

ISTANBUL TECHNICAL UNIVERSITY ★ GRADUATE SCHOOL OF SCIENCE
ENGINEERING AND TECHNOLOGY

**RISK ASSESSMENT OF
TRANS ANATOLIAN NATURAL GAS-PIPELINE PROJECT**



M.Sc. THESIS

Ali RAHİMLİ

Department of Environmental Engineering

Environmental Science, Engineering and Management Programme

JUNE 2018

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(501131701)**

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Thesis Advisor: Assoc. Prof. Alpaslan EKDAL

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**TRANS ANADOLU DOĞALGAZ BORU HATTI PROJESİNİN
RİSK DEĞERLENDİRMESİ**

YÜKSEK LİSANS TEZİ

**Ali RAHİMLİ
501131701**

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Tez Danışmanı: Doç. Dr. Alpaslan EKDAL

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Ali RAHİMLİ, a M.Sc. student of İTÜ Graduate School of Science Engineering and Technology student ID 501701131, successfully defended the thesis entitled “RISK ASSESSMENT OF TRANS ANATOLIAN NATURAL GAS PIPELINE PROJECT, which he prepared after fulfilling the requirements specified in the associated legislations, before the jury whose signatures are below.

Thesis Advisor : **Doç. Dr. Alpaslan EKDAL**
İstanbul Technical University

Jury Members : **Prof. Dr. Gülen İSKENDER**
İstanbul Technical University

Doç. Dr. Yalçın GÜNEŞ
Namık Kemal University

Date of Submission : 4 May 2018
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To my father



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(Petroleum Engineer)



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ABBREVIATIONS

ACG	: Azeri-Chirag-Gunashli Oilfield
API	: American Piping Products
BOTAŞ	: Boru Hatları İle Petrol Taşıma Anonim Şirketi
BP	: British Petroleum
BTC	: Baku–Tbilisi–Ceyhan Pipeline
CEPA	: Canadian Energy Pipeline Association
CIS	: Commonwealth of Independent States
DOT	: United States Department of Transportation
EGIG	: European Gas Pipeline Incident Data Group
EMRA	: Energy Market Regulatory Authority
LNG	: Liquefied Natural Gas
LTS	: Low-Temperature Separator
MAOP	: Maximum Allowable Operating Pressure
MOP	: Maximum Operating Pressure
NEB	: National Energy Board
NICO	: Naft Iran Intertrade Company
OD	: Outer Diameter
OECD	: Organization for Economic Cooperation and Development
ONGC	: Oil and Natural Gas Corporation
PHMSA	: Pipeline and Hazardous Material Safety Administration
PID	: Pipeline Incident Database
SCADA	: Supervisory Control and Data Acquisition
SCP	: South Caucasus Pipeline
SCPX	: South Caucasus Pipeline Expansion
SOCAR	: State Oil Company of the Azerbaijan Republic
TANAP	: Trans-Anatolian Natural Gas Pipeline
TPAO	: Türkiye Petrolleri Anonim Ortaklığı
UKOPA	: The United Kingdom Onshore Pipeline Operations



SYMBOLS

F_i	: First level modification factor
F_{ij}	: Second level modification factor
L_k	: Displacement Vector Components
N_k	: Number of incidents occurring on pipelines
P_i	: Failure probability for primary failure cause
R_i	: Baseline failure frequency
r_{ij}	: Mean failure frequency of the j th second level modification factor
w_{ij}	: Corresponding weight of the modification factor
α_i	: Percentage of incidents caused by primary failure
FP	: Fuzzy Probability
FPS	: Fuzzy Possibility Score
K	: Constant value
P	: Failure probability of pipeline system



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RISK ASSESSMENT OF TRANS ANATOLIAN NATURAL GAS-PIPELINE PROJECT

SUMMARY

TANAP project is designed to carry the Azeri natural gas from Shah Deniz 2 Gas Field along with other areas in the South Caspian Sea to Turkey and Europe. TANAP begins from the Georgia/Turkey border, goes through the borders of 20 provinces, and ends at Turkey/Greece border. Trans Anatolian Natural Gas Pipeline (TANAP) Project has the potential to cause accidents defined under the titles of corrosion, sabotage, material and equipment, incorrect operations, natural damage, and third-party damages. Also, TANAP pass through the areas that underground and groundwater resources, ecologically and socio-economically sensitive areas are located. Therefore, it is very important to evaluate the failure possibility and to determine risk value of TANAP project.

For this purpose, risk assessment method of gas transmission pipelines based on historical failure-related data that developed by (Shan, Shuai, Xu, & Zheng, 2018) has been used. Trans-Anatolian Natural Gas pipeline is separated into 16 segments according to the seismicity property of the pipeline crossings. Calculation of risk value of each segment has been done based on six main factors that lead natural gas transmission pipelines to the failure according to historical related data. The calculation of the risk value for these six main modification factors is done based on 34 secondary modification factors that carve out that six main factors. For increasing the objectivity of the risk calculation process, the modification factors was tried to be made as quantitative as possible. Given the different levels of difficulty in quantifying the sub level modification factors, they were divided into 3 different groups to calculate the second-order modification factors more precisely: a quantitative index, a semi-quantitative index, and a qualitative index. Quantitative indices are calculated by fitting functions that developed based on statistical data. However, qualitative and semi-quantitative indices are conceptualized by the expert-opinion based scale and fuzzy logic method which is developed by (Guo et al., 2016).

After calculation of second level modifications factors, corresponding weight of each second level modification factor in first level modification factor is calculated according to their mean failure frequencies. Sum of multiplication of second level modification factors to their corresponding weight gave us first level modification factor.

Failure frequency is the term used to show how often the failure is per kilometer of the pipeline. The basic failure frequency term defines the average failure frequency of the selected part of given pipeline. The basic failure frequency estimate for the TANAP project was derived from historical pipeline accidents collected by PIDs such as PHMSA, NEB, and ECIG. Data about failures in the pipelines in years 2002 and 2015 were used to calculate baseline failure frequency. The product of multiplication of baseline failure frequency to first level modification factors determines primary cause failure probability of each modification factor. Sum of every six determined primary cause failure probability demonstrates the failure probability of selected segment. The average failure probability of pipeline based on their length demonstrates failure probability of TANAP project.

Failure probability of TANAP is equal to $2,25 \times 10^{-4}$ per km per year. According to the assessment scale of failure probability, risk probability of selected segment was evaluated as medium level. For decreasing failure probability applicable recommendations are given such as enhancing subfactors of third party damage, corrosion, also material and equipment factors that are leading factors of TANAP project.

In order to ensure the reliability of the results of the risk values calculated for the TANAP project, calculated results are compared with the risk assessment score of TANAP project based on K.W. Muhlbauer risk assessment methodology. Correlation between the results of two evaluation method has demonstrated an agreement.

TRANS ANADOLU BORU HATTI PROJESİNİN RİSK DEĞERLENDİRMESİ

ÖZET

Güney Gaz Koridorunun bir parçası olan Trans Anadolu Doğal Gaz Boru Hattı (TANAP) Projesi, Şahdeniz 2 Gaz Sahası'ndan çıkarılan Azeri doğal gazının Türkiye ve Türkiye üzerinden de Avrupa'ya iletilmesini amaçlamaktadır. Güney Gaz Koridoru, TANAP, Güney Kafkas Boru Hattı (SCP) ve Trans Adriyatik Boru Hattı'dan (TAP) oluşmaktadır. TANAP koridoru SCP'ye bağlanmış olduğu Ardahan'daki Gürcistan/Türkiye sınırında başlar ve TAP Boru Hattı'na bağlandığı Edirne'deki Türkiye/Yunanistan sınırında sona erir. İlk aşamada yıllık 16 milyar metreküp dağıtım yapması planlanan boru hattı projesi için bu miktarın ikinci aşamada 24 milyar metreküpe, üçüncü aşamada da 31 milyar metreküpe yükselmesi planlanmaktadır. Ama bütün bu aşamalarda Türkiye'ye verilecek doğal gaz miktarı sabit olup, yıllık 6 milyar metreküpe eşittir. Türkiye'deki doğal gaz ağına besleme yapmak için Eskişehir ve Trakya'da olmak üzere birer adet çıkış istasyonu kurulmuştur. Gürcistan sınırından Eskişehir'e kadar olan 1333 kilometrelik arazide 56 inçlik borular kullanılan TANAP projesinde, Eskişehir'de BOTAŞ dağıtım hattına besleme yapıldıktan sonraki 458 km, 48 inçlik borularla devam etmektedir. Çanakkale Boğazı'nı bir birine paralel 30 inçlik bir birine paralel iki boru hattı ile geçecek olan TANAP, Türkiye/Yunanistan sınırına kadar tekrar 48 inçlik borularla devam edecektir. TANAP projesi için korozyon, sabotaj, makine ve ekipman arızası, yanlış işlemler, doğal felaketler ve üçüncü taraf hasarı başlıkları altında tanımlanan, altı risk oluşturacak faktör mevcuttur. Ayrıca TANAP projesi, ekolojik ve kültürel olarak hassas alanlar, yer altı ve yer üstü su kaynakları, insan yaşam alanları, demir ve kara yolları gibi birçok çevresel ve sosyo-ekonomik açıdan hassas alanlardan geçmektedir. TANAP projesinin devamlılığının hem ekonomik boyutlarının getireceği fayda, hem de oluşacak her hangi bir kazanın çevreye ve proje paydaşlarına verebileceği zarar gözönünde bulundurulduğunda, bu proje için rakamsal ve detaylı bir risk analizi yapılması zorunluluk teşkil etmektedir.

Bu risk deęerlendirmesinin gerekleřtirilmesi iin, (Shan et al., 2018) tarafından geliřtirilen bozulma olasılıęının tarihsel verilere gre elde edilen temel bozulma sıklıęı vasıtası ile hesaplanması yntemi kullanılmıřtır. Bu gne kadar olan doęal gaz boru hattı kazalarının en temel altı sebebinden olan ve TANAP iin de tanımlanan, sabotaj, makine ve ekipman arızası, yanlıř iřlemler, doęal felaketler ve nc taraf hasar faktrleri, proje riskine etki eden altı esas modifikasyon faktr olarak kabul edildi. TANAP boru hattı ok uzun bir alanı kapsadıęından, bu alan boyunca hem boru hattının getięi arazilerin doęal zellikleri hem de doęal gaz boru hattının teknik zellikleri byk deęiřkenlik gstermektedir. Bu yzden doęal gaz boru hattı, getięi arazilerin sismolojik zelliklerine ve boru hattını oluřturan boruların aplarının boyutuna gre 16 farkı segmente blnd. Bu 16 segmentin her biri iin altı modifikasyon faktr ve bu modifikasyon faktrlerinin temel bozulma sıklıkları baz alınarak bařarı risk deęeri hesaplandı.

Her bir modifikasyon faktrne etki eden birok etken vardır. rneęin, doęal gaz boru hattı iin korozyon bir ana modifikasyon faktr olarak ele alınacaksa, tařınan maddenin koroziyon zellięi, boru hattının apı, topraęın elektrik geirgenlięi, ya da boru hattının bakım kalitesi gibi birok faktrn bu ana faktre etkisi hesaplanmaya alınmalıdır. Her bir modifikasyon faktr iin farklı sayıda ikincil modifikasyon faktr mevcuttur. Belirli bir segmentin risk deęerine etki eden modifikasyon faktrnn deęeri bu ikincil faktrler hesaplanarak elde edilir. Toplamda altı tane ana modifikasyon faktr iin 34 tane ikincil modifikasyon faktre tanımlanmıřtır.

Her ne kadar bazı ikincil derece modifikasyon faktrlerinin hesaplanması kolay olsa da, bazı ikincil derece modifikasyon faktrlerinin riske etkisinin sayısallařtırılması pek mmkn deęildir. Boru hattını oluřturan borunun duvar kalınlıęının risk sonucuna etkisi, belirli bir fonksiyona ve formle uygun olarak yapılıyorsa da, boru hattının iři kalitesinin rakamsal ifadesi ok zor bir grevdir. Bu nedenle, ikincil derece modifikasyon faktrleri kantitatif, yarı-kantitatif ve kalitatif olarak  blme ayrıldı. Kalitatif ve yarı-kantitatif faktrlerin sayısallařtırması (Guo et al., 2016) tarafından geliřtirilen bulanık mantık ynetimine gre yapıldı.

řphesiz ki, her bir ikincil modifikasyon faktrnn esas modifikasyon faktrne etkisi aynı deęildir. Boru hattını teřkil eden borunun duvar kalınlıęının, boru hattında oluřacak korozyondan dolayı hasara etkisi, o boru hattının getięi topraęın direncinden daha nemlidir. İkincil modifikasyon faktrlerinin ana modifikasyon

faktörüne etkisi ağırlık eşdeğeri hesaba katılarak bulunur. İkincil modifikasyon faktörlerinin ağırlık eşdeğerleri ile çarpımının toplamı, oluşturuldukları birincil modifikasyon faktörünün değeri verir.

Her nasıl ki, ikincil modifikasyon faktörleri birincil modifikasyon faktörlerine farklı derecede etki gösteriyorsa, birincil modifikasyon faktörleri de nihai bozulma olasılığına farklı derecede etki ediyor. Bir ana seviye modifikasyon faktörünün boru hattının risk değerine etkisi, o modifikasyon faktörünün hesaplanan değerinin, aynı ana seviye modifikasyon faktörünün temel başarısızlık sıklığına çarpımı ile bulunur. Tarihsel bozulma sıklığı, bir boru hattının belirtilen ana faktörden dolayı yıllık kilometre başına kaç defa kazaya sebep olduğunu gösterir ve boru hatları ile ilgili tarihsel – istatistiksel veriler baz alınarak hesaplanır.

Boru hattının bir segmenti için belirlenen bu altı faktörden kaynaklı bozulma olasılıklarının toplamı, boru hattının o segmentinin yıllık kilometre başına başarısızlık olasılığını gösterir. Boru hattı projesinin ortalama bozulma olasılığı, segmentlerin kapsadıkları uzunluklar ve segmentlerin bozulma olasılıkları baz alınarak alınan ortalaması ile belirlenir.

Tezde, yukarıda bahsedilen metot TANAP projesine uygulandı ve TANAP projesi risk değeri yıllık kilometre başına $2,25 \times 10^{-4}$ 'a eşit olduğu ortaya konuldu. Bu da bahsedilen değerlendirme yönteminin, risk sonucu değerlendirme kriterlerine göre orta seviyede bir risk olarak kabul edilmektedir.

Boru hattının 56 inçlik borulardan oluşan kısmının risk değerinin 48 inçlik bölgesinden daha fazla olduğu ve proje sorumlularının bu bölgede oluşacak tehlikelere karşı daha dikkatli olmaları gerektiği ölçüldü. 56 inçlik bölgede risk değerinin yüksek olmasının esas nedeninin, 56 inçlik boruların çapları ve duvar kalınlıkları olduğu belirlense de, boru hattı projesinin inşasının sona yaklaşımından dolayı bu parametrelerin değiştirilmesi söz konusu değildir. Üçüncü taraf hasar faktörünü azaltmanın uygulanabilir yolu, önemli alanlardaki denetimin artırılması, güvenlik sistemlerinin iyileştirilmesi ve boru hattı için inşaat duvarları gibi yer üstü koruyucu olanakların artırılması olduğu ortaya konuldu. Bununla beraber, boru hattının risk değerine büyük payda etki eden esas seviye ve ikincil seviye modifikasyon faktörleri de belirlenerek, boru hattının riskinin minimizasyonu için uygulanabilir yöntemler gösterildi.

Boru hattının ölçülen risk değerlerinin güvenilirliğini kontrol etmek için, boru hattının seçilmiş segmentine, W.Muhlbauer tarafından geliştirilen ve yaygın olarak kullanılan bir risk değerlendirime yöntemi uygulandı. Her iki yöntemin uygulanması sonucunda elde edilen, seçilen segmente etki eden faktörlerin yüzdesel dağılımları arasındaki farkın neredeyse bir birine eşit olduğu gözlemlendi.



1. INTRODUCTION

1.1 Background

In the world demand for energy is increasing day by day, use of cleaner energy sources in terms of environment and also in terms of the sustainability of the energy source is very essential. Natural gas is also accepted as a cleaner source of energy than any other alternative energy sources in terms of the environment, however, transportation of natural gas has also some difficulties in terms of health, safety, environment, and sustainability. Transportation of natural gas by pipelines is the most common method used for long distance and high amount of transmissions. On the other hand, natural gas transmission by pipelines is not fully safe and it owns certain risk due to different factors to different ecosystems. According to historical data, there were many pipeline failures, which cause accidents that give serious damages to human life, environment, and safety of sustainability of natural gas transportation projects. Therefore, implement of minimization applications for probabilities of natural gas pipelines failure, respectively, minimization of damages of pipelines to human health, environment, and project sustainability demands exhaustive and quantitative risk assessment.

1.2 Research scope with objectives

Trans-Anatolian Natural Gas Pipeline (TANAP) project is the project that aims to carry Azeri natural gas extracting from Shah Deniz 2 to Turkey and to Europe over Turkey. TANAP project has a significant importance in terms of putting Azeri natural gas on the European market and supplying natural gas to Turkey and European countries. Outgoing project compromise very large and wide amount of area that starts from Turkey-Georgia border and leaves Turkey at Greece-Turkey border by crossing Marmara sea. It is also clear that such kind of long-distance pipeline passes from historical heritage areas, roads, railways, important habitats for people, lakes, rivers, agricultural areas and areas that have sensitive biodiversity. Passing through such kind of areas that have high intensity of above ground activities and environmentally

sensitive, makes implementation of quantitative and detailed risk assessment of TANAP obligatory, in terms of both project safety and safety of saying ecosystems. Nevertheless, there are six factors defined, which can cause failure at TANAP project, such as third party damage, corrosion, material and equipment failure, sabotage, incorrect operations, and natural damage. Besides, there are thirty-four subfactors, which were determined for these factors. In this study, it is aimed to analyze the risk of TANAP according to those factors, understand the risk value of the project and determine which segment of pipeline feeds this risk score mostly. For this aim, the pipeline was divided into sixteen segments according to the sensitivity of their location to seismicity. The final and the main objective of this study is to determine the best and the most rewarding ways of minimizing the risks of TANAP. By determining hole risk score of the pipeline project, determining which segments feeds this risk score mostly, and which factor feeds the risk value of that sector and which subfactor feeds that factor mostly, which supply us essential chance to decrease the failure probability and increasing safety of pipeline in very useful and quantitative way.

1.3 Context of thesis

The context of thesis includes the following chapters.

Chapter II starts with the explanation of risk terms. In Chapter II, brief information about physical and chemical properties of natural gas are given. Also, situations of natural gas as an energy source in the world market and its case in Turkey and Azerbaijan has been explained for understanding the importance of natural gas and TANAP. Chapter II continuous by explaining storage and process survey of natural gas. This chapter also includes transportation process of natural gas by pipelines for establishing the perception of basic properties of pipeline projects.

Chapter III is the materials and method part. As accepting TANAP project as our material and risk assessment process of the method applied, first part of Chapter III gives general and technical information about TANAP project. Chapter III continuous by explaining failure probability assessment method of gas transmission pipelines based on historical failure-related data and modification factors.

Chapter IV consists of the implementation of risk assessment method to TANAP project.

Chapter V is about understanding the situation of risk value of TANAP and sources of calculated risk amount. It also includes risk minimization strategies according to calculated result.





2. LITERATURE REVIEW

2.1 Definition of Risk

Risk and danger are two separate but related concepts. The hazard can be defined as a situation or characteristic which may cause harm or damage under certain circumstances. The damage is the result of injury or physical, functional or material loss if the danger is not able to control. The risk is used as an "accident probability" in everyday use, while risk is not only related to probability, but also to the consequences of the unwanted event. Environmental risk is the potential for realizing adverse and adverse consequences to human life, health, or the environment, and is manifested by two components. (Talınlı & Kahraman, 2002)

1. The possibility of occurrence of a negative or adverse event
2. Consequences of adverse event

In other words, the risk is the possibility of destruction or destruction, expressed as a measure of severity and likelihood of a negative impact on human health, environment, property or anything valuable. The risk estimate is usually based on the product of the outcome of the event and the expected value of the likelihood of occurrence of the event. If no one and nothing is exposed to an unwanted substance or situation, then there is no risk. (Talınlı & Kahraman, 2002)

$$\text{Risk} = \text{Exposure probability} \times \text{Severity of accident results}$$

In other words; exposure is the bridge between danger and risk.

2.2 General information about Natural gas

The gas phase is one of three states of matter. During this phase, the density of a substance is low, and fluidity is extremely high. It is important to note that substances in the gas phase have no shape and volume. When a solid material is heated, from solid state changes to liquid then the liquid state becomes a gas. This is called phase change. Particles that form a liquid (atoms or molecules) attract each other. When the liquid is

heated, the gravitational force among molecules is overcome and the particles that form liquid phase are separated from each other, which becomes a gas state. Gas particles can move in every direction and they can get every shape depending on which vessel they are in. Gases may mix with each other and the mixture that they make is homogeneous (Erdogan, 2011).

Natural Gas is a mixture of gases which mainly contains 70-95% methane (CH_4). Except for methane, it constitutes also heavier hydrocarbons like ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), pentane (C_5H_{12}) and hexane (C_6H_{14}) to some proportion. If the natural gas contains only these hydrocarbons, then it is called dry gas. However, there are also some other nonhydrocarbon impurities such as water vapor, nitrogen (N_2), hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium (He) in it. When natural gas contains a huge amount of either CO_2 or H_2S then it is called sour or acid gases. Before delivering to market these gases should be removed from natural gas. The gas which is sold mainly is methane and ethane. Typical composition of the raw natural gas is given in Table 2.1 : (Demirbas, 2010).

Natural gas is one of the most important sources of energy in the world. It is colorless, odorless, shapeless, and the cleanest, safest gas which makes it more preferable than other fossil fuels. Its usage started around 1785 in order to light the houses and streetlights. Nowadays, natural gas has a wide range of commercial applications such as generating electricity, vehicles, heating, as a chemical raw material for the production of plastics, etc. Thus, natural gas has many uses in different sectors like commercial, domestic and industrial (Daneshvar, 2011).

Table 2.1 : Typical chemical components of natural gas (Demirbas, 2010).

Component	Typical Analysis (vol%)	Range (vol%)
Methane	94.9	87.0-96.0
Ethane	2.5	1.8-5.1
Propane	0.2	0.1-1.5
Isobutane	0.03	0.01-0.3
n-Butane	0.03	0.01-0.3
Isopentane	0.01	Trace to 0.14
n-Pentane	0.01	Trace to 0.14
Hexane	0.01	Trace to 0.06
Nitrogen	1.6	1.3-5.6
Carbon Dioxide	0.7	0.1-1.0
Oxygen	0.2	0.01-0.1
Hydrogen	Trace	Trace to 0.02
Hydrogen Sulphide	Trace	Trace Occasionally

2.2.1 Natural Gas in the World

Nowadays renewable energy is growing rapidly and there is an expectation that it will replace fossil fuels in the future. However, our main source of energy is fossil fuels and they constitute 86% of total world energy consumption in the current period. The remaining proportions are of nuclear power, renewable and hydro which account for 4%, 3% and 7% respectively (BP, 2016).

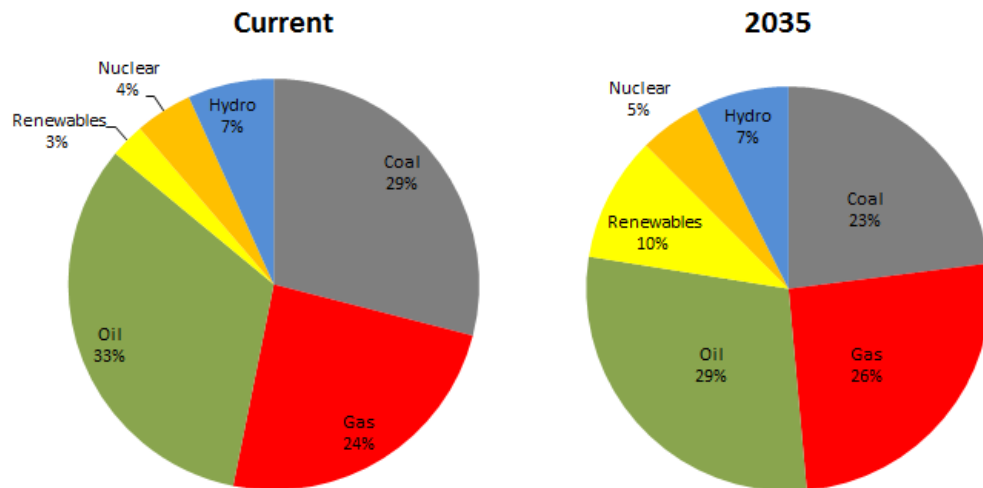


Figure 2.1 : The share of world energy consumption in 2016 and in 2035 (BP, 2016).

Figure 2.1 shows that after 20 years, there will be a slight transition towards to cleaner energy type, renewable energy will climb to 10% from 3%. However, in 2035 fossil fuels will still keep its dominance as the main source of energy. Gas is predicted to replace coal and will become second largest energy source after oil. (BP, 2016).

The world owns a wealth of natural gas reserves but they are not uniformly distributed. There are some countries such as Commonwealth of Independent States (CIS) countries, Middle East, US, Venezuela etc. which mainly possesses great amounts of proved gas reserves.

