A Numerical Study of Gas Injection and Caprock Leakage from Yort-e-Shah Aquifer in Iran

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Abstract—**In order to mitigate the adverse effects of global warming due to anthropogenic CO_2 emission into the atmosphere, geological sequestration of CO_2 into subsurface formations has been investigated by many studies over the last decade. However, selection of formations and sites for any field application is still open to debate. The most important properties of a formation suitable for carbon sequestration are those which impact the fluid flow processes. The injection or extraction of gas can change the pore pressure within the reservoir, which in turn results in redistribution of the stress field. These events may cause considerably leakage of the fluid into the surrounding geological formations or ground surface. The main objective of this paper is to evaluate the potential of Yort-e-Shah aquifer for CO_2 storage, through a series of analyses with a simplified numerical model. The numerical results suggest that the optimum injection pressure in Yort-e-Shah aquifer is about 15.51 MPa with a safety factor of about 1.7. The results of the fluid pressure and gas plume expansion are presented. Also, an analysis was carried out for a case with leak through cap rock. When there is no leak, the pressure within the aquifer is stable, while on the other hand, the pressure in case of leakage is slightly smaller. In case of leakage, the pressure is lowest in the middle of the reservoir, mainly because the nodes at the middle of the aquifer are influenced by all the leakage points, while around the wellbore or near the end of gas plume, are affected less due to their longer distance to leakage points.**

Keywords-Numerical model; Fluid flow; Co_2 sequestration; Optimum gas pressure; leakage through cap rock

I. INTRODUCTION

Global warming has a direct effect on climate patterns and this includes the increasingly frequent occurrence of extreme weather events such as heat waves, floods, storms, droughts and bushfires [1,2]. The increase in the global surface temperature from 1956 to 2005 is 0.13 ^{o}C per decade and eleven of the twelve years between 1995 and 2006 rank among the twelve warmest years since 1850 [3, 4]. Scientists have suggested several options through which the amount of greenhouse gas emissions into the atmosphere can be reduced. Among these, geological sequestration of carbon dioxide has received a lot of attentions over the last decade [5, 6], and different formations may be suitable for CO_2 storage. The estimated capacity of CO_2 storage in geological formations are

listed in Table I, where it can be seen that saline aquifers offer the highest potential storage capacity. The feasibility of storage in aquifers has been extensively studied [7] and it has exhibited some technological and economic attractiveness. The main parameters in selecting an aquifer for CO_2 storages, are its size, porosity, permeability and depth [8, 9]. In addition, an overlying formation is required to cover the aquifer which provides an impermeable seal to prevent the leakage of gas into the atmosphere. The injected CO_2 stored in aquifer by a combination of three mechanisms, namely immobilization in traps, dissolution in water, and geochemical interaction with reservoir rocks. In order to assess the suitability of the reservoir for gas storage purposes, a great number of theoretical, numerical, and analytical approaches have been employed [10-14] and strategies for site selection have been proposed [15]. Since the first CO_2 injection into saline aquifer (in the 90s), many progresses have been made and many pilot and filed scale projects have been planned and/or are being undertaken.

TABLE I.   GLOBAL   STORAGE   CAPACITY   FOR   GEOLOGICAL SEQUESTRATION OPTIONS

Reservoir type	Storage capacity (Gt CO_2)	
	Lower estimate	Upper estimate
Oil and gas fields	675[a]	900[a]
Un- mineable coal seams (ECBM)	3-15	200
Deep saline formation	1000	Uncertain,but possibly 10000

[a] These numbers would increase by 25% if undiscovered oil and gas were included in this assessment

In Iran, dating back at the 70s, different areas were studied to shortlist suitable locations. Based on the results of the primary studies, the Yort-e-Shah Region in Varamin was chosen for further studies by the National Iranian Oil Company [16]. Therefore, Yort-e-Shah aquifer can be alternatively considered for gas storage. This paper provides the results of numerical simulations where the potential of Yort-e-Shah aquifer for carbon sequestration is investigated. In order to achieve this, a simplified numerical model was employed where the radial flow is considered around a single vertical wellbore. Through a series of simulations the optimum injection pressure and the storage capacity of Yort-e-Shah aquifer is determined. Also, an analysis is carried out for a case

with leaking through cap rock. It should be noted that the model taking into account the numerical study of CO_2 injection and leakage through caprock, has been modified and verified compared with the previous study [17, 18]. The results of this study, however, are advantageous to many projects involving gas injection into subsurface formations, enhanced oil and gas recovery.

