WELL DISCHARGE STIMULATION OF SOME GEOTHERMAL WELLS IN THE PHILIPPINES BY NITROGEN GAS INJECTION

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Abstract

Most geothermal wells in the Philippines require some method of stimulation to initiate flow. In exploration projects, nitrogen gas injection has been recently employed for this purpose, and was also found to be successful in initiating flow of hard-to-discharge wells in developed fields. Gas injection reduces the wellbore pressure at the main permeable zone to its saturation pressure by lowering the weight of the water column, and thus initiating well discharge.

The present study investigated some field data of gas lifted wells and compared these with predicted data using two-phase flow correlations and equations. The results confirm the significant effect of injection depth on the gas lift process. A statistically derived factor was obtained to predict this injection depth. The Harrison-Freeston correlation was used to estimate the flow rates and volume relative to the gas velocity and water column. The results are closer to the actual values when the submergence ratios are within 0.70 to 0.80.

1.0 Introduction

Discharging newly completed wells in a geothermal development is perhaps the ultimate goal in well evaluation. Well data obtained provides the basis for decisions that could make or break the future of a geothermal project. In vapurdominated, and sometimes in highly two-phase geothermal systems, initiating discharge of a well is relatively easy as simply opening the master valve. Not so in liquid-dominated systems. Most often, developers and field operators are perennially faced with the problem of flowing a well which is made difficult by the presence of a cold water column standing above the major permeable zone. To initiate flow, a well discharge stimulation is required.

In the Philippines, where most of the geothermal fields are liquid-dominated, a number of methods had been tried, i.e. *air* compression, boiler stimulation, two-phase fluid injection from another discharging well, but each of this has limitations in certain well application. Sta. Ana (1985) discussed these methods in his study on stimulation by air compression on some geothermal wells in the Philippines. Recently, nitrogen gas injection has been employed. A tube is inserted into the wellbore from a coil and the nitrogen gas is injected. Flashing of geothermal fluid is induced by the reduction of the wellbore pressure to its saturation brought about by the "lifting" action of the gas on the water column. Hence, discharge of the well is initiated.

This particular method has been found more successful in discharging hard-todischarge wells in comparison with the other stimulation methods cited above. The same process is even used in clearing geothermal wells with mud and dnlling debris in a bid to improve the productivity or injectivity of the well. However, the method is expensive.

The present study investigates the mechanisms involved in an effort to understand them better, and hence see where costs can be reduced. To this end, two-phase flow principles and field data from nitrogen gas stimulated wells (both successful and unsuccessful) were investigated. Correlations between theoretical works and field data were attempted to facilitate location of the injection depth, estimation of the volume of gas required and flow rate that will give optimum performance.

2.0 Brief Background on the Gas Lift Operation

A brief background of the field procedure would allow better understanding of the mechanics of nitrogen gas lifting as a well discharge stimulation method, and the immediate constraints affecting it[1].

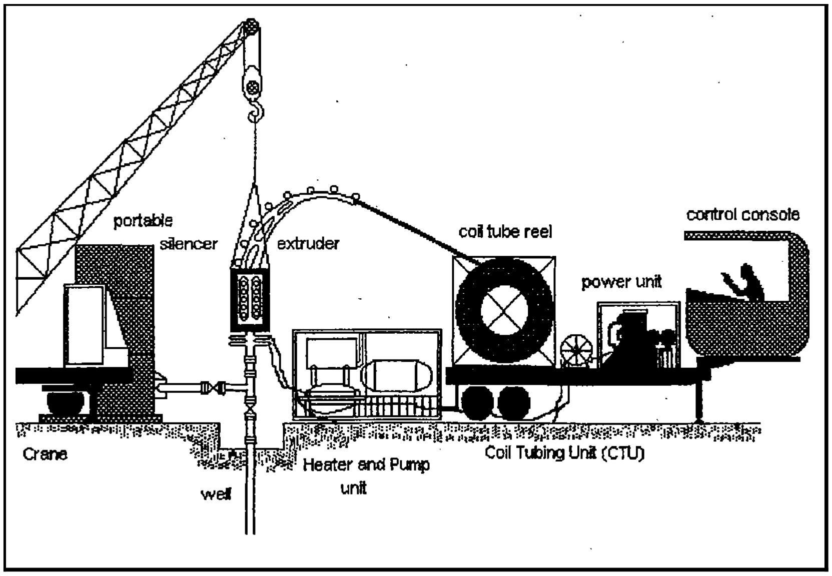
2.1 Why Nitrogen Gas?

