ISTANBUL TECHNICAL UNIVERSITY ★ GRADUATE SCHOOL OF SCIENCE ENGINEERING AND TECHNOLOGY

MODELING OF THE DEGIRMENKOY UNDERGROUND GAS STORAGE FIELD

M.Sc. THESIS

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Department of Petroleum and Natural Gas Engineering

Petroleum and Natural Gas Engineering Programme

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İSTANBUL TEKNİK ÜNİVERSİTESİ ★ FEN BİLİMLERİ ENSTİTÜSÜ

DEĞİRMENKÖY YERALTI GAS DEPOLAMA SAHASININ MODELLENMESİ

YÜKSEK LİSANS TEZİ

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To my parents,

FOREWORD

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May 2016

Gulzada SAGNALIYEVA
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ABBREVIATIONS

BOTAS	**:** Turkish Petroleum Pipeline Coorporation
BP	**:** British Petroleum
BSCF	**:** Billion Standard Cubic Feet
EIA	**:** Energy Information Administration
EMRA	**:** Energy Market Regulatory Authority
GIIP	**:** Gas Initially In place
IGDAS	**:** Istanbul Gas Distribution Industry and Trade Incorporated Company
LNG	**:** Liquefied Natural Gas
MBE	**:** Material Balance Equation
MMSCF	**:** Million Standard Cubic Feet
NGH	**:** Natural Gas Hydrate
OD	**:** Outer Diameter
TPAO	**:** Turkish Petroleum Coorporation
TSCF	**:** Trillion Standard Cubic Feet
UGS	**:** Underground Gas Srorage

SYMBOLS

d	: Pipe Diameter
f_M	: Moody Friction Factor
G	: Initial Gas In Place
G_p	: Cumulative Produced Gas
h	: Thickness
k	: Permeability
L_x, L_y, L_z	: Length
p	: Pressure
p_i	: Initial Pressure
p_{wf}	: Bottomhole Flowing Pressure
p_{wh}	: Wellhead Flowing Pressure
q_g	: Gas Flow Rate
r_e	: Drainage Radius
r_w	: Well Radius
T	: Temperature
s	: Skin Factor
z	: Deviation Factor
z_i	: Initial Deviation Factor
γ_g	: Specific Gravity of Gas
ε	: Absolute Pipe Roughness
μ	: Viscosity

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MODELING OF THE DEGIRMENKOY UNDERGROUND GAS STORAGE FIELD

SUMMARY

The major source of energy essential to life comes from fossil fuels, and the dominant fossil fuels used today by most industrialized and developing countries are oil, coal, and natural gas. Among these fossil fuels, the natural gas is a versatile, clean-burning, and efficient fuel that is used in a wide variety of applications.

According to the International Energy Agency (IEA), since the beginning of the 70s, the share of gas in the world energy balance has increased from 16 to 21% in 2008. According to the British Petroleum (BP) Statistical Review of World Energy, this share in 2010-2014 in global energy consumption was even higher - about 24%. BP forecasts that natural gas will be the fastest growing type of fuel in the next 25 years. The experts of IEA believe that the share of gas in the world energy by 2035 will increase to 25%, the gas will be the second energy source after oil, shifting coal into third place.

Stable development of the gas industry and its individual factors are related to the capital investment of both new construction and in the maintenance of the achieved level. Improving the reliability of gas supply to consumers is particularly important. Consequently, one way to increase the security of gas supply is the underground gas storage facilities.

Underground gas storage is an independent sub-sector of the gas industry. It plays an important role in ensuring the stability of gas supply by creating the reserve volume of gas in case of emergency situations in the gas pipeline system, which require prompt increase in supply. Involvement capacities of underground gas storage allows to balance the work of the gas supply system by increasing the productivity of the gas transportation system, or accumulating excessive amounts of commercial gas in the period of low demand.

Gas is stored most commonly in underground storage facilities under pressure. These underground facilities are depleted oil and/or natural gas reservoirs, aquifers, and salt cavern formations. Natural gas is also stored in liquid or gaseous form in aboveground tanks.

Gas is the major energy source consumed in Turkey. Today, Turkey needs to import substantial amount of energy since indigenous energy resources are not sufficient to meet increasing in demand. By virtue of this, the main goal of Turkish energy policies has been set as the supplying of required energy in a timely, dependable, cost-effective, environmentally sound and in a high-quality basis to support the development impulse and social progress. Turkey’s energy security is closely related with the amount of gas stored. In Turkey there exist surface storage in form of tanks and underground gas storage. However, underground gas storage provides significantly large volume and meets various strategic requirements and delivery rates. At present Turkey does not

have significant underground gas storage volumes comparable to other countries, despite the presence of suitable geology of both salt cavern and depleted field storage.

One of the depleted underground gas storage of Turkey is the Degirmenkoy field. The Degirmenkoy is one of the two reservoirs of Silivri underground natural gas storage facility. The field is located in the Thrace region of Turkey. It is an onshore gas field located 16 km northern-west of the Northern Marmara field. The feasibility of creating gas storage in the Degirmenkoy field was examined based on process design, geologic factors, and preliminary economical analysis.

The purpose of the design for an underground storage reservoir is to obtain the maximum working gas capacity for a given configuration of reservoir and surface properties under the influence of economics. The method of selecting the appropriate number of wells, wellhead pressure and base gas requirements is to fix one of the parameters and determine how the other parameters change depending on each other.

In this study, the Degirmenkoy natural gas field is designed for storage purposes using RUBIS simulator. Approaches to designing the Degirmenkoy gas field as underground gas storage are as follows:

- To design the current state of field maintaining the working gas capacity of 14.37 bscf for a given number of wells, reservoir and well properties.
- To observe the reservoir performance of field with additional wells.

The storage cycle for one year in Degirmenkoy UGS field is planned as follows: 180 days of injection period followed by 35 days of shut-in period, then 150 days production period is followed. It is assumed that all wells have the same wellbore and flow characteristics, accordingly simulated data are obtained from well #5.

To achieve a desired result, firstly the model is simulated with already existing six wells. By using RUBIS simulator, two approaches for operation of the underground gas storage facility, namely the constant flow rates for both injection and production periods and the constant bottomhole and wellhead pressures are investigated. After that, new six wells are added to maximize the working gas capacity. The capacities of six wells and twelve wells are compared. In addition, the mechanical skin effect is considered. Increasing the skin factor causes to decrease the working gas capacity, which is not desirable. Hence, the efforts to minimize wellbore damage is the cause for concern. The wellhead pressure is the key parameter for defining the quantity of horsepower requirements for compressing the gas to the market. Therefore, the wellhead pressure effect on performance of the underground gas storage reservoir is studied. The result show that decreasing the wellhead pressure leads to an increase in working gas capacity for a fixed number of wells.

DEĞİRMENKÖY YERALTI GAZ DEPOLAMA SAHASININ MODELLENMESİ

ÖZET

İnsanlığın en önemli ve vazgeçilmez ihtiyaclarından birisi enerjidir. Doğalgaz dünya enerji sektöründe yaygın olarak kullanılan bir petrol türevidir. Dünyada, ama özellikle Avrupa piyasasında doğalgazın önemi gittikçe artıyor. Bunun çeşitli nedenleri var ama bunlardan en önemlisi, doğalgazın diğer tüm yakıtlara nazaran daha fazla çevre dostu olması ile birlikte doğalgaz haricindeki birçok enerji kaynağının rezervlerinin geleceğe yönelik kaygılar oluşturmasıdır.

Uluslararası Enerji Ajansı'nın (IEA) verilerine göre 70'lerin başından 2008 yılına kadar dünya enerji dengesinde gazın payı %16'dan %21'e çıkmıştır. British Petroleum'in (BP) Dünya Enerji İstatistiksel araştırmalarına göre bu gaz payı 2010-2014 yıllar arasında küresel enerji tüketiminde daha yüksek, yaklaşık %24 olmuştur. BP doğalgazın önümüzdeki 25 yıl içinde hızlı büyüyen bir yakıt tipi olacağı belirtilmektedir. IEA uzmanlarına göre dünya enerjisindeki gazın payı 2035'te %25'e kadar artacağı ve gazın petrolden sonraki ikinci enerji kaynağı olacağı tahmin edilmektedir.

Gaz tüketicilerine gazın güvenilir bir şekilde sağlanması özellikle önemlidir. Bu nedenle gaz sağlama güvenliği arttırılmasının bir çözüm yolu olarak yeraltı gaz depolama tesisleri seçilmiştir.

Gaz endüstrisinin bir alt sektörü olarak, yeraltı gaz depolaması acil durumlarda gazın temininde önemli bir rol oynamaktadır. Gaz basınç altında en yaygın üç türlü yeraltı tesislerde depolanmaktadır. Bu yeraltı tesisleri, petrol veya doğalgaz tükenmiş rezervuarları, akiferler ve yeraltında açılan tuz oyuklarında depolama tesisleridir. Doğal gazın yeraltı rezervuarlarına depolanmasında temel amaç mevsimsel tüketim farklılıklarını gidermektir. Doğal gaz, talebin düşük olduğu dönemlerde depo ortamına basılıp ihtiyacın yüksek olduğu dönemlerde ise depodan geri üretilir. Doğalgaz, ayrıca yerüstü tanklarında sıvılaşmış halde depolanabilmektedir.

Gaz, Türkiye'nin önemli bir enerji kaynağıdır. Günümüzde Türkiye'de artan talebi karşılamak için, kendi enerji kaynağı yeterli olmadığından dolayı, enerjiyi başka ülkelerden ithal etmek zorundadır. Bu yüzden, gerekli olan enerjinin zamanlı, güvenli, düşük maliyetli, çevre açısından sağlıklı ve yüksek kalitede olmasının sağlaması Türk enerji politikalarının ana hedefi olarak belirlenmiştir.

Türkiye'nin enerji güvenliğinde gazın depolanan miktarı önem kazanmaktadır. Türkiye'de tank şeklinde olan yüzey depolama ve yeraltı gaz depolama tesisleri mevcut bulunmaktadır. Yeraltı gaz depolama önemli ölçüde büyük bir hacim sağlar ve çeşitli stratejik gereksinimleri karşılamaktadır. Şu anda Türkiye'nin doğal gaz sektörü gelişmiş diğer ülkelerdeki gibi önemli gaz depolama hacimleri yoktur. Buna rağmen, Türkiye jeolojisi hem tuz oyuklarında depolama, hem de tükenmiş rezervuar depolaması için uygundur.

Değirmenköy Silivri yeraltı doğalgaz depolama tesisinin iki rezervuarından biridir. Saha Trakya bölgesinde yer almaktadır; Küzey Marmara sahasının 16 km küzeybatısında yer alan bir on-shore gaz sahasıdır. Saha 1994 yılında kesfedilmiş olup 21.18 bscf olarak hesaplanan yerinde gaz miktarı belli bir süre gaz üretiminden sonra 27.53 bscf olarak düzeltilmiştir. Kuzey Marmara ve Degirmenköy dogal gaz sahaları, BOTAŞ ana dogalgaz iletim hattına ve İstanbul'a yakın olması ve sahaların rezervuar ve üretim özelliklerinin depolama rezervuarı için kullanıma uygun olması nedeniyle, Trakya Yarımadasında gaz deposu olarak geliştirilmek üzere en uygun sahalar olarak seçilmiştir.

Bu çalışmada, Değirmenköy yeraltı doğalgaz depolama sahasının modellenmesi RUBIS simülatörü kullanılarak yapılmıştır. Bir yeraltı depolama rezervuarının tasarım amacı, belirli bir rezervuar yapılandırması ve yüzey özellikleri için maksimum işletilen gaz kapasitesini elde etmektir. Bu nedenle kuyuların uygun sayısı, kuyubaşı basıncı ve yastık gaz gereksinimleri gibi parametreler bu çalışmada dikkate alınmaktadır.

Değirmenköy yeraltı gaz depolama sahasının modelleme yöntemleri aşağıdaki gibi olmuştur:

- İşletilen gaz kapasitesini 14.37 bscf tutarak Değirmenköy gaz sahasının mevcut durumun modellemek.
- İlave kuyuların ekleyerek rezervuarın performansını incelemek.

Değirmenköy yeraltı gaz depolama sahasında depolama süresi bir yıllık periyot kapsamında, ilk 180 gün enjeksiyon yapılması, sonrasında 35 gün akışa kapatılması, daha sonra 150 gün üretim yapılması şeklinde planlanmıştır. Değirmenköy #5 kuyusuyla sahadaki bütün kuyular aynı akış özelliklerine sahip olduğu varsayılmıştır, ve model verileri #5 kuyusundan elde edilmiştir.

İstenilen sonucu elde etmek için, öncelikle mevcut olan altı kuyu ile modelimiz simüle edilmiştir. 14.37 bscf'lik işletilen gaz kapasitesini elde edebilmek için enjeksiyon ve üretim dönemleri boyunca sabit akış debileri ve sabit kuyudibi ile kuyubaşı basınçları incelenmiştir. Bundan sonra, rezervuarun maksimum kapasitesini elde etmek için yeni altı kuyu ilave olarak eklenmiştir. Ayrıca, Değirmenköy yeraltı gaz depolama rezervuar performansına mekanik zar faktörü etkisi incelenmiştir. Bunun sonucu olarak zar faktörün arttığında işletilen gaz kapasitesinin azaldığı öğrenilmiştir. Aynı şekilde, kuyubaşı basıncının rezervuar performasına etkisi incelenmiştir. Kuyubaşı basıncının azalması işletilen gaz kapasitesinin artışı nedenidir. Ayrıca ortalama rezervuar basıncı ve yüzey akış debisi performansına kuyubaşı basıncının etkisi incelenmiştir.

1. INTRODUCTION

Natural gas is an essential element of the world's energy supply. Natural gas is one of the cleanest, safest, and most useful of all energy sources. It is colorless, shapeless, and odorless in its pure form. Natural gas is inflammable and when burned it emits a great deal of energy. In comparison with other fossil fuels, natural gas is a cleaner burning fuel and emits lower levels of potentially detrimental byproducts into the air. It is required an increasing supply of energy to heat homes, cook food, and generate electricity. Exactly this need for energy that has natural gas is more important in society, and in lives.

Natural gas is a flammable mixture of hydrocarbon gases. Natural gas is constituted basically from methane, it can also contain ethane, propane, butane and pentane. The composition of natural gas can differ greatly, Table 1.1 outlines the typical composition of natural gas before it is refined.

Table 1.1 : Typical composition of natural gas [Url-1].

Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

Natural gas is found in deep underground rock formations or associated with other hydrocarbon reservoirs in coal beds. It is considered 'dry' when it is almost pure methane, when commonly associated hydrocarbons are removed. When other hydrocarbons are present, the natural gas is 'wet'.

Natural gas has many uses in residential, commercial, and industrial applications. Natural gas is often related with oil reservoirs. Production companies search for reservoirs by using most advanced technology that helps to find the location of the natural gas, and drill wells in the earth where it is likely to be found. Prodused natural gas is refined to eliminate impurities such as water, other gases, sand, and other compounds. Some hydrocarbons are removed and sold separately, including propane and butane. Other impurities are also removed, such as hydrogen sulfide (the refining of which can produce sulfur, which is then sold separately). After refining, the clean natural gas is transfered through a network of pipelines. From these pipelines, natural gas is delivered to its point of use [Url-1].

1.1 Natural Gas in the World

The share of natural gas in the worldwide power generation sector is 22 %. This share is expected to increase in connection with general aging of power plants and the need for replacement worldwide. Natural gas has a higher conversion efficiency causing to lower loss of energy than other fossil fuels when producing electricity or heat.

The world proved natural gas reserves estimated to be around 6605.57 trillion standard cubic feet (Tscf) (BP, 2015). As can be seen from the Figure 1.1, most of these reserves are located in the Middle East with 2818.15 Tscf, or 42.66% of the world total, Europe and Eurasia 2049.1 Tscf, or 31.02% of total world reserves. The South and Central America, by this calculation, possess slightly over 4% of the world total natural gas reserves.

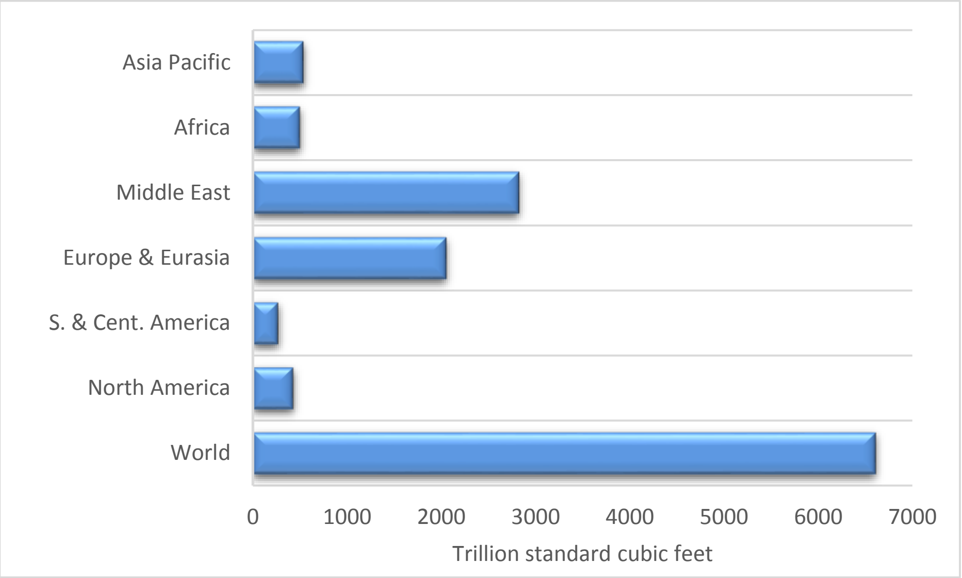

Figure 1.1: Proved reserves of natural gas by geographic regions (BP, 2015).

