"Well Management and Production in Contemporary Reservoir Simulators"

"Determination of Well Static Pressure in Full Field Scale Simulations"

A THESIS IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF

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Affidavit

I declare in lieu of oath that I did this work by myself using only literature cited at the end of this volume.

Hadi Hendizadeh

Leoben, October 2007

Dedication

Dedicated to my father and to my mother from whom I have learnt a pious and elegant way of life.

تقدیم به پدر و مادرم

Acknowledgments

I would like to express my deep gratitude to em.O. Univ. Prof. Dipl.-Ing. Dr.mont. Dr.h.c. Zoltán Heinemann for his great support during my studies at Montanuniversität Leoben and throughout the time, I spent working on thesis. He has an enormous contribution in this study. The collaboration with him enabled me to gain a deeper understanding of reservoir engineering. Also I am very grateful for having had the opportunity to have attended some of his final lectures at the university.

This project would not have been possible without the backing of Heinemann Oil's team, specially the CEO, Dr. Gabor Heinemann.

I would like to express my special appreciations to my friend, Dr. Georg Mittermeir, for his endless and valuable helps and advices during this thesis work.

Additionally I would like to thank all the members of the Petroleum Engineering Department for providing a perfect environment, suitable for me to accomplish my study and research.

The last but not the least, I would like to declare my special thanks and appreciations to my parents and my family members whose moral supports are very extremely dear to me.

Kurzfassung

History Matching bedeutet, reale Beobachtungen mit simulierten zu vergleichen. Produktion, Water Cut und GOR, etc. sind für entsprechende direkte Vergleiche geeignet. Der Vergleich von Bohrlochdrücken ist schwierig, da die entsprechenden Werte von der Beobachtungsmethode und –zeitraum abhängen. Die dynamischen Bohrlochdrücke können abgestimmt werden, statische allerdings nicht..

Per Definition ist der statische Bohrlochdruck der durchschnittliche Druck des Drainage Area. Dieser kann durch Buildup Test ermittelt werden, unter Verwendung von Horner & MBH Diagrammen. Diese Methode wird nur selten in Simulationsläufen reproduziert. Außerdem ist ein grober Raster nicht geeignet um transiente Druckverhalten von radialen Flüssen zu reproduzieren. .

Diese Diplomarbeit beschreibt Methoden, wie diese statischen Bohrlochdrücke in kommerzieller Software ermittelt werden, diskutiert und vergleicht die Resultate. Im Rahmen dieses Projekts wurden drei Software Pakete verwendet: SURE®, ECLIPSE® and HRC (Prof. Heinemann's Research Code).

Die Untersuchung der HRC Methode zeigte, dass HRC – unter den gleichen Bedingungen wie SURE® & ECLIPSE® – gute, vergleichbare Resultate liefert. Weitere Untersuchungen zeigten, dass die errechneten Drücke signifikant über Zeit variieren, wenn die Properties verändert werden. Diese Resultate können sehr unterschiedlich, im Vergleich zu einem möglichen Buildup Test ausfallen. Dadurch wird eine neue Perspektive für kunftige Forschungsarbeit eröffnet.

Abstract

History Matching means comparing the real observations with the simulated ones. Production, water-cut, GOR etc are suitable for direct comparison. But the comparison of bottom hole pressures is difficult because these values depend on the method and time of observation. Bottom hole flowing pressure can be tuned by modification of near well properties. But the static bottom hole pressure can not be tuned like this.

The static bottom hole pressure per definition is the average pressure of the drainage area. This can be measured by buildup test, utilizing Horner and MBH plots. This sequence is seldom reproduced in a simulation run; and besides any coarse grid is not suitable to reproduce the transient pressure behaviors of a radial flow.

This thesis describes the methods how these "well static pressures" are determined in the commercial software, discuses their theoretical backgrounds and compare their results. The applicability and limitations of the different methods are demonstrated in the examples. Three software packages were used in this project: SURE®, ECLIPSE® and HRC (Prof. Heinemann's Research Code).

Investigating the HRC method showed that HRC gives good comparable results under the same conditions as SURE® and ECLIPSE®. Further investigations showed that by changing the properties, the calculated pressures in time will vary significantly. These results may have drastic differences with a possible buildup test. These results opened a new perspective for further researches.

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Chapter 1

1 Introduction

1.1 Motivation of the work

The main difficulty of well modeling in reservoir simulation is the problem of the difference in scale between the reservoir size (several kilometers) and the wellbore radius (several centimeters). In applications, although the wellbore boundary can be discretized using flexible grids, the grid blocks in the vicinity of the well are usually not small enough, and the grid block sizes vary, usually geometrically, in the radial direction from the well. This kind of grid makes the commonly used linear approach inefficient for near-well flow modeling. In such a modeling, determination of well flowing pressure and well bottom hole pressure are of high importance. Accurate well modeling is very important for flow simulations in reservoir engineering. The key point of well modeling is to perform accurate fluid flow in the near-well region.

Production rate, water-cut, GOR, hydrocarbon composition etc are well defined quantities and suitable for history matching and comparison of simulated and measured data. But the comparison of pressures, especially bottom hole pressures is more difficult because this values depends on the method and time of the observation. BHP (Bottom hole flowing pressures) can be easily adjusted by modification of near well permeability, the skin factor or by using artificial multiplicators, known as flow efficiency factors. But the case of achieving static

bottom hole pressure (shut in pressure) is different and this pressure can not be tuned like BHP.

The static bottom hole pressure per definition is the average pressure of the drainage area. This will be measured by pressure build up, evaluated trough Horner and MBH plots. The wells are shut in during the measurement for a short time and then the static bottom hole pressure can be achieved; this is seldom reproduced in a simulation run. Nevertheless also if this would be done, the coarse Cartesian or corner point grid is not suitable to reproduce the transient pressure behaviors of a radial flow.

Commercial simulation software offer the option to calculate a certain kind of average pressure based on the well (perforation) block and its neighboring blocks. The description of the methods used in the contemporary simulators are described and analyzed. The applicability and limitations of the different methods is demonstrated on examples. Three software packages were used in this project: SURE®, ECLIPSE® 100 and HRC (Research Code of Prof. Heinemann).

Investigating the new HRC method showed that in all of the examples, HRC gives good comparable results under the same conditions as SURE® and ECLIPSE® 100.

Further investigations on this new method implied that by changing the reservoir parameters like permeability, porosity and net to gross ratio etc, the calculated static bottom hole pressures in time will vary significantly. These results may have drastic differences with a possible pressure buildup test on the same well.

These results opened a new perspective for researchers to find a new method that can propose better results, comparable with an actual pressure buildup test.

1.2 Scope of work

The scope of work for this thesis consists of three parts:

1. The first part should relate the theoretical aspects of well modeling in the reservoir simulation, presenting some basic definitions in reservoir simulation; and a short notice to well testing.
2. The second part should establish the relationship between theoretical background for well static pressure and the methods used in contemporary reservoir simulators. The alternative methods that are being used in the reservoir simulation should be discussed here.
3. The third part should pertain to the procedure of conducting the new method. The new method should be implemented into the existing research code.
4. The forth part can be related to the examining the methodology by providing examples; and should give a feedback of the comparison of the results.

1.3 Outline of the work

Chapter 2 reviews the relevant literature and background for gridding concepts around the well; and gives a survey of well modeling and BHP definitions.

Chapter 3 gives a survey of different averaging methods in contemporary reservoir simulators. Detailed description of the new method in HRC is described extensively here.

In **Chapter 4,** the implementation of the averaging method in HRC is described. And the code is tested with different examples. Conclusions of these examples are also presemted in this chapter which lead to the approval of the method.

In **Chapter 5,** a new logarithmic method is presented that gives a new perspective for future research.

Chapter 6 provides a short summary about the whole workflow and gives conclusions and recommendations

In **Chapter 7,** explanations for symbols and abbreviations used in this research are provided.

Chapter 8 provides the list of reference literature used for this thesis work.

Appendix 1 gives a detailed insight to the actual routine introduced in the research code HRC. Comments are well presented in the code for further understandings.

Appendix 2 gives the SCAL input file, PVT input file and SCHEDULE input file for ECLIPSE® examples. These files are equivalent to TDD, RCK and PVT input files of HRC.

Appendix 3 presents TDD (time dependant input data), RCK input file and PVT input file used for creating examples in HRC (equivalent to ECLIPSE® input files).

1.4 Scientific achievements and technological contributions

The scientific results of this thesis work and openings to new aspects future researches can be summarized as follows:

a) An averaging method for Well Static Bottom hole Pressure presented in this thesis work:

- An averaging method for Well Static bottom hole pressure is presented. This method has been programmed By FORTRAN 90 in the HRC (Prof. Heinemann's Research Code).

b) Documented Scientific Results:

- The applicability and concept of the presented method has been tested and confirmed.
- The Code has been tested by a number of examples and by at least 50 different cases in these examples.
- Examples can be listed as: a homogeneous reservoir and a heterogeneous reservoir, each of them with and without cross flow between the layers and examples with special feature around the well.
- All of the tested cases showed good and comparable results with the-state-of-the-art commercial software.

c) New Openings and Technical Contributions to future researches:

- Investigations showed that by changing the settings of the keywords or size of grids, the calculated pressures will vary significantly.
- Results will have drastic differences with a possible buildup test which gives the correct static pressure. These results opened a new perspective for further researches.

Chapter 2

2 Well definitions in reservoir engineering

2.1 Introduction

Accurate well modeling is of high importance for flow simulations in reservoir engineering. The key point of the well modeling is the accurate fluid flow simulations in the near-well region. This can be done by gaining a good understanding of pressure distributions in near-well region.

2.2 Reservoir pressure and Bottom hole Pressure

2.2.1 Average Reservoir Pressure

Reservoir pressure is the pressure that can be obtained if all fluid motion ceases in a given volume of reservoir. It is also the pressure to which a well will ultimately rise if shut in for an infinite period[13]. Reservoir pressure is one of the most important parameters of reservoir engineering calculations. Whether the calculations involve the tank type model or a more sophisticated reservoir simulator, accurate pressure values are required. However, there is an important difference between the requirements of the two models. The unit tank model relies on material balance equation calculations, and requires the average pressure for the whole reservoir as a function of time or production. In reservoir simulation

studies, however, it is strongly desirable to have available buildup pressure values for individual wells as a function of time. These values represent the average pressure for the drainage volumes of the wells, and are needed for the history-matching phase of the simulation study, which is performed to validate the accuracy of the model built to represent the reservoir. History matching is an essential step in "tuning" a reservoir model before conducting a predictive study.

Reservoir engineering calculations require a value for the pressure in the reservoir, away from the wellbore. To obtain this value, the well must be shut in and the pressure increase with shut-in time must be recorded. We refer to this as a pressure buildup test. From these data the average pressure value is calculated.

Another way of obtaining average values is to record the pressure in a well in which Production has been suspended. If such a well exists, and it is not very close to a producer or an injector, a pressure-measuring device can be used to continuously record the pressure, without interrupting production or injection operations.

For the single-tank model, an average value for the whole reservoir is required. This is normally obtained by a volumetric averaging of the pressure values from different wells. The equation for this purpose is

$$\overline{P}_R = \frac{\sum P_i V_i}{\sum V_i} \qquad \textbf{2-1}$$

where:

$\overline{P}_R$ = average pressure for reservoir

P_i = average pressure for Well i

V_i = the drainage volume of Well i

Thus, if there are three wells with pressures p_1, p_2, and p_3, and drainage volumes V_1, V_2, and V_3, then Equation above becomes:

$$\overline{P}_R = \frac{p_1 V_1 + p_2 V_2 + p_3 V_3}{V_1 + V_2 + V_3} \qquad \textbf{2-2}$$

Matthews et al. (1954) and Matthews and Russell (1967) have shown that the well-drainage volume V_i is proportional to its flow rate, q_i Substituting q_i for V_i in previous equation gives[12]:

$$\overline{P}_R = \frac{\sum p_i q_i}{\sum q_i} \qquad \textbf{2-3}$$

This equation above is the more practical equation because the flow rate is usually available, while it may be more difficult to estimate the drainage volume.

Before comparing the pressure values measured in wells at various depths in a reservoir (e.g. very thick and/or steeply dipping reservoirs), they should be referred and corrected to a datum depth (Figure 2-1).

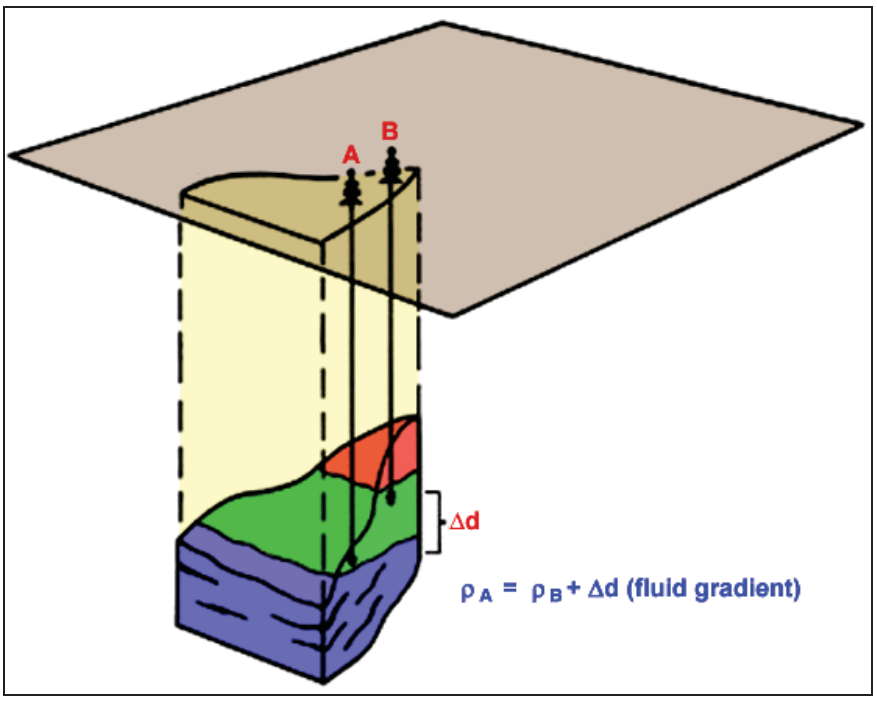

Figure 2-1: depth correction for pressures in the wells.

The depth of correction can be an arbitrary depth; but usually it refers to WOC (Water Oil Contact) or the depth of the volumetric midpoint of the reservoir is taken as the datum depth. This is determined by constructing a plot of depth versus cumulative pore volume (Figure 2-2).

