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**MULTIPHASE FLOW  
PRODUCTION MODEL  
(PROMOD1)  
THEORY AND USER'S MANUAL**

DEA 67  
PHASE I

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**Multiphase Flow Production Model  
(PROMOD1)**

- **Velocity String**
- **Nodal Analysis**
- **Gas Lift**

**Theory and User's Manual**

**DEA-67, Phase I**

**Project to Develop And Evaluate Slim-Hole And  
Coiled-Tubing Technology**

By

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# 1. Introduction

The PROMOD1 program was developed as part of the Drilling Engineering Association's DEA-67 project to "Develop and Evaluate Slim-Hole and Coiled-Tubing Technology." The program calculates oil, water, and gas production rate, as well as pressure drop along the wellbore, based on the wellbore configuration and reservoir properties. It can be used for 1) velocity string design, 2) nodal analysis, and 3) gas-lift calculations.

The program describes the complex multiphase flow in reservoir, wellbore, choke, and surface pipe lines. It uses Fetkovich's equations for flow in gas reservoirs and Vogel's or PI equations for flow in oil reservoirs. The multiphase flow in wellbores and pipe lines is handled by several multiphase flow equations including Beggs-Brill, Hagedorn-Brown, Hasan-Kabir, and Duns and Ros. A few other empirical correlations are used to describe the multiphase flow through the choke. A gas lift option is also included with the program. The injection depth can be specified anywhere along the wellbore.

PROMOD1 calculates production rate by solving reservoir and wellbore flow equations simultaneously. It also outputs the pressure profiles along the wellbore, the liquid hold-up distribution, gas and liquid velocities, and flow regime map along the wellbore. These results are displayed both in tabular and graphic forms.

Two types of inflow/outflow performance curves are provided, based on the solution node the user chooses. If the bottom-hole node is selected, the program displays two sets of bottom-hole pressures against production rates calculated from reservoir and tubing equations (including choke and surface line), respectively. When the wellhead node is selected, the program displays two sets of wellhead pressures against production rates calculated from reservoir plus tubing equations and choke plus surface line equations, respectively. The production point is determined by the cross point between these two sets of curves. In addition, the program calculates and displays the minimum production rate required for continuous removal of liquid from the wellbore, based on the droplet model developed by Turner et al., 1969.

## 1.1 MODEL FEATURES OF PROMOD

The key features of PROMOD are its ability to:

1. Handle both oil and gas wells
2. Deal with 3-D wellbores
3. Handle 15 sections of tubing strings and 10 well intervals (including casing strings and open-hole sections)
4. Select 1 of 4 correlations for multiphase flow
5. Select 1 of 2 solubility correlations for oil wells

6. Select 1 of 3 choke flow correlations or no choke at all
7. Include the gas lift option for oil wells
8. Input up to 3 reservoir pressures or production rates for comparison
9. Choice of unit systems: English or Metric

The output window is a compilation of “child” windows of text reports and graphs, which includes:

1. Tabulated results
2. Flow regime profiles
3. Pressure distributions
4. Liquid hold-up profiles
5. Liquid and gas velocities
6. Inflow/outflow performance curves with the bottom-hole or wellhead as the node
7. Minimum gas rate for continuous removal of liquid from gas wells

## 1.2 REQUIRED INPUT DATA

There are five data files associated with PROMOD1.

1. Well Data File (.WDI)
  - a. Company and project name
  - b. Well locations
  - c. Date and comments
2. Survey Data File (.SDI)
  - a. Directional survey data for the well. Survey must start with zero depth, zero azimuth, and zero inclination
3. Tubular Data File (.VT1)
  - a. Length, ID and OD of tubing string
  - b. Length and ID of casing string and open-hole section
  - c. Surface line length, deviation, and ID
  - d. Choke size
  - e. Perforation depth
  - f. Flow path either through tubing or annulus
4. Parameter Data File (.VP1)
  - a. Well type: oil or gas well
  - b. Rate data
  - c. Oil and gas properties
  - d. Temperature data



- e. Productivity data
- f. Gas lift data (optional)

5. Project Data File (.VJ1)

- a. Stores the names of the four files mentioned above and the units used.

All input data saved on disk or in memory are in the English system of units.

### 1.3 DISCLAIMER

No warranty or representation is expressed or implied with respect to these programs or documentation including their quality, performance, merchantability, or fitness for a particular purpose.

### 1.4 COPYRIGHT

Participants in DEA-67 can provide data output from this copyrighted program to their affiliates and can duplicate the program and manual for their in-house use, but are not to give copies of the program or this manual to third parties.



## 2. Theory and Equations

### 2.1 INTRODUCTION

A typical well production system, a gas well or an oil well, consists of several components including:

1. Flow through porous medium
2. Flow through vertical or directional wellbore
3. Flow through choke
4. Flow through surface line

Figure 2-1 shows a schematic of a simple producing system.

Each component affects the well production rate and pressure loss in a different way. A systematic approach has to be used to solve the total producing system. In doing so, nodes are placed to segment the portion defined by different equations or correlations.

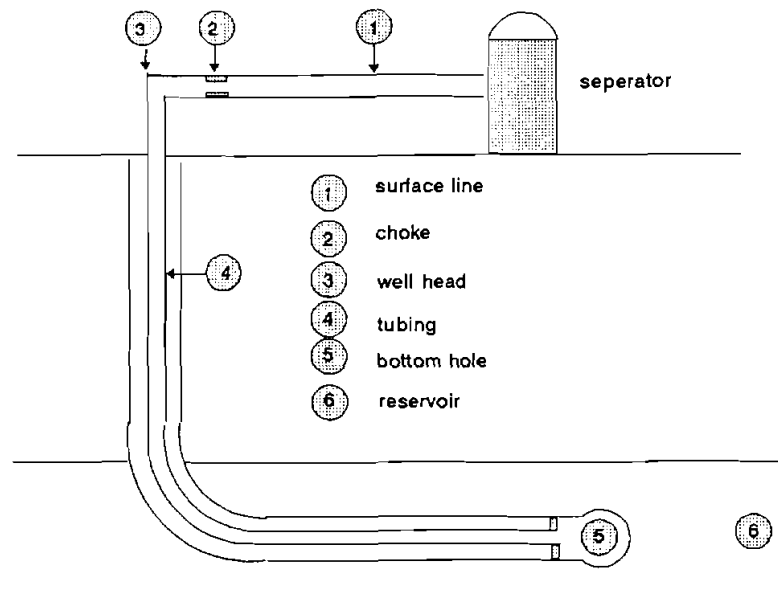


Figure 2-1. Well Production System

Two nodes are used in the program to segment the production system: 1) node No. 5 at the bottom of the hole and 2) node No. 3 at the wellhead. When the bottom-hole node is used, the system is segmented into a reservoir component and a well component which includes tubing, choke and surface line. When flowing through the annulus, the well component includes the annulus between the tubing and casing, the choke and the surface pipe line (Figure 2-2).

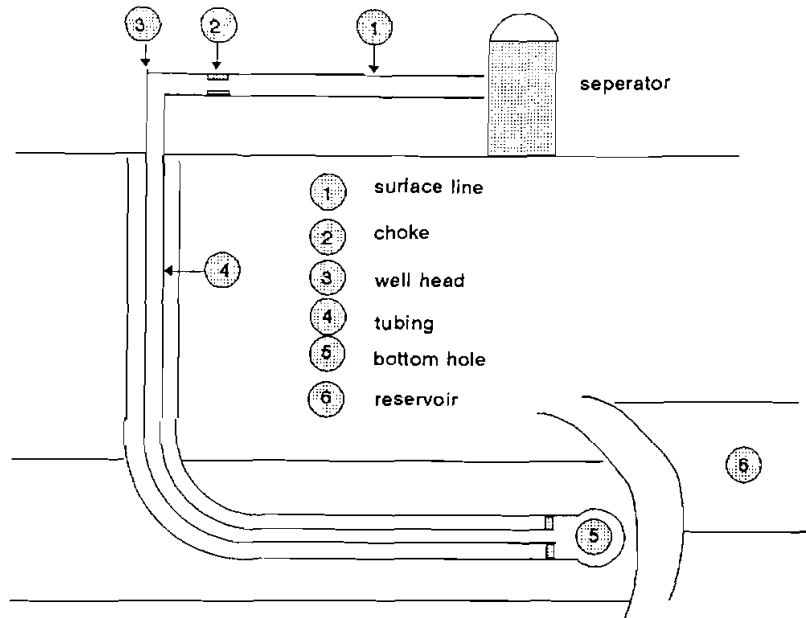


Figure 2-2. System Segmentation with Bottom-Hole Node

When the wellhead node is selected, the system is segmented into a surface component and a sub-surface component. The surface component includes the choke and surface pipe line. The sub-surface component includes the reservoir and tubing or annulus (Figure 2-3).

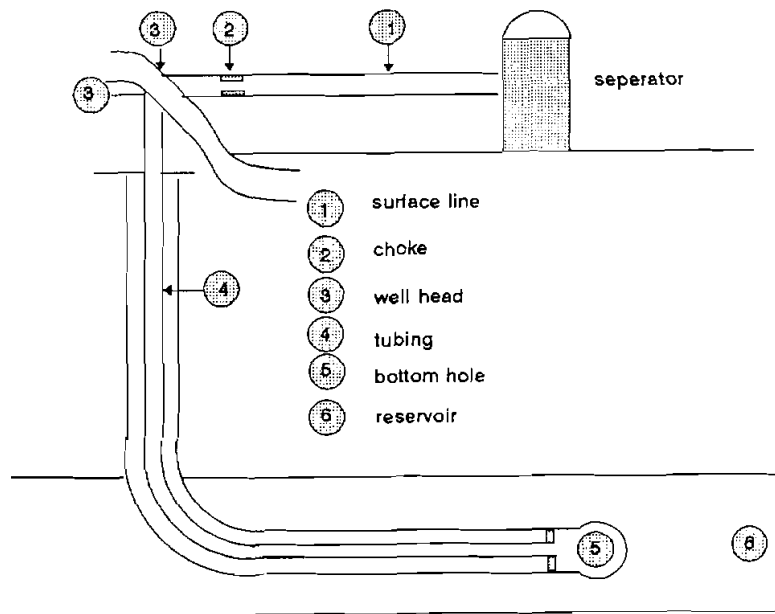


Figure 2-3. System Segmentation with Wellhead Node

## 2.2 SOLUTION PROCEDURE FOR BOTTOM-HOLE NODE

Figure 2-2 shows the two segmented components when the bottom-hole node is selected: reservoir and tubing components. For a given production rate, the bottom-hole pressure can be calculated in two ways: 1) from the reservoir component using inflow equations and 2) from the tubing component using multiphase flow correlations for pipes and chokes. Suppose the reservoir inflow is represented by the following equation:

$$P_{wf} = P_r - f_1(Q) \quad (2-1)$$

where  $f_1(Q)$  is the pressure loss across the reservoir. A plot of  $P_{wf}$  against  $Q$  from this equation is called the inflow performance curve, an example of which is shown in Figure 2-4 (solid data points). Equation (2-1) can take different forms depending on the fluid produced and the reservoir properties. Detailed descriptions are provided in later sections.

Another way of determining  $P_{wf}$  is to use multiphase correlations for flow in tubing, choke, and surface lines. For a known outlet pressure,  $P_{out}$ , the following equation gives the relationship between production rate and bottom-hole pressure:

$$P_{wf} = P_{out} + f_4(Q) + f_3(Q) + f_2(Q) \quad (2-2)$$

$f_2(Q)$  = pressure loss across tubing

$f_3(Q)$  = pressure loss across choke

$f_4(Q)$  = pressure loss across surface line

A plot of  $P_{wf}$  against  $Q$  from this equation is called the outflow performance curve (Figure 2-4, open data points). Equation 2-2 can take quite different forms, depending on the multiphase flow correlations used. There are several correlations available; four of them are included in the current version of the program. All of the correlations used in the program are presented in a later section.

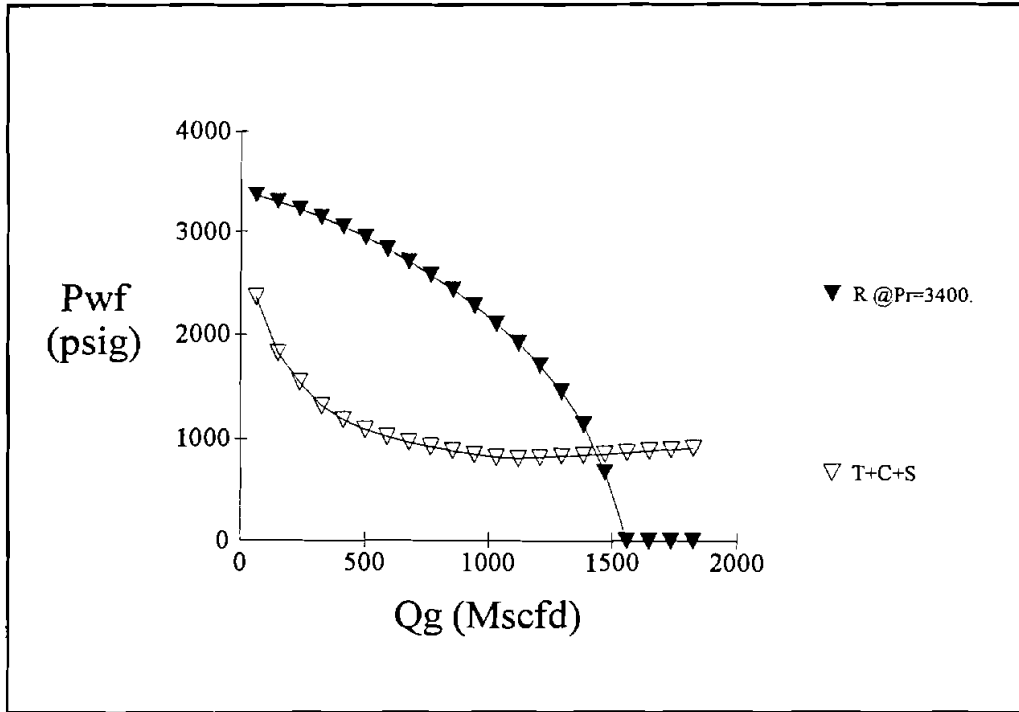


Figure 2-4. Inflow and Outflow Performance Curves with Bottom-Hole Node

These two different ways of calculating  $P_{wf}$  result in two curves as shown in Figure 2-4. The cross point of these two curves gives the production rate and the corresponding bottom-hole pressure for the production system. If there is no cross point between these two curves (Figure 2-5), the production system ceases producing any fluid because reservoir pressure is inadequate to lift the fluid out of the well. This inadequacy can be the result of declining reservoir pressure or too much energy loss in the tubing, choke, or surface line. A recompletion or an artificial lift method is required for such conditions.

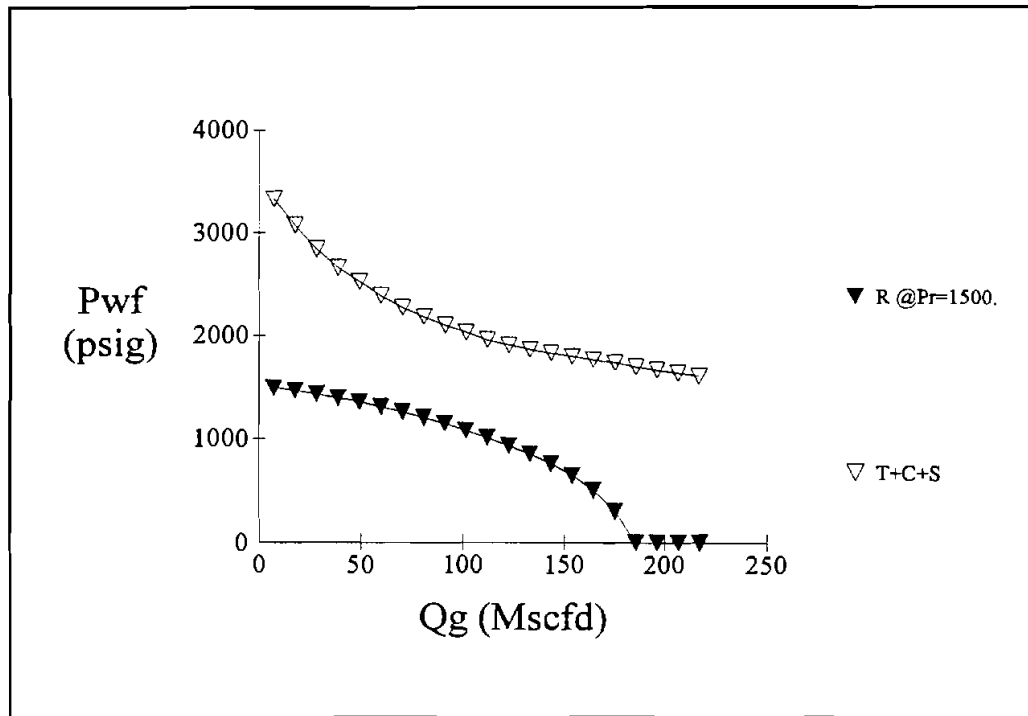


Figure 2-5. Inflow and Outflow Curves do not Intersect

### 2.3 SOLUTION PROCEDURE FOR WELLHEAD NODE

Figure 2-3 shows the two segmented components, surface and sub-surface, when the wellhead node is used. Accordingly, for a given production rate, the wellhead pressure can be calculated in two different ways from the surface and sub-surface components. Surface components include the choke and the surface line with known outlet pressure. For any production rate, the wellhead pressure can be calculated by adding the pressure loss across the surface line and the choke to the outlet pressure:

$$P_{wh} = P_{out} + f_4(Q) + f_3(Q) \quad (2-3)$$

A plot of  $P_{wh}$  against  $Q$  from Eq. (2-3) is called outflow performance curve (Figure 2-6). It can be determined using different empirical correlations for flows in the surface line and the choke. Details will be presented in a later section.

Another way of determining the wellhead pressure is to use the sub-surface component. It consists of two sections: 1) the reservoir flow, and 2) the flow in tubing or annulus. The calculation begins with the reservoir pressure. For the given rate, bottom-hole pressure can be determined using the reservoir equation. Once the bottom-hole pressure is known, the wellhead pressure is then calculated using the multiphase correlations for flows in tubing or annulus. The process is described in the following equation:

$$P_{wh} = P_r - f_1(Q) - f_2(Q) \quad (2-4)$$

A plot of  $P_{wh}$  against  $Q$  from Eq (2-4) is called the inflow performance curve (Figure 2-6).

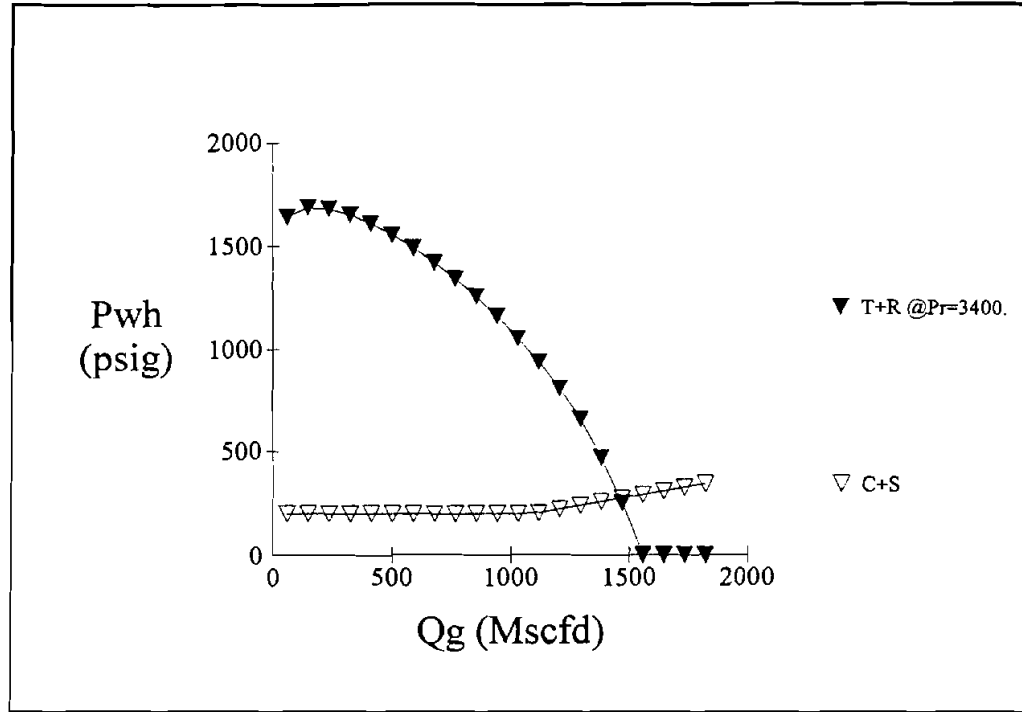


Figure 2-6. Inflow and Outflow Performance Curves with Wellhead as the Node

The cross point of the inflow and outflow performance curves provides the production rate and the wellhead pressure shown in Figure 2-6. If there is no cross point between these two curves, the well ceases production. A recompletion or a lift method is required.

## 2.4 RESERVOIR INFLOW PERFORMANCE EQUATIONS

The preparation of inflow performance relationship (IPR) curves for oil and gas wells is extremely important in production systems analysis. Unless some idea of the productive capacity of a well can be established, the design and optimization of the piping system becomes difficult. This section presents two flow equations for oil reservoirs and one equation for gas reservoirs.

### 2.4.1 PI Equation for Oil Reservoirs

When the bottom-hole pressure is higher than the bubble-point pressure, single-phase liquid flow results, since all of the gas dissolves in the oil. The production can be calculated using Darcy's equation from a vertical well with closed outer boundary (Brown, 1984).

$$q_o = PI (P_r - P_{wf}) \quad (2-5)$$



$$PI = \frac{7.08 \times 10^{-3} k_o h}{\overline{\mu}_o B_o (\ln r_e/r_w - 0.75 + S'' + a'q)} \quad (2-6)$$

where:

- PI = productivity index stb/d/psi
- $k_o$  = effective permeability (md)
- h = effective feet of oil pay (ft)
- $P_r$  = average reservoir pressure (psia)
- $P_{wf}$  = wellbore sandface flowing pressure at center of perforations (psia)
- $q_o$  = oil flow rate (stb/d)
- $r_e$  = radius of drainage (ft)
- $r_w$  = radius of wellbore (ft)
- $S''$  = total skin
- $a'q$  = turbulent flow term (The  $a'q$  term is normally not significant for low permeability wells and low flow rates)
- $\overline{\mu}_o$  = viscosity (cp) at average pressure of  $(P_r + P_{wf})/2$
- $B_o$  = formation volume factor at average pressure

For a horizontal well, Joshi's equation can be used (Joshi, 1986).

$$q_o = PI (P_e - P_{wf}) \quad (2-7)$$

$$PI = \frac{2 \pi k_H h}{B \mu \left[ \ln \left[ \left[ 1 + \left( \frac{2r_e}{L} \right)^2 \right]^{1/2} + \frac{2r_e}{L} \right] + \frac{\beta h}{L} \ln \left[ \frac{\beta h}{2 \pi r_w} \right] \right] \left[ 1 + \frac{S_H}{\ln \left( \frac{r_e}{r_w} \right)} \right]} \quad (2-8)$$

where

$$\beta = \sqrt{K_H/K_v} \quad (2-9)$$

- $K_v$  = Vertical Permeability (md)
- $K_H$  = Horizontal Permeability (md)
- L = Horizontal Well Length (ft)

Equations (2-5) and (2-7) are denoted as PI equations in the program for solution gas driven oil wells. PI can be estimated using Eqs. (2-6) or (2-8) for vertical and horizontal wells, respectively. The user can modify those equations as necessary since only the input of PI is required.

It is noted that in the current version of the program, all production is assumed to be from a single perforation point. This assumption may be appropriate for a vertical well. For a horizontal well, the assumption may lead to erroneous results. However, if the pressure loss in the horizontal section is small, the error should not be significant. An improvement in this area is planned for later versions when appropriate.

#### 2.4.2 Vogel's Equation for Oil Reservoirs

A simplified solution to the two-phase flow problem was offered by Vogel (1968). He gave the following general equation to account for two-phase flow in the reservoir (saturation effects):

$$q_o/q_{\max} = 1 - 0.2 \left[ \frac{P_{wf}}{P_r} \right] - 0.8 \left[ \frac{P_{wf}}{P_r} \right]^2 \quad (2-10)$$

He arrived at this equation from a computer solution to several solution-gas-drive reservoirs and for different fluid properties. Figure 2-7 may also be used to arrive at a solution. His solution has been found to be very good and is widely used in the prediction of IPR curves where two-phase flow exists (liquid and gas). It appears to work reasonably well for water percentages up to 50%.

