PETROLEUM INVESTMENT STRATEGY
COMPREHENSIVE REPORT

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EXECUTIVE SUMMARY

Western Panda Corporation has completed a petroleum investment strategy study to evaluate the investment opportunities between two wells. The first well, a gas well located in Wyoming County, West Virginia, will be referred to as the Red Panda well. The second well, an oil well located in Kern County, California, will be referred to as the Giant Panda well.

The casing design of the Red Panda well in West Virginia consists of 4 1/2-inch, J-55, 9.5 pounds per foot production casing, 8 5/8-inch, H-40, 28 pounds per foot intermediate casing, and 11 3/4-inch, H-40, 32.3.3 pounds per foot surface casing. A perforated, multiple-zone completion would be most desirable. The Ravenscliff Sand should be perforated from 1,538 feet to 1,543 feet, the Big Lime from 2,497 feet to 2,503 feet, and the Berea Sand from 3,346 feet to 3,360 feet. The casing design of the Giant Panda well in California consists of 7-inch, J-55, 23 pounds per foot production casing and 9 5/8-inch, H-40, 32.3 pounds per foot surface casing. A perforated, multiple-zone completion would be most desirable. From examination of the log provided, the Second Vedder sand should be perforated from 4,652 feet to 4,660 feet. The Third Vedder sand should be perforated in two separate intervals, 4,790 feet to 4,800 feet and 4,810 feet to 4,835 feet.

Interpretation of available well logs facilitated the estimation of original oil and gas in place on a per acre basis for both wells using the volumetric method. The Red Panda well was found to have an original gas in place of 12,083 MCF/acre. The productive zones have an average porosity of 10.1% and an average water saturation of 28%. The Giant Panda well will produce from a solution gas drive reservoir with an original oil in place of 80,616 STB/acre. The productive zones have an average porosity of 34% and an average water saturation of 27%.

From analysis of available well test data, initial formation pressure, permeability, skin factor, and flow efficiency were estimated. The well test analysis for the Red Panda gas well utilized the data that was made available from a build-up test. The results obtained were initial reservoir pressure of 6511 psi, permeability of 0.082 md, skin factor of 14.79, and flow efficiency of 34 percent. The well test analysis for the Giant Panda oil well utilized the data that was made available from a drawdown test. The initial reservoir pressure was found to be 2400 psi, with a permeability of 11.83 md, skin factor of 0.56, and flow efficiency of 95 percent.

The resulting maximum constant rate for the Red Panda well that can be maintained for seven years is 160.8 MCF/D. At the end of seven years of production with this flow rate, reservoir pressure is 248 psia, well-flowing pressure is 100 psia (abandonment pressure), wellhead

pressure is 85 psia. The cumulative gas produced is 415.5 MMCF. Likewise, the maximum oil production schedule for the Giant Panda well will have an initial flow rate of 245 STB/D. This flow rate will result in a cumulative production of 422,000 STB of oil and 762 MMCF of gas at the end of 7 years reaching the abandonment pressure. The final flow rate will be 37 STB/D.

Monte Carlo simulation was used in order to minimize the uncertainty of oil and gas prices, operation costs and the days required for drilling and completion. Uniform distributions were used for oil price (median value of $20/BBL) and gas price ($3/MCF). Triangular distributions were used for operating costs (median values of $0.75/BBL and $0.25/MCF). Discrete probability distributions were used for the days required for drilling and completion, with both skewed in a manner that allows for possible problems that may increase drilling or completion time. The initial investment for the Red Panda well is slightly under $90,000. The net cash flow will be approximately $1 million, with net present values of $860,000 and $515,000 at the interest rates of 5% and 20%, respectively. The rate of return for the Red Panda well is around 180%. Likewise, the initial investment for the Giant Panda well is slightly over $95,000. The net cash flow, over $10 million, is significantly higher than the Red Panda well. At interest rates of 5% and 20%, the net present values are $9.3 million and $7.5 million, respectively. The rate of return for the Giant Panda well is over 10,000%.

Western Panda Corporation feels very confident in the results obtained from this study. It has been shown that the Giant Panda well, an oil well located in California, will far outperform the Red Panda well, a gas well located in West Virginia. The Giant Panda well is a very certain investment that will generate a significant amount of money at all normal interest rates. Unless interest rates skyrocket to over 10,000%, the Giant Panda well is sure to make money for the company. It is therefore the indisputable and absolute recommendation of Western Panda Corporation that the company proceed forward with the Giant Panda well as a ‘GO’ and the Red Panda well as a ‘NO GO’.

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PROBLEM STATEMENT

Western Panda Corporation has been requested to evaluate the investment opportunities between two wells, the first of which is a gas well located in Wyoming County, West Virginia, the second, an oil well located in Kern County, California. Throughout this study, the gas well in West Virginia will be referred to as the Red Panda well, while the oil well in California will be referred to as the Giant Panda well. Management has indicated that it has only enough resources to invest in one of the two wells. Therefore, a recommendation must be made to management on this investment opportunity. Throughout this quarter, Western Panda Corporation will conduct a thorough examination of the two proposed wells, which will include the following:

1. **Casing Design, Bit Selection, and Completion:**

   A casing program must been designed for both wells. Bits should been selected, with respect to the desired casing program, in order to drill these wells. Completion information should also been determined and justified.

2. **Well Log Interpretation and Reserve Estimation:**

   An appropriate log suite, which contains induction, neutron, density, and gamma ray logs, must be obtained and interpreted. Using volumetric methods, an accurate estimate of petroleum reserves on a per acre basis must then be determined.

3. **Well Test Analysis:**

   The following parameters are to be calculated upon completion of the analysis of the well test data: initial formation pressure, permeability, skin factor, and flow efficiency.

4. **Reservoir Performance Prediction:**

   Correlations must be developed in order to predict z-factor and viscosity for the reservoir fluid at varying pressures and temperatures. In addition, pressure profiles will be forecasted for the next seven years for each well based on the predicted production schedule. For the gas well, this production schedule will consist of the maximum rate that can be maintained constant throughout the seven-year life of the reservoir. For the oil well, the production schedule will be the maximum flow rate that can be maintained for seven years. Since this is a solution-gas drive reservoir, this rate will not be constant.

5. **Monte Carlo Simulation and Economic Evaluation:**

   In order to minimize uncertainty, Monte Carlo simulation was utilized. Uniform distributions were used for oil and gas price, triangular distributions for operating costs, and discrete probability for the days required for drilling and completion. Net present value and rate of return were then determined for both wells.

At the conclusion of this study, Western Panda Corporation will provide a recommendation to management as to which well will be the more profitable investment.

INTRODUCTION

Well Information

The first well is the Red Panda well in the Clear Fork Field. It is located near Baileysville, West Virginia in Wyoming County. A state map of West Virginia can be seen in the Red Panda Appendix as Figure 1. In drilling this well, it is expected to encounter coal seams along with several fresh water streams. Some operating concerns with the Red Panda well may include climate and precipitation, particularly in frigid temperatures and/or heavy amounts of snow or rainfall. This well is located in a rural area, which may make it difficult to reach the well site. Furthermore, the surface rights belong to a local farmer rather than the company, which may present conflict. The Red Panda well is expected to produce only gas.

The second well is the Giant Panda well in the Kern River Field. It is located just north of Bakersfield, California in Kern County. A California state map and a detailed map of the Kern River Field can be seen in the Giant Panda Appendix as Figure 1. This field is a very old one and celebrated its 100th year of production last year. It is located in the San Joaquin Valley, home of much agriculture. In fact, many crops such as carrots, alfalfa, almonds, and oranges are grown very close to the field. The aqueduct, supplying much of the irrigation for these crops, runs directly through the Kern River Field. This area is also home to many endangered plants and animals, such as kit foxes, jackrabbits, rattlesnakes, and several species of cactus. Because of these circumstances, many safety and environmental precautions must be followed in the operation of the wells and facilities. This area is also subject to earthquakes due to its close proximity to the San Andreas Fault. The Kern River field consists of non-marine sediments of the Plio-Pleistocene Kern River formation. The beds strike approximately N-45 degrees-W and dip about 3 to 5 degrees-SW. They were deposited in a large braided stream/alluvial complex fed by the ancestral Kern River. Because of local non-deposition or erosion of the shales, separately named sand units may locally form a single sand package where the shale unit is missing. The Giant Panda well is expected to produce both oil and gas.

CASING DESIGN, BIT SELECTION, AND COMPLETION

Casing performs many vital functions in the drilling and completion of a well. First and foremost, it prevents collapse of the borehole while drilling. It also hydraulically separates the drilling or completion fluid from the formations and the formation fluid. It helps to minimize damage to both the well and the formations. Casing provides an excellent flow channel for the drilling fluid to reach the surface. It also aids blowout preventers to safely control formation pressure. Finally, properly cemented casing may be selectively perforated for communication with given formations that are of interest.

Of course, before casing may be set, the hole must first be drilled with the proper bit. A large variety of rotary drilling bits are available, but rolling cutter bits will be emphasized for this study. Rolling cutter bits have two or more cones containing the cutting elements, which rotate about the axis of the cone as the bit is rotated at the bottom of the hole. Of this kind of bit, the three-cone rolling cutter bit is by far the most common used today. It is available in an assortment of tooth design and bearing types, which makes it useful in a wide variety of formations. The most pronounced limitation that an engineer faces in bit selection is the fact that the bit must fit inside the borehole or casing. A three-digit code has been adopted in the designation and classification of bits. The first number is called the bit series number. The second digit is called the type number. The third number refers to the bit design features.

There are two chief completion types, the first of which are open-hole completions. An open-hole completion exists when the casing is set above the producing zone. There are many advantages with this type of completion. It is adaptable to special drilling techniques used to minimize formation damage or prevent lost circulation into the producing formation. With a gravel pack, this completion is an excellent sand control method, particularly where productivity is important. With open-hole completions, there is no perforating expense and log interpretation is not critical. Furthermore, open-hole completions can easily be deepened or converted to a liner or perforated completion. There are also several limitations to this type of completion. Excessive gas or water production is very difficult to control. Selective fracturing or acidizing is more difficult. For open-hole completions, the casing is set before the pay zone is drilled or logged. Open-hole completions also require more rig time during completion.

The second main type of completion is the perforated completion. This type of completion exists when casing is cemented through the producing zone(s) and is later perforated. This, too, has many advantages. Excessive gas and/or water production can be controlled more easily. Perforated completions can be selectively stimulated. Logs and formation samples are available to assist in the decision to set casing or abandon. Perforated completions can also be easily deepened. This type of completion will control most sands and is adaptable to special sand control techniques. It is also adaptable to multiple completion techniques. Minimum rig time is required upon completion. Perforated casing also has its limitations. The cost of perforating thick pay zones may be significant. It is not adaptable to special drilling techniques used to minimize formation damage. Finally, log interpretation is sometimes critical in order not to miss commercial sands, yet avoid perforating sub-marginal zones.

WELL LOG INTERPRETATION AND RESERVE ESTIMATION

Petrophysical characteristics of the subsurface can be estimated using information from geophysical logs. The accuracy of the estimate depends on the number of the logs available. While the logging tools are being pulled up in the well, logging equipment sensors are measuring certain physical properties of the formations encountered. These measurements are recorded on long strips of paper and digitally on magnetic tapes. Together they make up what are referred to as well logs. Many different logs can be run today. Some of the measured properties are resistivity or conductivity of the rocks, intensity of natural radioactivity, electrical potentials existing in the well, and velocity of sound waves.

The determination of the presence and amount of hydrocarbons in both wells after all measurements have been collected and the log has been analyzed can now be done. It is important to determine various characteristics such as permeability and the types of minerals present in the formations of interest.

WELL LOGGING TOOLS

Mostly all onshore well logging operations utilize similar surface equipment systems for a wide variety of downhole tools. Variations are present between these and offshore systems, which consist of a permanently mounted equipment assembly. In each case, the same surface equipment can be used for any electrically operated, wire-line tool by changing the control panel connections in the logging unit.

WELL SETUP

There are three basic well setups used, depending on the wellsite and type of downhole tool. The first setup is when the drilling rig is still on location. From the logging unit the cable is threaded through the lower sheave, which is anchored to the rig floor, and up over the upper sheave hanging from a strain gauge (weight indicator) which is coupled to the traveling block. The second and third setups are when the drilling rig has been removed from the wellsite. A mast is required to control large, heavy tools. Commonly a portable hydraulic mast is used for this purpose. Lastly, setting up a single sheave at the wellhead can run a small easy handled downhole tool into the hole.

LOGGING UNIT

The logging unit is the control center for all well logging operations. A unit can be a truck, barge, or platform that is mounted for offshore operations. It contains a control panel for monitoring all logging activities. The activities can range from moving the tool to recording data. More recently, sophisticated computers have enhanced the ease with which the engineer may operate the logging procedure.

HOISTING EQUIPMENT

It is required for well logging to have hosting equipment to operate. That includes a power source, hoisting drum, and power supply. The power supply, which operates the hoisting drum, is a variable-displacement hydraulic pump with a reversible hydraulic motor either electrically or gasoline operated.

CABLE CONSTRUCTION

Logging cable consists of seven rubber insulated, symmetrically spaced, stranded copper wires with a cloth braid wrapping separating the conductors from the outer steel jackets. A diagram of this can be seen as Figure 1 in the General Appendix. Usually, a seven-conductor cable is used for electrical logging operations, and a one or three-conductor cable for perforating. The number of conductors depends on the number of applications on the downhole tool.

The main components of a typical (downhole) logging tool are as follows:
Sonde
Cartridge
Head
Bridle
Weak Point
Wire Line
Drum
Brushes, Panels and Recorder

TYPES OF LOGS

DENSITY LOGS

Density logs are primarily used to determine porosity. Other uses include identification of minerals in evaporate deposits, detection of gas, determination of hydrocarbon density, evaluation of shaly sands and complex lithologies, determinations of oil-shale yield, calculation of overburden pressure and rock mechanical properties.

Principle:

A radioactive source, applied to the borehole wall in a shielded sidewall skid, emits medium-energy gamma rays into the formations. These gamma rays may be thought of as high-velocity particles that collide with the electrons in the formation. At each collision a gamma ray loses some, but not all, of its energy to the electron, and then continues with diminished energy. This type of interaction is known as Compton scattering. The scattered gamma rays reaching the detector, at a fixed distance from the source, are counted as an indication of formation density.

The number of Compton-scattering collisions is related directly to the number of electrons in the formation. Consequently, the response of the density tool is determined essentially by the electron density (number of electrons per cubic centimeter) of the formation. Electron density is related to the true bulk density, ρ_b, which, in turn, depends on the density of the rock matrix material, the formation porosity, and the density of the fluids filling the pores.

NEUTRON LOGS

Neutron logs are used principally for delineation of porous formations and determination of their porosity. They respond primarily to the amount of hydrocarbon in the formation. Thus, in clean formation whose pores are filled with water or oil, the neutron log reflects the amount of liquid-filled porosity.

Comparing the neutron log with another porosity log or a core analysis can often identify gas zones. A combination of the neutron log with one or more porosity logs yields even more accurate porosity values and lithology identification.

Principle:

Neutrons are electrically neutral, each having a mass almost identical to the mass of a hydrogen atom. High–energy (fast) neutrons are continuously emitted from a radioactive source in the sonde. These neutrons collide with nuclei of the formation materials in what may be thought of as elastic “billiard-ball” collisions. With each collision, the neutron loses some of its energy.

The amount of energy lost per collision depends on the relative mass of the nucleus with which the neutron collides. The greater energy loss occurs when the neutron strikes a nucleus. Collisions with which the neutron strikes a nucleus of practically equal mass – i.e., a hydrogen nucleus. Collisions with heavy nuclei do not slow the neutron very much. Thus, the slowing of neutrons depends largely on the amount of hydrogen in the formation.

Within a few microseconds the neutrons have been slowed by successive collisions to thermal velocities, corresponding to energies of around 0.025 eV. They then diffuse randomly, without losing more energy, until they are captured by the nuclei of atoms such as chlorine, hydrogen, or silicon.

The capturing nucleus becomes intense and emits a high-energy gamma ray of capture. Depending on the type of neutron tool, either these captured gamma rays or the neutrons themselves are counted by a detector in the sonde.

When the hydrogen concentration of the material surrounding the neutron source is large, most of the neutrons are slowed and captured within a short distance of the source. On the contrary, if the hydrogen concentration is small, the neutrons travel farther from the source before being captured. Accordingly, the counting rate at the detector increases for decreased hydrogen concentration, and vice versa.

INDUCTION LOGS

The induction-logging tool was originally developed to measure formation resistivity in boreholes containing oil-based muds and in air-drilled boreholes. Electrode devices did not work in the nonconductive muds, and attempts to use wall-scratchier electrodes were unsatisfactory.

Experience soon demonstrated that the induction log had many advantages over the conventional ES log when used for logging wells drilled with water-base muds. Designed for deep investigation, induction logs can be focused in order to minimize the influences of the borehole, the surrounding formations, and the invaded zone.

Principle:

Today's induction tools have many transmitter and receiver coils. However, the principle can be understood by considering a sonde with only one transmitter coil and one receiver coil.

A high-frequency alternating current of constant intensity is sent through a transmitter coil. The alternating magnetic field creates induction currents in the formation surrounding the borehole. These currents flow in circular ground loops coaxial with the transmitter coil and create, in turn, a magnetic field that induces a voltage in the receiver coil.

Because the alternating current in the transmitter coil is of constant frequency and amplitude, the ground loop currents are directly proportional to the formation conductivity. The voltage induced in the receiver coil is proportional to the ground loop currents and, therefore, to the conductivity of the formation. There is also a direct coupling between the transmitter and receiver coils. Using "bucking" coils eliminates the signal originating from this coupling.

The induction tool works best when the borehole fluid is an insulator-even air or gas. The tool also works well when the borehole contains conductive mud unless the mud is too salty, the formations are too resistive, or the borehole diameter is too large.

WELL TEST ANALYSIS

The pressure buildup test is the most commonly used pressure transient test. This test requires that a producing well be shut in and the resulting increase in formation face pressure be measured as a function of shut-in time. It is assumed that the test well was produced at constant formation face rate for a time prior to being shut in. Shut-in time is denoted by the symbol Δt.

The primary objectives are to show how the pressure buildup test can be designed and analyzed to evaluate permeability, formation damage, average reservoir pressure, and flow efficiency. Common problem of interpretation such as wellbore storage, and boundary effects will be discussed.

BUILDUP TEST ADVANTAGES

The problem of rate control, which is the greatest disadvantage of flowing tests, is eliminated since the well is shut in during the test. Wellbore storage can be reduced, or eliminated, by using a bottomhole shut-in device. Average pressure within the drainage volume of the shut-in period. The test can be used on wells with certain types of artificial life where subsurface pressure measurements would be difficult to obtain under flowing conditions.

BUILDUP TEST DISADVANTAGES

The first disadvantage is that loss of production occurs during the test. Redistribution of fluids in the wellbore during shut-in can make analysis of some data difficult, or impossible, if a bottomhole shut-in device is not used. Well can sand up, or experience other mechanical problem, during shut-in. The buildup test requires a reasonably constant rate for a period of time prior to shut-in. The pressure buildup test is a two- rate test; accordingly, superposition methods must be used to evaluate the data.

BUILDUP TEST ANALYSIS

A pressure buildup test is the simplest test that can be run on a gas well. If the effects of wellbore storage can be determined, much useful information can be obtained. This information includes permeability, apparent skin factor, average reservoir pressure, and flow efficiency. Generally, there are several methods of analysis that can be used to analyze the buildup test data.

P^2 METHOD

This method is subjected to three major limitations. It is assumed that pressure gradient around the wellbore of the test well are small. Laminar flow is assumed, where most gas wells experience turbulent flow to some degree. The μz product is assumed to be constant. This effectively limits the application of this method to pressures less than 2000 psia. Therefore, this method of analysis is not going to be used to analyze the build-up data of the two wells.

REAL GAS PSEUDO-PRESSURE METHOD, M(P)

In 1966, Al-Hussainy introduced the concept of the real gas pseudo-pressure, m(p). This function is defined as:

$$m(p) = 2 \int \frac{p}{\mu z} dp \text{ , } psi^2/cp$$

where,

μz are functions only of pressure

Since μ and z are integrated as a function of pressure, there are no limits on the pressure range. It is also important to observe that it does not contain the limitation that pressure gradients must be small.

In this project, the real gas pseudo-pressure method would be used to analyze the buildup test data. Therefore, a computer program is developed in visual basic to convert pressure to pseudo-pressure.

The relationship between P and m(P) can be obtained using the following procedure:

1. Determine viscosity and z as function of pressure for the entire range of pressures involved in the test analysis. Pressure increments of 50-100 psi are normally adequate.
2. Compute 2p/Δz for each pressure in step 1.
3. Compute m(P) as a function of pressure using numerical integration. In order to compute the value of m(P) at some pressure P_1 it is necessary to compute the area under the curve between P_1 and P_2.This area, A_1 is equal to

$$A= \int 2\{/ \mu z \, dp$$

If the pressure increment, P_1- P_2, is sufficiently small, the area can be assumed to be a trapezoid. The values of m(P) at other pressure can be determined in a similar manner.

Or for computing the pseudo-pressure we can use the formula:

$\Sigma\ [2P/\mu * z]_{av} * Dp$

The deviation z factor was computed with the formula using a trial and error procedure:

$Z = 1 + [A1 + A2/T_{pr} + A3/Tpr^3 + A4/T_{pr}^4 + A5/Tpr^5]\ \rho + [A6 + A7/T_{pr} + A8/T_{pr}^2]\ \rho^2$ -

$A9[A7T_{pr} + A8/T_{pr}^2]\ \rho^5 + A10(1 + A11\ \rho^2)\ (\rho^2/T_{pr}^3)\ EXP(-A11\ \rho^2)$

Where,

$\rho = 0.27[Ppr/(zTpr)]$ and

A1= 0.3265	A2= -1.0700	A3= -0.5339
A4= 0.01569	A5= 0.1844	A9= 0.5475
A10= 0.6134	A11= 0.7201	

Tpc and Ppc are calculated with the formula:

Tpc= 170.491+307.344Gg

Ppc= 709.604-58.718Gg

Pseudoreduced Temperature and Pseudoreduced Pressure are calculated with formula:

Tpr= T/Tpc

Tpc= P/Ppc

Gas viscosity was calculated with the correction:

For Tpr = 1.5 v= 34E-5 (Tpr)^ 8/9/xm

For Tpr = 1.5 v= 166.8E-5[0.1338 Tpr-0.0832]^5/9 /xm

Xm = 5.4402 (Tpc)^ 1/6/(Mwa)^ 1/2/(ppc)^ 3/2

μg = v / 10.8E-5[EXP91.439 ρ)-EXP(-1.111(_or)^1.888] / xm

Where:

μg = gas viscosity at reservoir pressure and temperature

μ = gas viscosity at atmospheric pressure and temperature, cp $\rho\Delta$

ρ = reduced gas density

Next step was to calculate pseudo-time, ta

$ta = \Sigma[(ti-ti-1)/(pi-pi-1)[I(pi-1)]$

where,

$Ip = S\ [1/v^*cg)_j + (1/v^*cg)_{j-1}](Pi-Pi-1)/2$

Gas compressibility was calculated with the relation:

$Cgr = 1/\ ppr - 0.27\ /\ z\ Tpr\ [dz/d\_r)\ /\ (\ 1 + dz/d\_r)]$

Where,

$Dz/d\_r = 1+[A1+A2/Tpr + A3/Tpr^3 + A4/Tpr + A5/Tpr^5]\_r +[A6+A7/Tpr+A8/Tpr^2]\_r^2-A9[A7Tpr+A8/Tpr^2]\_r^5+A10(1+A11\_r^2)(r^2/Tpr^3)\ EXP\ (-A11\_r^2)$

$cg = cgr\ /\ ppc$

A1- A11 are presented above.

The delta pseudo-pressure m(p) was calculated with the formula:

$Dm[p] = m[Pws] - m[Pwf]$

Reservoir Performance Prediction

Reservoir Fluid Properties

The z-factor (or compressibility factor) is a correction factor used in the ideal gas law to compensate for the behavior of real gases. It is the ratio of the volume actually occupied by a gas at a given temperature and pressure to the volume an ideal gas would occupy at the same temperature and pressure. The Law of Corresponding States says "all pure gases have the same z-factor at the same values of reduced pressure and reduced temperature." This law has been extended to apply to mixtures of closely related gases. The z-factor varies with changes in gas composition, temperature, and pressure and must be determined experimentally. For use in z-factor determination, the accepted standard of the industry is the Standing and Katz chart, which can be seen in the General Appendix as Figure 2.

The viscosity (or coefficient of viscosity) of a gas measures the resistance to flow put forth by a fluid. It is also called dynamic viscosity and is defined as the kinematic viscosity divided by the density of the fluid. Its units are usually given in centipoise. Gas viscosity decreases as reservoir pressure decreases. When the composition of a gas mixture is known and the viscosities of the components are known, the viscosity of the gas mixture can be found, as is indicated by the Law of Corresponding States. However, in most cases the composition is not available and correlations must be utilized. Typically, Figure 3 in the General Appendix is used to find the viscosity of the gas at atmospheric pressure. Then, the viscosity ratio is read from Figure 4 in the General Appendix. These two values are multiplied to obtain the viscosity of the gas.

The viscosity of oil is similar to that of gas. It is also a measure of the resistance to flow exerted by a fluid and typically has units of centipoise. At pressures above the bubble point, the viscosity of oil decreases almost linearly as pressure decreases. However, as reservoir pressure decreases below the bubble point, the liquid composition changes as gas evolves. Therefore, below the bubble point, the viscosity greatly increases as pressure decreases. For black oils, a combination of two charts is generally used to find the oil viscosity. The first, Figure 5 in the General Appendix, is used to determine the dead oil viscosity. This value is then used to enter into Figure 6 in the General Appendix to obtain the oil viscosity.

GAS RESERVOIRS

Gas flow through porous media is given by the partial differential equation that can be obtain by combining the continuity equation, Darcy's law, and equations of state. As can be seen from the partial differential equation for gases (for either horizontal flow or radial flow) compared with the partial differential equations for fluids, a new term appears [P/(μz)]. This is due to the gas deviation factor and the higher compressibility of gases compared to fluids, both of them being functions of pressure. In order to solve the equations, a new term called pseudo-pressure was defined, which results in increased accuracy. Mathematically, it is defined as the integral of [P/(μz)] between two pressures as seen below:

The most important advantage of this method is that it is applicable to all pressure ranges. For a particular gas gravity and reservoir temperature, the relationship between P and m(P) can be obtained using the following procedure:

$$\mathrm{m(P)} = 2\int \frac{\mathrm{P}}{\mu \mathrm{z}} \mathrm{dP}$$

Determine μ and z as functions of pressure for the entire range of pressures involved in the test analysis. Pressure increments of one to ten pounds per square inch are normally adequate. Then, compute the following for each pressure in Step 1:

$$\frac{2\mathrm{P}}{\mu \mathrm{z}}$$

Compute m(P) as a function of pressure using numerical integration. In order to compute the value of m(P) at some pressure P_1, it is necessary to compute the area under the curve between P_b and P_1. This area, A_l is equal to the following:

$$\mathrm{m(P)} = \int \frac{2\mathrm{P}}{\mu \mathrm{z}} \mathrm{dP}$$

If the pressure increment, P_l-P_b is sufficiently small, the area can be assumed to be a trapezoid. The values of m(P) at other pressures can be determined in a similar manner. Mathematically the pseudo-pressure can be calculated using the formula below:

$$m(P) = \sum \left[\left(\frac{P}{\mu z} \right)_j + \left(\frac{P}{\mu z} \right)_{j-1} \right] (P_j - P_{j-1})$$

Plot m(P) versus P. This plot will provide the real pressure for any value of pseudo-pressure.

SOLUTION-GAS DRIVE RESERVOIRS

An oil well can be produced at a constant rate as long as the reservoir pressure remains above the bubble point pressure. Reservoir pressure can be maintained if there is an active water drive or by some means of local injection. In the absence of some type of mechanism to supply constant pressure the reservoir pressure will decrease as oil is produced.

The initial reservoir pressure for the Giant Panda was found to be 1400 psia. The PVT data indicated the bubble point pressure to be 1300 psia. It is obvious that the saturation pressure will be reached allowing the escape of gas in solution. As the gas saturation increases the relative permeability of oil decreases and the relative permeability of gas increases. This is Graph 1 of the Giant Panda Appendix. The increase in gas permeability allows the gas to flow more easily in the reservoir making it harder for the oil to flow. Therefore, the result will be a decrease in the oil production rate and an increase in the gas production rate over the life of the well. Because of this phenomenon, it is desirable to find the maximum oil production schedule in which the well flowing pressure is above abandonment pressure.

Monte Carlo Simulation and Economic Evaluation

Uncertainty

A large amount of uncertainty exists regarding cost and days required for drilling and completion, so these quantities are treated as probabilistic. In this project, three distributions are considered: uniform, triangular, and discrete.

In many cases detailed data are so limited that no distribution curve maybe developed from that data. But, on the basis of experience and general data, professional judgment maybe exercised. If a minimum, maximum and most probable value maybe developed a triangular distribution is possible. In some instance it is not reasonable to predict a most probable value, only a probable minimum and maximum are possible. For this case a rectangular distribution may be drawn.

Uniform Distribution

Uniform distribution is used when upper and lower limits of the range of the variable can be specified and when any of the values between these limits are as likely to occur as any other value. Figure 7 in the General Appendix is a schematic representing uniform distribution.

The cumulative probability of x is given by

$$f(x) = \frac{x - x_L}{x_H - x_L}$$

Replacing f(x) with R_N, the uniform distributed number and solving for x.

$$x = x_L + R_N(x_H - x_L)$$

TRIANGULAR DISTRIBUTION

Trianguar distribution is used when a median value, upper limit, and lower limit of a range of the variable are specified and when the probability of a value to occur is dependent on whether the random number is above or below the median value. Figure 8 in the General Appendix is a schematic representing triangular distribution.

When $X_L \leq X \leq X_M$

$$F(x) = (\frac{x - x_L}{x_M - x_L})^2 * (\frac{x_M - x_L}{x_H - x_L})$$

When $X_M \leq X \leq X_H$

$$F(x) = 1 - (\frac{x_H - x}{x_H - X_M})^2 * (\frac{x_H - x_M}{x_H - x_L})$$

Replacing F(x) by random number (R_N),

If $R_N \leq \frac{x_M - x_L}{x_H - x_L}$

$$X = x_L + \sqrt{(x_M - x_L) * (x_H - x_L) * R_N}$$

If $R_N \geq (\frac{x_M - x_L}{x_H - x_L})$

$$x = x_H - \sqrt{(x_H - x_M) * (x_H - x_L) * R_N}$$

DISCRETE PROBABILITY DISTRIBUTION

Discrete probability distribution is used when there are few cases of which the distinct probability of each to occur is known. Figure 9 in the General Appendix is a schematic representing discrete probability distribution.

Required Condition	X Value
$0 \leq R_N \leq P_1$	X_1
$P_1 < R_N \leq P_1+P_2$	X_2
$P_1+P_2 < R_N \leq P_1+P_2+P_3$	X_3
$P_1+P_2+P_3 < R_N \leq 1$	X_4

ECONOMICS

Net Cash Flow (NCF) = Revenue – Initial cost – Operating cost – Taxes

Net Present Value (NPV) = Σ [NCF_j / $(1+i)^j$] , (J=0 : J=n)

Where,

J = Number of years

I = Discount rate

n = Toatl number of years

Discount Cash Flow Rate of Return (DCFROR) = [NCF_j / $(1+i)^j$] = 0

METHODOLOGY

Casing Design, Bit Selection, and Completion

From given well logs the main productive sands were identified. The depth of the bottom contact of the deepest producing zone was then used as the desired setting depth of the production casing, and the diameter of the production casing was also determined. It was then decided, based on expected soft formations (that may cause the wellbore to cave in) or coal seams or pressure requirements, whether it was necessary to set intermediate casing in the well. A target depth and desired diameter were established if intermediate casing were to be run in the well. The diameter and setting depth of the surface casing was also decided upon. Other values were gathered, such as drilling fluid type, drilling fluid weight, formation gradient in pounds per square inch per foot, bottomhole temperature, and the fracture gradient at the total depth. For the casing design, any gas kicks used in pressure requirement calculations are assumed to be ideal methane.

Since the fracture gradient for both wells was unknown, a simple procedure was be used to provide an accurate estimate. First, the tops and bottoms of the encountered formations were recorded. The rock type was then determined, and its corresponding density was recorded. For our purposes, the density of sandstone was 2.65 grams per cubic centimeter, and the density of shale was 2.69 grams per cubic centimeter. Then, using the thickness of the formations and their corresponding density, an average density was calculated. Overburden stress was calculated using total depth, drilling fluid weight, and average density. Formation pore pressure was determined as the product of formation gradient and total depth. Fracture pressure was then found using the following formula:

$$\text{Fracture Pressure} = \frac{\text{Overburden Stress} + 2\,(\text{Formation Pore Pressure})}{3}$$

The fracture pressure was then converted to the fracture gradient in pounds per gallon at total depth. The fracture gradient calculations and results for the Red Panda and Giant Panda wells are detailed as Table 1 in the Red Panda Appendix and Table 1 in the Giant Panda Appendix, respectively.

Once the above-mentioned values have been obtained, the casing design procedure began. Three key factors are examined: burst, collapse, and tension in the casing.

BURST DESIGN

In burst design, it is assumed that the well has an initial bottom hole pressure equal to the formation pore pressure and a gaseous produced fluid in the well. Therefore, the production casing must be designed so that it will not fail if the tubing fails. In the worst-case scenario, it is assumed that a leak in the tubing occurs at the surface. The bottom hole pressure was computed using the fracture gradient plus a 0.3 pounds per gallon safety. Then, the gas gradient was calculated in pounds per square inch per foot.

From this, the internal pressures at the top and the bottom of the casing were determined. The internal pressure at the top of the production casing was found by taking the difference of the bottom hole pressure and the pressure of the gas gradient at the target depth. In the intermediate casing, this is the maximum allowable surface pressure based on the working pressure of surface equipment or the attainable pressure after a kick when the annulus is filled with gas. The internal pressure in the surface casing is equal to the bottomhole pressure minus the pressure due to the gas column. The bottom internal pressure for the production casing is the sum of the top internal pressure and the pressure of the drilling mud at the target depth. The bottom internal pressure for the surface casing is equal to the formation fracturing pressure plus a safety margin of one pound per gallon. The bottom internal pressure for the intermediate casing is the same as for the surface casing, but it is assumed that the annulus is filled with mud and gas.

Next, external pressures were calculated. The top external pressure for production, intermediate, and surface casing is assumed to be zero. The external pressure for the production intermediate, and surface casing at the bottom is equal to the formation gradient pressure at the target depth or the water column pressure.

Then, the resultant pressures and design pressures were computed. The top and bottom resultant pressures were the result of the difference of the internal pressure and the external pressure. The top and bottom design pressures were determined by multiplying the resultant pressure by a burst design factor of 1.1. Using Table 7.6 in *Applied Drilling Engineering* for the desired casing diameter, the casing with the cheapest grade and smallest nominal weight that meets burst criteria is selected. The actual used safety factor can then be determined.

COLLAPSE DESIGN

The collapse design is based on the idea that the reservoir pressure has been depleted to a very low abandonment pressure. Since a leak in the tubing could cause the loss of the completion fluid, the entire casing is considered to be empty for design purposes.

Internal pressures are found first, with the top pressure being zero for production, intermediate, and surface casing. The bottom internal pressure is found for the intermediate casing due to the mud density used for the next casing setting depth with a column height equal to the normal formation pressure at the casing seat. The bottom internal pressure for both surface and production casing is zero.

For production, intermediate, and surface casing, the top external pressure is zero. The external bottom pressure for surface casing is due to the mud column or formation pressure gradient. The load increases due to cement column if it exists beyond a certain depth. For intermediate casing, the bottom external pressure is due to the mud column, and the load increases due to the cement column if it exists beyond a certain depth. Cement can even be considered to extend to the surface. The bottom external pressure for production casing is similar to the surface and intermediate casings with fluid density equal to the density of the mud used in the last interval.

The resultant pressures are then calculated, taking the difference of the external and internal pressures. Using a collapse safety factor of 1.1, the top and bottom design pressures were determined. Again, using Table 7.6 from *Applied Drilling Engineering*, the lightest, lowest grade of casing that meets collapse specifications is selected. This casing is compared to the one chosen during burst design; then the heavier, better grade casing is selected. The actual used safety factors are calculated.

TENSION DESIGN

The first step in the tension design is to combine the casing strings from the burst and collapse design, selecting the stronger casing for each segment. The calculations for tension design are identical for production casing, intermediate casing, and surface casing. The hydrostatic fluid pressure of the mud column at the bottom was found. Then, the metal area of the casing at the bottom was found using the outer and inner diameters of the selected casing.

The axial tension was then found by subtracting the product of the hydrostatic fluid pressure and the metal area at the bottom from the product of the casing nominal weight and the casing length. For the tension design safety factor, an additional 100,000 pounds force may be added or the axial tension may be multiplied by 1.6, whichever is greater. Table 7.6 in *Applied Drilling Engineering* is again used with the same logic as before to select the casing. The casing selected during tension is then compared to that which was chosen during burst design and collapse design. The stronger casing is then chosen as the final casing design, and the final used safety factors are calculated for each design criteria. The casing design calculations for the Red Panda and Giant Panda well can be seen as Table 2 in the Red Panda Appendix and Table 2 in the Giant Panda Appendix.

BIT SELECTION

Based on the selected production, intermediate, and/or surface casing, the bits to drill each casing string are selected. Table 7.7 in *Applied Drilling Engineering* is consulted first using the production casing outer diameter. Common bit sizes used to drill this size casing are then obtained. Next, Table 7.8 is checked to ensure that this size bit will pass through the next string of casing. If the bit size passes, Table 5.12 is consulted to determine the class specifications of the bit based on the types of rock encountered during drilling. Then, return to Table 7.7 to choose a bit size to drill the next string of casing. This procedure is repeated until bits have been chosen and checked for all casing strings. The bits chosen for both the Giant Panda and the Red Panda wells are listed in Results and Discussion.

COMPLETION TYPE

Well logs and other various well data were analyzed to determine the type of completion desired for each well. Based on thickness of pay zone, selective stimulation advantages, and other criteria, an open-hole or perforated completion was chosen for each well. If a perforated completion was selected, then well logs were used in order to select the perforation intervals. It was then decided whether the well should have single-zone production or production from multiple zones. If the well produces from multiple zones, it must then be decided whether co-mingled production should exist or not. Tubing diameters were also selected at this point. Also, the necessity of packers and hydraulically pumped wells was examined.

Well Log Interpretation and Reserve Estimation

In order to determine an estimate for reserves, an appropriate suite of well logs must be obtained. These logs are interpreted to obtain reservoir characteristic properties, which are then used to estimate the well's reserves based on the volumetric method. Since different logs were available for the Red Panda well and the Giant Panda well, the reserve estimate methodology for each well will be explained separately. The pay zones for all logs used in interpretation may be viewed in their respective appendices.

Red Panda Well

The Red Panda well has three pay zones, the first of which is the Ravenscliff sand (1538'-1544'), the second in the Big Lime (2498'-2504'), and the third in the Berea sand (3346'-3360'). All values were done for every two feet of pay zone. The induction log for the Red Panda well is shown as Log 1 in the Red Panda Appendix, and the bulk density and density porosity log is shown as Log 2.

First, the bulk density log (DRHO) was read in grams per cubic centimeter and recorded. The matrix density used was 2.68 grams per cubic centimeter. The fluid density used was 1.0 since the well was air-drilled. Then, values for calculated density porosity were found using the equation below:

$$\varphi_{D1} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

Values for density porosity were also read from the density porosity log (DPHI). For each two-foot interval, the calculated density porosity and density porosity read from the log were averaged to obtain the formation porosity.

Next, the dual induction log was analyzed using the deep induction log (ILD). Values for deep induction resistivity were read for every two feet and recorded. It was assumed that the true formation resistivity is equal to the deep induction resistivity read from the log. The formation resistivity factor was then calculated using the averaged porosity in the following equation, which is valid for tight sandstone:

$$F_R = \frac{0.81}{\varphi^2}$$

Next, the water saturation is calculated by equation below. A value of 0.055 ohm-meters was used for water resistivity, which is a valid assumption for this area of West Virginia.

$$S_w = \left(\frac{F_R R_w}{R_t} \right)^{1/2}$$

Finally, the original gas in place in thousand standard cubic feet per acre is found using the below equation:

$$G = \frac{0.4356 A h \varphi . (1 - S_w)}{B_{g_i}}$$

where,

A = Area, 1 acre

h = Height, ft

ϕ = Porosity, percent

S_w = Water Saturation, fraction

B_{gi} = Initial Gas Formation Volume Factor, SCF/STB

These values were then summed to obtain the original gas in place for the Red Panda well in thousand standard cubic feet per acre

GIANT PANDA WELL

The Giant Panda well also has three pay zones, the first of which is the 2nd Vedder sand (4652'-4660'), the second and third zones in the 3rd Vedder sand (4790'-4800' and 4810'-4836'). The 3rd Vedder sand has been divided into two separate pay zones due to the fact that this sand contains an intermediate shale at this location. All values were done for every two feet of pay zone. The induction log for the Giant Panda well is shown as Log 1 in the Giant Panda Appendix, and the bulk density and neutron porosity log is shown as Log 2.

First, the bulk density log (DRHO) was read in grams per cubic centimeter and recorded. Since the reservoir rock is sandstone, 2.65 grams per cubic centimeter was used as the matrix density. The fluid density used was 1.06, which is simply the mud density of 8.8 pounds per gallon divided by the density of water (8.33 pounds per gallon). Then, values for density porosity were calculated using the equation below:

$$\varphi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

Values for neutron porosity were read from the neutron porosity log (NPHI). For each two-foot interval, the density porosity and neutron porosity were averaged to obtain the formation porosity.

Next, the dual induction log was analyzed using the deep induction log (ILD). Values for deep induction resistivity were read for every two feet and recorded. It was assumed that the true formation resistivity is equal to the deep induction resistivity read from the log. The formation resistivity factor was then calculated using the averaged porosity using Humble's equation, which is valid for unconsolidated sandstone:

$$F_R = \frac{0.62}{\varphi^{2.15}}$$

Next, the water resistivity is calculated by dividing the true resistivity by the formation resistivity factor. Next, resistivity index is found by dividing each water resistivity by the minimum water resistivity value for the entire log. Then, the water saturation can be found using the following equation:

$$S_w = \frac{1}{I^{1/2}}$$

Finally, the original oil in place in stock tank barrels per acre is found using the below equation:

$$N = \frac{77.58Ah\varphi 7. - S_w)}{B_{o_i}}$$

where,

A = Area, 1 acre

h = Height, ft

ϕ = Porosity, percent

S_w = Water Saturation, fraction

B_{oi} = Initial Oil Formation Volume Factor, RB/STB

These values were then summed to obtain the original oil in place for the Giant Panda well in stock tank barrels per acre.

Well Test Analysis

Red Panda Well

The following build-up data were used in analysis of the Red Panda gas well in West Virginia. The well was tested prior to fracturing with a flow rate of 190 MCF/D. The producing time before the well test was 1,200 hours. The 0.65 gravity gas was produced through a wellbore radius of 0.25 inches with a bottomhole temperature of 202 degrees Fahrenheit. From well log interpretation, it is known that the net pay for this well is 25 feet with an average porosity of 10.1 percent.

Shut-in Time t, hours	Shut-in Pressure P_{ws}, psi
0.00	707
0.07	720
0.29	759
0.94	872
2.23	1088
3.58	1304
4.97	1521
6.41	1739
7.92	1957
9.46	2176
11.0	2395
16.1	3054
25.4	4136
29.9	4556
35.0	4961
45.6	5539
50.6	5702
66.6	6001
81.6	6118
110.0	6210
181.0	6283
301.0	6334
421.0	6363
541.0	6383
661.0	6397
781.0	6408
901.0	6417
1021.0	6424
1141.0	6429
1200.0	6432

Because the pressure data covers a large range, the pseudopressure method must be used in order to determine permeability, skin factor, and flow efficiency.

In order to analyze the deliverability of a gas reservoir, an engineer must know the reservoir and fluid parameters, which include things such as permeability, porosity, compressibility, and formation volume factor. Some are dependent upon pressure; therefore, these values are constantly changing during production of the reservoir.

Gas flow through porous media is given by the partial differential equation that can be obtain by combining the continuity equation, Darcy's law, and equations of state. As can be seen from the partial differential equation for gases (for either horizontal flow or radial flow) compared with the partial differential equations for fluids, a new term appears $[P/(\mu z)]$. This is due to the gas deviation factor and the higher compressibility of gases compared to fluids, both of them being functions of pressure. In order to solve the equations, a new term called pseudo-pressure m(P) was defined. Mathematically, it is defined as the integral of $[P/(\mu z)]$ between two pressures as seen below:

$$m(P) = 2\int \frac{P}{\mu z} dP$$

Using the pseudo-pressure results in increased accuracy for both drawdown and build-up tests; thus, this has become a very popular method of well test analysis.

The build-up test is the most common pressure transient test used for reservoir analysis. There are three methods of analysis of the build-up test.

1. **P^2 Method**

   This method is limited to pressures less than 1500 pounds per square inch. The pressure build-up can be analyzed by several differential methods developed by Horner, Miller-Dyes-Hutchinson, Muskat, and Agarwal.

2. **P Method**

   This method can be used if the pressure is higher than 3000 pounds per square inch when the behavior of gas is considered to be like that of fluids. This method for analyzing the gas well test data is similar to that which is used for fluids.

3. m(P) Method

This method is the most accurate method and has no major limitations. It does not assume that pressure gradients are small in the reservoir and does not require that the gas properties are constant at same specific pressure. The most important advantage of this method is that it is applicable to all pressure ranges.

For a particular gas gravity and reservoir temperature, the relationship between P and m(P) can be obtained using the following procedure:

Determine μ and z as functions of pressure for the entire range of pressures involved in the test analysis. Pressure increments of one to ten pounds per square inch are normally adequate.

Compute the following for each pressure in Step 1:

$$\frac{2P}{\mu z}$$

Compute m(P) as a function of pressure using numerical integration. In order to compute the value of m(P) at some pressure P_1, it is necessary to compute the area under the curve between P_b and P_1. This area, A_l is equal to the following:

$$m(P) = \int \frac{2P}{\mu z} dP$$

If the pressure increment, P_l-P_b is sufficiently small, the area can be assumed to be a trapezoid. The values of m(P) at other pressures can be determined in a similar manner. Mathematically the pseudo-pressure can be calculated using the formula below:

$$m(P) = \sum \left[\left(\frac{P}{\mu z} \right)_j + \left(\frac{P}{\mu z} \right)_{j-1} \right] (P_j - P_{j-1})$$

Plot m(P) versus P. This plot will provide the real pressure for any value of pseudo-pressure. Another transformation that improves the accuracy of the gas reservoir engineering analysis is the introduction of pseudo-time. The gas pseudo-time is defined as the following:

$$t_a = \int \frac{1}{\mu c_g} dt'$$

The use of pseudo-time enhances the accuracy of adoption of liquid flow solution and is useful for pressure transient analysis and production history matching with type curves. The pseudo-time can be approximated by the trapezoidal rule as the following:

$$m(P) = \sum \frac{(t_j - t_{j-1})}{(P_j - P_{j-1})(Ip_j - Ip_{j-1})}$$

Where,

$$Ip = \int \frac{1}{\mu c_g} dP$$

Ip can be determined using trapezoidal rule as follows:

$$Ip = \sum \left[\left(\frac{1}{\mu c_g} \right)_j + \left(\frac{1}{\mu c_g} \right)_{j-1} \right] \left(\frac{P_j - P_{j-1}}{2} \right)$$

To calculate the pseudo-pressure and pseudo-time, a previously developed computer program was utilized (Program 1 in the Red Panda Appendix). The steps used by the program were one pound per square inch, which is small enough to obtain good results in calculating m(P) and t_a.

