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Productivity and Injectivity of Horizontal Wells

Contract N0. DE-FG22-93BC14862

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Contract Date: March 10, 1993
Anticipated Completion: March 10, 1998

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Quarterly Report

Reporting Period: October 1, 1993 - December 31, 1993

"U.S./DOE patent clearence is <u>not</u> required prior to the publication of this document"

Summary of Technical Progress

A number of activities have been carried out in the last three months. A list outlining these efforts is presented below followed by brief description of each activity in the subsequent sections of this report:

- Progress is being made on the development of a black oil three-phase simulator which will allow the use of a generalized Voronoi grid in the plane perpendicular to a horizontal well.
- The available analytical solutions in the literature for calculating productivity indices (Inflow Performance) of horizontal wells have been reviewed. The pseudo-steady state analytic model of Goode and Kuchuk has been applied to an example problem.
- A general mechanistic two-phase flow model is under development. The model is capable of predicting flow transition boundaries for a horizontal pipe at any inclination angle. It also has the capability of determining pressure drops and holdups for all the flow regimes. A large code incorporating all the features of the model has been programmed and is currently being tested.
- The experimental data on the single phase oil and water have been analyzed in more detail for all the measured flow rates. The variation of the wellbore diameter along the flow direction has been considered. The apparent roughness of the wellbore model has been determined. The two-phase flow experiments of oil with air and nitrogen are being completed at the Marathon Oil Company.
- The first review meeting of the Horizontal Well Industrial Affiliates Program was held on October 7-8, 1993 at Stanford. The meeting was well attended and well received. In addition to the project presentations, a number of member presentations were also made at the meeting.
- A presentation of the project was given at The Second JNOC-TRC International Symposium, November 1-7, 1993 Chiba, Japan.

Development of a Simulator Based on Voronoi Gridding (Task 1)

The major objective of this facet of the project is to develop a three-phase black oil reservoir simulator which uses Voronoi gridding features. In the first version under development, Voronoi grids can be selected in the plane perpendicular to the well, with a Cartesian spacing of layers along the well. Thus the simulator should be able to honor local radial flow geometry, faults, major heterogeneities, boundaries, anisotropy, *etc.* in the plane perpendicular to a horizontal well. The solution approach is based on CVFD (Control Volume Finite Difference) formulation which is particularly appropriate for Voronoi grids because they are locally orthogonal. The development methodology includes topics such as coupling flow inside the well with fluid flow in the reservoir, grid generation algorithms, grid visualization, property allocation, well models, reservoir initialization and numerical solution methods. The simulator is being written using object oriented programming in C++. Work is nearing completion on the first stage of the simulator, which will give the 3-D generation capability described above for modeling horizontal wells.

Analytic Solutions for Well Productivity (Task 1)

There exits a number of analytic expressions for calculating the steady-state productivity index of a horizontal well with finite length of which one of the earlier results is that due to Giger [1]. These solutions require a constant pressure condition on the outer surfaces of a drainage volume encompassing the well. Since a horizontal well, because of its usually long length, occupies a significant portion of the drainage volume, the constant pressure boundary condition is rarely satisfied. Therefore, the steady-state productivity should only be looked upon as a rough estimate of the actual productivity for a horizontal well.

Usually the more appropriate boundary condition on all the outer surfaces of the drainage volume containing a horizontal well will be the no-flow condition. The pseudo-steady state solutions for the productivity of a horizontal well incorporating the no-flow outer boundary condition are more complex than their steady-state counterparts, but generally will be more realistic and practical for a horizontal well. Babu and Odeh [2] have given a derivation of complicated analytic expressions for the pseudo-steady state productivity of a horizontal well in a finite box-shaped drainage volume of a 3D-reservoir. The well is assumed to have finite length at an arbitrary location, with alignment along the y-axis of the box. Some slightly simplified approximations for these solutions are then illustrated by these authors in a summary paper [3]. A simpler analytic solution for the pseudo-steady state productivity of a horizontal well, has been derived by Goode and Kuchuk [4], which includes anisotropy in k_x, k_y, k_z. They have considered a horizontal well parallel to the x direction producing from a rectangular region of dimensions $x_e \times y_e$ with uniform thickness. The well of length L is located at x_w, y_w and z_w. Under the reasonable assumption that the thickness of the reservoir is small compared with the distance from the well to any of the boundaries in the x or y direction, the well is treated as an infinitely conductive fracture which fully penetrates the formation. The partial penetration in the z direction is accounted for by a geometric skin factor. The dimensionless pressure is derived as [4]

