PERFORMANCE ANALYSIS OF DEPLETED OIL RESERVOIRS FOR UNDERGROUND GAS STORAGE

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ABSTRACT

The performance of underground gas storage in depleted oil reservoir was analysed with reservoir Y-19, a depleted oil reservoir in Southern region of the Niger Delta. Information on the geologic and production history of the reservoir were obtained from the available field data of the reservoir. The verification of inventory was done to establish the storage capacity of the reservoir. The plot of the well flowing pressure (Pwf) against the flow rate (Q), gives the deliverability of the reservoir at various pressures. Results of the estimated properties signified that reservoir Y-19 is a good candidate due to its storage capacity and its flow rate (Q) of 287.61 MMscf/d at a flowing pressure of 3900 psig

Keywords: Crude oil, natural gas, storage, underground, leakage, injection, pressure, deliverability, depleted reservoir.

I. INTRODUCTION

Theory of Underground Natural Gas Storage

Underground natural gas storage involves the process of injecting natural gas into porous rock formation so that it can be withdrawn later for utilization. These rock formations are at a great depth and typically are depleted or abandoned oil and gas fields. Natural gas is injected into the underground oil/gas reservoirs for the purpose of storage so that it can be utilized in future (Dietert and Pursell, 2008).

Natural gas travels to the storage fields facilities through large underground pipelines, and undergo compression before injection into the rock formation can take place. The gas is injected into specially designed well that transfers it to the storage zones deep into the earth.

The underground natural gas storage technology involves the storing and withdrawing of stored natural gas and the characteristics of the storage system are such that:

i. Every natural gas storage facility is linked to the supply grid via an underground pipeline. Gas is transferred to the storage facility and fed back into the supply grid through this pipeline.
ii. Incoming gas first flows through a filter, which separates solid particles and liquids. Then the gas flows through a calibrated volume meter.
iii. The gas pressure has to be increased to inject the gas into the storage facility. This is done in compressor units powered by gas engines or turbines.
iv. Gas coolers remove the heat generated during the compression process.
v. Then the gas is pumped through high-pressure pipes into the wells and injected into the storage horizons.

Storage in Depleted Oil Reservoirs

This is an underground gas storage that occurs in porous and high deliverability depleted reservoirs, which are close to the consumption centres. The conversion of the oil fields from the production to storage duty takes advantage of the existing wells, gathering systems and pipeline connections. Depleted oil reservoirs are used for underground gas storage due to their wide availability and well known geology. The requirements for each of the reservoirs vary since no two reservoirs are the same, typically these types of reservoirs require 50% base gas (ie equal amount of working gas) and one cycle per season (Energy Information Administration, 2002). The 3 basic requirements in underground storage of natural gas are as given as follows; verification of inventory, retention against migration and assurance of deliverability

Fig 1. shows a process flow diagram for the conversion of depleted oil/gas reservoir for natural gas storage. The following steps are followed in designing the storage facility.

- Gathering of geological and engineering information
- Assessing the mechanical condition of the well
- Determining the working storage content (storage capacity) of the reservoir
- Consider compression, fieldlines, and conditioning of the gas

2. PROCEDURES FOR CHOOSING A CANDIDATE WELL FOR UNDERGROUND GAS STORAGE

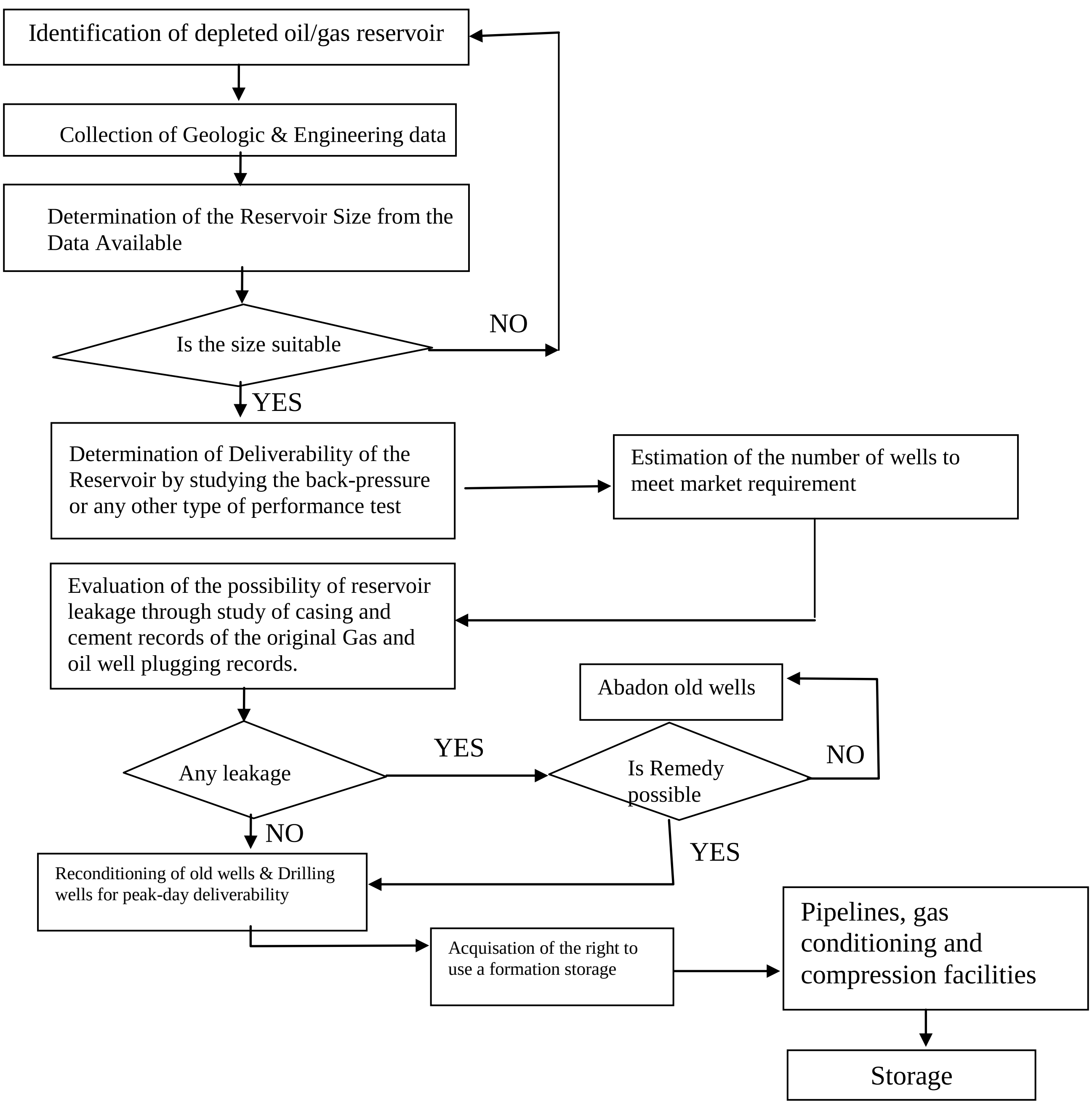

Fig.1 Flow Chart for the Conversion of a Depleted Gas or Oil Reservoir for Natural Gas Storage (Anyadiegwu, 2012).

In order to find the working storage content of the reservoir, range of pressures used must be selected. The upper pressure selected is based upon the information available, particularly the mechanical condition of the well. The pressure range also has much to do with the flow capacity of the well.

According to Katz and Tek (1981), the most essential features of the underground storage facility to be determined by equation (models) are

- Storage capacity (verification of inventory)
- Quantity to be injected at different pressures
- Storage retention against migration and determination of the amount of leakage
- Assurance of deliverability

The storage container is a porous solid with a cap rock overhead to prevent vertical migration. Water in the storage zone underlies all or part of the gas-filled sand. Wells designated I/W (Injection and Withdrawal) are completed in the storage zone.