Once the values for pseudo-pressure and pseudo-time were obtained, the following graphs were plotted:

1. Log-log plot of $\Delta m(P)$ versus t_a
2. Log-log plot of $\Delta m(P)$ versus Δt
3. Cartezian plot of m(P) versus P
4. Horner plot (semilog plot) of m(P) versus $(t_p+\Delta t)/\Delta t$

Permeability is computed from the slope of the Horner straight line using the equation below:

$$k = -\frac{1637qT}{mh}$$

Skin factor is computed using the following equations:

$$S' = 1.151 \left[\frac{m(P_{wf}) - m(P_{1hr})}{m} - \log \frac{k}{\varphi\mu * c_t * r_w^2} + 3.23 \right]$$

where, $\phi\mu$ and c_t are evaluated at P*.

The turbulence coefficient is then estimated using:

$$D = \frac{5.18 * 10^{-5} \gamma_g}{\mu * hr_w k^{0.2}}$$

The skin factor is thus:

S = S' - Dq

The pressure drop due to skin is:

ΔP_s = -0.869mS

The flow efficiency is found using the following equation:

$$E = \frac{m(P^*) - m(P_{wf}) - \Delta m(P)_s}{m(P^*) - m(P_{wf})}$$

Equations Used in Determination of Gas Properties

z-factor: The Dranchuk and Abu-Kassem Method was used, seen below:

$$z = 1 + \left[A_1 + \frac{A_2}{T_{pr}} + \frac{A_3}{T_{pr}^3} + \frac{A_4}{T_{pr}^4} + \frac{A_5}{T_{pr}^5}\right]\rho_r + \left[A_6 + \frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right]\rho_r^2 -$$
$$A_9\left[\frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right]\rho_r^5 + A_{10}(1 + A_{11}\rho_r^2)\left(\frac{\rho_r^2}{T_{pr}^3}\right)\exp(-A_{11}\rho_r^2)$$

Where,

$$\rho_r = 0.27 \frac{P_{pr}}{zT_{pr}}$$

and

A_1 = 0.3265

A_2 = -1.0700

A_3 = -0.5339

A_4 = 0.01569

A_5 = -0.05165

A_6 = 0 5475

A_7 = -0.7361

A_8 = 0.1844

A_9 = 0. 1056

A_{10} = 0.6134

A_{11} = 0.721 0

Gas Compressibility

$$c_g = \frac{c_{gr}}{P_{pc}}$$

Where,

$$c_{gr} = \frac{1}{P_{pr}} - \frac{0.27}{zT_{pr}} \left[\frac{\left(\frac{dz}{d\rho_r}\right)}{1 + \left(\frac{dz}{d\rho_r}\right)} \right]$$

And

$$\frac{dz}{d\rho_r} = 1 + \left[A_1 + \frac{A_2}{T_{pr}} + \frac{A_3}{T_{pr}{}^3} + \frac{A_4}{T_{pr}{}^4} + \frac{A_5}{T_{pr}{}^5} \right] + 2\left[A_6 + \frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}{}^2} \right] \rho_r -$$

$$4A_9 \left[\frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}{}^2} \right] \rho_r{}^4 + 2A_{10}(1 + A_{11}\rho_r{}^2 - A_{11}\rho_r{}^4) \left(\frac{\rho_r{}^5}{T_{pr}{}^3} \right) \exp(-A_{11}\rho_r{}^2)$$

Gas Viscosity: The Dean and Stiel Method was used.

For T_{pr} <= 1.5,

$$\mu_1 = 34 * 10^{-5} \frac{T_{pr}{}^{8/9}}{\xi_m}$$

$$\mu_1 = 166.8 * 10^{-5} \frac{(0.1338T_{pr} - 0.0832)^{5/9}}{\xi_m}$$

For T_{pr} > 1.5,

where,

$$\xi_m = \frac{5.4402 T_{pc}{}^{1/6}}{MW_a{}^{1/2} P_{pc}{}^{2/3}}$$

Following, the relationship to calculate the viscosity is seen below:

$$\mu_g = \mu_1 + 10.8*10^{-5}\frac{\left[\exp(1.439\rho_r) - \exp(-1.111\rho_r^{1.888})\right]}{\xi_m}$$

Where,

μ_g = Gas viscosity at reservoir pressure and temperature

μ_1 = Gas viscosity at atmospheric pressure and temperature, cp

ρ_r = Reduced gas density

GIANT PANDA

The following drawdown data were used in the analysis of the Giant Panda well in California. The well was tested while producing at a constant volumetric rate of 500 STB/D. The producing time during the test was 16.4 hours. At the onset of the test the pressure was assumed to be reasonably uniform in the reservoir at 2400 psi. The oil with a formation volume factor of 1.2 RB/STB was produced through a wellbore radius of 0.3 inches. From well log interpretation, it is known that the net pay for this well is 44 feet with an average porosity of 34.2 percent.

time (hr)	Δ Press (psi)	Press (psi)
0.0109	24	2376
0.0164	36	2364
0.0218	47	2353
0.0273	58	2342
0.0328	70	2330
0.0382	81	2319
0.0437	91	2309
0.0491	103	2297
0.0546	114	2286
0.109	215	2185
0.164	307	2093
0.218	389	2011
0.273	464	1936
0.328	531	1869
0.382	592	1808
0.437	648	1752
0.491	698	1702
0.546	744	1656
1.09	1048	1352
1.64	1172	1228
2.18	1232	1168
2.73	1266	1134
3.28	1288	1112
3.82	1304	1096
4.37	1316	1084
4.91	1326	1074
5.46	1335	1065
6.55	1349	1051
8.74	1370	1030
10.9	1386	1014
16.4	1413	987

The P method was used to analyze the Giant Panda well. A log-log plot of ΔP_{wf} versus t (Graph 2 in the Giant Panda Appendix) was constructed in order to estimate the time at which the effects of wellbore storage are no longer prevalent. To find this time one draws an extended straight line connecting the first several points. The point where the data deviate from the drawn line indicates t*, the end of complete control by wellbore storage. It is common practice to multiply t* by 50 to obtain the producing time when wellbore storage effects will end. Now, a semi-log graph of P_{wf} versus t (Graph 3 in the Giant Panda Appendix) is analyzed to estimate k, S, and E. A straight line is drawn through the data points on the semi-log graph beginning at the time obtained from 50t*. The slope of this line is used as the m (psi/cycle) value. The line is extended to obtain the pressure at 1 hour. With these values and the thickness that was obtained from the well logs analysis, the permeability, k, can now be estimated using the following formula:

$$k = -162.6\ qB\mu/mh$$

The skin value can now be estimated.

$$S = 1.151[P_{1hr}-P_i/m - (\log(k/\phi\mu c_t r_w^2)-3.23)]$$

Pressure loss due to skin

$$\Delta p_s = |0.87ms|$$

The flow efficiency is the ratio of J_{actual}/J_{ideal}

Or $E = (P_R - P_{wf} - \Delta p_s)/(P_R - P_{wf})$

RESERVOIR PERFORMANCE PREDICTION

RESERVOIR FLUID PROPERTY CORRELATIONS

A computer program was written in Visual Basic 6.0 (Program in General Appendix) in which correlations were utilized to calculate reservoir fluid properties. Next, three graphs were to be developed using these appropriate correlations and are shown in the General Appendix. The first graph to be developed is that of z-factor versus pseudo-reduced pressure for pseudo-reduced temperatures of 3.0, 2.4, 2.0, 1.8, 1.6, 1.4, 1.3, 1.2, and 1.1. The second graph is that of gas viscosity versus pressure for the given reservoir conditions of the Red Panda well, and the third graph is oil viscosity versus pressure for the reservoir conditions of the Giant Panda well.

For the z-factor correlations, the Dranchuk, Purvis, & Robinson Method was used. First, an initial density is estimated using the equation seen below:

$$\rho_0 = 0.27\, P_r / T_r$$

Next, a new density is calculated using the following sets of equations.

$$\rho_{k+1} = \rho_k - [\, f(\rho_k) / f'(\rho_k) \,]$$

Where,

$$f(\rho) = a\rho^6 + b\rho^3 + c\rho^2 + d\rho + e\rho^3 (1 + f\rho^2) \exp[-f\rho^2] - g$$

$$f'(\rho) = 6a\rho^5 + 3b\rho^2 + 2c\rho + d + e\rho^2 (3 + f\rho^2 [3 - 2f\rho^2]) \exp(-f\rho^2)$$

and

$$a = 0.06423$$

$$b = 0.5353T_r - 0.6123$$

$$c = 0.3151T_r - 1.0467 - 0.5783 / T_r^2$$

$$d = T_r$$

$$e = 0.6816 / T_r^2$$

$$f = 0.6845$$

$$g = 0.27\, P_r$$

The density is iterated upon until convergence.

Following this, the z-factor is calculated using the equation below:

$$z = 0.27\, P_r / \rho T_r$$

Using this method, the z-factor was found and plotted for pseudo-reduced temperatures of 3.0, 2.4, 2.0, 1.8, 1.6, 1.4, 1.3, 1.2, and 1.1 and pseudo-reduced pressures ranging from 0 to 15.

The gas viscosity was calculated using a combination of the Carr, Kobayashi, & Burrows Method and the Dempsey Equation as seen below:

$$\mu_{g1} = (1.709E\text{-}5 - 2.062E\text{-}6\ \gamma_g)T_F + 8.188E\text{-}3 - 6.15E\text{-}3 \log \gamma_g$$

$$Ln(T_r\ \mu_g / \mu_{g1}) = a_0 + a_1P_r + a_2P_r^2 + a_3P_r^3 + T_r(a_4 + a_5P_r + a_6P_r^2 + a_7P_r^2)$$

$$+ T_r^2(a_8 + a_9P_r + a_{10}P_r^2 + a_{11}P_r^2) + T_r^3(a_{12} + a_{13}P_r + a_{14}P_r^2 + a_{15}P_r^2)$$

where,

a_0 = -2.46211820

a_1 = 2.97054714

a_2 = -286264054E-1

a_3 = 8.05420522E-3

a_4 = 2.80860949

a_5 = -349803305

a_6 = 3.60373020E-1

a_7 = -1.04432413E-2

a_8 = -793385684E-1

a_9 = 1.39643306

a_{10} = -1.49144925E-1

a_{11} = 4.41015512E-3

a_{12} = 8.39387176E-2

a_{13} = -1.8608848E-1

a_{14} = 2.033667881E-2

a_{15} = -6.09579263E-4

The gas viscosity was calculated for values from 0 to reservoir pressure. A plot was then generated of gas viscosity versus pressure.

The oil viscosity was found using the equations from which Figures 5 and 6 in the General Appendix were developed. First the dead oil viscosity was determined:

$$\text{loglog}(\mu_{oD} + 1) = 1.8653 - 0.025086API$$

This value was then used in the following equation to obtain the oil viscosity:

$$\mu_o = A\mu_{oD}^B$$

Where,

$$A = 10.715(R_s + 100)^{-0.515}$$

$$B = 5.44(R_s + 150)^{-0.338} - 0.5644 \log(T)$$

The oil viscosity was calculated for values from 0 to reservoir pressure. A plot was then generated with oil viscosity versus pressure.

RED PANDA WELL

The objective of the Red Panda gas well calculations is to achieve the maximum constant flow rate possible for a seven-year contract period. This well is one of many wells in this field owned by the company, which is contributing to the contract. A minimum spacing of 40 acres and a well-flowing abandonment pressure of 100 psia have been assumed. Calculations were performed on a monthly basis using a computer program written in Visual Basic 6.0 (Program 2 in the Red Panda Appendix).

A combination of several equations was used in order to solve for the reservoir pressure and well-flowing pressure profiles. The first of these equations is the gas deliverability equation seen below:

$$P_r - P_{wf} = Aq + Bq^2$$

Where,

A and B are constant coefficients.

One can easily see that if the flow rate (q) is to remain constant, as the contract above declares, the right hand side of the deliverability equation must remain constant. By obvious mathematical reasoning, it is known that if one side of the equation is constant, the other side must also be constant. Following this logic, $P_r - P_{wf}$ (or ΔP) must remain constant. For this to be true, both P_r and P_{wf} must decline simultaneously keeping a constant ΔP.

For the calculations, pseudo-pressures will be used. Pseudo-pressures more accurately evaluate the effects of changes in viscosity and z-factor. The real gas pseudo-pressure is defined as:

$$m(P) = 2\int \frac{P}{\mu z} dP$$

Using pseudo-pressures, the deliverability equation takes the form:

$$m(P_r) - m(P_{wf}) = Aq + Bq^2$$

where,

$$A = (1422\ T / kh) * (\ln (0.472\ r_e / r_w) + S)$$
$$B = (1422\ T / kh) * D$$
$$D = 5.18E\text{-}5 * \gamma_g / \mu\ h\ r_w\ k^{0.2}$$

It was shown previously that ΔP must remain constant if rate is to remain constant. Modifying the deliverability equation for pseudo-pressure, it is seen now that $\Delta m(P)$ must remain constant ($m(P_r)$ and $m(P_{wf})$ must decline simultaneously) for the rate to remain constant.

In conjunction with the gas deliverability equation, the gas material balance was used in order to determine reservoir and well-flowing pressure. The gas material balance is defined as:

$$(P/z) = P_i/z_i \,(1 - G_p/G)$$

The gas material balance plot can be seen as [Figure 2](#) in the Red Panda Appendix. This is a plot of P/z versus G_p, which produces a straight line slope. This line intercepts the y-axis at P_i/z_i and the x-axis at G_i. Since the flow rate will be kept constant, the gas produced each month is also a constant, which is known. With this, cumulative gas production for each month is also known. This value can be used to enter the material balance plot to find the corresponding P/z (this was done by the program, since the equation for the straight line is known). The P/z value was then iterated upon until convergence when P and z for that month are found.

The outflow equation was used to determine the wellhead pressure:

$$P_{wf}^2 = P_{wh}^2\,\mathrm{EXP}(S) + (25\gamma_g\, q^2\, T\, z\, f\, D\, (\mathrm{EXP}\,(S) - 1) / (S\, d^5)$$

Where,

$$S = 0.0375\, \gamma_g\, D / TZ$$
$$f = 0.032 / d^{1/3}$$

The determination of wellhead pressure is also an iterative technique. The procedure is as follows:

Estimate z*.

1. Calculate wellhead pressure with z=z*.
2. Calculate average pressure.
3. Evaluate z at average pressure and temperature.
4. Compare z and z*. If convergence is not obtained, set z*=z and go back to step 2. Repeat until abs(z-z*)/z<0.001. When convergence is obtained, the calculated wellhead pressure is the actual wellhead pressure.

At this point, all pressures have been determined for the particular time step in question. This procedure is repeated for a total of 84 months (7 years). The constant gas rate can then be altered until the maximum constant rate at which the well-flowing pressure can be kept above the abandonment pressure of 100 psia for 7 years.

GIANT PANDA PRESSURE PROFILE

One may attempt to predict the behavior of an oil well experiencing a solution gas drive by considering the material balance equation:

$$N = \frac{N_P B_O + B_G(G_{PS} - N_P R_S)}{B_O - B_{OI} + (R_{SI} - R_S)B_G}$$

Tarner suggested iteration on the produced gas-oil ratio at the state of depletion to be calculated or at the time when N_P barrels of oil have been produced. Extrapolating a plot of the instantaneous gas-oil ratio, R, versus the reservoir pressure to the next average reservoir pressure at which the cumulative production of oil and gas is desired can carry out the iteration. The data for the plot can be previously calculated data or a plot of actual data. In either case the gas-oil ratio determined by extrapolation is used as the assumed gas-oil ratio, R_N, that exists after N_{PN} barrels of oil have been produced. With the gas-oil ratio plot completed, the cumulative gas production, G_{PN}, can be calculated as if N_{PN}, which we are calculating, were known using the following equation:

$$G_{PN} = G_{P(N-1)} + [(R_N+R_{N-1})/2](N_{PN} - N_{P(N-1)})$$

Consequently, we can substitute the expression for G_{PN} into a modified material balance equation without introducing new unknowns and solve for N_{PN}.

$$N_{PN} = \frac{N[B_O - B_{OI} + (R_{SI} - R_S)B_G] + G(B_G - B_{GI})}{B_O - B_G R_S + (R_N + R_{N-1})B_G/2} - \frac{B_G[G_{P(N-1)} - (R_N + R_{N-1})N_{P(N-1)}/2]}{B_O - B_G R_S + (RN + R_{N-1})B_G/2}$$

The N_{PN} is calculated based on an assumed R_N estimated from an extrapolation of a plot of the produced gas-oil ratio, R, versus the reservoir pressure. Then it is possible to determine the oil saturation in the reservoir at this time, S_{ON}, using the following equation:

$$S_{ON} = \frac{(N - N_P)B_O(1 - S_{WC})}{(NB_{OI})}$$

Based on this saturation, the permeability ratio can be determined from given data and R_N can be calculated from the following equation:

$$R_N = R_S + \frac{K_G\, \mu_O\, B_O}{K_O\, \mu_G\, B_G}$$

If the assumed and calculated R_N are in satisfactory agreement, the engineer can proceed with the calculation for the next lowest pressure of interest. If the R_N values do not agree sufficiently, it is necessary to adjust the GOR-plot extrapolation accordingly and repeat the calculations until the R_N by extrapolation and the R_N calculated agree.

MONTE CARLO SIMULATION AND ECONOMIC EVALUATION

In the economic evaluation of the Giant Panda and Red Panda wells, we are interested in determining the well that will provide the greater return on our investment over a seven-year period. The decision making process involves generating a net present value profile for each well and comparing the two results in the form of a probability distribution. The Monte Carlo method was implemented in the generation of the probability distributions, and an uncertainty of 10% in the data was used in carry out the calculations. An Excel spreadsheet was used to generate the random numbers necessary when using the Monte Carlo simulation, as well as the calculations for net present value, NPV.

The given price of oil was \$20/BBL, and the given price of gas was \$3/MCF. A uniform distribution was implemented in determining the oil and gas price with the following formulas:
Where,

R_N = random number

$$F(x) = \frac{x - x_L}{x_H - x_L}$$

$$x = x_L + R_N(x_H - x_L)$$

$x_{L(oil)}$ = \$19 $x_{L(gas)}$ = \$2.85
$x_{H(oil)}$ = \$21 $x_{H(gas)}$ = \$3.15

To determine the operating costs, a triangular distribution was used. The given value for oil was \$0.75, high of \$0.79, low of \$0.71. The given value for gas was \$0.25, high of \$0.26, low of \$0.24.

The following assumptions were made for operation costs:

OpCost for Oil = \$ 0.32 per bbl
OpCost for Gas = \$ .25 per MCF
Total Operating Cost/month =(Oil Op Cost)(N_p/mo)+(Gas Op Cost)(G_p/mo)

The following equations were used in triangular distribution of operating costs per barrel of oil and per thousand standard cubic feet of gas.

$$x_L \le x \le x_M$$

$$F(x) = \left(\frac{x - x_L}{x_M - x_L}\right)^2 \left(\frac{x_M - x_L}{x_H - x_L}\right)$$

$$x_M \le x \le x_H$$

$$f(x) = 1 - \left(\frac{x_H - x}{x_H - x_M}\right)^2 \left(\frac{x_H - x_M}{x_H - x_L}\right)$$

$$R_N \le \left(\frac{x_M - x_L}{x_H - x_L}\right)$$

$$x = x_L + \sqrt{(x_M - x_L)(x_H - x_L)R_N}$$

$$R_N \ge \left(\frac{x_M - x_L}{x_H - x_L}\right)$$

$$x = x_H + \sqrt{(x_H - x_M)(x_H - x_L)(1 - R_N)}$$

Finally, for the days required for drilling, as well as completion, a discrete probability distribution was implemented. The possibilities assumed for drilling were 7, 8, 9, and 10 days. The possibilities for completion were 1.5, 2, 2.5, and 3 days. The following rules were used after the random numbers were generated:

$$\begin{array}{ll} 0 \le R_N \le P_1 & X_1 \\ P_1 < R_N \le P_1 + P_2 & X_2 \\ P_1 + P_2 < R_N \le P_1 + P_2 + P_3 & X_3 \\ P_1 + P_2 + P_3 < R_N \le 1 & X_4 \end{array}$$

For the Red Panda well, Graph 1 and Graph 2 show the probability distribution used while determining the days required for drilling and the days required for completion, respectively in the Red Panda Appendix. For the Giant Panda well, Graph 4 and Graph 5 show the probability distribution used while determining the days required for drilling and the days required for completion, respectively in the Giant Panda Appendix.

Several variables had to be considered in determining the total investment cost. Those that were dependent on time were supervision, rig rate, and drilling. Other variables were assumed to be a one-time charge. The one- time charges are as follows: facilities, miscellaneous tools, perforating charges, other perforating charges, well supplies, transportation, drill string, other rentals and services, other subsurface, casing, tubing, and rods. The total investment was dependent upon tangibles, intangibles, and G&A. Tangibles are items that can be considered to depreciate. Intangibles include everything else such as supervision costs, rig costs, and transportation. G&A include labor and overhead costs. The investment determination for the Red Panda well is seen in Table 4 of the Red Panda Appendix. For the Giant Panda well, it is seen in Table 4 of the Giant Panda Appendix.

The determination of the values for cumulative oil and cumulative gas produced were calculated using the Tarner method. Several values were calculated based on surface pressures, and the corresponding times were then calculated. These values were plotted versus its corresponding time. The cumulative production for each month was then estimated and plotted until smooth lines between the points of those already obtained were formed. Graphs 6 and 7 in the Giant Panda Appendix display the cumulative oil and gas produced, respectively.

Using the values generated from the Monte Carlo simulation the investment, operating cost, and revenue values were inserted in the Excel spreadsheet, and an NPV was computed for many different interest rates. The next step was to make an NPV profile graph. This allowed us to determine the Discount Cash Flow Rate of Return, DCFROR. The line was assumed to be linear where it crossed the zero mark. The actual DCFROR was determined using a linear relationship. The net present value profile for the Red Panda Appendix may be viewed as Graph 3 in the Red Panda Appendix and as Graph 8 in the Giant Panda Appendix for the Giant Panda well.

The Frequency Distribution method was implemented to develop a graph of the Probability Distribution of the Anticipated Rate of Return. This was accomplished by computing 50 DCFROR values using the random number generator. They were then placed in their respective classes, totaled, and divided by the total number of values. For the Red Panda well, the probability distribution is shown as Graph 4 in the Red Panda Appendix. For the Giant Panda well, the probability distribution is shown as Graph 9 in the Giant Panda Appendix.

RESULTS AND DISCUSSION

CASING DESIGN, BIT SELECTION, AND COMPLETION

The table below displays the results of the casing design and bit selection for both the Giant Panda and the Red Panda wells. The detailed calculations may be seen for each well in the Red Panda Appendix as Table 2 and in the Giant Panda Appendix as Table 2.

Giant Panda Well			
Production Casing	7"	J-55	23 #/ft
Bit	8 3/4"	Class 5-3-7	
Surface Casing	9 5/8"	H-40	32.3 #/ft
Bit	12 1/4"	Class 5-3-7	

Red Panda Well			
Production Casing	4 1/2"	J-55	9.5 #/ft
Bit	6"	Class 5-3-7	
Intermediate Casing	8 5/8"	H-40	28 #/ft
Bit	11"	Class 5-3-7	
Surface Casing	11 3/4"	H-40	32.3 #/ft
Bit	17 1/2"	Class 5-3-7	

The casing strings in the above table show the final design of each well. It is important to note the presence of intermediate casing in the Red Panda well when there is none in the Giant Panda well, even though the Giant Panda well is deeper. It is expected to encounter a soft formation (likely to cause the wellbore to cave in) and a coal seam in the Red Panda well. This necessitated the use of intermediate casing in the well.

Based on the small interval of pay zone in the Giant Panda well, a perforated completion would be most desirable. In addition, pressure is expected to be low and some water production is expected. This further justifies a perforated completion. There are multiple zones that can be produced in the Giant Panda well. These zones should be perforated and produced simultaneously resulting in higher production rates and faster payout. From examination of the log provided, the Second Vedder sand should be perforated from 4,652 feet to 4,660 feet. The Third Vedder sand should be perforated in two separate intervals, 4,790 feet to 4,800 feet and 4,810 feet to 4,835 feet. Because of low pressure, the well should be hydraulically pumped. Tubing with a diameter of 2 7/8 inch should be used with a 2 1/4 inch pump. The packer should be set around 4,520 feet. This well will produce oil with small amounts of gas.

Like the Giant Panda well, the Red Panda well also has a small interval of pay zone. It is felt that a perforated completion would also be very advantageous in the Red Panda well. There are also multiple zones that can be produced in the Red Panda well. These zones should be perforated and produced simultaneously resulting in higher production rates and faster payout. From examination of the log provided, the Ravenscliff Sand should be perforated from 1,538 feet to 1,543 feet. The Big Lime should be perforated from 2,497 feet to 2,503 feet and the Berea Sand from 3,346 feet to 3,360 feet. Because of higher pressure, the well should not need to be hydraulically pumped. Tubing with a diameter of 2 3/8 inch should be used, and no packers should be necessary.

WELL LOG INTERPRETATION AND RESERVE ESTIMATION

The tables below display the results of the well log analysis for both the Red Panda and the Giant Panda wells. The detailed calculations may be found for each well in the Red Panda Appendix as Table 3 and in the Giant Panda Appendix as Table 3.

RED PANDA

	Depth, ft	ϕ, %	S_w	G, MCF
Ravenscliff	1538	6.9	0.35	441
	1540	13.8	0.18	1,110
	1542	8.9	0.26	645
	1544	4.1	0.29	286
				2,482
Big Lime	2498	4.4	0.43	244
	2500	10.4	0.18	830
	2502	5.4	0.39	321
	2504	2.9	0.65	99
				1,494
Berea	3346	10.4	0.24	768
	3348	11.5	0.24	856
	3350	12.1	0.25	894
	3352	13.0	0.24	974
	3354	13.0	0.24	974
	3356	15.3	0.16	1,257
	3358	16.9	0.18	1,367
	3360	13.3	0.22	1,016
				8,107
			Total	12,083

GIANT PANDA

	Depth, ft	ϕ, %	S_w	N, STB
2nd Vedder	4652	30.5	0.12	3,464
	4654	31.4	0.14	3,511
	4656	32.4	0.14	3,604
	4658	33.0	0.13	3,714
	4660	33.5	0.13	3,762
				18,054
3rd Vedder	4790	33.7	0.42	2,514
	4792	32.7	0.29	2,993
	4794	32.9	0.29	3,017
	4796	34.8	0.30	3,158
	4798	33.2	0.32	2,932
	4800	34.0	0.32	2,998
				17,611
3rd Vedder	4810	36.0	0.35	3,008
	4812	36.4	0.33	3,161
	4814	35.9	0.39	2,854
	4816	40.1	0.38	3,234
	4818	38.3	0.36	3,171
	4820	32.5	0.37	2,638
	4822	33.0	0.33	2,869
	4824	35.3	0.27	3,341
	4826	38.5	0.20	3,968
	4828	31.5	0.25	3,040
	4830	33.3	0.21	3,384
	4832	32.8	0.21	3,363
	4834	33.8	0.22	3,411
	4836	34.8	0.22	3,509
				44951
			Total	80616

The values presented in the above tables as well as those found in the appendix were obtained based on the volumetric estimate of oil in place method using the well log data available. The results are given on a per acre basis.

The equation used to calculate the amount of gas in place, which is relevant to the Red Panda, is as follows:

$$\text{Gas In Place} = \frac{.4356\ Ah\phi(1-S_w)}{B_{gi}}$$

The thicker Berea formation contains the majority of the natural gas. Therefore, it is expected to be responsible for higher amounts of production when compared to the thinner, shallower Big Lime and Ravenscliff formations.

A porosity value was read from the density log, and a value was calculated using the following equation:

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

where the bulk density, ρ_b, is recorded on the log. Porosity values were calculated by taking an average of the two. The water saturation, S_w, was found with the aid of the formation resistivity factor. Laboratory measurements of fluid samples were not available. Therefore, a correlation was made between reservoir temperature, pressure, and the z-factor to determine the initial formation volume factor. The z-factor was read from a z-factor chart, which can be found in most petroleum engineering handbooks.

The equation corresponding to the Giant Panda is similar to the one above. However, the constant differs due to the fact that we are discussing oil.

$$\text{Oil In Place} = \frac{77.58\ Ah\phi(1-S_w)}{B_{oi}}$$

The greatest amount of hydrocarbons found in the Giant Panda is contained in the deepest, thickest formation, as was the case in the Red Panda. The formation is referred to as the Third Vedder.

In the Giant Panda the porosity was obtained in a similar manner as explained above using the bulk density. However, the porosity read from a neutron log rather than a density log. In this case the initial formation volume factor was known to be 1.2 RB/STB.

WELL TEST ANALYSIS

RED PANDA WELL

The pseudo-pressure and pseudo-time were calculated using a computer program (code shown as Program 1 in the Red Panda Appendix) that utilizes the procedure and the relations presented in the methodology. The pseudo-pressures and pseudo-times were printed to a text file. From there, they were imported into Excel (Table 5 in the Red Panda Appendix) where the four plots mentioned previously were generated:

1. Log-log plot of $\Delta m(P)$ versus t_a (Graph 5 in the Red Panda Appendix)
2. Log-log plot of $\Delta m(P)$ versus Δt (Graph 6 in the Red Panda Appendix)
3. Horner plot (semilog plot) of m(P) versus $(t_p+\Delta t)/\Delta t$ (Graph 7 in the Red Panda Appendix)
4. Cartesian plot of m(P) versus P (Graph 8 in the Red Panda Appendix)

From Graph 5: $\Delta m(P)$ versus t_a, the last point on the straight unity-slope line is:

$t_a^* = 7*10^5$

$\Delta m(P) = 2.5*10^8$ psi^2/cp

Then from Graph 6: $\Delta m(P)$ versus Δt, the time when wellbore storage effects end can be calculated. Using the $\Delta m(P) = 2.5*10^8$ psi^2/cp found from Graph 5, the corresponding Δt can be read from Graph 6 and was found to be 8 hours. Applying the 50t rule,

$$\frac{t_p + \Delta t}{\Delta t} = \frac{1200 + 50(8hr)}{50(8hr)} = 4.0$$

Having this, a straight line with slope of $-0.1*10^9$ psi^2/cp/cycle is drawn on the Horner plot, Graph 7: m(P) versus $(t_p+\Delta t)/\Delta t$. Pseudo-P* and pseudo-P_{1hr} can then be read as follows:

$m(P^*) = 1.99*10^9$ psi^2/cp

$m(P_{1hr}) = 1.68*10^9$ psi^2/cp

The pseudo-P* was then transformed back to normal pressure using Graph 8 m(P) versus P, extrapolated to m(P*). This resulted in P* = 6511 psi.

The permeability was then calculated using the previously mentioned equation:

$$k = -\frac{1637(190\ \text{MCF/D})(662\ \text{deg.R})}{(-0.1*10^9\ \text{psi}^2/\text{cp/cycle})(25\ \text{ft})} = 0.082\ \text{md}$$

The following z-factor, μ_g, and c_g at m(P*) were calculated by the computer program:

z = 1.116

μ_g* = 0.02832 cp

c_g* = 0.00008163 psi^{-1}

Then, the skin factor prime was calculated:

$$S' = 1.151\left[\left(\frac{(0.38*10^8\ \text{psi}^2/\text{cp}) - (1.68*10^9\ \text{psi}^2/\text{cp})}{-0.1*10^9\ \text{psi}^2/\text{cp/cycle}}\right) - \log\left(\frac{0.082\ \text{md}}{(0.101)(0.0283\ \text{cp})(0.00008136\ \text{psi}^{-1})(0.25\ \text{ft})^2}\right) + 3.23\right] = 14.85$$

Then, the turbulence coefficient is:

$$D = \frac{(5.18*10^{-5})(0.65)}{(0.0283\ \text{cp})(25\ \text{ft})(0.25\ \text{ft})(0.082\ \text{md})^{0.2}} = 3.14*10^{-4}\ \text{MCF/D}^{-1}$$

The skin factor is:

S = 14.85 - (3.14*10^{-4} MCF/D^{-1})(190 MCF/D) = 14.79

The pressure drop due to skin was found to be:

$$\Delta m(P)_s = -0.869(-0.1*10^9\ \text{psi}^2/\text{cp/cycle})(14.79) = 1.285*10^9\ \text{psi}^2/\text{cp}$$

Finally, the flow efficiency was found using the previously mentioned equation:

$$E = \frac{(1.99*10^9\ \text{psi}^2/\text{cp}) - (0.38*10^8\ \text{psi}^2/\text{cp}) - (1.285*10^9\ \text{psi}^2/\text{cp})}{(1.99*10^9\ \text{psi}^2/\text{cp}) - (0.38*10^8\ \text{psi}^2/\text{cp})} = 0.34$$

There are some important things to notice from Graph 5 and Graph 6. If the time was used instead pseudo-time for the log-log plot, one is unable to determine when the well bore storage ends. This because the log-log plot of Δm(P) versus Δt results in a straight line with a slope greater than one, which is impossible. The correction that t_a provides is more than obvious since it results in a correct log-log plot with a unity-slope. The last point on the straight line gives the time when the well bore storage ends.

GIANT PANDA WELL

After plotting the necessary data and obtaining a value for m, the above formulas were entered into an Excel spread sheet and the following results were computed:

Data	
q (stb/d)	500
Porosity	0.342
visco (cp)	0.8
Ct (1/psi)	0.00001
rw (ft)	0.3
h (ft)	44
Bo (RB/STB)	1.2
Pi (psi)	2400

Results	
m (psi/log cycle)	-150.00
k (mD)	11.83
P1hr (psi)	1175.00
Skin	0.56
D Ps (psi/cycle)	72.88
Flow efficiency	0.95

Wellbore storage can cause several apparent straight lines to form on the semi-log plot, and it is often difficult to decide which line represents the true behavior of the reservoir. Luckily, the test was conducted for a time long enough so as the wellbore storage effects did not completely mask the transient flow. It must be noted that an accurate value of the initial pressure is necessary to use the log-log plot of ΔP versus t, otherwise the shape and position of the curve produced will be incorrect. Wellbore storage can easily lead an engineer to misinterpret pressure transient test data.

RESERVOIR PERFORMANCE PREDICTION

RESERVOIR FLUID PROPERTY CORRELATIONS

The results for the reservoir fluid property correlation computer program (Program in the General Appendix) were extremely pleasing. The user interface may be viewed in the General Appendix as Figure 10. The z-factor chart generated by the program (Figure 11) was compared to the Standing and Katz chart (Figure 2) with excellent results. The generated gas viscosity chart (Figure 12) shows a decrease in gas viscosity as reservoir pressure decreases as to be theoretically expected. Values read from the generated gas viscosity chart were very accurate when compared to those obtained by the method previously described using Figures 3 and 4. Finally, as theory indicates, the generated oil viscosity chart shows an increase in oil viscosity as reservoir pressure decreases (given that pressure is below the bubble point). Oil viscosity values from the generated graph (Figure 13) were also compared to those obtained by the method previously described that uses Figures 5 and 6. These values were matched with incredible accuracy.

RED PANDA WELL

The computer program (Program 2) developed for the pressure profile determination of the Red Panda gas well runs extraordinarily well. The user interfaces can be seen as Figures 3, 4, and 5 in the Red Panda Appendix. The resulting maximum constant rate that can be maintained for seven years is 160.8 MCF/D. At the end of seven years of production with this flow rate, reservoir pressure is 248 psia, well-flowing pressure is 100 psia (abandonment pressure), wellhead pressure is 85 psia. The cumulative gas produced is 415.5 MMCF.

The pseudo-pressure profile can be seen as Graph 9 in the Red Panda Appendix. It is vital to note that reservoir pseudo-pressure and well-flowing pseudo-pressure decrease simultaneously with a constant $\Delta m(P)$. This is in agreement with the previous assertion that $\Delta m(P)$ must remain constant if a constant flow rate is maintained. The actual pressure profile can be seen as Graph 10. This displays the profiles for reservoir pressure, well-flowing pressure, and wellhead pressure. It is interesting to note that reservoir pressure and well-flowing pressure do not decrease with a constant ΔP. In fact, ΔP increases as pressure decreases. This, however, is in disagreement with the earlier theory that stated that ΔP must be constant! Why is this so? This phenomenon is not a mistake. Graph 11 shows a graph of pseudo-pressure versus pressure. The answer to the previous dilemma lies within this graph. It is seen that for pressures above 700 psia, the data is pretty much linear. At pressures less than 700 psia, the data begins to concave upward and becomes very nonlinear. This explains why ∆P begins to increase around 700 psia. As the pressure gets lower, the pseudo-pressure deviates more and more. Therefore, ∆P increases more significantly until abandonment pressure is reached.

GIANT PANDA WELL

With the aid of the computer program (Program) the maximum production schedule is achieved with an allowable rate of 245 STB/D. This initial flow rate results in 422,000 STB of oil and 762 MMCF of gas produced in 7 years. The final flow rate is 37 STB/D at the abandonment P_{wf} of 100 psia. The pressure profile can be seen as Graph 10. The corresponding production schedule is Graph 11. As one can see, the production rate remains constant for the first few months of production and experiences a sharp decline due to the gas coming out of solution. This is to be expected as the reservoir pressure falls below the saturation pressure.

It would be ideal to find a constant rate that would result in an equivalent cumulative oil production at the end of the 7 years. To do so, one can estimate a rate that would provide us with the same area under the constant rate curve as is found under the maximum production rate curve. A rate of approximately 75 STB/D will accomplish this task. The ideal constant production schedule is seen in Graph 12, while the actual production schedule for 75 STB is in Graph 13. However, even at such a low flow rate the reservoir will still eventually fall below the bubble point pressure. As one can see, the production rate remains constant for a longer period of time (about one year of production) and then experiences a decline due to the gas coming out of solution, although not as sharp of a decline as the maximum schedule. This is to be expected as the reservoir pressure falls below the saturation pressure. With an initial flow rate of 75 STB/D, the cumulative oil produced is 320,000 STB and the cumulative gas produced is 360 MMCF. The final flow rate is found to be about 29 STB/D, and the reservoir pressure is 725 psia. In order to extract the maximum amount of oil and gas it would take 22.8 years.

If the goal were to actually use a constant rate for the duration of the 7 years we would need to stay above the bubble point pressure in the reservoir. This can be accomplished at the low rate of 10 STB/D. By producing the well at this rate we would obtain less than 25% of the maximum schedule in oil, only 99,800 STB, and only 5% of the maximum schedule in gas, 43 MMCF. This well could be produced for over 171 years before reaching the abandonment pressure. The final flow rate would be 2 STB/D. This production schedule compared to that of the maximum schedule is in Graph 14 with the corresponding pressure profile as Graph 15.

The user interfaces with the results for these scenarios are shown as Figures 2, 3, and 4.

Monte Carlo Simulation and Economic Evaluation

The probability distributions for the times required for drilling and completing each well were assumed to be the same but with different x values for the Giant Panda and the Red Panda. For the Red Panda well, Graph 1 and Graph 2 show the probability distribution used while determining the days required for drilling and the days required for completion, respectively in the Red Panda Appendix. For the Giant Panda well, Graph 4 and Graph 5 show the probability distribution used while determining the days required for drilling and the days required for completion, respectively in the Giant Panda Appendix. The investment was then calculated for both wells. The investment required for each, as well as the components, can be seen in Table 4 of the Red Panda Appendix and in Table 4 of the Giant Panda Appendix.

The results obtained from analyzing the production data from the Giant Panda and Red Panda wells in conjunction with the economic assumptions were found to be as expected. The Giant Panda oil well easily outperforms the Red Panda gas well. The gas, alone, produced from the Giant Panda well is predicted to rival that of the Red Panda well. Using a conservative estimate of \$20/bbl for oil and \$3/MCF for gas, it is obvious that the more lucrative investment will be the Giant Panda well. This can be deduced from observing the NPV profile where the DCROR for the Giant Panda is interpolated to be approximately 10,000%. Although the investment would not begin to lose money on the Red Panda well until an interest rate of about 180% was reached, when compared to the Giant Panda's 10,000% it becomes obvious which is the better choice. The spreadsheets containing the calculations for net present value are seen in Table 6 in the Red Panda Appendix and in Table 5 in the Giant Panda Appendix. The net present value profile may be viewed as Graph 3 in the Red Panda Appendix and as Graph 8 in the Giant Panda Appendix.

As was stated earlier, the probability distributions for the times required for drilling and completing each well were assumed to be the same for the Giant Panda and the Red Panda. These distributions influence the shape of the DCFROR probability distribution. This is evident in the skewed shape of the graph. For the Red Panda well, the probability distribution is shown as Graph 4 in the Red Panda Appendix. For the Giant Panda well, the probability distribution is shown as Graph 9 in the Giant Panda Appendix. Since the DCFROR represents the interest rate at which the company starts to lose money on the project, the higher DCFROR generally represents the more lucrative project. In this case, the cash generated from the Giant Panda well is far more than that generated from the Red Panda well. It is concluded by Western Panda Corporation that the Giant Panda oil well in California will far outperform the Red Panda gas well in West Virginia.

CONCLUSION

The casing design of the Red Panda well in West Virginia consists of 4 1/2-inch, J-55, 9.5 pounds per foot production casing, 8 5/8-inch, H-40, 28 pounds per foot intermediate casing, and 11 3/4-inch, H-40, 32.3.3 pounds per foot surface casing. A perforated, multiple-zone completion would be most desirable. The Ravenscliff Sand should be perforated from 1,538 feet to 1,543 feet, the Big Lime from 2,497 feet to 2,503 feet, and the Berea Sand from 3,346 feet to 3,360 feet. The casing design of the Giant Panda well in California consists of 7-inch, J-55, 23 pounds per foot production casing and 9 5/8-inch, H-40, 32.3 pounds per foot surface casing. A perforated, multiple-zone completion would be most desirable. From examination of the log provided, the Second Vedder sand should be perforated from 4,652 feet to 4,660 feet. The Third Vedder sand should be perforated in two separate intervals, 4,790 feet to 4,800 feet and 4,810 feet to 4,835 feet.

Interpretation of available well logs facilitated the estimation of original oil and gas in place on a per acre basis for both wells using the volumetric method. The Red Panda well was found to have an original gas in place of 12,083 MCF/acre. The productive zones have an average porosity of 10.1% and an average water saturation of 28%. The Giant Panda well will produce from a solution gas drive reservoir with an original oil in place of 80,616 STB/acre. The productive zones have an average porosity of 34% and an average water saturation of 27%.

From analysis of available well test data, initial formation pressure, permeability, skin factor, and flow efficiency were estimated. The well test analysis for the Red Panda gas well utilized the data that was made available from a build-up test. The results obtained were initial reservoir pressure of 6511 psi, permeability of 0.082 md, skin factor of 14.79, and flow efficiency of 34 percent. The well test analysis for the Giant Panda oil well utilized the data that was made available from a drawdown test. The initial reservoir pressure was found to be 2400 psi, with a permeability of 11.83 md, skin factor of 0.56, and flow efficiency of 95 percent.

The resulting maximum constant rate for the Red Panda well that can be maintained for seven years is 160.8 MCF/D. At the end of seven years of production with this flow rate, reservoir pressure is 248 psia, well-flowing pressure is 100 psia (abandonment pressure), wellhead pressure is 85 psia. The cumulative gas produced is 415.5 MMCF. For the Giant Panda oil well in California is it our recommendation to implement the maximum production schedule of 245 STB/D. It would not be prudent to produce the Giant Panda at a constant rate and only achieve 25% of the potential oil production and 5% of the potential gas production. This flow rate will result in a cumulative production of 422,000 STB of oil and 762 MMCF of gas at the end of 7 years reaching the abandonment pressure. The final flow rate will be 37 STB/D. It is interesting to note that the Giant Panda oil well will produce more gas than the Red Panda gas well.

Monte Carlo simulation was used in order to minimize the uncertainty of oil and gas prices, operation costs and the days required for drilling and completion. Uniform distributions were used for oil price (median value of $20/BBL) and gas price ($3/MCF). Triangular distributions were used for operating costs (median values of $0.75/BBL and $0.25/MCF). Discrete probability distributions were used for the days required for drilling and completion, with both skewed in a manner that allows for possible problems that may increase drilling or completion time. The initial investment for the Red Panda well is slightly under $90,000. The net cash flow will be approximately $1 million, with net present values of $860,000 and $515,000 at the interest rates of 5% and 20%, respectively. The rate of return for the Red Panda well is around 180%. Likewise, the initial investment for the Giant Panda well is slightly over $95,000. The net cash flow, over $10 million, is significantly higher than the Red Panda well. At interest rates of 5% and 20%, the net present values are $9.3 million and $7.5 million, respectively. The rate of return for the Giant Panda well is over 10,000%.

Western Panda Corporation feels very confident in the results obtained from this study. It has been shown that the Giant Panda well, an oil well located in California, will far outperform the Red Panda well, a gas well located in West Virginia. The Giant Panda well is a very certain investment that will generate a significant amount of money at all normal interest rates. Unless interest rates skyrocket to over 10,000%, the Giant Panda well is sure to make money for the company. It is therefore the indisputable and absolute recommendation of Western Panda Corporation that the company proceed forward with the Giant Panda well as a ‘GO’ and the Red Panda well as a ‘NO GO’.

