Petroleum & Coal
ISSN 1337-7027

Available online at www.vurup.sk/petroleum-coal
Petroleum & Coal 56 (1) 1-12, 2014

DEVELOPMENT AND CONVERSION OF AQUIFER FOR UNDERGROUND NATURAL GAS STORAGE IN NIGERIA

Chukwuemeka M. Muonagor[1], C. I. C. Anyadiegwu[2]

[1]Institute of Petroleum Studies, Port Harcourt, in affiliation with Institut Francais du Petrole (IFP), France. tissadeking@yahoo.com
[2]Department of Petroleum Engineering, Federal University of Technology, Owerri, Nigeria, drcicanyadiegwu@yahoo.com

Received July 29, 2013, Revised January2, 2014, Accepted January 4, 2014

Abstract

The storage of natural gas in aquifer was examined with Y-2, an underground aquifer located, South-East, Nigeria. The geological information and the fluid data of the aquifer water were gathered, which aided in the computation of the storage capacity at any given pressure of the storage vessel. The study which was primarily, for checking the suitability of the reservoir for underground gas storage shows that the reservoir is fit for such purpose because of its large working gas capacity of 7.58 Bscf. Three basic requirements in underground storage of natural gas which are: verification of inventory, determination of quantity of gas loss and assurance of deliverability were evaluated for the aquifer. The results of the estimated properties show that Y-2 is a good candidate for conversion into storage vessel and can also be monitored in the case of gas leakage. In evaluating the deliverability of underground gas storage in aquifer, gas flow rate data for the aquifer assuming it's already used for gas storage was generated. The gas flow rates data served as the production data of the aquifer as a gas storage vessel and were used for the generation of the plot of Log (P^2 – P_{wf}^2) versus Log Q to get the slope. The reciprocal of the slope of the performance line generated, n was used to get the performance coefficient, C. A Petroleum Engineering Software, Prosper was applied to generate the IPR curve and the AOF. With all these, the deliverability of the aquifer at Aquifer Storage Pressure was evaluated and used to generate a table, and a plot of deliverabilities at different withdrawal pressures.

Keywords: Natural gas; aquifer; storage; underground; gas loss; injection; pressure; capacity; performance; back-pressure; well flowing pressure; deliverability.

1. Introduction

According to Anyadiegwu and Anyanwu [2], underground natural gas storage provides pipelines, local distribution companies, producers, and pipeline shippers with an inventory management tool, seasonal supply backup, and access to natural gas needed to avoid imbalances between receipts and deliveries on a pipeline network.

There are three principal types of underground storage sites used today. They are:

- depleted natural gas or oil fields
- aquifers or
- salt caverns

According to Wikimedia Foundation Inc. [18], aquifers are underground, porous and permeable rock formations that act as natural water reservoirs. In some cases they can be used for natural gas storage. Usually these facilities are operated on a single annual cycle as with depleted reservoirs. The geological and physical characteristics of aquifer formation are not known ahead of time and a significant investment has to go into investigating these and evaluating the aquifer's suitability for natural gas storage. If the aquifer is suitable, all of the associated infrastructure must be developed from scratch, increasing the development costs compared to depleted reservoirs. This includes installation of wells, extraction equipment, pipelines, dehydration facilities, and possibly compression equipment. Since the aquifer initially contains water there is little or no naturally occurring gas in the formation and of the gas injected some will be physically unrecoverable. As a result, aquifer storage typically requires significantly more cushion gas than depleted reservoirs; up to 80% of the total gas volume. Most aquifer storage facilities were developed when the price of natural gas was low, meaning this cushion gas was inexpensive to sacrifice. With rising gas prices aquifer storage becomes more expensive to develop. A consequence of the above factors is that developing an aquifer storage facility is usually time consuming and expensive. Aquifers are generally the least desirable and most expensive type of natural gas storage facility. Storage of gas in aquifers require injection period of 200 – 250 days and withdrawal period of 100 – 150 days.

In some areas, most notably the Midwest, natural aquifers have been converted to gas storage reservoirs. An aquifer is suitable for gas storage if the water bearing sedimentary rock formation is overlaid with an impermeable cap rock. While the geology is similar to a depleted production field, the use of an aquifer for gas storage usually requires more base (cushion) gas and greater monitoring of withdrawal and injection performance. Deliverability rates may be enhanced by the presence of an active water drive [6].

According to EIA [3], there are several volumetric measures used to quantify the fundamental characteristics of an underground storage facility and the gas contained within it. They include:

- **Total gas storage capacity** is the maximum volume of gas that can be stored in an underground storage facility in accordance with its design, which comprises the physical characteristics of the reservoir, installed equipment, and operating procedures particular to the site.
- **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 adequate pressure and deliverability rates throughout the withdrawal season.
- **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.
- **Deliverability** is most often expressed as a measure of the amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. Also referred to as the deliverability rate, withdrawal rate, or withdrawal capacity, deliverability is usually expressed in terms of millions of cubic feet per day (MMcf/day). Occasionally, deliverability is expressed in terms of equivalent heat content of the gas withdrawn from the facility, most often in dekatherms per day (a therm is 100,000 Btu, which is roughly equivalent to 100 cubic feet of natural gas; a dekatherm is the equivalent of about one thousand cubic feet (Mcf)). The deliverability of a given storage facility is variable, and depends on factors such as the amount of gas in the reservoir at any particular time, the pressure within the reservoir, 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: it is at its highest when the reservoir is most full and declines as working gas is withdrawn.
- **Injection capacity (or rate)** is the complement of the deliverability or withdrawal rate-it is the amount of gas that can be injected into a storage facility on a daily basis. As with deliverability, injection capacity is usually expressed in MMcf/day, although dekatherms/day is also used. 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: it is at its lowest when the reservoir is most full and increases as working gas is withdrawn.