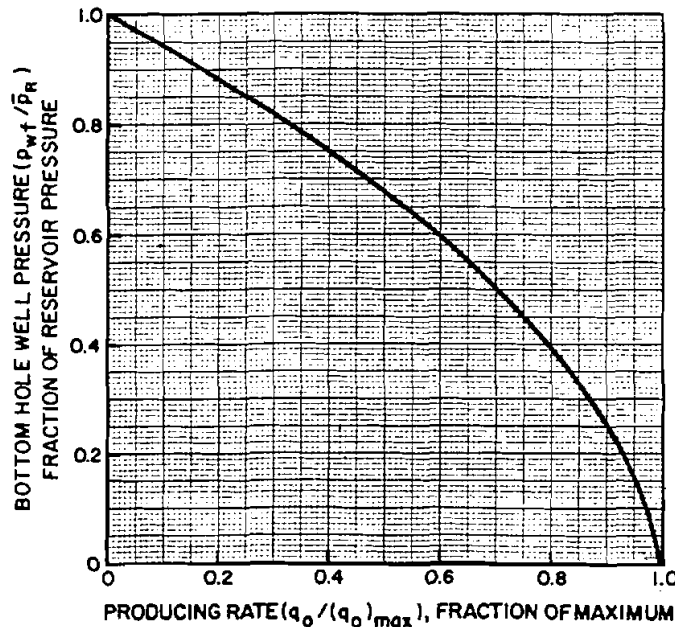


Figure 2-7. Inflow Performance Relationship for Solution-Gas-Drive Reservoirs (After Vogel)

#### 2.4.3 Fetkovich's Equation for Gas Reservoirs

One of the most common equations for gas rate prediction is the back-pressure equation, which takes the form of the following:

$$Q_g = c \left( P_r^2 - P_{wf}^2 \right)^n \quad (2-11)$$

where:  $Q_g$  = gas production rate MSCFD  
 $P_r$  = average reservoir pressure, psi  
 $P_{wf}$  = bottom-hole pressure, psi  
 $c$  = coefficient from well data  
 $n$  = exponent obtained from well tests

Note that  $c$  and  $n$  are usually determined based on the well testing data, which may not be practical from an economic viewpoint. Economic practicality is hampered by the fact that the well is probably already in the loaded condition. Thus, in order for the test data to be meaningful, the well would have to be put into an unloaded condition and maintained in that condition for the duration of the testing.

Rather than go the expense of this type of testing, it is often felt that it is adequate to apply a method for predicting future IPR curves. One such method is that of the Fetkovich equation shown below (SPE 4529):

$$Q_g = c \left[ \frac{P_r}{P_i} \right] \left( P_r^2 - P_{wf}^2 \right)^n \quad (2-12)$$

where:  $P_r$  = current average reservoir pressure  
 $P_{wf}$  = bottom-hole pressure  
 $P_i$  = initial reservoir pressure  
 $c$  = coefficient from testing data when pressure is at  $P_i$   
 $n$  = exponent from testing data when pressure is at  $P_i$

Using a method such as this allows any testing to be limited to a bottom-hole pressure build-up test to determine the current reservoir pressure. Once the IPR curve has been determined, it can be cross plotted on the tubing performance curve plot. The intersection of these two curves indicates where the well will produce with that particular set of tubulars and conditions.

## 2.5 MULTIPHASE CORRELATIONS FOR FLOW IN WELLBORE OR SURFACE LINES

As discussed earlier, the modeling of production systems involves a large amount of calculation of multiphase flow in wellbores and surface pipe lines. There is a number of correlations available in the industry for this purpose. However, none of the multiphase flow correlations works well across the full range of conditions encountered in oil and gas fields. Thus, in order to get a realistic tubing performance curve, great care should be taken to ensure that the input variables are as realistic as possible. *The correlations described below use SI units. The pressure drop calculated from these correlations has to be converted to English units before being used.*

### 2.5.1 Beggs-Brill Correlation (Beggs and Brill, 1973)

This empirical correlation was developed from air/water two-phase flow experiments. It applies to pipes of all inclination angles. The following is the procedure to calculate the liquid holdup:

- (1) Calculate total flux rate

$$v_m = v_{sl} + v_{sg} \quad (2-13)$$

- (2) Calculate no-slip holdup

$$\lambda_{ns} = \frac{v_{sl}}{v_{sl} + v_{sg}} \quad (2-14)$$

- (3) Calculate the Froude number,  $N_{FR}$

$$N_{FR} = \frac{v_m^2}{g d} \quad (2-15)$$

- (4) Calculate liquid velocity number

$$N_{Lv} = v_{sl} \left( \frac{\rho_L}{g \sigma_L} \right)^{0.25} \quad (2-16)$$

- (5) To determine the flow pattern which would exist if flow were horizontal, calculate the correlating parameters,  $L_1$ ,  $L_2$ ,  $L_3$ , and  $L_4$ :

$$\begin{aligned} L_1 &= 316 \lambda_{ns}^{0.302} & L_2 &= 0.0009252 \lambda_{ns}^{-2.4684} \\ L_3 &= 0.10 \lambda_{ns}^{-1.4516} & L_4 &= 0.5 \lambda_{ns}^{-6.738} \end{aligned} \quad (2-17)$$

- (6) Determine flow pattern using the following limits:

Segregated:

$$\lambda_{ns} < 0.01 \text{ and } N_{FR} < L_1$$

or

$$\lambda_{ns} \geq 0.01 \text{ and } N_{FR} < L_2$$

Transition:

$$\lambda_{ns} \geq 0.01 \text{ and } L_2 < N_{FR} \leq L_3$$

Intermittent:

$$0.01 \leq \lambda_{ns} < 0.4 \text{ and } L_3 < N_{FR} \leq L_1$$

or

$$\lambda_{ns} \geq 0.4 \text{ and } L_3 < N_{FR} \leq L_4$$

Distributed:

$$\lambda_{ns} < 0.4 \text{ and } N_{FR} \geq L_1$$

or

$$\lambda_{ns} \geq 0.4 \text{ and } N_{FR} > L_4$$

(7) Calculate the horizontal holdup  $\lambda_o$

$$\lambda_o = \frac{a\lambda_{ns}^b}{N_{FR}^c} \quad (2-19)$$

where a, b, and c are determined for each flow pattern from the table:

Flow Pattern	a	b	c
Segregated	0.98	0.4846	0.0868
Intermittent	0.845	0.5351	0.0173
Distributed	1.065	0.5824	0.0609

(8) Calculate the inclination correction factor coefficient.

$$C = (1 - \lambda_{ns}) \ln \left( d\lambda_{ns}^e N_{Lv}^f N_{FR}^g \right) \quad (2-20)$$

where d, e, f, and g are determined for each flow condition from the table:

Flow Pattern	d	e	f	g
Segregated uphill	0.011	-3.768	3.539	-1.614
Intermittent uphill	2.96	0.305	-0.4473	0.0978
Distributed uphill	No Correction		C = 0	
All flow patterns downhill	4.70	-0.3692	0.1244	-0.5056

(9) Calculate the liquid holdup inclination correction factor

$$\psi = 1 + c \left[ \sin(1.8\theta) - 0.333 \sin^3(1.8\theta) \right] \quad (2-21)$$

where  $\theta$  is the deviation from horizontal axis.

(10) Calculate the liquid holdup

$$\lambda = \lambda_o \psi \quad (2-22)$$

(11) Apply Palmer correction factor:

$$\begin{aligned} \lambda &= 0.918 \cdot \lambda && \text{for uphill flow} \\ \lambda &= 0.541 \cdot \lambda && \text{for downhill flow} \end{aligned} \quad (2-23)$$

(12) When flow is in transition pattern, take the average as follows:

$$\lambda = a \cdot \lambda_1 + (1-a)\lambda_2: \quad a = \frac{L_3 - N_{FR}}{L_3 - L_2} \quad (2-24)$$

where  $\lambda_1$  is the liquid holdup calculated assuming flow is segregated,  $\lambda_2$  is the liquid holdup assuming the flow is intermittent.

(13) Calculate frictional factor ratio

$$\frac{f_{tp}}{f_{ns}} = e^S \quad (2-25)$$

where

$$S = \frac{\ln(y)}{-0.0523 + 3.1821 \ln(y) - 0.8725 [\ln(y)]^2 + 0.01853 [\ln(y)]^4}$$

$$\text{and } y = \frac{\lambda_{ns}}{\lambda^2}$$

S becomes unbounded at a point in the interval  $1 < y < 1.2$ ; and for y in this interval, the function S is calculated from

$$S = \ln(2.2y - 1.2)$$

(14) Calculate frictional pressure gradient

$$(N_{Re})_{ns} = \rho_{ns} \cdot v_m \cdot de / \mu_{ns} \quad (2-26)$$

Use this no-slip Reynolds number to calculate no-slip friction factor,  $f_{ns}'$ , using Moody's diagram, then convert it into Fanning friction factor,  $f_{ns} = f_{ns}'/4$ . The two-phase friction factor will be

$$f_{tp} = f_{ns} \cdot \frac{f_{tp}}{f_{ns}} \quad (2-27)$$

The frictional pressure gradient is

$$\left( \frac{dp}{dx} \right)_f = \frac{2f_{tp} \rho_{ms} \cdot v_m^2}{d_e} \quad (2-28)$$

### 2.5.2 Hagedorn-Brown Correlation (Brown and Beggs, 1977)

The correlation used here is actually a combination of two correlations: Hagedorn-Brown correlation for slug flow and Griffith correlation for bubble flow. They apply only to vertical wells.

Check the flow regime to determine whether to continue with the Hagedorn-Brown correlation or proceed to the Griffith correlation for bubble flow.

$$A = 1.071 - \frac{0.2218 (v_{sl} + v_{sg})^2}{d_e \cdot 0.3048^2} \quad (2-29)$$

If  $A < 0.13$ , then  $A = 0.13$ .

$$B = \frac{v_{sg}}{v_{sl} + v_{sg}} \quad (2-30)$$

If  $B-A$  is positive or has a value of zero, continue with the Hagedorn-Brown correlation. If  $B-A$  is negative, proceed with the Griffith correlation.

Griffith correlation:

$$\lambda = 1 - 0.5 \left[ 1 + \frac{v_m}{v_s} - \sqrt{\left[ 1 + \frac{v_m}{v_s} \right]^2 - 4 \cdot \frac{v_{sg}}{v_s}} \right] \quad (2-31)$$

$$v_s = 0.8 \cdot 0.3048$$

Hagedorn-Brown correlation:

(1) Calculate liquid viscosity number and coefficient.

$$N_L = \mu_L \left[ \frac{g}{\rho_L \sigma_L} \right]^{1/4} \quad (2-32)$$

$$CN_L = \frac{0.0019 + 0.0322 \cdot N_L - 0.6642 N_L^2 + 4.9951 N_L^3}{1 - 10.0147 N_L + 33.8696 N_L^2 + 277.2817 N_L^3}$$

If  $N_L \leq 0.002$ , then  $CN_L = 0.0019$

If  $N_L \geq 0.4$ , then,  $CN_L = 0.0115$

(2) Calculate liquid, gas velocity number, and pipe diameter number.

$$N_{LV} = v_{sl} \left[ \frac{\rho_L}{g \sigma_L} \right]^{1/4}$$

$$N_{GV} = v_{sg} \left[ \frac{\rho_L}{g \sigma_L} \right]^{1/4}$$

$$\phi = \frac{N_{LV}}{N_{GV}^{0.575}} \left[ \frac{P}{14.7} \right]^{0.10} \left[ \frac{CN_L}{N_d} \right] \quad (2-33)$$

$$\frac{\lambda}{\psi} = \left[ \frac{0.0047 + 1123.32 \cdot \phi + 729489.64 \cdot \phi^2}{1 + 1097.1566 \cdot \phi + 722153.97 \cdot \phi^2} \right]^{1/2}$$



- (3) Determine the secondary correction factor correlating parameter

$$\phi = \frac{N_{GV} N_L^{0.380}}{N_d^{2.14}} \quad (2-34)$$

$$\psi = \frac{1.0886 - 69.9473 \phi + 2334.3497 \phi^2 - 12896.683 \phi^3}{1 - 53.4401 \phi + 1517.9369 \cdot \phi^2 - 8419.8115 \cdot \phi^3}$$

- (4) Calculate liquid holdup

$$\lambda = \frac{\lambda}{\psi} \cdot \psi \quad (2-35)$$

- (5) Calculate frictional pressure gradient.

$$\left[ \frac{dp}{dx} \right]_f = \frac{2f \cdot \rho_{ns} \cdot v_m^2}{d_e} \cdot \frac{\rho_{ns}}{\rho_s} \quad (2-36)$$

$f$  = Fanning friction factor

$\rho_{ns}$  = no-slip average of densities

$\rho_s$  = slip average of densities

### 2.5.3 Hasan-Kabir Correlation (Hasan and Kabir, 1992)

This correlation is a recent development in multiphase flow technology. It was established based on hydrodynamic conditions and experiment observations. It applies to flow in annuli of inclination up to 80°.

1. Flow pattern identification.

The flow occurs in four different patterns depending on the superficial velocities and properties. Figure 2-8 shows a typical flow regime map for wellbores.

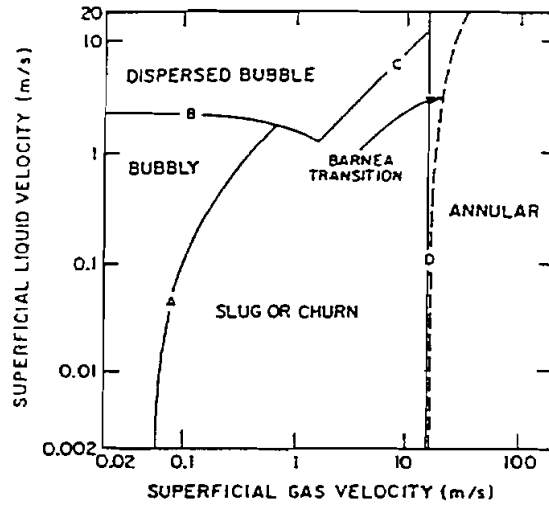


Figure 2-8. Typical Flow Regime Map for Wellbores

- a) Boundary A: transition from bubbly flow to slug or churn flow

$$v_{sg} = (0.429 v_{sl} + 0.357 \cdot v_s) \sin\theta$$

$$v_s = 1.53 \left[ \frac{g\sigma_L(\rho_L - \rho_g)}{\rho_L^2} \right]^{1/4} \quad (2-37)$$

$\theta$ : deviation from horizontal axis.

- b) Boundary B: transition from bubbly or slug flow to dispersed bubble

$$d = \left[ 0.725 + 4.15 \sqrt{\frac{v_{sg}}{v_m}} \right] \left[ \frac{\sigma_L}{\rho_L} \right]^{0.6} \left[ \frac{2fv_m^3}{d_e} \right]^{-0.4} \quad (2-38)$$

$$d_c = 2 \sqrt{\frac{0.4\sigma_L}{(\rho_L - \rho_g)g}}$$

When  $d \leq d_c$  and when superficial gas velocity stays on the left of Boundary C. Then the flow is in dispersed bubble.

- c) Boundary C: transition from slug to dispersed bubble.

$$v_{sg} = 1.083 v_{sl} + 0.52 v_s \quad (2-39)$$

d) Boundary D: transition from slug to annular flow.

$$v_{sg} = 3.1 \left[ \frac{g \sigma_L (\rho_L - \rho_g)}{\rho_g^2} \right]^{0.25} \quad (2-40)$$

2. Liquid holdup calculation.

For bubbly or dispersed bubble flow

$$\lambda = 1 - \frac{v_{sg}}{1.2 v_m + v_s} \quad (2-41)$$

For slug or churn flow

$$v_t = \left[ 0.345 + 0.1 \frac{d_T}{d_c} \right] \sqrt{\sin \theta} (1 + H \cos \theta)^{1.2} \sqrt{\frac{g d_c (\rho_L - \rho_g)}{\rho_L}} \quad (2-42)$$

$$\lambda_{TB} = 1 - \frac{v_{sg}}{1.2 v_m + v_t} \quad (2-43)$$

$$a = 1 - 0.1(1.2 v_m + v_s)/v_{sg}$$

$$\lambda = 1 - (a \cdot \lambda_{TB} + 0.1) \text{ if } v_{sg} \geq 0.4 \quad (2-44)$$

$$a = 1 - 0.25(1.2 v_m + v_s)$$

$$\lambda = 1 - (a \cdot \lambda_{TB} + 0.25 v_{sg}) \text{ if } v_{sg} < 0.4 \quad (2-45)$$

For annular flow

$$f_m = \frac{v_{sg} \cdot \rho_g}{v_{sl} \cdot \rho_L + v_{sg} \rho_g}$$

$$x = \left[ \frac{1 - f_m}{f_m} \right]^{0.9} \left[ \frac{\rho_g}{\rho_L} \left[ \frac{\mu_L}{\mu_g} \right] \right]^{0.1} \quad (2-46)$$

$$\lambda = 1 - \frac{1}{(1 + x^{0.8})^{0.378}}$$

3. Frictional pressure gradient calculation.

For bubble, slug, or dispersed bubble flow

$$N_{Re} = \frac{\rho_L v_m d_e}{\mu_L}$$

$$f_m = \frac{0.046}{N_{Re}^{0.2}}$$

$$\rho_m = \lambda \rho_L + (1 - \lambda) \rho_g \quad (2-47)$$

$$\left[ \frac{dp}{dx} \right]_f = \frac{2 f_m \cdot \rho_m \cdot v_m^2}{d_e}$$

For annular flow

$$v_{sgc} = v_{sg} \mu_g \sqrt{\frac{\rho_g}{\rho_l}} / \sigma_L \quad (2-48)$$

If  $v_{sgc} < 4 \times 10^{-4}$ , then

$$E = 0.0055 (10^4 v_{sgc})^{2.86}$$

If  $v_{sgc} \geq 4 \times 10^{-4}$ , then

$$E = 0.857 \cdot \log (10^4 \cdot v_{sgc}) - 0.2$$

#### 2.5.4 Duns and Ros Correlation (Sixth World Petroleum Congress)

The Duns and Ros correlation is a result of an extensive laboratory study in which liquid holdup and pressure gradients were measured. Correlations were developed for slip velocity (from which holdup can be calculated) and friction factor for each of three flow regimes.

1. Calculate the liquid viscosity number

$$N_L = \mu_L \left[ \frac{g}{\rho_L \sigma_L^3} \right]^{1/4} \quad (2-49)$$

2. Find the liquid and gas velocity number

$$N_{LV} = v_{sl} \left[ \frac{\rho_L}{g \sigma_L} \right]^{1/4} \quad (2-50)$$

$$N_{gv} = v_{sg} \left[ \frac{\rho_L}{g \sigma_L} \right]^{1/4} \quad (2-51)$$

3. Find the Pipe diameter number

$$N_d = d \sqrt{\frac{g \rho_L}{\sigma_L}} \quad (2-52)$$

4. Calculate dimensionless quantities

$$L_s = 50 + 36 N_{Lv} \quad (2-53)$$

$$L_m = 75 + 84 N_{Lv}^{0.75}$$

5. Find  $L_1$  and  $L_2$  in Figure 2-9.

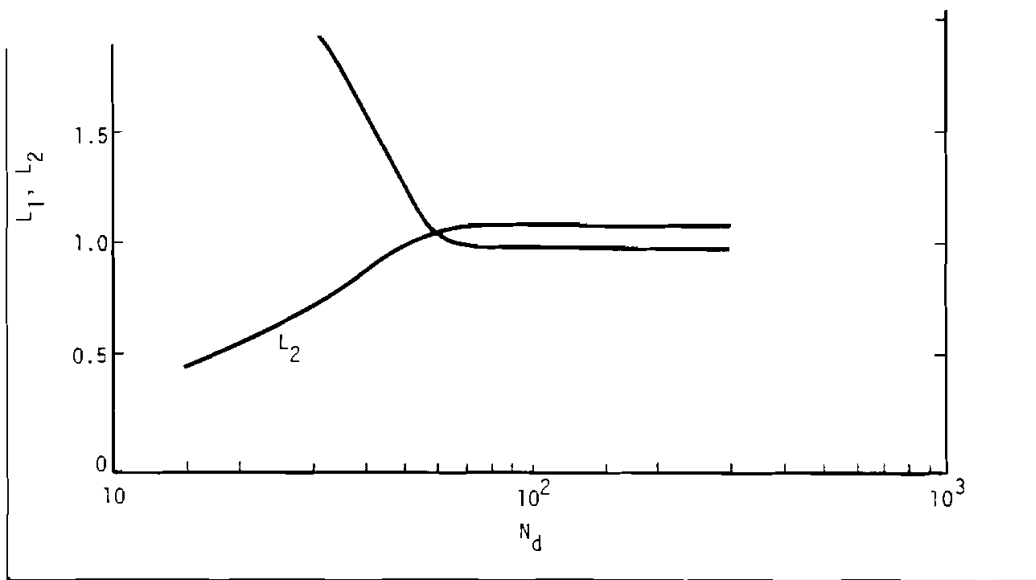


Figure 2-9. L-Factors Against Diameter Number  $N_d$  (after Ros)

6. Determine flow regime

$$\text{Bubble flow} = 0 \leq N_{gv} \leq L_1 + L_2 \cdot N_{Lv}$$

$$\text{Slug flow} = L_1 + L_2 \cdot N_{Lv} \leq N_{gv} \leq L_s$$

$$\text{Mist flow} = N_{gv} > L_m$$

$$\text{Transition} = L_s < N_{gv} < L_m$$

7. Determine the proper slip factor using the region found in the last step:

- a. Bubble flow

$$S = F_1 + F_2 N_{Lv} + F_3' \left[ \frac{N_{gv}}{1 + N_{Lv}} \right]^2 \quad (2-54)$$

$F_1$  and  $F_2$  are found in Figure 2-10.

$$F_3' = F_3 - \frac{F_4}{N_d} \text{ where } F_3 \text{ and } F_4 \text{ are found in Figure 2-10.}$$

For annular flow  $N_d$  is based on the wetted perimeter, thus:  $d = (d_c + d_t)$ .