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GENERAL APPENDIX

FIGURE 1: TYPICAL LOGGING CABLE

TYPICAL LOGGING CABLE

Typical downhole logging tool

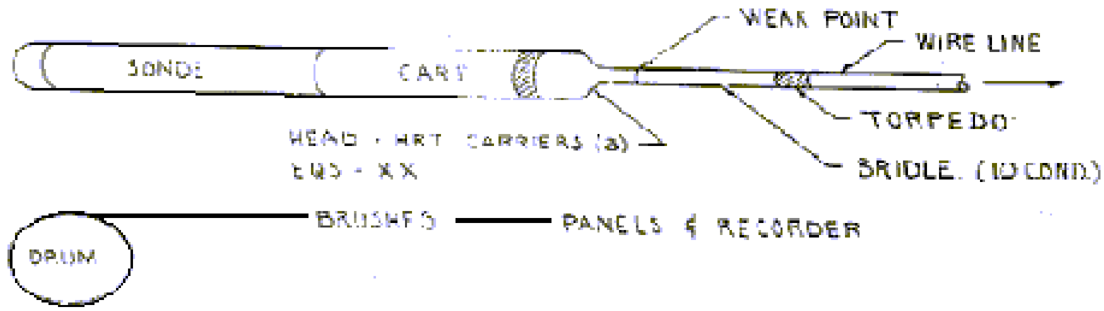


FIGURE 2: STANDING AND KATZ

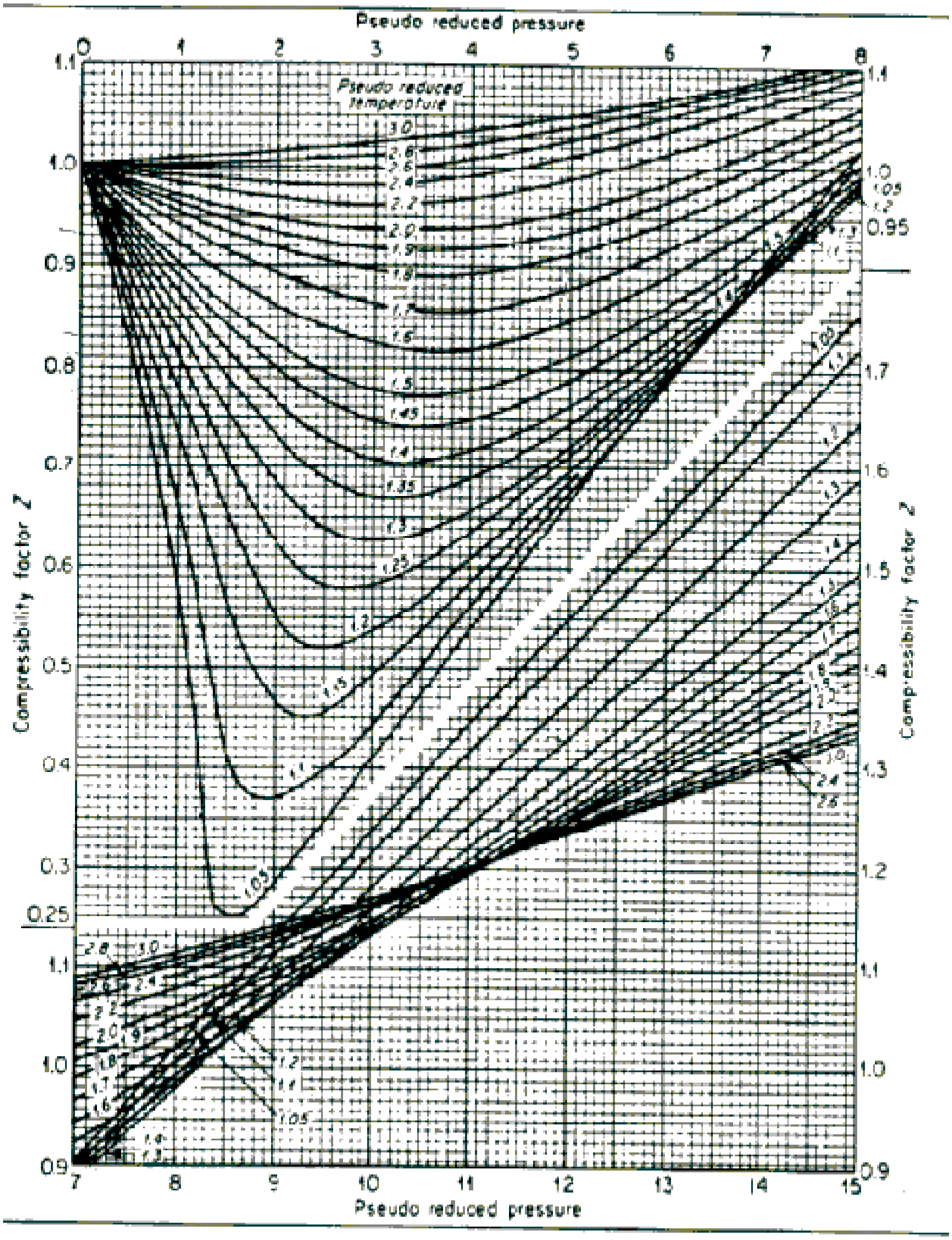


FIGURE 3: GAS VISCOSITY AT ATMOSPHERIC PRESSURE

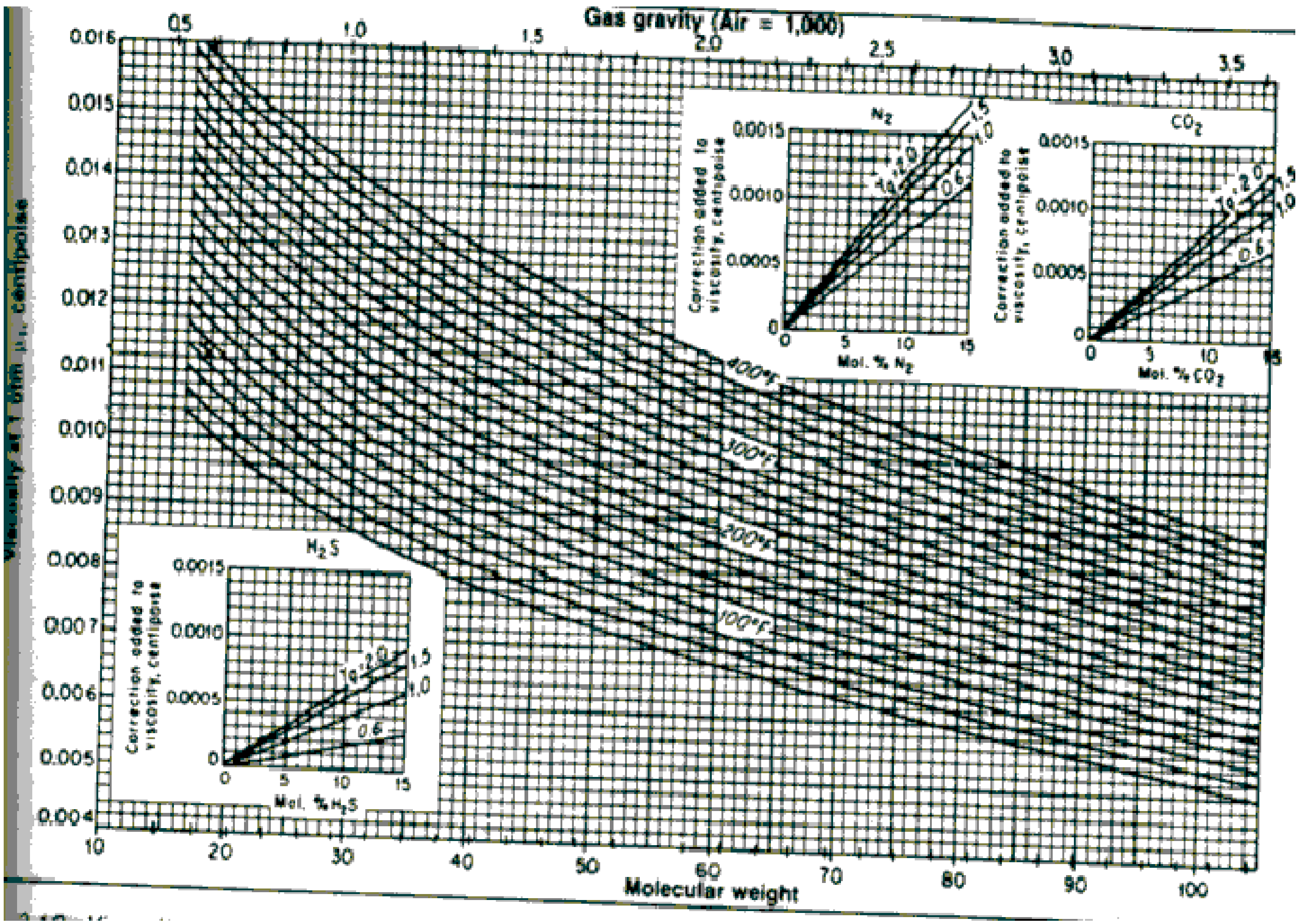


FIGURE 4: GAS VISCOSITY RATIO

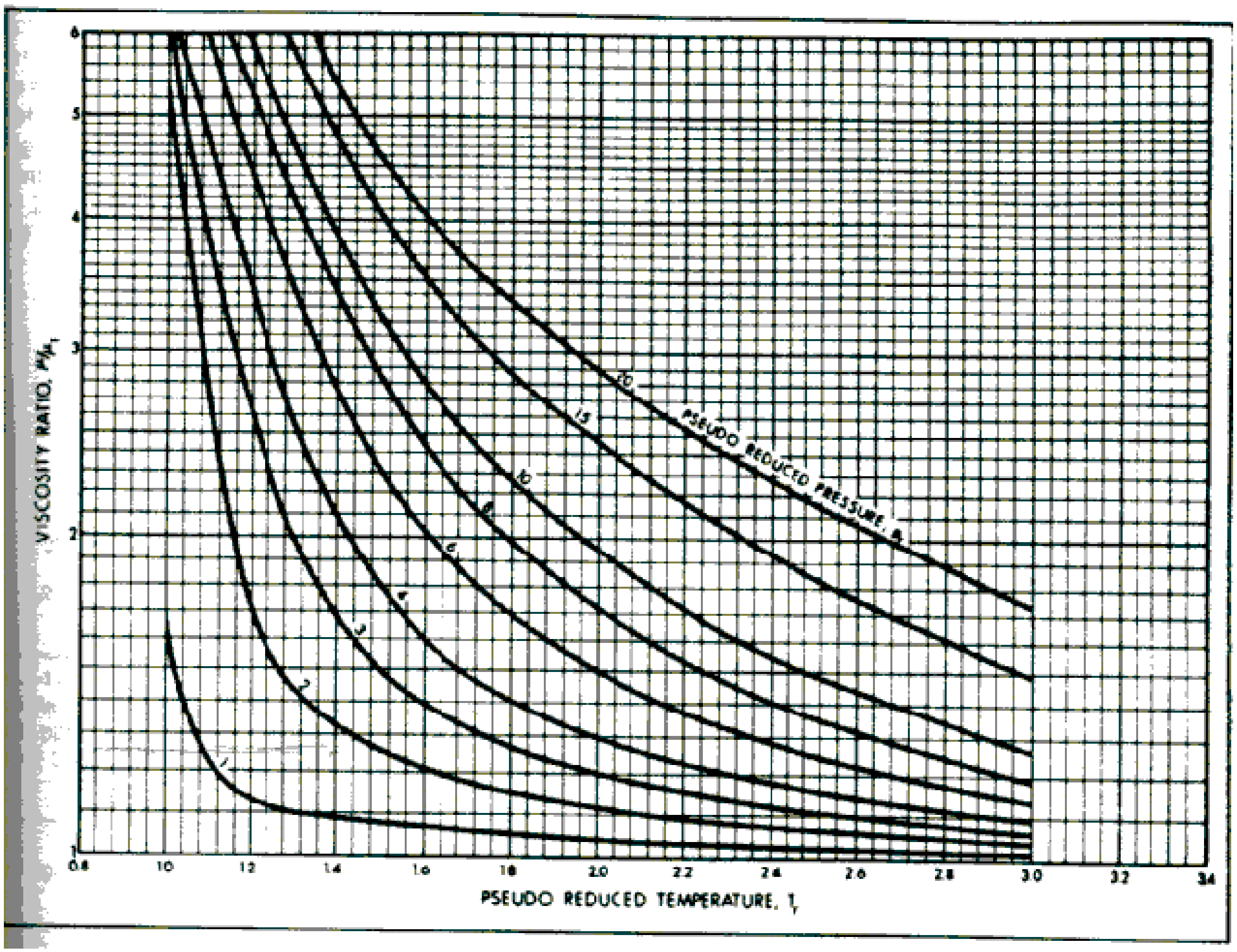


FIGURE 5: DEAD OIL VISCOSITY

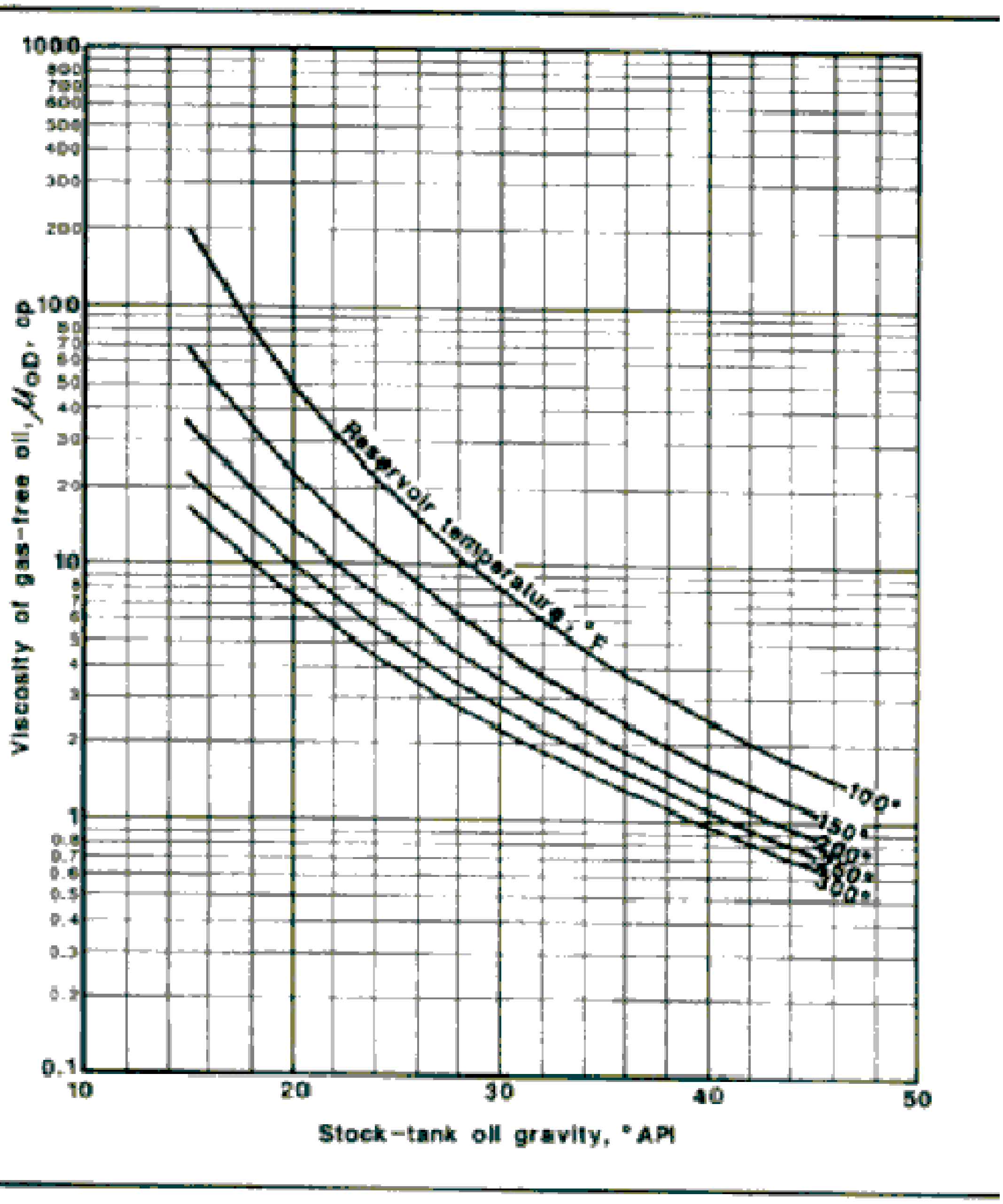


FIGURE 6: GAS-SATURATED OIL VISCOSITY

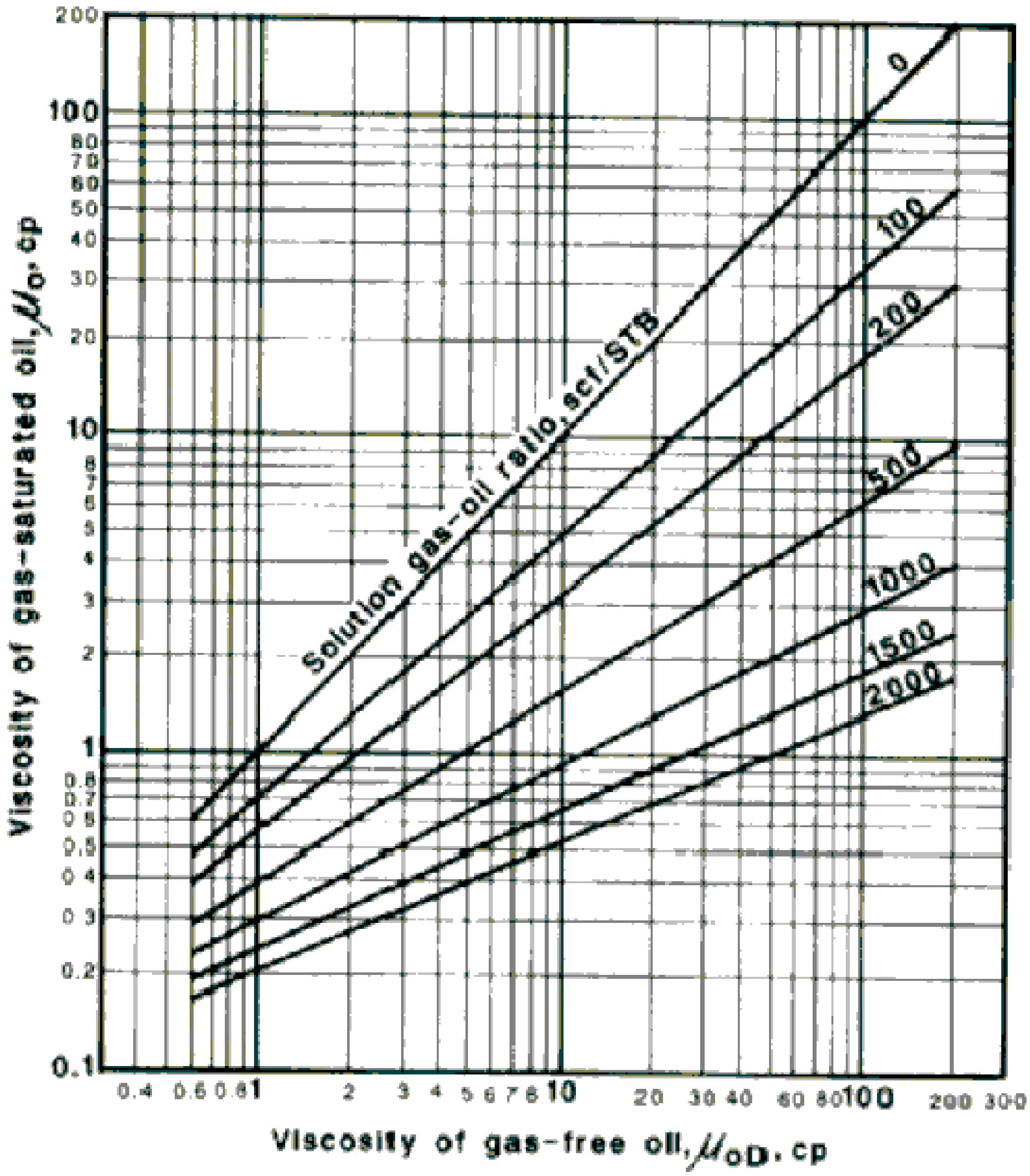


FIGURE 7: UNIFORM DISTRIBUTION

FIGURE 8: TRIANGULAR DISTRIBUTION

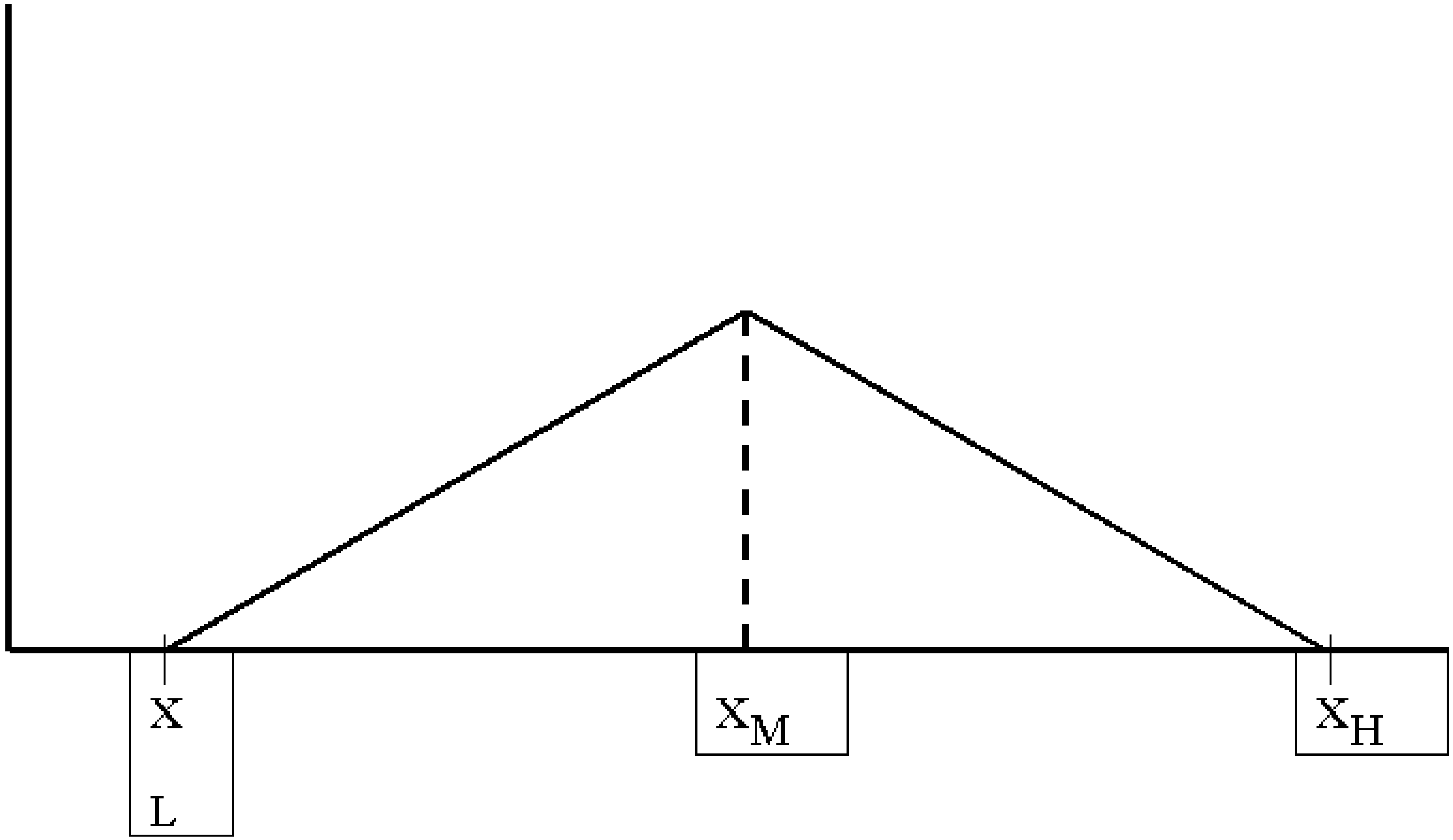


FIGURE 9: DISCRETE PROBABILITY DISTRIBUTION

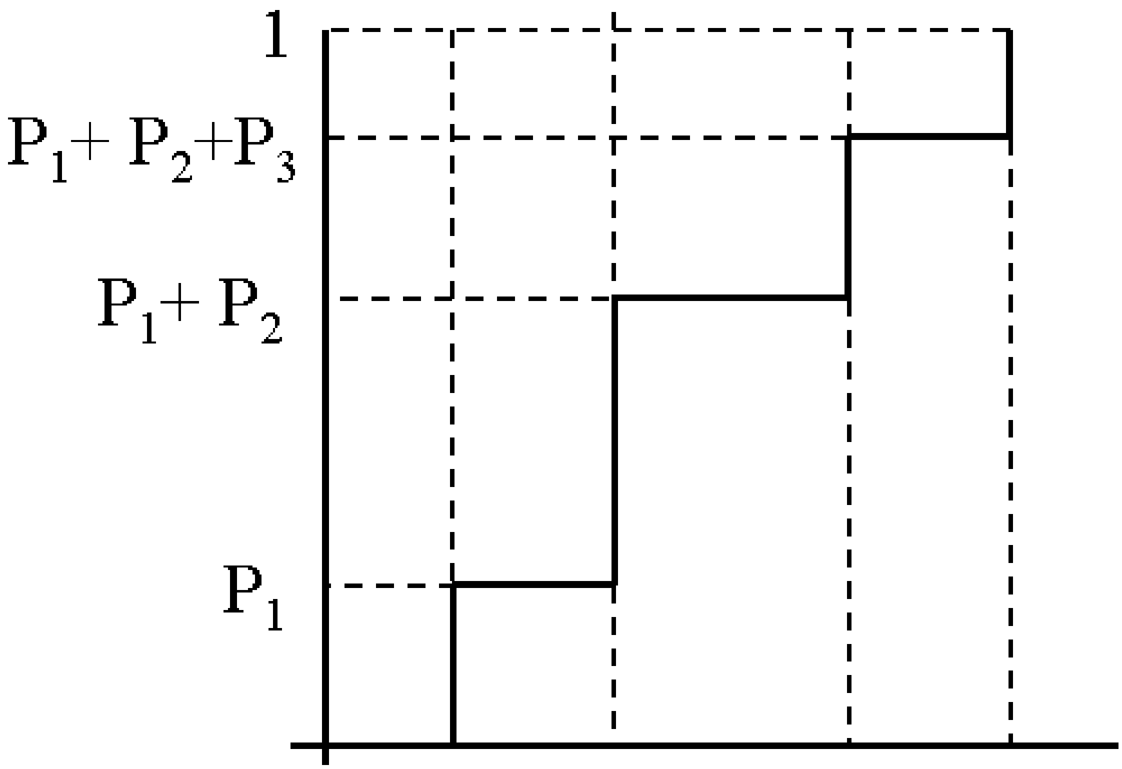


FIGURE 10: RESERVOIR PROPERTY CORRELATIONS INTERFACE

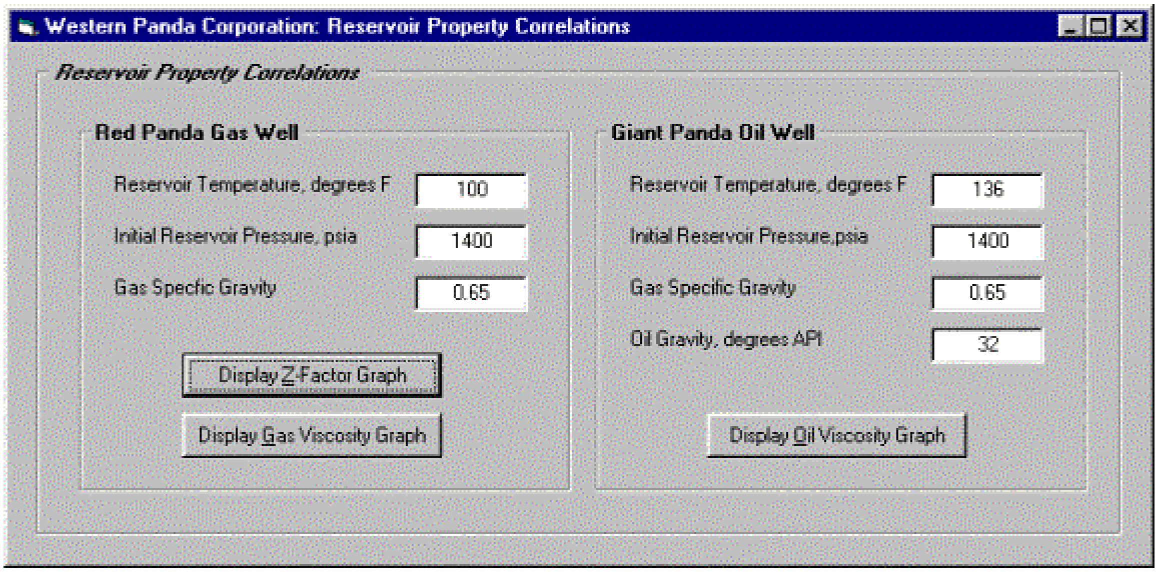


FIGURE 11: GENERATED Z-FACTOR

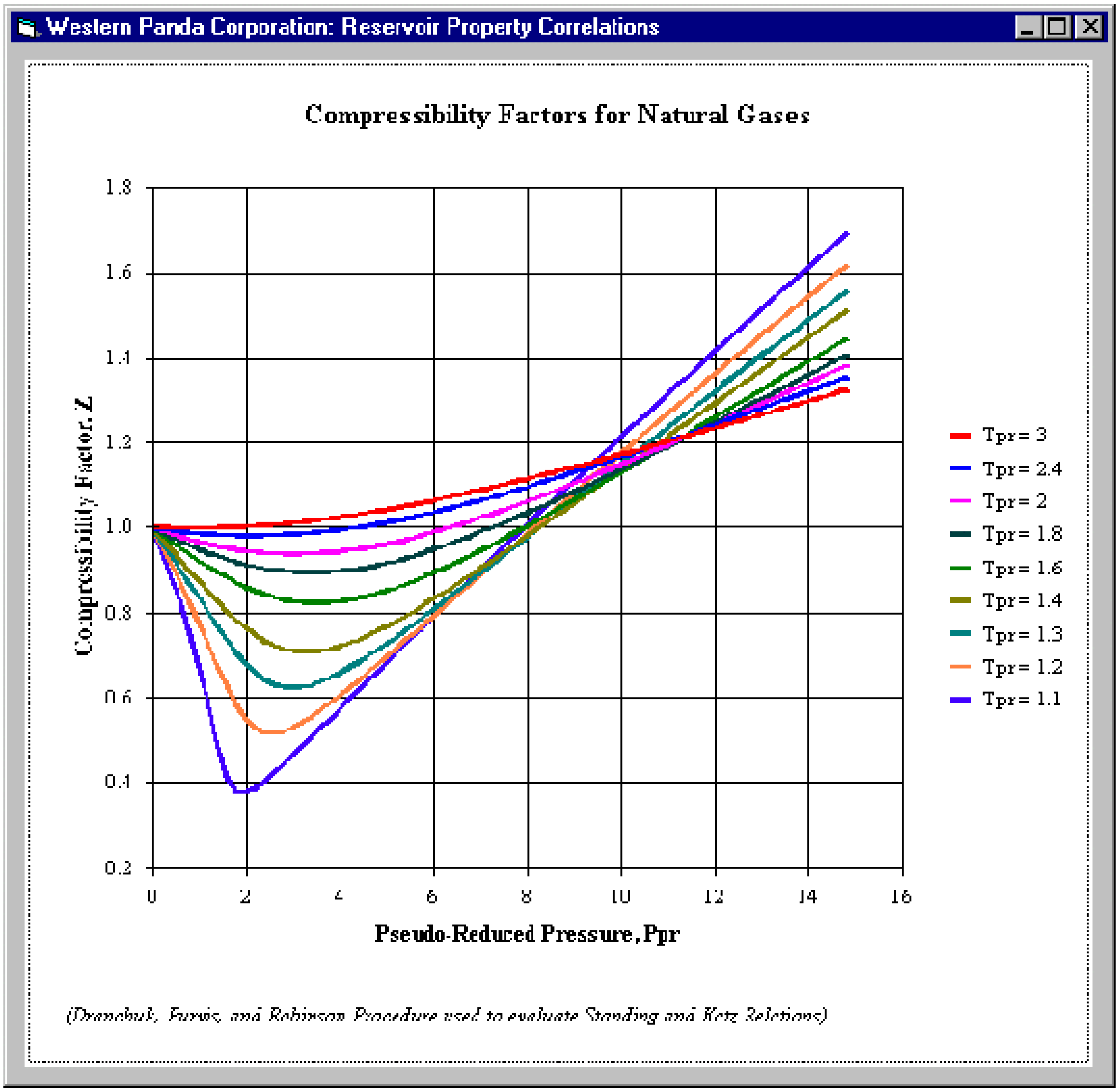


FIGURE 12: GENERATED GAS VISCOSITY

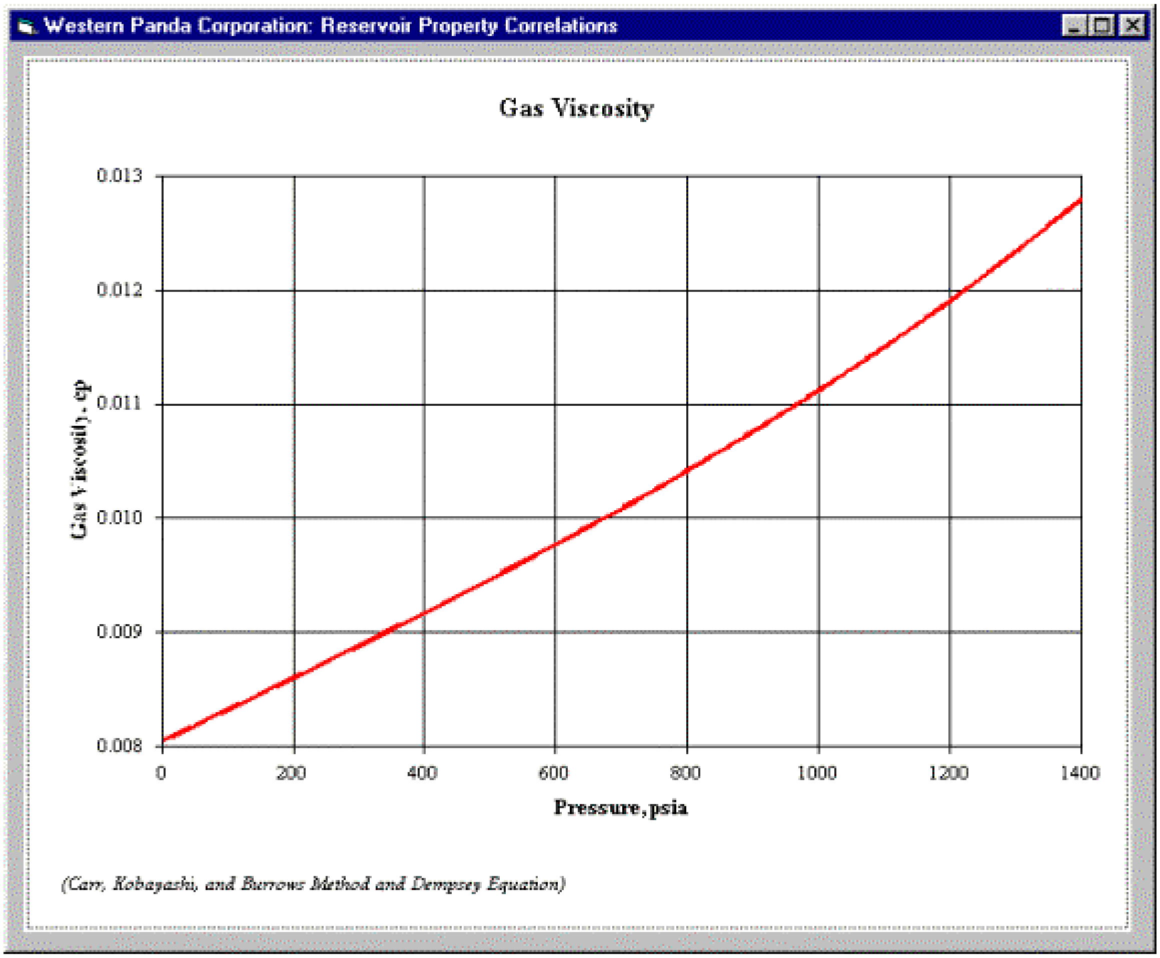
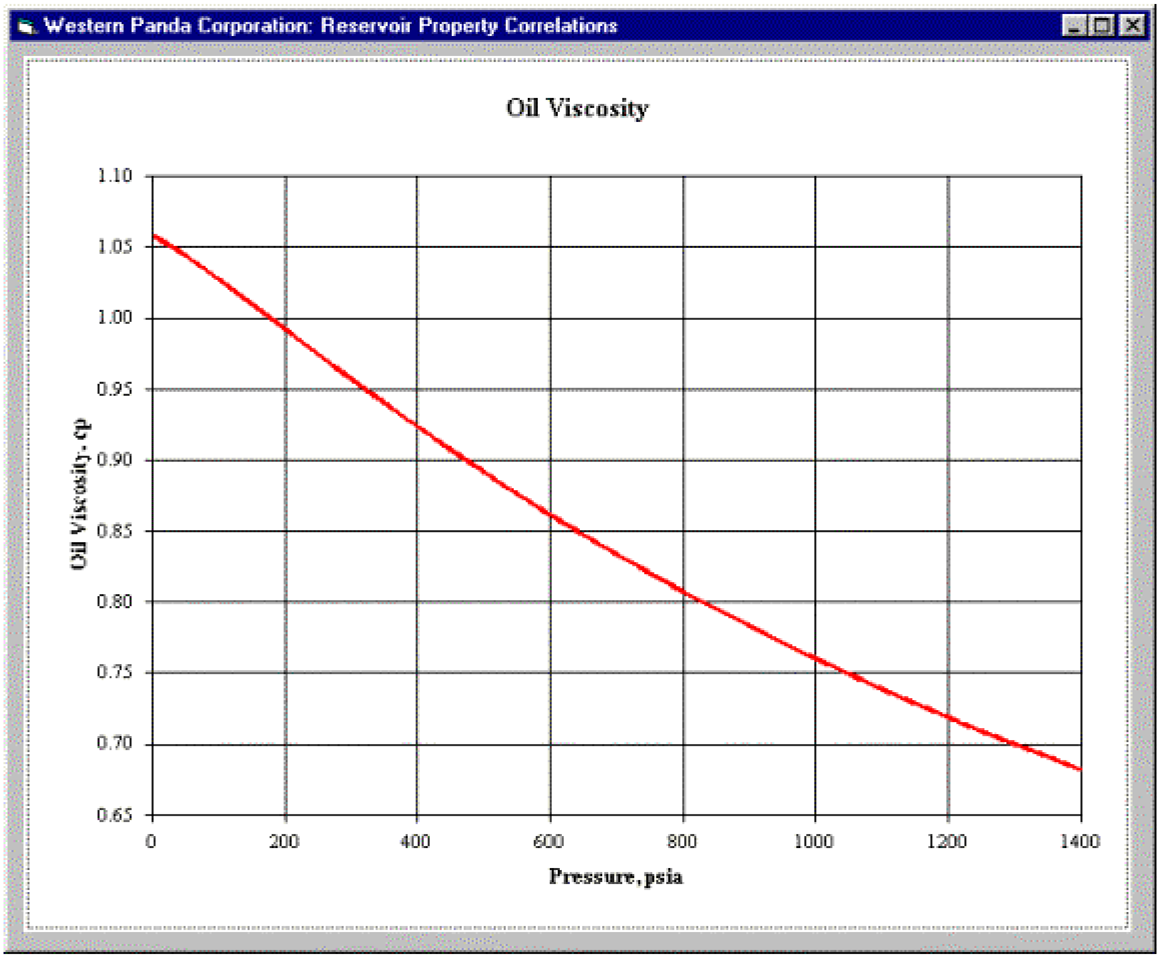


FIGURE 13: GENERATED OIL VISCOSITY



PROGRAM: RESERVOIR PROPERTY CORRELATIONS

```
Option Explicit

'Declare variables for user input
Private Tres As Double, Pres As Double, API As Double, GasGrav As Double

'Declare variables used in calculations
Private Tpr As Double, Ppr As Double, Rs As Double
Private Z As Double, GasVisc As Double

Private Sub cmdGraphZ_Click()

'Read user input values
Tres = (Val(txtTres1.Text)) + 460
Pres = Val(txtPres1.Text)

'Declare Variables
Dim GraphZ(0 To 5000, 1 To 10) As Double, GraphTpr(2 To 10) As Double
Dim j As Integer, k As Integer
Dim Rows As Integer, RowsMax As Integer, no_columns As Double

'Create array with Tpr values for z-factor chart
'   (given by Shahab on project handout)
GraphTpr(2) = 3#
GraphTpr(3) = 2.4
GraphTpr(4) = 2#
GraphTpr(5) = 1.8
GraphTpr(6) = 1.6
GraphTpr(7) = 1.4
GraphTpr(8) = 1.3
GraphTpr(9) = 1.2
GraphTpr(10) = 1.1

'Loop for Tpr values (above)
For j = 2 To 10 Step 1
   Tpr = GraphTpr(j)
   Rows = 0
   'Loop for Ppr values (use 0-15, like Standing & Katz chart)
   For Ppr = 0 To 15 Step 0.2
      Rows = Rows + 1
      If Ppr = 0 Then
         GraphZ(Rows, j) = 1#
      Else
         'Calculate z-factor (go to function)
         GraphZ(Rows, j) = Z_Factor(Tpr, Ppr)
      End If
   Next Ppr
Next j
RowsMax = Rows - 1

'Display results graphically
Form2.chtZFactor.chartType = VtChChartType2dXY
With Form2.chtZFactor
```

```
   .ColumnCount = 18
   .RowCount = RowsMax
   no_columns = 0
   For j = 2 To 10 Step 1
      For k = 1 To 2 Step 1
         no_columns = no_columns + 1
         For Rows = 1 To RowsMax Step 1
            . ColumnLabel = "Tpr = " & GraphTpr(j)
            .Row = Rows
                 .Data = GraphZ(Rows, 1)
             Next
      Next
   Next
   .Plot.UniformAxis = False
   .Visible = True
End With
Form2.Show

End Sub

Private Sub cmdGraphmuo_Click()

'Read user input values
Tres = (Val(txtTres2.Text)) + 460
Pres = Val(txtPres2.Text)
API = Val(txtAPI.Text)
GasGrav = Val(txtGrav2.Text)

'Declare variables
Dim Graphmuo() As Double, P As Double
Dim no_columns As Integer, Rows As Integer, k As Integer, Counter As Integer
ReDim Graphmuo(0 To Pres / 5, 1 To 2) As Double

'Loop for pressure from 0 to initital
For P = 0 To Pres Step 5
   Graphmuo(P / 5, 1) = P
   'Calculate oil viscosity (go to function)
   Graphmuo(P / 5, 2) = Oil_Viscosity(Tres, API, Rs)
Next P

'Display results graphically
Form4.chtOilVisc.chartType = VtChChartType2dXY
With Form4.chtOilVisc
   .ChartData = Graphmuo
   .Plot.UniformAxis = False
   .Visible = True
End With
Form4.Show

End Sub

Private Sub cmdGraphmug_Click()

'Read user input values
Tres = (Val(txtTres1.Text))
Pres = Val(txtPres1.Text)
```

```
GasGrav = Val(txtGrav1.Text)

'Declare variables
Dim Graphmug() As Double, P As Double
Dim no_columns As Integer, Rows As Integer, k As Integer
ReDim Graphmug(0 To Pres / 5, 1 To 2) As Double

'Calculate pseudo-reduced temperature (go to function)
Tpr = Calc_Tpr(GasGrav, Tres)
'Loop for pressure from 0 to initial
For P = 0 To Pres Step 5
   'Calculate pseudo-reduced pressure (go to function)
   Ppr = Calc_Ppr(GasGrav, P)
   'Calculate gas viscosity (go to function)
   Graphmug(P / 5, 2) = Gas_Viscosity(GasGrav, Tpr, Ppr)
Next P

'Display results graphically
Form3.chtGasVisc.chartType = VtChChartType2dXY
With Form3.chtGasVisc
   .ChartData = Graphmug
   .Plot.UniformAxis = False
   .Visible = True
End With
Form3.Show

End Sub

Private Function Calc_Ppr(Grav As Double, P As Double) As Double

'Declare variables
Dim Ppc As Double

'Calculate pseudo-critical pressure
Ppc = 709.6 - (58.7 * Grav)
'Calculate pseudo-reduced pressure
Calc_Ppr = P / Ppc

End Function

Private Function Calc_Tpr(Grav As Double, T As Double) As Double

'Declare variables
Dim Tpc As Double

'Calculate pseudo-critical pressure
Tpc = 170.5 + (307.3 * Grav)
'Calculate pseudo-reduced pressure
Calc_Tpr = T / Tpc

End Function

Private Function Gas_Viscosity(Grav As Double, Tr As Double, Pr As Double) As Double

'Declare variables
Dim Part1 As Double, Part2 As Double, Visc1 As Double
```

```
Dim a0 As Double, a1 As Double, a2 As Double, a3 As Double, a4 As Double
Dim a5 As Double, a6 As Double, a7 As Double, a8 As Double, a9 As Double
Dim a10 As Double, a11 As Double, a12 As Double, a13 As Double, a14 As Double
Dim a15 As Double, a16 As Double

'Calculate gas viscosity using Carr, Kobayashi, & Burrows Method
'   and Dempsey Equation
Part1 = (1.709 * (10 ^ -5)) - (2.062 * (10 ^ -6))
Part2 = (8.188 * (10 ^ -3)) - ((6.15 * (10 ^ -3)) * ((Log(Grav)) / (Log(10))))
Visc1 = (Part1 * Tr) + Part2
a0 = -2.4621182
a1 = 2.97054714 * Pr
a2 = -2.86264054 * (10 ^ -1) * (Pr ^ 2)
a3 = 8.05420522 * (10 ^ -3) * (Pr ^ 3)
a4 = 2.80860949
a5 = -3.49803305 * Pr
a6 = 3.6037302 * (10 ^ -1) * (Pr ^ 2)
a8 = -7.93385684 * (10 ^ -1)
a9 = 1.39643306 * Pr
a10 = -1.49144925 * (10 ^ -1) * (Pr ^ 2)
a11 = 4.41015512 * (10 ^ -3) * (Pr ^ 2)
a12 = 8.39387176 * (10 ^ -2)
a14 = 2.03367881 * (10 ^ -2) * (Pr ^ 2)
a15 = -6.09579263 * (10 ^ -4) * (Pr ^ 2)
a16 = a0 + a1 + a2 + a3 + (Tr * (a4 + a5 + a6 + a7)) + ((Tr ^ 2) * _
   (a8 + a9 + a10 + a11)) + ((Tr ^ 3) * (a12 + a13 + a14 + a15))
Gas_Viscosity = (Exp(a16)) * Visc1 / Tr

End Function

Private Function Oil_Viscosity(T As Double, API As Double, Rs As Double) As Double

'Declare variables
Dim OilViscZ As Double, OilViscY As Double, OilViscX As Double
Dim DeadOilVisc As Double, OilViscA As Double, OilViscB As Double

'Calculate oil viscosity using correlations from PNGE 232
OilViscZ = 0.5644 * ((Log(T)) / (Log(10)))
OilViscY = 1.8653 - (0.025086 * API)
OilViscX = 10# ^ (OilViscY - OilViscZ)
DeadOilVisc = (10# ^ OilViscX) - 1
OilViscB = (5.44 * ((Rs + 150#) ^ -0.338))
Oil_Viscosity = OilViscA * (DeadOilVisc ^ OilViscB)

End Function

Private Function Solution_GOR(Grav As Double, P As Double, degAPI As Double, T As Double)
As Double

'Declare variables
Dim RsC1 As Double, RsC2 As Double, RsC3 As Double

'Calculate solution gas-oil ratio using correlations from PNGE 232
If API <= 30 Then
   RsC1 = 0.0362
   RsC2 = 1.0937
```

```
   RsC3 = 25.724
Else
   RsC1 = 0.0178
   RsC2 = 1.187
   RsC3 = 23.931
End If
Solution_GOR = RsC1 * Grav * (P ^ RsC2) * (Exp((RsC3 * degAPI) / (T + 460)))

End Function

Private Function Z_Factor(Tr As Double, Pr As Double) As Double

'Declare variables
Dim aDen As Double, bDen As Double, cDen As Double, dDen As Double
Dim eDen As Double, fDen As Double, gDen As Double, a1Den As Double
Dim b1Den As Double, c1Den As Double, d1Den As Double, e1Den As Double
Dim f1Den As Double, a2Den As Double, b2Den As Double, c2Den As Double
Dim d2Den As Double, e2Den As Double, f2Den As Double
Dim F1Density As Double, F2Density As Double
Dim DensityK As Double, DensityK1 As Double, DiffDensity As Double

'Calculate density and z-factor with Dranchuk, Purvis, & Robinson
'   Procedure to evaluate Standing & Katz Relations
aDen = 0.06423
bDen = (0.5353 * Tr) - 0.6123
cDen = (0.3151 * Tr) - 1.0467 - (0.5783 / (Tr ^ 2))
dDen = Tr
eDen = 0.6816 / (Tr ^ 2)
fDen = 0.6845
gDen = 0.27 * Pr
DensityK = 0.27 * Pr / Tr
DiffDensity = 100
Do
   a1Den = aDen * (DensityK ^ 6)
   b1Den = bDen * (DensityK ^ 3)
   c1Den = cDen * (DensityK ^ 2)
   d1Den = dDen * DensityK
   e1Den = eDen * (DensityK ^ 3)
   f1Den = (1 + (fDen * (DensityK ^ 2))) * (Exp(-fDen * (DensityK ^ 2)))
   F1Density = a1Den + b1Den + c1Den + d1Den + (e1Den * f1Den) - gDen
   a2Den = 6 * aDen * (DensityK ^ 5)
   c2Den = 2 * cDen * DensityK
   d2Den = dDen
   e2Den = eDen * (DensityK ^ 2)
   f2Den = (3 + (fDen * (DensityK ^ 2) * (3 - (2 * fDen * (DensityK ^ 2))) * (Exp(-fDen * (DensityK ^
2)))))
   F2Density = a2Den + b2Den + c2Den + d2Den + (e2Den * f2Den)
   DensityK1 = DensityK - (F1Density / F2Density)
   DensityK = DensityK1
Loop Until (DiffDensity < 0.0001)
Z_Factor = (0.27 * Pr) / (DensityK1 * Tr)

End Function
```