Figure 2.2 gives a distribution of proved reserves according to the continents. The illustration shows that there is still enough amount of natural gas with 186.9 cm, which can meet more than 50 years of current production. Middle East holds its dominance as the largest proved reserves owner (80 cm or 42.8% of all) over other countries (BP, 2016).

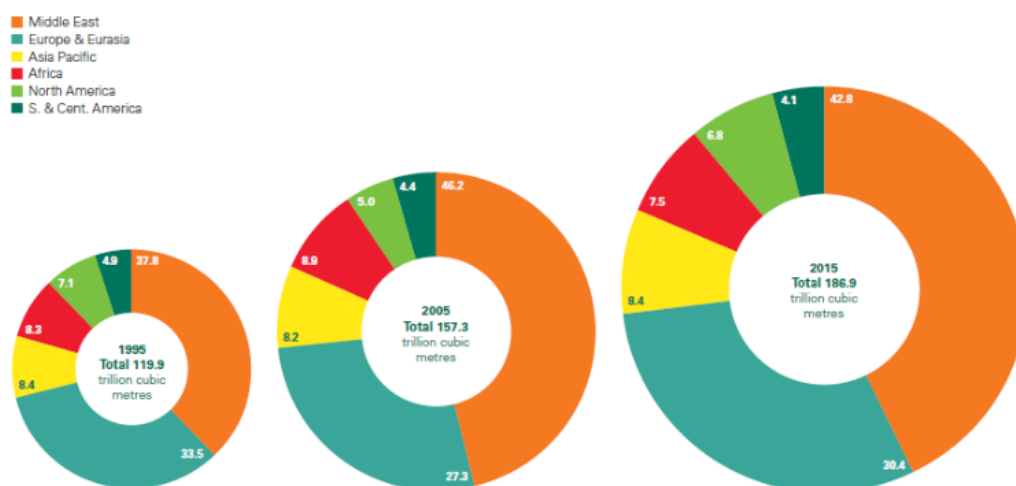


Figure 2.2 : Distribution of Proved Reserves in 1995, 2005 and 2015 (BP, 2016).

BP energy outlook 2035 forecasts, global demand for natural gas will rise by 1.9% and reach to 490 bcf/d (13.8 bcm) in 2035 because of increased usage in some sectors such as power and industrial. This increment is driven by non-OECD (Organization for Economic Cooperation and Development) countries mainly China and India for their growth in demand. Power and industrial sectors constitute 80% of total demand growth. Another fastest growing sector is transport which will increase by 3% in 2035. Approximately half of the increment in gas supply comes from the Middle East and Russia conventional gas. Non-shale resources account for large growth in non-OECD regions.

To meet increasing demand for natural gas global producers such as the Middle East, non-OECD Asia, and OECD America increase supply. China develops its shale resources and grows its production by 15.0 Tcf. Russia and the US raise their production by 10.0 Tcf and 11.3 Tcf, respectively. China, Russia, and the US together make up almost 44% of total increase in global natural gas production. (U.S. Energy Information Administration, 2015).

Table 2.2 : shows us North America, Europe&Eurasia, Middle East and the Asia Pacific are main producers and consumers in the world. The US is the essential producer of North America with 767.3 bcm where it consumes 778.0 bcm. Following the US is Canada with the production of 163.5 bcm and 102.5 bcm consumption. Russia is the largest producer in Europe & Eurasia with 573.3 bcm production, and it consumes 391.5 bcm amount of gas. Iran and Qatar are main players in the Middle East with 192.5 bcm and 181.4 bcm productions, respectively. Iran consumes 191.2

bcm gas where Qatar consumes 45.2 bcm of its production. China is the biggest producer in the Asia Pacific with the production of 138.0 bcm while at consumption Japan is also the largest one with 113.4 bcm and China is 197.3 bcm. (BP, 2016)

Table 2.2 : World natural gas production and consumption by regions (BP, 2016).

REGIONS	PRODUCTION (bcm)	CONSUMPTION (bcm)
North America	984.0	963.6
S. and Central America	178.5	174.8
Europe and Eurasia	989.0	1003.5
Middle East	617.9	490.2
Africa	211.8	135.5
Asia Pacific	556.7	701.1
Total World	3538.6	3468.6

As discussed, we can mention that non-OECD countries have more overall production of 2245.5 bcm than other regions, whereas its consumption is 1862.1 bcm. It means the remaining amount is exported to other countries. OECD countries follow them with total 1293.2 bcm production while their consumption is more than their production with 1606.1 bcm; thus, these countries import gas to meet their demand. CIS countries have 751.6 bcm production and 545.4 bcm consumption, which clarifies these countries have export to EU countries or to other regions because members of EU have more consumption than production with 402.1 bcm and 120.1 bcm, respectively. These are statistics of BP in 2016, which is published annually (BP, 2016).

2.2.2 Natural Gas in Turkey

In a fast-growing economy, Turkey is one of the rapidly growing energy markets globally. Turkey is witnessing a growing demand in all parts of energy sectors through decades. Following China, Turkey is the second largest country regarding increasing demand for natural gas and electricity, and it is expected that the growing trend will go on. Limited resources of Turkey meet only 25% of domestic demand and therefore,

increasing demand force country to import a remaining part from other countries especially in terms of oil and gas (“Natural Gas,” n.d.).

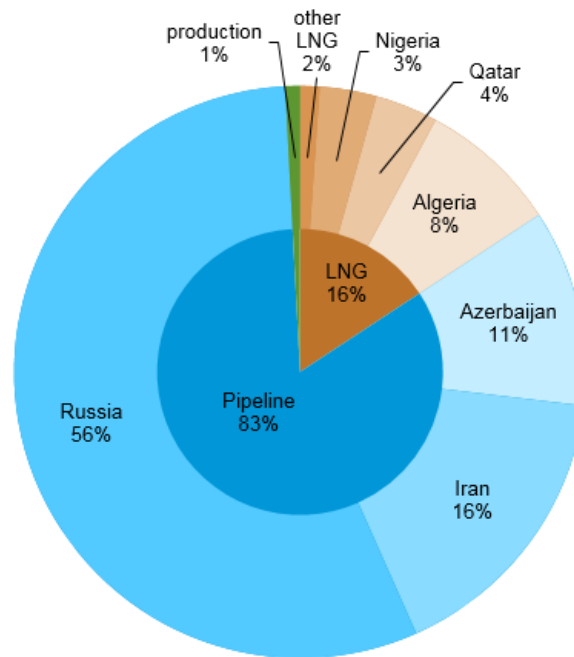


Figure 2.3 : Turkey’s Natural Gas Supply by Source (U.S Energy Information Administration, 2016b).

Turkey is one of the most important countries either for consumption or transition for natural gas suppliers due to its location. Its consumption continues to grow strongly and with this demand, it is one of the rare countries in Europe. Located between Continental Europe, world’s second-largest natural gas market, and the Caspian Basin and the Middle East, which they are having world’s substantial reserves, brings many contractors to the country and new pipelines are being constructed to increase imports and exports of natural gas.

Figure 2.3 reveals us, the main supplier of Turkey gas is Russia (56%), then Iran (16%) following is Azerbaijan (11%), Algeria (8%), Qatar (4%), Nigeria (3%) and from other sources (2%). As can be seen also from the figure, only 1% comes from domestic production. Production of natural gas in Turkey is lower than consumption and 99% of its consumption is imported from other countries (U.S Energy Information Administration, 2016b).

In order to avoid natural gas dependence from abroad, exploration and investment in new local gas sources continue. However, to cover Turkey's demand even in the best case, domestic production will not constitute a significant proportion of its gas balance.

Estimated proved natural gas is 0,26 bcm and amount of recoverable gas is 0,21 bcm in Turkey, however, this only will be sufficient to meet a very small part of its consumption.

According to Table 2.3 : Turkey's total proved gas is 0.26 bcm and 0.21 bcm is recoverable. Cumulative production of the total recoverable gas amount is 0.13 bcm and 0.7 bcm still remains and is recoverable (Rzayeva, 2014).

Table 2.3 : Total Proved, Recoverable, Cumulative and Remaining Recoverable Gas (Rzayeva, 2014).

	Original Gas in Place (bcm)	Recoverable Gas (bcm)	Cumulative Production (bcm)	Remaining Recoverable Gas (bcm)
Total	0,26	0,21	0,13	0,7

Local gas production in Turkey was 812.5 MMcm (private companies 64% and TPAO 36%) in 2012 and it accounts for only 1.5% of the total consumption. Besides conventional gas, there are exploration and developments of shale gas resources in Turkey. Data obtained by EMRA from wells drilled in Southeastern Anatolia and Turkey Thrace indicates that estimation of shale resources is 420 bcm. Drilling of first shale gas well which is named as Saribuğday-1 started in August 2013. Private companies like Thrace Basin and Amity Oil by using hydraulic fracking methods drilled wells to extract shale gas and can be applied to other parts of Turkey (Rzayeva, 2014).

Turkey's natural gas consumption is increasing sharply and BOTAS forecasts demand will go up twice from 45 bcm in 2012 to around 81 bcm in 2030 (Rzayeva, 2014). It can be seen from Figure 2.4, in comparison with production-consumption is very high. Its main reason is gas generated electricity and in 2015 natural gas was the main source of electricity which accounted for 39.61% of total electricity generation that is shown in Figure 2.5.

2.2.3 Natural Gas in Azerbaijan

Azerbaijan globally is one of the oldest oil and gas producing country and essential supplier of oil and gas in Caspian Sea region to European markets. Traditionally Azerbaijan mainly was an oil producer but its importance as a crucial gas supplier is growing. Azerbaijan's economy is mainly dependent on its natural sources such as oil and natural gas. Azerbaijan is a key player in Eurasia and expands its energy industry which allows the country to safely supply its energy to the world. Azerbaijan is increasing its number of co-operation with multiple customers and planning to be a main supplier of gas to Europe in the future decades. Main fields that Azerbaijan produces its gas are shown in Figure 2.4.

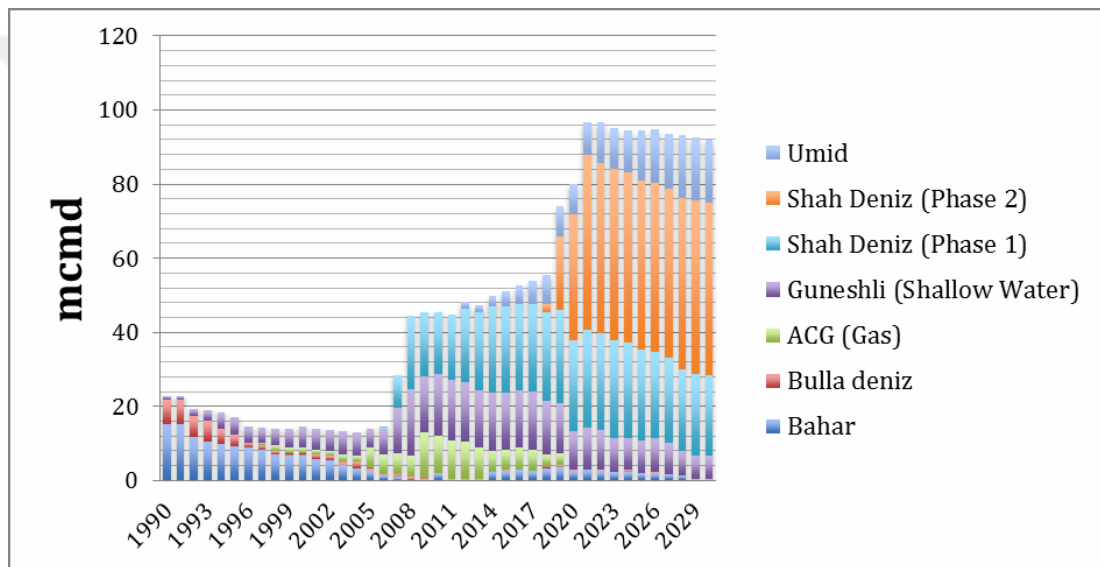


Figure 2.4 : Azerbaijan's gas production from key fields (Rzayeva, 2014).

Azerbaijan has over three trillion cubic meters of gas reserves. Most of these are Shah Deniz field reserves which are a giant field and dominates Azerbaijan's gas sector and gas production. The main part of the gas is produced from offshore fields such as Shah Deniz and ACG complex (U.S Energy Information Administration, 2016a).

Shah Deniz Field is one of the largest gas condensate fields in the world and discovered in 1999. BP operates the field in agreement with its partners in the Production Sharing Agreement (PSA). Shah Deniz field has two stages, production of the first stage started in 2006 and allowed Azerbaijan to start net export in 2007. Its capacity was to produce approximately 10 bcm of gas annually and in 2014 its daily production capacity was 29.5 million standard cubic meters of gas. In 2016, production of the field was 10.7 bcm. Currently, its daily production capacity is 30 million cubic meters of gas.

Currently phase one constitutes 75% of Azerbaijan commercial gas reserves. The second stage is planned to start production in 2018. This will add extra 16 bcm of gas per year to stage one which produces 9 bcm annually. Shah Deniz 2 is considered as one of the biggest developments in the world and will bring Caspian gas securely to Europe. The main operator of field is BP which has the biggest share with 28.8% of the joint venture. Other shareholders are SOCAR (16.7%), TPAO (19%), Lukoil (10%) and NICO (10%), and Statoil sold its share (15.5%) of Shah Deniz field to Petronas in 2015(BP, n.d.).

ACG (Azeri Chirag Guneshli) complex is a source of associated gas for domestic use through undersea pipelines, which stored in Sangachal Terminal, is one of the largest natural gas and oil processing terminals. The terminal is located at the south of Baku and is being used for different purposes like receiver, storage and processes natural gas from SD and ACG fields. The field is discovered in the 1970s and is one of the largest fields in Caspian Basin. It is also operated by BP and there are other partner companies such as BP (35,78%), SOCAR (11.64%), Chevron (11.27%), Inpex (10.96%), Statoil (8.56%), ExxonMobil (8%), TPAO (6.75%), Itochu (4.29%) and ONGC (2.72%) (BP, 2015). Azerbaijan's key oil and gas infrastructure is given in Figure 2.7.

Demand for Azerbaijan's gas in the domestic market is also extremely higher than other types of energy sources. Natural gas plays a crucial role in the domestic market and constitutes almost two-thirds of total energy consumption. Higher than 90% of electricity comes from gas generated electricity and is growing through years. The other largest consumption sector is households and commercial consumers. Following sectors are heat and power transformation, agricultural, industrial and losses (Pirani, 2016).

According to BP statistical review of World Energy 2016, Azerbaijan has total more than 18.0 bcm production where it consumed almost half of it which is 9.8 bcm. The remaining amount allows the country to export to another country.

Most of Azerbaijan gas through SCP (South Caucasus Pipeline other name is Baku Tbilisi Erzurum) passes through Georgia and destined in Turkey. Some amount of it goes to Greece. Under the new agreement, Azerbaijan will directly export its gas to Europe. After Shah Deniz 2 export will increase to 565 Bcf, Turkey will take its 212

Bcf, Italy 283 Bcf, Bulgaria and Albania will take its 35 Bcf. Delivery to Turkey will start in 2018 and for other countries, it will start a year later.

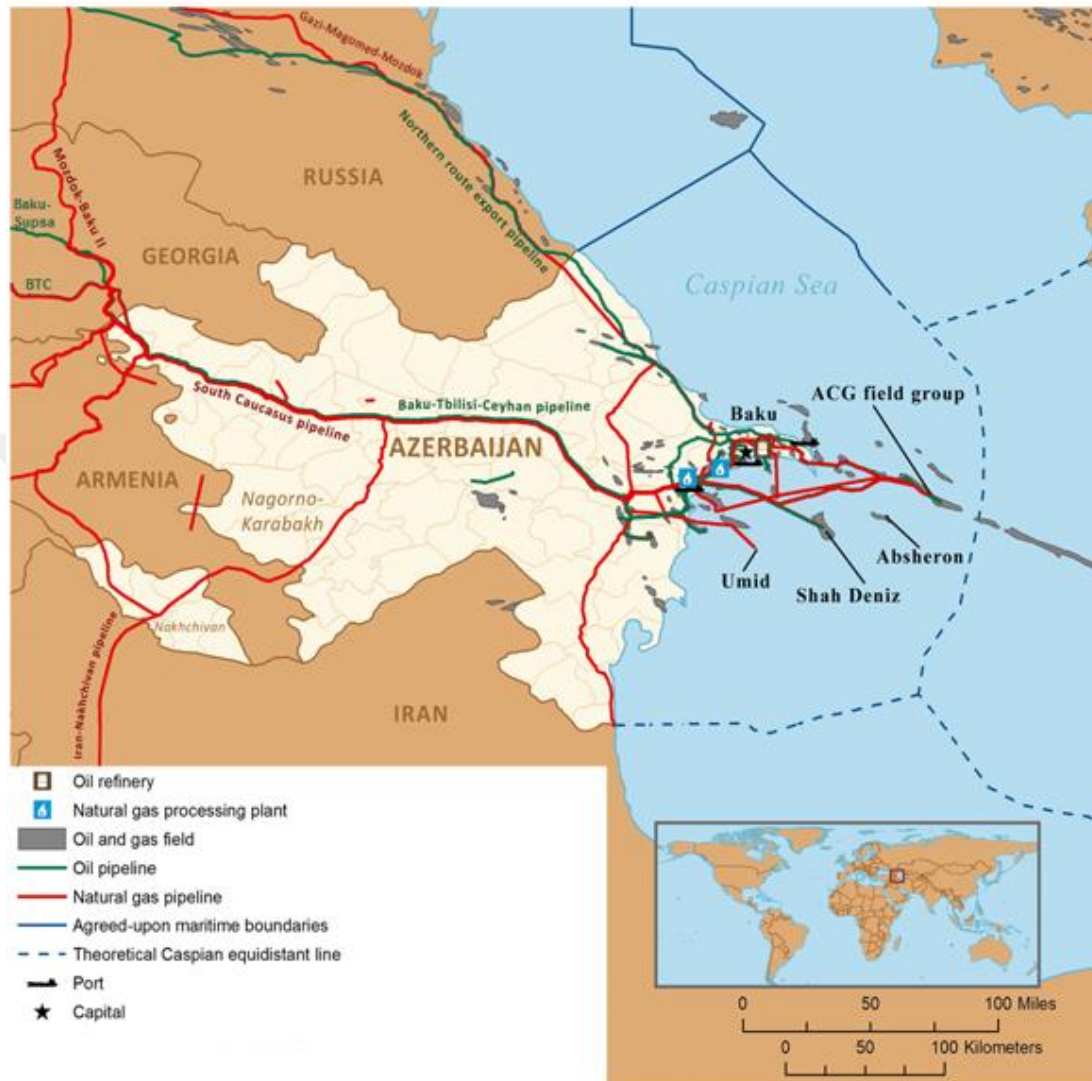


Figure 2.5 : Key oil and gas infrastructure in Azerbaijan(U.S Energy Information Administration, 2016a).

Through Hajiqabul-Mozdok pipeline Azerbaijan also exported some amount of gas to Russia between 2007-2014 and other small amounts of gas via Hajiqabul-Astara pipeline are shipped to Iran. As an interchange, Iran exports gas to Nakhchivan, which is Azerbaijan's exclave between Iran and Turkey. Nakhchivan is mainly dependent on gas supplied by Iran. One of the main pipelines is TANAP (Trans-Anatolian) natural gas pipeline, which brings Azerbaijan gas to Turkey and further to Europe. The aim of this pipeline is to expand Azerbaijan gas export markets and develop secure energy supply of Turkey and South Eastern Europe. Georgia also gets benefit from this project

as an extra gas to its network due to transportation to Turkey through the country (U.S Energy Information Administration, 2016a).

Table 2.4 : shows possible production capacities of Azerbaijan main fields now and throughout future years.

Table 2.4 : Summary of possible ranges of outputs (bcm) (Pirani, 2016).

Fields	2015	2020	2025
Shah Deniz 1	9.9	10	7
Shah Deniz 2	0	10	16.3
ACG associated gas	3.2	2 – 3	2 – 3
Absheron	0	0	0 – 5
SOCAR fields	5.8	5.2 – 7.7	5.4 – 10.9
TOTAL	18.9	27.2 – 30.7	30.7 – 42.2

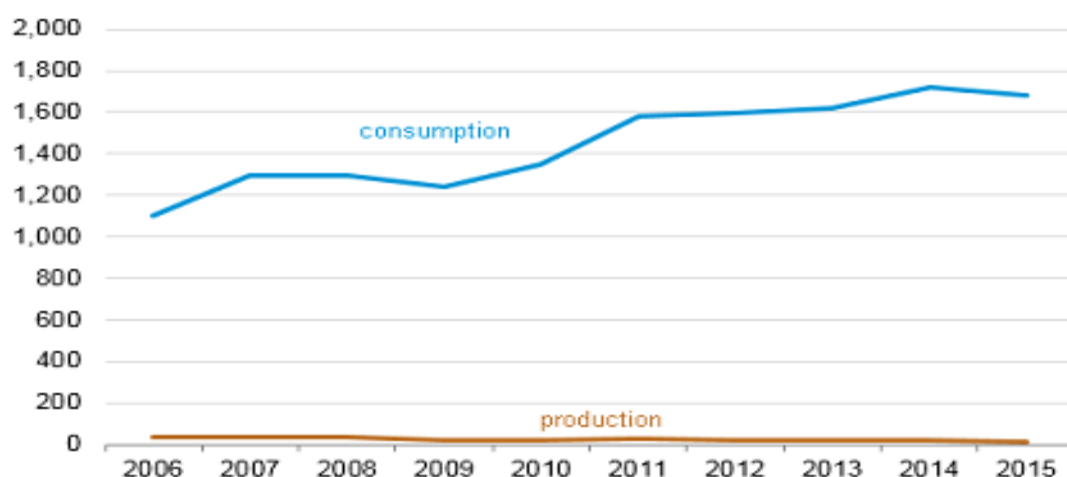


Figure 2.6 : Turkey's natural gas consumption and production (U.S Energy Information Administration, 2016b).

There are also other two main sectors, which drive demand. Following electricity production, industrial consumption is the second most gas consumed sector with 29.10% and it is expected to grow. The third factor that contributes to total natural gas demand increment is residential use, which accounts for 22.92%, and it is also forecasted to grow (Energy Market Regulatory Authority Of Turkey Republic, 2016).

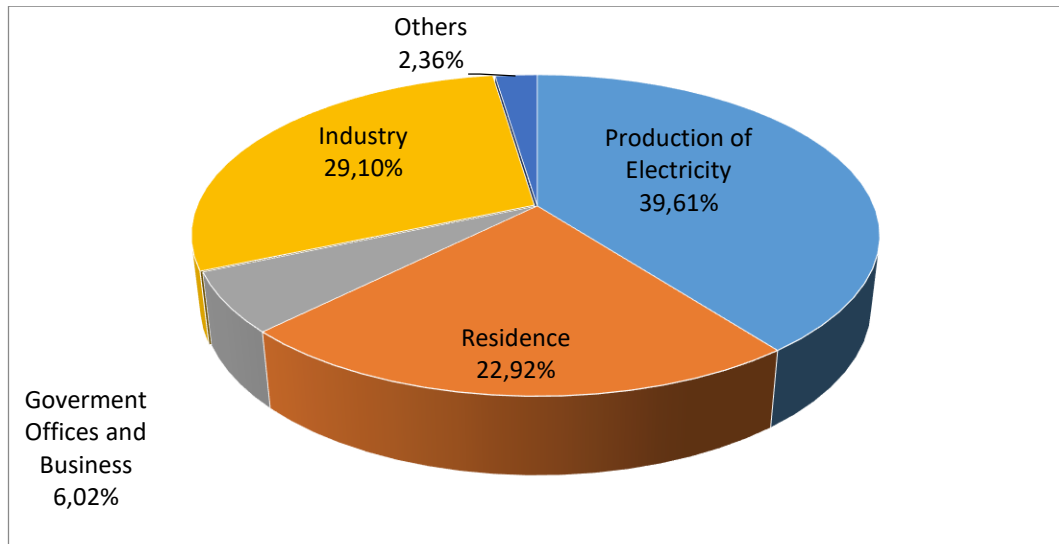


Figure 2.7 : Share of sectorial consumption in 2015 (%) (Energy Market Regulatory Authority Of Turkey Republic, 2016).

2.3 Natural Gas Storage

Underground natural gas storage is the process of storing unused quantities in a storage reservoir at a time when it falls below a fixed quantity. This process plays an important role in adjusting supply outages and industrial demand changes, as well as demand surplus due to seasonal differences.

Natural gas in the world is consumed in four common widespread areas:

1. Power generation,
2. Residential,
3. Commercial,
4. Industrial.

Gas demand in residential heating shows significant changes depending on settlement area, months and years. In particular, while gas demand reaches its highest level in winter months, there will be no demand in summer months. On the other hand, the gas demand of the industry will change according to its current state of the economic structure. However, the gas demand of the power generation sector varies depending on the power balance of the area.

When underground storage of natural gas is below the fixed amount provided by the consumer demand pipelines, the excess amount is injected into the underground

storage, and when the demand exceeds the amount provided by the pipelines, the excess demand is met by the amount from the underground storage. Underground storage provides the most economical solution to variable demand with the fixed quantity of gas. Underground gas storage is the most important part of the natural gas distribution system since gas can be supplied to houses, hospitals, and commercial buildings without any problem with this facility (Karaalioglu, 1997).