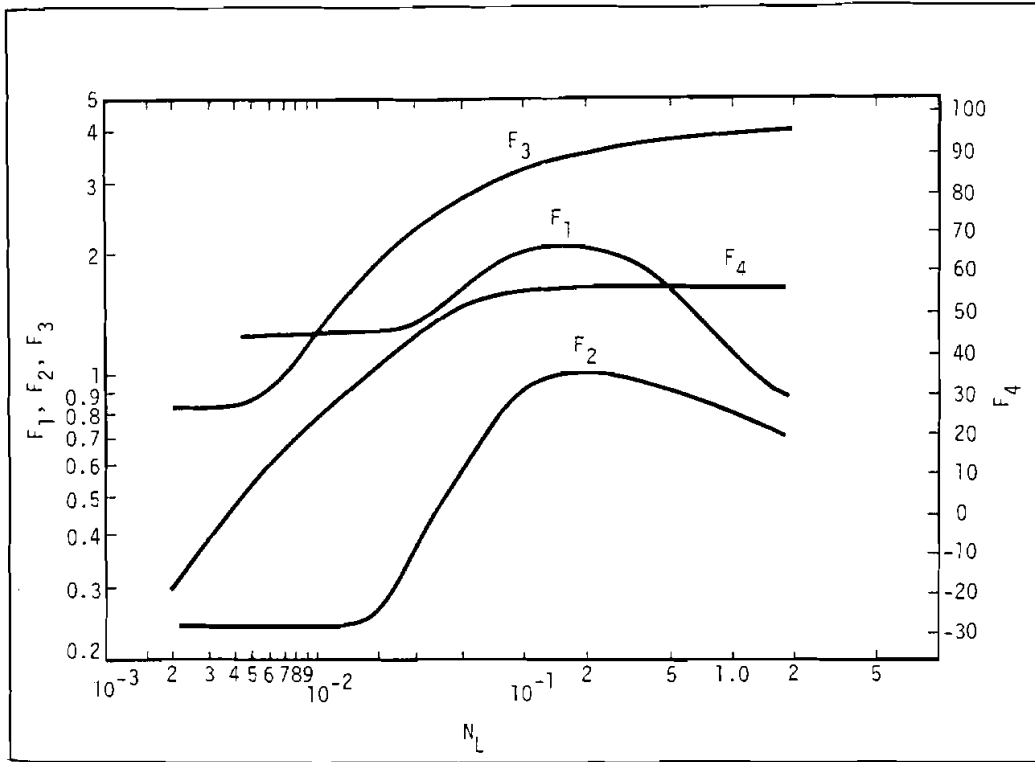


Figure 2-10.  $F_1$ ,  $F_2$ ,  $F_3$ , and  $F_4$  Against Viscosity Number  $N_L$  (After Ros).

b. Slug flow

$$S = (1 + F_5) \frac{(N_{gv})^{0.982} + F_6'}{(1 + F_7 N_{Lv})^2} \quad (2-55)$$

$F_5$ ,  $F_6$  and  $F_7$  can be found in Figure 2-11 where  $F_6' = 0.029 N_d + F_6$

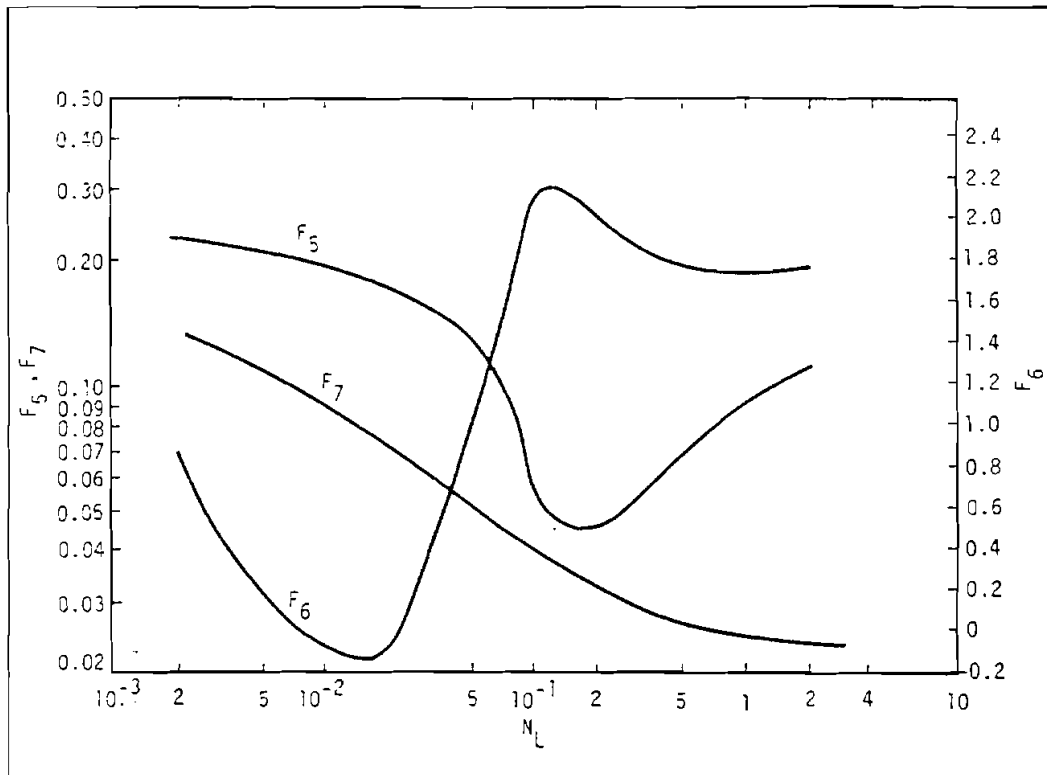


Figure 2-11.  $F_5$ ,  $F_6$  and  $F_7$  Against Viscosity Number  $N_L$  (After Ros)

c. Mist flow

$$S = 0$$

$$\text{Therefore, } H_L = \frac{1}{1 + V_{sg}/V_{sL}} \quad (2-56)$$

8. Determine the slip velocity for bubble or slug flow regime:

$$V_s = \frac{S}{(\rho_L / (\sigma_{LG}))^{0.25}} \quad (2-57)$$

9. Determine the liquid holdup:

$$H_L = \frac{v_s - v_{sg} - v_{sL} + \sqrt{(v_s - v_{sg} - v_{sL})^2 + 4v_s v_{sL}}}{2v_s} \quad (2-58)$$

10. Determine the liquid Reynolds number:

$$N_{Re} = \frac{\rho_L v_{sL} d}{\mu_L} \quad (2-59)$$

11. Determine the friction gradient according to the flow region:

a. For bubble and slug flow

$$\left[ \frac{dp}{dz} \right]_f = \frac{f_m \rho_L v_{sL} v_m}{2 g_c d} \quad (2-60)$$

where:

$$F_m = (f_1) \frac{f_2}{f_3}$$

$f_1$  is found in Figure 2-11

$f_2$  is found in Figure 2-12

The abscissa must be determined in Figure 2-12 and is  $f_1 R N_d^{3/8}$

where:

$$R = \frac{v_{sg}}{v_{sL}}$$

$$f_3 = 1 + f_1 \sqrt{R/50}$$

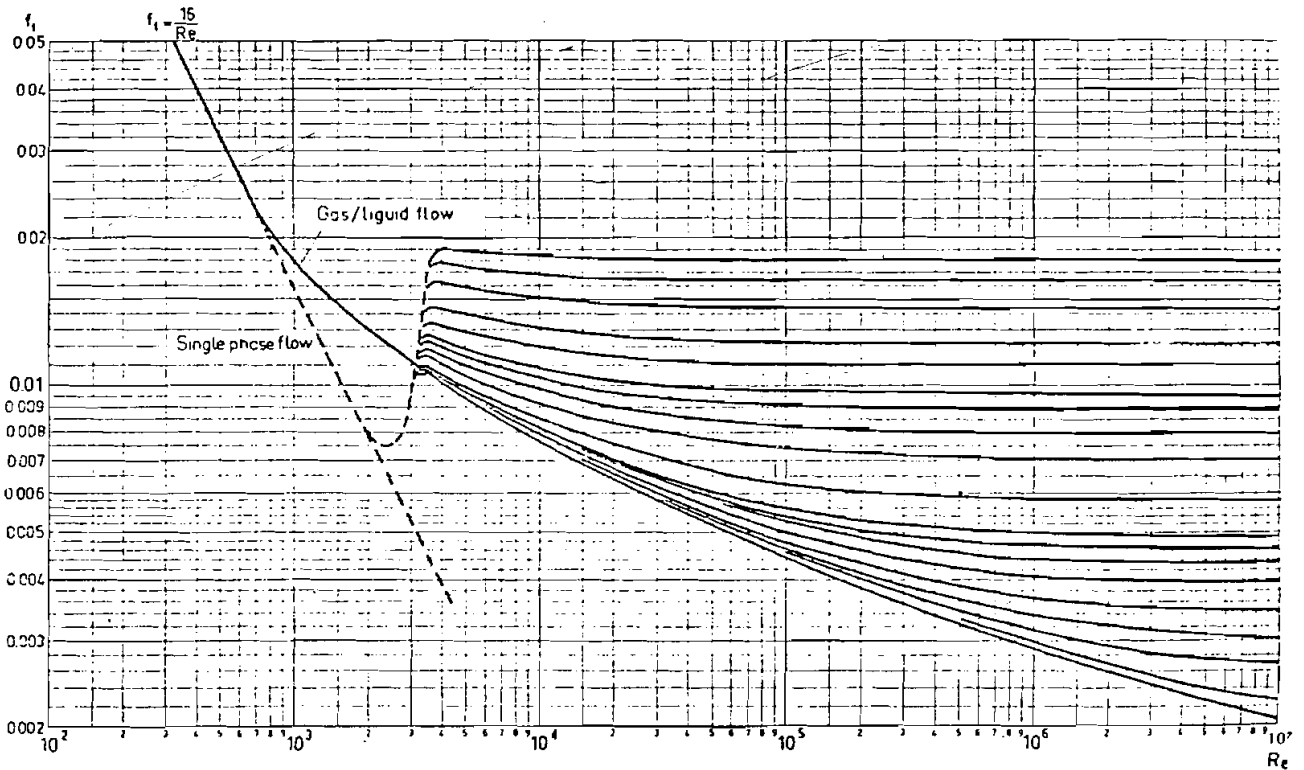


Figure 2-12.  $F_1$  Against Reynolds  $R_e$  (After Ros)



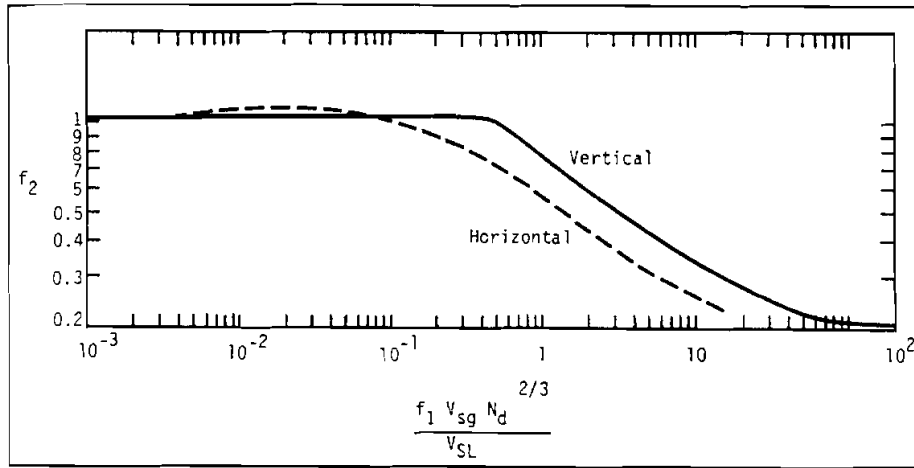


Figure 2-13. Bubble Friction Correction (After Ros)

b. For mist flow

In this region, the friction term is based on the gas phase only. Thus,

$$\left[ \frac{dp}{dZ} \right]_f = \frac{f \rho_g v_{sg}^2}{2 g_c d} \quad (2-61)$$

Since there is no slip, the friction factor is given in a Moody diagram, but as a function of a Reynolds number of the gas:

$$N_{Re} = \frac{\rho_g v_{sg} d}{\mu_g} \quad (2-62)$$

Duns and Ros noted that the wall roughness for mist flow is affected by the film of liquid on the wall of the pipe. The ripples of the wall film cause a drag on the gas. This process is governed by a form of the Weber number:

$$N_{we} = \frac{\rho_g v_{sg}^2 \epsilon}{\sigma_L} \quad (2-63)$$

and is also affected by liquid viscosity. This influence was accounted for by making  $N_{we}$  a function of a dimensionless number containing liquid viscosity,

$$N_{\mu} = \frac{\mu_L^2}{\rho_L \sigma_L \epsilon} \quad (2-64)$$

The functional relationship is shown in Figure 2-14 where the coordinates are  $N_{we}$  vs.

$N_{we} N_{\mu}$ .

The value of roughness may be very small but  $\epsilon/d$  never becomes smaller than the value for the pipe itself. At the transition zone to slug flow,  $\epsilon/d$  may approach 0.5. Between these limits,  $\epsilon/d$  can be obtained from the following equations which were developed from Figure 2-14.

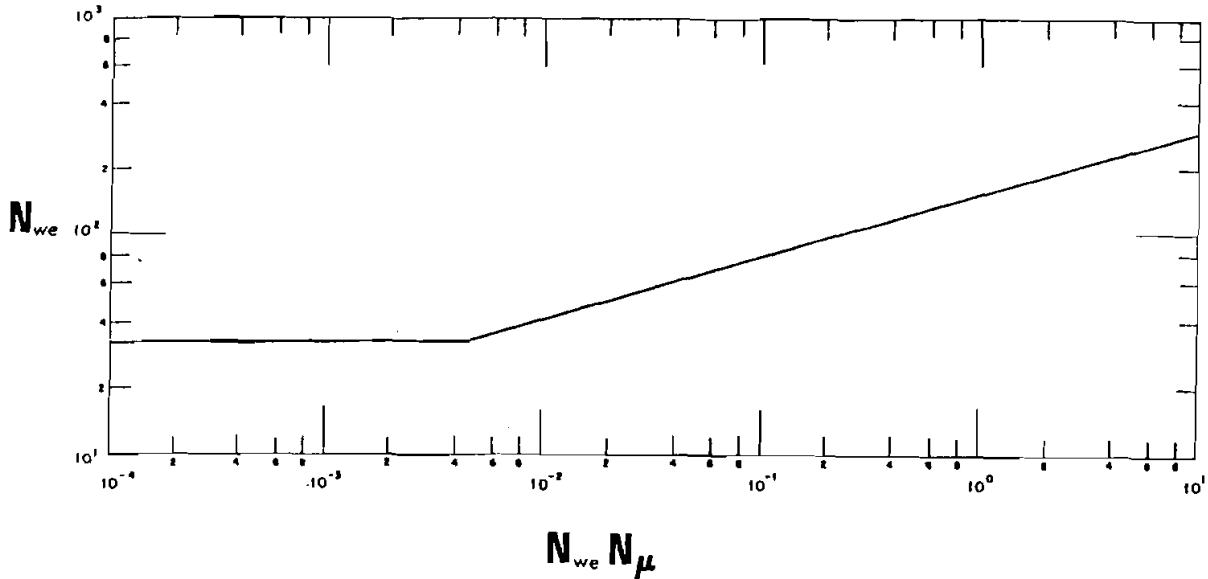


Figure 2-14. Mist Flow Film Thickness

$$N_{we} N_{\mu} \leq .005 : \frac{\epsilon}{d} = \frac{.0749 \sigma_L}{\rho_g v_{sg}^2 d} \quad (2-65)$$

$$N_{we} N_{\mu} \leq .005 : \frac{\epsilon}{d} = \frac{.3713 \sigma_L}{\rho_g v_{sg}^2 d} (N_{we} N_{\mu})^{0.302} \quad (2-66)$$

where:

- $\sigma_L$  = gas-liquid interfacial tension, dynes/cm
- $\rho$  = gas density, lbm/ft<sup>3</sup>
- $v_{sg}$  = superficial gas velocity, ft/sec, and
- $d$  = pipe diameter, ft

Values of  $f$  for the mist flow regime may be found for  $\epsilon/d > 0.005$  from

$$f = \left[ \frac{1}{[4 \log_{10} (0.27\epsilon/d)]^2} + 0.067 (\epsilon/d)^{1.73} \right] \times 4 \quad (2-67)$$

As the wave height on the pipe walls increase, the actual area through which the gas can flow is decreased, since the diameter open to flow of gas is  $d-\epsilon$ . Duns and Ros suggested that the prediction of friction loss could be refined by substitution of  $d-\epsilon$  for  $d$  and  $\frac{v_{sg} d^2}{(d-\epsilon)^2}$  for  $v_{sg}$  throughout the calculation of friction gradient. In this case, the determination of roughness,  $\epsilon$ , is iterative.

In the transition zone between slug flow and mist flow, Duns and Ros suggested linear interpolation between the flow regime boundaries,  $L_s$  and  $L_m$ , to obtain the pressure gradient. This means that when  $N_{gv}$  falls between  $L_s$  and  $L_m$ , pressure gradients must be calculated using both the slug flow correlations and the mist flow correlations. The pressure gradient in the transition zone is then calculated from

$$\frac{dp}{dZ} = A \left[ \frac{dp}{dZ} \right]_{\text{slug}} + B \left[ \frac{dp}{dZ} \right]_{\text{mist}} \quad (2-68)$$

where:

$$A = \frac{L_m - N_{gv}}{L_m - L_s}, \quad B = \frac{N_{gv} - L_s}{L_m - L_s} = 1 - A$$

Increased accuracy was claimed if the gas density used in the mist flow pressure gradient calculation was modified to

$$\rho_g' = \frac{\rho_g N_{gv}}{L_m}$$

where  $\rho_g$  is the gas density calculated at the given conditions of pressure and temperature. This modification accounts for some of the liquid entrained in the gas.

### 2.5.5 Gray Correlations (1974)

A vertical flow correlation for gas condensate wells was developed by H.E. Gray. It is included in the vertical flow package in the computer program described in *API 14b* for sizing subsurface safety valves.

This program uses a pressure balance with a term,  $\xi$ , the gas volume fraction obtained from a fit of a few condensate data systems to build a simplified empirical model of a retrograde phenomenon requiring only specific gravity, pressure, and temperature data for input.

The pressure balance equation used is:

$$dP = \frac{g}{g_c} [\xi \rho_g + (1 - \xi) \rho_L] dh + \frac{f_t G^2}{2g_c D P_{mf} dh} + \frac{G^2}{g_c} d \left[ \frac{1}{\rho_{mi}} \right] \quad (2-69)$$

where  $\xi$ , the gas volume fraction, is:

$$\xi = \frac{1 - \exp \left\{ -0.2314 \left[ N_v \left[ 1 + \frac{205.0}{N_D} \right] \right]^B \right\}}{R + 1} \quad (2-70)$$

$$B = 0.0814 \left[ 1 - 0.0554 \ln \left[ 1 + \frac{730R}{R + 1} \right] \right] \quad (2-71)$$

and

$$N_v = \frac{\rho_m^2 V_{sm}^2}{g \tau (\rho_L - \rho_g)} \quad (2-72)$$

$$N_D = \frac{g (\rho_L - \rho_g) D^2}{\tau} \quad (2-73)$$

$$R = \frac{V_{so} + V_{sw}}{V_{sg}} \quad (2-74)$$

- D = ID of flow conduit
- $f_t$  = two-phase flow friction factor
- G = mass velocity
- h = depth
- P = pressure
- q = flow rate
- R = superficial liquid/gas ratio
- S = specific gravity
- $s_g$  = gas gravity
- t = temperature
- V = velocity
- $\rho$  = density
- $\tau$  = mixture surface tension

*subscripts:*

- f = friction effect
- g = gas phase
- i = inertia effect
- l = liquid phase
- m = gas/liquid ratio
- o = hydrocarbon condensate
- s = superficial value
- w = free-water phase

The following indicates data ranges over which the Gray correlation was developed. Any calculations beyond the following acceptable guidelines should be viewed with caution:

1. Flow velocities below 50 fps
2. Tubing sizes below 3½ in.
3. Condensate production 50 bbl/MMscf
4. Water production 5 bbl/MMscf

The program was compared to 108 sets of well data. The results were found superior to dry-gas well predictions. The Gray correlation can be used to evaluate gas condensate wells by generating tubing performance J curves and comparing them to reservoir performance. Although the above restrictions should be considered, several calculations made with up to 300 bbl/MMscf indicated less than a 10% error compared to data.

## 2.5.6 Gas Well Liquid Loading-Up Process and Identification

### 2.5.6.1 Gas Well Load-Up Process

As natural gas is produced from depletion-drive reservoirs, the energy available to transport the produced fluids to the surface declines. This transport energy eventually becomes low enough that flow rates are reduced and fluids produced with the gas are no longer carried to the surface. These liquids accumulate in the wellbore over time, and cause additional hydrostatic back pressure on the reservoir, which results in continued reduction of the available transport energy. In most cases, if this condition is allowed to continue, the wellbore will accumulate sufficient fluids to balance the available reservoir energy completely and cause the well to die. This phenomenon is known as gas well load-up (Figure 2-15).

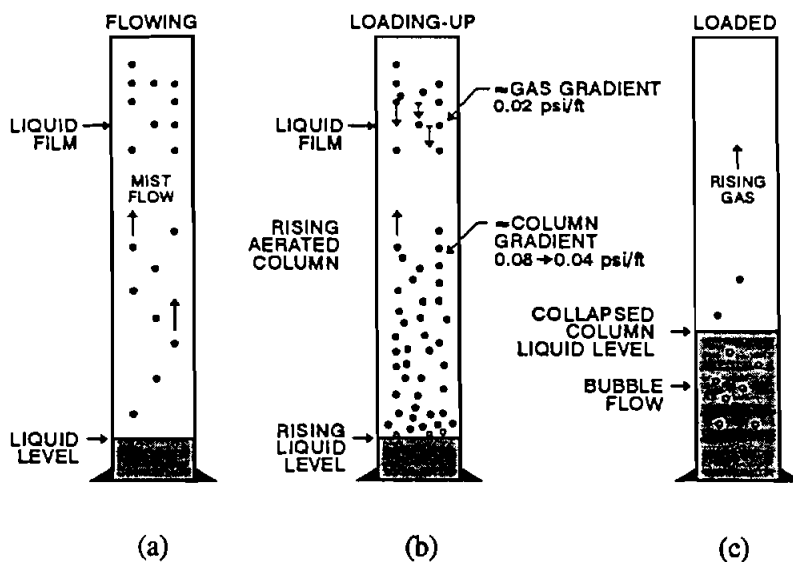


Figure 2-15. Gas Well Load-Up Process (Coleman et al., 1991)

The liquid held in the wellbore comes from two sources: 1) liquids condensed from the gas, and 2) free liquids produced into the wellbore with the gas. Both liquid hydrocarbons and water may be present, depending on the specific reservoir. As Figure 2-15 illustrates, under normal production conditions, gas flows at a velocity high enough that an annular flow pattern develops (Figure 2-15a). This flow pattern is characterized by the presence of a fast moving core of the gaseous phase carrying with it entrained droplets of the liquid phase. The remainder of the liquid phase is present in the form of a flowing film on the pipe wall. As the reservoir energy declines, gas velocity decreases,

and the entrained liquid droplets in the gas core start to drop instead of being carried upwards. The liquid film starts to thicken and move downward at a higher velocity. These factors cause the liquid column at the bottom to rise. The well begins to load-up with liquid (Figure 2-15b). The rising liquid column increases the bottom-hole pressure, further reducing the gas production rate. Eventually, no liquid can be carried upward to the surface and the well will die (Figure 2-15c).

#### 2.5.6.2 Gas Well Load-Up Identification

The liquid exists in the wellbore in two forms: 1) the liquid film along the wall of the pipe and 2) liquid droplets entrained in the high velocity gas core. Two models were developed by Turner et al., in 1969, to predict the onset of load-up based on two different assumptions:

1. The continuous film model assumes that in order to keep a gas well from loading up, the annular liquid film must be moved upward along the walls. This model calculates the minimum rate of gas flow required to move the film upward.

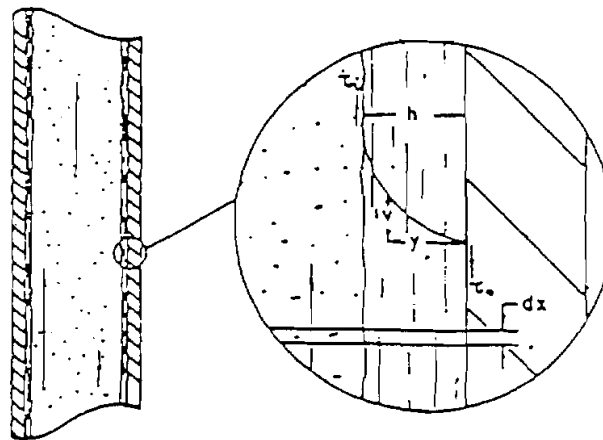


Figure 2-16. Liquid Film Movement (Turner et al., 1969)

2. The liquid droplet model assumes that the liquid droplets in the gas core are the controlling factor. If the liquid droplets cannot be carried upward, then the liquid will load-up in the gas well. This model predicts the minimum gas flow rate required to move the liquid droplets upwards.

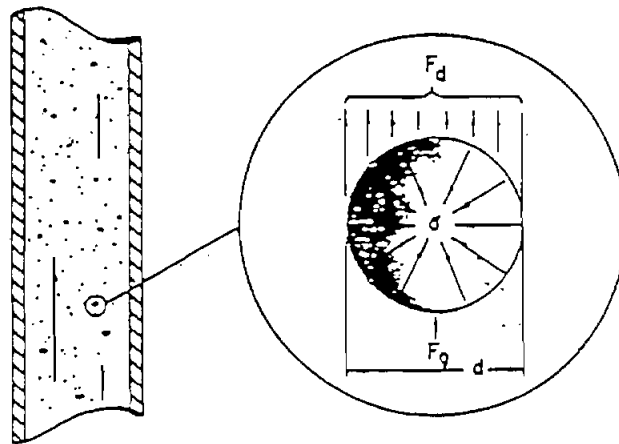


Figure 2-17. Entrained Drop Movement (Turner et al., 1969)

After comparing the results from these two models with field data, Turner et al. found that the liquid film movement does not represent the controlling liquid transport mechanism, i.e., when the liquid film begins to fall back down the well, the film will thicken and bridge the pipe, causing the film to break up into drops, which will be carried up the hole by the gas (Figure 2-18). Therefore, the transport of entrained drops is the controlling mechanism and the minimum gas rate calculated from the entrained drop model is best used to identify the onset of the load-up.