RED PANDA APPENDIX

FIGURE 1: WELL LOCATION MAP

FIGURE 2: GAS MATERIAL BALANCE

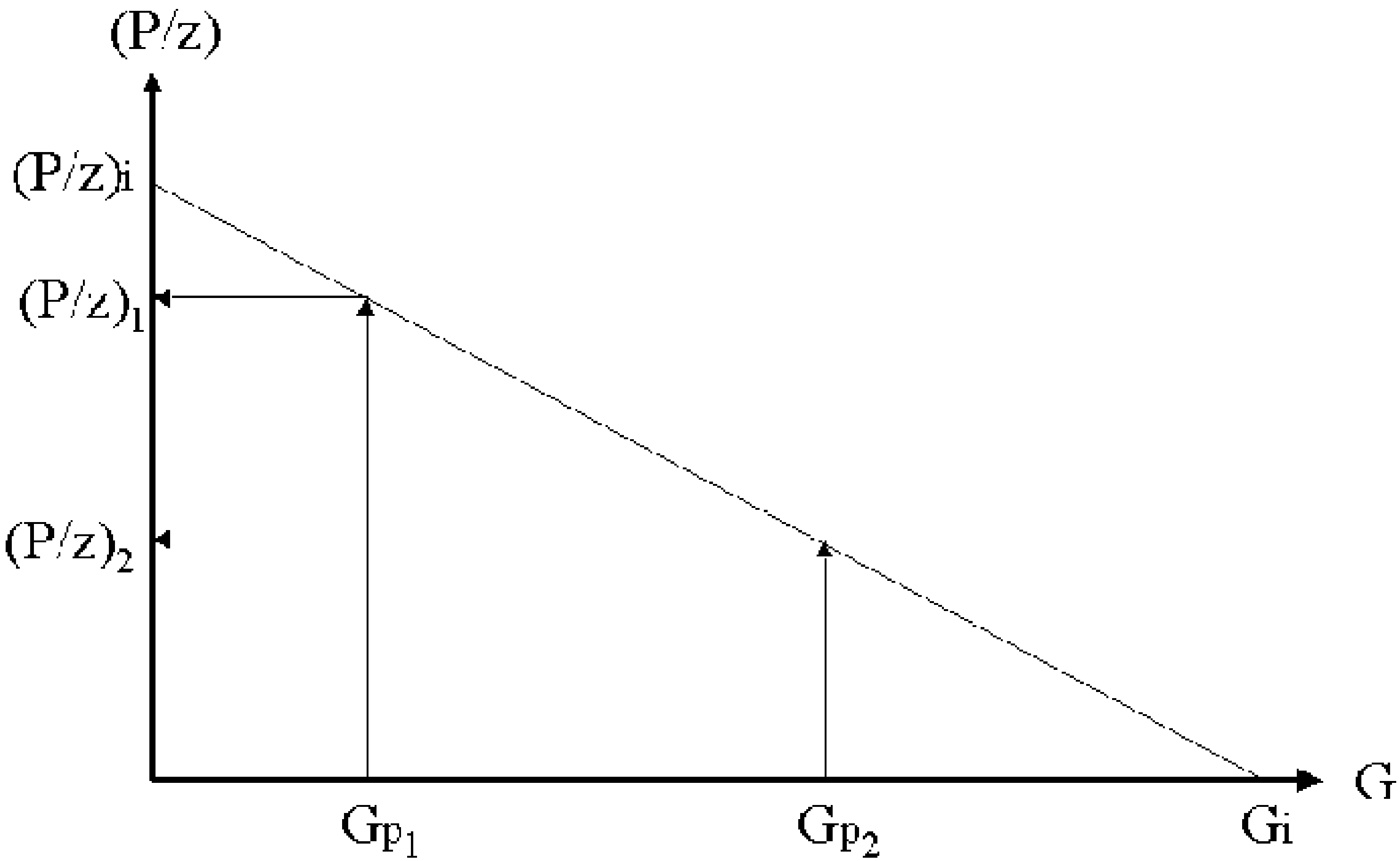


FIGURE 3: INPUT USER INTERFACE

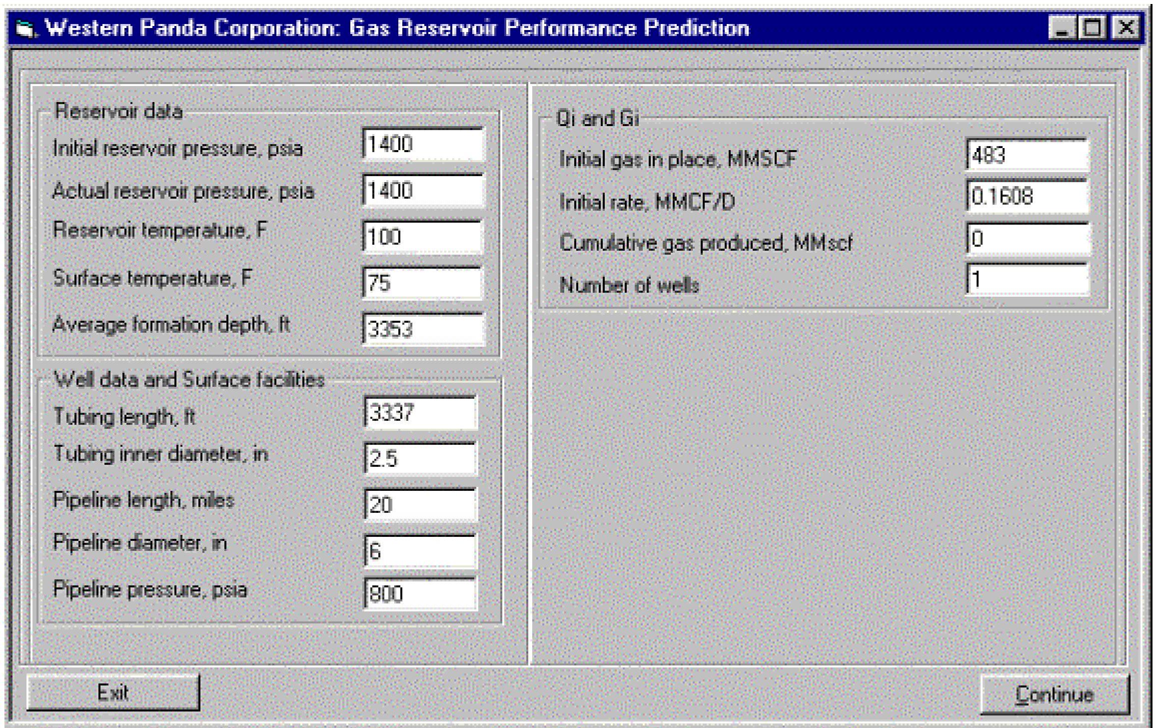
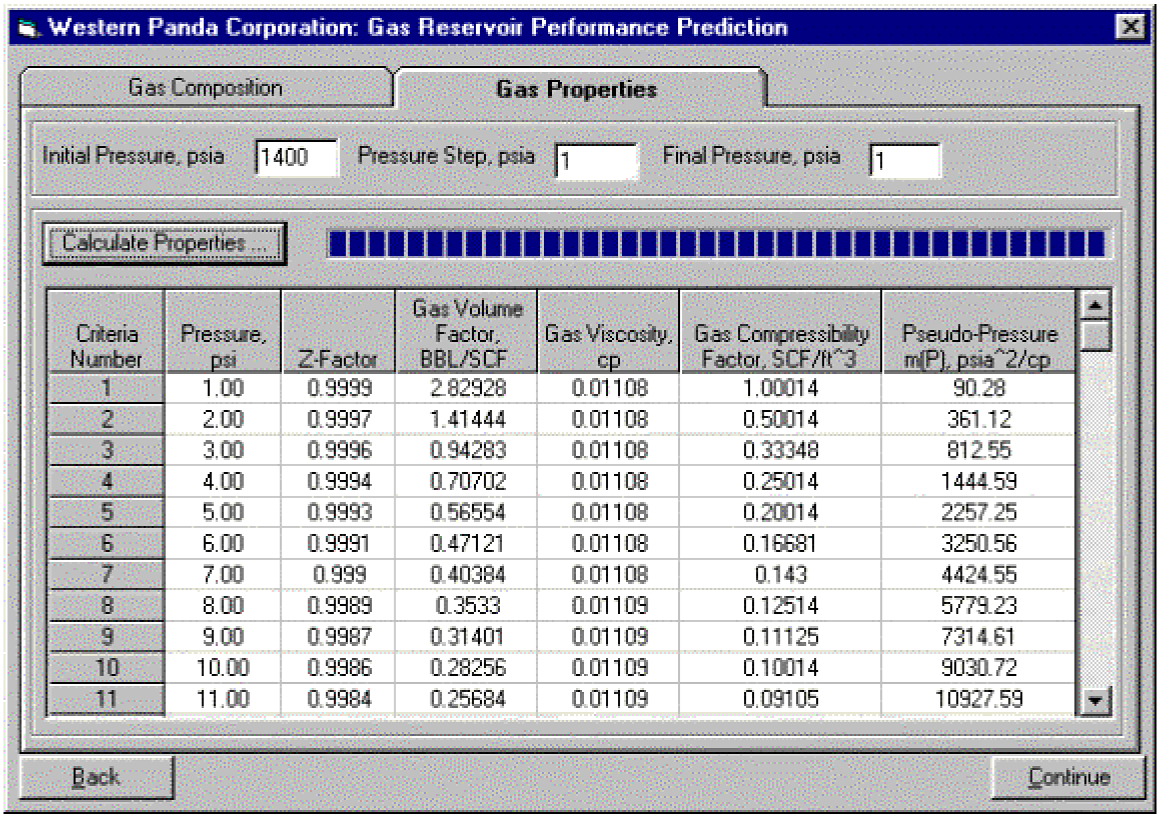
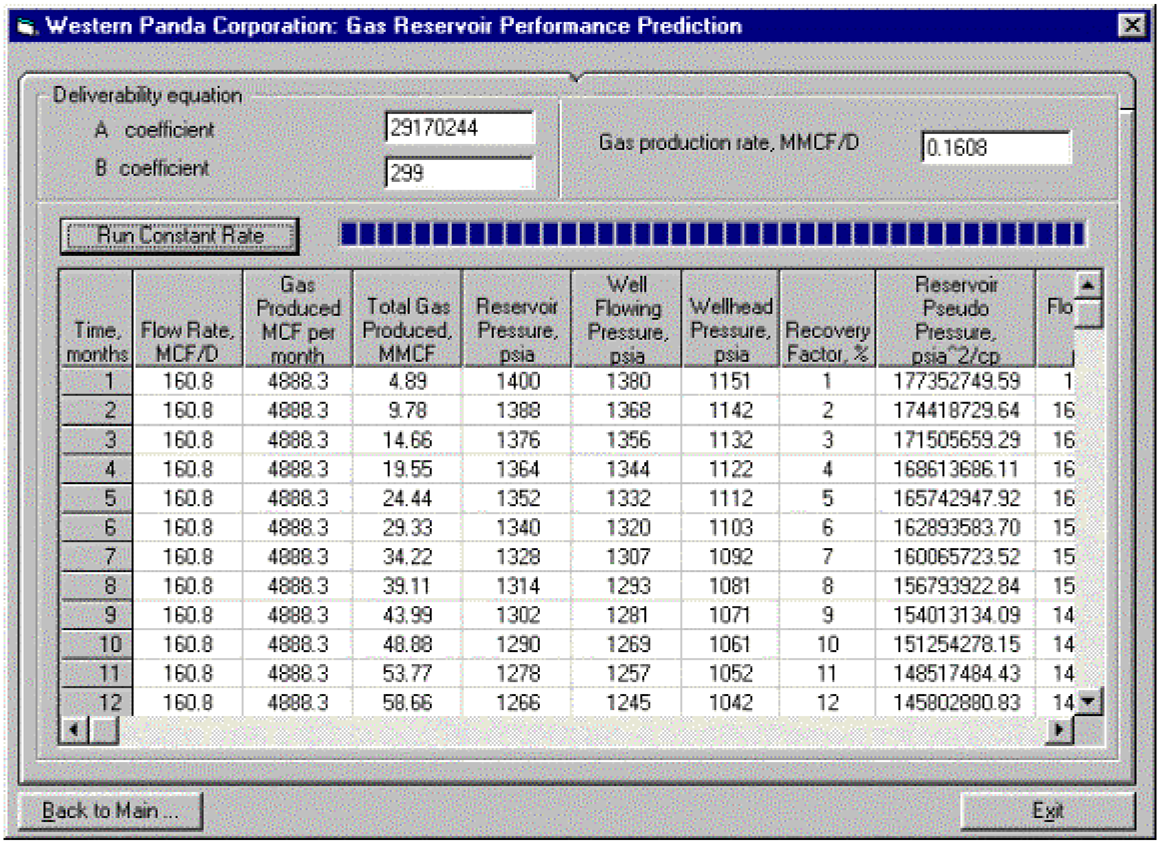


FIGURE 4: GAS PROPERTIES USER INTERFACE



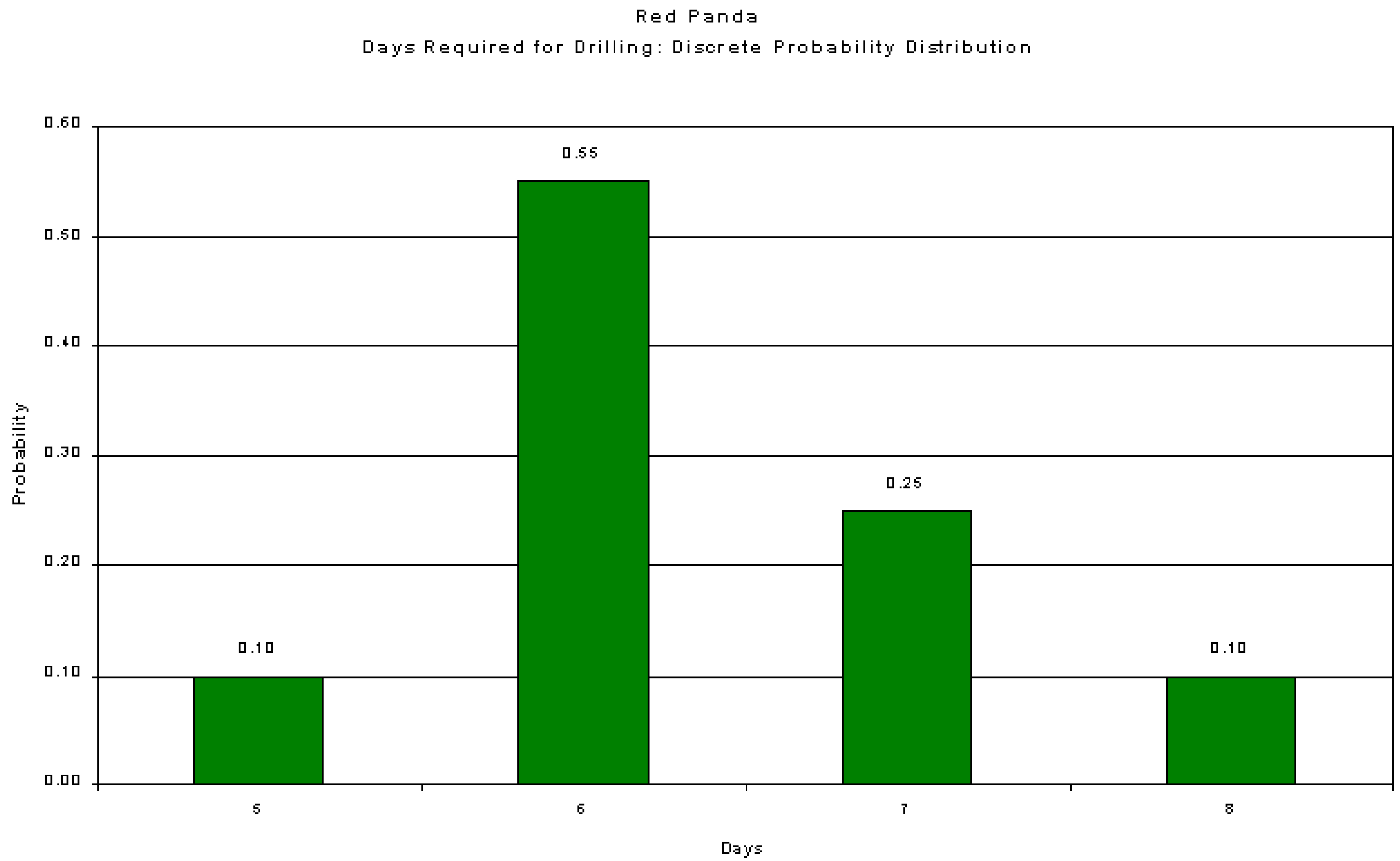
Criteria Number	Pressure, psi	Z-Factor	Gas Volume Factor, BBL/SCF	Gas Viscosity, cp	Gas Compressibility Factor, SCF/ft^3	Pseudo-Pressure m(P), psia^2/cp
1	1.00	0.9999	2.82928	0.01108	1.00014	90.28
2	2.00	0.9997	1.41444	0.01108	0.50014	361.12
3	3.00	0.9996	0.94283	0.01108	0.33348	812.55
4	4.00	0.9994	0.70702	0.01108	0.25014	1444.59
5	5.00	0.9993	0.56554	0.01108	0.20014	2257.25
6	6.00	0.9991	0.47121	0.01108	0.16681	3250.56
7	7.00	0.999	0.40384	0.01108	0.143	4424.55
8	8.00	0.9989	0.3533	0.01109	0.12514	5779.23
9	9.00	0.9987	0.31401	0.01109	0.11125	7314.61
10	10.00	0.9986	0.28256	0.01109	0.10014	9030.72
11	11.00	0.9984	0.25684	0.01109	0.09105	10927.59

FIGURE 5: PERFORMANCE PREDICTION USER INTERFACE

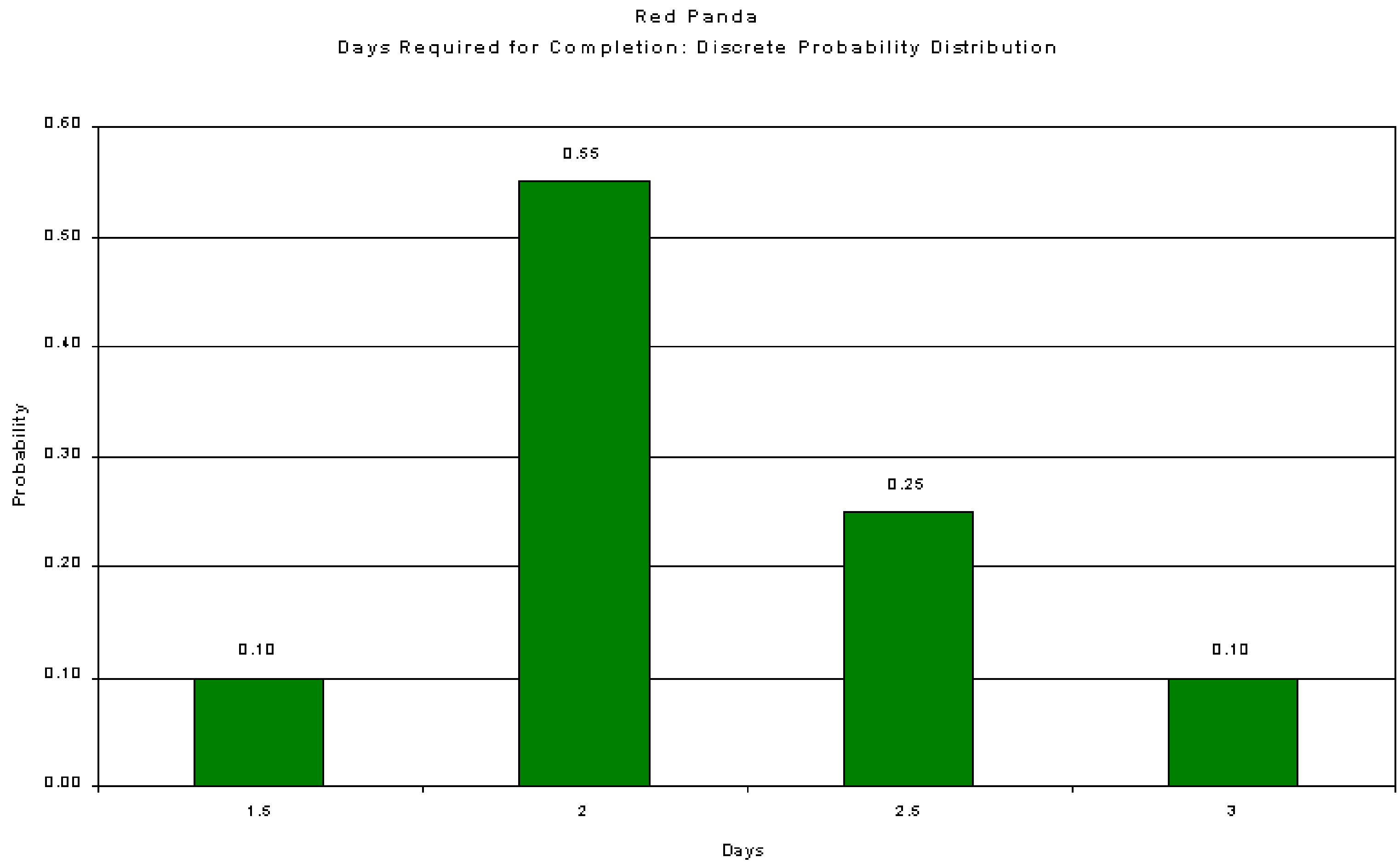


Time, months	Flow Rate, MCF/D	Gas Produced MCF per month	Total Gas Produced, MMCF	Reservoir Pressure, psia	Well Flowing Pressure, psia	Wellhead Pressure, psia	Recovery Factor, %	Reservoir Pseudo Pressure, psia^2/cp	Flo
1	160.8	4888.3	4.89	1400	1380	1151	1	177352749.59	1
2	160.8	4888.3	9.78	1388	1368	1142	2	174418729.64	16
3	160.8	4888.3	14.66	1376	1356	1132	3	171505659.29	16
4	160.8	4888.3	19.55	1364	1344	1122	4	168613686.11	16
5	160.8	4888.3	24.44	1352	1332	1112	5	165742947.92	16
6	160.8	4888.3	29.33	1340	1320	1103	6	162893583.70	15
7	160.8	4888.3	34.22	1328	1307	1092	7	160065723.52	15
8	160.8	4888.3	39.11	1314	1293	1081	8	156793922.84	15
9	160.8	4888.3	43.99	1302	1281	1071	9	154013134.09	14
10	160.8	4888.3	48.88	1290	1269	1061	10	151254278.15	14
11	160.8	4888.3	53.77	1278	1257	1052	11	148517484.43	14
12	160.8	4888.3	58.66	1266	1245	1042	12	145802880.83	14

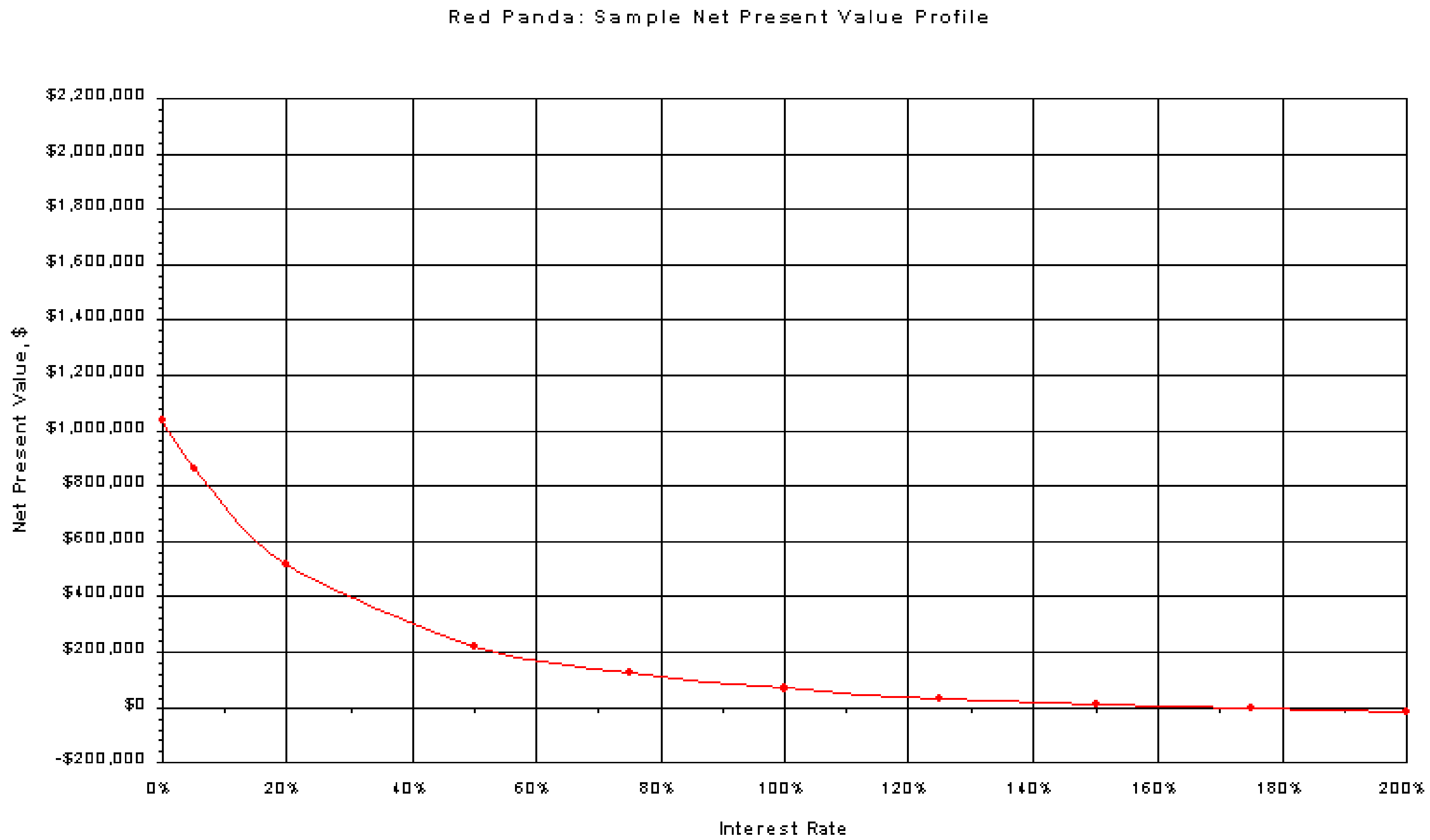
GRAPH 1: DAYS REQUIRED FOR DRILLING



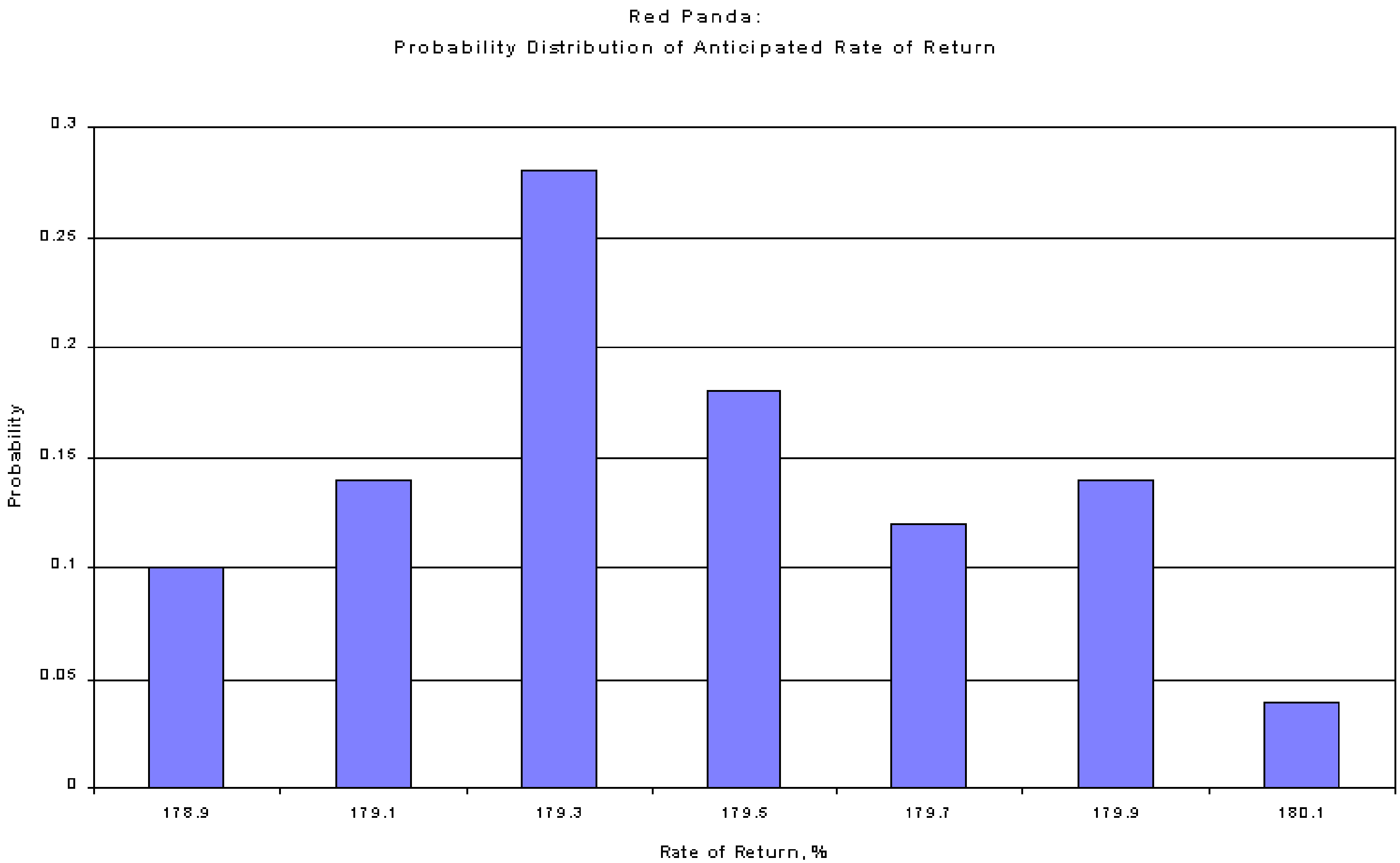
GRAPH 2: DAYS REQUIRED FOR COMPLETION



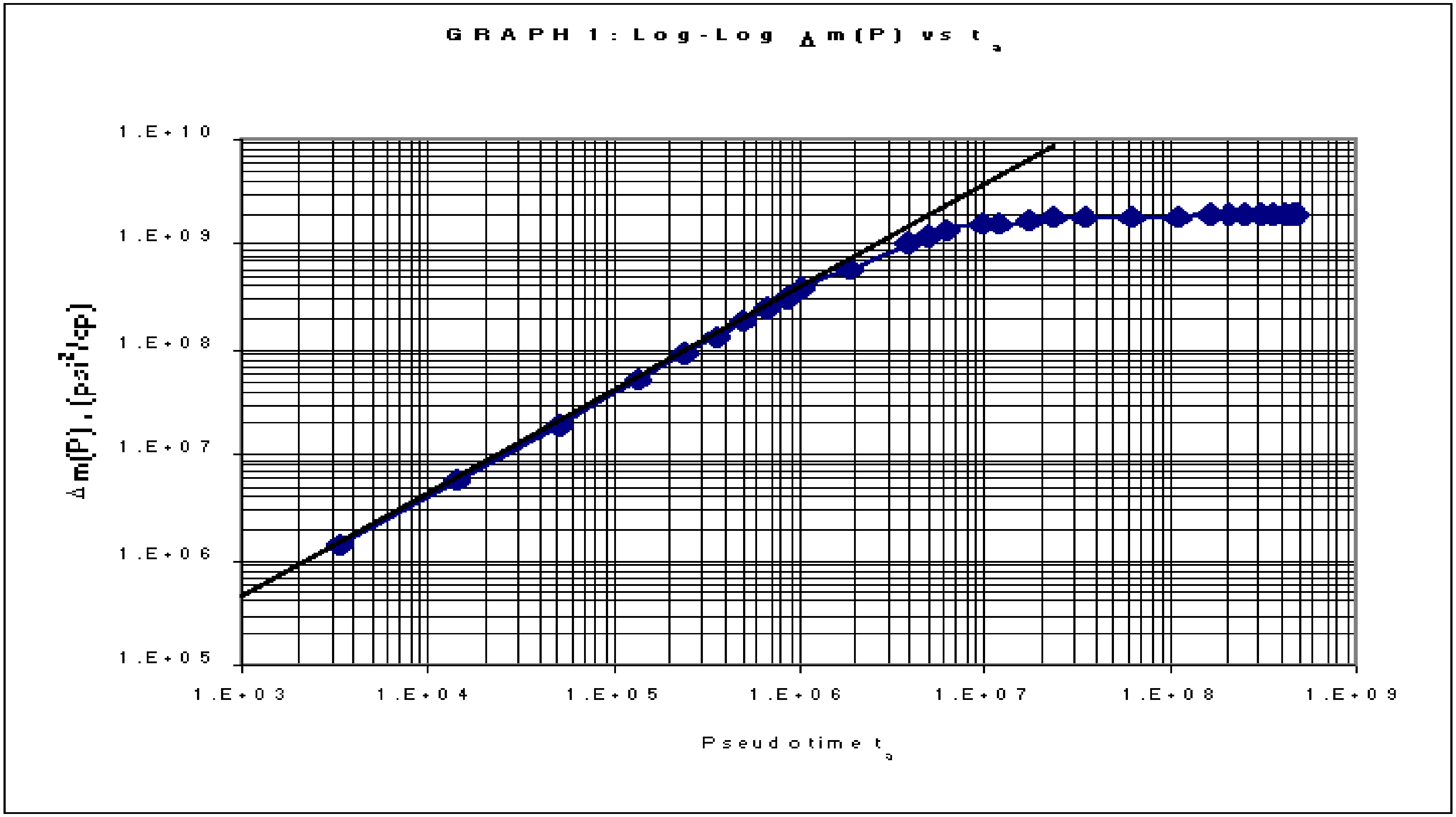
GRAPH 3: PRESENT VALUE PROFILE



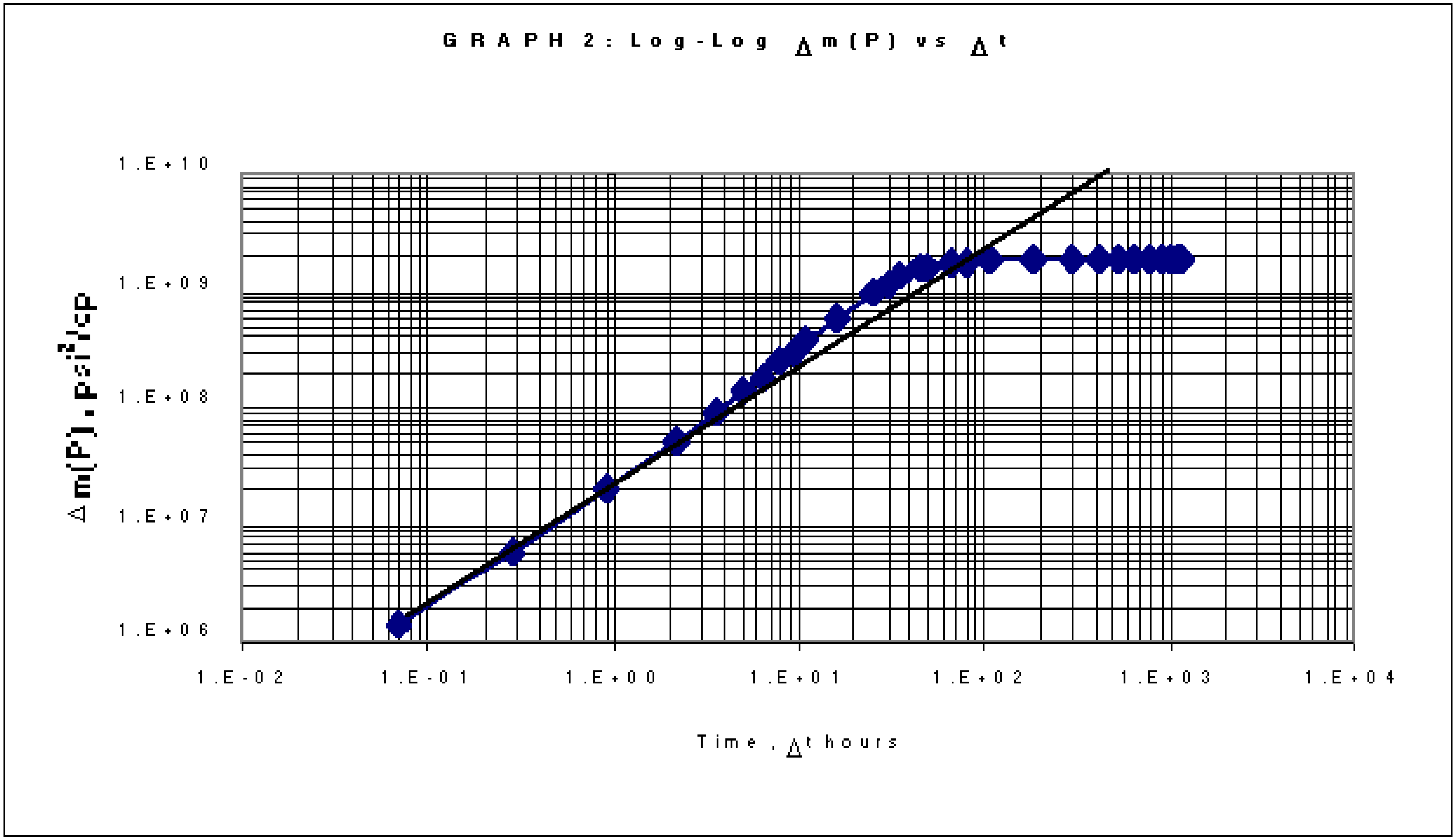
GRAPH 4: RATE OF RETURN PROBABILITY DISTRIBUTION



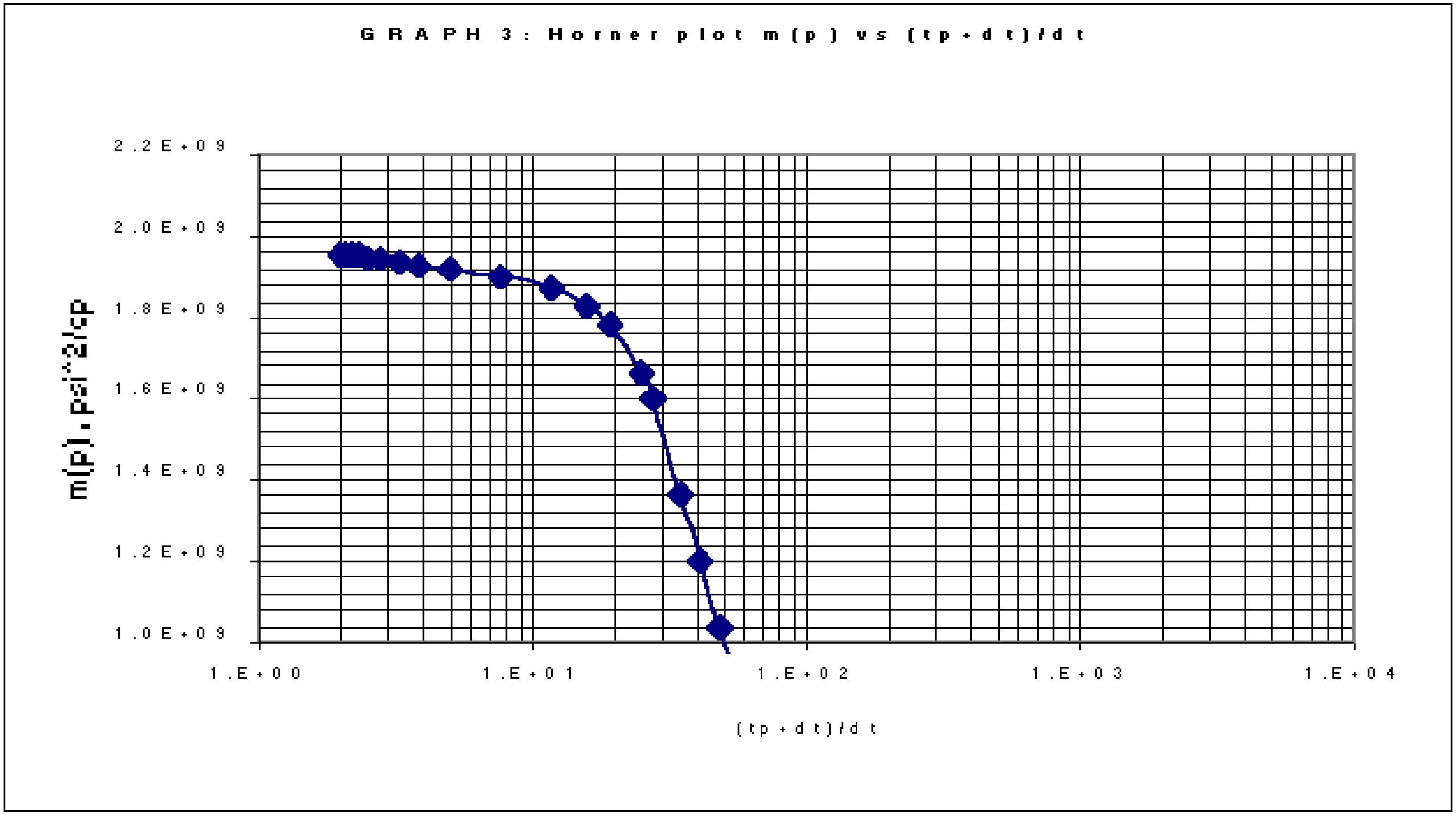
GRAPH 5: CHANGE IN PSEUDO-PRESSURE VERSUS PSEUDO-TIME



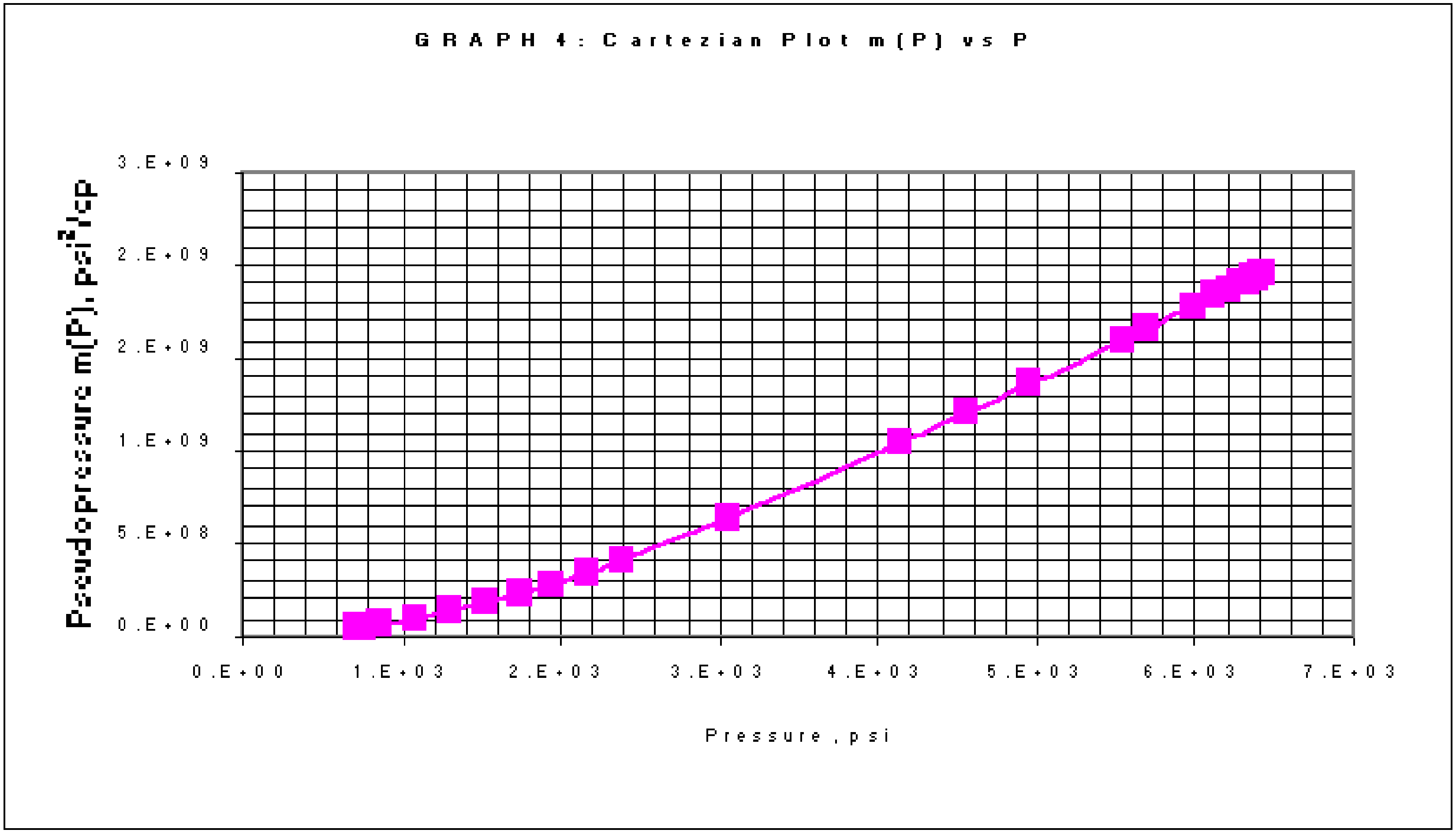
GRAPH 6: CHANGE IN PSEUDO-PRESSURE VERSUS CHANGE IN TIME



