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INTEROFFICE CORRESPONDENCE

date January 23, 1980

to C. A. Allen/D. Goldman

from O. J. Demuth

subject EFFECTS OF TEMPERATURE OF INJECTED WATER ON INJECTION PRESSURE -OJD-1-80

Ref: O. J. Demuth memo to C. A. Allen/D. Goldman, OJD-9-79, Calculation of Wellbore Pressure at the Receiving Zone for Injection Tests, November 9, 1979

I. Introduction and Summary

The purpose of this memo is to present a simple method for predicting wellhead pressures required during long-term injection of low-temperature water, based on hot-water injection tests. The method is intended for application to single-phase liquid reservoir flows; it has been applied for the prediction of injection pressures required for injecting 150^{o}F water into RRGI-7 at the Raft River Site after one and five years.

Strict application of the method requires that sufficient hot-water injection data exist to adequately define wellhead pressure for the desired well flows and time span at that temperature. Assumptions implicit in the approach are: (1) that the prediction of low-temperature injection behavior corresponds to a reservoir having the same geometry and formation properties as existed during the hot-injection tests; (2) that the region of importance to well pressures is occupied by low-temperature water throughout the entire period for which the prediction of wellhead pressures is to be made (SPE 8232, "A Study of Thermal Effects on Well 7 and Analysis," by Mangold, Tsang, et al., presented in September 1979 at Las Vegas, suggests that after about 5 minutes, wellbore pressures for the RRGI-7 reservoir should vary with time as if the reservoir contains only injected water); and (3) that the hot-water injection tests are of sufficient duration that effects of reservoir boundaries are included in the hot-water injection data.

Wellhead pressures for RRGI-7, measured during the period August 9-15, 1979, and corrected as discussed in the referenced memo, were used in the application of the method. The corrected pressures were assumed to define the behavior of RRGI-7 during long-term injection of 265^{O}F water. From these data, a wellhead pressure of 303 psia was estimated to be required for injection of 1000 gallons per minute (gpm) of 265^{O}F water after five years. Wellhead pressures of 529 and 651 psia were predicted for injecting 1000 and 1250 gpm of 150^{O}F water after five years.

II. Method for Predicting the Effect of Water Temperature on Injection Pressure

General. The overall approach for the present method of predicting required cold-water injection pressures will be reviewed before discussing the method in detail. The method assumes that wellhead pressure as a function of injection time and flow rate is known from long-term injection testing of warm water. By long-term it is meant that the region of the reservoir surrounding the injection well which is important to the wellhead pressure behavior is occupied entirely by the warm water during injection testing. (Injection testing using water whose temperature is equal to that already existing in the receiving zone, would tend to make this assumption easier to satisfy.)

Actual application of the method consists of starting with wellhead pressure expressed as a function of time and flow (either in algebraic form or in the form of a map) for warm water injection (say 265^{o}F), and then correcting the function or map to represent injection behavior with colder (150^{o}F) water.

Flow Field Similitude. The present method incorporates principles taken from experimental modeling techniques. If two phenomena can be described by the same partial differential equation, the same initial conditions, and the same boundary conditions, a solution of the equation for one of the phenomena is also a solution for the other; numerical values of the independent and dependent variables bear the same functional relationships to each other for the two phenomena.

For the problem of injecting constant-temperature liquid water into a confined, porous, isotropic reservoir of the same temperature, where viscosity, compressibility and permeability are uniform and constant, where squares of pressure gradients and gravity forces can be neglected, and where the flow through the medium is laminar, the flow can be described by a partial differential equation, written in terms of dimensionless variables, as follows:

$$\frac{\partial^2 \Delta P_D}{\partial {x_D}^2} + \frac{\partial^2 \Delta P_D}{\partial {y_D}^2} + \frac{\partial^2 \Delta P_D}{\partial {z_D}^2} = \frac{\partial \Delta P_D}{\partial t_D} \qquad 1)$$

In this equation the variables consist of dimensionless groupings as follows:

Independent Variables

$$x_D = \frac{x}{r_w}, \quad y_D = \frac{y}{r_w}, \quad z_D = \frac{z}{r_w},$$

$$\text{and } t_D = \frac{kt}{\phi \mu c\, r_w^2}$$

Dependent Variable

$$\Delta P_D = \frac{P - P_i}{q\mu/2\pi kh}$$

where: x and y are components of the horizontal distance of a point from the center of the well

z is the verical distance from the bottom of the receiving zone at the wellbore

r_w is the radius of the wellbore

k is the formation permeability

t is time from start of flow

ϕ is the formation porosity

μ is the water viscosity

c is the effective compressibility of the formation plus water

P is the pressure in the formation at a given point defined by x,y,z,t

P_i is the initial pressure of the reservoir before flow starts

q is the volume flow rate being injected or withdrawn

h is the thickness of the receiving (or producing) zone at the wellbore radius

The initial and boundary conditions are as follows:

1) $\Delta P_D = 0$ at $t_D = 0$ for all x_D, y_D, z_D.