There are three main types of underground natural gas storage:

- Storage in Aquifers
- Storage in Salt Caverns
- Storage in Depleted oil/gas fields

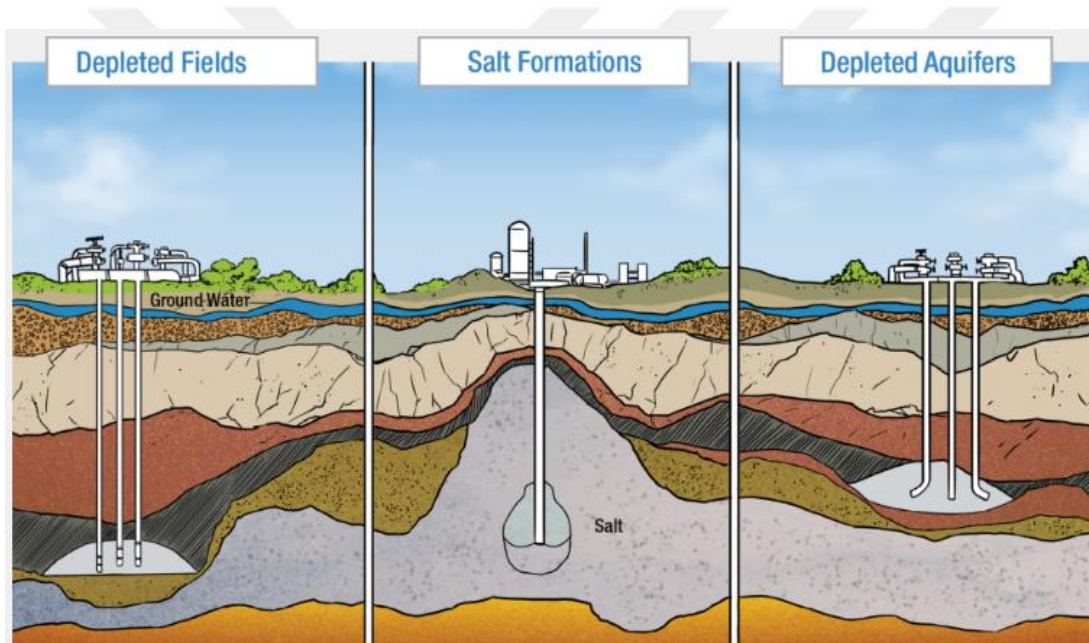


Figure 2.8 : Underground natural gas storage types(“Underground Natural Gas Storage,” n.d.).

There is also another type of storage, which is storing gas in abandoned mines whereas it is not a prevailed one. Each of these storage methods has own physical or economic characteristics (Figure 2.8).

Depleted gas reservoirs are the most suitable geological structures to store gas because they are the natural environment of gas. Depleted oil reservoirs also provide a convenient environment for storage, but residual oil in the reservoir can create technical problems.

Storage in the aquifers requires more processing than in the depleted oil or gas reservoirs. For this reason, first depleted oil or gas reservoirs are searched for storage if they are not available then natural gas is stored in the aquifers. If there is no suitable aquifer for storage, the priority salt deposits and then abandoned mines can be examined as storage reserves (Karaalioglu, 1997).

2.3.1.1 Natural gas storage in aquifers

Aquifers are porous and permeable sediment layers, where horizontal pores are filled with water of several km. In order for an aquifer to be used as an underground natural gas storage, it must have the same geological characteristics as natural gas or oil reservoirs.

There are certain preconditions that aquifer must have in order to store gas in aquifers:

1. It is necessary to have a geological structure in which the gas can be stored.
2. There should be a porous and permeable medium that allows the flow of stored fluid to the well at the desired rate.
3. There should be an impermeable cover layer that prevents the vertical movement of the stored fluid.
4. In order to store the required amount of gas, storage pressure must be much higher than the atmospheric pressure. For this reason, there must be a sufficient upper layer pressure to allow storage at this high pressure. Here depth is a very important criterion. Generally, depths of 305 m or more are preferred in terms of economics.
5. The stored fluid must be limited in each direction by the aquifer water. Thus, the downward and lateral movement of the stored gas is prevented by the water due to the density difference. Upward gas movement is only possible with a low permeable cover layer.

Beside blocking vertical movement, the cover layer should be anticlinal-shaped so as to prevent lateral movement as well.

Storage volume in the aquifers occurs when the injected gas displaces the water in the aquifer. Because of the more viscous nature of the water fingering can happen; so to avoid this stored gas should be slowly injected from the injection wells. Rapid injection

and production can be done in later stages. In order to follow the movement of water and gas in the reservoir, it is necessary to open more observation and injection wells than other storage techniques (Karaalioglu, 1997).

Advantages of storage in aquifers:

- Locates in close to final consumers
- High withdrawal rate
- The capability of running multiple cycles in one season is better than storage in depleted reservoirs

Disadvantages of storage in aquifers:

- This type of structure did not contain hydrocarbons previously, so it means there is uncertainty as to tightness of such facility thus it has geological risks
- Regarding water extraction, there are high operating costs
- It is needed to create large cushion gas (Ipi.gasstoragepoland.pl, n.d.)

2.3.1.2 Storage in salt caverns

Hydrocarbon storage in salt deposits is a common practice. Recent advances in techniques for forming salt cavities have led to the development and preference of such deposits. Unlike other storage techniques, in this method, the cavities to be stored are not naturally existing, but are formed artificially and then storage is carried out.

Salt is a geologically diverse structure. Wave shaped deformations of layered rocks from various folds. Salt domes are also formed as a result of these folds. Plastic materials such as gypsum and salt (chloride salts, NaCl) cause stratification in the anticlinal areas - resulting in the formation of such structures in the form of mushroom. The presence of limestone cover rock in the upper part of the salt domes is important in the storage of the gas.

It is not possible to store in all salt domes. The following three factors must be considered in the selection of salt deposits as storage cavities:

1. Enough salt must be available in depths,
2. Coexistence of easily (such as potassium salts) and more difficultly (alkali salt types such as gypsum, anhydrite, dolomite) and solvable structures create

geometric irregularities in the reservoir, so the mineral distribution in the salt domes should be as homogeneous as possible,

3. There should be enough fresh water for the salt leaching process and a suitable place for deposition of salt water, which is formed at the end of the leaching process.

Freshwater from the surface is injected into the salt formation and the salt is melted to form a cavity. The salty water formed at the end of this process is taken back and storage is done in salt deposits. This method has been used for years in salt production. Generally, attention should be paid to the shape and size of the cavity, stability or pressure resistance.

Since the fresh water used in the salt leaching process is low density, it melts the upper part of the cavity as well. In order to prevent this, the hydrocarbon covering material is injected. This injected hydrocarbon is known as a covering material (blanket). Because of its density, the hydrocarbon is located at the top of the cavern and prevents melting from fresh water.

The salt melting process is based on the principle that 360 g of salt can be dissolved in 1 lt of water. For this, 7 m³ fresh water is required for 1 m³ storage capacity.

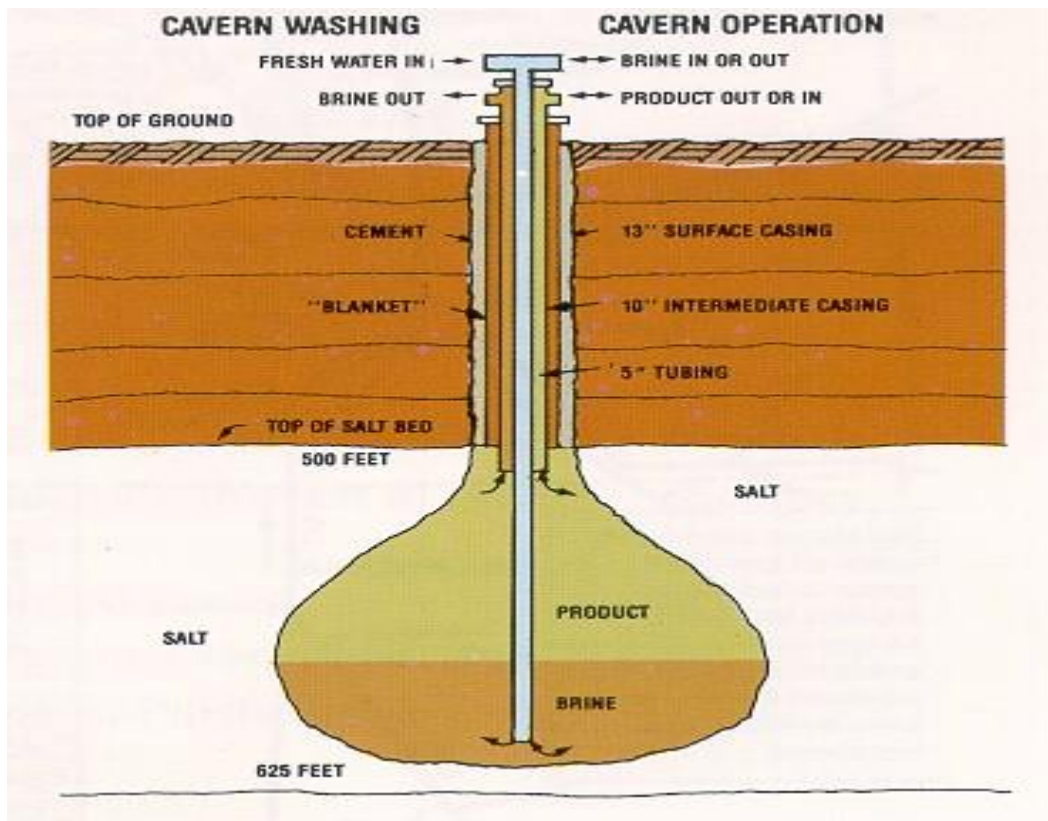


Figure 2.9 : Direct and reverse leaching processes(The international association for natural gas (CEDIGAZ), 2017).

There are two types of leaching processes, direct and reverse. When the storage formation process is started, firstly direct then reverse leaching process is applied and then the final shape of the storage is obtained.

In the direct leaching process, fresh water is injected through the inner protection tube. The salty water is withdrawn through the annulus of outer and inner protection tube. Thus the lower part of the cavern becomes larger than the upper part.

In the reverse leaching process, the fresh water is injected from the annulus of outer and inner protection tube. The resulting salt water is withdrawn from the inner protection tube. In contrast to the direct leaching process, the upper part of the cavern is larger than the lower part. Direct and reverse leaching process is shown in Figure 2.9.

Various cavern shapes can be obtained by making different combinations of direct and reverse leaching processes. However, the presence of insoluble anhydrite or easily soluble potassium in the salt prevents the uniformity of the cavern. In order to achieve

the desired shape and size while forming the salt cavern, the following controls must be made:

1. Daily mass balance should be calculated between the injected fresh water and taken saline to calculate the volume of the cavity.
2. The shape, size, and location of the cavity should be measured by taking the sonar log. These measurements should be repeated at every 50000 m³ increment of the cavity volume.
3. The depth of the covering layer/saltwater interface must be continuously checked.

Uncontrolled increments at the interface depth (which may be due to leaks from the protection tube or surface equipment) can cause a rapid change in cavity shape. Therefore, the interface depth should be measured with appropriate logs (gamma/gamma or neutron/gamma logs) approximately every 4 weeks.

Finally, the brine formed at the end of the leaching process,

- By using semi-submersible pumps to discharge salt water or
- By displacement of the fluid in the storage medium

removed from the cavern.

The second method is used more because it is more economical. Generally, the cost of storing in salt caverns is low. Factors affecting the finance can be summarized as follows:

1. The size of the cavern,
2. The geology of the place where the reservoir is located
3. The depth of the salt dome
4. The characteristics of the covering layer,
5. The cost of the necessary power,
6. The presence of surface equipment,
7. Salty water discharge operation (Karaalioglu,1997).

Advantages of storage in salt caverns:

- Small buffer gas in the total volume of storage
- In high demands, high injection and withdrawal rate
- Running multiple injections and withdraw cycles capability in a year and which helps to balance fluctuations in gas supply and demand
- The non-tightness risk is low

Disadvantages of salt caverns storage:

- Construction of storage facilities requires high investment
- Operation cost is high
- Utilization or disposal of saline after leaching process has limited options
- After convergence, there is working volume loss(Ipi.gasstoragepoland.pl, n.d.)

2.3.1.3 Natural gas storage in abandoned mines

Abandoned mines are also suitable for underground storage, but not as widely used as other methods. After the idea of storing the gas underground has been put forward, in the west it is planned to use opened mines as a purpose of storage.

If the rocks surrounding the mine is more stable, which is planned to be used as storage, the more gas can be stored because the pressure can be increased as the gas is stored. For example, granite, limestone, sandstone, shale, anhydrite, and salt are suitable rocks for storage.

The biggest problem in the galleries to be stored is gas leaks. If cracks and breaks are found in the rocks on the gallery surface, it is necessary to seal them with the sealing materials, which requires an additional investment cost. In addition, abandoned mines are fed continuously by underground waters. For this reason, the stability of the water level must be ensured. In order to be able to store in the galleries, besides the observation and gas injection wells, extra wells should be opened to the gallery to prevent groundwater from coming in (Karaalioglu, 1997).

2.3.1.4 Natural gas storage in depleted fields

It is a form of storage that allows large volumes of natural gas to be stored to meet seasonal demand fluctuations. For this reason, it is the type of storage which is most preferred, used and evaluated at every possibility. Billions of cubic meters of natural

gas can be stored in this interconnected void spaces, which they are permeable in the reservoir.

Natural gas reservoirs are the most suitable candidates for storage because a reservoir contained gas previously and can maintain gas again for a long time. Among the gas reserves, dry gas reserves are the primary candidates because they will provide single-phase flow during reproduction.

There are some factors such as shape, aquifer size, geological structure dimensions, gas-water contact, reservoir and cap rock properties that should be paid for storage. Other important characteristics of the reservoir rock, which need careful evaluation, are:

- High porosity which determines the storage capacity
- High permeability defines its suitability for storage
- Water saturation should be very low unless it decreases available volume.

Underground natural gas storage can allow for economical storage of large quantities of gas that can be used for space heating and can store enough gas to prevent pressure increases due to accumulations in pipelines during periods of low demand. Since the aquifers and reservoirs are permeable, they operate at relatively low and limited flows in the injection and recovery stages. Therefore, they are used as stabilizers in seasonal variations rather than sudden changes (Erdogan, 2011).

Advantages of storage in depleted reservoirs:

- The connections with major gas pipelines
- Previously having well and surface facilities significantly reduce the cost of construction and can be used after maintenance.
- Geology of reservoir is known and there is no risk of uncontrolled gas leakage from storage because the reservoir is forming a trap.
- Unproduced gas is used as cushion gas which decreases investment expenditures

Disadvantages of storage in depleted fields:

- This facility generally are capable of running one injection and withdrawal cycle throughout annually
- Existing wells and surface infrastructures are relatively old and need costly reconstruction(Ipi.gasstoragepoland.pl, n.d.)

2.4 Natural Gas Processing

There is a big difference between the natural gas that consumed by people and the natural gas that is carried from underground up to the wellhead. The processing of natural gas is in any amounts of respects more straightforward than the processing and refining of crude oil. However, both of them have importance before its use by end consumers.

Although the natural gas consumed by users is contained practically completely of methane, the natural gas found at the wellhead is not as pure as it. As a fact, There are three types of wells where natural gas comes from oil wells, gas wells, and condensate wells. Natural gas, which is derived from oil wells, is typically termed as 'associated gas'. Associated gas can exist in two ways: free gas or dissolved gas. Free gas separates from oil in the formation and dissolved gas dissolves in the crude oil. If there is a minor amount of crude oil or there is no any crude oil, in the well (gas wells and condensate wells) natural gas is defined as 'non associated gas'. Natural gas is produced in free form with a semi-liquid hydrocarbon condensate in condensate wells while it is produced in raw form by gas wells. Principally, natural gas separated from crude oil always exists in the mixture form with other small chain alkanes: ethane, propane, butane, and pentanes. Furthermore, the raw natural gas contains water vapor, hydrogen sulfide, carbon dioxide, helium, nitrogen, and some other chemicals. (Naturalgas.org, 2013)

The main intention of natural gas processing is the separation all of the other alkanes and fluids from the pure natural gas, to reach the level that called as 'pipeline quality' dry natural gas. Most important transport pipelines usually enforce restrictions on the make-up of the natural gas that is permitted into the pipeline. This means that the natural gas must be purified before it is transported. At field processing, some of the required processing can be accomplished at or near the wellhead. However, the complete processing of natural gas occurs at a natural gas processing plant, generally

placed in a natural gas producing area. Transportation of the extracted natural gas takes place through a network of gathering pipelines consisted of small-diameter, low-pressure pipes to the processing plants. (Naturalgas.org, 2013)

There are four essential application methods for treatment of different impurities to get dry natural gas quality:

1. Oil and Condensate Removal
2. Water Removal
3. Separation of Natural Gas Liquids
4. Sulfur and Carbon Dioxide Removal

2.4.1 Oil and Condensate Removal

Separation of natural gas from the oil, which it is dissolved, is a pivotal step for both processing and transportation of it. Generally, natural gas is separated from the oil by the equipment which is established next to wellhead. The process of natural gas separation changes according to the equipment used. In spite of that, dry pipeline quality natural gas is almost the same in various geographic places, it is possible that compositions and separation requirements of raw natural gas from these areas may change. In many cases, formation pressure in underground dissolves the natural gas in the oil. Because of that after production of natural gas and oil pressure decrease, natural gas will separate from oil on its own. The most modest type of separator consists of a simply closed tank which is known as a conventional separator. In this separator, gravity force is used to separate heavy liquid from light gases (oil from natural gas). But this may not always be enough. In such cases, specific equipment is compulsory to separate oil and natural gas. Low-Temperature Separator (LTS) is one of the most used equipment, which can be shown as an example. Operation scheme of Low-Temperature Separator is shown in Figure 2.10 LTS is used for wells which produce high-pressure gas along with light crude oil or condensate. (Naturalgas.org, 2013)

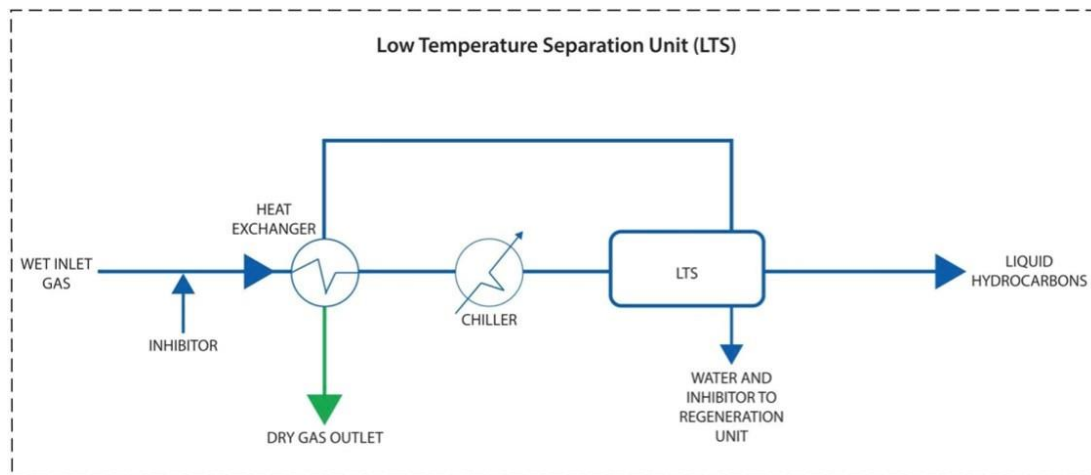


Figure 2.10 : Low-Temperature Separator (LTS)(“Natural Gas Dehydration Unit,” n.d.)

Wet natural gas is cooled by these separators by pressure differentials and by this way oil and condensate are separated from each other. After this step, the heat exchanger is used for cooling entered wet gas. Formerly, the gas passes over high-pressure liquid, which is used to eliminate any liquid from the low-temperature separator. After that, this gas run through this low-temperature separator through a throttling mechanism that enlarges as the gas enters the separator. Such quick expansion of the gas reasons the temperature in the separator to decrease. The dry gas, which is returned from the heat exchanger, is heated by the incoming wet gas subsequently the liquid is removed. By changing the gas pressure in various parts of the separator it is possible to vary the temperature and the temperature causing the condensation of oil and some water from the wet gas stream. It is also possible to use same basic pressure-temperature relationship for the abolition of gas from an oil stream. (Naturalgas.org, 2013)

2.4.2 Water Removal

Removal of the majority of the associated water is as much as essential to separate oil and condensate from the wet gas stream. The liquid associated with the extracted natural gas is removed by simple separation methods at the beginning of the well or near the wellhead. On the other hand, removal of soluble water vapor in natural gas requires more complex treatment methods that are compulsory for removing soluble water vapor in natural gas. This process involves the 'dehydration' of natural gas, which includes one of absorption or adsorption processes. The adsorption takes place when the surface is coated by the condensed water vapor. However, absorption takes place when a dehydrating agent takes out the water vapor.(Naturalgas.org, 2013)

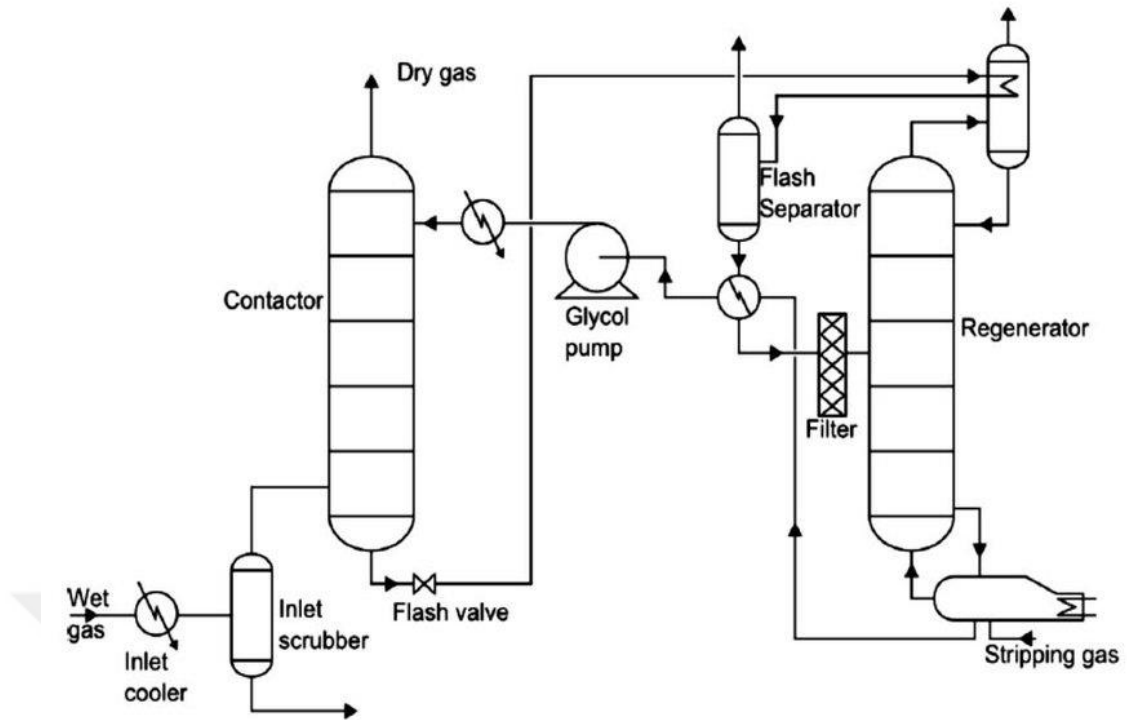


Figure 2.11 : Glycol Dehydration(Ezzeghni & Nuclear, 2018)

Solid-Desiccant Dehydration and Glycol Dehydration processes that are used for adsorption and absorption of water from natural gas, which is given in Figure 2.11 and Figure 2.12, can be given as an example. In Glycol Dehydration process, water vapor is absorbed by a liquid desiccant dehydrator from the gas stream. The ability of glycol to have a chemical affinity for water makes it be the main agent in this process. Which means, when it comes into contact with a natural gas stream containing water, glycols absorb the water from the gas stream.(Naturalgas.org, 2013)

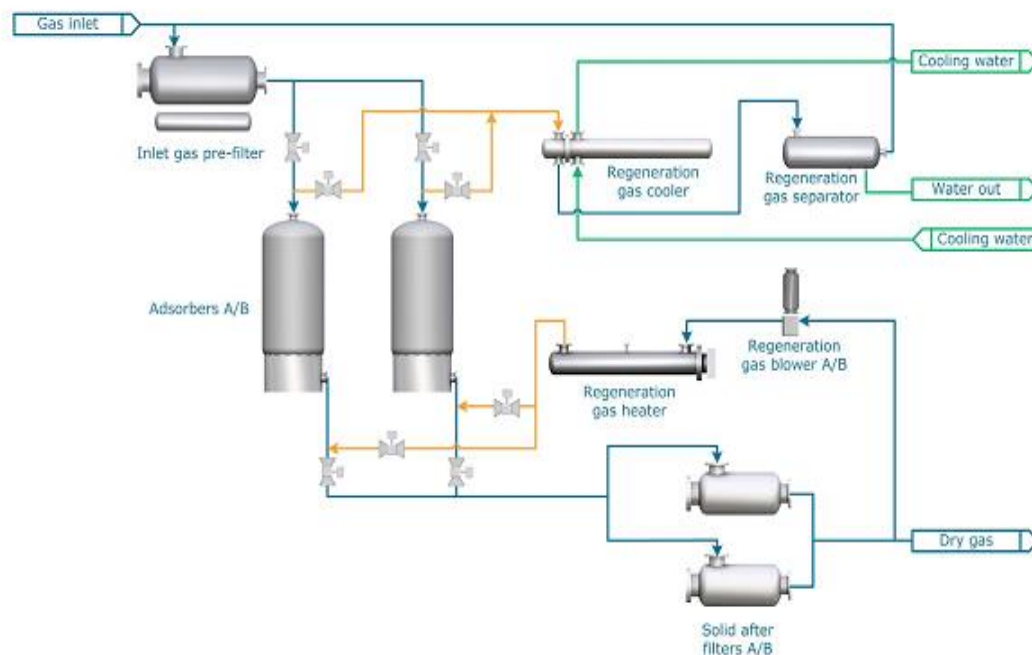


Figure 2.12 : Solid-Desiccant Dehydration(Definition & Description, n.d.-b)

The main dehydration method for natural gas adsorption is solid-desiccant dehydration. Solid-desiccant dehydration consists of at least minimum two adsorption tower with a solid desiccant. Characteristic desiccants contain one or both of granular silica gel material or activated alumina. Wet natural gas is conveyed from these towers to the bottom from the top. Water is retained on the surface of the desiccant material that the wet gas passes around the particles of them. As the entire dryer passes through the bed, almost all the water is absorbed into the dryer material and the dry gas is left to come out of the bottom of the tower. (Naturalgas.org, 2013)

2.4.3 Separation of Natural Gas Liquids

Treatment processes are supposed to be applied to the natural gas, which comes directly from a well; due to its high amount of natural gas liquids contents. In many cases, as separate products, natural gas liquids (NGLs) are more valuable than natural gas. Therefore, it is economically adventures to separate them from the gas stream. The treatment process of natural gas liquids is similar with techniques for dehydration of natural gas. As different from dehydration of natural gas, separation of natural gas liquids occurs in a relatively consolidated processing plant. It is possible to mention two main step for natural gas liquids removal. Initially, removal of the liquids from natural gas must be provided. After that, separated liquids need to be separated from themselves to their main components. Extraction of the liquids from natural gas is

carried out by the absorption method while the cryogenic expander process is used to separate the separated liquids to their main components. (Naturalgas.org, 2013)

2.4.3.1 The Absorption Method

Absorption technique for removing natural gas liquids and dehydration are very similar. Operation scheme of absorption method is shown in Figure 2.13. There is the important difference that an absorbing oil is used for absorption of natural gas liquids instead of glycol. Just as water has glucosamine affinity, this absorbing oil also has a certain affinity for the natural gas liquids. The oil is called as "lean" absorption oil before it catches any natural gas liquids.