$$\begin{aligned} P_{wD} &= \frac{2\pi y_e}{y_w}\sqrt{\frac{k_x}{k_y}}\left(\frac{1}{3}-\frac{y_w}{y_e}+\frac{y_w^2}{y_e^2}\right) \\ &\quad +\frac{8x_e^2}{\pi^2 L^2}\sum_{n=1}^{\infty}\frac{1}{n}E_x^2(1+\xi)+S_{zD} \end{aligned} \tag{1}$$

where E_x, ξ, and S_{zD} are functions of the dimensions of the system.

The productivity index (PI) can then be calculated from

$$PI = \frac{2\pi\sqrt{k_x k_y}h}{\mu_o B_o (P_{wD}+S_m^\star)} \tag{2}$$

in which

$$S_m^\star = (h/L)\sqrt{k_x/k_z}S_m \tag{3}$$

and S_m is the mechanical skin.

We have used the above method to compute PIs for a numerical example. A reservoir with dimensions of $x_e = 5000$, $y_e = 5500$, $h = 120\ ft$ with $\mu_o = 2\ cP$ and $B_o = 1.22\ RB/STB$ is being produced by a single horizontal well of length $L = 4000\ ft$ with $r_w = 0.26\ ft$ located at $x_w = 2500$, $y_w = 2750$, and $z_w = 30\ ft$. Permeabilities in the x and y directions are taken as $k_h = 100\ mD$ whereas the vertical permeability k_v in the z direction is varied. Variation of the PI with the length of the well is calculated for three values of $k_v/k_h = 1.0, 0.1$, and 0.01 with $S_m = 0$. Results are shown in Fig. 1. It can be seen that the productivity increases almost linearly with the length of the well for a fixed ratio of k_v/k_h. The PI also increases , as expected, with an increase in the vertical permeability. The effect of a change in the wellbore radius on the PI is also studied. Results with a smaller wellbore radius of 0.18 ft and $k_v/k_h = 0.1$ are shown in Fig. 1 where a weak dependence of PI on the wellbore radius is obtained for this example. Simulation results are being used to confirm this analysis, and how the results shift if non-uniformities in permeabilities are introduced, *etc.*