2) $$\frac{r_w}{h} \int_0^{h/r_w} \left[\frac{\partial \Delta P_D}{\partial r_D} \bigg|_{r_D = 1} \right] d\, z_D = -1 \quad \text{for } t_d > 0$$

(Constant well flow)

where: $r_D = \left(\sqrt{x^2 + y^2} \right) \Big/ r_w$

(To simplify the expression, this boundary condition has been written as if the flow at the wellbore radius has axial symmetry about the well centerline, but varies with z in the receiving zone.)

3) A boundary condition at the edge of the reservoir:

$$\Delta P_D = 0 \text{ at } x_D = x_e/r_w,\ y_D = y_e/r_w, \text{ and } z_D = z_e/r_w$$

for all t_D, where x_e, y_e, and z_e are the coordinates of the edge, or boundary, of the reservoir.

This boundary condition corresponds to a constant pressure, $P = P_i$ at the edge of the reservoir, and could apply to a finite or infinite reservoir. (Another boundary condition which might be applicable, corresponds to a bounded reservoir at x_e, y_e, and z_e, and takes

the form: $\frac{\partial \Delta P_D}{\partial n} = 0$ for all t_D, at $x_D = \frac{z_e}{r_w}$, $y_D = \frac{y_e}{r_w}$, and

$z_D = \frac{z_e}{r_w}$, where n is in a direction normal to the reservoir boundary.)

If Equation 1) and its boundary conditions describe the reservoir flow during a given long-duration injection test, such as the test during which 265°F water was injected into RRGI-7, they will also describe the flow for the same reservoir for a long-duration test during which 150^{O}F water is injected. It follows, then, that at the same dimensionless time, $t_D = \frac{kt}{\phi\mu c r_w^2}$, the dimensionless pressure, $\Delta P_D = \frac{P-Pi}{q\mu/2\pi kh}$, will have the same numerical value for the hot and cold injection tests.

Effect of Temperature on Wellhead Pressure. In the expression for dimensionless pressure, P and P_i correspond to conditions in the wellbore at some "receiving-zone" depth. If wellhead pressure is the primary pressure measurement, the pressure difference $(P_{wh} - P_{whi})$ can be used (the added subscript, wh, denotes wellhead conditions), and is equal to $P-P_i$ at the receiving zone at the same instant for a temporally constant wellbore temperature (density). If the initial wellhead pressure, P_{whi}, is known for a reference wellbore temperature (T_{REF}), and the corresponding initial wellhead pressure is desired for a second wellbore temperature (say 150^{O}F), the following correction is made:

$$(P_{whi})_{150^\circ} = (P_{whi})_{REF} - \frac{(\rho_{150^\circ} - \rho_{REF})\,\ell}{144} \qquad 2)$$

where: P_{whi} is the initial wellhead pressure, psia;
ρ is the density of water, lbm/ft^3;
Subscripts 150^{O} and REF denote conditions at wellbore temperatures of 150^{O} and a reference temperature;
ℓ is the depth of the receiving zone, ft.

Stepwise Procedure. A simple, approximate procedure for predicting wellhead pressure required for long-term cold-water injection at a given flow rate and time is as follows:

1. Establish wellhead pressure minus initial pressure as a function of time and flow for the given reservoir, and for warm water injection (265°F, for example).

$$(P_{wh} - P_{whi})_{265°} = f\ (q,t)$$

(Note that this function must include reservoir boundary effects if the prediction is to include the effects of the reservoir boundary.)

2. Calculate the corrected time for hot-water injection, corresponding to the time at which the cold-water prediction is desired. (The dimensionless time values are equal.)

$$t_{265°} = t_{150°} \frac{\mu_{265°}}{\mu_{150°}}$$

3. Find $(P_{wh}-P_{whi})_{265^o}$ using Step 1 as a function of the corrected time, t_{265^o} (from Step 2), and of a reference flow, q_{REF}.