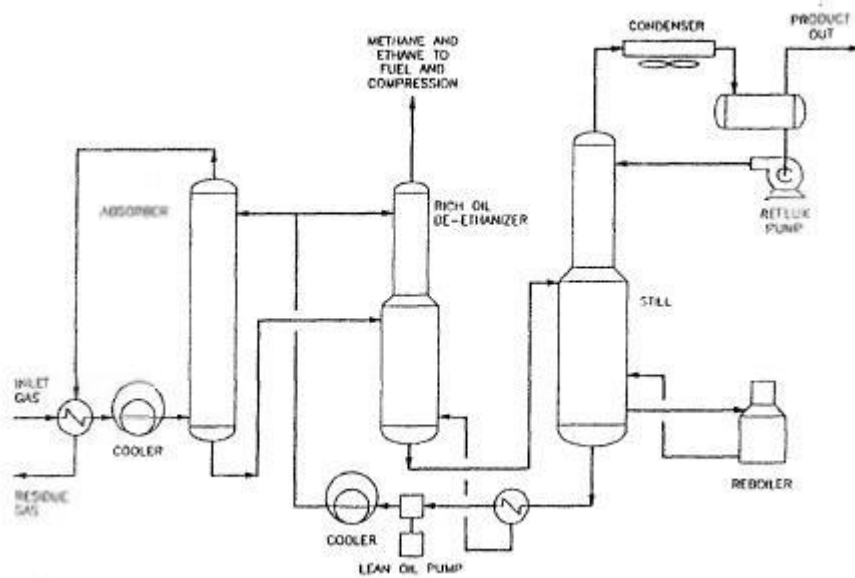


Figure 2.13 : Absorption Method("Hydrocarbon Compression," n.d.)

As a rule, it is supposed to activate interaction between the absorption oil and natural gas liquids during the natural gas is being moved through an absorption tower. At this stage, absorption of the essential amount of the natural gas liquids leans absorption oil takes place. We define absorption oil, which soaks up the natural gas liquids, a 'rich' absorption oil. The 'rich' absorption oil, which contains absorption oil, pentane, propane, butane and some other heavier hydrocarbons, leaves the absorption tower through the lowermost. After all these stages have come to an end, rich absorption oil is meld to the lean absorption oil and heat of the mixture is arranged to the temperature between the boiling points of the natural gas liquids and the oil. Through this process,

75% percent of butane and 85-90% of pentanes and heavy hydrocarbons are reclaimed.(Naturalgas.org, 2013)

2.4.3.2 The Cryogenic Expansion Process

Due to the fact that absorption methods are able to remove almost all natural gas liquids from natural gas, while it has certain difficulties for lighter hydrocarbons for natural gas, cryogenic processes can be accepted as an important complement method for separation of natural gas liquids. In spite of that in some cases leaving lighter natural gas liquids in gas, steam is economically more beneficial, cryogenic processes are required for high recovery rates. Operation scheme of Cryogenic Expansion Process is shown in Figure 2.14. The main principle of the cryogenic process is the reduction of temperature of the natural gas stream to approximately -85 degrees Celsius.(Naturalgas.org, 2013)

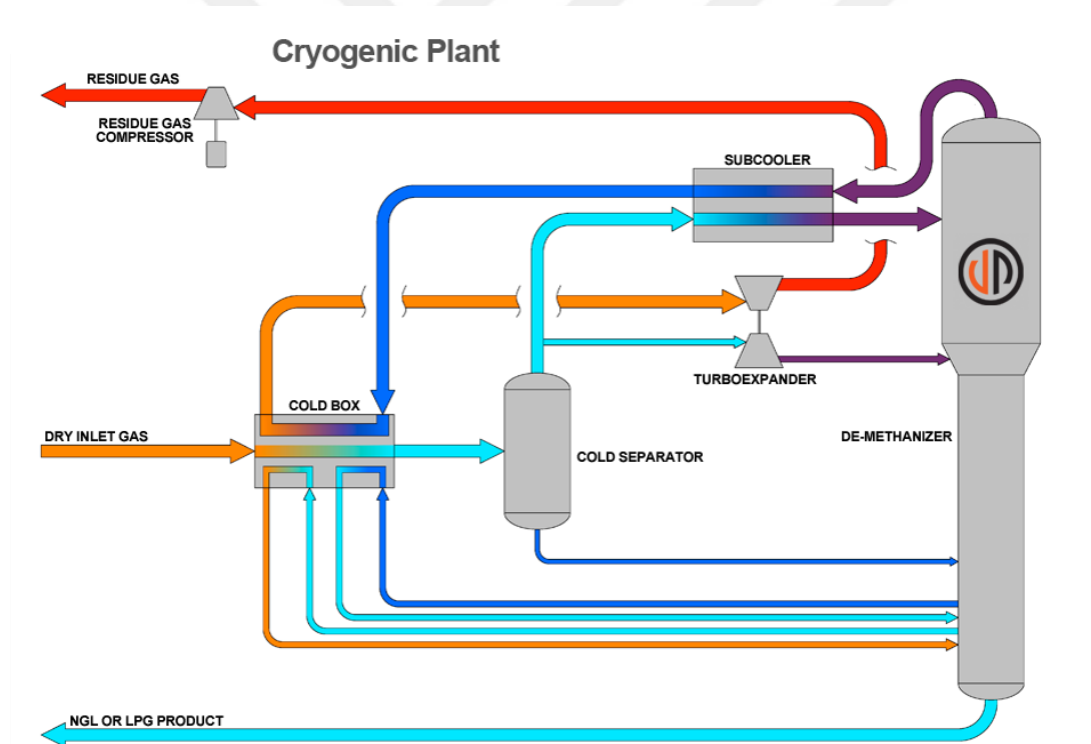


Figure 2.14 : Cryogenic Expansion Process(Expertise & With, n.d.)

The turbo-expander process is the method with the highest amount of efficiency for cooling gas temperature between a number of other methods. According to the procedure of the process, external refrigerants are supposed to be used for cooling natural gas steam. After that, for decreasing temperature meaningfully, an expansion turbine is supposed to be used for expanding cooled gas rapidly. Because of these

processes, methane is kept in gas form, while other lighter hydrocarbons mix to the gas stream. The efficiency of recovering ethane and other lighter hydrocarbons in the gas stream is about 90-95% at the end of the process.(Naturalgas.org, 2013)

2.4.3.3 Sulfur and Carbon Dioxide Removal

Removal process of sulfur and carbon dioxide is another essential part of the treatment of natural gas after water, oil and natural gas liquids. Because of a rotten smell of sulfur, sulfur containing natural gas is named as ‘sour gas’. Sulfur content of the sour gas is not desirable for tremendously harmful and poisonous for breathing. Operation scheme of Carbon Dioxide Removal process is shown in Figure 2.15.

If the amount of hydrogen sulfide in natural gas surpasses 5.7 milligrams per cubic meter, natural gas is accepted as a sour gas. Because of decreasing sourness, treatment process of natural gas from hydrogen sulfide is named as ‘sweetening’.(Naturalgas.org, 2013)

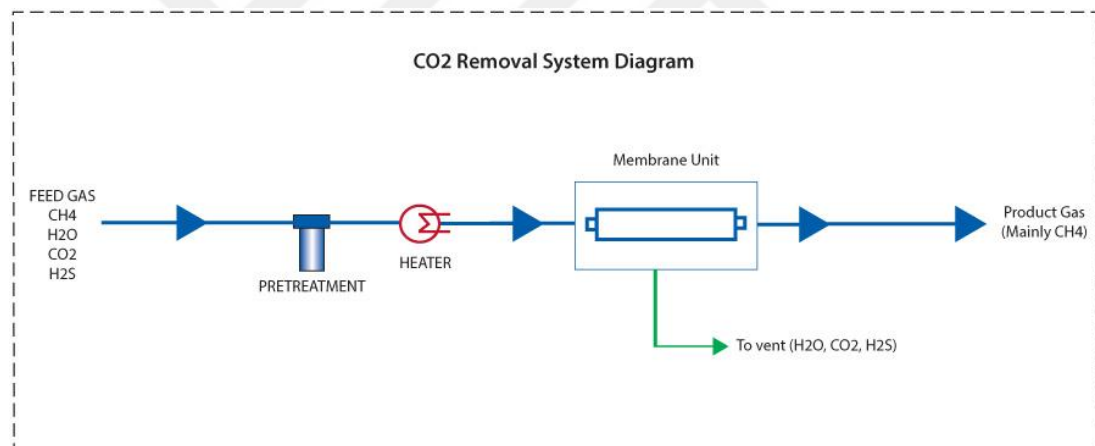


Figure 2.15 : Carbon Dioxide Removal(Definition & Description, n.d.-a)

There is a big similarity between the main method for sweetening sour natural gas and glycol dehydration and natural gas absorption methods. As different from glycol dehydration and natural gas absorption methods, amine solutions are used for separating natural gas from hydrogen sulfide. Relatively, hydrogen sulfide removing process is called as the ‘amine process’ or Girdler process. Similar to the recovery of natural gas liquids method, the sour gas contains amine solution that runs through a tower in Girdler process. Amine solutions have an affinity for hydrogen sulfide in the same logic with glycol absorption of water. Monoethanolamine and diethanolamine are the basic examples of amine solutions for the processes of absorption of sulfur.

Any of these amine solutions will absorb, in liquid form, the sulfur contents passing through the natural gas. Due to the fact that the effluent gas formally does not own any hydrogen sulfide content, it cannot be called as a 'sour gas' anymore. After removing absorbed sulfur amine, solutions are suitable to be used in the treatment of more sour gas like glycol dehydration and recovery of natural gas liquids methods. (Naturalgas.org, 2013)

Most of the separation of hydrogen sulfide from natural gas occurs by the amine absorption process in some cases, using iron sponges as a solid desiccant for extraction of the sulfide and carbon dioxide is also possible.

Processing of natural gas is a contributory piece of the natural gas price chain. To safeguard that the natural gas used is as clean and pure as possible, ensuring the cleanly burning of natural gas and being beneficial from environmental aspects is essential. When the processing of natural gas has come to the conclusion, transportation of natural gas from production region to consumers is also compulsory. (IEA, 2017)

2.5 Transportation of Natural Gas

A comprehensive transportation system is required to transport natural gas from production regions to consumption regions. Transportation of natural gas produced in a specific place to the consumer is provided by pipeline. The natural gas can be put into storage facilities if needed.

There are three types of pipelines: Collection system, interstate pipeline system, and distribution system. The collection system is a small-scale system that transfers raw natural gas from the source to the processing system. If the crude natural gas contains high sulfur and carbon dioxide, it is transported by a special pipe. Pipelines are designed to be interstate. The interstate pipelines are similar to the interstate highway system. They carry gas along state borders. (naturalgas.org, 2013)

2.5.1 Interstate Natural Gas Pipelines

Interstate natural gas pipelines transport processed natural gas from the processing centers in the production area to areas where natural gas is needed. This pipeline stretches across the entire country. The natural gas moves with a high pressure in these

pipes. As the pressure decreases, the movement of natural gas also decreases. (naturalgas.org, 2013)

2.5.2 Pipeline Components

Interstate pipelines consist of a number of components that ensure the efficiency and reliability of a system that delivers such an important energy source year-round and includes a number of different components. (naturalgas.org, 2013)

2.5.2.1 Transmission Pipes

These pipes can be of different sizes. These pipes are usually used in collection and distribution systems. Most mainline distribution pipes are approximately 30 inches. These pipes are designed in accordance with the standards set by the American Petroleum Institute. However, due to the ease of replacement, some distribution pipes are made of high-quality plastic. Distribution pipes are produced by steel factories. There are two different techniques for pipe production. Large diameter pipes are welded to each other. Small diameter pipes can be produced more easily. Both pipes are tested in accordance with the press standards required to transport natural gas. There are many ways to protect pipes from moisture and rust. The most common of these is to pass electrical current through the pipes to prevent corrosion. (naturalgas.org, 2013)

2.5.2.2 Compressor Stations

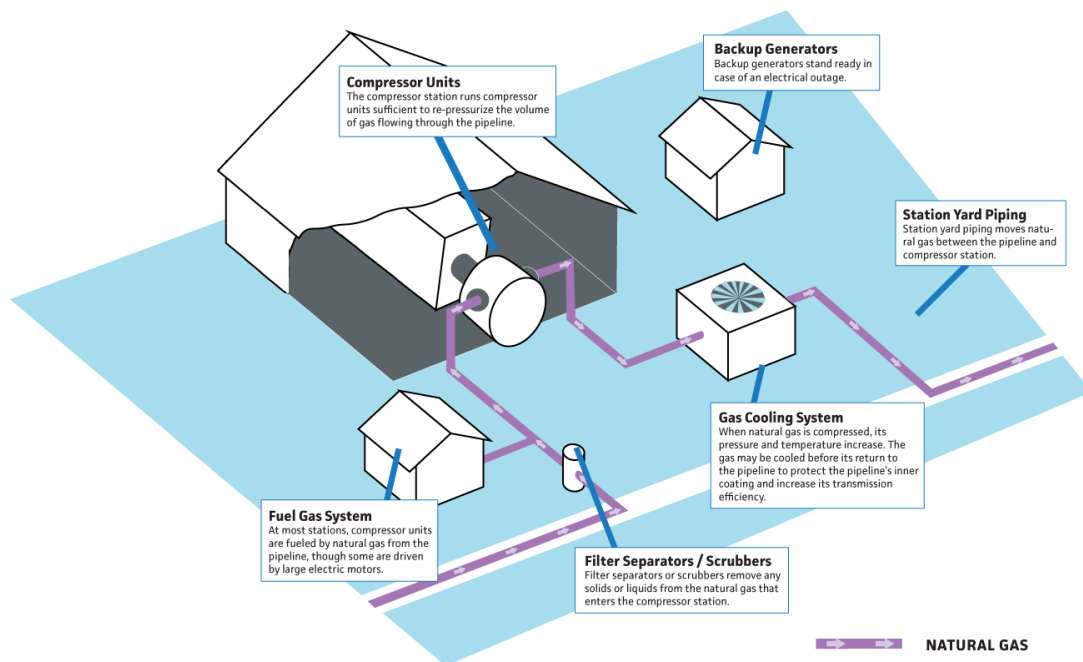


Figure 2.16 : Scheme of Compressor Station (“Compressor Stations - Enbridge Inc.,” n.d.)

The progress of the natural gas to the pipes is provided by pressure. This pressure is generated by the compressors placed on the pipeline. These compressors take their energy from natural gas. Some compressors work with electricity. For these compressors, a strong electrical supply is needed. Other compressors work with large motors. These compressors use natural gas as fuel. Operation scheme of typical compressor station is shown in Figure 2.16.

In addition to compressing the natural gas, there is also the process of cleaning the gas carried in the pipeline. In this process, together with natural gas, the unwanted parts in the pipes are separated from the gas. These stations allow the natural gas to be filtered and be as pure as possible. (naturalgas.org, 2013)

2.5.2.3 Metering Stations

The metering stations are located at specific distances on the interstate natural gas pipeline. They measure the natural gas that companies receive. They use devices that do not interfere with natural gas movement when measuring.

2.5.2.4 Valves

There are many valves on natural gas pipelines. These valves provide or stop the gas flow. There are many reasons for stopping the flow. As is shown in Figure 2.17. The gas flow is stopped during the change or maintenance of the pipes. This is done for the safety of workers. These valves are located at certain distances.



Figure 2.17 : Pipeline Control Valve

2.5.2.5 Control Stations and SCADA Systems

Natural gas pipeline companies have customers on both ends of the pipeline – the producers and processors that input gas into the pipeline, and the consumers and local gas utilities that take gas out of the pipeline. To accomplish this task of monitoring and controlling the natural gas that is traveling through the pipeline, centralized gas control stations collect, assimilate, and manage data received from monitoring and compressor stations all along the pipe.

Most of the data that is received by a control station is provided by Supervisory Control and Data Acquisition systems. These systems note all movement on the pipeline and transmit it to the center. There is very little latency between transmitted information.

It is possible to react quickly to a possible unexpected situation with this data. (naturalgas.org, 2013)

2.5.3 Pipeline Construction

Constructing natural gas pipelines requires a great deal of planning and preparation.

A lot of permission must be given to construct a pipeline. In the event of a possible hazard, the damage must be minimal. Therefore, the pipeline is analyzed carefully when selecting the path.



Figure 2.18 : Natural Gas Pipeline Construction

The pipeline company cannot begin construction of the pipe without obtaining all permits. Pipeline progresses progressively step by step. Pipe thickness and coating material may vary in some areas. The pipeline way must first be cleaned. In Figure 2.18, construction application for a pipeline is shown.

The trenches that will be put into the pipes are excavated. These trenches are about 6 meters deep. Pipes are carefully welded. After welding, coatings are applied to prevent corrosion in the pipes. finally, all operations are carefully checked.

After all this, the line is then checked. After the process is finished, high-pressure water is filled into very high pipes. This pressure is much higher than the pressure of the natural gas. The line is checked with this test.

There are two methods for construction of pipelines in areas where there are roads, streams, and so on. One of these methods is to excavate a trench from the bottom of the barrier. The pipe is placed on this scraper. It is carefully checked to avoid any leakage. Alternatively, a tunnel through which the pipeline can pass open is opened. The same procedures apply here.

2.5.4 Pipeline Inspection and Safety

The internal safety of the pipelines is done with robots called 'smart pigs'. Operation scheme of the typical pigging station is shown in Figure 2.19. These robots are left in the pipes. These robots control the roundness of the pipe and corrosion in the pipe.

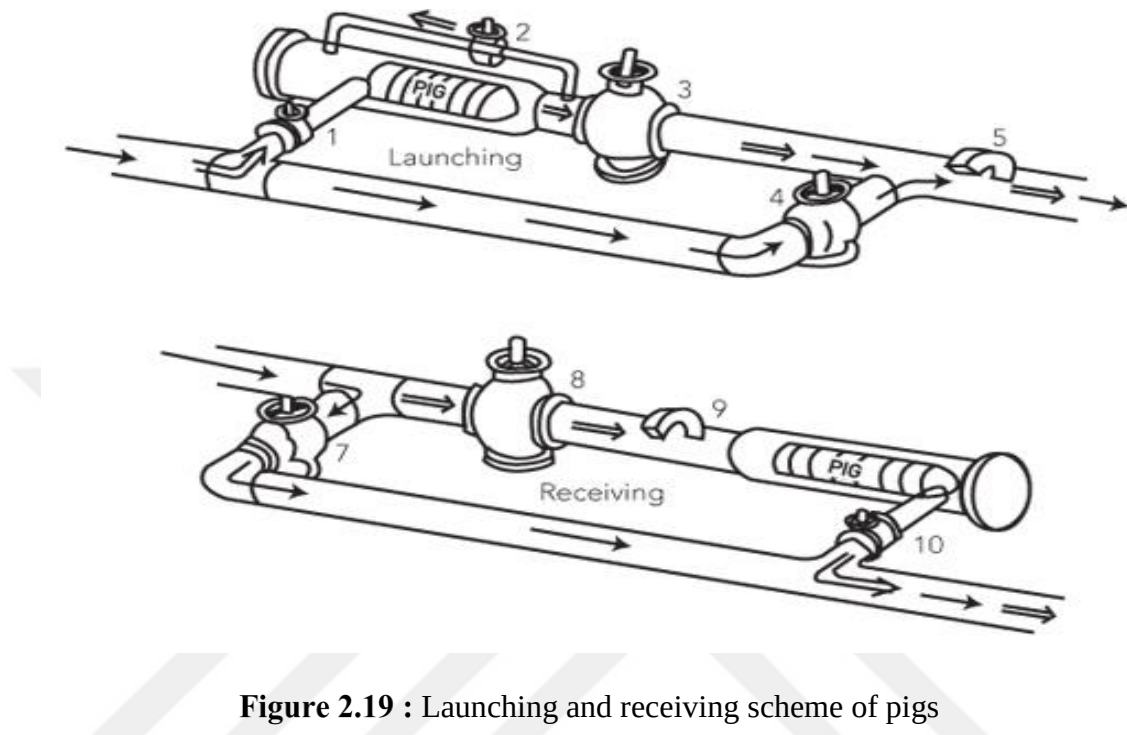


Figure 2.19 : Launching and receiving scheme of pigs

Aerial Patrols – Planes are used to ensure no construction activities are taking place too close to the route of the pipeline, particularly in residential areas.

Leak Detection – Natural gas detecting equipment is periodically used by pipeline personnel on the surface to check for leaks.

Pipeline Markers – Signs on the surface above natural gas pipelines indicate the presence of underground pipelines to the public, to reduce the chance of any interference with the pipeline.

Gas Sampling – a routine sampling of the natural gas in pipelines ensures its quality. May also indicate corrosion of the interior of the pipeline, or the influx of contaminants.

Preventative Maintenance – This involves the testing of valves and the removal of surface impediments to pipeline inspection.

Emergency Response – Pipeline companies have extensive emergency response teams that train for the possibility of a wide range of potential accidents and emergencies.



3. MATERIAL AND METHODS

3.1 Trans Anatolian Natural Gas Pipeline Project

3.1.1 Project Overview

TANAP project is designed to carry the Azeri natural gas from Shah Deniz 2 Gas Field along with other areas in the South Caspian Sea to Turkey and Europe.

TANAP begins from the Georgia/Turkey border, goes through the borders of 20 provinces, namely, Ardahan, Kars, Erzurum, Erzincan, Bayburt, Gümüşhane, Giresun, Sivas, Yozgat, Kırşehir, Kırıkkale, Ankara, Eskişehir, Bilecik, Kütahya, Bursa, Balıkesir, Çanakkale, Tekirdağ and Edirne, and ends at İpsala district of Edirne at Turkey/Greece border. TANAP project is made up of 56-inch pipeline aisle from the Georgia/Turkey border to the off take station located around Eskişehir continuing to be 48-inch pipeline aisle to the Turkey/Greece border. The project crosses the Marmara Sea with 30" diameter 2 parallel pipelines with a length of 18km. Route of TANAP project is shown in Figure 3.1

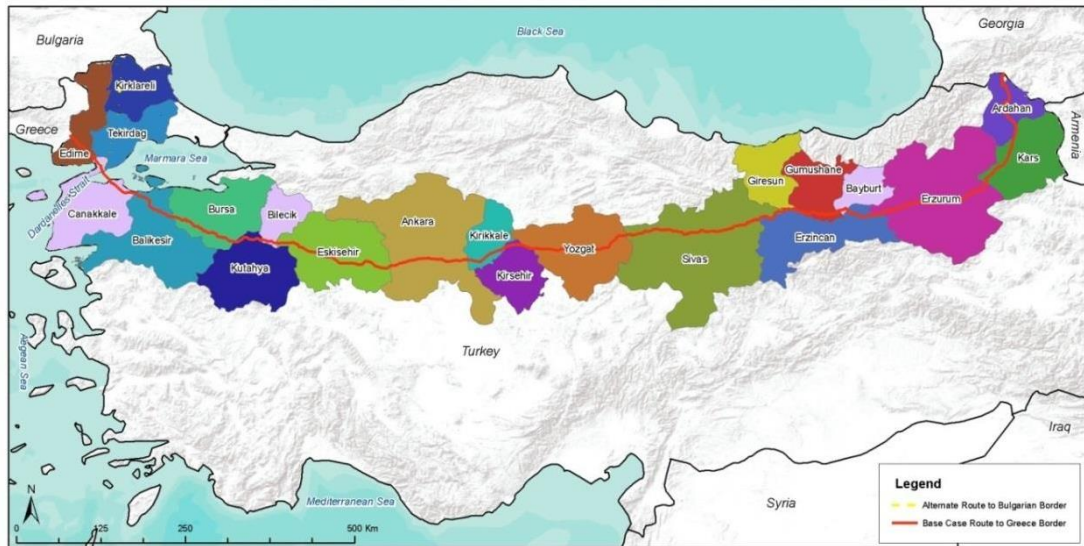


Figure 3.1 : Route of TANAP project

Using this venture the natural gas is going to be transported by an 1805 km natural gas pipeline structure in total, consisting of 1787 km below ground and also 18 km

Marmara crossing subsea pipeline, along with almost all above as well as underground facilities in the Republic of Turkey.