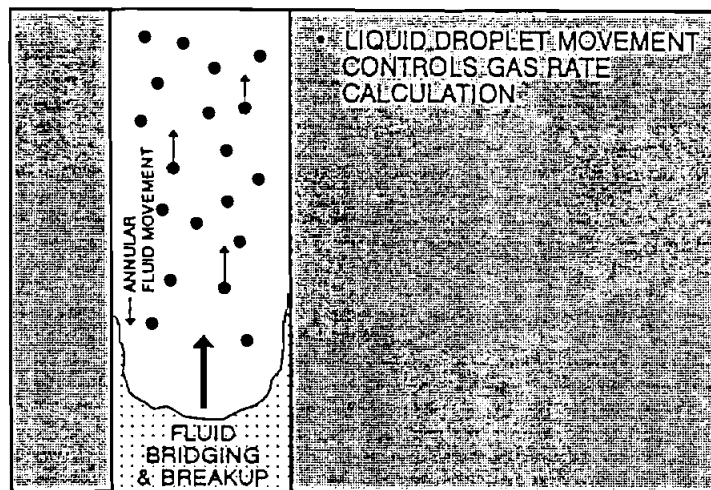


Figure 2-18 Fluid Movement Field Results

### 2.5.6.3 Critical-Rate Theory (Liquid-Droplet Model)

As Turner et al. showed, a free-falling particle in a fluid medium will reach a terminal velocity that is a function of the particle size, shape, and density and of the fluid-medium density and viscosity (Figure 2-18).

Applying this concept to liquid droplets in a flowing column of gas, the terminal velocity,  $v_t$ , of the drop is

$$v_t = c \cdot 1.6 \left\{ \left[ \sigma^{1/4} (\rho_L - \rho_g)^{1/4} \right] / \rho_g^{1/2} \right\} \quad (2-75)$$

which assumes a fixed droplet shape, size, and drag coefficient and includes the +20% adjustment suggested by Turner et al.

Applying this terminal velocity equation to wellbores and correcting to standard conditions, the minimum gas flow rate,  $q_c$ , for the continuous removal of liquids from a wellbore can be determined:

$$q_c = 3.06 p v_t A / T z \quad (2-76)$$

- $v_t$  - Critical gas velocity, ft/sec
- $\sigma$  - Interfacial tension, dynes/cm
- $\rho_L$  - Liquid density, lbm/cf
- $\rho_g$  - Gas density, lbm/cf
- $p$  - Wellhead flowing pressure, psi
- $A$  - Cross-sectional area for flow, ft<sup>2</sup>
- $T$  - Temperature, °R
- $z$  - Gas compressibility
- $q_c$  - Critical gas flow rate, MMscfd

This rate, also known as the critical rate, can be used to predict the onset of gas well load-up. Figure 2-19 plots this critical rate for typical 2<sup>7</sup>/<sub>8</sub>-in. tubing with water as the droplet fluid. If the gas production rate is above this critical rate, the well is not loading liquid at the bottom. "C" in Eq. (2-74) is an adjustment factor. Turner et al., showed that an upward adjustment of 20% (i.e.,  $c = 1.2$ ) is needed to conform with the field data. However, Coleman et al. state that for wells with wellhead flowing pressure lower than 500 psi, the adjustment is not needed (i.e.,  $c = 1$ ).



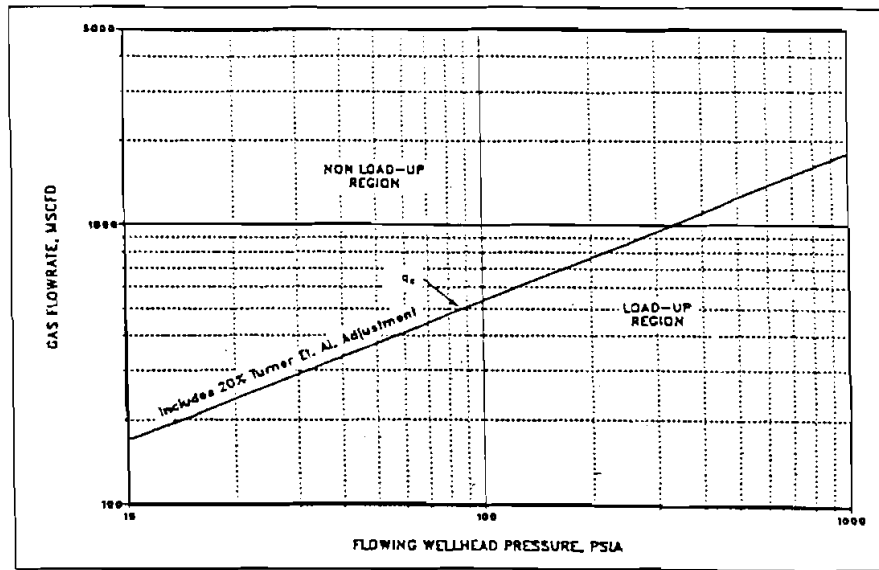


Figure 2-19 Wellbore Critical Rate: 2 7/8-in. Tubing (Coleman et al., 1991)

Eq. (2-74) can be simplified assuming:  $c = 1.2$ ,  $\sigma$  (water) = 60 dynes/cm,  $\sigma$  (condensate) = 20 dynes/cm,  $\rho_L$  (water) = 67 lbm/cf,  $\rho_L$  (condensate) = 45 lbm/cf. Gas density is a function of pressure, temperature and gas gravity. Further simplification is possible by using an average value of gas gravity (0.6) and gas temperature (120°F). The simplified equations are as follows:

$$V_t(\text{water}) = \frac{5.62(67 - 0.0031 p)^{1/4}}{(0.0031 p)^{1/2}} \quad (2-77)$$

$$V_t(\text{condensate}) = \frac{4.02(45 - 0.0031 p)^{1/4}}{(0.0031 p)^{1/2}} \quad (2-78)$$

## 2.6 MULTIPHASE CORRELATIONS FOR FLOW IN CHOKES (BRILL AND BEGGS, 1991)

Chokes are frequently installed in wells to restrict flow rates to desired levels. They normally operate in "Critical" or "Sonic" flow conditions (i.e., the velocity of the fluids through the choke reaches a level identical to the velocity of sound, pressure or compressional wave). Flow then becomes independent of downstream disturbance of pressure, temperature, or density because the disturbance cannot travel in the upstream direction.

Most publications involving multiphase flow through chokes have been for critical flow. The problem solved in these works has been to calculate the pressure upstream from a choke, given the choke diameter, the liquid production rate, and the gas/liquid ratio. The alternate case is to calculate the liquid production rate given the upstream pressure. The equations and/or figures used to predict critical flow behavior through chokes are given below together with other information where pertinent.

The equations proposed by Gilbert, Ros, Baxendell and Achong are all of the form

$$P_1 = \frac{A q_L R_P^B}{d^C} \quad (2-79)$$

where:

- $P_1$  = upstream pressure
- $q_L$  = liquid production rate, stb/d
- $R_P$  = producing gas/liquid ratio, scf/STBL
- $d$  = choke diameter in 64th's of an inch
- A,B,C = empirical coefficients given in Table 2-1

**TABLE 2-1. Empirical Coefficients for Two-Phase Critical Flow Correlations**

Correlation	A	B	C
Gilbert	10.00	0.546	1.89
Ros	17.40	0.500	2.00
Baxendell	9.56	0.546	1.93
Achong	3.82	0.650	1.88

Analysis of Eq. (2-78) clearly shows that the production rate or fluid throughput is independent of the pressure downstream from the choke. As mentioned previously, this is a characteristic of critical flow.

Equation (2-78) is also very sensitive to the choke size. Gilbert stated that an error of 1/128 in. in bean size can cause errors of 5 to 20% in pressure estimates. Also, he pointed out that gas-liquid ratios are frequently reported only to the nearest 50 or 100 scf/STB and are frequently difficult to determine because of fluctuations which occur in many wells. These fluctuations can require changing choke sizes several times in a well's production history to obtain desired production rates. Finally, Gilbert stated that his formula (or coefficients) applies only when the upstream pressure (tubing pressure) is at least 70% greater than the line pressure (downstream pressure). When this percentage is less than 70%, the bean size indicated will be too small for the given conditions.

## 3. Program Installation

### 3.1 BEFORE INSTALLING

#### 3.1.1 Hardware and System Requirements

PROMOD1 is written in Visual Basic®. It runs in either standard or enhanced mode of Microsoft Windows 3.0 or higher. The basic requirements are:

- Any IBM-compatible machine built on the 80286 processor or higher (with math co-processor)
- 2 megabytes of RAM; 4 megabytes is recommended
- Hard disk
- Mouse
- CGA, EGA, VGA, 8514, Hercules, or compatible display. (EGA or higher resolution is recommended)
- MS-DOS version 3.1 or higher
- Windows version 3.0 or higher in standard or enhanced mode

For assistance with the installation or use of PROMOD1 contact:

<p>Weiping Yang or Russell Hall Maurer Engineering Inc. 2916 West T.C. Jester Boulevard Houston, Texas 77018-7098 U.S.A. Telephone: (713) 683-8227      Fax: (713) 683-6418 Telex: 216556</p>
---

#### 3.1.2 Check the Program Disk

The program disk you received is a 3½-inch, 1.44 MB disk containing twenty-one files. These twenty-one files are as follows:

```
SETUPKIT.DLL
VBRUN300.DLL
VER.DLL
COMMDLG.DLL
GSDLL.DLL
GSW.EXE
SETUP.EXE
SETUP1.EXE
PROMOD1.EXE
SETUP.LST
CMDIALOG.VBX
GAUGE.VBX
GRAPH.VBX
GRID.VBX
MDICHILD.VBX
THREED.VBX
TEST.VI1
TEST.WD1
TEST.SDI
TEST.VT1
TEST.VPI
```

We recommend that all .VBX and .DLL files that have the potential to be used by other DEA-44/67 Windows applications be installed in your Microsoft WINDOWS\SYSTEM subdirectory. This applies to all the .VBXs and .DLLs included here. The PROMOD1 executable (PROMOD1.EXE) file should be placed in its own directory (default "C:\PROMOD1") along with the example data files TEST.\*. All these procedures will be done by a simple setup command explained in Section 3.2.

In order to run PROMOD1, the user must install all of the files into the appropriate directory on the hard disk. Please see Section 3.2 to setup PROMOD1.

It is recommended that the original diskette be kept as a backup, and that working diskettes be made from it.

### **3.1.3 Backup Disk**

It is advisable to make several backup copies of the program disk and place each in a different storage location. This minimizes the probability of all disks developing operational problems at the same time.

The user can use the COPY or DISKCOPY command in DOS, or the COPY DISKETTE on the disk menu in the File Manager in Windows.

## **3.2 INSTALLING PROMOD1**

The following procedure will install PROMOD1 from the floppy drive onto working subdirectories of the hard disk (i.e., copy from A: or B: drive onto C: drive subdirectory PROMOD1 and WINDOWS\SYSTEM).

1. Start Windows by typing "WIN" <ENTER> at the DOS prompt.
2. Insert the program disk in drive B:\.
3. In the File Manager of Windows, choose Run from the File menu. Type B:\setup and press Enter.
4. Follow the on-screen instructions.

This is all the user needs to setup PROMOD1. After setup, there will be a new Program Manager Group which contains the icon for PROMOD1 as shown in Figure 3-1.

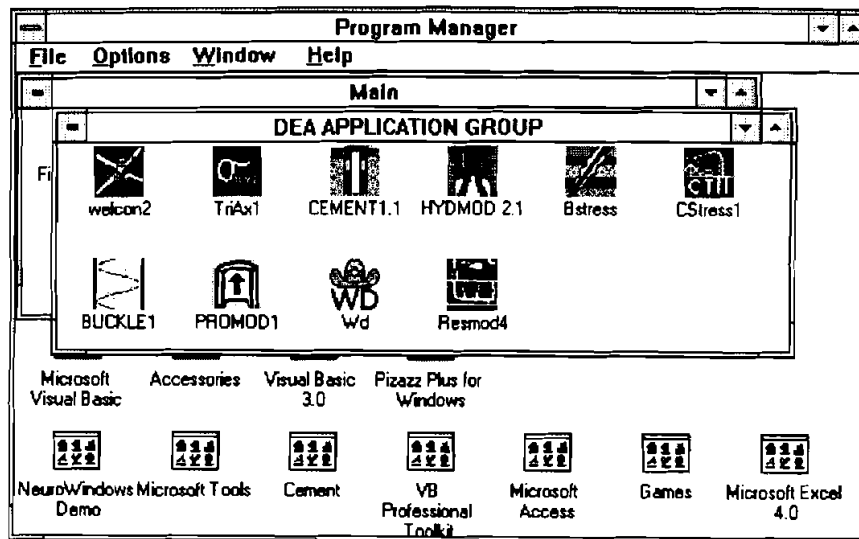


Figure 3-1. DEA APPLICATION GROUP Window Created by Setup

### 3.3 STARTING PROMOD1

#### 3.3.1 Start PROMOD1 from Group Window

To run PROMOD1 from Group Window, the user simply double-clicks the "PROMOD1" icon, or when the icon is focused, press <ENTER>.

#### 3.3.2 Use Command-Line Option from Windows

In the Program Manager, choose Run from the File menu. Then type C:\PROMOD1\PROMOD1.EXE <ENTER>.



## 4. Running the Program

### 4.1 INTRODUCTORY REMARKS

PROMOD1 runs in a Microsoft Windows environment. It is assumed that the user is familiar with Windows, and that his or her computer is equipped with Windows 3.0 or a later version.

For information about Windows in a concise and convenient form, *10 Minute Guide to Microsoft Windows 3* by Katherine Murray and Doug Sabotin, published by Sams, is recommended.

In this quick start, step-by-step instructions take the user rapidly through the program. To save time and space, data will be input from the prefabricated files, TEST.\*, which are included on the program disk and which are stored in directory C:\PROMOD1 during the SETUP process in Section 3.2.

### 4.2 GETTING STARTED

1. Call up Windows and make DEA APPLICATION GROUP the active window, as shown in Figure 4-1.

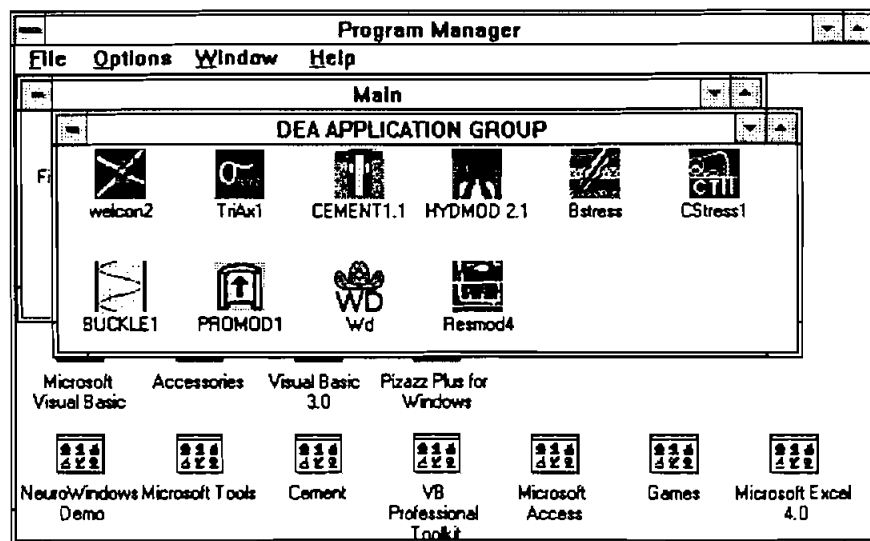


Figure 4-1. DEA APPLICATIONS GROUP Window

2. Double click on the PROMOD1 icon. This displays the screen shown in Figure 4-2. Click on the [OK] button and this opens the PROMOD1 front window shown in Figure 4-3. If the [Exit] button is clicked on instead, the program returns to the program manager.

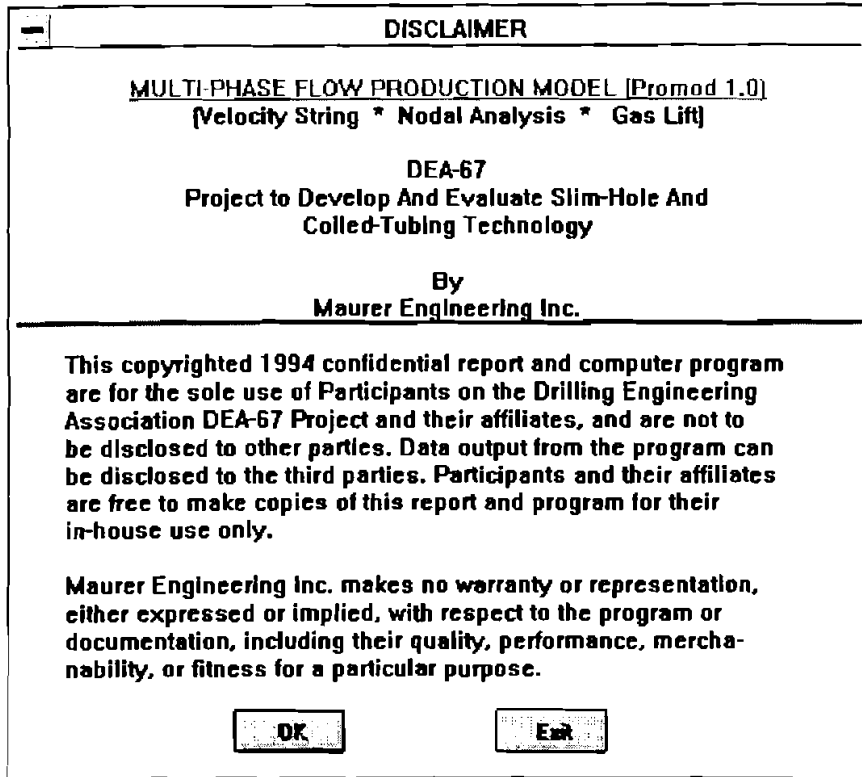


Figure 4-2. Disclaimer

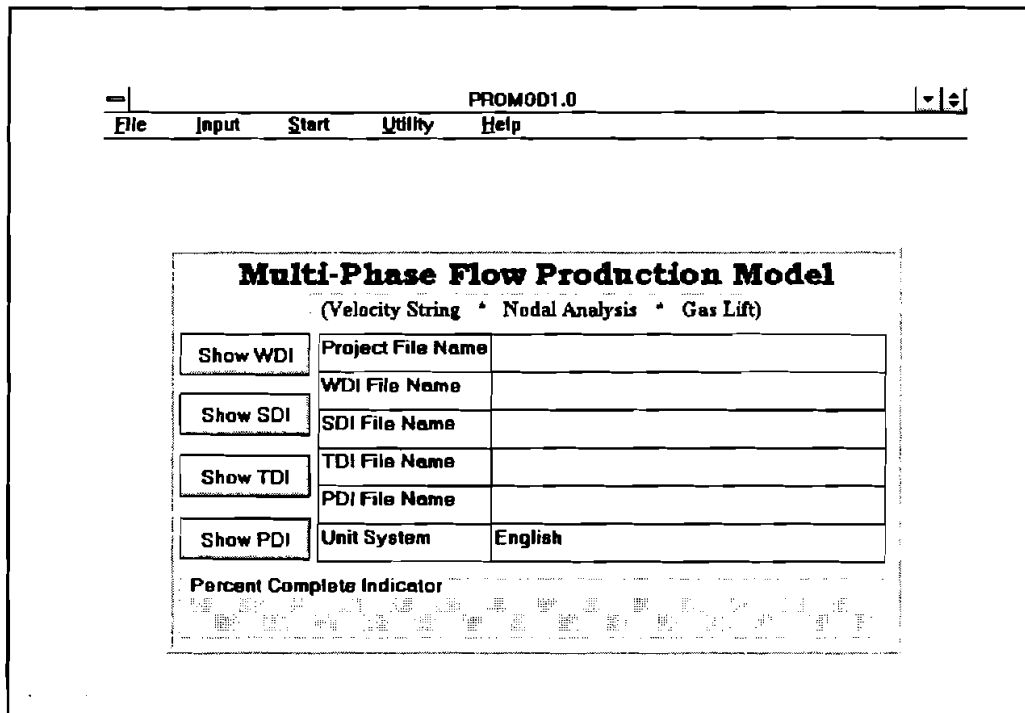


Figure 4-3. Front Window



3. The menu bar at the top of the screen facilitates all operations of the program. To access individual menu items, the user can utilize either a mouse or the keyboard. The four buttons on the left of the screen are used to speed access to the four data files. When a data file is ready, the name of the file is displayed in the grid on the right. The percent complete indicator shows the percentage of computation finished.
4. The "File" menu facilitates the operation of the project files. Click on the "File" menu and the "File" pull-down menu is displayed as shown in Figure 4-4. Click on individual items to perform the corresponding task.

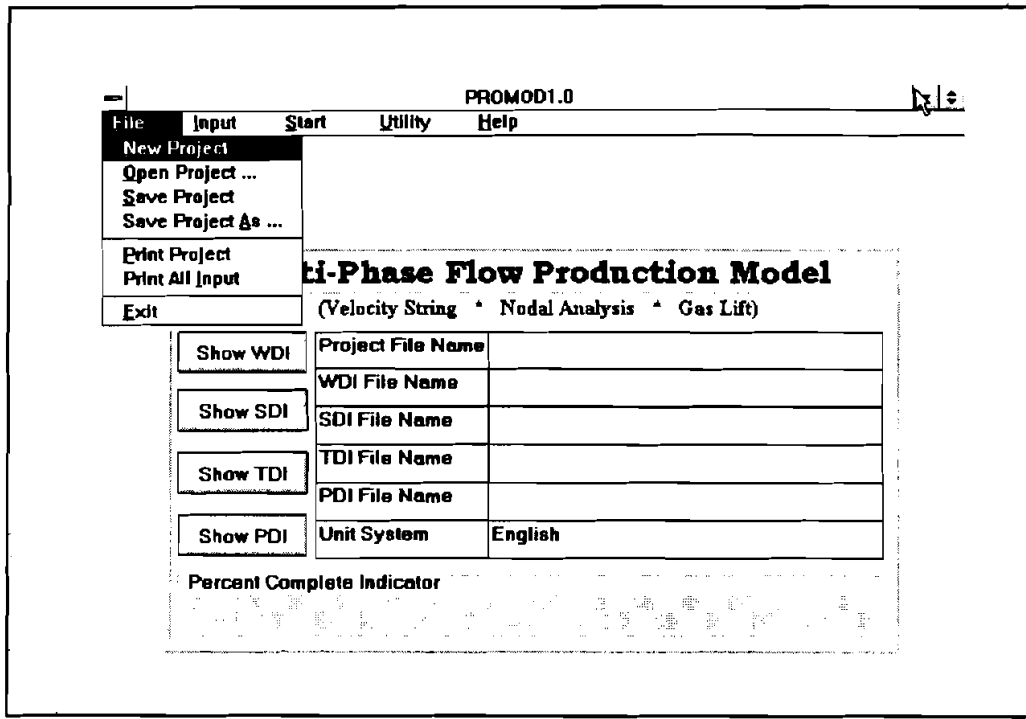


Figure 4-4. File Pull-Down Menu

5. Before any calculation begins, the data have to be entered by reading an existing file or entered manually. Four data files need to be prepared. Three of them are absolutely required for any calculation. They are SDI, TDI, and PDI files. The fourth file, WDI, is for information only. The data in the WDI file do not go into any of the calculations.
6. There are two ways to access the WDI file (Figure 4-6): 1) by clicking on the Input menu as shown in Figure 4-5, then clicking on WDI, or 2) by clicking on the [Show WDI] button only.