Depleted gas reservoirs are prime candidates for conversion to storage. The size of the reservoir is determined by calculations from geological data or from the oil production reservoir pressures. In considering a depleted oil fields, it should be recognized that the gas withdrawal take about 120days in a given year. This requires more wells than used during oil production, and enlarged gathering and injection pipeline system from the well to the central station (Okwananke et al, 2011).

A delivery system can be installed to cover the market demand for the year. Some flexibility is needed, since variation in weather causes varying demands. Storage field pipelines may require some period of reduced load in summer for testing

Natural gas is injected into the porous sandstone through the surface facilities during the period of low demand and withdrawn for use during the period of high demand as shown in Fig 2 below. For temperate countries the periods correspond to summer and winter periods respectively.

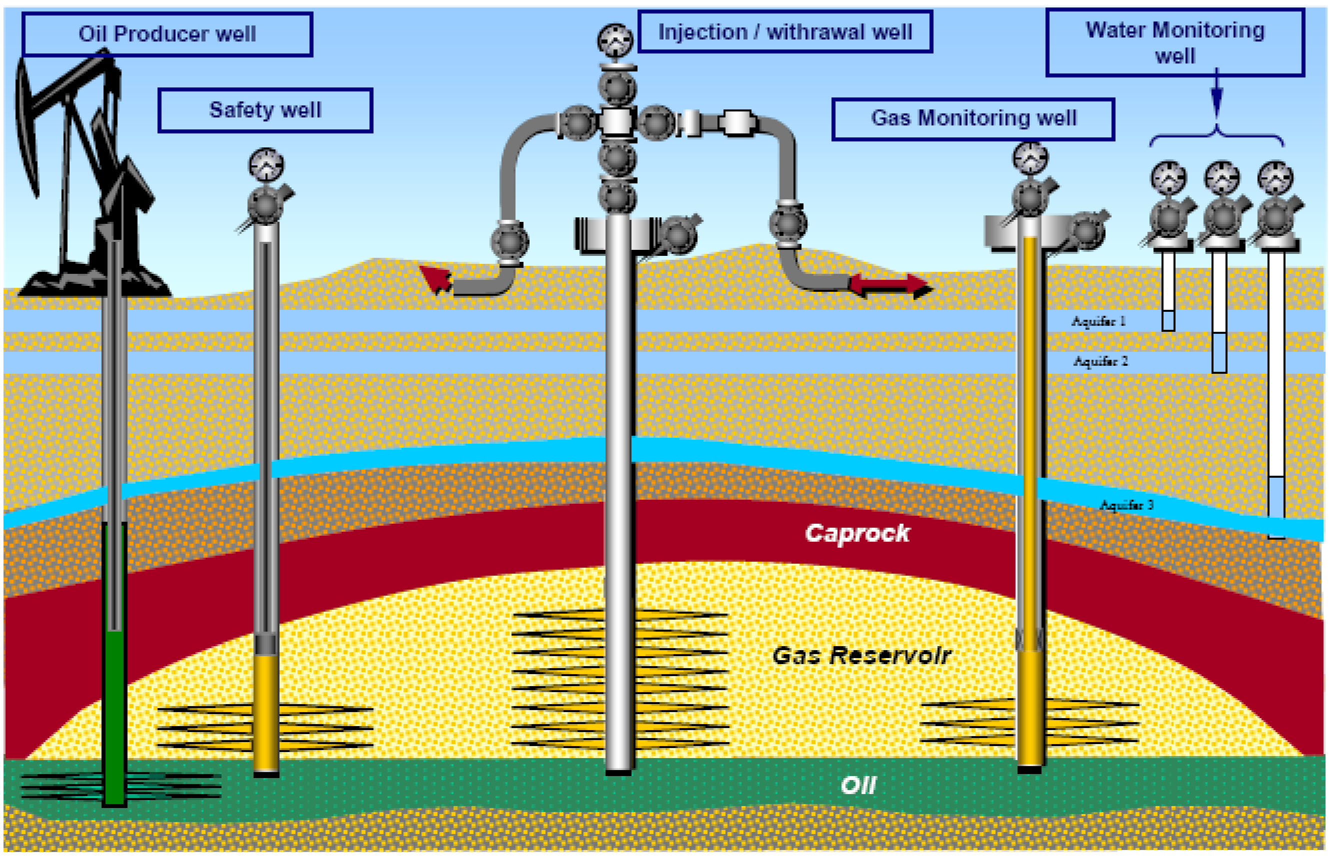

Fig 2: Basic elements of underground gas storage reservoir (Rodriguez et al., 2006).

Determination of reservoir characteristics

Inventory Verification (Estimation of Storage Capacity). To determine the volume of gas to be injected at different pressures of the storage reservoir, pressure is varied for fifteen different cases. At each pressure variation, new reservoir parameters, B_o, B_g, R_s and R_p were obtained. Table of values was generated for the plot of gas versus reservoir 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 reservoirs are as shown in the storage capacity flow chart below.

Storage capacity of the reservoir at a given pressure represents the amount of gas that can be injected into the storage reservoir at that pressure. It helps in the analysis of reservoir 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.

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

The flow chart for estimating the storage capacity of depleted reservoir for gas storage which was derived using eqs 2.1 to 2.9 is as shown in Fig 2.3.

Mathematical Expressions for Storage Capacity

According to Katz and Lee, (1990), 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 theory 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 theory 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 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}). Fig 3.1 is a correlation of Z as a function of these quantities (Ikoku, 1984).

The pseudo-critical pressure and temperature are evaluated using eqns 2.1 and 2.2 respectively (Katz and Lee, 1990).

$P_{pc} = 709.604 – 58.718 * SG$ 2.1

$T_{pc} = 170.491 – 307.344 * SG$ 2.2

Accordingly, the pseudo-reduced pressure and temperature are determined from eqns 2.3 and 2.4 respectively

$P_{pr} = P/P_{pc}$ 2.3

$T_{pr} = T/T_{pc}$ 2.4

The following equations were used to estimate B_g, B_o and R_s. The gas formation volume factor is given by equation 2.5 and the oil formation volume factor is given by equation 2.6.

The gas formation volume factor, B_g, is estimated from eqn 2.5 (Tharek, 2001).

$B_g = 0.02827ZT/P$ (Tharek, 2001) 2.5

The oil formation volume factor, B_o, is estimated from eqn 2.6 (Vasquez and Beggs, 1980).

$B_O = 1.0 + C_1R_S + (T – 520)(API/SGS)(C_2 + C_3R_S)$ 2.6

The gas-oil-ratio, R_s, is estimated from eqn 2.7 (Tharek, 2001).

$R_S = SG[(P / 18.2 + 1.4)10^X]^{1.2048}$ 2.7

Where SG = gas specific gravity

SGS = solution-gas specific gravity

With x = 0.0125 API – 0.00091 (T – 460) 2.8

The volume of gas required to replace the produced oil, also called the working gas capacity as estimated by Anyadiegwu, (2012) when there is no water production is given as:

$V_{inj} = 5.615[N_pB_o/B_{gi} + N_p(R_p-R_s)]$ 2.9

A Microsoft Visual Basic Program was developed using eqs 2.1 to 2.9, and was used to obtain the volume of gas injected into the reservoir at various pressures and presented in a table which was used to make a plot of volume of gas injected against Reservoir pressure.

Storage retention against migration and determination of the amount of leakage for the reservoirs

A system of observation wells permits measurements to verify if the injected gas is confined to the designated area and has not migrated away. When there is leakage, the amount of leaked gas is estimated by applying the amount of leakage flow chart derived from eq 2.10a as shown in Fig 4.

