has also a major role in the Israeli plan that wants to use the Idle Egyptian LNG. Finally this work leads to the birth of a gas alliance in the region called the Eastern Mediterranean Gas Forum "EMGF".

The EastMed Gas Forum (EMGF or EGF) is an international organization formed by Cyprus, Egypt, Greece, Israel, Italy, Jordan, and Palestine. It was established as an international body on 16 January 2020 with headquarters located in Cairo, Egypt. The forum is a regional energy

[83] André B. Dorsman, Volkan Ş. Ediger, and Mehmet Baha Karan, *Energy Economy, Finance and Geostrategy* (Springer, 2018).

organization on the model of OPEC that will work, according to its announcement, to complete or reinforce the implementation of the provisions of the United Nations Convention for the Law of the Sea (UNCLOS), including the elaboration of a regional treaty in order to regularize the exploitation of marine resources to protect the environment. But as it appears, the forum is the first forum of declared alliance over the energy issue in the region. This alliance is backed by the US and EU, as France and the United States asked to join the Forum, as a member and permanent observer respectively[84]. This western backup may suppose that the alliance will try to form a consolidated entity to face any Russian attempt to exert pressure on each of these states to take decisions that align with the Russian interests.

Beside the interstate gas contracts between the states of this alliance, the alliance exportation strategy can appear from the steps achieved in the last decade. Instead of affording the high expenses of building exportation infrastructure in each country alone, the alliance will depend on two main exportation infrastructures that are already built or to be built in collaboration between them. The alliance depends mainly on the LNG units in Egypt that have been put idle for several years. Here Egypt has the potential of being an LNG hub benefiting from its location on the Mediterranean and proximity to Europe and its location on the Suez Canal to export LNG to the Asian market. Israel and Cyprus looks to benefit from these LNG plants instead of building LNG plants on their territories. The other main exportation way, is East Med pipeline with an initial capacity of 10 bcm/year and planned to have a capacity of 20 bcm/year in a second phase. This capacity may be high to be fulfilled by one country so the alliance counts on filling it from Israel, and Cyprus and may be Egypt later on.

The alliance is considered as a challenge to other countries in the region. Countries like Lebanon and Syria that don't have the choice to join such a forum, because of their persisted state of war with Israel, will see themselves with minor capabilities competing with an alliance. Viewing the recent emergences in the region with respect to the normalization of relations between Israel, and a number of Arab countries, one can expect that the forum will put these countries under the pressure of joining it or pay the expenses of developing their gas profile without support.

However, Syria and Lebanon are considered to have low gas profiles in comparison with Turkey. In other words, the alliance now is mainly challenging Turkey which see it as a block that could jeopardize Turkey's interest in the region. Although Turkey is not rich with natural gas, but Turkey has started a long journey to be a gas hub for Europe benefiting from its position between Middle East and central Asia from a side and Europe from the other side. This Turkish ambition was backed up from the western alliance at the first place, with the plan for Nabucco pipe line and the talk about the southern corridor that brings the gas from Azerbaijan and Turkmenistan to Europe. The Nabucco pipe line was then cancelled due to several reasons. One of these reasons is that Trans Caspian pipeline was canceled due to the dispute over the Caspian Sea where Iran and Russia argue that it is a lake and it is not subject to the sea demarcation laws. The cancelation of Trans

[84] Reuters.com, *France Asks to Join Eastern Mediterranean Gas Forum* (2020).

Caspian pipe line prevented Nabucco from reaching the gas sources in Turkmenistan. In addition, Nabucco project had faced financial and political problems. In the last two decades, Turkish-European relations witnessed several tensions due to the failure of Turkey's efforts to join the European Union. This is in addition to the internal political change that Turkey witnessed after the Justice and Development Party took control of the government, and worked on turning the Turkish external policies toward the east and then its endeavor to intervene in the region's countries to restore something of its role during the Ottoman Empire. Turkey is always a member in NATO and an important ally for the US, this makes the Turkish relation with the west complicated. On the other hand, Turkey has a complicated Relation with Russia, the two players compete on different stages of the region from central Asia to the Syrian war where the situation leads them to high levels of tensions and direct confrontation between their armies. In contrast to this complicated competing relations, the two countries could reach good relations and agreements regarding the natural gas, they even use natural gas agreements to settle other serious conflicts. For example the two countries reach the deal over the Turkish stream just after the Turkish forces shot down a Russian SU-24 fighter jet near the Syrian border.

Regarding to the eastern Mediterranean gas, Turkey's interest can be summarized to prevent the direct pass of large quantities to Europe through the Mediterranean, which can reduce the European need for the southern corridor leading to weakening Turkey's opportunity to become a gas hub. Therefore Turkey tried to bring a part of this gas to pass through its pipelines. For example Turkey started talks with Israel to build pipeline that bring natural gas form Israeli fields to Turkey. But later on, Israel deprioritize this track and worked on the track of EASTMED pipeline and the alliance with Egypt and Cyprus. Turkey has political problems with both the Republic of Cyprus (ROC) and with Egypt. Thus, Turkey looks at EMGF alliance as a try to isolate it. Thus, Turkey attempt to put obstacles on this route, to prevent Eastern Mediterranean gas to reach Europe without its accordance. Turkey claims that the maritime demarcation agreements signed by ROC with other countries are null, first because Turkey does not recognize ROC, and these agreements does not represent the Turkish Cypriot population. Also, Turkey claims that the Cypriot maritime activities in the west of the island may overlap with the Turkey's continental shelf. On another level Turkey hurried to sign a maritime deal with Libya, the agreement on the demarcation of the continental shelf zone boundaries between the two countries within the Eastern Mediterranean. Besides, Turkey benefits from the instability in Libya to strengthen its influence there. The thing that gives Turkey the upper political hand over a complete longitudinal section of the eastern Mediterranean that elongates from its shores to the Libyan shores. This section may be used by Turkey to cut the route of the EASTMED pipeline.

As seen in this rapid overview the geopolitics of the natural gas in the eastern Mediterranean is complicated and still evolving with time. To date, the birth of EMGF as an alliance backed by Europe and the US is witnessed. On the other side, no recognized complete steps towards a gas alliance backed by Russia are detected, but this doesn't neglect the huge Russian influence and presence in the region. Meanwhile, the Turkish policy seems complicated between being a NATO member but feels to be isolated from an alliance backed by the west. This may push Turkey for more collaboration with Russia, or negotiations to enter the alliance in a way that conserve its interests.

Conclusion

As a conclusion the natural gas profile in the region has witnessed major developments in the last decade. Countries are working on their gas profiles as consumers, exporters, or even gas hubs. Every country has certain developments and Lebanon seems to be late in comparison to all its neighbors. In addition, a gas alliance was born and Israel is the main member in it which may narrow Lebanon possibilities of finding markets or at least cooperating with most of the regional countries. In the following, the conclusions of each country and its position with respect to Lebanon are detailed.

Jordan has now a sum of 200 bcf / year contracted quantities of natural gas from Israel and Egypt. Also, Jordan has an FSRU to import natural gas as LNG to cover any shortage of natural gas if any interruption occurs to the supply quantities. But depending on the forecast of electricity demand in Jordan, it seems that Jordan will be in need to contract new quantities of natural gas before the end of this decade. This is true if the kingdom keeps relying on natural gas in its electricity sector and doesn't have major improvements on its nuclear or renewable energy projects. Jordan is also a part of the East Mediterranean Gas Forum, and noting that the country doesn't have any potential to become a gas producer in the near future, it can be concluded that Jordan is joining the forum as a consumer. So, will the position of Jordan in this alliance entail any placements on the country to import natural gas only from other members of the forum? Or can Jordan contract new quantities from other countries such as Lebanon. As a conclusion Jordan will be a potential market for the Lebanese natural gas, but it will not be easy to reach such a market since the country had already contracts and infrastructure with Israel and Egypt and the country had already joined a gas alliance that Lebanon cannot be a part of it.

After a perturbed path, Egypt seems to reach finally a clear natural gas profile. The country could finally rebalance its natural gas production and consumption. With the growing population and the rise in living standards Egypt will focus on covering the additional needs of natural gas and there will remain little quantities for export. Egypt has exportation infrastructure that has been put idle after the country was not able to produce enough natural gas quantities for exportation. These infrastructure are mainly the Arab gas pipe line that reach Syria and Lebanon passing through Jordan with a capacity of 10 bcm/year, also Egypt has two LNG plants with a capacity of 19 bcm/year. These infra structure and mainly the LNG plant make give Egypt the potential to be a natural gas hub. Egypt is also a member of the EMGF, it try to achieve its goal of being a gas hub through this forum. Israel and Cyprus aims to use the LNG plants in Egypt instead of building LNG plants on their shores. Israel has already started exporting 2.1 bcm/year natural gas to Egypt and the quantity is expected to rise to 4.7 bcm/year. Cyprus and Egypt signed agreement to construct pipeline of capacity 8 bcm/year to export natural gas from Cyprus to the LNG plants in Egypt. But these quantities are challenged by the ability of Cyprus to have enough quantities especially after the project of EASTMED pipeline. After all Lebanon can also benefit from the Egyptian exportation infrastructure by renting the Arab gas pipeline or even use the LNG plants. Since the Egyptian LNG plants can still accommodate more quantities, even with the contracted imports from Israel and Cyprus.

Israel is the only country that reached production in the Levant basin. Exploration, production and exportation have developed rapidly. The Israeli planned for a gas master plan that divides the produced gas between the domestic development and exportation. They already contracted to export quantities to Jordan for domestic consumption and to Egypt to be re-exported via LNG. They also started the project of EASTMED pipeline to export Israeli and Cypriot gas to Europe. Israel, the enemy of Lebanon, benefits the most from every delay in the Lebanese natural gas profile. This benefit is not limited to the exploration of the fields on the maritime borders that may have extensions to the Lebanese EEZ. But, every retardation gives also Israel the chance to sign contracts with the countries of the region without any competition. Israel is a main member of the EMFG and tries to benefit most by turning this alliance into a political lever over all the countries of the region. Israel will have more production than the sum of its consumption and the signed contracts till now. Thus, it will try to have more contracts with new costumers before the end of this decade.

Cyprus started developing its natural gas profile. It passed some steps in the exploration and have now proven gas reserve. Production is estimated to begin in 2025. For the exportation, Cyprus followed the same steps as Israel. It will try to use the Egyptian LNG plants beside the East med project pipeline. Lebanon should explore the possibility of cooperating with Cyprus in the light of its commitments to Israel.

Turkey should be regarded from two point of views. Turkey the huge gas consumer, and Turkey the ambitious country that want to be the gas hub for every natural gas passing to Europe. Both profiles will make the Lebanese gas important for Turkey. It may need to import the Lebanese gas for local consumption especially with its policy to diversify its gas sources. Turkey would also work on bringing the Lebanese gas through its territories if Lebanon is willing to export gas to Europe. So it is a possible market or a transit country

Chapter Two: Analysis of the Exportation Scenarios

Introduction

All the exportation scenarios for Lebanon should be examined from a technical, economical, commercial and geopolitical point of view. Starting from the geographic location of Lebanon, one should analyze the possible regional and universal markets. All Lebanese neighbors are already gas producers or have the potential to be a gas producer. From Syria to Iraq to Iran to the Arab gulf countries they are all classified as countries rich with oil and gas. As shown in Figure 31, Jordan would be the only country in the region that may have an energy shortage to be a possible market of the Lebanese natural gas. Thus Lebanon should look to possible markets out of the region. The main reachable global gas markets for Lebanon would be Europe and the Asia pacific region from India and China up to Japan and South Korea in the Far East. Europe can be reached through two techniques pipeline or LNG whereas the Asian market could be reached only by LNG.

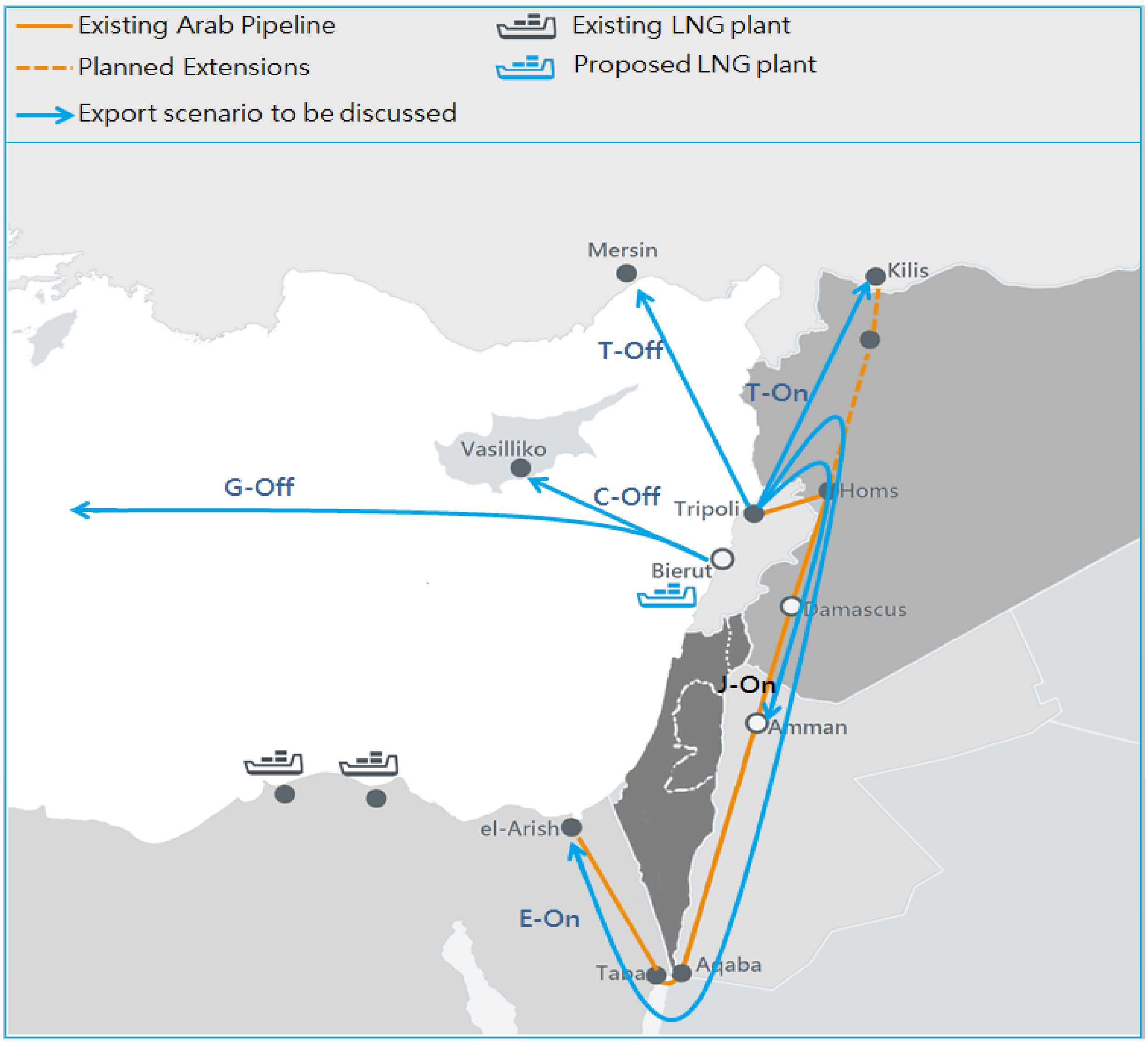

Figure 31 : Representative map of the possible exportation scenarios for the Lebanese natural gas.

To reach these markets several exportation techniques are possible but the analysis will only tackle exportation via pipelines or via LNG. Figure 32 presents the scenarios to be studied showing the technique of exportation to be implemented, the destination market, and the transit countries through which these pipelines will pass. A reference name has been given to each scenario to be used this section of the report.

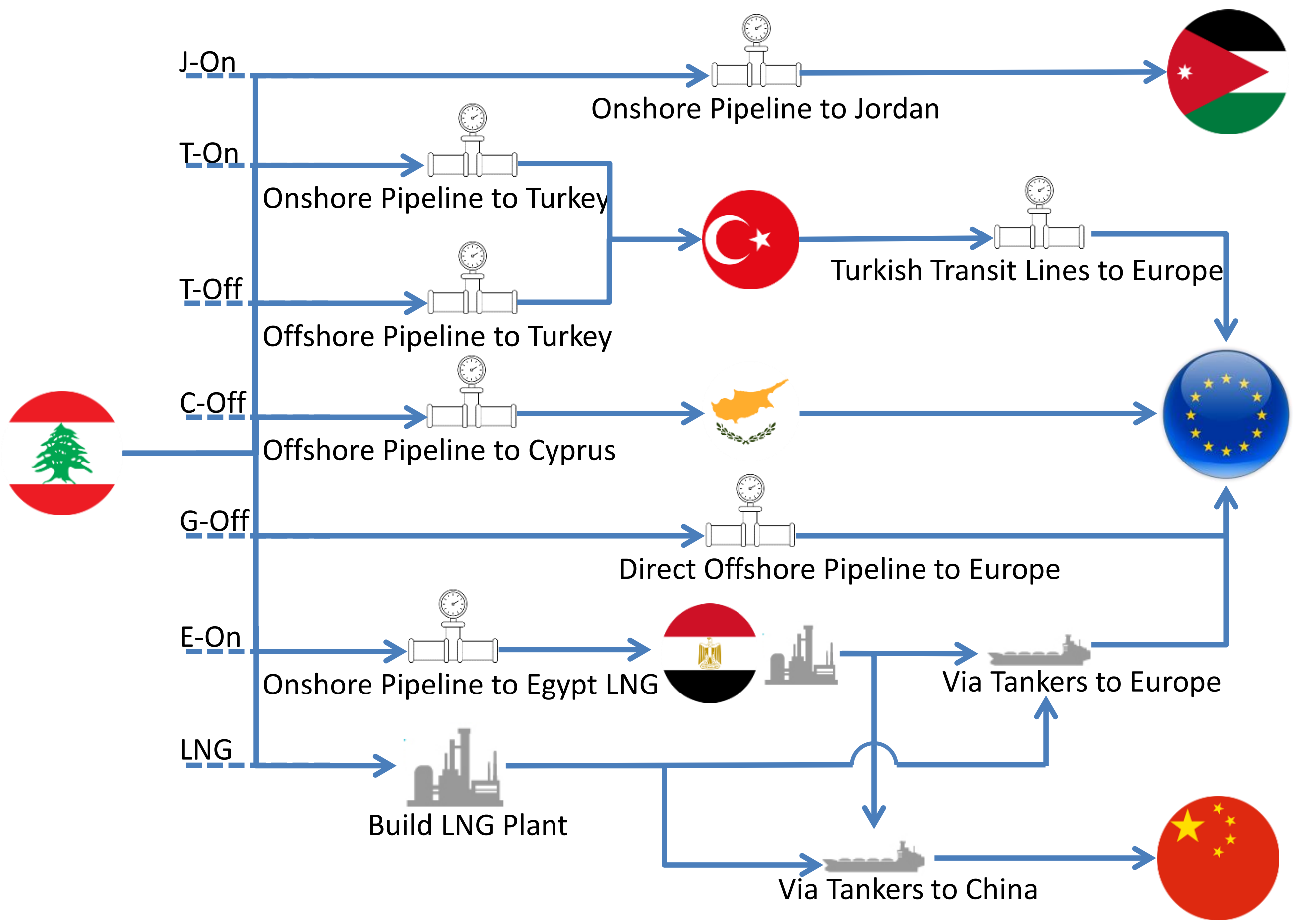

Figure 32 : Exportation scenarios to be studied.