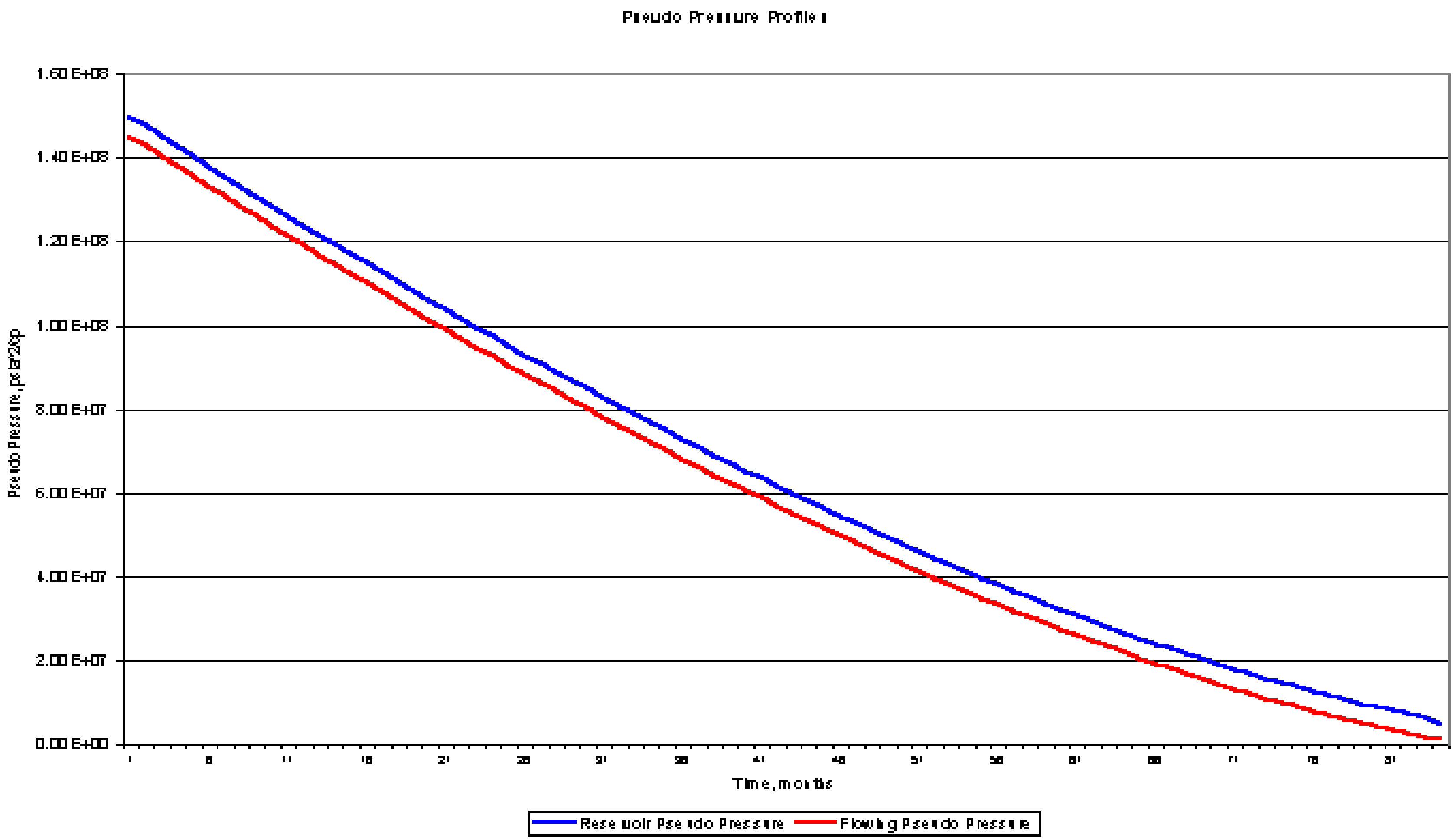
GRAPH 7: HORNER PLOT



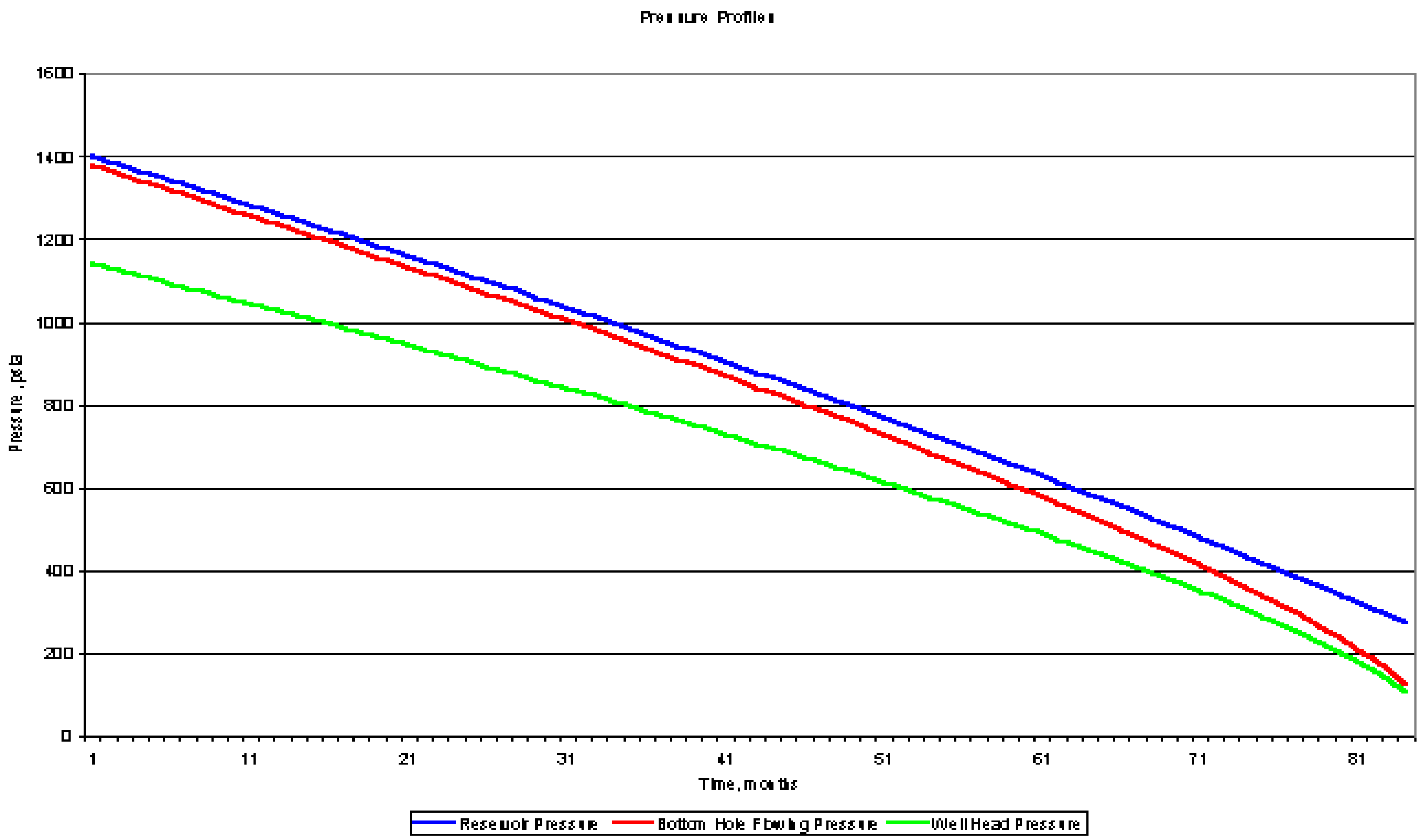
GRAPH 8: PSEUDO-PRESSURE VERSUS PRESSURE



GRAPH 9: PSEUDO-PRESSURE PROFILE



GRAPH 10: PRESSURE PROFILE



GRAPH 11: PSEUDO-PRESSURE VERSUS PRESSURE

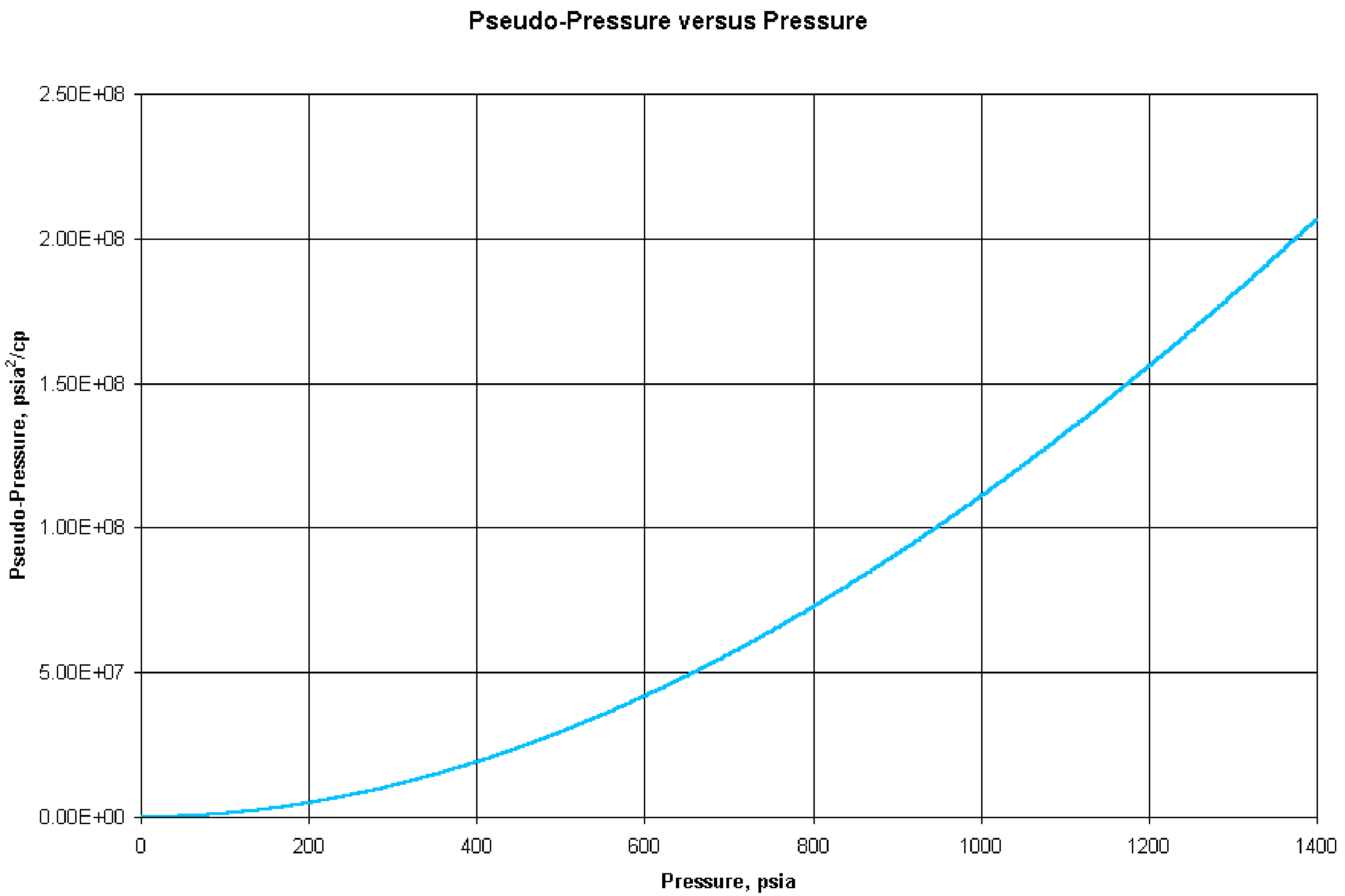


TABLE 1: FRACTURE GRADIENT

Formation Depth, ft		Thickness, ft	Density, g/cm³	Average Density, g/cm³	
Top	Bottom				
0	2300	2300	2.68	2.680	From given data
2300	2750	450	2.71	2.685	From given data
2750	3468	718	2.68	**2.684**	From given data

Overburden Stress =	4,032	psig
Formation Pore Pressure =	1,522	psig
Fracture Pressure =	2,359	psig
Fracture Gradient =	**13.080**	**ppg**

TABLE 2: CASING DESIGN

Casing Design: Red Panda Well

Total Depth =	3468	ft		
Bottomhole Temperature =	76	degrees F		
Formation Gradient =	0.433	psi/ft		
Fracture Gradient =	13.08	ppg		
Drilling Fluid Weight =	8.33	ppg	Air (use fresh water)	
Casing Type =	Production	Intermediate	Surface	
Casing Outer Diameter =	4.5	8.625	11.75	in
Setting Depth =	3,468	1,376	225	ft
BURST				
Bottomhole Pressure =	2,413	957	157	psig
Gas Gradient =	0.0469	0.0188	0.0033	psi/ft
Internal Pressures				
Top =	2,250	932	156	psig
Bottom =	3,752	1,528	157	psig
External Pressures				
Top =	0	0	0	psig
Bottom =	1,502	596	97	psig
Resultant Pressures				
Top =	2,250	932	156	psig
Bottom =	2,251	932	59	psig
Design Pressures				
Top =	2,475	1,025	171	psig
Bottom =	2,476	1,025	65	psig
Minimum Casing Requirements				
Grade =	H-40	H-40	H-40	
Nominal Weight =	9.5	28	32.3	#/ft
Inner Diameter =	4.09	8.017	0.312	in
Internal Pressure Resistance =	3,190	2,470	2,270	psi
Actual Casing Used				
Grade =	J-55	H-40	H-40	
Nominal Weight =	9.5	28	32.3	#/ft
Inner Diameter =	4.09	8.017	9.001	in
Internal Pressure Resistance =	4,380	2,470	2,270	psi
Used Safety Factor				
SF =	1.95	2.65	38.40	

COLLAPSE

Internal Pressures				
Top =	0	0	0	psig
Bottom =	0	97	0	psig
External Pressures				
Top =	0	0	0	psig
Bottom =	1,502	596	97	psig
Resultant Pressures				
Top =	0	0	0	psig
Bottom =	1,502	499	97	psig
Design Pressures				
Top =	0	0	0	psig
Bottom =	1,652	548	107	psig
Minimum Casing Requirements				
Grade =	H-40	H-40	H-40	
Nominal Weight =	9.5	28	32.3	#/ft
Inner Diameter =	4.09	8.017	9.001	in
Collapse Resistance =	2,760	1,610	1,370	psi
Actual Casing Used				
Grade =	J-55	H-40	H-40	
Nominal Weight =	9.5	28	32.3	#/ft
Inner Diameter =	4.09	8.017	9.001	in
Collapse Resistance =	3,310	1,610	1,370	psi
Used Safety Factor				
SF =	2.20	3.23	14.06	

TENSION

Hydrostatic Fluid Pressure =	1,502	596	97	psig
Metal Area at Bottom =	2.766	7.947	44.803	in^2
Axial Tension =	28,791	33,791	2,901	lbf
Design Tension =	128,791	133,791	102,901	lbf
Minimum Casing Requirements				
Grade =	J-55	H-40	H-40	
Nominal Weight =	9.5	28	32.3	#/ft
Inner Diameter =	4.09	8.017	9.001	in
Pipe Body Yield Strength =	152,000	318,000	365,000	lbf
Actual Casing Used				
Grade =	J-55	H-40	H-40	
Nominal Weight =	9.5	28	32.3	#/ft
Inner Diameter =	4.09	8.017	9.001	in
Pipe Body Yield Strength =	152,000	318,000	365,000	lbf
Used Safety Factor				
SF =	5.28	9.41	3.55	

TABLE 3: RESERVE ESTIMATION

	Depth, ft	ρ_b, g/cc	ϕ_{D1}, %	ϕ_{D2}, %	ϕ, %	R_{ID}, Ω-m	R_t, Ω-m	F_R	S_w	G, MCF/acre
Ravenscliff	1538	2.55	7.7	6.0	6.9	79.0	79.0	171.7	0.35	441
	1540	2.45	13.7	14.0	13.8	70.0	70.0	42.3	0.18	1,110
	1542	2.55	7.7	10.0	8.9	85.0	85.0	103.0	0.26	645
	1544	2.625	3.3	5.0	4.1	300.0	300.0	473.3	0.29	286
					8.4				**0.27**	**2,413**
Big Lime	2490	2.6	4.3	4.0	4.4	125.0	125.0	422.0	0.43	244
	2500	2.5	10.7	10.0	10.4	125.0	125.0	75.5	0.18	830
	2502	2.6	4.3	6.0	5.4	100.0	100.0	279.7	0.39	321
	2504	2.65	1.3	4.0	2.9	125.0	125.0	367.9	0.65	99
					5.8				**0.41**	**1,321**
Berea	3346	2.5	10.7	10.0	10.4	70.0	70.0	75.5	0.24	768
	3348	2.46	11.9	11.0	11.5	60.0	60.0	61.8	0.24	856
	3350	2.475	12.2	12.0	12.1	50.0	50.0	55.3	0.25	894
	3352	2.46	13.1	13.0	13.0	46.0	46.0	47.6	0.24	974
	3354	2.46	13.1	13.0	13.0	46.0	46.0	47.6	0.24	974
	3356	2.45	13.7	17.0	15.3	70.0	70.0	34.4	0.16	1,257
	3358	2.38	17.9	16.0	16.9	50.0	50.0	28.3	0.18	1,367
	3360	2.45	13.7	13.0	13.3	50.0	50.0	45.5	0.22	1,016
					13.2				**0.22**	**8,066**
Total Pay Zone					**10.1**				**0.28**	**12,083**

ρ_m = 8.33 ppg
ρ_f = 1
ρ_{ma} = 2.68 g/cc
A = 1 acre
R_w = 0.055 Ω m

P_{res} = 1400 psi
T_{res} = 76 deg F
γ_g = 0.6

ρ_b = From RHOB log
$\phi_{D1} = (\rho_{ma}-\rho_b)/(\rho_{ma}-\rho_f)$
ϕ_{D2} = From DPHI log
$\phi = (\phi_{D1}+\phi_{D2})/2$
R_{ID} = From ILD log
$R_t = R_{ID}$
$F_R = 0.81/\phi^2$
$S_w = (F_R{*}R_w/R_t)^{0.5}$

P_{pc} = 674.23 psi
T_{pc} = 354.83 deg R
P_{pr} = 2.08
T_{pr} = 1.51
z = 0.82
B_{gi} = 0.0083 ft^3/SCF

$P_{pc} = 709.6 - 58.7\gamma_g$
$T_{pc} = 170.5 + 307.3\gamma_g$
$P_{pr} = P_{res}/P_{pc}$
$T_{pr} = T_{res}/T_{pc}$
z = From z-factor chart
$Bgi = 0.0283zT_{res}/P_{res}$

TABLE 4: INVESTMENT DETERMINATION

Investment	Cost	Days	$
Supervision	450	8.54	3,844.76
Rig Rate	1,000	8.54	8,543.91
Misc. Tools	500		500.00
Perf Charges	500		500.00
Other Perf Charges	200		200.00
Drilling Fluids	1,000		1,000.00
Contract Drilling	1,200	6.38	7,650.30
Well Supplies	3,500		3,500.00
Transportation	1,500		1,500.00
Drillstring	4,000		4,000.00
Other Rentals	8,500		8,500.00
Other Subsurface	3,000		3,000.00
Casing, Tubing, Rods	9,500		9,500.00
Logging	25,000		25,000.00
Facilities	10,000		10,000.00
(*Italicized - Cost per day)		**TOTAL**	**87,238.97**

Facilities	$10,000
W/O Tan	$9,500
W/O Int	$67,739
Subtotal	**$87,239**
G&A Facilities	$1,300
G&A Wells	$1,235
TOTAL	**$89,774**

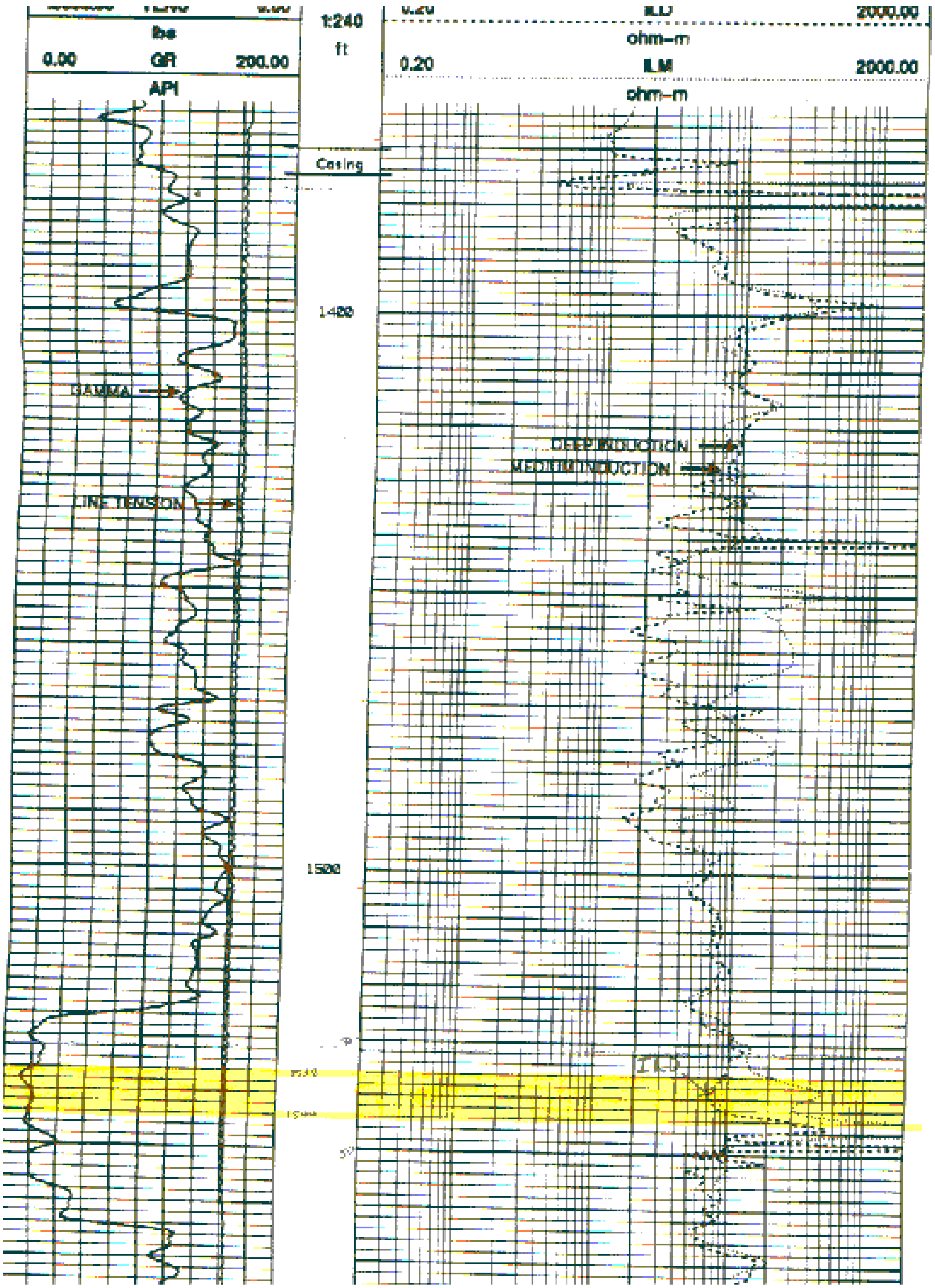
TABLE 5: PSEUDO-PRESSURE AND PSEUDO-TIME

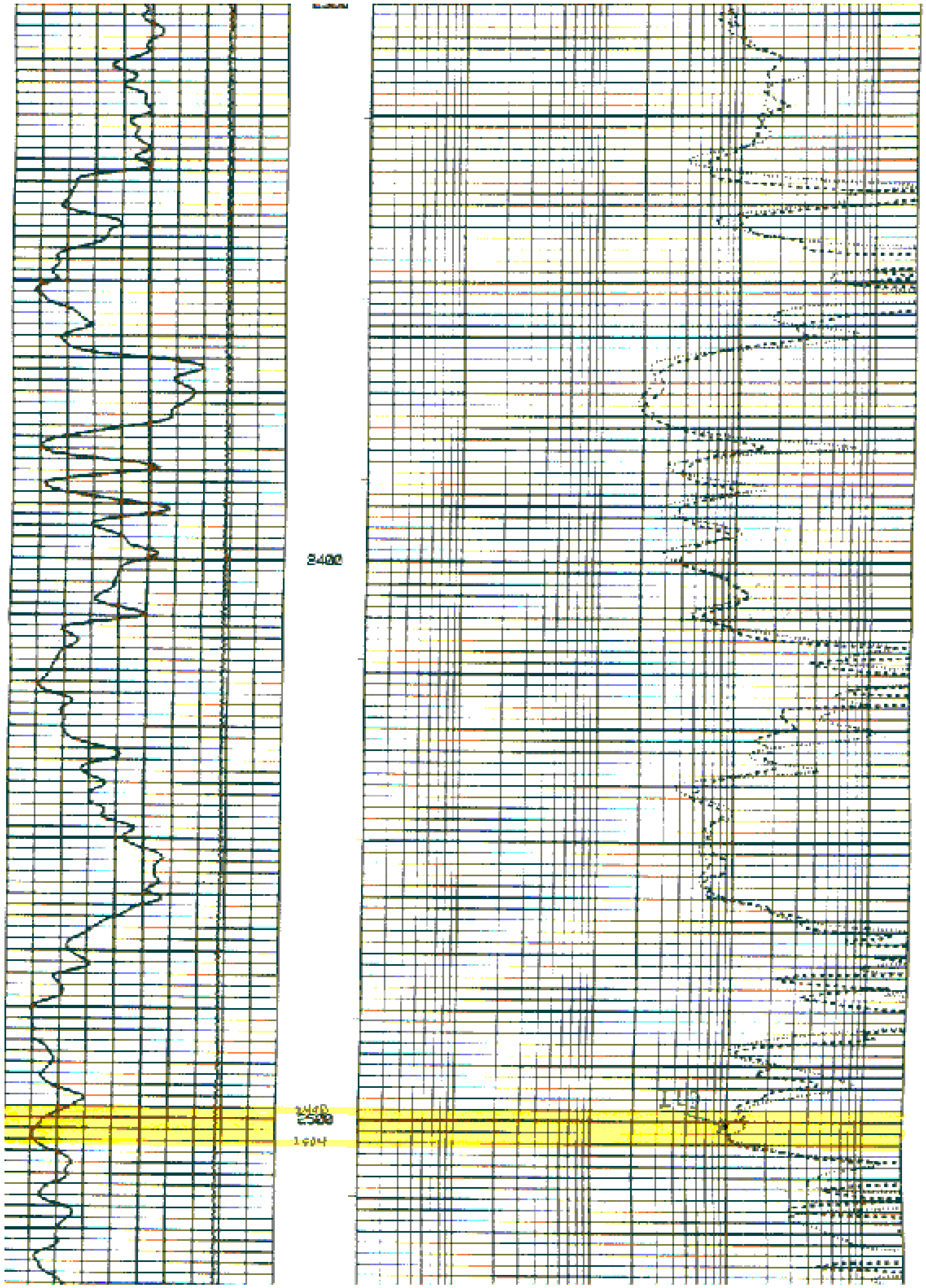
Time	$(t_p+\Delta t)/\Delta t$	Pressure	Z	m(P)	t_a	Δm(P)
hours	-	psi	-	psi^2/cp		psi^2/cp
0.00	0.00	707	0.9470	3.842E+07	0.000E+00	0.000E+00
0.07	17143.86	720	0.9461	3.984E+07	3.447E+03	1.420E+06
0.29	4138.93	759	0.9436	4.425E+07	1.463E+04	5.832E+06
0.94	1277.60	872	0.9364	5.831E+07	5.067E+04	1.989E+07
2.23	539.12	1088	0.9241	9.035E+07	1.346E+05	5.193E+07
3.58	336.20	1304	0.9134	1.289E+08	2.386E+05	9.051E+07
4.97	242.45	1521	0.9046	1.739E+08	3.618E+05	1.355E+08
6.41	188.21	1739	0.8979	2.250E+08	5.057E+05	1.866E+08
7.92	152.52	1957	0.8931	2.814E+08	6.734E+05	2.430E+08
9.46	127.85	2176	0.8906	3.431E+08	8.617E+05	3.047E+08
11.00	110.09	2395	0.8902	4.091E+08	1.067E+06	3.707E+08
16.10	75.53	3054	0.9008	6.293E+08	1.871E+06	5.909E+08
25.40	48.24	4136	0.9480	1.036E+09	3.827E+06	9.973E+08
29.90	41.13	4556	0.9732	1.202E+09	4.998E+06	1.163E+09
35.00	35.29	4961	0.9999	1.364E+09	6.476E+06	1.325E+09
45.60	27.32	5539	1.0412	1.597E+09	9.934E+06	1.559E+09
50.60	24.72	5702	1.0534	1.663E+09	1.171E+07	1.625E+09
66.60	19.02	6001	1.0763	1.784E+09	1.766E+07	1.746E+09
81.60	15.71	6118	1.0854	1.831E+09	2.349E+07	1.793E+09
110.00	11.91	6210	1.0927	1.869E+09	3.475E+07	1.830E+09
181.00	7.63	6283	1.0984	1.898E+09	6.336E+07	1.860E+09
301.00	4.99	6334	1.1025	1.919E+09	1.123E+08	1.880E+09
421.00	3.85	6363	1.1048	1.930E+09	1.616E+08	1.892E+09
541.00	3.22	6383	1.1064	1.938E+09	2.112E+08	1.900E+09
661.00	2.82	6397	1.1075	1.944E+09	2.609E+08	1.906E+09
781.00	2.54	6408	1.1084	1.949E+09	3.107E+08	1.910E+09
901.00	2.33	6417	1.1091	1.952E+09	3.607E+08	1.914E+09
1021.00	2.18	6424	1.1096	1.955E+09	4.107E+08	1.917E+09
1141.00	2.05	6429	1.1100	1.957E+09	4.607E+08	1.919E+09
1200.00	2.00	6432	1.1103	1.958E+09	4.854E+08	1.920E+09

TABLE 6: ECONOMIC ANALYSIS

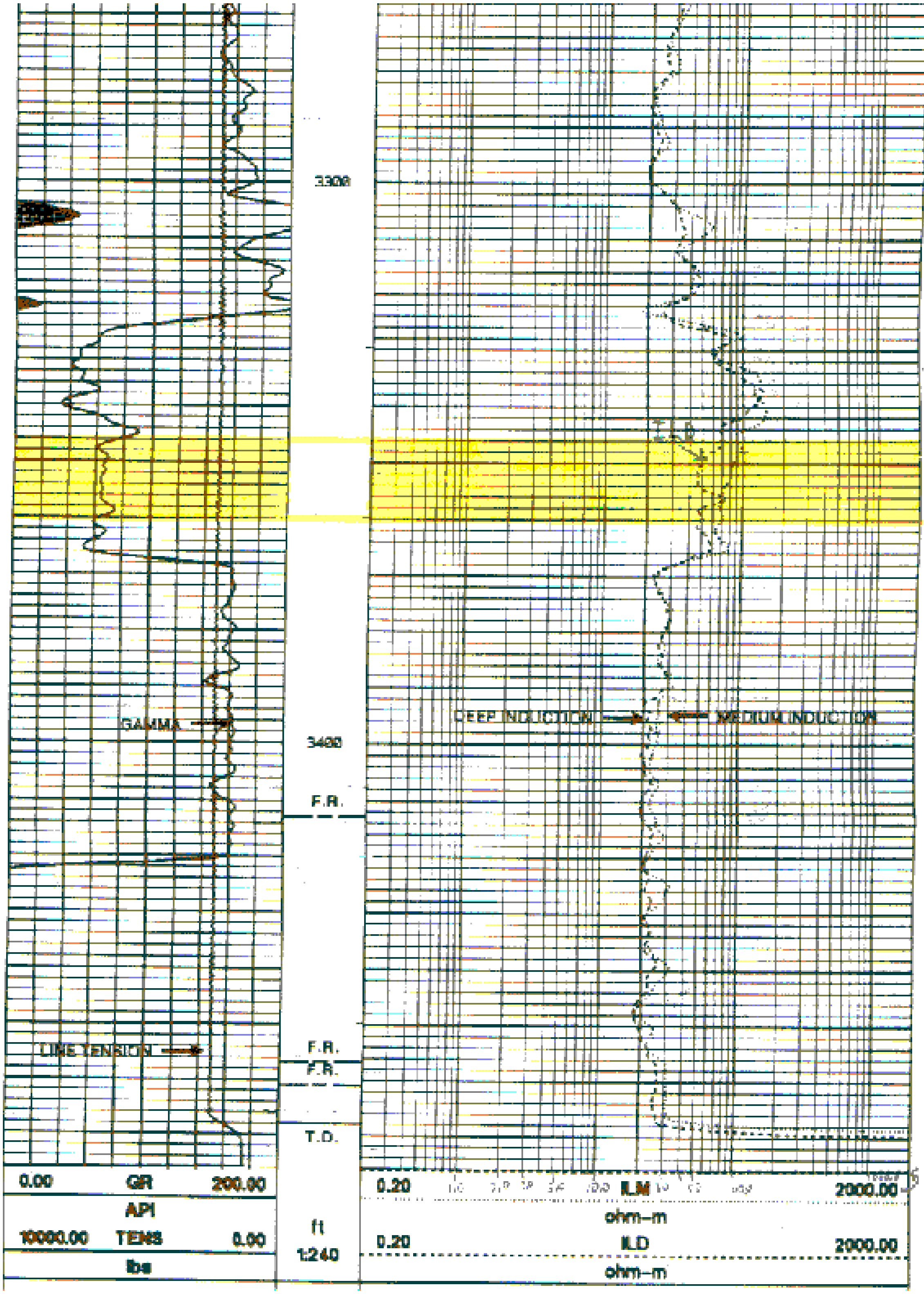
	Time, months	Production per Month, MCF/month	Investment, $/month	Operating Cost, $/month	Revenue, $/month	Net Cash Flow, $/month	NPV 5%, $/month	NPV 20%, $/month	NPV 50%, $/month	NPV 75%, $/month	NPV 100%, $/month	NPV 125%, $/month	NPV 150%, $/month	NPV 175%, $/month	NPV 200%, $/month
Investment	0	0	89,732	0	0	-89,732	-89,732	-89,732	-89,732	-89,732	-89,732	-89,732	-89,732	-89,732	-89,732
	1	4879.2	0	1,217	14,631	13,413	13,358	13,193	12,877	12,624	12,381	12,148	11,923	11,706	11,497
	2	4879.2	0	1,217	14,631	13,413	13,302	12,977	12,362	11,882	11,429	11,002	10,598	10,216	9,855
	3	4879.2	0	1,217	14,631	13,413	13,247	12,764	11,867	11,183	10,550	9,964	9,421	8,916	8,447
	4	4879.2	0	1,217	14,631	13,413	13,192	12,555	11,392	10,525	9,738	9,024	8,374	7,781	7,240
	5	4879.2	0	1,217	14,631	13,413	13,137	12,349	10,937	9,906	8,989	8,173	7,443	6,791	6,206
Year 1	6	4879.2	0	1,217	14,631	13,413	13,083	12,147	10,499	9,323	8,298	7,402	6,616	5,927	5,319
	7	4879.2	0	1,217	14,631	13,413	13,028	11,948	10,079	8,775	7,659	6,703	5,881	5,172	4,559
	8	4879.2	0	1,217	14,631	13,413	12,974	11,752	9,676	8,258	7,070	6,071	5,228	4,514	3,908
	9	4879.2	0	1,217	14,631	13,413	12,921	11,559	9,289	7,773	6,526	5,498	4,647	3,939	3,350
	10	4879.2	0	1,217	14,631	13,413	12,867	11,370	8,918	7,315	6,024	4,980	4,131	3,438	2,871
	11	4879.2	0	1,217	14,631	13,413	12,814	11,183	8,561	6,885	5,561	4,510	3,672	3,001	2,461
	12	4879.2	0	1,217	14,631	13,413	12,760	11,000	8,218	6,480	5,133	4,084	3,264	2,619	2,109
	13	4879.2	0	1,217	14,631	13,413	12,707	10,820	7,890	6,099	4,738	3,699	2,901	2,285	1,808
	14	4879.2	0	1,217	14,631	13,413	12,655	10,642	7,574	5,740	4,374	3,350	2,579	1,994	1,550
	15	4879.2	0	1,217	14,631	13,413	12,602	10,468	7,271	5,403	4,037	3,034	2,292	1,741	1,328
	16	4879.2	0	1,217	14,631	13,413	12,550	10,296	6,980	5,085	3,727	2,748	2,037	1,519	1,139
	17	4879.2	0	1,217	14,631	13,413	12,498	10,127	6,701	4,786	3,440	2,489	1,811	1,326	976
Year 2	18	4879.2	0	1,217	14,631	13,413	12,446	9,961	6,433	4,504	3,176	2,254	1,610	1,157	837
	19	4879.2	0	1,217	14,631	13,413	12,394	9,798	6,176	4,239	2,931	2,041	1,431	1,010	717
	20	4879.2	0	1,217	14,631	13,413	12,343	9,637	5,929	3,990	2,706	1,849	1,272	881	615
	21	4879.2	0	1,217	14,631	13,413	12,292	9,479	5,692	3,755	2,498	1,674	1,131	769	527
	22	4879.2	0	1,217	14,631	13,413	12,241	9,324	5,464	3,534	2,306	1,516	1,005	671	452
	23	4879.2	0	1,217	14,631	13,413	12,190	9,171	5,245	3,326	2,128	1,373	893	586	387
	24	4879.2	0	1,217	14,631	13,413	12,139	9,021	5,035	3,131	1,964	1,244	794	511	332
	25	4879.2	0	1,217	14,631	13,413	12,089	8,873	4,834	2,947	1,813	1,126	706	446	284
	26	4879.2	0	1,217	14,631	13,413	12,039	8,727	4,641	2,773	1,674	1,020	627	389	244
	27	4879.2	0	1,217	14,631	13,413	11,989	8,584	4,455	2,610	1,545	924	558	340	209
	28	4879.2	0	1,217	14,631	13,413	11,939	8,444	4,277	2,457	1,426	837	496	297	179
	29	4879.2	0	1,217	14,631	13,413	11,890	8,305	4,106	2,312	1,317	758	441	259	153
Year 3	30	4879.2	0	1,217	14,631	13,413	11,840	8,169	3,942	2,176	1,215	686	392	226	132
	31	4879.2	0	1,217	14,631	13,413	11,791	8,035	3,784	2,048	1,122	622	348	197	113
	32	4879.2	0	1,217	14,631	13,413	11,742	7,903	3,633	1,928	1,035	563	309	172	97
	33	4879.2	0	1,217	14,631	13,413	11,693	7,774	3,487	1,814	956	510	275	150	83
	34	4879.2	0	1,217	14,631	13,413	11,645	7,646	3,348	1,707	882	462	245	131	71
	35	4879.2	0	1,217	14,631	13,413	11,597	7,521	3,214	1,607	814	418	217	114	61
	36	4879.2	0	1,217	14,631	13,413	11,548	7,398	3,085	1,512	752	379	193	100	52
	37	4879.2	0	1,217	14,631	13,413	11,501	7,277	2,962	1,424	694	343	172	87	45
	38	4879.2	0	1,217	14,631	13,413	11,453	7,157	2,843	1,340	641	311	153	76	38
	39	4879.2	0	1,217	14,631	13,413	11,405	7,040	2,730	1,261	591	281	136	66	33
	40	4879.2	0	1,217	14,631	13,413	11,358	6,925	2,620	1,187	546	255	121	58	28
	41	4879.2	0	1,217	14,631	13,413	11,311	6,811	2,516	1,117	504	231	107	51	24
Year 4	42	4879.2	0	1,217	14,631	13,413	11,264	6,699	2,415	1,051	465	209	95	44	21
	43	4879.2	0	1,217	14,631	13,413	11,217	6,590	2,318	989	429	189	85	38	18
	44	4879.2	0	1,217	14,631	13,413	11,171	6,481	2,226	931	396	171	75	34	15
	45	4879.2	0	1,217	14,631	13,413	11,124	6,375	2,137	876	366	155	67	29	13
	46	4879.2	0	1,217	14,631	13,413	11,078	6,271	2,051	825	338	141	59	26	11
	47	4879.2	0	1,217	14,631	13,413	11,032	6,168	1,969	776	312	127	53	22	10
	48	4879.2	0	1,217	14,631	13,413	10,986	6,067	1,890	731	288	115	47	19	8
	49	4879.2	0	1,217	14,631	13,413	10,941	5,967	1,815	688	266	104	42	17	7
	50	4879.2	0	1,217	14,631	13,413	10,895	5,870	1,742	647	245	95	37	15	6
	51	4879.2	0	1,217	14,631	13,413	10,850	5,773	1,672	609	226	86	33	13	5
	52	4879.2	0	1,217	14,631	13,413	10,805	5,679	1,606	573	209	78	29	11	4
	53	4879.2	0	1,217	14,631	13,413	10,760	5,586	1,541	540	193	70	26	10	4
Year 5	54	4879.2	0	1,217	14,631	13,413	10,716	5,494	1,480	508	178	64	23	9	3
	55	4879.2	0	1,217	14,631	13,413	10,671	5,404	1,421	478	164	58	21	8	3
	56	4879.2	0	1,217	14,631	13,413	10,627	5,315	1,364	450	152	52	18	7	2
	57	4879.2	0	1,217	14,631	13,413	10,583	5,228	1,309	423	140	47	16	6	2
	58	4879.2	0	1,217	14,631	13,413	10,539	5,143	1,257	399	129	43	14	5	2
	59	4879.2	0	1,217	14,631	13,413	10,495	5,058	1,207	375	119	39	13	4	2
	60	4879.2	0	1,217	14,631	13,413	10,452	4,975	1,158	353	110	35	11	4	1
	61	4879.2	0	1,217	14,631	13,413	10,408	4,894	1,112	332	102	32	10	3	1
	62	4879.2	0	1,217	14,631	13,413	10,365	4,813	1,067	313	94	29	9	3	1
	63	4879.2	0	1,217	14,631	13,413	10,322	4,735	1,025	294	87	26	8	3	1
	64	4879.2	0	1,217	14,631	13,413	10,279	4,657	984	277	80	24	7	2	1
	65	4879.2	0	1,217	14,631	13,413	10,237	4,581	944	261	74	21	6	2	1
Year 6	66	4879.2	0	1,217	14,631	13,413	10,194	4,506	907	245	68	19	6	2	1
	67	4879.2	0	1,217	14,631	13,413	10,152	4,432	870	231	63	18	5	1	0
	68	4879.2	0	1,217	14,631	13,413	10,110	4,359	836	217	58	16	4	1	0
	69	4879.2	0	1,217	14,631	13,413	10,068	4,288	802	205	54	14	4	1	0
	70	4879.2	0	1,217	14,631	13,413	10,026	4,217	770	193	49	13	4	1	0
	71	4879.2	0	1,217	14,631	13,413	9,984	4,148	739	181	46	12	3	1	0
	72	4879.2	0	1,217	14,631	13,413	9,943	4,080	710	171	42	11	3	1	0
	73	4879.2	0	1,217	14,631	13,413	9,902	4,013	681	161	39	10	2	1	0
	74	4879.2	0	1,217	14,631	13,413	9,861	3,947	654	151	36	9	2	1	0
	75	4879.2	0	1,217	14,631	13,413	9,820	3,883	628	142	33	8	2	0	0
	76	4879.2	0	1,217	14,631	13,413	9,779	3,819	603	134	31	7	2	0	0
	77	4879.2	0	1,217	14,631	13,413	9,738	3,756	579	126	28	7	2	0	0
Year 7	78	4879.2	0	1,217	14,631	13,413	9,698	3,695	556	119	26	6	1	0	0
	79	4879.2	0	1,217	14,631	13,413	9,658	3,634	533	112	24	5	1	0	0
	80	4879.2	0	1,217	14,631	13,413	9,618	3,575	512	105	22	5	1	0	0
	81	4879.2	0	1,217	14,631	13,413	9,578	3,516	491	99	21	4	1	0	0
	82	4879.2	0	1,217	14,631	13,413	9,538	3,459	472	93	19	4	1	0	0
	83	4879.2	0	1,217	14,631	13,413	9,498	3,402	453	88	17	4	1	0	0
	84	4879.2	0	1,217	14,631	13,413	9,459	3,346	435	82	16	3	1	0	0
					Total NPV	$1,036,978	$859,277	$514,298	$221,749	$123,561	$71,033	$39,004	$17,569	$2,244	-$9,253
					Interest Rate	0%	5%	20%	50%	75%	100%	125%	150%	175%	200%
														Rate of Return	179.9%