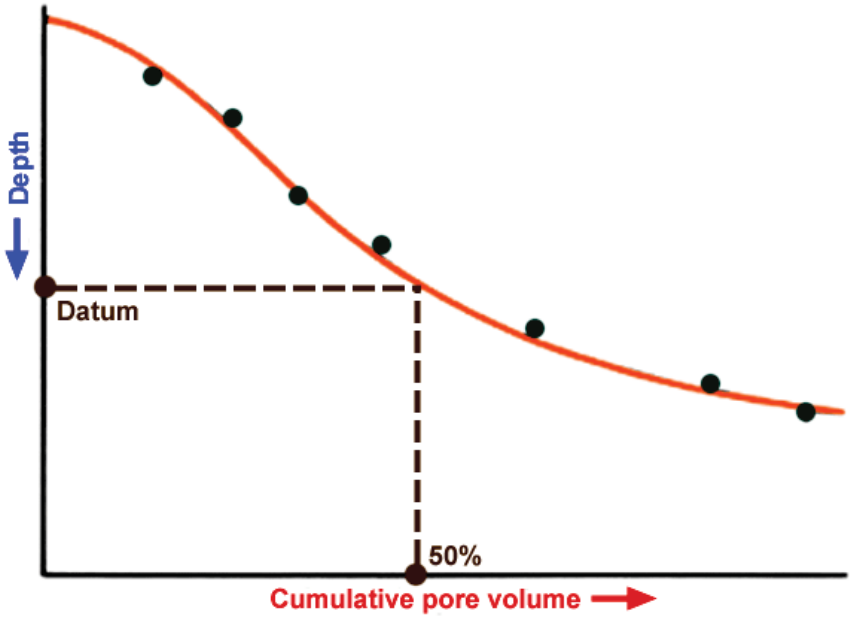

Figure 2-2: volumetric midpoint of the reservoir[12].

The depth corresponding to 50% pore volume is the volumetric midpoint depth. If a particular pressure value is obtained at a different depth than the datum, it is adjusted to the datum by the below formulas. Equations 5 and 6 apply when the point at which the Pressure was determined is, respectively, above and below the datum depth.

$$P_{adj} = p + 0.433\gamma\Delta H \qquad \textbf{2-4}$$

$$P_{adj} = p - 0.433\gamma\Delta H \qquad \textbf{2-5}$$

where:

p = the pressure at any elevation, *psi*

γ = specific gravity of fluid.

ΔH = the vertical distance between the point at which the pressure was measured and the datum depth, ft.

When an aquifer is associated with the reservoir, the Pressure behavior as a function of time at the hydrocarbon-water contact (or as close as possible to it) is needed for water influx calculations. If this is not available, one usually uses the

average reservoir Pressure and adjusts it to the hydrocarbon-water contact depth.

The average reservoir pressure is needed in many reservoir engineering calculations. In the case of miscible EOR techniques, for example, the average reservoir pressure determines whether miscibility will occur when CO_2 or other gases are injected. This in turn affects overall recovery and the economic feasibility of the project.

Reservoir pressure is a topic of significance in reservoir engineering because it is one of the critical pieces of data required by the reservoir engineer for an effective analysis of a reservoir. Obtaining reliable pressure data should be a primary goal of any reservoir management program.

2.2.2 Bottom hole pressure

Bottom hole pressure is the pressure which is measured in a well at or near the depth of the producing formation. It is often desirable to refer this pressure to a datum level chosen at a reference depth by calculating the pressure that would occur if the pressure measurement were made at the datum level rather than at the actual depth of the gauge[13].

In this thesis wherever the abbreviation BHP is used, it refers to well static bottom hole pressure which is different from bottom hole flowing pressure.

The practice of using bottom hole pressure (BHP) to improve oil production and to solve petroleum engineering problems started in about 1930. Pressures in oil wells were first calculated from fluid levels and later by injecting gas into the tubing until the pressure became constant. BHP can be calculated also, from surface pressure and fluid level, although less accurate than measured pressure, it is sufficient for many practical uses[2].

The importance of pressure analysis in projecting and enhancing the performance of producing oil and gas wells emphasizes the need for precision pressure measurement systems. Today's petroleum engineer must have sufficient information about the reservoir, to adequately analyze current performance and predict and optimize future performance. More specifically, such pressures are a

basic part of reservoir simulation and calculations.

Static pressure is the most frequent BHP measurement. Pressures are taken under reasonably uniform conditions after the wells have been shut in a specified length of time such as 24 or 48 hours, or longer, if the pressure buildup (pressure buildup test) is at a slow rate. The pressures should be measured at or adjusted to a common data plane. In many cases, the pressures will not reach equilibrium in the specified shut-in time. However, if the pressures are determined for several surveys under the same conditions, the indicated rate of decline of the reservoir pressure should be reasonably accurate. Tests in representative wells which have been shut in long enough to reach pressure equilibrium will show the relation of the measured pressure to the actual reservoir pressure. Pressures in inactive wells may be used to confirm the actual pressure and the rate of decline[2].

Well static bottom hole pressure is depended on various parameters of the reservoir. Some of the most important ones are listed below:

1. Radius of investigation: The calculated maximum radius in a formation in which pressure has been affected during the flow period of a transient well testis called Radius of investigation. While not absolutely accurate, the value has meaning in relation to the total volume of reservoir that is represented by calculated reservoir parameters, such as kh, the permeability thickness[13] (Figure 2-3).

   In chapter 3, some methods that have been being used by commercial software will be discussed. It will be seen that determination of the well static bottom hole pressure, strongly depends on this factor.

2. Permeability around the wellbore or other alternative variable like mobility ratio are affecting the well static bottom hole pressure (Figure 2-3).

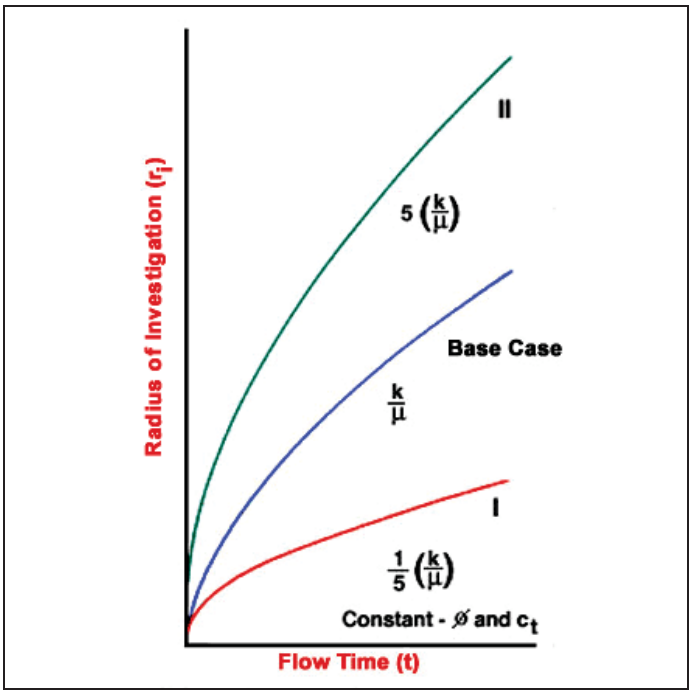

Figure 2-3: The effect of mobility ratio on radius of investigation versus time[12].

3. Net to gross ratio of the layers has the effect on the deliverability of the reservoir to the well.

4. Skin factor: It is well known that the properties of the formation near the wellbore are usually altered during drilling, completion, and stimulation procedures. Invasion by drilling fluids, the presence of mud cake and cement, partial well penetration, and limited entry perforations are some of the factors that cause damage to the formation; and, hence, an additional localized pressure drop during flow. On the other hand, well stimulation techniques, such as acidizing and fracturing, will normally enhance the properties of the formation and increase the permeability around the wellbore, so that a decrease in pressure drop over that otherwise expected for a given flow rate is observed. Therefore, with the basic flow system and with our basic solution, we should incorporate the additional pressure effects caused by near-wellbore differences in formation properties. The zone of altered permeability is referred to as a skin and the resulting effect as a skin effect (Figure 2-4 & Figure 2-5).

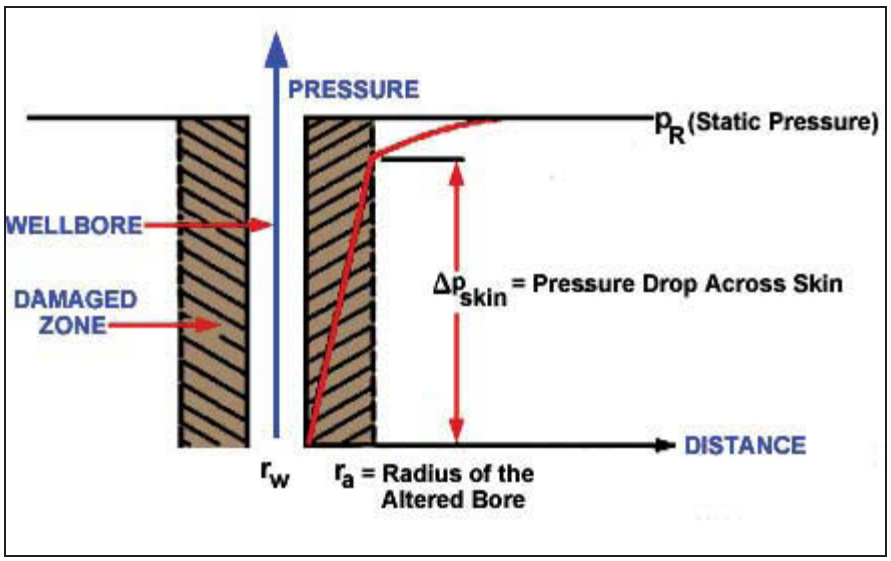

Figure 2-4: Schematic representation of near wellbore skin effect, also shows the additional pressure drop caused by a damaged zone in the vicinity of the wellbore[12].

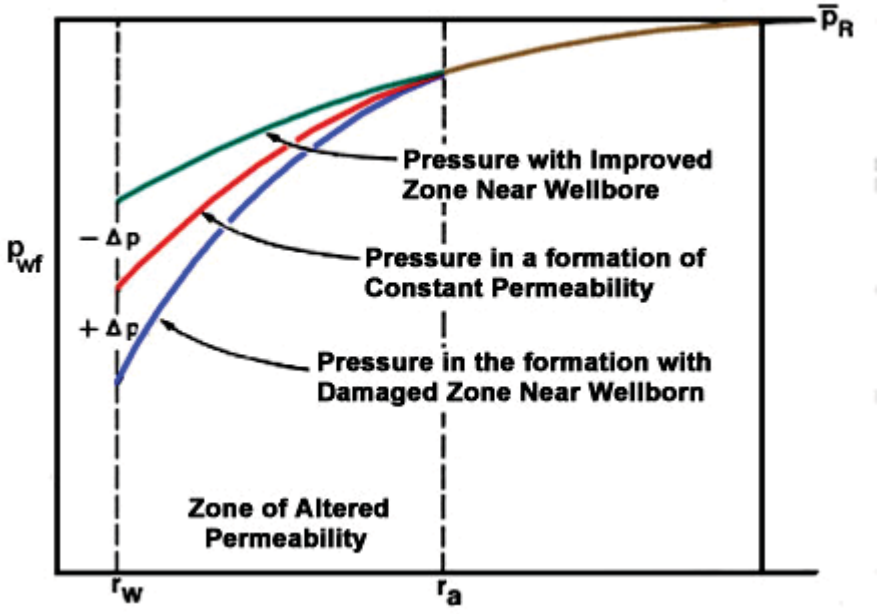

Figure 2-5: Schematic representation of positive and negative skin effects, also compares the differences in pressure distribution in a formation of constant k [12].

2.3 Practical procedures for well and reservoir pressure measurements (pressure buildup test)

A means of assessing reservoir performance by measuring flow rates and pressures under a range of flowing conditions and applying the data to a mathematical model is called well testing. Fundamental data relating to the interval under test, such as reservoir height and details of the reservoir fluids, are also considered for input. The resulting outputs typically include an assessment of reservoir permeability, the flow capacity of the reservoir and any damage that may be restricting productivity. In most well tests, a limited amount of fluid is allowed to flow from the formation being tested. The formation is isolated behind cemented casing and perforated at the formation depth or, in open hole, the formation is straddled by a pair of packers that isolate the formation. During the flow period, the pressure at the formation is monitored over time. Then, the formation is closed (or shut in) and the pressure monitored at the formation while the fluid within the formation equilibrates. The analysis of these pressure changes can provide information on the size and shape of the formation as well as its ability to produce fluids[13].

It is difficult to keep the rate constant in a producing well. This is not an issue in a buildup test since the well is closed. The rate is zero. This test may be conducted any time. The disadvantage is that the well has to be closed for a period. Since the well is closed, it will not generate income during this period. Hence the shut-in time should be as short as possible.

The procedure of pressure build up test is as follows[7]:

1. For performing a well test, a pressure disturbance in the reservoir will be created and the response to changing production will be monitored at the wellbore. Well is producing at constant rate, at time t_p it will be shut-in.
2. The last well flowing pressure will be measured, which we call it p_{wf}. Then the pressure in the well will start to build up again (Figure 2-6). This pressure is called shut-in pressure p_{ws}.

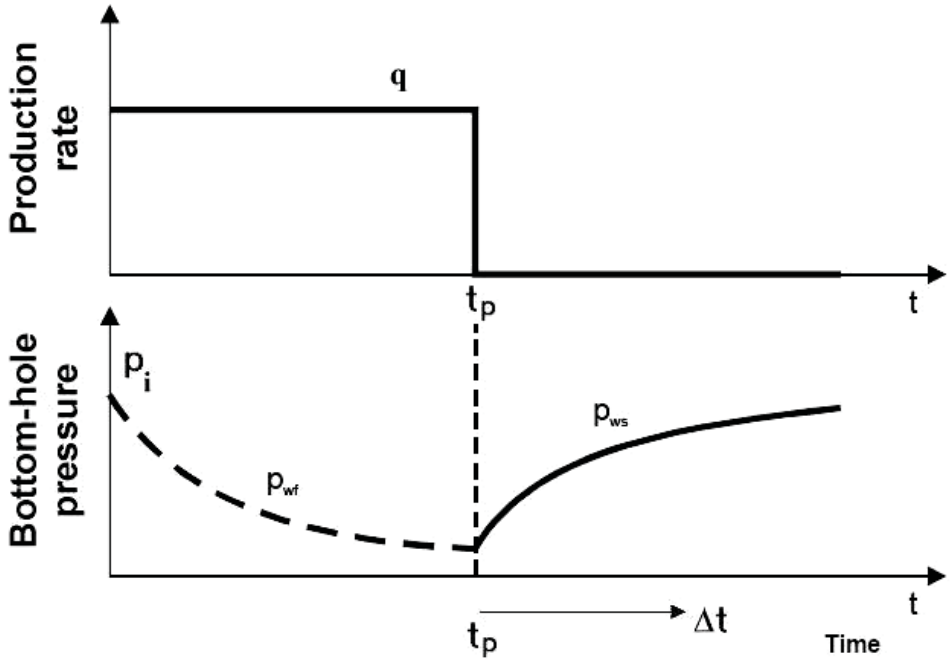

Figure 2-6: Schematic of an ideal buildup test[6].

3. By monitoring the pressure buildup in the well, different properties of the reservoir and well can be obtained by interpretation.

In Figure 2-6, t_p and Δt denote production time and shut-in time respectively. Properties of the reservoir that can be obtained from well testing are listed below. Some of them are in the reservoir scale and the others are related to the well itself.

- Determination of permeability
- Determination of the reservoir initial pressure
- Determination of bounded reservoir
- Determination of average static pressure
- Identify candidates for stimulation and workover
- Deliverability (volumetric average reservoir pressure)

It should be kept in mind that reservoir rock characteristics as determined from well tests are averaged values over the area of the reservoir that is contacted during the test[12].