Mathematical Expressions for Amount of Leakage

The pressure content data relates the measured change in inventory to the initial content as shown in equation 2.10 (Katz and Tek,1981).

$AOL = [P_1/Z_1 – P_2/Z_2] * V_1Z_1/P_1$ 2.10

$AOL = V_1[1 – ((P_2/Z_1) / (P_1/Z_2))]$ 2.10a

Initial content (volume), V_1 in Eq 2.10 represents maximum storage capacity of depleted reservoir, and is estimated using eq 2.9.

A Microsoft Visual Basic Program was developed using eq 2.10a for the determination of amount of leakage from the reservoir.

Deliverability of Reservoir

According to Katz and Coats (1968), flow tests on individual wells are employed for gas storage obtained as in gas production operations. From gas inventory and/or reservoir pressure measurements plus deliverability data, it is possible to predict the field flow at several stages of the storage cycle.

The performance of storage reservoirs become less predictable during high withdrawal rates due to pressure sinks which develop as a result of heterogeneities. Another problem of continuing interest relates to interference by water reaching the wellbore. The presence of water not only reduces the permeability to gas but also effectively cuts down the bottomhole pressure drawdown available for gas flow due to increased density of well fluid. For aquifers, water interference problems are likely to subside as the gas bubbles thickens with growth in stored gas. Each reservoir and set of wells must be tested to give assurance for future years with regard to which

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well will have water intrusion at a given stage of the withdrawal cycle. Deliverability of storage wells after several years of repetitive use decreases as a result of sandface contamination. For the purpose of this work, a duration of eight years of running the gas storage reservoir was assumed.

The flow chart for evaluating the deliverability of depleted reservoir for gas storage which was derived from eqs 2.11 to 2.13 is as shown in Fig 2.5.