Nitrogen gas is chemically stable, non-corrosive, have low solubility, and non-toxic (Moeller, et. al., 1984). These chemical properties make it suitable for gas injection in geothermal wells. Its non-corrosive property make it desirable in geothermal application where well casing integrity is very important. Corrosion reduces the operating life of the casing and could lead to pre-mature failure. Hence, it must be avoided. This could be the reason why nitrogen gas is preferred than compressed *air* for injection as **air** contains oxygen that enhances corrosion. The low solubility of nitrogen in water compared with other gases also makes it desirable in lifting the liquid column out **of** the wellbore. Although, gas solubility with water increases with increasing pressure, the amount is not significant as its solubility decreases also with increased temperature. The property of nitrogen to **stay** in its gaseous form is desirable because it would give better "gassifying effect", and thus improve the Lifting of the water column. Finally, nitrogen *gas* is inert and non-toxic. **As such,** it is not harmful to the personnel working in the ***gas* lift** operation, and does not require sophisticated equipment for handling, and during mobilization. Being an inert *gas*, it is stable and will not react chemically with other fluids present in the wellbore.

2.2 Nitrogen Gas Injection Equipment

The present operation involves the use of *two* major equipment, the coil tubing unit (CTU), and the nitrogen gas heater and pumping unit which are operated by two different contractors. The cost of nitrogen gas and the cost of mobilization of equipment and personnel to the well site are usually borne by the customer. Before mobilization, the well pad **is** made ready (i.e. sufficient lighting installed, compressed air and water available, and power source), and the necessary downhole KT/KP survey conducted on the well. **A** portable silencer is installed where geothermal fluids are discharge when the well **starts** flowing. The gas injection equipment (Figure -1) is laid-out according to a typical set-up shown in Figure - 2.

Figure 1: Gas Lifting Equipment



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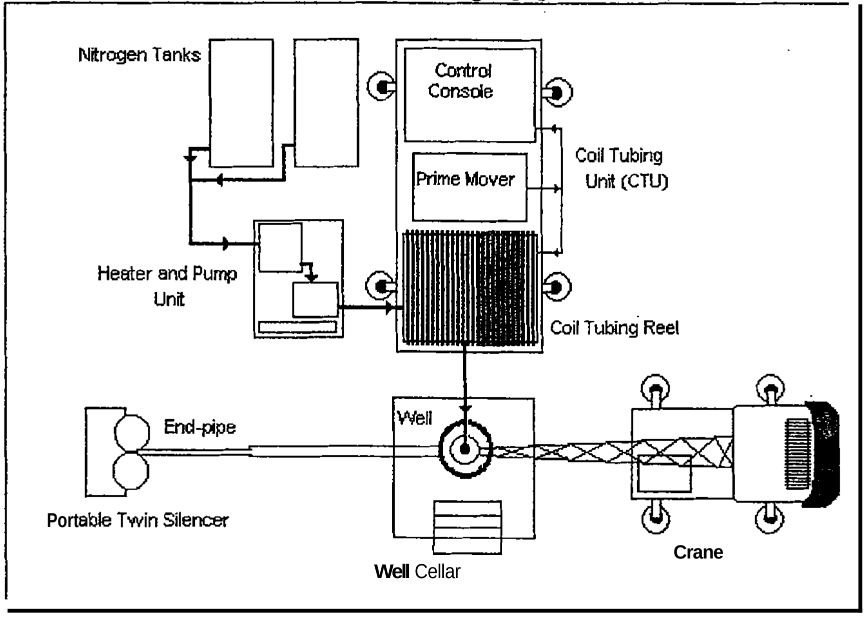
[1] Besed on the PNOC-EDC experience.

The trailer-mounted CTU which is rigged to the well head, consists of a power drive to uncoil and coil the tube, a reeled 1 inch-or 2 inch-coil tubing, and an extruder that guides the tube during run-in and pull-out. A small blowout preventer (BOP) is attached between the well head and extruder to contain blowouts. The heater and pumping unit is connected to the liquid nitrogen tank and to the CTU. Liquid nitrogen is heated by a portable boiler to a temperature of about 70°C before pumping into the wellbore.