TANAP Project is an element of the Southern Gas Corridor that comprises the South Caucasus Pipeline (SCPX), TANAP and also the Trans-Adriatic Pipeline (TAP). Route of Southern Gas Corridor project is shown in Figure 3.2

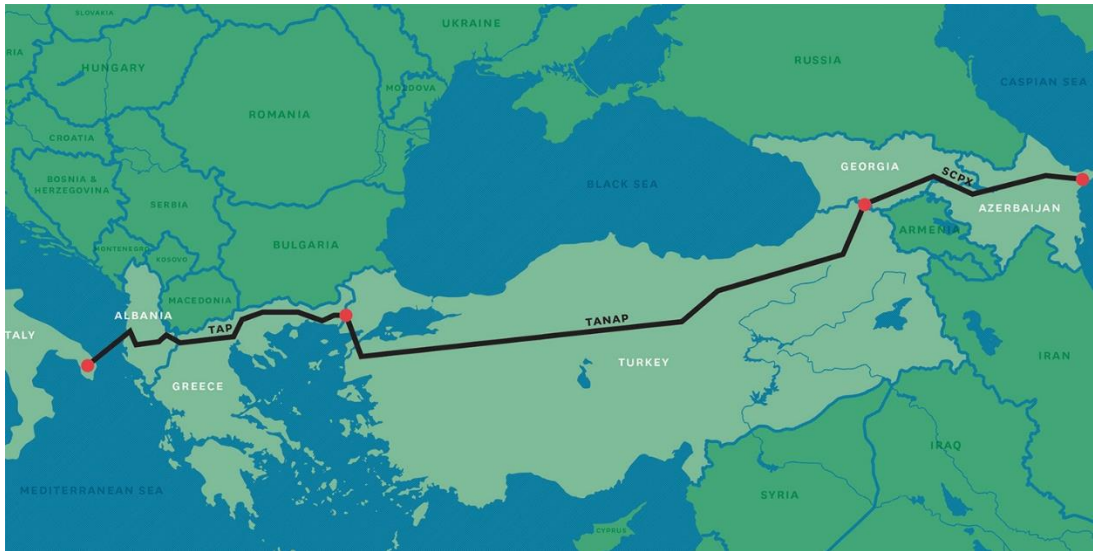


Figure 3.2 : Route of Southern Gas Corridor project

The principal pipeline facilities consist of the required amount of compression facilities, block valve stations, distribution and custody transfer metering facilities. The pipeline crosses surface with challenging geotechnical functions, which includes landslides along with other geohazards, additionally to crossing regions with a variety of levels of economic activity and urbanization.

3.1.2 Above Ground Installations of TANAP.

3.1.2.1 Compressor stations

Compressor stations are designed to increase the gas pressure in order to adjust the desired volume of gas flow. Every compressor station will be worked by gas turbines and the gas supply will be given from the gas stream in the pipeline.

To ensure the pressure conditions, there are 7 intermediate compressor stations (2 in the first stage, 4 in the second stage and 7 in the third stage) at the intermediate points. It is planned to move Eskişehir connection line, natural gas from Eskişehir Compressor Station (CST-5A) to the connection point of BOTAŞ system at a point near to existing BOTAŞ Station in Eskişehir. The CST-5AL unit in CST 5A will set the pressure of

the natural gas to be transported to BOTAS by supporting the connection line. Locations of compressor stations for TANAP are given in Table 3.1

Facilities shall be designed and equipped to perform daytime maintenance and inspection. There will be 24-hour security at the stations. All gas compressor stations shall be operated for the transmission of gas of 31 bcma.

Table 3.1 : Locations of Compressor Stations for TANAP

Compressor Station No / Name	Power to be Installed (MW)	Province
CST-1A	157	Ardahan
CST-3A	157	Sivas
CST-5A	157	Eskişehir
CST-7A	94	Balıkesir

3.1.2.2 Pigging Stations

Pig stations are established with the aim of ensuring the cleanliness of the pipeline and preventing corrosion. Within the scope of the natural gas pipeline project, a total of 12 pig stations (one in each of the four compressor stations, one in the two measurement stations, one in the 30-inch side-line measurement station from CST-5A which supplies gas to the BOTAS network) one independent station on each side and three individual stations along the route) will be installed.

Pig launching will be performed as a routine maintenance activity. It is planned that the frequency of pig launching will be 1 (one) per year for cleaning pigs and 5 years for smart pigs. Operational pigging activities will be carried out within the station (compressor or pig station) area. Pig launch will cause a gas release in the pig receiver. Before the pig receiver is opened, it is necessary to discharge the pressure by releasing the gas inside the drum. Locations of pigging stations for TANAP are given in Table 3.2

Table 3.2 : Locations of Pig Stations for TANAP

Pig Station No/ Name	Province
PST-AN-1	Çanakkale
PST-EU-A3	Tekirdağ
PST-CS2	Erzurum
PST-CS4	Kırşehir
ST-CS6	Bursa

In addition, regular "smart" pigs will be sent along the pipeline to check for corrosion and irregularities in the pipeline. The intelligent pigs will carry a device to detect and record state data such as metal loss, dents, hollows, and collapses as they move through the pipeline system. The smart pig will be pitched from the pig launcher, navigated in the pipeline segment, held and picked up by the pig receiver. The data will then be downloaded and analyzed from the intelligent pig data storage unit. The company operating the pipeline system will keep detailed records of all inspections and will manage the corrosion protection system as required.

3.1.2.3 Metering Stations

The project will include 4 gas metering stations. These will be facilities for the transfer of natural gas in a controlled way on the border crossings on both sides of the pipeline, 1 in the Trakya exit station and 1 in the Eskişehir connection line. Locations of metering stations for TANAP are given in Table 3.3.

Table 3.3 : Locations of Metering Stations for TANAP

Metering Station No / Name	Province
FMS-GR-A1	Edirne
FMS-GE-A1	Ardahan
FMS-ES	Eskişehir

3.1.2.4 Block Valve Stations

Block Valve Stations (BVSs) are installations established to close the gas flow and provide partial isolation needed in emergencies. 49 block valve stations are planned within the scope of the project and the information about their locations is given in Table 3.4

Table 3.4 : Locations of Block Valve Stations for TANAP

Block Valve Stations No / Name	Amount	Province
BVS-01 to BVS-03	3	Ardahan
BVS-04 to BVS-06	3	Kars
BVS-07 to BVS-11	5	Erzurum
BVS-12 to BVS-14	3	Erzincan
BVS-15 to BVS-17	3	Gümüşhane
BVS-18 to BVS-24	7	Sivas
BVS-25 to BVS-31	7	Yozgat
BVS-32	1	Kırıkkale
BVS-36 to BVS-36	4	Ankara
BVS-37 BVS-41	5	Eskişehir
BVS-42	1	Bilecik
BVS-43	1	Kütahya
BVS-44 and BVS-45	2	Bursa
BVS-46 and BVS-47	2	Balıkesir
BVS-48	1	Çanakkale
BVS-49	1	Edirne

3.1.3 Pipeline Material and Wall Thickness

The outer diameter (OD) will be fixed for 4 pipe sections (56 inches, 48 inches, 36 inches and 30 inches), and different wall thicknesses will determine the inside diameters. Pipe material API 5L will be class X70.

Both external and internal coating will be applied to the pipeline. The coating to be used on the inner surfaces will be the modified epoxy known to support the gas flow in the pipeline.

- The first layer is a coat of powder epoxy,
- An intermediate layer of rolled adhesive,
- A final layer of rolled polyethylene.

3.1.4 Properties of natural gas to be transported

The pipeline will carry natural gas with the following composition as well as used in process simulation (the gas that will theoretically exist in Shah Deniz 2 in 2025). The composition of natural gas has been shown in Table 3.5 :

Table 3.5 : Design natural gas composition for process calculations

Natural gas composition (mole%)	
Nitrogen	0,23
CO ₂	0,2
Methane	94,17
Ethane	3,26
Propane	1,24
i-butane	0,25
n-butane	0,37
i-pentane	0,11
n-pentane	0,09
n-hexane	0,06
n-heptane	0,02

3.1.5 TANAP Project Pipeline Capacity

TANAP pipeline capacity is based on the following three stages and capacity figures that vary accordingly are provided in Table 3.6 :

Table 3.6 : Amounts of natural gas to be transported

Phase	Actual year(s)	Total pipeline capacity at completion (bcma)	Off-take within the Republic of Turkey (bcma)	Volume to European countries (bcma)
1	2018-2021	16	6	10
2	2022-2025	24	6	18
3	2026-2061	31	6	25

3.1.6 Environmental Impacts of TANAP

3.1.6.1 Soil impacts

The protection of soil quality is among the objectives of the TANAP Project, as it is in the national, European and international legislative and guiding principles being assessed. The soil is a key resource, as it forms the basis of many agricultural and forestry activities as well as many ecological processes. Soil; with the disappearance of the vegetation cover, wind and water are exposed to many effects such as exposure to erosion, change of physical properties due to compaction, change of chemical properties due to fertilizing activities, accumulation of wastewater discharge and air pollution. The soil is also becoming a scarce resource in regions that are more exposed to the adverse effects of global changes such as climate change, acidification,

nitrification, and desertification. Excessive pollution will increase the risk for the project, as it will require disposal or treatment of the soil to be produced by excavation activities and some special construction techniques may be needed.

Table 3.7 : The risk for TANAP due to erosion areas

Assessment endpoint: Erosion in areas high erosion potential		
Low impact	Medium impact	High impact
Minor or localised soil erosion, soil creep.	Soil erosion evident and potentially leading to some rill or shallow gulley erosion.	Rill and gully formation predicted to be extensive with potential impacts on neighboring land and pipe integrity.

3.1.6.2 Geological and geomorphological impacts

Protecting geological stability and avoiding potential geological risks are among the objectives of the TANAP Project in terms of ensuring safe construction and operational integrity as well as avoiding the triggering of geological instabilities that could damage existing infrastructure and human life as well as the integrity of protected areas and ecosystems. Sensitivity is defined by the presence of elements that can constitute a geological risk to the project or existing infrastructure or settlement sites as a consequence of the interference caused by the project. The risk of TANAP due to the crossing of geohazards is shown in Table 3.8

The important geological risk factors are determined as follows:

- Linear geological risks (major fault lines)
- Regional geological risks (landslides, karst areas, liquefaction areas, if any, fluvial erosion areas).

Table 3.8 : The risk for TANAP due to the crossing of geohazards

Assessment endpoint: Crossing of geohazards (faults and landslides)	
Low impact	High impact
Excavation activities along the aboveground facilities or related to the construction of the aboveground facilities in areas with inactive faults or inactive landslides.	Excavation activities along aboveground facilities or related to the construction of aboveground facilities in areas with active faults or active landslides.
Presence of aboveground facilities during operations in areas of inactive landslides.	Presence of aboveground facilities during operations in areas of active landslides.

3.1.6.3 Seismological impacts

Project transit area is an integral part of the account in terms of seismology, construction stage and integrity of the operator together with security. In addition to evaluations in terms of engineering and construction, safe construction and operation are important from an environmental and social point of view. Because earthquakes can trigger significant outbreaks from the project if the destruction is high. These include air, water and soil pollution emissions, high production of waste, increased pressure on health and rescue services. The risk of TANAP due to the seismological areas is shown in Table 3.9.

Table 3.9 : The risk of TANAP due to the seismological areas

Assessment endpoint: Crossing of areas with seismic risk		
Low impact	Medium impact	High impact
Location of the aboveground facilities in areas classified as seismic zones IV and V.	Location of the aboveground facilities in areas classified as seismic zones II and III.	Location of the aboveground facilities in areas classified as seismic zones I.

3.2 Failure probability assessment of gas transmission pipelines

3.2.1 Introduction

The progress of the risk assessment of oil and natural gas pipelines, which have been studied on a number of topics, has evolved from qualitative to quantitative evaluation. Many methods are still used today to report the risk values of the natural gas pipelines and the probability of failure. Muhlbauer has established an index system to calculate the risk value of long-distance pipelines. This indexing system has been very successful over time. (Koornneef et al., 2010) presented a systematic data study for the effect of uncertainty on the quantitative risk assessment of CO₂-carrying pipelines. (Zhang et al., 2012) prepared a probabilistic method for valuing damaged pipes due to corrosion based on the methods of valence assessment. (Jamshidi, Yazdani-Chamzini, Yakhchali, & Khaleghi, 2013) used risk assessment methodology based on expert logic to evaluate uncertainties in pipelines through fuzzy logic. (Lu et al., 2015) used a broad risk assessment methodology that combines the risk matrix with a bow tie model. (Guo et al., 2016) also developed a combination of fuzzy logic and a fuzzy Petri net (FPN) model for risk assessment of long-distance oil and gas pipelines. While all of the above-mentioned studies attempted to predict the probability of failure of oil and natural gas pipelines using expert sifting and fuzzy logic, historical data could not be used to measure pipeline failure probability and risk amount because of lack of definitive data, fluctuations in parameters, uncertainties in the current situation, changing environment and newcomers. Consequently, all researchers used historical data to control the validity of the method they propose. (Shan et al., 2018)

While the risks that may occur in natural gas pipelines are evaluated using the above-mentioned methods, the following statistical sources have been used to measure the amount of these risks. Information about accidents in the gas and liquid pipelines was collected by the Pipeline and Hazardous Material Safety Administration (PHMSA) (“Data and Statistics Overview | PHMSA,” n.d.) of the United States Department of Transportation (DOT) and reported in accordance with the defined reporting criteria. The National Energy Board (NEB) (“National Energy Board,” n.d.) of Canada is a free organization that collects and analyzes information about accidents in pipelines to ensure safety and security. The Canadian Energy Pipeline Association (CEPA) (CEPA, 2016) is another organization that shares the latest information on the pipeline

industry with the Canadian public to protect the public and ensures the safety of pipelines. The Canadian Energy Pipeline Association (CEPA) (CEPA, 2016) is another institution that has collected information on all pipeline events since the 1970s in Europe and publishes it regularly in certain years. The United Kingdom Onshore Pipeline Operators' Association (UKOPA) (UKOPA, 2016) engages in collecting and sharing information about onshore pipeline events in the United Kingdom. Useful information to the investigator about potential threats and harm mechanisms for risk management of oil and gas pipelines are provided by the pipeline incident database (PID). (Shan et al., 2018)

On the other hand, these statistical surveys above have focused solely on the causes of accidents in pipelines and are insufficient to assess the failure and risks of pipelines. The above researches can be criticized since they focus only on some basic pipeline parameters for risk assessment. Risk assessment of natural gas pipelines is a very difficult task due to hundreds of kilometers of pipelines, the use of different materials from different ages. Operational and environmental conditions can vary widely in both time and space. There are many factors to consider in the assessment of pipeline risk. In the risk assessment process, some parameters related to the pipeline (e.g. pipe diameter, wall thickness, cover depth and s) can be obtained from statistical data. However, parameters such as the worker's quality of work or public education are difficult parameters to quantify. The method developed by (Shan et al., 2018) which was used in this study for the risk assessment of the TANAP project includes quantitative analyzes formed by integrating historical data of failures and qualitative analyzes used to compensate for the lack of clear net statistics data

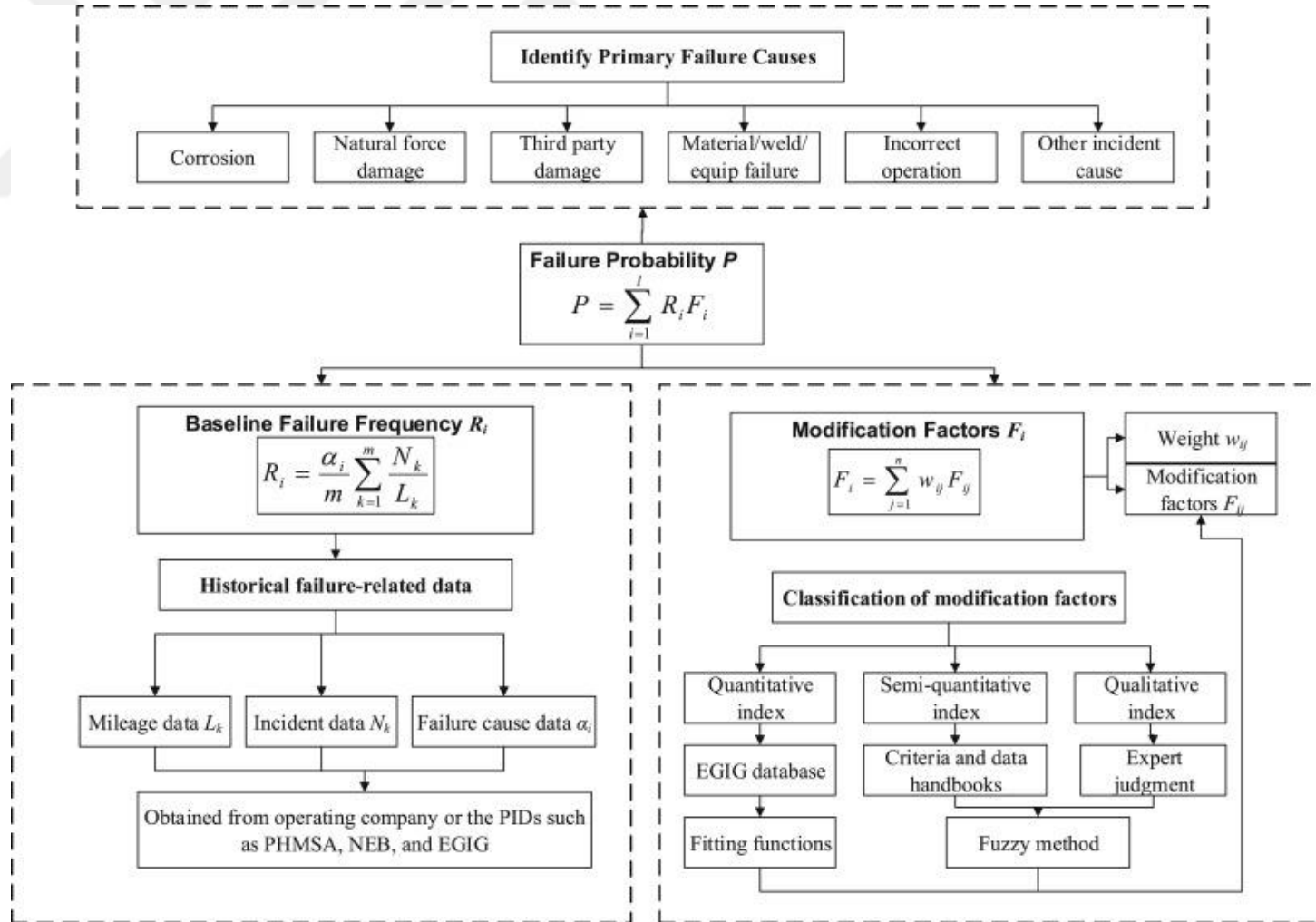


Figure 3.1 : Failure probability assessment method for gas transmission pipeline

3.2.2 Failure probability estimation model

3.2.2.1 Estimation model

In the estimation method, the primary causes that can cause failure in natural gas pipelines are divided into six parts: corrosion factor, sabotage factor, weld, and equipment factor, natural damage factor, and third-party damage factor. (Shan et al., 2018)

The probability of failure of a pipeline system is calculated by the following formula:

$$P = \sum_{i=1}^l P_i = \sum_{i=1}^l R_i F_i \quad 1$$

P ; Failure probability of pipeline system, per km per year.

P_i ; Failure probability for primary failure cause i , per km per year.

R_i ; Baseline failure frequency for primary failure cause i , per km per year.

F_i ; First level modification factor which corresponds to primary failure cause i .

l ; number of the primary failure causes, and $l = 6$

3.2.2.2 Baseline failure frequency

Failure frequency is the term used to show how often the failure is per kilometer of the pipeline. The basic failure frequency term defines the average failure frequency of the selected part of given pipeline. (Shan et al., 2018)

Following formula shows the calculation method of the baseline failure frequency for primary failure cause i .

$$R_i = \frac{\alpha_i}{m} \sum_{k=1}^m \frac{N_k}{L_k} \quad 2$$

R_i ; Baseline failure frequency for primary failure cause i .

N_k ; Number of incidents occurring on pipelines in the k th year.

L_k ; Corresponding length of pipelines in the k th year, km.

α_i ; Percentage of incidents caused by primary failure cause i.

m; total number of years for which the incident and mileage data are available.

The basic failure frequency estimate for the TANAP project was derived from historical pipeline accidents collected by PIDs such as PHMSA, NEB, and ECIG. Data about failures in the pipelines in years 2002 and 2015 were used to calculate baseline failure frequency. The percentages of them are shown in Table 3.10 :

Table 3.10 : Baseline failure frequencies for primary causes

Primary failure cause	Baseline failure frequency
Corrosion	24.14%
Natural force damage	11.68%
Third party damage	21.94%
Material/weld/equip failure	29.80%
Incorrect operation	3.47%
Other incident cause	8.97%

3.2.2.3 Failure probability modification factors

Modification factor of failure probability is used for arranging baseline frequency and this factor is calculated based on the characteristics of a selected segment of the pipeline.

The value of the primary level modification factors is calculated from the sum of the multiplication of the secondary level modification factors and their corresponding weights. (Shan et al., 2018)

$$F_i = \sum_{j=1}^n w_{ij} F_{ij} \quad 3$$

F_i ; First level modification factors.

w_{ij} ; Corresponding weight of the modification factor

F_{ij} ; jth second level modification factor in the first level modification factor index i.

3.2.3 The evaluation method of modification factors

3.2.3.1 Modification factors index system

The modification factor system consists of six first-order modification factors (corrosion factor, sabotage factor, weld, and equipment factor, natural damage factor, and third-party damage factor), which was mentioned previously, that cause the most casualties in natural gas pipelines. Each first-level modification factor consists of some second-level modification factors and the weight associated therewith. As a result of all of these, we have a total of 34 second-level modification factors. (Shan et al., 2018)

3.2.3.2 Classification of modification factors

In order to increase the objectivity of the risk assessment process, the modification factors index system was tried to be made as quantitative as possible. Given the varying degrees of difficulty in quantifying the second-order modification factors, they were divided into 3 different groups to calculate the second-order modification factors more precisely: a quantitative index, a semi-quantitative index, and a qualitative index. Generally, qualitative and quantitative terms are often used to distinguish how much historical data is used in calculations and how much mathematical calculation is done to obtain the model result. In particular, indices using historical frequency data are called quantitative indices, whereas calculations based on expert opinion and based on the figure determined on the basis of this view are called qualitative or semi-quantitative indexes. (Shan et al., 2018)

3.2.3.3 Quantitative index

A large statistical database is needed to obtain the necessary results in the quantitative index system. In this method, European Gas Pipeline Incident Data Group (EGIG) is used as such a database. This database examines the changes in the failure frequencies of natural gas pipelines depending on the basic characterization of pipelines. As an example, the pipe material used, the wall thickness of the pipe, the diameter of the pipe and the depth of the cover may be shown. As can be easily understood from the graphs, the greater the age of the pipeline, the larger the pipe diameter and the smaller the wall thickness of the pipe, the higher the risk of damage to the pipe due to corrosion. The dependence of the primary failure frequencies of the pipelines on the basic characteristics of the pipelines is given in Table 3.13 : in the given table, $f(x)$ denotes

the fitting function and x is the basic characteristic of the pipeline. Fitting functions allow us to calculate the modification factors and their corresponding weights. In addition to all these, it is not possible to show the relationship between the corrosion factor of the pipeline and the coating type. Because this relationship is not a continuing relationship along the pipeline. The situation is also same for weld and equipment factor and material grade. (Shan et al., 2018)

3.2.3.4 Semi-quantitative index

Due to the lack of clear net data on semi-quantitative indices, it is not possible to create a relationship between failure frequency of pipeline and modification factors by means of fitting function method. In this method risk scoring for the TANAP project was used, with scales ranging from one (very low) to five (very high) to quantify the semi-quantitative indices. Modification factors for semi-quantitative indices and appropriate measurement ratios are given in Table 3.11, Table 3.12 and Table 3.14 (Shan et al., 2018)

Table 3.11 : Modification factor level criteria for semi-quantitative indices(Shan et al., 2018)

Second level index	Scale criterion		Modification factor level				
			I	II	III	IV	V
Corrosion factor	Soil corrosivity factor	Soil resistivity (ohm-cm)	>10000	5000–10000	2000–5000	1000–2000	<1000
	Cathodic protection factor	Potential pipe to the soil (V)	–1.2 ~ –1.0	–1.0 ~ –0.95	–0.95 ~ –0.9	–0.9 ~ –0.85	>–0.85 or <–1.2
	Stray current interference factor	AC--current density (A·m ^{–2})	<30	30–50	50–80	80–100	>100
		DC--Surface potential gradient (mV/m)	<0.5	0.5–1.0	1.0–2.5	2.5–5.0	>5.0
	Coating insulation resistance factor (kΩ·m ²)	For polyethylene coating	>100	50–100	20–50	5–20	<5
		For other type of coating	>10	7–10	5–7	2–5	<2
	Product corrosivity factor	Growth rate (mm/year)	<0.02	0.02–0.1	0.1–0.5	0.5–2.5	>2.5
Third party damage factor	Activity level factor	Location class	1, Division 1	1, Division 2	2	3	4
	Patrol factor	Patrol frequency	Daily	Once every two days	Once every three days	Once every four days	Weekly or less
	Right-of-way condition factor	Sign intactness	100%	90%–99%	80%–89%	70%–79%	<70%

Table 3.12 : Modification factor level criteria for semi-quantitative indices(Shan et al., 2018)

Second level index	Scale criterion		Modification factor level				
			I	II	III	IV	V
Material/weld/equip failure factor	Seam weld factor	Qualification rate of welding	100%	90%–99%	80%–89%	70%–79%	<70%
	Pipe safety factor	Actual wall thickness/Design wall thickness	>1.60	1.41–1.60	1.21–1.40	1.10–1.20	<1.10
	Non-Pipe components factor	Design pressure/MOP	>1.75	1.51–1.75	1.26–1.50	1.10–1.25	<1.10
	Pressure test factor	Test pressure/MAOP	>1.60	1.41–1.60	1.26–1.40	1.10–1.25	<1.10
Incorrect operation factor	SCADA system factor	SCADA system reliability	99.9%	95%	80%	50%	No SCADA

Table 3.13 : Fitting functions for quantitative indices(Shan et al., 2018).