None of these measures for any given storage facility are fixed or absolute. The rates of injection and withdrawal change as the level of gas varies within the facility. Additionally, in practice a storage facility may be able to exceed certificated total capacity in some circumstances by exceeding certain operational parameters. But the facility's total capacity can also vary, temporarily or permanently, as its defining parameters vary. Further, the measures of base gas, working gas, and working gas capacity can also change from time to time. This occurs, for example, when a storage operator reclassifies one category of gas to the other, often as a result of new wells, equipment, or operating practices (such a change generally requires approval by the appropriate regulatory authority). Also, storage facilities can withdraw base gas for supply to market during times of particularly heavy demand, although by definition, this gas is not intended for that use [3].

According to Katz and Tek [10], the most essential features of the underground storage aquifers are:

- Storage capacity (verification of inventory)
- Storage retention against migration and determination of the amount of leakage
- Assurance of deliverability

Verification of Inventory involves the estimation of the storage capacity of the aquifers used for underground natural gas storage. Storage retention against migration involves ensuring that the gas injected into the aquifer is confined to the given space and determination of the amount of leakage at any given pressure drop. In depleted oil or gas reservoir storage or in aquifer storage the presence of a suitable cap rock is of paramount importance for the retention of natural gas within the structural boundaries of the reservoir. The cap rock that constitutes the overburden to a natural petroleum reservoir obviously does possess proved integrity to retain the gas at least up to discovery pressure [16].

During the primary production period of a gas field especially older gas fields, the operator usually is not aware of any gas loss from the reservoir, such as loss to shallow or deeper formations by means of well bore communication gas vented from surface production equipment, or gas lost by leaks in such equipment. Though the operator may be aware of these losses, a reasonable accurate accounting is rarely attainable. However, in gas storage operations, losses can be experienced from usual causes encountered during primary production as well as from other causes. Verification of gas inventory by the operator of storage field is necessary in order to maintain storage field performance and it is also necessitated by cost considerations. Consequently, the operators of storage fields routinely gather reservoir performance data to verify that gas injected into the field is indeed within the reservoir. If there are losses, the operator should be able to determine the magnitude of such loss.

Most gas storage fields were originally, gas fields, oil fields or aquifers that were converted to gas storage after depletion of native gas or oil reserves. Many of these fields were bounded down structure by water. The production of native gas or oil allowed water to expand into the reservoirs reducing the pressure in the surrounding aquifer in the vicinity of the field. To inject into these reservoirs, a volume of storage gas equal to that produced from the field during primary production, reservoir space voided by primary production and now occupied by encroached water must be regained during gas injection by the movement of water back into the aquifer. Bypassing of encroached water and movement of gas beyond the original gas/water contact has been observed during gas injection in numerous gas storage fields. This is because the aquifer pressure has been reduced by primary production and gas flow through the paths of least resistance [11].

According to Glenn *et al.* [4], if known volumes of injected storage gas per psi do not reproduce the historical pattern of injection and withdrawal pressures with time, the storage reservoir is therefore not functioning properly and there might be leakage.

In the assurance of the deliverability of aquifers, application of flow-after-flow method or back pressure testing to fast stabilizing and usually high capacity wells as described by Rawling and Schelldart [15], currently characterized the behavior of the wells. The flow-after-flow method of testing could be used to describe the behavior of slowly stabilizing back-pressure behavior of a gas well. This was based on the requirements that the data is to be obtained from the well under stabilizing condition. That is C is constant and does not vary with time but depends on the physical properties of the flowing fluids. Flow in highly permeable formations requires only a short period of time to stabilize. For a given well, n is always a constant with values ranging between 0.5 and 1.0.

According to Kashy and Shahab [7], the flow rates required to meet peak loads and to turn over the working inventory during the withdrawal cycle in gas storage reservoirs are much higher than are those used in normal production practices. Therefore, significantly higher number of wells are needed to meet the deliverability requirements. The number of storage wells necessary to meet the deliverability requirements can be determined based on the individual well deliverabilities. Storage field deliverability is the summation of individual well deliverability for all the active storage wells.

2. Theory

2.1 Determination of Aquifer Characteristics

2.1.1 Inventory Verification (Estimation of Storage Capacity)

To determine the volume of gas to be injected at different pressures of the storage aquifer, pressure is varied for fifteen different cases. At each pressure variation, new aquifer and gas parameters, B_w and B_g were obtained. Table of values was generated for the plot of gas injection versus aquifer pressure which represents the volume to be injected at different pressures

The steps for the reservoir engineering calculation of the gas storage capacity of the aquifer are as determined below. The amount of produced water from the aquifer is given as:

$$\text{Produced water} = W_p B_w \tag{2.1}$$

The total water production is in units of barrels of fluid (bbl) and may be converted to standard cubic feet (scf) using eq 2.2

$$1bbl = 5.615scf \tag{2.2}$$

For the purpose of underground natural gas storage, the aquifer must be reconditioned to contain a volume of gas equal to the volume of total water production. This is the amount of natural gas to be injected into the reservoir for storage.