Figure 2: Nitrogen Gas Lifting Equipment Set-up, at Well Site



2.3 Nitrogen Gas Injection Programme

Prior to the stimulation job, the reservoir engineer prepares the stimulation programme for the gas lift equipment operators. This programme is influenced by the following factors:

a) Water level and Depth of Permeable Zone

In the Philippines where most of the geothermal fields are situated in high-relief terrains, the water level varies generally with the location of the upflow and outflow zones as well as with the elevation'. It is not therefore unusual for wells to have water levels over 1000 meters below the wellhead in some'places, and 150 meters in other places. It was found by experience that wells with deep water levels are harder to stimulate by gas lifting compared with those with shallow water levels. Consequently, the nitrogen gas and the pressure drop required to lift the unwanted water column out of the wellbore is significantly large. The setting depth of the coil tubing is usually determined by the location of the major permeable zone.

b) Temperature and Pressure at the Main Permeable Zone, and its Permeability

Injection is usually concentrated at the vicinity of the major permeable zone where the temperature is usually at the maximum. The high feed zone temperature helps "gassify" the liquid column which leads eventually to the flashing of the geothermal fluids. However in actual stimulation jobs, this is not always the case. Permeable zones are sometimes clogged with mud which hinders spontaneous flashing of the fluid. To

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'Sta. Ana (1985)

remove the mu4 the coil tubing has to be moved up and down in a "swabbing motion" in the clogged section until discharge is **induced.**

As a standard practice, injection commences when **the coil** tubing reaches the water level. **This** practice lightens the liquid column while running into the well **thus speeding** up the removal of the remaining liquid from the well[4]. Nitrogen gas injection continues until ***sustained*** discharge of the well is attained. This condition is indicated **by** a strong continuous discharge flow of geothermal fluids in the silencer. The coil tubing is pulled-out of the wellbore and the gas injection is eventually stopped.

Based on experience, volume of liquid nitrogen consumed during stimulation ranges from 500-1000 gals. for good wells, 1000-2000 gals. for average wells and 3600-4000 **gals.** for very poor wells[5]. Usually, two liquid nitrogen **tanks** with a capacity of 2000 gals/tank are **made** available at the site. The actual volume of nitrogen gas that induces sustained well discharge may require more **than** the liquid nitrogen in the tanks. In this case, additional liquid nitrogen has to be shipped to the well site. If possible nitrogen gas supply at the well site should be sufficient, otherwise a well on the verge of discharge will fail to flow because of lack of gas.

2.4 Cost and Problems Encountered

The high cost involved in nitrogen gas lifting **limits** its use in stimulating only new wells in exploration projects, and production wells which are either evaluated to be hard-to-discharge wells (i.e. air compression and two phase injection are not applicable) or those that have to be discharged immediately to meet the requirements of fast-tracked power projects. From experience, hard-to-discharge wells fall under the following conditions[6]: a) deep water level, b) low downhole temperature, c) poor permeability, and **d)** presence of **"fill"** obstructing flow from the permeable zones. Well stimulation job is usually a once-through activity after which the discharging well is either shut, i.e. once all discharge test has **been** completed, or connected to the steam gathering system. Repeat jobs are avoided **as** much **as** possible obviously for economic reasons.

Total stimulation cost consists of the contractors' fees, mobilization cost, cost of liquid nitrogen and miscellaneous cost. The **bulk** of the cost falls on the **first three** items. Mscellaneous cost which covers the well site preparation and ***cost*** of personnel attending the stimulation job is **minimal.**

Nitrogen gas lifting **as** a well stimulation method is not spared of operational problems. These problems can be classified into two categories, a) maintenance which pertains to the physical condition of the two major equipment, and b) logistical which covers problems in the mob/demobilization of equipment.

3.0 Literature Survey

The mixing of gas with geothermal fluid in a pipe classifies gas lifting under two-phase flows. The considerable amount of work made on this subject provide sufficient theoretical information for **this *study.*** In geothermal applications, the gas lifting process is made more complicated with the dynamic characteristic of the well, i.e. the presence of high temperature and pressure in the wellbore. To simplify analysis, gas injection processes will be dealt with more **than** the well dynamics. Detailed analysis will be made later once the appropriate correlations are defined.

3.1 Annular Two-phase Flow Regimes

Over the years, studies of two-phase flows in vertical pipe had standardized the various flow regimes involved. Perry and Chilton (1974) discuss the flow pattern of two-phase flow in a vertical pipe. However, for gas injection in a geothermal well, the coil tubing inserted into the wellbore forms an annular configuration

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[3] J.R.M. Salera (1996): ***Personal Communication***

[4] **Coil** Tubing Technology, HYDRA RIG Inc.