II. GEOLOGICAL STUDIES OF YORT-E-SHAH AQUIFER IN VARAMIN

Yort-e-Shah aquifer is in the form of an anticline and is located 70 kilometers southeast of Tehran and 40 kilometers south of Varamin. Yort-e-shah anticline was formed in 4 stages by extension during middle Alpine movements, then stagnation and reactivated extension by late middle Alpine movements, and finally compressions by late Alpine movements [16]. Detailed geological studies of this aquifer, started in 1997, for the purpose of natural gas storage. The primary phase of the project carried out by establishing descriptive wellbores number 2 and 3 by KBB. Then, Sofregaz was responsible for drilling wells number 4 and 5, and also performed supplementary studies. From the geological point of view, there are three formations in the region as listed in Table II. The Upper Red formation is a sequence of sandstone, clay stone and anhydrite, below which Qum formation contains sequences of anhydrite, gypsum and limestone. Below Qum formation, there is a Volcanic formation. Qum formation has shown promising properties for storage of gas, while the Upper Red formation has shown high potential to prevent gas leakage and is considered as a suitable cap rock, given its very low permeability and porosity measured from laboratory analysis, as listed in Table III [16].

III. MODELING

In order to model and evaluate the capacity of storage in Yort-e-Shah aquifer, a simplified numerical model is employed. The model considers a vertical wellbore in the middle of the aquifer, through which gas can be injected. The gas plume, which is the only phase and the component, can flow in the radial and angular direction through the uniform thickness of the aquifer, while the cap rock provides a seal to the storage site. This ideal conditions are depicted in Figure 1.

TABLE II.   PROPERTIES OF YORT-E-SHAH GEOLOGICAL FORMATIONS

Formation name	Geological sequence	Upper depth in well No. 2 (m)	Upper depth in well No. 3 (m)	Upper depth in well No. 4 (m)
Upper Red Formation	Sequence of sandstone, clay stone and anhydrite	16	20.50	33
Qum Formation	Sequence of anhydrite, limestone and gypsum	575.10	1002.50	948
Volcanic Formation	Porphyry andesite	804.9	1396.8	1273

TABLE III.   LABORATORY ANALYSIS OF CAPROCK

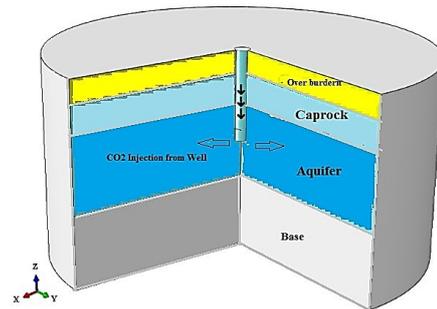| Sample number	Depth (m)	Brine Permeability (m²)	Gas drive pressure (MPa)	Permeability(m²)
14V	571.45	$7.007 \cdot 10^{-21}$	3.445	No flow
			5.516	No flow
			6.895	No flow
			11.032	No flow
			13.790	No flow
			17.926	No flow
			26.890	$1.974 \cdot 10^{-23}$
20V	585.8	$3.948 \cdot 10^{-21}$	3.445	No flow
			5.516	No flow
			6.895	No flow
			11.032	No flow
			13.790	No flow
			17.926	No flow
			26.890	No flow
29V	618.75	$4.935 \cdot 10^{-20}$	3.445	No flow
			5.516	No flow
			6.895	No flow
			11.032	No flow
			13.790	No flow
			17.926	No flow
			26.890	$<9.869 \cdot 10^{-23}$
39V	635.70	$1.875 \cdot 10^{-20}$	3.445	No flow
			5.516	No flow
			6.895	No flow
			11.032	No flow
			13.790	No flow
			17.926	No flow
			26.890	$<9.869 \cdot 10^{-23}$

Fig. 1.   Idealized schematic illustration of gas storage in the aquifer.