Therefore, the volume of gas to be injected in units of standard cubic feet (scf) into aquifer to fill the space created from withdrawal of water is given by:

$$\text{Volume of gas to be injected} = V_{inj} B_{gi} \tag{2.3}$$

This also represents gas production from the system if it were to contain gas. Equating volume of gas injected to total water production to obtain

$$V_{inj} B_{gi}(scf) = 5.615 \ W_p B_w \tag{2.4}$$

Dividing through by B_{gi}

$$V_{inj}(scf) = 5.615 \, W_p B_w / B_{gi} \tag{2.5}$$

Storage capacity of the aquifer at a given pressure represents the amount of gas that can be injected into the storage aquifer at that pressure. It helps in the analysis of aquifer storage economics. It also guides the operator to know when the pressure of the storage vessel is at its maximum capacity for inventory verification. This helps in proper monitoring of injection and withdrawal program.

In estimating the storage capacity of the aquifer, aquifrer pressure in psig is converted to pressure in psia using eq 2.6

$$P(psia) = P(psig) + 14.7 \tag{2.6}$$

The aquifer temperature is also converted to degrees Rankine (^0R) as in eq 2.7

$$^0R = {}^0F + 460 \tag{2.7}$$

According to Katz and Lee [9], for the determination of gas compressibility factor, Z, of the natural gas in storage, the pseudo-reduced properties of the gas are used.

The pseudo-reduced properties are pseudo-reduced temperature and pseudo-reduced pressure. The values of Z for natural gas mixtures have been experimentally correlated as functions of pressure, temperature and composition. This correlation is based on the well known Theorem of Corresponding States which states that the ratio of the volume of a particular substance to its volume at its critical point is the same for all substances at the same ratio of absolute pressure to critical pressure, and absolute temperature to critical temperature. This theorem is not completely true but may satisfactorily be applied to compounds of similar molecular structure such as the light paraffins and natural gases. In preparing a correlation for hydrocarbon mixtures, the ratios of actual pressure and temperature to the modal average critical or pseudo-critical pressure, (P_{pc}) and pseudo-critical temperature, (T_{pc}) have been used. These ratios are called pseudo-reduced pressures, (P_{pr}) and pseudo-reduced temperatures, (T_{pr}) [5].

The pseudo-critical pressure and temperature are evaluated using eqs 2.8 and 2.9 resp. [17].

$$P_{pc} = 677 + 15SG - 37.5SG^2 \quad (2.8)$$

$$T_{pc} = 168 + 323SG - 12.5SG^2 \quad (2.9)$$

Accordingly, the pseudo-reduced pressure and temperature are determined from eqs 2.10 and 2.11 respectively

$$P_{pr} = P / P_{pc} \quad (2.10)$$

$$T_{pr} = T / T_{pc} \quad (2.11)$$

Having gotten the pseudo-reduced properties, the gas compressibility factor can be obtained with the use of the gas compressibility factor chart. B_g can be estimated with eq 2.12 as shown below [17]:

$$B_g = 0.02827 * zT_g/P \quad (2.12)$$

Microsoft Visual Basic Program was used to develop software for the estimation of the value of B_w at given pressure and temperature.

As stated in this section, the storage capacities at various pressures represent the volume of gas to be injected into the storage aquifer at the various pressures. It guides the operator of the gas storage facility in choosing the initial injection pressure.

A Microsoft Visual Basic Program was developed using eq 2.5, and was used to obtain the volume of gas injected into the aquifer at various pressures and presented in a table which was used to make a plot of Volume of gas injected against Aquifer pressure.

2.1.2 Storage Retention Against Migration and Determination of the Quantity of Gas Loss from the Aquifer

A system of observation wells permits measurements to verify if the injected gas is confined to the designated area and has not migrated away. Each year, the gas storage operating team must assure the management (investors) that the inventory of the net stored gas resides in the aquifer in communication with the wellbores. Closed pressure measurements for a period of 3 to 15 days or more are used for all wells, usually when at maximum and minimum storage pressures.

The pressure content data relates the measured change in inventory to the aquifer pore volume as shown in equation 2.13 (Muonagor and Anyadiegwu [12]).

Pressure was varied for several cases to obtain new Z-factors (Z_1 and Z_2) in each case, using the Z-factor chart as shown in Fig 2.1.

In determining the quantity of gas loss from a gas storage aquifer, several parameters are taken into consideration, which include:

- Pressures of the system before and after the gas loss
- Temperatures of the system before and after the gas loss
- Compressibility factors of the gas in the storage system before and after the gas loss
- Volume of the storage system

According to Muonagor and Anyadiegwu [12], the quantity of gas loss from a gas storage system is estimated with Eq 2.13 below:

$$G = 35.3021 * V * [(P_1/(T_1Z_1)) - (P_2/(T_2Z_2))] \quad (2.13)$$

where: G = Estimated Quantity of Gas Loss, scf; P_1 = Initial Pressure of the Storage System, psia; T_1 = Initial Temperature of the Storage System, ^{0}R; Z_1 = Initial Compressibility Factor of the Gas in the Storage System; P_2 = Final Pressure of the Storage System, psia; T_2 = Final Temperature of the Storage System, ^{0}R; Z_2 = Final Compressibility Factor of the Gas in the Storage System; V = Volume of the Storage System, scf.

V is expressed as the pore volume of the aquifer in scf using the equation below (Muonagor and Nnakaihe [13]):

PV = 43560 * Formation Area * Formation thickness * Porosity (2.14)

A Microsoft visual basic program was developed using eqs 2.13 and 2.14, the equation for the determination of quantity of gas loss from an underground gas storage system.

2.1.3 Evaluation of the Deliverability

In evaluating the performance of a storage aquifer, a deliverability test (back pressure test) was carried out on the aquifer for the prediction of well flow rate against any pipeline back pressure.

It was observed that a plot of $P_R^2 - P_{WF}^2$ (difference of the squares of aquifer pressure and well flowing pressure) versus Q_{sc}, (flow rate at standard condition) yields a straight line on logarithm plot, which represents the aquifer performance curve.