[5] J.R.M. Salera (1996): ***Personal Communication***

[6] *Ibid.*

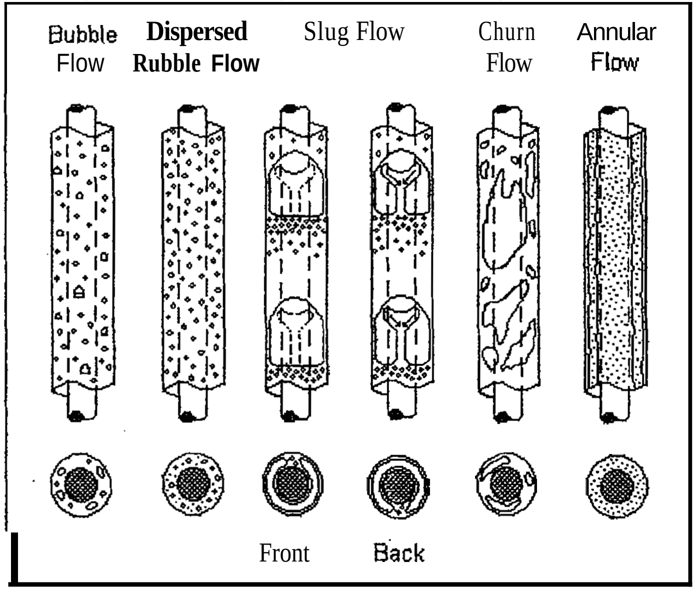
between the coil tubing and the well Casing. Hence, the annular geometry defined **by** Caetano et.al. (1992) **is** appropriate for gas injection in geothermal wells. Please refer to the brief descriptions and illustrations of the **flow** regimes below:

a) Bubble Flow - **small** bullet or spherically shaped bubbles rise in a continuous liquid phase. The bullet **shaped** bubbles rise faster than the spherical bubbles and **often** coalesce **with** each Other.

b) Dispersed Bubble Flow - spherically **shaped** bubbles move in a straight lines; no or little relative motion between the bubbles and the liquid phase **occurs.**

c) Slug Flow - intermittent flow **of** gas slug **(known as** Taylor bubble) **and** liquid slugs occurs. The flat-tailed bubbles with elliptic **fronts** occupy a large proportion of cross section though only partially wrap around **the** inner pipe of the annulus. The constant flow of liquid draining through the gaps between gas slugs **keeps** the length of the liquid slug constant.

Figure - **3:** Pow Regime in an Annulus (Torrens, **1993)**



d) **Chum** Flow - the gas slug bubble **starts** to lose its distinctive shape owing to the more chaotic and disturb state of the two-phase fluids. Build-up of gas voids upset the liquid **slugs** causing it to fall downwards. It then accumulates and form a bridge between the *two* walls of the **annulus** before it is lifted again **by** the gas. Chum flow is characterisedby the oscillatory motion **of** the liquid slug,

e) Annular Flow - the liquid flows upward as wavy, liquid films both on the inner and outer walls of **the** casing **and** the inner pipe, **respectively**. The outer liquid film **is** thicker than the inner **liquid** film. The gas flows in between the two liquid films. Depending on the gas flow rate some liquid may be distributed **as** liquid droplets in the gas core (also known as **mist** flow).

Because of the relatively deep wells involved in the stimulation process (average of about 2000 meters); a long length of coil tube is required to inject the gas at the vicinity **of** the **main feed** zone. Evidently, a uniform annular configuration along the whole length **of** the casing **string is** not possible. Although, little has been done to determine the effect of eccentricity, the experimental results of Kelessidis and Dukler (1990) showed it **has** insignificant influence on the flow regime.

3.2 *Air* Lifting Performance

Stenning and **Martin** (1968) have shown by analytical and experimental study that air lifting performance is controlled by the flow regime which is influenced by the air flow rate, and by the submergence ratio. It was observed that maximum water flow occurs during slug flow which forms at relatively lower air flow rates. Increasing the air flow changes the flow regime which eventually reduces the water flow. It was further observed that better **air lift** performance were attained if the submergence ratio', R_s is high (i.e. > 0.60) and the gas-liquid ratio is between 1 to 2. These theoretical information, despite being obtained from experiments on very shallow wells, are noteworthy for geothemal well stimulation, particularly in gas injection where removal of the liquid column is similar to pumping of water from the well by air lift.