LOG 1: INDUCTION LOG



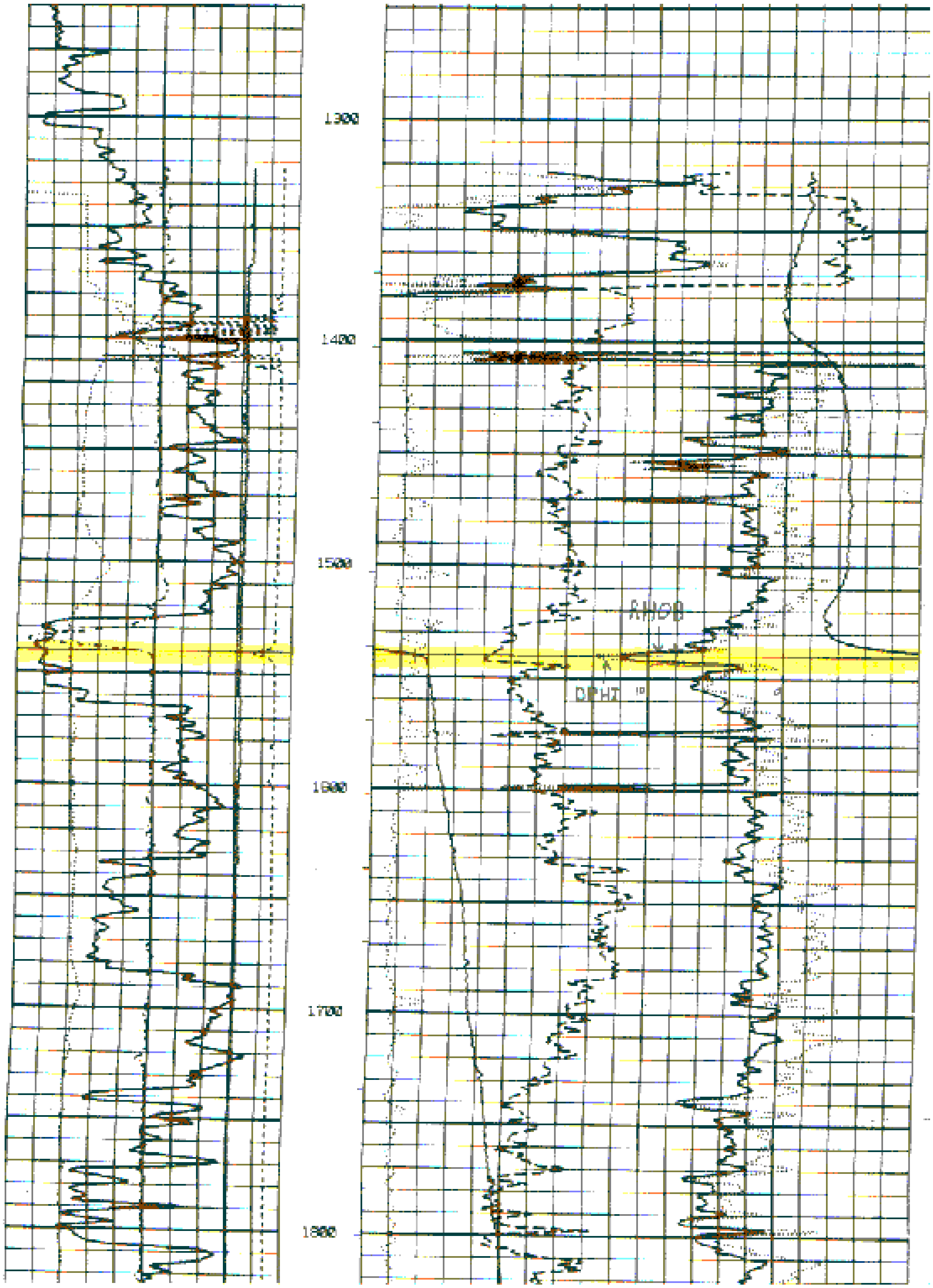


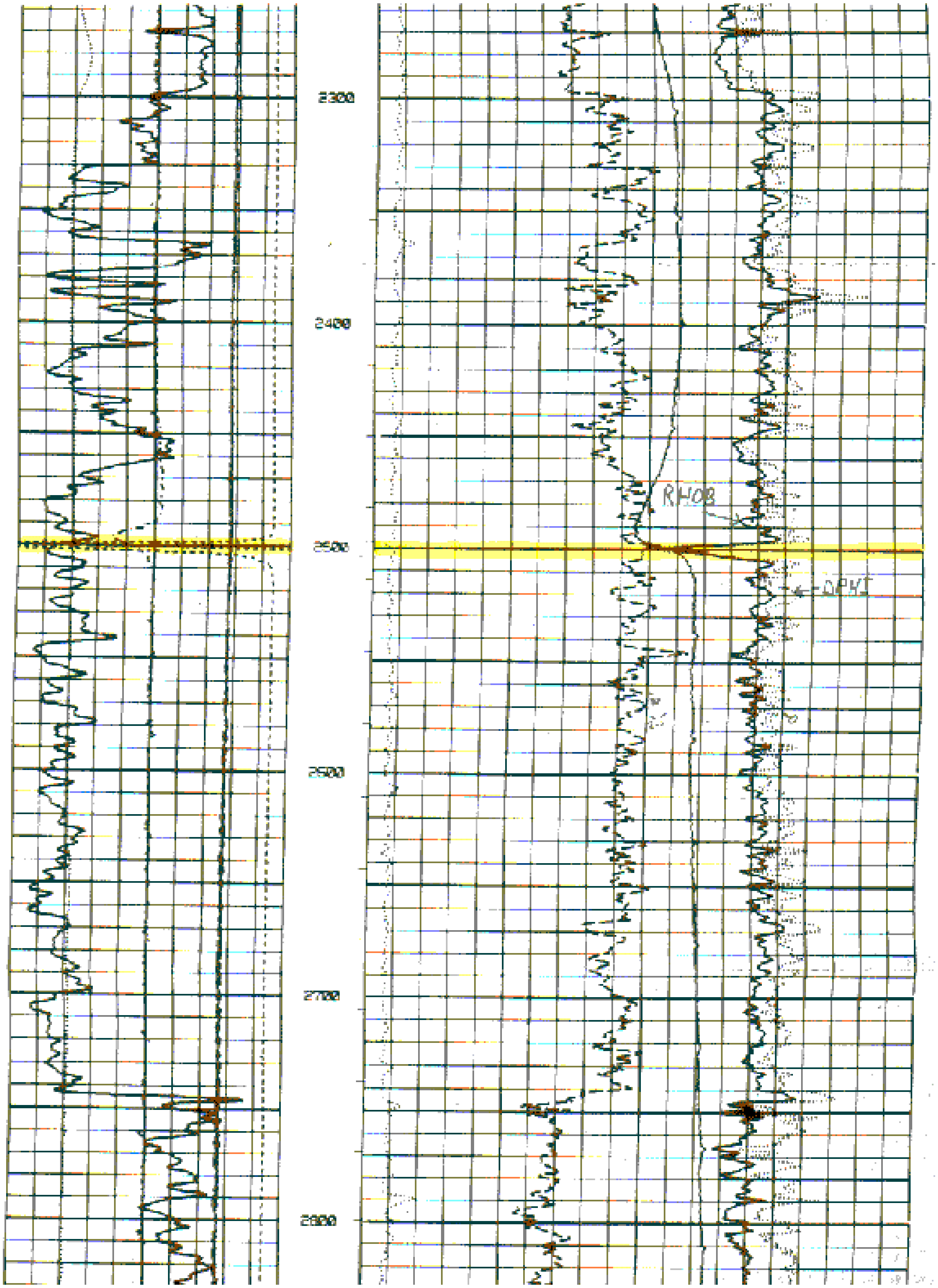
2400
2500
1604



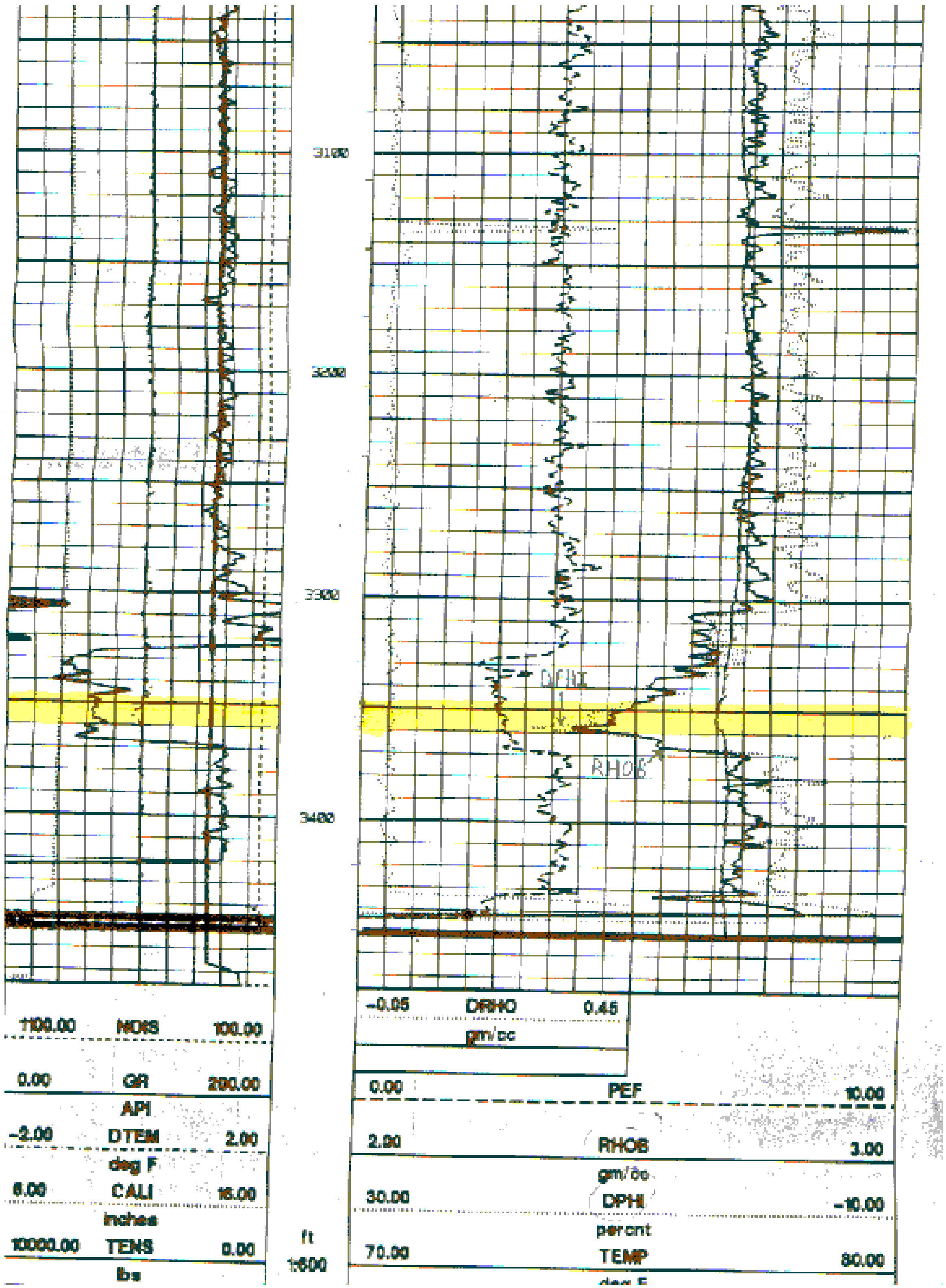
3300
GAMMA
3400
DEEP INDUCTION
MEDIUM INDUCTION
F.R.
LINE TENSION
F.R.
F.R.
T.D.
0.00 GR 200.00
API
10000.00 TENS 0.00
lbs
ft
1:240
0.20 ILM 2000.00
ohm-m
0.20 ILD 2000.00
ohm-m

LOG 2: BULK DENSITY & DENSITY POROSITY LOG





2300
2400
RHOB
2500
DPHI
2600
2700
2800


3100
3200
3300
3400
DPHI
RHOB
-100.00 NOIS 100.00
0.00 GR 200.00
API
-2.00 DTEM 2.00
deg F
6.00 CALI 16.00
inches
10000.00 TENS 0.00
lbs
ft
1:600
-0.05 DRHO 0.45
gm/cc
0.00 PEF 10.00
2.00 RHOB 3.00
gm/cc
30.00 DPHI -10.00
percnt
70.00 TEMP 80.00
deg F

PROGRAM 1: PSEUDO-PRESSURE AND PSEUDO-TIME

VISUAL BASIC COMPUTER PROGRAM

The computer program has one form, which includes the main body of the project. The form has a menu bar with the following options:
File (with submenus Open and Exit)
Import (with submenu Start Import)
The Open submenu allows the user to open the file that contains the values for time and pressure from the well test. It can be any type of text or Excel file. The Start Import submenu imports the data from the file opened previously. The Exit submenu exits the program. The form presents a table where the imported values for the time and pressure and the calculated values for pseudo-time and pseudo-pressure are displayed. Also, the same values are written to an output file in order to plot the needed graphs in Excel. After determining the slope and reading the m(P*) and m(P_{1hr}), the values for z, c_g, and μ at m(P*) are calculated by the program.

VISUAL BASIC PROGRAM CODE

The following is the code for Module 1 :

```
Option Explicit
Public i, j, counterf As Integer
Public tz, pz, gama, mwa, ror, q, h, prodt, rw, por
Public p(100), t(100), ppc, tpc, ppr, tpr, cgg
Public miu(7000), zi(7000), pprr(7000), cg(7000)
Public pp(7000), mp2(7000), mpp(7000), mp(7000), ipp(7000)
Public ip(7000), tp(7000), zii(50)
Public miug, z
```

```
Public Function ef(ByVal ror As Double)     / Code for calculation the deviation factor

Const a1 = 0.3265
Const a2 = -1.07
Const a3 = -0.5339
Const a4 = 0.01569
Const a5 = -0.05165
Const a6 = 0.5475
Const a7 = -0.7361
Const a8 = 0.1844
Const a9 = 0.1056
Const a10 = 0.6134
Const a11 = 0.721

Dim m1, m2, m3, m4 As Double

m1 = a1 + a2 / tpr + a3 / (tpr ^ 3) + a4 / (tpr ^ 4) + a5 / (tpr ^ 5)
m2 = a6 + a7 / tpr + a8 / tpr / tpr
m3 = a9 * (a7 / tpr + a8 / tpr / tpr)

ef = m1 * ror + m2 * (ror ^ 2) - m3 * (ror ^ 5) _
    + m4 * Exp(-a11 * (ror ^ 2)) + 1 - 0.27 * ppr / tpr / ror

End Function
```

```
Public Sub dividemethod()
```
/ code for the Newton Raphson iteration method

```
Dim n1, n2, nm  As Double

n1 = 0.00001
n2 = 1.5
nm = (n1 + n2) / 2

Do
   If (ef(n1) * ef(nm)) < 0 Then
                        n1 = n1
 nm = (n1 + n2) / 2
     Else:     n1 = nm
              n2 = n2
             nm = (n1 + n2) / 2
    End If
 Loop Until Abs(ef(n1)) < 0.0001

 ror = n1
 z = 0.27 * ppr / tpr / ror

End Sub
```

```
Public Sub deanstiel()
```
/ code for calculating the Viscaosity using Dean-Stiel Method

```
Const b1 = 0.00034
Const b2 = 0.001668
Const b3 = 0.000108

Dim a12, miu1, xiem, tpcra As Double

'tpcra = 1.8 * (tpc - 273.15) + 492
xiem = 5.4402 * (tpc ^ (1 / 6)) / (mwa ^ 0.5) / ((ppc) ^ (2 / 3))
If tpr <= 1.5 Then
  miu1 = b1 * ((tpr) ^ (8 / 9)) / xiem
 Else
  a12 = (0.1333 * tpr - 0.0932) ^ (5 / 9)
  miu1 = b2 * a12 / xiem
End If
miug = miu1 + b3 * (Exp(1.439 * ror) - Exp(-1.111 * (ror ^ 1.888))) / xiem

End Sub
```

```
Public Sub fcg()
```
/ function code for calculating the gas compressibility

```
Const a1 = 0.3265
Const a2 = -1.07
Const a3 = -0.5339
Const a4 = 0.01569
Const a5 = -0.05165
Const a6 = 0.5475
```

```
Const a7 = -0.7361
Const a8 = 0.1844
Const a9 = 0.1056
Const a10 = 0.6134
Const a11 = 0.721

Dim m11, m21, m31, m41, dzdror As Double
```

```
m11 = a1 + a2 / tpr + a3 / (tpr ^ 3) + a4 / (tpr ^ 4) + a5 / (tpr ^ 5)
m21 = a6 + a7 / tpr + a8 / tpr / tpr
m41 = a10 * 2 * ror * (1 + a11 * (ror ^ 2) - (a11 ^ 2) * (ror ^ 4)) / (tpr ^ 3)

dzdror = m11 + 2 * m21 * ror - 5 * m31 * (ror ^ 4) _
     + m41 * Exp(-a11 * (ror ^ 2))

cgg = (1 / ppr - 0.27 / (z ^ 2) / tpr * (dzdror / (1 + dzdror * ror / z))) / ppc


End Sub
```

MAIN BODY OF THE PROGRAM

Private Sub Command1_Click()   ***/ code for the command CALCULATE button***

```
gama = Val(txtgama.Text)
por = Val(txtpor.Text)
tz = Val(txttz.Text)
prodt = Val(txtprodt.Text)
h = Val(txth.Text)
rw = Val(txtrw.Text)
q = Val(txtq.Text)
prodt = Val(txtprodt.Text)

mwa = gama * 28.96
ppc = 709.605 - 58.718 * gama
tpc = 170.491 + 307.344 * gama
tpr = (tz + 460) / tpc

pp(0) = 0
For i = 1 To 7000 Step 1
SSPanel1.FloodPercent = (i / 7000) * 100
   pp(i) = pp(i - 1) + 1
   ppr = pp(i) / ppc
    dividemethod
    fcg
 cg(i) = cgg
    zi(i) = z
    miu(i) = miug
    mp2(i) = 2 * pp(i) / miu(i) / zi(i)

    If i = 1 Then
      mpp(i) = mp2(i) / 2
      ipp(i) = miu(i) * cg(i) / 2
```

```
      Else
      mpp(i) = mpp(i - 1) + (mp2(i) + mp2(i - 1)) / 2
      ipp(i) = ipp(i - 1) + (1 / miu(i) / cg(i) + 1 / miu(i - 1) / cg(i - 1)) / 2
    End If
Next

For j = 1 To counterf Step 1
   For i = 1 To 7000 Step 1
    If pp(i) = p(j) Then
      ip(j) = ipp(i)
      zii(j) = zi(i)
    End If

    If i = 1 Then
      tp(j) = 0
    Else
   tp(j) = tp(j - 1) + (t(j) - t(j - 1)) / (p(j) - p(j - 1)) * (ip(j) - ip(j - 1))
  End If
 Next
Next

grddata.Col = 3
For j = 1 To counterf Step 1
grddata.Row = j
grddata.Text = Format(mp(j), "#####.#")
Next
grddata.Col = 4
For j = 1 To counterf Step 1
grddata.Row = j
grddata.Text = Format(tp(j), "######.#")
Next

Open "A:\res391.txt" For Output As #2
Print #2, "pressure     Z - factor     Pseodopress       ip       Pseudotime"
For j = 1 To counterf Step 1
Print #2, p(j), "", zii(j), "", mp(j), "", ip(j), "", tp(j)
'Print #2, zi(3150), "", miu(3150), "", cg(3150)
Close #2

End Sub
```

```
Private Sub Form_Load()
```

<u>/ code for setting the dimensions of the table</u>

```
For i = 0 To 69 Step 1
grddata.Row = i
grddata.ColWidth(0) = 250
grddata.ColWidth(2) = 600
grddata.ColWidth(3) = 800
grddata.ColWidth(4) = 820
Next

grddata.Col = 0
grddata.Row = 0
grddata.Text = "No."
For i = 1 To 68 Step 1
```

```
grddata.Row = i
grddata.Text = Format(i, " ##")
Next

End Sub
```

```
Private Sub mnuexit_Click()
End
End Sub
```

<u>/ code for the Exit submenu</u>

```
Private Sub mnuopen_Click()

Dim filter As String

filter = "All Files (*.*)|*.*|"
filter = filter + "Text Files (*.txt)|*.txt|"
filter = filter + "Excel Files (*.xls|*.xls|"
CommonDialog1.FilterIndex = 2
CommonDialog1.Action = 1

End Sub
```

<u>/code for the Open submenu - open the input file</u>

```
Private Sub mnustimport_Click()

Open CommonDialog1.filename For Input As 1
Counter = 1
i = 1
Do While Not EOF(1)
Input #1, t(i), p(i)
i = i + 1
Counter = Counter + 1
Loop
counterf = Counter - 1
Close #1

grddata.Col = 1
For i = 1 To counterf Step 1
grddata.Row = i
grddata.Text = Format(t(i), "##0.#0")
Next

grddata.Col = 2
For i = 1 To counterf Step 1
grddata.Text = Format(p(i), " ####")
Next

Command1.Enabled = True

End Sub
```

<u>/code for the Import submenu- importing the data from input file</u>

PROGRAM 2: GAS PERFORMANCE PREDICTION

```
Option Explicit

Private c1(12) As Double
Private agas_pvt As PVT
Private azfact As Double, abg As Double
Private flag_gas_option As Boolean
Private graph(3000, 2) As Double

Private Sub cmdcalculate_Click()

Dim atemp As Double, apress As Double, step_press As Double
Dim acg_gas As Double, avisc As Double, a_mpp As Double
Dim i1 As Double, mp2() As Double

calculate_gas_pvt
atemp = Val(txtatemperature.Text)
step_press = Val(txtsteppressure.Text)
With msfgridgaspvt
.Rows = (Val(txtinitialpressure.Text) - Val(txtfinalpressure.Text)) / step_press + 2
ReDim mp2(.Rows) As Double
i1 = 1
apress = Val(txtfinalpressure.Text)
prgbarg.Min = 1
prgbarg.max = .Rows

Do
  azfact = agas_pvt.Z_Factor(atemp, apress, agas_pvt.Pseudo_Critical_Temp _
                , agas_pvt.Pseudo_Critical_Press)
  acg_gas = agas_pvt.Gas_Compressibility_Cg(agas_pvt.Pseudo_Reduced_Temp _
            , agas_pvt.Pseudo_Reduced_Press, agas_pvt.Pseudo_Critical_Press, azfact)
  avisc = agas_pvt.Gas_Viscosity(azfact)

  .TextMatrix(i1, 0) = Format(i1, "#")
  .TextMatrix(i1, 1) = Format(apress, "#####.#0")
  .TextMatrix(i1, 2) = Format(azfact, "0.####")
  .TextMatrix(i1, 3) = Format(abg, "0.#####")
  .TextMatrix(i1, 4) = Format(avisc, "0.#####")
  .TextMatrix(i1, 5) = Format(acg_gas, "0.#####")

  mp2(i1) = 2 * apress / avisc / azfact
    If i1 = 1 Then
      a_mpp = mp2(i1) / 2
    Else
      a_mpp = .TextMatrix(i1 - 1, 6) + (mp2(i1) + mp2(i1 - 1)) / 2
    End If
  .TextMatrix(i1, 6) = Format(a_mpp, "#0.##")

  apress = apress + step_press
  If apress <= 0 Then Exit Do
  i1 = i1 + 1
  prgbarg.Value = i1
Loop Until (apress > Val(txtinitialpressure.Text))
```

```
End With

Set agas_pvt = Nothing
Erase mp2()

End Sub

Private Sub Cmdcomposition_Click()
Dim apress As Double, atemp As Double

calculate_gas_pvt
apress = Val(txtapressure.Text)

azfact = agas_pvt.Z_Factor(atemp, apress, agas_pvt.Pseudo_Critical_Temp _
            , agas_pvt.Pseudo_Critical_Press)
abg = agas_pvt.Gas_Volume_Factor(atemp, apress, azfact)

txttpc.Text = Format(agas_pvt.Pseudo_Critical_Temp, "#0.###")
txtppc.Text = Format(agas_pvt.Pseudo_Critical_Press, "#0.###")
txttpr.Text = Format(agas_pvt.Pseudo_Reduced_Temp, "#0.###")
txtppr.Text = Format(agas_pvt.Pseudo_Reduced_Press, "#0.###")
txtzfactor.Text = Format(azfact, " #0.####")
txtbg.Text = Format(abg, " #.###e-#")
txtgasgravity.Text = Format(agas_pvt.gas_gravity, "#0.###")
Set agas_pvt = Nothing

End Sub
Private Sub calculate_gas_pvt()
Dim sum_c1 As Double, i1 As Integer, res

c1(1) = Val(Txtc1.Text):    c1(2) = Val(Txtc2.Text):    c1(3) = Val(Txtc3.Text)
c1(4) = Val(Txtic4.Text):   c1(5) = Val(txtnc4.Text):   c1(6) = Val(Txtic5.Text)
c1(7) = Val(txtnc5.Text):   c1(8) = Val(txtc6.Text):    c1(9) = Val(txtc7.Text)
c1(10) = Val(txtn2.Text):   c1(11) = Val(txtco2.Text):  c1(12) = Val(txth2s.Text)

Set agas_pvt = New PVT

If optcomposition.Value = True Then
    sum_c1 = 0
    For i1 = 1 To 12 Step 1
        sum_c1 = sum_c1 + c1(i1)
        agas_pvt.Get_Gas_Component c1(i1), i1
    Next
    If (sum_c1 < 100) Or (sum_c1 > 100.001) Then
      MsgBox "Your composition is not corect!", vbCritical, "Gas Composition System"
      SSTab1.Tab = 0
    End If
     Txtcomposition.Text = Format(sum_c1, "#.00##")
    agas_pvt.Pseudo_Critical_Parameters_Composition
Else
  If txtgasgravity.Text = "" Then
     res = MsgBox(" You have to enter Gas Gravity !", vbCritical, "Gas Composition System")
     Txtcomposition.Text = Format(100, "#.00##")
     Exit Sub
  Else:   agas_pvt.gas_gravity = Val(txtgasgravity.Text)
```

```
    End If
       If optnaturalgas.Value = True Then
          agas_pvt.Pseudo_Critical_Param_Correl_Natural_Gas agas_pvt.gas_gravity
       Else
          agas_pvt.Pseudo_Critical_Param_Correl_Gas_Condensat agas_pvt.gas_gravity
       End If
End If

gas_Pseudo_Critical_Press = agas_pvt.Pseudo_Critical_Press
gas_Pseudo_Critical_Temp = agas_pvt.Pseudo_Critical_Temp
gas_gas_gravity = agas_pvt.gas_gravity
gas_Mwa = agas_pvt.mwa

End Sub

Private Sub cmdbacke_Click()
End Sub
Private Sub Cmdcontinuee_Click()

GasComposition.Hide
calculate_gas_pvt
GasDryReservoir.Show

End Sub

Private Sub Form_Load()
Dim intloopindex As Integer, k_col As Integer

Flag_gas_composition = True
With msfgridgaspvt
   For intloopindex = .FixedRows To .Rows - 1
      .TextArray(.Cols * intloopindex) = Format(intloopindex, "      #")
   Next

   .RowHeight(0) = 650
   .WordWrap = True
   .Row = 0
   For k_col = 0 To 5 Step 1
       .ColAlignment(k_col) = 3
       .ColWidth(k_col) = 1100
   Next
      .ColAlignment(6) = 3
      .ColWidth(0) = 900:    .ColWidth(1) = 900: .ColWidth(2) = 880:
      .Col = 0:    .Text = "Criteria Number":                        .CellAlignment = 5
      .Col = 1:    .Text = "Pressure, psi":                          .CellAlignment = 5
      .Col = 2:    .Text = "Z-Factor":                               .CellAlignment = 5
      .Col = 3:    .Text = "Gas Volume Factor, BBL/SCF ":            .CellAlignment = 5
      .Col = 4:    .Text = "Gas Viscosity, cp":                      .CellAlignment = 5
      .Col = 5:    .Text = "Gas Compressibility Factor, SCF/ft^3 ":  .CellAlignment = 5
      .Col = 6:    .Text = "Pseudo-Pressure m(P), psia^2/cp ":       .CellAlignment = 5
      .ColWidth(5) = 1560: .ColWidth(6) = 1500
End With

End Sub

Private Sub SSTab1_Click(PreviousTab As Integer)
```

```
Cmdcomposition_Click
End Sub

Option Explicit
Private Gi As Double, Qi As Double, Fndi As Double, Xi As Double
Private A As Double, B As Double, No_Wells As Double
Private Pipe_lenght As Double, Pipe_diam As Double, Pipe_press As Double
Private Depth As Double, Tubing_diam As Double
Private Res_Press As Double, pwf As Double, Surf_Press As Double
Private Res_Temp As Double, Surf_Temp As Double
Private zi() As Double, mpp() As Double

Private Qg(100) As Double, Qgaverage(100) As Double, Qgdaily(100) As Double
Private Actual_press(100) As Double, Recovery_fact(100) As Double
Private Cum_Gp(100) As Double, Delta_Gp(100) As Double
Private Time As Integer, Cum_Time(100) As Double
Private P_tubing(100) As Double, Pipe_line(100)
Private Pizi As Double, Ppz As Double
Private mp_actual(100) As Double, mp_Time_t(100) As Double

Private gas_param As PVT

Private Sub cmdRun_dpconstant_Click()

Dim max As Integer, i As Integer, i1 As Integer
Dim Delta_press_bottom_hole As Double
Dim ppza As Double
Dim Temp_tg As Double, Temp_average_surface As Double, res
Dim mp_pwf(100) As Double, actual_pwf(100) As Double

Res_Temp = Val(MainGas.txtrestemp.Text)
Surf_Temp = Val(MainGas.txtsurfacetemp.Text)
Res_Press = Val(MainGas.txtgasrespressure.Text)
Depth = Val(MainGas.txttubinglenght.Text)
Tubing_diam = Val(MainGas.txttubingdiameter.Text)
Pipe_diam = Val(MainGas.txtpipediameter.Text)
Pipe_lenght = Val(MainGas.txtpipelenght.Text)
Pipe_press = Val(MainGas.txtpipepressure.Text)
Gi = Val(MainGas.txtGi.Text)
Qi = Val(MainGas.txtQi.Text)
Delta_Gp(0) = Val(MainGas.txtgasproduced.Text)
No_Wells = Val(MainGas.txtnowells.Text)
A = Val(txta.Text):     B = Val(txtb.Text)

If A = 0 Or B = 0 Then
   res = MsgBox("Deliverability Ecuation Coefficients has not been entered !", vbCritical, " Main
Gas ")
   Exit Sub
End If

Set gas_param = New PVT
gas_param.Pseudo_Critical_Press = gas_Pseudo_Critical_Press
gas_param.Pseudo_Critical_Temp = gas_Pseudo_Critical_Temp
gas_param.gas_gravity = gas_gas_gravity
gas_param.mwa = gas_Mwa
```

```
Pizi = Res_Press / gas_param.Z_Factor(Res_Temp, Res_Press, gas_param.Pseudo_Critical_Temp _
        , gas_param.Pseudo_Critical_Press)
mp_Time_t(1) = mpp(Res_Press)
Actual_press(0) = Res_Press
If Val(MainGas.txtgasproduced.Text) > 1 Then
  i = 0
  Recovery_fact(i) = Delta_Gp(i) / Gi
  Ppz = Pizi * (1 - Recovery_fact(i))
  Actual_press(i) = Res_Press
  Do
    Actual_press(i) = Actual_press(i) - 8
    ppza = Actual_press(i) / gas_param.Z_Factor(Res_Temp, Actual_press(i), gas_param.Pseudo_Critical_Temp _
        , gas_param.Pseudo_Critical_Press)
  Loop Until Abs(Ppz - ppza) < 10
  mp_Time_t(1) = mpp(Int(Actual_press(i)))
End If

Cum_Time(0) = 0:  Time = 1
i = 1
Qgdaily(1) = Val(txtaa.Text)
Do
  prgbarrun.Value = i
  Qg(i) = Qgdaily(1) * 30.4
  Delta_press_bottom_hole = A * Qg(i) / 30.4 + B * (Qg(i) / 30.4) ^ 2
  mp_pwf(i) = mp_Time_t(i) - Delta_press_bottom_hole
  If mp_pwf(i) < 0 Then
    res = MsgBox(" The deliverability coefficiets must be changed", vbCritical, " Program")
    Exit Do
  End If
  Qgaverage(i) = Qg(i)
  Qgdaily(i) = Qgaverage(i) / 30.4
  Delta_Gp(i) = Delta_Gp(i - 1) + Qg(i) * Time
  Ppz = Pizi * (1 - Recovery_fact(i))
  Actual_press(i) = Actual_press(i - 1)
  Do
     Actual_press(i) = Actual_press(i) - 2
     ppza = Actual_press(i) / gas_param.Z_Factor(Res_Temp, Actual_press(i), gas_param.Pseudo_Critical_Temp _
        , gas_param.Pseudo_Critical_Press)
  Loop Until Abs(Ppz - ppza) < 3

  For i1 = 1 To Res_Press Step 1
    If i1 = Int(Actual_press(i)) Then mp_actual(i) = mpp(i1)
    If (mpp(i1) < mp_pwf(i)) And (mp_pwf(i) < mpp(i1 + 1)) Then actual_pwf(i) = i1
  Next

  Cum_Time(i) = Cum_Time(i - 1) + Time
  If actual_pwf(i) < 100 Then Exit Do
  i = i + 1
  If i > 100 Then Exit Do
  mp_Time_t(i) = mp_actual(i - 1)
prgbarrun.Value = 100
max = i - 1
Temp_tg = (Res_Temp + Surf_Temp) / 2
```

```
Temp_average_surface = (520 + Surf_Temp + 460) / 2

For i = 1 To max Step 1
   prgbarrun.Value = i
   P_tubing(i) = Flowing_Pressure_Wellhead(Temp_tg, actual_pwf(i), Qg(i) / 30.4)
Next
   prgbarrun.Value = 100

With msfgridgasres
   .Rows = 2
   .Rows = max + 2
   For i = 0 To 9 Step 1
      .ColAlignment(i) = 3
   Next
   For i = 1 To (max) Step 1
     .TextMatrix(i, 0) = Format(Cum_Time(i), "     #"):
     .TextMatrix(i, 1) = Format(Qgdaily(i) * 1000, "#0.0"):        .CellAlignment = 6
     .TextMatrix(i, 2) = Format(Qgaverage(i) * 1000, "#0.0"):      .CellAlignment = 6
     .TextMatrix(i, 3) = Format(Delta_Gp(i), "#0.#0"):             .CellAlignment = 6
     .TextMatrix(i, 4) = Format(Actual_press(i - 1), "#0"):        .CellAlignment = 6
     .TextMatrix(i, 5) = Format(actual_pwf(i), "#0"):              .CellAlignment = 6
     .TextMatrix(i, 6) = Format(P_tubing(i), "#0"):                .CellAlignment = 6
     .TextMatrix(i, 7) = Format(Recovery_fact(i) * 100, "#0"):     .CellAlignment = 6
     .TextMatrix(i, 8) = Format(mp_Time_t(i), "#0.#0"):            .CellAlignment = 6
     .TextMatrix(i, 9) = Format(mp_pwf(i), "#0.#0"):               .CellAlignment = 6
   Next
End With

Open "c:\pnge295gas.txt" For Output As #1
For i = 1 To max Step 1
Print #1, Format(Cum_Time(i), "        #"), Format(Qgdaily(i), "#0.###0"), Format(Qgaverage(i),
"#0.###0"), _
 Format(P_tubing(i), "#0.#0"), Format(Recovery_fact(i), "#0.#0"), Format(mp_Time_t(i - 1),
"#0.#0"), _
       Format(mp_pwf(i), "#0.#0")
Next
Close #1


End Sub

Private Function Flowing_Pressure_Wellhead(ByVal tm As Double, ByVal pwf As Double, ByVal
Qd As Double) As Double
Dim ptgf As Double, ptgd As Double, ptgc As Double, ptgc1 As Double
Dim pm As Double, zm As Double, s As Double, s1 As Double, res

ptgf = pwf
Do
   pm = (ptgf + pwf) / 2
   zm = gas_param.Z_Factor(tm, pm, gas_param.Pseudo_Critical_Temp _
                , gas_param.Pseudo_Critical_Press)
   s = 2 * gas_param.gas_gravity * Depth / (53.34 * (tm + 460) * zm)
   s1 = 25 * (tm + 460) * gas_param.gas_gravity * zm * 0.017 * Depth * (Exp(s) - 1)
   ptgc1 = ((pwf ^ 2) - (s1 * (Qd ^ 2) / s / (Tubing_diam ^ 5)))
   If ptgc1 < 0 Then
      res = MsgBox(" Surface pressure smaller than zero ", vbCritical, " Program")
```

```
      ptgc = 0
      Exit Function
   End If
   ptgc = (ptgc1 ^ 0.5) / Exp(s)
   ptgd = ptgf:       ptgf = ptgc
Loop Until Abs(ptgd - ptgc) < 1
   Flowing_Pressure_Wellhead = ptgd

End Function

Private Function Surface_Line_Pressure(ByVal tms As Double, ByVal ptgl As Double, ByVal Qd
As Double) As Double

Dim pplf As Double, pplfd As Double, pipepc As Double
Dim pm As Double, zm As Double, s2 As Double, s3 As Double

pplf = ptgl
Do
   pm = (pplf + ptgl) / 2
   zm = gas_param.Z_Factor(tms, pm, gas_param.Pseudo_Critical_Temp _
                , gas_param.Pseudo_Critical_Press)
   s2 = (14.73 ^ 2) * gas_param.gas_gravity * (tms + 460) * Pipe_lenght
   s3 = (433.49 ^ 2) * (520 ^ 2) * (Pipe_diam ^ (16 / 3))

pplfd = pplf
   pplf = pipepc
Loop Until Abs(pplfd - pipepc) < 1
Surface_Line_Pressure = pipepc

End Function

Private Sub Form_Load()

Dim i1 As Integer

With msfgridgasres
  .ColWidth(0) = 600:   .ColWidth(1) = 900:     .ColWidth(2) = 900
  .ColWidth(3) = 900:   .ColWidth(4) = 900:     .ColWidth(5) = 900
  .ColWidth(6) = 800:   .ColWidth(7) = 800:     .ColWidth(8) = 1300
  .ColWidth(9) = 1300
   ReDim zi(GasComposition.msfgridgaspvt.Rows)
   ReDim mpp(GasComposition.msfgridgaspvt.Rows)

   For i1 = 1 To 49 Step 1
      .TextMatrix(i1, 0) = Format(i1, "   ##")
   Next
   .Row = 0:   .RowHeight(0) = 800
   .WordWrap = True
   .Col = 0:   .CellAlignment = 5:      .Text = "Time, months"
   .Col = 1:   .CellAlignment = 5:      .Text = "Flow Rate, MCF/D"
   .Col = 2:   .CellAlignment = 5:      .Text = "Gas Produced MCF per month"
   .Col = 3:   .CellAlignment = 5:      .Text = "Total Gas Produced, MMCF"
   .Col = 4:   .CellAlignment = 5:      .Text = "Reservoir Pressure, psia"
   .Col = 5:   .CellAlignment = 5:      .Text = "Well Flowing Pressure, psia"
   .Col = 6:   .CellAlignment = 5:      .Text = "Wellhead Pressure, psia"
   .Col = 7:   .CellAlignment = 5:      .Text = "Recovery Factor, %"
```

```
    .Col = 8:   .CellAlignment = 5:      .Text = "Reservoir Pseudo Pressure, psia^2/cp"
    .Col = 9:   .CellAlignment = 5:      .Text = "Flowing Pseudo Pressure, psia^2/cp"
End With

For i1 = 1 To GasComposition.msfgridgaspvt.Rows - 1 Step 1
    zi(i1) = Val(GasComposition.msfgridgaspvt.TextMatrix(i1, 2))
    mpp(i1) = Val(GasComposition.msfgridgaspvt.TextMatrix(i1, 6))
Next

End Sub

Private Sub cmdback_Click()
    Me.Hide
End Sub

Private Sub cmdexit_Click()
    End
End Sub
```

GIANT PANDA APPENDIX

FIGURE 1: WELL LOCATION MAP

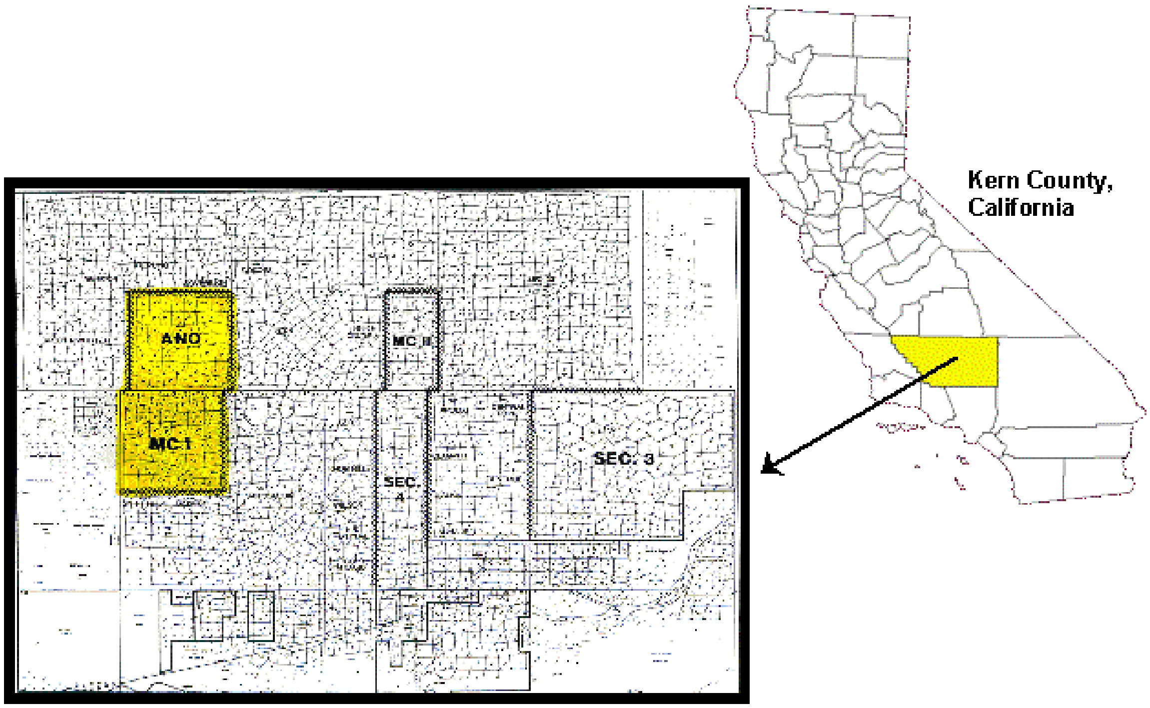
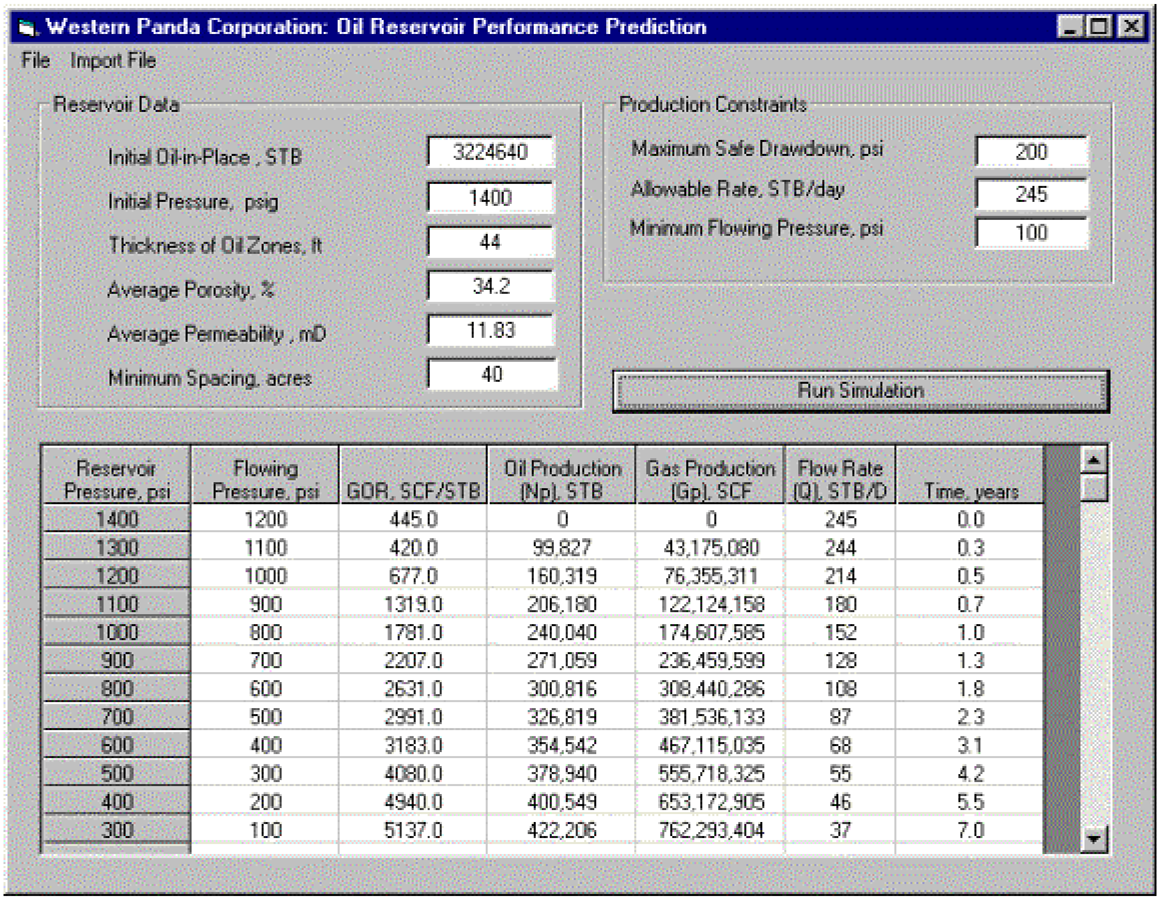
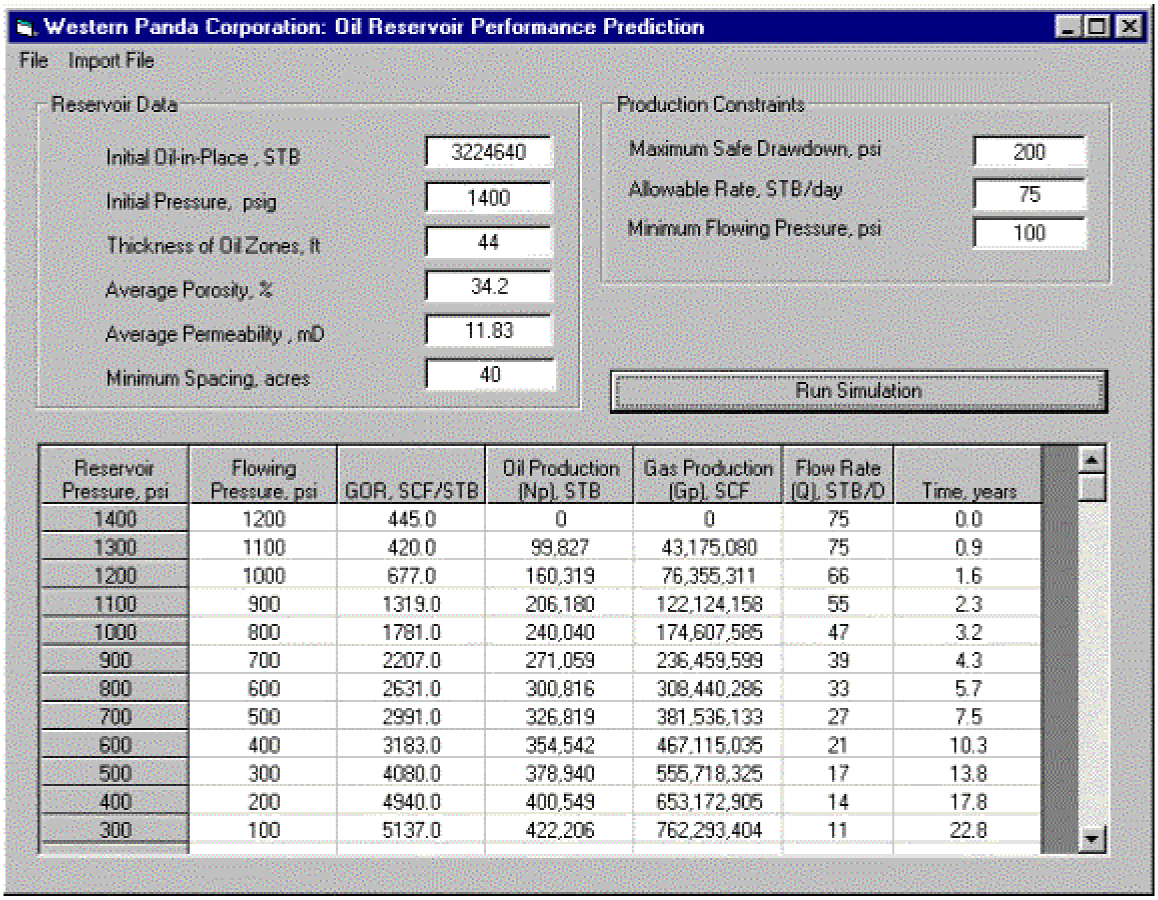


FIGURE 2: USER INTERFACE FOR MAXIMUM SCHEDULE



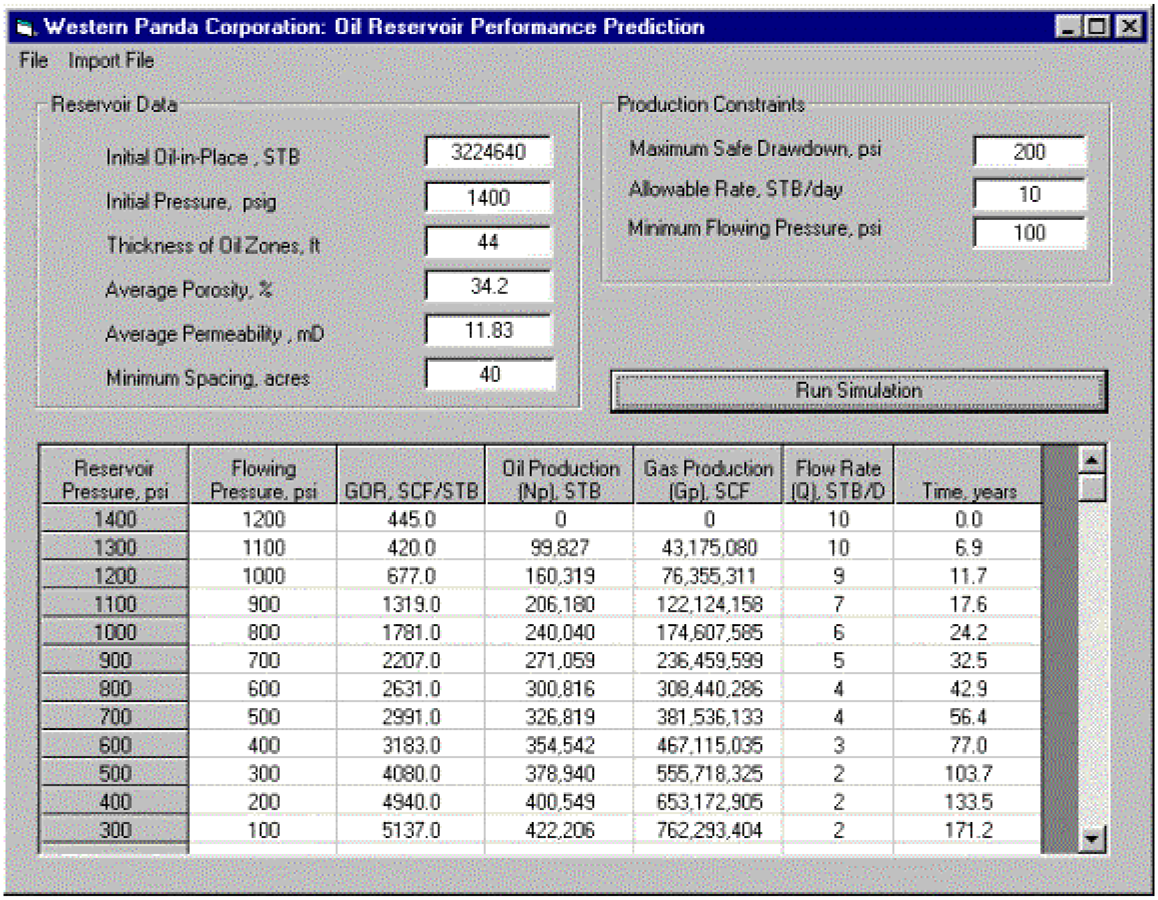
Reservoir Pressure, psi	Flowing Pressure, psi	GOR, SCF/STB	Oil Production (Np), STB	Gas Production (Gp), SCF	Flow Rate (Q), STB/D	Time, years
1400	1200	445.0	0	0	245	0.0
1300	1100	420.0	99,827	43,175,080	244	0.3
1200	1000	677.0	160,319	76,355,311	214	0.5
1100	900	1319.0	206,180	122,124,158	180	0.7
1000	800	1781.0	240,040	174,607,585	152	1.0
900	700	2207.0	271,059	236,459,599	128	1.3
800	600	2631.0	300,816	308,440,286	108	1.8
700	500	2991.0	326,819	381,536,133	87	2.3
600	400	3183.0	354,542	467,115,035	68	3.1
500	300	4080.0	378,940	555,718,325	55	4.2
400	200	4940.0	400,549	653,172,905	46	5.5
300	100	5137.0	422,206	762,293,404	37	7.0