Table 1.2 gives production and consumption data with regions in the year 2015. North America appears to be the largest producer and consumer with a production of 27.4% and consumption of 27.98% of the worldwide production and consumption respectively, followed by the Eurasia with 25.45% of production and 19.4% of consumption.

Table 1.2 : World natural gas consumption and production by regions (BP, 2015).

REGIONS	PRODUCTION (bscf)	CONSUMPTION (bscf)
Africa	7 155.36	4 240.82
Asia Pacific	18 756.69	23 961.84
Central and S.America	6 178.66	6 006.35
Europe	10 574.14	19 610.15
Eurasia	31 098.49	23 246.80
Middle East	21 222.44	16 426.54
North America	33 489.37	33 523.98
WORLD	122 196.21	119 809.20

The largest natural gas importing region appears to be Europe, importing almost 38.6% of the gas it consumes, while the largest exporting country is the Russia exporting almost 25.78% of its production [Url-2].

The world's largest gas field is the offshore South Pars / North Dome Gas-Condensate field, shared between Iran and Qatar. It is estimated to have 1800 Tscf of natural gas and 50 billion barrels of natural gas condensates [Url-2].

Natural gas is an environmentally safe in heating, industry and city transport alternative to other fossil fuels. Fuel substitution and replacing old appliances with gas-based heating technologies are fast and cost-effective ways of reducing both CO_2 and other emissions. Large quantity of cities around the world are taking advantage of natural gas benefits in public transportation, which significantly improved air quality and a smaller urban carbon footprint (The Energy Charter Secretariat, 2010).

The cleanest hydrocarbon is natural gas. It is easy to control and efficient in distribution and use. Natural gas gives solutions to the world’s economic and environmental challenges in a safe and sustainable way.

1.2 Natural Gas in Turkey

In natural gas transportation Turkey has a strategic role due to its position between continental Europe, which is the world's second largest natural gas market, and the Caspian Basin and the Middle East, which have the substantial natural gas reserves.

Turkey's natural gas consumption has been gradually rising since the mid 1980s. It is expected that the demand for natural gas has reached 1.6-1.76 Tscf in 2014 and will reach 2.12-2.3 Tscf in 2020, respectively [Url-3].

Turkish natural gas reserves are estimated as 218 bscf (EMRA, 2014). Turkey produces only a small amount of natural gas, with the total production 16.9 billion standard cubic feet (bscf) in 2014 (Figure 1.2). Turkey is an important consumer of natural gas and is becoming an important transit state for natural gas. It is one of the few countries in Europe where natural gas consumption continues to demonstrate high growth rates. This growing consumption has contributed to spur development of multiple pipelines to supply natural gas into the country. To increase both Turkey's imports and exports of natural gas the new supplies have been contracted and new pipelines are under construction.

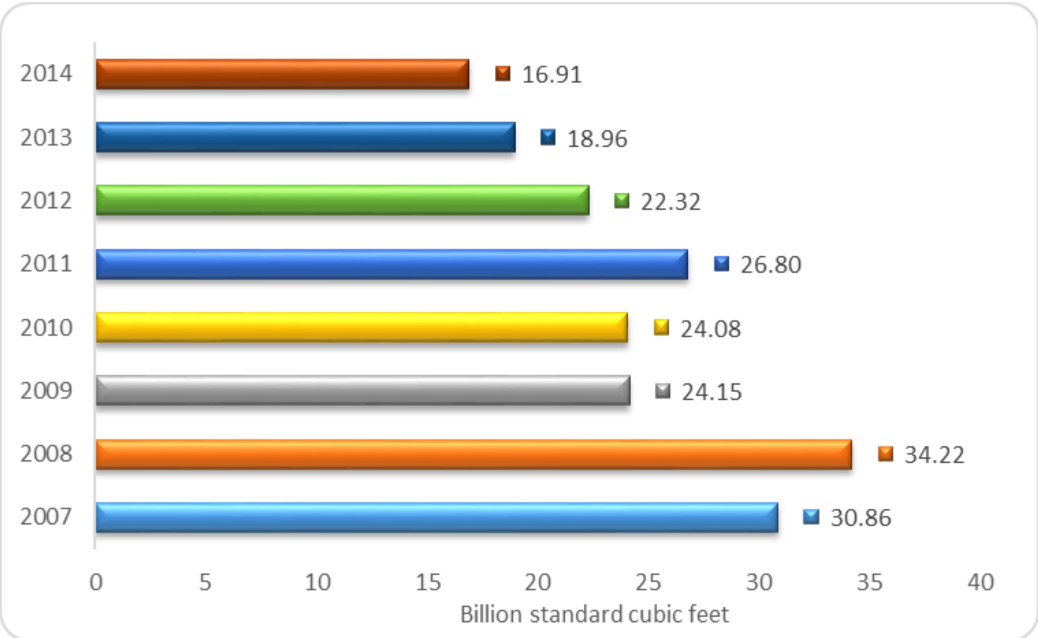

Figure 1.2: Turkey natural gas production, 2007-2014 (EMRA, 2014).

2014 sectoral distribution of natural gas is calculated as in percentage; 19.1% is home consumption, 48.12% is electricity consumption, and 25.4% is industrial consumption. Share of sectoral natural gas consumption is seen in Figure 1.3.

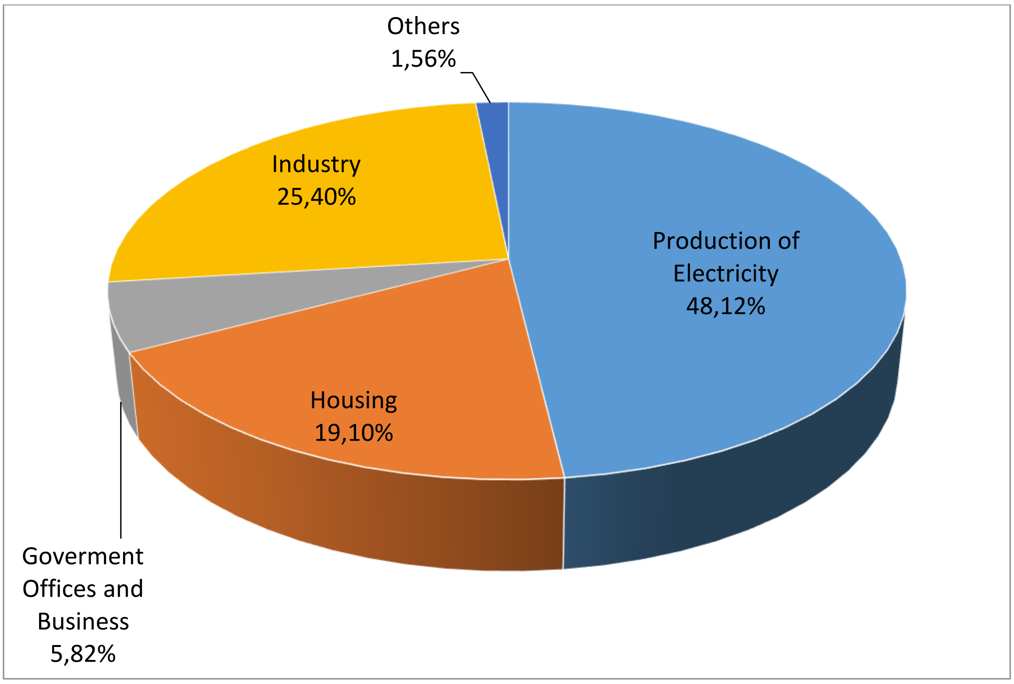

Figure 1.3: Share of sectoral consumption (EMRA, 2014).

The state-owned Petroleum Pipeline Corporation (BOTAS) prevails in the natural gas sector. BOTAS accounts for about 80% of natural gas imports; it builds and operates natural gas pipelines in Turkey; and it accounts for most exports of natural gas. BOTAS has transferred 350 bscf of import contracts, equal to about 20% of Turkish natural gas consumption (IEA, 2015).

Turkey is increasingly dependent on natural gas imports as its domestic consumption, mainly in the electric power sector, which continues to grow significantly.

Natural gas consumption in Turkey has increased rapidly over the past decade. In Turkey natural gas is mainly used in power generation, which accounted for more than 40% of consumption in 2014. Most of the remaining consumption is about evenly distributed between the buildings sector and the industrial sector. Consumption growth is expected to remain strong as industrial sector growth and rising electricity consumption continue to spur demand.

In 2014, Turkey imported 1.7 Tscf of natural gas, accounting for 99% of total natural gas supply (IEA, 2015). Russia's Gazprom is by far the largest single supplier, accounting for 54.76% (950 bscf) of Turkey's total natural gas supply in 2014. Russia was followed by Iran (18.13%), Azerbaijan (12.33%), Algeria (8.48% via LNG), Nigeria (2.8% via LNG), and spot LNG (3.43%) (Figure 1.4).

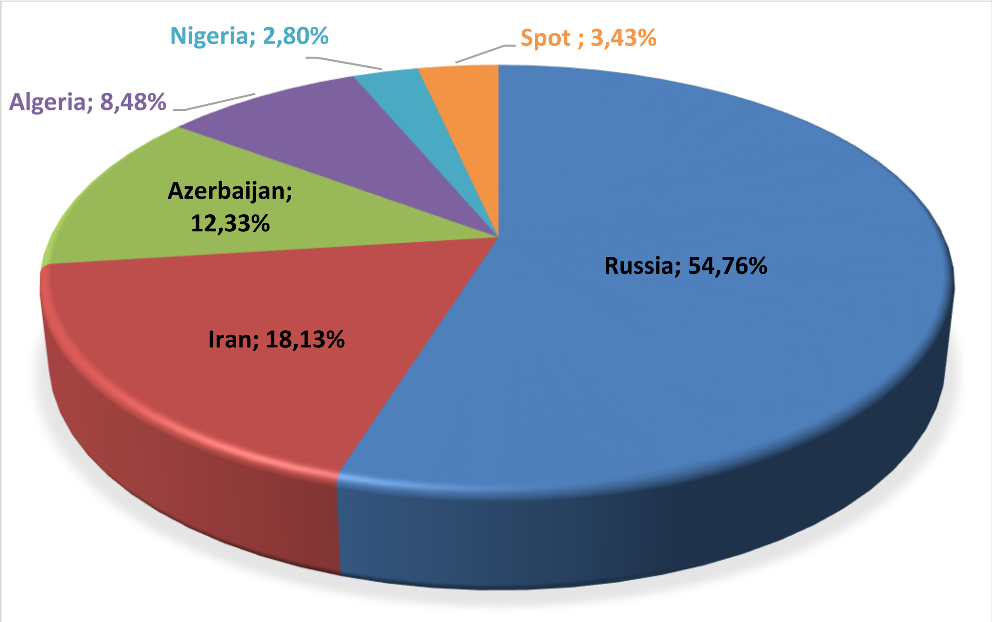

Figure 1.4: Turkey’s natural gas supply by source (EMRA, 2014).

2. NATURAL GAS STORAGE

Natural gas can be stored for an undetermined period of time. Normally, natural gas has been a seasonal fuel. Demand for natural gas is commonly higher through the winter, since it is used for heating in residential and commercial terms. Natural gas in storage is important in ensuring that any oversupply delivered during the summer months is obtainable to meet the increased demand of the winter months. Nevertheless, with the modern tendency to natural gas fired electric generation, demand for natural gas during the summer months is now increasing (due to the demand for electricity to power air conditioners and the like). Stored natural gas also used as insurance against any unexpected accidents, natural disasters, or other incidents that may affect the production or delivery of natural gas [Url-1]. Briefly, gas storage meets different needs as:

- Regulation of supply and demand

The high seasonality of gas demand is incompatible with the generally steady rate of supply over the year. Therefore, refilling the storage facilities in summer (period of low gas demand) and emptying them in winter (period of high gas demand) allows gas suppliers to balance supply and demand.

- Short-term flexibility

Storing natural gas during short time (a few days), or during the day is also a way of maintaining the necessary flexibility. Gas demand can differ from one period to another (e.g. school holidays or weekdays/weekends) or with temperature changes. Gas demand is also unstable over the day, with consumption peaks occurring in the morning (around 8 a.m.) and in the afternoon (around 6 p.m.)

- Responding to the needs of the transmission system

Storage allows operator to achieve balancing and maintain flexibility of the gas transmission system [Url-5].

Generally, types of natural gas storage can be identified and categorized as: 1-surface storage, 2-underground storage. Each of them have distinct physical and economic characteristics, which define the suitability of a particular type of storage for a given application.

Gas storage in surface storage facilities, so-called high pressure gas tanks or pipe storage facilities, is insufficient because of the very limited capacity that is available. Much larger storage volumes can be provided underground. Underground storage is by far the most effective and economical technique for the large-scale storage of natural gas.

2.1 Surface Storage of Natural Gas

Surface storage consists:

- Liquefied Natural Gas (LNG) storage
- Natural gas storage in pipeline
- Natural gas storage in high pressure tanks
- Natural Gas Hydrate (NGH) storage

Among the surface storages, LNG is commonly used for gas storage in high capacity. NGH is also a new technique that has been suggested for high capacity gas storage.

2.1.1 Liquefied natural gas storage

Liquefied natural gas is a natural gas (mostly methane) that has been converted temporarily to liquid form for ease of storage or transport. LNG is odorless, colorless, non-toxic, non-corrosive natural gas. It has been liquefied at close to atmospheric pressure by cooling it to about -260°F (-162°C). Liquefied natural gas takes up approximately 1/600 volume of natural gas in the gaseous state. A typical LNG process includes extracting and transporting the gas to a processing plant where it is purified by removing any condensates such as water, oil, mud, as well as other gases like CO_2 and H_2S and sometimes solids as mercury. The gas is then cooled down in stages until it is liquefied. LNG is finally stored in storage tanks (Figure 2.1).

Contemporary LNG storage tanks are full containment type. This tanks have a prestressed concrete outer wall and a high-nickel steel inner tank, with very effective insulation between the walls.

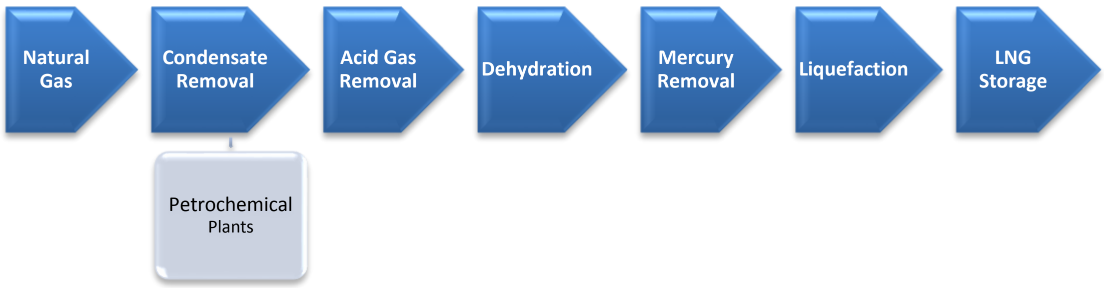

Figure 2.1 : Typical LNG chain (Khamenchi et al, 2013).

Large tanks are low aspect ratio (height to width) and cylindrical in design with a domed steel or concrete roof. A full containment tank may have a nominal capacity up to 5.65 bscf and a design pressure of 18.7 psia. LNG must be kept cold to remain a liquid, independent of pressure. In spite of efficient insulation, there will unavoidably be some heat leakage into the LNG, resulting in vaporization of the LNG. This boil-off gas acts to keep the LNG cold. The boil-off gas is typically compressed and exported as natural gas, or is liquefied and returned to storage (Khamenchi et al, 2013).

2.1.2 Storage in pipelines

In periods when demand is low the pipeline systems are frequently used as temporary gas storage facilities to retain small amount of natural gas. Local compression stations allow the pressure to be significantly raised in the main pipeline system to increase the amount of gas and then use the system for storage purposes. When the demand is high, the stored gas can be used to maintain it simply by decreasing the pressure in the pipeline system allowing the compressed gas flow. The pipeline storage capacity can be defined as the difference of the amount of gas in the pipe under packed and unpacked conditions. A pipeline is packed when withdrawal from the pipe is at a minimum and the discharge pressure is at a maximum during constant supply and unpacked when withdrawal from the pipe is at a maximum and the discharge pressure is at minimum. Pipeline gas storage is good in compensating peaks demand which have time intervals of a few hours. However, due to low capacity of storage it is unable to meet the seasonal demand (Tureyen, 2000).