The outer periphery of the aquifer is impervious to gas flow, as is the underlying rock formation. There is an axial symmetry around the single vertical injection wellbore. The well is subject to a variable pressure which was known as function of time. The viscosity of the gas is assumed to be constant, while its density slightly increases with pressure, i.e. slightly compressible gas. It is also assumed that the flow of gas is an isothermal process, an assumption which is made in many of reservoir simulation works. In order to assess the conditions under which the imperfection of the cap rock seal leads to gas leakage from the reservoir, a leakage rate has also been employed. The leakage rate is assumed to only depend on the local pressure of the gas plume and its spatial position. To describe the mathematical foundation and governing equations for gas flow, we start with Darcy's law as below:

$$v_r = -\frac{k}{\mu}\frac{\partial p}{\partial r} \tag{1}$$

$$v_\theta = -\frac{k}{\mu}\frac{\partial p}{\partial \theta} \tag{2}$$

Where p is local pressure in the gas plume, k is the intrinsic permeability of the aquifer, μ is gas viscosity, v_r is superficial radial velocity component, v_θ is superficial angular velocity component. The equation of continuity, taking into account radial and angular flows, accumulation due to density change and leakage through the cap rock, gives:

$$\frac{1}{r}\frac{\partial}{\partial r}(\rho v, r) + \frac{1}{r}\frac{\partial}{\partial \theta}(\rho v_\theta) + m = -\varphi\frac{\partial \rho}{\partial t} \tag{3}$$

where ρ is the gas density, φ is the porosity of the aquifer and t is the injection time. Note that m is the leakage parameter that defines the mass flow rate of gas per unit surface area of cap rock per unit depth of the aquifer. In other words, the leakage rate has been added as a sink term into the flow equation. Following [19], parameter m is defined as a function of gas pressure as below:

$$m = k^*(p - p_l), p > p_l \tag{4}$$

$$m = 0, p \le p_l \tag{5}$$

Where p_l is the threshold pressure beyond which the leakage through cap rock occurs, and k^* is a coefficient that defines how the leakage rate depends on the gas plume pressure. In other words, the leakage rate is dined as a piecewise function whose value is zero when the gas pressure is below the leakage threshold, and it is linearly related to the differential pressure across leakage, when the gas pressure is beyond the leakage threshold. The gas is considered to be slightly compressible and hence follows this simple equation:

$$\rho = cp \tag{6}$$

Where c is the rock compressibility. Substituting Darcy's law into the equation of continuity yield the basic flow equation as below:

$$p\frac{\partial^2 p}{\partial r^2} + \frac{p}{r}\frac{\partial p}{\partial r} + \left(\frac{\partial p}{\partial r}\right)^2 + \frac{p}{r^2}\frac{\partial^2 p}{\partial \theta^2} + \frac{1}{r^2}\left(\frac{\partial p}{\partial \theta}\right)^2 - \frac{m\mu}{kc} = \frac{\varphi\mu}{k}\frac{\partial p}{\partial t} \tag{7}$$

It is convenient to introduce the dimensionless flow equation, using the following non-dimensional variables:

$$p = \frac{p}{p_0} \tag{8}$$

$$T = \frac{tkp_0}{\varphi\mu r_1} \tag{9}$$

$$M = \frac{m\mu r_1^2}{kcp_0^2} \tag{10}$$

$$\eta = \frac{r}{r_1} \tag{11}$$

where, p_0 is the initial uniform pressure throughout the aquifer, r_1 is the radius of injection well and r_2 is radius of gas plume within the aquifer. Equation (7) will then become:

$$P\frac{\partial^2 P}{\partial \eta^2} + \frac{p}{\eta}\frac{\partial P}{\partial \eta} + \left(\frac{\partial P}{\partial \eta}\right)^2 + \frac{P}{\eta^2}\frac{\partial^2 p}{\partial \theta^2} + \frac{1}{\eta^2}\left(\frac{\partial P}{\partial \theta}\right)^2 - M = \frac{\partial P}{\partial T} \tag{12}$$