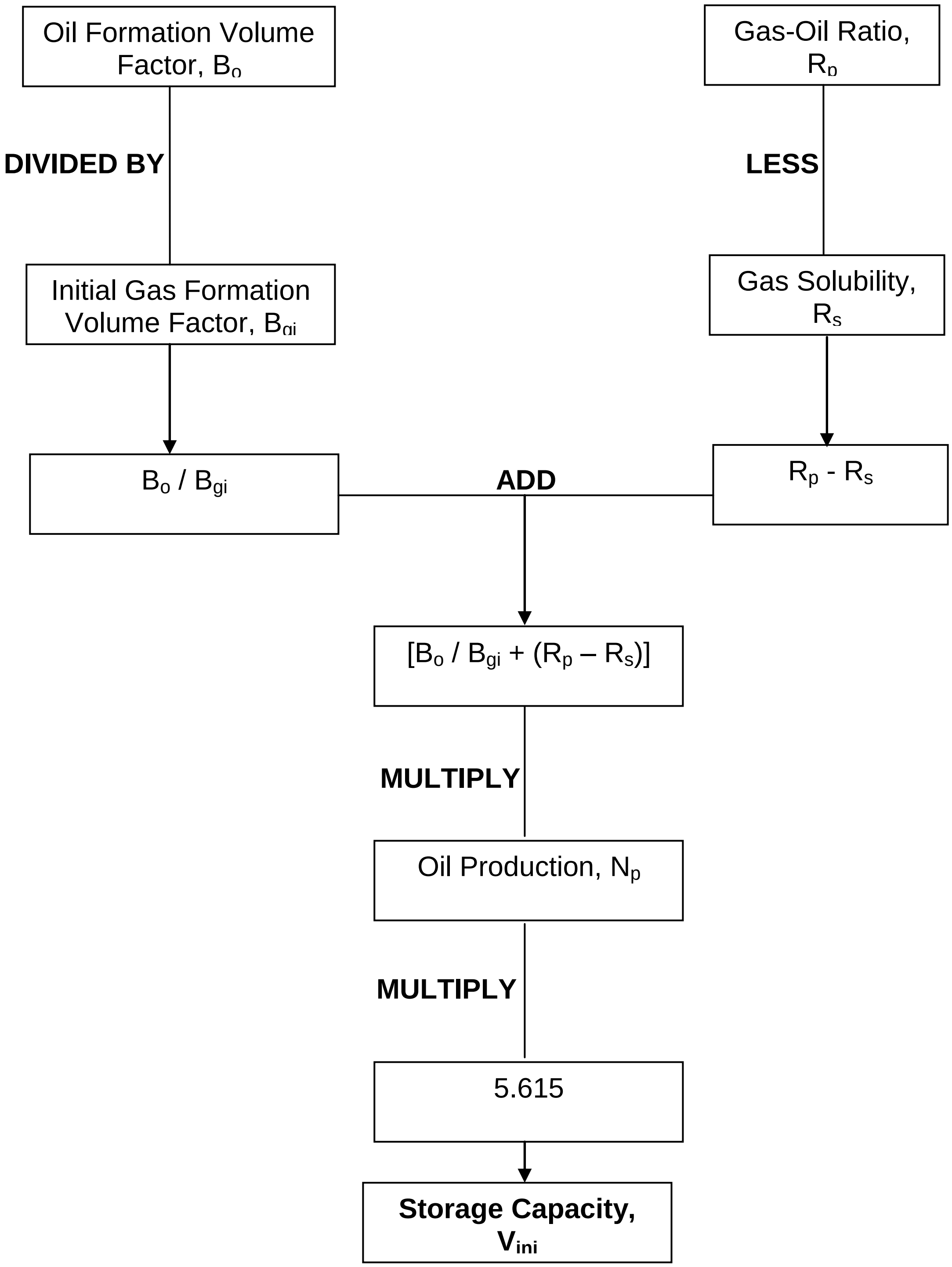

Fig 3: Storage Capacity Flow Chart

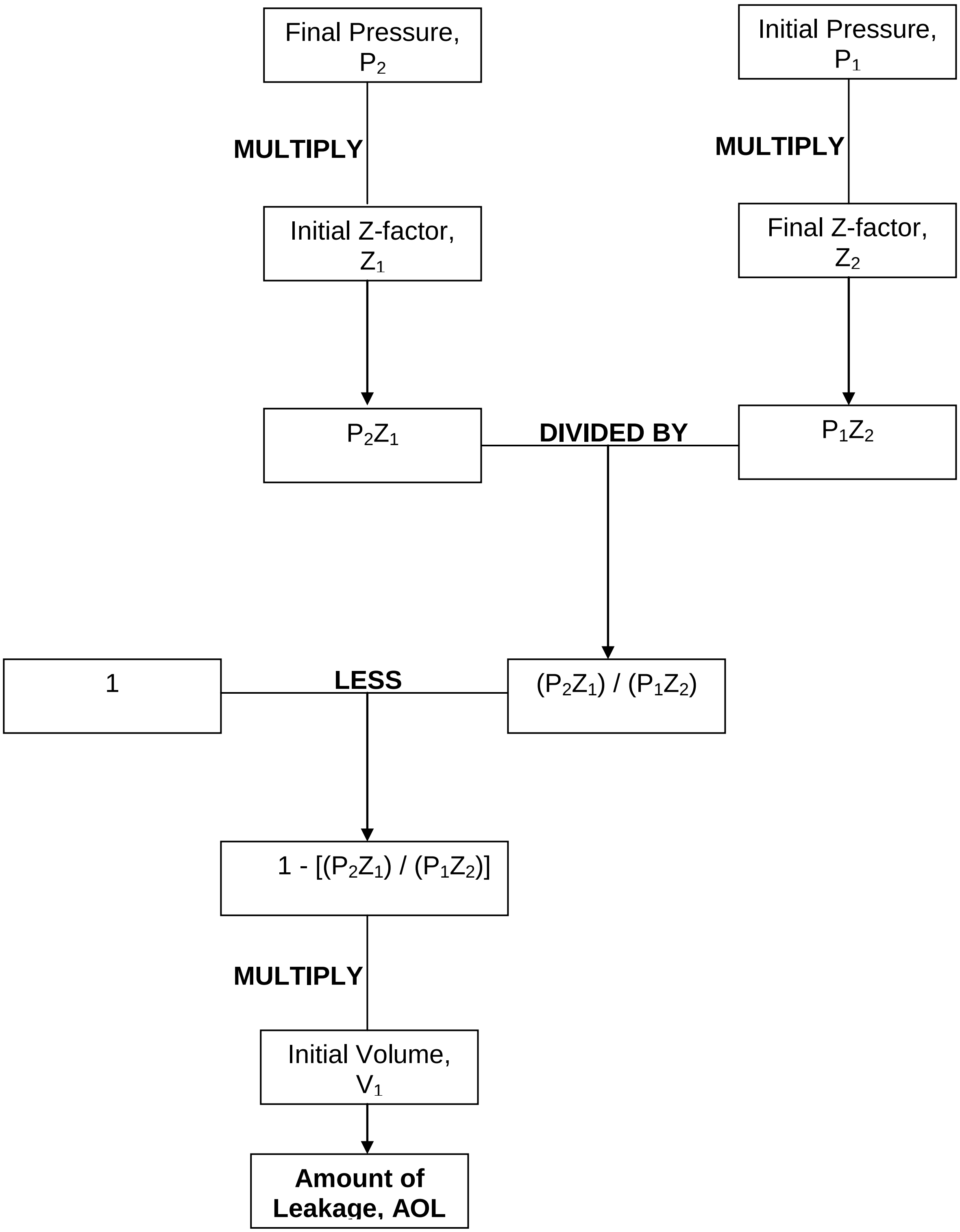

Fig 4: Flow Chart for Amount of Leakage from the Storage Reservoir

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Evaluation of Deliverability

In evaluating the deliverability/performance of a storage reservoir, a deliverability test (back pressure test) was carried out on the reservoir 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 reservoir pressure and well flowing pressure) versus Q_{sc}, (flow rate at standard condition) yields a straight line on logarithm plot, which represents the reservoir 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) equations as developed by Rawlins and Schellhardt (1935) are also expressed as:

$C = Q / [P_{r8}^2 – P_{wf8}^2]^n$ 2.11

$Q/yr = C/ [P_r^2 – P_{wf}^2]^n$ at any Given Well Flowing Pressure in MMscf/year 2.12

$Q/d = C / [P_r^2 – P_{wf}^2]^n$ at any Given Well Flowing Pressure in MMscf/day 2.13

Where n = 1/slope of the plot of Log (P_r^2 – P_{wf}^2) versus Log Q and C is the reservoir flow coefficient.

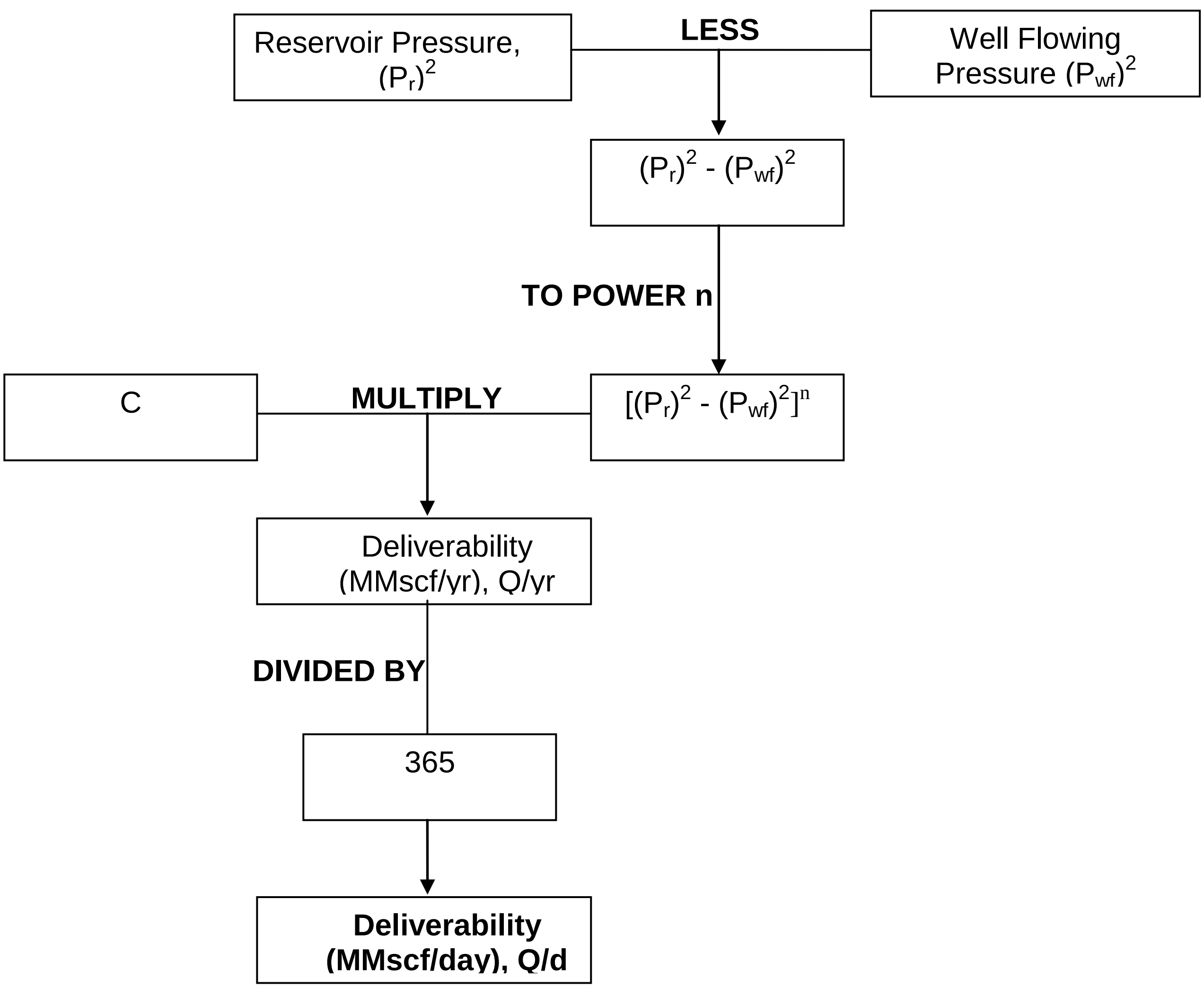

Fig 2.5: Flow Chart for the Deliverability of the Storage Reservoir

A Microsoft Visual Basic Program was developed using eqs 2.11 to 2.13, and was used to obtain the deliverability of the depleted reservoir, Q (MMscf/d) at different well flowing pressures, P_{wf} (psig) and presented in a table which was used to make a plot of P_{wf} against Q.