2.1.3 Liquefied gas hydrate storage

In the petroleum and natural gas industries one of the well-known problem is the formation of natural gas hydrates. However, nowadays with significant development of technology NGH can be used as a new method of natural gas storage. Natural gas hydrates are ice-like mixtures of natural gas and water in which gas molecules are trapped within the crystalline structures of frozen water. 160 to 180 volume units of gas at standard conditions can potentially be packed into 1 volume unit of gas hydrates. Besides, natural gas stored in hydrates would be safer because gas is essentially encased in ice; natural gas stored in hydrates would be released slowly, in case of storage tank rupture. In this method of gas storage, there is no need for high pressures or very low temperatures (Gudmundsson, 1996). For NGH storage at atmospheric pressure, the hydrates should be stored at a subzero temperature near equilibrium (e.g. -25.6°F), but achieving this temperature requires high amount of energy and thus it would be costly. In the Gudmundsson NGH storage method natural gas hydrates are stored adiabatically in a well-insulated tank, and so the storage can be operated at 5°F which is more economical (Khamenshi et al, 2013).

2.2 Underground Gas Storage

Natural gas is stored underground in geological structures whose properties permit gas to be stored and withdrawn when required.

The underground storage of gas has a sufficient role in supporting the development and stabilization of the gas market. The demand significantly varies on a seasonal basis, predominantly because of the residential sector, where gas is mainly used for heating. It should be noted that the ratio of winter to summer consumption is on average 3:1; this may become 4:1 at times of peak daily demand (Altieri, 2010). Figure 2.2 shows an example of daily values for the consumption and supply of gas. Production and transport systems for technical and economic reasons require a constant operating regime to maximize usage and reduce costs. Consequently, storage structures capable to meet gas supply to the market requirements outlined above are necessary.

It should be remembered that when discussing natural gas storage we usually refer to:

Total gas storage capacity is the maximum volume of gas that can be stored in an underground storage facility by design and is determined by the physical characteristics of the reservoir and installed equipment.

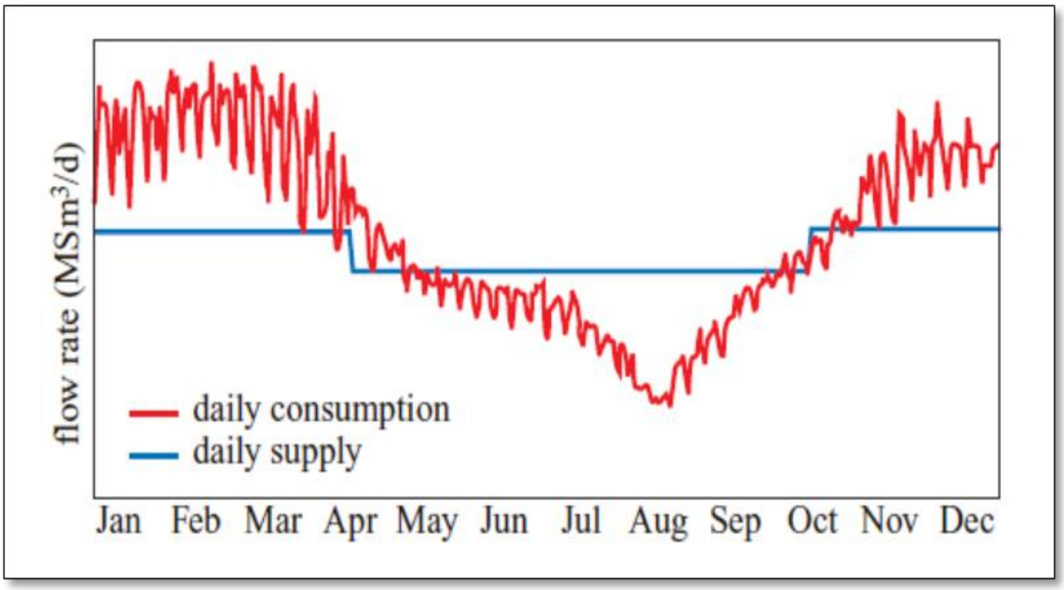

Figure 2.2 : Typical daily values for the consumption and supply (Altieri, 2010).

Total gas in storage is the volume of storage in the underground facility at a particular time.

Base gas (or cushion gas) is the volume of gas intended as permanent inventory in a storage reservoir to maintain suffisient pressure and deliverability rates throughout the withdrawal season. It can constitute up to half of the total amount of gas stored and make up the largest part of the investment of a storage project.

Working gas capacity refers to total gas storage capacity minus base gas.

Working gas is the volume of gas in the reservoir above the level of base gas. Working gas is available to the marketplace (Altieri, 2010).

Deliverability is most often expressed as a measure of the amount of gas that can be withdrawn from a storage facility on a daily basis. The deliverability of a given storage facility is depends on the amount of gas in the reservoir at any particular time, the reservoir pressure, compression capability available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the total amount of gas in the reservoir. Deliverability rate is highest when the reservoir is most full and declines as working gas is withdrawn (Kidnay et al, 2011).

Injection capacity (or rate) is the complement of the deliverability rate. The injection capacity of a storage facility is also variable, and is dependent on factors comparable to those that determine deliverability. By contrast, the injection rate varies inversely with the total amount of gas in storage. Injection rate is lowest when the reservoir is most full and increases as working gas is withdrawn (Kidnay et al, 2011).

Peak rate. The daily peak flow rate, which can be withdrawn when the reservoir is completely full.

Efficiency. The ratio between working gas and immobilized gas (immobilized gas: the amount of working gas, cushion gas and any remaining reserves present in the reservoir when it is converted into a storage system).

These measures for any given storage facility are not necessarily complete and are may vary. For instance, in practice, a storage facility may be able to exceed certificated total capacity in some cases by exceeding certain operational parameters. In addition, the distinction between base gas and working gas is to a certain extent arbitrary; so gas within a facility is sometimes reclassified from one category to the other. Beyond, storage facilities can withdraw base gas for supply to market during times of particularly high demand, despite the fact that this gas is not intended for that use [Url-2].

It is most commonly held in inventory underground under pressure in three types of facilities. These underground facilities are:

- Aquifers

- Salt cavern formations, and

- Depleted reservoirs in oil and/or natural gas fields

Each storage type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation and maintenance costs, deliverability rates, and cycling capability), which govern its suitability for particular applications. Two main features of an underground storage reservoir are its capacity to hold natural gas for future use and the rate at which gas inventory can be withdrawn–called its deliverability rate.

2.2.1 Underground gas storage in aquifers

Aquifers are underground permeable rock formations that act as natural water reservoirs. These formations may be used as natural gas storage facilities where gas is injected on top of the water formation displacing the water further down within the structure. Most of these facilities are located in the upper Mid-West where there is a lack of depleted oil and gas reservoirs.

Foremost, the geological structure (trap) of the aquifers, which should preferably be an anticline, must be found. The structure is sometimes identified using geological surveys, but generally is confined using geophysical systems. The most important requirement for storage facilities in aquifers is the seal of the cap rock, which must be properly thick and have low permeability values, close to zero, as in shaly formations. This requirement is necessary as during the injection of gas the hydrostatic pressure is always exceeded. When the initial pressure is exceeded in order to increase the volume of working gas in storage of this type, it must be careful not to exceed the pressure above which the gas begins to pass through the cap rock (threshold pressure). The threshold pressure is determined in the laboratory by means of tests on cores collected during the drilling phase, and subsequently with long injection tests performed in the wells (early injection). To research gas storage in aquifers extrapolations based on the data obtained with early injection are used. As a result, predictions of the reservoirs behavior during the different phases of storage are originally undefined because production history for the reservoir rock is not available. When storage is initiated in an aquifer, the gas displaces the water, advancing more rapidly, where permeability is higher, and thus leads to the formation of a gas bubble. After several years, as injection continues, the water in the upper part of the reservoir is fully displaced by the gas; thereby, the storage can become operational (Bary et al, 2002).

Aquifer storage is the least desirable type of storage because of its physical and economic shortcomings. A significant amount of time and money is spent testing the suitability of an aquifer for natural gas storage and subsequently developing the infrastructure needed for an effective natural gas storage facility. In addition, in aquifer formations, base gas requirements are as high as 80 % of the total gas volume. This high base gas requirement increases the initial cost of capital for aquifer storage projects, thus limiting their number. Most aquifer storage facilities were developed when the price of natural gas was low, meaning this base gas was not very expensive to give up. However, with higher prices, aquifer formations are increasingly expensive to develop.

2.2.2 Underground gas storage in salt caverns

Salt cavern storages are high pressured, solution-mined cavities in existing salt dome caverns located at depths several hundred to several thousand feet below the earth's surface. They are obtainable by one or more wells per cavern. The construction of salt caverns places certain demands on the geological condition of the salt:

- Sufficient thickness and extent of the salt deposit in depths above 6500 ft;

- As homogeneous a salt quality as possible, which for solution mining purposes should for the most part be free of insoluble and poorly-soluble components such as salt clays, anhydrite and/or dolomite bands as well as easily soluble components such as potassium salts.

The production of brine from salt deposits by the dissolution of the mineral salt using water has been a common way of producing rock salt over the centuries. The technology of brine production was already developed in ancient China more than 1000 years ago. The salt was dissolved either from below ground in mine galleries or from above-ground via wells. The cavities created by this form of solution mining tend to display uncontrolled development. However, they were not generally intended to be used for later storage purposes (Tek, 1989).

Underground salt formations are well suited to natural gas storage allowing for little injected natural gas to escape from the formation unless specifically extracted. The walls of a salt cavern have the structural strength of steel making it resilient against degradation over the life of the facility. The stability requirement of the salt caverns puts limitations on the shape, the height and the maximum and minimum operating pressures. Maximum pressure must be below lithostatic pressure, and below the pressure at which salt would start fracturing. The minimum pressure is governed by the need to keep cavern wall convergence to acceptable levels. The minimum allowable pressure is around 20-35% of a maximum pressure. This means the cushion gas will be relatively low, around a quarter to a third of total gas stored in a full cavern, with the working gas comprising around two third (Evans & Chadwick, 2009). On average, salt formation storage is capable of multiple cycling of inventory per year, in comparison to the typical one cycle or less for depleted gas field and aquifer storage. In this way, salt formation storage is well suited for meeting large fluctuations in demand. Disadvantages of this type of storage are volume limitations where each cavern size typically ranges from 5.3-10.6 bscf of working gas, significantly smaller than capacity abilities of depleted reservoirs and aquifers. Besides, initial costs generated during cavern development are substantial, and the disposal of saturated salt water produced during the solution mining can be detrimental to the environment (Bary et al, 2002).

2.2.3 Underground gas storage in depleted fields

Most gas is stored in depleted gas fields (around 70%). Storages in depleted reservoirs are the cheapest and easiest to develop, operate, and maintain of the three types of underground storage.

The expertise developed in countries where depleted gas reservoirs are used admit guidelines to be drawn up for the selection of fields, which are have to be converted into gas storage. This selection is based on a careful analysis of geological data and the physical parameters of the pre-selected structures. The essential factors are the shape and dimensions of the geological structure, the aquifer size, the gas-water contact (in the case of depleted or partially depleted reservoirs), the properties of the reservoir rock and cap rock. The most important physical parameters of the reservoir rock, which require careful evaluation, are:

- The extremely high porosity, which provides greater storage capacity.
- The higher the permeability of the reservoir rock, the better suited it is to storage.
- The water saturation, which should be as low as possible since, if it is high, it reduces available volume (Altieri, 2010).

Additionally, the drive mechanism is the important factor of reservoir. It is the ability of the aquifer to move within the reservoir rock, as the reservoir is filled and emptied. In the depletion drive reservoirs the gas-water contact remains substantially stable during the production and injection periods allowing high performances and minor problems during the production. To the contrary, in the water drive reservoirs the gas-contact moves upwards during the production phase and the water, which has risen, must be pushed back during the gas injection phase. In these reservoirs, the performance is reduced due to water production and the need for more pressure to displace the water (Montalvo, 2014).

Depleted reservoirs account for 87% of the total jurisdictional storage capacity, with salt caverns (3%) and aquifers (10%) accounting for the rest. Depleted reservoirs are most common because of their availability and the advantage of using existing infrastructure. Salt caverns are more expensive to construct due to the increase in capital cost associated with the leaching and mining of the salt.

2.3 Gas Reservoir as a Storage

Reservoirs containing only free gas are called gas reservoirs. Such a reservoir contains a mixture of hydrocarbons, which exists wholly in the gaseous state. Storage is a useful application of gas reservoirs. One of the best ways of storing natural gas is with the use of depleted gas reservoirs. The advantage of depleted gas reservoir storage compared to other types of UGS facilities is the use of already developed reservoir, which allows the utilisation of the equipment (extraction and distribution) left in-place from when the field was used for the production of natural gas. Having these existent extraction and distribution facilities reduces the costs of converting a depleted gas reservoir into a UGS facility. This makes, on average, reservoir storage facilities the least expensive to develop, operate and maintain, compared to salt cavern and aquifer storage facilities.

Katz and Tek (1981) listed three primary objectives in the design and operation of gas storage reservoir:

1 - Verification of inventory

2 - Retention against migration

3 - Assurance of deliverability.

Inventory represents the total amount of the natural gas in the storage reservoir at any point in time. It represents the sum total volume of native gas and injected gas. It varies from a minimum value at the conclusion of withdrawal to a maximum value at the conclusion of injection.

Verification of inventory is knowing the storage capacity of the reservoir as a function of pressure. This indicates that a *p/z* or some other measure of material balance be known for the reservoir of interest (Craft & Hawkins, 1991).

The material balance equation (MBE) has long been recognized as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance. The MBE is structured to simply keep inventory of all materials entering, leaving, and accumulating in the reservoir. The equation for calculating gas in place by MBE method given in Equation 2.1.

$$\frac{p}{z} = \frac{p_i}{z_i}\left(1 - \frac{G_p}{G}\right) \tag{2.1}$$

where:

p = pressure, psia

z = gas deviation factor at p, dimensionless

p_i = initial pressure, psia

z_i = gas deviation factor at p_i, dimensionless

G = initial gas in place, ft^3

G_p = cumulatie gas production, ft^3.

Equation 2.1 is an equation of a straight line when (*p/z*) is plotted versus the cumulative gas production G_p, as shown in Figure 2.3. This straight-line relationship is perhaps one of the most widely used relationships in gas-reserve determination (Tarek, 2006). If *p/z* is set to zero, which represent the production of all the gas from a reservoir, then the corresponding G_p equals *G*, the initial gas in place. When the plot *p/z* versus G_p deviates from the linear relationship, it indicates the presence of water encroachment (Figure 2.3). Additionally, abnormally pressured volumetric reservoir also deviates from linearity. Normal pressure gradients observed in gas reservoirs are in the range of 0.4 to 0.5 psia per foot of depth. Reservoir with abnormal pressure may have gradients as high as 0.7 to 1 psia per foot of depth (Craft & Hawkins, 1991). For an abnormally pressured volumetric reservoir, the *p/z* plot, as seen in Figure 2.3, is a straight line during the early time of production, but then it usually curves downward during the later stages of production.

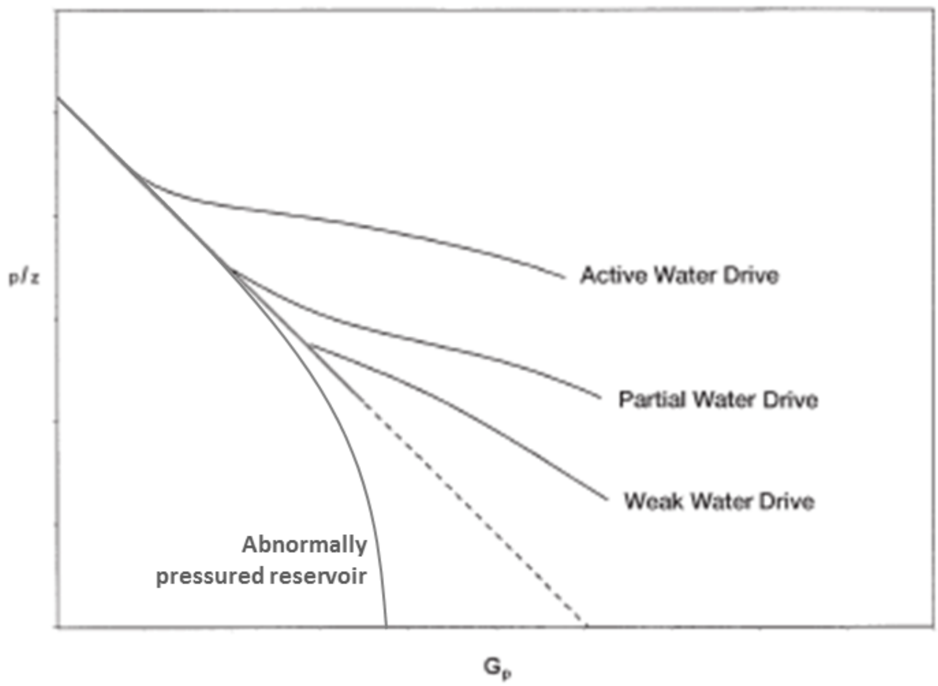

Figure 2.3 : Types of deviations from linear *p/z* versus G_p relationship (Tarek, 2006).

