Numerical Modeling of the Flow of Fluids and Energy in EOR Injection Wells Using PROSPER

by

Kumar Nathan

Dissertation submitted in partial fulfillment

of the requirements for the

Bachelor of Engineering (Hons)

(Petroleum Engineering)

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CERTIFICATION OF APPROVAL

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Approved by,

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UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

January 2012

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

KUMAR NATHAN

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ABSTRACT

This report is written to mainly discuss about the final year project entitled "Numerical Modeling of the flow of fluids and energy in Enhanced Oil Recovery (EOR) injection wells using PROSPER". Oil and gas industries are looking for new ways to maximize their production and at the same time maximize their profit. One of the main focuses of all the oil and gas industries is increasing the recovery of the oil and gas using Enhanced Oil Recovery (EOR) method. Steam injection is one of the EOR methods that have been given higher priority by oil and gas industries. Many researchers have done the study on the heat losses along the wellbore during the steam injection. In this project, heat losses have been calculated using PROSPER software which in one of the commercial software used by oil and gas industries. The main purpose of this study is to calculate the heat losses, pressure losses, temperature losses, and steam quality changes along the wellbore during steam injection. Increment or decrement of the fluid temperature will directly affect the energy that going to be transferred to the production fluid. Wellbore cement failure due to the higher temperature along the wellbore can be avoided once the heat losses are known. The results that have been obtained from this project work clearly shows the amount of heat losses to the formation and how it affect steam quality, temperature, pressure of injected steam. Greater heat losses can be avoided using insulation material in the wellbore. The optimum injected steam temperature and pressure as well as steam quality at the wellhead can be calculated once the amount of energy of the steam is known at the bottomhole. Cement failure can be prevented by using the proper cement to counter the effect of the heat. Taking into the consideration the effect of friction and slippage effect between phases, PROSPER can accurately calculate the heat losses that occurs in the wellbore.

ACKNOWLEDGEMENT

The past 28 weeks of my enrolment in final year project have been truly valuable experience to me. I have learned many aspects on heat transfer phenomena as well as Enhanced Oil Recovery Method. I have broadened my knowledge and experiences in these related fields. Hence, I would like to take this opportunity to express my sincerest gratitude to a number of people that have helped me to achieve this.

First of all I would like to express my gratitude to God for letting me complete this project in good health and well being. Next, I would like to express my deepest appreciation to Mr. Mohd Amin Shoushtari, my supervisor, who has supervised me throughout my project period. His ever willingness to teach me and guide me has helped me tremendously in achieving my goals on my final year project. On top of that, he was constantly supportive of the decisions that I make and is always there to share his knowledge and experiences with me.

Secondly, my utmost gratitude goes to my FYP coordinators who guided me throughout my final year project. Without their guidance it is impossible for me to finish the final year project within the time period.

In short, I feel blessed to have done my final year project and for all the help that the aforementioned parties have given me. Only with their help was my final year project becomes a success.

CHAPTER 1

INTRODUCTION

1.1 Background Study

In the past few years the price of the oil and gas is increases very fast as the demand for the oil and gas is increasing drastically. The usage of the oil and gas in developing countries like India and China are increasing very fast. The major sector that is using oil and gas as the major fuel is the industrial sector followed by the oil and consumption for transportation and domestic usage. More industrial activities that are being carried out these days compared to past days. More oil and gas need to be produce in order to fulfill the demand of the customers. Higher oil and gas price will be the advantage for the oil and gas industries to invest more on this sector in order to get more profit out of their revenues. Thus the oil and gas industries are looking for new ways to maximize their production and at the same time maximize their profit. One of the main focuses of all the oil and gas industries are on the technique on how to increase the recovery of the oil and gas. Enhance Oil Recovery (EOR) is one of their main focus nowadays in worldwide oil and gas industries. The oil and gas industries' aim is to extract oil and gas as much as possible. Leaving lesser oil in the subsurface will give them more profit. Thus EOR studies are one of the important studies that have been growing very rapidly nowadays.

Oil production is separated into three phases which are the primary, secondary and tertiary which is also known as the Enhanced Oil Recovery (EOR). Primary oil recovery is limited to hydrocarbons that naturally rise to the surface, or those that use artificial lift devices, such as pump jacks. Secondary recovery employs water and gas injection, displacing the oil and driving it to the surface. The way to further increase oil production is through the tertiary recovery method or EOR. Although more expensive to employ on a field, EOR can increase production from a well to up to 75% recovery. There are three main types of EOR, including chemical flooding, gas injection and thermal

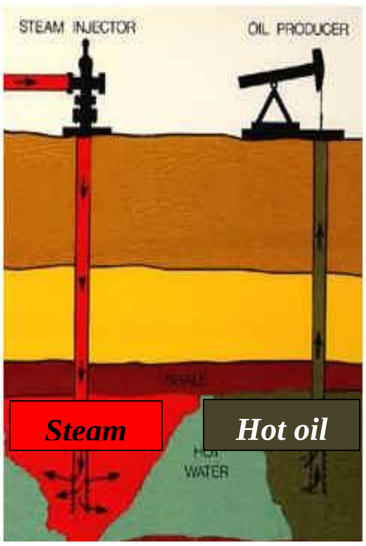


Figure 1.1: Injection well and Production well

recovery. Thermal recovery introduces heat to the reservoir to reduce the viscosity of the oil. Many times, steam is applied to the reservoir, thinning the oil and enhancing its ability to flow. First applied in Venezuela in the 1960s, thermal recovery now accounts for more than 50% of applied EOR. Chemical injection EOR helps to free trapped oil within the reservoir. This method introduces long-chained molecules called polymers into the reservoir to increase the efficiency of water flooding or to boost the effectiveness of surfactants, which are cleansers that help lower surface tension that inhibits the flow of oil through the reservoir. Less than 1% of all EOR methods presently utilized in the US consist of chemical injections. Gas injection used as a tertiary method of recovery involves injecting natural gas, nitrogen or carbon dioxide into the reservoir. The gases can either expand and push gases through the reservoir, or mix with or dissolve within the oil, decreasing viscosity and increasing flow.

Increasing the cost of development alongside the hydrocarbons brought to the surface, producers do not use EOR on all wells and reservoirs. The economics of the development equation must make sense. Therefore, each field must be heavily evaluated to determine which type of EOR will work best on the reservoir.

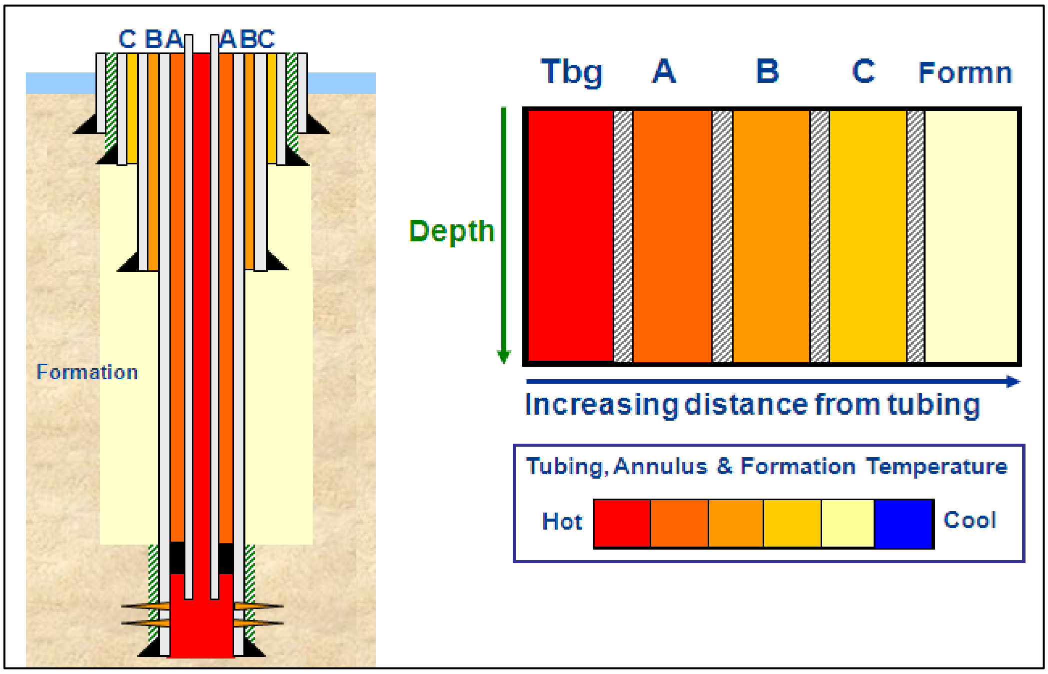


Figure 1.2: Wellbore and Geothermal Temperature

This is done through reservoir characterization, screening, scoping, and reservoir modeling and simulation. Knowing there are several types of EOR injection purpose the most widely used by industries and the most complicated and effective method is steam injection method. Using steam as a injection fluid to increase the oil viscosity in the production to increase the mobility of oil will sound simple but the mechanism that happens in the injection well is quite complex to really measure the properties of the steam that will be in contact with the oil. One of the most important mechanisms that will be take place in this steam injection method is heat transfer in the injection well.

Heat transfer process in the wellbore is one of the most complicated issues and none of them have fully understood the mechanism fully. Why we need to know the heat transfer that will be happen in the wellbore? This is the question that will be in most of the peoples mind when they first heard that heat transfer need to be study thoroughly in steam injection well. Heat transfer will make the fluid to gain or lose its heat which directly will increase or decrease its temperature. Increment or decrement of the fluid temperature will directly affect the energy that going to be transferred to the production fluid. Let's say all the way from up to bottom to the injection well the injection fluid is losing its heat thus at the point it reaches the production fluid there will not be enough energy to heat up the oil to increase its viscosity. This tells us that we need to change the parameters for injection at the wellhead (temperature, wellhead injection rate).

Other problem that can be avoided because of knowing the heat transfer in the wellbore is the failure of cement. Too much of heat can weaken the cement and can break it. Thus the ultimate aim of this project is to study on the heat transfer and to come out with an outcome that can tell us the heat properties at the different point of injection well depth. In line with this PROSPER software will be used to come out with the end result. Choosing the correct models and inputting the correct field data in PROSPER and quality check it will be the main task during this project. Thus, Modeling of the flow of the fluids and energy in EOR steam injection wells using PROSPER will be the main task in this final year project.

1.2 Problem Statement

There is no single model that can elaborate on the fluid flow accurately. Modeling a fluid flow in the wellbore is a very hard activity as the fluid flow and energy will vary all the times depending on other factors like pressure and so on. Thus fluid flow only can be measured at the surface at the wellhead using the equipment and the fluid flow at the wellhead will not entirely represent the fluid flow in the wellbore. The properties of injection fluid are not the same as the producing fluid as the temperature increase and pressure increase will be different. When steam is injected in the well there are a lot of mechanisms that will take into place. Those mechanisms capable of changing the properties of steam injected at the wellhead. The characteristics of the fluid that have been injected will differ as the depth of travelling increases. Thus none of us can really tell what will be the characteristic of the fluid at any point in the wellbore. One of the most difficult parameter to guess is the fluid temperature. The fluid temperature in our case which is steam is very difficult to predict as the process of heat transfer that will be occurring inside the wellbore. Adding heat to the fluid will increase the fluid temperature while losing the fluid heat to the formation will decrease the fluid temperature.

Predicting the fluid temperature is one of the crucial things as the temperature can affect the wellbore structure as well as the production. Many wellbore heat problems exist which involve heat effects is not considered in the subject development. Examples are: expansion of gas, heat generated by friction and latent heat effects from phase changes (Ramey[1] 1962). Often such complications can be handled by proper modification of the solution. In line with that modeling fluid flow using heat transfer technique will give us the picture on the fluid flow. Multiphase nature of flow inside the wellbore, complex heat transfer mechanism between the wellbore and the surrounding medium make the entire system intricately coupled and difficult to solve. Thus many aspects need to be considered in the calculation of heat transfer to get a good result which is near to the real situation.EOR method is become a crucial method for oil and gas industries nowadays thus there will be always studies going on this sector to find out the best technique for the EOR technique. Developing a model in this field will definitely benefits the oil and gas industries.

1.3 Objectives

1) To study on the heat transfer mechanism for EOR steam injection well

2) To model the steam flow in EOR injection well using PROSPER software

3) To analyze the results from the PROSPER software and to study on the fluid properties (mainly temperature and pressure) that have been changed according to the well depth

4) To prove that the effects of the heat transfer process to the EOR injection wells during steam injection.

1.4 Scope of Studies

The scope of study mainly to model a fluid flow of the EOR injection wells in the PROSPER software. The study will be divided into two stages; the first stage involves researching on the correlation between the heat transfer and the fluid flow. Research will also be conducted on the type of the EOR that are being used in the oil and gas industries. The second stage will focus on modeling work in the lab, using PROSPER software. Thus, it will be just nice to finish the research on the related topic and doing the modeling for the EOR injection within the time given. Scope of the study have been focused on the EOR steam injection wells only in order to fit within the time frame, hence proper research must be done into the modeling and calculations beforehand. The project will involve in the understanding of fluid mechanics and process of heat transfer. Those are two major topics that going to explain the fluid behavior and the fluid flow in the wellbore. Proper understanding in those two topics is needed in order to keep the project work in the right track. Once the numerical model of the fluid flow is done the result that will be gotten from the software model will be analyzed and discussed to analyze the accuracy of the data.

1.5 Relevancy of the Project

This project is relevant to the author's field of study since fluid flow in the wellbore is one of the focus areas in Petroleum Engineering. This fluid flow analysis is fall under the reservoir engineering sub-disciplinary where Reservoir Engineers will simulate the fluid flow to know the fluid properties. The ultimate aim of the reservoir engineers will be to maximize the production thus they will be always concern about this producing or injecting fluid. In this project author has do research on the process of heat transfer which is one of the important mechanism that need to be understood by majority of the engineering discipline. The knowledge of this heat transfer of steam injection fluid can be used in the industries later and it has high demand from the oil and gas sectors recently. Petroleum engineers always find a way to increase the production of oil and gas and nowadays the focus have been on the Enhance Oil Recovery method because of the high oil and gas price. The EOR method can recover up to 75% thus this directly tell us the relevancy of the author's project on doing research on EOR steam injection wells.

1.6 Feasibility of the Project

The project is feasible since it is within the scope and time frame. The author has planned to complete the research and literature review by the end of the first semester while he doing some tutorials and get to know the PROSPER software well. Author has planned to do thorough research on the process of heat transfer and he has planned to be completely clear about the topic and become expert in PROSPER software by the end of Final Year Project 1 (FYP1) period. Then, he plans to dedicate the first six weeks to input the real field data into the PROSPER software and quality check the data and pick the most accurate model for steam injection wells. Then he plans to thoroughly analyze the result of the software and prove the effect of the heat transfer mechanism to the wellbore. The result that he get need to be study to get the real picture on how process of heat transfer become the leading criteria for the steam flow in the EOR injection wells. The PROSPER software and other PETEX software are readily available at the university Lab (Block-15) and thus there is no wastage of time in purchasing and installing the software.

CHAPTER 2

LITERATURE REVIEW AND THEORY

2.1 Literature Survey

2.1.1 Heat Transmission Discussion from Authors

Estimation of temperatures in a wellbore during injection or production is a recurring problem in petroleum engineering. Examples are the prediction of bottomhole temperatures of injection fluids and of wellhead temperatures in gas and oil wells. During past few years, considerable interest has been generated in fluid injection enhanced oil recovery method. Many papers have been published on various aspects of heat transfer between wellbore fluid and formation. Ramey[1] in 1962 was the first who presented a theoretical model for estimating the temperature of fluids, tubing and casing in the wellbore as a function well depth and time and the result have been expressed in simple algebraic form suitable for slide-rule calculation. Ramey[1] made several assumptions in his paper. He assumed that fluid is non-compressible and flow is single phase with constant thermal and physical properties along the wellbore. He considered that heat flows radially away the wellbore and the overall heat transfer coefficient is independent of depth. He did not take into account frictional pressure loss and kinetic energy effect in his calculation.

Squier et al[2] Solved differential equations describing fluid temperature along the wellbore, using a complete analytical method. They assumed there is no heat transfer by conduction in the vertical direction in either the injection stream or the formation and the linear volumetric and mass flow rate of the water is constant throughout the injection stream. The product of density and heat capacity is constant for both the water and the formation, and the formation thermal conductivity is constant. They also have assumed that initially, both the water in the wellbore and the reservoir are at temperature given by the (constant) ambient surface temperature plus the product of depth and geothermal gradient (assumed constant). They considered at large distances for the wellbore, the formation will remain at this temperature and the water temperature and the formation temperature at $r = r_{to}$ are equal for all depths D.

Satter[3] (1965) later included the effect of phase change during steam injection operations. He presents a method of estimating the quality of condensing fluid as a function of depth and time. He stated that overall heat transfer coefficient dependent on depth-step method for calculating heat loss and steam quality for saturated steam as a function of depth. He assumed steam is injected at a constant rate, wellhead pressure, temperature and quality. A downhole packer is used to prevent steam from entering the tubing-casing annulus. The annulus is assumed to be filled with air at low pressure. He considered the heat transfer in the wellbore is under steady-state conditions, while heat transfer to the earth involves unsteady state radial conduction.

Later Holst and Flock[4] 1966 added the friction loss and kinetic energy effects on Ramey's[1] and Satter's models, in order to calculate the heat loss and quality distribution versus depth for saturated steam injection operations. They neglected, however, the static pressure change. In 1966, Leutwyler[5] gave a comprehensive treatment of casing temperature behavior. Hans and Huitt[6] 1966 developed e graphical solution for wet steam injection operations. In their model, they calculate wellbore heat loss, steam condensation rate, and casing temperature.

In 1967, Willhite[7] proposed his well known method for estimation of over-all heat transfer coefficient that is applied in our calculation as well. His paper presents comparison of calculated and measured casing temperatures during steam injection. Shiu and Beggs[8] developed an empirical correlation for producing oil wells to determine the relaxation distance that Ramey[1] defined. This work is actually an attempt to avoid the complex calculation of the overall heat-transfer coefficient in the wellbore and the transient heat-transfer behavior of the reservoir. Although this correlation simplifies the Ramey[1] method, it should be used with caution as a rough approximation. All the heat transmission discussion has been summarized in Appendix A. Two of the pioneers in the prediction of heat loss and pressure drop in the wellbore were Pacheco and Farouq Ali[9] , 1972. They formulated a mathematical model that consisted of two coupled nonlinear differential equations that were solved iteratively in terms of pressure and quality of steam. They assumed a single phase flow in the wellbore which is not valid. Later at 1981, Farouq Ali[10] solved this problem by taking into account slip between the fluids and the flow regime. He used several correlations and stated that importance of applying two-phase flow concept and flow regime. In 1982, Fontanilla and Aziz[11], developed a mathematical model for multiphase, nonisothermal down flow of steam in pipes. Later in 1991, Wu and Pruess[12] presented a new analytical for wellbore heat transmission without Ramey's[1] assumptions. Their approach was assuming non-homogeneous formations as layered formation with different physical properties.