First level Index	Second level Index	Fitting function
Corrosion factor	Wall thickness factor	$f(x) = -0.00001527x^3 + 0.00109x^2 - 0.02481x + 0.1783$
	Line pipe age factor	$f(x) = 0.0000002047x^4 - 0.00001907x^3 + 0.0006045x^2 - 0.006608x + 0.01931$
	Coating type factor	Discontinuous
Natural force damage factor	Diameter factor	$f(x) = 0.00000000004882x^3 - 0.00000006429x^2 - 0.0000369x + 0.04801$
Third party damage factor	Wall thickness factor	$f(x) = 0.000003226x^4 - 0.0002949x^3 + 0.009806x^2 - 0.1404x + 0.7302$
	Diameter factor	$f(x) = -0.0000000007608x^3 + 0.000002131x^2 - 0.001944x + 0.5833$
	Cover depth factor	$f(x) = 2.068 \times 10^{(15)}x^{-0.413}$
Material/weld/equip failure factor	Material grade factor	Discontinuous
		$f(x) = -0.00000009733x^4 + 0.0000128x^3 - 0.0004953x^2 + 0.006852x - 0.02312$
Incorrect operation factor	Line pipe age factor	
	Diameter factor	$f(x) = -0.00000000006731x^3 + 0.0000001963x^2 - 0.0001849x + 0.05601$

Table 3.14 : Modification factor level criteria for qualitative indices(Shan et al., 2018)

Qualitative indices			Modification factor level				
			I	II	III	IV	V
Corrosion factor	Internal corrosion preventions factor	1 - Internal monitoring 2 - Inhibitor injection 3 - Internal coating 4 - Pigging	All of them	3 of them	2 of them	1 of them	None
Natural force damage factor	Earth movement factor	Potential for landslide, earthquake, or subsidence	Very low	Low	Medium	High	Very High
	Heavy weather factor	The potential for heavy rain/flood, high wind, or lightning	Very low	Low	Medium	High	Very High
Incorrect operation factor	Construction factor	Quality of installation, joining, handing and backfill	Excellent	Above Average	Average	Below Average	Poor
	Maintenance factor	Quality of documentation, schedule, and procedures	Excellent	Above Average	Average	Below Average	Poor
	Quality of worker factor	The sense of responsibility, safety awareness, and professional knowledge	Very low	Low	Medium	High	Very High
Sabotage incident factor	Sabotage incident factor	Sabotage incident probability	Very low	Low	Medium	High	Very High

Table 3.15 : Modification factor level criteria for qualitative indices(Shan et al., 2018)

Qualitative indices			Modification factor level				
			I	II	III	IV	V
Third party damage factor	Public education factor	1 - Mailouts					
		2 - Meeting with public officials					
		3 - Meeting with local contractors	All of them	3 of them	2 of them	1 of them	None
		4 - Door-to-door contact with adjacent residents					
	Alarm call system factor	1 - Protection legislation					
		2 - Successful warning case					
		3 - 24 h a day available	All of them	Above Average	Average	Below Average	Poor
		4 - A contingency plan					
	Above ground facilities factor	Distance above 6 m					
		With wall					
		With security systems	Excellent	Above Average	Average	Below Average	Poor
		Inspection of important areas					

3.2.3.5 Qualitative index

All parameters related to the pipeline and pipeline company are examined and evaluated in detail to compensate for the lack of clear net data in the calculation of the modification factor for quantitative indices. In this method risk scoring for the TANAP project was used, with scales ranging from one (very low) to five (very high) to quantify the semi-quantitative indices. Modification factors for qualitative indices and appropriate measurement ratios are given in Table 3.14 and Table 3.15 (Shan et al., 2018)

3.2.3.6 The evaluation methods of the second level modification factors and the corresponding weights

The values of the second level modification factors are determined according to the condition of the modification factors. (Shan et al., 2018)

1. If the modification factor is to be at a moderate level according to the error frequency, it is assumed that the value corresponding to the modification factor is equal to 1. In this case, the failure of the pipeline would be equal to baseline failure frequency.
2. If the modification factor needs to take a low value, the value of the second level modification factor will be less than 1. On the contrary: if the modification factor needs to take a high value, the value of the second-level modification factor will be greater than 1.

3.2.3.7 The evaluation method of modification factor for the quantitative index

The evaluation of quantitative indices is calculated by the four-step method mentioned below. (Shan et al., 2018)

Step 1. As mentioned previously, the calculation of the quantitative indices is done by means of the basic features of the pipeline. Therefore, parameters such as pipe diameter, cover depth, the wall thickness of the pipe and of the pipeline must be collected.

Step 2. Using Table 3.13 : the modification factors are supposed to be calculated by using corresponding $f(x)$ fitting function.

Step 3. Using Formula 4, mean failure frequency must be calculated.

The Mean Value Theorem, which is useful for determining the integrals to calculate the median state for quantitative parameters, is used.

$$r_{ij} = \frac{\int_b^a f(x) dx}{b-a} \quad 4$$

r_{ij} ; Mean failure frequency of the j th second level modification factor in the first level modification factor index i ;

$f(x)$; Fitting function

b and a ; Basic characteristic parameters of the pipeline which changes along the pipeline

Step 4. Second level modification factor calculation

The second level modification factor is calculated according to the formula given below.

$$F_{ij} = \frac{f(x_{ij})}{r_{ij}} \quad 5$$

F_{ij} ; Second level modification factor

$f(x_{ij})$; Pipeline failure frequency which relates to the basic characteristic parameter of the pipeline

r_{ij} ; Mean failure frequency of the j th second level modification factor in the first level modification factor index i

3.2.3.8 The evaluation method of modification factor for the semi-quantitative index and qualitative index

The application of the fuzzy logic method, which is used to calculate the modification factors of the qualitative indices with semi-quantitative indices, is explained in the following 5 steps:(Shan et al., 2018)

Step 1. Information on secondary level modification factors such as cathodic protection, above ground facilities, and non-pipe components factors must be gathered from semi-quantitative indices on the pipeline to what qualitative indices are involved.

Step 2. Select modification factors from Table 3.11, Table 3.12, Table 3.14, and Table 3.15 that correspond to the parameters of the semi-quantitative indices and the qualitative indices.

Step 3. By means of the method described below, the fuzzy possibility score corresponding to the modification factors is calculated.

With the numerical prediction system shown in Figure 3.3, the fuzzy possibility scores of the modification factors are found. I is equivalent to “0.1”, II is equivalent to “0.3”, III is equivalent to “0.5”, IV is equivalent to “0.7”, IV is equivalent to “0.9”.

Step 4. Adaptation of fuzzy possibility scores to fuzzy probability is done with the help of empirical equations proposed by (Onisawa, 1988)

$$FP = \begin{cases} \frac{1}{10^k} & FPS \neq 0 \\ 0 & FPS = 0 \end{cases} \quad 6$$

where;

$$k = \left[\frac{1-FPS}{FPS} \right]^{1/3} \times K \quad 7$$

FP; Fuzzy Probability

FPS; Fuzzy Possibility Score

K; is a constant value calculated by the following formula:

$$K = \frac{1}{\lg(1/r)} \quad 8$$

r; average failure frequency

According to the Pipeline Incident Databases (PIDs) used in this risk assessment method, the average error rate of natural gas transport pipelines is equal to 2.32×10^{-4} . In this study, this value is assumed to be 2.32×10^{-5} for second level modification factors.

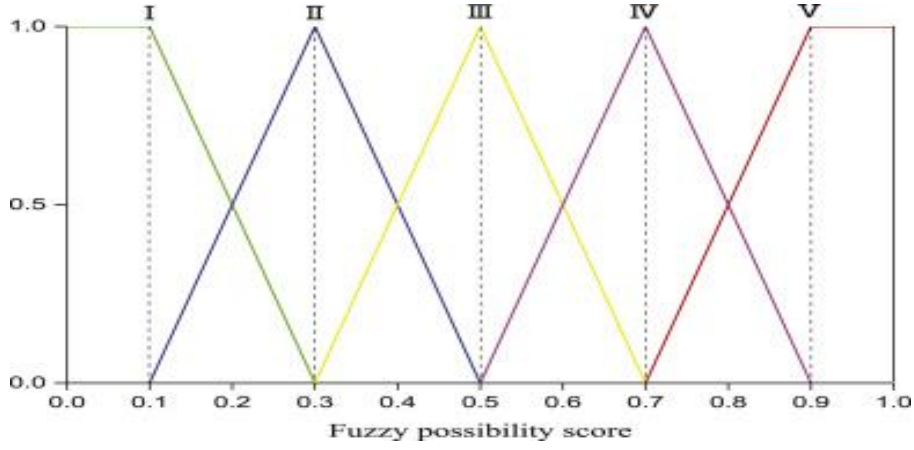


Figure 3.3 : Fuzzy numbers represent modification factor level(Shan et al., 2018)

Step 5. At this stage, III level of probability of failure corresponds to medium level for semi-quantitative indices and qualitative indices. In such a case, fuzzy probability corresponds to the average failure frequency, and the corresponding second level modification factor is equal to 1. For the remaining 4 levels, the second level modification factors are calculated based on the fuzzy probability that is based on the ratios to III level.

3.2.3.9 The evaluation method of the corresponding weights

Once the second level modification factors have been calculated, the corresponding weights are calculated to determine at what level these factors will affect the first order modification factors. The weight of each second level modification factor is calculated by the following formula. (Shan et al., 2018)

$$w_{ij} = \frac{r_{ij}}{\sum_j^n r_{ij}} \quad 9$$

w_{ij} ; Corresponding weight of the second level modification factor.

r_{ij} ; Mean failure frequency of the j th second level modification factor in the first level modification factor index i .

Table 3.16 : Pipeline failure frequency presented in different databases

Country or region	Database	Period	Failure frequency (per year per 103 km)	
			Historic	Last 5 years
US	PHMSA	2004–2015	0.155	0.149
Canada	CEPA	2011–2015	0.225	0.225
Europe	EGIG	1970–2013	0.33	0.16
UK	UKOPA	1962–2014	0.219	0.078
Average			0.232	0.153

3.2.3.10 The evaluation method of failure probability of the whole pipeline

Failure probability of pipeline is system is calculated by following formula:

$$P_p = \sum_{i=1}^n \frac{l_i \times P_i}{L} \quad 10$$

l_i ; Corresponding length of the pipeline segment.

P_i ; Failure probability of the pipeline segment.

L ; Total length of the pipeline.

3.2.3.11 Definitions of semi-quantitative indices

3.2.3.11.1 Soil corrosivity factor

The most important factor affecting steel corrosion is the specific resistance of the soil. Since the low specific resistivity of the soil does not constitute a significant obstacle for the electron exchange on the pipe surface, chemical and electrochemical reactions occur more quickly, which leads to faster corrosion. (Yapılır, n.d.)

Soil resistance is the reaction that the soil shows to the electric current. The soil is actually a weaker conductor than conductors like copper. However, if the field is large enough for the current, the resistance is low and the soil may become a good conductor. This is why there is a resistance between the conductors in the system and the earth.

Before the pipeline is installed, these measurements are made and the installation is carried out after the necessary calculations and preparations. One of the important things that affect soil resistance is humidity.

3.2.3.11.2 Cathodic protection factor

Cathodic protection is to change the potential of a metal undergoing corrosion (acting as an anode), to force it to act as a cathode. An insoluble strain is connected to the direct current circuit so that a structure protected by an anode will form a negative pole of the circuit.

The goal of cathodic protection is to protect the metal from all kinds of corrosion by polarizing the metal negatively with respect to the ground below a constant potential threshold for each metal in a given environment.

3.2.3.11.3 Stray current interference factor

Stray current is a current generated by electrical equipment and flowing through electrolytes, originating from natural gas pipes. The results are expressed in terms of AC - current density or DV - Surface potential gradient. Stray current flows through the ground - through metal conductors such as natural gas pipelines. The presence of such influx can cause corrosion in pipelines. (v. Baeckmann & Prinz, 1997)

3.2.3.11.4 Coating insulation resistance factor

Insulation has indisputable designation to protect the buried pipe from corrosion. Polyethylene coating is defined as a type of electrochemical insulation. The parameters of the electrochemical protection are defined by the characteristics of the environment and protecting equipment, amount of protecting current equipment.

3.2.3.11.5 Product corrosivity factor

Another cause of corrosion in the pipeline is the carried product. Corrosivity level of carried natural gas is evaluated by its growth rate. If growing of corrosivity of the product is high, it means failure risk due to corrosion is also high.

3.2.3.11.6 Activity level factor

Land use and location class of selected route for the pipeline is another important factor which can affect the risk value of pipeline. Location classes demonstrate the activity level in the selected area. Location class criteria are shown in Table 3.17. A higher number of location classes are more dangerous for pipelines. ("SCP Expansion Project,

Table 3.17 : Activity level factors criteria

Design Location Class	Typical Land Use for Location Class	No. of Buildings for Human Occupancy within 200m of Pipeline
1 (Division 1)	Sparsely populated areas, wasteland, desert, mountain, grazing and farmland	< 10
1 (Division 2)	Sparsely populated areas, wasteland, desert, mountain, grazing and farmland	< 10
2	Fringe areas around cities and towns, industrial areas, ranch or country estates	Greater than 10 and less than 46
3	Suburban housing developments, shopping centers, residential areas, industrial areas and other populated areas not meeting Location Class 4 requirements	Greater than 46
4	Includes areas where multi-story buildings (4 or more floors) are prevalent, where traffic is heavy or dense and where there may be numerous other underground utilities	Any number

3.2.3.11.7 Patrol factor

Patrol is very essential for the safety of the pipeline. Patrol is useful for inspection of a pipeline to check for leaks, washouts or other abnormal conditions by airplanes that are used for patrol. If patrol frequency is high, it means pipeline is protected well against possible failures. Low amount of patrol frequency creates difficulties for the inspection of the problem through the pipeline. (“Schlumberger Oilfield Glossary,” n.d.)

3.2.3.11.8 Right-of-way condition factor

The number of constructions such as pigging and compressor stations, along the pipeline will be increased by the multiplication of the pressure of the distributed natural gas. It is the task of the Right-of-way group that, to ensure the continuity of the buildable land lane for the facilities throughout the entire pipeline. A continuous

pipeline right-of-way includes surface sites for compressor stations, pump stations, meters, valves, storage sites and additional workspaces, without any area limitation.

One of the main thing that Right-of-way group is obliged to deliver to the project is route selection. There are many land and building obstacles that can directly affect the project budget in route selection. There may be no construction activity on the selected road, but this land may belong to another project which was previously authorized by the competent authority to work. The selected route may look very beneficial route for any pipeline, but to negotiate with each individual can damage to the project budget. It is also possible that third parties who have legal permission on this land or route can start their own activity without permission from pipeline project. Therefore, sign intactness for each chosen area and route must be at reliable level. (Bauer & Bauer, 2011)

3.2.3.11.9 Seam weld factor

Pipelines will be integrated with the welding of the pipes by bringing them into the field. Welding has a significant impact on the construction, repair, and modification of natural gas pipelines. Although much research and development work has been done on the welding of pipelines in the present day, the source of the boron is still being made manually. The method of welding and the quality of the weld are important in terms of reducing the failure of the pipelines and reducing the risk value. (Bubar & Bubar, 2011)

3.2.3.11.10 Pipe safety factor

The diameter of the pipe is fixed along the pipeline. But the inner diameter of the pipe and the wall thickness of the pipe can vary. Determining the wall thickness of a pipe is one of the most important processes for designing pipelines. The current pipe thickness of the pipe is always greater than the design pipe thickness of the pipe. The wall thickness of the pipe is calculated by taking internal pressure loads, external hydrostatic pressure and impact loads in concentration and with the help of certain formulas. Throughout the pipeline, the thickness of the wall of the pipe is increasing and decreasing.

At points, where the external impact loads are expected to be higher, the wall thickness of the pipe will be higher. The higher the ratio of the existing pipe wall thickness to

the design pipe thickness means the higher the safety of the pipeline. (Bai, Bai, Bai, & Bai, 2014)

3.2.3.11.11 The non-pipe component safety factor

Maximum Operating Pressure is the pressure that, which is used for balancing the possible pressure surge caused by some margin. The design pressure of any pipe is determined from its maximum operating pressure. If the ratio of design pressure to MOP is bigger, it means failure probability due to material and equipment is low. MOP results from the lowest of three factors: design pressure, hydrostatic test pressure, or flange rating.

3.2.3.11.12 Pressure test factor

At the point when a pipeline is intended to work at a specific most operation pressure (MOP), it must be tried to guarantee that it is fundamentally stable and can withstand the inside pressure before being put into the task. For the most cases, gas pipelines are hydro tested by filling the test area of pipe with water and directing the weight up to an esteem that is higher than most allowable operation pressure (MAOP) and holding the pressure for a time of four to eight hours. Operation company must meet the requirement that the hydrostatic test pressure of a pipeline must be at least 1.25 times the MAOP(Kiefner & Maxey, 2017).

4.1.3.5.13. SCADA system factor

Natural gas pipeline companies have customers on both ends of the pipeline – the producers and processors that input gas into the pipeline, and the consumers and local gas utilities that take gas out of the pipeline. To accomplish this task of monitoring and controlling the natural gas that is traveling through the pipeline, centralized gas control stations collect, assimilate, and manage data received from monitoring and compressor stations all along the pipe.

Most of the data that is received by a control station is provided by Supervisory Control and Data Acquisition systems. These systems note all movement on the pipeline and transmit it to the center. There is very little latency between transmitted information.

Thanks to this data it is possible to react quickly to a possible unexpected situation. (naturalgas.org, 2013)



4. RESULT AND DISCUSSION

Trans-Anatolian Natural Gas pipeline is separated into 16 segments according to the seismicity property of the pipeline crossings, As it is shown in Table A.7.

In these parts, calculations have been shown for the segment settling located between 394th and 692nd of the pipeline which is one of these 16 segments. The calculation method of the other 15 segments will be the same as this one.

4.1.1 Calculation of quantitative indices.

4.1.1.1 Wall thickness factor calculation for corrosion factor

The 56-inch pipe is used for this part of the pipeline. The pipe supplier company of the TANAP project stated that the wall thicknesses of the pipes through this diameter will vary between 10.45 mm and 16.67 mm along the pipeline. As shown in Table 3.13 the wall thicknesses of the pipes in the pipelines affect the failure probability due to the corrosion of the pipes in accordance with the following fitting function:

$$f(x) = -0.00001527x^3 + 0.00109x^2 - 0.02481x + 0.1783$$

$$f(x) = -0.00001527 \times (10.45)^3 + 0.00109 \times (10.45)^2 - 0.02481 \times 10.45 + 0.1783$$

$$f(x) = 0,0206$$

Mean failure frequency will be calculated according to the Formula 4.

$$r_{ij} = \frac{\int_b^a f(x)dx}{b-a} = \frac{\int_{10,45}^{16,67} f(x)dx}{16,67-10,45}$$

$r_{ij} =$

$$\frac{\int_{10,45}^{16,67} (-0.00001527 \times (10.45)^3 + 0.00109 \times (10.45)^2 - 0.02481 \times 10.45 + 0.1783)dx}{6,22}$$

$$r_{ij} = \frac{0,0356842}{6,22} \approx 0,0057$$

Wall thickness factor for corrosion factor:

$$F_{ij} = \frac{f(x_{ij})}{r_{ij}} = \frac{0,020640618}{0,0057} = 3,5978$$

4.1.1.2 Line pipe age factor for corrosion factor

According to Environmental, Social Impact Assessment Report of TANAP, the pipeline was designed for 49 years of usage. The report also states that; the pipeline is planned to carry natural gas at least until 2061 (minimum 43 years. That's why our b and values will be 49 and 43. As shown in Table 3.13, pipeline age affects the failure probability due to the corrosion of the pipes in accordance with the following fitting function:

$$f(x) = 0.0000002047x^4 - 0.00001907x^3 + 0.0006045x^2 - 0.006608x + 0.01931$$

$$f(x) = 0.0000002047x(43)^4 - 0.00001907x(43)^3 + 0.0006045x(43)^2 - 0.006608x43 + 0.01931$$

$$f(x) = 0,0365$$

Mean failure frequency was being calculated according to the Formula 4.

$$r_{ij} = \frac{\int_b^a f(x)dx}{b-a} = \frac{\int_{43}^{49} f(x)dx}{49-43} = \frac{0,339121}{6}$$

$$r_{ij} \approx 0,0565$$

Line pipe age factor for corrosion factor is:

$$F_{ij} = \frac{f(x_{ij})}{r_{ij}} = \frac{0,036516575}{0,0565} = 0,646$$

4.1.1.3 Coating type factor for corrosion factor

Value of coating type factor does not change even from the pipeline to pipeline or through the pipeline; that's why this factor is discontinuous. According to the risk

assessment method used in this study, the modification factor for the polyethylene coating is accepted to be 0.167. The mean failure frequency is also accepted to be 0.06.

4.1.1.4 Diameter factor for natural damage factor

The diameter of the pipes in the selected segment is equal to 56 inches, or approximately 1422.4 mm. As shown in Table 3.13, the diameter of the pipes in the pipelines affects the failure probability due to the natural damage factor of the pipes in accordance with the following fitting function. Mean of giving function is equal to 0,018 and it is accepted to be mean failure frequency of diameter factor.

$$f(x) = 0.0000000004882x^3 - 0.00000006429x^2 - 0,0000369x + 0.04801$$

$$f(x) = 0.0000000004882x1422.4^3 - 0.00000006429x1422.4^2 - 0,0000369x1422.4 + 0.04801$$

$$f(x) = 0,0059$$

Diameter factor for natural damage factor is:

$$F_{ij} = \frac{f(x_{ij})}{r_{ij}} = \frac{0,005946204}{0,018} = 0,3303$$

4.1.1.5 Wall thickness factor for third party damage factor

The 56-inch pipe is used for this part of the pipeline. The pipe supplier company of the TANAP project stated that the wall thicknesses of the pipes through this diameter will vary between 10.45 mm and 16.67 mm along the pipeline. As shown in Table 3.13, the wall thicknesses of the pipes in the pipelines affect the failure probability due to the third party damage of the pipes in accordance with the following fitting function:

$$f(x) = 0.000003226x^4 - 0.0002949x^3 + 0.009806x^2 - 0.1404x + 0.7302$$

$$f(x) = 0.000003226x10,45^4 - 0.0002949x10,45^3 + 0.009806x^2 - 0.1404x10,45 + 0.7302$$

$$f(x) = 0,0358$$

Mean failure frequency will be calculated according to the Formula 4.

$$r_{ij} = \frac{\int_b^a f(x)dx}{b-a} = \frac{\int_{10,45}^{16,67} f(x)dx}{16,67-10,45} = \frac{0,047898}{6,22}$$

$$r_{ij}=0,0077$$

Wall thickness factor for third party damage factor is:

$$F_{ij} = \frac{f(x_{ij})}{r_{ij}} = \frac{0,035800475}{0,0077} = 4,65$$

4.1.1.6 Diameter factor for third party damage factor

The diameter of the pipes in the selected segment is equal to 56 inches, or approximately 1422.4 mm. As shown in Table 3.13, the diameter of the pipes in the pipelines affects the failure probability due to the third party damage factor of the pipes in accordance with the following fitting function. Mean of giving function is equal to 0.087 and it is accepted to be mean failure frequency of diameter factor.

$$f(x) = -0.0000000007608x^3 + 0.000002131x^2 - 0.001944x + 0.5833$$

$$f(x) = -0.0000000007608 \times 1422.4^3 + 0.000002131 \times 1422.4^2 - 0.001944 \times 1422.4 + 0.5833$$

$$f(x) = -0,06$$

The risk is one of the most important philosophies of risk assessment that risk can never be less than 0, there is always a certain risk. But the minus value of the modification factor indicates that this risk is too small to be accounted for. Therefore, it is assumed that the diameter factor of the 56-inch diameter portion of the pipeline does not affect the third-party damage.