4. Calculate the $(P_{wh}-P_{whi})$ for cold water ($150^{o}F$) injection at the desired flow $q_{150^{o}}$.

$$(P_{wh} - P_{whi})_{150°} = (P_{wh} - P_{whi})_{265°} \frac{q_{150°}\ \mu_{150°}}{q_{REF}\ \mu_{265°}}$$

5. Establish the receiving zone depth, ℓ, for the injection well.

6. Calculate the initial wellhead pressure for the cold-water injection, $(P_{whi})_{150^{o}}$, using Equation 2).

7. Calculate the wellhead pressure for cold-water injection, $(Pwh)_{150^{o}}$, for the desired flow and time using values from Steps 5 and 6.

$$(P_{wh})_{150°} = (P_{wh} - P_{whi})_{150°} + (P_{whi})_{150°}$$

III. <u>Range of Applicability of Method</u>

Equation 1) was included to illustrate the basis for the method presented. It was derived with restrictive assumptions consisting primarily of:

1) The rock and fluid in the reservoir maintain a constant and uniform temperature.

2) Fluid viscosity is uniform and constant.

3) Gravity forces are negligible.

4) Reservoir permeability is uniform, isotropic, and constant.

5) Reservoir porosity is uniform.

6) The total system compressibility $\left(\frac{1}{\rho}\frac{\partial\rho}{\partial p} + \frac{1}{\phi}\frac{\partial\phi}{\partial p}\right)$ is small and constant.

7) Laminar flow exists throughout the reservoir. (Darcy's Law applies.)

Application of the method for prediction of cold water injection behavior at Raft River is not in strict compliance with these assumptions; however, a more detailed prediction, based on hot-water injection data, would require application of a much more comprehensive numerical analysis (probably with a computer model of the reservoir). Furthermore, at the present time, sufficient knowledge does not exist regarding definition of the reservoir to expect a unique prediction even if detailed modeling were attempted.

The present method is intended to provide a simple approach for obtaining our best "current prediction" of reservoir behavior during long-term cold-water injection using hot-water injection data as a base. Accordingly, the viewpoint adopted was to consider possible errors in prediction associated with the lack of compliance of the Raft River reservoir with the assumptions noted above. If those errors are judged to be of the same order of magnitude as effects of our lack of knowledge of the reservoir, application of the simplified prediction method should constitute a reasonable engineering approach toward a best current prediction.

Effects of Nonuniform Temperatures in Reservoir. Injection of water at a temperature different from that of the reservoir will, in principle, violate Assumptions 1) and 2) listed above. A paper, SPE 8232, by Mangold, Tsang, et al. (titled "A Study of Thermal Effects in Well Test Analysis," and presented at Las Vegas in September 1979), contains results of analyses that pertain to the effects of nonuniform reservoir temperatures. Figure 13 of that paper suggests that for injection into RRGI-7, after about five minutes of injection the wellbore pressure will show the same slope on a plot versus log time as if the entire reservoir (fluid and rock) were at the temperature of the injectant. Prior to that time the pressure behaves almost as if the entire reservoir were at the original reservoir temperature. The long-term cold water injection pressure predicted by the present method would tend to be a little high due to the effect of nonuniform reservoir temperature (the error might be expected to be less than perhaps 40 psi for a 1000 gpm flow rate into RRGI-7).

Effect of Neglecting Gravity. The magnitude of error introduced by neglecting gravity effects, Assumption 3), depends on the reservoir characteristics and on the temperature of the injectant. Qualitatively, however, two major contributions to this error are expected to be: 1) Effects of differences in free convection flows within the reservoir (associated with nonuniform temperatures), and 2) effects of differences in pressure between different elevations, and corresponding differences in water storage (due to water and formation compressibility) from one elevation to another. For the application of this method to RRGI-7 injection, it is assumed that effects of gravity can be neglected. (It should be pointed out that the direct effect of neglecting gravity is to eliminate the variation in pressure associated with elevation. That effect, alone, would not influence the reservoir flow field for an incompressible fluid.)

Effects of Nonuniform and Anistropic Permeability. In a fracture dominated reservoir such as exists at the Raft River Site, formation permeability cannot be expected to be uniform and isotropic (Assumption 4) above). However, if the permeability is nonuniform and anisotropic, but is independent of water temperature, then use of the dimensionless time and wellbore pressure, as defined in Equation 1), should be applicable for the prediction method presented here.