2.3.1 Infinite-acting reservoir

For a new well, the pressure wave associated with the flow period may not have reached the outer boundary. Then the following equation applies:

$$p_{ws} = p_i - \frac{q\mu B \cdot 1.15}{2\pi hk} \log \frac{t_p + \Delta t}{\Delta t} \qquad \textbf{2-6}$$

This formula is called Horner equation.

The above equation shows up as a straight line on a p_{ws} vs. log $\frac{t_p + \Delta t}{\Delta t}$ plot.

2.3.2 Determination of permeability

Perfect control of the reservoir flow rate is impossible. Immediately after shut-in, the wellbore pressure is lower than out in the reservoir. Fluid will continue to flow into the well after shut-in. The wellbore pressure will increase as a result of fluid compression. Eventually the pressures will be equalized and the inflow into the well will stop [8]. It should be mentioned here that the rate profile of Figure 2-6 is idealized. Instantaneous shut-in is not possible. Therefore there will always be some after-flow due to wellbore storage effect. As a consequence the measured pressure will not obey the Horner equation initially.

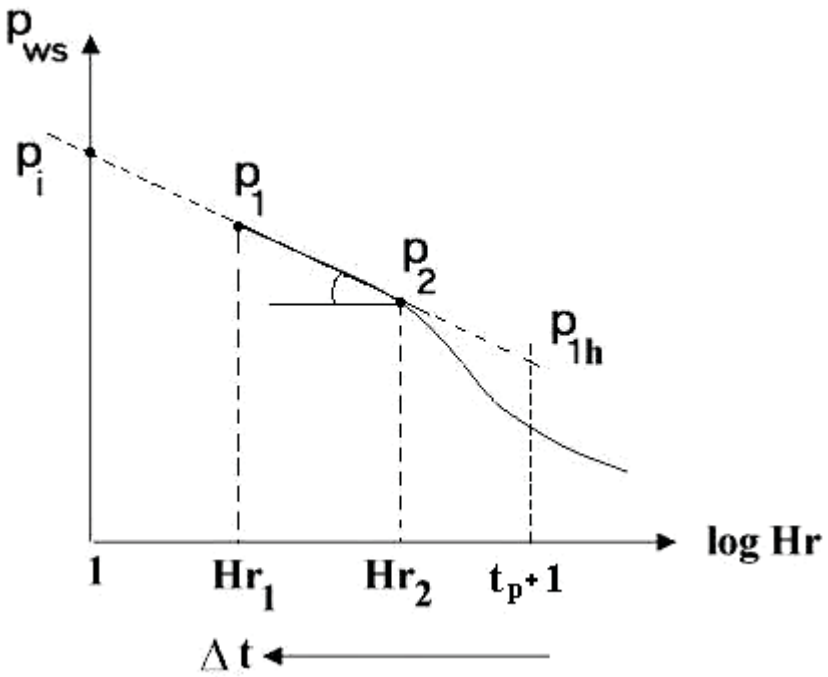

Figure 2-7: Schematic of a Horner plot of a well with after-flow due to wellbore storage and skin factor[7].

"Hr" in the plot is used to represent the Horner time: $\mathrm{Hr} = \frac{t_p + \Delta t}{\Delta t}$

It can be seen from the plot that the shut-in time, Δt, increases to the left in the Horner plot, Figure 2-7. The Horner time will decrease as Δt increases.

The general formula of the pressure buildup can be summarized in simpler form which is a straight line. This is depicted here:

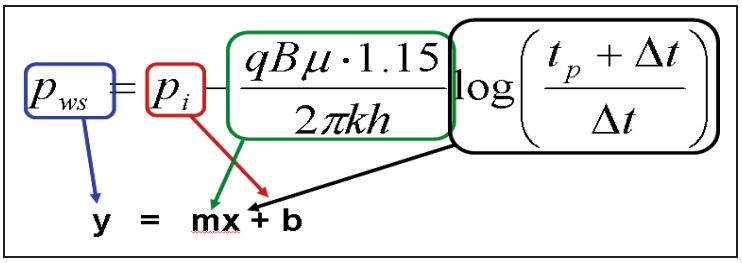

Figure 2-8: simplification of the well testing general formula.

From these explanations the slope of the line will be as follows:

$$m = \frac{q\mu B \cdot 1.15}{2\pi hk} \qquad 2\text{-}7$$

And eventually the permeability may be determined from the following equation:

$$k = \frac{q\mu B \cdot 1.15}{2\pi mk} \qquad \text{2-8}$$

The slope is also defined by two points on the straight line

$$m = \frac{p_1 - p_2}{\log Hr_1 - \log Hr_2} \qquad \text{2-9}$$

As mentioned previously it is difficult to keep the flow rate constant for any length of time. The rate may have fluctuated significantly during the production period. Horner proposed the following correction:

$$t_p = \frac{N_p}{q_{LAST}} \qquad \textbf{2-10}$$

where N_p is the cumulative production since the last major shut-in period and q_{LAST} is the last stabilized rate.

2.3.3 Determination of the initial reservoir pressure

The Horner equation may be written:

$$p_{ws} = p_i - \frac{q\mu B \cdot 1.15}{2\pi hk} \log Hr \qquad \textbf{2-11}$$

Note that: $p_{ws} = p_i$ for $Hr = 1$

The Horner ratio will approach 1 for infinite shut-in time Δt; and consequently the initial reservoir pressure may be obtained by extrapolating the straight line back to $Hr = 1$. The technique is illustrated in Figure 2-7.

2.3.4 Determination of the skin factor

For determination of the skin factor, we have to have drawdown test also in conjunction with the pressure buildup. The skin is not included in the Horner

equation. To involve this parameter, the last flowing pressure p_{wf} is subtracted from both sides of the Horner equation. The last flowing pressure is given by the drawdown equation. On the right hand side of the Horner equation we subtract the mathematical model and on the left hand side the observed pressure[7].

The result is like this:

$$p_{ws} - p_{wf} = \frac{q\mu B \cdot 1.15}{2\pi hk}(\log\frac{t_p + \Delta t}{\Delta t} - \log\frac{kt_p}{\varphi\mu c_t r_w^2} - 0.351 + 0.87s) \qquad \textbf{2-12}$$

Normally in well testing the shut-in time is very small in comparison with the production time ($t_p >> \Delta t$). Hence this assumption is valid: $t_p + \Delta t \approx t_p$.

Therefore the above equation will simplify since the production time t_p disappears. The modified Horner equation may be solved for the skin factor once the shut-in time is specified. The traditional choice in the petroleum industry is $\Delta t = 1$ hour. This choice leads to:

$$S = 1.15\left(\frac{p_{ws\Delta t=1h} - p_{ws}}{m} - \log\frac{k}{\varphi\mu c_t r_w^2} - 3.91\right) \qquad \textbf{2-13}$$

In the equation above, it is obvious that the argument of the Log is a constant value and depends on the characteristics of the reservoir and wellbore radius. Therefore the skin factor is depended on the nominator of the first term in the parentheses. The skin factor is controlled by the difference between well flowing pressures with time ($p_{ws\ (1\ hour)} - p_{wf}$).

It is possible that the measured wellbore pressure at 1 hour may not be on the straight Horner line. Then the line is extrapolated until it intersects the $Hr_{\Delta t = 1h}$ vertical line.

All the above explanations can be seen in the figure below. The Horner ratio at 1 hour may be computed from $Hr_{\Delta t\ =\ 1h} = t_p + 1$.

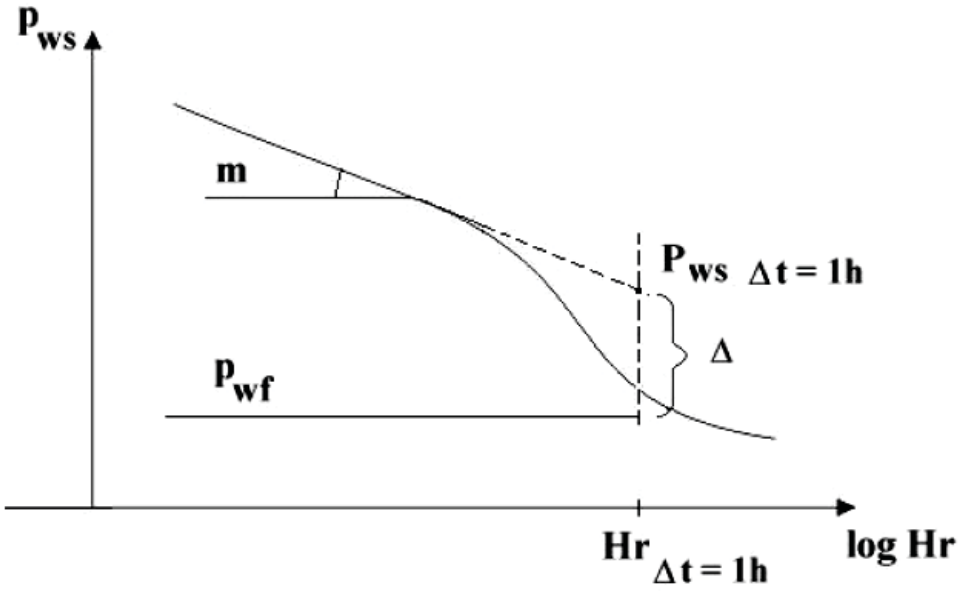

Figure 2-9: The skin depends on the difference in pressures Δ[7].

2.3.5 Bounded reservoir

Sooner or later in every reservoir, the pressure wave associated with the flow period will hit the outer boundary. Suppose that this is of no-flow type (sealed boundary). If the well is closed during pseudo-steady flow, then the pressure will build up towards the average pressure rather than the initial pressure. This is illustrated in the Figure 2-10.

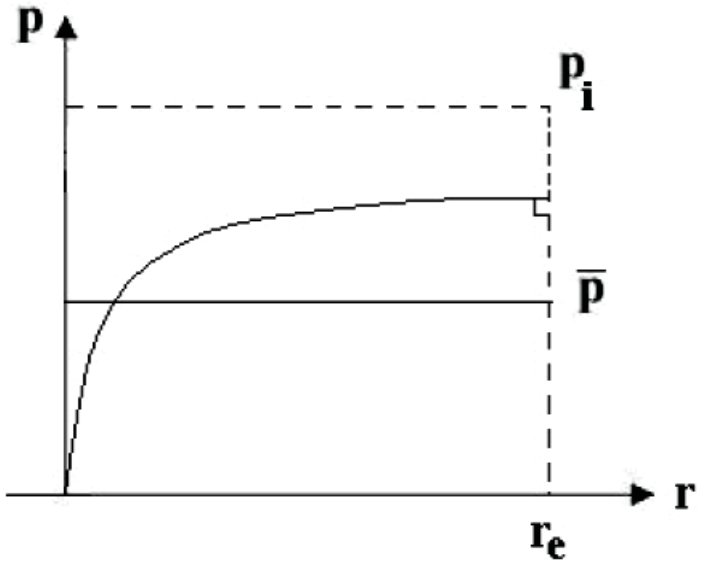

Figure 2-10: Pressure versus distance, pseudo-steady flow.

The effect of the outer boundary appears at the late part of the Horner plot while the early part essentially remains unchanged. The boundary effect will show up as a break off from the straight line.

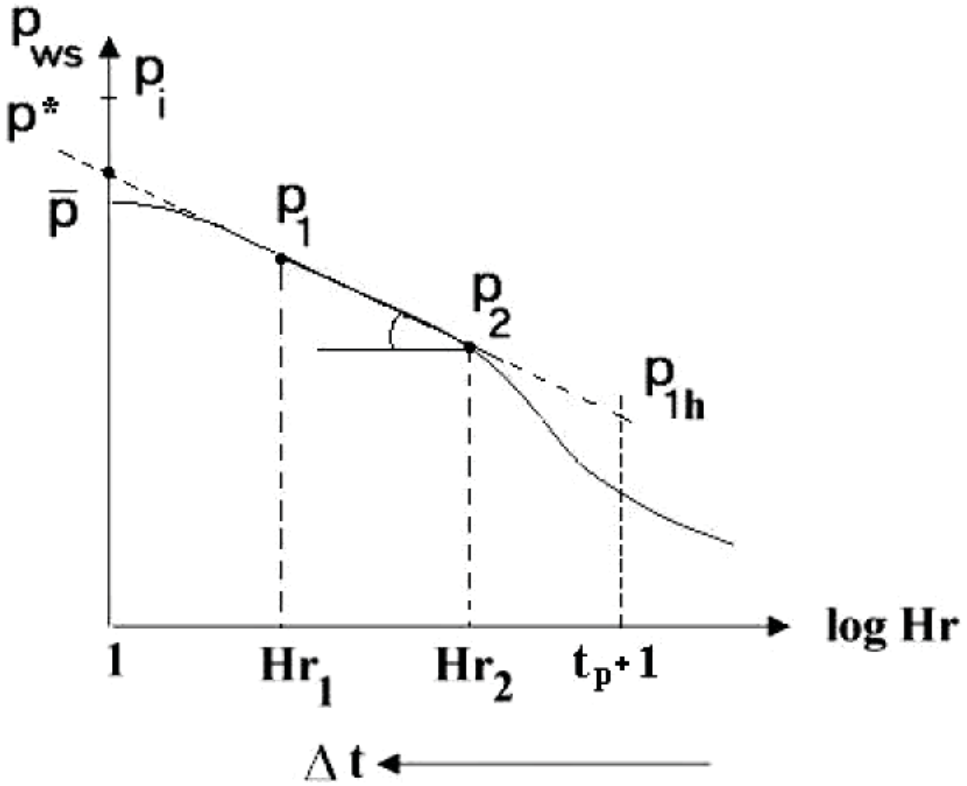

Figure 2-11: Horner plot, bounded reservoir [7].

As mentioned previous the Horner equation for the straight line section was like this:

$$p_{ws} = p^* - \frac{q\mu B \cdot 1.15}{2\pi hk} \log \frac{t + \Delta t}{\Delta t} \qquad \textbf{2-14}$$

where p* is the intersection with the Hr =1 axis. The intersection has been called the false pressure. It has no physical interpretation but it is related to the average pressure, $\overline{p}$. The straight line on the Horner plot may be used to determine the permeability and skin factor as discussed previously.

2.3.6 Determination of the average pressure

Matthews, Brons and Hazebroek presented charts that relate the false pressure to

the average pressure for various geometries. Index D in this part will be used to denote dimensionless variables.

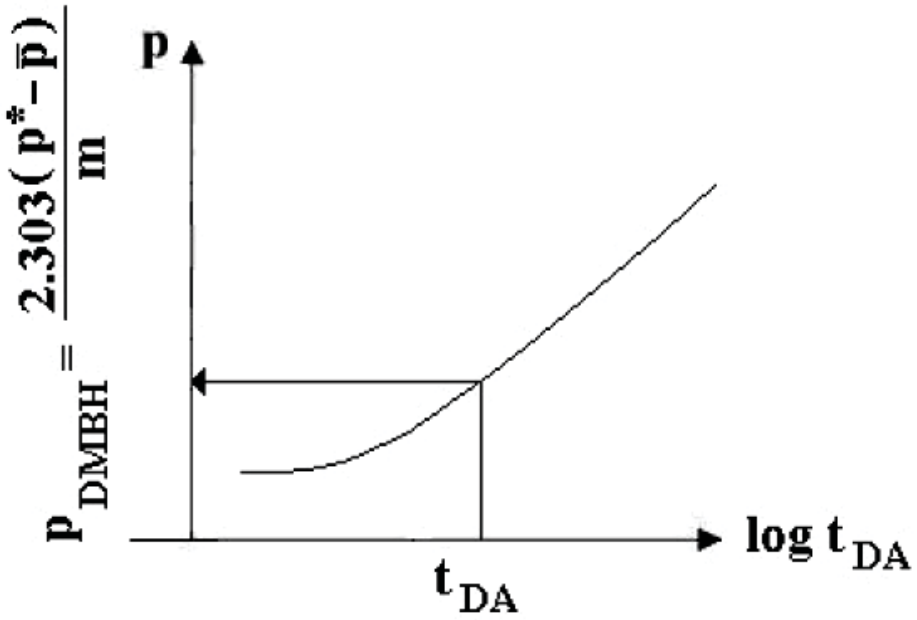

Figure 2-12: Schematic of a Mattews, Brons and Hazebroek plot (MBH plot).