4.1.1.7 Cover depth factor for third party damage factor

The minimum covering depth along the pipeline varies between 200 mm and 150 mm. However, since the worst case approach is adopted in pipeline risk assessments, 150 for a value and 200 for b are accepted.

$$f(x) = 2.068 \times 10^{15} x^{-8.213}$$

$$f(x) = 2.068 \times 10^{15} x (150) - 8.213$$

$$f(x) = 0,00277532$$

Mean failure frequency will be calculated according to the Formula 4.

$$r_{ij} = \frac{\int_b^a f(x) dx}{b-a} = \frac{\int_{150}^{200} f(x) dx}{200-150} = \frac{0,504688}{50}$$

$$r_{ij} = 0,0101$$

Cover depth factor for third party damage factor is:

$$F_{ij} = \frac{f(x_{ij})}{r_{ij}} = \frac{0,00277532}{0,0101} = 0,275$$

4.1.1.8 Material grade factor for material and equipment factor

Value of material grade factor does not change even from the pipeline to pipeline or through the pipeline; that's why this factor is discontinuous. According to the risk assessment method used, the modification factor for the X70 Carbon Steel Pipe is accepted to be 0,438. The mean failure frequency is also accepted to be 0.016.

4.1.1.9 Line pipe age factor for material and equipment factor

According to Environmental, Social Impact Assessment Report of TANAP, the pipeline was designed for 49 years of usage. The report states that the pipeline is planned to carry natural gas at least until 2061 (minimum 43 years. That's why our b and values will be 49 and 43. As shown in Table 3.13, pipeline age affects the failure probability due to the material and equipment of the pipes in accordance with the following fitting function:

$$f(x) = -0.00000009733x^4 + 0.0000128x^3 - 0.0004953x^2 + 0.006852x - 0.02312$$

$$f(x) = -0.00000009733 \times 43^4 + 0.0000128 \times 43^3 - 0.0004953 \times 43^2 + 0.006852 \times 43 - 0.02312$$

$$f(x) = 0,040643999$$

Mean failure frequency will be calculated according to the Formula 4.

$$r_{ij} = \frac{\int_b^a f(x) dx}{b-a} = \frac{\int_{43}^{49} f(x) dx}{49-43} = \frac{0,325339}{6}$$

$$r_{ij} \approx 0,0542$$

Line pipe age factor for material an equipment factor is:

$$F_{ij} = \frac{f(x_{ij})}{r_{ij}} = \frac{0,040643999}{0,0542} = 0,749$$

4.1.1.10 Diameter factor for incorrect operation factor

The diameter of the pipes in the selected segment is equal to 56 inches, or approximately 1422.4 mm. As shown in Table 3.13, the diameter of the pipes in the pipelines affects the failure probability due to the incorrect operation factor of the pipes in accordance with the following fitting function. Mean of giving function is equal to 0.00,1 and it is accepted to be mean failure frequency of diameter factor.

$$f(x) = -0.00000000006731x^3 + 0.0000001963x^2 - 0.0001849x + 0.05601$$

$$f(x) = -0.00000000006731 \times 1422,4^3 + 0.0000001963 \times 1422,4^2 - 0.0001849 \times 1422,4 + 0.05601$$

$$f(x) = -0,003596365$$

The minus value of the modification factor indicates that this risk is too small to be accounted for. Therefore, it is assumed that the diameter factor of the 56-inch diameter portion of the pipeline does not affect the incorrect operations.

4.1.2 Calculation of semi-quantitative indices and qualitative indices

Modification factor levels of semi-quantitative indices and qualitative indices were evaluated based on information that is given in Environmental and Social Impact Assessment Report of Trans-Anatolia Natural Gas Pipeline Project. Unknown values of semi-quantitative indices are regarded as the worst case approach as level V. Modification factor levels of semi-quantitative indices and qualitative indices are given in

Table 4.1 : Modification factor levels of semi-quantitative indices.

Second level index	Scale criterion	Modification factor level
Corrosion factor	Soil corrosivity factor	V
	Cathodic protection factor	V
	Stray current interference factor	V
	Coating insulation resistance factor	V
Third party damage factor	Product corrosivity factor	IV
	Activity level factor	V
	Patrol factor	V
	Right-of-way condition factor	II
Material and equip failure factor	Seam weld factor	II
	Pipe safety factor	III
	Non-Pipe components factor	V
	Pressure test factor	V
Incorrect operation factor	SCADA system factor	II

Modification factors of semi-quantitative and qualitative indices are calculated according to Formula 5. As an example, the calculation for II modification level is shown below. The same method was applied to other indices, and the results are given in Table 4.2 and Table 4.3

Fuzzy Possibility Score for II level modification factor is chosen from Figure 3.3. For II, this value is equal to 0.3

Table 4.2 : Modification factor levels of qualitative indices

First level index	Second level index	Modification factor level
Corrosion factor	Internal corrosion preventions factor	II
Natural damage factor	Earth movement factor	V
	Heavy weather factor	V
	Public education factor	II
Third party damage factor	Alarm call system factor	II
	Above ground facilities factor	IV
	Construction factor	II
Incorrect operation factor	Maintenance factor	II
	Quality of worker factor	II
	Sabotage incident factor	II

As mentioned before, average failure frequency for second level modification factors of semi-quantitative and qualitative indices (r) is accepted as $2,32 \cdot 10^{-5}$.

$$K = \frac{1}{\lg(1/r)} = \frac{1}{\lg(\frac{1}{2,32 \cdot 10^{-5}})} = 4,63$$

$$k = \left[\frac{1-0,3}{0,3} \right]^{1/3} \times 4,63 = 6,14$$

$$FPS \neq 0$$

$$FP = \frac{1}{10^k} = \frac{1}{10^{6,14}} = 7,23 \times 10^{-7}$$

The second level modification factor is calculated according to the following formula.

$$F = \frac{FP}{r} = \frac{7,23 \times 10^{-7}}{2,32 \times 10^{-5}} = 3,08 \times 10^{-2}$$

Table 4.3 : Modification factors for modification factor levels

Modification factor level	FPS	k	FP	F
I	0,1	9,63	$2,34 \times 10^{-10}$	10^{-5}
II	0,3	6,14	$7,24 \times 10^{-7}$	$3,08 \times 10^{-2}$
III	0,5	4,63	$2,34 \times 10^{-5}$	1
IV	0,7	3,49	$3,24 \times 10^{-4}$	13,8
V	0,9	2,23	$5,89 \times 10^{-3}$	251,2

Table 4.4 : Values of second level modification factors of semi-quantitative indices

Second level index	Scale criterion	Second level modification factors
Corrosion factor	Soil corrosivity factor	251,2
	Cathodic protection factor	251,2
	Stray current interference factor	251,2
	Coating insulation resistance factor ($k\Omega \cdot m^2$)	251,2
	Product corrosivity factor	13,8
Third party damage factor	Activity level factor	251,2
	Patrol factor	251,2
	Right-of-way condition factor	$3,08 \times 10^{-2}$
Material and equip failure factor	Seam weld factor	$3,08 \times 10^{-2}$
	Pipe safety factor	1
	Non-Pipe components factor	251,2
	Pressure test factor	251,2
Incorrect operation factor	SCADA system factor	$3,08 \times 10^{-2}$

Table 4.5 : Values of second level modification factors of quantitative indices

First level index	Second level index	Modification factors
Corrosion factor	Internal corrosion preventions factor	$3,08 \times 10^{-2}$
Natural damage factor	Earth movement factor	251,2
	Heavy weather factor	251,2
Third party damage factor	Public education factor	$3,08 \times 10^{-2}$
	Alarm call system factor	$3,08 \times 10^{-2}$
	Above ground facilities factor	13,8
Incorrect operation factor	Construction factor	$3,08 \times 10^{-2}$
	Maintenance factor	$3,08 \times 10^{-2}$
	Quality of worker factor	$3,08 \times 10^{-2}$
Sabotage incident factor	Sabotage incident factor	$3,08 \times 10^{-2}$

4.1.3 Calculations of corresponding weights

Average failure frequency of each second level modification factor is shown in Table 4.6 as they have been calculated above. As an example, calculation of wall thickness factor corrosion first level modification factor is shown below. Other second level modification factors for each first level modification factors are calculated the same and the results are shown below.

$$w_{ij} = \frac{r_{ij}}{\sum_j^n r_{ij}} = \frac{0,0057}{0,12239} = 0,0469$$

Table 4.6 : Corresponding weights of corrosion factor

Second level modification factor	r	w
Wall thickness factor	0,0057	0,0469
Line pipe age factor	0,057	0,4618
Coating type factor	0,06	0,4902
Soil corrosivity factor	$2,32 \times 10^{-5}$	$1,9 \times 10^{-4}$
Cathodic protection factor	$2,32 \times 10^{-5}$	$1,9 \times 10^{-4}$
Stray current interference factor	$2,32 \times 10^{-5}$	$1,9 \times 10^{-4}$
Coating insulation resistance factor	$2,32 \times 10^{-5}$	$1,9 \times 10^{-4}$
Product corrosivity factor	$2,32 \times 10^{-5}$	$1,9 \times 10^{-4}$
Internal corrosion preventions factor	$2,32 \times 10^{-5}$	$1,9 \times 10^{-4}$

Table 4.7 : Corresponding weights of natural damage factor

Second level modification factor	r	w
Diameter factor	0,018	0,997
Earth movement factor	$2,32 \times 10^{-5}$	$1,29 \times 10^{-3}$
Heavy weather factor	$2,32 \times 10^{-5}$	$1,29 \times 10^{-3}$

Table 4.8 : Corresponding weights of third party damage factor

Second level modification factor	r	w
Wall thickness factor	0,0077	0,429
Cover depth factor	0,0101	0,563
Activity level factor	$2,32 \times 10^{-5}$	$1,29 \times 10^{-3}$
Patrol frequency factor	$2,32 \times 10^{-5}$	$1,29 \times 10^{-3}$
Right of way condition factor	$2,32 \times 10^{-5}$	$1,29 \times 10^{-3}$
Public education factor	$2,32 \times 10^{-5}$	$1,29 \times 10^{-3}$
Alarm call system factor	$2,32 \times 10^{-5}$	$1,29 \times 10^{-3}$
Above ground facilities factor	$2,32 \times 10^{-5}$	$1,29 \times 10^{-3}$

Table 4.9 : Corresponding weights of incorrect operation factor

Second level modification factor	r	w
SCADA system factor	$2,32 \times 10^{-5}$	0,25
Construction factor	$2,32 \times 10^{-5}$	0,25
Maintenance factor	$2,32 \times 10^{-5}$	0,25
Quality of worker factor	$2,32 \times 10^{-5}$	0,25

Table 4.10 : Corresponding weights of material and equipment failure factor

Second level modification factor	r	w
Material grade factor	0,016	0,228
Line pipe age factor	0,054	0,771
Seam weld factor	$2,32 \times 10^{-5}$	$3,3 \times 10^{-4}$
Pipe safety factor	$2,32 \times 10^{-5}$	$3,3 \times 10^{-4}$
Non-pipe componenets factor	$2,32 \times 10^{-5}$	$3,3 \times 10^{-4}$
Pressure test factor	$2,32 \times 10^{-5}$	$3,3 \times 10^{-4}$

Because of that, there is an only one-second level factor for sabotage factor, respectively its corresponding weight will be 1.

In this example, second-level factors that have negative modification factors are not included in equivalent weight calculations. In other examples, the same factors were included in the calculations if they had positive values.

4.1.4 Calculation of first level modification factor

4.1.4.1 Calculation for primary cause failure probability

As mentioned above, first level modification factors were calculated from the sum of the multiplication of the secondary level modification factors and their corresponding weights. Calculated secondary level modification factors, corresponding weights of secondary level modification factors and result of their multiplication to each other are given below.

Table 4.11 : Multiplication of second level modification factors to their corresponding weights for corrosion

Second level modification factors	w	F	w x F
Wall thickness factor	0,0469	3,5978	0,169
Line pipe age factor	0,4618	0,6461	0,298
Coating type factor	0,4902	0,1670	0,298
Soil corrosivity factor	$1,9 \times 10^{-4}$	251,2	$4,81 \times 10^{-2}$
Cathodic protection factor	$1,9 \times 10^{-4}$	251,2	$4,81 \times 10^{-2}$
Stray current interference factor	$1,9 \times 10^{-4}$	251,2	$4,81 \times 10^{-2}$
Coating insulation resistance factor	$1,9 \times 10^{-4}$	251,2	$2,61 \times 10^{-3}$
Product corrosivity factor	$1,9 \times 10^{-4}$	13,8	$4,81 \times 10^{-2}$
Internal corrosion preventions factor	$1,9 \times 10^{-4}$	$3,08 \times 10^{-2}$	$5,87 \times 10^{-6}$

$$F_i = \sum_{j=1}^n w_{ij} F_{ij} \approx 0,96$$

4.1.4.2 First level modification factor for natural damage factor

Calculated secondary level modification factors, corresponding weights of secondary level modification factors for natural damage factor and result of their multiplication to each other are given in Table 4.12.

Table 4.12 : Multiplication of second level modification factors to their corresponding weights for natural damage

Second level modification factor	w	F	w x F
Diameter factor	0,997	0,330	0,329
Earth movement factor	$1,29 \times 10^{-3}$	251,2	0,326
Heavy weather factor	$1,29 \times 10^{-3}$	251,2	0,326

$$F_i = \sum_{j=1}^n w_{ij} F_{ij} \approx 0,98$$

4.1.4.3 First level modification factor for third party damage

Calculated secondary level modification factors, corresponding weights of secondary level modification factors for third party damage factor and result of their multiplication to each other are given in Table 4.13.

Table 4.13 : Multiplication of second level modification factors to their corresponding weights for third party damage

Second level modification factor	w	F	w x F
Wall thickness factor	0,429	4,649	1,996
Cover depth factor	0,563	0,275	0,155
Activity level factor	$1,29 \times 10^{-3}$	251,2	0,328
Patrol frequency factor	$1,29 \times 10^{-3}$	251,2	0,328
Right of way condition factor	$1,29 \times 10^{-3}$	$3,08 \times 10^{-2}$	$3,99 \times 10^{-5}$
Public education factor	$1,29 \times 10^{-3}$	$3,08 \times 10^{-2}$	$3,99 \times 10^{-5}$
Alarm call system factor	$1,29 \times 10^{-3}$	$3,08 \times 10^{-2}$	$3,99 \times 10^{-5}$
Above groundfacilities factor	$1,29 \times 10^{-3}$	13,8	$1,79 \times 10^{-2}$

$$F_i = \sum_{j=1}^n w_{ij} F_{ij} \approx 2,81$$

4.1.4.4 First level modification factor for material and equipment failure

Calculated secondary level modification factors, corresponding weights of secondary level modification factors for material and equipment failure factor and result of their multiplication to each other are given in Table 4.22.

Table 4.14 : Multiplication of second level modification factors to their corresponding weights for material and equipment failure

Second level modification factor	w	F	w x F
Material grade factor	0,228	0,438	0,1
Line pipe age factor	0,771	0,750	0,578
Seam weld factor	$3,3 \times 10^{-4}$	$3,08 \times 10^{-2}$	$1,02 \times 10^{-5}$
Pipe safety factor	$3,3 \times 10^{-4}$	1	$3,3 \times 10^{-4}$
Non-pipe componenets factor	$3,3 \times 10^{-4}$	251,2	0,084
Pressure test factor	$3,3 \times 10^{-4}$	251,2	0,084

$$F_i = \sum_{j=1}^n w_{ij} F_{ij} \approx 0,85$$

4.1.4.5 First level modification factor for incorrect operation

Calculated secondary level modification factors, corresponding weights of secondary level modification factors for incorrect operation factor and result of their multiplication to each other are given in Table 4.23.

Table 4.15 : Multiplication of second level modification factors to their corresponding weights for incorrect operation

Second level modification factor	w	F	w x F
SCADA system factor	0,25	$3,08 \times 10^{-2}$	$7,71 \times 10^{-3}$
Construction factor	0,25	$3,08 \times 10^{-2}$	$7,71 \times 10^{-3}$
Maintenance factor	0,25	$3,08 \times 10^{-2}$	$7,71 \times 10^{-3}$
Quality of worker factor	0,25	$3,08 \times 10^{-2}$	$7,71 \times 10^{-3}$

$$F_i = \sum_{j=1}^n w_{ij} F_{ij} \approx 3,08 \times 10^{-2}$$

4.1.4.6 First level modification factor for sabotage

Calculated secondary level modification factors, corresponding weights of secondary level modification factors for sabotage factor and result of their multiplication to each other are given in Table 4.16.

Table 4.16 : Multiplication of second level modification factors to their corresponding weights for sabotage

Second level modification factor	w	F	w x F
Sabotage factor	1	$3,08 \times 10^{-2}$	$3,08 \times 10^{-2}$

$$F_i = 3,08 \times 10^{-2}$$

4.1.5 Calculation for baseline failure frequency

The calculation method for baseline failure frequency is explained in section 4.1.2.2. Total corresponding length of pipelines for 1788 accidents of concern in 14 years (from 2002 in 2013) is equal to $5,87 \times 10^7$ km according to PIDs such as PHMSA, NEB, and ECIG. Percentages of each primary failure causes are also given in Table 3.10 as mentioned above. As an example, baseline failure frequency of corrosion failure cause is shown below. Calculation for other primary failure causes would be the same and results of all primary failure causes are shown in Table 4.17.

$$R_i = \frac{\alpha_i}{m} \sum_{k=1}^m \frac{N_k}{L_k} = \frac{24,14}{14} \sum_{k=1}^{14} \frac{1788}{5,87 \times 10^7} = 5,25 \times 10^{-5}$$

Table 4.17 : Baseline failure frequency for each primary causes

Primary failure cause	Baseline failure frequency
Corrosion	$5,25 \times 10^{-5}$
Natural force damage	$2,54 \times 10^{-5}$
Third party damage	$4,77 \times 10^{-5}$
Material/weld/equip failure	$6,48 \times 10^{-5}$
Incorrect operation	$7,54 \times 10^{-5}$
Sabotage cause	$1,95 \times 10^{-5}$

4.1.6 Calculation for primary cause failure probability

Primary cause failure probability for each first level modification factor is equal to the multiplication of the value of first level modification factor to its baseline failure frequency. Results for primary cause failure probability per km per year are shown in Table 4.18.

Table 4.18 : Primary cause failure probabilities

Primary failure cause	Baseline failure frequency	First level modification factor	Primary cause failure probability
Corrosion	$5,25 \times 10^{-5}$	0,96	$5,04 \times 10^{-5}$
Natural force damage	$2,54 \times 10^{-5}$	0,982	$2,49 \times 10^{-5}$
Third party damage	$4,77 \times 10^{-5}$	2,81	$1,34 \times 10^{-4}$
Material/weld/equip failure	$6,48 \times 10^{-5}$	0,845	$5,48 \times 10^{-5}$
Incorrect operation	$7,54 \times 10^{-5}$	0,031	$2,32 \times 10^{-7}$
Sabotage	$1,95 \times 10^{-5}$	0,031	$6,01 \times 10^{-7}$

Total failure probability of selected segment of pipeline is equal to the sum of primary failure cause probabilities, and it is equal to $2,65 \times 10^{-4}$ per km per year. Second level modifications factors, first level modification factors and primary failure causes of each segment has shown in Appendix A.

4.1.7 Calculation of probability of the whole pipeline

Failure probability of pipeline is system is calculated by following formula:

$$P_p = \sum_{i=1}^n P \times l = 2,25 \times 10^{-4}$$

Failure probability of TANAP is equal to $2,25 \times 10^{-4}$ per km per year.



5. CONCLUSIONS AND RECOMMENDATIONS

Failure probability of each segment is shown in Table A.7. The failure probability for a selected segment of TANAP is $2,65 \times 10^{-4}$ per km per year. According to the assessment scale of failure probability, risk probability of selected segment was evaluated as medium level.

Table 5.1: Assessment scale of failure probability

Evaluation	Failure probability
Very high	$> 10^{-2}$
High	10^{-3} to 10^{-2}
Medium	10^{-4} to 10^{-3}
Low	10^{-4} to 10^{-5}
Very Low	$< 10^{-5}$

Influence percentage of primary cause failure probabilities for failure probability has been shown in Figure 5.1.

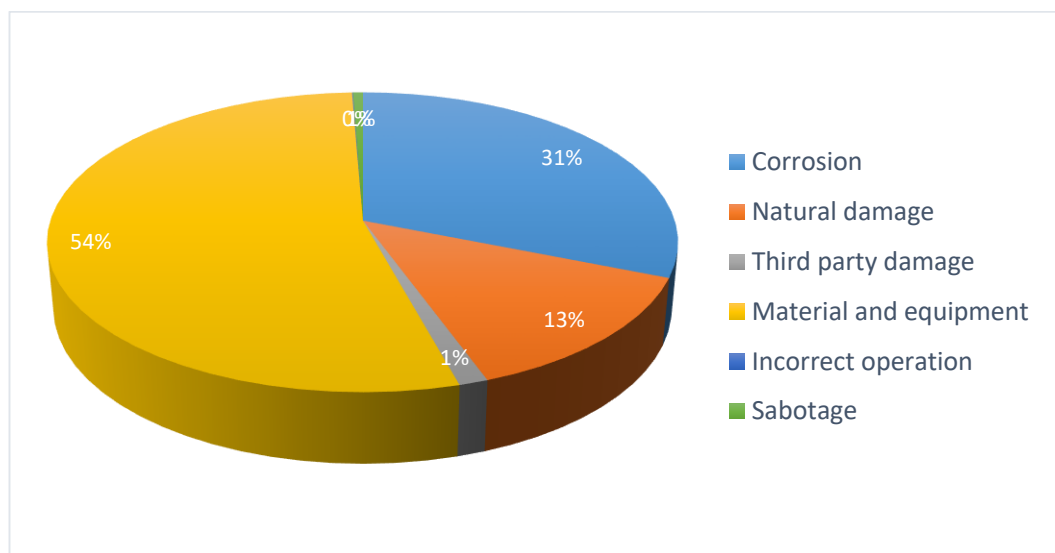


Figure 5.1 : Percentages of the contribution of first level modification factors to risk amount for the selected segment.

For a selected segment of TANAP, results of primary cause failure probabilities have some differences than average results of statistics, which has been shown in Figure 5.2.

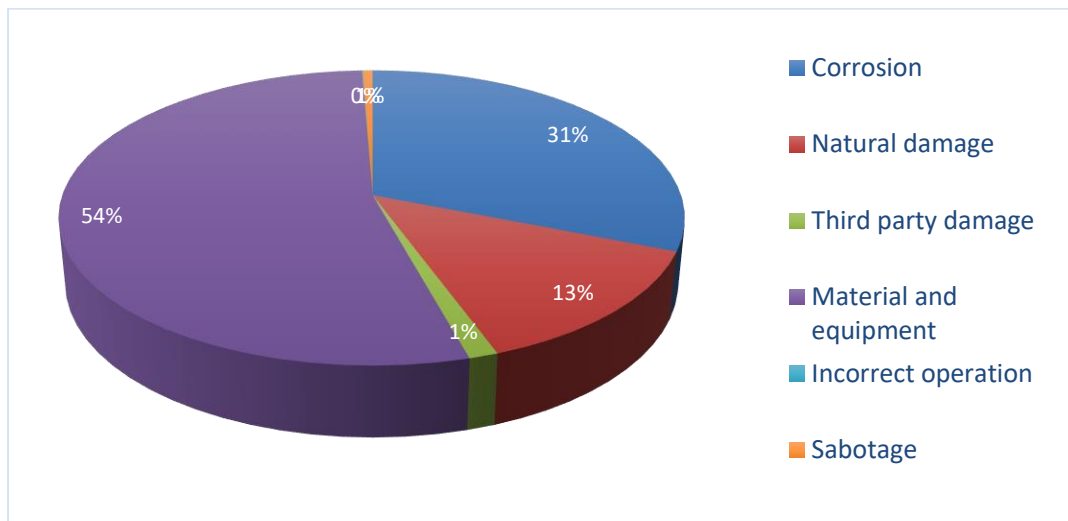


Figure 5.2 : Percentages of the contribution of first level modification factors to risk amount for statistical data.

As it is demonstrated in Figure 5.2, the statistical accidents data offers that accidents were mostly caused by material and equipment failure (29.80%), corrosion (24.14%), and third-party damage (21.94%). The remaining incidents were caused by natural damage (11.68%), sabotage (8.97%) and incorrect operation (3.47%). Figure 5.1 shows that third-party damage (50.06%) and material and equipment (20.07%) are the two leading factors with the greatest threat for selected pipeline segment that consists of a length of 297 km, followed by corrosion (19%) and natural damage (9,4%), incorrect operation and sabotage are the smallest threat for which accounting for only 0.1% and 0.2% of accidents. Industry stakeholders and pipeline operators are supposed to be more careful about third party damage in this selected segment of the pipeline.