For example, in Earlougher's "Advances in Well Test Analysis" (SPE Monograph Vol. 5, 1977), an approach for simply treating anisotropic, but uniform, permeability is presented. For that approach, the dimensionless pressure and time are not changed in form; the coordinate system is distorted to account for the anistropy as

$$x_D = {}^{x}/_{r_w} \sqrt{{}^{\overline{k}}/_{k_x}}, \; y_D = y/r_w \sqrt{{}^{\overline{k}}/_{k_y}} \; .$$

That type of coordinate system transformation allows the same partial differential equation in ΔP_D to be applicable for isotropic and anisotropic permeabilities. The geometry distortion would be independent of temperature (viscosity); therefore, the prediction method should not be invalidated by permeability anisotropy. Neglecting products of gradients such as $(\partial k/\partial x)\ (\partial P/\partial x)$ and $(\partial P/\partial x)^2$ and extending the rationale applied for treating uniform anisotropy, the method is expected to be applicable, within "engineering approximation," for reservoirs having nonuniform permeability.

Effects of Nonuniform Porosity. If the porosity distribution throughout the reservoir remains the same for the different injection temperatures, the prediction method presented remains applicable. No restrictions need to be placed on the gradients of porosity, $\frac{\partial \phi}{\partial x}$, $\frac{\partial \phi}{\partial y}$, $\frac{\partial \phi}{\partial z}$, for application of the method.

Assumption of Small Compressibility. The assumption of small and constant compressibility is a common and widely accepted assumption for reservoir analysis, and is expected to be suitable for application of the prediction method presented here. The compressibility must be small and independent of pressure and temperature, but need not be uniform throughout the reservoir for application of the method.

Assumption of Laminar Flow. The relationship between volumetric flow and pressure gradient used in development of Equation 1) is $u = -\frac{k}{\mu} \nabla p$, which assumes that laminar flow exists throughout the reservoir. For porous media at relatively low flow velocities this assumption is generally valid. For fracture dominated reservoirs, the flow may or may not be laminar. If the major pressure drops occur in small cracks where velocities are low and Reynolds numbers are small, the reservoir pressure will be mainly influenced by laminar flow.

The critical Reynolds number, $R_c = \rho v d/\mu$, below which the flow is laminar, is about 2000 for pipe flow (although for very smooth flow conditions, laminar flow has been observed at Reynolds numbers as high as 40,000). As an example, assuming $R_c = 2000$ for a fracture, a gap of 0.1 inch (0.0083 ft), 200^{o}F water ($\mu = 0.738$ lb/fthr, $\rho = 60$ lb/ft^3), laminar flow would exist at velocities less than about 50 ft/min. During injection, laminar flow would be characterized by a linear relationship between $(P_{wh}-P_{whi})$ and volume flow at a given time of injection. This linear behavior was exhibited during injection into RRGI-7; therefore, for that well, reservoir flow is apparently primarily laminar.

IV. Application of Method to RRGI-7

The wellhead data, upon which the cold water (150^{O}F) injection predictions were based, were measured August 9-15, 1979 at the Raft River Site, RRGI-7. These data are shown in Figs 1, 3, 4 of the referenced memo, where the wellhead pressures have been "corrected" for variations in wellbore water temperature (density) as described in that memo.

Establishing Wellhead Pressure Behavior at 265^{O}F. The first step of the method was to describe a functional relationship between wellhead pressure, flow, and time representing the warm water injection data (in this case taken as 265^{O}F). Figure 1 shows the "corrected" wellhead pressure at 100 minutes of injection plotted versus injection flow for the RRGI-7 injection data. The paper by Mangold, et al., previously mentioned, shows that this plot is significantly influenced by the initial water in the reservoir (although the slope of the pressure versus log time curve is influenced mainly by the injected water temperature after a few utes of injection). If the initial reservoir temperature had been equal to the 265^{O}F injection temperature rather than equal to about 200^{O}F, the slope of the curve would have been smaller because of the lower viscosity at the higher water temperature. The exact magnitude of that effect is not known, but to be conservative, the slope indicated by Figure 1, $\partial P_{wh}/\partial q \Big|_{100\ min}$ =0.180psi/gpm was used as if it applied for 265^{O}F injection.