The main factor in the design of a depleted reservoir to a storage is the retention against migration. Retention against migration refers to a monitoring system capable of ascertaining if the injected gas remains in the storage reservoir. Obviously, leaks encasing and so on would be detrimental to the storage process. The operator needs to be assured that the reservoir can be produced during peak demand times to provide the proper deliverability. A major concern with the deliverability is that water encroachment not interfere with gas production. With these design considerations, it is clear that a good candidate for a storage reservoir would be a depleted volumetric gas reservoir. With a depleted volumetric reservoir, the *p/z* versus G_p curve is usually known and water influx is not a problem.

Another important parameter in underground storage operations is the assurance of deliverability. *Assurance to deliverability* is keyed to the pressure in the reservoir or to inventory. The reservoir must be able to deliver the peak load requirements of the country during the coldest days of the winter season. It should be remembered that storage reservoirs must be able to deliver as much as 50% or more of its original content within 3 or 4 months. Therefore, storage operations normally require many more wells than the number of wells drilled for original production (Katz and Tek, 1981).

A major advantage of storing gas in a depleted gas reservoir is that the performance, where in many cases is reflected by a plot of gas production versus reservoir pressure, is known. In this way, it is very easy to predict storage properties in advance. The top pressure of a storage reservoir corresponds to the pressure where the reservoir contains the maximum amount of gas it can store (Figure 2.4). The use of the field at the highest-pressure level will normally give the maximum storage capacity and the highest flow capacity of the wells, and this is usually the goal of the design. (Tureyen, 2000).

Produced gas has a value. When this produced gas is injected into the storage reservoir, there is always risk of possible gas loss. Cushion gas and working gas capacities are the largest cost item in a storage facility. Leakage is one of the major concerns when a reservoir is analysed as a potential storage unit. The leakage of gas from storage can be determined by examining of the pressure-volume history of the reservoir. To achieve this, it is first need to understand what a normal history cycle looks like. The injection and withdrawal of gas from storage leads to pressure changes in the reservoir. When injection and withdrawal cycles are similar from year to year and no leakage exists, the pressure-volume history also should be similar from year to year.

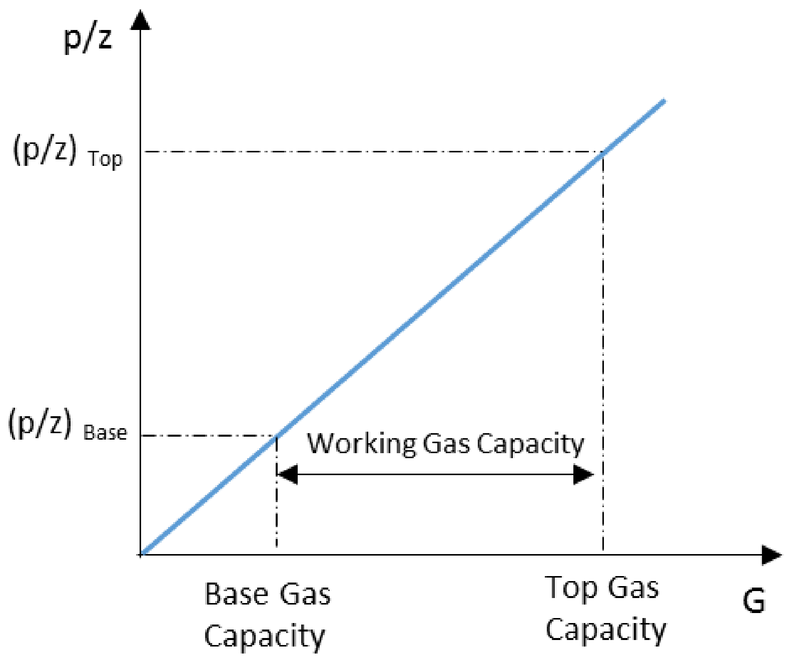

Figure 2.4 : Material balance graph with top and base gas capacities (Tureyen, 2000).

A more realistic type of storage operation is shown in Figure 2.5 (Flanigan, 1995). This figure is for a volumetric reservoir that has permeability values that are normally encountered in storage fields. The dashed line represents the pressure decline curve for the reservoir.

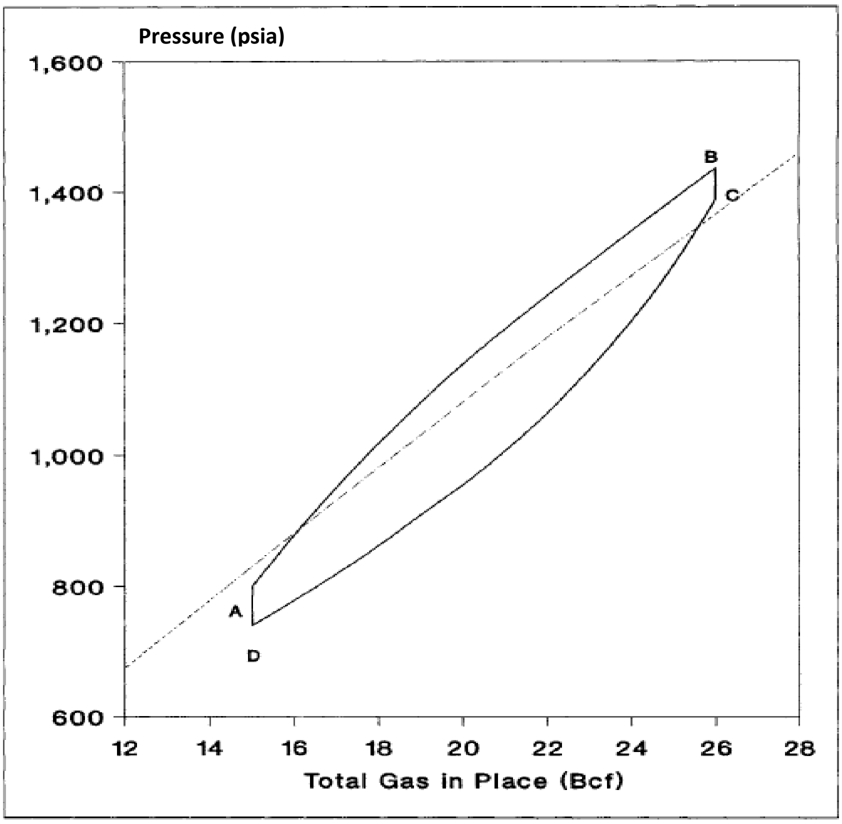

Figure 2.5 : Typical injection-withdrawal cycle for volumetric reservoir (Flanigan, 1995).

The injection period would be from point A to B. At point B the reservoir is full and the pressure is significantly above the pressure decline curve. This is because the pressure is measured from one or more injection-withdrawal wells. The pressure has not equalized throughout the reservoir, and the pressure at the well is higher than the rest of the reservoir. At the end of the injection cycle the storage field is usually shut in for a time period. This time period varies among various companies, but a typical time period is 15 to 30 days. One of the objectives of this shut-in period is to permit the pressures to equalize, thus a check can be made on the gas inventory in storage. This shut-in period is represented by the vertical line B to C in Figure 2.5. It can be seen that there is a significant drop in the pressure during this shut-in period. At the end of the period, the pressure is shown at point C. Point C is still above the pressure decline curve, indicating that the pressure is not completely equalized throughout the reservoir.

The production period is shown by the line C to D in Figure 2.5. During production period the pressure at the well drops below the pressure decline curve until point D. Point D represents the pressure in the well at the end of production period. This pressure is much below the pressure decline curve, indicating that the pressure is not equalized in the reservoir. It is also could be another shut-in period at the end of the production period. This period is represented by line D to A on the Figure 2.5. During this shut-in period, the pressure increases from point D to point A. Although this is a high pressure rise indicating that some pressure equalization has occurred, the pressure at point A is still below the pressure decline curve. This indicates that the reservoir pressure is still not completely equalized.

Figure 2.5 represents the reservoir that have been developed into storage units, which reached stable and repeatable operating cycles with no leakage. During the development and filling of a reservoir with gas there are transition cycles. For a volumetric reservoir the development of the pressure-volume history may similar to Figure 2.6.

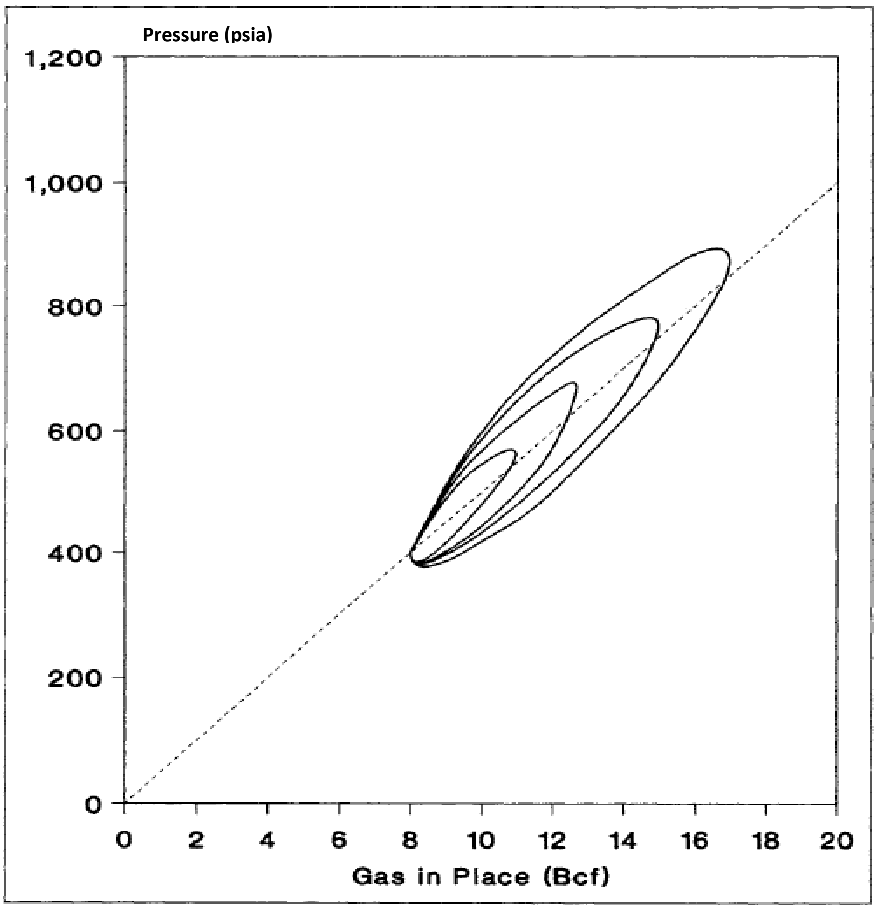

Figure 2.6 : Development of a volumetric storage reservoir (Flanigan, 1995).

After the cushion gas is injected, a part of the working gas is injected the first year. Following the injection period, the small amount of working gas which was injected is produced. The second year the working gas which was produced is reinjected plus some additional working gas is injected. This scheme may be followed for two or more years until the full complement of working gas has been injected. This schedule is usually governed by the availability of gas to inject into the reservoir. The pressure-volume cycles during this growth period are fixed around the pressure decline curve. When all of the working gas has been injected, the facility will operate similar to Figure 2.5.

Underground storage facility requires large investment. The cost is in dozens of millions of dollars and sometimes in the hundreds of millions of dollars. It is advisable to attempt to manage these investment costs in accordance with good judgement to achieve the lowest annual cost over a long period of time (Flanigan, 1995).

Table 2.1 lists some of the factors that have significant impact to storage facility performance and by this affect the economics. After the reservoir is chosen, the storage capacity and the maximum reservoir pressure are fixed. The variable factors of the storage are the number of wells, the flowing wellhead pressure, and the working-gas to cushion-gas ratio. Other factors are variable in certain extent and include the size of the gathering system piping and the size of the transmission line connecting the storage facility to the rest of the transmission system. Proper principles of design, usually prescribe what the sizing on these components will be. Sometimes a decreasing in cost can be obtained by trading off compressor horsepower with either gathering system cost or transmission line cost.

Table 2.1 : Factors affecting storage characteristics (Flanigan, 1995).

Fixed Factors	Reservoir capacity
	Maximum reservoir pressure
Variable Factors	Number of wells
	Wellhead pressure
	Working gas to cushion gas ratio

2.4 Historical Development of Underground Storage Systems

Natural gas began stored underground in Canada in 1915 and in the United States the next year. Canada and USA were the first to realize the economic importance and technical capability of storing natural gas in natural reservoirs. The use of gas storage spread significantly with the development and production of gas reservoirs at large distances from the areas where the gas was used, and especially with the development of importation from one country to another. The gradual discovery of gas production fields in areas more distant from areas of consumption and the seasonal variability of natural gas consumption created the proper conditions for the development of storage activities. The tendency to store gas began by using tanks located at the surface near cities. Since the production fields became depleted, they also were begun converting into storage reservoirs. Depleted fields have extremely high storage capacity and are thus more suited to the growing need of the gas market for storage. From 1950 to 1965, the number of new gas storage fields increased dramatically. Aquifer storage was developed in the Middle to serve the large Greater Chicago market; deeper depleted gas fields were developed in Pennsylvania, Ohio, and West Virginia and the first bedded salt storage cavern was developed in Michigan. The first storage cavern in a salt dome opened in Mississippi in 1970 as a back-up supply needed after hurricanes (Barnes & Levine, 2011).

Global gas storage capacity is expected to increase from 12.54 Tscf in approximately 640 facilities at the beginning of 2013 to 16.42 Tscf in 760 facilities that is already planned by 2020. In addition, there are approximately 140 identified projects at different stages of planning at worldwide level. These planned projects would add another 3 Tscf of working gas capacity if they were all implemented [Url-6].

Table 2.2 shows the availability of working gas capacity and daily peak rate for each country. Most of Europe's large storage facilities have been carried out in depleted or partially depleted gas reservoirs. About 80% of total working gas and daily peak rate is related to 40 fields out of a total of 103 fields. Currently, Germany is in first place for the availability of working gas and daily peak rate, followed by Italy. Also, in the

United States and Canada most gas storage is in depleted or partially depleted reservoirs; in the USA, the greatest concentration is found in the Eastern States.

Table 2.2 : World gas storage capacity, 2014 [Url-2].

COUNTRY	TYPE	Working capacity (bscf)	Peak output (bscf/day)
Austria	Depleted gas field	275.95	3.21
Belgium	LNG/Depleted	38.31	2.01
Czech Republic	Depleted/Aquifer/Cavern	121.33	2.30
Denmark	Aquifer/Salt cavern	35.56	0.71
France	Aquifer/Salt/Depleted/LNG	455.30	9.00
Germany	Depleted/Salt cavern/Aquifer	841.14	22.61
Hungary	Depleted gas field	223.52	2.82
Italy	Depleted gas field/LNG	575.92	9.88
Netherlands	Depleted/Salt/LNG	507.38	11.97
Poland	Depleted/Salt	78.57	1.55
Romania	Depleted gas field	103.67	0.99
Spain	Depleted/Aquifer/LNG	144.88	1.11
Turkey	Depleted/LNG	105.30	2.05
UK	Depleted/Salt/LNG	162.43	5.44
Europe Total		111 716	3944.77
Canada	Depleted/Salt cavern/LNG	708.23	11.83
USA	Depleted/Aquifer/Salt/LNG	4745.23	88.28
Australia	Depleted/LNG	157.80	0.78
New Zealand	Depleted gas field	15.61	0.04

2.5 Natural Gas Storage in Turkey

Due to fast demand growth, Turkey's annual natural gas consumption is nearing the annual capacity limits of the country's import infrastructure. At the same time, Turkey's natural gas demand is not flat during the year, but peaks in the winter months, when natural gas use for power generation and space heating is highest. Additionally, Turkey has a small amount of natural gas storage capacity and primarily depends on increased imports to meet the seasonal increase in demand. Natural gas deficiencies are not uncommon in winter, as the pipeline capacity is insufficient to meet peak winter demands. Through liquefied natural gas, underground gas storages and multiple pipeline connections, Turkey has a reasonably diversified supply mix.

Considering Turkey’s underground natural gas storage there are studies in the literature, which refer the design and current status of UGS, seasonal flexibility and its challenges. Unluuysal (2012) lay stress on the TPAO Northern Marmara and Degirmenkoy UGS facilities as a crucial in strategic respect in order to be fed

European side of Istanbul by these UGS facilities and provide security of supply. Also he pays attention to the IGDAS (Istanbul Gas Distribution Industry and Trade Incorporated Company) natural gas distribution network structure and statistical information of subscriber consumptions. An addition, Unluuysal (2012) reports that during the peak demands the feeding distribution carried out from underground storage facilities in case of cut on the BOTAS national transmission line.