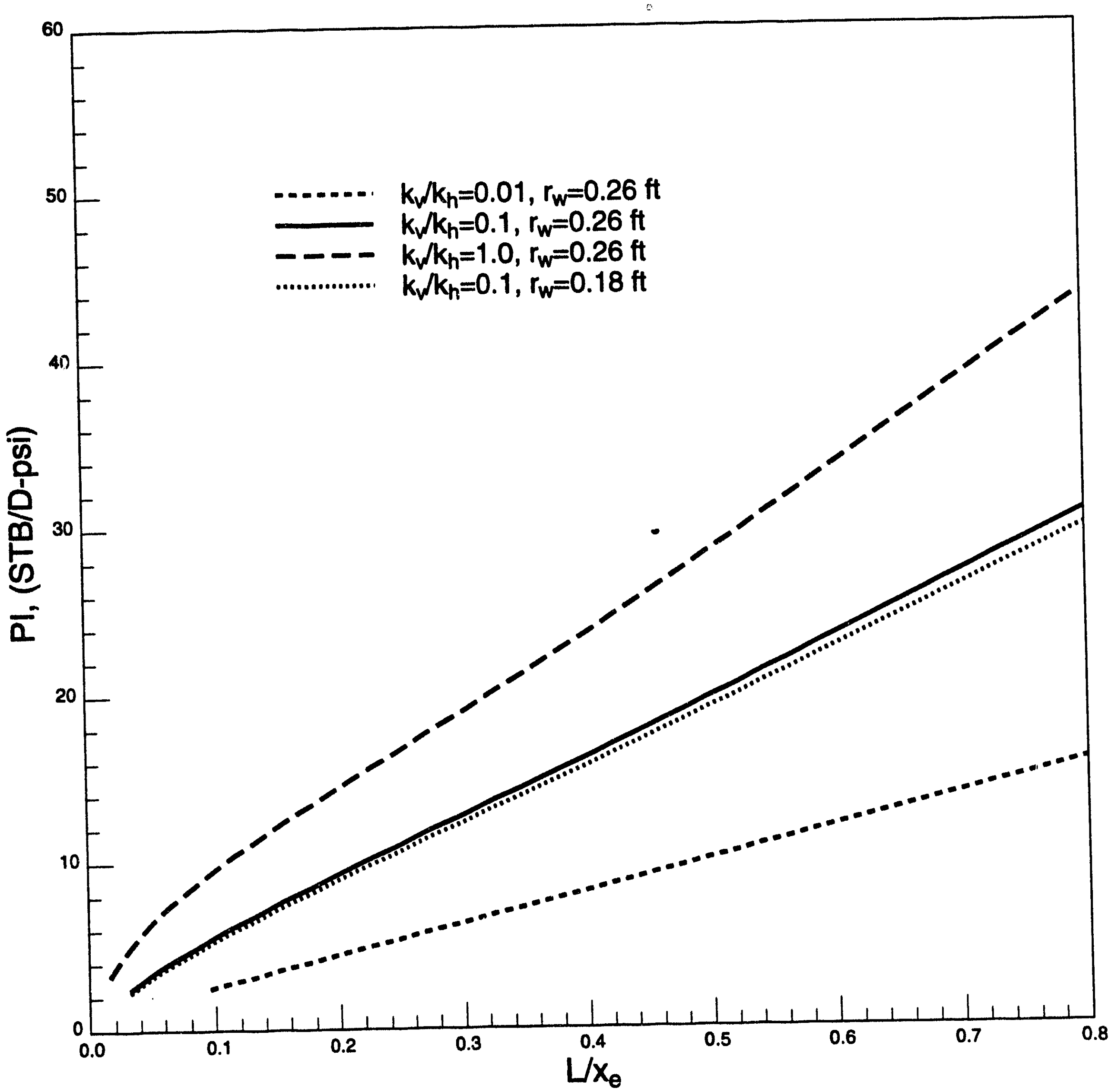

Figure 1- Variations of PI for the Example Problem

Development of a General Mechanistic Two-Phase Flow Model (Task 3)

Besides the uncertainty of the applicability of two-phase flow correlations to the horizontal well problems, there is also considerable uncertainty about the accuracy of these correlations even for standard pipe flow calculations. Furthermore, many of the well known correlations have sharp discontinuities in holdup and pressure drop across flow pattern boundaries. A general mechanistic model is being developed for modeling two-phase flows in pipes. This model which is an extension of the work of Barnea [5], is also capable of calculating pressure drops and holdups for all flow regimes. The flow pattern predictions by this method are sensitive to changes in the angle of inclination and fluid properties, with significant differences between up-flow and down-flow in tilted pipes. Figure 2 shows flow pattern transitions predicted by this model for a two-phase oil/gas flow in a horizontal pipe with ID=6.18 inches and an absoulte roughness of 0.01 ft. The oil and gas viscosities were taken as 2.8 and 0.018 cP respectively. The oil density was 52.53 lbm/scf and that of gas was 8.139 lbm/scf. Figure 3 shows the flow pattern transitions predicted by a modification of the Beggs and Brill method [6] due to Brown [7] for the same case. Significant differences in the location of transition boundaries are seen from the log scales of the axes. Moreover, The Beggs and Brill method uses the same flow pattern prediction method for all angles of inclination.