J-On scenario presents the option to deliver the Lebanese natural gas to Jordan for the Jordanian domestic use as final destination. The pipe line starts in Tripoli and uses the section from Tripoli to Homs that already exist in the Arab pipe line, then from Homs to Damascus to Amman. The pipeline length is estimated to be parallel to the existing Arab pipeline. As the Arab pipeline already exists, another option will be discussed is renting this part of the pipeline. The renting option condition will be discussed later and a new option will be added for it named **J-On-Rent**.

T-On scenario presents the option to deliver the Lebanese natural gas via on-shore pipeline to Kilis on the Syrian Turkish borders via Homs and Aleppo. The link between Homs and Kilis was already proposed as an extension to the Arab pipeline but it was not achieved. Also the pipeline length for this option is estimated via the existing data for the Arab pipeline.

T-Off scenario presents the option to reach the Turkish coasts from Tripoli via an offshore pipeline at Mersin since it is considered a gas domestic hub in the Turkish domestic pipeline network. The pipeline length is estimated roughly using the map.

C-Off scenario is the option to deliver the Lebanese natural gas to the Cyprus coast via an offshore pipeline at Vasilikos Power Station. The pipeline length is estimated roughly using the map. This length may vary slightly according to the starting point of this pipeline at the Lebanese coast, thus Beirut being a midpoint is selected as start point.

G-Off scenario presents the option to deliver the Lebanese natural gas to Greece directly on the coast of south Peloponnese where the gas can be linked to the network that feed Europe. The length of this offshore pipeline is estimated through the data published about EASTMED[85] pipeline project about the links from Cyprus to Crete to Peloponnese, while the length of the first part from Beirut to Cyprus is taken as the one in C-Off scenario.

E-On scenario presents the option to deliver the Lebanese natural gas to Egypt from Tripoli to Homs to Damascus to Amman to Aqaba to Taba to reach finally el Arish. This onshore pipeline is exactly parallel to the Arab pipeline in the reverse direction. The objective here is to reach the LNG facilities in Egypt. Here also the option of building a new pipeline is considered beside the option of renting the Arab pipeline and a new scenario is proposed and named **E-On-Rent**.

[85] NS Energy, "Eastern Mediterranean Pipeline Project," (2020). https://www.nsenergybusiness.com/projects/eastern-mediterranean-pipeline-project/ (accessed 3/16/2020).3/16/2020)

Discounted cash flow method

The Lebanese natural gas may be exported through different routes and different techniques that vary from LNG, to different pipelines options. These exportation projects have different CAPEX values and different markets with different pricing techniques. This complicates the comparison between these projects on a common base line. Thus the economic comparison will be based on discounted cash flow, or DCF techniques. DCF is an analysis tool that is used to assess the economical merit of capital intensive projects. The main advantage of this method is the ability of an "apple to apple" comparison of different projects.

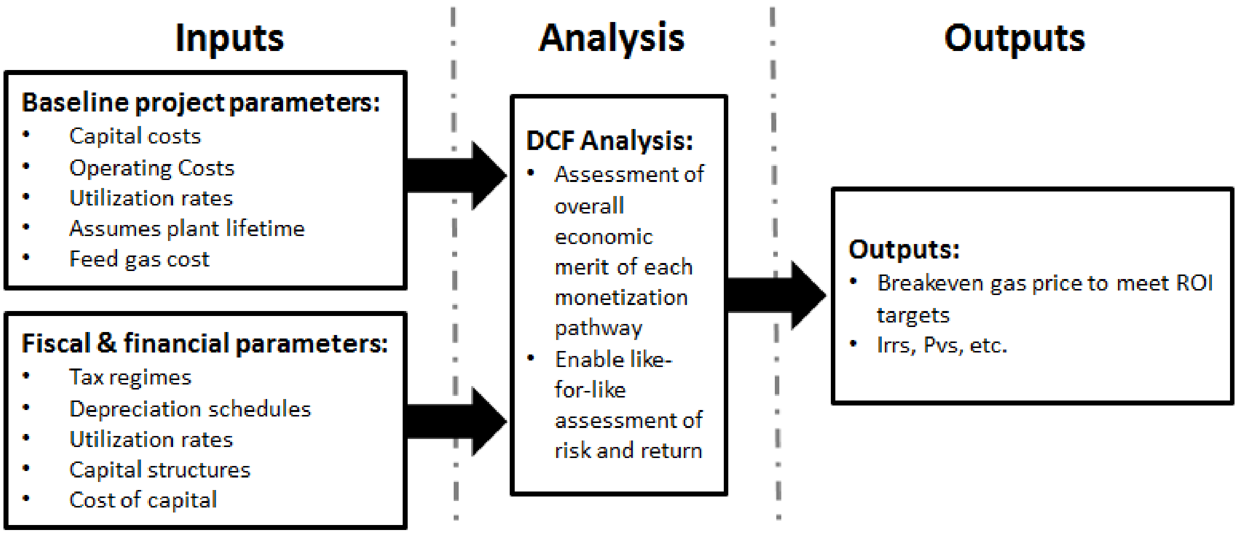

Figure 33 : Illustration of the DCF technique inputs and results

Inputs to DCF include all the expenses that play a role in the pricing mechanism for the exported natural gas. These include the capital and operation costs, which are dependent on the project capacity, the project life time, the plant utilization rate, and the feed gas cost. Mainly the capacity of the project and the project life time will be estimated according to the gas reserves in Lebanon, while the utilization rate and feed gas cost will be estimated according to available similar projects.

Besides the baseline project parameters, some fiscal and financial parameters should be inputted. These include the tax regime, and discount rate "cost of capital". The depreciation schedule of the project should be also assumed.

DCF method may give a range of outputs that can be used as metrics to quantify whether the project will create or destroy value. A popular output from DCF is the Net Present Value (NPV), a metric which reveals the net value of the project in today's money, taking into account all the future revenues and expenditures. In this thesis the discounted cash flow method will be represented in terms of the Break Even Price (BEP). The BEP presents the price needed to get the NPV neutral. In other words, the price at which the NPV of a specific project option will be zero after the project duration, is calculated. This price will be compared to the prices defined from the analysis of the gas markets. If the price that can be realized exceeds the BEP the project option will create a value and the amount of profit can be estimated, otherwise the project option should not be considered as profitable option. Moreover options can be ranked from the lower to the higher BEP and thus can be ranked accordingly from the maximum to the minimum economic profitability.

In this approach to apply the DCF model it is required to assume some parameters. Even the parameters, for which significant detailed data are available, are subject to unforeseen changes in market conditions. Therefore the method will present the "likely" costs and prices that should not be considered "exact". But the method remains valuable while comparing between the different options, since most of the assumptions will affect all the options in the same way.

DCF Inputs

Inputs for DCF can be classified into three main categories, inputs regarding the CAPital EXpenditure (CAPEX), expenditure during the operation, and financial inputs. In this paragraph the notion of every used parameter will be explained as well as the method used to estimate or calculate it.

CAPEX or CAPital EXpenditure is the fund used in the beginning of a project to acquire fixed assets. In the gas scenarios cases these assets can be a pipeline to transport gas to a destination market, Liquefied Natural Gas (LNG) plant, or Compressed Natural Gas (CNG) plant. The calculation of CAPEX is not simple and a detailed study of the CAPEX estimation of each option will be explained in details in separate section.

Project life time for this kind of facilities is normally considered between 15 and 25 years[86]. In this report the project life time will be considered 20 years as the mid-point of the proposed range with three years of construction starting 2023. This means that the facility will be in service between 2026 and 2045 included.

Capacity of the project depends on the amount of natural gas that will be exported. The amount of natural gas that should be exported is usually determined by the government when it draws its gas master plan. Since Lebanon does not have any real estimations of the volume of gas reserve yet, the capacity of the project will be estimated depending on the least estimation of the reserve and an assumed life time of the project.

In May 2018 Lebanon began the first search for oil and gas reserves, following the approval by the authorities of an exploration plan submitted by a consortium of France's Total, Italy's Eni and Russia's Novatek[87]. The exploration period can last up to three years and the first well was

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[86] Sergey Paltsev et al., *Natural Gas Monetization Pathways for Cyprus: Interim Report – Economics of Project Development Options* (2013).9/11/2018)

[87] Lisa Barrington, "**Lebanon Begins Offshore Oil and Gas Exploration**," *Reuters* 2018.

expected to be drilled in 2019[88]. This report will consider that the production may start in 2023 for lifetime duration of 20 years.

The estimation of the Lebanese gas reserves varies from one source to another. Early in 2013, Former Minister of Energy and Water, Jibran Bassil, gave optimistic figures, quoting 95.5 "trillion cubic feet" tcf of natural gas[89]. A study for Fransabank says that surveyed Lebanese water show some 30 tcf of gas[90]. According to French Beicip Franlab, Lebanon's seabed could hold between 12 and 25 tcf of technically recoverable gas[91]. While estimations vary from very optimistic to very pessimistic, Lebanon has not made any discovery yet. Any real estimation could not be done before the drilling of the first well.

The consumption of natural gas in Lebanon is limited to cooking, heating and little industrial usage. This annual consumption varies between 150 kilo tonnes and 250 kilo tonnes of liquid gas, which is equivalent to 0.012 tcf per year at its maximum level. Meanwhile the Lebanese electricity sector is still not depending on natural gas. For a short period of time, in 2010, Lebanon has imported natural gas from Egypt through Syria, using the Arab Gas Pipeline, to generate electricity. These imports stopped after a very short period due to the political perturbations that occurred in Egypt in that period. The Lebanese government has future plans of importing natural gas in order to increase the share of gas used to generate power. The plan is start producing power using imported natural gas until the Lebanese gas production starts. In order to estimate the future consumption of natural gas in Lebanon, a full gasification of the Lebanese electricity sector is assumed. Thus, a forecast of the gas need for the electricity sector in Lebanon during the 20 years that represent the lifetime of the project is performed. Lebanon total need of electricity was about 20000 GWh in the year 2014[92] this is equivalent to 0.067 tcf of natural gas. By applying an annual growth rate of 7%[93] this need will be around 0.09 tcf in 2020 and 0.38 tcf in 2040. Under these conditions, the cumulative sum of all the need of natural gas in these 20 years will be around 4.7 tcf.

As seen earlier, the Lebanese seabed contains around 12 tcf according to the most pessimistic scenario. With these estimations of the internal consumption, 7 tcf will remain for exportation. To compare the different scenarios of exportation, it is assumed that Lebanon will be able to export 5 million metric tons per year (mtpa) of LNG since this quantity is enough to build an average one train LNG plant. This quantity of LNG is equivalent to 243.5 "billion cubic feet" bcf per year, with a total of 4.87 tcf for 20 years.

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[88] Ibid.
[89] Laila Bassam, "**Lebanon Says Gas, Oil Reserves May Be Higher Than Thought**," *Reuters*2013.
[90] Imad Shehab, "**Is Lebanon Really an Oil and Gas Producing Country?**" file:///C:/Users/user/Downloads/Study%20-%20Is%20Lebanon%20Really%20an%20oil%20and%20Gas%20Producing%20Country.pdf (accessed 11/6/2018).
[91] Fadlo Choueiri and Patrick Karawani, ***Oil & Gas Sector: A New Economic Pillar for Lebanon*** (2015).
[92] Sorina Mortada, ***The First Energy Indicators Report of the Republic of Lebanon*** (2018).
[93] Gebran Bassil, "**Policy Paper for the Electricity Sector**," *Ministry of Energy and Water*2010.11/9/2018)

Plant utilization factor is normally the ratio of the actual usage of a plant or a pipe line divided by it maximum capacity usage. A project could not be used on its maximum capacity for its whole lifetime due to various factors that cause perturbation of the production process. As shown in Figure 34 the utilization rate of LNG facilities differs from one country to another. This high variance is affected by the market, type of contracts and shortage in the produced amounts. Also the same can happen for pipelines the gas flow may be perturbed due many reasons from the source country or the receiving country. In this report an averaged utilization factor of 85% will be used for all the projects. Thus, the capacity used in the project will be the estimated full capacity multiplied by 0.85.

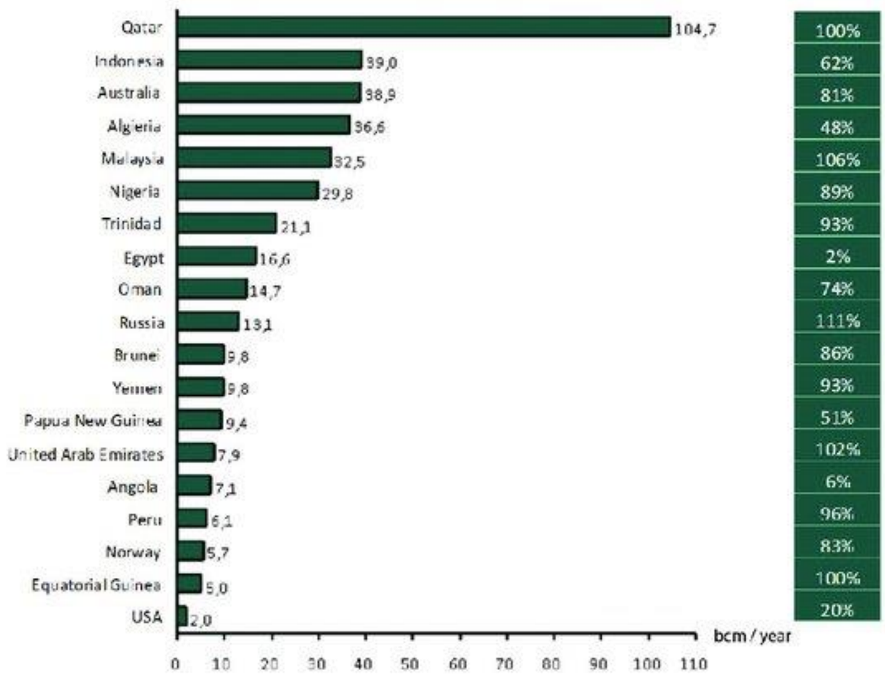

Figure 34 : Export capacity and the level of terminal utilization in LNG-exporting countries[94]

Operation and maintenance costs (O&M costs) this includes fuel gas consumption, operations personnel, maintenance, consumables, support vessel costs, and insurance. These items may differ according to the exportation technology LNG, CNG or pipe line. The O&M cost may be considered as a percentage from the project CAPEX on yearly basis or calculated on production unit basis. Report for the World Bank about gas pipelines in the Arab countries estimated the yearly O&M costs to be 4% of the CAPEX for pipe lines and 3% for LNG.[95] An MIT study for Cyprus estimated the yearly O&M Cost for Pipe line to be 5% of the CAPEX.[96] For LNG it's more common to consider the O&M costs on production unit basis, in 2014 NERA Economic Consulting

[94] Marcin Galczynski et al., *Global Lng Market*, ed. 978-83-946727-0-6, 1 ed. (Ignacy Lukasiewicz Energy Policy Institute, 2017).14/1/2020)

[95] World Bank, *Regional Gas Trade Projects in Arab Countries* (Sustainable Development Department (MNSSD), Middle East and North Africa Region (MNA), 2013), 76114-MEN.20/1/2020)

[96] Paltsev et al.

considered the O&M for LNG as 0.2$/MMBtu[97]. An analysis between different LNG plants in 2018 showed that the O&M costs are 0.28$/MMBtu for Sabine Pass, 0.59$/MMBtu for Queensland Curtis, 0.81$/MMBtu for Gorgon, and 0.9$/MMBtu Wheatstone[98]. The authors refer the high figures in Gorgon and Wheatstone plants for the complexity and the remote locations of these plant but they advise that the operation and maintenance cost should align with 2.5% of the CAPEX.

As for this study the O&M costs will be considered to be 5% of the CAPEX for the pipe line and 0.25$/MMBtu for the LNG.

Fuel consumption factor is a factor that should be considered to take into account the amount of gas that can be lost during the operation. This is typically the largest single operating cost which accounts for the energy usage by the plant or the facility, mostly for refrigeration in LNG and compression stations for pipelines. This factor must include also other reasons such as inaccuracies in metering, errors of accounting, leakage, etc. LNG plants use approximately 10 to 12 per cent of the feed gas depending on the liquefaction process used. Some processes quote figures as low as 8 per cent.[99] For a pipeline the compression stations consume between 3% and 5% of the transported gas.[100]

In this thesis the fuel loss factor will be considered as 6% for pipe lines and 9% for LNG.

Feed gas cost, is accounted very differently in several studies. Some take it as zero-cost since it is a free natural cost. Other considers that it is a lost opportunity and should be charged. In Lebanon the figure is more complicated. The exploration and production agreement[101] signed between the Lebanese Government and the consortium of Total, Eni, Novatek, in blocks 4 and 9, shows that there are formulas that split the discovered gas between two parties in terms of royalties, cost gas and profit gas. In this study, the exportation facility is considered to export the whole amount of gas regardless how the portions will be divided between the Lebanese government and the consortium later on. Thus the exportation facility should pay a rate for its feed gas equivalent to the cost gas considered by the consortium or in other words it’s called the wellhead price or the upstream cost. Estimating the upstream cost is not easy since it depends on many parameters such as the depth of the wells, the number of wells needed, the technology used and the amount of the discovered reserves. Around the world the well head prices can be similar in the discoveries region, thus estimations in eastern Mediterranean region are considered. The gas in the east Mediterranean region is discovered on a depth of 5000 m which implies very high exploratory costs,– up to $100

[97] Robert Baron et al., *Updated Macroeconomic Impacts of Lng Exports from the United States* (2014).
[98] Brian Songhurst, *Lng Plant Cost Reduction 2014–18* (2018).
[99] Ibid.
[100] T. M. Elshiekh, "Optimization of Fuel Consumption in Compressor Stations," *Oil and Gas Facilities* 4, no. 1 (2014).
[101] Lebanese petroleum administration, *Exploration and Production Agreement*2018.13/1/2020)

million per well[102]. In a report presented to the Government of Turkish Republic of Northern Cyprus in 2014[103] the estimated price for Aphrodite gas field was considered to be 3.5/MMBtu. In a recent estimation late 2019 the wellhead gas cost of Leviathan gas field is considered in the range of 4-5$/MMBtu[104].

Gas Price will not be used as an input in this approach; it will be used as a result to be quantified as BEP.

Inflation rate is considered to be 10%.

Discounted rate is considered to be 3%.

Tax rate is considered to be 20% as specified by the Lebanese law. In 05/10/2017 the Lebanese government issued the law number 57 based on the law number 132 issued in 24/8/2010, which specify the Tax Provisions Related to Petroleum Activities[105]. At the forefront of the provisions stipulated by the law, a 20% income tax is imposed on the profits of operating petroleum companies. In this project, we the exportation facilities will be considered taxed under this law.

Depreciation rate is considered to be linear and constant over the first 12 years of the project life time.

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[102] Constantinos Taliotis and Maïté de Boncourt, *East-Mediterranean Gas Potential: Opportunities and Barriers* (zenodo.org: The Cyprus Institute,, 2015).14/1/2020)

[103] Tahir ÇELİK and Ali POURBOZORGI, *Cyprus Natural Gas Evaluation Alternatives* (Research Gate: Eastern Mediterranean University, Government of Turkish Republic of Northern Cyprus, 2014).13/1/2020)

[104] Charles Ellinas, "Challenges to Israel's Gas Exports" https://cyprus-mail.com/2019/09/15/challenges-to-israels-gas-exports/ (accessed 3/5/2020).

[105] The Lebanese official journal, "Tax Provisions Related to Petroleum Activities," in *57*, ed. The Lebanese Parlement (The Lebanese official journal: The Lebanese official journal, 2017).