Equation (12) is a non-linear second-order partial differential equation that mathematically explain the transient diffusion of pressure within the radial and angular positions distance within the aquifer. This equation can be solved using a finite difference scheme. For the purpose of a more convenient finite difference solution, we can change the radial distance variable into the following logarithmic variable:

$$R = \ln\left(r_2 / r_1\right) \tag{13}$$

The flow equation then becomes as follows:

$$P\frac{\partial^2 P}{\partial R^2} + \left(\frac{\partial P}{\partial R}\right)^2 + P\frac{\partial^2 P}{\partial \theta^2} + \left(\frac{\partial P}{\partial \theta}\right)^2 - Q = U\frac{\partial P}{\partial T} \tag{14}$$

Where

$$Q = Q(R, \theta, T) = Me^{2R} \tag{15}$$

$$U = U(R) = e^{2R} \tag{16}$$

To simplify this relationship, equation (14) can be solved for one vertical half of the gas plume, i.e. in the semi-circular region. Both the curved boundary at R=ln(r₂/r₁), i.e. the gas/water interface, and the meridian plane represented by θ=0 and θ=π will be effectively impervious to gas flow. An approximation to the solution of (14) and its associated initial and boundary conditions can be obtained by a finite difference technique. We introduce a series of grid points spaced uniformly by a dimensionless radial increment ΔR and an angular increment $\Delta\theta$. Subscripts i and j may then be used to denote that grid point having coordinates R=iΔR and θ=j$\Delta\theta$. Details of this model are presented in [19]. In order to verify the numerical model, its results can be compared with the results of an analytical model. Assuming an incompressible fluid is injected at constant rate, Q, into a horizontal homogenous isotropic reservoir with an infinite extent and initial pressure of P_0, through a vertical wellbore at its center, an analytical solution can be found following [6].

$$P(r,t)_{r=\infty} = P_0 - \frac{Q\mu_f}{4\pi k_f H}Ei\left(-\frac{r^2}{4tk_f / \varphi_f\mu_f c_f}\right) \tag{17}$$

Where H is thickness of the aquifer and Ei is the exponential integral function, which can also be defined for any positive y using Ei, as below:

$$Ei(-y) = -Ei_1(y) = -\int_1^\infty \frac{e^{-y}}{y}dy \tag{18}$$

An example was analyzed by both the numerical and analytical solutions, and the pressure predictions exhibit perfect match, as depicted in Figure 2.

IV.   RESULTS AND DISCUSSION

The main problem investigated in this study, is to determine the optimum injection pressure and time needed to fill the aquifer with gas. As such, the potential capacity of gas storage in the aquifer can be assessed. The optimum injection pressure

and time, can be estimated following the concept developed in [19]. In order to do that, the properties of Yort-e-Shah aquifer is used as an input for the numerical model, as listed in Table IV. The case was then simulated for different gas injection pressures. For each case, the injection time required for the gas pressure within the aquifer to nearly reach the injection

pressure is estimated. The injection pressure under which the shortest injection time, with suitable safety factor, was achieved considered to be the optimum injection pressure. This approach was employed for wellbores number 2 to 4 in Yort-e-Shah aquifer. The results of these analyses are shown in Table V.

TABLE IV.   PROPERTIES OF YORT-E-SHAH AQUIFER USED IN NUMERICAL SIMULATION

Parameters	Symbol	Value	Units	Reference
Averaged porosity in wellbore No. 2	φ_f	0.086	-	[16, 20]
Averaged porosity in wellbore No. 3	φ_f	0.069	-	[21, 22]
Averaged porosity in wellbore No. 4	φ_f	0.08	-	[18, 23]
Averaged permeability in well wellbore No. 2	k_f	$1.59 \cdot 10^{-15}$	m^2	[16, 20]
Averaged permeability in wellbore No. 3	k_f	$5.05 \cdot 10^{-15}$	m^2	[21, 22]
Averaged permeability in wellbore No. 4	k_f	$2.44 \cdot 10^{-15}$	m^2	[18, 23]
Gas viscosity	μ_f	$1 \cdot 10^{-4}$	Pa s	[24]
Reference gas density	ρ_{f^o}	955.3	Kg/m^3	From real gas equation of state
Initial reservoir pressure	p_i	9.7	MPa	[21, 22]
Radius of the reservoir	r_0	500	m	[21, 22]
Radius of the wellbore	r_w	0.13	m	[21, 22]
Reservoir depth in wellbore No. 2	d_r	804.9	m	[21, 22]
Reservoir depth in wellbore No. 3	d_r	1396.8	m	[21, 22]
Reservoir depth in wellbore No. 4	d_r	1273	m	[18, 23]
Reservoir thickness wellbore No. 2	t_r	229.8	m	[21, 22]
Reservoir thickness in wellbore No. 3	t_r	394.3	m	[21, 22]
Reservoir thickness in wellbore No. 4	t_r	325	m	[18, 23]
Numerical time step	Δt	0.1	days	-