The average pressure may be calculated by the sequences presented below [7]:

1. The first step would be the obtaining the slope *m* and the false pressure p* from the Horner plot.
2. Then the shape and size of the drainage area must be estimated.
3. In the third step, the dimensionless production time from the formula blow should be calculated:

$$t_{DA} = \frac{kt_p}{\varphi \mu c_t A} \qquad \textbf{2-15}$$

4. Look up the MBH-curve that corresponds to the estimated shape of the drainage area, and find P_{DMBH}.
5. Calculate the average pressure from the formula:

$$\bar{p} = p^* - \frac{mp_{DMBH}}{2.303} \qquad \textbf{2-16}$$

The difficult part in this calculation procedure is point 2. Estimation of the size

and shape of the drainage area is beyond the scope of these notes.

The average pressure is used in material balance calculations. Also it is used to calculate the flow efficiency, FE.

$$FE = \frac{\overline{p} - p_{wf} - \Delta ps}{\overline{p} - p_{wf}} \qquad \textbf{2-17}$$

p_{wf} is the last flowing pressure. For pseudo-steady flow, the difference $\overline{p} - p_{wf}$ is independent of time. This condition leads to a constant value of the flow efficiency. Otherwise it will depend on time.

Sometimes the flow efficiency is approximated by this formula:

$$FE = \frac{p^* - p_{wf} - \Delta p_s}{\left(p^* - p_{wf}\right)} \qquad \textbf{2-18}$$

The result is not as accurate but easier to obtain.

2.4 Well model

A well in reservoir simulation is normally modeled by a source (injection) or sink (production) term in the conservation equation. Wells are an integral part of every reservoir simulator and they have to be dealt with in any study on reservoir simulation. Pressure in a grid block (in which a well is completed) cannot be assumed to be equal to the flowing bottom hole pressure p_{wf}, because the grid block dimensions are much larger than the wellbore diameter, Hence the need for a well model.

2.4.1 Definition of Well Model

An equation which provides the relationship between grid block pressure p_0, well flowing bottom hole pressure p_{wf} and production rate q is called a well model[18].

Peaceman (1978) was the first to present a rigorous treatment of wells in reservoir

simulation. He showed that for a well completed in grid block 0, p_0 is neither the average pressure of the grid block nor is it equal to the flowing well bottom hole pressure. In fact, he showed it to be the pressure for radial flow at a distance of r_0 from the grid node. He provided the following simple equation for a well model:

$$q = \frac{2\pi hk}{\mu B} \frac{p_{wf} - p_0}{\ln\left(r_0 / r_w\right)} \qquad \textbf{2-19}$$

Thus given, an expression for r_0 , p_{wf} can be computed using eq.2-19. From numerical experiments and an analytical technique, he found that $r_0 = 0.2\Delta x$, for uniform grids (grid block dimension $\Delta x = \Delta y$), isotropic and homogeneous permeability and the well sufficiently away from other wells and reservoir boundary.

Most of the models available in the literature assume that the well penetrates the full thickness of the reservoir, the permeability tensor in the well block is diagonal and in the direction of coordinate axes and the well is aligned along one of the coordinate axes (Peaceman, 1983)[10]. Peaceman's well models are for wells which are away from the reservoir boundary and other wells. Kuniansky and Hillestad (1980) extended Peaceman's work for wells which are not located in an interior grid block. Abou-Kassem and Aziz (1985) proposed an analytical well model for various well-block geometries. Sharpe and Ramesh (1992) presented modifications of Peaceman type well models for nonuniform grids with application to horizontal well and coning problems. Babu et al. (1991) presented expressions for r_0 which are valid for vertical and horizontal wells and for any location, aspect ratio of the well's drainage area and anisotropy[1].

Some well models allow partially penetrating wells (Lin 1995), inclined wells, etc., but they have been proposed for Cartesian grids. Lee and Milliken (1993) presented methods to determine the productivity index of an inclined well for Cartesian finite difference grids. They assumed a diagonal tensor with the coordinate axes aligned along the principal directions of the tensor. Mochizuki

(1995) and Chen et al. (1995) have also presented equations for well index calculations for arbitrary inclined wells. Their assumptions are the same as that of Lee and Milliken (1993). Nolen (1990) provides a very good review of the treatment of wells in reservoir simulators. Peaceman (1995) presented calculations for r_0 for arbitrary well rates and also accounted for interaction between wells[10].

Shiralkar (1989) presented a well model for nine point schemes for full tensor permeability on Cartesian grids[12]. Well models have been proposed for PEBI (Palagi and Aziz, 1992, Heinemann and Brand, 1989) and CVFE grids (Fung et al., 1991, Sonier and Eymard, 1993) but they assume no grid flexibility in the vertical/well axis direction.

2.4.2 Well Models for Homogeneous Reservoirs

Peaceman (1978) was the first to present how to calculate r_0 exactly. r_0 is said to be exact when it gives the same well pressure (in the numerical solution) as that given by the exact analytical solution of the same single phase model problem[10]. Determining exact r_0 requires solution of both the continuous and discrete problems. To illustrate this eq.2-19 is written as:

$$\ln\left(\frac{r_0}{r_w}\right) = \frac{2\pi hk}{q\mu B}\left(p_0 - p_{wf}\right) \qquad \textbf{2-20}$$

p_{wf} in the above equation can be obtained from an analytical solution if one exists for the given problem. p_0 is the pressure in the grid block containing the well and can be solved for numerically or obtained analytically for simple cases. Thus r_0 can be computed and then be used in the reservoir simulator. Eq.

2-12-20 can be put in the following form:

$$q = \lambda WI\left(p_0 - p_{wf}\right) \qquad \textbf{2-21}$$

where

$$WI = \frac{2\pi hk}{\ln\left(\frac{r_0}{r_w}\right)} \qquad \textbf{2-22}$$

and $\lambda = {}^{1}\!\!\diagup\!\!{}_{(\mu B)}$ for single phase flow.

Several model problems for analytical solution of p_{wf} have been used in the literature. Peaceman (1978), Kuniansky and Hillestad (1980), Peaceman (1991), Babu et al. (1991), Ding et al. (1995) and Palagi and Aziz (1992) all use different model problems[2]. Peaceman (1978) used the analytical solution provided by Muskat (1937) for a repeated five-spot problem. Palagi and Aziz (1992) also describe how to determine r_0 once a model problem has been defined[6]. For homogeneous reservoir they use an analytical solution to determine p_{wf} . Their model problem for analytical solution consists of a group of wells producing or injecting at constant rate in a rectangular reservoir with closed boundaries. They use superposition of line source solutions to get the pressure p_{wf} at any location. They then solve the same problem numerically to obtain p_0 which can then be used to determine r_0.

The major problem in the computation of exact well indices is that it may require significant effort. Simplified well models allow r_0 to be computed directly in the simulator without any effort from the user. Palagi and Aziz (1992) give such an expression for PEBI grids for homogeneous and isotropic reservoir.

$$\ln r_0 = \left[\sum_j T_{ij} \ln d_{ij} - 2\pi hk\right] / \sum_j T_{ij} \qquad \textbf{2-23}$$

d_{ij} is distance between the grid nodes i and j and T_{ij} is transmissibility between the grid nodes i and j. r_0 is then used in Eq.**Error! Reference source not found.** to determine the well production rate using Eq.2-21.

2.4.3 Well Models for Heterogeneous Reservoirs

For heterogeneous reservoir Palagi and Aziz (1992) assumed that a fine scale pressure solution for the given boundary conditions is the analytical solution. In the fine scale solution it is assumed that the permeability distribution is sufficiently homogeneous to allow the use of a simple well model. If it is assumed that at fine scale the permeability is isotropic then this method can be used with the gridding scheme of this work, without any significant limitation. The procedure is reproduced from their work below.

1. The well equation, Eq.2-21, is written as following:

$$WI = \frac{1}{\xi^{w}_{fine} - \xi^{0}_{coarse}} \qquad \textbf{2-24}$$

where

$$\xi^{w}_{fine} = \frac{\overline{p} - p_{wf}}{q\mu B} \qquad \textbf{2-25}$$

and

$$\xi^{0}_{coarse} = \frac{\overline{p} - p_{0}}{q\mu B} \qquad \textbf{2-26}$$

2. Perform fine grid simulation to determine the exact value of ξ^{w}_{fine}. The fine grid should have very small uniform grids distributed around the well such that an analytical well model such as that given by Eq.2-23 can be used. At this scale one can use Cartesian grids and assume the permeability tensor to be diagonal. Peaceman's simple model for anisotropic formations can be used to determine p_{wf} at the fine grid level.

3. Simulate the same configuration with the coarse grid of interest and find ξ^{0}_{coarse} .

4. Compute the well index WI based on equation Eq.2-24. No expression for r_0 can be obtained because a single uniform k can not be determined for the coarse grid block.

As Palagi and Aziz (1992) mention, this process is based on material balance conditions. The average pressure $\overline{p}$ can be obtained from

$$p_{ini} - \overline{p} = \frac{W_{ini} - W_{cur}}{c_t W_{ini}} = \frac{q_{tot} t}{c_t W_{ini}} \qquad \textbf{2-27}$$

where W_{ini} is the original fluid in place, W_{cur} is the remaining fluid in place at time t, q_{tot} is the net production rate, and c_t is total fluid compressibility. Stabilized values of ξ^w_{fine} and ξ^0_{coarse} should be used.

Fung et al. (1991) present a simplified well model for CVFE type of grids[5]. The flux into a well-block for well-index calculation is computed using a different equation than the normal CVFE discretization. They do not present any numerical verification of the model. They develop the equation in a manner very similar to Peaceman (1978). They assume steady-state radial flow around the well which gives:

$$p_{wf} - p_0 = \frac{q\mu B}{2\pi hk} \ln\left(\frac{r_w}{r_0}\right) \qquad \textbf{2-28}$$

Flow into well block from neighboring blocks i is assumed to be:

$$p_i - p_0 = \frac{q\mu B}{2\pi hk} \ln\left(\frac{r_w}{r_i}\right) \qquad \textbf{2-29}$$

While the finite-difference equation for steady state flow is:

$$q = \frac{kh}{\mu B}\left[\sum_i \frac{w_i}{r_i}\left(p_i - p_0\right)\right] \qquad \textbf{2-30}$$

Where w_i is the width and r_i is radial distance as shown in Figure 7. Eqs.2-29 and 2-30 are combined to compute r_0 which is then used in Eq. 2-28 to compute p_{wf} or q.

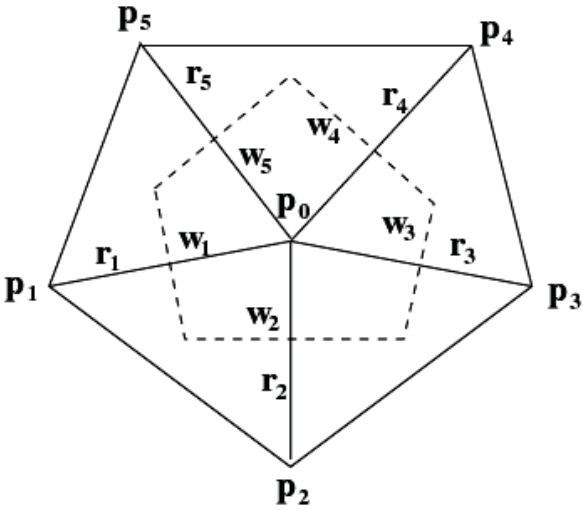

Figure 2-13: Well control-volume for well index and r_0 calculation as used by Fung et al. (1991).

Chapter 3

3 Available averaging methods in the state of the art simulators

3.1 Practical averaging methods in contemporary simulators

The methods that famous commercial software is using for determination of the well bottom hole static pressure are presented in this chapter. ECLIPSE® and SURE® has been investigated for their averaging methods; and finally the HRC method has been presented with detailed explanation.

3.1.1 ECLIPSE® averaging method[15]

ECLIPSE® reservoir simulators have been the benchmark for commercial reservoir simulation for over 25 years because of its vast capabilities. In this software the calculation of the bottom hole pressure is being done by a kind of weighting of the 4 normal direct neighbors of the well block and another 4 diagonal neighbors of the well block.

Two major factors should be entered for weighting F1 & F2. F2 is the weighting factor for specifying a value between “connection factor weighted average pressure” and “the pore volume weighted average pressure”. F2 provides this range by a value between zero and one.

$$\overline{P}_{well} = F2 \cdot \overline{P}_{well,cf} + (1 - F2) \cdot \overline{P}_{well,pv} \qquad \textbf{3-1}$$

Where:

$\overline{P}_{well}$ Well block average pressure

$\overline{P}_{well,cf}$ Connection factor weighted average pressure

$\overline{P}_{well,pv}$ Pore volume weighted average pressure

3.1.1.1 Connection factor weighted average pressure:

Transmissibility factor weighted average pressure is a weighted pressure of each layer or perforation or each single block containing the well.

Firstly the average of each block containing the well will be averaged by one of these formulas below (eq. 3-2& eq. 3-3).

The factor that will determine which one of these formulas should be used is F1. If F1 is higher than zero (0 < F1 < 1), then eq. 3-2 will be used; and if F1 is minus, then (F1 < 0), then eq. 3-3 will play the role.

F1 is an arbitrary value entered by the user. If it has not been specified by user then the default value (F1 = 0.5) will be taken into account, which shows the combination of both formulas. Equation 3-2 is using the well pressure and a normal arithmetic averaging for the neighbors. Equation 3-3 is the pore volume weighting average pressure.

$$\overline{P}_{L} = F1 \cdot P_{well,L} + (1 - F1) \frac{\sum_{neigh,L} P_{neigh,L}}{N_{neigh,L}} \qquad \textbf{3-2}$$

$$\overline{P}_{L} = \frac{V_{well,L} P_{well,L} + \sum V_{neigh,L} P_{neigh,L}}{V_{well,L} + \sum_{neigh,L} V_{neigh,L}} \qquad \textbf{3-3}$$

Where:

F1 Weighting factor between well block and neighboring blocks

$\overline{P}_L$ Total average pressure in each well block or at each layer or perforation

$P_{well,L}$ Well block pressure

$P_{neigh,L}$ Neighboring block pressures

$V_{well,L}$ Pore volume of well block

$V_{neigh,L}$ Pore volume of neighboring blocks

In the second step, the calculated pressure in each well block $\overline{P}_L$ will be weighted by transmissibility of the each perforation. It should be mentioned that by default, perforations that are open will considered for this calculation, unless user enters the keyword "all".

$$\overline{P}_{well,cf} = \frac{\sum_k T_k \cdot \overline{P}_L}{\sum_k T_k} \qquad \textbf{3-4}$$

Where:

$\overline{P}_{well,Tf}$ Total average pressure of well weighted by transmissibility

$\overline{P}_L$ Total average pressure in each well block or at each layer or perforation

T_k Transmissibility factor at each perforation

By calculating this value one part of equation 3-1 is completed.