Net Present Value Calculations

The DCF evaluates the Net Present Value denoted by NPV of the project, after accounting for all the cash flows during its lifetime. As noted previously this project consider that a 3 years construction phase will start in 2022 then the plant will be in function for a life time of 20 years starting 2025 to 2045.

The DCF method requires quantifying the yearly Cash Flow CF_n of the project. The cash flow will be the net difference between the revenues at year n, denoted by R_n, and the costs in year n denoted, denoted by C_n, as shown in Figure 35.

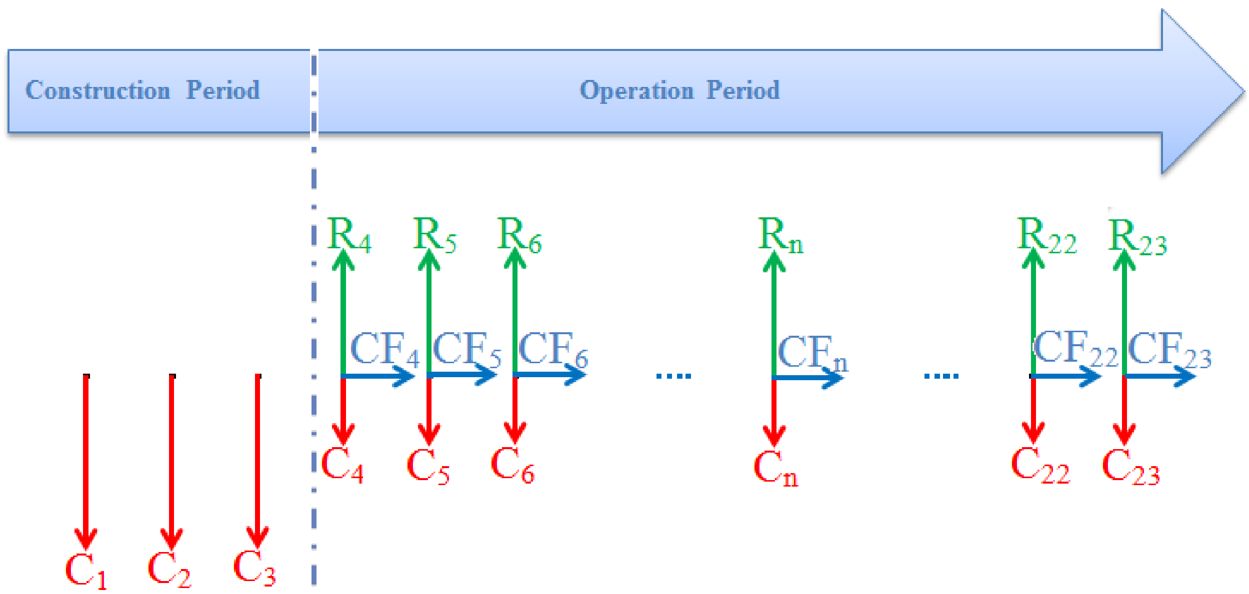

Figure 35 : Cash flow representing scheme over the project life time

In the construction period, years 1, 2 and 3, there will be no revenues and the cost will be the CAPEX divided by three, as shown in Equation 1

$$C_1 = C_2 = C_3 = \frac{CAPEX}{3}$$

Equation 1

For the operation period, the calculation process starts by calculating the yearly gas output in million tons of natural gas per year by multiplying the project yearly capacity by the plant utilization factor, as shown in Equation 2.

$$Gas\ output\ \left(\frac{MT}{year}\right) = Project\ Capacity\ \left(\frac{MT}{year}\right) \times utilization\ rate$$

Equation 2

Then, the yearly gas production in million British thermal units is calculated in order to simplify the calculus of the costs and the profits later on, as shown in Equation 3.

$$Gas\ production\ \left(\frac{mmbtu}{year}\right) = Gas\ output\ \left(\frac{million\ ton}{year}\right) \times 48600000\ \left(\frac{mmbtu}{million\ ton}\right)$$

Equation 3

Then, the cost in year n denoted by C_n is calculated. C_n is the sum of feed gas cost in that year denoted by FGC_n and the operating and maintenance cost in that year denoted by $O\&M_n$. These costs are considered in nominal values thus they will be multiplied by the inflation rate denoted by IR, as shown in Equation 4.

$$\boldsymbol{C_n\left(\frac{\$}{year}\right) = \left(FGC_n\left(\frac{\$}{year}\right) + O\&M_n\left(\frac{\$}{year}\right)\right) \times (1 + IR)^{(n-2025)}}$$

Equation 4

The feed gas cost in year n is calculated by multiplying the yearly gas production by the assumed feed gas cost, which represents the wellhead gas price. This should account for all the gas that entered to the facility even that had considered to be lost by the fuel loss factor as shown in Equation 5.

$$FGC_n\left(\frac{\$}{year}\right) = Gas\ production\ \left(\frac{mmbtu}{year}\right) \times (1 +\ loss\ factor) \times Feed\ gas\ cost\ \left(\frac{\$}{mmbtu}\right)$$

Equation 5

The operation and maintenance in year n is calculated according to the way it was assumed. As seen before, the operation costs can be calculated as per unit of production or as a yearly percent of the project CAPEX. In case of calculation based on unit of production, the fuel loss should be taken into account as shown in Equation 6.

$$O\&M_n\left(\frac{\$}{year}\right) = Gas\ production\ \left(\frac{mmbtu}{year}\right) \times\ (1 + fuel\ loss\ factor)\ \times O\&M\ cost\ \left(\frac{\$}{mmbtu}\right)$$

Equation 6

Otherwise it will be simply calculated by multiplying the calculated CAPEX by a fixed ratio.

After calculating the costs we calculate the revenues in year n, denoted by R_n, as the gas sale price assumed multiplied by the production. Also the sales revenues will be considered in nominal values and multiplied by the inflation rate as shown in Equation 7.

$$R_n\left(\frac{\$}{year}\right) = Gas\ production\ \left(\frac{mmbtu}{year}\right) \times\ Gas\ price\ \left(\frac{\$}{mmbtu}\right) \times\ (1 + IR)^{n-2025}$$

Equation 7

Now after calculating the yearly costs and revenues the yearly cash flow income before taxation denoted by $\grave{CF}_n$ is calculated as shown in Equation 8

$$\grave{CF}_n = R_n \left(\frac{\$}{year}\right) - FGC_n \left(\frac{\$}{year}\right) - O\&M_n \left(\frac{\$}{year}\right)$$

Equation 8

The tax at year n, denoted by Tax_n, is calculated by multiplying the cash flow by the considered tax rate. For the first twelve years the value of the plant depreciation from the cash flow is subtracted as shown in Equation 9

$$Tax_n = (\ \grave{CF}_n - Depreciation\ in\ year\ n\ ) x\ Tax\ rate$$

Equation 9

Finally, the net cash flow income of the project in year n can be calculated after subtracting the tax value from $\grave{CF}_n$ as shown in Equation 10

$$CF_n = \grave{CF}_n - Tax_n$$

Equation 10

Now at this point the net present value of the project will be calculated using

$$\text{NPV} = \sum_{n=2022}^{n=2045} \frac{CF_n}{(1+d)^{n-2022}}$$

Equation 11

Where *d* is the discounted rate, it represents the interest rate used in the DCF method to determine the present value of a future cash flow. In this model, d is considered to be constant and equal to 10 %. This value of d represents the real cost of capital. Meanwhile, the cash flows were calculated in nominal values considering the inflation rate. Thus Equation 11 should be modified, the cash flows should be divided by the inflation factor to convert them from "nominal" to "real" terms, and then the "real" cash flows are divided by the "real" cost of capital, as follows in Equation 12.

$$\text{NPV} = \sum_{n=2022}^{n=2045} \frac{CF_n}{(1+d)^{n-2022} \times (1+IR)^{n-2022}}$$

Equation 12

In this report the DCF method is used to evaluate the Break Even Price for the gas sales. The BEP is calculated as the gas price at which the project NPV would be zero.

LNG CAPEX Calculation Methodology

The Liquefied Natural Gas is a very old technology that started in the beginning of the 7'Th decade of the last century. But prior to the year 2000 LNG was still considered to be a minor source of natural gas in comparison to pipelines. This fact started to change from the mid 2000' and LNG took more and more a great chunk of the market. The Australian and American LNG had a great change in the market in the last decade.

This evolution in the LNG market had its effect on the LNG CAPEX. The LNG CAPEX is usually calculated in terms of the Capacity of the plant. Where normal LNG train sizes are in range of 4-5 mtpa with some small trains of a capacity of 1 mtpa and the largest train built till now is located in Qatar with a capacity of 7.8 mtpa.

Normally the CAPEX is give in the unit of $/tpa which is equivalent to the cost of the plant in million dollars divided by the capacity of the plant in mtpa.

Its hard estimate the value of LNG CAPEX that can be considered realistic in this thesis since each plant has its special characteristics and special conditions thus it cannot estimate based on a specific plant value. Thus an extended research has been done to collect the available data about the LNG CAPEX all around the world from 1969 till now.

Table 4 shows the data collected from resources[106] [107], it covers 77 LNG projects all around the world that include almost the majority of LNG plants to date. Please note that some of the CAPEX numbers are extracted from figures thus it could contain a slight variance.

	Country	**Project**	**Year**	**Capacity mtpa**	**Trains**	**CAPEX $/tpa**
1	USA	Kenai LNG	1969	1	1	1001
2	Brunei	BruneiLNG T1 4	1972	4.4	4	701
3	Algeria	Skikda	1972	4	1	N/A
4	Brunei	BruneiLNG T5	1974	2.1	1	N/A
5	UAE	ADNOC LNG T1 2	1977	2.6	2	752
6	Indonesia	Bontang T 1 2	1977	1.8	2	N/A
7	Indonesia	Arun 1	1978	1.7	2	N/A
8	Algeria	Arzew GL1Z T1 6	1978	8.4	6	N/A
9	Algeria	Skikda GL2k T1 6	1981	7.8	6	N/A
10	Algeria	Arzew GL2Z T1 6	1982	7.8	6	N/A
11	Indonesia	Bontang LNG T3 4	1983	4.6	2	N/A
12	Malaysia	MLNG Satu T1 3	1983	6	3	503
13	Indonesia	Arun 2	1984	4.4	2	N/A
14	Indonesia	Arun 3	1986	2.5	1	N/A

[106] Songhurst.

[107] Brian Songhurst, "Lng Plant Cost Escalation," *Oxford Institute for energy Studies*, (2014).

15	Indonesia	Bontang LNG T5	1989	2.9	1	N/A
16	Australia	North W Shelf T1 2	1989	4.2	2	703
17	Algeria	Arzew I & 2	1990	5.2	2	N/A
18	Australia	North W Shelf T3	1993	2.1	1	N/A
19	UAE	ADNOC LNG T3	1994	1.3	1	N/A
20	Indonesia	Bontang LNG T6	1994	2.9	1	N/A
21	Malaysia	MLNG Dua T1 3	1995	7.8	3	403
22	Algeria	Arzew	1996	9.6	6	N/A
23	Qatar	Qatargas I T1 2 3	1996	6	3	457
24	Indonesia	Bontang LNG T7	1998	2.7	1	N/A
25	Trinidad	Atlantic LNG T1	1999	3.1	1	455
26	Indonesia	Bontang LNG T8	1999	3	1	705
27	Qatar	RasGas T1 2	1999	6.6	2	404
28	Nigeria	Nigeria LNG T1 2	2000	6	2	205
29	Oman	Oman LNG T1 2	2000	6.6	2	705
30	Trinidad	Atlantic LNG T2 3	2000	6.8	2	N/A
31	Nigeria	Nigeria LNG T3	2002	3	1	N/A
32	Malaysia	MLNG Tiga T1 2	2003	6.8	2	N/A
33	Qatar	RasGas II T3 4 5	2004	14.1	3	N/A
34	Egypt	SEGAS LNG T1	2005	5	1	N/A
35	Egypt	Egyptian LNG T1	2005	3.6	1	506
35	Egypt	Egyptian LNG T2	2005	3.6	1	205
36	Trinidad	Atlantic LNG T4	2006	3.3	1	N/A
37	Australia	Darwin LNG T1	2006	3.5	1	506
38	Nigeria	Nigeria LNG T4 5	2006	8.2	2	N/A
39	Oman	Qalhat LNG	2006	3.3	1	N/A
40	Equatorial Guinea	EG LNG T1 2	2007	6.8	2	494
41	Norway	Snøhvit LNG T1	2007	4.2	1	2008
42	Nigeria	Nigeria LNG T6	2008	4.1	1	N/A
43	Australia	North West Shelf T5	2008	4.4	1	N/A
44	Yemen	Yemen LNG T1	2009	3.6	1	605
45	Qatar	Qatargas II T 4 5	2009	15.6	2	405
46	Qatar	RasGas III T 6 7	2009	15.6	2	307
47	Russia	Sakhalin 2 T1 2	2009	9.6	2	N/A
48	Indonesia	Tangguh LNG T1 2	2009	7.6	2	N/A
49	Peru	Peru LNG T1	2010	4.5	1	593
50	Qatar	Qatargas III T6	2010	7.8	1	459
51	Qatar	Qatargas IV T7	2011	7.8	1	554
52	Australia	Pluto LNG T1	2012	4.5	1	1209
53	Algeria	Skikda GL1K	2013	4.5	1	N/A

64	New Guinea	PNG	2014	6.9	2	1349
74	Angola	Angola LNG	2014	5.2	1	1154
66	Indonesia	Donggi Senoro	2015	2	1	1305
69	Australia	Queen land Curtis	2015	8.5	2	1412
55	USA	Sabine Pas T1-4	2016	18.04	4	550
70	Australia	Pacific-LNG	2016	9	2	1300
72	Australia	Gorgon	2016	15.6	3	2106
73	Australia	Gladstone	2016	7.8	2	1291
67	Indonesia	Bintulu T-9	2017	3.6	1	625
59	USA	Cove-Point	2018	5.3	1	710
63	Russia	Yamal	2018	16.6	3	1311
68	Australia	Wheatstone	2018	8.9	2	1987
71	Australia	Ichthys	2018	8.4	2	1929
56	USA	Sabine Pass T-5	2019	4.5	1	844
57	USA	Freeport	2019	15	3	799
58	USA	Elba-Island	2019	2.5	1	832
60	USA	Corpus Christi 2	2019	4.5	1	667
61	USA	Corpus Christi 1	2019	9	2	1044
62	USA	Cameron-LNG	2019	13.5	3	733
75	Timor Sea	Prelude FLNG	2019	3.6	1	2000
65	Indonesia	Tangguh	2020	3.8	1	1053
76	Malaysia	Petronas PFLNG1	2020	1.2	1	968
77	Malaysia	Petronas PFLNG2	2020	1.5	1	825

Table 4 : LNG Plants Capacity and CAPEX

As shown in Figure 36, plotting all the collected data will not give clear indications about the prices trend of the LNG facilities. Thus, some filters will be applied on this data to mask the values that are considered far from the Lebanese case.

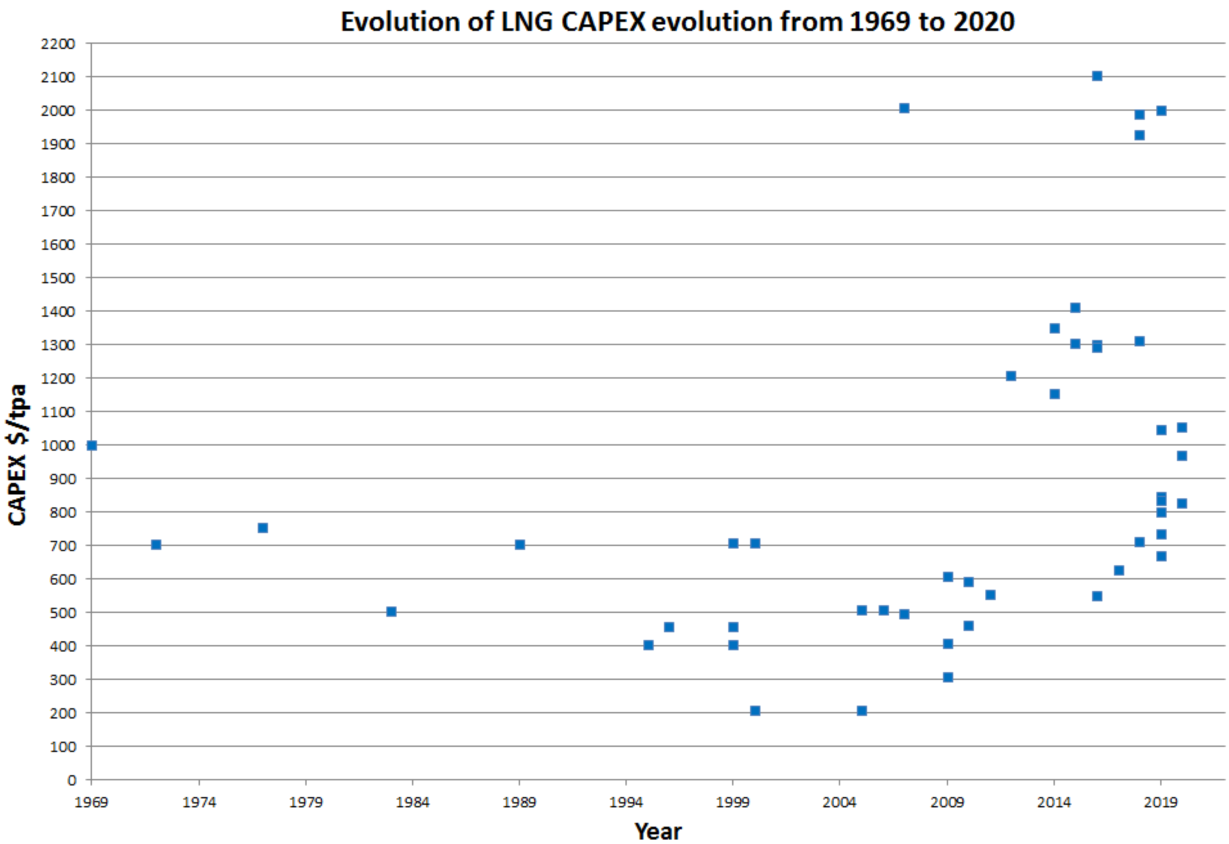

Figure 36 : The evolution of LNG CAPEX over the last 50 years.

As noted previously the CAPEX of LNG plants depends on various types of parameters. Thus, data in Table 4 will be filtered according to two main parameters that affect the most the total price.

First the projects are classified as green field and brown field projects. Green field projects refers to projects that have to be built on a new area and construct all the facilities related to the project while brown field refers to the construction on a prepared site where all the facilities already exist. In the case of LNG plants, brown field projects refer to the extension of preexisting plants by adding new liquefaction trains. Adding liquefaction plant cost typically around 50% of the total plant cost of the project[108] , which explains the large difference between the green field and brown field projects. In this study the interest is to build a new facility thus the category of a green field represents the case. Thus, only data of green field plants are used as shown in Figure 37.

[108] Ibid.