In a comparative study in 1992, Alves[13] et al reported that all existing models up to then suffered from serious assumptions on the thermodynamic behavior of fluids, and thus were applicable only for limited operational strategies. These authors developed a unified equation for temperature prediction inside the wellbore. In 1994, Hasan and Kabir[14] developed an analytical model to determine the flowing fluid temperature inside the well. They started with a steady-state energy balance equation and combined it with definition of fluid enthalpy in terms of heat capacity and Joule-Thompson coefficient. Then, by using some simplifications, they converted the original partial differential equation to an ordinary differential equation and solved it with appropriate boundary conditions. In 2004, Hagoort [15] did a comprehensive study on Ramey's[1] model in order to find applicable scenarios for this model. Many researchers (including Hagoort) found that Ramey's[1] model works for late times (more than a week) temperature estimation but can cause serious errors for early time temperature distribution. Later in 2007, Pourafshary[26] developed and a non-isothermal wellbore simulator to model transient fluid flow and temperature and couple the model to a reservoir simulator. In 2008, Livescu et al[16] developed a comprehensive numerical non-isothermal multiphase wellbore model. After their initial attempts to solve the fully coupled conservation equations, they decoupled the wellbore energy balance equation from the mass balance equation in most of their investigations. They reported that decoupling can be justified when the density difference in each phase with respect to temperature is much less than that with respect to pressure. Additionally, they found that this decoupling approach can decrease computation time of simulation without violating stability. Then, Bulent Izgec[28] simulated transient wellbore model coupled with a semi analytic temperature model for computing wellbore fluid temperature profile in flowing and shut-in wells.

Later in 2010, Bahonar[29] developed a numerical non-isothermal two-phase wellbore simulator coupled with tubular and cement material, and surrounding formation. Selcuc Fidan[25], investigated heat losses along the wellbore during steam injection in both onshore and offshore environments in 2011.

This paper presents a numerical transient wellbore model for computing wellbore fluid temperature, pressure, heat loss at steam injection wells using PROSPER software. This model in PROSPER took into account the slippage between the phases of fluid as well as the heat loss due to friction factor between the tubing and fluids. This model has some important features for accurate and fast prediction of wellbore conditions. PROSPER currently has nearly 20 different inflow models for water/ steam injection wells and the IPR model selection depends upon the purpose of the study, the suitability of the particular model and the data available for the study. At last, variations of steam pressure, temperature, and quality versus well depth in one of heavy oil reservoirs are predicted.

2.1.2 Multiphase Flow Modeling Discussion from Authors

The hydrodynamics of the flow and the flow mechanisms change significantly from one flow pattern to another. To accurately estimate the pressure drop and phase fraction, it is necessary to know the flow pattern for any flow conditions. These patterns include bubble, slug, churn and annular flow for vertical multiphase flow. Due to the complexity of multiphase flow, empirical correlations are widely used to solve such problems. Empirical correlations are based on experimental results obtained from special cases, so they cannot be used with confidence for a wide range of problems. The empirical correlations can be either specific for each flow regime or can be independent from flow regimes. The Hagedorn and Brown correlation (Hagedorn et al.[17] 1965) is one of the correlations used in oil wells, and the Orkiszewski correlation (Orkiszewski[18], 1967) is the first correlation developed for gas wells with gas/liquid ratio above 50000 scf/bbl. Duns et al. (1963), Beggs et al.[19] (1973), and Mukherjee et al.[20] (1983) developed different experimental correlations for multiphase flow in vertical and inclined pipes. Another approach to model multiphase flow is the use of homogeneous models. A homogeneous model assumes that the fluid properties can be represented by mixture properties, so single-phase flow can be applied to the mixture. These models can also consider the velocity difference between moving phases (slip velocity). Empirical parameters are required to calculate slip velocity. Homogeneous models with slip are called drift-flux models. (Shi et al.[21], 2005)

In this project paper, reliable vertical performance correlation has been used to consider the slippage effect between the phases with different type of flow regime. Petroleum Experts 2 have been used as the vertical lift correlation which give us the high accuracy in result. Petroleum Experts 2 correlation combines the best features of existing correlations. It uses the Gould et al flow map and the Hegedorn Brown correlation in slug flow, and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist results is used.

2.2 Significance of Steam Injection Method

An interesting application of the wellbore heat transmission problem is estimation of heat losses from the wellbore during injection of a hot fluid for recovery of oil. Of the various heat-transport mediums available, steam or high-pressure hot water appear most attractive.

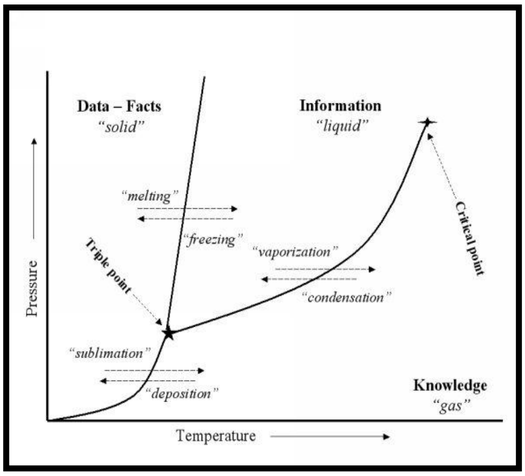


Figure 2.1: Water Phase Diagram

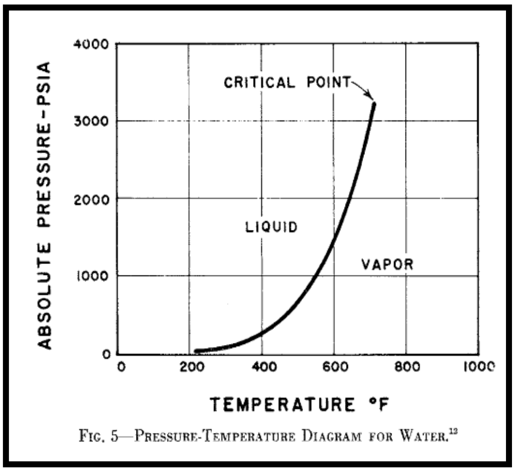


Figure 2.2: Pressure Temperature Diagram for Water (by Ramey)

Above pictures is showing us the phase relationships for water. It is very important for us to study the phase diagram for water as we can know the temperature where the water vapor (steam) will condensate and turn into liquid. Thus in the injection well heat losses to the wellbore formation will reduce the temperature of the steam and condensation will happen. Two phase flow will be considered as the flowing medium as there is water in liquid and vapor form.

There are two types of steam injection method which are cyclic steam stimulation and steam flooding. Cyclic steam stimulation method consists of 3 stages: injection, soaking, and production. Steam is first injected into a well for a certain amount of time to heat the oil in the surrounding reservoir to a temperature at which it flows. After it is decided enough steam has been injected, the steam is usually left to "soak" for some time after. Then oil is produced out of the same well, at first by natural flow (since the steam injection will have increased the reservoir pressure) and then by artificial lift. Production will decrease as the oil cools down, and once production reaches an economically determined level the steps are repeated again.

The process can be quite effective, especially in the first few cycles. However, it is typically only able to recover approximately 20% of the Original Oil in Place (OOIP), compared to steam flooding, which has been reported to recover over 50% of OOIP. It is quite common for wells to be produced in the cyclic steam manner for a few cycles before being put on a steam flooding regime with other wells.

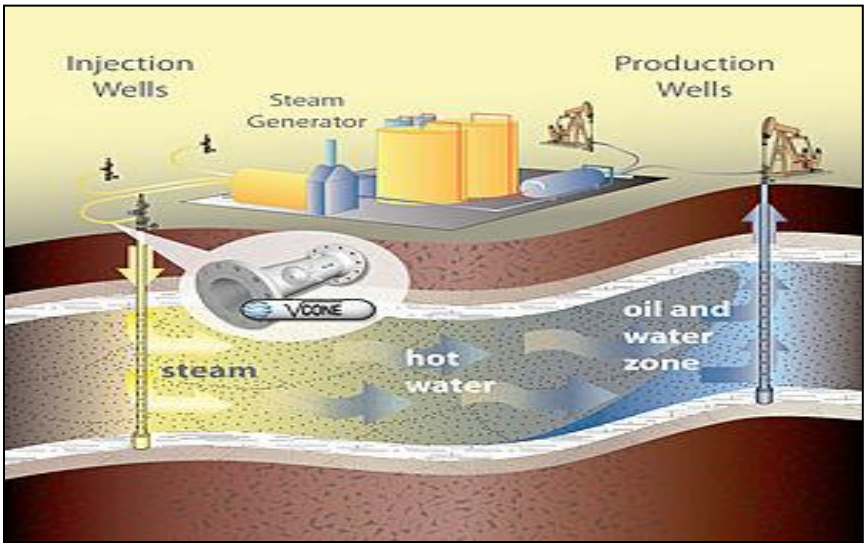


Figure 2.3: Steam Injection Well

In steam flood, sometimes known as a steam drive, some wells are used as steam injection wells and other wells are used for oil production. Two mechanisms are at work to improve the amount of oil recovered. The first is to heat the oil to higher temperatures and to thereby decrease its viscosity so that it more easily flows through the formation toward the producing wells. A second mechanism is the physical displacement employing in a manner similar to water flooding, in which oil is meant to be pushed to the production wells. While more steam is needed for this method than for the cyclic method, it is typically more effective at recovering a larger portion of the oil.

2.3 Heat Transmission Mechanism

2.3.1 Heat Transfer by Conduction

Heat conduction also called diffusion is a mode of transfer of energy within and between bodies of matter, due to a temperature gradient. It is the transfer of energy from the more energetic particles of a substance to the adjacent, less energetic ones as a result of interaction between particles.

$$\dot{Q}_{cond} = -kA\frac{T_1 - T_2}{\Delta x} \tag{1}$$

where k is the thermal conductivity of the material.

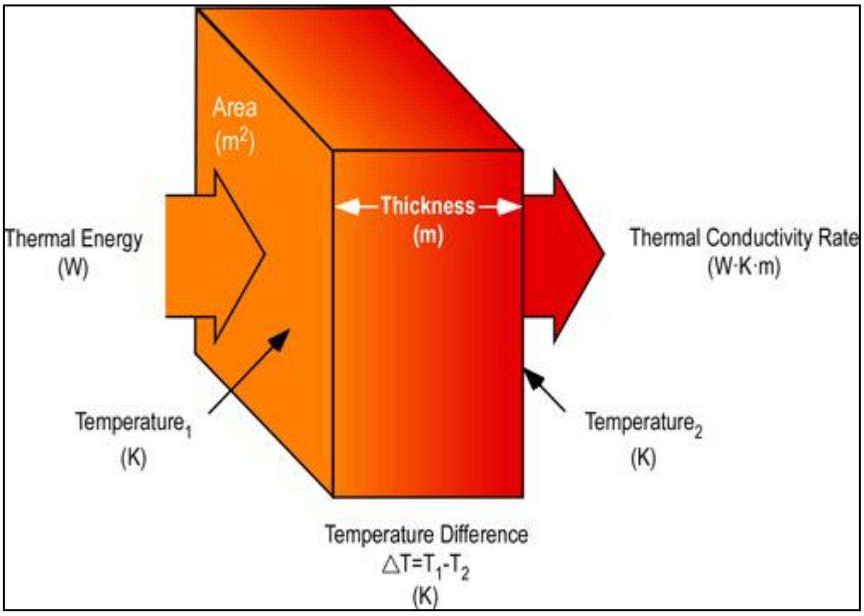


Figure 2.4: Heat Conduction

In the limiting case $\Delta x \rightarrow 0$ the equation above reduces to the differential form that is called Fourier's law of heat conduction after J. Fourier and becomes,

$$\dot{Q}_{cond} = -kA\frac{dT}{dx} \tag{2}$$

2.3.2 Heat Transfer by Convection

Convection is gravitationally-induced heat transport, driven by the expansion of a fluid on heating. The hot expanded fluid has lower density, so will rise to the top of colder, and therefore denser, fluid. The simplest example is water in a kettle heated from below: hot water will rise in a central column, spread through the top layer, cooling, then flow back down around the outside. The pattern becomes more complicated if a fluid is being heated over a large area, with no obvious center.

Fluid cools by losing heat through the surface

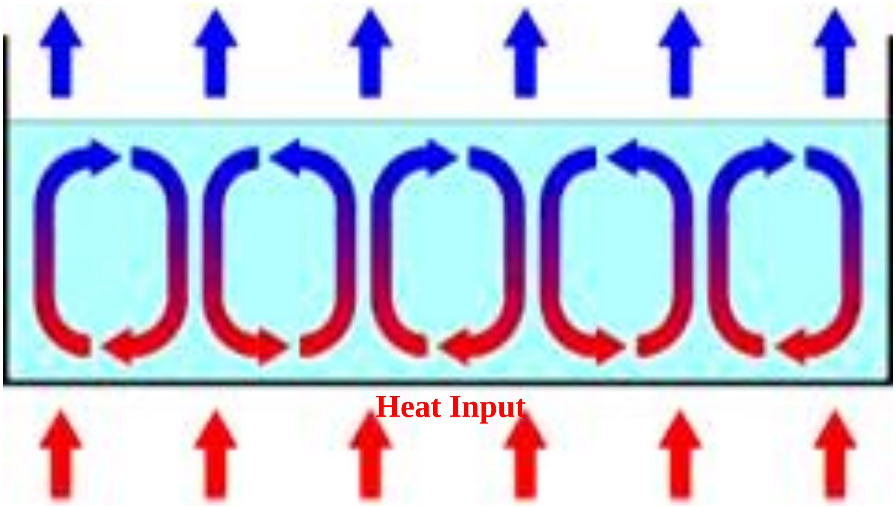


Figure 2.5: Heat convection

Convection cells can arise, each having a pattern like that in the kettle, the cells in a hexagonal pattern. This can happen in weather: a storm can be such a cell. However, many patterns are possible: the fluid mechanics is extremely complex. One important example of convection currents is inside the earth. The rate of convection heat transfer is expressed by Newton's law of cooling as

$$\dot{Q}_{cond} = -hA_s(T_s - T_\infty) \tag{3}$$

2.3.3 Heat Transfer by Radiation

Radiation is the energy emitted by matter in the form of electromagnetic waves as a result of changes in the electronic configurations of the atoms or molecules. Heat from the sun reaches us as radiation, much of it visible light, the rest similar electromagnetic waves but at wavelengths our eyes are not sensitive to. All bodies not at absolute zero temperature radiate, at room temperature the radiation is in the infrared, wavelengths longer than those of the visible spectrum. Microscopically, the radiation comes about because the oscillating ions and electrons in a warm solid are accelerating electric charges, and as you will find next semester, such charges radiate.

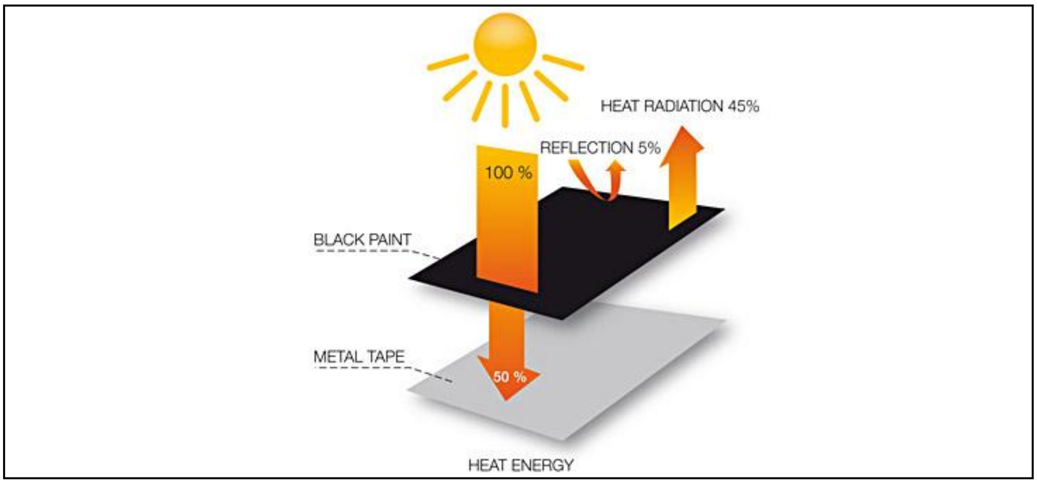


Figure 2.6: Heat radiation

Different substances radiate with different efficiencies, those that radiate better also absorb incoming radiation better. The radiation that can be emitted from a surface at an absolute temperature Ts (in K or R) is given by the Stefan-Boltzman law as,

$$\dot{Q}_{emit,max} = \sigma A_s T_s^4 \tag{4}$$

2.4 Model Formulation

Steam at a constant injection pressure, constant mass flow rate, and constant quality (at the surface) is injected through the tubing into the wellbore. The complete system consists of fluid, the tubing, the annular space containing air, the casing, the cement and the formation. Martha Bigpond wells data have been extracted and have been simulated using PROSPER software. Pressure, temperature and quality of steam will be computed as functions of depth. Slippage effect and friction factor between tubing and fluid have been considered. Overall heat transfer coefficient has been calculated first as an input in PROSPER. Two-phase flow can be analyzed using homogeneous models: two-fluid models or drift-flux models. In the homogeneous model, the components are treated as a pseudo-fluid that obeys the usual equations of single-component flow. All of the standard methods of fluid mechanics can then be applied.

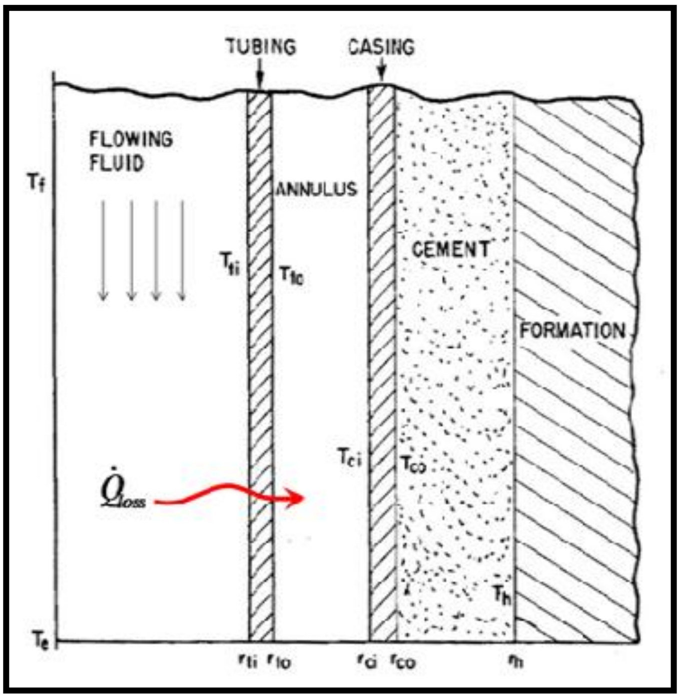


Figure 2.7: Heat Loss into Formation from Wellbore

The drift-flux model is essentially a separated-flow model in which attention is focused on the relative motion, rather than on the motion of individual phases. This model gives a very useful way for modeling two-phase flow, in particular for steady-state calculations. The two-fluid model takes into account the fact that the two phases can have different properties and different velocities. In the most sophisticated version, separate equations of continuity, momentum, and energy are written for each phase and these six equations are solved simultaneously. Gas phase and liquid phase (steam and water) are treated as a pseudo-single phase (mixture), which has density given by:

$$\rho_m = \rho_L . H + \rho_g . (1 - H) \tag{5}$$

The continuity, momentum, and energy equations given by;

- Mass balance Equation

$$\frac{\partial}{\partial z}(\rho_g v_g + \rho_L v_{sL}) = \frac{\partial}{\partial t}(\rho_m) \tag{6}$$

- Momentum balance Equation

$$\frac{\partial P}{\partial z} = -(\rho_m . v_m . \frac{\partial}{\partial z} - \rho_m . g + \frac{\rho_m f_m v_m}{2 \times t_i}) \tag{7}$$

- Energy Balance Equation

$$\frac{\dot{Q}_{loss}}{3600\ \times A_{ti}} = -\frac{\partial}{\partial z}\sum \rho_p v_p \cdot \left(h_p + \frac{v_p^2}{2}\right) + \sum \rho_p v_{sp}\, g \qquad (8)$$

2.5 Mathematical Model

The steam flow inside the wellbore involve occurrence of phase change, thus simultaneous solution of both the momentum balance and energy balance equations is required for the problem at hand. For steady flow systems, the pressure gradient, dp/dz, is balanced by the static head, ρgsinθ, the friction head, $\rho f v^2$/d, and the kinetic head, $(\rho v)\left(\frac{dv}{dz}\right)$. Therefore, the momentum balance equation becomes

$$-\frac{dp}{dz} = \rho g \sin\theta + \frac{f p v^2}{2d} + \rho v \frac{dv}{dz} \qquad (9)$$

Here the friction factor,f, must account for flow of two-phase mixture. For mixture density, we need to use the appropriate expression given by

$$\rho_m = f_L \rho_L + (1 - f_L)\rho_g \qquad (10)$$

We can use either the Hasan model, or the Beggs and Brill correlation for the computation of liquid holdup and pressure drop downward two phase flow. Griston-Willhite model for concentric steam injection involves simultaneous solution of four partial differential equations, two each for two conduits, using a numerical scheme. Because we are using PROSPER software to model the steam injection flow, we will be using the Beggs and Brill correlation that are available in PROSPER software.