The assessment consequences of the selected segment with the selected method are compared with those of W. Kent Muhlbauer (Muhlbauer, 2004) scoring technique which is presently notable and a standout amongst the most broadly utilized hazard evaluation strategies. W. Kent Muhlbauer scoring technique proposes that higher score, the lower failure probability of pipeline (Shan et al., 2018). Risk Assessment of Baku-Tbilisi-Ceyhan Crude Oil Pipeline (BTC) based on W. Kent Muhlbauer scoring method was conducted by Özbek (2004). According to the Environment, Impact, Social Assessment Report of TANAP, Trans Anatolian Natural Gas and Baku-Tbilisi-

Ceyhan Crude Oil pipelines continuous in parallel from 245th km till 255th km. This means that many of the parameters of these two pipelines will be identical to one another at these distances. The properties of the material and equipment used, the properties of the material carried, and some parameters originating from the project company vary from TANAP to BTC. In order to obtain a comparison of used risk assessment method and check the reliability of our results, risk assessment results of TANAP based on Muhlbauer scoring and historical related data methods are compared. The parameters for TANAP that differ from BTC were changed according to the TANAP parameters, and the parameters that are the same for both pipelines in parallel route were not changed. At the same time, in the risk assessment of BTC, incorrect operation factors and sabotage factors were not taken into account. Obtained results for percentages of the contribution of first level modification factors to risk amount for the segment of parallel route located are shown in Figure 5.3 and Figure 5.4.

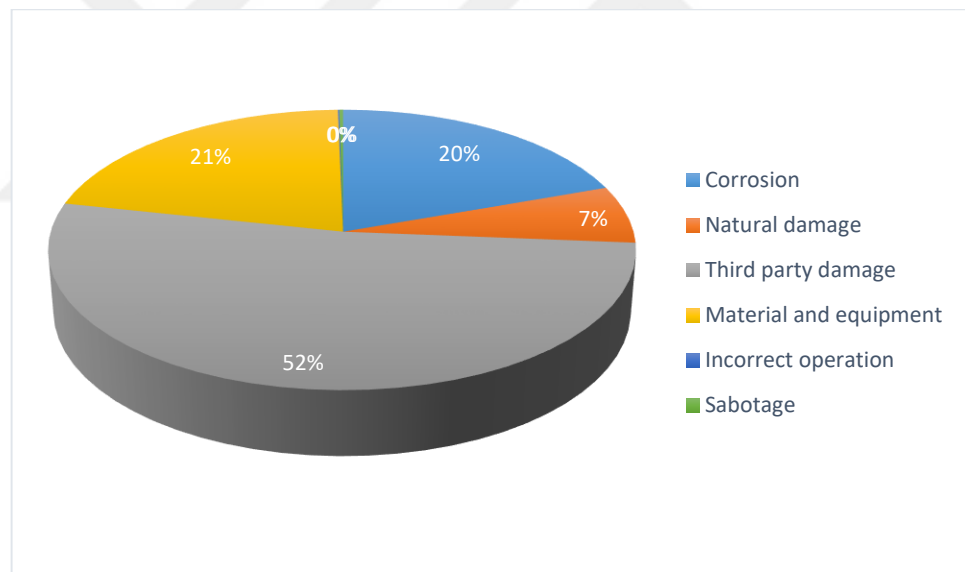


Figure 5.3 : Percent distribution according to selected method for TANAP.

In both methods, leading factors are third party damage (47% for Muhlbauer, 52% for historical failure-related method) and material and equipment (24% for Muhlbauer, 21% for historical failure-related method). The following factors are corrosion (21% for Muhlbauer, 20% for historical failure-related method) and natural damage (7% for both of Muhlbauer and historical failure-related method).

The correlation between the results based on two methods can be seen clearly, which supports the risk results for TANAP with the selected method.

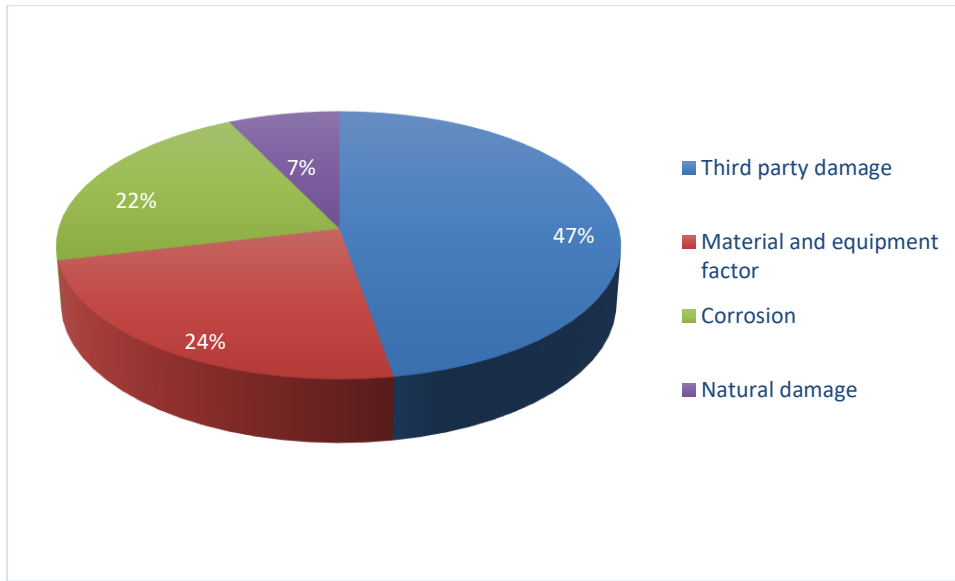


Figure 5.4 : Percent distribution according to Muhlbauer method for TANAP.

Figure 5.5 demonstrates primary causes failure probabilities of each segment along the pipeline. After 1333rd km of pipeline primary cause failure probability decreased rapidly. The main reason for such kind of decrease is the change of the diameter of pipe used. After changing pipe diameter from 56 inches to 48 inches, risk probability decreases. Diameter factor for third party damage factor has decreased to the level that diameter factor literally has no influence to risk amount. As a rule, for safety issues, pipe with a small amount of diameter was thicker wall thickness that it is also essential for decreasing risk amount. As an example for the importance of the influence of third-party damage factor to risk amount, comparison of the proportion of first level modification factor contribution to primary cause failure probabilities shown in Figure 5.1 and Figure 5.6. However, increasing wall thickness to nominal level decreases failure probability, the segment with the lowest probability in TANAP is about 1.02×10^{-4} and it is more than 10^{-4} that the lowest segment is evaluated as medium level. Increase in risk value, after 1498th km, is because of planned compressor stations. Because of that, sabotage possibility of the segment where stations have been located is accepted as medium level.

As it is noticed in Figure 5.1 and Figure 5.3, incorrect operation factor is the safest factor for TANAP project, which comprises only 0.1% of hole risk value. Not possible threat approximately failure probability is not predicted from this factor.

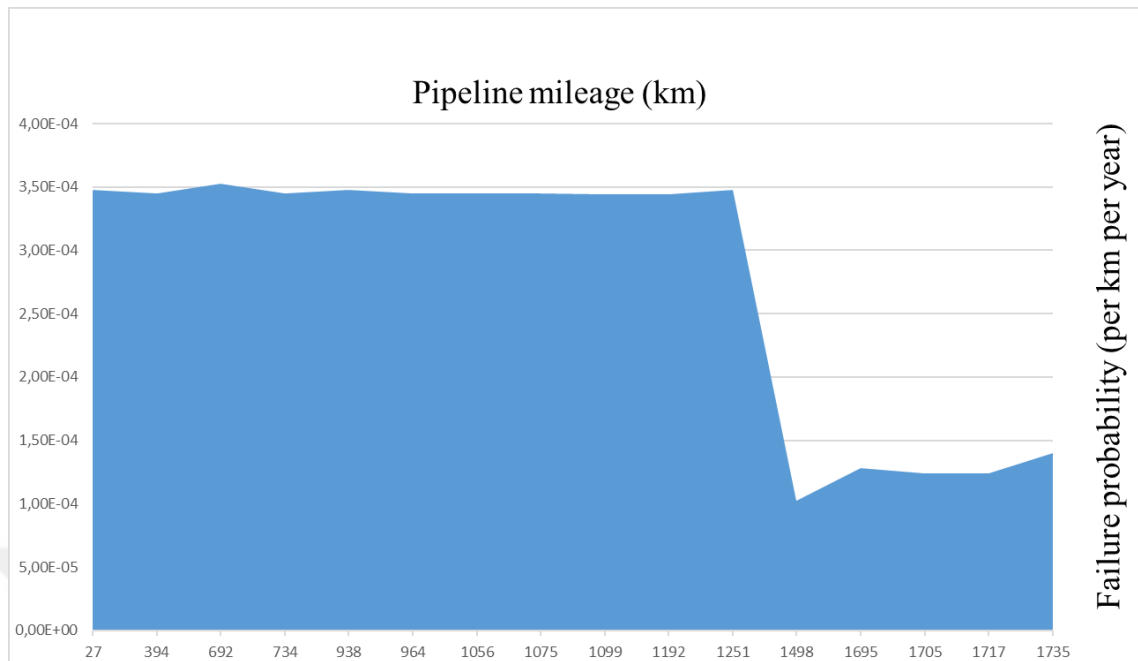


Figure 5.5 : Failure probability of TANAP along the route

Corrosion factor has an essential influence on risk value of TANAP project. Soil corrosivity factor, cathodic protection factor, stray current interference factor, and coating insulation resistance factor are the subfactors that feed primary failure cause probability of corrosion. The reason for these values to be so high is because they are unknown. The worst case approach has been adopted for situations in which no data is available. Once the aforementioned factors have been measured and determined, keeping them at the optimum level will decrease the risk probability of system due to corrosion primary factor. Moreover, the fact that the pipeline will be used for many years increases its risk of failure significantly. As the corrosion level increases over time, regular maintenance of the pipes will bring this risk to a more controllable level.

However, natural damage factor is an important factor for risk assessment of TANAP, since there's not many for avoiding from this factor. Taking into the account that, construction of TANAP project has almost finished, changing wall thickness or diameter of the pipe is not easy and commercially beneficial choice. The possible way to reduce the damages that may arise from this factor is to be ready for emergency situations.

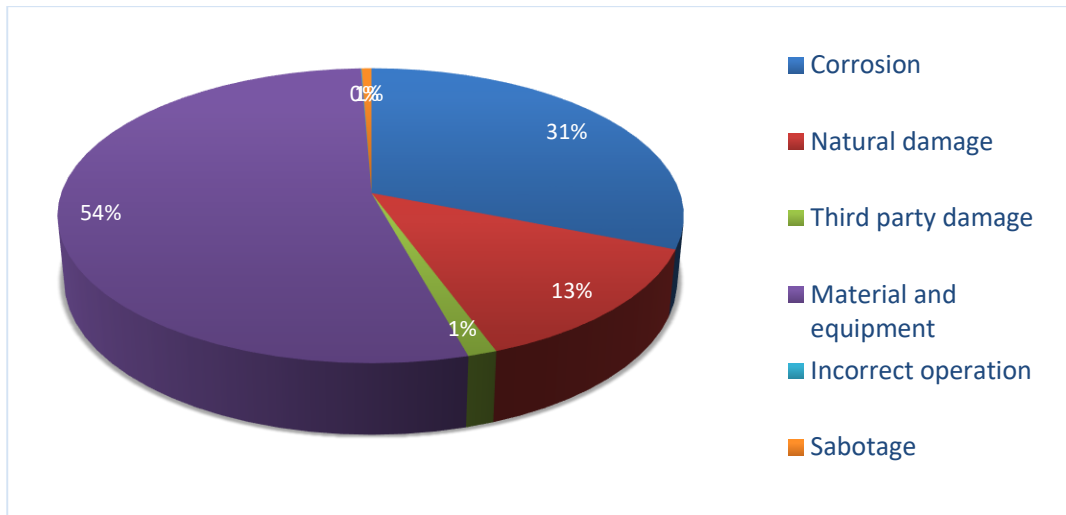


Figure 5.6 : Percentages of the contribution of first level modification factors to risk amount for the segment with 48-inch pipe.

As it is seen from Table A.4, the second level modification factors which feed third-party damage primary cause failure factor are wall thickness and diameter factors. As it's mentioned above, construction of TANAP project has almost done, and it would not be a logical argument for decreasing diameter and the wall thickness of the pipe. However, as it is seen from Table 5.5 decreasing diameter of the pipe and the thicker wall thickness of pipe with the small diameter, decrease the risk value of pipeline system approximately two times. The applicable way for decreasing third-party damage factor is the treatment of above-ground facilities which is possible such as increasing intensity on inspection in important areas, improving security systems, and building walls for the pipeline.

The material and equipment factor is one of the leading risk factors for the pipeline. This factor is one of the most important contributing factors for the pipeline to be used for many years. The recommendations given for making the pipeline more secure for long time use are also valid for this section. In spite of that values of second level modification factor for material and equipment factor, a is not that much high, material and equipment factor has high importance because of its high value of baseline line frequency. From that point of view, it is essential to understand the importance of second level factors such as non-pipe components factors and pressure test factors, which quantitatively has the small value. Therefore, determining Test pressure, Most Allowable Operating Pressure in more nominal level will decrease the risk value of TANAP.

As it is noticed in Figure 5.1 and Figure 5.3, incorrect operation factor has the minimum risk value for TANAP project, which comprises only 0.1% of whole risk value. Not any possible threats are predicted from this factor for failure probability of TANAP.

The sabotage factor is the most difficult factor to predict among other factors that are calculated. This factor can be attributed to many socio-economic, sociological and political reasons which can not be calculated. It should be noted that although the sabotage factor calculated for TANAP is a low value, it is 8.97% of the probability of general failure, based on historical evidence.





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APPENDIX

APPENDIX A:

Table A.1 : Primary cause failure probability for sabotage factor

Sector range (km)	Terrorism factor	First level modification factor	Baseline failure frequency	Primary cause failure probability
0-27	1,0000E+00	1,0000E+00	1,9500E-05	1,9500E-05
27-394	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
394-692	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
692-734	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
734-938	1,0000E+00	1,0000E+00	1,9500E-05	1,9500E-05
938-964	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
964-1056	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
1056-1075	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
1075-1099	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
1099-1192	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
1192-1333	1,0000E+00	1,0000E+00	1,9500E-05	1,9500E-05
1333-1498	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
1498-1690	1,0000E+00	1,0000E+00	1,9500E-05	1,9500E-05
1690-1705	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
1705-1728	3,0831E-02	3,0831E-02	1,9500E-05	6,0121E-07
1728-1805	1,0000E+00	1,0000E+00	1,9500E-05	1,9500E-05

Table A.2 : Primary cause failure probability for corrosion factor

Sector range (km)	Wall thickness factor	Line pipe age factor	Coating type factor	Soil corrosivity factor	Cathodic protection factor	Stray current interference factor	Coating insulation resistance factor	Product corrosivity factor	Internal corrosion prevention factor	First level modification factor	Baseline failure frequency	Primary cause failure probability
0-27	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
27-394	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
394-692	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
692-734	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
734-938	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
938-964	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
964-1056	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
1056-1075	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
1075-1099	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
1099-1192	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
1192-1333	3,5978	0,6461	0,6461	0,0481	0,0481	0,0481	0,0481	0,0026	5,871E-06	5,0848477	5,25E-05	2,670E-04
1333-1498		0,3130	0,0859	0,0504	0,0504	0,0504	0,0504	0,0027	0,00019887	0,6035725	5,25E-05	3,169E-05
1498-1690		0,3130	0,0859	0,0504	0,0504	0,0504	0,0504	0,0027	0,00019887	0,6035725	5,25E-05	3,169E-05
1690-1705		0,3130	0,3130	0,0504	0,0504	0,0504	0,0504	0,0027	0,00019887	0,8307002	5,25E-05	4,361E-05
1705-1728		0,3130	0,3130	0,0504	0,0504	0,0504	0,0504	0,0027	0,00019887	0,8307002	5,25E-05	4,361E-05
1728-1805		0,3130	0,3130	0,0504	0,0504	0,0504	0,0504	0,0027	0,00019887	0,8307002	5,25E-05	4,361E-05

Table A.3 : Primary cause failure probability for natural damage factor

Sector range (km)	Diameter factor	Earth movement factor	Heavy weather factor	First level modification factor	Baseline failure frequency	Primary cause failure probability
0-27	0,3295	0,0013	0,3260	0,6568	0,0000254	1,6682E-05
27-394	0,3295	0,0177	0,3260	0,6732	0,0000254	1,71E-05
394-692	0,3295	0,3260	0,3260	0,9815	0,0000254	2,493E-05
692-734	0,3295	0,0177	0,3260	0,6732	0,0000254	1,71E-05
734-938	0,3295	0,0013	0,3260	0,6568	0,0000254	1,6682E-05
938-964	0,3295	0,0177	0,3260	0,6732	0,0000254	1,71E-05
964-1056	0,3295	0,3260	0,0481	0,7036	0,0000254	1,7871E-05
1056-1075	0,3295	0,0177	0,3260	0,6732	0,0000254	1,71E-05
1075-1099	0,3295	0,0013	0,3260	0,6568	0,0000254	1,6682E-05
1099-1192	0,3295	0,0000	0,3260	0,6555	0,0000254	1,6651E-05
1192-1333	0,3295	0,0013	0,3260	0,6568	0,0000254	1,6682E-05
1333-1498	0,1942	0,0177	0,3260	0,5379	0,0000254	1,3663E-05
1498-1690	0,1942	0,3260	0,3260	0,8462	0,0000254	2,1493E-05
1690-1705	0,1949	0,3260	0,3260	0,8470	0,0000254	2,1513E-05
1705-1728	0,1949	0,0177	0,3260	0,5387	0,0000254	1,3682E-05
1728-1805	0,1949	0,0013	0,3260	0,5222	0,0000254	1,3265E-05

Table A.4 : Primary cause failure probability for third party damage factor

Sector range (km)	Wall thickness factor	Diameter factor	Cover depth factor	Activity level factor	Patrol frequency factor	The right of way condition factor	Public education factor	Alarm call system factor	Above ground facilities factor	First level modification factor	Baseline failure frequency	Primary cause failure probability
0-27	1,9963		0,1548	0,3281	1,29E-08	3,988E-05	3,988E-05	3,988E-05	0,00129	2,480504	4,77E-05	1,18E-04
27-394	1,9963		0,1548	0,3281	0,328056	3,988E-05	3,988E-05	3,988E-05	0,00129	2,80856	4,77E-05	1,34E-04
394-692	1,9963		0,1548	0,3281	0,328056	3,988E-05	3,988E-05	3,988E-05	0,00129	2,80856	4,77E-05	1,34E-04
692-734	1,9963		0,1548	0,3281	0,328056	3,988E-05	3,988E-05	3,988E-05	0,00129	2,80856	4,77E-05	1,34E-04
734-938	1,9963		0,1548	0,3281	1,29E-08	3,988E-05	3,988E-05	3,988E-05	0,00129	2,480504	4,77E-05	1,18E-04
938-964	1,9963		0,1548	0,3281	0,328056	3,988E-05	3,988E-05	3,988E-05	0,00129	2,80856	4,77E-05	1,34E-04
964-1056	1,9963		0,1548	0,3281	0,328056	3,988E-05	3,988E-05	3,988E-05	0,00129	2,80856	4,77E-05	1,34E-04
1056-1075	1,9963		0,1548	0,3281	0,328056	3,988E-05	3,988E-05	3,988E-05	0,00129	2,80856	4,77E-05	1,34E-04
1075-1099	1,9963		0,1548	0,3281	0,328056	3,988E-05	3,988E-05	3,988E-05	0,00129	2,80856	4,77E-05	1,34E-04
1099-1192	1,9963		0,1548	0,3281	0,328056	3,988E-05	3,988E-05	3,988E-05	0,00129	2,80856	4,77E-05	1,34E-04
1192-1333	1,9963		0,1548	0,3281	1,29E-08	3,988E-05	3,988E-05	3,988E-05	0,00129	2,480504	4,77E-05	1,18E-04
1333-1498		0,0034	0,0047	0,0099	0,009912	1,205E-06	1,205E-06	1,205E-06	3,9E-05	0,02794	4,77E-05	1,33E-06
1498-1690		0,0034	0,0047	0,0099	3,9E-10	1,205E-06	1,205E-06	1,205E-06	3,9E-05	0,018027	4,77E-05	8,60E-07
1690-1705	0,0264	0,0597	0,0284	0,0603	0,060302	7,332E-06	7,332E-06	7,332E-06	0,00024	0,235342	4,77E-05	1,12E-05
1705-1728	0,0264	0,0597	0,0284	0,0603	0,060302	7,332E-06	7,332E-06	7,332E-06	0,00024	0,235342	4,77E-05	1,12E-05
1728-1805	0,0264	0,0597	0,0284	0,0603	2,37E-09	7,332E-06	7,332E-06	7,332E-06	0,00024	0,175039	4,77E-05	8,35E-06

Table A.5 : Primary cause failure probability for material and equipment factor

Sector range (km)	Material grade factor	Line pipe age factor	Seam weld factor	Pipe safety factor	Non-pipe components factor	Pressure test factor	First level modification factor	Baseline failure frequency	Primary cause failure probability
0-27	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
27-394	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
394-692	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
692-734	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
734-938	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
938-964	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
964-1056	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1056-1075	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1075-1099	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1099-1192	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1192-1333	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1333-1498	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1498-1690	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1690-1705	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1705-1728	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05
1728-1805	0,09966	0,57802	1,02E-05	0,00033	0,0836685	0,08367	0,8453611	6,480E-05	5,478E-05

Table A.6 : Primary cause failure probability for incorrect operation factor

Sector range (km)	Diameter factor	SCADA system factor	Construction factor	Maintenance factor	Quality of worker factor	First level modification factor	Baseline failure frequency	Primary cause failure probability
0-27		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
27-394		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
394-692		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
692-734		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
734-938		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
938-964		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
964-1056		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
1056-1075		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
1075-1099		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
1099-1192		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
1192-1333		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
1333-1498	0,0069	1,275E-05	1,275E-05	1,275E-05	1,275E-05	0,0069	7,54E-06	5,22E-08
1498-1690	0,0069	1,275E-05	1,275E-05	1,275E-05	1,275E-05	0,0069	7,54E-06	5,22E-08
1690-1705		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
1705-1728		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07
1728-1805		0,0077	0,0077	0,0077	0,0077	0,0308	7,54E-06	2,32E-07

Table A.7 : Failure probability for each segment

Sector range (km)	Corrosion Factor	Natural damage factor	Third party damage factor	Material and equipment factor	Incorrect operation factor	Sabotage Factor	Primary cause failure probability
0-27	5,041E-05	1,668E-05	1,183E-04	5,478E-05	2,325E-07	1,950E-05	2,5993E-04
27-394	5,041E-05	1,710E-05	1,340E-04	5,478E-05	2,325E-07	6,012E-07	2,5709E-04
394-692	5,041E-05	2,493E-05	1,340E-04	5,478E-05	2,325E-07	6,012E-07	2,6492E-04
692-734	5,041E-05	1,710E-05	1,340E-04	5,478E-05	2,325E-07	6,012E-07	2,5709E-04
734-938	5,041E-05	1,668E-05	1,183E-04	5,478E-05	2,325E-07	1,950E-05	2,5993E-04
938-964	5,041E-05	1,710E-05	1,340E-04	5,478E-05	2,325E-07	6,012E-07	2,5709E-04
964-1056	5,041E-05	1,787E-05	1,340E-04	5,478E-05	2,325E-07	6,012E-07	2,5709E-04
1056-1075	5,041E-05	1,710E-05	1,340E-04	5,478E-05	2,325E-07	6,012E-07	2,5709E-04
1075-1099	5,041E-05	1,668E-05	1,340E-04	5,478E-05	2,325E-07	6,012E-07	2,5668E-04
1099-1192	5,041E-05	1,665E-05	1,340E-04	5,478E-05	2,325E-07	6,012E-07	2,5664E-04
1192-1333	5,041E-05	1,668E-05	1,183E-04	5,478E-05	2,325E-07	1,950E-05	2,5993E-04
1333-1498	3,169E-05	1,366E-05	1,333E-06	5,478E-05	5,217E-08	6,012E-07	1,0212E-04
1498-1690	3,169E-05	2,149E-05	8,599E-07	5,478E-05	5,217E-08	1,950E-05	1,2837E-04
1690-1705	4,361E-05	2,151E-05	1,123E-05	5,478E-05	2,325E-07	6,012E-07	1,2413E-04
1705-1728	4,361E-05	1,368E-05	1,123E-05	5,478E-05	2,325E-07	6,012E-07	1,2413E-04
1728-1805	4,361E-05	1,326E-05	8,349E-06	5,478E-05	2,325E-07	1,950E-05	1,3974E-04



CURRICULUM VITAE



Name Surname : Ali Rahimli
Place and Date of Birth : 2nd March 1992
E-Mail : ali.rahimli@rocketmail.com

EDUCATION :

- **B.Sc.** : 2013, Azerbaijan Oil and Industry University, Faculty of Oil and Gas Production, Oil and Gas Transportation and Storage