The mechanistic flow model is currently being tested and the two-phase flow experiments are underway. The flow model will then be used to predict the experimental data. The results will then be employed in verification and refinement of the flow model.

Experiments at the Marathon Oil Company: Data Analyses (Task 3)

We have analyzed the reported data for the single-phase flow experiments. Only the core flow data with no influx of water or oil are considered in this first analysis. We have also characterized the wellbore model (i.e., selected the appropriate roughness of the pipe) using the single-phase flow calculations.

The water core flow data are analyzed first. We have considered the data with water core flow rates of $Q = 400, 500$, and 580 gpm, in both forward and reverse directions. In the computation of the pressure drops, we have taken into account the measured variations of the wellbore diameter along the length of the model. For each 10 ft section of the wellbore, an average diameter was calculated from the reported ultrasonic measurements of the diameter along the model. We first used the smooth pipe assumption and calculated the pressure drops

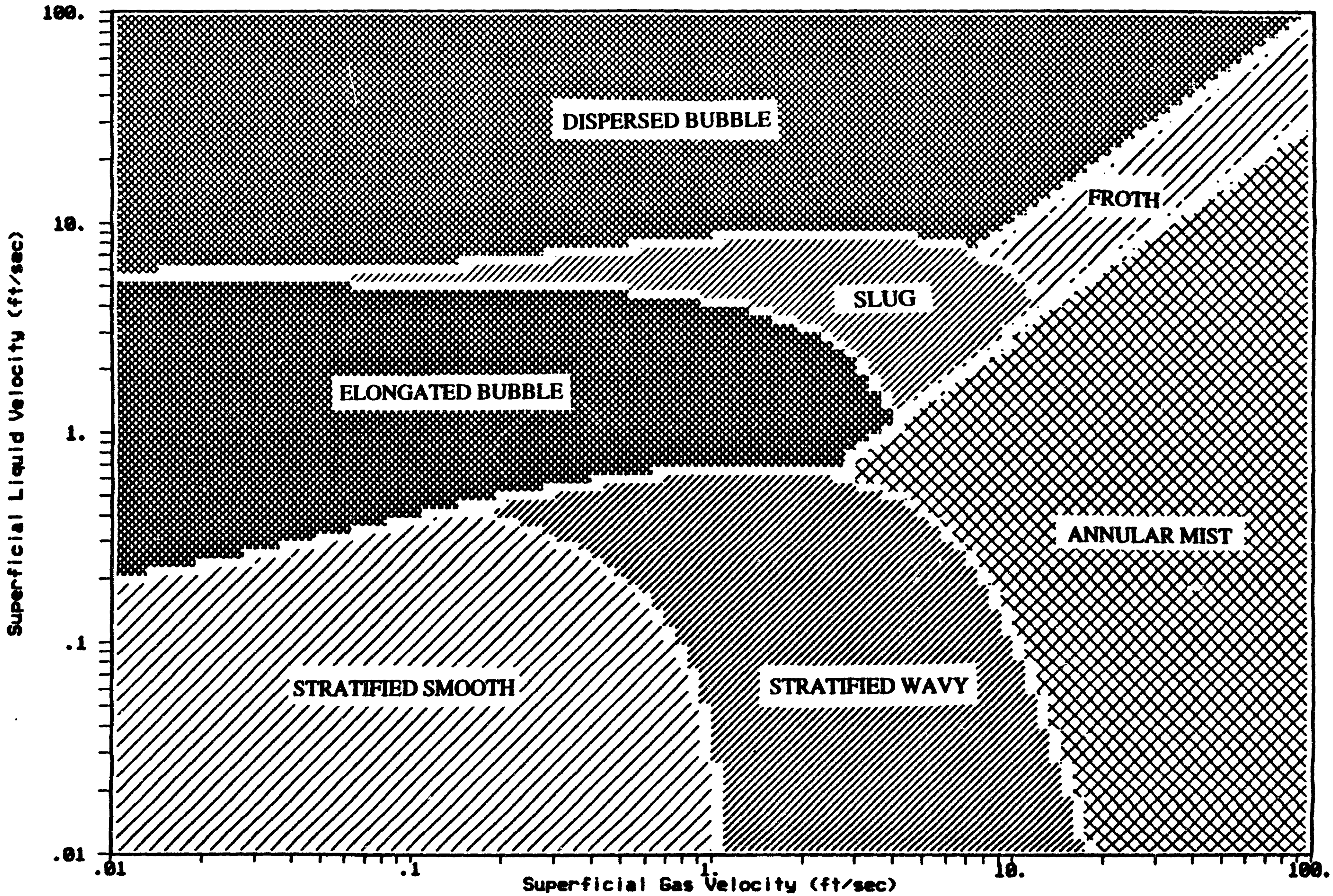

Figure 2- Prediction of Flow Regimes from the General Mechanistic Model under Development