3.3 Pressure Drop

Studies made by Gunn (1992) and Torrens (1993) on two-phase flows for geothermal well application indicated three components to the pressure **drop** or gradlent, the gravitational, the frictional and the accelerational components. The last component is usually neglected as *this* is relatively **small** compared to the **first** two. Hence, total pressure drop at the point of gas injection is,

$$\delta p_t = \delta p_f + \delta p_g + Spa \quad \text{------------------} \quad \text{Eqn. 1}$$

where,

δp_t - total pressure drop

δp_f - frictional pressure **drop** component

δp_g - gravitational pressure drop component

δp_a - pressure due to acceleration

3.4 Bubble Rise and Velocity

Many experimental studies had **been** conducted to measure the bubble velocity in two-phase flows in vertical pipes. Dumitrescu (1943) established for **stagnant** liquid, the bubble velocity to **be**, $V_b = 0.35(gD)^{1/2}$ where g is the gavitational acceleration, and D is the characteristic length of the pipe. In the case of annular flows $D = d_i + d_o$. But for bubbles rising through a stagnant liquid in an annular geometry, the bubble rise velocity *can* be estimated by a similar equation derived from the combined theoretical investigations of Grace and **Harrison** (1967)[8] and Kelessidis and Dukler (1989), as follows:

$$V_b = 0.2935(2gD_{ch})^{1/2} \quad \text{------------------} \quad \text{Eqn. 2}$$

where V_b is the bubble velocity

D_{ch} is the characteristic dimension

$$D_{ch} = \pi\left[R_i + \left(\frac{R_o - R_i}{2}\right)\right] \quad \text{------------------} \quad \text{Eqn. 3}$$

R_o = casing radius, m

R_i = coil tube radius, m

Nicklin et. **al.** (1962) also observed that for expanding slugs or bubbles (i.e. liquid is flowing out above the slug), the rising velocity increases with slug length and the increase varies with the absolute pressure of the system. In annular flows, Kelessidis and Dukler concluded that bubble velocity in an annulus **is** faster than the corresponding circular tube, and that the bubble never occupies the whole cross-sectional area.

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[7] Ratio between submergence of the tube below the water level and the total height from the bottom of the tube to the discharge point.

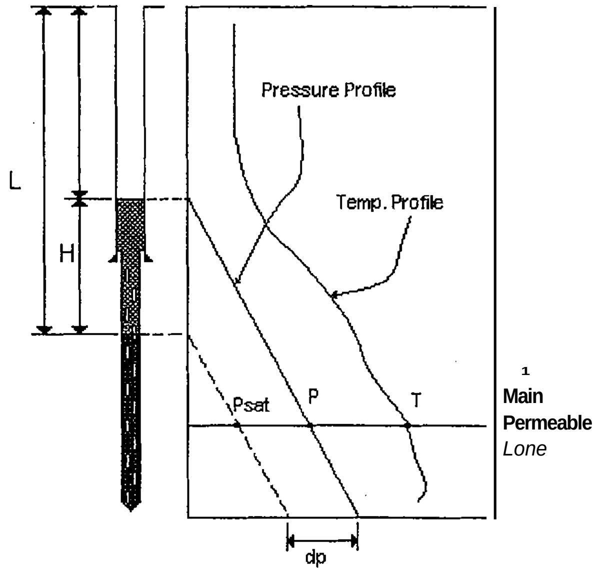
[8] As quoted in the works of Kelessidis and Dukler (1989)

4.0 Correlation of Field Data and Theoretical Calculations

4.1 Well at Static Condition

Consider the schematic diagram of a theoretical well at static condition illustrated in Figure - **4.** In order for the well to discharge, the wellbore temperature, T at the main permeable zone must equal the saturated temperature corresponding to the wellbore pressure at that depth. In liquid dominated **systems,** wellbore temperature is most often way below the saturation value. There are two ways to attain the condition that will initiate well discharge, one is by increasing the wellbore temperature until it reaches the saturation temperature, and the second is by reducing the wellbore pressure to a saturated value corresponding the wellbore temperature. The latter is what gas lifting is trying to do.

Figure - **4:** Schematic diagram of the well at static condition.