III. RESULTS

Depleted Reservoir Y-19
Estimation of storage capacity of reservoir Y-19

Table 3.1: Reservoir and Fluid Data for Reservoir Y-19

Discovery pressure, P	3955 psig
Saturation pressure	3002 psig
Reservoir temperature, T	216^of
Stock tank oil initial in place, N	1.2444 MMstb
Cumulative oil produced, N_p	0.5825 MMstb
Initial oil formation volume factor, B_{oi}	1.405
Specific gravity, SG	0.9
Thickness, h	80 ft
Porosity, Ø	0.25
Initial oil water saturation	20 %
Permeability, k	30 mD
Well depth, D	11 000 ft
Oil API gravity	26 ^{0}API
Remaining gas in formation	7.01 Bscf
Solution-gas specific gravity	0.89

The storage capacity of Y-19 is evaluated below. From data of Table 3.1, API = 26, the discovery pressure of the reservoir is 3955 pounds per square inch gauge (psig) which is the same as 3969.7 psia and reservoir temperature,

T = 216^0F = 216 + 460 = 676^0, N_p is 0.5825 MMstb

From the flow chart given in Fig 2.3, the storage capacity of depleted reservoir Y-19 is estimated as follows:

P_{PC} = 709.604 – 58.718 * 0.9 = 656.8 psia
T_{PC} = 170.491+ 307.344 * 0.9 = 447.1^0R
P_{PR} = 3969.7 psia/656.8 psia = 6.04
T_{PR} = 676/447.1 = 1.51
B_g = 0.02827*0.86*676/3955 = 0.004156
B_o = 1.0 + 4.677*10^{-4}*847.24+ (676 – 520)(26/0.956)(1.751*10^{-5} + (-1.811*10^{-8}*847.24)) = 1.4054
x = 0.1284

$R_S = 0.9[(3955/18.2 + 1.4)10^{0.1284}]^{1.2048} = 847.2412$
R_P = 3200
$V_{inj} = 5.615 * 0.5825 * 10^6 [1.4054/0.004156 + [3200 – 847.24]] = 8.80$ Bscf

Compressibility factor, Z is obtained using Fig 3.1. At pseudo-reduced pressure of 6.04 and pseudo-reduced temperature of 1.51, compressibility factor is, Z at (6.04; 1.51) = 0.86
C_1, C_2 and C_3 are obtained from Table 3.2 below:

Table 3.2: Values for the Coefficient C_1, C_2 and C_3

Coefficient	API < or = 30	API > 30
C_1	$4.677 * 10^{-4}$	$4.670 * 10^{-4}$
C_2	$1.751 * 10^{-5}$	$1.100 * 10^{-5}$
C_3	$-1.811 * 10^{-8}$	$1.337 * 10^{-9}$

The volume of gas injected into reservoir Y-19 at various pressures
The storage capacities at various pressures of Reservoir Y-19 was determined using Microsoft Visual Basic Program as shown in Fig 3.2.

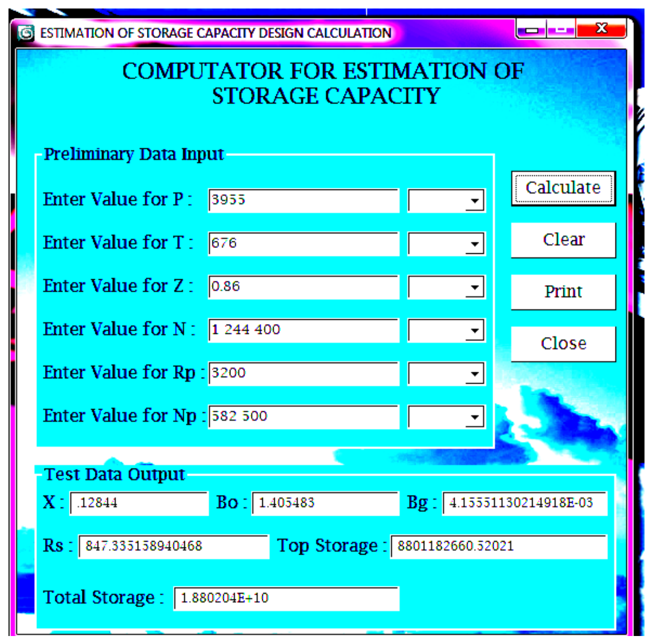

Fig 3.2: Storage Capacity of reservoir Y-19 at a pressure of 3955psig

The volume of gas that can be injected at various reservoir pressures are presented in Table 3.3, from which a plot of volume of gas to be injected at various pressures was generated as shown in Fig 3.3

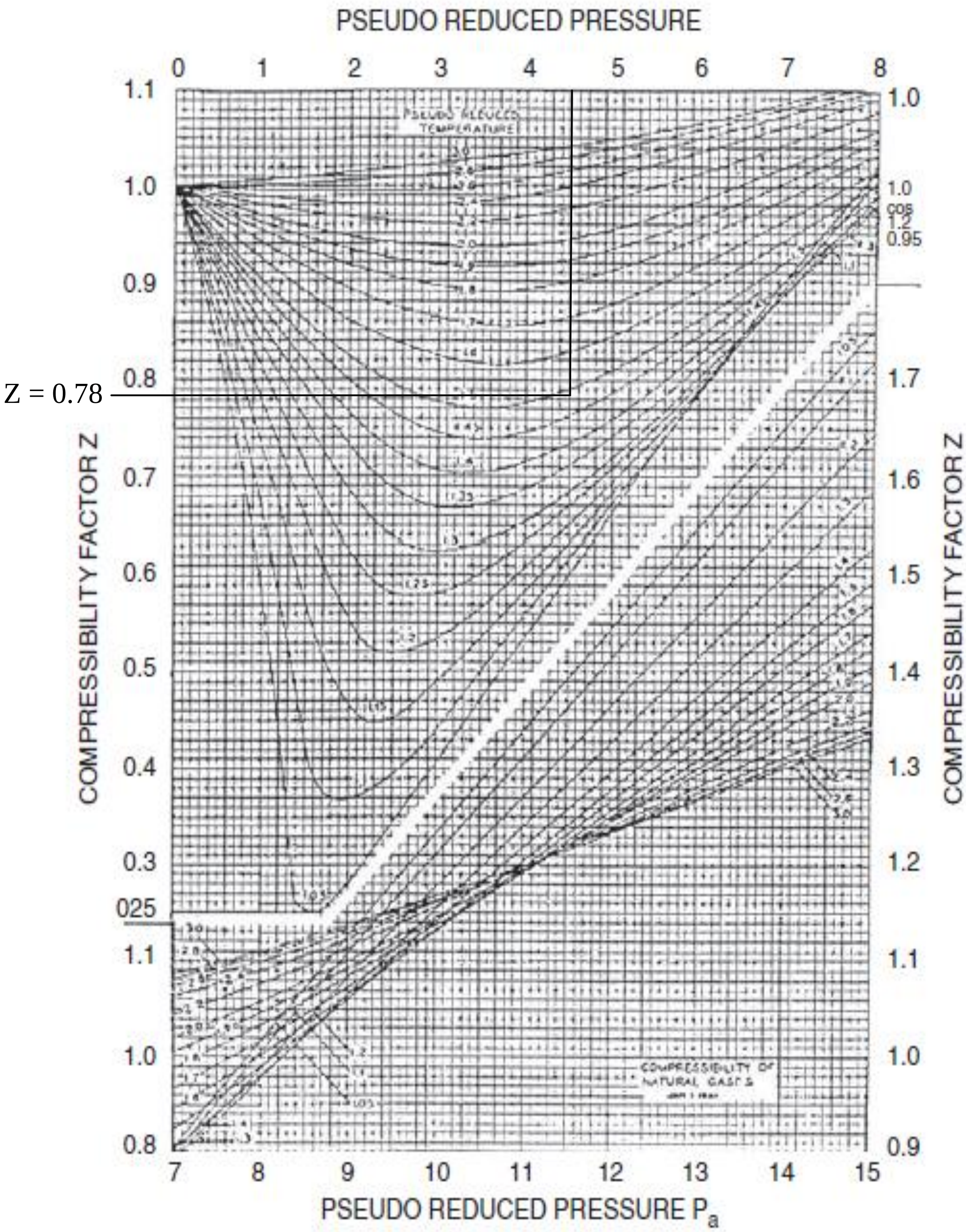

Fig 3.1: Compressibility of natural gas as a function of reduced temperature and pressure, Standing and Katz, (1942)