The straight line relationship for a particular well applies throughout the lifetime of the well, as long as the production remains in single phase (gas or liquid). The back-pressure (deliverability) equation as developed by Rawlins and Schellhardt [15] is expressed as:

$$Q_{sc} = C\,[\Delta P\,]^n \quad (2.15)$$

By extending the performance curve, the absolute open flow, (AOF) is obtained. Although this AOF does not reflect reality, it does approximate the capacity of the well [9].

The slope of the plot of Log $(P^2 - P_{wf}^2)$ versus Log Q is computed and used to obtain the back-pressure exponent as:

$$n = 1 / \text{slope} \quad (2.16)$$

Then the flow capacity at standard condition is given as:

$$Q_{sc} = C\,[P_R^2 - P_{wf}^2]^{(1/SLOPE)} \quad (2.17)$$

At $P_{WF} = 0$, equation 2.17 reduces to:

$$Q_{sc} = C\,[P_R^2]^n \quad (2.18)$$

But the reservoir flow coefficient, C is expressed as:

$$C = Q/[P_R^2 - P_{wf}^2]^n \quad (2.19)$$

According to Katz and Coats [8] flow tests on individual wells are employed for gas storage obtained as in gas production operations. From gas inventory and/or reservoir or aquifer pressure measurements plus deliverability data, it is possible to predict the field flow at several stages of the storage cycle.

3. Results

Case: Aquifer Y-2

Table 3.1 Aquifer and Fluid Data for the Aquifer

Aquifer storage pressure, P	3450 psia	Gas viscosity, u	0.2 cp
Storage gas temperature, T_g	149.45^{0}F	Drainage radius, r_e	1000 ft
Storage gas specific gravity, SG	0.6	Wellbore radius, r_w	0.4 ft
Aquifer Thickness, h	85 ft	Apparent skin factor, s	0.03
Formation Area	50 acres	Aquifer water temperature	130^{o}F
Porosity	0.25	Producible water volume, W_p	29.55 MMstb
Permeability, k	40 MD	Total water volume, W	30 MMstb
Well depth, D	10 000 ft	Water salinity	0.01ppm

Substituting the appropriate values of data in eqs 2.8 to 2.11, the values of P_{pc}, T_{pc}, P_{pr} and T_{pr} are determined as indicated below:

$P_{pc} = 677+15*0.6-37.5*0.6^2 = 672.5$ psia $\quad P_{pr} = 3450$ psia/672.5 psia = 5.13
$T_{pc} = 168+325*0.6-12.5*0.6^2 = 358.5^0R \quad T_{pr} = 609.45/358.5 = 1.7$

Compressibility factor, Z is indicated in Fig 3.1. At pseudo-reduced pressure of 5.13 and pseudo-reduced temperature of 1.7 compressibility factor becomes, Z at (5.13; 1.7) = 0.88. At 3450 psia, B_w is estimated using the Microsoft Visual Basic Program as 1.0039. At 3450 psig, from eqn 2.12, B_g = 0.02827*0.88*609.45/3450 = 0.004394.

From eqn 2.5, V_{inj} = 5.615 * 29.55 * 10^6 [1.0039/0.004394] = 37.9 Bscf

The volume of gas that can be injected at various aquifer pressures are presented in Table 3.2, from which a plot of volume of gas to be injected at various pressures was generated as shown in Fig 3.1. According to Anyadiegwu and Anyanwu [1], the significance of the plot to the natural gas storage operator include:

- Knowing when to inject (low pressure) or withdraw (high pressure) from the aquifer.
- It also helps to ascertain that the injected gas remain in the aquifer without migration.
- The operator can also rely on the plot to know when the storage aquifer is at full capacity (maximum pressure).

Table 3.2: Vol. of gas injected at various pressures of Aquifer Y-2

P (psig)	B_g (scf/scf)	B_w (rb/stb)	Vinj (Bscf)
3450	0.00439	1.0027	37.9
3015	0.00494	1.0039	33.7
2940	0.00505	1.0041	33.0
2821	0.00525	1.00445	31.7
2700	0.00547	1.0048	30.5
2533	0.00582	1.0053	28.7
2400	0.00616	1.00566	27.1
2201	0.00673	1.0062	24.8
2125	0.00698	1.00619	23.9
1989	0.00748	1.0068	22.3
1800	0.00834	1.0074	20.0
1600	0.00948	1.0080	17.6
1542	0.00985	1.0081	17.0
1347	0.01140	1.0087	14.7
1134	0.01370	1.0093	12.2
1000	0.01580	1.0097	10.6