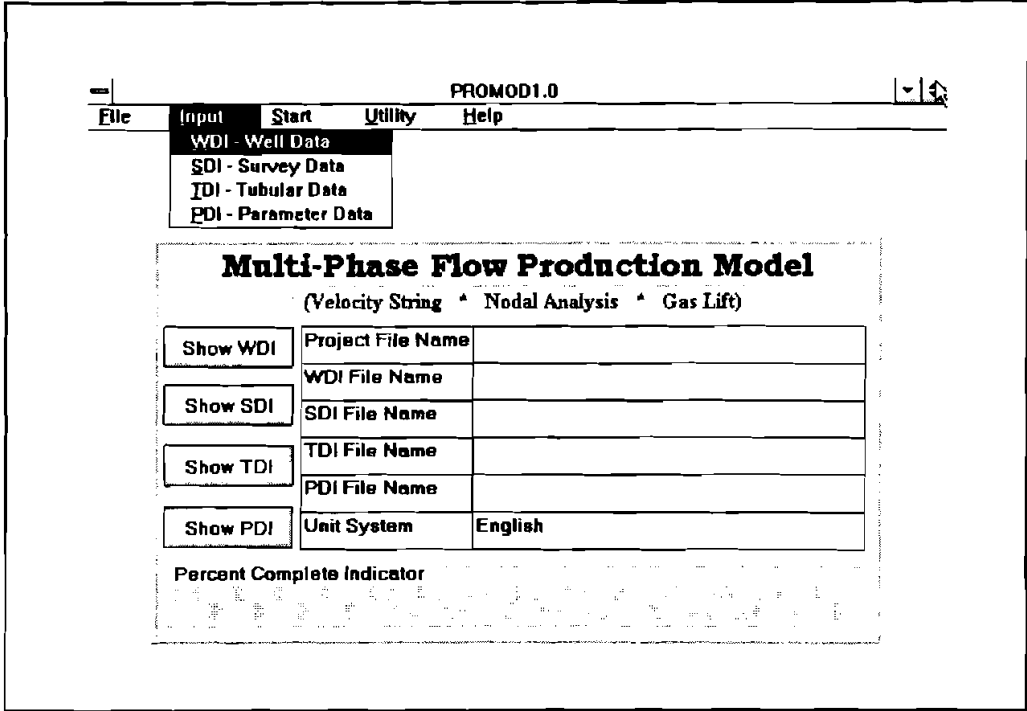


Figure 4-5. "Input" Pull-Down Menu

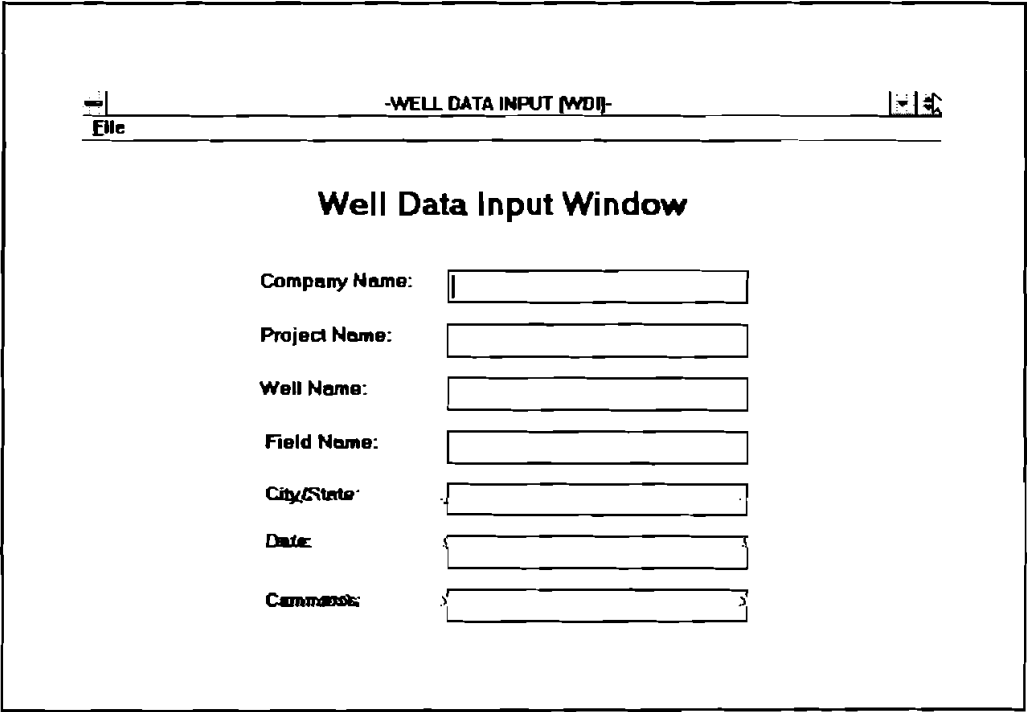


Figure 4-6. WDI Window

The user can input all pertinent data manually at this point or retrieve an existing file. To do that, click on the menu "File" for the pull-down menu box as shown in Figure 4-7. Then, click on "open." This opens the file dialog box as shown in Figure 4-8 and highlights the file name to be retrieved. Click on the [OK] button and the WDI window is filled with the data from the file, shown in Figure 4-9.

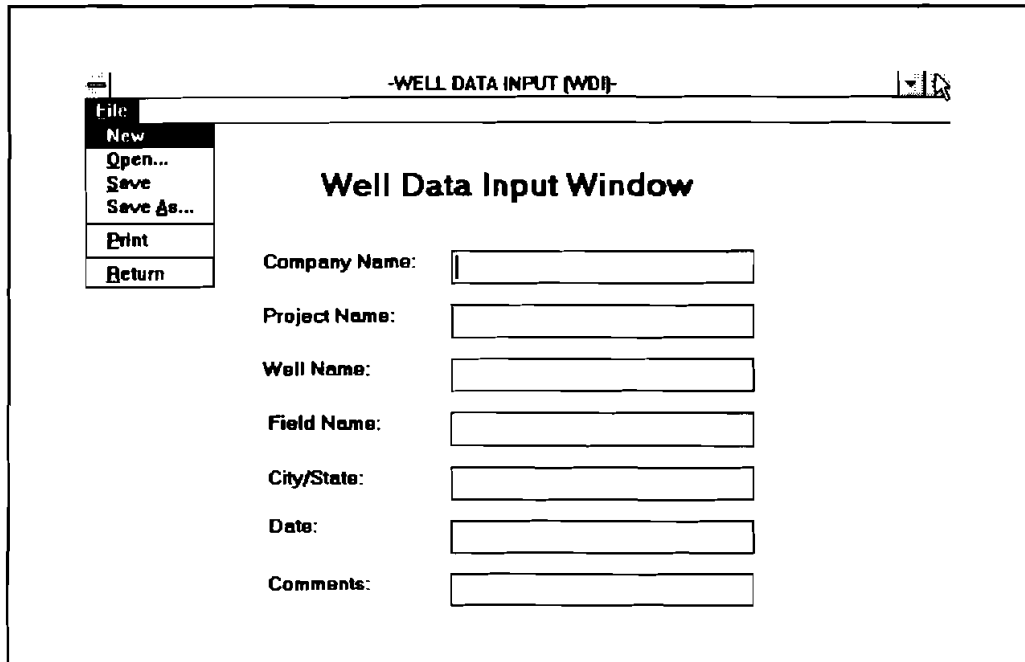


Figure 4-7. WDI File Pull-Down Menu

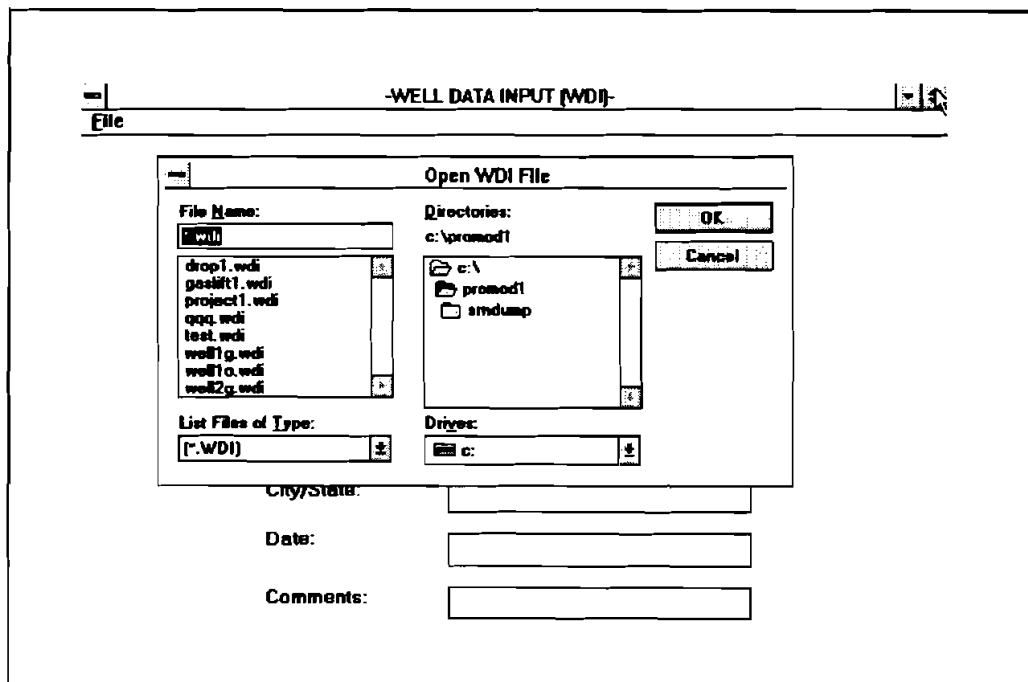


Figure 4-8. File Dialog Box

**Well Data Input Window**

Company Name:

Project Name:

Well Name:

Field Name:

City/State:

Date:

Comments:

Figure 4-9. WDI Window Filled

To exit from the WDI window, click on "File" and click "Return."

- Similarly, there are two ways to access the SDI file (Figure 4-10): 1) by clicking on [Show SDI], or 2) clicking on the "Input" menu and then clicking on "SDI." Either procedure will open the SDI window as shown in Figure 4-10.

**-SURVEY DATA INPUT (SDI)-**

File

Station	M. Depth	Inclination	Azimuth
1	0.0	0.0	0.0

Depth :  Feet  Meters

Inclination :  Decimal  Deg. Min

Azimuth :  Angular  D&D Field

Edit

Figure 4-10. SDI Window

To retrieve an existing file, click on "File" at the top of the screen. This opens the "File" pull-down menu as shown in Figure 4-11.

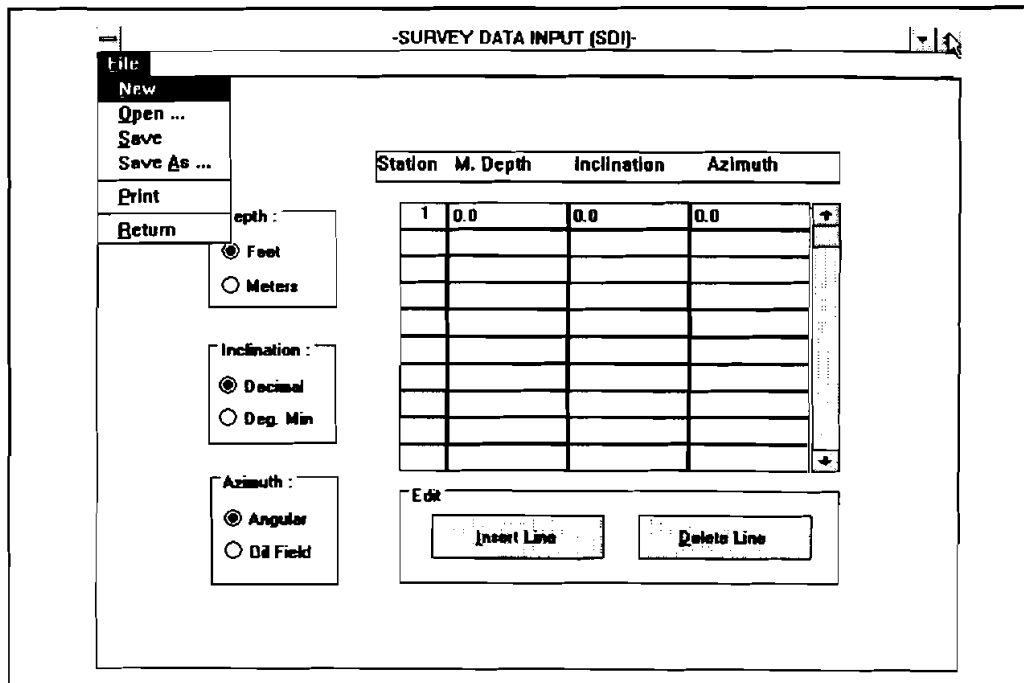


Figure 4-11. SDI File Pull-Down Menu

Click on "Open." This opens the file dialog box. Highlight the SDI file name to be retrieved. Click on [OK] button. The SDI Window is filled with the data from the File, as shown in Figure 4-12.

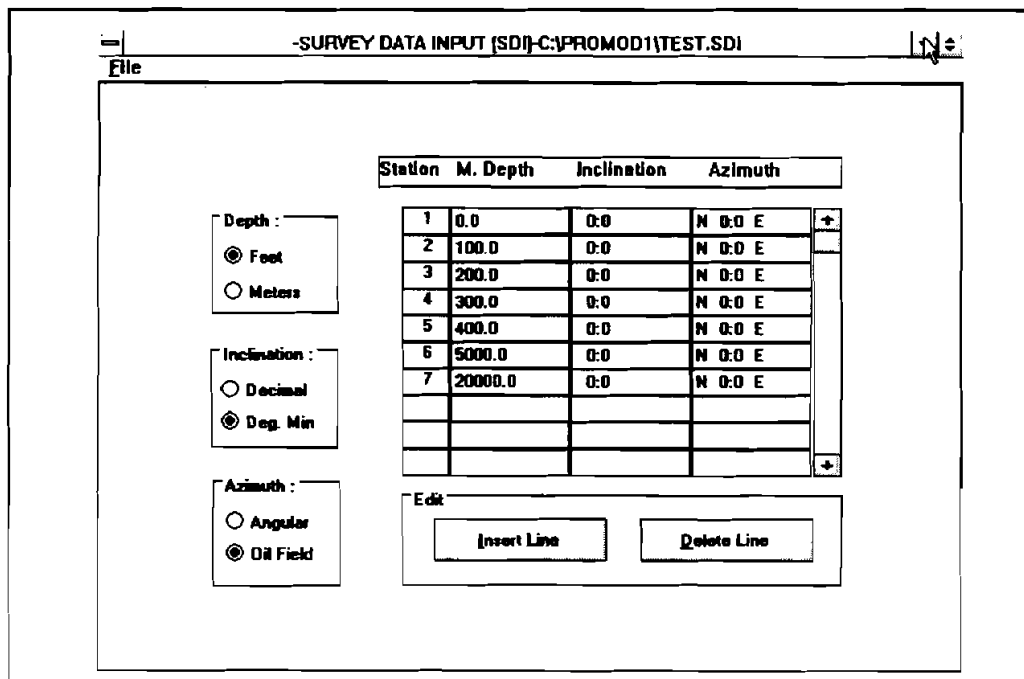


Figure 4-12. SDI Window Filled

Now, click on "File" in the menu bar at the top of the Survey Data Input window. When the "File" window opens, click on "Return."

- To access the TDI window, click on the [Show TDI] button or click on "Input" menu, then click on TDI. Either procedure will display the TDI window as shown in Figure 4-13.

File
-TUBULAR DATA INPUT (TDI)-
[-] [x]

**TUBING STRING**

#	Description	ID (in)	OD (in)	Length (ft)	Volume (bbls)	+
1						
2						
3						
4						
5						
				<b>TOTAL</b>		

\* Input from bottom up

Perforation depth (ft)

Calc. Interval (ft)

Surface Choke Size (1/64 in)

**WELL DATA**

Flow through  Tubing  Annulus

#	Description	ID (in)	Length (ft)	Volume (bbls)	+
1					
2					
3					
4					
5					
				<b>TOTAL</b>	

\* Input from top down

**SURFACE PIPE LINE DATA**

Deviation positive if flowing uphill,  
negative if flowing downhill

#	ID (in)	Deviation (Degree)	Length (ft)	+
1				
2				
3				
4				
5				
6				
7				
8				
9				
				<b>TOTAL</b>

\* Start from well head

Figure 4-13. TDI window

4-8

To retrieve an existing file, click on "File" in the menu to open the "File" pull-down menu (Figure 4-14). Then, click on "Open" to display the file dialog box as shown in Figure 4-15.

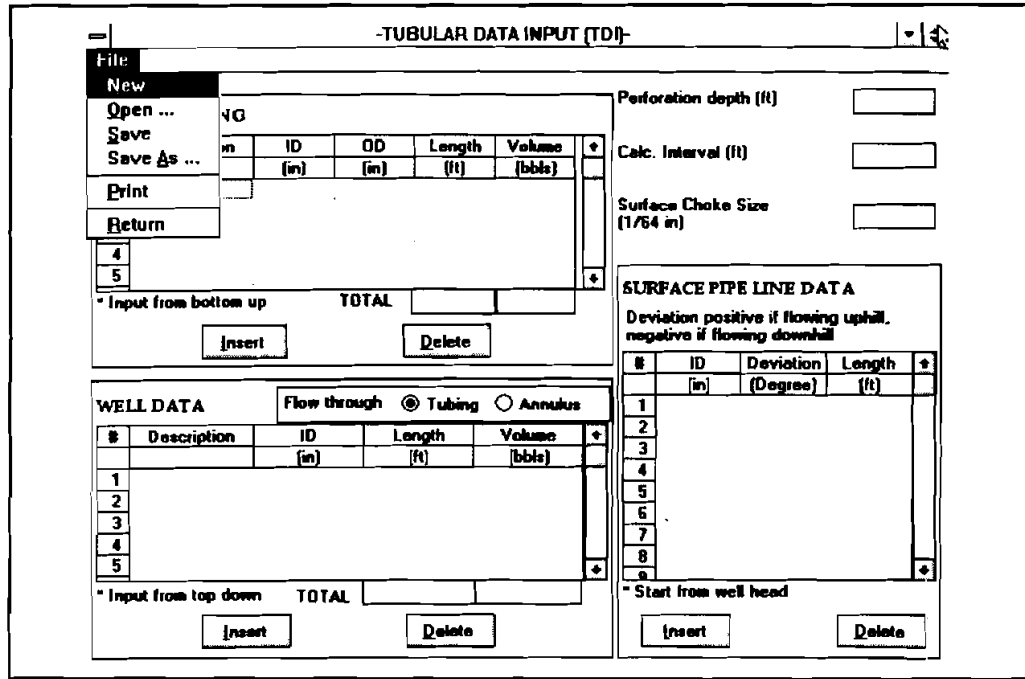


Figure 4-14. TDI File Pull-Down Menu

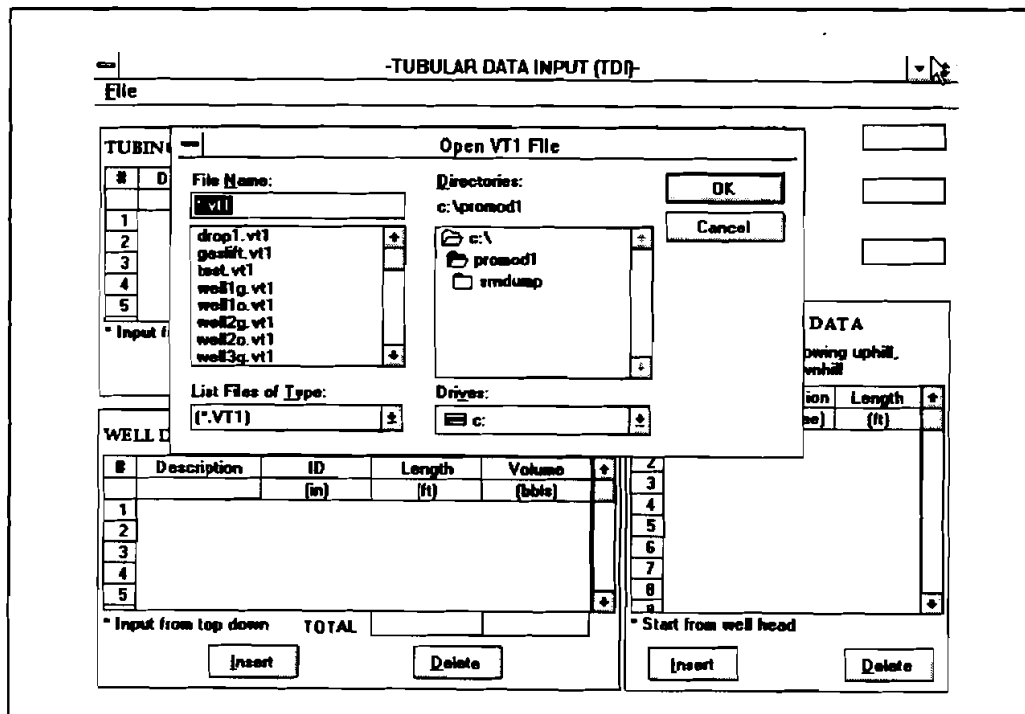


Figure 4-15. TDI File Dialog Box

Highlight the file to be retrieved, and click on the [OK] button. The TDI window is filled with the data from the file as shown in Figure 4-16.

-TUBULAR DATA INPUT (TDI)-C:\PROMOD1\TEST.VT1

File

**TUBING STRING**

#	Description	ID (in)	OD (in)	Length (ft)	Volume (bbls)
1	Tubing	2.441	2.875	7505.	43.436
2					
3					
4					
5					
* Input from bottom up				TOTAL	7505. 43.436

Insert Delete

Perforation depth (ft)

Calc. Interval (ft)

Surface Choke Size (1/64 in)

**WELL DATA**      Flow through  Tubing  Annulus

#	Description	ID (in)	Length (ft)	Volume (bbls)	
1	Casing	4.892	7600.	176.665	
2					
3					
4					
5					
* Input from top down				TOTAL	7600. 176.665

Insert Delete

**SURFACE PIPE LINE DATA**  
Deviation positive if flowing uphill,  
negative if flowing downhill

#	ID (in)	Deviation (Degree)	Length (ft)
1			
2			
3			
4			
5			
6			
7			
8			
9			

\* Start from well head

Insert Delete

Figure 4-16. TDI Window Filled

To go back to the Main window, click on the "File" menu again and then click on "Return."



9. The last file to be retrieved is the PDI file. To access this file, click on the [Show PDI] button or click on the "Input" menu and then click on "PDI." Either procedure will display the PDI window as shown in Figure 4-17.

Figure 4-17. PDI Window

To retrieve an existing file, click on the "File" menu to open the pull-down menu, as shown in Figure 4-18 and then click on "Open." A file dialog box appears (Figure 4-19).

Figure 4-18. PDI File Pull-Down Menu

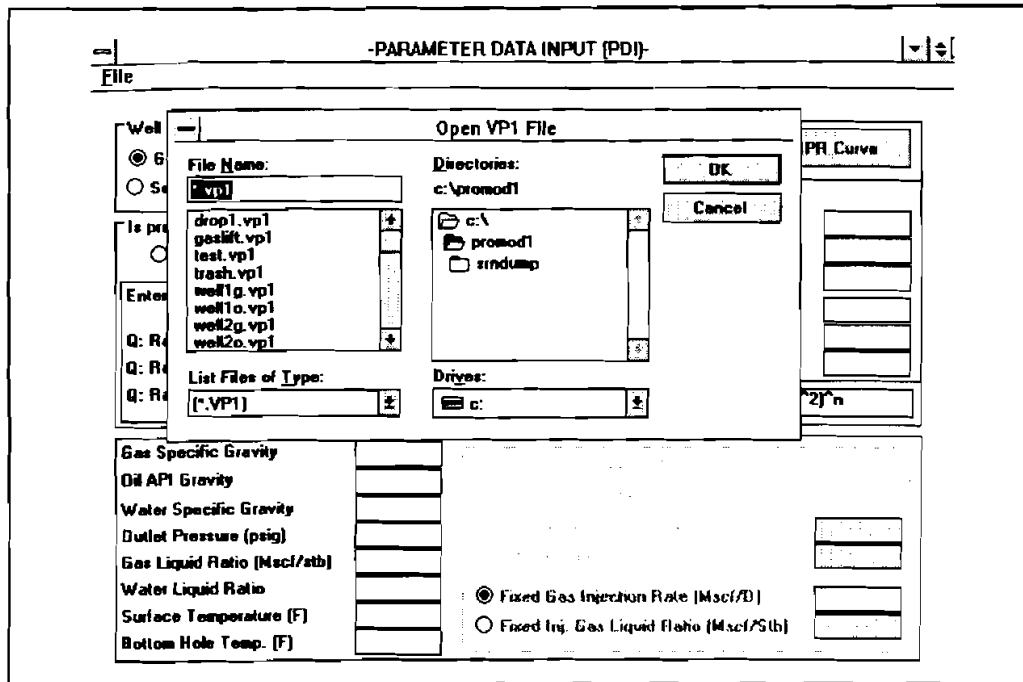


Figure 4-19. PDI File Dialog Box

Highlight the file to be retrieved, and click on the [OK] button. The PDI window is filled with the data from the file. Figure 4-20 shows the data from the sample file.