One point to notice is that in this software number of neighboring blocks surrounding the well block will be determined by WBP keywords[14].

3.1.1.2 Pore volume weighted average pressure

For the second part of the equation 3-1 the below formula will be used. This is the pore volume weighted average pressure. This rather more simple than the previous

precedure. With only one weighting formula by pore volume, this part is completed also.

$$\overline{P}_{well,pv} = \frac{\sum_{nb} V_{nb} P_{nb}}{\sum_{nb} V_{nb}} \qquad \textbf{3-5}$$

Where:

$\overline{P}_{well,pv}$ Total average pressure of well, weighted by pore volume

P_{nb} Pressure of each block considered for this averaging

V_{nb} pore volume of each block considered for this averaging

nb Number of grid blocks for this calculation

The number of grid blocks for this calculation is determined by WBP keywords (WBP1, WBP4, WBP5, and WBP9):

In the case of "WBP1", only the well block will be considered.

In the case of "WBP4", only four direct neighbors will be considered.

In the case of "WBP5", well block and four direct neighbors will be considered.

In the case of "WBP9", well block and eight neighbors will be considered (four direct neighbors and four diagonal neighbors).

3.1.2 SURE® averaging method

3.1.2.1 Well Block Average Pressure Calculation[16]

This option in SURE® calculates weighted average pressures for wells and perforations using the pressure in the well block and its neighboring blocks, which are grouped into rings around the perforated block (Figure 3-1).

In SURE® the number of neighbors in a Cartesian grid is dealt with differently in the case of WPAVE. For example in Cartesian Grid the number of direct

neighbors is 4 (first ring, the same as ECLIPSE® & HRC) but the number of number of surrounding blocks in the second ring is 8 (in ECLIPSE® & HRC, second ring is only 4 diagonal blocks). SURE® has the ability to handle unstructured grid, noting that this software search for neighboring blocks which can be any number in unstructured grid. Searching for neighboring blocks can be done for the first 5 rings around the wellbore (the number of rings can be adjusted through the TDD file of SURE®).

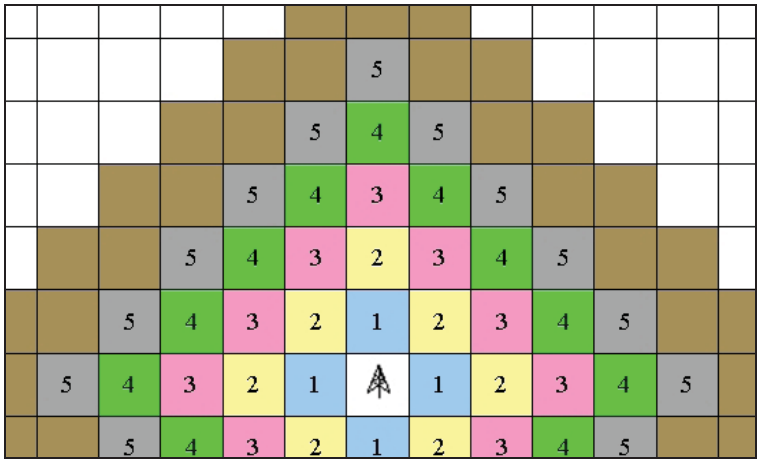

Figure 3-1: The neighboring blocks around the well in this software.

There are distinctive keywords for this identifier in SURE® which are almost similar to ECLIPSE® & HRC, like “F1” which is the weighting factor between the well block and neighboring rings; “F2” is the weighting factor between the well index weighted average pressure and pore volume weighted average pressure.

The number of fractions following the Keyword F1 for the software to search for neighbors in the number rings which is equal to the number of fractions in the TDD file following the F1 fraction. Up to five F1 fractions can be defined for five neighboring rings. Each fraction is allocated to one ring, firstly the existence of this fraction determines the block search in this ring, and secondly the value of the fraction is the weighting factor for the average pressure in this ring.

3.1.2.2 Average Pressure for Perforations

For every connection the average pressure is calculated as:

$$P_{connection} = \left(1 - \sum_{i}^{N_{Rings}} F1_i\right) P_{wellblock} + \sum_{i}^{N_{Rings}} \left(F1_i \frac{\sum_{j}^{N_i} P_{i,j}}{N_i} \right) \qquad \textbf{3-6}$$

Where:

$P_{connection}$	average pressure for each connection
N_{Rings}	number of rings that are taken for averaging
F_{1i}	weighting factor for ring i
$P_{wellblock}$	pressure of the well block according to the reference depth
N_i	number of blocks in ring i
$P_{i,j}$	pressure of grid block k in ring i corrected to the reference depth

The default setting for F1 in SURE® is 0.5; this means that the average pressure for every connection is calculated as an average of the well block pressure and the first ring of block neighbors.

The fraction(s) following the keyword “F1” must not be more than 1.0 and less than 0.0. If “F1” is entered a value less than zero (minus), this means that SURE® will calculate the average pressure for each connection by pore volume weighted average pressure of the neighboring blocks (Eq. 3-7). The weighting factor for the inner well block itself is defined as (1-∑F1) when it is positive, and when it is negative, it is averaged by pore volume weighting.

If (F1 < 0.0) is defined, the average pressure for each connection in the well is calculated using a pore volume weighted average (Eq. 3-7).

$$p_{connection} = \frac{PV_{wellblock} \cdot p_{wellblock} + \sum_{i}^{N_{Rings}} \sum_{j}^{N_i} PV_{i,j} \cdot p_{i,j}}{PV_{wellblock} + \sum_{i}^{N_{Rings}} \sum_{j}^{N_i} PV_{i,j}} \quad \textbf{3-7}$$

Where:

$PV_{wellblock}$ pore volume of the well block (at the current well block pressure)

$PV_{i,j}$ pore volume of the block j in ring i (at the current grid block pressure)

$p_{i,j}$ pressure of grid block j in ring i corrected to the reference depth

$p_{wellblock}$ pressure of the well block corrected to the reference depth

N_{Rings} number of rings that are considered

N_i number of grid blocks in ring i

3.11.2 Average Pressure for Wells

The average static pressure for a well is determined by weighting between the weighting of average of the well-index weighted perforation pressures and weighting of a pore volume weighted average pressure of all locks in the considered rings.

$$p_{well} = F2 \cdot p_{wi} + (1 - F2) \cdot p_{PV} \quad \textbf{3-8}$$

Where:

p_{well} average well pressure

p_{wi} well index weighted average of the perforation pressures

p_{PV} pore volume weighted average of the pressures of all blocks in the considered rings

F2 user-defined weighting factor

The default value for F2 in SURE® for F2 is 1.0 like in ECLIPSE®, this means that by default there will be no participation of the pore volume weighted average in the the calculation.

The well-index weighted average pressure is calculated as follows:

$$p_{WI} = \frac{\sum_{k}^{N_{connection}} WI_k \cdot p_{connection,k}}{\sum_{k}^{N_{perf}} WI_k} \qquad \textbf{3-9}$$

Where:

p_{WI}	well-index weighted average pressure
$N_{connection}$	number of perforations
WI_k	well index of perforation k
$P_{connection,k}$	average perforation pressure of perforation k

The pore volume weighted average pressure of all blocks in the considered rings is calculated as

$$p_{PV} = \frac{PV_{wellblock} \cdot p_{wellblock} + \sum_{j}^{N_{perf}} \sum_{k}^{N_{Rings}} \sum_{i}^{N_i} PV_{j,k,i} \cdot p_{j,k,i}}{PV_{wellblock} + \sum_{j}^{N_{perf}} \sum_{k}^{N_{Rings}} \sum_{i}^{N_i} PV_{j,k,i}} \qquad \textbf{3-10}$$

Where:

p_{PV}	pore volume weighted average pressure
$PV_{wellblock}$	pore volume of the well block (at the current well block pressure)
$p_{wellblock}$	pressure of the well block corrected to the reference depth
$PV_{j,k,i}$	pore volume of block k which belongs to ring i and connection k (at the current grid block pressure)

$p_{j,k,i}$ pressure of block k corrected to the reference depth

N_i number of grid blocks in ring i

N_{Rings} number of rings that are considered

$N_{connection}$ number of perforations

In all the three simulators, there is a possibility to define for the software whether all the connections should be considered for this calculation (open or close); or only the connections which are open right now should participate in the calculation. This option in SURE® is determined by TDD file attributes "openperfs" and "allperfs".

Some investigations in this thesis work indicated that SURE® gives the same results as ECLIPSE® under the same conditions; but the fluctuations of the SURE® results are higher than ECLIPSE®. This mainly because of the different approach that SURE® has comparing to ECLIPSE®. The approach of SURE® can be more controlled by the user than the other simulators.

3.1.3 HRC well pressure averaging method

3.1.3.1 Identifiers, Keywords and Attributes

The instructions to calculate an average well pressure should be entered with the identifier WELLSPEC, alternatively the identifiers WPAVE and WPAVEDEP can be also used but not recommended. The attribute WPAVE controls the calculation of well block average pressures. These averages represent a certain kind of average pressure of the grid blocks containing connections to a given well, and optionally their direct and diagonal neighbors also, weighted either the connection production index factors or the grid block pore volumes.

A list of identifiers, keywords and attributes is presented in the table Table 3-1.

Table 3-1: Identifiers, Keywords and Attributes used for calculating well block average pressure.

Identifiers	***Keywords***	***Attributes***
WELLSPEC (WPAVE)	F1, F2	WPAVE, FORALL, RES, WELL, NONE OPEN, ALL WBP 1, WBP 4, WBP 5, WBP 9 DREFWPAVE
(WPAVEDEP)		FORALL, DREFWPAVE

The WELLSPEC identifier should be accompanied by a number of keywords and attributes containing the data.

- F1: This is the weighting factor between the inner well block and the outer ring of neighbors, for calculating the production index factor weighted average. For values of F1 which are between 0.0 and 1.0 ($0.0 < F1 < 1.0$) the average pressure will be calculated by equation 3-13; and for values of F1 below 0.0 (minus values), the average pressure will be calculated by equation 3-143-14, which is a pore volume weighting average pressure.

  The value 0.0 gives the complete weight to the neighboring blocks and the value 1.0 gives the complete weight to inner well block. Therefore for neighboring keywords, wbp 1 (one block average pressure) & wbp 4 (only four direct neighboring blocks), F1 will be selected as 1.0 and 0.0 respectively by the software, no matter which values has been entered by the user.

  Default value for F1 is 0.5.

- F2: The weighting factor adjusting the pressure by producing a spectrum combination of Production index factor weighted average and the pore volume weighted average pressure by equation 3-11.

  Default value for F2 is 1.0.

- WPAVE: This attribute must be entered for the WELLSPEC identifier for calculating the well block average pressure.

- FORALL: This attribute tells the software to calculate well block average pressure for "all the wells" in the reservoir. Instead of this attribute one can enter a well name or well group name (see examples).

- Depth Correction Attribute: This attribute defines whether the software should correct the pressure according to the reference depth or not. Three attributes are related to Depth Correction are as follows:

  1. RES: Calculated average pressure will be corrected to the reference depth by using the representative densities of the fluids inside the reservoir. These densities are weighted by their saturation percentage.

  2. WELL: Calculated average pressure will be corrected to the reference depth by using the density of the fluid inside the wellbore.

  3. NONE: Calculated average pressure will not be depth corrected by any fluid densities.

     Default attribute is RES.

- Well Perforations Attribute: This attribute manages whether the calculation should be done by considering all the perforations or only the open ones should participate in the calculation.

1. ALL: The calculation procedure will consider all the grid blocks around the well, no matter if the perforation is open or close.

2. OPEN: The calculation procedure will consider “only” the grid blocks which contain an open perforation and its neighbors. Default attribute is OPEN.

- Well neighboring attributes: number of neighbors to be considered in the calculation is defined by these attributes:

1. WBP 1: Just the inner well block (F1 = 1.0, green block in the Figure 3-2 a).
2. WBP 4: Only the 4 direct neighbors (F1 = 0.0, blue blocks in the Figure 3-2 b).
3. WBP 5: The inner well block (green block) plus 4 direct neighbors (blue blocks in the Figure 3-3 c).
4. WBP 9: The inner well block (green block) plus 4 direct neighbors (blue blocks) plus 4 diagonal neighbors (gray blocks in the Figure 3-3 d).
   Default attribute is WBP 5.

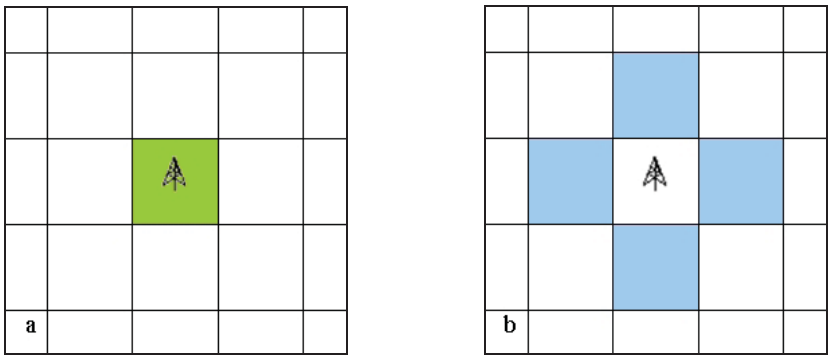

Figure 3-2: WBP 1 (figure a) and WBP 4 (figure b) schematic view.

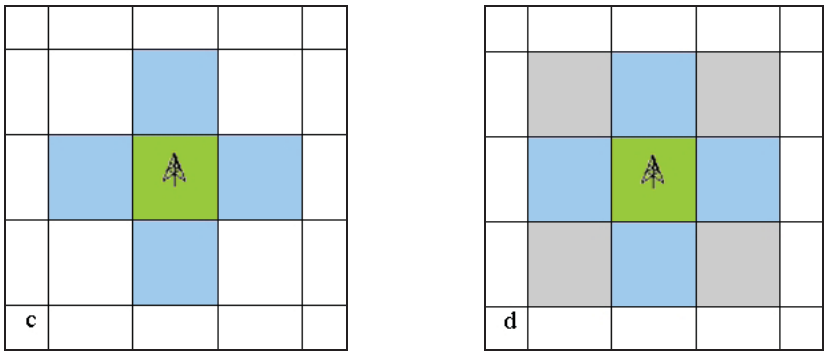

Figure 3-3: WBP 5 (figure c) and WBP 9 (figure d) schematic view.

3.1.3.1.1 Prototype and Examples

The general prototype and guideline for WELLSPEC identifier is as follows:

WELLSPEC + 'DATE' + 'Name of well or well group or FORALL' + 'WPAVE'+ 'F1 xx' + 'F2 xx' + 'RES / WELL / NONE' + 'OPEN / ALL' + 'WBP n' + 'DREFWPAVE xxxx'

F1: The value is 0.0 < xx < 1.0 or a minus value for pore volume weighting (equations 3-13 &3-14).