2.6 PROSPER Software

2.6.1 About PROSPER

PROSPER is a well performance, design and optimization program for modeling most types of well configurations found in the worldwide oil and gas industry today. This software have been developed by Petroleum Experts Ltd. together with GAP, MBAL, PVTP, REVEAL, RESOLVE, and the combination of all those softwares is called IPM Suite.

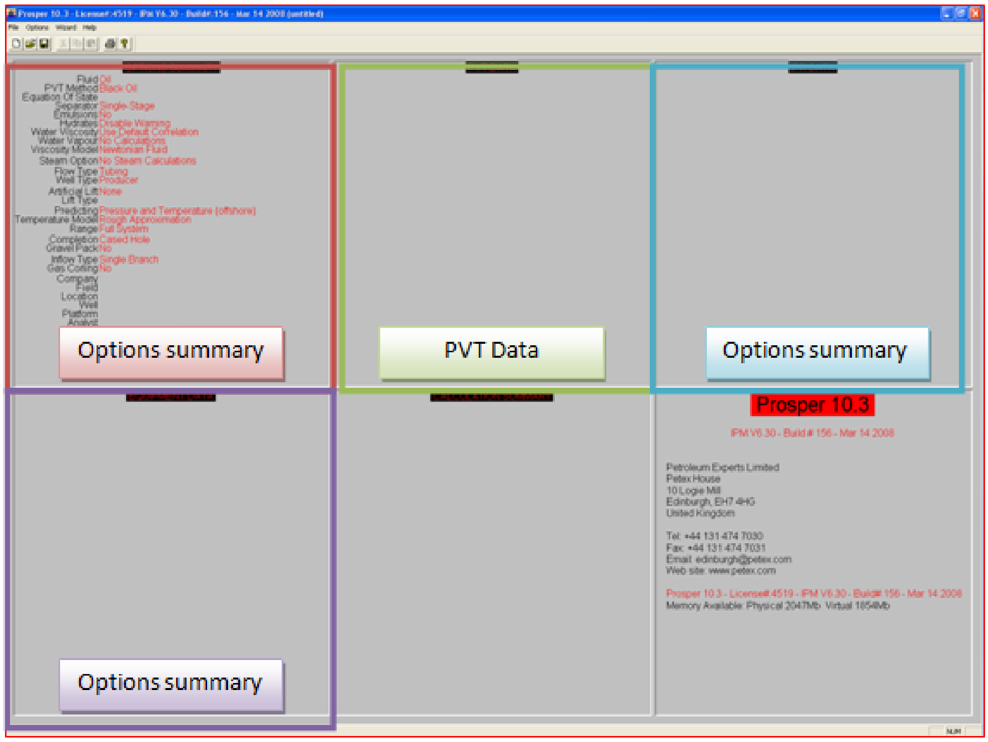
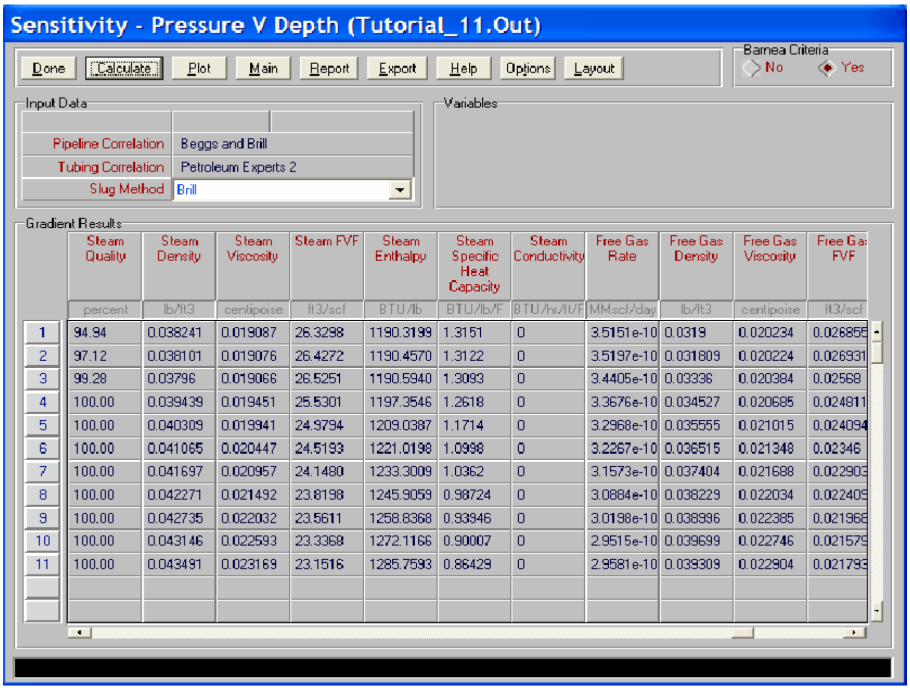


Figure 2.8: PROSPER software interface

We can estimate the initial flow rate against a well head flowing pressure in PROSPER when fluid data (PVT), reservoir data (IPR) and down hole equipment description (VLP) is provided for the steam injection well. Studies need to be done to select the proper inflow models for steam injection as there are more than 20 models available in the software. The IPR model selection depends upon the purpose of study, the suitability of the particular model and the data available for the study. For the pipeline correlation we will be using the Beggs and Brill while for the Slug Method we will be using the Brill method. For the vertical lift performance we will be using Petroleum Expert model as this correlation combines the best features of existing correlations. It uses the Gould et al flow map and the Hagedorn Brown correlation in slug flow, and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist results is used.

Sensitivity analysis can be done in the PROSPER software where it will plot the value according to the pressure versus depth.



	Steam Quality	Steam Density	Steam Viscosity	Steam FVF	Steam Enthalpy	Steam Specific Heat Capacity	Steam Conductivity	Free Gas Rate	Free Gas Density	Free Gas Viscosity	Free Ga FVF
	percent	lb/ft3	centipoise	ft3/scf	BTU/lb	BTU/lb/F	BTU/hr/ft/F	MMscf/day	lb/ft3	centipoise	ft3/scf
1	94.94	0.038241	0.019087	26.3298	1190.3199	1.3151	0	3.5151e-10	0.0319	0.020234	0.026855
2	97.12	0.038101	0.019076	26.4272	1190.4570	1.3122	0	3.5197e-10	0.031809	0.020224	0.026931
3	99.28	0.03796	0.019066	26.5251	1190.5940	1.3093	0	3.4405e-10	0.03336	0.020384	0.02568
4	100.00	0.039439	0.019451	25.5301	1197.3546	1.2618	0	3.3676e-10	0.034527	0.020685	0.024811
5	100.00	0.040309	0.019941	24.9794	1209.0387	1.1714	0	3.2968e-10	0.035555	0.021015	0.024094
6	100.00	0.041065	0.020447	24.5193	1221.0198	1.0998	0	3.2267e-10	0.036515	0.021348	0.02346
7	100.00	0.041697	0.020957	24.1480	1233.3009	1.0362	0	3.1573e-10	0.037404	0.021688	0.022903
8	100.00	0.042271	0.021492	23.8198	1245.9059	0.98724	0	3.0884e-10	0.038229	0.022034	0.022409
9	100.00	0.042735	0.022032	23.5611	1258.8368	0.93946	0	3.0198e-10	0.038996	0.022385	0.021968
10	100.00	0.043146	0.022593	23.3368	1272.1166	0.90007	0	2.9515e-10	0.039699	0.022746	0.021579
11	100.00	0.043491	0.023169	23.1516	1285.7593	0.86429	0	2.9581e-10	0.039309	0.022904	0.021793

Figure 2.9: PROSPER Sensitivity Analysis

2.6.2 Enthalpy Balance

Enthalpy Balance temperature model in PROSPER applies the general energy equation for flowing fluid,

$$\Delta U + \Delta\left(\frac{mv^2}{2}\right) + \Delta(mgz) + \Delta(PV) - Q = 0 \tag{11}$$

In terms of enthalpy

$$H = U + pV \tag{12}$$

This is written:

$$\Delta H + \Delta\left(\frac{mv^2}{2}\right) + \Delta(mgz) - Q = 0 \tag{13}$$

In other terms:

$$\frac{dT}{dz} = \frac{1}{c_{pm}}\left(\frac{dQ}{dZ} - gsin\theta - v\frac{dv}{dz}\right) + \mu_T\frac{dP}{dz} \tag{14}$$

If heat transfer with the surroundings (Q) is neglected, the usual pressure equation solved in multiphase flow results. PROSPER solves the general energy equation by considering the enthalpy balance across an incremental length of pipe. The enthalpy term includes the effects of pressure (including Joule-Thompson effect) and phase changes. For a given pipe increment, the enthalpy (H_2) at the other end of pipe is estimated. The difference (H_2-H_1) is compared to ΔH where,

$$\Delta H = -\frac{\Delta Q}{\rho_l q_l + \rho_g q_g} + \Delta L cos\theta + \frac{1}{2}\frac{\overline{V_{tot}^2}}{g} \tag{15}$$

The total heat transfer coefficient is estimated for the T, P of the iteration step to calculate the heat exchanged. Using the energy equation, we can find dh. If dh does not equal H_2-H_1, the iteration continues until convergence. The Enthalpy Balance method solves the energy equation simultaneously for both temperature and pressure. The solution temperature at the downstream side of the pipe increment is therefore the value of T_2 when the iteration has converged. The heat transfer coefficient is used to calculate dQ within the enthalpy balance iterations and not the temperature. The heat transfer coefficient is itself a function of the temperature of both the fluid and the surroundings; therefore iteration is required to find both the heat transfer coefficient and the enthalpy balance. The formation is a thermal sink at temperature T_e. The temperature profile near the wellbore is dependent upon producing time and the thermal diffusivity of the formation. The heat diffusivity equation accounts for localised heating (or cooling) of the formation by the well fluids.

For a pipe increment, the heat flow is calculated using:

$$dQ = 2\pi \left[\frac{(T_f - T_e)}{\frac{f(t)}{k_e} + \frac{1}{r_{to}U_{TO}}}\right] \Delta L \tag{16}$$

Where,

T_f-T_e is the temperature difference between the fluid and the formation at infinity.
k_e is the effective thermal conductivity of the formation
f(t) is the solution of the heat diffusivity equation
The exact solution of heat diffusivity equation is:

$$\frac{1}{f(t)} = \frac{4}{\pi^2}\int_0^{\infty} e^{-x^2u^2}\frac{du}{U\left(J_0^2(u)+Y_0^2(u)\right)}$$

This integral poses numerical problems as u0 and is slow. This equation is evaluated for very early times only. For intermediate times, PROSPER uses a fit of the TD vs tD generated using the exact solution. At later times a logarithmic approximation is used:

$$f(t) = 0.982log_e\left(1+1.81\frac{\alpha t}{r_n}\right) \quad (18)$$

Where thermal diffusivity $\alpha = \frac{k}{\rho C_p}$

This formulation approximates the exact solution with less than 1% error. U_{TO} is the overall heat transfer coefficient.

$$\frac{1}{U_{TO}} = \frac{1}{h_f}+\frac{1}{h_c}+\frac{1}{h_r}+\frac{1}{h_{co}} \quad (19)$$

The overall heat transfer coefficient takes into account forced convection inside the pipe and free convection outside the pipe plus radiation and conduction.

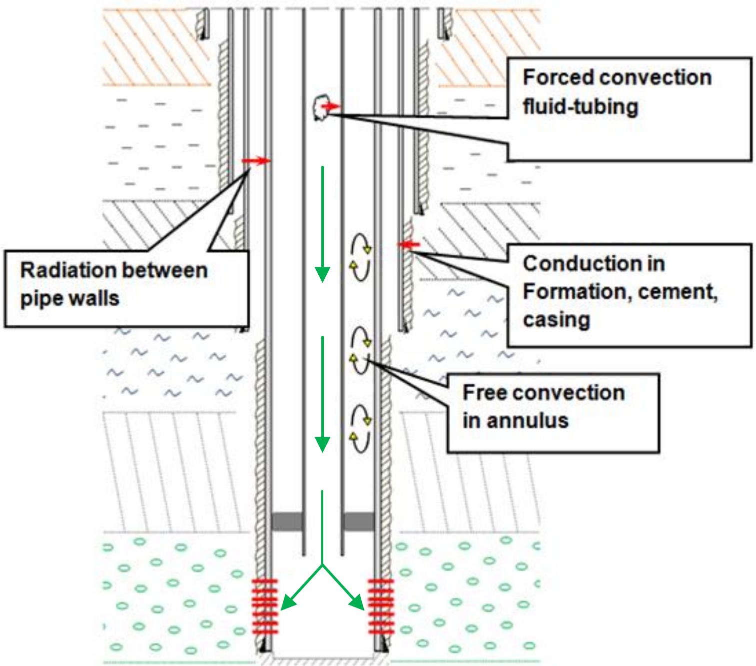


Figure 2.10: Heat Transmission Mechanism in the Wellbore

Heat transfer from the pipe is in three terms:

Conduction:

$$\Delta Q = 2\pi k \Delta L \frac{T_1 - T_2}{log_e\left(\frac{r_2}{r_1}\right)} \tag{20}$$

Forced Convection:

$$\Delta Q = 2\pi r_2 h_f \Delta L (T_1 - T_2) \tag{21}$$

Free convection and Radiation:

$$\Delta Q = 2\pi r_1 (h_c + h_r)(T_1 - T_2) \tag{22}$$

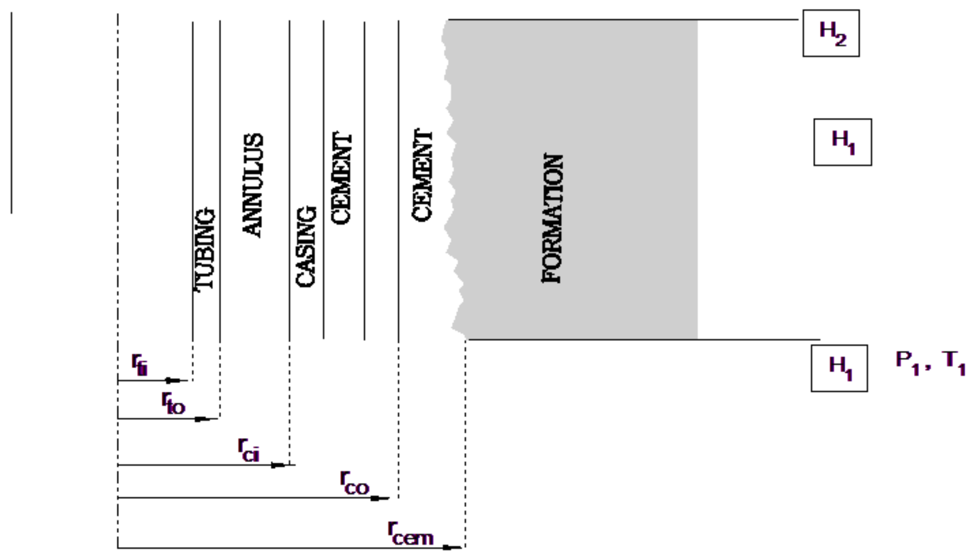


Figure 2.11: Wellbore Geometry

2.6.3 Steam Calculation

Steam injection is a technique of Enhanced Oil Recovery. Steam is injected in the reservoir in order to displace and at the same time heat up the oil, making it easier to flow. When modeling steam injection, it is important to take in account that the following parameters are interrelated:

- Pressure
- Temperature
- Steam quality(vapor fraction)
- Enthalpy

To properly model steam injection an Enthalpy Balance model needs to be used (Enthalpy Balance or Improved Approximation):

$$H_T = H_L(1 - x_v) + H_v x_v \tag{23}$$

H_T = total enthalpy

$H_{L,V}$=liquid vapor enthalpy

x_V=steam quality

Rearranging

$$xV = \frac{H_T - H_L}{H_V - H_L} \tag{24}$$

This shows that Steam quality is calculated from knowledge of enthalpy. As steam quality, pressure, temperature and Enthalpy are interdependent, the Enthalpy Balance model has to iterate on pressure, temperature, enthalpy until convergence is found.

2.7 Multiphase flow correlation

2.7.1 Two Phase Flow

Unlike single-phase flow, two-phase flow behaviour is more complex than for single-phase flow. The phases tend to separate because of differences in density. Shear stresses at the pipe wall are different for each phase because of their different densities and viscosities. The main difference between gas and liquid phase is they do not travel at the same speed in the pipe. For downward flow, liquid always flows faster than the gas or vapor phase. We give information about the two phase correlations that are applied in our calculations for vertical downward flow with insulated and uninsulated tubing for both an onshore and offshore environments. The two-phase flow correlations we used in our calculations are modified Beggs and Brill, Aziz, Govier and Fogarasi, Drift Flux model, and Hasan and Kabir correlations. Besides, we also addressed flow regimes for vertical flow.

2.7.2 Liquid Holdup

Liquid holdup H_L, is defined as the fraction of an element of pipe which is occupied by liquid at same instant.

H_L = Volume of liquid in a pipe element / volume of the pipe element

It is necessary to be able to determine liquid holdup to calculate such things as mixture density, actual gas and liquid viscosities, effective viscosity and heat transfer. The value of liquid holdup varies from zero for single-phase gas flow to one for single phase liquid flow. Liquid holdup may be measured experimentally by several methods, such as resistivity or capacitance probes or by trapping a segment of the flow stream between quick closing valves and measuring the volume of liquid trapped. The relative in-situ volume of liquid and gas is sometimes expressed in terms of the volume fraction occupied by gas, called gas holdup Hg, or void fraction. Gas holdup is expressed as:

$$H_g = 1 - H_L \tag{25}$$

A value for liquid holdup cannot be calculated analytically. It must be determined from empirical correlations and is a function of variables such as gas and liquid properties, flow pattern, pipe diameter and pipe inclination. Liquid holdup equations are functions of dimensionless liquid and gas velocity numbers in addition to liquid viscosity number and angle of inclination. When gas and liquid flow concurrently in a pipe, the gas normally travels faster than the liquid, causing a slippage between the phases. Because of this slippage, the in-situ liquid volume fraction at any given location in the pipe cannot be computed directly from input conditions. An accurate prediction of liquid holdup is required to compute the hydrostatic head losses in two-phase. Many attempts to develop empirical correlations for predicting liquid holdup have been made. The liquid holdup of Hagedorn and Brown was not measured but was calculated to satisfy the measured pressure gradients after the pressure gradients due to friction and acceleration were accounted for.