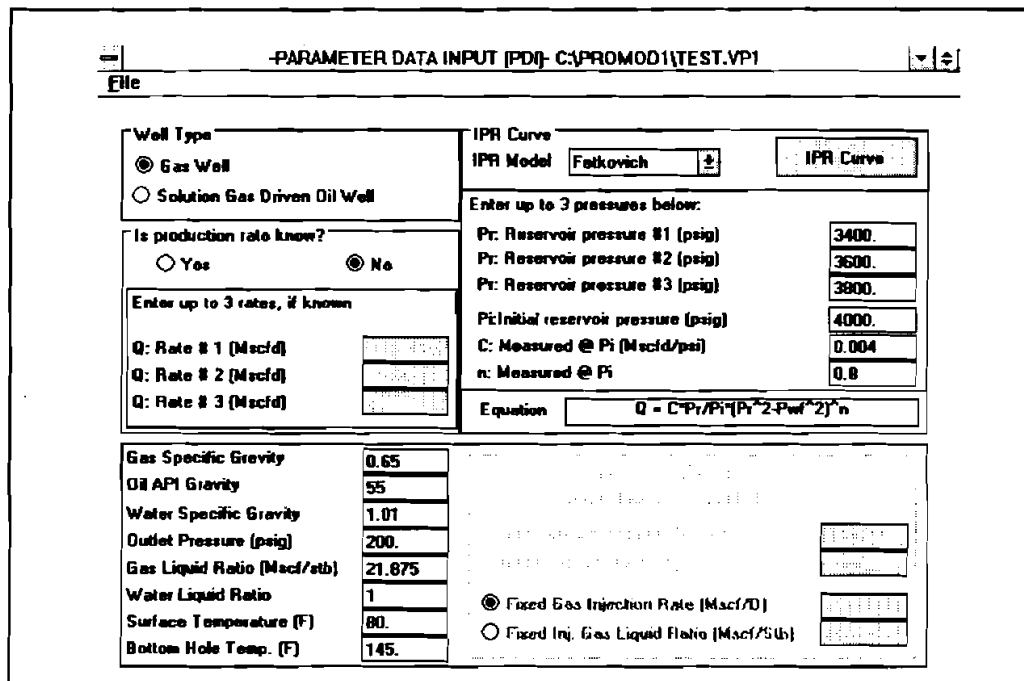


Figure 4-20. PDI Window Filled

To exit the PDI window, click on the "File" menu, then click on "Return." This returns the user to the front window as shown in Figure 4-21.

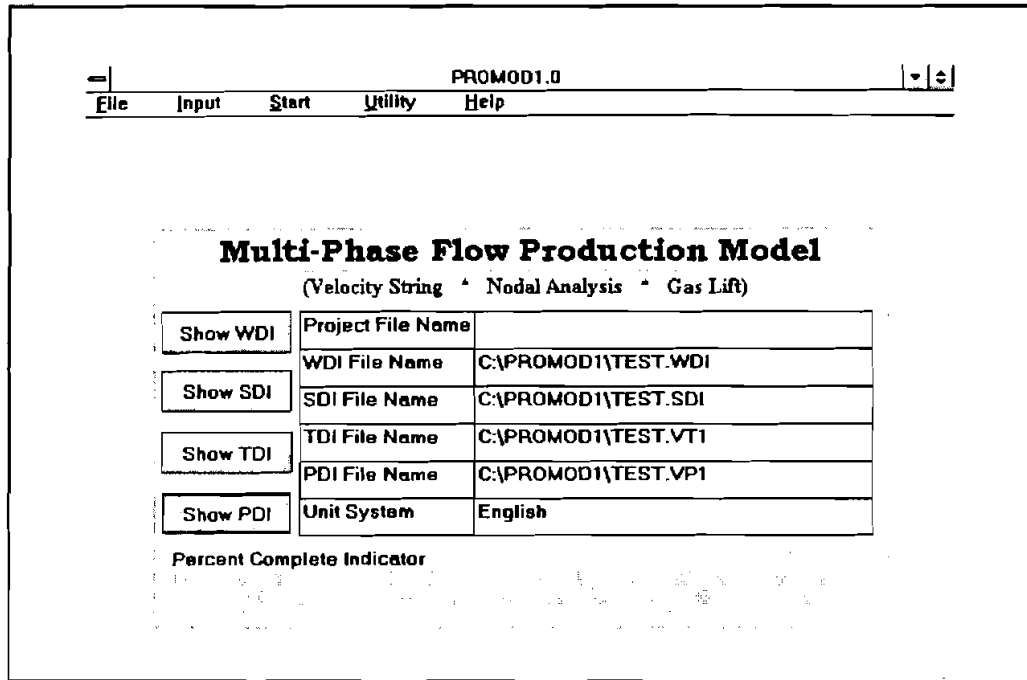


Figure 4-21. PROMOD1 Front Window

Now, all four data file boxes in the front window are filled with the names of the four chosen files.

At this time, the user can create a project file which contains all four of the input data files. Calling up this project file will simultaneously input all four data files for future computation. The project file is established as follows:

10. Click on "File" at the left end of the menu bar. When the pull-down window appears, click on "Save project" (Figure 4-22).

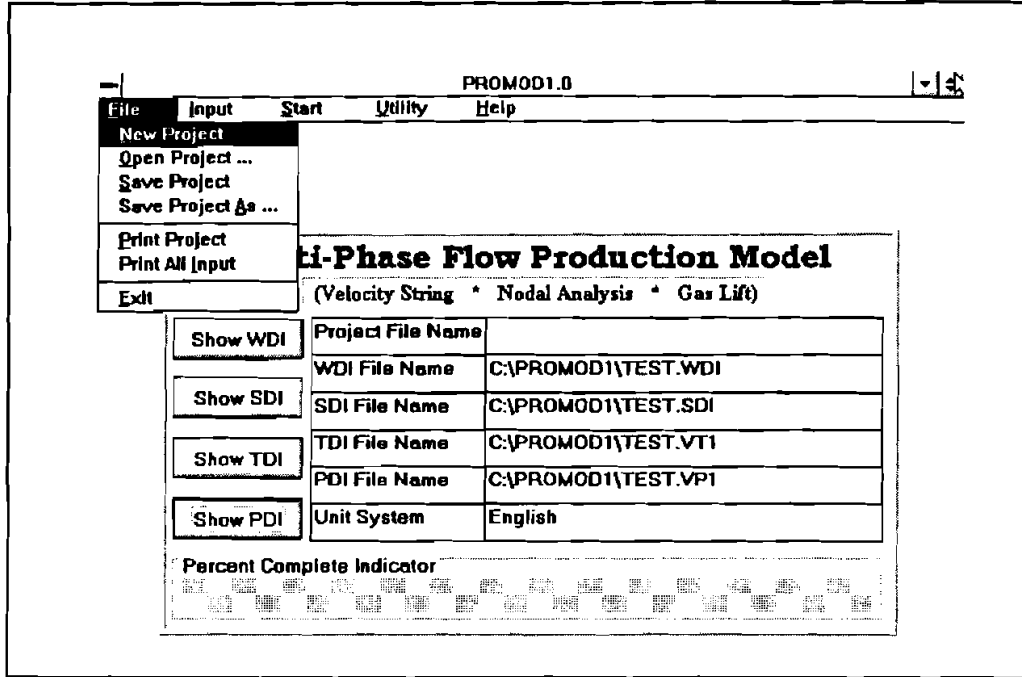


Figure 4-22. Project File Pull-Down Menu

This opens the file save dialog box as shown in Figure 4-23.

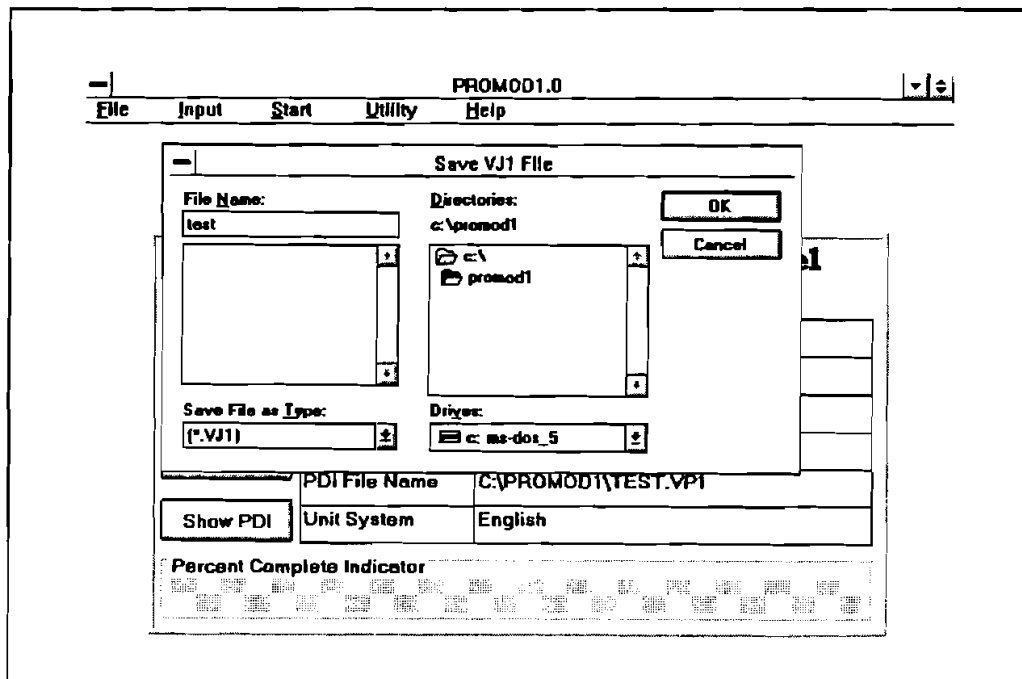


Figure 4-23. Project File Dialog Box

In the box directly below File Name, type the name of the project file without the extension. For this example, the file name is TEST and the extension VJ1. Click on the [OK] button to close the dialog box. The project file designator has been added to the list of titles in the boxes at the top of the window. This is shown in Figure 4-24.

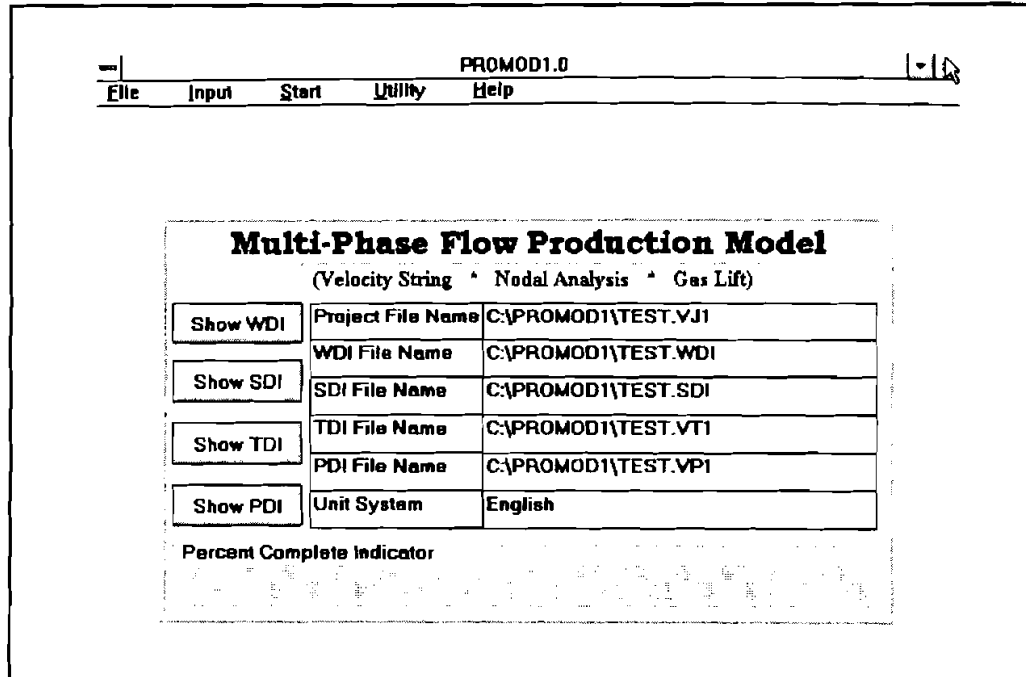


Figure 4-24. Front Window: Filled

- Click on "Start" from the menu bar to display the "Start" pull-down menu, as shown in Figure 4-25. Click on "Calc and Output" and calculation begins. The percent complete indicator at the bottom of the window monitors the calculation process. When calculation is complete, the program brings out the "Output" window automatically as shown in Figure 4-26.

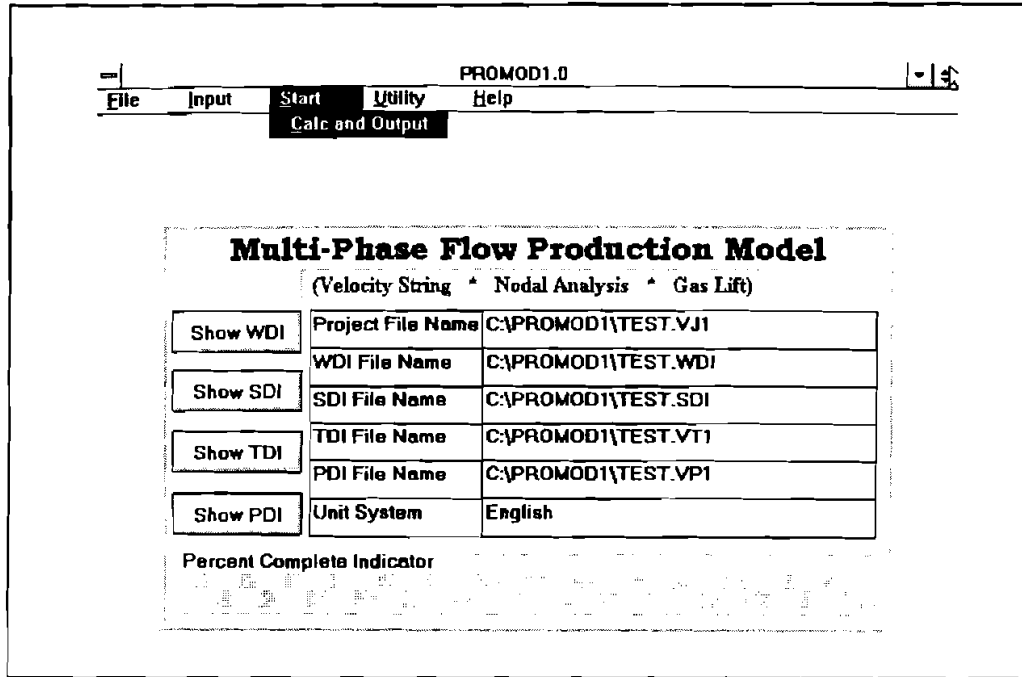


Figure 4-25. "Start" Pull-Down Menu

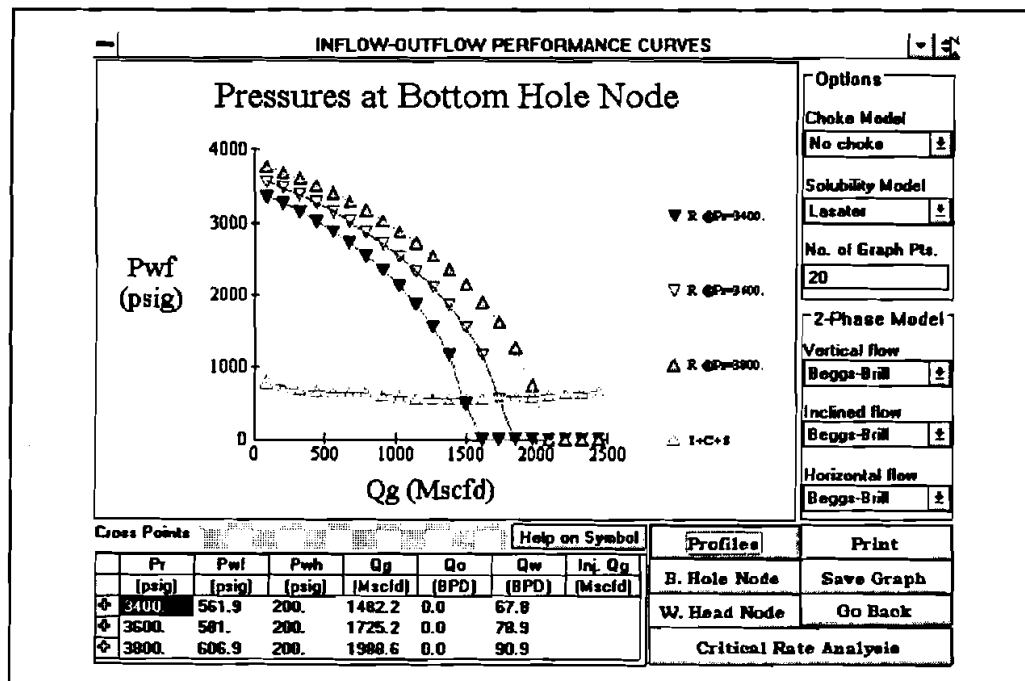


Figure 4-26. "Output" Window

12. The graphics plot in the "Output" window shows the inflow/outflow performance curves. The grid under the plot shows the production parameters at the crossing of inflow/outflow performance curves. The option box on the right of the screen provides available calculation options, including choke model, solubility model, and two-phase flow correlations.
13. To select a choke model, click on the down arrow to the right of the choke model bar to pull down the available choke models, as shown in Figure 4-27. Click on the appropriate model and the pull-down box disappears and the selected model is displayed in the choke model bar. The results are recalculated if the choke model changes. A horizontal bar under the plot box monitors the calculation process.

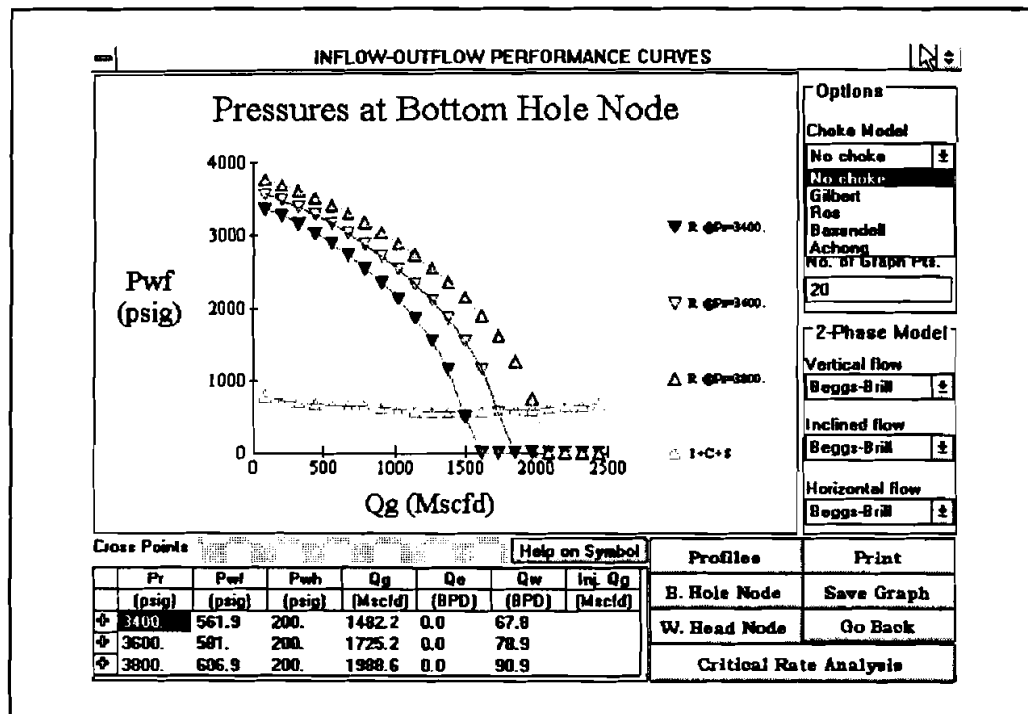


Figure 4-27. Choke Model Selection

14. If the reservoir is under solution gas drive, a solubility model is required. There are two models available. To select either one of these, first click on the down arrow to pull down the selection box (Figure 4-28), make the selection by clicking on the name of the model.

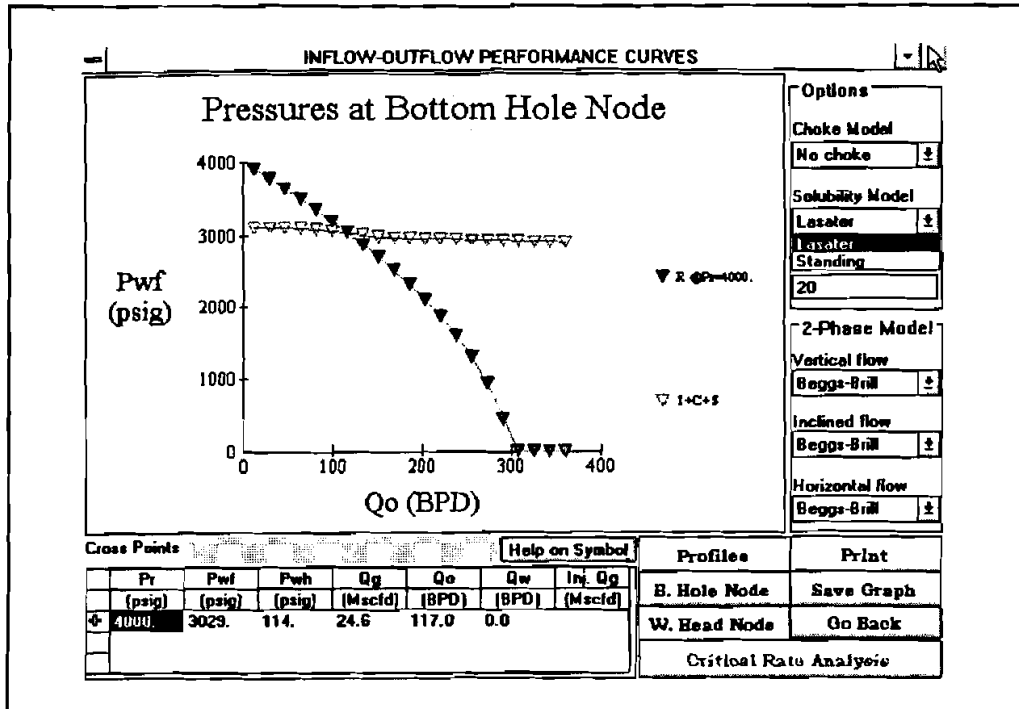


Figure 4-28. Solubility Model Selection

15. The user can customize the inflow/outflow performance curves by specifying the points plotted. To do this, simply enter the number of points in the graph points field. The graph is replotted once the recalculation finishes.
16. To select multiphase correlations for vertical, inclined, or horizontal flow, click on the down arrow beside the correlation box to pull down the selection box, as shown in Figure 4-29. Make the selection by clicking on the appropriate model. The selected model is displayed in the model box. The graph is then updated automatically when the calculation is finished. The horizontal bar under the plot box monitors the calculation process.



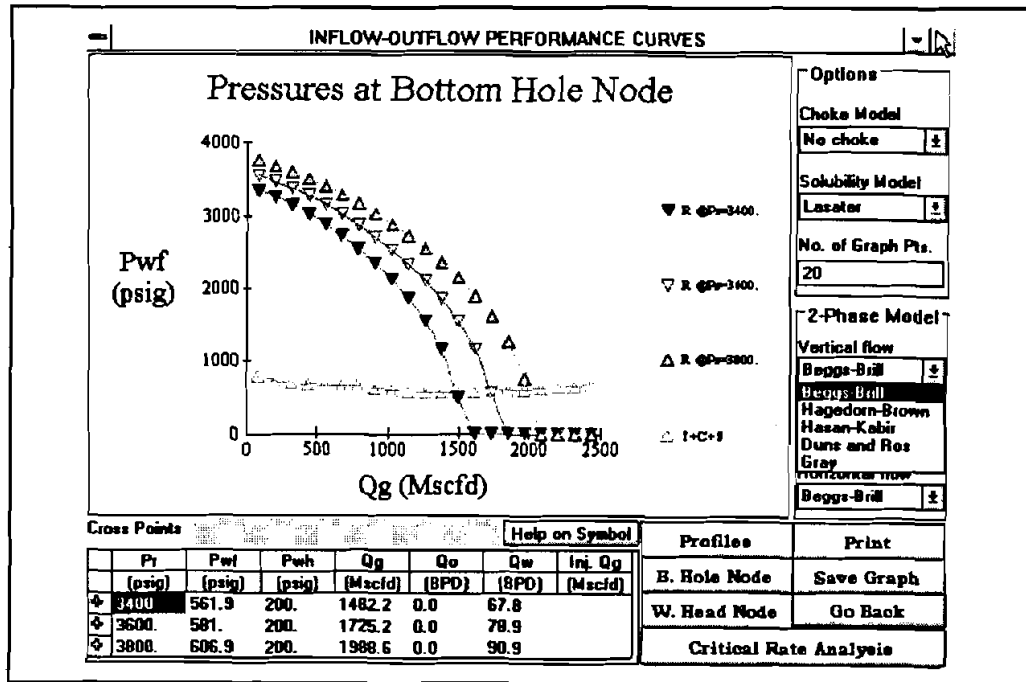


Figure 4-29. Correlation Selection Box

17. There are several buttons in the bottom corner at the right of the screen. These are:
  - a. <B. Hole Node> button: Clicking on this button switches the solution node from the wellhead node to the bottom-hole node. The inflow/outflow performance curves plots bottom-hole pressures against production rates accordingly, as shown in Figure 4-30.