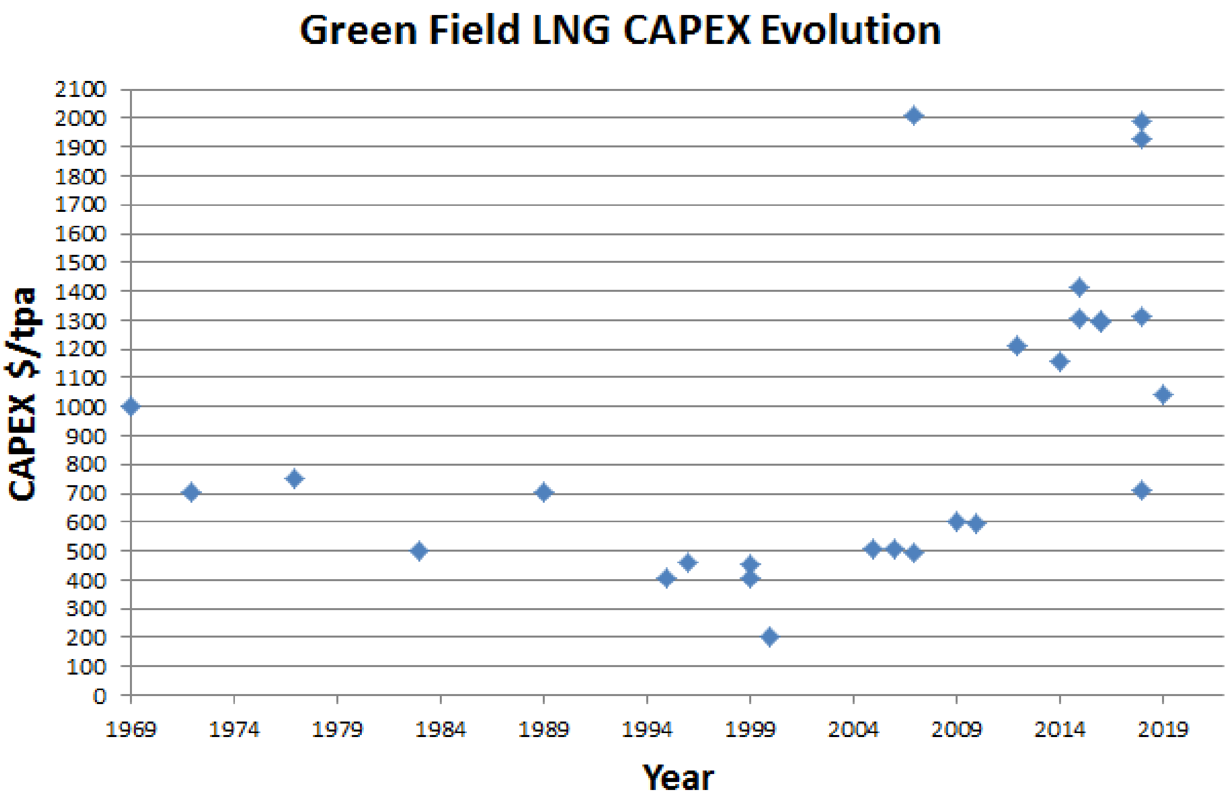

Figure 37 : Green field LNG CAPEX evolution

Even after applying the green fields filter, the data shown in Figure 37 does not give a clear indicator about the trend in the CAPEX evolution. Some high cost plants still appear inconsistent with other data. Looking for the origin of this inconsistency, it was found that these refer to special plants such Snøhvit LNG project in Norway which has been built in a remote place that increased the whole CAPEX of the project. Moreover, the breakdown of the CAPEX components into categories shows that the construction cost constitutes a large chunk of the whole price, as shown in Figure 38.

Most of the high cost projects shown in Figure 37 are located in Australia where the construction related costs are very high. In their report, Songhurst[109] noted that Australian gas workers earn almost double the globalaverage and the buget of all the LNG plants there jumped because of the relatively high labour and construction costs. Consequently in this thesis, a new filter ia applied over the data shown in Figure 37. This filter will remove the data of the projects before 1995, and all the data of the Australian projects and the projects in remote places.

[109] Ibid.

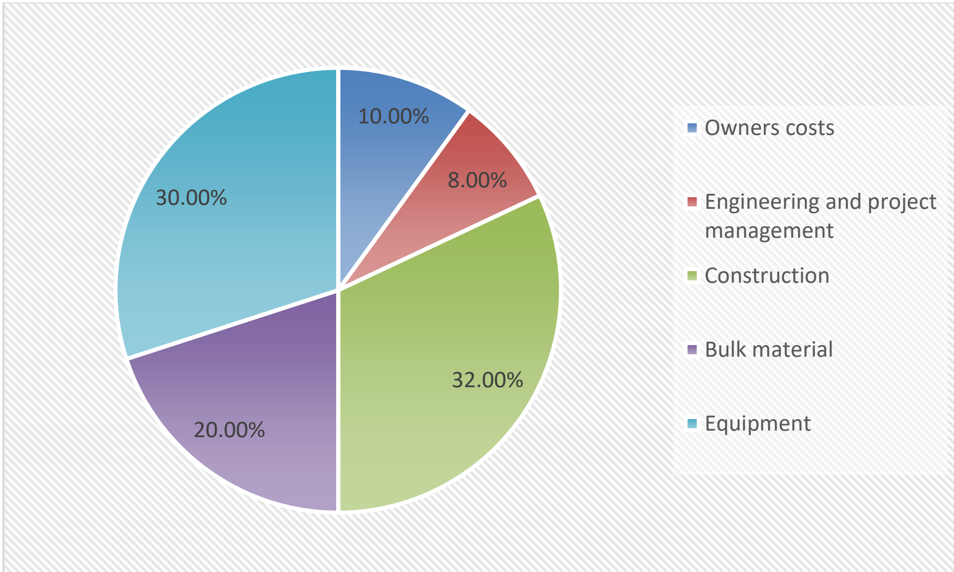

Figure 38 : CAPEX components breakdown according to categories[110].

The new data is presented in Figure 39. It shows a clear trend of the evolution of the LNG CAPEX in from 1995 to date. Based on this trend it can be assumed that a green field LNG plant will cost between 1000 $/tpa and 1300 $/tpa. Therefore, 1200 $/tpa is used.

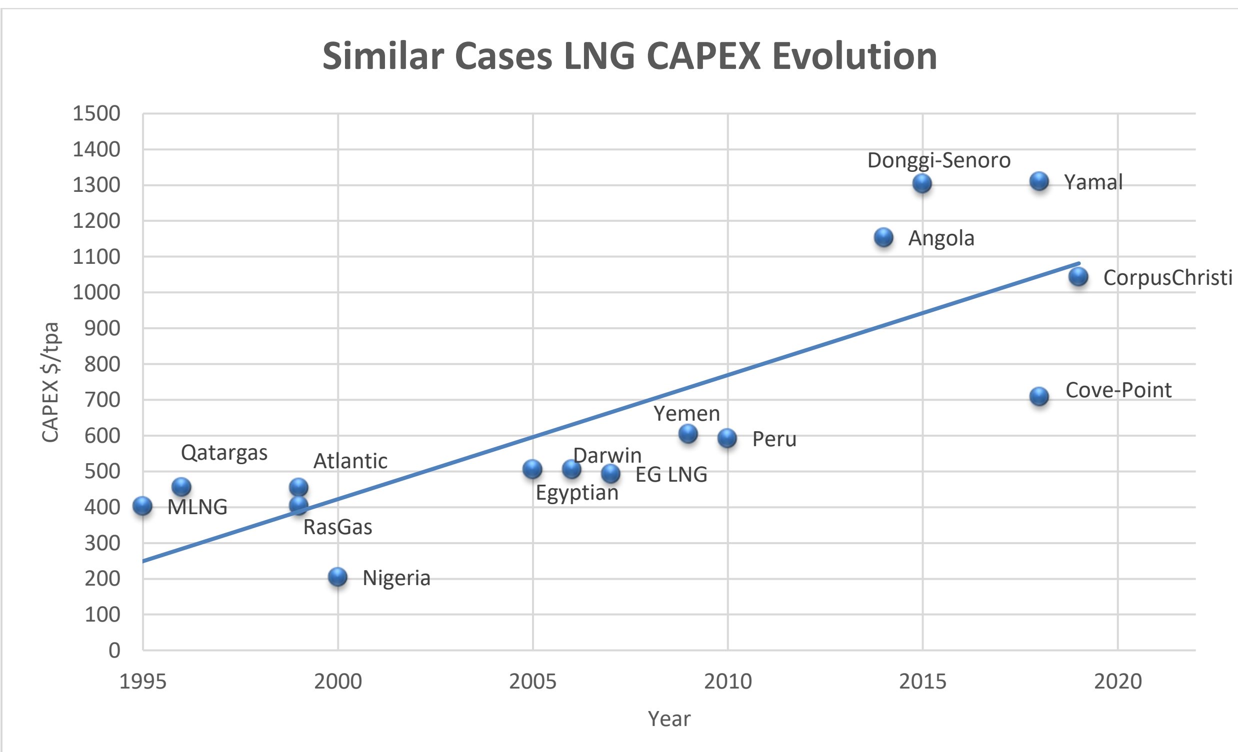

Figure 39 : Similar cases LNG CAPEX.

[110] Ibid.

Pipeline CAPEX Calculation Methodology

The sizing and design of natural gas transportation pipeline depends on several parameters. The main point is to design a pipeline that has a capacity capable of transporting the entire amount projected to be exported. The capacity of the pipeline mainly depend on the inside diameter of the pipeline and the compression ratio applied to the transported natural gas. This means that the same amount can be transported with a pipeline having a smaller diameter if the number or the power of compressing stations is increased. If the amount of natural gas is definitive and predetermined, then an optimum choice of the diameter and compression power should be taken to ensure the best combination between the capital expenditure and the operating costs through the project lifetime. This may be achieved by a techno economic study. However, in most of the cases, the diameter of the pipeline is chosen in a way that permits to enlarge the capacity for future increase of the exportation. This may be done by increasing the number of compression stations.

To determine the size of the diameter of the pipeline one can use a rule of thumb such as the one proposed in World Bank report[111] given in Table 5

Capacity	Pipeline diameter (inches)	Number of compressors
Up to 4 bcm/year	24	1/100 km
8 bcm/year	32	1/100 km
8–12 bcm/year	40	1/100 km
12–18 bcm/year	44	1.5/100 km
20–30 bcm/year	56	1.5/100 km

Table 5 : rule of thumb to estimate for pipe line sizing[112]

The Capital expenditure of a large international gas transmission pipeline can be mainly decomposed into 2 categories, the cost of the pipeline and the cost of the compression stations.

Thus the pipeline CAPEX can be calculated through Equation 13

$$CAPEX = PpLCost + CompCost$$

Equation 13

Where

$PpLCost$ is the cost of the pipeline material and construction
$CompCost$ is the cost of the compression stations

Since the technology and cost of both pipeline construction and compression differs between onshore and offshore projects thus Equation 13 can be expanded to be

[111] Hussam Beides, Hossien Razavi, and Venkataraman Krishnaswamy, *Regional Gas Trade Projects in Arab Countries* (Public-Private Infrastructure Advisory Facility (PPIAF) and the World Bank., 2013), 76114-MEN.
[112] Ibid.

$$CAPEX = PpLCost_{on} + CompCost_{on} + PpLCost_{off} + CompCost_{off}$$

Equation 14

Where the "on" and "off" subscripts refers to onshore and offshore sections respectively.

The cost of the pipeline construction is directly related to the quantity of material, normally steel, used in the pipeline. The quantity of material can be calculated by multiplying the cross sectional area of the pipe section by the length, this include mainly three parameters the pipeline diameter the pipeline thickness and the pipeline length. This can be expressed through Equation 15.

$$PpLCost_{\substack{on\\off}} = UC_{\substack{on\\off}}\left(\emptyset_{\substack{on\\off}}, t_{\substack{on\\off}}\right) \times L_{\substack{on\\off}} \times \emptyset_{\substack{on\\off}}$$

Equation 15

Where

$UC_{\substack{on\\off}}$ is the unit cost of the onshore/offshore, in \$/km/inch

$L_{\substack{on\\off}}$ is the onshore/offshore distance in km

$\emptyset_{\substack{on\\off}}$ is the onshore/offshore pipeline diameter in inch

$t_{\substack{on\\off}}$ is the onshore/offshore pipeline thickness

The cost of the compression stations can be estimated according to the compression power needed to overcome the pressure losses in the pipe and to achieve the required pressure at the delivery point. In onshore pipelines it's possible to have several compression stations at specified intervals while for the offshore cases normally one compression station with large power is implemented on the shore of source point. Thus the cost of the compression stations can be estimated through Equation 16 and Equation 17

$$CompCost_{on} = Pow_{on} \times UCC_{on} \times N$$

Equation 16

$$CompCost_{off} = Pow_{off} \times UCC_{off}$$

Equation 17

Where

$Pow_{on/off}$ is the power for each onshore/offshore compressor

$UCC_{on/off}$ is the unit compressor cost per unit power

N is the number of onshore compressors

Values for UC and UCC could be gathered from other references of similar studies about projects in the region. Another way is to estimate the values for these unit costs depending on functions based on existing projects.

Two different studies present estimations of the CAPEX of gas pipelines in the Middle East and MENA region. The first study was done by Mott MacDonald in 2010[113] and the second one by the World Bank[114]. The two studies give different values for UC depending on the diameter as shown in Table 6.

Pipeline diameter	Mott Macdonald	World Bank
inches	$/inch/km	$/inch/km
22	47880	-
24	-	50000
26	45015	-
30	45396	-
32	-	47500
36	48470	-
40	-	45000
42	55732	
44	-	45000
48	59850	-
56	58899	40000

Table 6 : Unit Cost of pipe line based done by the author based on data given in

Figure 40 shows the trends of variation of the unit cost of the pipe line as a function of the diameter. It shows that the two estimations have different trends, while they converge on small diameters they highly diverge as the diameter increases.

113 Mott Macdonald, *Supplying the Eu Natural Gas Market* (2010).
114 Beides et al.

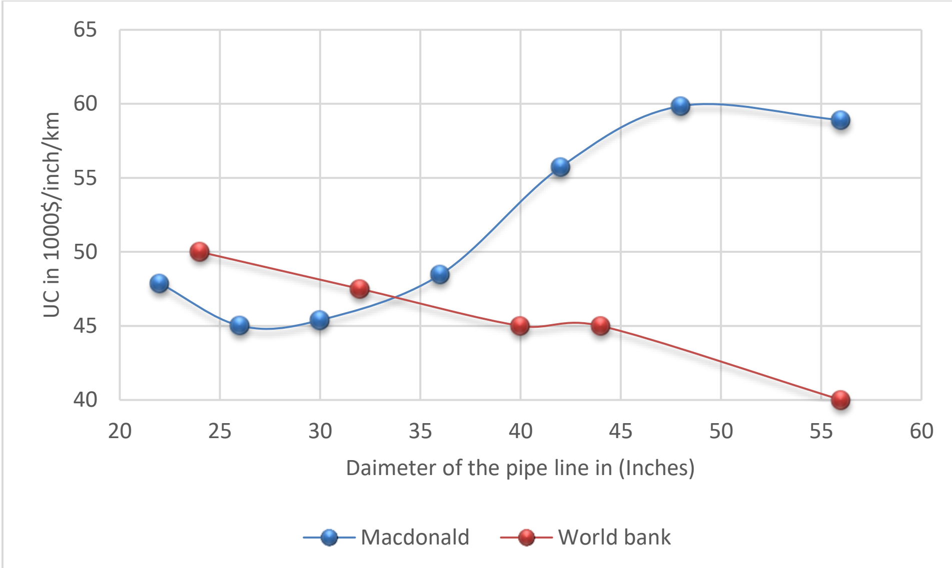

Figure 40 : Trends of variation of unit cost of pipe line from two reports

These are all for unit cost for onshore pipelines. While for offshore pipelines many other parameters are important other than the pipeline diameter and thickness, for example the sea depth is a crucial parameter that should be considered thus a different approach should be applied. The World Bank report[115] stated that, in general, offshore pipelines are about twice as costly as onshore. Macdonald report gave a different table that estimates the unit cost of the offshore pipelines according to the diameter. As shown in Table 7 the unit cost of offshore pipelines is far from being just twice the unit cost of the onshore pipelines as noted.

Offshore Pipeline diameter	Mott Macdonald
inches	$/inch/km
20	558600
22	585200
26	548369
36	461805

Table 7 : Unit Cost of offshore pipelines as given in

For compression unit cost, UCC, it is also reported differently in different studies. As for the unit cost of compression was taken as a 2.5 million dollars for every station noting that he considered a compression station every 100 km in all his projects, which can be applied just in onshore projects. While considered a UCC based on the power as 0.95 million dollars for every MW of compression power which he calculated through a technical simulation.

According to the inconsistency of unit costs presented in different reports, one can depend on published data of achieved projects to estimate the CAPEX using a linear regression. This can be

[115] Ibid.

achieved by introducing a semi-empirical model considering the unit cost of compression is internally included in the unit cost of the pipeline to be written as a linear function of the consumed material which is presented in the ring shaped area of the pipeline. Thus the overall unit cost can be written as follows

$$UC_{\substack{on\\off}}\left(\emptyset_{\substack{on\\off}}, t_{\substack{on\\off}}\right) = \left[A_{\substack{1\\3}}\pi\left(\emptyset^2_{\substack{on\\off}} - \left(\emptyset_{\substack{on\\off}} - t_{\substack{on\\off}}\right)^2\right) + A_{\substack{2\\4}}\right]$$

Equation 18

where

$A_{\substack{1\\3}}$ is a constant for (on/off) obtained from regression related to the consumed material

$A_{\substack{2\\4}}$ is a constant for (on/off) obtained from regression

According to this semi-empirical model the total cost of any project can be written as in Equation 19

$$CAPEX = \left[A_1\pi\left(\emptyset^2_{on} - (\emptyset_{on} - t_{on})^2\right) + A_2\right] \times L_{on} \times \emptyset_{on} + \left[A_3\pi\left(\emptyset^2_{off} - \left(\emptyset_{off} - t_{off}\right)^2\right) + A_4\right] \times L_{off} \times \emptyset_{off}$$

Equation 19

A separate regression should be proposed for each part of the equation. Two new variables shall be defined.

$$Y = \frac{CAPEX\ in\ 2020}{legnth \times diameter \times numberofpipes} \quad \& \quad X = \pi\left(\emptyset^2_{\substack{on\\off}} - \left(\emptyset_{\substack{on\\off}} - t_{\substack{on\\off}}\right)^2\right)$$

CAPEX in 2020 is calculated using all the given costs of the project by a rate of inflation of 1.5% to estimate its value in 2020. After drawing Y in terms of X The regression will estimate the values of $A_{\substack{1\\3}}$ & $A_{\substack{2\\4}}$.

For the onshore part, the data in Table 8 is used. And the regression is presented in Figure 41.

Name of the project	Number of pipelines	Length (km)	daimeter (inch)	Thickness (mm)	Capacity (BCM Year)	Cost (billion dollars)	Year
Transmed	2	920	48	14.3	30.2	2.95	1984
Nord stream	2	1827	56	30.9	55	6.5	2012
South Stream	3	1455	56	30.9	63	8.45	2015
Blue Stream	1	817	51	14.3	16	1.5	2002
Medgaz	1	547	48	14.3	8	1.2	2010

Table 8 : Data about existing projects of onshore pipelines collected by to be used in the regression.

Name of the project	Number of pipelines	Length (km)	daimeter (inch)	Thickness (mm)	Capacity (BCM Year)	Cost (billion dollars)	Year
Transmed	2	155	20	20	30.2	1.5	1990
Nord stream	2	1222	48	38	55	11.44	2012
South Stream	3	925	32	39	63	13	2015
Blue Stream	1	396	24	32	16	1.7	2002
Medgaz	1	210	24	28	8	0.882	2010

Table 9 : Data about existing projects of offshore pipelines collected by to be used in the regression.