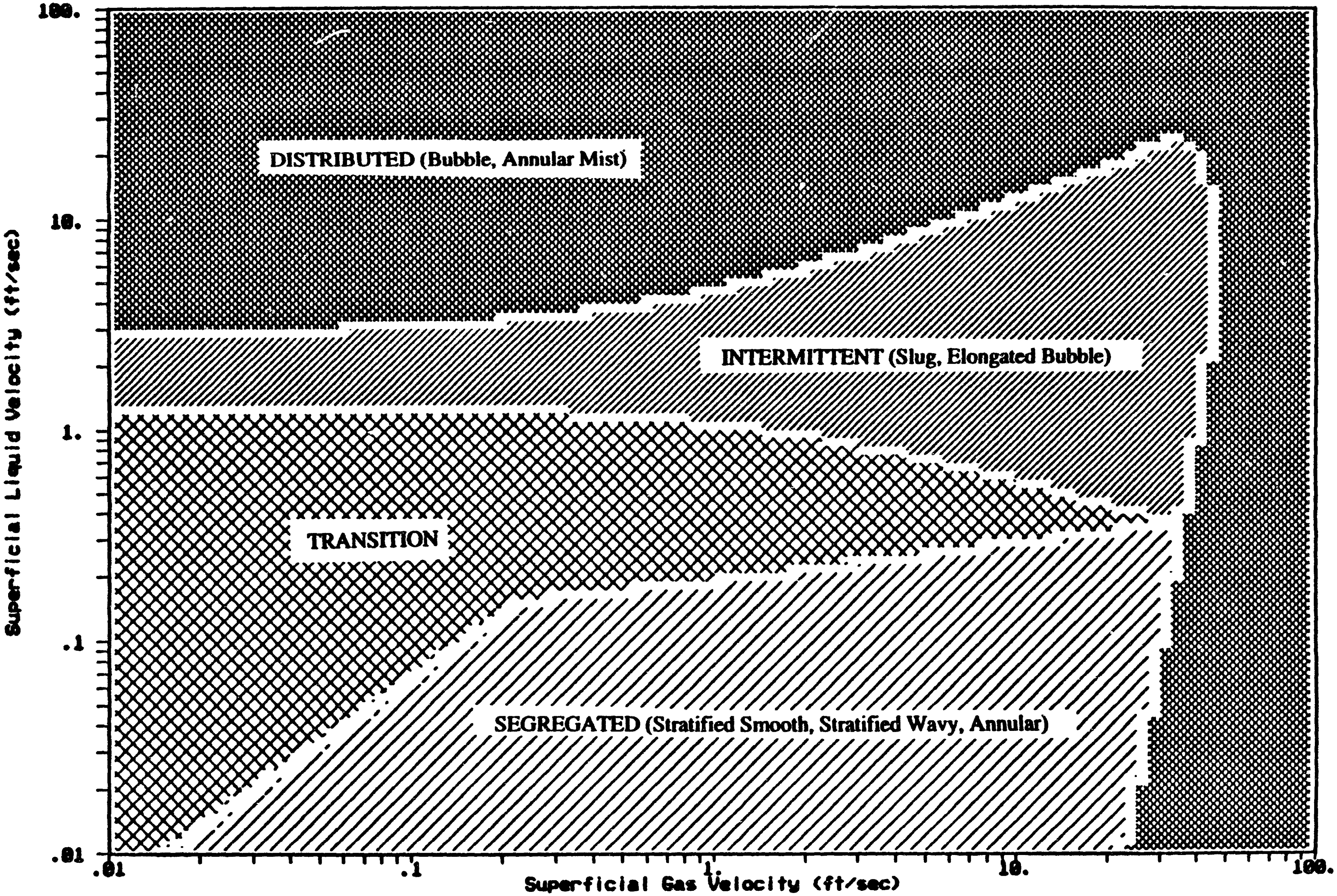

Figure 3- Prediction of Flow Regimes for a Horizontal Pipe from a Modification of the Beggs and Brill Method

per 10 ft length of the pipe (DP). Next we tried to match a single data point (the data for the 60-70 ft section with $Q = 580$ *gpm* was used). A good match is obtained with a small absolute roughness of $\epsilon = 8 \times 10^{-5}$ ft. The pressure drop computations are then performed with this value of roughness for all the cases. The data and results are shown in Figure 4. The DPs are placed at the middle of the sections to which they apply in the figure.

It can seen from Fig. 4 that the calculated "rough" case predicts the pressure drop data better than the calculated smooth case. In general the agreement between the data and the calculated values is good except for the last two sections in the forward flow direction (i.e., the 15-25 and 5-15 ft sections). The 15-25 ft section reads low in both directions for all flow rates while the 5-15 ft section reads very high especially for the reverse flow. The pressure drop in the 5-15 ft section is possibly influenced by the end or entrance effects in the forward or reverse flow directions respectively. An important feature is the observed consistency in the data. For instance, the same section reads low for all the flow rates in both directions. The sensitivity to flow direction which appears for the 5-15 ft section is not seen at the opposite end (80-90 ft) even though the connection arrangements at each end are similar, i.e., 4 inch pipe joined to 6 inch test section. The reasons for this sensitivity at only one end are under investigation. Next, we examined the oil core flow data for flow rates of $Q = 311, 400$, and 493 *gpm*. These were performed in only one direction. Pressure drop calculations were made for the smooth pipe and the "rough" cases with the same roughness as used in the water case. Figure 5 displays the pressure drop data and the predictions. The higher oil viscosity results in lower Reynolds numbers than those of water ($Re \approx 4 \times 10^4$ for oil versus $\approx 2 \times 10^5$ for water with $Q = 400$ *gpm*). Therefore, the pipe roughness and the variations of the diameter have a smaller effect on the pressure drops in oil runs in comparison with the water experiments as shown in Fig. 5. All the computations were performed using the ASA software package [8].

Various changes are being made to the rig to give better conditions for two-phase flow experiments of oil/air or Nitrogen. A number of experimental runs with oil/water core flow and air influx have recently been undertaken. Higher gas flow rates are achieved by vaporizing liquid Nitrogen which is then supplied, instead of air, to the wellbore model through the perforations. The higher gas inflow rate causes a larger pressure drop in the wellbore and changes the flow patterns which are recorded on a TV-scanning system.