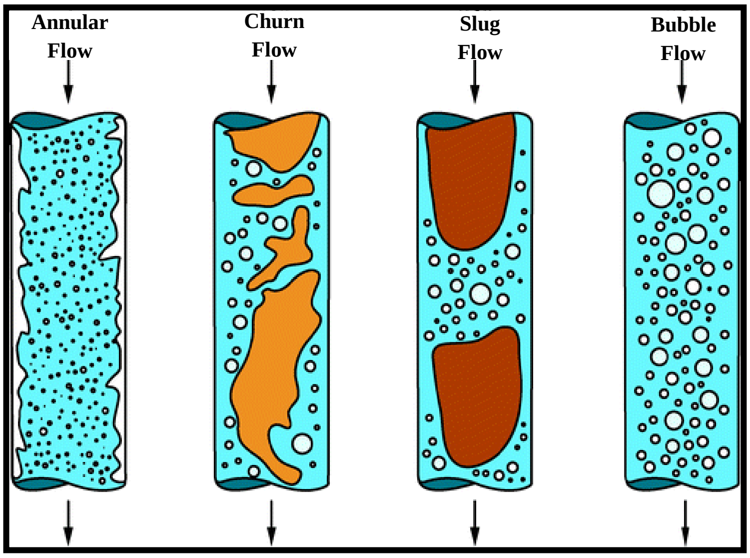


Figure 2.12: Principle Flow Patterns

The data used are consisted of 51 field pressure profiles for vertical well. Other correlation was developed by Duns and Ros based on flow pattern map and function on the slip velocity, and Griffith presented a correlation as a gas void fraction for bubble flow. With increases in exploration and production activity offshore during 1960's resulted in the drilling of a large number of wells with large deviations in inclination angle from the vertical. It soon became obvious that flow-pattern and liquid holdup prediction methods developed for vertical flow often failed in directional wells.

The Beggs and Brill and the Mukherjee and Brill generalized correlations were developed to improve pressure drop prediction in directional wells and hilly-terrain pipelines based on experimental studies. In PROSPER software we will be using the Petroleum Experts correlation for tubing flow correlation as this correlation combines the best features of existing correlations. It uses the Gould et al flow map and the Hagedorn Brown correlation in slug flow, and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist results is used.

2.7.3 Multiphase correlation models

Beggs and Brill

For multiphase flow, many of the published correlations are applicable for "vertical flow" only, while others apply for "horizontal flow" only. Few correlations apply to the whole spectrum of flow situations that may be encountered in oil and gas operations, namely uphill, downhill, horizontal, inclined and vertical flow. The

Beggs and Brill (1973) correlation, is one of the few published correlations capable of handling all these flow directions. It was developed using 1" and 1-1/2" sections of pipe that could be inclined at any angle from the horizontal.

The Beggs and Brill multiphase correlation deals with both the friction pressure loss and the hydrostatic pressure difference. First the appropriate flow regime for the particular combination of gas and liquid rates (Segregated, Intermittent or Distributed) is determined. The liquid holdup, and hence, the in-situ density of the gas-liquid mixture is then calculated according to the appropriate flow regime, to obtain the hydrostatic pressure difference. A two-phase friction factor is calculated based on the "input" gas-liquid ratio and the Fanning friction factor. From this the friction pressure loss is calculated using "input" gas-liquid mixture properties.

If only a single-phase fluid is flowing, the Beggs and Brill multiphase correlation devolves to the Fanning Gas or Fanning Liquid correlation.

Hagedorn and Brown

Hagedorn and Brown (1965) adopted an approach of backing out the liquid holdup. After obtaining multiphase flow performance data from an experimental well, the acceleration term and the friction term were solved in the conventional manner and then a value of liquid holdup was calculated to satisfy the observed pressure gradient. To correlate the liquid holdup, Hagedorn and Brown (1965) drew upon the dimensionless groups defined by Ros (1961)

Aziz, Govier, and Fogarasi

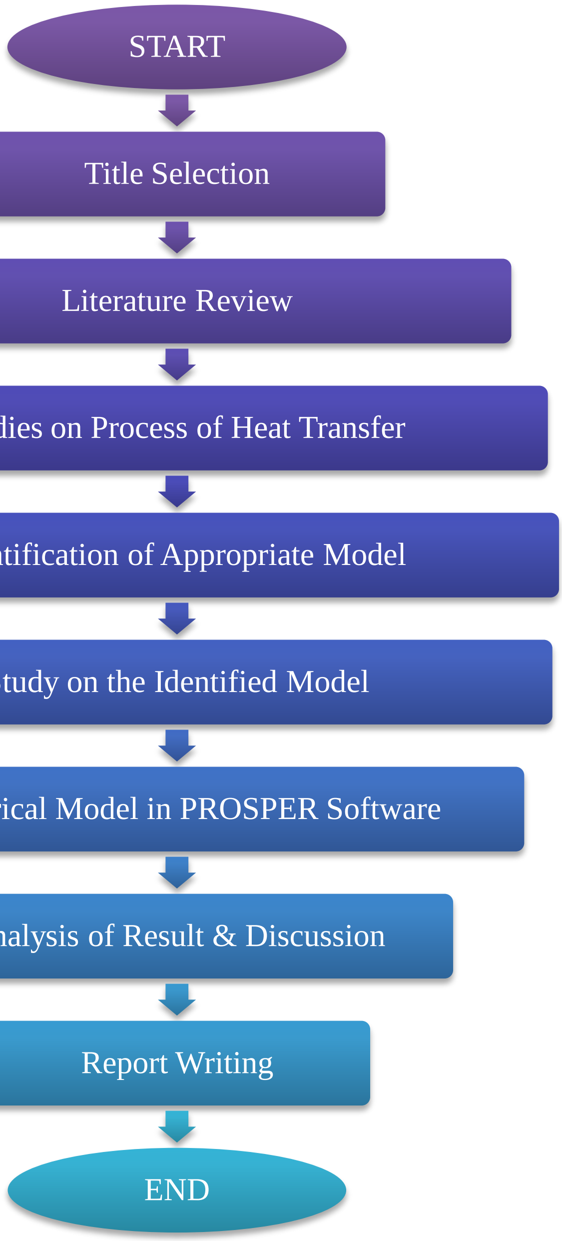
Aziz, Govier, and Fogarasi (1972) proposed a multiphase flow correlation that was dependent on the flow regime. The Aziz et al. (1972) correlation has some theoretical justification and is considered to be one of the least empirical correlations available. Four flow regimes are considered: Bubble, slug, transition, and annular-mist. Aziz et al. (1972) presented original correlations for the bubble and slug flow regimes and used the method of Duns and Ros (1963) for the transition and annular-mist flow regimes.

CHAPTER 3

METHODOLOGY

3.1 Process Flow

Below is the process flow diagram for the Project throughout Final Year Project 1(FYP1) and Final Year 2(FYP2) period. This diagram summarize the project flow and describe the activities or task that have been done and going to be done during the Final Year Project period. This is very important in order to make sure the project is going on the correct path and to know the work that have been left and have to be done in the future.



3.2 Project Work

Prelim Research

Conduct literature review on the fluid and energy flow in the EOR steam injection wells. Do researches to understand the mechanism of heat transfer and the parameters that related to it.

↓

Exploring PROSPER software

Getting to know the PROSPER software deeply and conduct the studies to get to know the models that are being used in the PROSPER software.

↓

Identification of appropriate model

Conduct a studies on the PROSPER software to find the most appropriate model for pipeline correlation, tubing flow correlation and inflow correlation.

↓

Simulation using PROSPER software

Input the data in PROSPER software for steam injection wells and conduct a sensitivity analysis to get a result for heat transfer parameters (temperature, enthalpy, quality and so on) as a function of pressure and depth.

↓

Analysis Result and Discussion

Analyze the result of the PROSPER software for fluid flow of steam injection well. Discuss the findings from the results obtained and make a conclusion out of the study, and determine if the objective has been met.

3.3 PROSPER modeling

Simulation have been done in PROSPER software for steam injection wells using hypothetical well data. The input data are given below.

1

PVT input

Parameter	
Water Salinity	10000ppm
Wellhead Steam Temperature	700°F

2

Deviation Survey

Measured Depth (ft)	True Vertical Depth(ft)
0	0
2000	2000

3

Downhole Equipment

Equipment Type	Measured Depth(ft)	Internal Diameter(in)	Roughness(in)	Rate Multiplier
Xmas tree(wellhead)	0	N/A	N/A	N/A
Tubing	1590	2.124	0.0006	1
Casing	1600	4	0.0006	1

4

Static Geothermal Gradient

Measured Depth(ft)	True Vertical Depth(ft)	Static Temperature(°F)	Heat Transfer coefficient(btu/h/ft2/F)
0	0	70	8
2000	2000	130	8

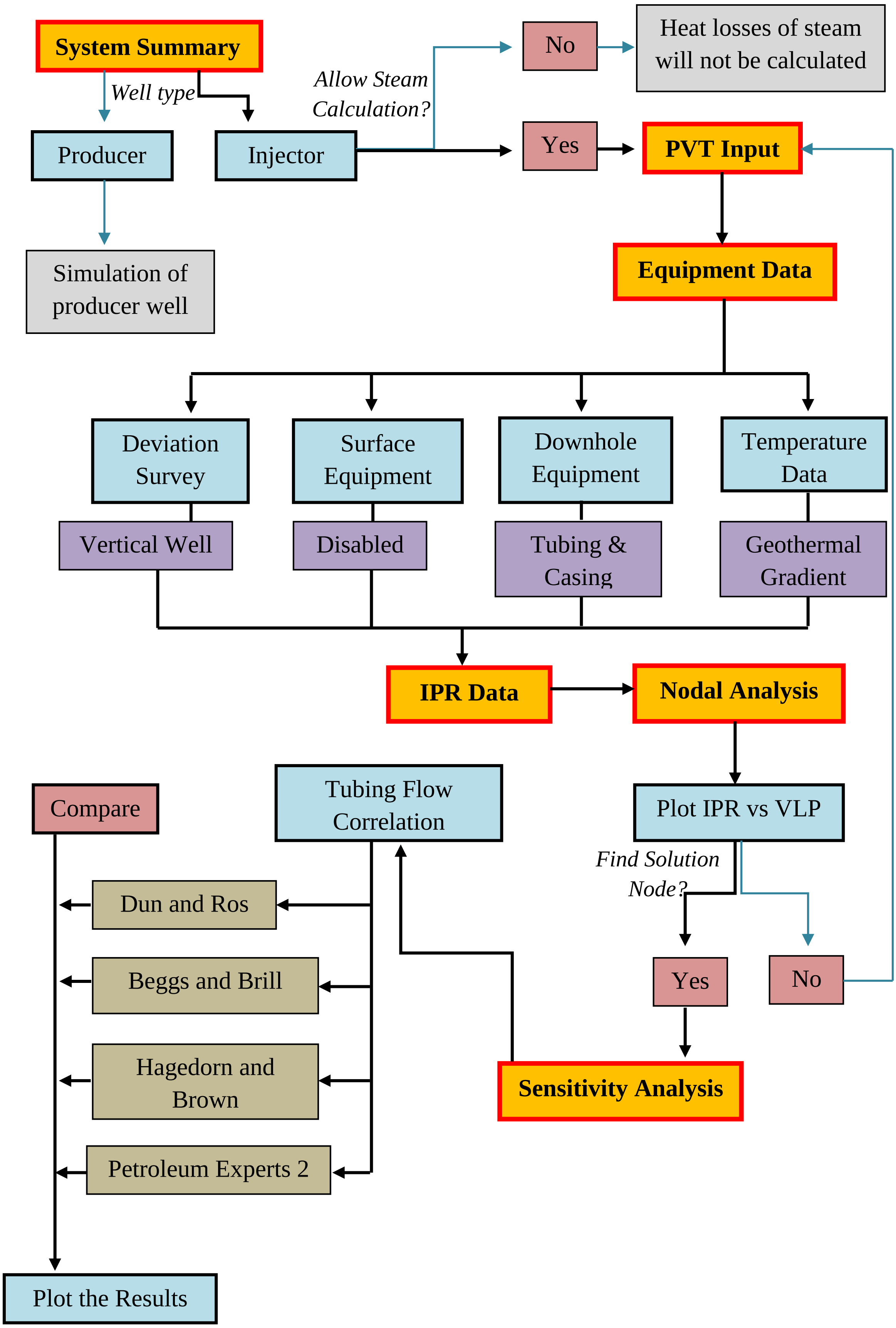
5

Reservoir Input Data

IPR model:	PI Entry
Static Reservoir Pressure:	1000 psig
Reservoir Temperature:	130 °F
Water Cut:	100%
Total GOR:	0
Compaction Permeability Reduction Model:	No
Productivity Index:	100 stb/d/psi

Table 3.1: PROSPER Input Parameters

3.4 Simulation Steps in PROSPER



3.5 Data Validation

A model have been simulated using PROSPER software in order to validate the results in the software. Martha Bigpond injection well has been simulated and the data for this well have been taken from Fontanila Thesis paper.

Input Parameters		Field Data	Units
Tubing Inner Radius	r_{ti}	0.885	ft
Tubing Outer Radius	r_{to}	0.104166667	ft
Insulation Radius	r_{ins}	no insulation	
Casing Inside Radius	r_{ci}	0.166666667	ft
Casing Outside Radius	r_{co}	0.1875	ft
Hole radius	r_h	0.6	ft
Thermal conductivity of Earth	k_e	1	Btu/d/ft/ºF
Thermal diffusivity of Earth	α_e	0.0286	Ft^2/d
Thermal conductivity of cement	k_{cem}	0.2	Btu/d/ft/ºF
Emissivity of outer tubing	ε_{to}	0.9	
Emissivity of inner casing	ε_{ci}	0.9	
Emissivity of Earth	ε_{EARTH}	0.94	
Steam Injection Rate	W_m	4640	bbl/day
Quality	x	0.8	
Wellhead Pressure	p_{wh}	250	psia
Surface formation temperature	T_m	50	ºF
Depth	Z	1600	ft
Steam Injection Time	t	71	h

Table 3.2: Martha Bigpond Well Geometry

The parameters that have been tabulated at above have been used to validate the model in PROSPER by comparing it with the existing models. The trend of the results of the PROSPER have been compared with those models such as Fontanila model, Beggs and Brill model, and Field Data model.

1

PVT input

Parameter	
Water Salinity	10000ppm
Wellhead Steam Temperature	403ºF

2

Deviation Survey

Measured Depth (ft)	True Vertical Depth(ft)
0	0
1600	1600

3

Downhole Equipment

Equipment Type	Measured Depth(ft)	Internal Diameter(in)	Roughness(in)	Rate Multiplier
Xmas tree	0	N/A	N/A	N/A
Tubing	1590	2.124	0.0006	1
Casing	1600	4	0.0006	1

4

Static Geothermal Gradient

Measured Depth(ft)	True Vertical Depth(ft)	Static Temperature(ºF)	Heat Transfer coefficient(btu/h/ft2/F)
0	0	50	9
1600	1600	95	9

5

Reservoir Input Data

IPR model:	PI Entry
Static Reservoir Pressure	100 psig
Reservoir Temperature	95 ºF
Water Cut	100%
Total GOR	0

Table 3.3: PROSPER Input Parameters

Above are the data that have been input in the PROSPER. Wellhead steam temperature has been calculated and validated using this equation:

$$T = 100P^{0.25} + H(P)$$

Where,

$$H(P) = d_1 + d_2 log_{10}P + d_3(log_{10}P)^2$$

Where,

d_1= -3.1246x10^1
d_2=5.7188x10^1
d_3=-1.7601X10^1

This equation has been taken from Dave O.Cox[31] et al thesis paper. The result that has been obtained shows us that the injected temperature is accurate as the results are the same.

3.5.1 Overall Heat Transfer Coefficient Calculation

For the calculation overall heat transfer coefficient, modified Fontanilla model approach has been developed. The model has been developed using mathematica software by AbdelRahman[30], 2011 with some modification. Fontanilla model input the thermo physical properties of the annulas fluid before the calculation starts. In his study air is been assumed to be the annulas fluid for all time and the thermo physical properties all have been changed to be function of air temperature only.

ρ density of air = 360.77819 ∗ T^{-1}

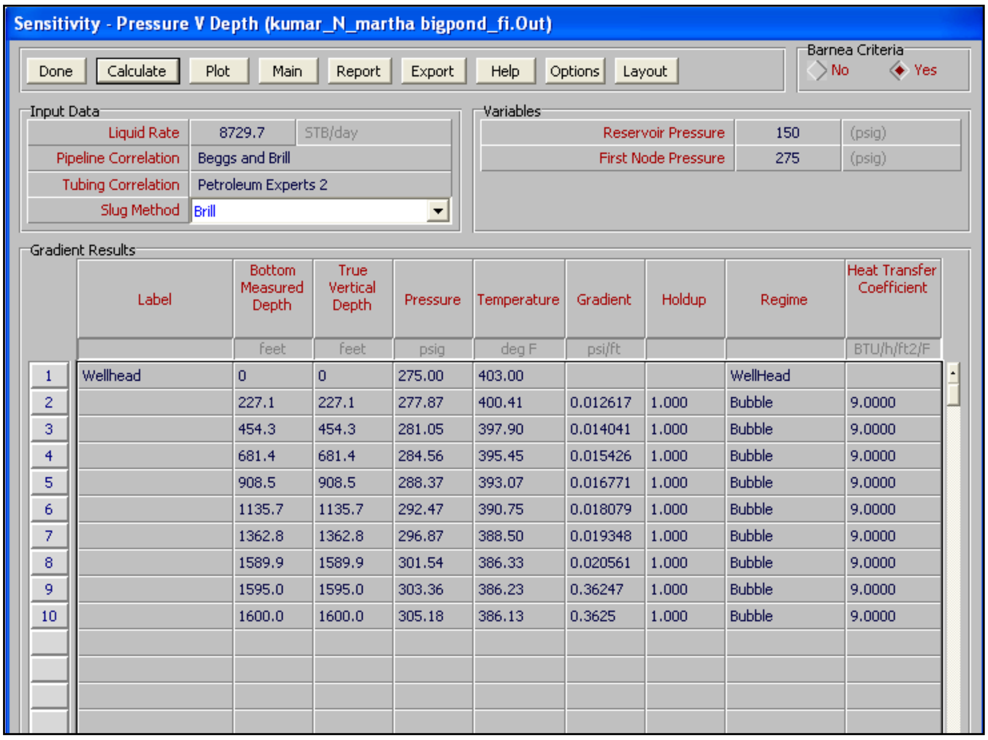
v (Kinematic Viscosity) = −1.1555 ∗ 10−14 ∗ T3 + 9.5728 ∗ 10−11∗ T2 + 3.7604 ∗ 10−8 ∗ T − 3.4484 ∗ 10^{-6}

a (Thermal Diffusivity) = 9.1018 ∗ 10−11T2 + 8.8197 ∗ 10−8 ∗ T−1.0654 ∗ 10^{-5}

The rest of other parameters such as Pr (Prandtl number**),** Gr (Grashof number) are based on this parameters, by doing this modification the input parameters have been reduced. Model has been simulated using Mathematica software.