FIGURE 3: USER INTERFACE FOR IDEAL CONSTANT SCHEDULE



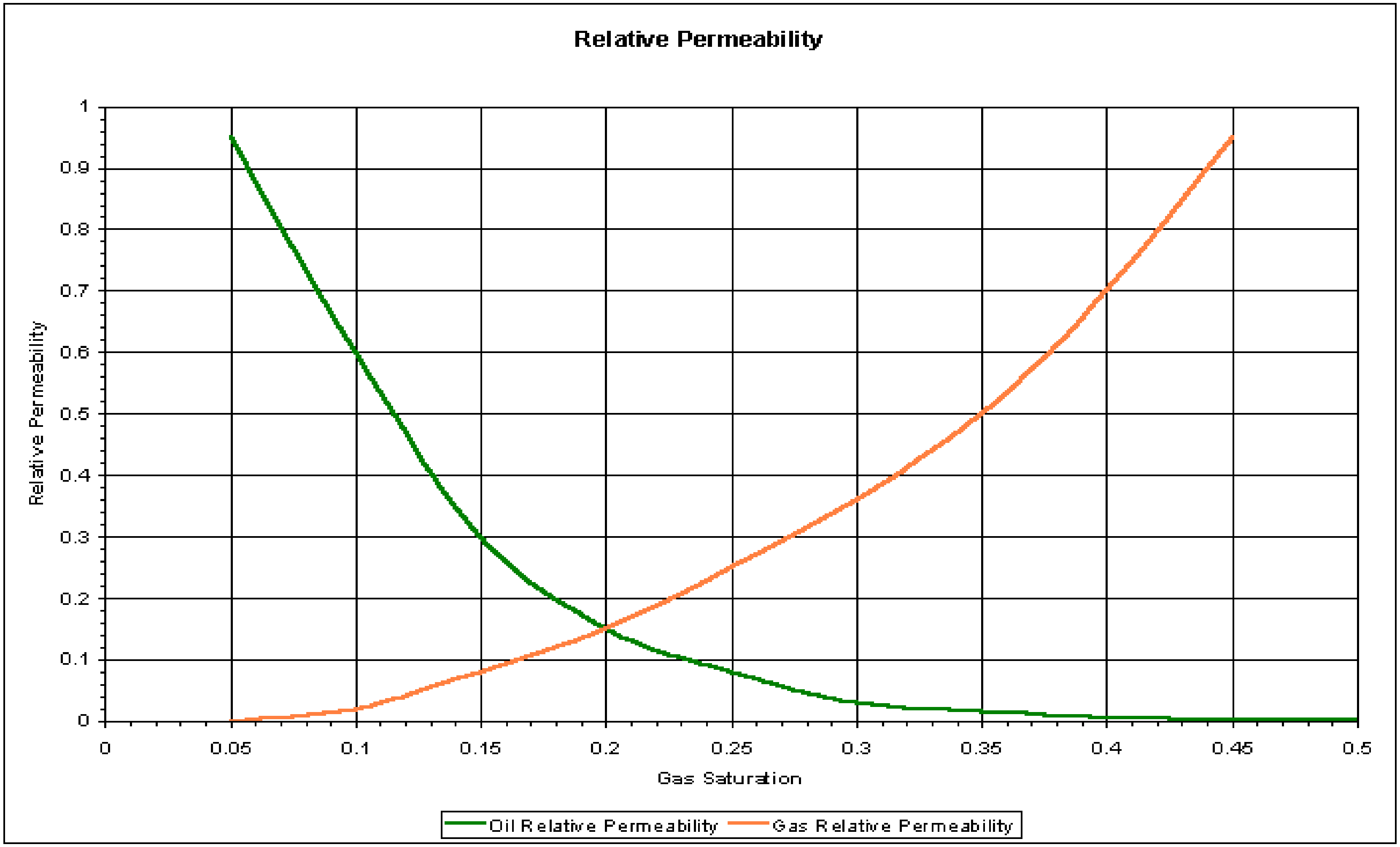
Reservoir Pressure, psi	Flowing Pressure, psi	GOR, SCF/STB	Oil Production (Np), STB	Gas Production (Gp), SCF	Flow Rate (Q), STB/D	Time, years
1400	1200	445.0	0	0	75	0.0
1300	1100	420.0	99,827	43,175,080	75	0.9
1200	1000	677.0	160,319	76,355,311	66	1.6
1100	900	1319.0	206,180	122,124,158	55	2.3
1000	800	1781.0	240,040	174,607,585	47	3.2
900	700	2207.0	271,059	236,459,599	39	4.3
800	600	2631.0	300,816	308,440,286	33	5.7
700	500	2991.0	326,819	381,536,133	27	7.5
600	400	3183.0	354,542	467,115,035	21	10.3
500	300	4080.0	378,940	555,718,325	17	13.8
400	200	4940.0	400,549	653,172,905	14	17.8
300	100	5137.0	422,206	762,293,404	11	22.8

FIGURE 4: USER INTERFACE FOR TRUE CONSTANT SCHEDULE

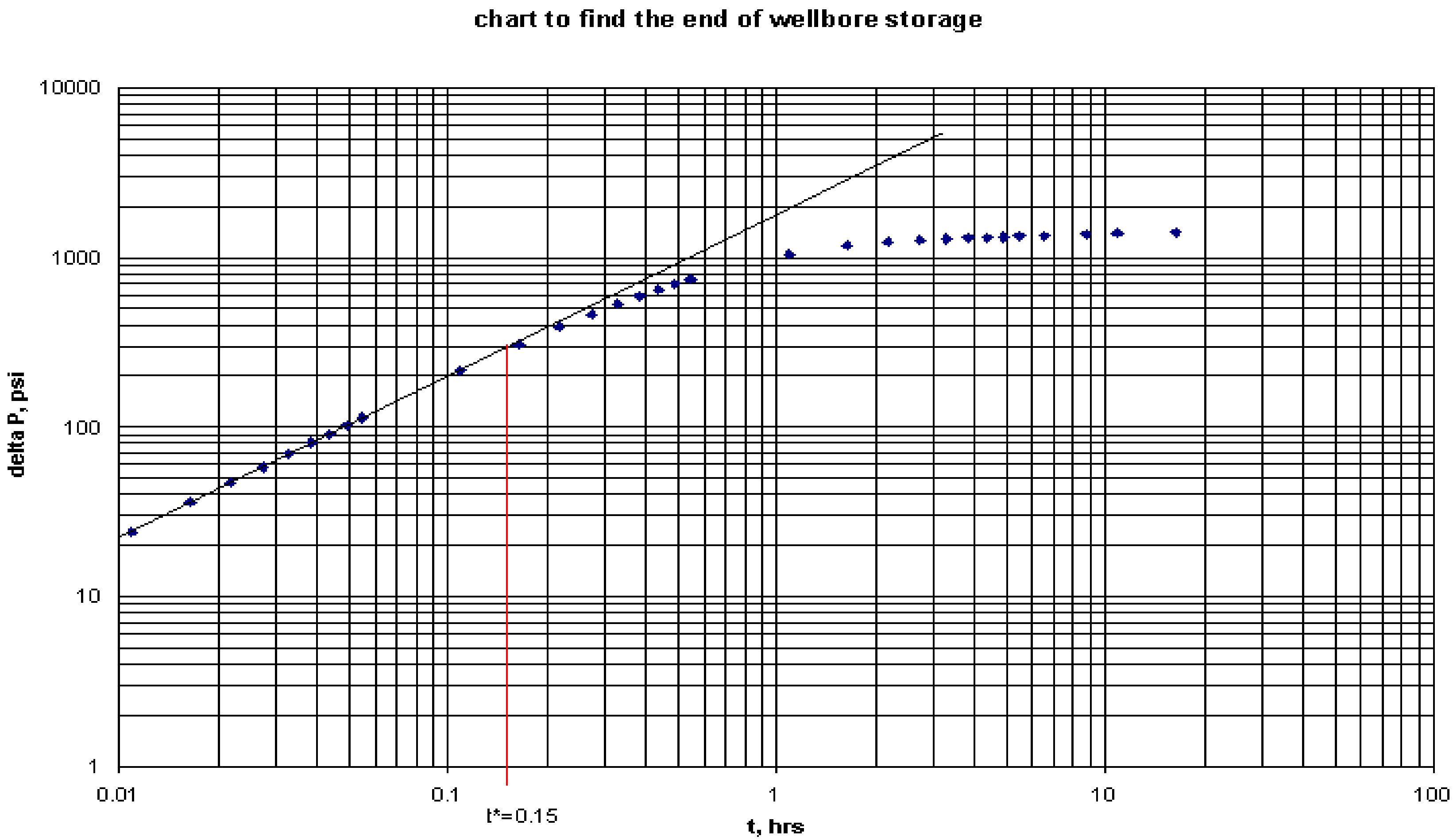


Reservoir Pressure, psi	Flowing Pressure, psi	GOR, SCF/STB	Oil Production (Np), STB	Gas Production (Gp), SCF	Flow Rate (Q), STB/D	Time, years
1400	1200	445.0	0	0	10	0.0
1300	1100	420.0	99,827	43,175,080	10	6.9
1200	1000	677.0	160,319	76,355,311	9	11.7
1100	900	1319.0	206,180	122,124,158	7	17.6
1000	800	1781.0	240,040	174,607,585	6	24.2
900	700	2207.0	271,059	236,459,599	5	32.5
800	600	2631.0	300,816	308,440,286	4	42.9
700	500	2991.0	326,819	381,536,133	4	56.4
600	400	3183.0	354,542	467,115,035	3	77.0
500	300	4080.0	378,940	555,718,325	2	103.7
400	200	4940.0	400,549	653,172,905	2	133.5
300	100	5137.0	422,206	762,293,404	2	171.2

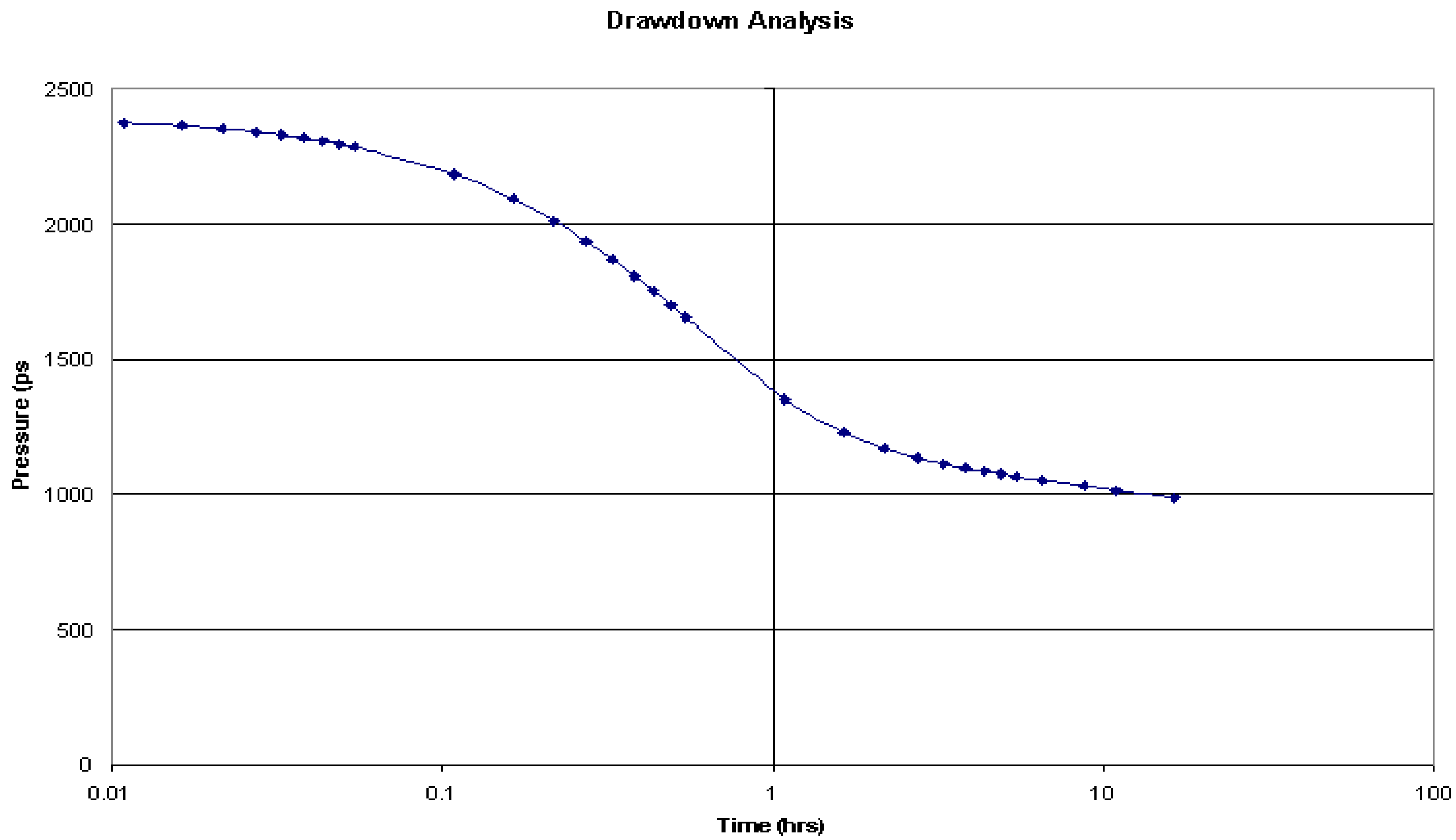
GRAPH 1: RELATIVE PERMEABILITY



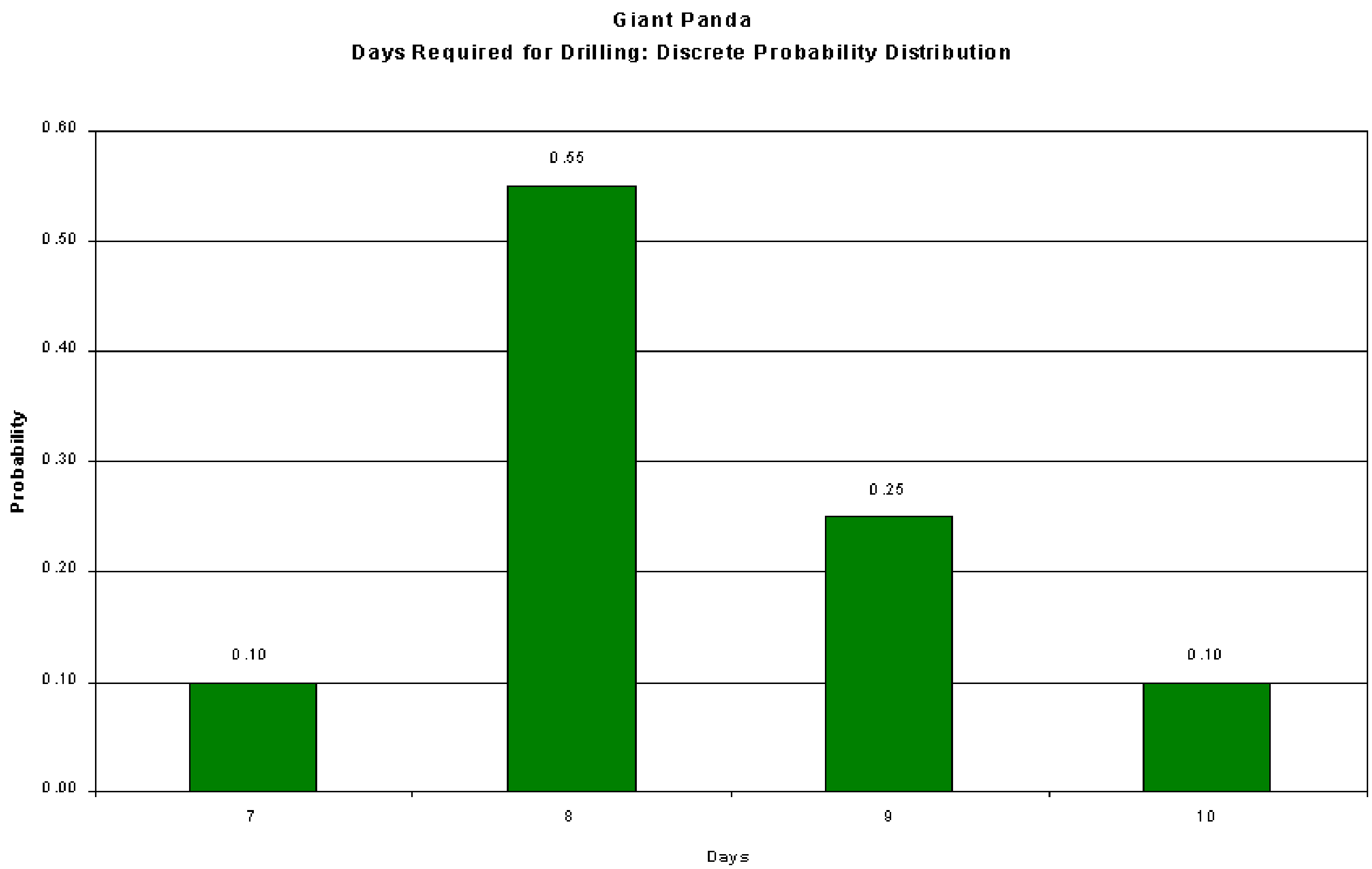
GRAPH 2: ΔP_{WF} VERSUS T



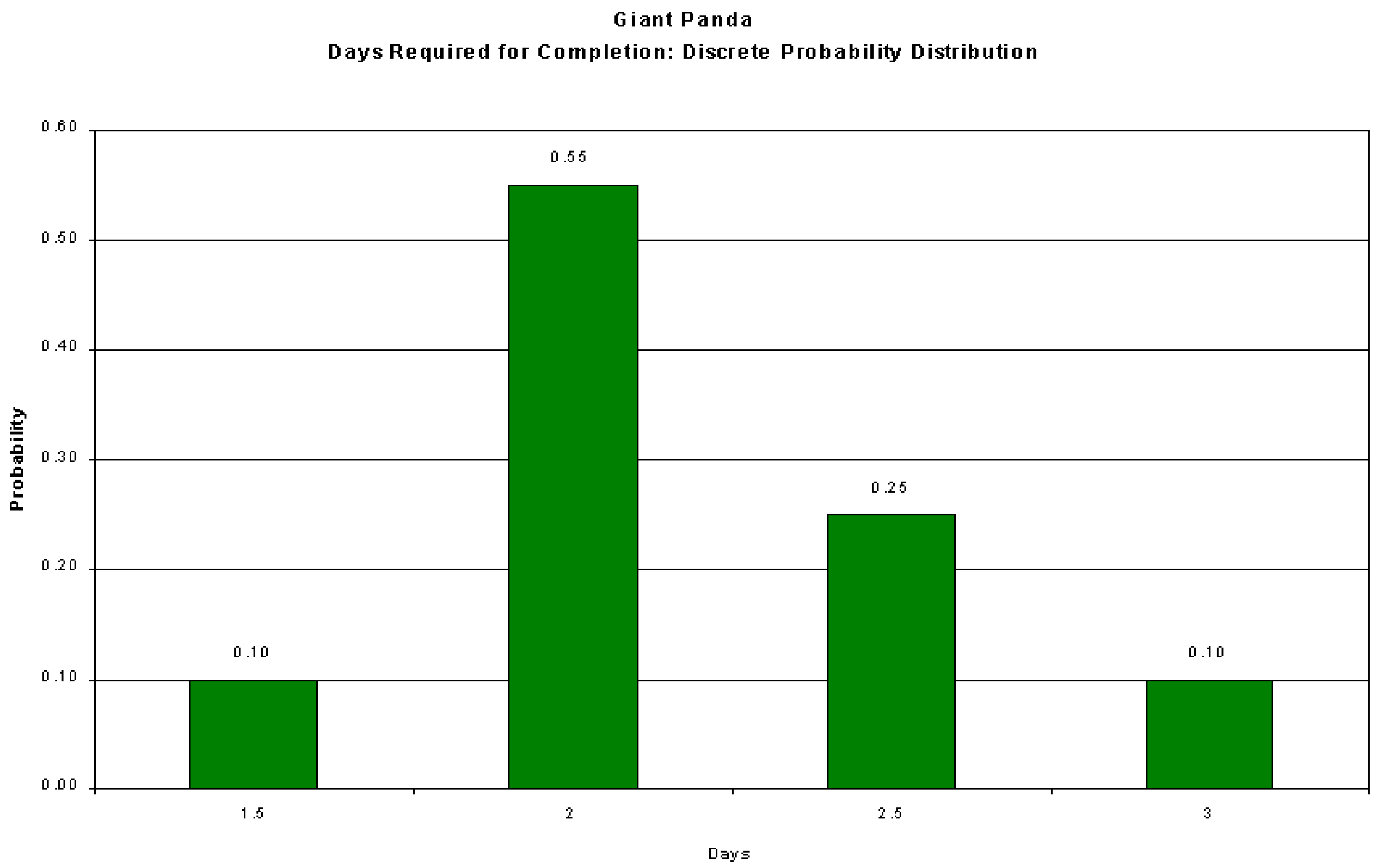
GRAPH 3: SEMI-LOG P_{WF} VERSUS T



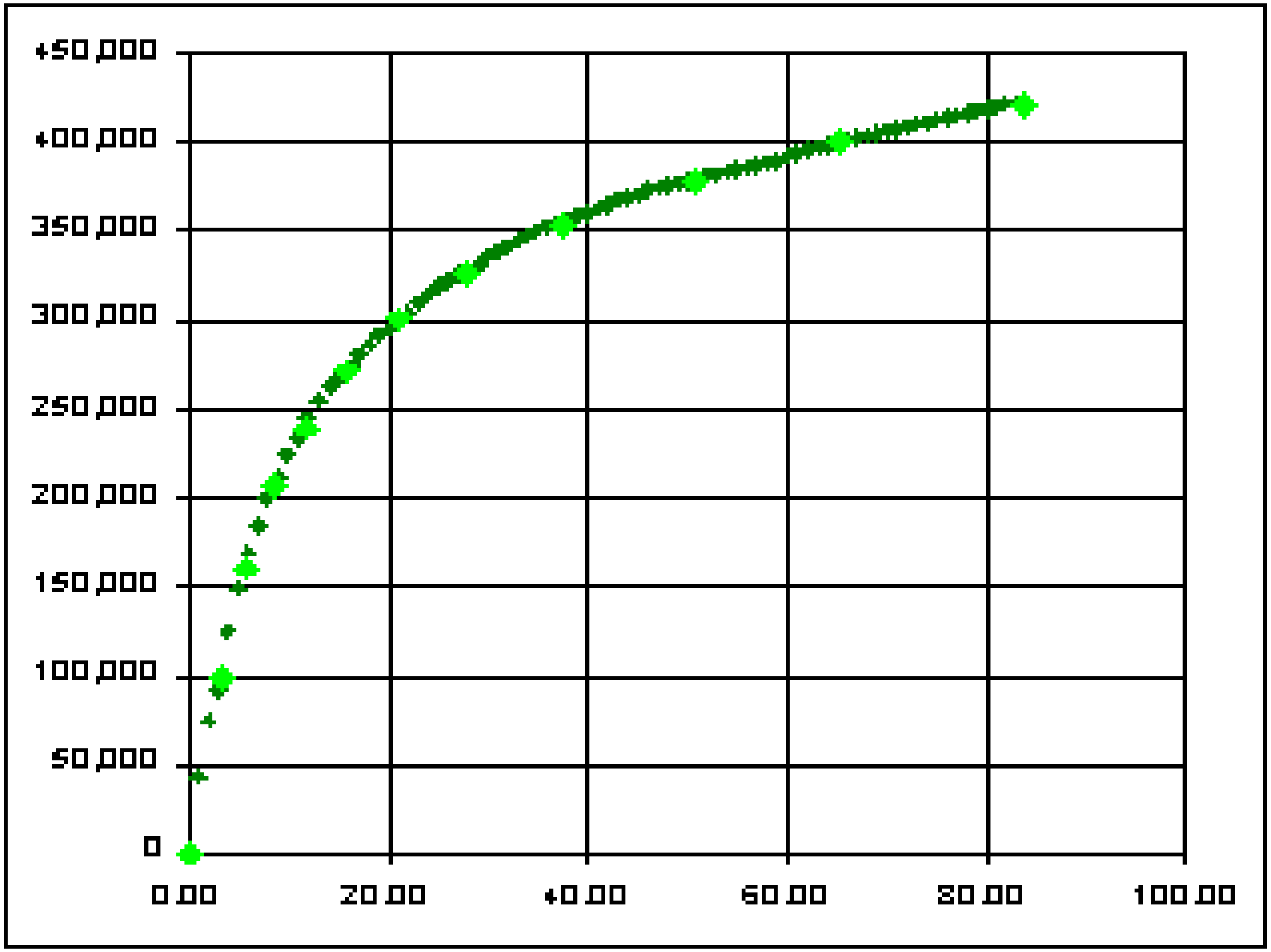
GRAPH 4: DAYS REQUIRED FOR DRILLING



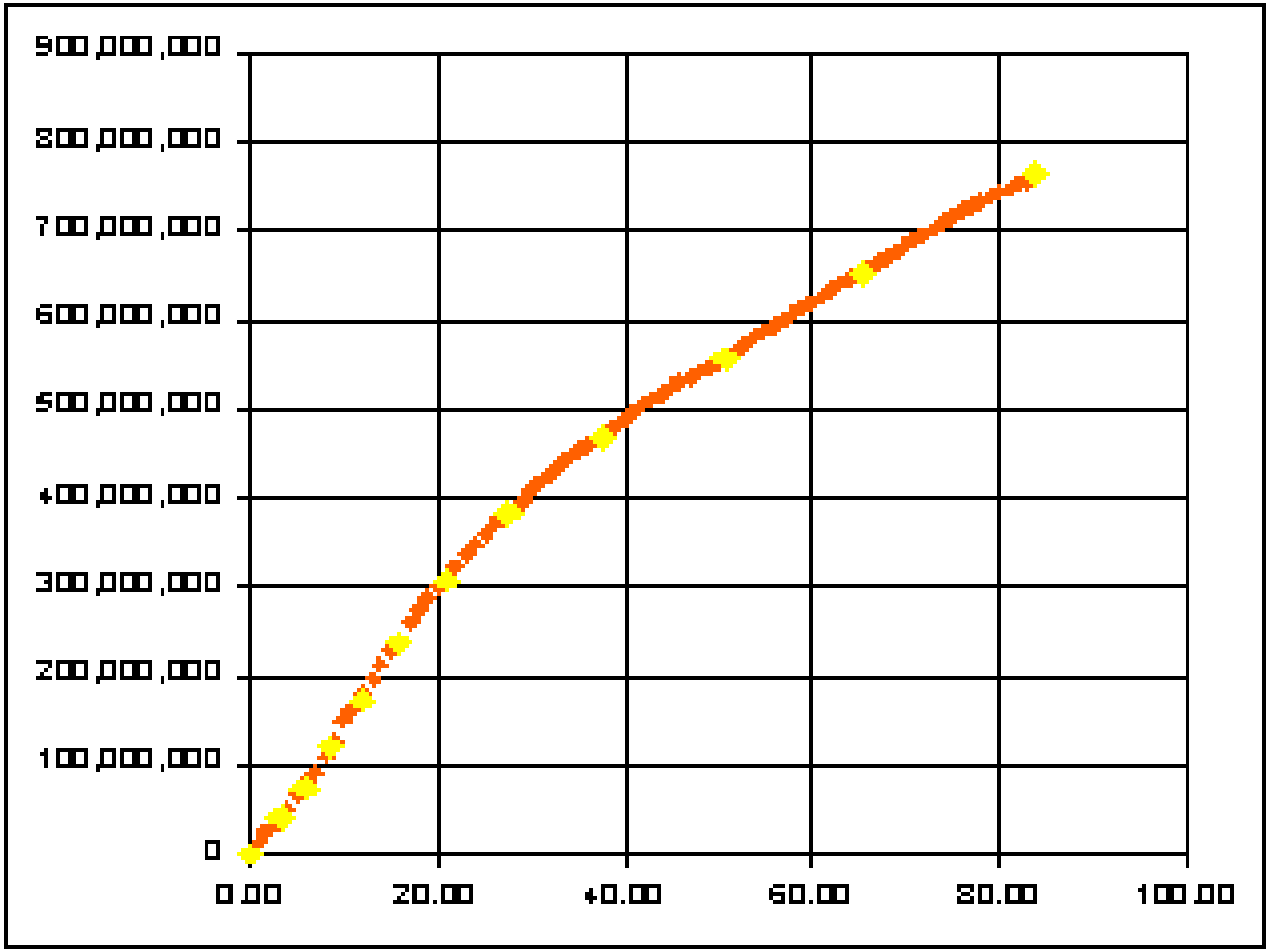
GRAPH 5: DAYS REQUIRED FOR COMPLETION



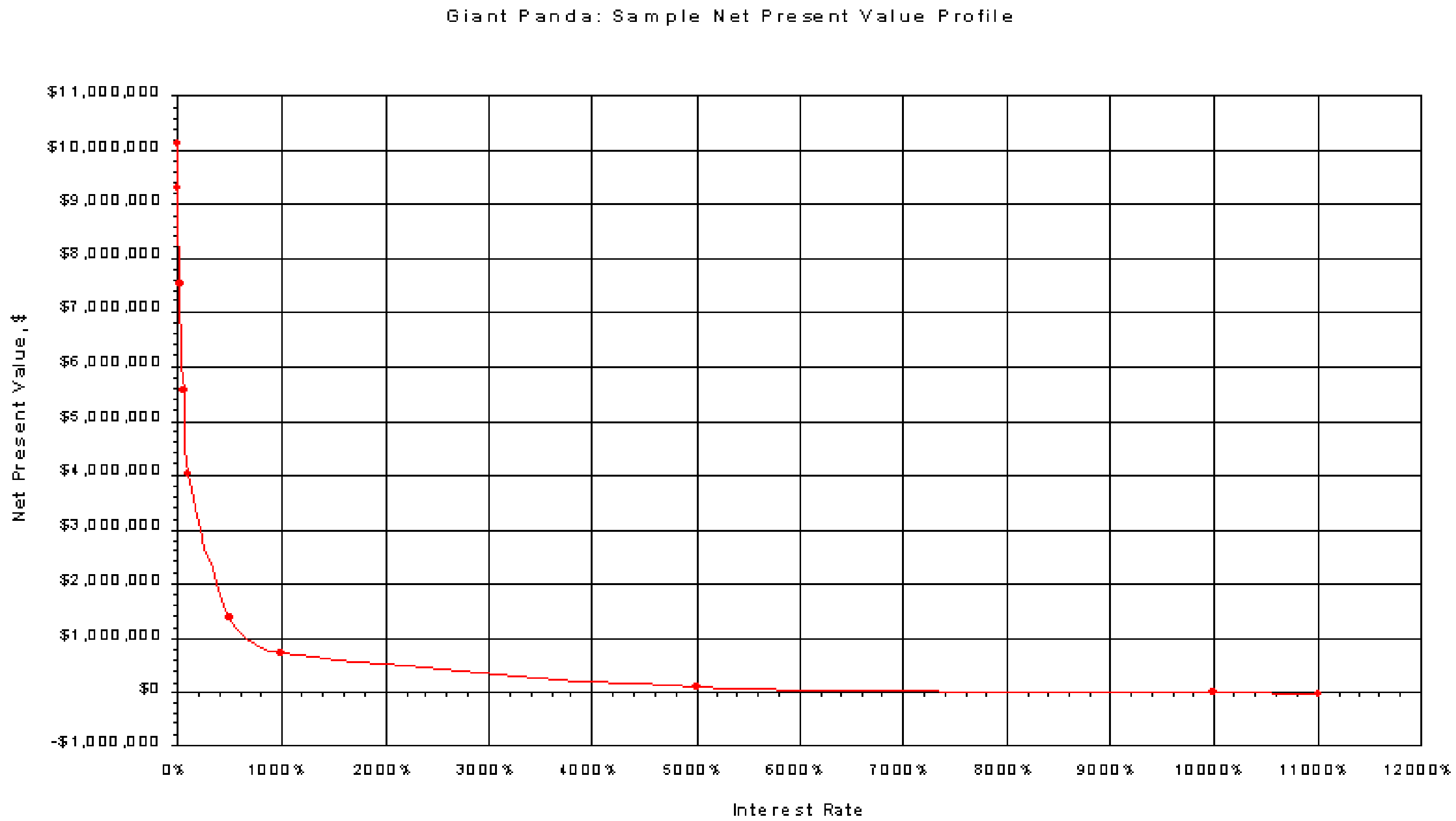
GRAPH 6: Cumulative Oil Produced



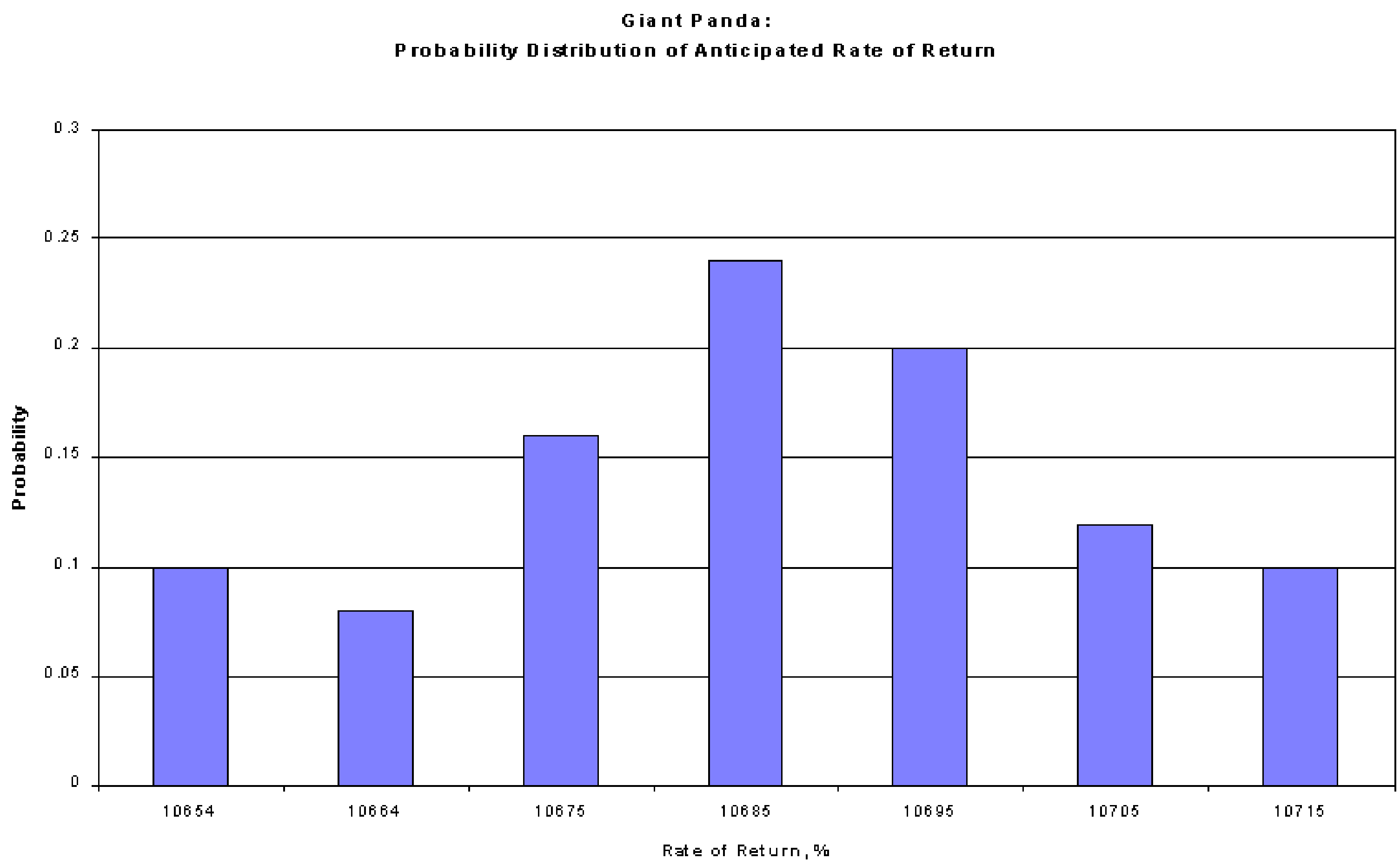
GRAPH 7: CUMULATIVE GAS PRODUCED



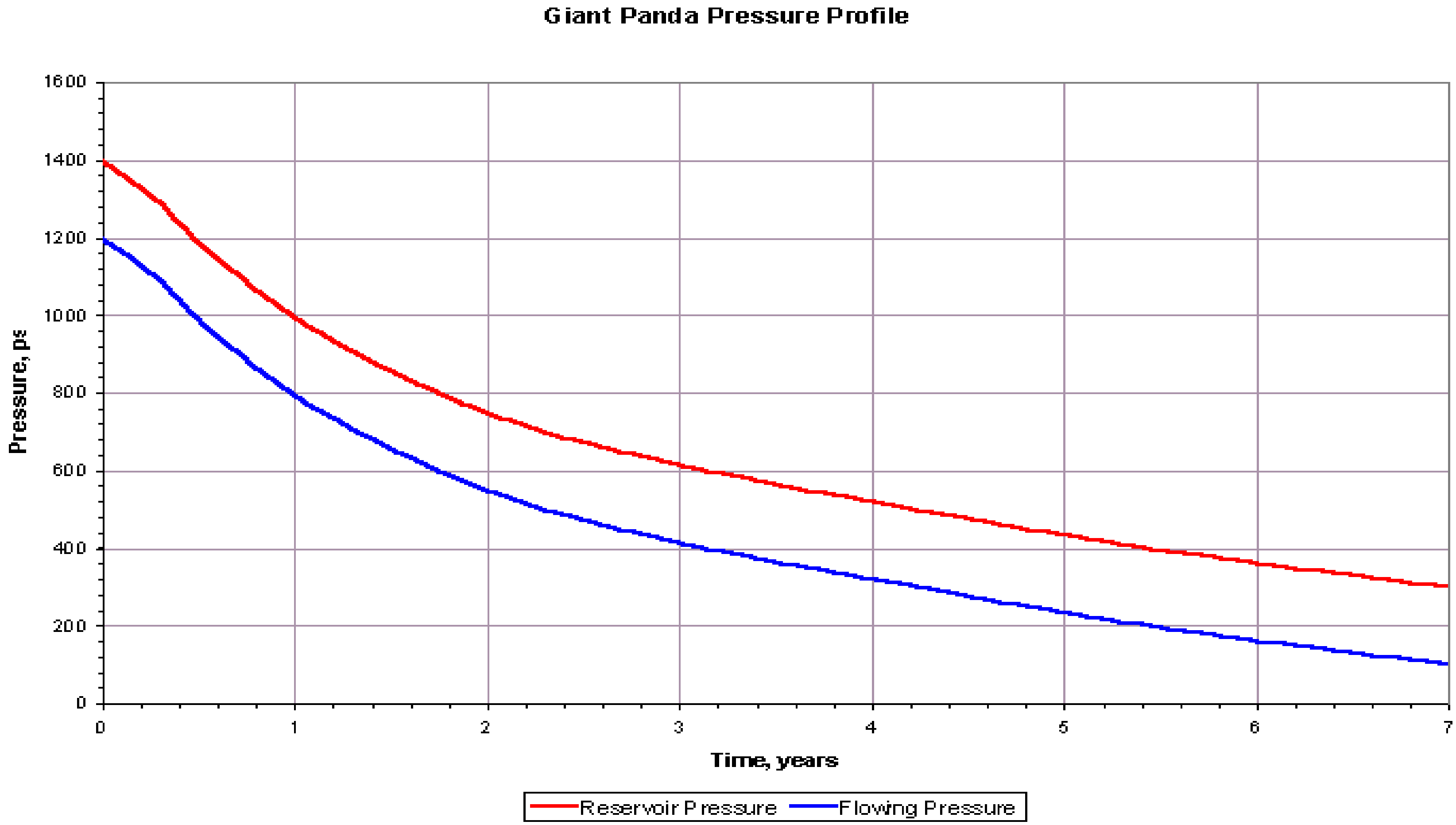
GRAPH 8: PRESENT VALUE PROFILE



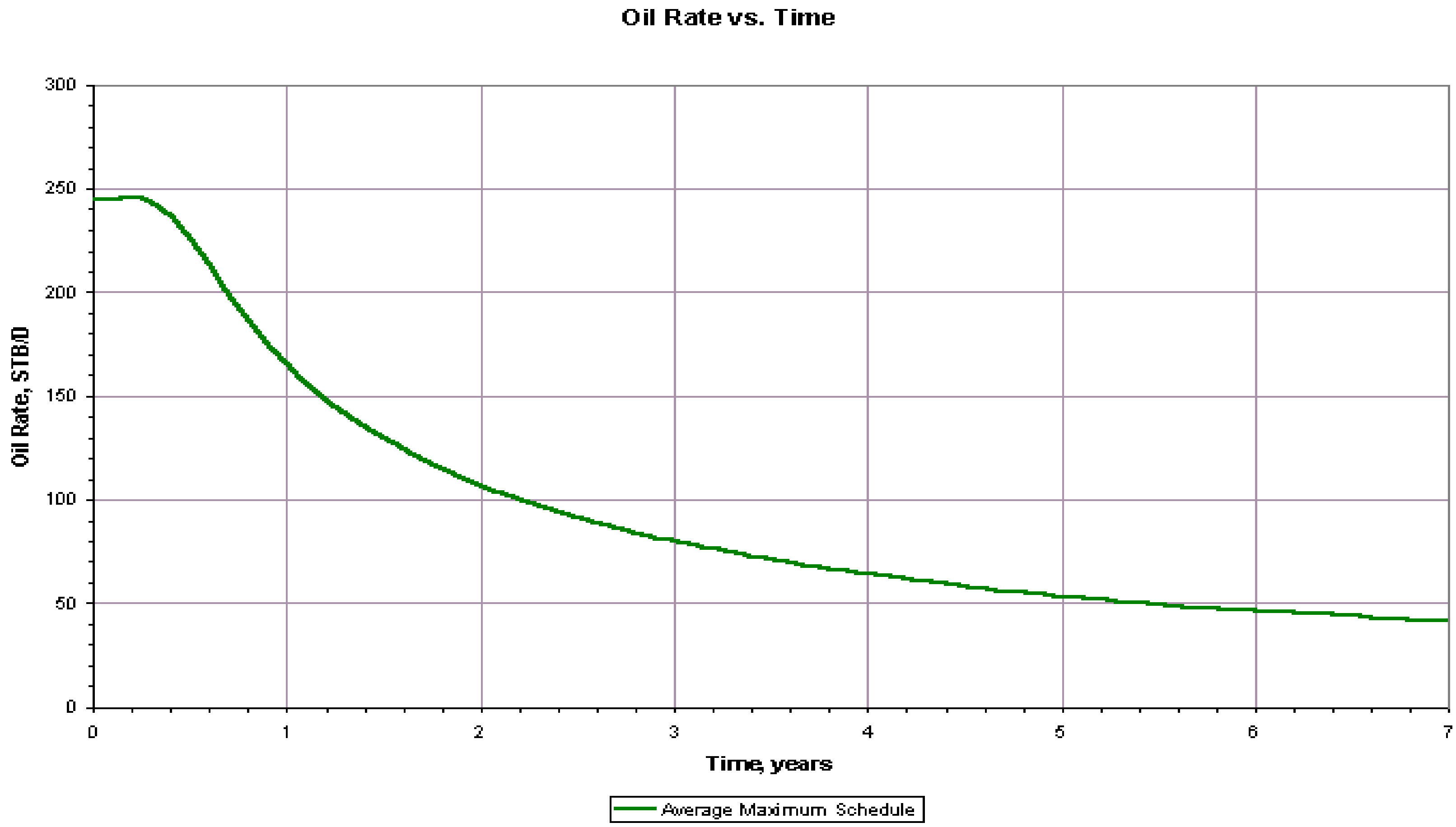
GRAPH 9: RATE OF RETURN PROBABILITY DISTRIBUTION



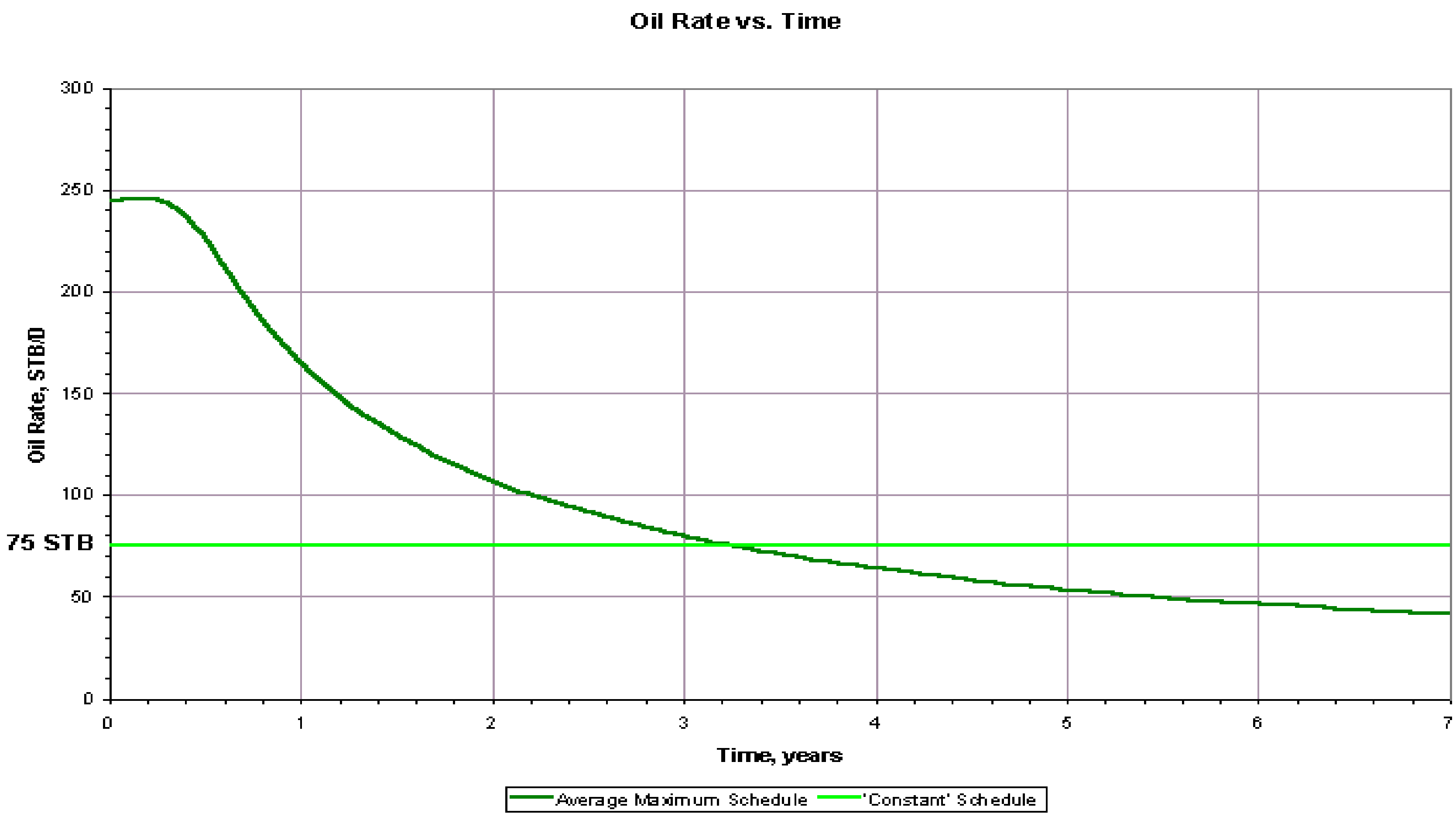
GRAPH 10: MAXIMUM SCHEDULE PRESSURE PROFILE