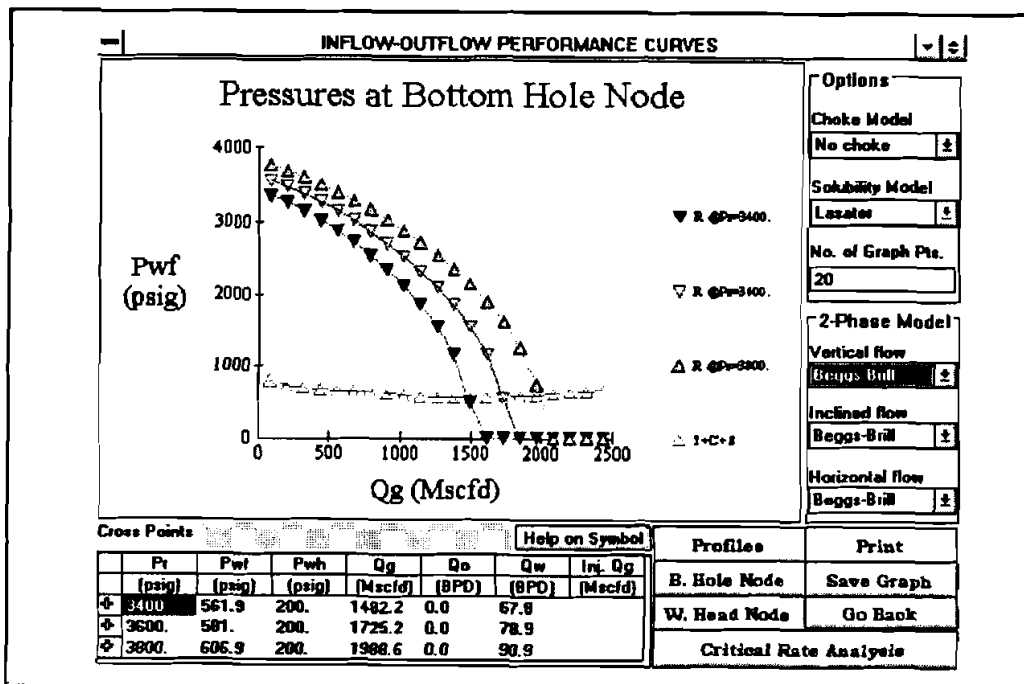


Figure 4-30. Inflow/Outflow Performance Curves with the Bottom-Hole Node

- b. <W. Head Node>: Clicking on this button switches the solution node from the bottom-hole node to the wellhead node. The inflow/outflow performance curves plot the wellhead pressures against the production rate accordingly, as shown in Figure 4-31.

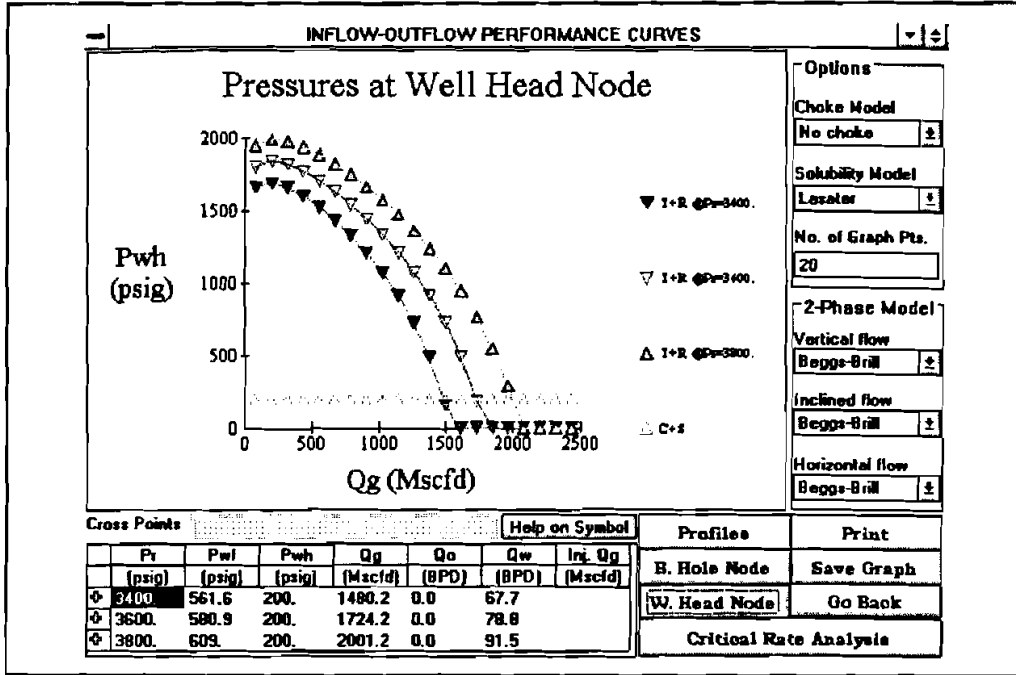


Figure 4-31. Inflow/Outflow Performance Curves with the Wellhead Node

18. Click on the <Critical Rate Analysis> button to open a window with critical flow rate plotted against the tubing ID, as shown in Figure 4-32.

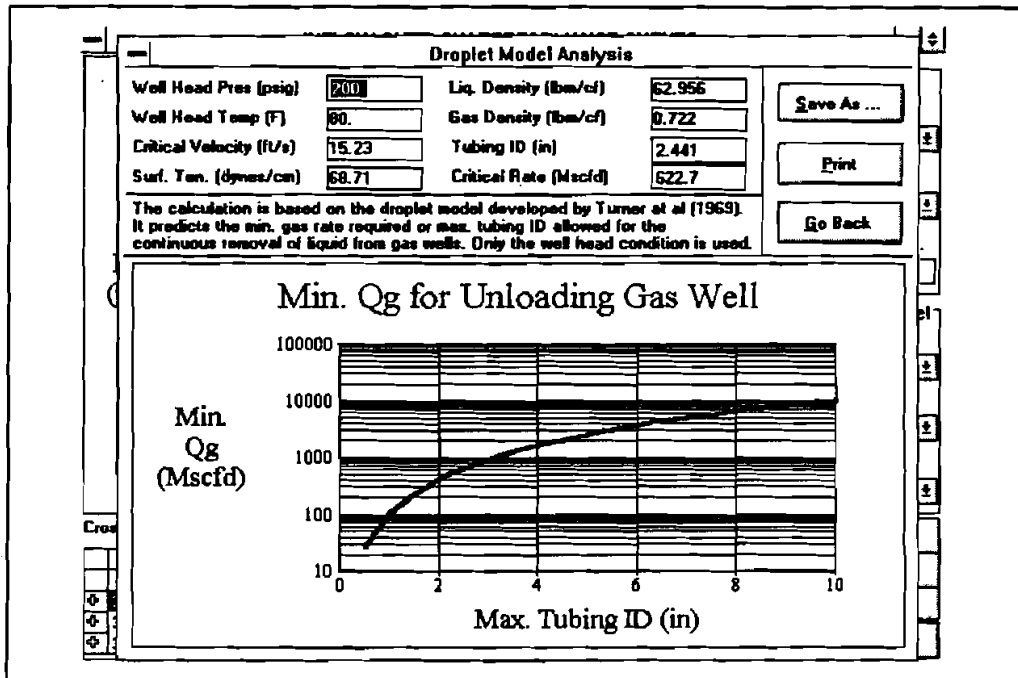


Figure 4-32. Critical Rate Window

In this window there are three white fields where the user can enter the wellhead pressure, tubing ID and critical rate. When a new wellhead pressure is entered, the critical rate curve is updated based on the new input. To read a particular point on the plot, type in the tubing ID. The corresponding critical rate is then displayed in the critical rate field. If the critical rate is entered, the maximum tubing ID is then displayed. To return to the previous window, click on the <Go Back> button.

- Clicking on the <Profile> button displays a group of "child" windows as shown in Figure 4-33. These windows display several types of output, including flow regime, velocity, liquid hold-up, and pressure distribution. Before clicking on the <Profile> button decide the number of curves to be plotted in each graph. This is determined by the number of "+" signs in the table under the plot box. Clicking on a particular row in the table will switch the "+" on or off.

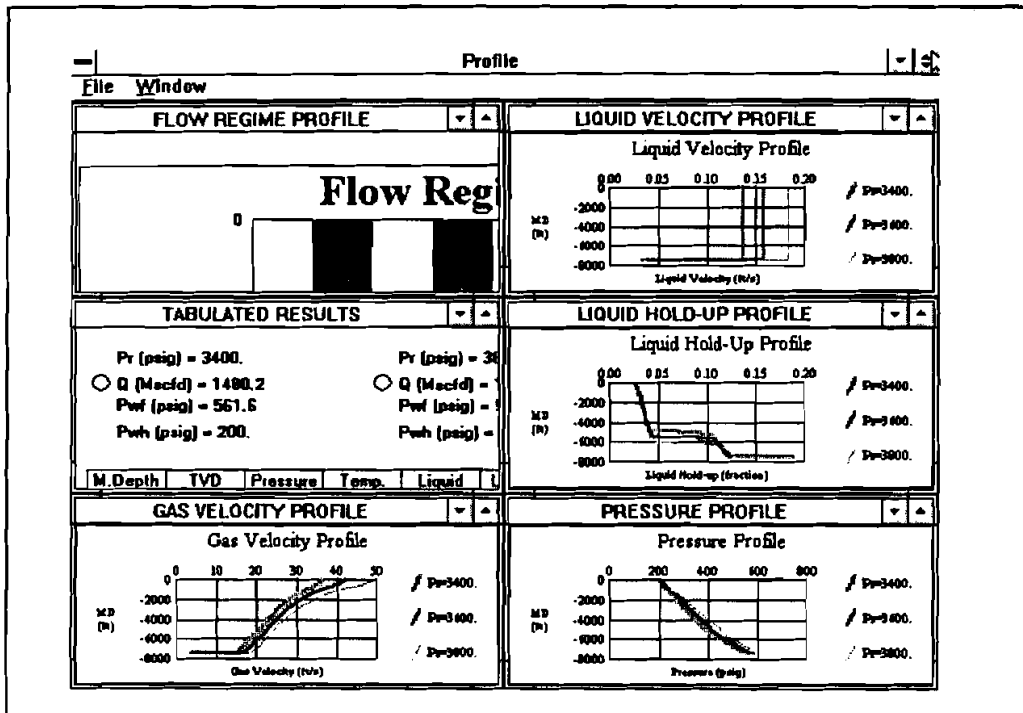


Figure 4-33. Output "Child" Windows

20. There are two ways to bring a particular "child" window to the screen. One way is to click on the particular window when a mouse is available. Another is to click on the "Window" pull-down menu at the top to display the "Window" pull-down menu (Figure 4-34), then, click on the title of the individual plot.

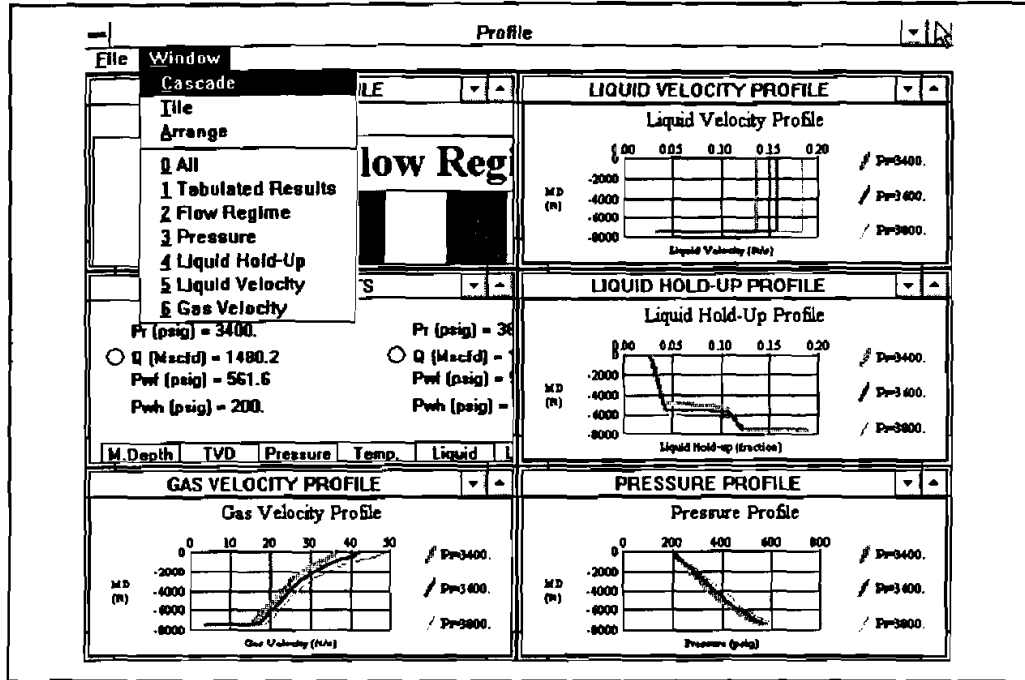


Figure 4-34. "Window" Pull-Down Menu

21. The "child" windows can be arranged in two ways, either in "Cascade" or "Tile." To cascade, click on the "Window" menu at the top, then click on "Cascade." (Figure 4-35).

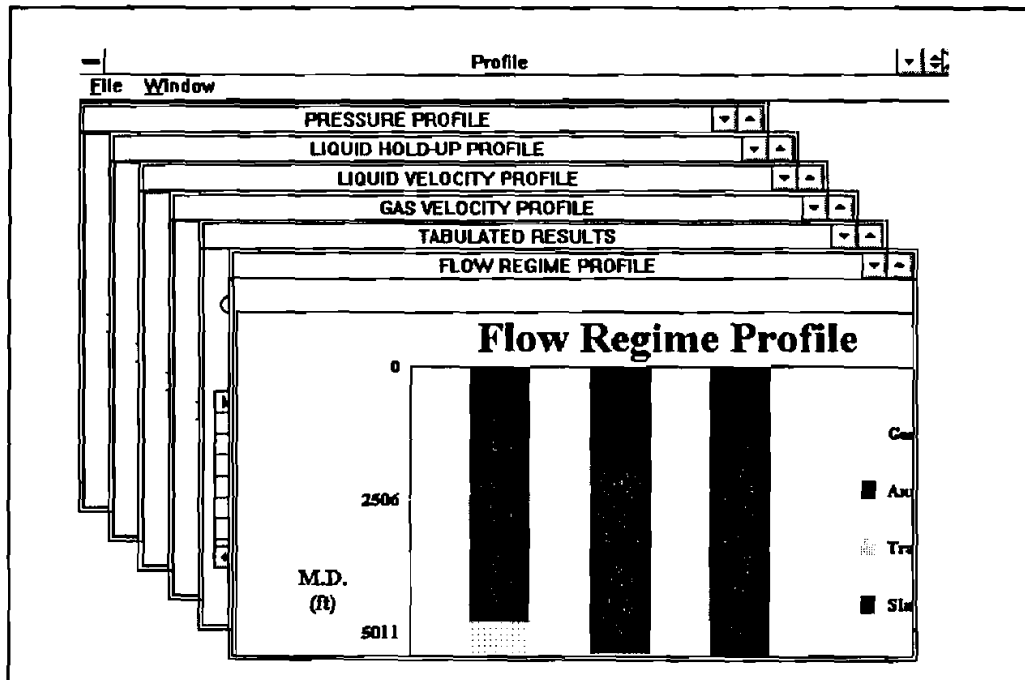


Figure 4-35. "Child" Windows Cascaded

22. To arrange the "child" windows in Tile, click on the "window" menu, then click on "Tile." The program titles the "child" windows as shown in Figure 4-36.

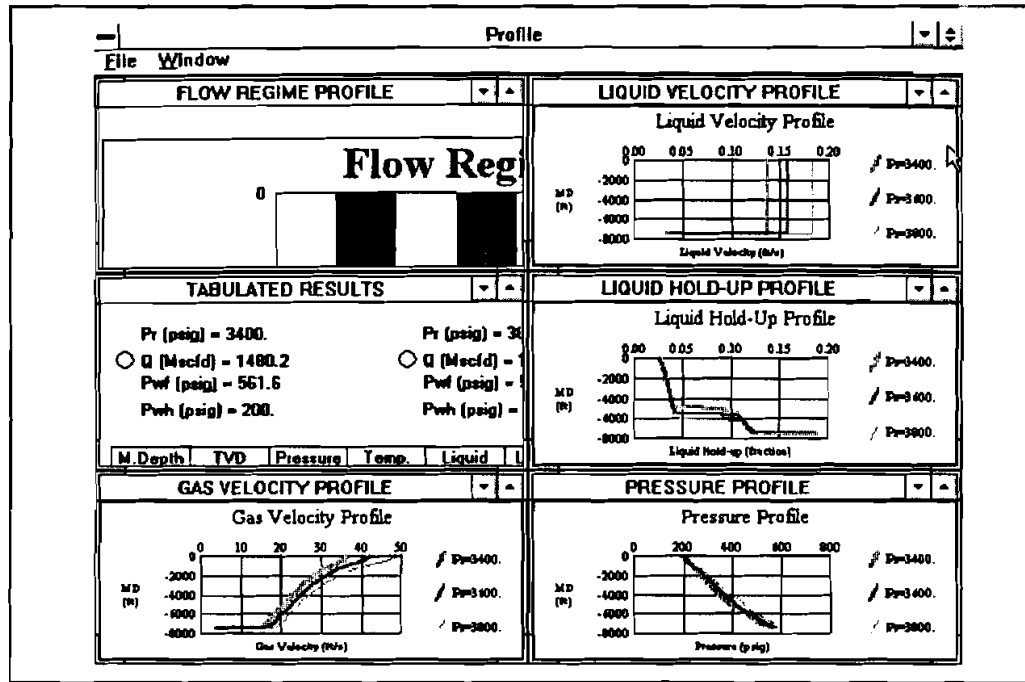


Figure 4-36. "Child" Windows Titled

23. To return to the previous window, click on "File" at the top of the screen, then, click on "Return" to go back to the inflow/outflow performance window, as shown in Figure 4-37.

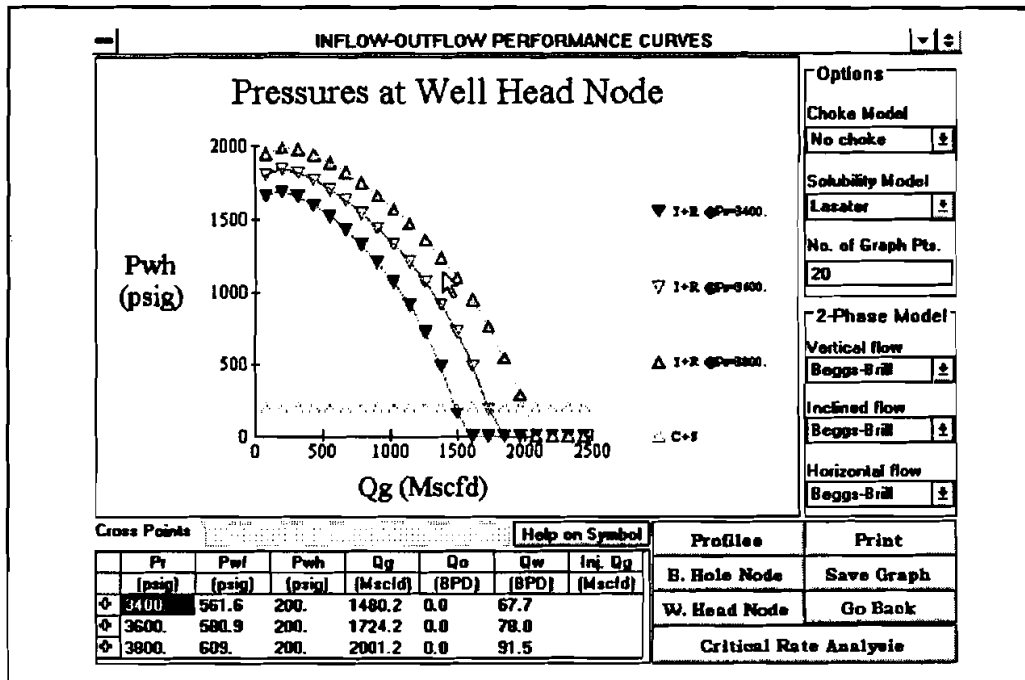


Figure 4-37. Inflow/Outflow Performance Window

24. Clicking on the <Go Back> button causes the program to return to the Main window as shown in Figure 4-38.

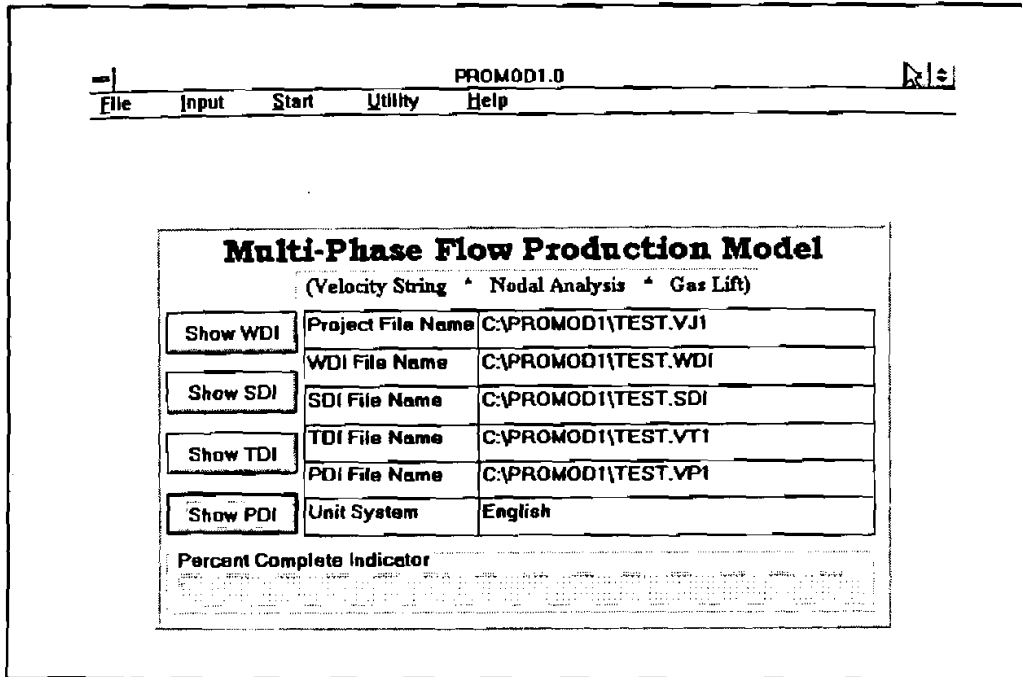


Figure 4-38. PROMOD1 Main Window

25. The **Help** option at the right end of the menu bar opens the Help window. The two options available in this window are **Assistance..** and **About..**. Clicking on **Assistance** opens the window shown in Figure 4-39, which gives phone and FAX numbers and individuals to contact for assistance with the program.

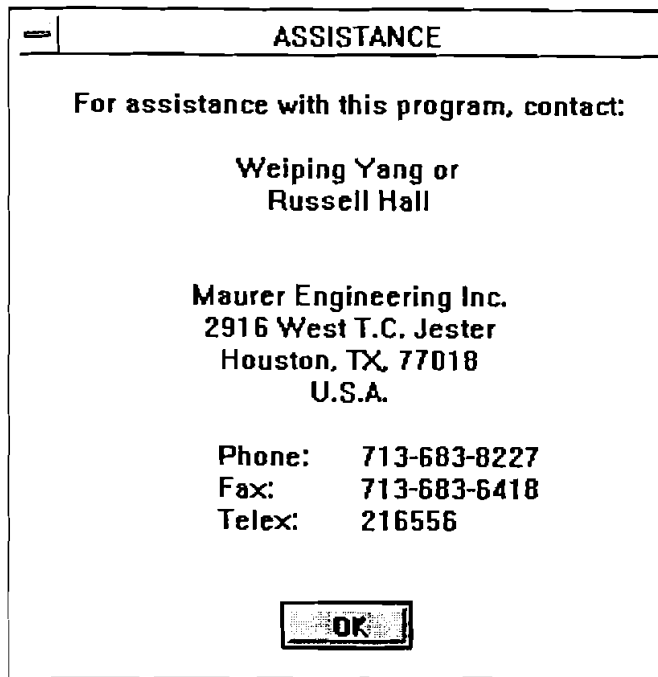


Figure 4-39. Assistance Window

Clicking on **About..** in the **Help** window opens a window with information about the program, and a listing of the equipment you are using to run the program (Figure 4-40).