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Table 3.3
Vol. of gas injected at various pressures of Reservoir Y-19

P (psig)	N_p (MMstb)	B_g (scf/scf)	B_o (rb/stb)	R_s (scf/rb)	R_p (scf/rb)	V_{inj} (Bscf)
3955	0.582458	0.004156	1.405446	847.2412	3200	8.8008221
3900	0.607124	0.004214	1.399941	833.157	3440	10.16050424
3782	0.811398	0.004346	1.388184	803.0767	3960	16.5628319
3534	0.908459	0.004651	1.363718	740.4834	4980	25.87601973
3350	1.406055	0.004906	1.34579	694.6139	6030	52.2869859
3288	1.823687	0.004998	1.339793	679.2715	10010	118.2306619
3212	2.468388	0.005117	1.332473	660.5449	11540	190.1140618
3199	2.847551	0.005138	1.331225	657.3506	11980	228.9435032
2922	3.187355	0.005625	1.304872	589.9283	12570	295.8255308
2881	3.590383	0.005705	1.301013	580.0558	13990	377.4371605
2857	4.099377	0.005753	1.298759	574.29	15000	466.8585916
2767	4.852182	0.00594	1.290342	552.7562	17560	670.7650069
2427	5.463045	0.006772	1.259058	472.7173	18980	934.4265758
2237	5.878718	0.007347	1.241952	428.9518	20870	1202.798298
2145	6.446661	0.007662	1.233772	408.0254	21880	1443.844736
2057	6.957614	0.00799	1.226015	388.1781	23190	1724.267519

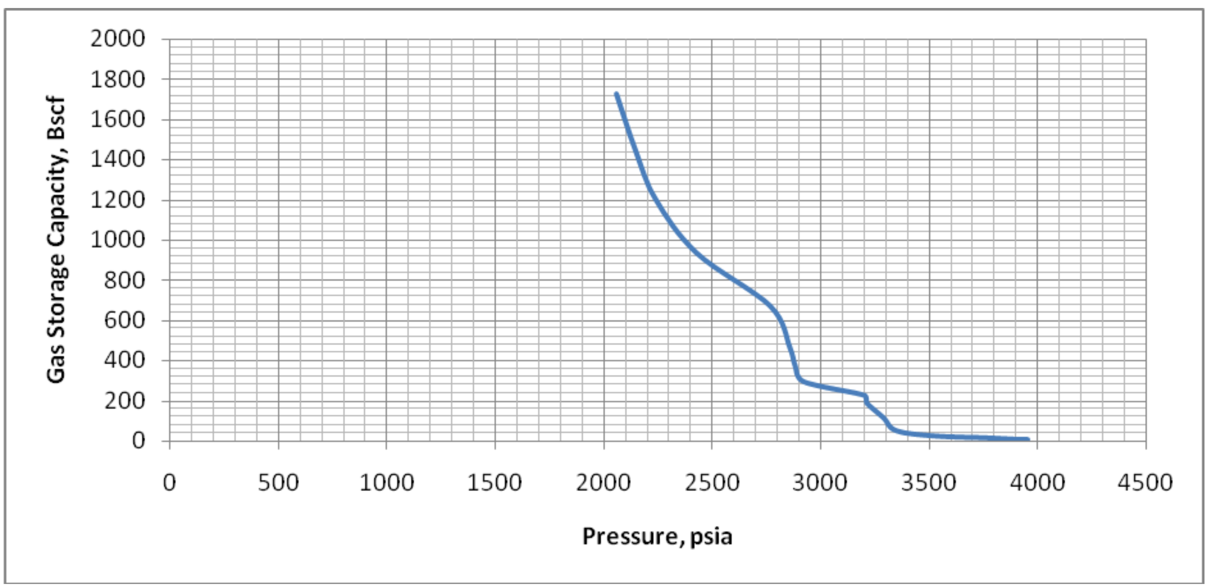

Fig 3.3: A plot of volume of gas to be injected at various pressures for reservoir Y-19.

Determination of amount of gas leakage at various pressure drops of reservoir Y-19
If the reservoir pressure drops from 3955 psig to 3900 psig ie 3969.7psia to 3914.7psia, the initial volume, V_1 is the volume of gas injected at 3955 psig which was earlier calculated. Its value is given as 8.8Bscf, Z_1 and Z_2 are 0.86 and 0.857 respectively

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From the flow chart given in Fig 2.4, the amount of leaked gas is estimated as:
AOL = [3969.7/0.86 – 3914.7/0.857]*8.8Bscf * 0.86/3969.7 = 91.5MMscf
If the reservoir pressure drops from 3900 psig to 3782 psig (3796.7psia), the initial volume, V_1 is 8.71Bscf, Z_1 and Z_2 are 0.857 and 0.85 respectively.
AOL = [3914.7/0.857 – 3796.7/0.85]*8.7Bscf*0.857/3914.7 = 192.94MMscf
If the reservoir pressure drops from 3782 psig to 3534 psig (3548.7psia), the initial volume, V_1 is 8.52Bscf, Z_1 and Z_2 are 0.85 and 0.84 respectively.
AOL = [3796.7/0.85 – 3548.7/0.84]*8.5Bscf * 0.85/3796.7 = 461.48MMscf

The amount of leakages at various pressure drops in Y-19 was also determined using Microsoft Visual Basic Program as shown in Fig 3.4.

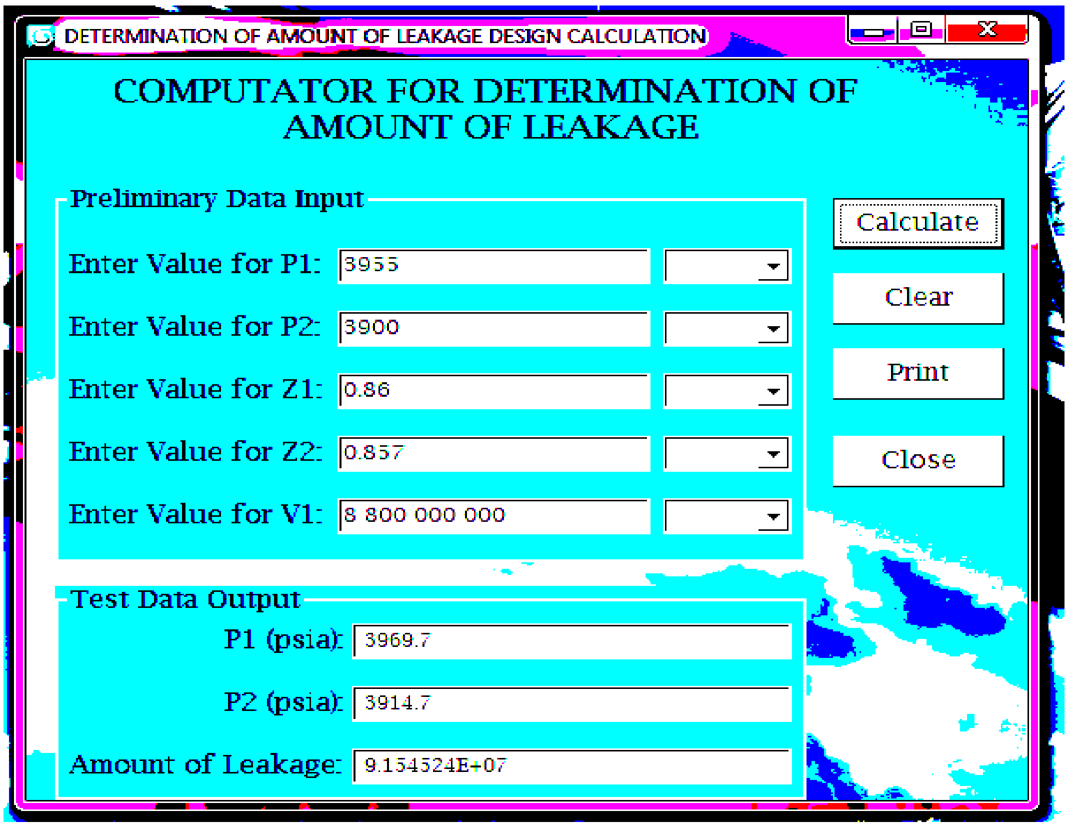

Fig. 3.4: Amount of Leakage at a pressure drop from 3955psig to 3900psig, Y-19

Evaluation of the deliverability of reservoir Y-19 at given well flowing pressure