From the steam tables, the saturated pressure, P_{sat} corresponding to the wellbore temperature can be known. The water column, H to be gas lifted *can* then be approximated graphically as indicated in the figure which is equivalent to the pressure difference, dp between the saturated and the measured pressure 'values. "Gas lifting" of this water column out from the wellbore, theoretically initiates flashing in the wellbore.

4.2 Submergence Ratios

The submergence ratios of all the wells stimulated by nitrogen gas lifting were calculated to check possible effect on the setting depth of the coil tubing, i.e. injection depth. These were calculated in the same manner that Stenning and Martin did in their experimental *study.* Refer to the appendix for the details. Submergence ratio, R_s is calculated by dividing the submergence, H by the total lift, L. **A** statistical correlation of the submergence ratio *can* be established to predict the **minimum** depth of injection for a successful gas lift. Since the coil tubing had been "swabbed" up and down the wellbore during stimulation, the exact values of H **and** L cannot be ascertained. For the purpose of establishing this numerical correlation, submergence ratios at the main permeable zone as wells as at the bottom of liner were evaluated.

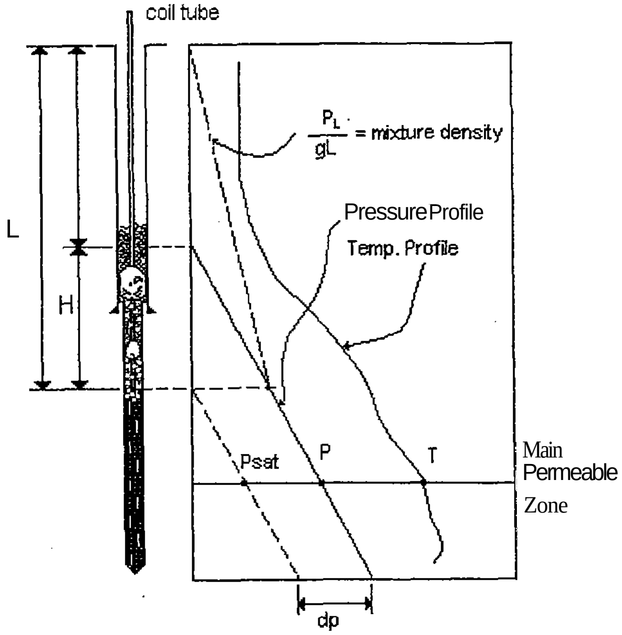
4.3 Gas Flow Rate and Volume

The approximate volume of gas to be injected was investigated using Bernoulli's principle. For ease of calculation, the average pressure and temperature of the water column to be gas lifted was used. Figure **5** depicts the well under gas lift stimulation.

Initially, only the gravity component of the pressure drop was taken into consideration. **A** more accurate result can be obtained if the frictional as well as the accelerational components cited by Gunn and Torrens are included, Torrens was able to estimate the effect of the frictional component as between 5 to 20% of the total pressure drop. The mixture density was estimated as follows,

$$\rho_{mixture} = \rho_a \frac{H}{L} = \left[\frac{P_L}{gL}\right] \text{ ---------------------------------- Eqn. 4}$$

Figure - 5: Well at Stimulated Condition



where P_L is the wellbore pressure at the bottom of the water column to be gas lifted, L is the total lift, H is the water column to be gas lifted and r_a is the actual density of the water column. The fractional mass of the water and gas components of the two-phase mixture was then calculated from the mixture density as follows:

$$'_{mixture} = {}^{1}\!/_{\rho_{mixture}} = (1-x)\upsilon_{water} + (x)\upsilon_{gas} \text{ ---------------- Eqn. 5}$$

From the gas mean velocity equation by Harrison and Freeston **(1975)** for two-phase flow, the nitrogen gas flow rate can be computed,

$$V_{gas} = \frac{W(x)\upsilon_{gas}}{A(1-\alpha)} \text{ -- Eqn. 6}$$

where **Wx** is the gas flow rate
υ_{gas} is the specific volume of the gas
A is the cross-sectional area of the casing-coil tube annulus
V_{gas} is the bubble **gas** velocity estimated from Dukler et. al.
and Grace et. al. equation (see **Section** 4.4) where R_o
R_i are the casing and coil tube radii, respectively.
void fraction derived by Harrison from geothermal pipe data

$$\alpha = \frac{1}{1+\left(\frac{1-x}{x}\right)^{0.8}\left(\frac{\upsilon_f}{\upsilon_g}\right)^{0.515}} \text{ ------------------------------ Eqn. 7}$$

The gas volume can then be estimated from this flow rate and from the bubble break-out time whch is discussed in the next section.