F2: The value is 0.0 < xx < 1.0.

The examples below show how WELLSPEC identifier and its keywords & attributes should be used.

1. WELLSPEC 2000/01/01 cw1 wpave F1 0.5 F2 1.0 RES OPEN wbp 5 drefwpave 6250
2. WELLSPEC 2000/01/01 cw1 wpave F1 -0.3 F2 1.0 RES ALL wbp 9 drefwpave 6250
3. WELLSPEC 2000/01/01 cw1 wpave F1 0.5 F2 0.3 NONE OPEN wbp 1
4. WELLSPEC 2000/01/01 cw1 wpave F1 0.5 F2 0.7 WELL OPEN wbp 4 drefwpave 6250

Example 1 shows that for well cw1 the default values of the software will be taken into account. Without entering these values software will automatically takes these values.

Example 2 shows that for well cw1, because of a minus value of F1, the pore volume weighting average will be calculated; all of the perforation will participate

in the calculation, pressure is depth corrected by reservoir fluids, inner well block and 8 neighbors will participate in the averaging. Because

Example 3 shows that for well cw1, only open perforations will participate in the calculation, pressure is NOT depth corrected, only inner well block will participate in the averaging. F1 value will be changed to “1.0” because of the “WBP 1” attribute by software.

Example 4 shows that for well cw1, only open perforations will participate in the calculation, pressure is depth corrected by the wellbore fluids, only the direct neighbors will participate in the averaging. F1 value will be changed to “0.0” because of the “WBP 4” attribute by software.

3.1.3.2 Calculation of well block average pressures

This part pertains to the theoretical background that has been used in the HRC. This method in the first step is programmed for Cartesian grid; and for development, it will be generalized to the unstructured grid also.

Normally in the Cartesian grid system for every block, two kinds of neighbors can be addressed, direct neighbors and diagonal neighbors. Direct neighbors are shown with blue color and diagonal neighbors are shown with gray (Figure 3-4).

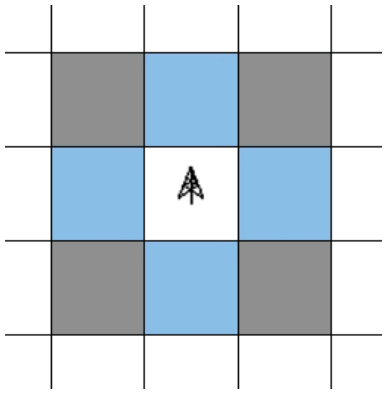

Figure 3-4: Direct neighbors “blue” and diagonal neighbors “gray”.

The well block average pressure is calculated by a weighted combination of two other average pressures. One is the average pressure which is calculated and weighted by production index and the other pressure is calculated and weighted by

pore volume of the neighbors. The total well block average pressure will be a combination of the two pressures weighted by a factor from 0 to 1, which is called F2. By F2 one can calculate a value in the spectrum between the two average weighted pressures.

$$\overline{P}_{well} = F2 \cdot \overline{P}_{well,Pf} + (1 - F2) \cdot \overline{P}_{well,pv} \qquad \textbf{3-11}$$

Where

$\overline{P}_{well}$ Well block average pressure

$\overline{P}_{well,Pf}$ Production index weighted average pressure of neighboring blocks

$\overline{P}_{well,pv}$ Pore volume weighted average pressure of neighboring blocks

$F2$ Weighting factor

3.1.3.3 Production index factor weighted average pressure

This pressure is the average pressure of all perforations, weighted by the production index of each perforation. So if $\overline{P}_{well,Pf}$ is the "Production index factor weighted average pressure", it can be calculated by:

$$\overline{p}_{well,Pf} = \frac{\sum_{k}^{N_{perf}} PI_k \cdot \overline{P}_k}{\sum_{k}^{N_{perf}} PI_k} \qquad \textbf{3-12}$$

Where:

$\overline{P}_{well,Pf}$ Production index factor weighted average pressure,

$\overline{P}_k$ Average well block pressure at each perforation,

PI_k Production index factor between each perforation and well block,

N_{perf} The number of perforations,

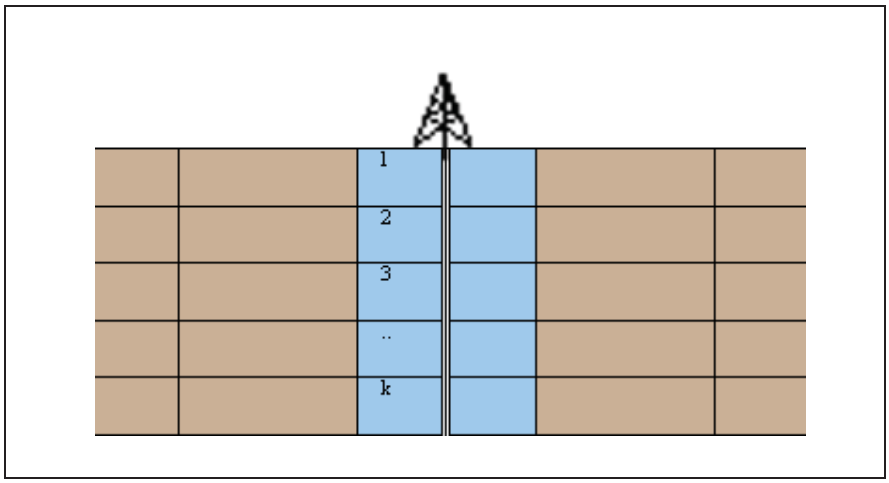

Figure 3-5: a schematic view for eq. 3-12.

OPEN or *ALL* attributes will determine whether only the perforations which are open should participate in this calculation (*OPEN*); or closed and open perforations both will participate (*ALL*).

$\overline{P}_k$ 'Average well block pressure at each perforation' is calculated by weighted factor $F1$. When $F1 \geq 0$, the average block pressure ($\overline{P}_k$) for each perforation k is the weighted average of the inner well block pressure $P_{well,k}$, and the average of the pressures in the surrounding blocks $P_{ring,k}$

$$\overline{P}_k = F1 \cdot P_{well,k} + (1 - F1)\frac{\sum_{ring,k} P_{ring,k}}{N_{ring,k}} \qquad \textbf{3-13}$$

Where

$\overline{P}_k$	Average well block pressure at each perforation
$P_{well,\,k}$	Well block pressure at one perforation
$P_{ring,\,k}$	Average surrounding blocks pressure
$N_{ring,\,k}$	Number of blocks in one ring
$F1$	Weighting factor

When $F1 < 0$, the average block pressure ($\overline{P}_k$) for each perforation k is the average of the pressures in the inner well block $P_{well,\,k}$ and pore volume weighted

average pressure of surrounding blocks $P_{ring,\ k}$, weighted according to their pore volumes $V_{well,\ k}$ and $V_{ring,\ k}$

$$\overline{P}_k = \frac{V_{well,k}P_{well,k} + \sum V_{ring,k}P_{ring,k}}{V_{well,k} + \sum_{ring,k} V_{ring,k}} \qquad \textbf{3-14}$$

Where

$\overline{P}_k$	Average well block pressure at each perforation
$P_{well,\ k}$	Well block pressure at one perforation
$P_{ring,\ k}$	Average surrounding blocks pressure
$V_{well,\ k}$	Pore volume of the inner well block
$V_{ring,\ k}$	Pore volume of the surrounding blocks

The number of blocks participating in the calculation is controlled by attribute *WBP n*; we can determine which blocks, well block or surrounding blocks, should contribute in the calculation of pore volume weighted average pressure.

3.1.3.4 Pore volume weighted average pressure

This pressure is the average pressure of well block and/or all neighboring blocks, weighted by the pore volume. It is arbitrary to select which blocks can contribute in this calculation by introducing the WBPn attributes.

This pressure is the average depth corrected pressure in the selected blocks *i*, weighted by their pore volumes V_{i}

$$\overline{P}_{well,pv} = \frac{\sum_i V_i P_i}{\sum_i Vi} \qquad \textbf{3-15}$$

Where

$\overline{P}_{well,pv}$ Pore volume weighted average pressure of blocks

P_i Pressure of grid block *i*

V_i Pore volume of grid block *i*

Firstly the selection of blocks will be controlled by the attributes *OPEN* or *ALL* (well connection flags). In the case of *OPEN*, every block which is in connection with an open perforation will be used; and in case of *ALL* all of the perforations will contribute in this calculation. Secondly the number of blocks is controlled by another attribute (*WBP n*); we can determine which blocks should contribute in the calculation of pore volume weighted average pressure.

1. WBP 1: Just the inner well block (F1 = 1.0, green block in the Figure 3-2 a).
2. WBP 4: Only the 4 direct neighbors (F1 = 0.0, blue blocks in the Figure 3-2 b).
3. WBP 5: The inner well block (green block) plus 4 direct neighbors (blue blocks in the Figure 3-3 c).
4. WBP 9: The inner well block (green block) plus 4 direct neighbors (blue blocks) plus 4 diagonal neighbors (gray blocks in the Figure 3-3 d).

Chapter 4

4 Implementation of the averaging method in the code

4.1 Introduction

The HRC method for Well Static bottom hole pressure is presented in this thesis work. This method has been programmed By FORTRAN 90 in the HRC (Prof. Heinemann's Research Code). The scientific background of the averaging methods have been presented in previous chapter. Here there will be given a brief explanation of the logic behind the code. This chapter describes the routine in which the method has been introduced.

4.1.1 Workflow of the implementation

The actual body of the code has been presented in the appendix 1. A short workflow of the implementation of the method in the code is given here. This procedure can be split into five parts:

1. Determination of number of neighbors around the well in the first and second ring of neighbors. Figure 3-4 shows the neighbors in this method. HRC will automatically search for the neighboring blocks in these rings.

2. Calculation of the average pressure for each perforation by equations 3-13 or 3-14. Then calculation of production index weighted average pressure of perforations for each well.

3. Calculation of the pore volume average pressure for neighboring blocks.

4. Weighting item 2 and 3 by factor F2, between production index weighted average pressure and pore volume weighted average pressure.

4.2 Examination of the implemented method with test examples

In the following part of this chapter the static pressure averaging method, as has been sifted thorough and implemented in the HRC, is tested on lab-scale examples. The method will be tested by four different examples. The settings of these examples have been altered also to create a variety of cases that the code has been tested with.

In each example firstly there will be a brief clarification about the type of example and the related reservoir properties. Then a brief approval will be presented that ECLIPSE®, SURE® and HRC examples are equivalent. And finally all the results from the three simulators will be being compared.

4.2.1 A homogeneous reservoir

In all the cases in coding, the first example should as simple as possible to minimize the effort of finding bugs in the code. This example is simplest example. For approving that the models created in the three simulators are the same, the total average pressure of reservoirs and well bottom hole flowing pressures are plotted in the graphs for comparison (Figure 4-1 & Figure 4-2). In these graphs, curves are shown in different colors: ECLIPSE® (green), SURE® (blue) & HRC (red). But because of overlapping curves, the differentiation among the curves is

not easy.

The reservoir properties for each example are slightly different, so it is necessary to provide the properties for each example. The reservoir properties of this example are presented in the table below.

Table 4-1: Reservoir properties for homogeneous example.

Layer	Top-depth	Thickness	N/S	Porosity	Kx	Ky	Kz	Vertical Discontinuity (MULTZ)
1	5850	20	1	0.15	5	5	5	1
2	5870	20	1	0.15	5	5	5	1
3	5890	20	1	0.15	5	5	5	1
4	5910	20	1	0.15	5	5	5	1
5	5930	20	1	0.15	5	5	5	1

These coming figures will approve that the models created in the three software are the same, the total average pressure of reservoirs and well bottom hole flowing pressures are plotted in graphs for comparison (Figure 4-1 & Figure 4-2).

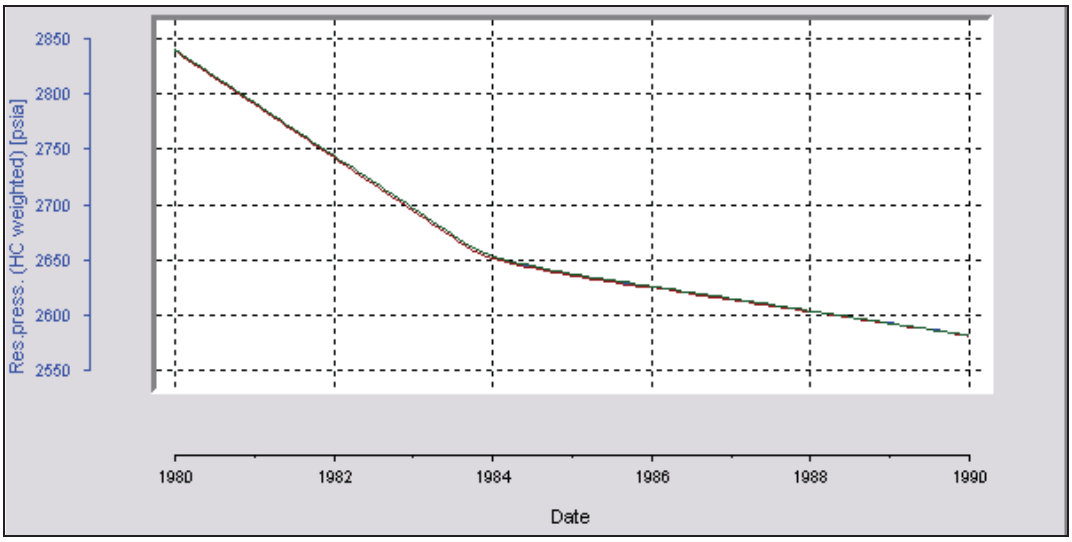

Figure 4-1: Total average pressure of reservoirs in ECLIPSE® (green), SURE® (blue) & HRC (red).

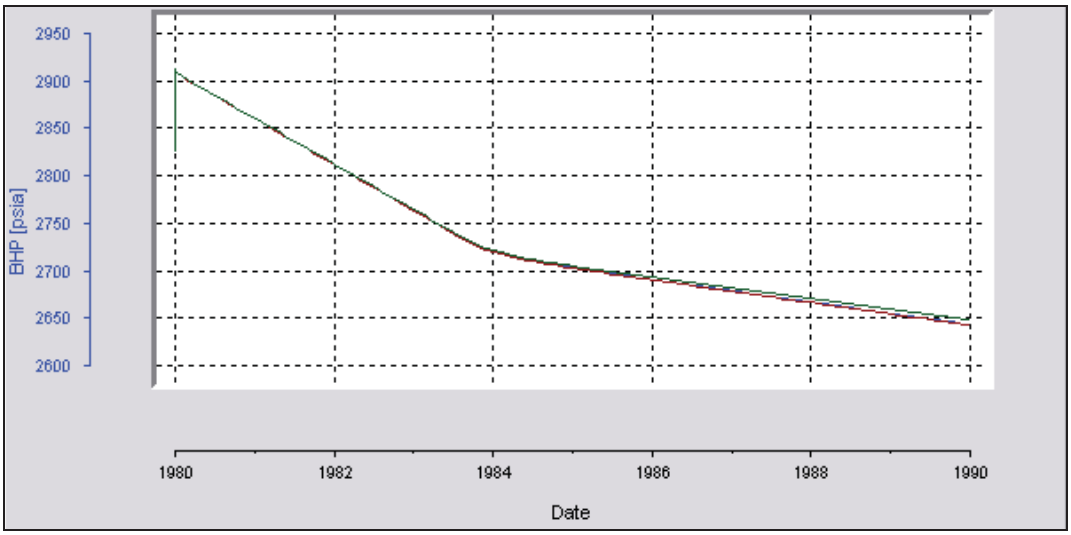

Figure 4-2: well bottom hole flowing pressures in ECLIPSE® (green), SURE® (blue) & HRC (red).