This model has been modified by the author to make it suitable for the Martha Bigpond well geometry. One of the main modifications is on the parameters involving insulation in the well. Since there is no insulation is considered some modification in the code has been adopted. The effect of insulation has been studied in the separate part of this project to know the effect of the insulation materials.

After inputting the data in PROSPER sensitivity analysis can be run in the software by making the wellhead pressure and reservoir pressure as a variable. Since PROSPER is using nodal analysis method to calculate the heat losses in the wellbore, it is necessary to input two node pressure. Sensitivity analysis in PROSPER will give us the steam properties throughout the well. Temperature, Pressure, and Steam Quality versus Depth can be calculated using the Sensitivity analysis in PROSPER.



	Label	Bottom Measured Depth	True Vertical Depth	Pressure	Temperature	Gradient	Holdup	Regime	Heat Transfer Coefficient
		feet	feet	psig	deg F	psi/ft			BTU/h/ft2/F
1	Wellhead	0	0	275.00	403.00			WellHead	
2		227.1	227.1	277.87	400.41	0.012617	1.000	Bubble	9.0000
3		454.3	454.3	281.05	397.90	0.014041	1.000	Bubble	9.0000
4		681.4	681.4	284.56	395.45	0.015426	1.000	Bubble	9.0000
5		908.5	908.5	288.37	393.07	0.016771	1.000	Bubble	9.0000
6		1135.7	1135.7	292.47	390.75	0.018079	1.000	Bubble	9.0000
7		1362.8	1362.8	296.87	388.50	0.019348	1.000	Bubble	9.0000
8		1589.9	1589.9	301.54	386.33	0.020561	1.000	Bubble	9.0000
9		1595.0	1595.0	303.36	386.23	0.36247	1.000	Bubble	9.0000
10		1600.0	1600.0	305.18	386.13	0.3625	1.000	Bubble	9.0000

Figure 3.1: PROSPER Sensitivity Analysis Results

3.5.2 Insulation Effect

In this project author has studied on the effect of the insulation as well. The effect of the insulation is not studied deeply as it is not the main requirement of this project. The code have been developed in the Matlab software referring to Fidan Thesis[25]. The code has been developed to study the effects of different type of insulation materials on the overall heat transfer coefficient.

```
Command Window
File  Edit  Debug  Desktop  Window  Help
>> TsteamWins = 550;
TaverageWins = 60;
PipeLengthWins = 100;
InjTimeWins = 365*24;
AvrWindSpeedWins = 20;
rinsideWins = 0.1478;
routsideWins = 0.1667;
rinsulatedWins = 0.4167;
lambdaPipeWins = 600/24;
lambdaInsWins = [0.166 0.194 0.388 0.499 0.569 0.96]./24;
hfWins = 2000;
hpiWins = inf;
hpoWins = 2000;
CollectDatasWithins = [];
hfcWins = (18*(AvrWindSpeedWins*0.6)*(rinsulatedWins*0.6)/rinsulatedWins)/24;
hfcWins = (18*(AvrWindSpeedWins*0.6)*(rinsulatedWins*0.6)/rinsulatedWins)/24;
colors = lines(length(lambdaInsWins));
for i=1:length(lambdaInsWins)
RhWins = 1/(2*pi)*(1/(hfWins*rinsideWins)+
1/(hpiWins*rinsideWins)+(1/lambdaPipeWins)*log(routsideWins/rinsideWins)
+1/(hpoWins*routsideWins)+(1/lambdaInsWins(i))*log(rinsulatedWins/routsideWins)
+1/(hfcWins*rinsulatedWins));
QlsWins = (TsteamWins - TaverageWins)/RhWins;
QlWins = QlsWins*InjTimeWins*PipeLengthWins;
CollectDatasWithins = [CollectDatasWithins;[RhWins QlsWins QlWins]];
InjTimeplotWins = (1:InjTimeWins)';
PlotQlWins=(QlsWins*PipeLengthWins).*InjTimeplotWins;
figure(1)
plot(PlotQlWins, InjTimeplotWins./24, 'color',colors(i,:),'Linewidth',3)
hold on
grid on
set(gca,'XAxisLocation','top','YDir','rev')
xlabel(['Cumulative Heat Losses (in Btu) for '
num2str(PipeLengthWins) 'ft'],'Fontname','Calibri','Fontsize',16)
ylabel(['Time (in Days) ' num2str(InjTimeWins/24)], 'Fontname', 'Calibri', 'Fontsize', 16)
LambdaValStr = sprintf('%0.3G',lambdaInsWins(i));
labels {i} = ['\lambda = ' num2str(LambdaValStr)];
legend(labels,2,'Location','NE')
set(gcf,'Units','normalized');
set(gcf,'OuterPosition',[0 0 1 1]);
end
```

Figure 3.2: Matlab Code to study on the effect of insulation

3.6 Gantt Chart

No	Detail / Week	1	2	3	4	5	6	7		8	9	10	11	12	13	14	15
1	Learning to use PROSPER software								**Mid Semester Break**								
2	Modeling steam injection well in PROSPER																
3	Submission of Progress Report																
4	Validating the PROSPER model																
4	Pre-EDX																
5	Submission of draft report																
6	Submission of dissertation(soft bound) and technical paper																
7	Oral presentation																
8	Submission of project dissertation (hard bound)																

Table 3.4: Gantt chart(FYP II)

Processes

Milestones

3.7 Tools Required

In order to complete this project, the end product would be modeling of fluid flow in computation software. The software is needed to model the fluid flow and to get the reliable result.

The software chosen is the modeling software which is PROSPER. This software was developed by Petroleum Experts (PETEX). This software is a well performance, design and optimization program for modeling most types of well configurations found in the worldwide oil and gas industry today.

3.8 Knowledge required

There are several things that need to be understood in order to conduct the project successfully. They are:

1) Understanding the Enhance Oil Recovery (EOR) Method and its advantages in oil recovery.
2) Understanding the Steam Injection as one of the EOR method and how it help in oil and gas production.
3) Understanding the properties of steam as the fluid that flows in wellbore.
4) Understanding the heat transfer process that will occur in the wellbore because of the differential temperature that occur between wellbore and formation.
5) Understanding the natural geothermal gradient.
6) Understanding the wellbore structure.
7) Understanding the energy flow in the wellbore
8) Get to know the PROSPER software the models that are being used by the software.

Thus several papers and several books need to be referred to understand all the topics that are given above and two of the main books are Fluid Flow and Heat Transfer in Wellbores by A.R. Hasan and C.S. Kabir and Heat Transfer Principles and Applications by Binay K. Dutta.

CHAPTER 4

RESULTS AND DISCUSSION

This chapter will discuss about the results of the steam injection well that have been simulated in PROSPER software.

4.1 PROSPER Sensitivity Analysis

4.1.1 Temperature Profile

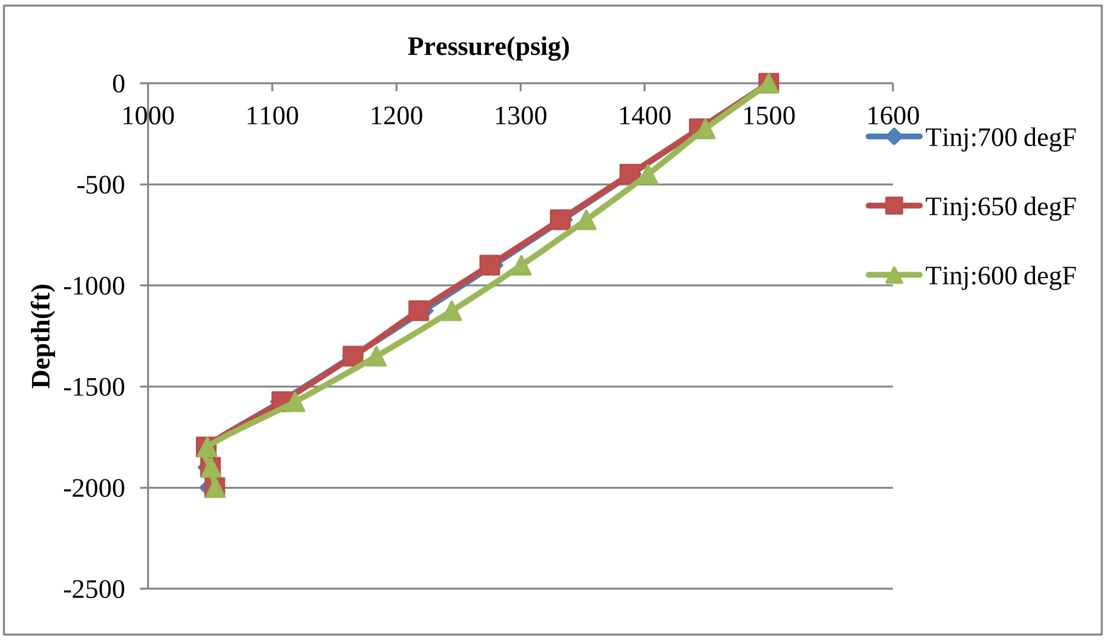


Figure 4.1: Pressure vs Depth

Figure above shows us that the pressure drops throughout the well. The original injection temperature value is 700 degF and the other two values have been used to study the effect of injection steam temperature on the pressure. The pressure decreased from 1500 psig to 1080 psig throughout the well. This is because of the heat losses, friction pressure losses due to the tubing and slippage between the different phases. The end part of the graph shows us the phase change of the steam. Increasing liquid phase in the steam will make the pressure to increase. As we can see the pressure drop is not much when we reduce the injection steam temperature by 50 degF. The slopes of those three lines are almost the same and the pressure at the bottomhole is around 1080 psig.

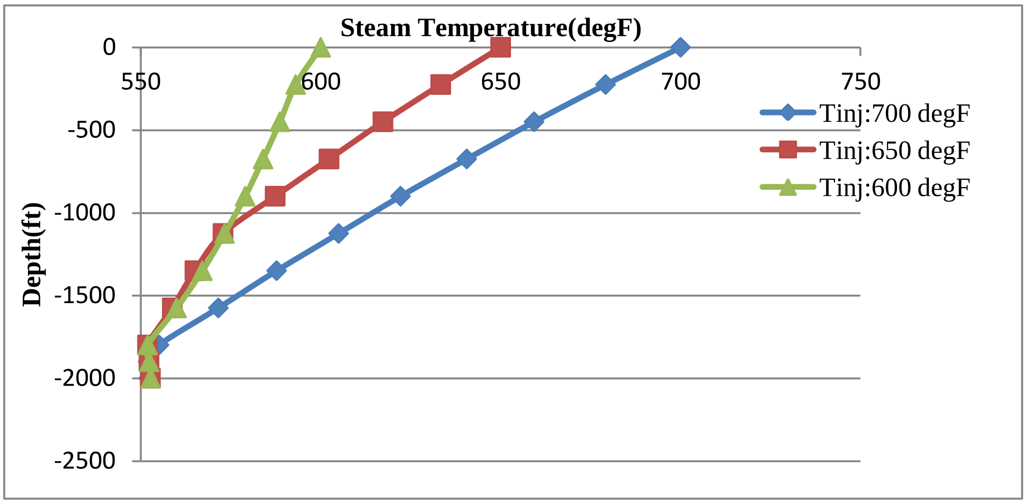


Figure 4.2: Steam Temperature vs Depth

The temperature has been decreased from 700degF to 550degF. Temperature decreases due to the heat losses. The temperature gradient for the 700 degF injected steam temperature is lower than the temperature gradient for 600 degF. The temperature change is higher when 700degF steam injected to the well as the steam temperature at the bottomhole is 550 degF thus it involves a lot of heat losses to the formation rather than the injected steam with lower temperature.

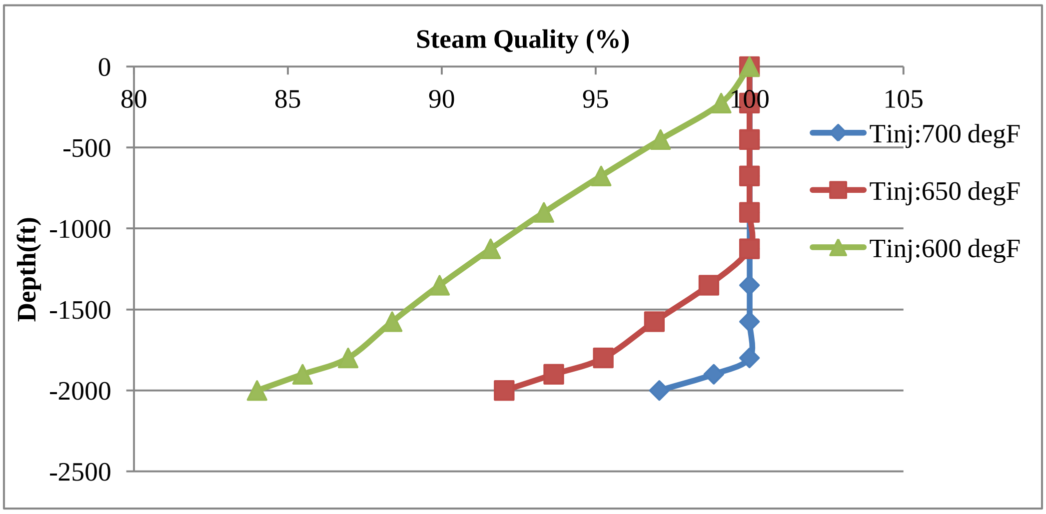


Figure 4.3: Steam Quality vs Depth

The steam quality is changes a lot when steam with lower temperature is injected. This is because; the phase ratio in the steam will change as the steam losses its heat to the surrounding formation. The temperature will stay constant although the quality is different at the bottomhole as shown in figure 4.3 because of the Joule Thompson effect.

4.1.2 Pressure Profile

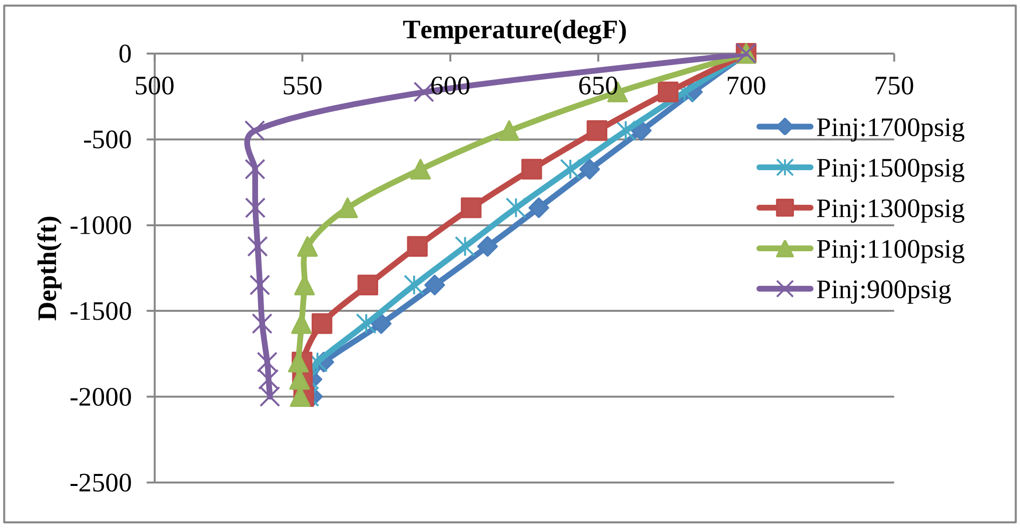


Figure 4.4: Steam Temperature vs Depth

Figure above shows that pressure decrement is higher when injected steam pressure is lower. When the injected steam pressure is lower than the reservoir pressure, we can see that the temperature at the bottomhole is changing.

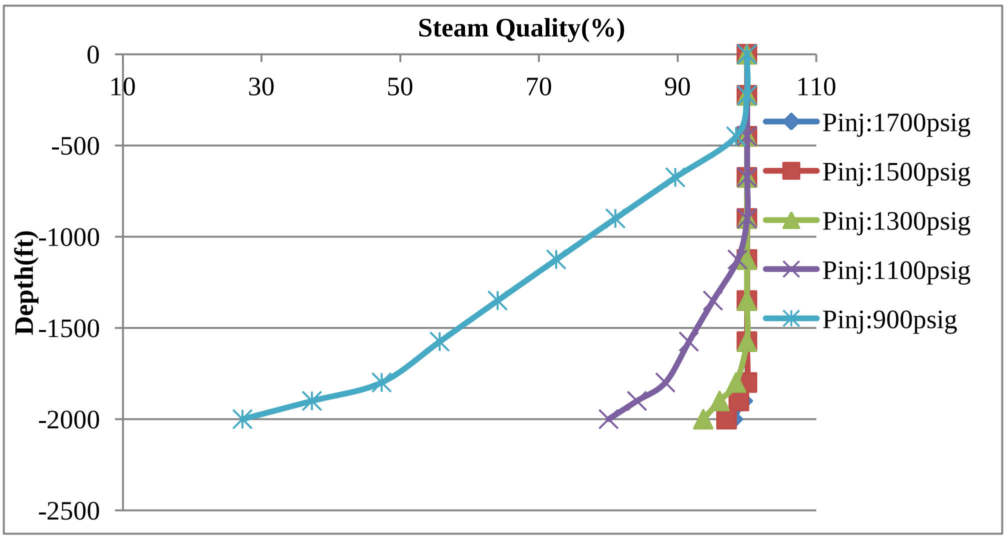


Figure 4.5: Steam Quality vs Depth

Quality of the steam at the bottomhole changes a lot when the injected pressure is decreasing. Steam with lower injection pressure will make the steam to loss its heat easily thus decreasing its gas liquid ratio.

4.1.3 Overall Heat Transfer Coefficient Effect

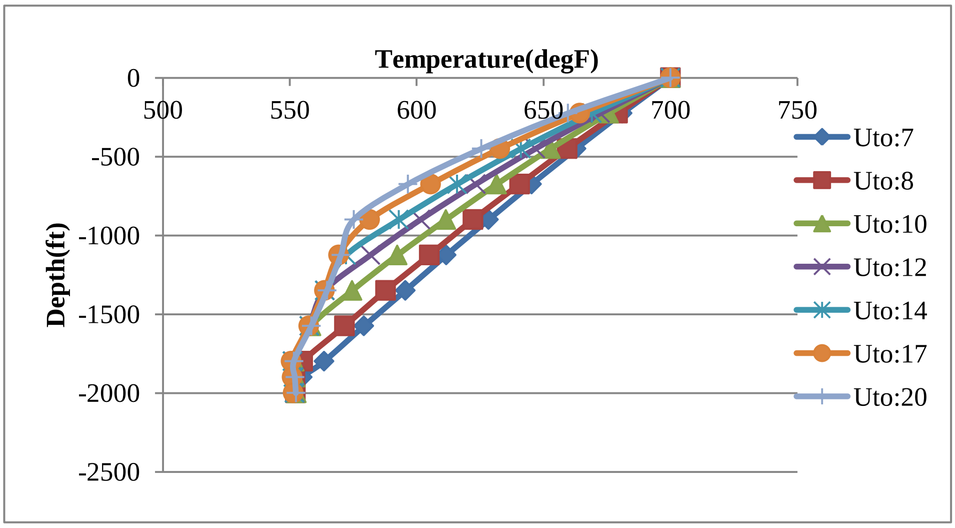


Figure 4.6: Temperature vs Depth

Increasing the overall heat transfer coefficient will make the temperature of the steam to decrease very fast. This is because the heat losses through the formation will be very high when the overall heat transfer coefficient is very high.