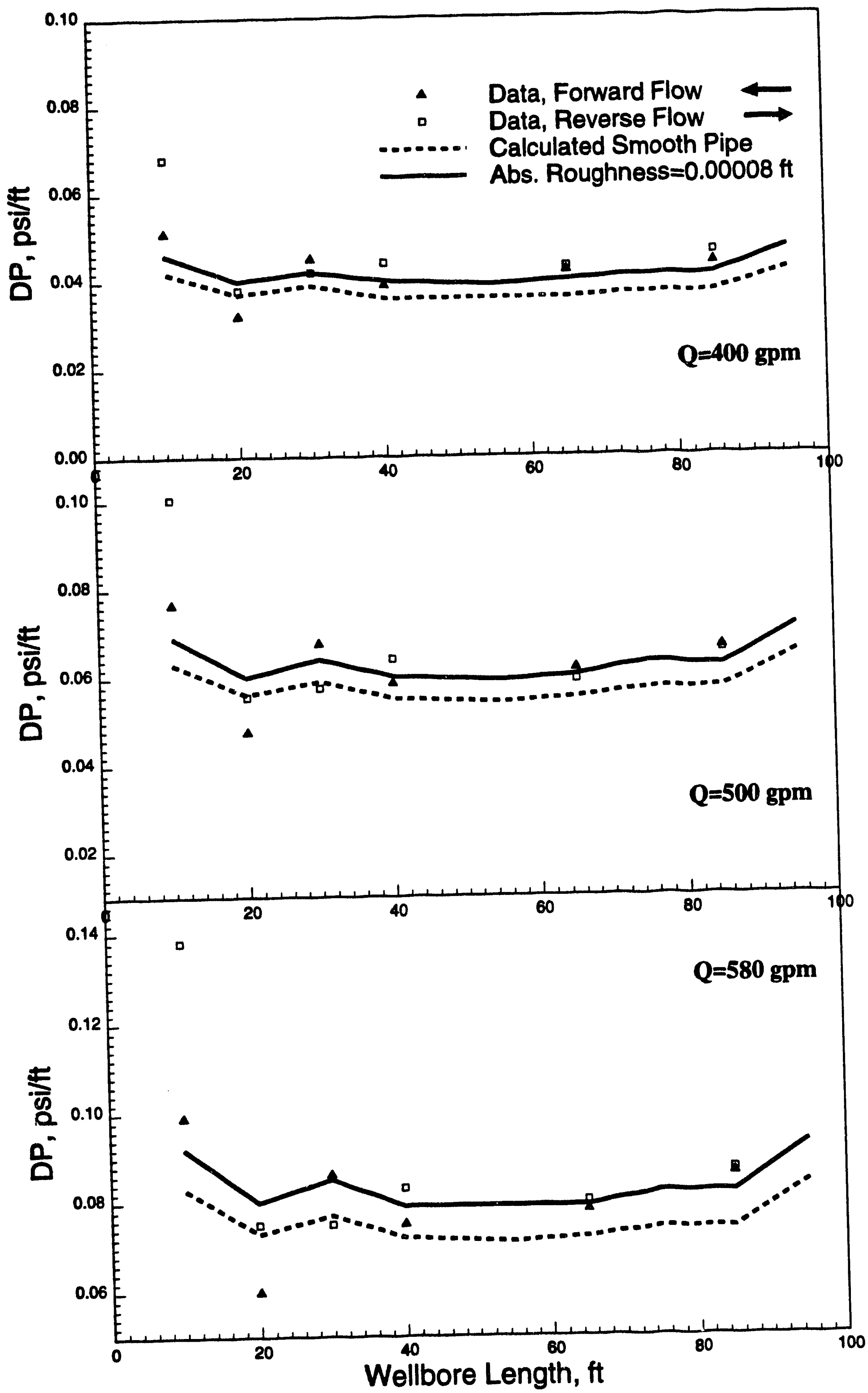

Figure 4- Data Analysis of Single-Phase Water Core Flow Experiments

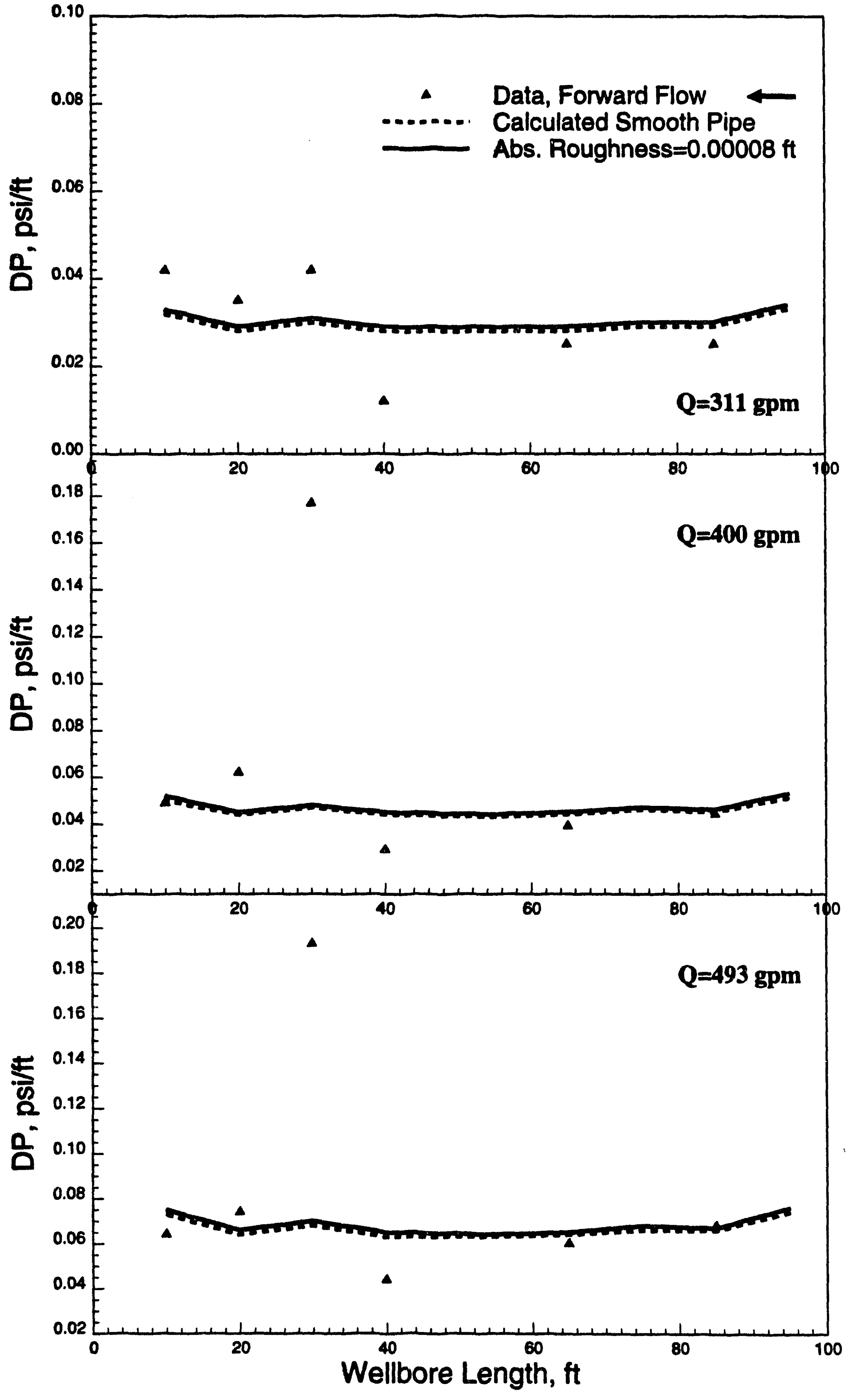

Figure 5- Data Analysis of Single-Phase Oil Core Flow Experiments

Nomenclature

B_o	Oil formation volume factor
h	Oil column thickness
k_i	Permeability in the i^{th} direction
P_w	Well pressure
P_D	Dimensionless pressure
r_w	Well radius
S_m	Skin factor
x_e	Longitudinal well spacing
x_w	x co-ordinate location of the well
y_e	Transverse well spacing
y_w	y co-ordinate location of the well
z_w	Height of well above the bottom of pay zone
μ_o	Oil viscosity

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