TABLE V.   RELATIONSHIP BETWEEN GAS PRESSURE AND INJECTION TIME

Injection Pressure (MPa)	Well No. 2 Injection Time (day)	Well No. 3 Injection Time (day)	Well No. 4 Injection Time (day)
13.448	1195	184	635
13.789	1170	165	623
14.478	1145	152	610
15.168	1115	145	595
15.513	1090	141	586
15.858	1160	175	612
16.547	1120	152	597
17.237	1095	145	585
18.616	1095	150	579
19.305	1065	140	555

Fig. 2.   Pressure profiles at different times predicted by the analytical solution and numerical simulation

From the data presented in this table, it can be seen that increasing pressure generally leads to shorter injection time, regardless of injection well. To determine the optimum injection pressure, however, it is essential to consider the leakage threshold. The leakage threshold was assumed to be 27 MPa (according to the Table III).
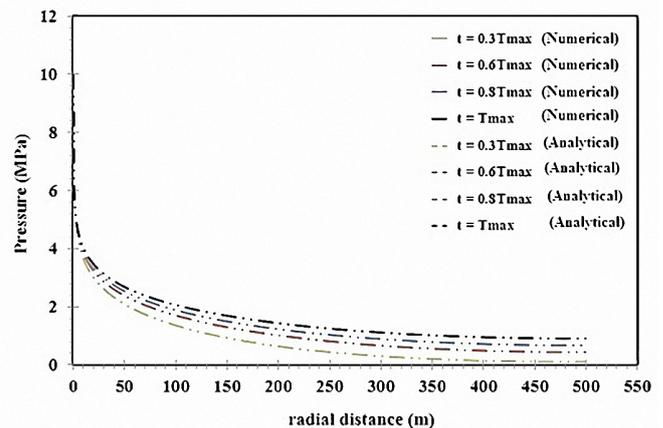
In order to reduce the risk of leakage a safety factor of 1.7 is chosen, based on which, the optimum gas injection pressure is determined to be 15.5 MPa. Assuming no leakage through the cap rock, the simulations were repeated for each depth within the reservoir, considering the corresponding

permeability and porosity and an injection pressure of 15.5 Mpa applied for 330 days. Figures 3-5 depict the typical variations of gas pressure as a function of depth for the storage wells No. 2 to 4. It can be seen that for wellbore No. 4, the maximum gas pressure within the reservoir was achieved at a depth of about 1034 m. Also, it can be seen that in the maximum pressure was achieved at a depth of 623 m and 1344m for wellbore No. 2 and wellbore No. 3, respectively. From the results given in Figures 3-5, no relationship between depth, porosity, permeability and maximum injection pressure can be concluded, as this is mainly due to the variability of the reservoir. To study the effect of leakage through cap rock, on pressure distribution within the reservoir, a case was considered in which a cascade of leaking points contributed to the leakage (Figure 6). In this case, injection was simulated at a depth of 1041.15 m in wellbore No. 4, while the leakage threshold was assumed to be p_L=14.8 MPa and the leakage coefficient was considered to be k^*=0.0047 kg/cu.m.day.pa. The same simulation was performed without leakage and the results are summarized in Figure 7. The results for the case with leak are also summarized in Figure 8.