For the offshore part, the data in Table 9 is used. And the regression is presented in Figure 42.

From the regressions in Figure 41 & Figure 42, a new relation for the total CAPEX of a pipeline is written as follows.

$$CAPEX = [-0.0000000640 \times \pi (\emptyset_{on}^2 - (\emptyset_{on} - t_{on})^2) + 0.0000634885] \times L_{on} \times \emptyset_{on} + \left[-0.0000003980 \times \pi \left(\emptyset_{off}^2 - \left(\emptyset_{off} - t_{off}\right)^2\right) + 0.0002848559\right] \times L_{off} \times \emptyset_{off}$$

Equation 20

Refilling the data of the projects in Equation 20 gives an error less than 10% for all onshore and offshore cases, except for the offshore case of Transmed project.

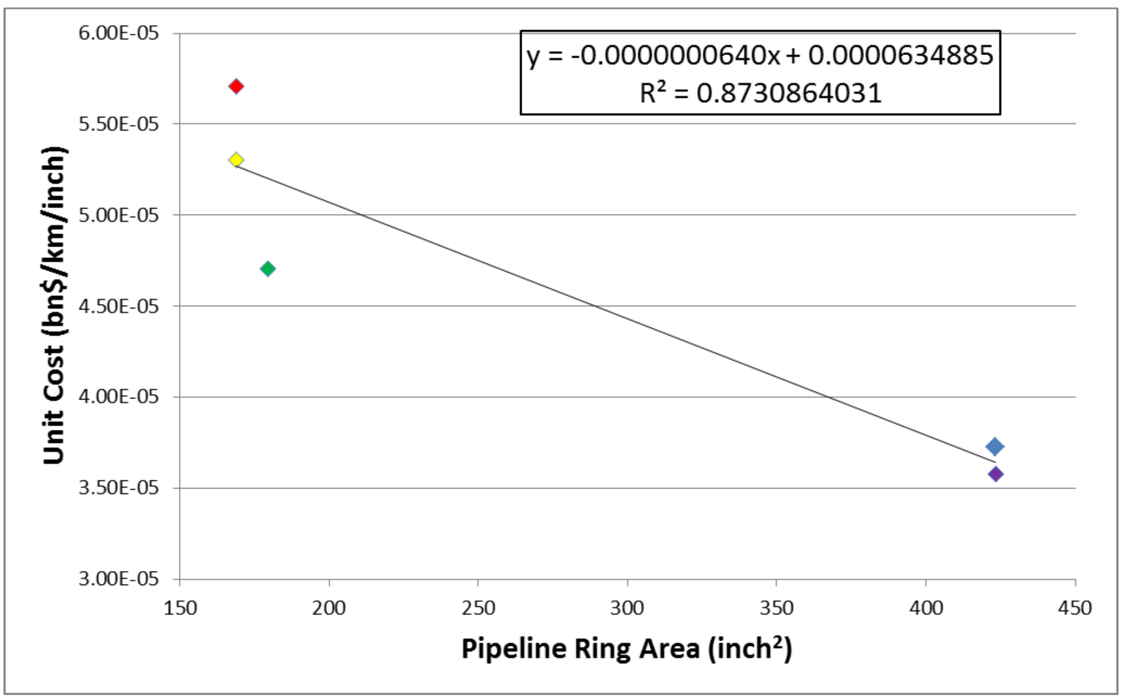

Figure 41 : Linear Regression for the Onshore pipeline CAPEX.

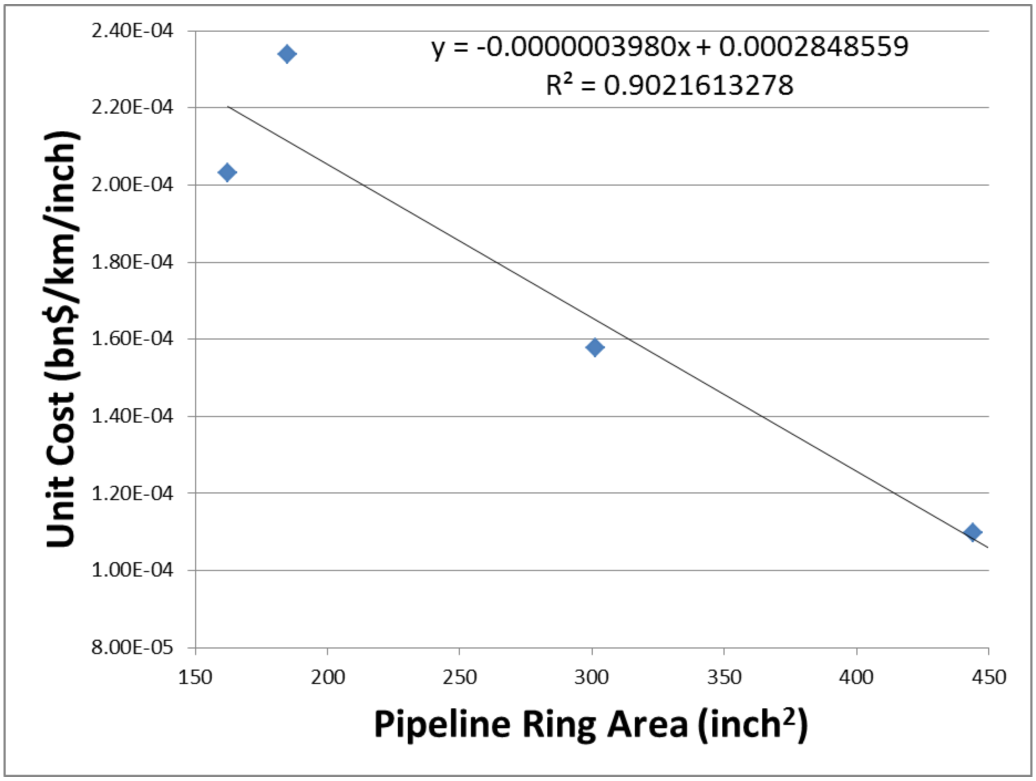

Figure 42 : Linear Regression for the onshore pipeline

Back into the Lebanese case Table 10 explains the characteristics of pipelines for each of the proposed scenarios showing also the cities through which these pipe lines will pass.

Scenario Name	Cities on route	On/Off	Length (km)	Diameter (inch)	Thickness (mm)
J-On	Tripoli-Homs-Damascus-Amman	On	400	42	28
T-On	Tripoli-Homs-Aleppo-Kilis	On	325	42	28
T-Off	Tripoli-Mersin	Off	290	24	14.3
C-Off	Beirut-Vassiliko	Off	250	24	14.3
G-Off	Beirut-Vassiliko-Crete-Peloponnese	Off	1380	24	14.3
E-On	Tripoli-Homs-Damascus-Aqaba-Taba-Arish	On	1200	42	28

Table 10 : Characteristics of pipe line scenarios to be studied.

Table 11 shows the CAPEX of each of the pipelines in the proposed scenarios calculated in three different ways. The first column shows the CAPEX calculated through the regression obtained in Equation 20. Columns 2 shows the CAPEX calculated by using the unit costs taken from Mott Macdonald, as in **Table 6** and **Table 7**, after applying a fixed inflation rate to adjust the time difference between the report date and the project date. The fourth column indicates the CAPEX of the pipelines in the proposed projects according to the unit cost values taken in the World Bank report, as values given in **Table 6**, also after applying a fixed inflation rate. Since the world bank report only gives unit cost for onshore pipelines, the offshore pipelines CAPEX was calculated as twice the cost of the same project if it would be onshore as it was indicated early in that report.

Scenario Name	CAPEX by regression (bn$)	CAPEX by values in (bn$)	Error %	CAPEX by values in (bn$)	Error %
J-On	0.91	1.09	20%	0.87	-4%
T-On	0.74	0.89	20%	0.71	-4%
T-Off	1.53	4.51	195%	1.25	-18%
C-Off	1.32	3.89	195%	1.08	-18%
G-Off	7.29	21.45	194%	5.96	-18%
E-On	2.72	3.28	21%	2.62	-4%

Table 11 : The CAPEX of the construction of the pipelines in the proposed scenarios using the regression and the unit costs given in the Macdonald Report and the World Bank report and the error of each in comparison with the regression.

The third column shows the error between the CAPEX calculated by the unit costs given by Mott Macdonald report with respect to the values obtained in the regression. These errors shows that the unit cost given in the report over estimates onshore pipelines by almost 20 %, while it tripled the value for offshore projects. The last column shows the error between the CAPEX calculated using the unit costs given by World Bank report with respect to the values obtained in the regression. These errors shows that the unit costs given by the report underestimates the CAPEX of the onshore projects by about 4% while it underestimates the offshore projects by about 20%. Following this analysis, this report will consider the values obtained by the regression for all onshore projects. The values obtained for offshore projects remain questioned after the large variance with the available data using Mott Macdonald unit costs which are basically the only other parameters to refer to.

To re-examine the regression for offshore projects, the published data about EASTMED project was used. East med is a planned pipeline similar to G-off scenario that will connect the gas fields in the sea bed of the Palestinian occupied territories with Cyprus field to Crete to Greece to Italy. The published data about this projects says that it is a 7 billion dollars project divided totally into 1300 km offshore pipeline and 600 km onshore pipeline. Substituting this data in the regression in Equation 20, gives the CAPEX of this project which is about 8.5 billion dollars. This represents an over estimation by about 20% compared to the published. As a conclusion, the CAPEX calculated by the regression in Equation 20 will be considered for onshore and offshore projects for the rest of this report.

BREAK EVEN PRICES

The break-even price of the gas for a certain scenario will be the price of the gas sales in ($/MMBtu) at which the project get a net present value zero at the end of the project lifetime. After explaining and deciding all the inputs for the discounted cash flow, DCF, now these values are substituted in Equation 12. Then, the value of the gas price for which the value of NPV turns zero is searched and considered BEP for the exportation scenario.

Scenario Name / Model Inputs	J-On	T-On	T-Off	C-Off	G-Off	E-On	LNG
Capacity of the project (TBTU/year)	357	357	357	357	357	357	357
Capacity (mtpa)	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Capacity (bcma)	10	10	10	10	10	10	10
Capital Cost (bn $)	0.91	0.74	1.53	1.32	7.29	2.71	9
Capacity Utilization Factor	85%	85%	85%	85%	85%	85%	85%
Fuel loss factor	6%	6%	6%	6%	6%	6%	9%
O&M Costs	5% CAPEX	5% CAPEX	5% CAPEX	5% CAPEX	5% CAPEX	5% CAPEX	0.25 ($/MMBtu)
Feed gas Cost ($/MMBtu)	4	4	4	4	4	4	4
Gas price ($/MMBtu)	TBA	TBA	TBA	TBA	TBA	TBA	TBA
Inflation rate	3%	3%	3%	3%	3%	3%	3%
Tax rate	20%	20%	20%	20%	20%	20%	20%
Discount rate	10%	10%	10%	10%	10%	10%	10%

Table 12 : Discounted Cash Flow inputs for all the proposed exportation scenarios

Table 12 shows all the discounted Cash flow inputs for all the proposed exportation scenarios.

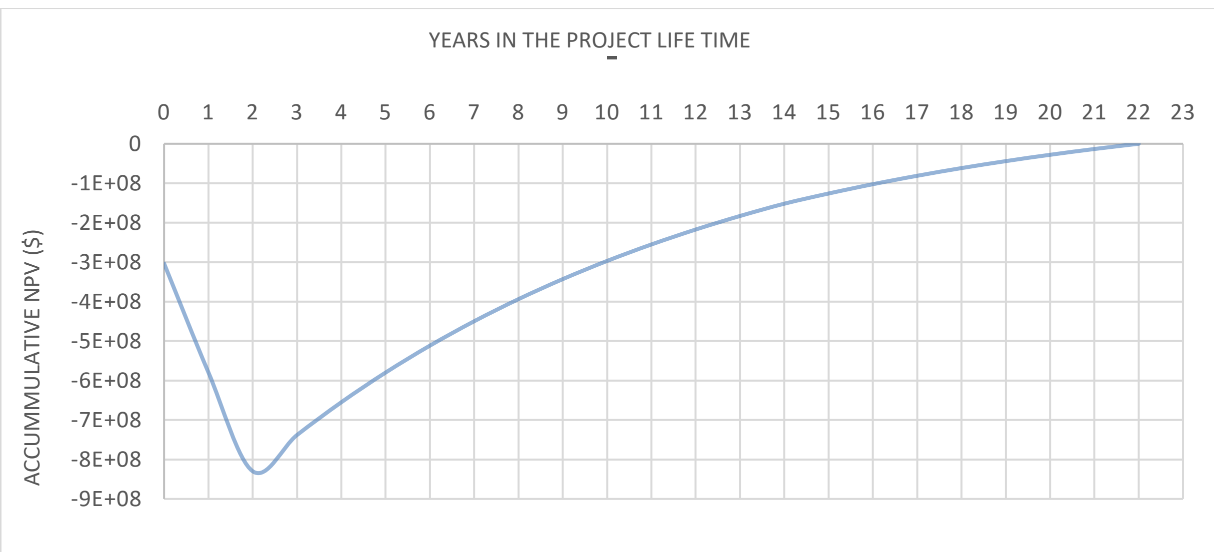

Figure 43 : The evolution of the Net present Value for the project J-On

To show the calculation of the breakeven price, Figure 43 shows the evolution of the NPV for the J-On scenario. This curve was obtained for a gas price of 4.862 ($/mmbtu) which will be the BEP for this scenario. As the curve shows, in the first three years of the project, the NPV decreased and reached a minimum. This is due to paying the CAPEX through three equal payments in the construction period. After that, the curve of the NPV increases till it reach the value of zero at the end of the project life time which is exactly the parameter needed to guess the BEP.

Scenario Name	BEP($/MMBtu)
J-On	4.862
T-On	4.746
T-Off	5.287
C-Off	5.143
G-Off	9.227
E-On	6.101
LNG	9.304

Table 13 : BEP price for each scenario

The same work have been repeated for all the proposed exploration scenarios and a different BEP has been found for each scenario which are all given here in Table 13.

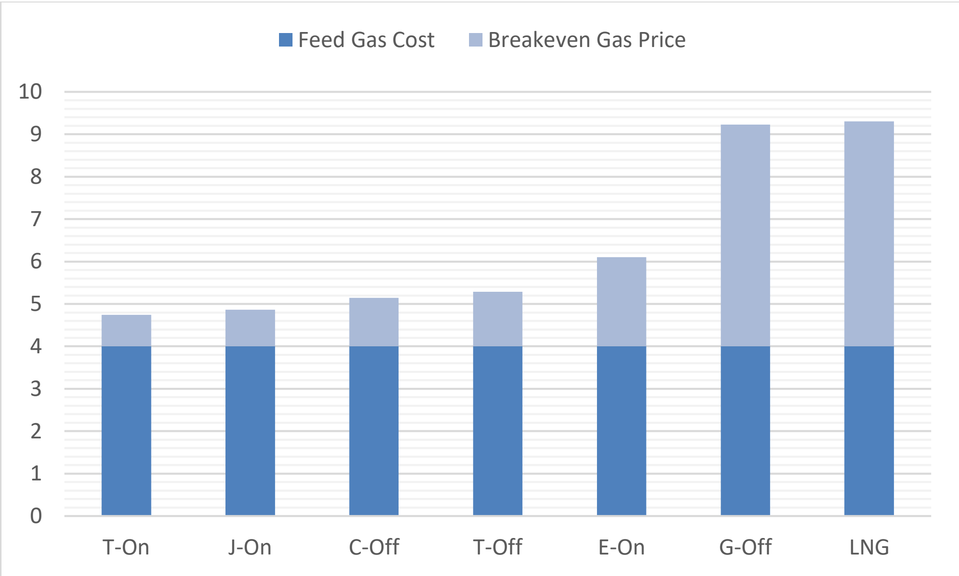

Figure 44 : Breakeven price for different exportation scenarios separating the feed gas cost.

Figure 44 shows the ascending order of the different BEP for different scenarios. It can be noticed that feed gas cost constitutes a large part of the price. The BEP price starts low for short onshore pipelines while it increases slightly for short offshore pipelines then it increases to pass 6 $ for E-On which presents the case of a long onshore pipeline. Then, the BEP jumps to pass 9 $ for G-off which is a long offshore pipeline and for LNG which gives the highest BEP among the proposed scenarios.

Renting Scenarios

As discussed previously, scenarios E-On and J-On propose building pipelines parallel to an existing pipeline which is the Arab Gas Pipeline. Since the Arab Gas Pipeline, has been put idle since 2010 because Egyptian gas production has been unable to fulfill the need of this pipeline, two extra scenarios are proposed to present the possibility of renting a part, Tripoli to Amman, or the whole pipeline, Tripoli to el Arish, instead of constructing a new one. These scenarios will be named J-On-Rent and E-On-Rent respectively.

The deal of renting this facility may vary according to the negotiation with owners. The owner may have high interest in renting the facility since it is already not working and they may have the interest of making the Lebanese gas reach Egypt LNG plants. However, on the other hand many other political and commercial issues may appear to form obstacles in front of such a deal. Thus, this section will discuss for each scenario of the three renting options. The low rent option proposes that the owners have high interest and they will accept renting the facility for a yearly payment equal to the initial price of the pipeline, 1.2 bn $, divided by 20. The medium rent option proposes the yearly payment will be the actual price of the pipeline calculated by the previously proposed regression divided by 20. And finally, the high rent option proposes that the yearly payment will be the actual price plus 20% profit divided by 20. Then, the DCF calculations will be done on a period of 20 years excluding the construction period. Instead of the CAPEX, a yearly rent payment will be added as a fixed sum on the costs.

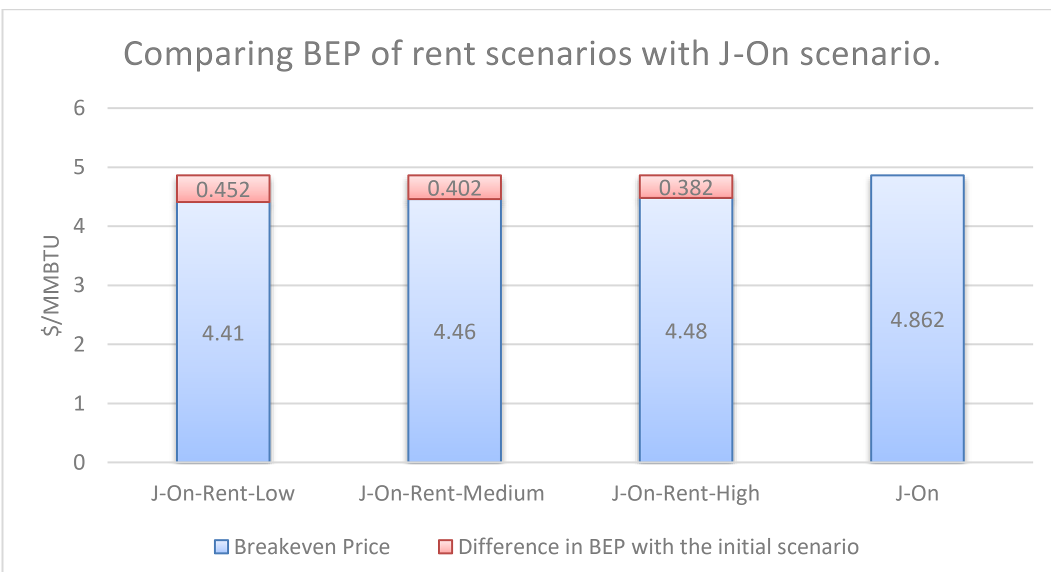

Figure 45 : The effect of renting the Arab Gas Pipeline instead of construction on BEP exporting to Jordan

Figure 45 and Figure 46 show the impact of paying a yearly fixed rent instead of paying a huge CAPEX in the construction period on the breakeven price for each scenario. Both figures show that renting will always reduce the BEP for all the proposed renting scenarios. While the price reduction varies between 38 and 45 cents for Jordan scenarios, renting the whole Arab Gas Pipeline may reduce the BEP of 1 to 1.5 $ for each MMBtu of natural gas. These results are considered very interesting and make studying the renting scenarios an obligatory option.