4.4 Bubble Rise Time

The bubble rise times were obtained for each well to determine the time of a single gas bubble to break out from the water column. This was estimated from the bubble velocity equation above, and from the length of the water column to be gas lifted. For gas injection to be effective, **all** the nitrogen gas must be injected within this period of time, otherwise the lifting action of the gas bubbles will cease after it breaks out of the water column. The flow rate obtained from the Hamson-Freeston correlation serves as the injection flow rate that will ensure that all the gas is injected before it ***starts*** breaking out of the water column. Consequently, from the break-out time and the estimated nitrogen gas flow rate, the volume of liquid nitrogen was estimated.

5.0 Discussion of Results

Table - 1 summarizes the results of the investigation. It shows the length of the water column to be gas lifted, and the submergence ratios at three different depths, namely: at the main permeable zone, at the bottom of liner, and at the inferred depth of the water **column** that will initiate discharge. It also shows the estimated gas flow rates and mass obtained using the Harrison-Freeston correlation to lift the water column, H. Please refer to Appendix **A** for the details.

gence Ratios, Gas Flow Rates and Gas Volumes

Well Name	Water Level	Total Lift @ L	Water Column H	H/L Ratio	H/L Ratio	H/L Ratio @ BOL	Gas Flow Rate	Rise Time from H	N2 Gas Req'd.
	(mVD)	(m)	(m)				(kg/s)	(sec)	(kg)
BL-ID	1240				0.17	0.488			
BL-2D	1157	1234	86	0.06	0.27	0.272	0.17	122.99	20.55
HG-1D	350	1648	1298	0.77	0.81	0.839	1.26	2073.28	2618.40
LB-1D	350	2052	1702	0.83	0.86	0.866	1.44	2718.59	3922.10
LB-3D	150	1542	1392	0.90	0.92	0.934	1.64	2223.43	3655.69
LB-4D	1023	1671	648	0.39	0.49	0.532	1.15	1035.04	1187.68
LB-5D	400	2054	1654	0.80	0.85	0.851	1.68	2641.92	4441.96
MG-15D	600	1238	638	0.52	0.64	0.738	0.65	1019.07	644.16
MG-18D	600	893	293	0.33	0.55	0.727	0.29	468.01	134.03
PS-1D	495	1130	635	0.56	0.75	0.767	0.46	1014.28	468.71
PT-1D	450	1578	1128	0.71	0.73	0.809	0.91	1801.74	1640.98
SG-1	1000	1200	200	0.17	0.38	0.638	0.08	319.46	26.00
SK-3D	400	1486	1086	0.73	0.78	0.803	0.71	1734.66	1228.86

All calculations were based on a production casing diameter of 9-5/8 inches and a coil **tube** diameter of 2 inches. Well BL-2D had a fill of mud at the bottom when it was stimulated, but was successfully discharged. Well PT-1D was also successfully stimulated but a break at the upper section of the production casing prevented **sustained** discharge. The rest of the wells were successfully stimulated and sustained discharge. The blank spaces at the bottom **part** of the table is due to the absence of **data** for the affected wells.

5.1 Injection Depth

The evaluation results of the submergence ratios are in agreement with the findings of Stenning and Martin (see Section 4.2). Wells classified as poor or hard-to-discharge wells[9], e.g. BL-1D, **BL-2D**, LB-4D, SG-1 and KN-2D consistently have lower submergence ratios except that of well PS-1D. The average or good wells i.e. LB-1D, PT-1D, **PT-2D**, HG-1D, LB-5D MG-15D, **MG-18D**, SK-3D and LB-3D have an average submergence ratio of 0.77 and 0.82 at the main permeable zone and bottom of liner, respectively. However, it must be noted that fractional **mass** of gas increases with depth, hence the deeper the injection depth, the more gas is needed and so will the cost.

The importance of submergence ratio in the gas injection process is **best** illustrated **by** the results of well SG-1. Despite the poor submergence ratios i.e. less **than** the average value of 0.77, at the bottom of the water column to be gas lifted (1200 m), and at the main permeable zone (1600 m), the well was still successfully discharged. It is the opinion of the author that injection of the gas at the maximum clear depth dunng stimulation, where the submergence ratio was increased to 0.64, helped induce discharge of the well. The same deduction applied for the successful discharge of the other hard-to-discharge wells cited above. From ***this*** information, it is then possible to estimate the injection depth of nitrogen gas for a particular well from the statistically obtained submergence ratio for successfully *gas* lifted wells of about 0.77 to 0.82, and from the length of the water column to be "lifted". However, the statistically obtained values still needs to be fine-tuned to give more accurate results.