Pore volumes of these examples are also compared with each other; and the bias of the total pore volumes and volumes of each phase were less than 1%.

After proving that the examples in three simulators are the same by the above mentioned items, now the well block average pressure can be compared. The graph below shows a prefect overlapping of the well block average pressure, calculated by these simulators.

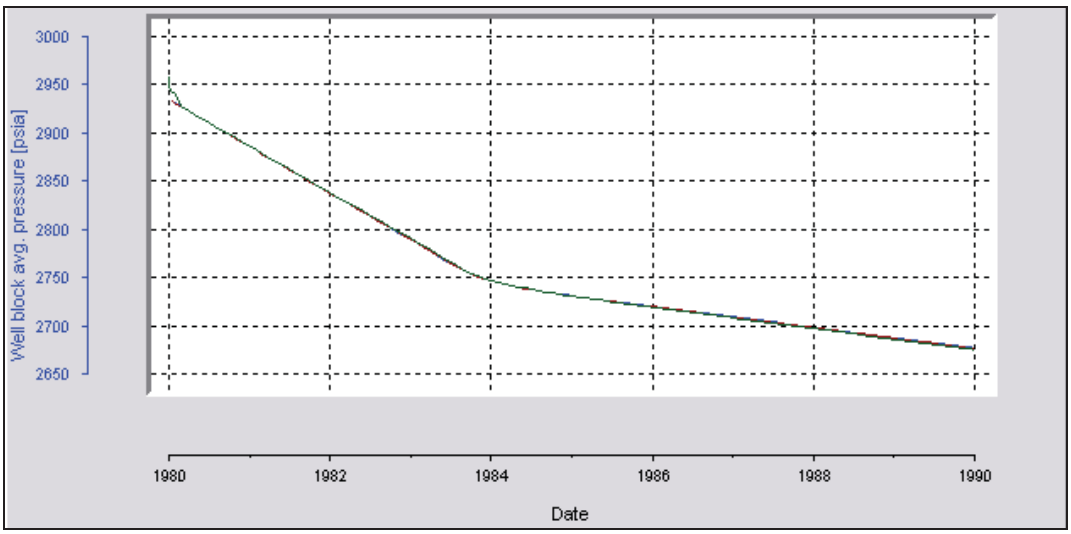

Figure 4-3: Well block average pressure in ECLIPSE® (green), SURE® (blue) & HRC (red).

In the table below, some combinations of settings are presented. Code has been tested with all of these cases; but naturally showing all the results is not logical and besides all the results were showing perfect match like Figure 4-3.

Table 4-2: some combinations of settings in the cases.

Case No.	Case definition and settings
1_F1	WELLSPEC 1980/01/01 cw1 wpave F1 0.1 F2 1.0 RES OPEN wbp 5 drefwpave 6250
2_F1	WELLSPEC 1980/01/01 cw1 wpave F1 -0.3 F2 1.0 RES OPEN wbp 5 drefwpave 6250
3_F2	WELLSPEC 1980/01/01 cw1 wpave F1 0.5 F2 0.0 RES OPEN wbp 5 drefwpave 6250
4_Depth	WELLSPEC 1980/01/01 cw1 wpave F1 0.5 F2 1.0 WELL OPEN wbp 5 drefwpave 6250
5_Perf	WELLSPEC 1980/01/01 cw1 wpave F1 0.5 F2 1.0 RES ALL wbp 5 drefwpave 6250
6_wbp 1	WELLSPEC 1980/01/01 cw1 wpave F1 0.5 F2 1.0 RES OPEN wbp 1 drefwpave 6250
7_wbp 4	WELLSPEC 1980/01/01 cw1 wpave F1 0.5 F2 1.0 RES OPEN wbp 4 drefwpave 6250
8_wbp 5	WELLSPEC 1980/01/01 cw1 wpave F1 0.5 F2 1.0 RES OPEN wbp 5 drefwpave 6250
9_wbp 9	WELLSPEC 1980/01/01 cw1 wpave F1 0.5 F2 1.0 RES OPEN wbp 9 drefwpave 6250

4.2.2 A heterogeneous reservoir

After comparison of the methods by a homogeneous reservoir, it is the time to test the code by a heterogeneous reservoir. The characteristics of the reservoir are depicted in the table below. The dimensions of the reservoir are the same as the previous example but the properties are varying from layer to layer.

In this reservoir anisotropy in x and y directions are the same but in z direction is 1/10 of the xy plane. Porosities are also varying from layer to layer.

In this reservoir, there is vertical cross flow between the layers (vertical discontinuity = 1, MULTZ = 1). This will let the pressure to be equalized in

vertical direction among the layers.

Table 4-3: Reservoir properties for heterogeneous example.

Layer	Top-depth	Thickness	N/S	Porosity	Kx	Ky	Kz	Vertical Discontinuity (MULTZ)
1	5850	20	1	0.3	4	4	0.45	1
2	5870	20	1	0.1	1.5	1.5	0.15	1
3	5890	20	1	0.35	5	5	0.5	1
4	5910	20	1	0.1	1.5	1.5	0.15	1
5	5930	20	1	0.3	10	10	1	1

Again basic comparison among the examples has been performed. The figures below will approve that the models created in the three simulators are the same, the total average pressure of reservoirs and well bottom hole flowing pressures are plotted in graphs for comparison (Figure 4-4 & Figure 4-5). Again in these graphs, because of overlapping curves differentiation among the graphs is not easy.

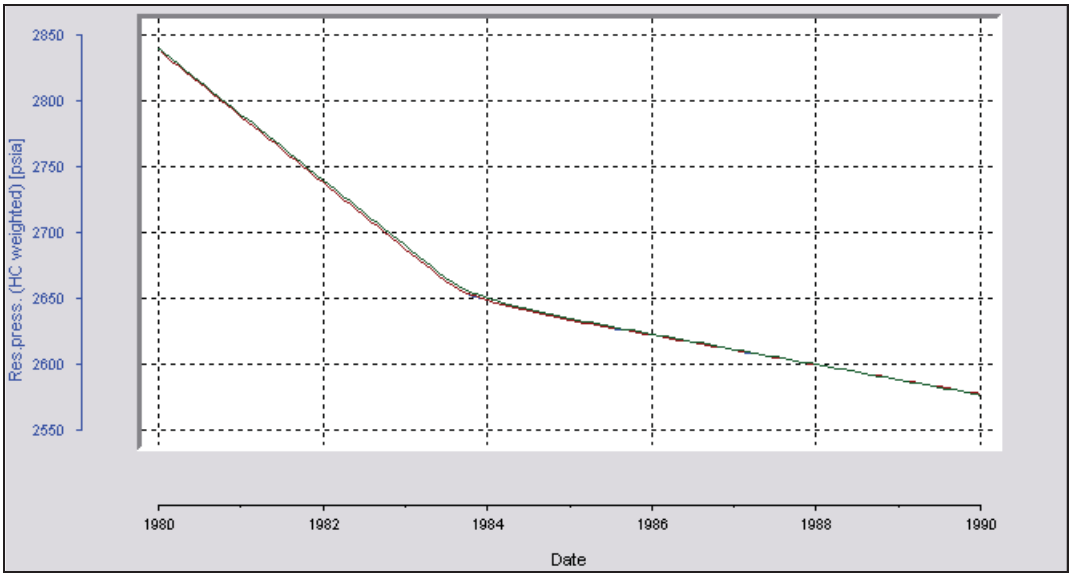

Figure 4-4: Total average pressure of reservoirs (HC weighted) in ECLIPSE® (green), SURE® (blue) & HRC (red).

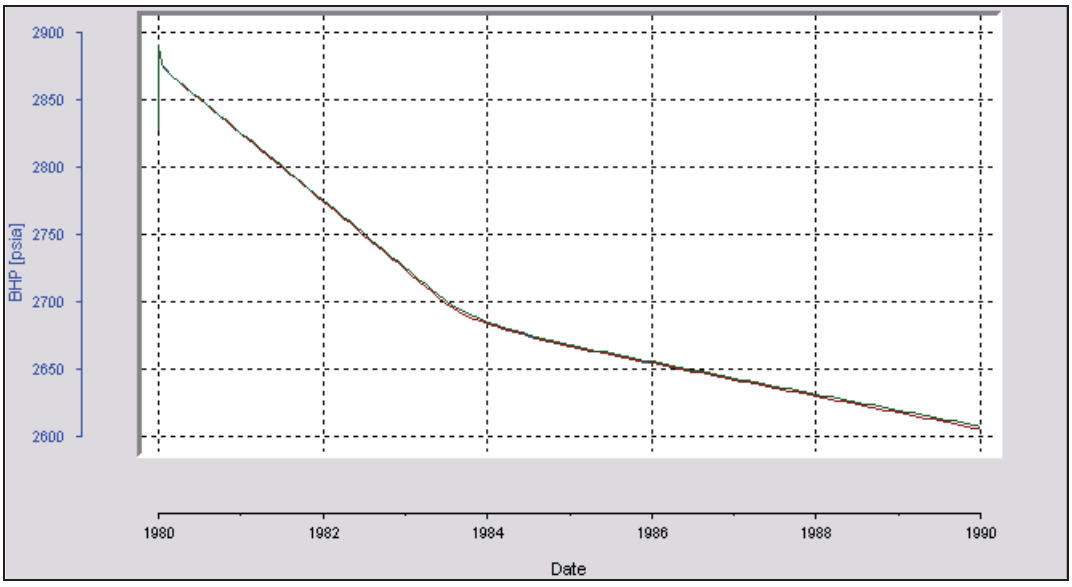

Figure 4-5: well bottom hole flowing pressures in ECLIPSE® (green), SURE® (blue) & HRC (red).

After proving that the examples in three simulators are the same by the above mentioned items, now the well block average pressure can be compared. The graph below shows a prefect overlapping of the well block average pressure, calculated by these simulators.

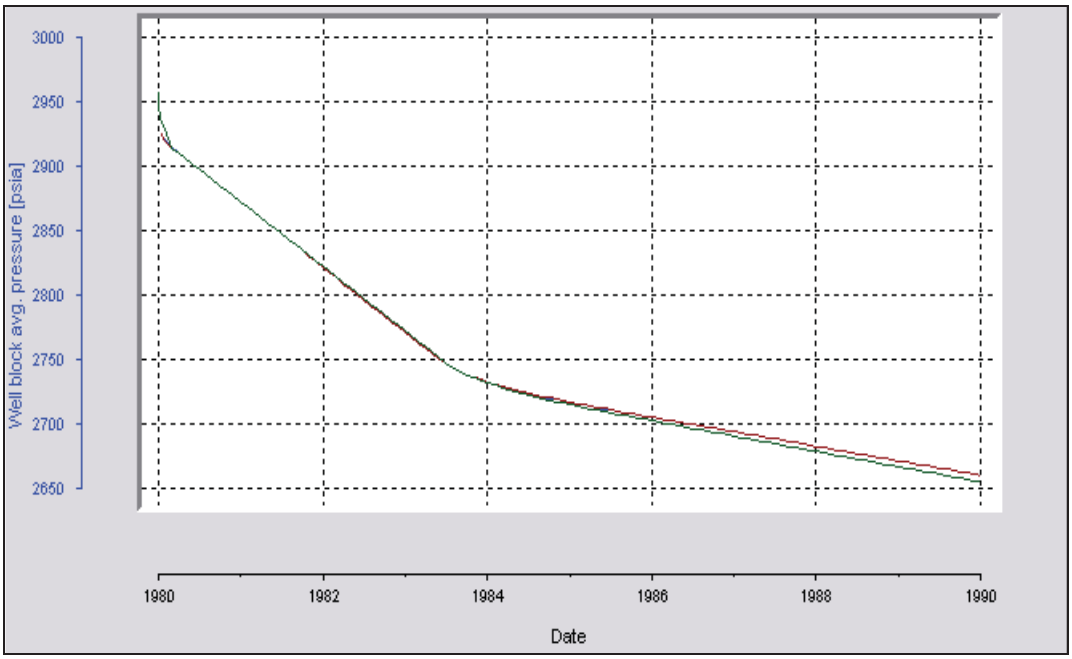

Figure 4-6: Well block average pressure in ECLIPSE® (green), SURE® (blue) & HRC (red).

In the previous graph until the end of 10 years simulation, HRC and SURE® showed perfect matching results (red overlapping blue) under same conditions. but ECLIPSE® gave a little different results. The difference after 10 years is almost 5 psi which is a peanut, considering that we are comparing two complete different simulators with different internal calculations.

In figures below one can see what is happening around the well

4.2.3 A homogeneous reservoir with vertical discontinuity (layered reservoir)

After testing the code with previous examples, it was suggested by the supervisor that vertical discontinuity should be introduced to the model. This will impose “no cross flow” among the layers.

This option in SURE® is in *parameter assigning* window. By choosing the vertical discontinuity zero, no cross flow will happen among the layers. Vertical discontinuity can be called as multiplication factor for the transmissibility between the layer and its layer below. A value of 0.0 indicates no communication of the actual layer to the layer located below[16].

This option in ECLIPSE® can be handled by the keyword *MULTZ*. As it is obvious by the name, this keyword provides the ability to define a multiplier for transmissibility in Z direction. Naturally by giving zero value to this multiplier, transmissibility will be 0.0 and therefore there will be no cross flow in Z direction.

Properties of the reservoir for this example are the same as example 1 and depicted in Table 4-1. As this example is completely equal to example 1 with only the difference of vertical discontinuity, the graphs of reservoir pressure and well bottom hole flowing pressure for proving the equality of the examples in three simulators are not depicted here.

As it can be seen in the Figure 4-7, after 10 years of production HRC and SURE® again showed a perfect match, but ECLIPSE® (green curve) showed a little difference. This difference is 8.39 psi for well block average pressure after 10 years production. Again this difference has been ignored.