As expected, when there is no leak, the pressure within the aquifer is stable, while on the other hand, the pressure in case of leakage is slightly smaller. In case of leakage, the pressure is lowest in the middle of the reservoir, mainly because the nodes at the middle of the aquifer are influenced by all the leakage points, while around the wellbore or near the end of gas plume, are affected less due to their longer distance to leakage points.
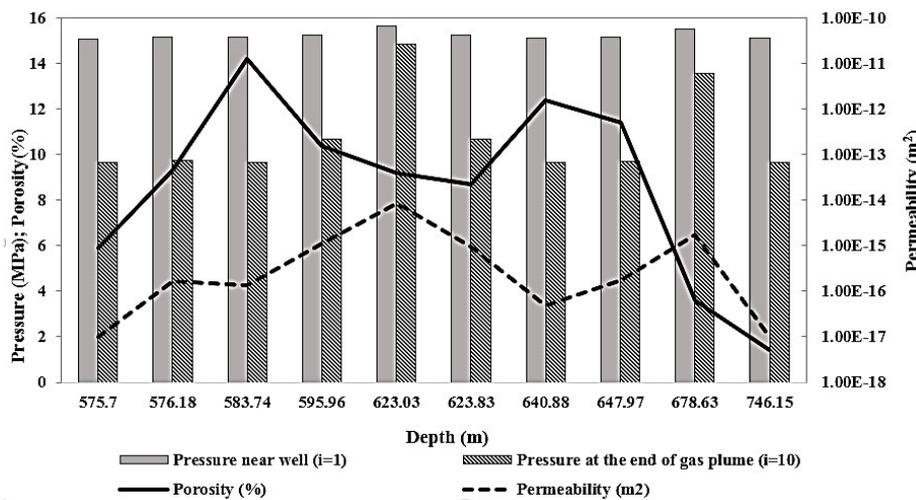

Fig. 3.   Gas pressure, porosity and permeability as a function of depth at wellbore No. 2
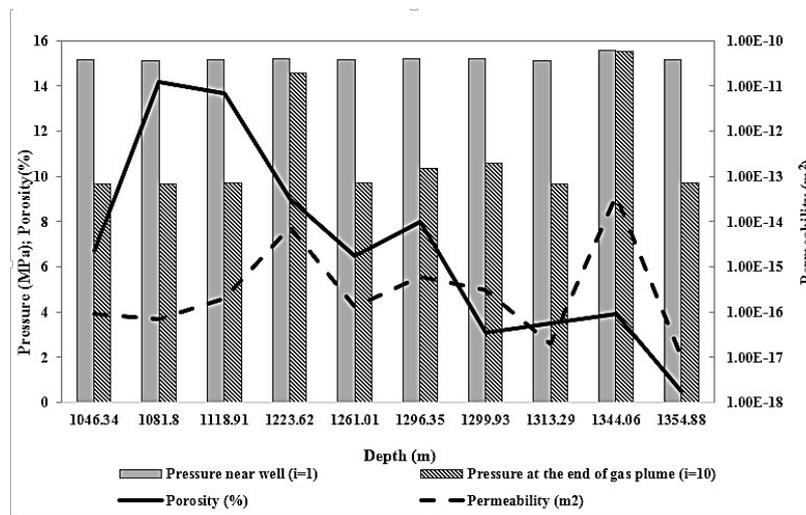

Fig. 4.   Gas pressure, porosity and permeability as a function of depth at wellbore No. 3
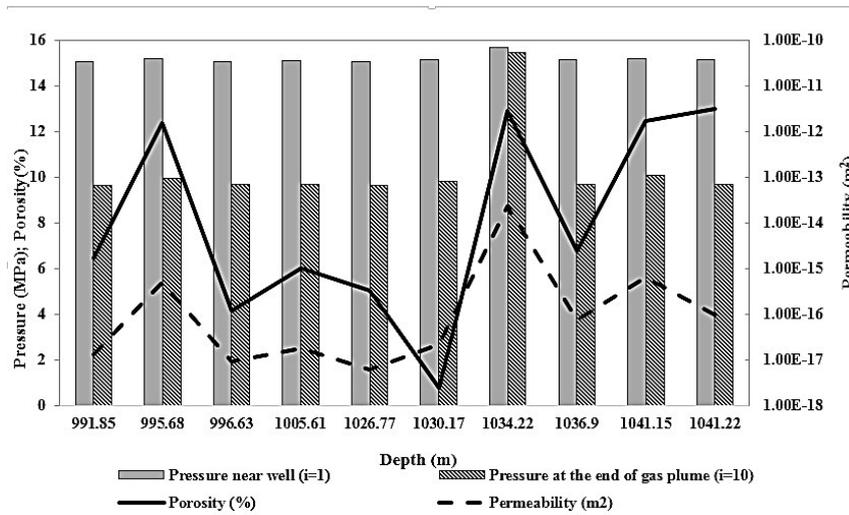
Fig. 5.   Gas pressure, porosity and permeability as a function of depth at wellbore No. 4
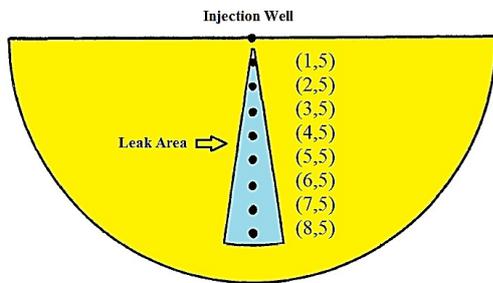