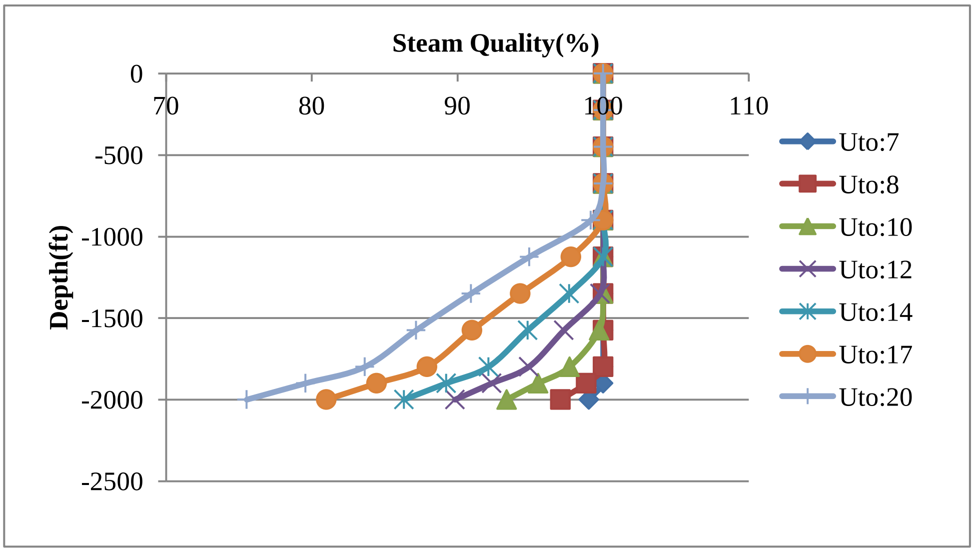


Figure 4.7: Steam Quality vs Depth

The trend is showing us that steam quality decreasing very fast when the overall heat transfer coefficient is high. Rapid heat losses to the formation will cause ratio of liquid quickly to be higher than the gas.

4.2 Data Validation

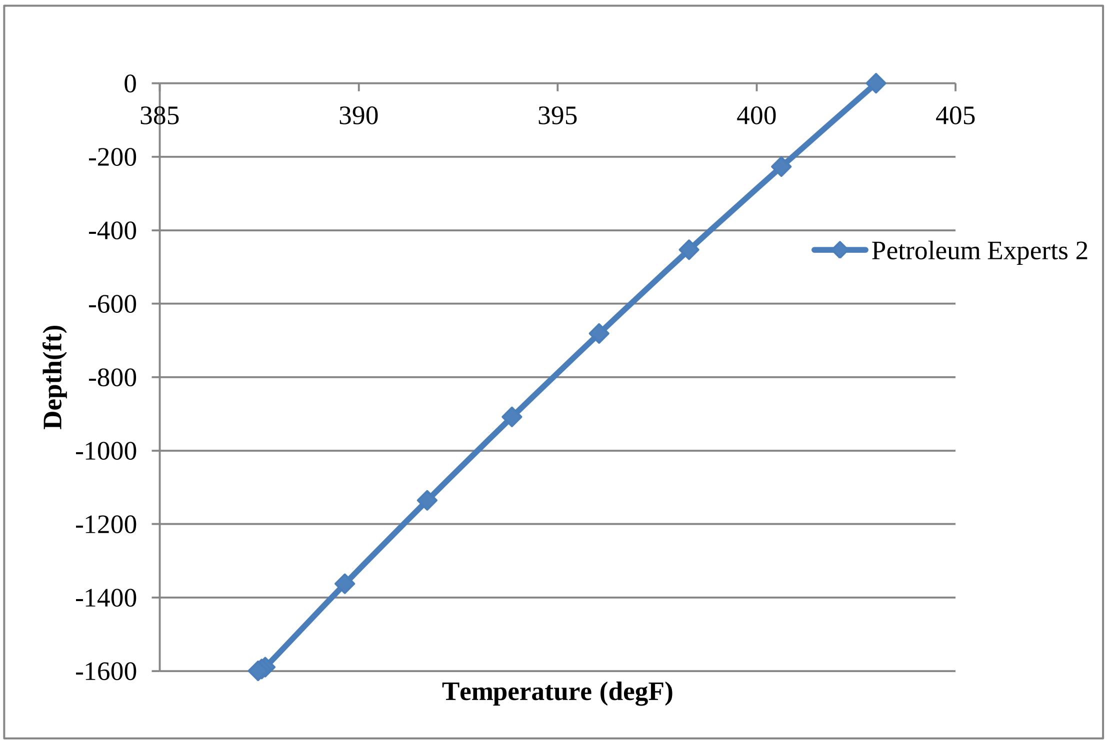


Figure 4.8: Temperature vs Depth

Martha Bigpond steam injection well have been simulated using the PROSPER software in order to validate the PROSPER simulation data. Study on the temperature profile throughout the well has showed us that the temperature is decreasing when the steam is injected from the wellhead to the bottom of the well. This is because of the heat losses that occur in the wellbore. Injected steam temperature is 403 degree F and the steam temperature at the bottom of the well is about 387 degree F. Temperature profile has been simulated using the Petroleum Experts 2 vertical lift correlation which is the most accurate one. The result shows the trend is following the trend other existing models.

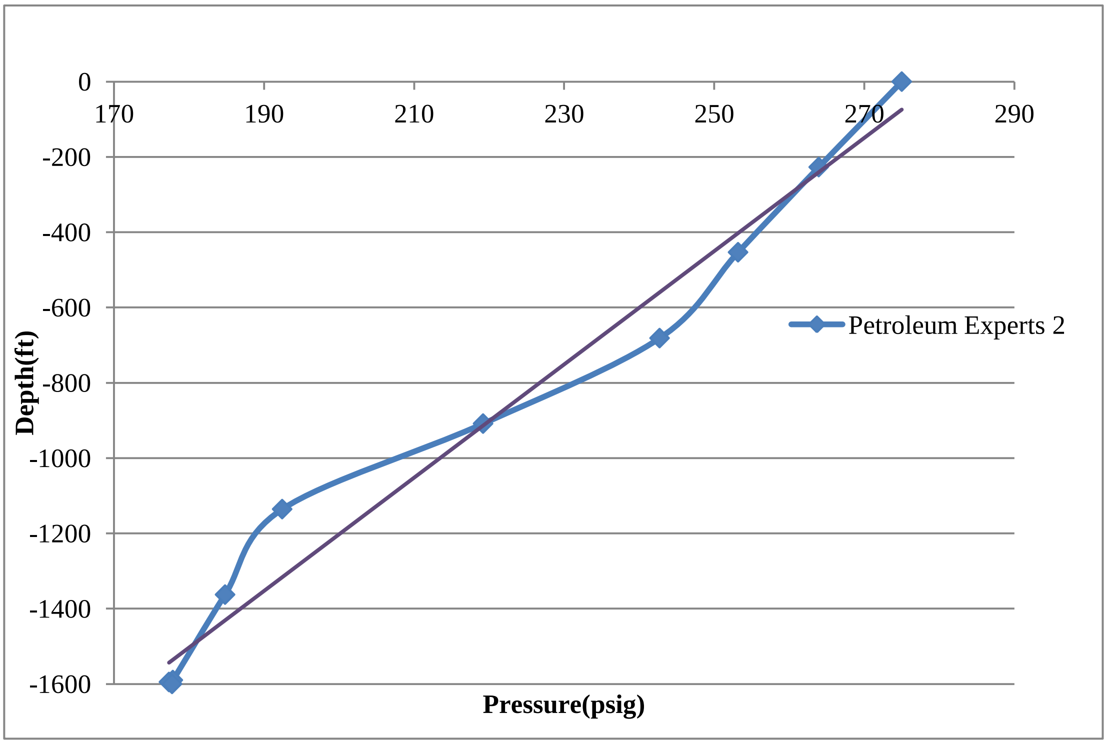


Figure 4.9: Pressure vs Depth

Study on the pressure profile in the wellbore has showed us that the pressure is decreasing when the steam is injected from the wellhead to the bottom of the well. This is because of the pressure drop that occurs in the wellbore due to the phase changes. Injected steam pressure is 275 psig and the steam pressure at the bottom of the well is around 177 psig. The decreasing trend of the graph matches with the other models. The decrement is quite low compared to other model yet it is within acceptable range.

Data that have been further validated by plotting and comparing the PROSPER model with the other existing models.

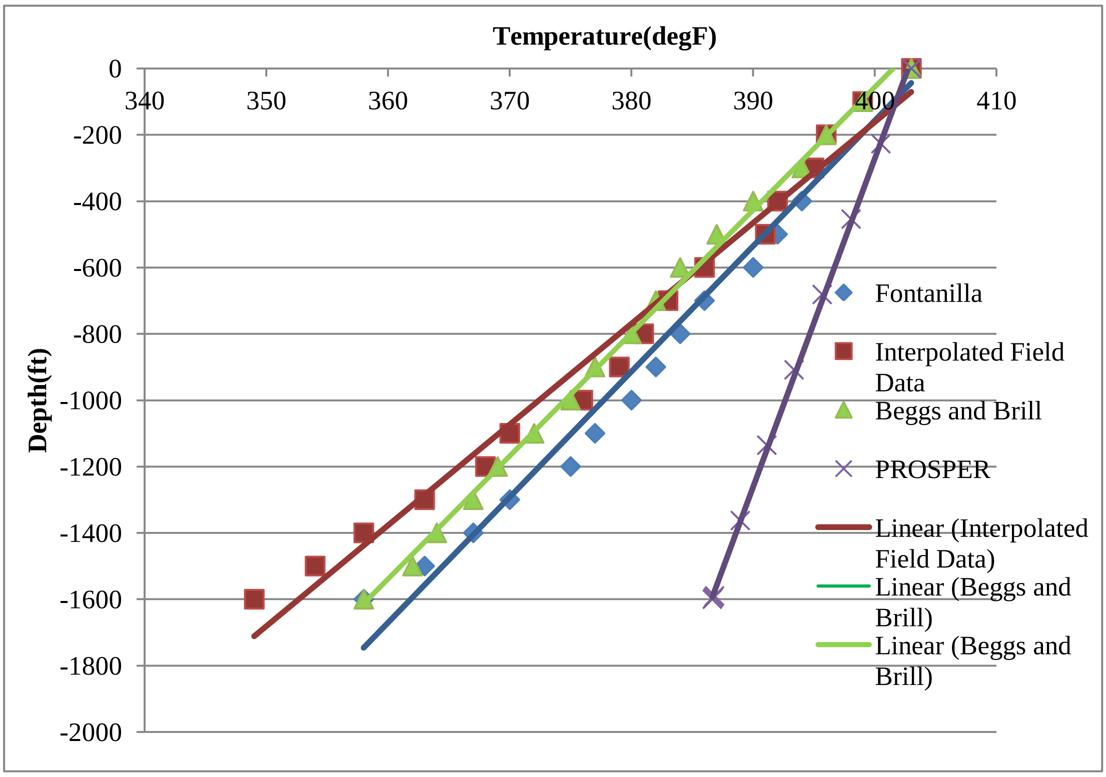


Figure 4.10: Comparison of Temperature vs Depth of different models

PROSPER model has been compared with Fontanilla model, Interpolated Field data model, and Beggs and Brill model. The temperature decrement of PROSPER model using Petroleum Expert 2 vertical lift correlation is lower than the other model but still in the acceptable range. Pressure versus depth plot also shows us the trend that is matching with the existing models. The injected temperature have been validated to be 403 degF using the equation from Dave O.Cox[31].But our model have encountered some serious problem in comparing the results with other models as in other models the steam quality that have been used at the wellhead is 80% while for our model we used 100%. PROSPER software does not have the options to change the steam quality at the wellhead. Thus, it is quite not accurate to compare our models with other models.

4.3 Overall Heat Transfer Coefficient Calculation

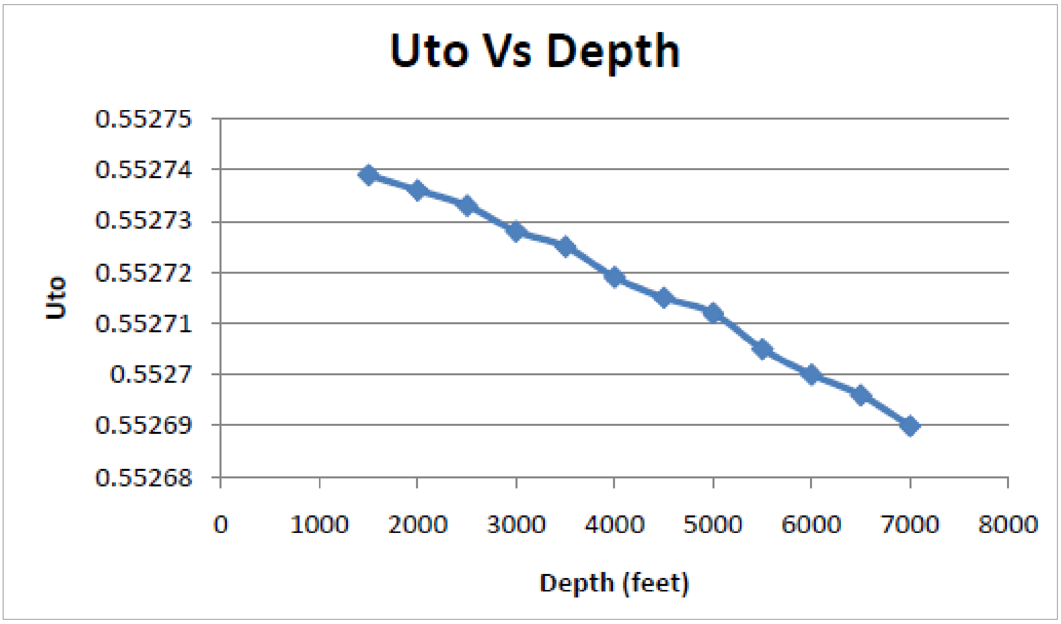


Figure 4.11: Overall Heat Transfer Coefficient vs Depth

Figure 4.11 shows the behaviour of overall heat transfer coefficient with respect to well depth. The curve shows decrease in the value of the overall heat transfer coefficient as we go deeper. The theory behind this is by going deeper the temperature of the formation around the wellbore will increase and the temperature of the injection fluid will decrease. Therefore, the temperature difference that responsible for heat flow from the injected fluid to the formation is reduced which will cause decrease in the overall heat transfer coefficient and heat loss. The significant of this curve or the usefulness is that can indicate to which extend or depth insulation is needed, it's known that the cost of insulation is high and any saving in the insulation cost is much appreciated. Therefore knowing at what depth the heat lost or the overall heat transfer coefficient is insignificant is important. Thus in PROSPER; we can input the overall heat transfer coefficient according to the depth. Thus the results from the work of Abdel Rahman [30] can be used to calculate the overall heat transfer coefficient according to the depth with some modification.

4.4 Effect of Insulation Material on Heat Losses

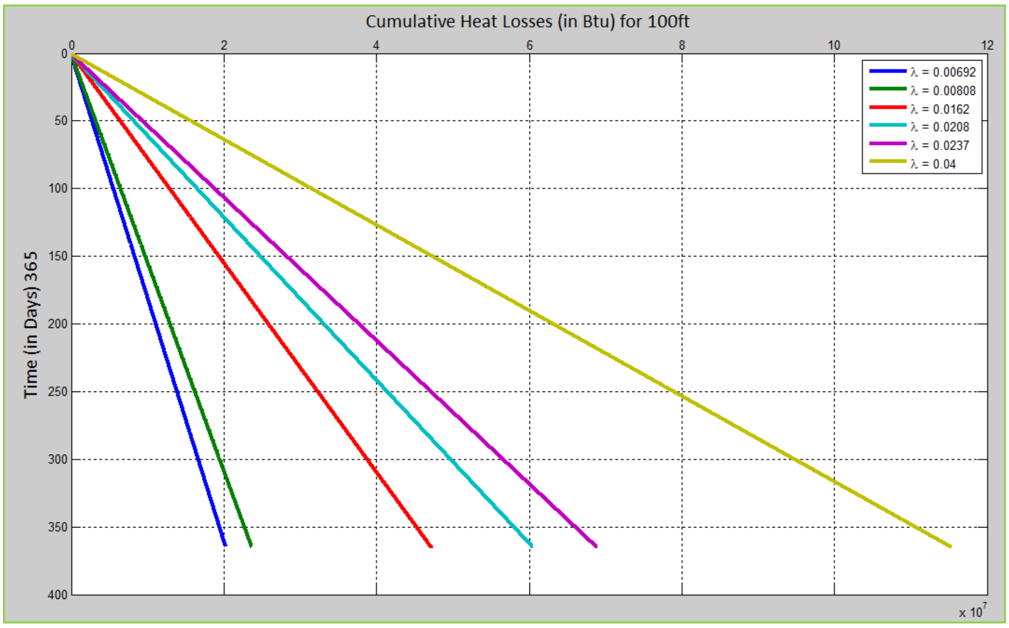


Figure 4.12: Effect of insulation material on heat losses

Figure above shows the effect of different type of insulation material on the heat losses. Highly insulated tubing will resist the heat losses to the formation more than the tubing with low insulation material. This effect of insulation has been studied to get to know on whether the insulation materials affect mush on the heat losses. The effect seems to be significantly important as the result shows the tubing with insulation can reduce the heat losses highly. The code have been developed by Fidan[25] and some of the modification have been adopted in the code.

4.5 PROSPER as the Tool to Model Steam Injection Wells

Throughout this project study, PROSPER software has been understood fully and the mechanism that worked behind the PROSPER software has been studied thoroughly. As discusses in the methodology part, PROSPER uses many correlation in order to calculate the heat losses to the formation. Understanding the theory behind the mechanism can lead us to choose the correct correlation to model the well. Throughout the study on this software some of the advantages and disadvantages of the software have been identified. The advantages are:

- PROSPER is a very user friendly software and modelling the steam injection well in the PROSPER is relatively easy.
- Most of the oil and gas industries are using this PROSPER software thus it is will be very convenient to use this software to model the steam injection as we can apply it in real industry work purposes.
- The effect of different overall heat transfer coefficient, steam injection pressure and temperature can be studied using this PROSPER software.
- PROSPER will calculate for us the solution node (the flow rate of steam) by computing the IPR and VLP curve.

Below are some disadvantages of PROSPER software.

- PROSPER assumes the steam quality at the wellhead is 100% even though in the real industrial data shows us that the steam quality is impossible to be 100%.
- The effect of time is not calculated using this PROSPER software. Heat losses to the formation will decrease as the time increase because the formation will be heated by the steam.
- PROSPER is using Nodal Analysis method to calculate the heat losses thus Reservoir Data (Reservoir Pressure and Temperature) need to be known.

CHAPTER 5

CONCLUSION and RECOMMENDATIONS

5.1 Conclusion

So far from the study and research done, the objectives set have been achieved. Steam flow in the EOR injection well has been understood. The heat transfer mechanism has been understood fully as well as the wellbore structures that are causing the heat loss have been understood. Heat losses that occurs from injected steam to the formation have been understood and PROSPER has been used to study on the effects. Injected steam temperature, pressure and quality will influence the amount of heat losses. The slippage effect between the phases as well as the friction between tubing and fluid has been considered. It has been realized that the amount of heat losses need to be calculated to estimate the accurate injection pressure and temperature (to optimize the production). In PROSPER the suitable flow correlation has been identified which is Petroleum Experts 2 which combines the best features of existing correlations. It uses the Gould et al flow map and the Hagedorn Brown correlation in slug flow, and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist results is used. The ultimate objectives have been achieved and further studies has been done on the advantages and disadvantages of this PROSPER software.