Concerning future expectations of gas storage capacities, Abravci (2014) accentuate that Turkey meets 5.8% of storage requirement and in 2023 it will be 6.1%. With the finalization of the planned Tuz Golu project, besides existing forecasted stored gas capacity of 74.15 bscf, it should reach 127.12 bscf.

Underground Gas Storage

About 5% of the natural gas consumption of Turkey will be able to be stored (IGDAS, 2014).

Turkish Petroleum Corporation (TPAO) decided to convert the producing two gas fields, Northern Marmara (off-shore) and Degirmenkoy (on-shore), into underground gas storage facilities to accommodate seasonal variations in natural gas consumption [Url-5]. The main reasons in choosing the Northern Marmara and Degirmenkoy fields (the Silivri facility) as gas storage are the nearness of the fields to the gas pipeline network and Istanbul, and their suitability for gas storage because of their reservoir characteristics.

The facility with a capacity of 90 bscf (70 bscf capacity is allocated to BOTAS) became operational on 13th of April 2007. Gas from the existing supply pipeline is injected into the storage reservoirs and subsequently reproduced into the supply pipeline during the periods of high demand. TPAO operates those storage facilities with an injection capacity of 565 MMscf/day and a withdrawal capacity of 706.21 MMscf/day in total. The storage capacity of the facility is expected to be expanded to reach 100 bscf with a withdrawal capacity of 883 MMscf/day in the second phase of construction by the end of 2015, and then 152 bscf with a withdrawal capacity of 2472 MMscf/day in the revised phase III by 2017 [Url-5].

Several projects are ongoing: one is the Tuz Golu (salt lake) salt dome natural gas storage project. The first phase, which includes the construction of six domes was planned for completion in 2015-2016; the second phase in 2018-2019 will increase the facility by an additional six units (IEA, 2015). The Tuz Golu underground gas storage facility is located in an underground salt formation close to Tuz Golu – a salt lake in South Central Turkey. The facility, upon completion, will have a storage capacity of about 35 bscf of working gas and 16.24 bscf of cushion gas. The facility will have the capacity to deliver 1412.43 MMscf/day for up to 20 days, and can be refilled at the rate of 1059.32 MMscf/day over a period of 25 days [Url-7].

Another ongoing underground gas storage project is in Tarsus province. The facility in Tarsus province in southern Turkey will be undertaken by Toren Natural Gas Storage and Mining Company, a subsidiary of Turkish energy company Bendis Energy Production and Mining Consultation. The facility will have a gas storage capacity of 18 bscf, with a withdrawal rate of 847.5 MMscf/day (Jordan, 2014).

Liquefied Natural Gas Storage

In 2014, Turkey imported liquefied natural gas (LNG) from seven countries (Algeria, Nigeria, Qatar, Norway, Egypt, Netherlands, and France), which accounted for 13% of Turkey's total natural gas supply [Url-6].

The Marmara Ereglisi LNG Import Terminal was commissioned in line with Turkey's natural gas supply security and diversification policy on August 1st in 1994. LNG is imported to the terminal from Algeria and Nigeria. If required, spot LNG purchases from different countries can be made. The imported LNG is stored, regasified and sent out to the main transmission system. The design capacity of the terminal is 212 bscf/yr. There are three LNG storage tanks each has a capacity of 3.4 MMscf with a total capacity of 10.2 MMscf. The terminal has a maximum design capacity of 600 MMscf/day [Url-7].

Ege Gaz owns two full containment LNG tanks with total capacity of each 5.6 MMscf in Aliaga terminal in Izmir. The Aliaga terminal has started to operate in 2006, and has capacity of 579 MMscf/day of natural gas. A construction project for a new LNG terminal, which is expected to have a capacity of 635.6 MMscf/day, is under evaluation [Url-8].

Companies importing natural gas into Turkey are required to hold rights to storage capacity equal to 10% of their annual imports. However, Turkey currently has one operating underground storage facility (Table 2.3) with total storage capacity of about 5% of Turkey's imports of natural gas. For comparison, the 28 countries of the

European Union (EU) collectively have storage capacity equal to a little less than 20% of total annual consumption. If all the storage capacity currently proposed in Turkey is realized, capacity will amount to about 20% of annual imports for domestic consumption [Url-2].

Table 2.3 : Turkey's natural gas storage facilities (IEA, 2015).

Facility	Status	Operator	Working Gas Capacity (bscf)	Details
Northern Marmara & Degirmenkoy	operating	TPAO	90	Facility consists of two depleted gas fields; plans to expand capacity
Marmara Eregesli LNG	operating	BOTAS	10	LNG terminal storage
Aliaga LNG	operating	EgeGaz	11	LNG terminal storage
Tuz Golu	planned	BOTAS	35	Salt dome storage
Tarsus Province	planned	Bendis Energy	18	Salt cavern storage

2.6 Scope of Thesis

As in most developing gas consuming countries, Turkey's natural gas consumption varies in seasonal basis. As a solution to this, Turkish Petroleum Corporation (TPAO) decided to convert the producing Silivri gas field, into underground gas storage facilities to accommodate seasonal variations in natural gas consumption.

Silivri Underground Natural Gas Facility has two depleted gas reservoirs. One of them is Northern Marmara field, which has a depth of 3937 feet and discovered in Marmara Sea in 1988. Other one is Degirmenkoy field, which has a depth of 3609 feet and discovered in 1994. After feasibility study that determines the fields' appropriateness for storage services, "Natural Gas Storage and Reproduction Services Agreement" was signed between TP and BOTAS on 21.07.1999.

The purpose of the design of UGS reservoir is to obtain the maximum gas capacity for a given configuration of reservoir and surface properties under the influence of economics. The method of selecting the appropriate number of wells, wellhead pressures and base gas requirements is to fix one of the parameters and determine how the other parameters change depending on each other. Subsequently, the proper values of the parameters affecting the performance of the UGS are defined under the consideration of economics.

There are several studies and researches analyzing the Northern Marmara gas field. As an example, Karaalioglu (1997) studied the modelling of the Northern Marmara field as an underground gas storage reservoir; and accentuated that modelling the gas reservoir for underground gas storage purpose requires an optimization approach correlating and combining the effects of fluid, rock, well and other operation parameters. Tureyen (2000) modelled the Northern Marmara field for storage by using material balance graphs. Another study of Bulent (2004) was related to the simulation of the Northern Marmara field as UGS with IMEX reservoir simulator software.

Taking into account the aforesaid, there are lack of researches and studies of the Degirmenkoy field as separate underground gas storage field. For that reason, this study is devoted to the modeling of Degirmenkoy field as an underground gas storage reservoir. The scope of this thesis work is focused on the design and modeling of the Degirmenkoy underground gas storage reservoir using RUBIS software.

In this study are considered five sections, which two of them have been discussed in previous parts.

The main section of this study begins with introduction of the Degirmenkoy UGS field, where the main properties of the field, the basis of design surface and subsurface UGS facilities, and informations related to the wells of the Degirmenkoy field are explained.

The next Modeling Study section represents the simuation of Degirmenkoy field using RUBIS software. The aim of the study is to generate a model of the Degirmenkoy field and to make future predictions of the working gas capacity when additional wells are added.

The collected data, analysis of results, achieved goals are concluded in last Conclusions section relation to the research question.

3. DEGIRMENKOY FIELD

3.1 Properties of Degirmenkoy Gas Field

The Degirmenkoy is the one of the two reservoirs of Silivri underground natural gas storoge facility. The Degirmenkoy field is located in the Thrace region of Turkey. It is an onshore gas field located 16 km northernwest of the Northern Marmara field. The field was discovered in 1994 with an estimated gas in place (GIIP) of 21.18 bscf. After some period, GIIP was recalculated as 27.5 bscf. A small dome covering an area 2921.26 ft ^{x} 3280.84 ft, with an indistinct major axis striking from Northerneast to Southwest represents the Degirmenkoy structure. The gas bearing formation is the Sogucak formation. The reservoir top is located at 3543.31 ft below the surface. The cap rock of the reservoir is the Mezardere formation, which has an alternating sequence of shale, thin sandstone and limestone. The original reservoir pressure and temperature are 1900 psia and 149 ^{0}F, respectively. Fluid production data and the reservoir pressure response to production of the field indicate no water drive in the reservoir. The average porosity, water saturation and permeability are 8.3 %, 15 % and 55 mD, respectively. The average thickness is 164 ft (Table 3.1) (Sahin et al, 2012).

Table 3.1 : Degirmenkoy UGS field properties (Sahin et al, 2012), (Tirek et al, 2005).

Reservoir extension, ft*ft	2921.26 ^{x} 3280.84
Reservoir top, ft	3543.31
Reservoir thickness, ft	164
Average porosity, %	8.3
Average permeability, mD	55
Average water saturation, %	15
Original reservoir pressure, psi (bar)	1900 (131)
Original reservoir temperature, ^{0}F (^{0}C)	149 (65)
Initial gas in place, bscf (bcm)	27.53 (0.78)
True vertical depths of wells, ft	4216-4429
All measured depths, ft	4593-5085
Final tangential section	28-43^{o}
Working gas volume, bscf	14.37
Max.withdrawal capacity, MMscf /d	134.2
Max.injection capacity, MMscf/d	100.3
Connection pipeline length & dimension, ft, inch (mm)	42693.5, 16 (406.4)

Gas production in the field started in 1995. The field's average production from 2 wells was 10.6 MMscf/day. Cumulative production from the field is 20.72 bscf. For the storage purpose, the maximum gas injection and withdrawal rates were foreseen as 100.3 MMscf/day, and 134.2 MMscf/day, correspondingly. For the Degirmenkoy field, working gas was calculated as 14.37 bscf and the cushion gas as 13.28 bscf. The original gas composition is shown in Table 3.2.

Table 3.2 : Gas composition of Degirmenkoy UGS field (Cinar & Dolek, 1995).

Component	Degirmenkoy	
	Sogucak formation	Osmancik formation
N_2	1.660	1.383
CO_2	0.176	0.061
C_1	90.476	92.805
C_2	4.920	3.633
C_3	1.614	1.200
$i\text{-}C_4$	0.298	0.252
$n\text{-}C_4$	0.437	0.322
$i\text{-}C_5$	0.153	0.122
$n\text{-}C_5$	0.103	0.078
$n\text{-}C_{6+}$	0.163	0.144

3.1.1 Basis of Silivri UGS design

The Silivri UGS system consists of the equipment necessary to inject the gas to the storage and process the gas from the reservoir into pipeline and then gas transmission system.

Degirmenkoy UGS field is fed by the same pipeline as Northern Marmara field. The pipeline pressure varies between 220-330 psia. Hydrocarbon dew point and water dew point of the gas reinjected into the pipeline are 32^{o}F at 971.75 psia and -17.6^{o}F at 565.6 psia, respectively. The gas was not odorized before returning to the pipe (Sahin et al, 2012).

The facilities were designed to operate the two storage fields in common or independently. The design was also made to meet the following requirements:

1) To handle maximum and minimum flow rates for the injection period

2) To process maximum and minimum flow rates for the withdrawal period

3) To deliver the gas corresponding to the required pipeline specification and particular with the water and hydrocarbon dew points

4) To allow gas composition changes during the storage life

5) To be configured at an optimized level of automation for the injection or withdrawal cycle operation

6) To offer the highest level of safety

7) To give a high operation flexibility in order to be able to inject or withdraw the gas at any time

8) To reduce the corrosion due to the CO_2 potential content

9) To allow for pigging in the pipelines (Sahin et al, 2012).

3.1.2 Surface facilities of Degirmenkoy field

One common shared surface facility was designed for Silivri UGS application. This shared surface facility used to condition, meter, compress and inject the gas into the storage far from the network, and also to produce gas from the storage, condition, depressurize, meter and compress towards the network. Additionally to this facility, the gathering points were set up near the wellheads of both Northern Marmara and Degirmenkoy field storages to allow for primary separation and glycol injection.

The gas supply is provided by pipeline with 24 inches OD line. The gas is transported up to Degirmenkoy storage with 16 inches pipeline. This pipeline was designed for bi-directional flow, as it was intended to be used for both injection and withdrawal process (Tirek et al, 2005).

Compression is realized in normal mode of injection period. However, injection-withdrawal can be done with or without compression by changing pressures and well performances of storage and transmission line. Expansive withdrawal is preferred mode of operation in withdrawal period.

In the storage fields a 6 months injection period is followed by a one month shut-in period, with 5 months production period. The surface facilities were designed for simultaneous injection and production.

3.1.3 Design, drilling and completion of the operation wells

The feasibility of creating gas storage in the Degirmenkoy field was examined based on process design, geologic factors, and preliminary economic analysis. The study showed that the required injection and withdrawal capacity can be achieved with adding another 7 wells to existing 2 wells in Degirmenkoy field.

After engineering design and optimization studies, the directional wells in the Degirmenkoy field were drilled in 2001-2002, and completed in mid-2003. The performances of the wells exceeded the expectations forecasted during the design in terms of injection and withdrawal capacity. Drilling and completion of the storage wells were carried out without jeopardizing caprock, casing and cement integrity. In Degirmenkoy field, the reservoir pressure during the drilling of the wells was at the level of 841.2 psia.

The wells in Degirmenkoy were designed with 7 inches casing and 4 ½ inches production strings to decrease the pressure loss in the wells. Completion with monobore string was preferred to minimize the erosion problems due to turbulence and the probable troubles, which may occur during the well completion and workover operations, and to decrease the scaling potential inside the wellbore strings. There are other gas bearing formations at the upper zones called Danisment and Osmancik. Keeping the gas at the considered storage zone is extremely critical in terms of economics and safety. Consequently, once the caprock has been identified by logs, casing was landed just above the storage zone carefully. Besides, the cemented inner casing string was provided with gas tight type connections (Sahin et al, 2012).

Drilling of 7 deviated wells were started at the end of 2001 and completed in mid-2003. The true vertical depth, horizontal extension and the inclination at the wells were in between 4216-4429 ft, 1181-2297 ft and 28^o-43^o, respectively.

Moreover, for existing 9 (2+7) wells in Sogucak formation there were drilled another additional 8 wells in between 2012-2015. During drilling operations the variability of reservoir pressure led to mud leaks. Therefore, one well was abondoned because of technical reasons, and 2 wells completed before the target depth. Currently 16 (8+8) wells are ready to use. However, the number of wells that can be efficiently used for storage purpose is 12 (6+6), i.e, 6 are existing wells and another 6 are the newly added wells in between 2012-2015 (Abravci, 2016).

4. RUBIS MODELING STUDY

In this modelling study, two cases of Degirmenkoy gas field simulation are considered:

- Simulation of the reservoir with existing six wells to design the current state of field.
- Simulation of the reservoir with additional six wells to observe the reservoir performance for the future years.

Before presenting the simulation cases and the related issues, a general review of the Degirmenkoy gas field properties and its RUBIS model are represented first.

4.1 RUBIS Model of Degirmenkoy Field

This study describes the detailes of the design of the Degirmenkoy underground gas storage field. The Degirmenkoy UGS field, which is the depleted dry gas reservoir, is modeled by the RUBIS, a subprogram of ECRIN software. RUBIS is a three dimensional, three-phase multi purpose numerical simulator.

A three dimensional, one phase (dry gas) numerical model is used to simulate the injection and production behavior of the Degirmenkoy gas field.

Modeling with RUBIS is performed in eight steps. First is the Field General Information step. In this section, general information related to the Degirmenkoy field is entered. Since the gravity affects the calculations of gas viscosity, compressibility, deviation factor, and solution gas-oil-ratio the gravity effect is included into account in this model.

Following, in PVT part, the type of reservoir hydrocarbon has been defined as dry gas including no water and no condensate. The gas composition for this model is used from BOTAS gas given in Table 4.1. The gas deviation factor is computed by Dranchuk – Abou-Kassem correlation. The correlation provided by Lee et al is used for defining the viscosity. Figure 4.1 and Figure 4.2 are represent the *p/z* versus pressure-deviation factor graph and viscosity versus pressure graph at T=149^{o}F, respectively.

Table 4.1 : Gas composition of BOTAS gas used in the model (Banar & Cokaygil, 2010)

Components	Mole fraction, %
N_2	0.75
CO_2	0.06
C_1	96.63
C_2	1.87
C_3	0.50
i-C_4	0.08
n-C_4	0.08
i-C_5	0.01
n-C_5	0.02

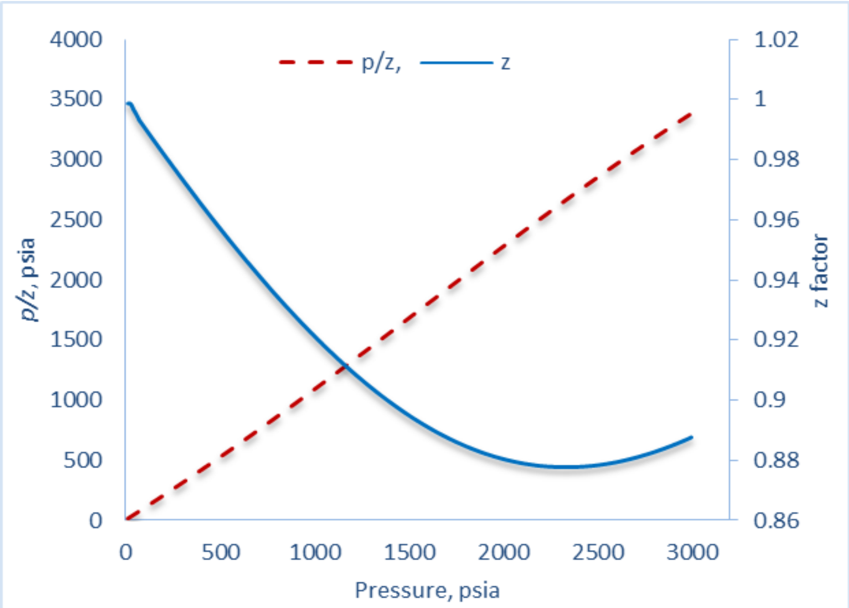

Figure 4.1 : *p/z* versus pressure and *z* factor graph at T=149^{o}F.