To evaluate the performance of reservoir Y-19, the performance history was generated from the production data given in Table 3.4 from Anyadiegwu (2012) and the slope of the performance curve;
Log ($P_r^2 – P_{wf}^2$) versus Log Q shown in Fig 3.5 is obtained as 1.25
From the flow chart given in Fig 2.5
n = 1.000 / 1.25 = 0.80

$$C = \frac{29471.21}{(88288)^{0.80}} = 3.256$$

AOF = 3.256 $(3199^2)^{0.80}$ = 1320405 MMscf/year = 3617.548 Mscf/d
At P_{wf} of 3900 psig;
Q/yr = 3.256 $[3955^2 – 3900^2]^{0.80}$ = 104976.35 MMscf/yr
Q/d = 287.61 MMscf/d

Table 3.4
Production Data for Reservoir Y-19

Time (year)	P (psig)	N_p (MMstb)	R_p (scf/rb)	Cumulative oil Production (MMstb)	Oil Flow Rate (stb/d)	W_p (bbl)	W_e (bbl)
1.	3955	0.582458	3200	0.582	5868	2777.612	31255.78
2.	3900	0.607124	3440	1.189	3296	2895.24	32579.41
3.	3782	0.811398	3960	2.000	1671	3869.377	43541.14
4.	3534	0.908459	4980	2.908	3118	4332.239	48749.62
5.	3350	1.406055	6030	4.314	9279	6705.163	75451.54
6.	3288	1.823687	10010	6.137	9466	8696.757	97862.46
7.	3212	2.468388	11540	8.605	5014	11771.19	132458.3
8.	3199	2.847551	11980	11.453	7827	13579.34	152804.9
9.	2922	3.187355	12570	14.643	6044	15199.79	171039.4
10.	2881	3.590383	13990	18.230	5281	17121.74	192666.6
11.	2857	4.099377	15000	22.329	9014	19549.01	219980.2
12.	2767	4.852182	17560	27.181	7507	23138.97	260377.2
13.	2427	5.463045	18980	32.644	8219	26052.04	293157.3
14.	2237	5.878718	20870	38.523	7345	28034.3	315463.1
15.	2145	6.446661	21880	44.970	9620	30742.69	345940
16.	2057	6.957614	23190	51.928	6060	33179.31	373358.5

Table 3.5: Performance History of Reservoir Y-19

Time Year	$Q=R_pN_p$ (MMscf)	Flowing Pressure P_{wf} (Psig)	P_{wf}^2	P_r^2-P_{wf}^2 ($Psig^2$)	Log (P_r^2-P_{wf}^2)
1	681.156	3900	15210000	432025	5.635509
2	1157.37	3700	13690000	1952025	6.290485
3	1566.18	3500	12250000	3392025	6.530459
4	2515.942	3300	10890000	4752025	6.676879
5	5110.378	3100	9610000	6032025	6.780463
6	11119.864	2900	8410000	7232025	6.85926
7	10320.56	2700	7290000	8352025	6.921792
8	294721.21	2500	6250000	9392025	6.972759
9	43461.18	2300	5290000	10352025	7.015025
10	58664.76	2100	4410000	11232025	7.050458
11	91514.14	1900	3610000	12032025	7.080339
12	129787.21	1700	2890000	12752025	7.105579
13	184851.81	1500	2250000	13392025	7.126846
14	241798.02	1300	1690000	13952025	7.144637
15	335199.69	1100	1210000	14432025	7.159327
16	405174.40	900	810000	14832025	7.1712
17	538451.20	700	490000	15152025	7.180471
18	588541.25	500	250000	15392025	7.187296
19	641298.55	300	90000	15552025	7.191787
20	705943.41	100	10000	15632025	7.194015

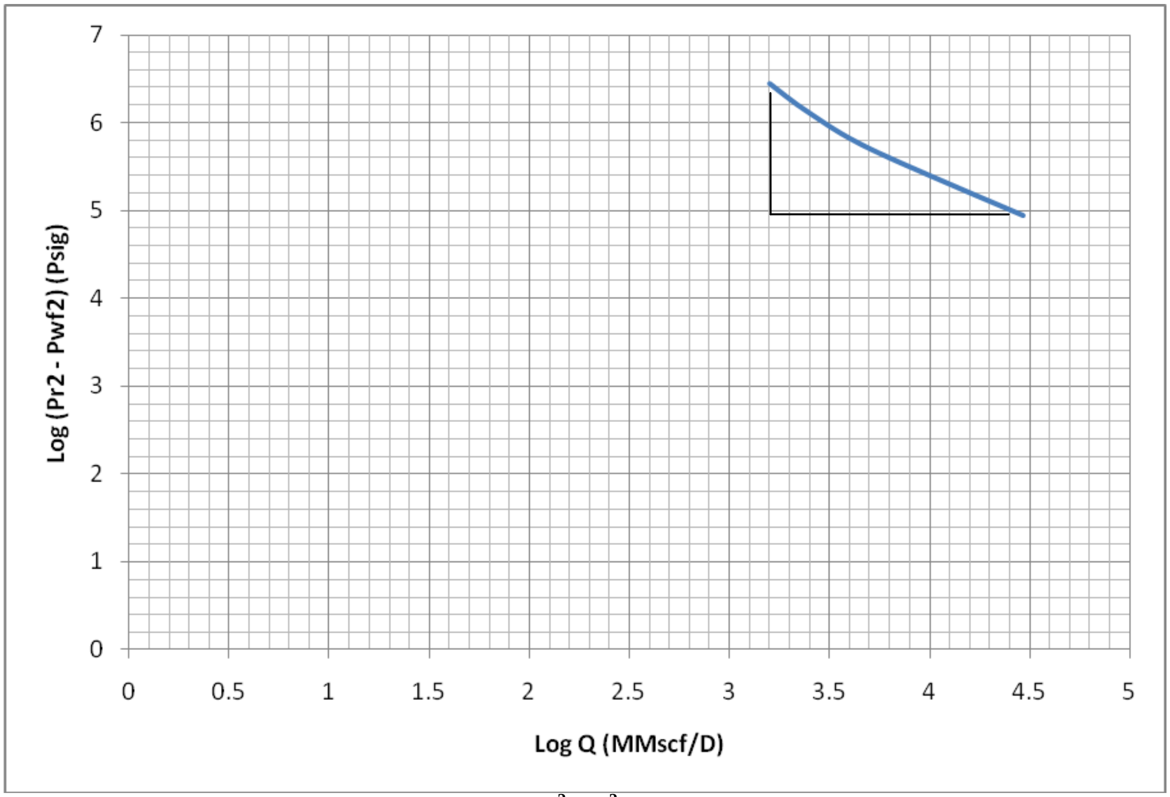

Fig. 3.5: Plot of Log [P_r^2-P_{wf}^2] Vs. Log Q for Reservoir Y-19

The deliverability of Y-19 was also evaluated to obtain 287.61 MMscf/d using Microsoft Visual Basic Program as shown in Fig 3.6