5.2 Recommendations

There is still lack of knowledge in fully understanding the process of heat transfer. Deep knowledge will be needed in the heat transfer area thus it is recommended to take the heat transfer course. More concentration needs to be given to the offshore structure where we need to take into account the heat losses from riser to the sea as well. Since heat losses from wellbore to formation depends also on the time factor, REVEAL (PETEX software) software need to be used to simulate the reservoir and wellbore structure to see the effect of time. Besides that, the study was based hypothetical field data, and in the sensitivity analysis most of the data were arbitrary numbers to check the effect of each parameter only. The study could be further improved if all the analysis were based on real industrial data.

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APPENDIX

[A] Heat Transmission Discussion by Authors

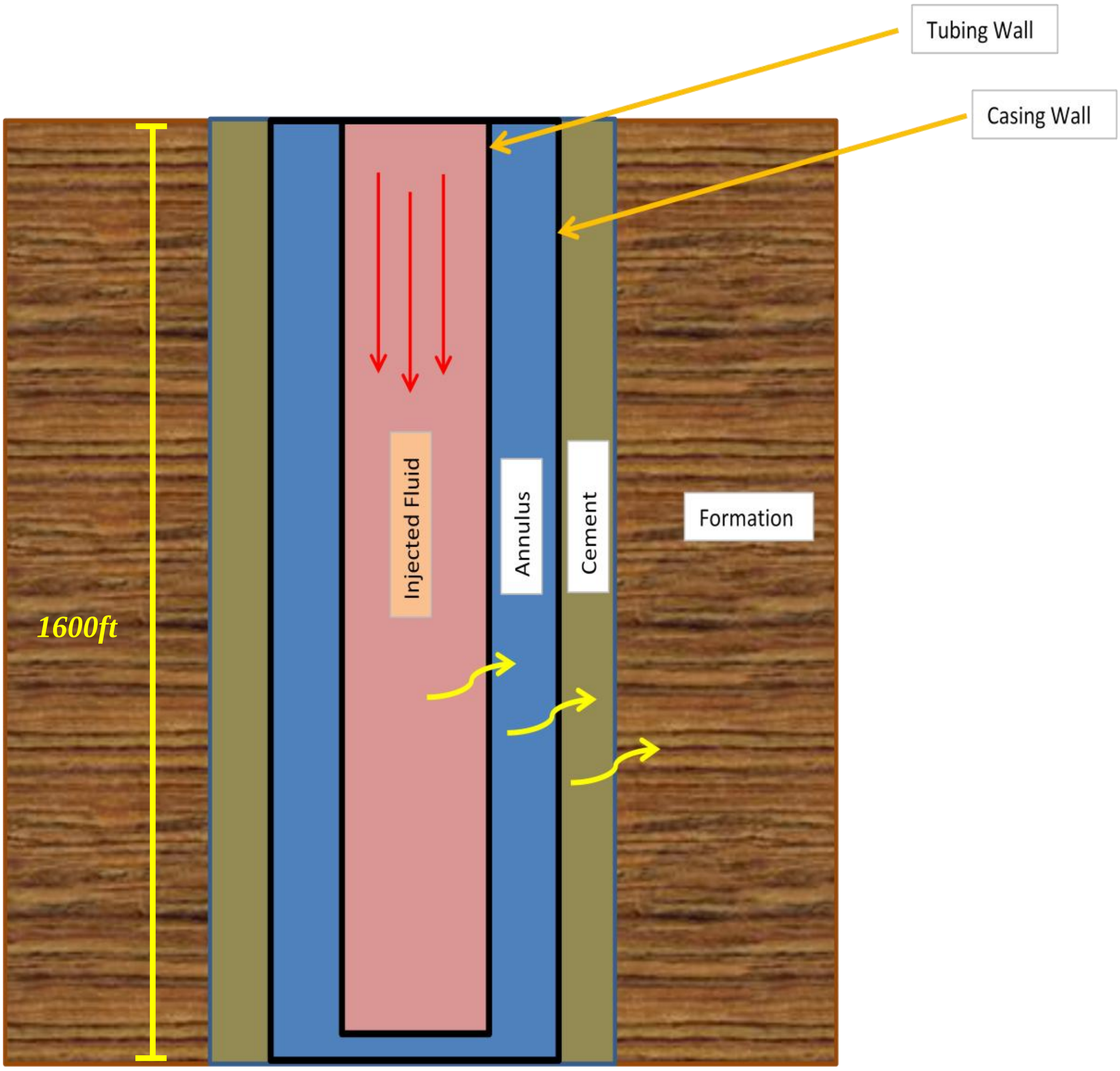
Model	Year	Description
Ramey	1962	- **Approximate analytical solution for wellbore heat transmission** - Assumed that fluid is non-compressible and flow is single phase with constant thermal and physical properties along the wellbore - He considered that heat flows radially away the wellbore and the overall heat transfer coefficient is independent of depth. - did not take into account frictional pressure loss and kinetic energy effect in his calculation
Squier et al	1962	- **Solved differential equations describing fluid temperature along the wellbore, using a complete analytical method** - Assumed there is no heat transfer by conduction in the vertical direction in either the injection stream or the formation. - The linear volumetric and mass flow rate of the water is constant throughout the injection stream. - The product of density and heat capacity is constant for both the water and the formation, and the formation thermal conductivity is constant. - Initially, both the water in the wellbore and the reservoir are at temperature given by the (constant) ambient surface temperature plus the product of depth and geothermal gradient (assumed constant). At large distances for the wellbore, the formation will remain at this temperature. - The water temperature and the formation temperature at $r=r_{to}$ are equal for all depths D.
Satter	1965	- **Presents a method of estimating the quality of condensing fluid as a function of depth and time. The overall heat transfer coefficient dependent on depth-step method for calculating heat loss and steam quality for saturated**

		steam as a function of depth. - Assumed steam is injected at a constant rate, wellhead pressure, temperature and quality. - A downhole packer is used to prevent steam from entering the tubing-casing annulus. The annulus is assumed to be filled with air at low pressure. - The heat transfer in the wellbore is under steady-state conditions, while heat transfer to the earth involves unsteady state radial conduction. - Kinetic energy changes are negligible. - Any variation in pressure of the steam with depth due to hydrostatic effects and frictional losses is negligible. - There is negligible variation in thermal conductivity and diffusivity of the earth with depth
Holst and Flock	1966	- **Added the friction loss and kinetic energy effects on Ramey's and Satter's models, in order to calculate the heat loss and quality distribution versus depth for saturated steam injection operations. They neglected, however, the static pressure change.**
Leutwyler	1966	- **Gave a comprehensive treatment of casing temperature behavior**
Hans and Huitt	1966	- **Developed e graphical solution for wet steam injection operations. In their model, they calculate wellbore heat loss, steam condensation rate, and casing temperature.**
Willhite	1967	- **Proposed his well known method for estimation of over-all heat transfer coefficient that is applied in our calculation as well.**
Pacheco and Farouq Ali	1972	- **Come out with prediction of heat loss and pressure drop in the wellbore. They formulated a mathematical model that consisted of two coupled nonlinear differential equations that were solved iteratively in terms of pressure and quality of steam.** - assumed single phase flow
Farouq Ali	1981	- **Took into account slip between the fluids and the flow regime. Used several correlations and stated that importance of applying two-phase flow concept and flow regime.**

Fontanilla and Aziz	1982	- **Developed a mathematical model for multiphase, nonisothermal down flow of steam in pipes.**
Wu and Pruess	1991	- **Presented a new analytical for wellbore heat transmission without Ramey's assumptions. Their approach was assuming non-homogeneous formations as layered formation with different physical properties.**
Alves et al	1992	- **Reported that all existing models up to then suffered from serious assumptions on the thermodynamic behavior of fluids, and thus were applicable only for limited operational strategies. These authors developed a unified equation for temperature prediction inside the wellbore.**
Hasan and Kabir	1994-2007	- **Developed an analytical model to determine the flowing fluid temperature inside the well. They started with a steady-state energy balance equation and combined it with definition of fluid enthalpy in terms of heat capacity and Joule-Thompson coefficient. Then, by using some simplifications, they converted the original partial differential equation to an ordinary differential equation and solved it with appropriate boundary conditions.**
Hagoort	2004	- **Did a comprehensive study on Ramey's model in order to find applicable scenarios for this model**
Livescu et al	2008	- **Developed a comprehensive numerical non-isothermal multiphase wellbore model. After their initial attempts to solve the fully coupled conservation equations, they decoupled the wellbore energy balance equation from the mass balance equation in most of their investigations. They reported that decoupling can be justified when the density difference in each phase with respect to temperature is much less than that with respect to pressure. Additionally, they found that this decoupling approach can decrease computation time of simulation without violating stability.**
Bulent Izgec	2008	- **Simulated transient wellbore model**

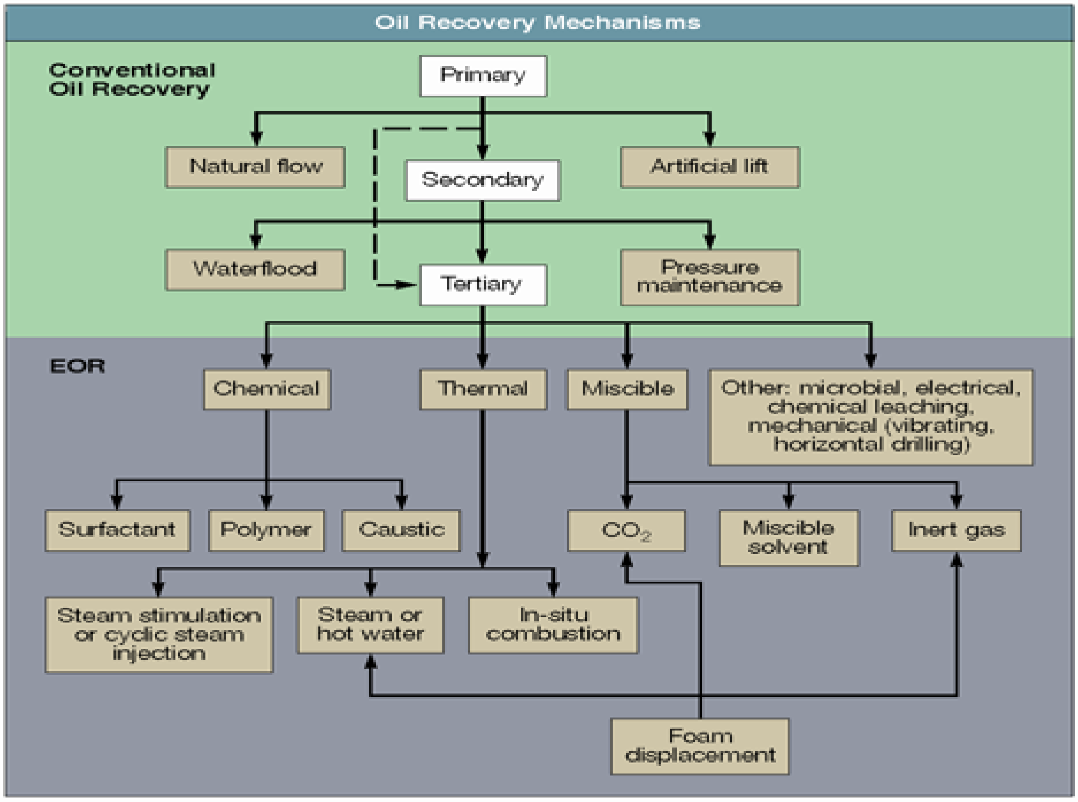
		coupled with a semi analytic temperature model for computing wellbore fluid temperature profile in flowing and shut-in wells.
Bahonar	2010	- **Developed a numerical non-isothermal two-phase wellbore simulator coupled with tubular and cement material, and surrounding formation.**
Selcuc Fidan	2011	- **Investigated heat losses along the wellbore during steam injection in both onshore and offshore environments**