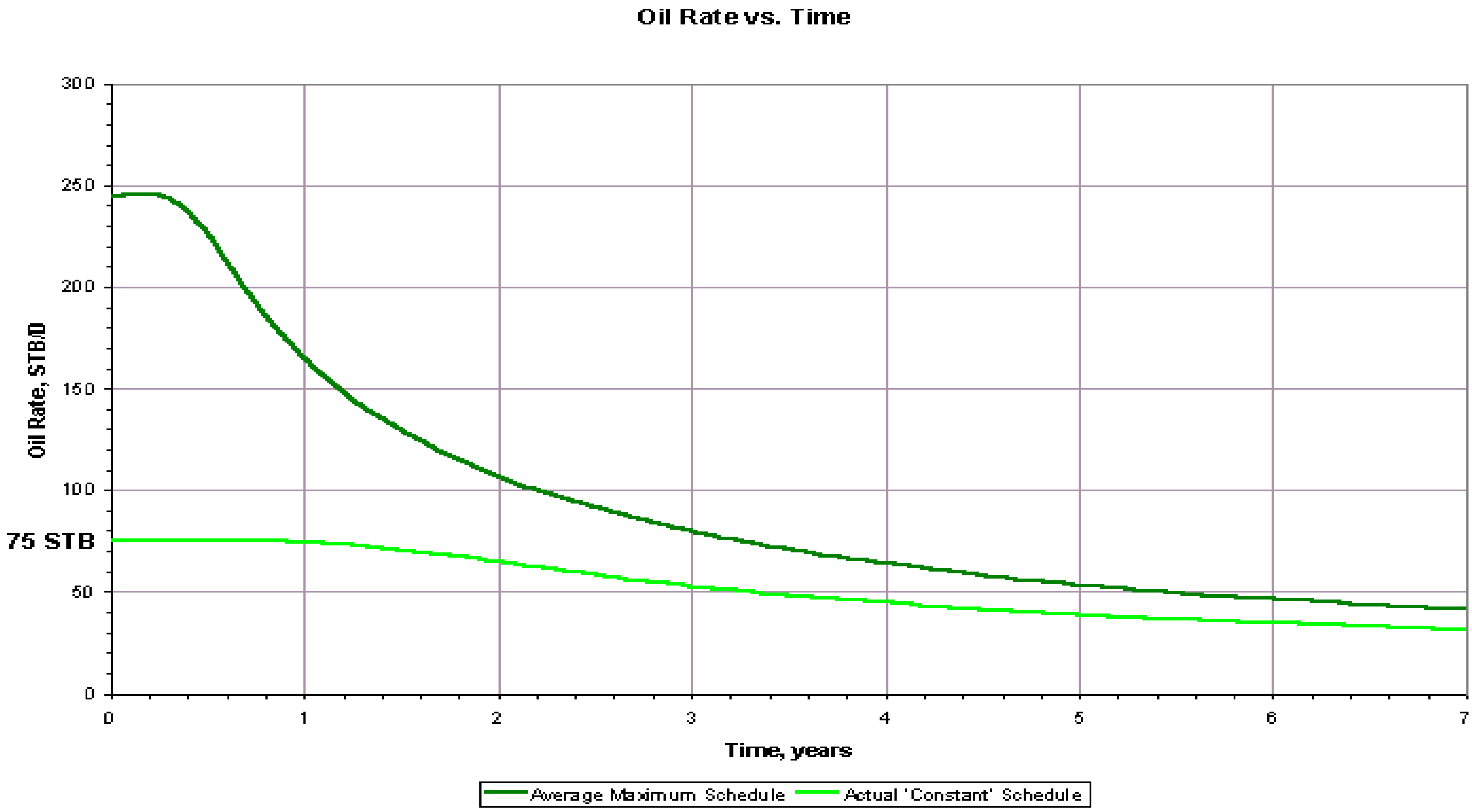
GRAPH 11: MAXIMUM OIL SCHEDULE



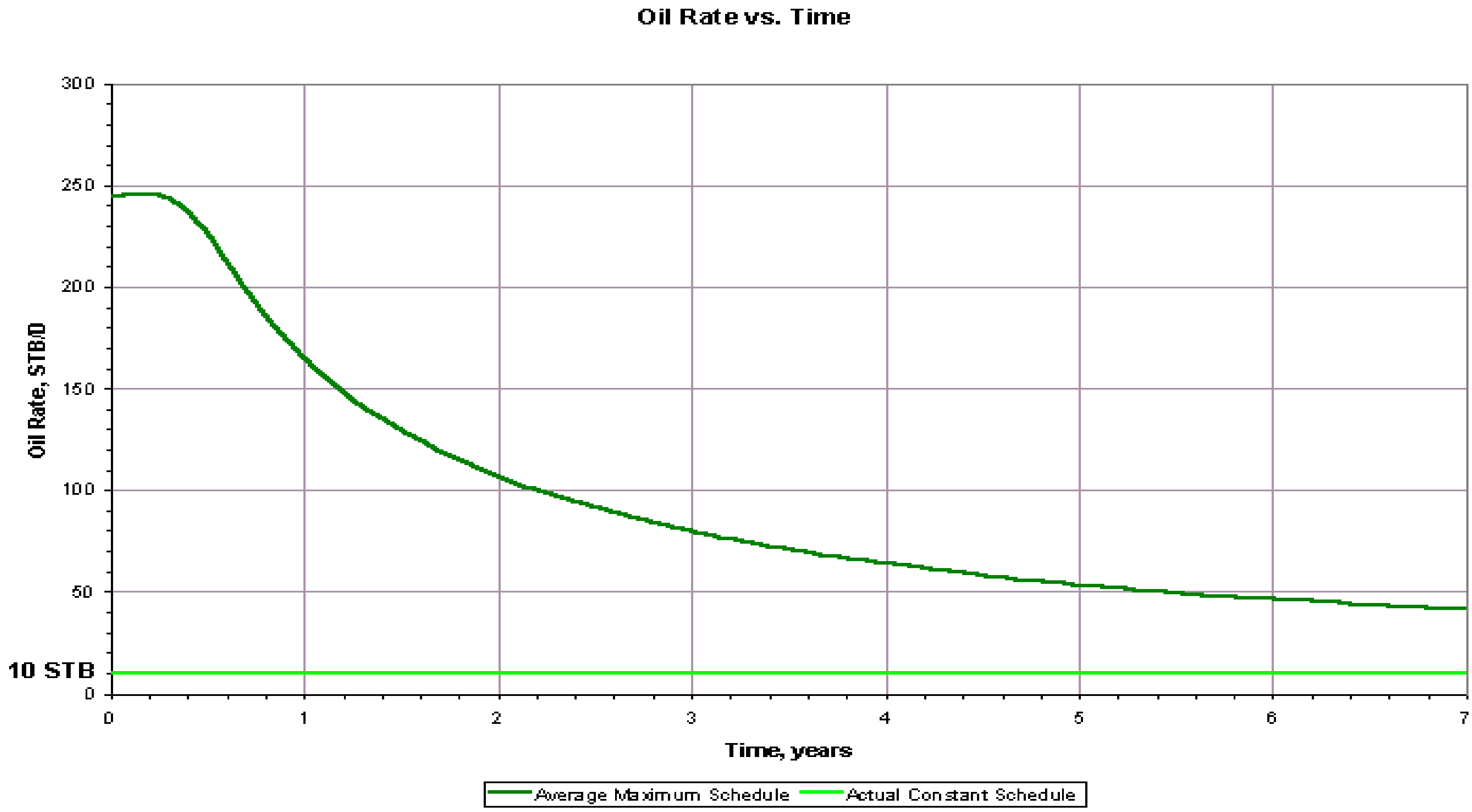
GRAPH 12: IDEAL CONSTANT OIL SCHEDULE



GRAPH 13: ACTUAL IDEAL CONSTANT OIL SCHEDULE



GRAPH 14: TRUE CONSTANT OIL SCHEDULE



GRAPH 15: PRESSURE PROFILE

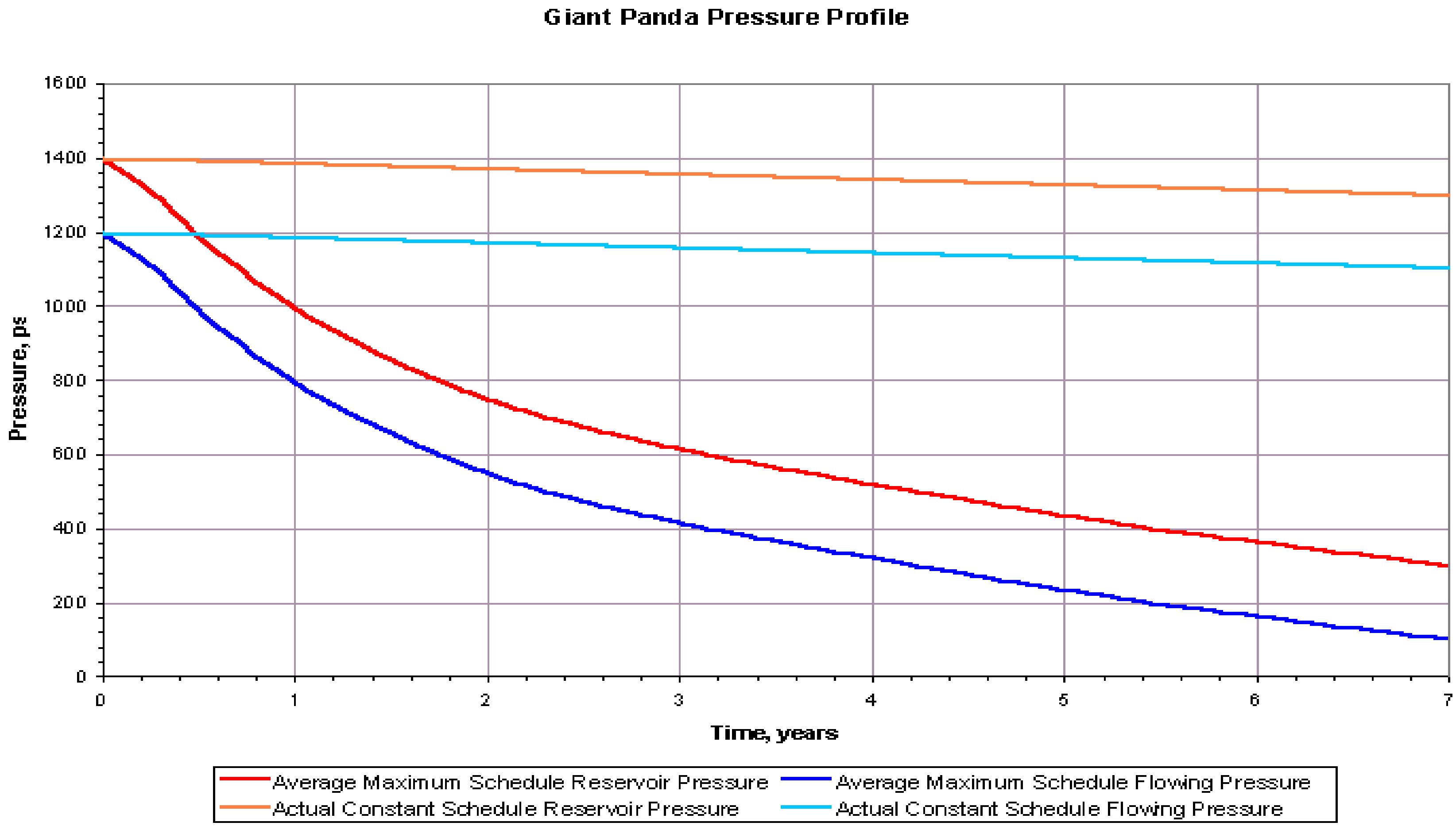


TABLE 1: FRACTURE GRADIENT

Formation Depth, ft		Thickness, ft	Density, g/cm^3	Average Density, g/cm^3	
Top	Bottom				
0	138	138	2.69	2.690	Shale
138	190	52	2.65	2.679	G
190	238	48	2.65	2.673	G1
238	287	49	2.65	2.669	G2
287	332	45	2.65	2.667	K
332	380	48	2.65	2.665	K1
380	4428	4048	2.69	2.688	Shale
4428	4639	211	2.65	2.686	1st Vedder
4639	4697	58	2.65	2.686	2nd Vedder
4697	4788	91	2.69	2.686	Shale
4788	5120	332	2.65	**2.683**	3rd Vedder

Overburden Stress =	5,951	psig
Formation Pore Pressure =	2,248	psig
Fracture Pressure =	3,482	psig

Fracture Gradient = 13.079 ppg

TABLE 2: CASING DESIGN

Casing Design: Giant Panda Well

Total Depth =	5120	ft	
Bottomhole Temperature =	136	degrees F	
Formation Gradient =	0.439	psi/ft	
Fracture Gradient =	13.079	ppg	
Drilling Fluid Weight =	8.8	ppg	Polymer

Casing Type =	Production	Surface	
Casing Outer Diameter =	7	9.625	in
Setting Depth =	5,120	900	ft
BURST			
Bottomhole Pressure =	3,562	626	psig
Gas Gradient =	0.0622	0.0111	psi/ft
Internal Pressures			
Top =	3,244	616	psig
Bottom =	5,587	626	psig
External Pressures			
Top =	0	0	psig
Bottom =	2,248	395	psig
Resultant Pressures			
Top =	3,244	616	psig
Bottom =	3,339	231	psig
Design Pressures			
Top =	3,568	678	psig
Bottom =	3,673	254	psig
Minimum Casing Requirements			
Grade =	J-55	H-40	
Nominal Weight =	20	32.3	#/ft
Inner Diameter =	6.456	0.312	in
Internal Pressure Resistance =	3,740	2,270	psi
Actual Casing Used			
Grade =	J-55	H-40	
Nominal Weight =	23	32.3	#/ft
Inner Diameter =	6.366	9.001	in
Internal Pressure Resistance =	4,360	2,270	psi
Used Safety Factor			
SF =	1.31	9.83	

COLLAPSE

Internal Pressures			
Top =	0	0	psig
Bottom =	0	0	psig
External Pressures			
Top =	0	0	psig
Bottom =	2,343	412	psig
Resultant Pressures			
Top =	0	0	psig
Bottom =	2,343	412	psig
Design Pressures			
Top =	0	0	psig
Bottom =	2,577	453	psig
Minimum Casing Requirements			
Grade =	J-55	H-40	
Nominal Weight =	23	32.3	#/ft
Inner Diameter =	6.366	9.001	in
Collapse Resistance =	3,270	1,370	psi
Actual Casing Used			
Grade =	J-55	H-40	
Nominal Weight =	23	32.3	#/ft
Inner Diameter =	6.366	9.001	in
Collapse Resistance =	3,270	1,370	psi
Used Safety Factor			
SF =	1.40	3.33	

TENSION

Hydrostatic Fluid Pressure =	2,343	412	psig
Metal Area at Bottom =	6.655	9.128	in^2
Axial Tension =	102,167	25,311	lbf
Design Tension =	202,167	125,311	lbf
Minimum Casing Requirements			
Grade =	H-40	H-40	
Nominal Weight =	20	32.3	#/ft
Inner Diameter =	6.456	9.001	in
Pipe Body Yield Strength =	230,000	365,000	lbf
Actual Casing Used			
Grade =	J-55	H-40	
Nominal Weight =	23	32.3	#/ft
Inner Diameter =	6.366	9.001	in
Pipe Body Yield Strength =	366,000	365,000	lbf
Used Safety Factor			
SF =	3.58	2.91	

TABLE 3: RESERVE ESTIMATION

	Depth, ft	ρ_b, g/cc	ϕ_D, %	ϕ_N, %	ϕ, %	R_{ID}, Ω-m	R_t, Ω-m	F_R	R_w, Ω-m	I	S_w	N, STB/acre
2nd Vedder	4652	2.175	23.8	31.2	30.5	30.0	30.0	8.0	3.768	67.4	0.12	3,464
	4654	2.19	23.9	34.0	31.4	22.5	22.5	7.5	3.014	53.9	0.14	3,511
	4656	2.175	29.8	35.0	32.4	20.0	20.0	7.0	2.860	51.2	0.14	3,607
	4658	2.19	23.9	37.2	33.0	22.0	22.0	6.7	3.279	58.7	0.13	3,714
	4660	2.175	29.8	37.2	33.5	21.0	21.0	6.5	3.227	57.7	0.13	3,762
					32.2						**0.13**	**18,056**
3rd Vedder	4730	2.125	32.9	34.5	33.7	2.0	2.0	6.4	0.312	5.6	0.42	2,514
	4732	2.15	31.4	34.0	32.7	4.5	4.5	6.9	0.656	11.7	0.29	2,993
	4734	2.16	30.7	35.0	32.9	4.6	4.6	6.3	0.364	11.9	0.29	3,017
	4736	2.1	34.5	35.0	34.8	3.8	3.8	6.0	0.632	11.3	0.30	3,158
	4738	2.16	31.4	35.0	33.2	3.7	3.7	6.3	0.567	10.0	0.32	2,932
	4800	2.125	32.9	35.0	34.0	3.5	3.5	6.3	0.554	9.9	0.32	2,998
					33.5						**0.32**	**17,616**
3rd Vedder	4810	2.125	32.9	39.0	36.0	2.5	2.5	5.5	0.448	8.0	0.35	3,008
	4812	2.11	33.9	39.0	36.4	2.8	2.8	5.4	0.516	9.2	0.33	3,161
	4814	2.11	33.9	38.0	35.9	2.1	2.1	5.5	0.375	6.7	0.39	2,854
	4816	2.01	40.2	40.0	40.1	1.8	1.8	4.4	0.396	7.1	0.38	3,234
	4818	2.05	37.7	39.0	38.3	2.1	2.1	4.9	0.431	7.7	0.38	3,171
	4820	2.14	32.0	33.0	32.5	2.8	2.8	6.9	0.403	7.2	0.37	2,638
	4822	2.14	32.0	34.0	33.0	3.5	3.5	6.7	0.521	9.3	0.33	2,860
	4824	2.05	37.7	33.0	35.3	4.5	4.5	5.8	0.775	13.9	0.27	3,341
	4826	1.9	47.1	30.0	38.5	6.5	6.5	4.8	1.349	24.1	0.20	3,968
	4828	2.125	32.9	30.0	31.5	6.5	6.5	7.4	0.873	15.6	0.25	3,040
	4830	2.09	35.1	31.5	33.3	8.0	8.0	6.6	1.215	21.7	0.21	3,384
	4832	2.1	34.5	31.0	32.8	9.0	9.0	6.8	1.317	23.6	0.21	3,363
	4834	2.1	34.5	33.0	33.8	7.5	7.5	6.4	1.171	21.0	0.22	3,411
	4836	2.1	34.5	35.0	34.8	7.0	7.0	6.0	1.164	20.8	0.22	3,509
					35.7						**0.29**	**45,058**
min	4298	2.5	9.4	40.0	24.7	0.7	0.7	12.5	0.056	1.0	1.00	
Total Pay Zone					**34.2**						**0.27**	**80,616**

ρ_m = 8.8 ppg
ρ_f = 1.08
ρ_{ma} = 2.65 g/cc
B_o = 1.2 RB/STB
A = 1 acre

ρ_b = From RHOB log
$\phi_D = (\rho_{ma} - \rho_b)/(\rho_{ma} - \rho_f)$
ϕ_N = From NPHI log
$\phi = (\phi_D + \phi_N)/2$
R_{ID} = From ILD log

$R_t = R_{ID}$
$F_R = 0.62/\phi^{2.15}$
$R_w = R_t/F_R$
$I = R_w/R_{wmin}$
$S_w = 1/I^{1/2}$

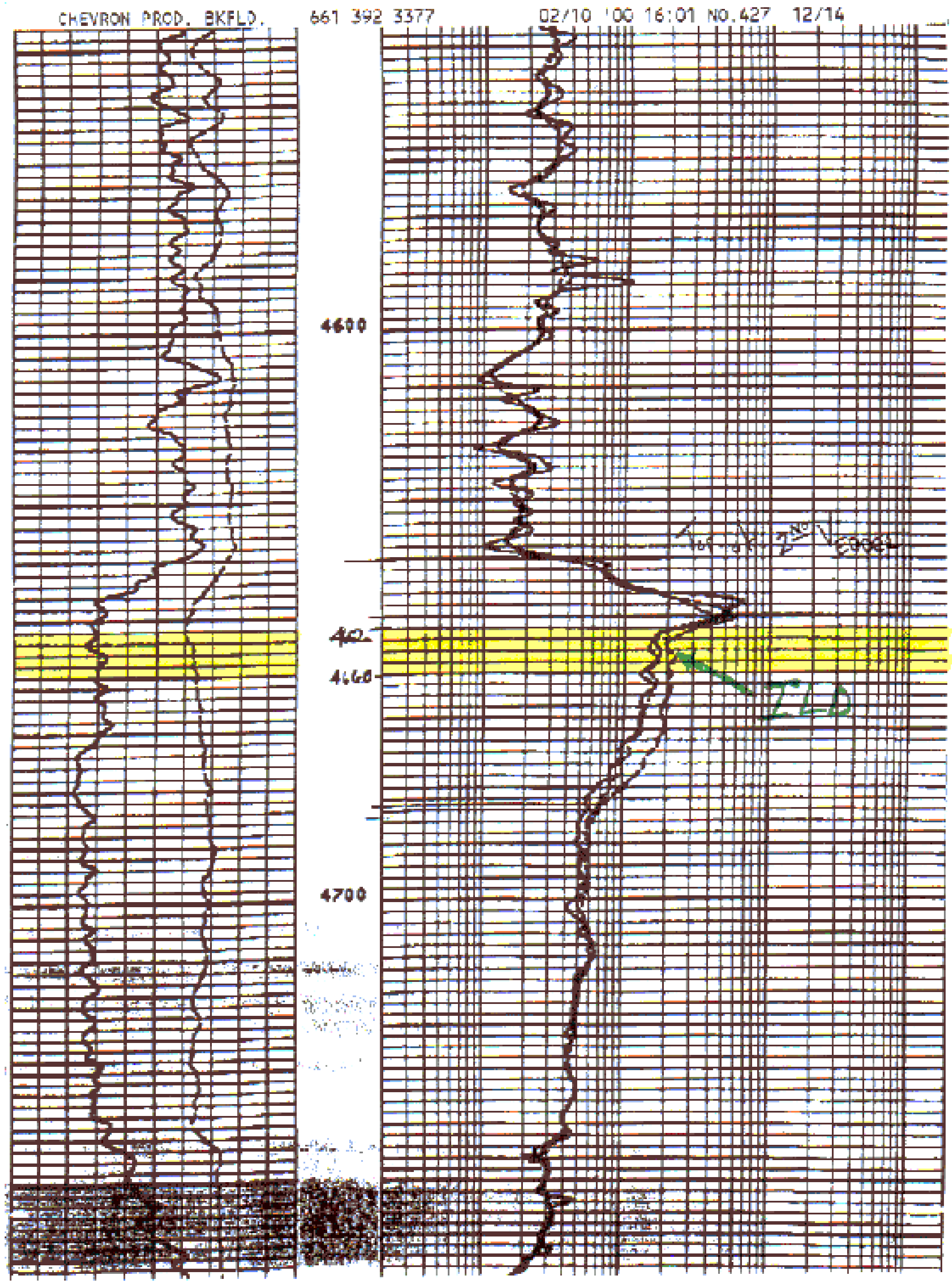
TABLE 4: INVESTMENT DETERMINATION

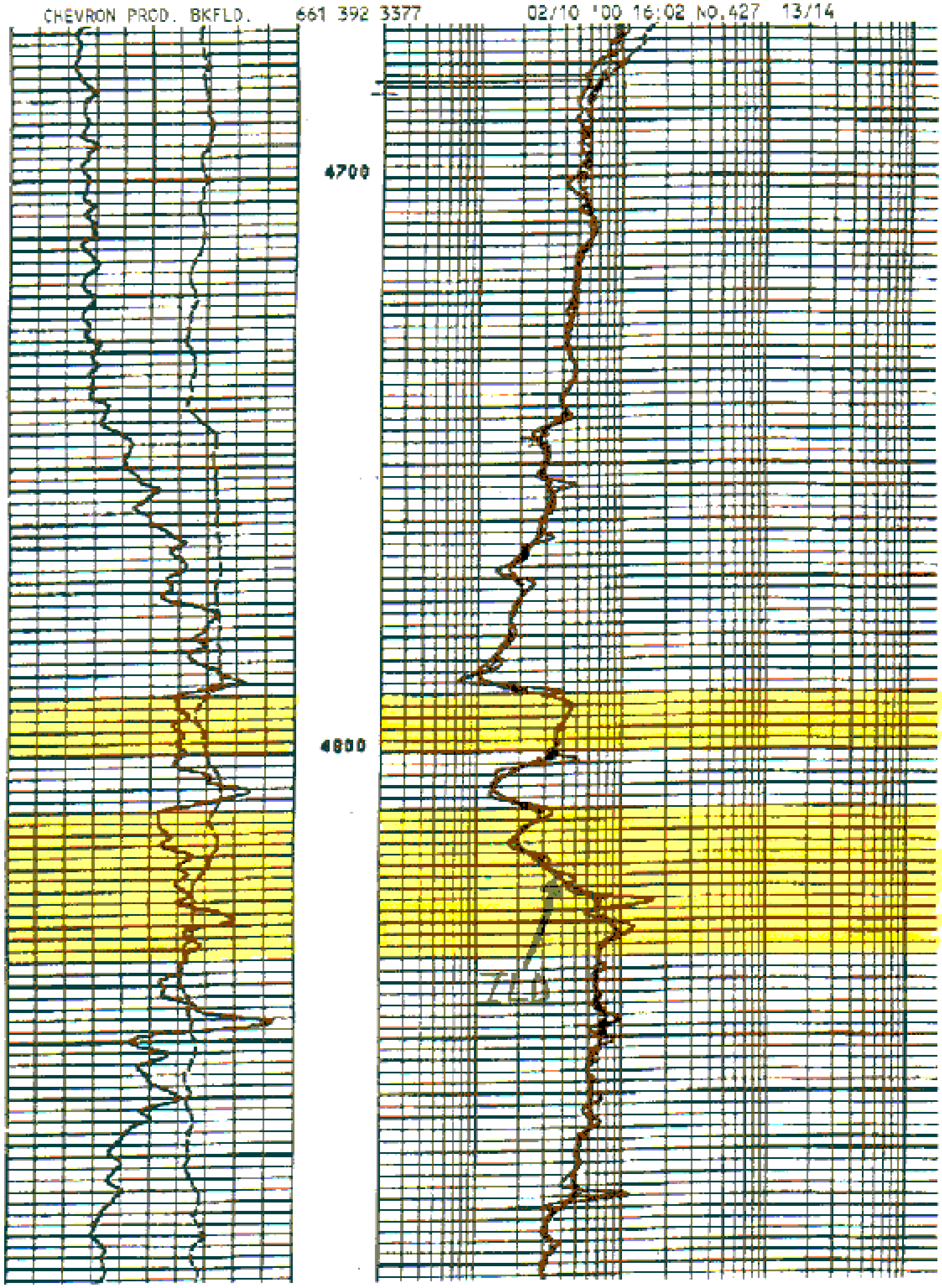
Investment	Cost	Days	$
Supervision	450	10.48	4,717.37
Rig Rate	1,000	10.48	10,483.03
Misc. Tools	500		500.00
Perf Charges	500		500.00
Other Perf Charges	200		200.00
Drilling Fluids	1,000		1,000.00
Contract Drilling	1,200	8.33	9,992.81
Well Supplies	3,500		3,500.00
Transportation	1,500		1,500.00
Drillstring	4,000		4,000.00
Other Rentals	8,500		8,500.00
Other Subsurface	3,000		3,000.00
Casing, Tubing, Rods	9,500		9,500.00
Logging	25,000		25,000.00
Facilities	10,000		10,000.00
(*Italicized - Cost per day)		**TOTAL**	**92,393.21**
		Facilities	$10,000
		W/O Tan	$9,500
		W/O Int	$72,893
		Subtotal	**$92,393**
		G&A Facilities	$1,300
		G&A Wells	$1,235
		TOTAL	**$94,928**

TABLE 5: ECONOMIC ANALYSIS

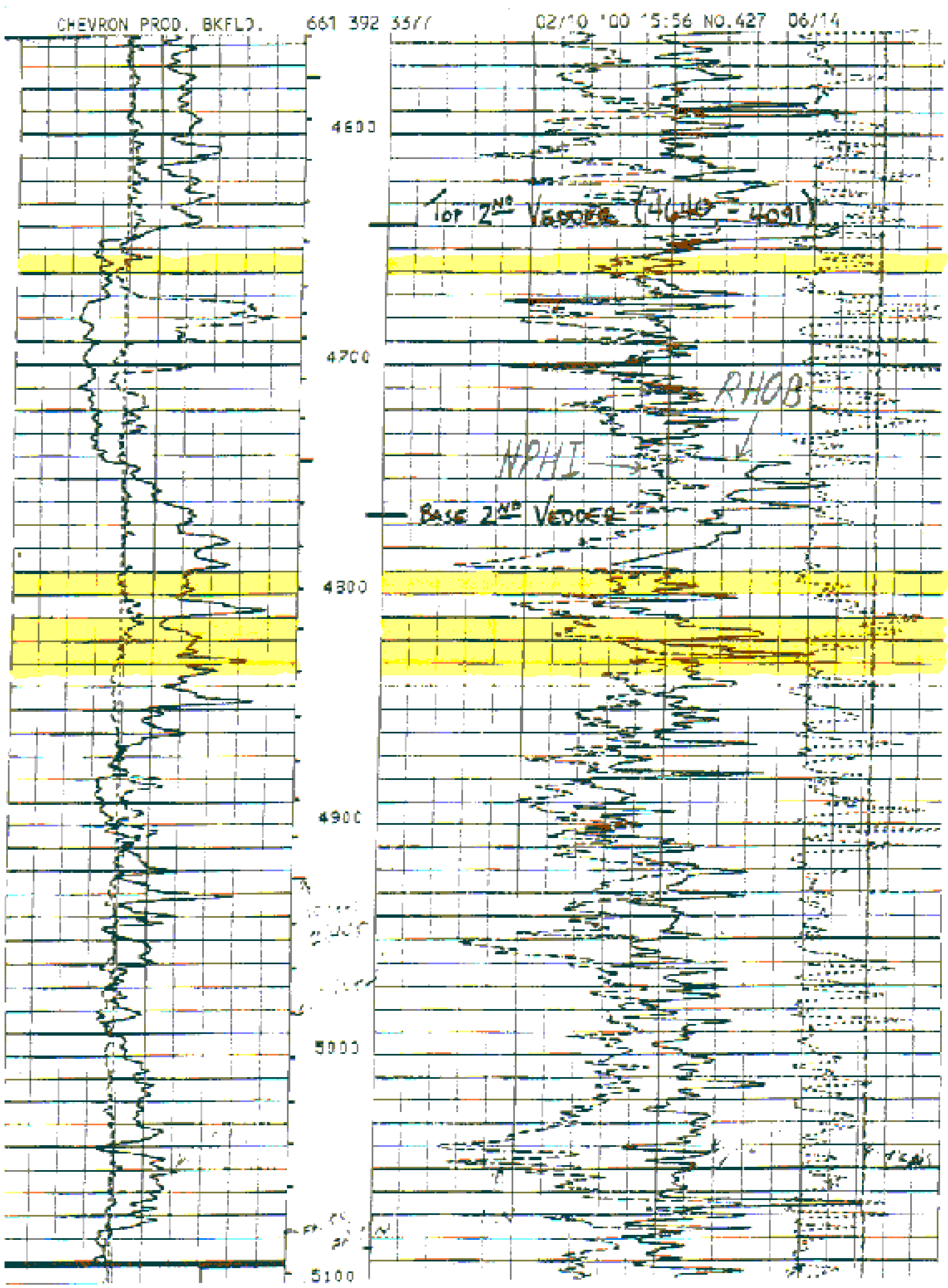
	Time, months	Production per Month, BO/month	Production per Month, MCF/month	Investment, $/month	Operating Cost, $/month	Revenue, $/month	Net Cash Flow, $/month	NPV 5%, $/month	NPV 20%, $/month	NPV 50%, $/month	NPV 100%, $/month	NPV 500%, $/month	NPV 1,000%, $/month	NPV 5,000%, $/month	NPV 10,000%, $/month	NPV 11,000%, $/month
Investment	0	0	0	94,897	0	0	-94,897	-94,897	-94,897	-94,897	-94,897	-94,897	-94,897	-94,897	-94,897	-94,897
Year 1	1	43,000	15,000	0	35,978	905,797	869,819	866,209	855,559	835,026	802,910	613,990	474,447	168,352	93,195	85,556
	2	32,000	14,000	0	27,484	682,599	655,115	649,690	633,812	603,754	558,204	326,424	194,910	24,541	7,520	6,338
	3	17,000	9,100	0	15,017	367,622	352,605	348,234	335,547	311,962	277,333	124,018	57,222	2,557	434	336
	4	33,000	13,900	0	28,208	702,317	674,108	662,989	630,979	572,551	489,419	167,363	59,671	946	89	63
	5	24,000	16,000	0	21,989	528,461	506,472	496,052	466,297	412,964	339,426	88,760	24,454	138	7	5
	6	21,000	15,000	0	19,490	465,406	445,915	434,928	403,814	349,044	275,854	55,163	11,744	23	1	0
	7	15,000	10,000	0	13,743	330,288	316,545	307,465	281,959	237,867	180,759	27,642	4,547	3	0	0
	8	15,000	17,000	0	15,494	351,303	335,809	324,823	294,215	242,249	177,009	20,699	2,631	1	0	0
	9	12,000	18,000	0	13,495	294,252	280,757	270,444	241,948	194,433	136,606	12,216	1,200	0	0	0
	10	13,000	23,000	0	15,495	329,280	313,785	301,005	265,978	208,614	140,932	9,637	732	0	0	0
	11	10,000	13,000	0	10,746	239,206	228,460	218,246	190,478	145,812	94,717	4,953	291	0	0	0
	12	10,000	18,000	0	11,996	254,216	242,220	230,431	198,640	148,410	92,697	3,707	168	0	0	0
Year 2	13	10,000	15,000	0	11,246	245,210	233,964	221,653	188,724	137,618	82,650	2,527	89	0	0	0
	14	8,000	18,000	0	10,498	214,181	203,683	192,165	161,605	115,014	66,418	1,553	42	0	0	0
	15	5,000	15,000	0	7,499	145,121	137,622	129,301	107,401	74,603	41,424	741	15	0	0	0
	16	6,000	10,000	0	6,998	150,128	143,130	133,918	109,869	74,485	39,768	544	9	0	0	0
	17	6,000	20,000	0	9,499	180,149	170,651	159,004	128,846	85,255	43,768	458	6	0	0	0
	18	7,000	15,000	0	8,998	185,157	176,159	163,456	130,825	84,486	41,705	333	3	0	0	0
	19	5,000	12,000	0	6,749	136,115	129,366	119,539	94,499	59,563	28,271	173	1	0	0	0
	20	4,000	13,000	0	6,249	119,099	112,850	103,845	81,083	49,880	22,765	106	1	0	0	0
	21	3,000	6,000	0	3,749	78,066	74,317	68,103	52,522	31,534	13,838	49	0	0	0	0
	22	6,000	18,000	0	8,999	174,145	165,147	150,710	114,800	67,272	28,386	78	0	0	0	0
	23	5,000	14,000	0	7,249	142,119	134,870	122,569	92,216	52,742	21,399	45	0	0	0	0
	24	5,000	12,000	0	6,749	136,115	129,366	117,080	87,003	48,566	18,947	30	0	0	0	0
Year 3	25	5,000	10,000	0	6,248	130,110	123,862	111,633	81,936	44,639	16,745	20	0	0	0	0
	26	3,000	10,000	0	4,749	90,075	85,325	76,582	55,518	29,521	10,648	10	0	0	0	0
	27	3,000	10,000	0	4,749	90,075	85,325	76,264	54,608	28,340	9,829	7	0	0	0	0
	28	3,000	10,000	0	4,749	90,075	85,325	75,948	53,713	27,206	9,073	5	0	0	0	0
	29	3,000	8,000	0	4,249	84,070	79,821	70,754	49,424	24,433	7,835	3	0	0	0	0
	30	4,000	12,000	0	5,999	116,097	110,098	97,186	67,053	32,353	9,975	3	0	0	0	0
	31	3,000	6,000	0	3,749	78,066	74,317	65,329	44,520	20,965	6,215	2	0	0	0	0
	32	3,000	11,000	0	5,000	93,077	88,077	77,104	51,898	23,853	6,799	1	0	0	0	0
	33	3,000	7,000	0	3,999	81,068	77,069	67,188	44,667	20,037	5,492	1	0	0	0	0
	34	3,000	10,000	0	4,749	90,075	85,325	74,077	48,641	21,296	5,613	1	0	0	0	0
	35	2,000	10,000	0	4,000	70,057	66,057	57,110	37,040	15,827	4,011	0	0	0	0	0
	36	3,000	6,000	0	3,749	78,066	74,317	63,985	40,988	17,094	4,165	0	0	0	0	0
Year 4	37	1,000	7,000	0	2,500	41,033	38,533	33,038	20,904	8,509	1,994	0	0	0	0	0
	38	2,000	6,000	0	3,000	58,048	55,049	47,003	29,374	11,670	2,629	0	0	0	0	0
	39	3,000	7,000	0	3,999	81,068	77,069	65,532	40,450	15,684	3,397	0	0	0	0	0
	40	2,000	10,000	0	4,000	70,057	66,057	55,935	34,102	12,905	2,688	0	0	0	0	0
	41	2,000	7,000	0	3,250	61,051	57,801	48,741	29,350	10,841	2,171	0	0	0	0	0
	42	2,000	8,000	0	3,500	64,053	60,553	50,850	30,244	10,903	2,100	0	0	0	0	0
	43	3,000	5,000	0	3,499	75,064	71,565	59,848	35,158	12,370	2,291	0	0	0	0	0
	44	2,000	7,000	0	3,250	61,051	57,801	48,137	27,930	9,591	1,708	0	0	0	0	0
	45	1,000	9,000	0	3,000	47,037	44,037	36,522	20,930	7,015	1,201	0	0	0	0	0
	46	2,000	4,000	0	2,499	52,044	49,545	40,920	23,162	7,577	1,247	0	0	0	0	0
	47	2,000	5,000	0	2,749	55,046	52,297	43,013	24,048	7,678	1,215	0	0	0	0	0
	48	1,000	7,000	0	2,500	41,033	38,533	31,561	17,428	5,431	827	0	0	0	0	0
Year 5	49	1,000	6,000	0	2,250	38,031	35,781	29,185	15,918	4,841	708	0	0	0	0	0
	50	1,000	5,000	0	2,000	35,028	33,028	26,829	14,453	4,290	604	0	0	0	0	0
	51	2,000	6,000	0	3,000	58,048	55,049	44,530	23,694	6,864	929	0	0	0	0	0
	52	2,000	8,500	0	3,625	65,554	61,929	49,888	26,218	7,413	964	0	0	0	0	0
	53	1,000	5,500	0	2,125	36,530	34,404	27,600	14,327	3,954	495	0	0	0	0	0
	54	1,000	8,000	0	2,750	44,035	41,285	32,982	16,910	4,554	548	0	0	0	0	0
	55	1,000	6,000	0	2,250	38,031	35,781	28,466	14,415	3,789	438	0	0	0	0	0
	56	1,000	7,000	0	2,500	41,033	38,533	30,528	15,270	3,918	436	0	0	0	0	0
	57	2,000	7,000	0	3,250	61,051	57,801	45,604	22,530	5,642	603	0	0	0	0	0
	58	750	7,000	0	2,313	36,028	33,715	26,491	12,926	3,159	325	0	0	0	0	0
	59	1,250	7,000	0	2,688	46,037	43,350	33,919	16,347	3,899	385	0	0	0	0	0
	60	3,000	5,000	0	3,499	75,064	71,565	55,764	26,545	6,180	587	0	0	0	0	0
Year 6	61	1,000	6,000	0	2,250	38,031	35,781	27,765	13,054	2,966	271	0	0	0	0	0
	62	2,000	8,000	0	3,500	64,053	60,553	46,792	21,730	4,819	424	0	0	0	0	0
	63	2,000	6,000	0	3,000	58,048	55,049	42,363	19,431	4,206	355	0	0	0	0	0
	64	1,000	7,000	0	2,500	41,033	38,533	29,530	13,378	2,826	230	0	0	0	0	0
	65	500	5,000	0	1,625	25,020	23,394	17,854	7,989	1,647	129	0	0	0	0	0
	66	2,500	6,000	0	3,374	68,057	64,683	49,159	21,727	4,372	328	0	0	0	0	0
	67	1,000	7,000	0	2,500	41,033	38,533	29,163	12,731	2,500	181	0	0	0	0	0
	68	1,000	4,000	0	1,750	32,026	30,276	22,820	9,839	1,886	131	0	0	0	0	0
	69	2,000	8,000	0	3,500	64,053	60,553	45,450	19,356	3,621	242	0	0	0	0	0
	70	1,000	6,000	0	2,250	38,031	35,781	26,745	11,250	2,054	132	0	0	0	0	0
	71	1,000	6,000	0	2,250	38,031	35,781	26,634	11,065	1,972	122	0	0	0	0	0
	72	1,000	5,000	0	2,000	35,028	33,028	24,483	10,047	1,748	104	0	0	0	0	0
Year 7	73	2,000	9,000	0	3,750	67,055	63,305	46,732	18,941	3,215	184	0	0	0	0	0
	74	1,000	8,000	0	2,750	44,035	41,285	30,350	12,150	2,013	111	0	0	0	0	0
	75	1,000	4,000	0	1,750	32,026	30,276	22,165	8,764	1,417	75	0	0	0	0	0
	76	1,000	8,000	0	2,750	44,035	41,285	30,099	11,755	1,855	94	0	0	0	0	0
	77	2,000	4,000	0	2,499	52,044	49,545	35,971	13,875	2,137	104	0	0	0	0	0
	78	1,000	7,000	0	2,500	41,033	38,533	27,860	10,614	1,596	75	0	0	0	0	0
	79	1,000	5,000	0	2,000	35,028	33,028	23,781	8,949	1,313	59	0	0	0	0	0
	80	1,000	4,000	0	1,750	32,026	30,276	21,709	8,069	1,156	50	0	0	0	0	0
	81	1,500	5,000	0	2,375	45,037	42,663	30,463	11,184	1,563	65	0	0	0	0	0
	82	1,000	5,000	0	2,000	35,028	33,028	23,486	8,516	1,162	47	0	0	0	0	0
	83	500	4,000	0	1,375	22,017	20,642	14,618	5,235	697	27	0	0	0	0	0
	84	1,000	8,000	0	2,750	44,035	41,285	29,114	10,299	1,338	50	0	0	0	0	0
						Total NPV	$10,160,909	$9,328,112	$7,536,312	$5,587,130	$4,050,786	$1,366,365	$737,285	$101,663	$6,348	-$2,600
						Interest Rate	0%	5%	20%	50%	100%	500%	1000%	5000%	10000%	11000%
															Rate of Return	10709%

LOG 1: INDUCTION LOG




4700
4800
ZLD

LOG 2: BULK DENSITY & NEUTRON POROSITY LOG



PROGRAM: OIL PERFORMANCE PREDICTION

```
Option Explicit
Private n As Double, pi As Double, ho As Double, hg As Double
Private por As Double, ka As Double
Private dp As Double, all As Double, pmin As Double, spacing As Double

Private p(30), rn(30), rn1(30), q(30)
Private np(30), gp(30), dnp(30), dgp(30), gp1(20)
Private rs(30), bo(30), bg(30), yo(30), yg(30)
Private roo(30), rog(30)
Private sg(30), kgo(30), ko(30), s(30), kog(30), kfr(30)

Private i As Integer, j As Integer
Private time(30) As Double

Private Sub cmdrun_Click()
Dim v1 As Double, v2 As Double, v3 As Double
Dim boi, rsi, bgi, so As Double
Dim g As Double, swo As Double, sl As Double, sgl As Double
Dim flag1 As Boolean, Flag2 As Boolean

mnuperm_Click
mnupvt_Click
DoEvents
boi = bo(1):    bgi = bg(1)
np(1) = 0:      gp(1) = 0: g = 0
swo = 25
q(1) = all
For i = 2 To 14
rn(i) = rs(i)
Do
    rn(i) = rn(i) + 5
    v1 = n * (bo(i) - boi + (rsi - rs(i)) * bg(i))
    v2 = bg(i) * (gp(i - 1) - (rn(i) + rn(i - 1)) / 2 * np(i - 1))
 np(i) = (v1 + g * (bg(i) - bgi) - v2) / v3
        gp(i) = (rn(i) + rn(i - 1)) / 2 * (np(i) - np(i - 1)) + gp(i - 1)
    so = (1 - swo / 100) * (1 - np(i) / n) * bo(i) / boi
 sgl = 1 - sl
For j = 1 To 9 Step 1
    If (sgl >= sg(j) / 100) And (sgl < sg(j + 1) / 100) Then
      kog(i) = (kgo(j + 1) - kgo(j)) * (sgl - sg(j) / 100) / (sg(j + 1) / 100 - sg(j) / 100) + kgo(j)
      Exit For
    End If
For j = 1 To 9 Step 1
    If (sgl >= sg(j) / 100) And (sgl < sg(j + 1) / 100) Then
      kfr(i) = (ko(j + 1) - ko(j)) * (sgl - sg(j) / 100) / (sg(j + 1) / 100 - sg(j) / 100) + ko(j)
      Exit For
    End If
Next
dp = 250
If kfr(i) = 0 Then kfr(i) = 1
    q(i) = all * kfr(i) / yo(i) / bo(i) / (1 / yo(1) / boi)
    dnp(i) = np(i) - np(i - 1)
```

```
    rn1(i) = rs(i) + kog(i) * yo(i) / yg(i) * bo(i) / bg(i)
Loop Until Abs(rn(i) - rn1(i)) < 10
Exit For
End If
Next

With grddata
    For i = 1 To 12
        .TextMatrix(i, 0) = Format(p(i), "0")
        .TextMatrix(i, 1) = Format(p(i) - 200, "0")
        .TextMatrix(i, 2) = Format(rn(i), "0.0")
        .TextMatrix(i, 3) = Format(np(i), "#,##0")
        .TextMatrix(i, 4) = Format(gp(i), "#,##0")
        .TextMatrix(i, 5) = Format(q(i), "0")
        .TextMatrix(i, 6) = Format(time(i), "0.0")
    Next
End With

Open "a:\results.dat" For Output As #3
For i = 1 To 12 Step 1
    Print #3, p(i), rn(i), np(i), gp(i), q(i), gp1(i), time(i)
Next
Close #3


End Sub

Private Sub Form_Load()
readoildata

With grddata
.RowHeight(0) = 500
.WordWrap = True
.Col = 0
For i = 0 To 6
    .Row = i
    .ColWidth(i) = 1260
    .ColAlignment(i) = 5
Next
.Row = 5:   .ColWidth(5) = 950
.Row = 0
.Col = 0:       .Text = "Reservoir Pressure, psi"
.Col = 1:       .Text = "Flowing Pressure, psi"
.Col = 2:       .Text = "GOR, SCF/STB"
.Col = 3:       .Text = "Oil Production (Np), STB"
.Col = 4:       .Text = "Gas Production (Gp), SCF"
.Col = 5:       .Text = "Flow Rate (Q), STB/D"
End With

End Sub

Public Sub readoildata()

n = Val(txtn.Text)
pi = Val(txtpi.Text)
ho = Val(txtho.Text)
```

```
por = Val(txtpor.Text)
ka = Val(txtka.Text)
dp = Val(txtmsdp.Text)
all = Val(txtall.Text)
spacing = Val(txtspace.Text)

End Sub

Private Sub mnupvt_Click()
Dim count1 As Integer
Open "a:\pvtfile.txt" For Input As #1
count1 = 0
i = 1
Do While Not EOF(1)
Input #1, p(i), bo(i), rs(i), bg(i), yo(i), yg(i), roo(i), rog(i)
count1 = count1 + 1
i = i + 1
Loop
Close #1
End Sub

Private Sub mnuexit_Click()
End
End Sub
```