From Figures 1, 3, 4 of the referenced memo, a value of 0.0146 (psi/log cycle)/gpm volume flow was obtained by averaging the slopes of the plots of corrected wellhead pressure versus log time for the three injection flow rates.

Combining the contributions, the wellhead pressure behavior for $265^{O}F$ injection was approximated as:

$$(P_{wh} - P_{whi})_{265°} = \left[0.180 + 0.0146 \log_{10} (t/100)\right] q$$

where: q is the volume flow, gpm

t is the injection time, minutes

<u>Calculation of Corrected Time for the Prediction</u>. The corrected time, t_{265^o}, with which to calculate $(Pwh - Pwhi)_{265^o}$ at a desired prediction time (for $150^{O}F$ injection) was computed as:

$$t_{265°} = t_{150°} \frac{0.213}{0.432}$$

where 0.432 and 0.213 are the values of viscosity, in centipoises, for water at 150 and $265^{O}F$. t_{265^o} was calculated for values of t_{150^o} of one and five years (5.260×10^5 and 26.30×10^5 minutes).

<u>Calculation of $P_{wh\ 150^o}$</u>. Calculation of $(P_{wh} - P_{whi})_{150^o}$ was made for several volume flows, for one and five years injection. As indicated in Step 4 of the procedure, $(P_{wh} - P_{whi})$ was calculated using:

$$\left(\frac{P_{wh} - P_{whi}}{q}\right)_{150°} = \left(\frac{P_{wh} - P_{whi}}{q}\right)_{265°} \times \frac{.432}{.213}$$

where $(P_{wh}-P_{whi})_{265^o}$ was determined at the values of t_{265^o} calculated as discussed in the preceding paragraphs.

For Step 6, $(P_{whi})_{150°}$ was calculated, based on the observed initial wellhead pressures of 65.4, 58.2, and 64.7 psia as shown in Figures 1, 3, 4 of the referenced memo. The average wellbore temperature was assumed to be 200°F at the times those pressures were measured. $(P_{whi})_{150°}$ was calculated using Equation 2) as:

$$(P_{whi})_{150°} = \frac{65.4 + 58.2 + 64.7}{3} - \left(\frac{1}{0.016343} - \frac{1}{0.016637}\right)\frac{2700}{144}$$

$$= 42.5 \text{ psia}$$

In this expression 0.016343 and 0.016637 are the values of specific volume, ft^3/lb, for water at 150 and 200°F. 2700 feet was assumed to equal the depth of the receiving zone, and 144 converts ft^2 to in^2.

Finally, values of $(P_{wh})_{150°}$ were calculated as shown in Step 7.

Summary of Predictions. The following table summarizes the predictions made for injection into RRGI-7:

Injection Temperature, °F	Injection Flow, gpm	Wellhead Pressure at 1 year, psia	Wellhead Pressure at 5 years, psia
265	450	164	169
265	1000	293	303
265	1250	351	364
150	1000	509	529
150	1250	625	651

In this table the predictions for the 265^{o}F injection temperature were made by extending the values shown on Figure 1 to one and five years injection time. At 265^{o}F injection temperature

$$P_{wh} - (P_{wh})_{100\ min} = 0.0146\ q\ \log_{10}\ (t/100\ min)$$

V. Conclusions

The predictions of wellhead pressure for long-term injection of 150^{o}F water into RRGI-7, summarized in the preceding table, are believed to represent the best estimates available at the present time, consistent with the state of knowledge of the Raft River reservoir.

The estimates tend to be conservative (high) because of two assumptions. The first is that the value $\partial P_{wh}/\partial q \Big|_{t=100min} = 0.180$, used to describe the wellhead pressure for the 265^{o}F injectant, was obtained for an initial reservoir temperature of about 200^{o}F; the reservoir was nonisothermal. Had the initial temperature been 265^{o}F, the value of $\partial P_{wh}/\partial q\ (t=100min)$ would have been lower, perhaps by as much as 30%. Second, the viscosity correction applied to obtain values of $P_{wh} - P_{whi}$ at 150^{o}F was applied as if the 150^{o}F water were to be injected into a 150^{o}F reservoir. The actual initial temperature, being closer to 200^{o}F, will tend to result in slightly lower ($P_{wh} - P_{whi}$) values than those predicted.