[B] Well Geometry

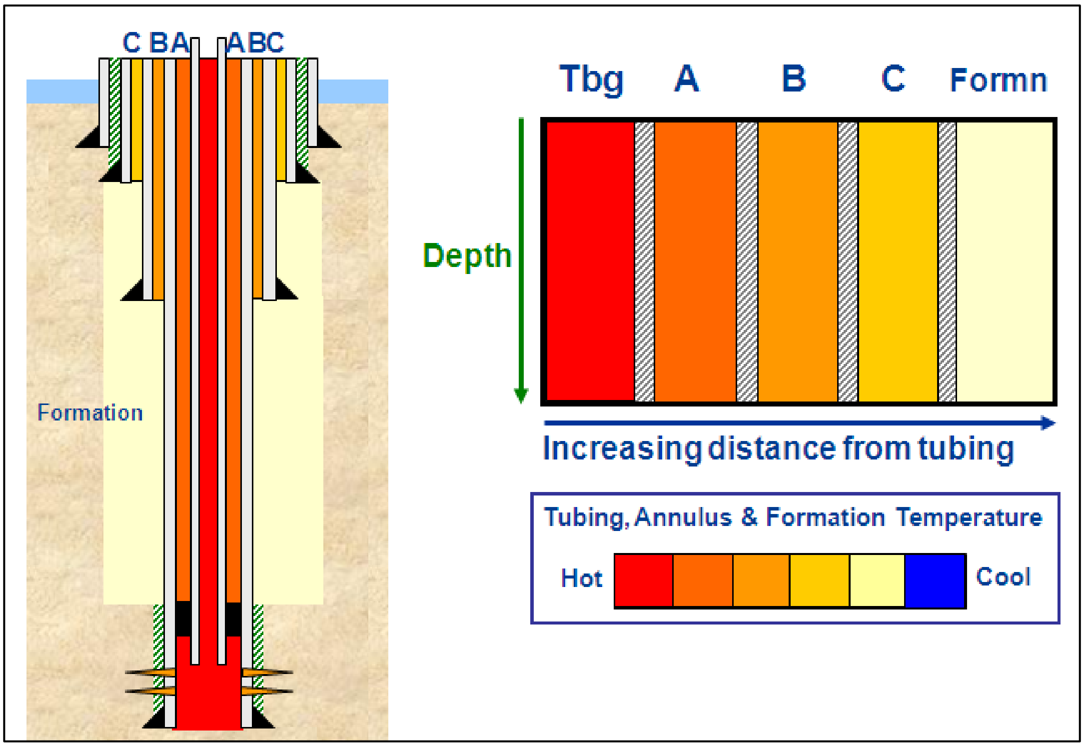


[C] EOR

Oil Recovery Mechanism

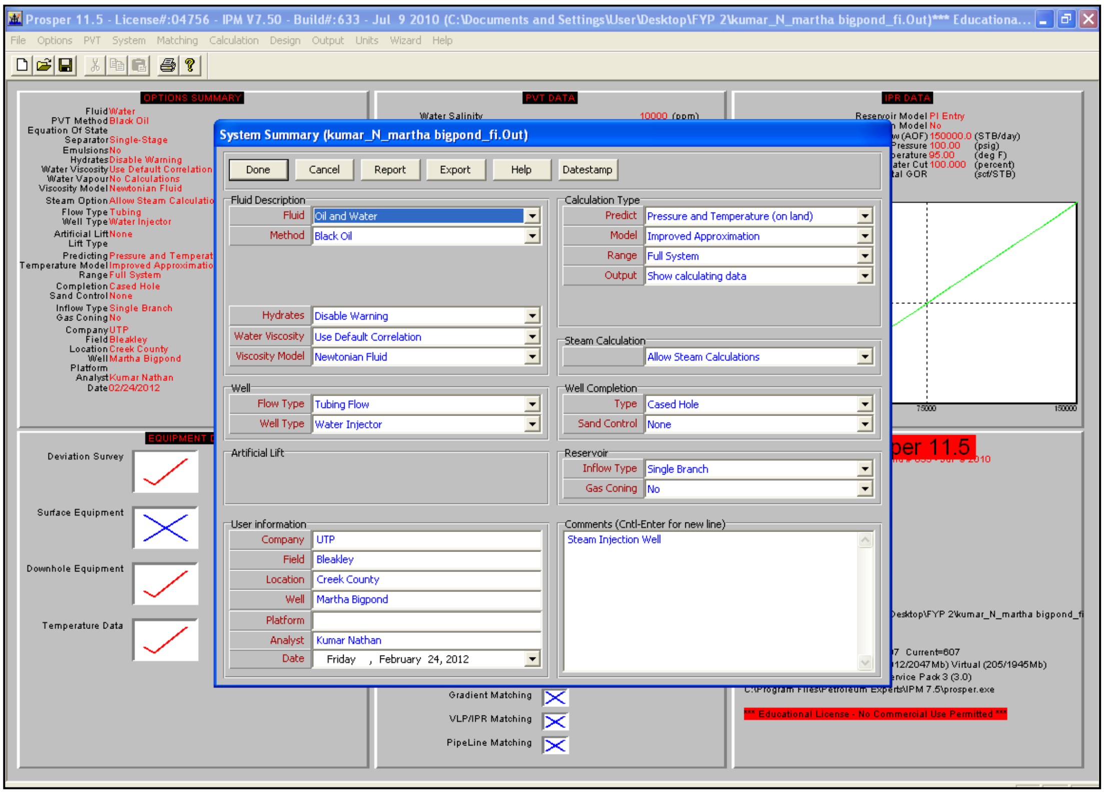


Formation Temperature

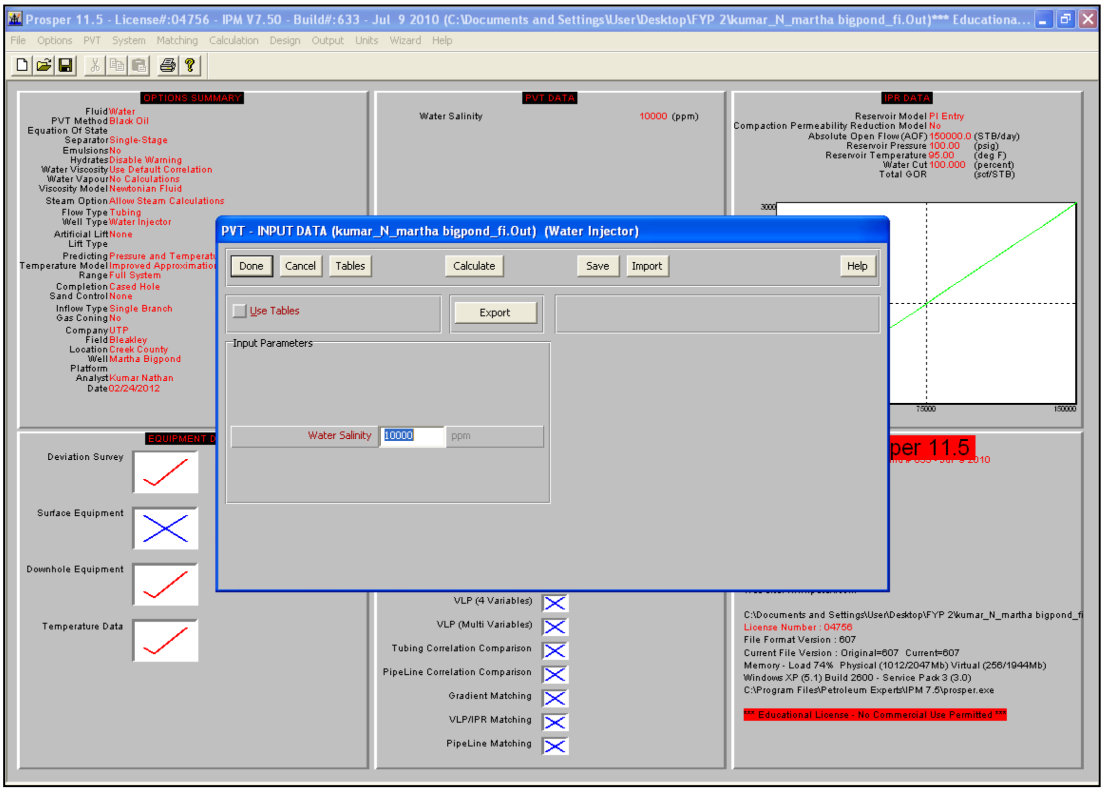


[C] PROSPER Interface

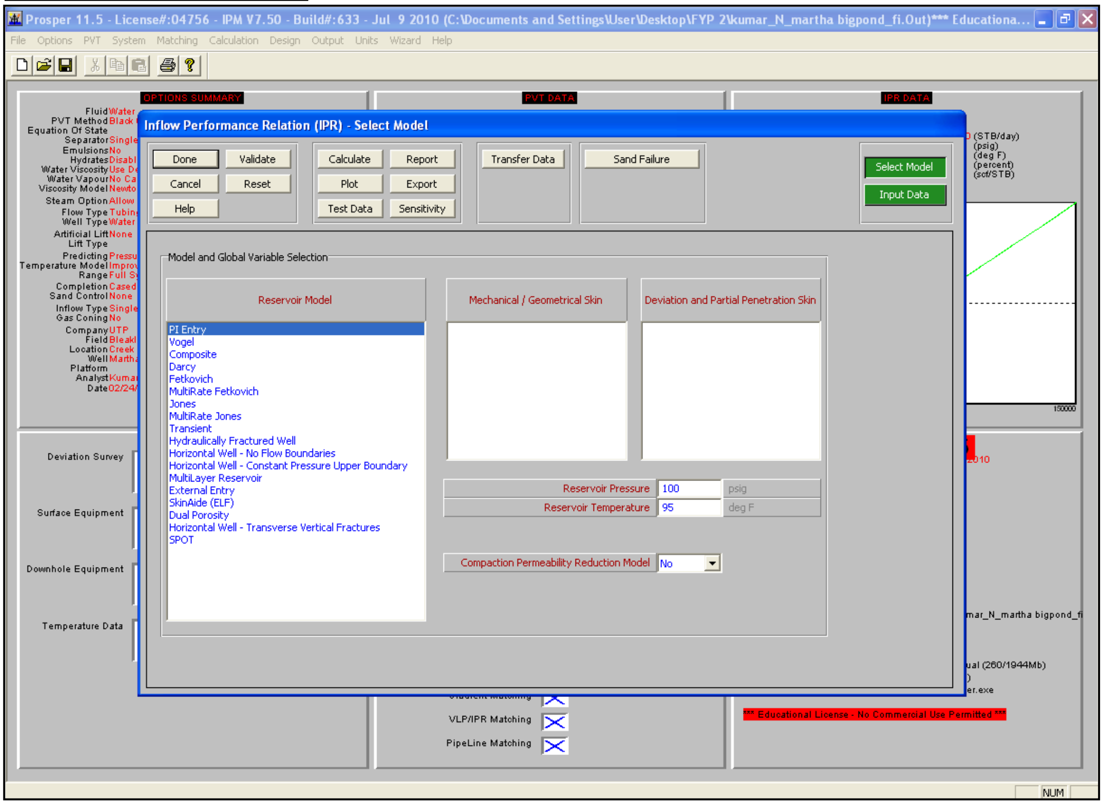
System Summary



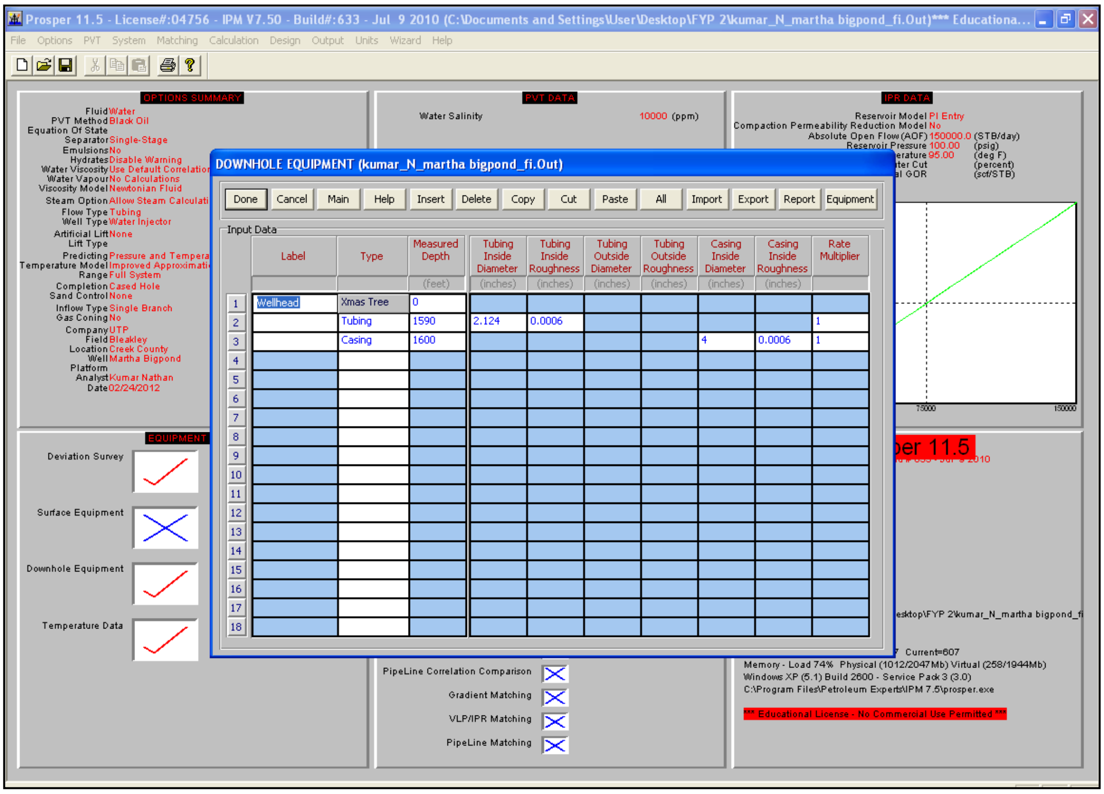
PVT Data



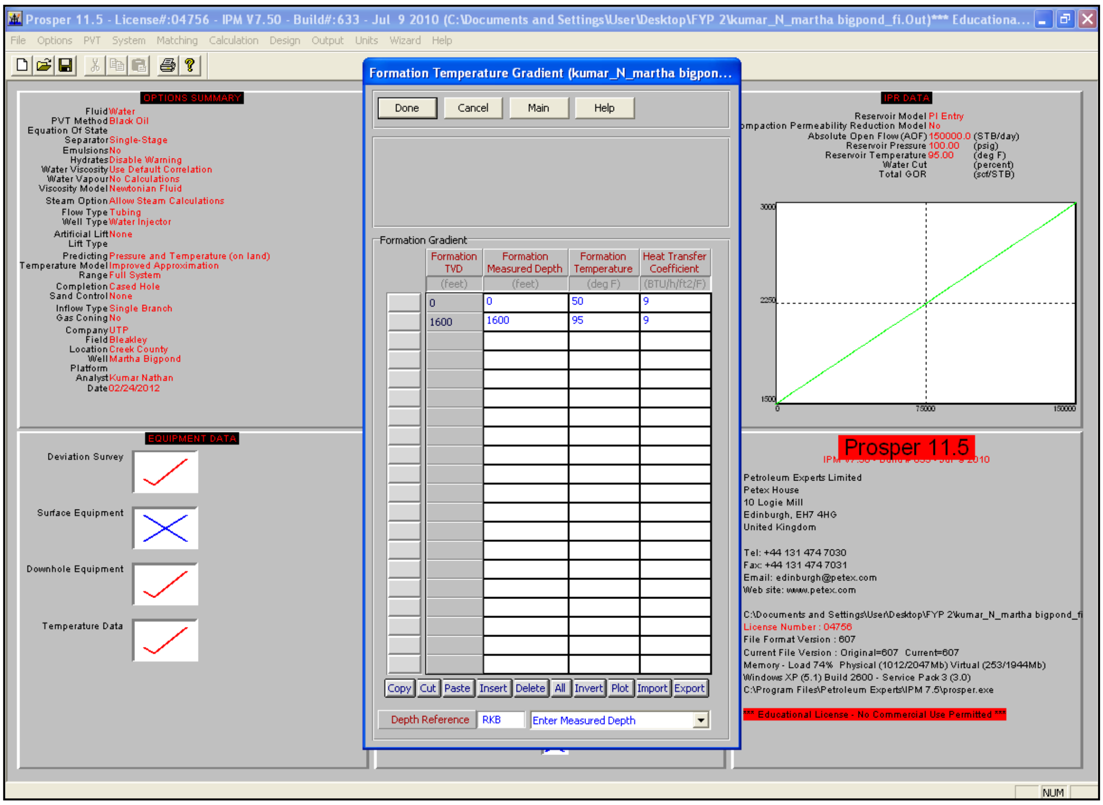
IPR Data



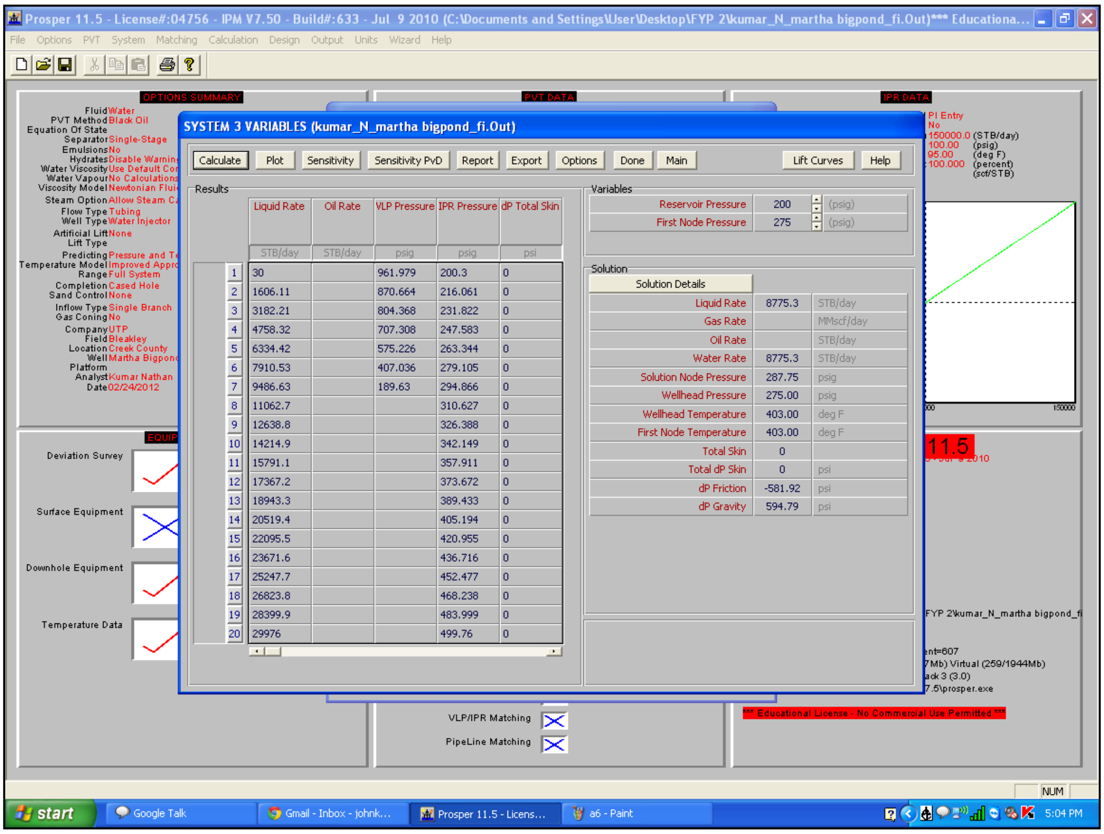
Equipment Data



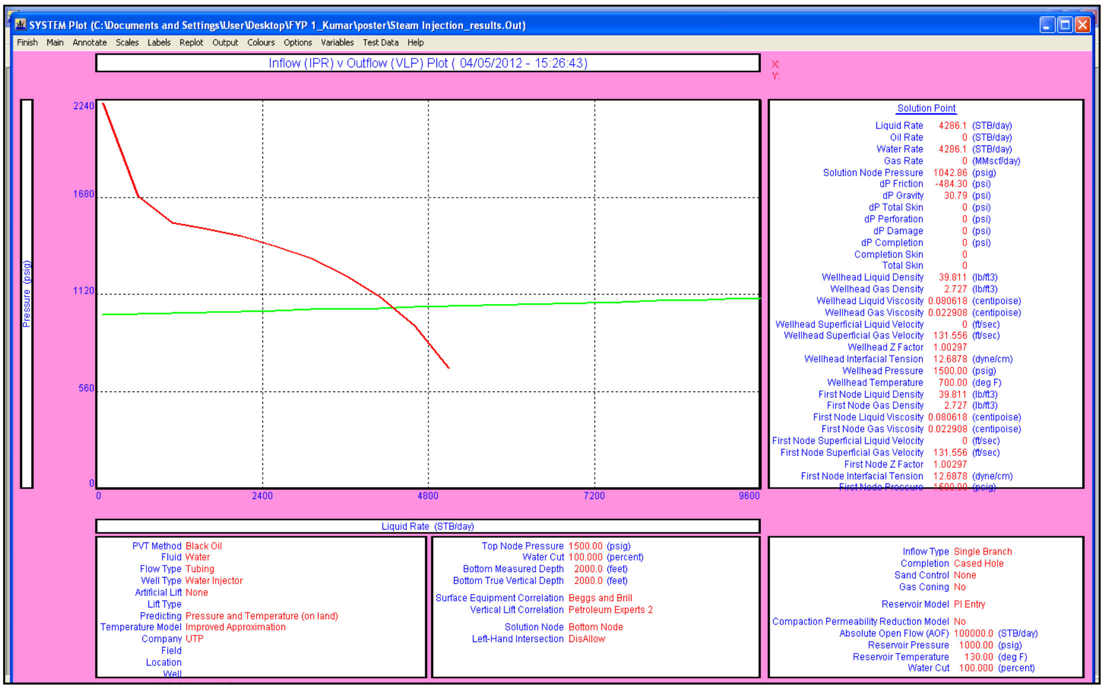
Formation Temperature

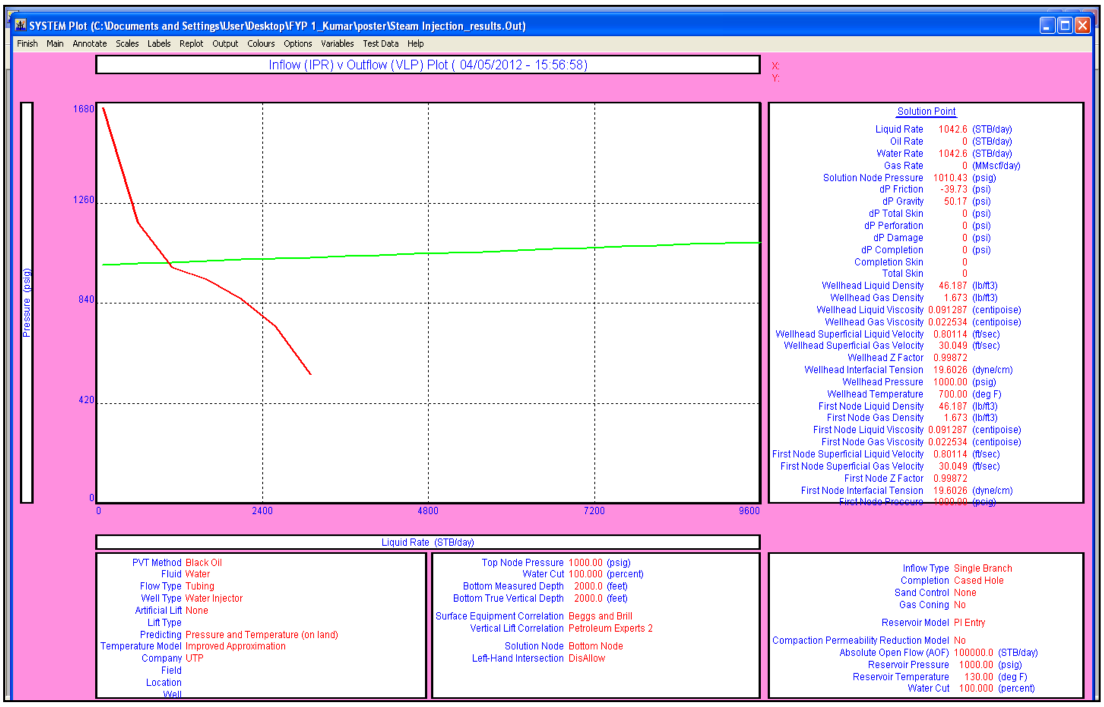


System Calculations



IPR vs VLP curves





[D] Nomenclature

Symbols

fNS	no slip friction factor, dimensionless
Frm	Froud number of mixture
g	acceleration due to gravity, 4.17e − 8 ft/hr^2
Gr	Grashoff's number
h	enthalpy, BT U/lb
hf	film coefficient of heat transfer of the pipe, BT $U/ft^2 - hr$
hfc	coefficient of heat transfer forced convection, , BT $U/ft^2 - hr$
hpipe	coefficient of the heat transfer of pipe, BT $U/ft^2 - hr$
hc,an	radiation and convection coefficient of heat transfer, BT $U/ft^2 - hr$
HL	liquid holdup density
J	mechanical equivalent of heat, 778 ft − lbf /BT U length, ft
k	thermal conductivity of the material, BT U/(ft − hr − ^oF)
khc	effective thermal conductivity of the annular fluid, BT U/(ft −hr − ^oF)
kha	actual thermal conductivity of the annular fluid, BT U/(ft − hr − ^oF)
KE	kinetic energy, BT U/lb
NRe	Reynolds number
P	pressure, psi
PE	potential energy, BT U/lb
Pr	Prandtl's number
qg	gas flow rate, ft^3/hr
rti	inner radius of the tubing, ft
rto	outer radius of the tubing, ft
rins	insulation radius of the tubing, ft
rci	inside radius of the casing, ft
rco	outside radius of the casing, ft
rh	wellbore radius, ft

r_{Ea}	radius of the altered zone in the earth near the well, ft
R	Reynolds number
R_h	specific thermal resistance
R_{NS}	no-slip Reynolds number
t	time, hrs
T	temperature, ^oF
T_a	absolute temperature, $^oR = ^oF + 460$
T_A	ambient temperature of the atmosphere, ^oF
T_b	bulk temperature of the fluid in the pipe, ^oF
T_m	mean surface temperature, ^oF
U	overall coefficient of heat transfer, $BTU/hr - ft^2 - ^oF$
v	specific volume, ft^3/lb
v_w	wind velocity, mph
V	velocity, ft/hr
v_{sg}	superficial velocity for gas phase, ft/hr
v_g	actual velocity for gas phase, ft/hr
v_{sL}	superficial velocity for liquid phase, ft/hr
v_s	actual velocity for liquid phase, ft/hr
v_m	mixture velocity, ft/hr
W_m	steam injection rate, lb/hr
X	steam quality, fraction by weight
z	elevation or depth, ft