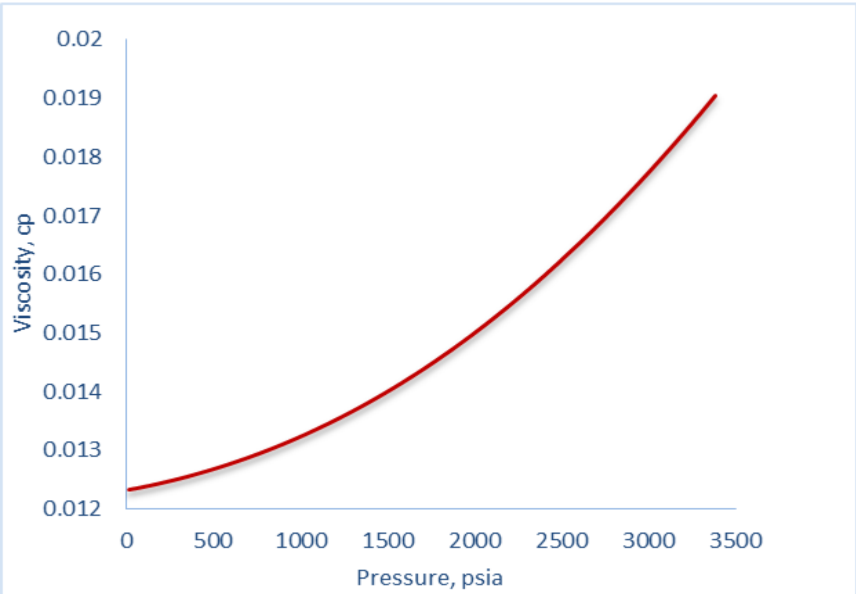

Figure 4.2 : Viscosity versus pressure graph at T=149^{o}F.

In Field Geometry section, entering the top depth and thickness of the reservoir, RUBIS fills the entire topology using different interpolation tools.

In Petrophysics part of the program, layering of reservoir, reservoir properties and the initial state of the system are provided. The petrophysical properties for the Degirmenkoy field model is selected as a homogeneous, single porosity reservoir.

In Well Information section, data regarding the wells and the production/injection schedule is given. The RUBIS is simulated using six deviated vertical wells. Currently existing six well properties used in this model are given in the Table 4.2.

Table 4.2 : Properties of existing wells used in the model.

Wells	#1	#2	#3	#4	#5	#6
Locations:X (ft) Y (ft)	1050 2460	2460 2625	4134 2461	1050 886	2460 1542	4134 886
Inclination angle	28^{o}	43^{o}	35^{o}	35^{o}	28^{o}	43^{o}
True vertical depth (ft)	3543.31-3707.35					
Gauge depth (ft)	4013	4844.85	4325.6	4325.6	4013	4844.85
Perforation depth (ft)	4013-4177	4844.85-5008.9	4325.6-4489.6	4225.6-4489.6	4013-4177	4844.85-5008.9

In Grid Construction part, the grid's geometry is set as rectangular, where L_x=4921.26 ft, L_y=3280.84 ft and L_y=164 ft. The reservoir is represented using grid system consisting of a total approximately 2500 blocks. The thickness of the reservoir is represented with five blocks. The resulting grid is displayed in a 3D graph (Figure 4.3).

Next in Simulation Characteristics section, duration of the simulation and the types of the output results are determined. The user can override the default time range, solver settings, list of output results and frequency of simulation restarts.

The Simulation, the last step, is then started and could be paused at any time. Then using Browser window the user can deal with obtained results. Individual well production and pressures, together with reservoir data are displayed in time versus plot and updated in real time during the simulation. The other reservoir data used in this model are given in the Table 4.3.

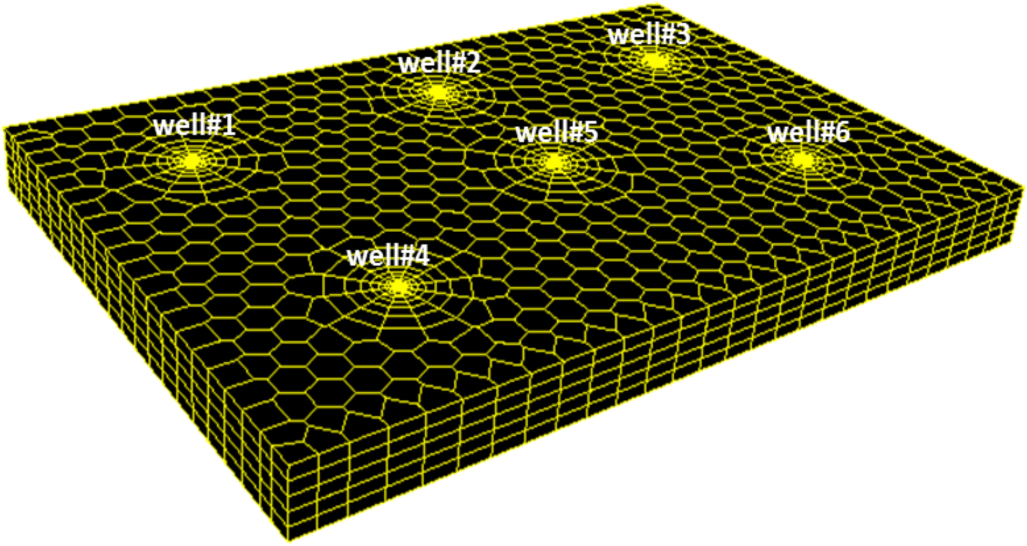

Figure 4.3 : 3D view of reservoir.

Table 4.3 : Reservoir data used in the Model.

Reservoir extension	4921.26ft*3280.84ft
Reservoir top	3543.31 m
Reservoir thickness	164 m
Average porosity	8.3 %
Average permeability	55 mD
Original reservoir pressure	1900 psia (131 bar)
Original reservoir temperature	149 ^{0}F (65 ^{0}C)
Initial gas in place	27.53 bscf (0.78 bscm)
Production string diameter	4 ½ inches (114.3 mm)
Working gas volume	14.37 bscf

Production data are used to estimate the production history and total gas initally in place (GIIP). The average reservoir pressure per deviation factor (p/z) versus cumulative produced gas (G_p) plot is illustrated in Figure 4.4. This graph is obtained using the production data of the RUBIS model (Table 4.4), and GIIP is found to be 27.5 bscf. In addition, the material balance behavior of RUBIS model is in agreement with volumetrically calculated GIIP, which is determined as 27.43 bscf. This is also in agreement with GIIP reported by Sahin et al (2012), which is 27.53 bscf.

Table 4.4 : Production data of Degirmenkoy gas field.

Average Reservoir Pressure, psia	Average reservoir pressure per z factor (p/z), psia	Total Gas Production, bscf
1900	2204.69	0
1800.84	2082.38	1.533
1758.51	2044.78	2.19

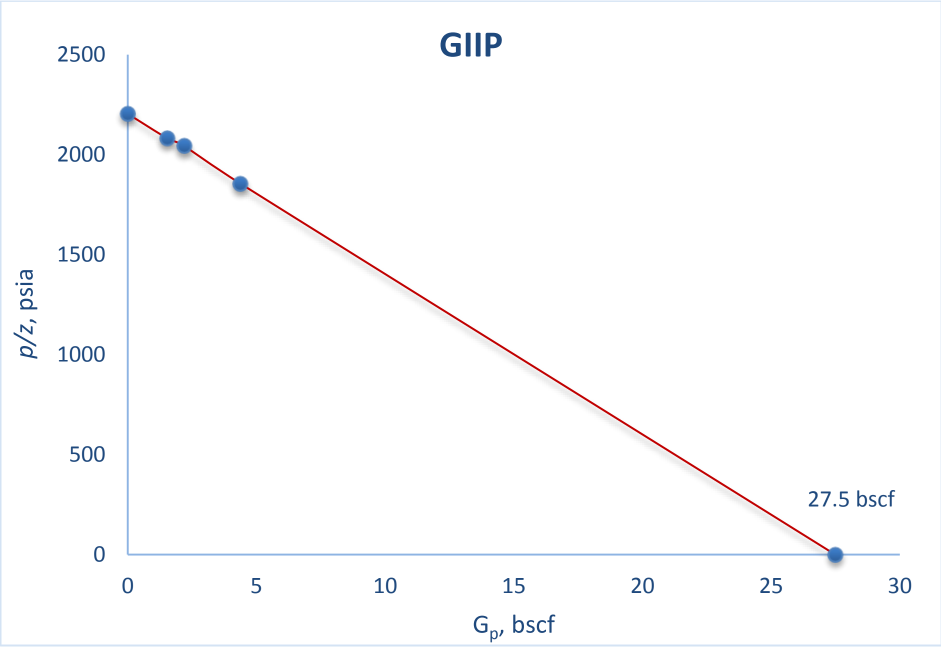

Figure 4.4 : p/z vs G_p graph of Degirmenkoy field

4.2 Modeling Study

4.2.1 Simulation of the reservoir with existing six wells

The aim of this simulation is to design the current state of the field with already existing 6 wells using RUBIS. Two cases are considered:

Case 1 – keeping constant the flow rates for both injection and production periods to observe wellhead pressure and bottomhole pressure behaviors.

Case 2 – keeping constant the wellhead and bottomhole pressures for injection and production periods to observe the flow rate behavior.

In this study, the Degirmenkoy field is considered as follows:

1. The model is simulated for one phase dry gas reservoir;
2. The reservoir is homogeneous;
3. There are 6 vertical deviated injection/withdrawal wells in the reservoir;
4. The vertical wells are deviated with inclination angles varying between 28^o - 43^o;

5. The storage cycle is defined for a one year period as follows: 6 months (180 days) injection period is followed by a one month shut-in period for maintenance, then 5 months (150 days) production period is performed.

First of all, the simulation begins with maintaining the working gas capacity of 14.37 bscf (present amount of working gas volume) during injection-production periods. Figure 4.5 gives the plot of average pressure and GIP indicating the base gas and top gas capacities of the reservoir. The top gas capacity is determined as 27.65 bscf from the RUBIS model at the top pressure which is 1939 psia. Knowing amount of the working gas and top gas capacities the base gas capacity is determined as 13.28 bscf at 960 psia base gas pressure.

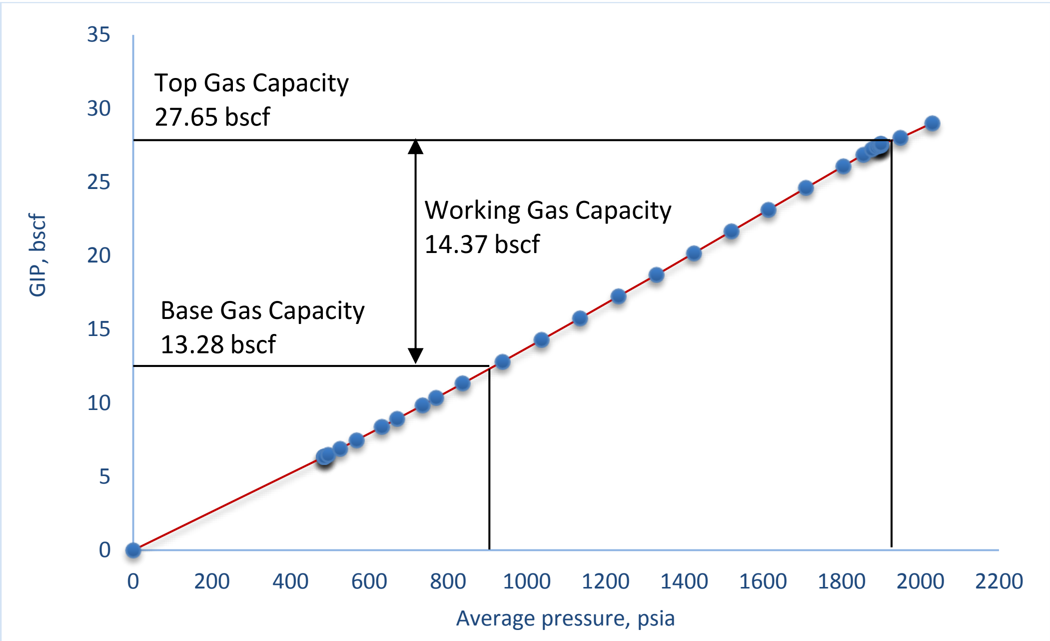

Figure 4.5 : Average pressure versus GIP graph representing top, base and working gas capacities

4.2.1.1 Case 1

The modeling performs with defining the constant flow rates for both injection and production periods to observe pressure behaviors for the case considered.

It was assumed that all wells have the same wellbore and flow characteristics, accordingly simulated data are obtained from well #5. The constant flow rates are defined when working gas capacity is 14.37 bscf. Flow rate during injection period is 13.315 MMscf/day and during production period is 15.973 MMscf/day (Figure 4.6).

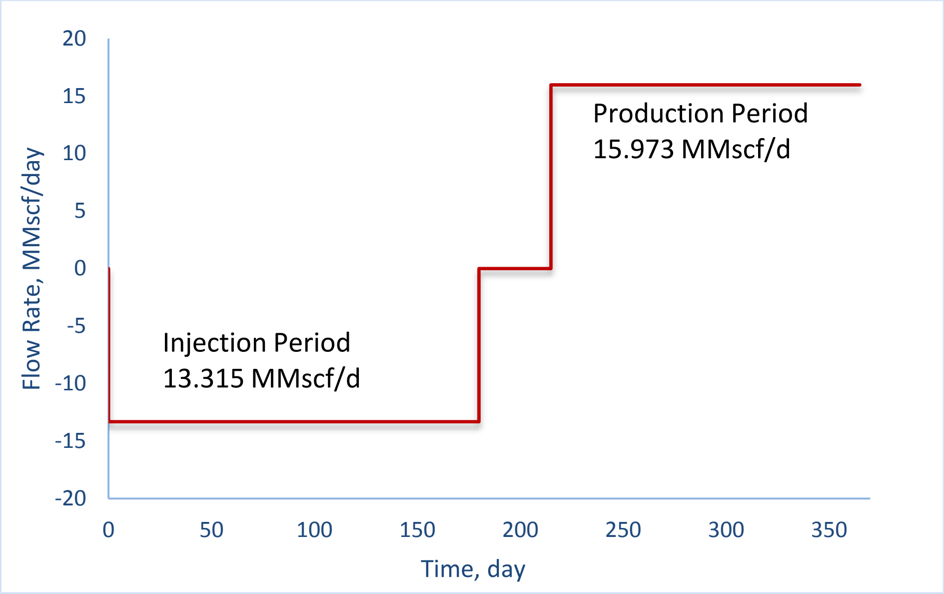

Figure 4.6 : Flow rates for injection and production periods.

The behaviors of wellhead and bottomhole pressures at constant flow rates are given in Figure 4.7. As expected, both bottomhole and wellhead pressures tend to increase during injection period with the bottomhole pressure increasing to maximum bottomhole pressure. During 35 days shut-in period both pressures decrease tending to come in balance with the average reservoir pressure. During production period both pressures decrease as expected with the wellhead pressure decreasing to the minimum wellhead pressure.