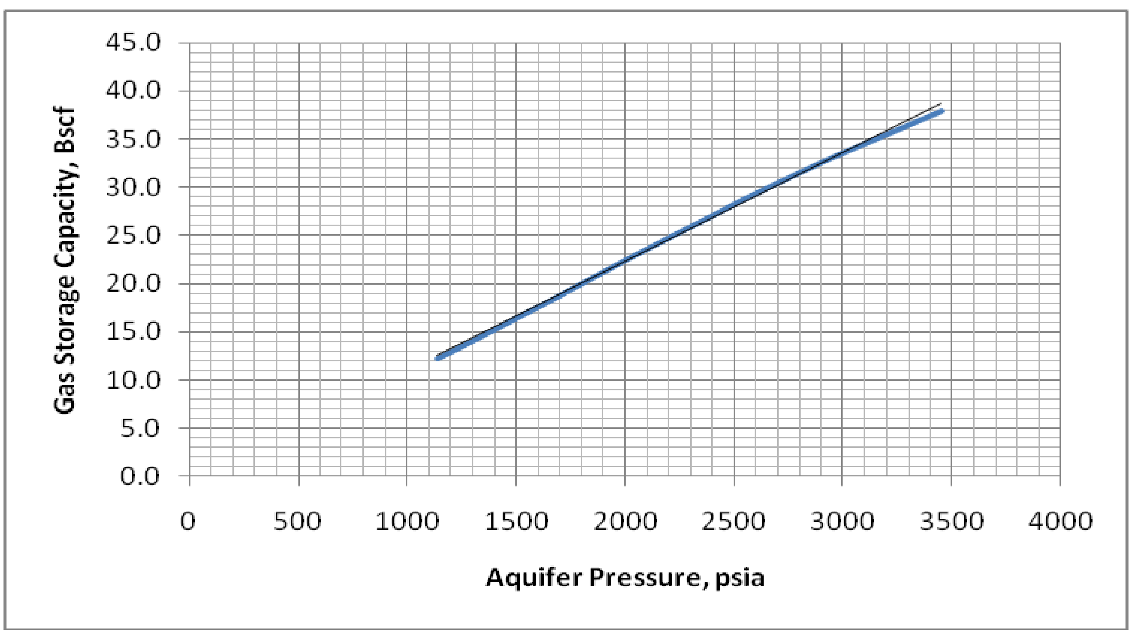

Fig 3.1 A plot of volume of gas to be injected at various pressures for aquifer.

3.3 Determination of Quantity of Gas Loss from the Aquifer at given Pressure Drop.

The Storage data for the underground gas storage aquifer is shown in Table 3.3 below:

Table 3.3 Storage data for aquiferY-2

Initial Aquifer Pressure	3450 psia
Initial Aquifer Temperature	609.45^{0}R
Initial Aquifer Gas Z-factor	0.88
Final Aquifer Pressure	3200 psia
Final Aquifer Temperature	604^{0}R
Final Aquifer Gas Z-factor	0.855
Aquifer Thickness	85 ft
Formation Area	50 acres
Porosity	0.25

The pore volume of aquifer Y-2 is estimated using eq 2.14 as:

PV = 43560 * 85 * 50 * 0.25 PV = 46.28 MMscf

The quantity of gas loss from aquiferY-2 is estimated with eq 2.13 as:

G = 35.3021 * 46.28 * [(3450/(609.45*0.88)) – (3300/(604*0.855))]= 69.6 MMscf

3.1 Evaluation of Deliverability of Aquifer Y-2

To evaluate the performance of aquifer Y-2, the Pressure-squared approach was employed to generate the rate of flow of gas from the aquifer used as underground storage vessel.

By assumptions, the pressure data were generated for use in the estimation of the flow rate of gas from the vessel at given pressures. Table 3.4 shows the pressure data of the aquifer used as underground gas storage vessel.

Table 3.4 Pressure data for the aquifer

Interval	Aquifer Pressure, psi	Well Flowing Pressure, psi
1	3350	3300
2	3288	3100
3	3212	2900
4	3199	2700
5	2922	2500
6	2881	2300
7	2857	2100
8	2767	1900
9	2427	1700
10	2237	1500
11	2145	1300

The gas flow rates are evaluated at the eleven intervals with eq 3.1 shown below:

$$Q = kh(P^2 - P_{wf}^2)/[(1422 z_{avg} T\mu(\ln(r_e/r_w) - 0.75 + s)))] \quad (3.1)$$

The flow rate values are shown in Table 3.5 at their corresponding well flowing pressures and aquifer pressures.

Table 3.5 Flow rates at the eleven intervals

Interval	Aquifer Pressure, psi	Well Flowing Pressure, psi	Average Pressure, psi	Average Z- Factor	Flow Rate, scf/day
1	3350	3300	3325	0.88	1043
2	3288	3100	3194	0.87	3812
3	3212	2900	3056	0.865	6087
4	3199	2700	2950	0.861	9440
5	2922	2500	2711	0.857	7372
6	2881	2300	2591	0.855	9721
7	2857	2100	2479	0.857	12090
8	2767	1900	2334	0.859	13007
9	2427	1700	2064	0.862	9611
10	2237	1500	1869	0.869	8751
11	2145	1300	1723	0.875	9186

To generate the performance curve values of Log Q and Log ($P^2 - P_{wf}^2$) were generate from Table 3.5 and are as shown in Table 3.6 which were used to generate the plot of Log ($P^2 - P_{wf}^2$) against Log Q as shown in Fig 3.2.

Table 3.6 Log Q and Log ($P^2 - P_{wf}^2$) at the Eleven Intervals

Interval	Aquifer Pressure, psi	P_{wf}, psi	Flow Rate, Q scf/day	$P^2 - P_{wf}^2$ (psi^2)	Log (Q), scf/day	Log ($P^2 - P_{wf}^2$) (psi^2)
1	3350	3300	1043	332500	3.018417	5.521792
2	3288	3100	3812	1200944	3.581112	6.079523
3	3212	2900	6087	1906944	3.78443	6.280338
4	3199	2700	9440	2943601	3.974984	6.468879
5	2922	2500	7372	2288084	3.867599	6.359472
6	2881	2300	9721	3010161	3.987732	6.47859
7	2857	2100	12090	3752449	4.082442	6.574315
8	2767	1900	13007	4046289	4.114172	6.607057
9	2427	1700	9611	3000329	3.98277	6.477169
10	2237	1500	8751	2754169	3.942079	6.439991
11	2145	1300	9186	2911025	3.963146	6.464046