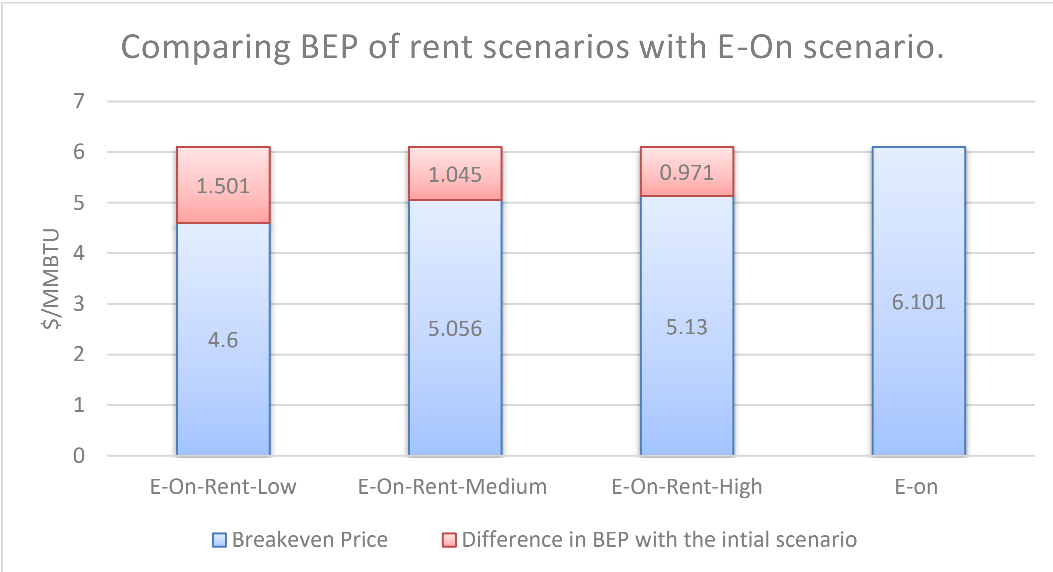

Figure 46 : The effect of renting the Arab Gas Pipeline instead of construction on BEP exporting to Egypt.

Different financial options

As discussed in the renting scenario changing the financing plan can affect the BEP, thus in this section loan scenarios are studied. In all the scenarios the CAPEX should be paid in three consecutive payments during the construction period.

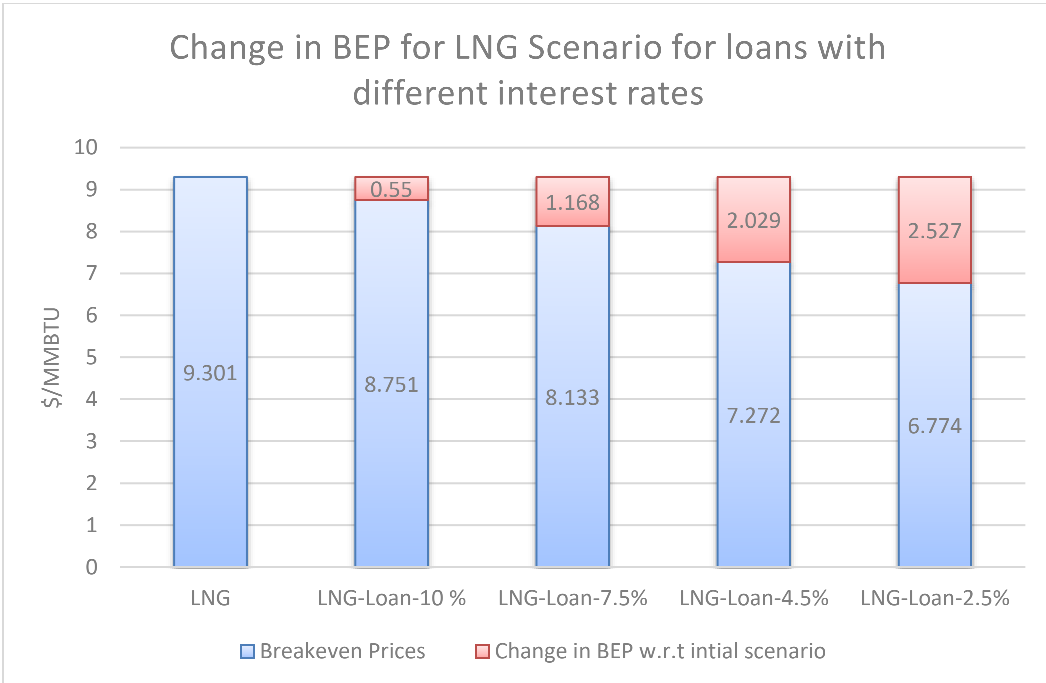

Figure 47 : Effect of different financial plans of loans with different interest rate on the BEP for the LNG scenario.

In this paragraph four financing scenarios are discussed and compared to the initial scenario of building an LNG facility. All these scenarios propose replacing the initial three payments plan with a long term loan for 23 years. The interest rate of these loans ranges from soft loan with 2.5% interest rate up to 4.5% to 7.5% to 10% interest rate which is considered a high interest rate for such a type of loans. Figure 46 shows the effect of these loan plans on the final BEP of the natural gas. It shows that any loan plan will reduce the BEP by a certain amount which ranges from about half a dollar to 2.5 dollars for each MMBtu if the country succeeded to get a soft loan with low interest rate. This reduction of 2.5$/MMBtu can be a game changer while discussing the feasibility of a certain option. The effect of loan financial plans has been studied here only for LNG, as it has the highest CAPEX in comparison with other proposed scenarios, but the same comparison can be repeated for all the other scenarios.

Competitiveness of Lebanese Gas by Market

The different scenarios shown in this study target different markets thus they target different market prices. As the price of natural gas and the pricing mechanisms changes form one region to another, a separate analysis should be done on each proposed market to discuss the competitiveness of the Lebanese gas in these markets and conclude the commercial feasibility of the exportation scenario. Howevwe, comparing the BEP directly with the market price may not give a realistic result since some extra transit fees in the case of pipelines or shipment fees in the case of LNG should be added.

Talking about natural gas prices, one should note that natural gas has different markets across the globe, so the prices diverge from one region to another as it's shown in Figure 48. This divergence is a result of the existence of two pricing systems. The oil-indexation pricing system is when the gas price is determined from the oil market by special formulas that vary from one contract to another. The gas-on-gas pricing system depends on the supply and demand in the gas market.

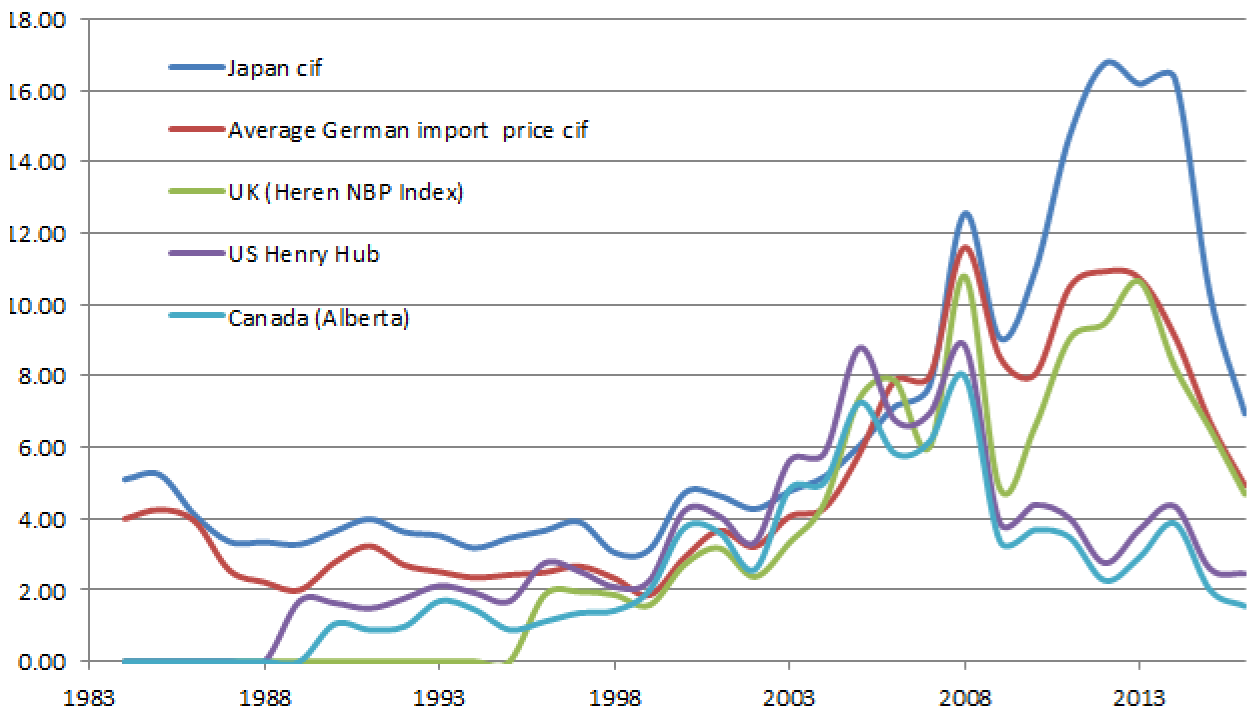

Figure 48: Natural gas prices in selected regional markets ($/MMBtu)[116]

Figure 49 shows that in the Asian market the prices are based on oil-indexed pricing system while the prices in North America are based on a competitive process between different suppliers (gas-on-gas based prices). In Europe gas was priced on the oil-indexation basis but the use of gas-on-gas pricing is increasing in the last years.

[116] British Petroleum, *Bp Statistical Review*.

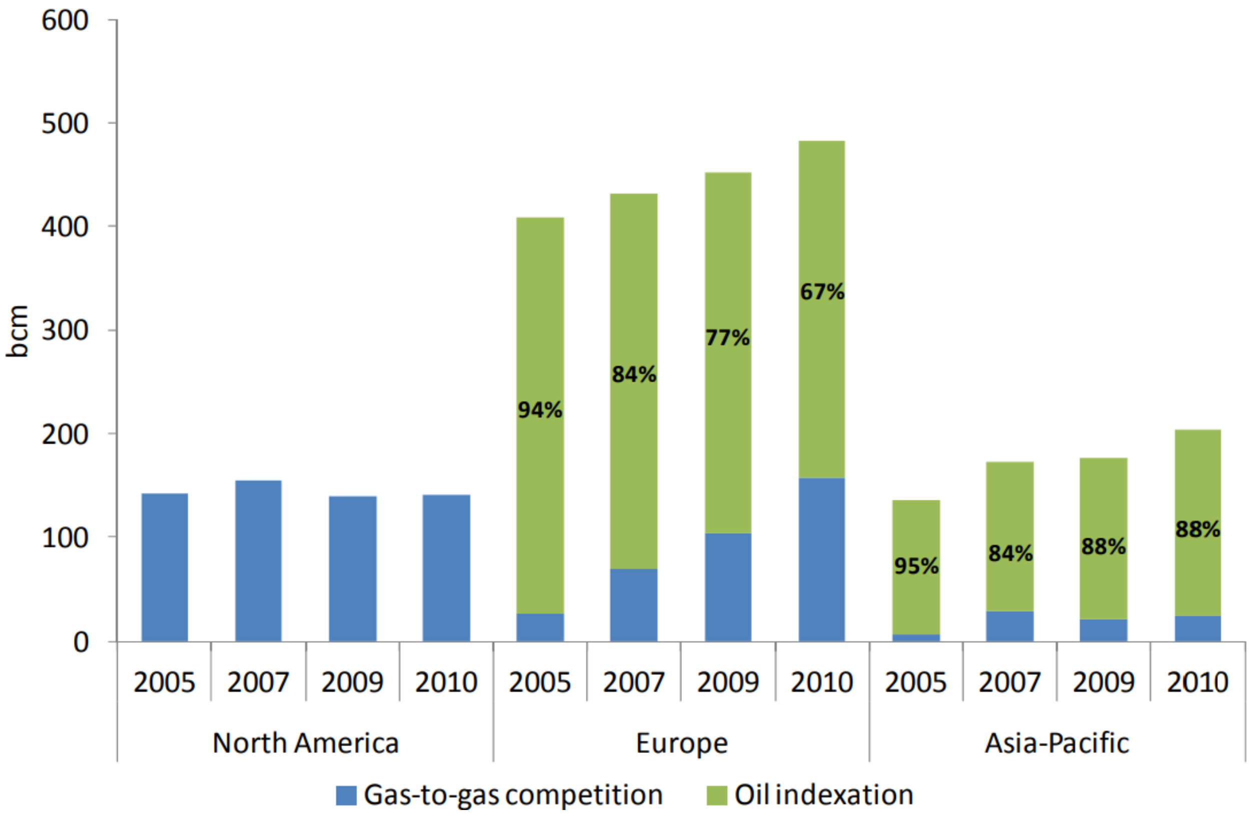

Figure 49: Market-based pricing in gas trade in North America, Europe and Asia-Pacific.

Jordan Market

The studied scenarios propose that the Lebanese gas can reach the market of Jordan via an onshore pipeline. Through this scenario, it was proposed to construct a new pipeline or to rent the Arab gas pipeline. In addition, for renting three scenarios according to the rate of the rent were studied. On the other hand in "Jordan Natural Gas Profile" it was noticed that Jordan market has two main suppliers at the moment Egypt and Israel. In this section, the competitiveness of the Lebanese gas with these suppliers will be checked.

Several reports indicates that Jordan import gas from Egypt at a rate of 5$/MMBtu[117]. For imports from Israel the price is not reported in references. But a leaked copy of the contract between NBL Jordan marketing limited, an Israeli company, and NEPCO, Jordanian National Electric Power Company, that was signed in September 26 2016 is found on a webpage[118]. The contract reveals in its 11'th paragraph that the price is calculated on the basis of the oil price index according to a special formulation.

$$GB = BP + MF + SF$$

Where "GP" It is the gas price applicable for that month expressed in US dollars per million British thermal units.

BP is the base price for the applicable month, calculated as follows

For Brent < 30$	BP=$ 5.65
For 30$ ≤ Brent < 50$	BP=$ 5.65+(0.0175x(B-30))
For 50$ ≤ Brent < 70$	BP=$ 6.00
For 70$ ≤ Brent < 80$	BP=$ 6.00+(0.05x(B-70))
For 80$ ≤ Brent < 160$	BP=$ 6.50+(0.039063x(B-80))
For 160$ ≤ Brent < 320$	BP=$ 9.625+(0.008594x(B-160))
For Brent ≥ 320$	BP=$ 11.00

Brent is the Brent review month index and the Brent average is the weighted average price (in dollars per barrel)

MF Marketing fees are in US dollars per million British thermal units for the applicable month, ranging between 0.05 and 0.07 $/MMBtu

SF It is a follow-up fee in US dollars per million British thermal units for the month applicable and equal to 0.1 $/MMBtu

[117] Stuart Elliott, "Egypt's Plans for $5/Mmbtu Lng Term Sales Deals Questionable: Analysts," *S&P Global*, (2020).
[118] Tamara Nassar, "Secret Israel-Jordan Gas Deal Revealed," (2019).

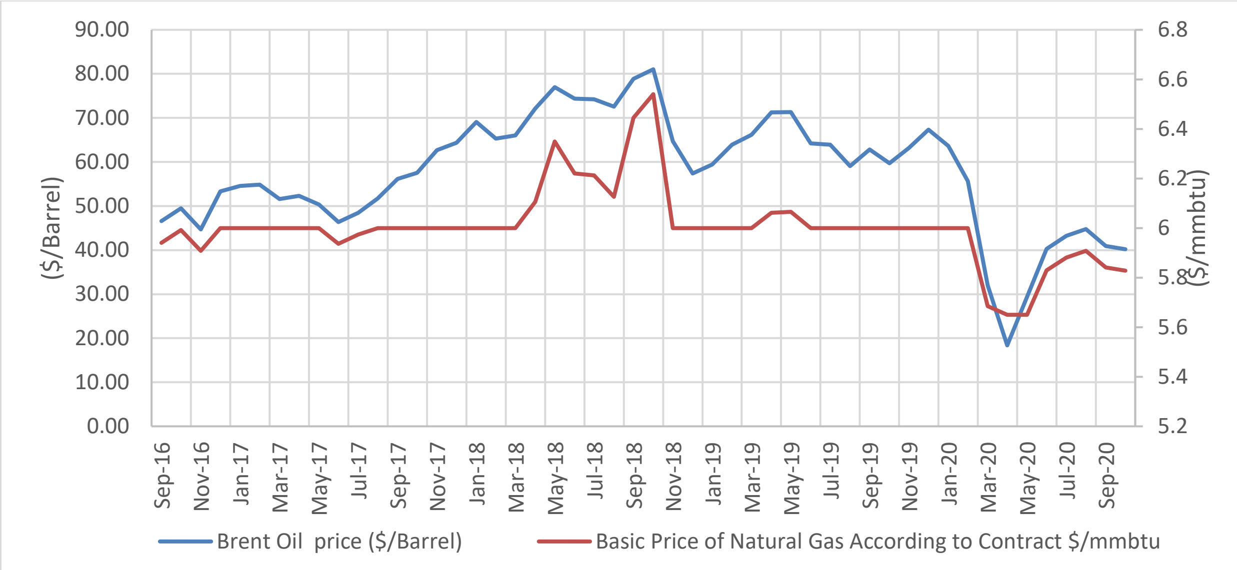

Figure 50 : The basic price of Natural gas imported to Jordan from Israel

Figure 50 shows the how the price of natural gas imported by Jordan from Israel has changed relatively with the oil price since the signature of the contract. The price ranges around 6$ as the oil prices ranges around 50$.

In Figure 45, it was shown that the breakeven prices for the Lebanese gas to reach Jordan will range between 4.41$/MMBtu in case of renting the Arab Gas Pipeline and 4.86$/MMBtu if we built a new pipeline. These prices will allow competition with Israeli gas and the low renting scenario will allow competition with the Egyptian gas.

Turkish Market

As discussed in "Turkey Natural Gas Profile" paragraph, Turkey has several long term pipeline contracts with Russia, Iran and Azerbaijan in addition to several LNG contracts. It was also discussed that Turkey need to renew these long term contracts in the next few years. It was also noted that in the last year Turkey increased the portion of imported gas from spot LNG because of the low prices. All these factors indicates that the Turkish natural gas market is in the phase of transition where Turkey needs to renegotiate the conditions upon the renewal of their contracts.

All Turkey's long term contracts are oil based contracts although one can see some differences in the prices between these contracts. These differences can be due to different formulas or some limited time discounts or offers agreed with the suppliers. For example Figure 51 shows the price of natural gas changes according to supplier between 2016 and 2017.