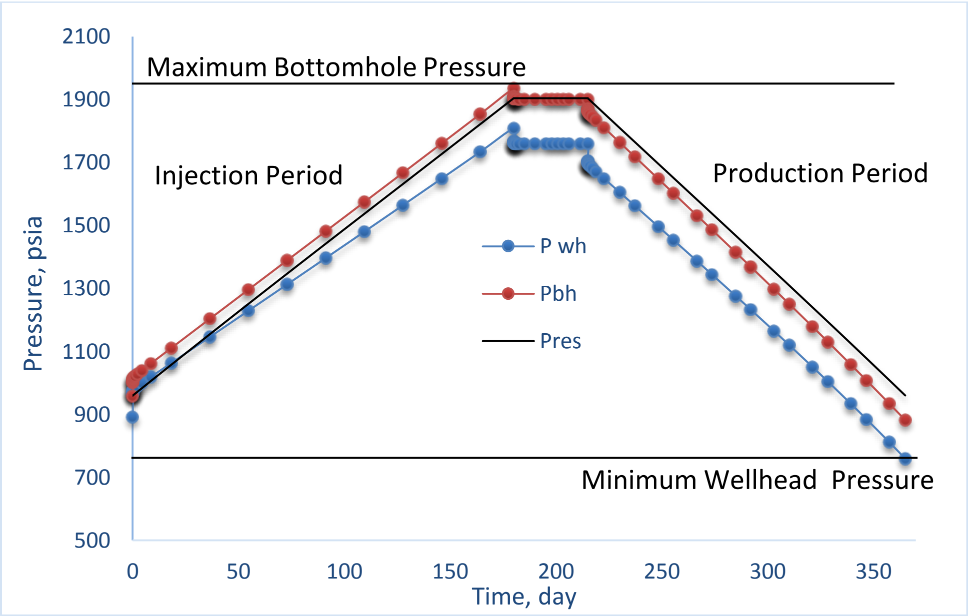

Figure 4.7 : Wellhead and bottomhole pressures for injection and production periods

The maximum bottomhole pressure at well #5 increases up to 1937.7 psia, and the minimum wellhead pressure decreases down to 754. 2 psia.

Along with using the RUBIS there is also considered an analytical approach to determine the conformity of the wellhead and bottomhole pressures. A number of researchers have developed techniques to calculate bottomhole pressure from measurements at the wellhead. A simplified method for calculating the pressure drop in gas wells assuming an average temperature and average compressibility factor over the flow length was presented by Katz et al (1959) (Lee & Wattenbarger, 1996):

$$p_{wf}^2 = p_{wh}^2 e^S + \frac{6.67 \times 10^{-4} q_g^2 f_M T^2 z^2 (e^S - 1)}{d^5 \cos(\theta)} \tag{4.1}$$

where:

$$f_M = \left(2 \log \left[\frac{3.71}{\left(\frac{\varepsilon}{d}\right)} \right] \right)^{-2} \tag{4.2}$$

$$S = \frac{0.0375 \gamma_g L cos(\theta)}{Tz} \tag{4.3}$$

d	=	pipe diameter, inches
p_{wf}	=	bottomhole pressure, psi
p_{wh}	=	wellhead pressure, psi
L	=	length, ft
q_g	=	gas flow rate, ft^3/day
T	=	temperature, ^oR
z	=	gas compressibility factor, dimensionless
γ_g	=	gas specific gravity, dimensionless
ε	=	absolute pipe roughness, inches
θ	=	inclination degree.

The bottomhole pressure calculated using the value of wellhead pressure at constant flow rate by equation 4.1. Then the result has been compared with bottomhole pressure obtained by RUBIS software. For clearness, Figure 4.8 represents the values of bottomhole pressure obtained by using both RUBIS model and analytical method. The pressure value is selected from RUBIS model, and then substituted to the equation 4.1. The comparison between two approaches is in good agreement, it means that the RUBIS model for the case with constant flow rate is simulated appropriately.

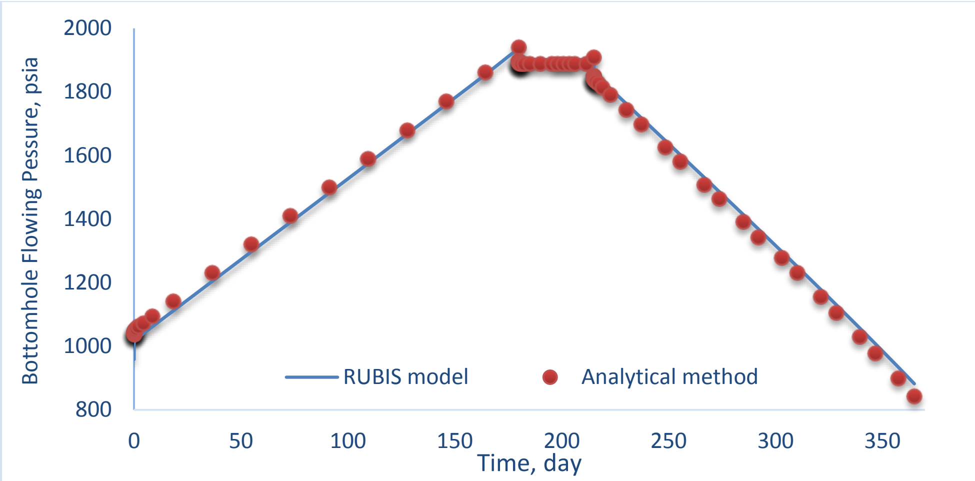

Figure 4.8 : The comparison of RUBIS model and analytical method results for constant flow rate case.

4.2.1.2 Case 2

Case 2 is performed with constant bottomhole and wellhead pressures. The aim is to keep constant the bottomhole pressure for injection period and the wellhead pressure for production period so that to observe the flow rate behavior. Also in this case the amount of working gas capacity has to retain at 14.37 bscf. To do so, during injection period bottomhole pressure is kept constant at 1900 psia and during production period wellhead pressure kept constant at 996.7 psia (68.72 bar). In one year period gas is injected during first 180 days, followed by 35 days of shut-in period, then gas is produced for a duration of 150 days. The model data are obtained from well #5. Figure 4.9 represents the behaviors of pressures and surface flow rate for one year injection-production period.

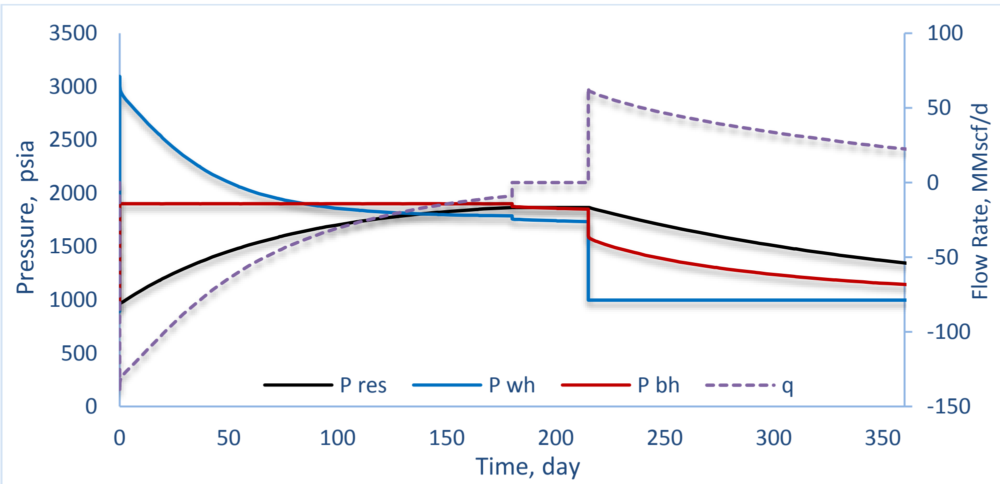

Figure 4.9 : Pressures and flow rate behavior for one year run period.

Figure 4.10 shows pressures behaviors for two years period. From this graph, it is observed that average reservoir pressure is slightly increased next year. It is explained that the amount of injected gas is higher than amount of produced gas.

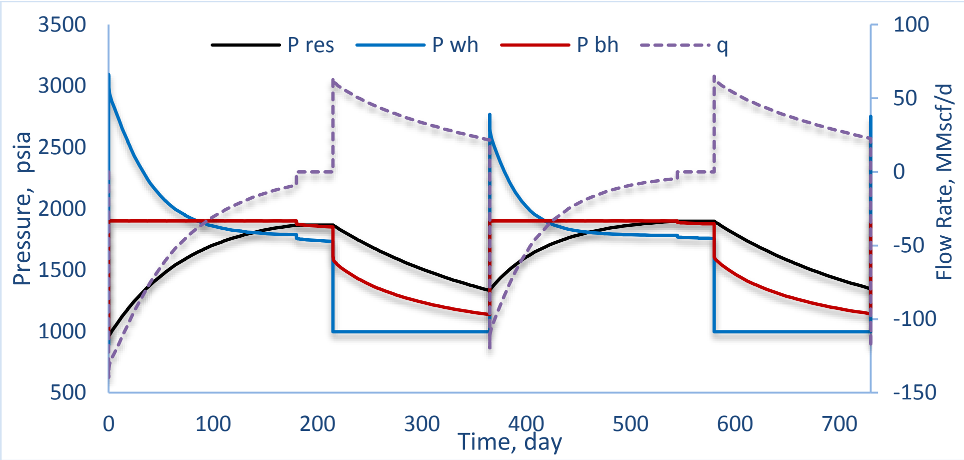

Figure 4.10 : Pressures and flow rate behavior for two years run period.

Figure 4.11 gives 4 year performance of total surface flow rate and average reservoir pressure. The reservoir pressure as expected is increased with injection and decreased with production. After initial year the surface flow rate is held to be constant, in other words, the flow rate is stabilized during injection-production periods.

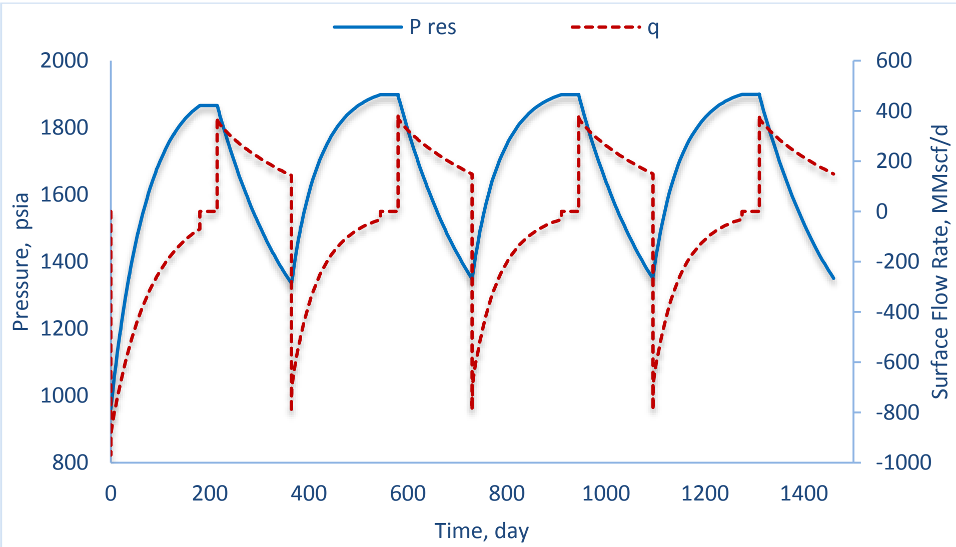

Figure 4.11 : Average reservoir pressure and total surface flow rate behavior of 6 wells for 4 year run period.

The analytical approach to check the pressures consistency is also used in this case. The inflow performance relationship for vertical well under low pressured (2000 psia) pseudo-steady state flow is given by Golan and Whitson (1986) (Tarek, 2006):

$$q_g = \frac{kh(\bar{p}_r^2 - p_{wf}^2)}{1422T\bar{\mu}\bar{z}\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]} \tag{4.4}$$

where:

k	=	permeability, mD
h	=	thickness, ft
$\bar{p}_r$	=	average reservoir pressure, psia
μ	=	gas viscosity, cp
r_e	=	drainage radius, ft
r_w	=	well radius, ft
s	=	skin factor, dimensionless

Both the theoretical equation and RUBIS have been used to determine the flow rate for the given model pressure constants: during injection period bottomhole pressure is 1900 psia and during production period wellhead pressure is 996.7 psia (68.72 bar). The procedure starts with picking up the value of the bottomhole pressure from the RUBIS model. Further, it substitutes to equation 4.4. The obtained result again is compared with RUBIS result. Figure 4.12 shows the comparison of the surface flow rate values for the case considered. According to the results, the pressures consistency in this simulation case is also held.

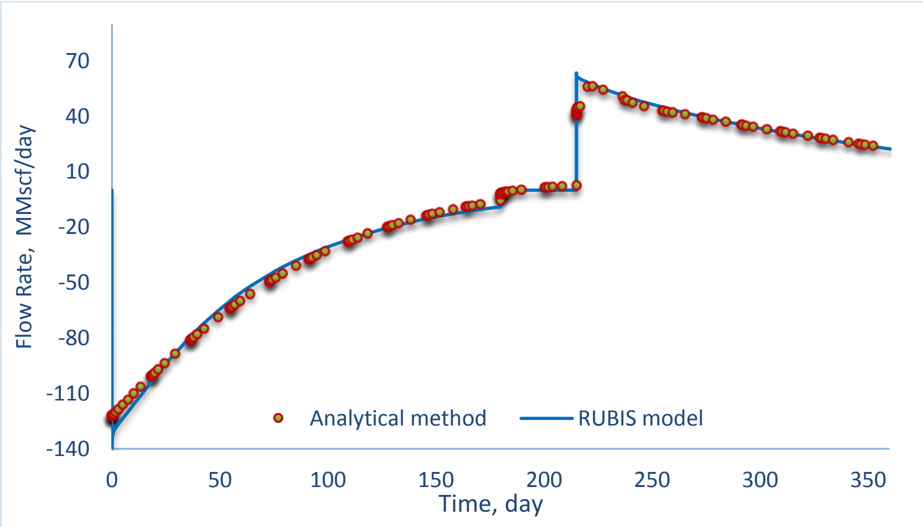

Figure 4.12 : The comparison of RUBIS model and analytical method results of well#5 for constant pressures case.

4.2.2 Simulation of the reservoir with additional six wells

The main goal of this simulation is to observe the performance of the reservoir with additional 6 wells for the future years using RUBIS. Three cases are considered:

Case 1 – observing the reservoir behavior by adding another new 6 wells to the existing 6 wells at constant wellhead pressure.

Case 2 – observing the mechanical skin effect on the reservoir performance.

Case 3 – observing the wellhead pressure effect on the reservoir performance.

4.2.2.1 Case 1

There are various parameters affecting the performance of an underground storage reservoir. One of the main parameter is the number of wells for injection-production purposes. Increasing the number of wells for any underground storage would increase the working gas capacity of the reservoir. In this case, 6 additional wells are added to the existing 6 wells in the Degirmenkoy field. The scenario for this case begins with continuing the injection/production periods for already existing 6 wells. After end of 4 years run, adding another 6 new wells, in total 12 wells are used for 8 years injection/production periods. Figure 4.13 represents the behavior of the surface rate at 996.7 psia wellhead pressure with respect to time. As seen in Figure 4.13, during the first 4 year the surface flow rate approximately stays constant, except initial year where the amount of injected gas is higher than produced gas volume. At the end of 4 years run the flow rate is increased sharply due to adding another 6 wells, then it stabilized.

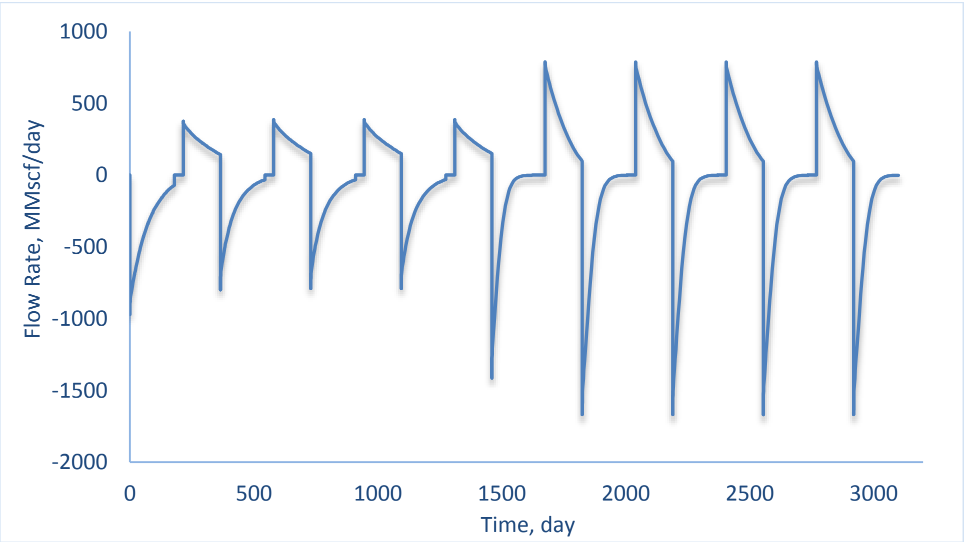

Figure 4.13 : Total surface flow rate behavior for 12 wells at constant wellhead pressure

Figure 4.14 shows the reservoir pressure behavior for the scenario mentioned above. During the first 4 year the average reservoir pressure is slightly increased at the end of each year due to high amount of injected gas volume. At the end of 4 year another 6 new wells are added; afterwards the reservoir pressure is sudden increased and then it stays close to the constant value during another 4 year run.