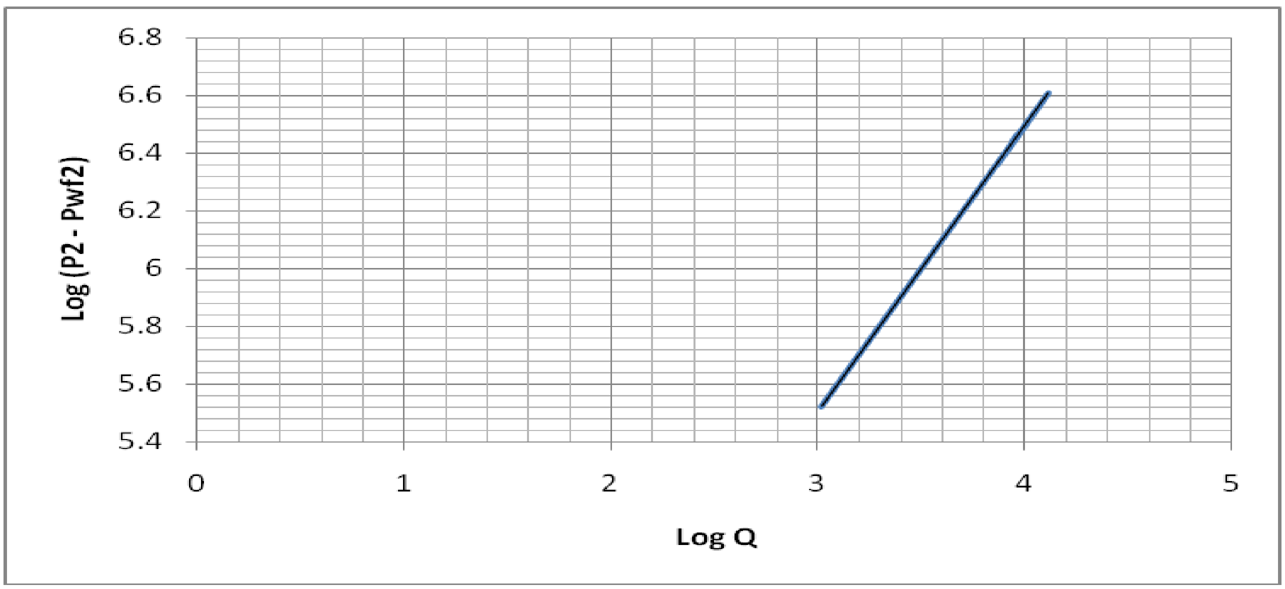

Fig 3.2 Plot of Log ($P^2 - P_{wf}^2$) against Log Q

The slope of the performance curve; Log ($P^2 - P_{wf}^2$) versus Log Q shown in Fig 3.2 is obtained as 0.99.

From eqn 2.16, the back-pressure exponent is estimated as:n = 1.000 / 0.99 = 1.01

For aquifer Y-2, values of Q, P and P_{wf} were chosen from Table 3.5 at the 11^{th} interval and substituted into equation 2.19.

$C = 9186/(2911025)^1 = 0.00272$

Note that the aquifer performance coefficient, C falls within the range of 0.00276 ± 0.000041 for all the intervals.

The IPR curve is plotted with the use of Prosper, a Petroleum Engineering Software, as shown in Fig 3.3 below from which the AOF is generated as 1305.792 MMscf/day.

Having established the AOF, C and n, with the use of eq 2.17 the deliverability of the aquifer can then be evaluated, taking P to be Aquifer Storage Pressure which decreases as withdrawal takes place and P_{wf} to be the Withdrawal Pressure of Gas from the aquifer during storage. At the Aquifer Storage Pressure and Withdrawal Pressure at the first interval, the deliverability of the aquifer is evaluated as:

From eq 2.17, $Q = C [P^2 - P_{wf}^2]^n$

At the first interval, Pwf = 3300, Aquifer Storage Pressure = 3450

$Q = 0.00272 [3450^2 - 3300^2]^{1.01} = 3162.41$ scf/day

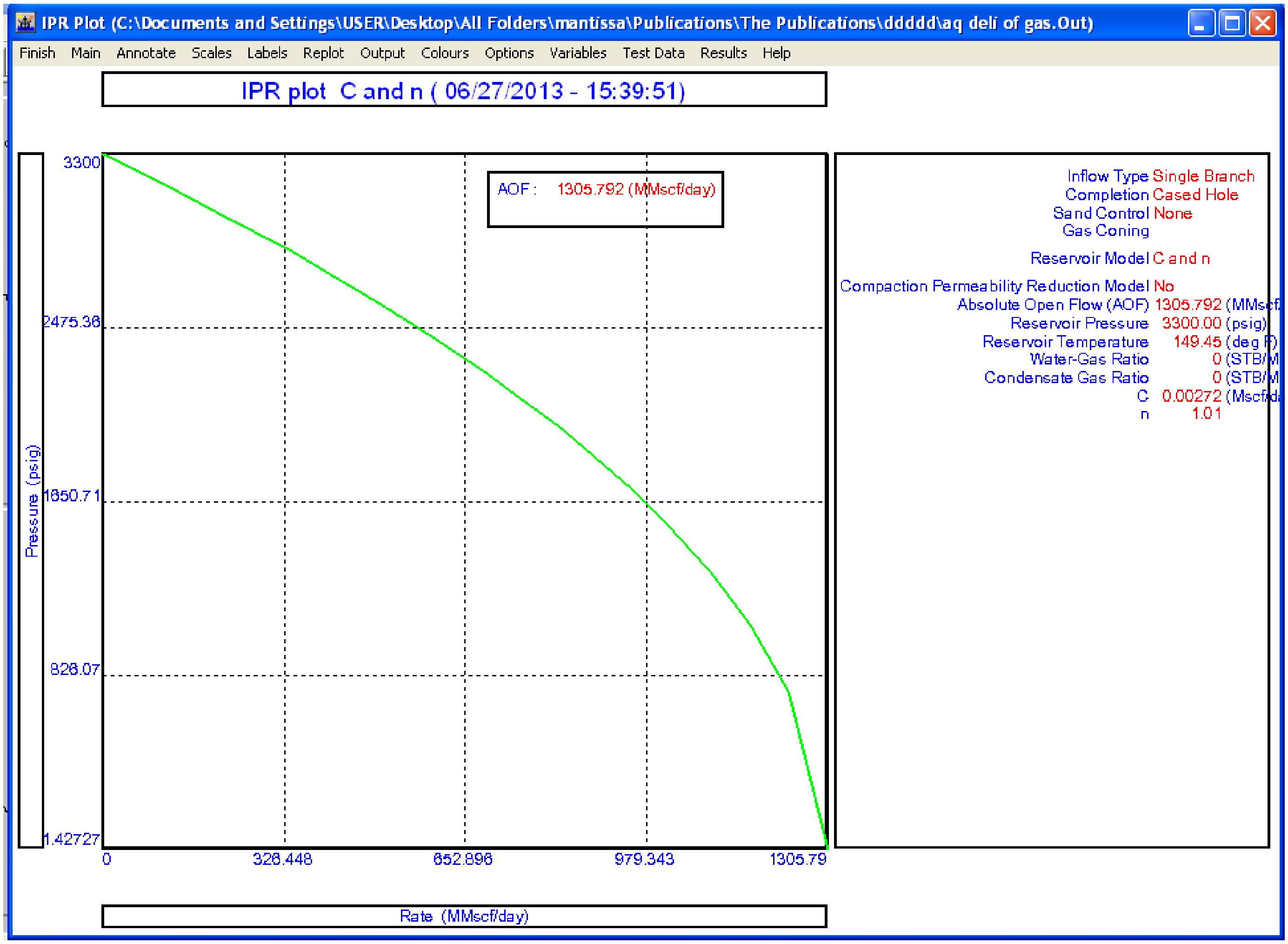

Fig. 3.3 IPR Curve generated with Prosper, a Petroleum Engineering Software, *Source: (Petroleum Experts Limited)* [14]

The deliverabilities of aquifer Y-2 at various withdrawal pressures are presented in Table 3.7 which is used to obtain the plot of the deliverabilities at various withdrawal pressures as shown in Fig 3.4.

Table 3.7: Deliverabilities at Various Withdrawal Pressures

Interval	Aquifer Storage Pressure, P, psi	Withdrawal Pressure, P_{wf}, psi	Deliverability, scf/day
1	3450	3300	3162.41
2	3450	3100	7219.07
3	3450	2900	11044.3
4	3450	2700	14626.6
5	3450	2500	17961.1
6	3450	2300	21044.5
7	3450	2100	23874.9
8	3450	1900	26450.9
9	3450	1700	28771.5
10	3450	1500	30835.8
11	3450	1300	32643.2

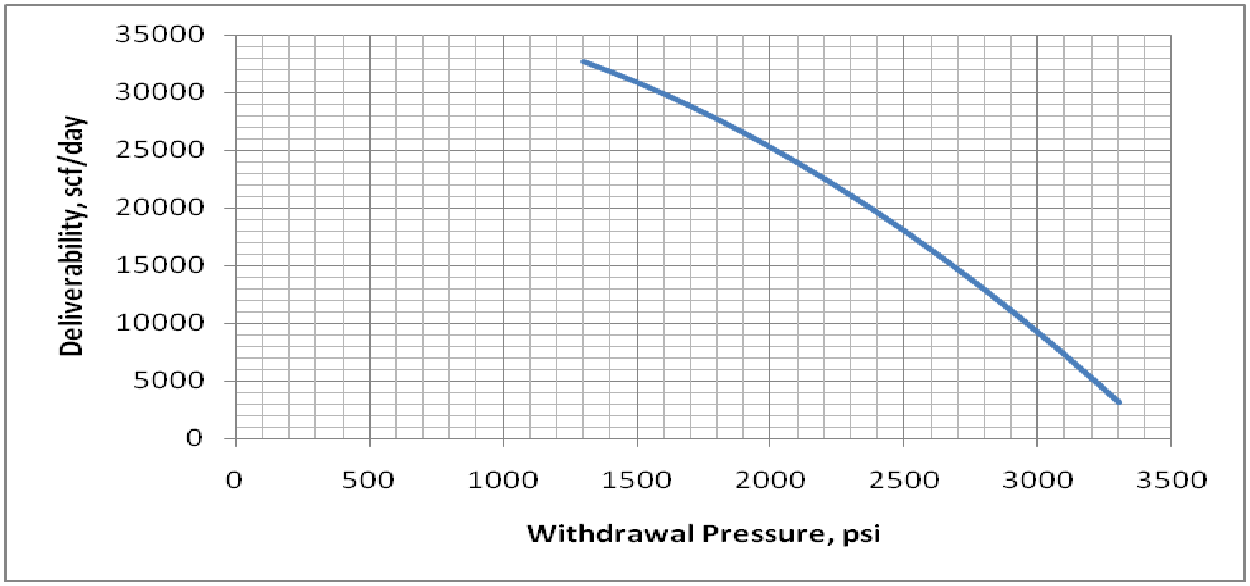

Fig 3.4 Plot of Deliverability against Withdrawal Pressure.