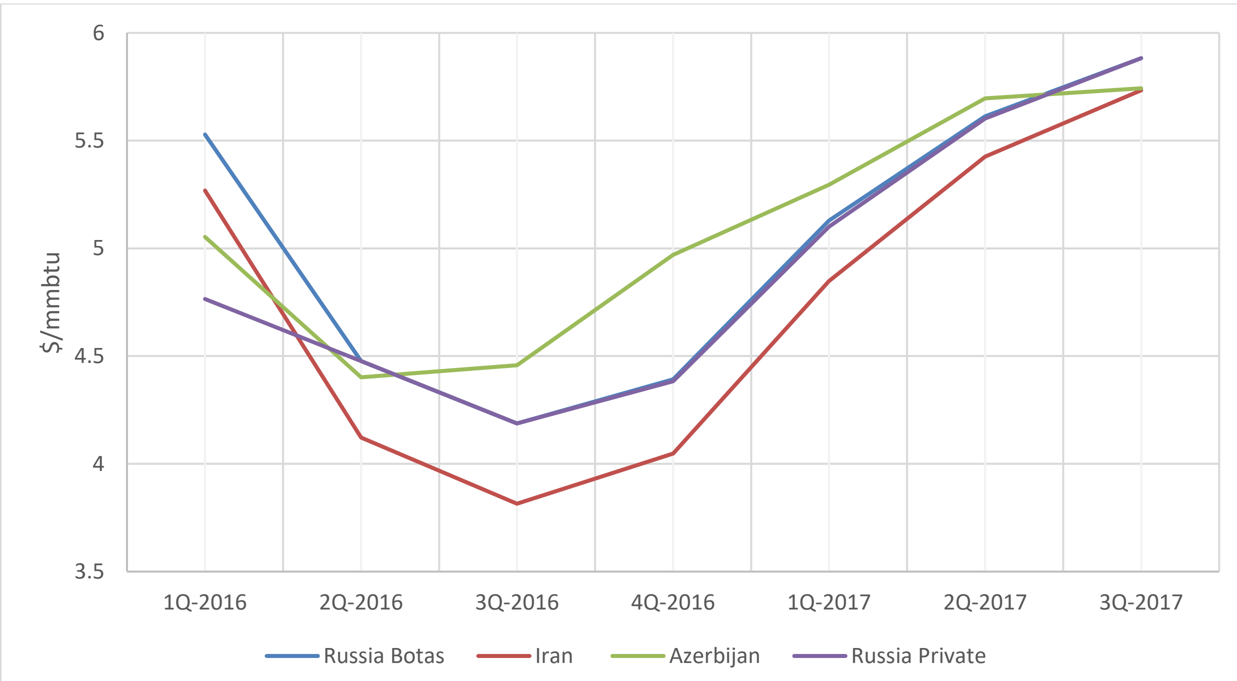

Figure 51 : Prices of imported natural gas to Turkey according to suppliers 2016-2017[119]

As the competitiveness of the Lebanese natural gas depends on the how the prices will be in the next years, two forecast scenarios published in a recent study[120] are considered. Scenario 1 assumes that Turkey will be able to negotiate better prices and change the pricing mechanism to hub indexation, where imported gas prices will be defined by the supply–demand dynamic and market conditions. Scenario 2 assumes that Turkey fails to negotiate better terms, such as lower prices and changes in the price formula to link prices to the market-defined hub price. Prices remain almost unchanged. As Figure 52 shows, if Turkey could renegotiate the conditions of the long term

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[119] Gulmira Rzayeva, "Gas Supply Changes in Turkey," *The Oxford Institute For Energy Studies*, (2018).

[120] Gulmira Rzayeva, "The Renewal of Turkey's Long Term Contracts: Natural Gas Market Transition or 'Business as Usual'? ," *The Oxford Institute For Energy Studies*, (2020).

contracts the price will be below 4.5 $/MMBtu otherwise the price will remain between 5 and 6 $/MMBtu. In the proposed exportation scenarios, two scenarios to export to turkey were discussed, T-on that reaches Turkey via onshore pipeline where the breakeven price is 4.74 $/MMBtu and T-off to reach turkey via offshore pipeline where the BEP is 5.28 $/MMBtu. In comparison with the prices forecast, Lebanese gas can be competitive in the Turkish market in case Turkey could not renegotiate it long term contract conditions and via onshore pipeline.

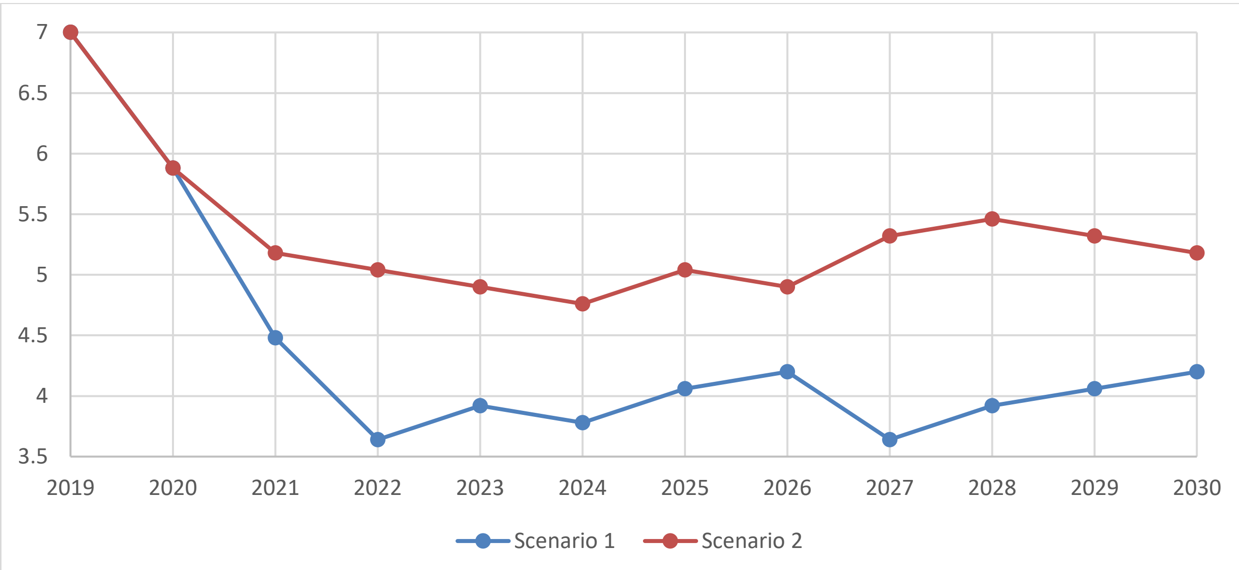

Figure 52 : Forecast Scenarios for the imported natural gas prices in Turkey.

Egyptian LNG

No published data has been found about the price of the imported natural gas to Egypt from Israel. Noble Energy told Reuters that the prices under the agreements were linked to the Brent oil benchmark[121]. Thus, it is assumed that they will use the same formulas of the contract with Jordan. It is also assumed that Lebanese natural gas can reach Egypt via on shore pipeline. There are 4 scenarios, and prices range between 4.6 $/MMBtu to 5.13 $/MMBtu for renting scenarios and goes up to 6.1 $/MMBtu in case of building a new pipeline. Thus, it can be concluded that Lebanese gas may be competitive with the Israeli gas in case of low renting scenarios. But here, an additional question should be added: does this gas remain competitive in the LNG market after adding the price of liquefying and shipment?

[121] Tova Cohen and Ari Rabinovich, "Egyptian Firm to Buy $15 Billion of Israeli Natural Gas," *reuters*2018.

European market

The European market seems as an ultimate destination for all the producers in the Eastern Mediterranean region. However, this analysis is only backed up with political point of view counting on the will of the European countries to diversify their gas sources. On the other hand the commercial study seems more pessimistic for this option. That's due to the competition in these markets from different sources that limit the gas prices and the high well head prices of the gas in the Eastern Mediterranean that ranges between 4 and 4.5$/MMBtu. Adding the transportation prices to the extraction prices will make it hard for the Eastern Mediterranean gas to achieve any profit in the European Market.

The analysis of the price mechanisms in the European markets needs separate study. Figure 53 shows the prices evolution in the last decades. The figure shows fluctuations between high and low prices. After 2016, the yearly average prices were always under 8$/MMBtu and reached values beyond the level of 5$/MMBtu in 2016 and 2019.

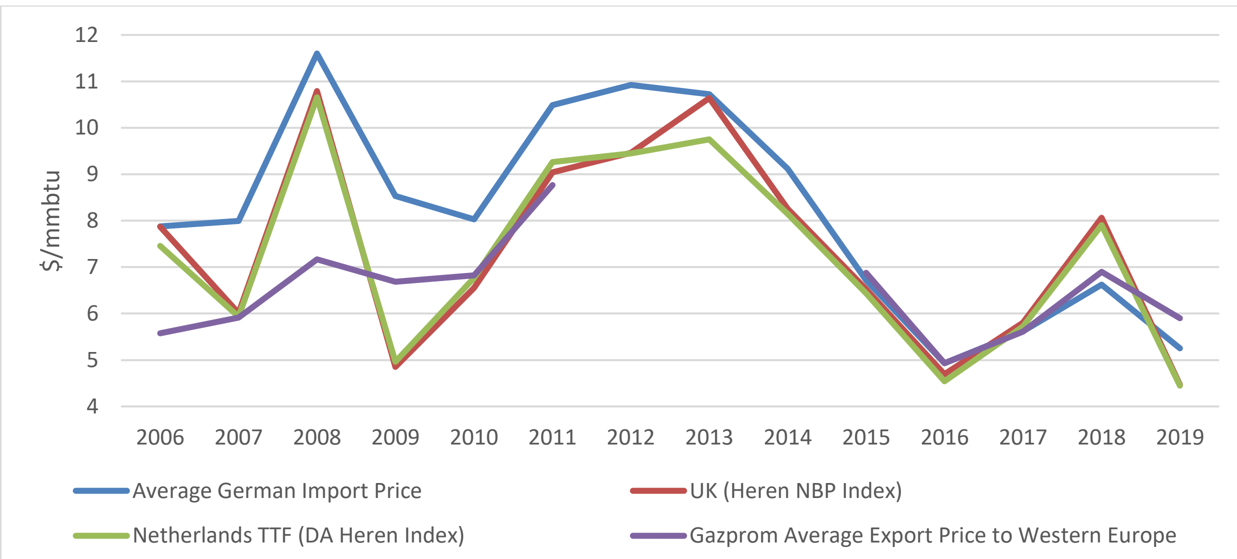

Figure 53 : Comparison between gas prices at different European Gas hubs and Average Export prices to EU as announced by Gazprom[122,123]

This yearly average fluctuation figure can be also expanded to look at the monthly fluctuation as shown in Figure 54. The figure shows that prices are different always between different markets and that the prices fluctuate monthly. Till 2018 the prices could reach 9 $/MMBtu in some cases but in the last two years the prices has fallen below 4 $/MMBtu. One can also notice that in the last two years the prices in south east Europe continue to reach relatively high prices above 7 $/MMBtu in winter season.

[122] British Petroleum, *Bp Satistitical Review*

[123] Gazprom, *Gazprom Annual Report 2019* (2019).

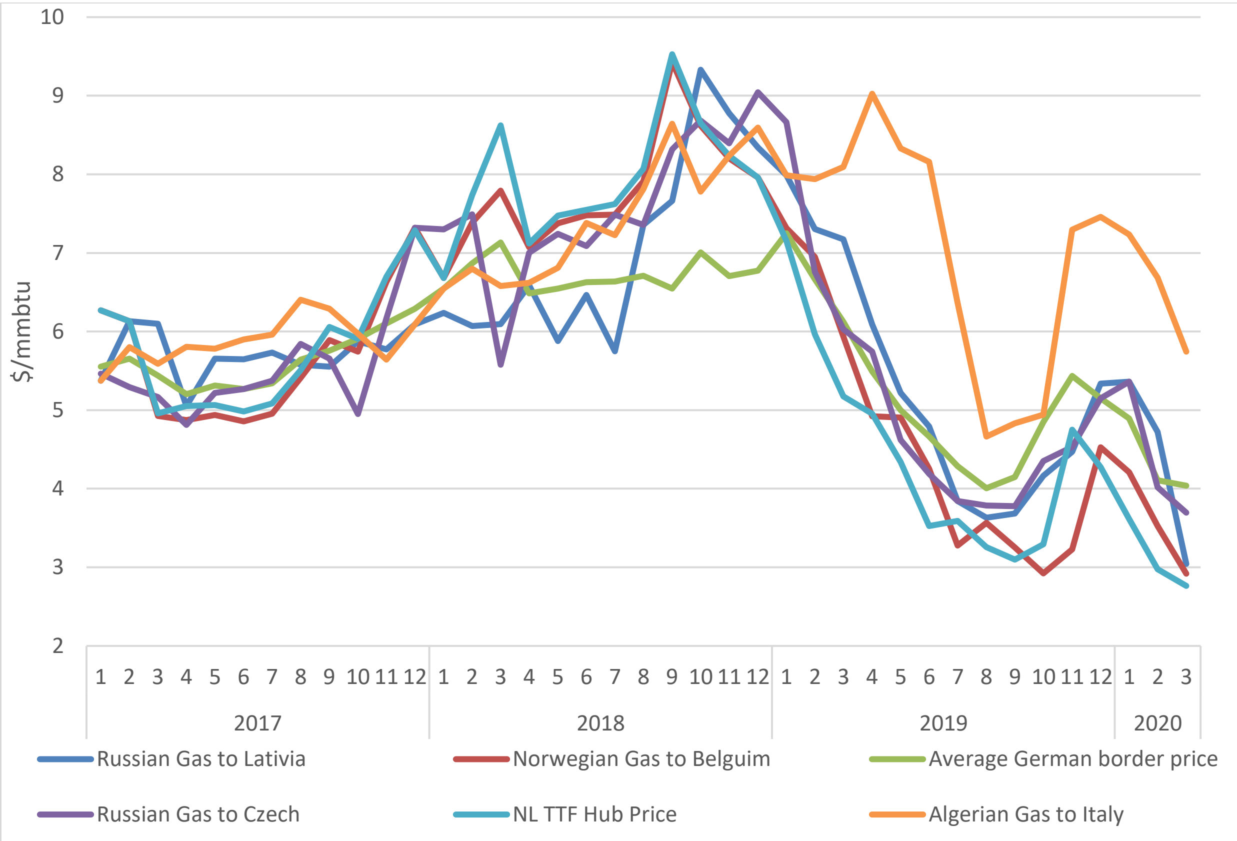

Figure 54 : Comparison of EU wholesale gas price estimations[124]

The question here will be: above which prices it will be profitable for the Lebanese gas to reach Europe?

To answer this question, three exportation scenarios are considered through which the Lebanese gas can reach Europe. The first scenario is G-off in which the Lebanese gas can reach Europe with a direct offshore pipeline to Greece. The second scenario is to reach Europe via turkey after reaching turkey with an onshore pipeline, here transit fees will be added. The third scenario is to reach Europe with LNG shipments where the BEP of the LNG plant includes the shipment fees.

For G-off scenario the calculated BEP is about 9.2$/MMBtu. This requires market prices above 10 $/MMBtu which seems not possible in the European market. Note that no further financial options in this scenario were calculated as for the case of LNG since this project will be a competitor for the EASTMED pipeline and it is unlikely to find parties ready to finance it from the European Union.

For the scenario to reach Europe via Turkey, the BEP of the Lebanese gas at the Turkish borders is calculated to be 4.746 $/MMBtu. To reach the Greece borders, transit fees of TANAP "Trans

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[124] European Commision, *Quarterly Report on European Gas Markets* (DG Energy 2020).

ANAtolian Pipeline" which are 2.81 $/MMBtu[125] added leading to a total of 7.556 $/MMBtu. To reach the Italian borders, the transit fees via TAP "Trans Adriatic Pipe line" which are 2.05 $/MMBtu[126] are added leading to a total of 9.606 $/MMBtu. This value is more than the BEP calculated via G-off scenario.

For the scenario of reaching Europe by LNG, the BEP calculated is 9.3 $/MMBtu but with different financial plans with loans of different rates of interest. The BEP ranges between 8.75 $/MMBtu to 6.7 $/MMBtu. The shipment price varies with the distance with several LNG importing Terminals around Europe as shown in Figure 55.

The shipment price is calculated using a detailed calculation module[127]. The results are presented in Table 14, where it ranges from 0.16 $/MMBtu for near ports to 0.24 for midrange ports up to 0.4 $/MMBtu for far ports.

Destination Port	Shipment Fees $/MMBtu
Izmir - Turkey	0.163
Toscana FSRU - Italy	0.234
FOS - France	0.249
Euro Port - Netherland	0.408

Table 14 : Calculated Approximate Shipment fees to different European Ports

As a conclusion the Lebanese gas can be competitive in the European Markets only in case of building an LNG plant with a good financial plan. In this case Lebanon can export cargos to Europe in high prices seasons not all year.

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[125] Simon Pirani, "Let's Not Exaggerate : Southern Gas Corridor Prospects to 2030," *The Oxford Institute For Energy Studies*, (2018).
[126] Ibid.
[127] Howard Rogers, "The Lng Shipping Forecast : Costs Rebounding, Outlook Uncertain," *The Oxford Institute For Energy Studies*, (2018).

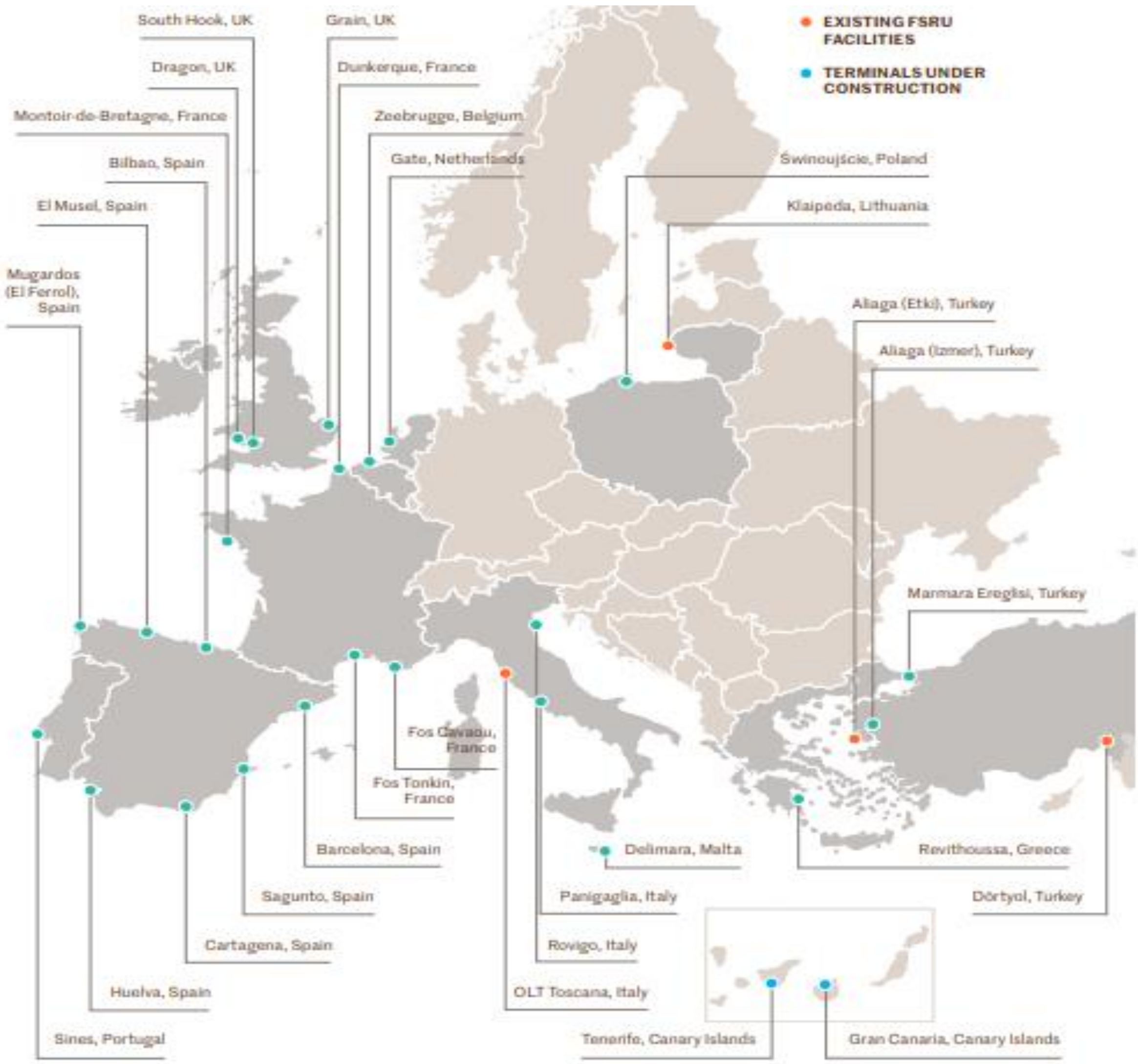

Figure 55 : Map of LNG Importing Terminal around Europe[128]

[128] Dan Rogers, Richard Nelson, and Nina Howell, "An Overview of Lng Import Terminals in Europe," *KING & SPALDING*, (2018).