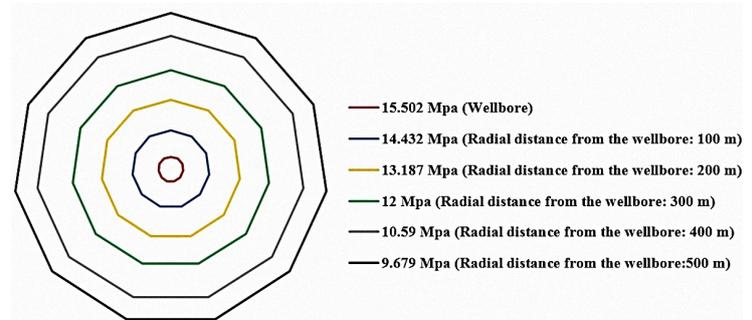Fig. 6.   Location of leak in the aquifer

Fig. 7.   Gas pressure within aquifer at depth of 1041.15 m in wellbore No. 4 (no leak)
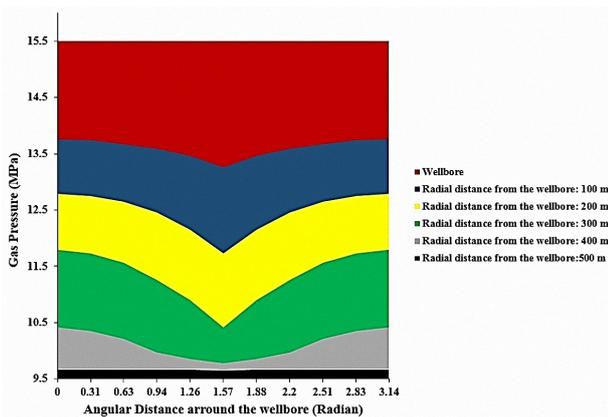

Fig. 8.   The gas pressure in depth 1041.15 m of wellbore No. 4(leaky condition)

V.   CONCLUDING REMARKS

To reduce the adverse effects of global warming, geological sequestration has been suggested, which includes capturing and pumping anthropogenic The Yort-e-Shah aquifer near Tehran, was investigated in this study as a potential candidate for gas storage. One of the main practical aspects for gas storage is to determine the optimum gas pressure and injection time. No particular relationship was found to connect the optimum injection pressure with the depth of the injection within the reservoir. The results of this study showed that an optimum pressure of about 15.5 MPa, provides a leakage safety factor of 1.7. A comparative analysis was also conducted to study the effect leakage on pressure distribution within the aquifer. The leakage, as expected, resulted to a lower pressure level within the aquifer. To determine the suitability of this site for gas storage or CO_2 sequestration, further studies are needed, including a more rigorous parametric study. In addition, more exploratory wellbores are needed to understand the extent of variability in the reservoir characteristics. In addition, to evaluating the leakage potential through cap rock, more comprehensive field and experimental investigations are required, where the hydro-mechanical properties of the cap rock are examined. The results of this preliminary study provide some useful first-hand estimation of the gas pressure distribution within the reservoir, with or without leakage potential. The model provided in this paper, can also be further

developed to include the geomechanical response of the reservoir to gas injection.

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