5.2 Gas Flow Rates and Volumes

The gas mass estimates computed showed remarkable results. Although the values do not match exactly with the actual figures, a striking relationship **between** *gas* volumes and the submergence ratio, i.e. injection depth was observed. The results showed that wells with relatively high submergence ratios i.e. > 0.78 at the injection depth, yielded gas volumes that are closer to the actual values. Examples are LB-1D, LB-5D, and HG-1D (highlighted in the table). Conversely, those that have lower submergence ratios i.e. < 0.6 yielded lower values which are extremely opposite to the actual figures. To mention a few are wells BL-2D, SG-1, PS-1D, and LB-4D. The big difference is likely the result **of** deeper injection during the actual stimulation job. Well LB-3D whch was identified as a good well i.e. low gas volume consumed during the actual stimulation, yielded a relatively higher estimated gas volume. It appeared that gas injection at 1542 mVD where the submergence ratio is ~0.90 had, in this case, resulted to ***an*** overestimate of the gas volume. Please refer to Table - 2 for the comparative values of actual and computed gas volumes.

Actual and Predicted as Volumes

Well Name	Submergence Ratio	Computed Gas Volume (gals)	Actual Gas Volume Consumed (gals)	REMARKS
BL-2D	0.06	6.72	3600 - 4000	poor well
HG-1D	0.79	856.61	1000 - 2000	average well
LB-1D	0.83	1283.12	1000 - 2000	average well
LB-3D	0.90	1195.96	500 - 1000	good well
LB-4D	0.39	388.55	3600 - 4000	'poor well
LB-5D	0.80	1453.19	1000 - 2000	average well
MG-15D	0.52	217.28	1000 - 2000	average well
MG-18D	0.33	43.85	1000 - 2000	average well
PS-1D	0.56	153.34	3600 - 4000	**poor** well
PT-1D	0.71	536.85	1000 - 2000	average well
SG-1	0.17	8.50	3600 - 4000	poor well
SK-3D	0.73	402.02	1000 - 2000	average well

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[9] **Classification** made **by** Salera, J.R.M. (PNOC-EDC)

Generally, the results show a significant effect of injection depth on the gas injection process. These also suggest an optimum submergence ratio that will give a more accurate prediction of the gas volume and flow rate necessary to lift the unwanted water column. This means that injection depths for wells with shallow submergence, H e.g. BL-2D and SG-1 should be made deeper as what was done during the actual job. In the case of LB-3D, the overestimate is most likely the result of the failure to consider the frictional pressure drop and drawdown factor of the well in the calculation.

6.0 Conclusions and Recommendations

Three parameters involved in the nitrogen gas injection as a geothermal well stimulation method were investigated in the present study, namely the injection depth, gas volume and mass flow rate. Correlations suitable for geothermal application and equations derived for two-phase flows were used. The results of these investigations were compared with actual gas lifting field data to arrive at the following conclusions:

a) There is evidence of a significant effect of the injection depth on the success of gas injection. There is an optimum submergence ratio for each well to obtain a more accurate prediction of the gas flow rate and volumes, and this can be derived from statistical data of gas lifted wells.

b) The Harrison-Freeston cotrelation appears to predict closer values of gas volumes with the actual data when the submergence ratio is within 0.7 - 0.8.

c) The length of the water column to be gas lifted and the main permeable zone (or the pressure control point for multi feed zones) in connection with the submergence ratio define a likely minimum and maximum injection depths. If "swabbing" of the coil tubing dunng injection is necessary, it has to be done within this section of the wellbore.

d) The rise time of the gas within the length of water column to be gas lifted facilitates the estimation of the gas volume required to start the lifting process.

To improve the accuracy of prediction of the gas volumes and flow rates, it is recommended that a detailed calculation will be made to include other factors i.e. frictional pressure drop, drawdown factor etc. whch were not considered in this study. Where applicable, a sensitivity test of the variables that affect the above parameters be made, or better still, the use a suitable wellbore simulator is recommended to obtain optimum values.

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