On the other hand, a major uncertainty in the present application of the method results in potential prediction errors which are unconservative. This uncertainty is related to the premise that the injection data, upon which the predictions are based, were obtained for a sufficiently long duration to justify the assumption that the straight line plots of observed $\left(P_{wh} - P_{whi}\right)$ versus log time are valid up to the point in dimensionless time for which the prediction is desired. If a closed boundary of the reservoir were to be "encountered" shortly after testing terminated, for example, the extension of the observed straight line to later times, of course, would not be valid.

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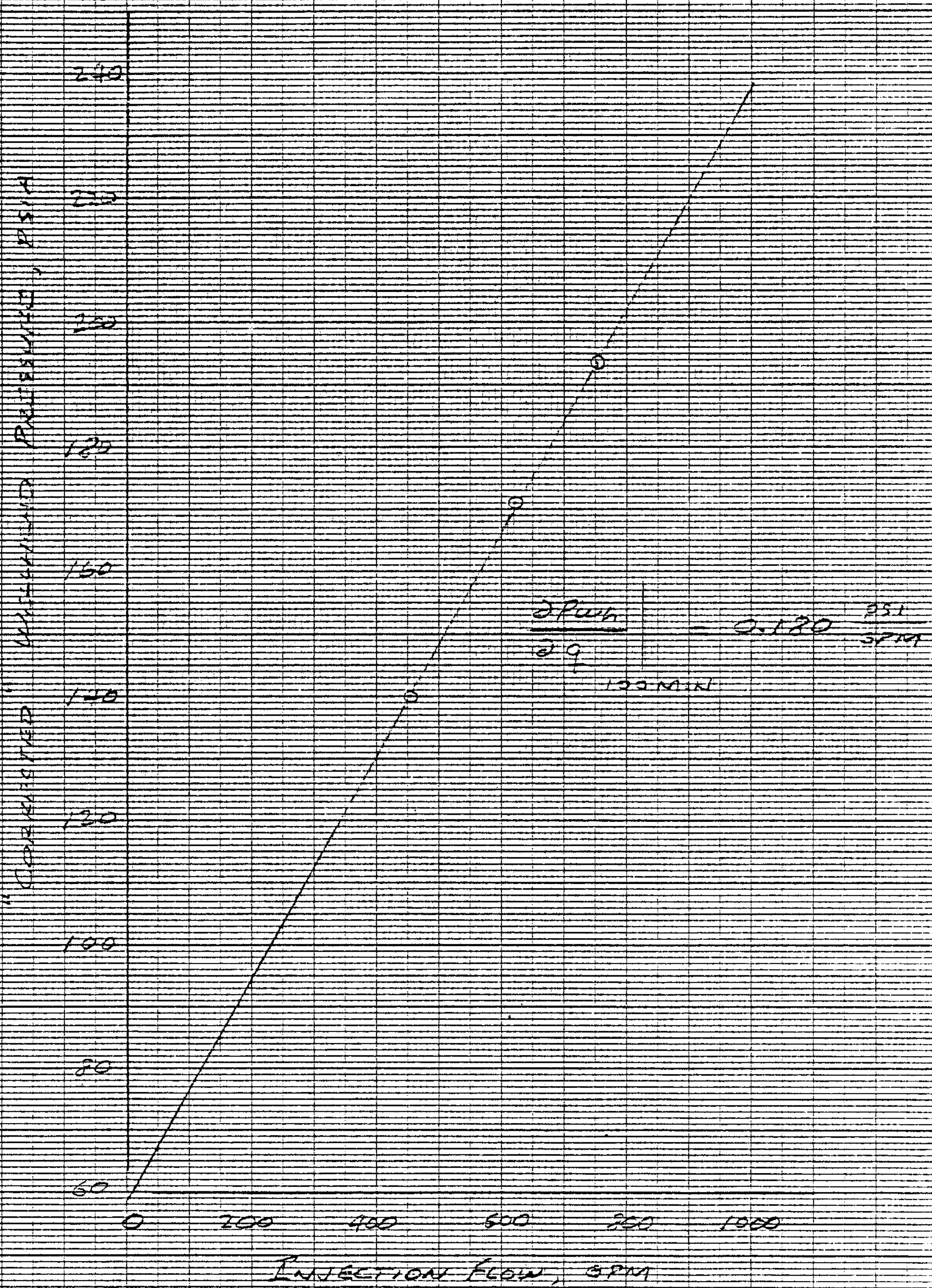

Fig. 1 Effect of Injection Flow on Wellhead Pressure, 100 Minutes Injection at 265 °F into R[illegible]