4. Conclusion

At the end of this study, it has shown that in developing aquifers for underground gas storage, three basic requirements are considered and evaluated. They include storage capacity estimation, quantity of gas loss determination and the evaluation of the deliverability of the aquifer. From the analysis of the storage capacity of aquifer Y-2, it is shown that aquifer Y-2 is if developed, suitable for underground natural gas storage. It is also seen that at any noticed pressure drop in the aquifer, the quantity of leaked gas from the aquifer can be determined.

The analysis on evaluating the deliverability of underground gas storage in aquifer has shown that;

- Natural gas can be stored in underground aquifers to meet seasonal demands.
- The aquifer delivers more gas as the well flowing pressure decreases.
- After using the aquifer for underground gas storage purpose, it is still capable of delivering gas after injection.

Nomenclature

AOF	Absolute open flow	P_2	Final pressure of the storage system, psia
bbl	Barrel	Q	Deliverability/flow rate
B_g	Gas formation volume factor	Q_{sc}	Deliverability at standard conditions
Bscf	Billion standard cubic foot	r_e	Drainage radius
B_w	Water formation factor	r_w	Wellbore radius
C	Performance coefficient	s	Apparent skin factor
G	Estimated quantity of gas loss, scf	scf	Standard cubic foot
h	Aquifer thickness	scf/day	Standard cubic foot per day
IPR	Inflow performance relation	SG	Specific gravity
k	Permeability	T_g	Gas temperature
MMscf	Million standard cubic foot	T_{pc}	Pseudo-critical temperature
MMSTB	Million stock tank barrel	T_{pr}	Pseudo-reduced temperature
Mscf	Thousand standard cubic foot	T_1	Initial temperature of the storage System, ^{0}R
n	Back-pressure exponent	T_2	Final temperature of the storage System, ^{0}R
P	Aquifer pressure	V	Volume of the storage System, scf
P_{pc}	Pseudo-critical pressure	V_{inj}	Volume of gas injected
P_{pr}	Pseudo-reduced pressure	Z	Gas compressibility factor

psia	Pounds per square inch (atmospheric)	Z_1	Initial compressibility factor of the gas in the storage system
psig	Pounds per square inch (gauge)	Z_2	Final compressibility factor of the gas in the storage System
PV	Aquifer pore volume	^0F	Degree Fahrenheit
P_{wf}	Well flowing pressure/withdrawal pressure	^0R	Degree Rankine
P_1	Initial pressure of the storage system, psia	u	Gas viscosity

Reference

[1] Anyadiegwu C.I.C and Anyanwu E.E., (2012): Estimation of Storage Capacity of an Underground Gas Storage Reservoir, International Journal of Academic Research, Azerbaijan.

[2] Anyadiegwu C.I.C and Anyanwu E.E., (2013): Conversion of Depleted Oil Reservoirs for Underground Natural Gas Storage; Petroleum & Coal 55 (2) 137 – 147, 2013.

[3] Energy Information Administration, (2004): Underground Natural Gas Storage; Natural Gas; About US Natural Gas Pipelines.

[4] Glenn A.K. and Cuthbert J.F., (1979): Gas Storage Problems and Detection Methods; paper presented at the1979 SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, 23-26 September.

[5] Ikoku C.U., (1984): Natural Gas Production Engineering, New York: John Wiley and Sons Publishing Company.

[6] INGAA, (2013): Types of Underground Gas Storage; *www.ingaa.org/cms/4691.aspx*; retrieved December 31, 2013.

[7] Kashy A. and Shahab M., (2009): Natural Gas Storage Engineering, in Petroleum Engineering-Downstream, (Ed.Pedro de Alcantara Pessoa Filho), in Encyclopedia of Life Support Systems (EOLSS), Developed under the Auspices of the UNESCO, Eolss Publishers, Oxford, UK.

[8] Katz D.L. and Coats K.H. (1968): Underground Storage of Fluids, Ulrich's Book Inc, Ann Arbor, MI 575 pages.

[9] Katz D.L. and Lee R.L., (1990): Natural Gas Engineering Production and Storage, McGraw-Hill Publishing Company, New-York, U.S.A., 758 pages.

[10] Katz D.L. and Tek M.R (1981): Overview on Underground Storage of Natural Gas. JPT, June, PP 943-951.

[11] Mayfield J.F. (1981): Inventory Verification of Gas storage fields, JPT, SPE 9391.

[12] Muonagor C.M. and Anyadiegwu C.I.C., (2013): The New System Equation for Determining the Quantity of Gas Loss from an Underground Natural Gas Storage System; Academic Research International (ARInt); Part 1: Natural and Applied Sciences.

[13] Muonagor C.M. and Nnakaihe S.E., (2011): Secondary Oil Recovery by Waterflooding, Case Studies: Reservoirs in Niger Delta; B.Eng Thesis, Department of Petroleum Engineering, Federal University of Technology, Owerri, Nigeria.

[14] Petroleum Experts Limited: PROSPER; An Integrated Production Modeling Software.

[15] Rawlins E.L., and Schellhardt M.A., (1935): Back-pressure Data on Natural Gas Wells and their Application to Production Practices, American Gas Association, Baltimore, Md., Lord Baltimore Press, OCLC Number: 887590

[16] Tek M.R. and Wilkes J.O. (1966): New Concepts in Underground Storage of Natural Gas, Prepared by University of Michigan Catalog No.: L00400e.

[17] Tharek Ahmed (2001): Reservoir Engineering Handbook, Elsevier: Amsterdam.

[18] Wikimedia Foundation Inc., (2013): Natural Gas Storage; Perth Western Australia, Retrieved from Wikipedia.org.