Asian market

The Asian pacific market is one of the main LNG markets in the world and has its special pricing mechanism. This thesis gives a general outlook about this market. As shown in Figure 56 Japan, South Korea, and Taiwan were the main LNG importers in the last two decades. China and India also emerge as main exporters in the last decade. China obtained major chunk of the imports in 2019.

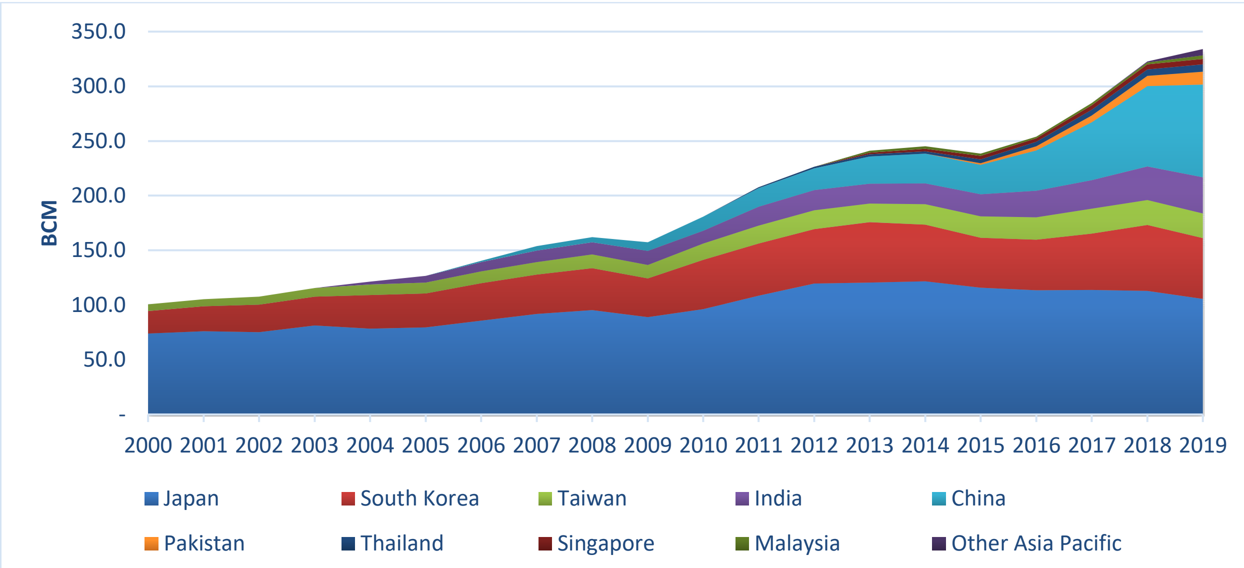

Figure 56 : Evolution of the imports of LNG in the Asia pacific market by country 2000-2019.[129]

The Asia Pacific is also the market for the main LNG exporters in the world. Figure 58 shows that the main exporters are Australia, US, Qatar, Angola, Malaysia, Etc.

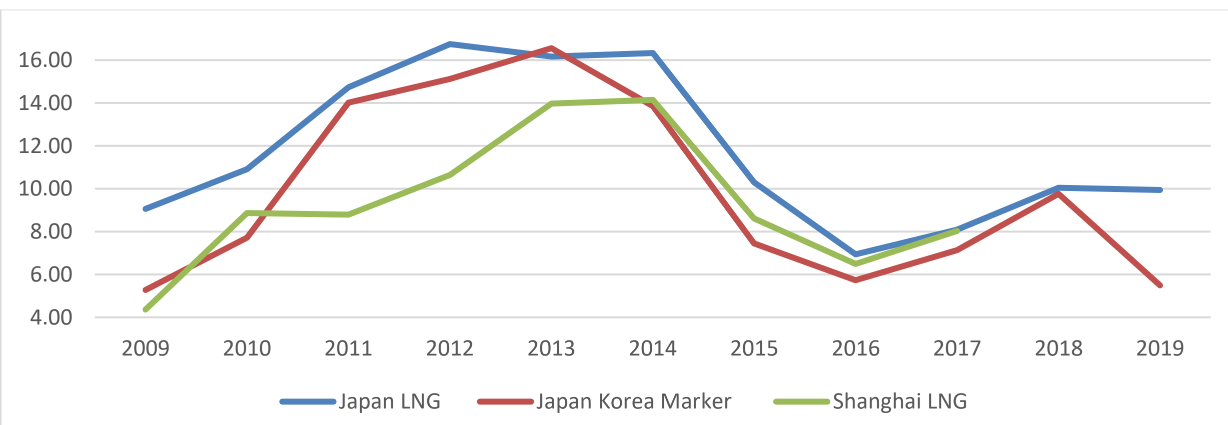

Figure 57 : LNG Prices in Japan LNG, JKM, and Shanghai LNG 2009-2019. [130,131]

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[129] British Petroleum, *Bp Satistitical Review*

[130] Ibid.

[131] Stephen O'Sullivan, "China's Long March to Gas Price Freedom : Price Reform in the People's Republic," *The Oxford Institute For Energy Studies*, (2018).

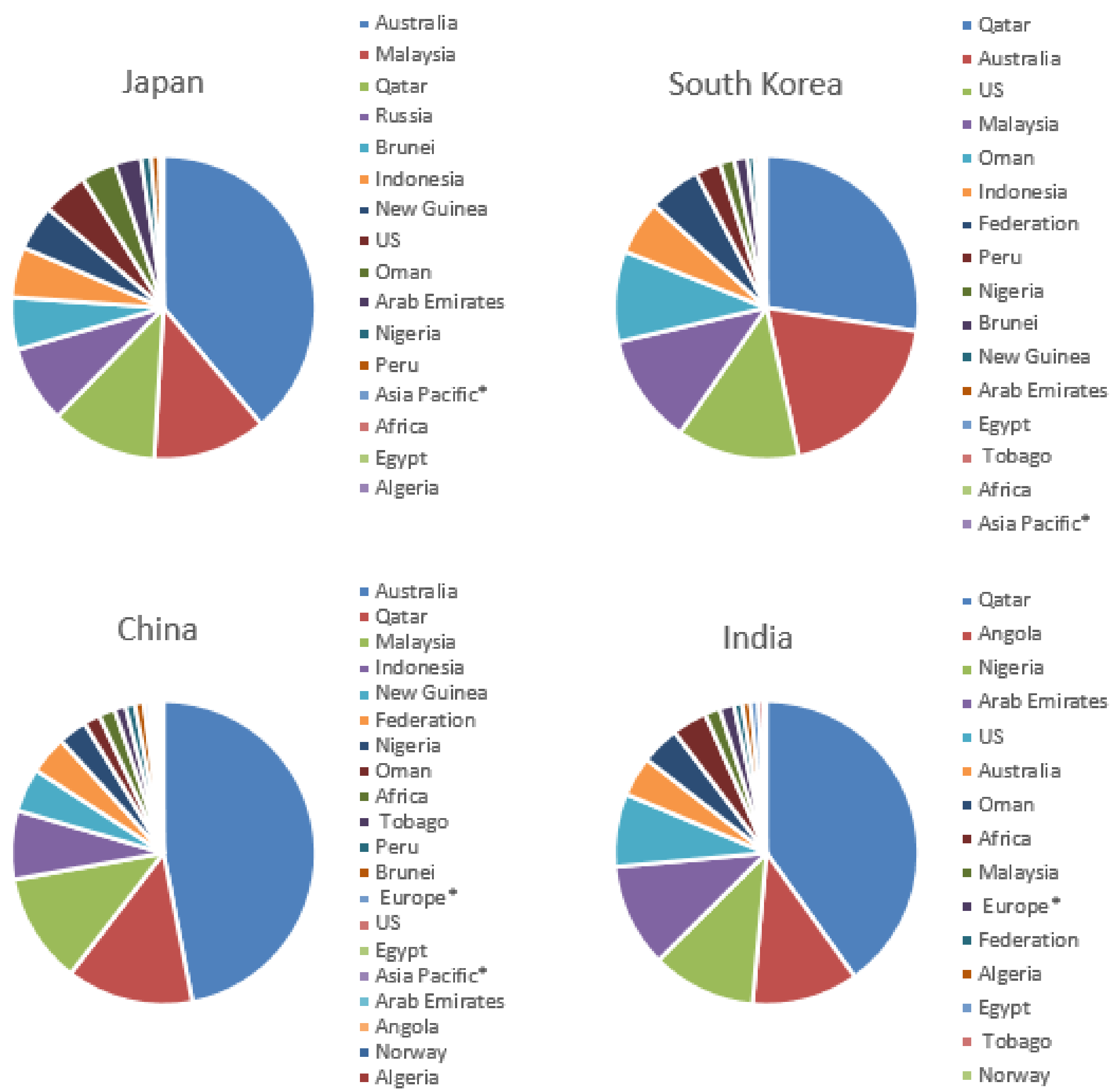

Figure 58 : Exporters share in the LNG markets of Japan, South Korea, China, and India in 2019.[132]

Figure 57 shows the prices in Japan LNG which usually indicates long contracts, JKM which indicates short-time contracts and spot prices, and Shanghai market. The prices are usually higher than the prices in Europe.

Lebanon can reach the Asian market only by LNG. Thus, the BEP calculated for the LNG scenario should be added to the shipment fees. The shipment fees are calculated in the same module as the previous section.

[132] British Petroleum, *Bp Satistitical Review*

Destination Port	Shipment Fees $/MMBtu
Kochi - India	0.658
Guangzhou - China	0.97
Himeji - Japan	1.083

Table 15 : Calculated Approximate Shipment fees to different Asian Ports

As a conclusion the Lebanese gas can be competitive in the Asian Markets only in case of building an LNG plant with a good financial plan. In this case Lebanon can export Cargos to Europe in high prices seasons not all year

Conclusion

While struggling in the administrative and exploration phase, Lebanon has been late in its gas profile with respect to the fast evolving natural gas profile in the region. One should never forget that after the exploration phase the production phase totally depends on the exportation phase. The more a country can find markets for its natural gas the more it gets money to invest in the production phase and vice versa. Thus, with no clear plan about how Lebanon will monetize its natural gas and what are the possible exportation routes, the country will face years and years of more retardation in its gas path. And every month of delay narrows the chances in the potential markets. Lebanon has a competitor with hostile plans such as Israel seeks to use the gas file to subdue Lebanon and draw it into options that contradict its interests and strategic options. This turns time into a lethal weapon, and every delay increases the likelihood that Lebanon will lose this battle before it begins.

The regional gas profile analysis shows that Israel has already preceded Lebanon to all potential markets. Israel has already signed long-term contracts without any competition. It has also moved up to a stage higher than trade relations, by establishing a regional gas alliance that includes most of the countries of the region. This alliance can be used later by Israel as a pressure tool on members to limit the possibility of their cooperation with Lebanon.

While Lebanon is suffering from the biggest economic crisis in its history, the region is witnessing a political shift through the new wave of “normalization agreements” between a number of Arab countries and Israel. Amidst many regional and international players are hinting that Lebanon's strategic orientation is one of the most important causes of its economic crisis. Thus, it is difficult to isolate the Lebanese gas file from this context. Rather, reviewing the natural gas file in the region indicates that Lebanon’s chances of exporting its gas have been narrowed. The proposal to join the Mediterranean Gas Forum, which includes Israel, may be one of the coming pressure levers in the near future. This will pave the way for a kind of normalization of relations that Lebanon has so far completely rejected.

Facing this difficult reality, Lebanon must carefully study its options in order to choose solutions that secure the minimum of its interests, without compromising its strategic options Here comes this research which starts by studying export options from a purely economic perspective before presenting them to geopolitical facts. This will help to accurately diagnose the economic interest in each option and then look at the political obstacles that will oppose this option to study how to solve them. Table 16 shows a condensed summary of all the thesis showing the commercial competiveness and the geopolitical constraints of each exportation option. In the following paragraphs, the conclusion of this table will be rephrased a set of recommendations for the exportation path that Lebanon should adopt will be stated.

The excluded scenarios:

- **G-Off**, which proposesto export natural gas via an offshore pipeline to Greece, is excluded since it is very expensive and will result in a high breakeven price that will not be competitive. The discussion about this scenario applies also for the similar proposed EASTMED pipeline where many scholar argue that it is not commercially feasible. To reach the feasibility limit, this project should be helped with a financial plan and loans, which will be impossible in the Lebanese scenario knowing that the European countries will prioritize EASTMED and will never work on two parallel pipelines.
- **C-Off**, which proposes to export gas to Cyprus via an offshore pipeline then to Europe, is excluded since Cyprus is a partner with Israel in EASTMED pipeline. Going in this scenario means that Lebanon will have a contract with EASTMED and with Israel which is not possible.
- **T-Off**, which propose to reach Turkey via an offshore pipeline, is excluded since it is less expensive to reach turkey via an onshore pipeline. Even if someone would argue that the offshore pipeline may help to avoid passing through Syria, the offshore pipeline also needs a Syrian agreement since it will pass through its EEZ.

The possible scenarios:

- **J-On** and **E-On** scenarios share the same infrastructure, the same financial options and the same Geopolitical constrains. If Lebanon can reach an exportation deal to Jordan or to Egypt then renting the Arab gas pipeline will become foregone option since this pipeline has no other available options to return to service. With renting scenarios, the Lebanese gas will be able to compete with the prices of Israeli gas in both Jordan and Egypt. But these scenarios may face geopolitical obstacles. First, these scenarios will make the Lebanese gas in competition with the Israeli gas thus the Israeli interest is to prevent these scenarios. This could be done by applying political pressure on Egypt and Jordan through EMGF not to sign these deals. Jordan and Egypt are considered allies to the US which is backing the EMGF. The US may use the need of Lebanon for these deals to push it to join the EMGF as a step of normalizing its relations with Israel.
- **T-On** the Lebanese gas may be competitive in the Turkish domestic market through this scenario. But reaching southeastern European countries will imply transit fees which will make it not competitive there. However, if Turkey wants to work on being a gas hub, it will consider the Lebanese gas an extra source that benefit this plan. The political constraints here are that Turkey may use this contract for political influence in Lebanon, and that the European countries will not encourage this step as their policy to avoid making Turkey a European gas hub.
- **LNG** the positive point here is that this option imply the least political constraints. Short term contracts with variety of markets between Europe and Asia, give Lebanon the chance to escape from the narrow options that may be applied in the region. However,

economically speaking, this project needs financial facilities to become feasible. Lebanese LNG will always risk to become uncompetitive during low prices seasons. This is mainly due to the high wellhead prices in the Mediterranean considered “4 $/mmBtu” in the previous assumption. Lebanon can think of this option as a step to become an LNG hub on the Mediterranean for countries that can’t join EMGF such as Iraq and Syria where the wellhead price of natural gas is cheaper. This may be the best solution to make the Lebanese LNG facility produce Natural gas at competitive rates all year long.

Recommended path:

1- First Lebanon should start talks with Egypt and Jordan to discover their ability to sign gas deals with it.
2- If Egypt and Jordan are able to import gas from Lebanon, the next step will be negotiating to rent the Arab gas pipeline with the least rent possible to enlarge the margin of profit.
3- In parallel, Lebanon should negotiate exporting gas to the Turkish domestic market without negotiating the route of this gas to European countries to avoid any western pressure on this option.
4- If the discovered quantities are large enough Lebanon should consider the choice of being an LNG gas hub on the Mediterranean.

Scenario	BEP	Rent or Loan	Destination Market	Transit or shipment fees	Market Price Range	Commercial Competitivity	Geopolitical Constraint & Comments
J-On	4.862	x	Jordan	x	6		- Jordan has contracts with Israel and Egypt
	4.48	Rent-H		x	6		- Israel may lower its price on further quantities
	4.46	Rent-M		x	6		- Jordan is a member of EMGF and may refuse to have
	4.41	Rent-L		x	6		contracts with Lebanon without Joining EMGF
T-On	4.746	x	Turkey	x	5-5.5		- Turkey may use this contract for political influence.
	4.746	x	Greece	2.81	5 to 8		- Turkey has no clear political position yet
	4.746	x	Italy	4.85	5 to 8		- Turkey may lower the transit fees.
T-Off	5.287	x	Turkey	x	5 to 5.5		- This option is not good because it can be replaced with
	5.287	x	Greece	2.81	5 to 8		on-shore less expensive option
	5.287	x	Italy	4.85	5 to 8		
C-Off	5.143	x	Europe	x	5 to 8		- This option propose using Eastmed which is not possible as Israel is a main owner of East-Med
G-Off	9.227	x	Greece	x	5 to 8		- There is no possibilty to have financial help to construct a pipeline parralel to East-med
E-On	6.101	x	Egypt LNG	x	5.5 -6.5		- Egypt has contracts with Israel
	5.13	Rent-H		x	5.5 -6.6		- Egypt is a member of EMGF
	5.056	Rent-M		x	5.5 -6.7		- Egypt may refuse to rent the AGP and unless he join EMGF
	4.6	Rent-L		x	5.5 -6.8		- Egypt may use gas contracts to make lebanon join the Arab countries and Normalize its relations with israel
LNG	9.304	x	Europe	0.2-0.5	5 to 8		- Not like Pipelines LNG has less political constraints
	8.751	loan-10%		0.2-0.5	5 to 8		- Short term contracts need less political alliances
	8.133	loan-7.5%		0.2-0.5	5 to 8		- This option is very expensive and need financial help
	7.272	loan-4.5%		0.2-0.5	5 to 8		which may need political alliances.
	6.774	loan-2.5%		0.2-0.5	5 to 8		- This option will be competitive if the spot price are
	9.304	x	Asia Pacific	1	6 to 10		around 8 $/mmbtu in Europe and 10 $/mmbtu in Asia pacific
	8.751	loan-10%		1	6 to 10		- This option may turn Lebanon to a LNG hub if he could
	8.133	loan-7.5%		1	6 to 10		import extra quantities via pipeline from syria and Iraq
	7.272	loan-4.5%		1	6 to 10		in the future.
	6.774	loan-2.5%		1	6 to 10		

Table 16 : All studied exportation scenarios comparing their commercial competitiveness and presenting their Geopolitical constraint

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