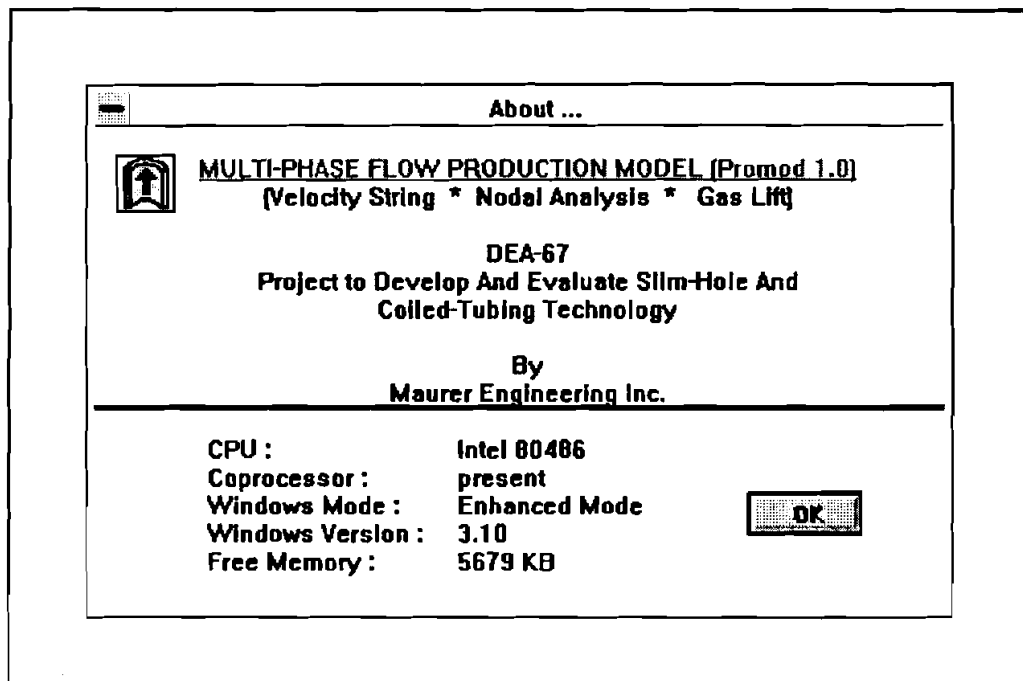


Figure 4-40. About Window

26. To leave the program, click on "File" on the menu bar. When the "File" window opens, click on "Exit."





## 5. Data File Preparation

### 5.1 SDI DATA

The SDI Data Input window is shown in Figure 5-1.

The screenshot shows a window titled "-SURVEY DATA INPUT [SDI]-". Inside the window, there is a menu bar with "File". Below the menu bar is a table with the following columns: "Station", "M. Depth", "Inclination", and "Azimuth". The first row of the table contains the values "1", "0.0", "0.0", and "0.0". To the left of the table are three sets of radio button options: "Depth:" with "Feet" (selected) and "Meters"; "Inclination:" with "Decimal" (selected) and "Deg. Min"; and "Azimuth:" with "Angular" (selected) and "Oil Field". Below the table is an "Edit" section with two buttons: "Insert Line" and "Delete Line".

Figure 5-1. SDI Data Input Window

Note the three sets of options that are available. They are:

1. Depth — Feet or Meters
2. Inclination — Decimal Degrees or Degrees and Minutes
3. Azimuth — Angular or Oil Field Measure

To change any of these, click on the desired option. If not using a mouse, use the tab key to move from one field to another, and use the arrow keys to move within a field. As the user moves from one value to another, the highlight will move accordingly. Default choices are Feet, Decimal, and Angular, respectively.

Before leaving this Survey Data Input window, set these three options to suit your needs.

### 5.2 TDI DATA

The TDI Data Input Window is shown in Figure 5-2.

Figure 5-2. TDI Data Input Window

There are four blocks of data in this window:

1. Tubing string data block in the upper left corner
2. Casing and open-hole data block in the lower left corner
3. Surface pipe line data block in the lower right corner
4. Perforation depth, calculation interval and choke size

Input errors can be deleted only by pressing the <Back Space> key.

The first column in the tubing string data block is the tubing section description. Only letters and numbers are accepted as the input for this column.

The tubing ID, OD and length are all required for a complete definition of a tubing section. The capacity of the tubing (volume) is calculated automatically by the program once the necessary data become available. The total length and volume of the tubing is updated every time a change is made to the tubing string. These two values are displayed at the bottom of the block.

The input to the casing and open-hole data block is basically the same; however, the casing OD is not required. Also note that the casing and open-hole data input starts at the top and proceeds downward. However, for tubing string, the input starts at the bottom and moves upward.

The surface pipe line input starts from the wellhead. The ID, deviation, and length of each section are required. Deviation is the angle relative to the horizontal line. The deviation is positive when flow is uphill; negative when flow is downhill; zero when flow is horizontal. The user can leave this block blank if there is no surface line in the system.

Perforation depth is the mid-point of the perforation section for a vertical well. For a horizontal well, it is assumed that all the flow enters the well at the well end, therefore, the perforation depth is the measured depth of the horizontal well end.

Calculation interval is used to partition the flow line into a number of blocks. A longer interval usually means faster calculation but less accuracy. A shorter interval usually means slower calculation, but better accuracy. The user has to decide what interval to use according to the well length, computer CPU speed, and the time available. An interval between 50 to 300 ft should be good in most cases.

Choke ID is a required input, whether the well is equipped with a choke or not. It is required so that later the user can choose to see how the production changes when a choke is added to the system.

### 5.3 PDI DATA

The PDI Data Input window is shown in Figure 5-3.

The screenshot shows a software window titled "PARAMETER DATA INPUT [PDI]". The window is divided into several sections:

- Well Type:** Radio buttons for "Gas Well" (selected) and "Solution Gas Driven Oil Well".
- Is production rate known?:** Radio buttons for "Yes" and "No" (selected).
- Enter up to 3 rates, if known:** Three input fields for "Q: Rate #1 (Mscfd)", "Q: Rate #2 (Mscfd)", and "Q: Rate #3 (Mscfd)".
- IPR Curve:** A dropdown menu for "IPR Model" set to "Folkovich" and a button labeled "IPR Curve".
- Enter up to 3 pressures below:** Three input fields for "Pr: Reservoir pressure #1 (psig)", "Pr: Reservoir pressure #2 (psig)", and "Pr: Reservoir pressure #3 (psig)".
- Initial reservoir pressure (psig):** An input field labeled "Pi".
- Measured @ Pi (Mscfd/psi):** An input field labeled "C".
- Measured @ Pi:** An input field labeled "rc".
- Equation:** A text box containing the equation  $Q = C \cdot P_r / P_i \cdot (P_i^2 - P_wf^2)^n$ .
- Fluid Properties:** A vertical list of input fields for "Gas Specific Gravity", "Oil API Gravity", "Water Specific Gravity", "Outlet Pressure (psig)", "Gas Liquid Ratio (Mscf/stb)", "Water Liquid Ratio", "Surface Temperature (F)", and "Bottom Hole Temp. (F)".
- Gas Lift Options:** Radio buttons for "Fixed Gas Injection Rate (Mscf/D)" (selected) and "Fixed Inj. Gas Liquid Ratio (Mscf/Stb)".

Figure 5-3. PDI Data Input Window

The PDI Data Input window is divided into 5 blocks. They are:

1. Well type block
2. Production rate input block
3. IPR curve input block
4. Fluid properties block
5. Gas lift option block in the lower right corner

The gas lift option block is dimed because it is inappropriate for a gas well. When the well type is switched to a solution gas driven oil well, the gas lift option is enabled as shown in Figure 5-4.

The screenshot shows the 'PARAMETER DATA INPUT (PDI)' window. The 'Well Type' section has 'Solution Gas Driven Oil Well' selected. The 'IPR Curve' section has 'Vogel' selected as the 'IPR Model'. The 'Is production rate known?' section has 'No' selected. The 'Enter up to 3 rates, if known' section has three empty input fields for 'Q: Rate # 1 (BPD)', 'Q: Rate # 2 (BPD)', and 'Q: Rate # 3 (BPD)'. The 'Enter up to 3 pressures below:' section has three input fields for 'Pr: Reservoir pressure #1 (psig)', 'Pr: Reservoir pressure #2 (psig)', and 'Pr: Reservoir pressure #3 (psig)'. The 'Equation' section has the equation  $Q/Q_{max} = 1 - 0.2(P_{wf}/P_i) - 0.8(P_{wf}/P_i)^2$ . The 'Gas Lift Data Input' section is active and contains input fields for 'Injection Gas Specific Gravity', 'Gas Injection Depth (ft)', and 'Fixed Gas Injection Rate (Mscf/D)'. The 'Fixed Inj. Gas Liquid Ratio (Mscf/Stb)' option is dimmed.

Figure 5-4. PDI Window with Gas Lift Option Enabled

### 5.3.1 Production Rate Block and IPR Curve Block

Only one of either the production rate input block or the IPR curve input block can be enabled. When production rate is known, rate block is enabled and IPR curve block is disabled. When the production rate is unknown, then IPR curve needs to be defined and rate block is disabled. The input fields of the disabled block have a gray background.

The production rate input is straightforward, and is not described in detail here. The IPR curve input depends on the well type selected and the IPR model chosen. Figure 5-5 shows the input requirements for a gas well using Fetkovich's IPR model (*note*: only one IPR model is available for gas wells).

Figure 5-5. IPR Input for Gas Wells

The three reservoir pressures are the pressures of the reservoir at different stages of production. The user can input 1, 2, or 3 pressures, depending on the data available.

C and n are both constants determined from well testing results when reservoir pressure is at  $P_i$ . They are used to predict IPR curves for reservoirs with a different pressure than  $P_i$ . The prediction equation is displayed at the bottom of the block.

Click on the <IPR Curve> button after the relevant data are entered to open a window with the IPR curves displayed, as shown in Figure 5-6.

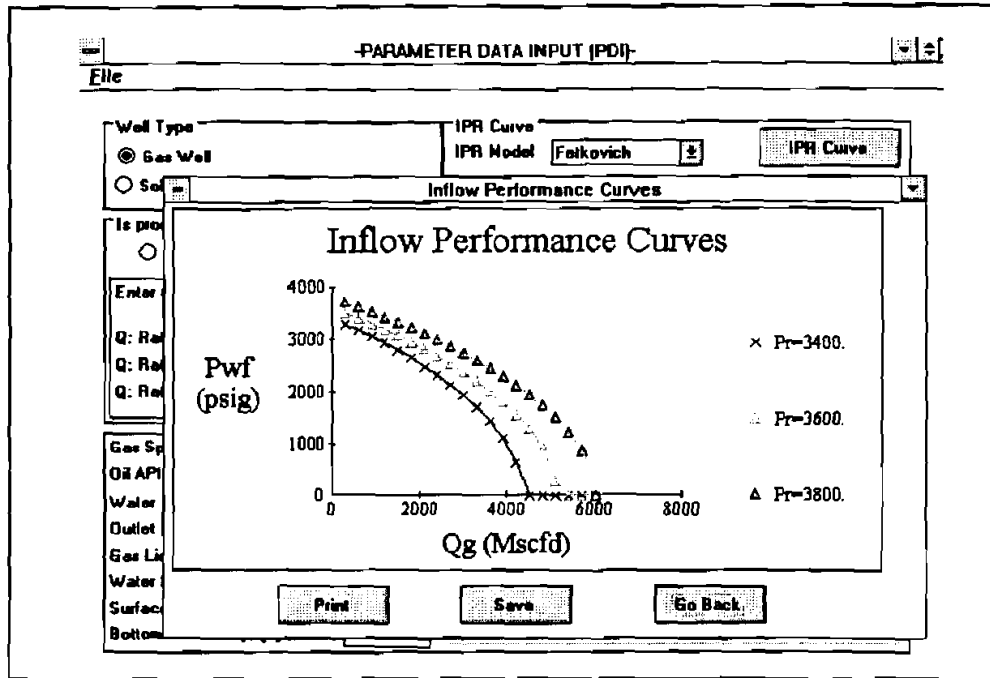


Figure 5-6. IPR Curves

The curves can be saved or printed by clicking on the <Save> or <Print> buttons, respectively. The user can return to the previous window by clicking on the <Go Back> button.

IPR input requirements are different when the reservoir is under solution gas drive. Selecting solution gas driven oil well under well type displays the IPR input shown in Figure 5-7.

**Well Type**  
 Gas Well  
 Solution Gas Driven Oil Well

**IPR Curve**  
 IPR Model: **Vogel** [dropdown]  
 [IPR Curve] button

**Is production rate know?**  
 Yes  
 No

**Enter up to 3 rates, if known**

Pr: Reservoir pressure #1 (psig)	3400
Pr: Reservoir pressure #2 (psig)	3600
Pr: Reservoir pressure #3 (psig)	3800
Qfmax at reservoir pres #1 (BPD)	200
Qfmax at reservoir pres #2 (BPD)	300
Qfmax at reservoir pres #3 (BPD)	400

**Equation:**  $Q/Q_{fmax} = 1 - 0.2 \left[ \frac{P_{wf}}{P_r} \right] - 0.8 \left[ \frac{P_{wf}}{P_r} \right]^2$

**Gas Specific Gravity** [input]  
**Oil API Gravity** [input]  
**Water Specific Gravity** [input]  
**Outlet Pressure (psig)** [input]  
**Gas Liquid Ratio (Mscf/stb)** [input]  
**Water Liquid Ratio** [input]  
**Surface Temperature (F)** [input]  
**Bottom Hole Temp. (F)** [input]

**Gas Lift Data Input**  
 (Leave blank if no gas lift)

**Injection Gas Specific Gravity** [input]  
**Gas Injection Depth (ft)** [input]

Fixed Gas Injection Rate (Mscf/D) [input]  
 Fixed Inj. Gas Liquid Ratio (Mscf/Stb) [input]

Figure 5-7. IPR Curve Input for Oil Wells and Vogel's IPR Model

Vogel's equation requires a current reservoir pressure and the maximum production rate under the current reservoir pressure. The user can enter up to 3 pairs to evaluate the production at different stages of reservoir depletion. Again, clicking on the <IPR Curve> button opens a window displaying the IPR curve, as shown in Figure 5-8.

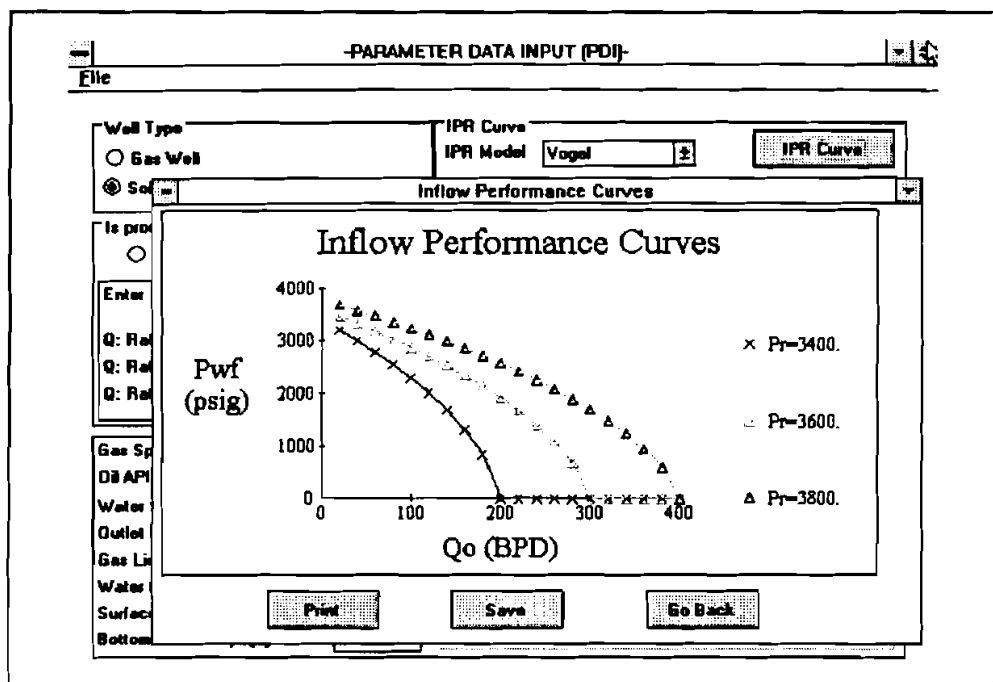


Figure 5-8. IPR Curve for Oil Wells with Vogel's Equation

Another equation that is available for oil wells is the PI equation. It is useful for reservoirs with pressures above the bubble point pressure. These conditions result in single liquid-phase flow in the reservoir. To activate the PI equation, click on the down arrow beside the IPR model to pull down the IPR model selection box, then click on "PI equation." The input fields for the PI equation are displayed in the IPR curve block, as shown in Figure 5-9.

-PARAMETER DATA INPUT (PDI)-

---

File

<p><b>Well Type</b></p> <p><input type="radio"/> Gas Well</p> <p><input checked="" type="radio"/> Solution Gas Driven Oil Well</p> <p><b>Is production rate known?</b></p> <p><input type="radio"/> Yes      <input checked="" type="radio"/> No</p> <p><b>Enter up to 3 rates, if known</b></p> <p>Q: Rate # 1 (BPD)      <input type="text"/></p> <p>Q: Rate # 2 (BPD)      <input type="text"/></p> <p>Q: Rate # 3 (BPD)      <input type="text"/></p>	<p><b>IPR Curve</b></p> <p>IPR Model <span style="border: 1px solid black; padding: 2px;">PI equation</span> <span style="float: right;"><input type="button" value="IPR Curve"/></span></p> <p>Enter up to 3 pressures below:</p> <p>Pr: Reservoir pressure #1 (psig)      <input type="text" value="3400"/></p> <p>Pr: Reservoir pressure #2 (psig)      <input type="text" value="3600"/></p> <p>Pr: Reservoir pressure #3 (psig)      <input type="text" value="3800"/></p> <p>PI at reservoir pres #1 (bbls/D/psi)      <input type="text" value="0.2"/></p> <p>PI at reservoir pres #2 (bbls/D/psi)      <input type="text" value="0.25"/></p> <p>PI at reservoir pres #3 (bbls/D/psi)      <input type="text" value="0.3"/></p> <p>Equation      <span style="border: 1px solid black; padding: 2px;"><math>Q = PI * (Pr - Pwf)</math></span></p>
<p>Gas Specific Gravity      <input type="text"/></p> <p>Oil API Gravity      <input type="text"/></p> <p>Water Specific Gravity      <input type="text"/></p> <p>Outlet Pressure (psig)      <input type="text"/></p> <p>Gas Liquid Ratio (Mscf/stb)      <input type="text"/></p> <p>Water Liquid Ratio      <input type="text"/></p> <p>Surface Temperature (F)      <input type="text"/></p> <p>Bottom Hole Temp. (F)      <input type="text"/></p>	<p style="text-align: center;"><b>Gas Lift Data Input</b> (Leave blank if no gas lift)</p> <p>Injection Gas Specific Gravity      <input type="text"/></p> <p>Gas Injection Depth (ft)      <input type="text"/></p> <p><input checked="" type="radio"/> Fixed Gas Injection Rate (Mscf/D)      <input type="text"/></p> <p><input type="radio"/> Fixed Inj. Gas Liquid Ratio (Mscf/Stb)      <input type="text"/></p>

Figure 5-9. IPR Input for Oil Wells with the PI Equation



The PI equation requires a current reservoir pressure and the corresponding productivity index at the current pressure. Up to 3 pairs can be entered into the IPR block to evaluate the performance at the different stages of production. An example of the IPR curves with the PI equation is shown in Figure 5-10

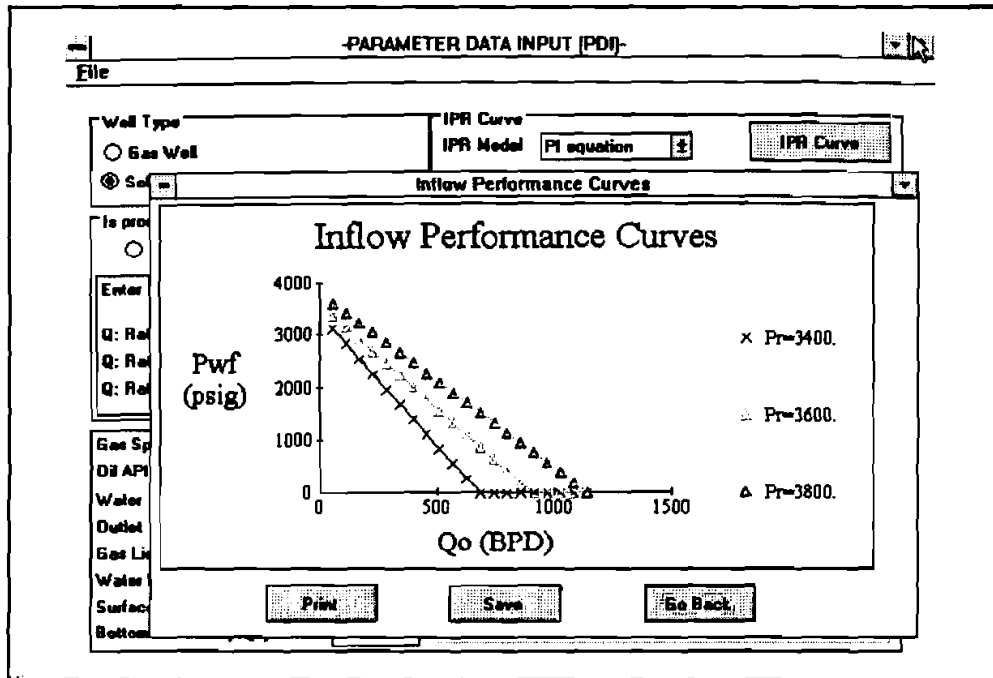


Figure 5-10. IPR Curves for Oil Wells with the PI Equation

### 5.3.2 Fluid Properties Input Block

The following are the input parameters for this block:

1. Gas specific gravity
2. Oil API gravity
3. Water specific gravity
4. Outlet pressure
5. Gas/liquid ratio
6. Water/liquid ratio
7. Surface temperature
8. Bottom-hole temperature

The outlet pressure can be separator or wellhead pressure when no surface line or choke is present in the production system.

### **5.3.3 Gas Lift Input Block**

This block lists all of the parameters required for a continuous gas lift operation. It is available only when oil well is selected. The user has to specify the injection depth and the injected gas specific gravity. There are two options available for specifying gas injection amounts: 1) fixed gas injection rate, and 2) fixed injection gas/liquid ratio. To select either one, click on the radio button preceding each option. *Note:* Injection gas/liquid ratio refers to the amount of gas injected per barrel of liquid produced. It does not include the formation solution gas, i.e., it does not equal the produced gas/liquid ratio.

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## 7. Bug Report or Enhancement Suggestion Form

Name: \_\_\_\_\_ Company: \_\_\_\_\_

Address: \_\_\_\_\_ City: \_\_\_\_\_ State: \_\_\_\_\_

Phone No.: \_\_\_\_\_ Fax No.: \_\_\_\_\_ Date: \_\_\_\_\_

Bug/Problem Report

Enhancement Suggestion

Program Name and Version Number: \_\_\_\_\_

Bug/Problem Description or Enhancement Suggestion: \_\_\_\_\_

Regarding the Bug Report, please answer the following questions:

### Computer System

Brand: \_\_\_\_\_

Chip:  286  386  486  Pentium

Type:  Desktop  Laptop  Notebook  Other

RAM: \_\_\_\_\_ MB Speed: \_\_\_\_\_ MHz

Math-Coprocessor Present:  Yes  No  Unknown

Printer Type: \_\_\_\_\_ (for printing error only)

Plotter: \_\_\_\_\_ (for plotting error only)

Within Network System:  Yes  No Type: \_\_\_\_\_

Video Type:  EGA  VGA  SVGA  Mono  LCD

Video Card Ram: \_\_\_\_\_ (video problem only)

### Operating System

MS-DOS Version No.: \_\_\_\_\_ MS-Windows Version No.: \_\_\_\_\_ (for Windows applications)

OS2 \_\_\_\_\_ MS-Windows NT Version No.: \_\_\_\_\_

Other \_\_\_\_\_

### Data Causing Bug

Will be mailed on diskette  Will be faxed  Attached  None

Other Comments: \_\_\_\_\_

Please send or fax to:

**Lee Chu**  
**MAURER ENGINEERING INC.**  
**2916 West T.C. Jester**  
**Houston, TX 77018-7098**  
**Ph.: 713/683-8227 • Fax: 713/683-6418**