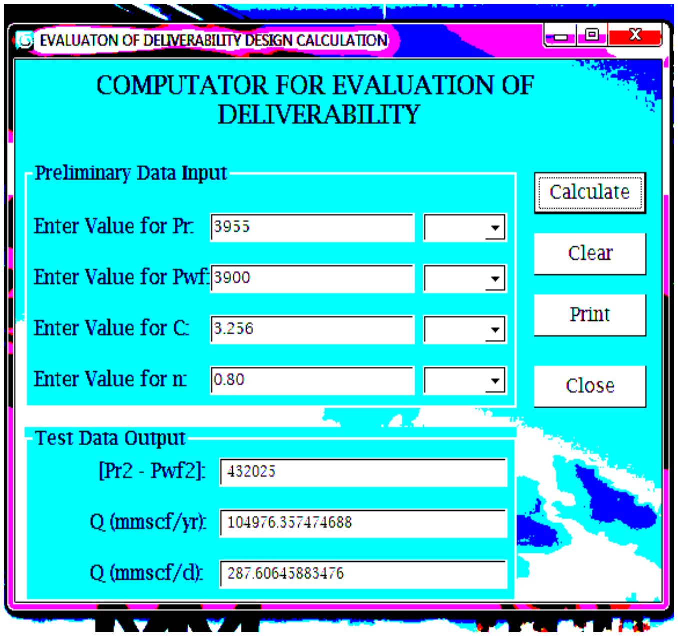

Fig 3.6: Deliverability at well flowing pressure of 3900psig

Table 3.6
Deliverability of Reservoir Y-19

P_{wf} (psig)	P_{wf}^2 ($psig^2$)	P_r^2-P_{wf}^2 ($psig^2$)	Q (MMscf/yr)	Q (MMscf/d)
3900	15210000	432025	104976.3575	287.6064588
3700	13690000	1952025	350810.5913	961.1249075
3500	12250000	3392025	545822.7482	1495.40479
3300	10890000	4752025	714804.651	1958.368907
3100	9610000	6032025	865077.2729	2370.07472
2900	8410000	7232025	1000212.623	2740.308556
2700	7290000	8352025	1122322.901	3074.857263
2500	6250000	9392025	1232797.622	3377.527733
2300	5290000	10352025	1332614.842	3650.999567
2100	4410000	11232025	1422495.317	3897.247444
1900	3610000	12032025	1502987.528	4117.774049
1700	2890000	12752025	1574518.329	4313.748846
1500	2250000	13392025	1637424.926	4486.095689
1300	1690000	13952025	1691975.978	4635.550625
1100	1210000	14432025	1738385.994	4762.701353
900	810000	14832025	1776825.406	4868.01481
700	490000	15152025	1807427.721	4951.856769
500	250000	15392025	1830294.625	5014.505821
300	90000	15552025	1845499.589	5056.163257
100	10000	15632025	1853090.327	5076.959799

The deliverabilities of reservoir Y-19 at various withdrawal pressures are presented in Table 3.6 which is used to obtain the plot of the deliverabilities at various well flowing pressures as shown in Fig 3.7.

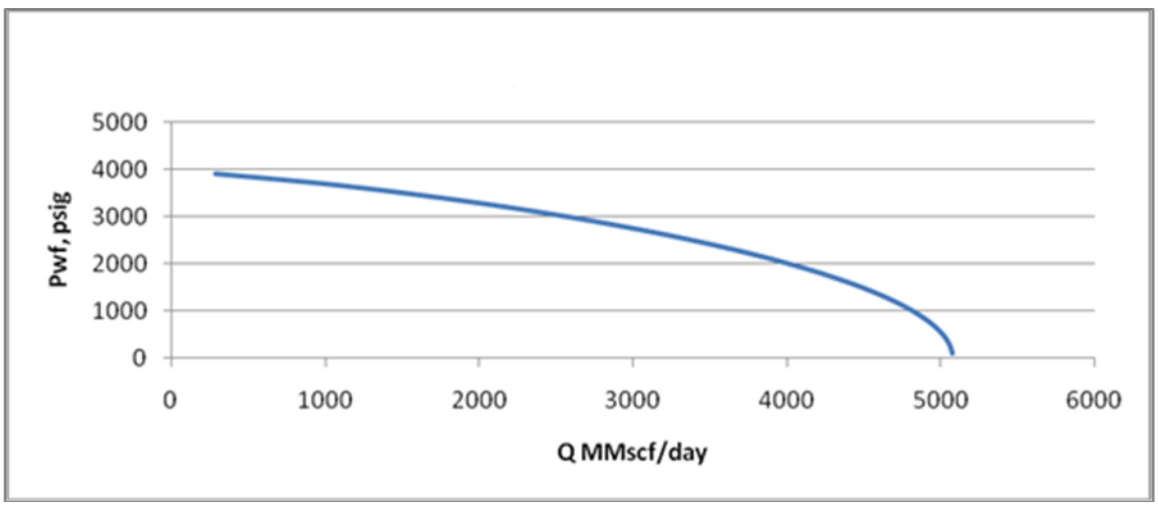

Fig. 3.7: A Plot of Well Flowing Pressure versus Deliverability, Y-19

IV. CONCLUSION

The following conclusion can be drawn at the end of this study;

1. The performance of an underground storage system developed in depleted oil reservoir can be analyzed by evaluating the basic characteristics of the reservoir.
2. Gas loss from the storage reservoir can be determined by using the amount of leakage equation.
3. Depleted oil reservoir, Y-19 is suitable for underground storage operation due to its large storage capacity for gas injection and ability to deliver enormous quantity of gas during withdrawal.

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NOMENCLATURE

AOL = Amount of Leakage
API = American Petroleum Institute
bbl = Barrel
B_o = Oil formation volume factor
Boi = Initial oil formation volume factor
B_g = Gas formation volume factor
Bscf = Billion standard cubic foot
B_w = Water formation factor
C = Reservoir flow coefficient
D = Well depth
ft = Foot
h = Thickness
k = Permeability
mD = Milidarcy
MMSTB = Million stock tank barrel
MMscf = Million standard cubic foot
MMscf/d = Million standard cubic foot per day
n = Back-pressure exponent
N = Stock tank oil-in-place
N_p = Cumulative oil production
P = Pressure of gas
P_1 = Initial pressure of reservoir
P_2 = Final pressure of reservoir
P_{pc} = Pseudo-critical pressure
P_{pr} = Pseudo-reduced pressure
P_r = Reservoir pressure
psia = Pounds per square inch (atmospheric)
psig = Pounds per square inch (gauge)
P_{wf} = Well flowing pressure
Q = Flow rate
Q/d = Deliverability (MMscf/d)
Q/yr = Deliverability (MMscf/yr)
Q_{sc} = Flow rate at standard condition
R_s = Gas solubility
R_p = Gas-oil-ratio
scf = Standard cubic foot
SG = Specific gravity
SGS = solution-gas specific gravity
T = Temperature of gas
T_{pc} = Pseudo-critical temperature
T_{pr} = Pseudo-reduced temperature

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V_{inj} = Volume of gas injected
V_1 = Initial volume of gas
V_2 = Final volume of gas
W_e = Water encroachment
W_p = Water Production
Z = Gas compressibility factor
Z_1 = Initial gas compressibility factor
Z_2 = Final gas compressibility factor
^0F = Degree Fahrenheit
^0R = Degree Rankine
Ø = Porosity
% = Percent

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