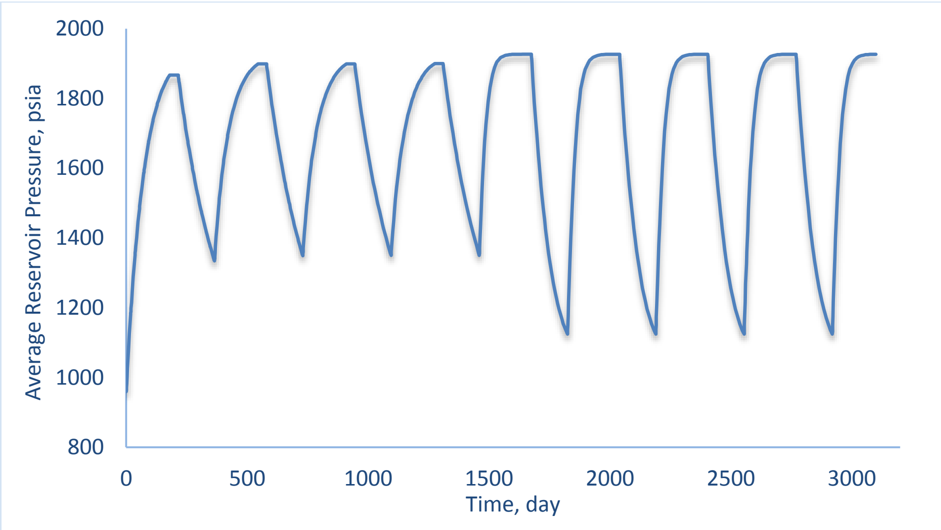

Figure 4.14 : Average reservoir pressure of 12 wells for 8 years run period.

In the previous case, where considered 6 wells the working gas capacity was estimated as 14.37 bscf at constant wellhead pressure of 996.7 psi (68.72 bar). As expected, the working gas capacity is increased up to 27.72 bscf with additional wells at the same wellhead pressure (Figure 4.15). This means that reservoir production capacity is expanded by adding new wells.

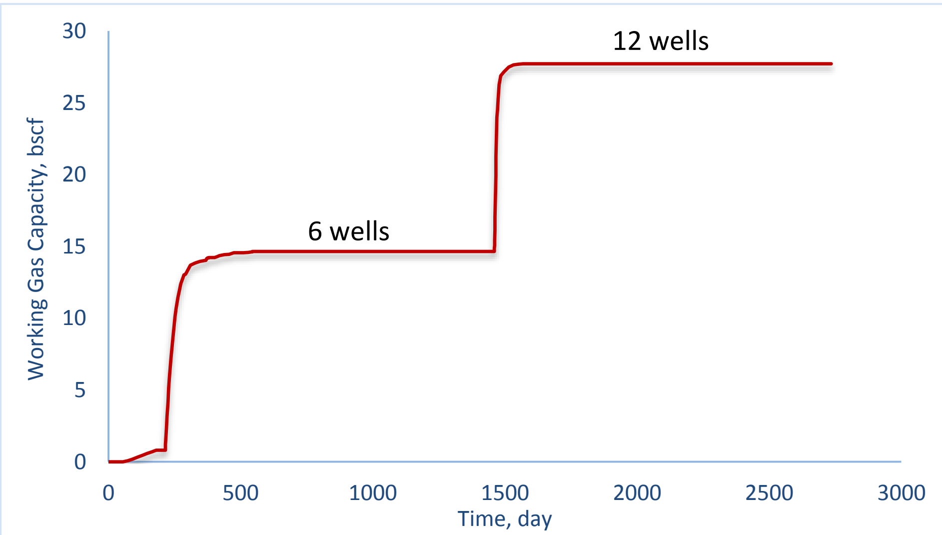

Figure 4.15 : Working gas capacity for 8 year run period.

4.2.2.2 Case 2

Efforts to minimize wellbore damage help to improve the production/injection performance of the storage reservoirs. Therefore, in this case considered the effects of skin factor to the reservoir performance after producing 27.72 bscf working gas capacity at the constant wellhead flowing pressure of 996.7 psia (68.72 bar) in vertical deviated wells. The results are shown in Figure 4.4. Working gas capacities were determined for various mechanical skin factors (-2, 0, 5 and 20). As expected the working gas capacity decreases as the skin factor increases. In the case where mechanical skin factor is 20 there is approximately 10% loss of working gas capacity when compared with the case where no wellbore damage exists.

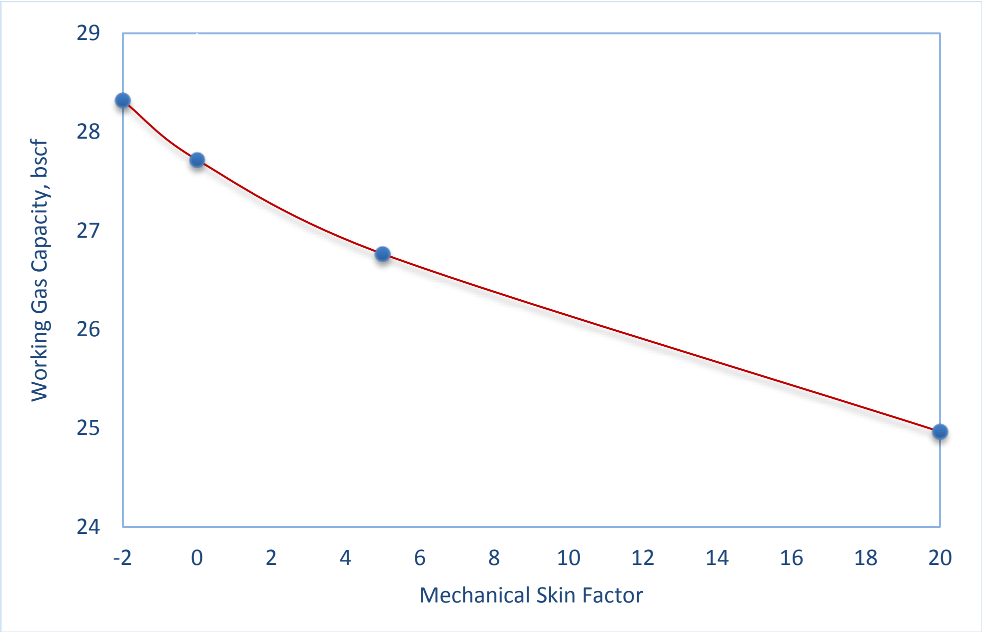

Figure 4.16 : Mechanical skin factor versus working gas capacity for 12 wells.

4.2.2.3 Case 3

The wellhead pressure has a great value in the design of storage reservoir. The wellhead pressure is the key parameter for defining the quantity of horsepower requirements for compressing the gas to the market. Operations with higher wellhead pressures are cause of reduction in cost which is desirable in economic consideration. At the same time, the storage reservoir must be capable to deliver gas to the market needs, then a minimum wellhead pressure would be desirable.

In this case, for the model of Degirmenkoy gas storage field a minimum wellhead pressure is considered as 290 psia (20 bar). Figure 4.17 shows the graph of working gas capacity against time for wellhead pressures of 996.7 psia (68.72 bar) and 290 psia (20 bar) against time. As seen in Figure 4.17, decreasing the wellhead pressure leads to an increase in working gas capacity for a fixed number of wells. When wellhead pressure is lowered from 996.7 psia (68.72 bar) to 290 psia (20 bar), the working gas capacity for 12 wells is increased from 27.72 bscf to 39.1 bscf.

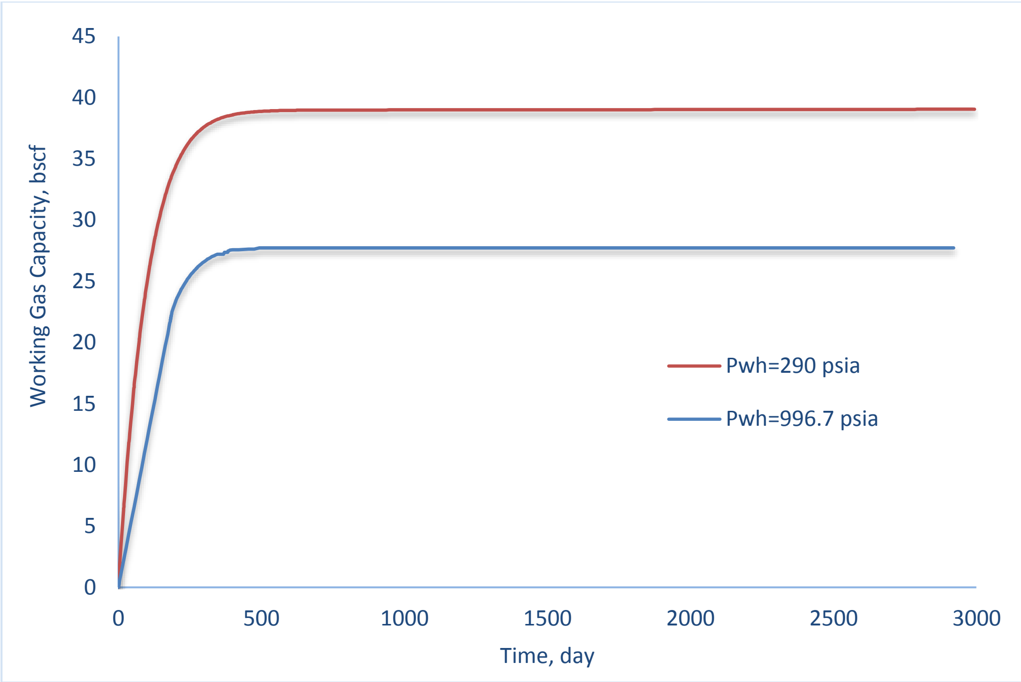

Figure 4.17 : Working gas capacity versus time plot for 12 wells at wellhead pressures of 996.7 psia and 290 psia.

A minimum wellhead pressure is also affected to the average reservoir pressure and surface flow rate. Figure 4.18 and Figure 4.19 give the surface flow rate and average reservoir pressure changes versus time plot for 12 wells at wellhead pressures of 996.7 psia (68.72 bar) and 290 psia (20 bar), respectively. Lowering wellhead pressure leads to increase the surface flow rate, and to decrease the average reservoir pressure at the end of production period.

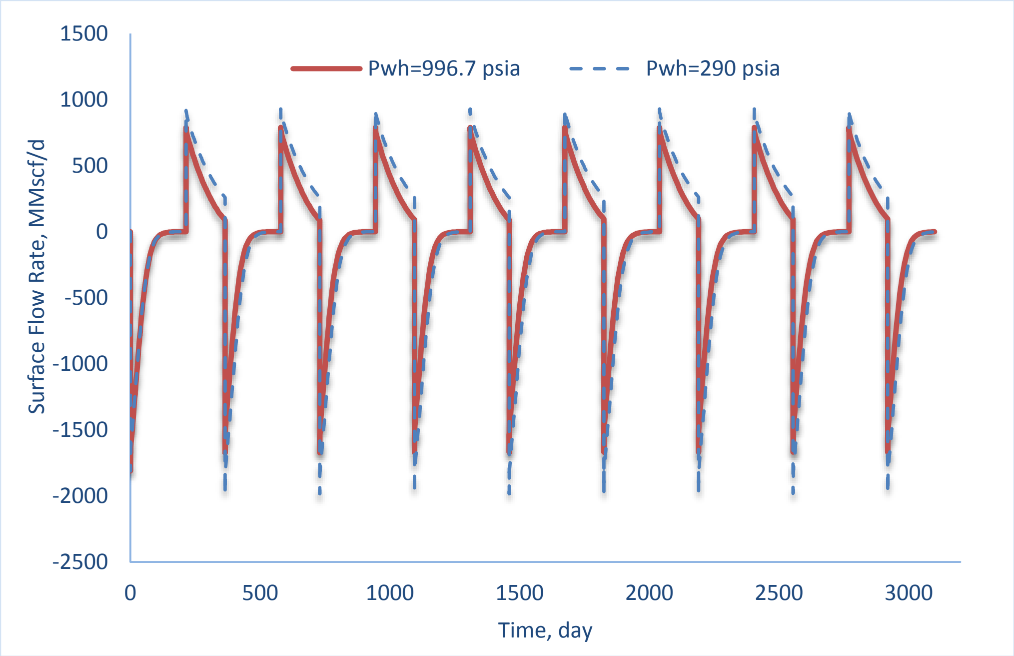

Figure 4.18 : Total surface flow rate for 12 wells at wellhead pressures of 996.7 psia and 290 psia.

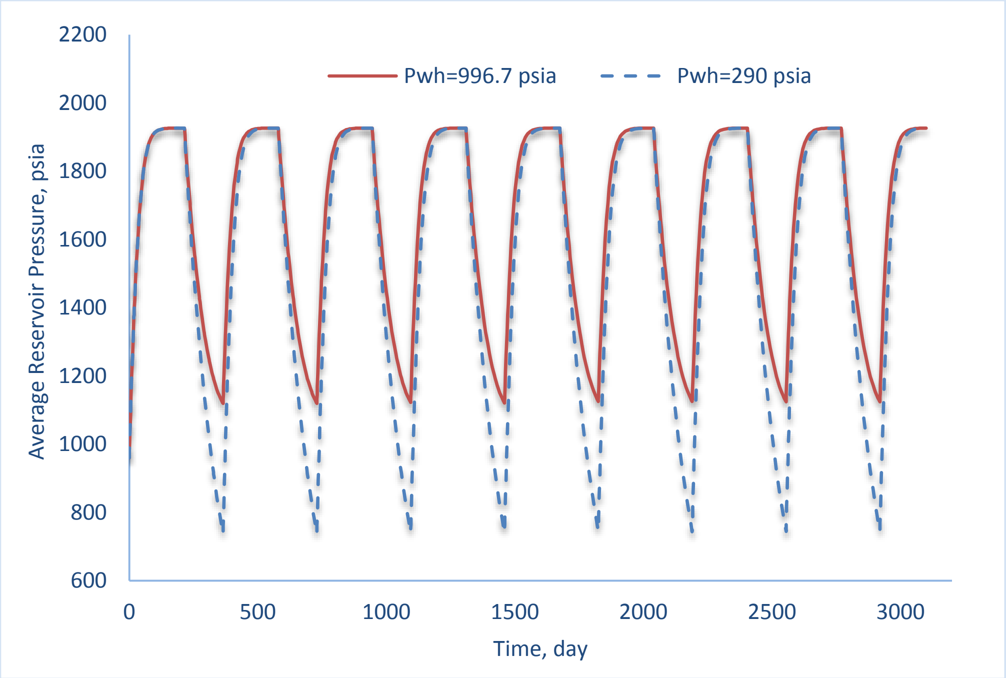

Figure 4.19 : Average reservoir pressure for 12 wells at wellhead pressures of 996.7 psia and 290 psia.

5. CONCLUSIONS

A model of Degirmenkoy depleted gas field has been created using RUBIS simulator in this thesis study. The initially gas in place for considered field was estimated to be 27.5 bscf, the working gas capacity and cushion gas capacity were defined to be 14.37 bscf and 13.28 bscf, respectively.

The main aim of this study was modeling of the Degirmenkoy gas field as an underground gas storage reservoir using RUBIS software.

Two cases to design the current state and three cases to predict the future performance of field were simulated in this modeling study. The following conclusions were drawn at the end of this study:

- To maintain working gas capacity of 14.37 bscf the constant flow rates were investigated for injection and production periods as 13.315 MMscf/day and 15.973 MMscf/day, respectively. The storage cycle for one year was as follows: 180 days of injection period followed by 35 days of shut-in period, then 150 days production period was performed. It was assumed that all wells have the same wellbore and flow characteristics, accordingly simulated data were obtained from well #5.
- Constant bottomhole and wellhead pressures were determined to be 1900 psia and 996.8 psia (68.72 bar), respectively, to maintain working gas capacity of 14.37 bscf for existing 6 wells.
- Analytical approaches were used to check the pressures consistency; as a result of this, both RUBIS and analytical methods were in good agreement.
- The number of wells is the one of the main parameters taken into consideration in design of a storage field and have significant effect on the performance of the storage reservoir. In this connection, the case with additional wells were considered. 6 new wells were added at 996.7 psia constant wellhead pressure to the existing 6 wells after 4 year storage cycle in the field, i.e. in total 12 wells had been simulated for 8 years run period in between 2012-2020.

- Increasing the number of wells for any underground storage would increse the working gas capacity of the reservoir. Simulating the reservoir with existing 6 wells the working gas capacity defined to be 14.37 bscf at constant wellhead pressure of 996.7 psia. Further, adding another 6 wells this value of working gas capacity is increased up to 27.72 bscf as expected.
- Efforts to minimize wellbore damage help to improve the production/injection performance of the storage reservoirs. Therefore, the case with effects of mechanical skin factor was also examined. When wells were simulated with -2 skin factor the working gas capacity was increased up to 28.32 bscf. In the case where mechanical skin factor is 20 the working gas capacity was decreased down to 24.86 bscf.
- The wellhead pressure is the key parameter for defining the quantity of horsepower requirements for compressing the gas to the market. The wellhead pressure has a weighty effect on performance of UGS reservoir. In this connection the case with minimum wellhead pressure was considered. Minimizing the wellhead pressure leads to an increase in working gas capacity for a fixed number of wells. When wellhead pressure is lowered from 996.7 psia to 290 psia, the working gas capacity for 12 wells is increased from 27.72 bscf to 39.1 bscf. This also affected to the average reservoir pressure and surface flow rate performances.

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