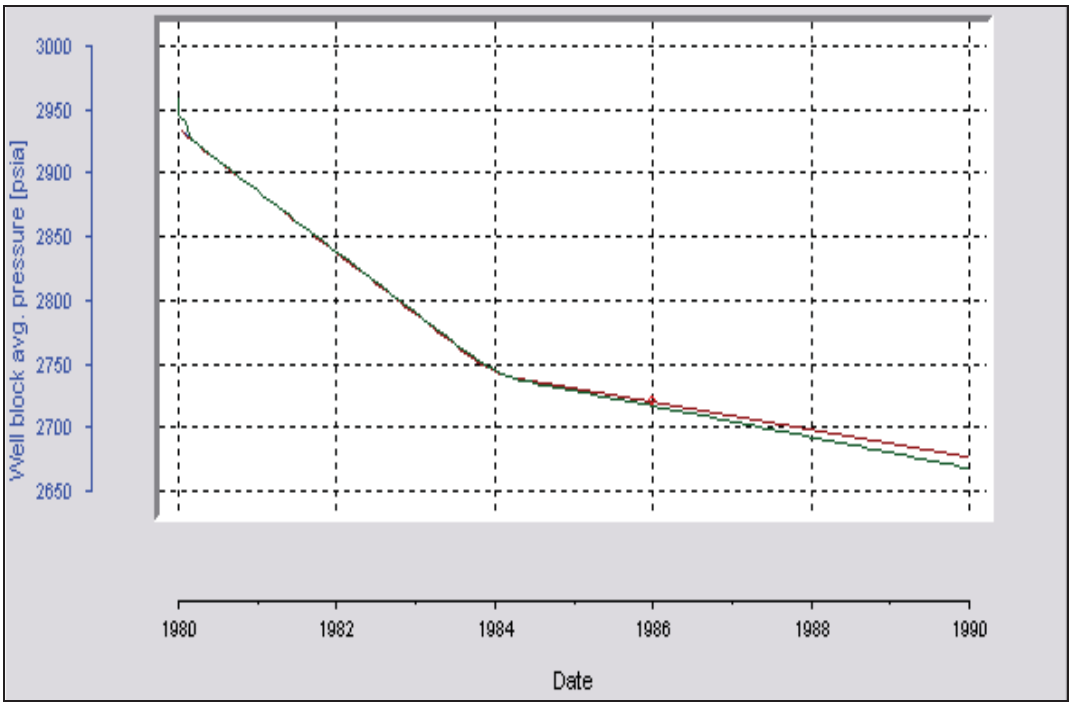

Figure 4-7: Well block average pressure in ECLIPSE® (green), SURE® (blue) & HRC (red).

4.2.4 A heterogeneous reservoir with vertical discontinuity (layered reservoir)

Probably the most sophisticated example would be this one with a complete heterogeneous reservoir and vertical discontinuity. The settings have been changed a lot for creating different alternatives. Two main alternatives of this example are OPEN and CLOSED perforations.

Figure 4-8 depicts the case of OPEN perforations. The last calculated pressure for HRC and ECLIPSE® are 2646.68 and 2637.51 psi respectively. In this case the difference in pressure is 9.17 psi after 10 year of production. In this example like the previous ones, the difference starts divergence after the pressure drops below bubble point pressure.

Normally around the bubble point pressure, very small fractions of saturations of free gas are created that different simulators handle it differently. And also this will cause the difference that can be seen in the amount of gas that is being produced from this reservoir.

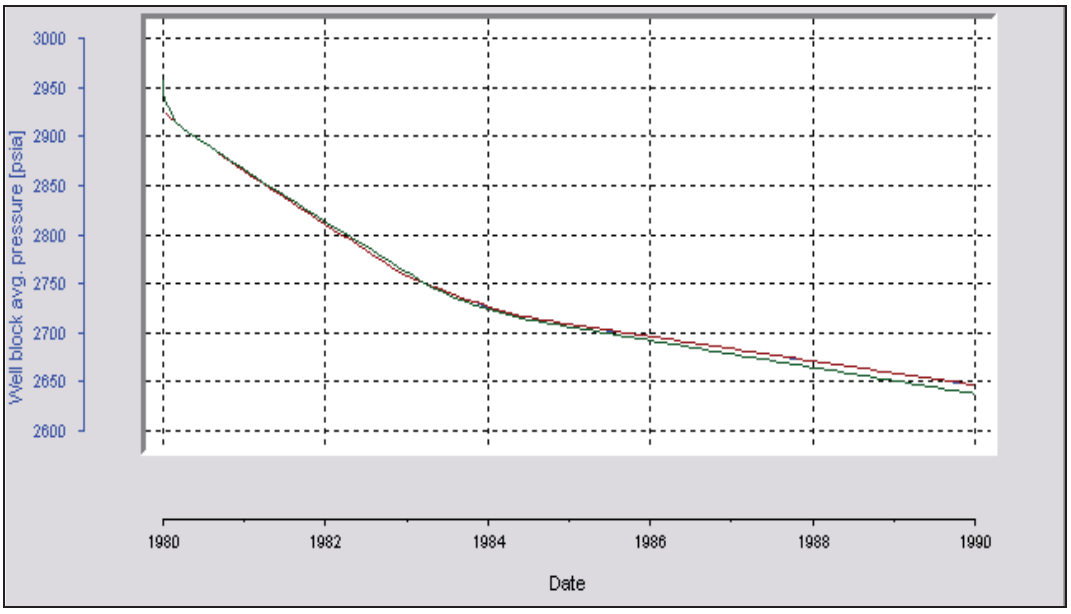

Figure 4-8: Well block average pressure in ECLIPSE® (green), SURE® (blue) & HRC (red) for heterogeneous reservoir and completely open perforations.

The next alternative would be the closed perforation. In this example we have five perforations which perforations 2 and 4 are closed. Closing the perforations has caused an increase in the value of well block pressure. This is due to less production in this case. The last calculated pressure for HRC and ECLIPSE® are 2661.09 and 2653.59 psi respectively. In this case the difference in pressure is 7.5 psi after 10 year of production.

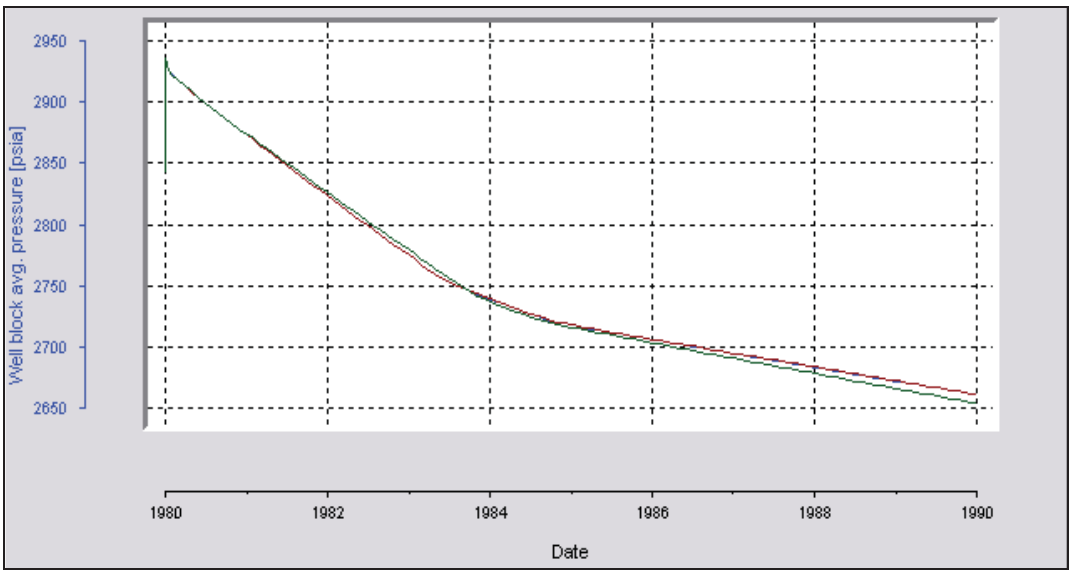

Figure 4-9: Well block average pressure in ECLIPSE® (green), SURE® (blue) & HRC (red) for heterogeneous reservoir, perforations 2 & 4 (every even number/ out of 5) are closed.

4.3 Approving the code

After all the tests that have been performed on this routine, it can be said that the results have good agreements with the other simulators. This will lead to approve the code in HRC. Further steps which are monitoring the effects of setting parameters and monitoring the effects of reservoir parameters on the results comes to the spotlight afterwards.

4.4 The effects of setting variation on the results

Changing the setting of the calculation creates different results. Specially when changing F1 & F2, WBP 1, WBP 4, WBP 5 and WBP 9. Here some of the results has been investigated.

4.4.1 The effect of F1

In the graph below the max and min for F1 which are 0.0 and 1.0 are shown. Also a minus value has entered (blue curve). It can be measured that the difference in the pressure value is about 20 psi. This value shows the effect of F1 setting.

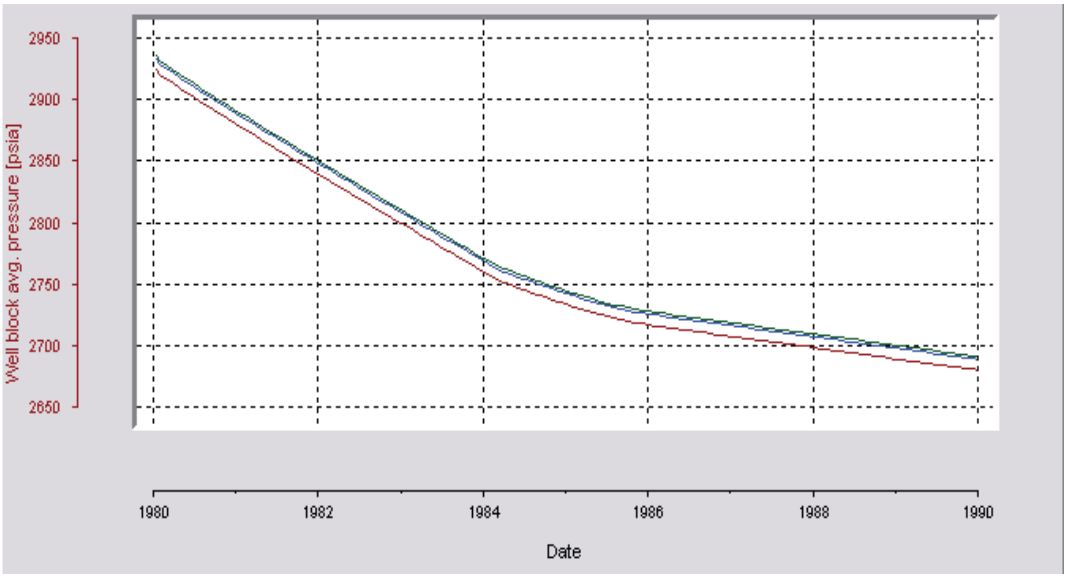

Figure 4-10: The effect of F1 on the results F1=0.0 (red), F1=1.0 (green) and F1=(blue).

4.4.2 The effect of F2

In the graph above the max and min for F2 which are 0.0 and 1.0 are shown. This the weighting factor between the production index weighted average pressure and pore volume weighted average pressure. It can be seen that the difference in the pressure value is about 20 psi. This value shows the effect of F2 setting.

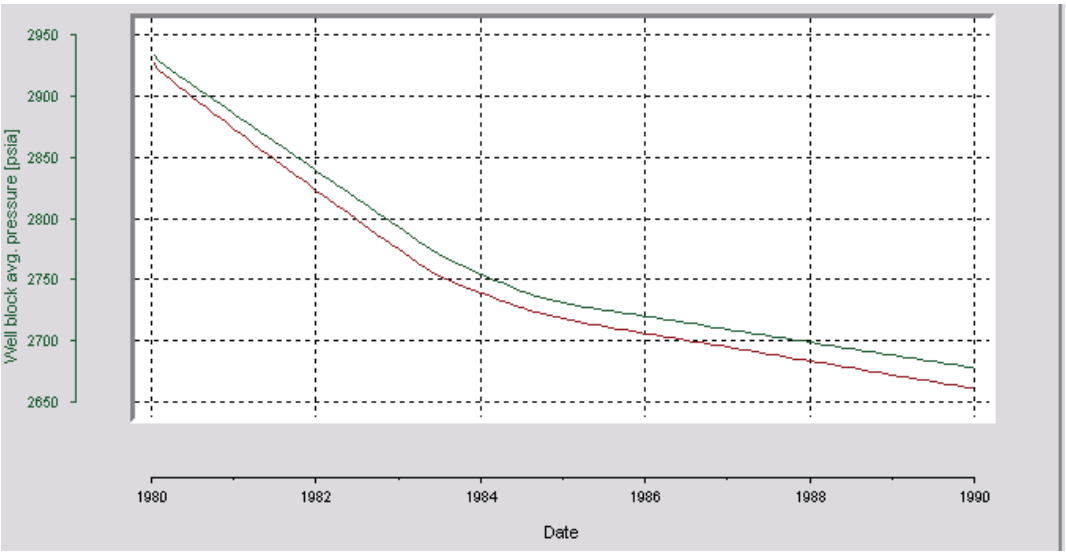

Figure 4-11: The effect of F2 on the results F1=1.0 (red), F1=0.0 (green).

4.4.3 Effect of Neighboring Attributes WBP 1, WBP 4, WBP 5, WBP 9

In the figure below one can identify the effect of neighboring blocks attributes. Green is WBP 1, red is WBP 4, blue is WBP 5 and dark_green is WBP 9. As for WBP 1, F1 value is absolutely 1.0 and for WBP 4, F1 value is absolutely 0.0, then it can be judged that this graph is the same as the graph for F1 values.

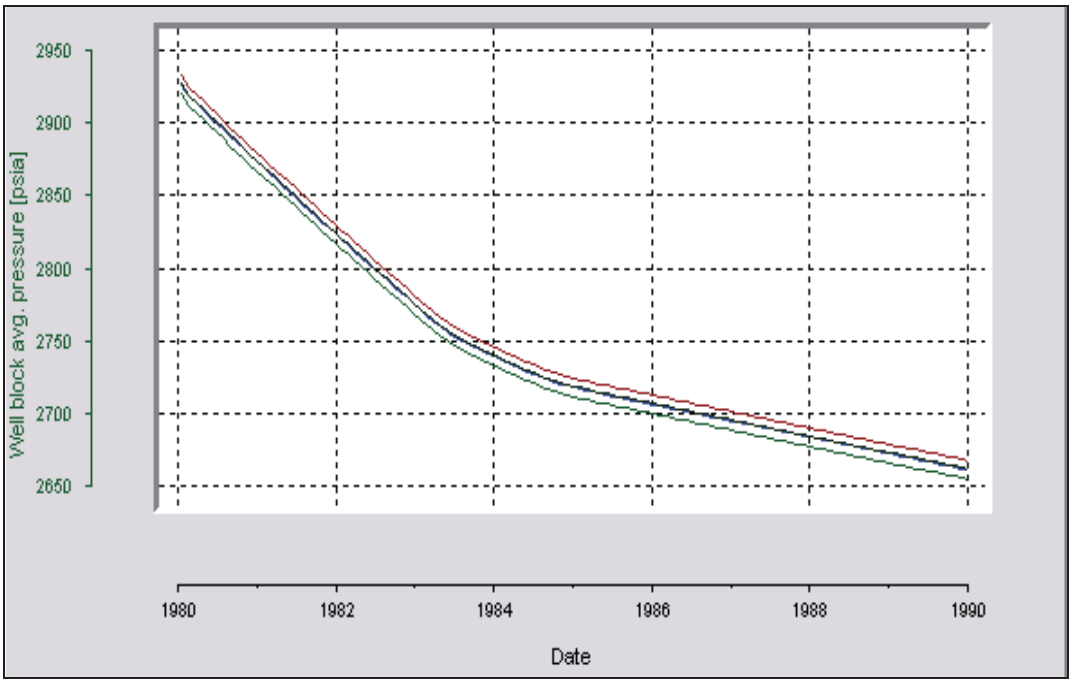

Figure 4-12: The effects of neighboring attributes on the calculated pressure.

4.5 Variation of results within a range

Besides of the effect of settings, some other items affect these averaging methods directly. Here the most important items are discussed.

4.5.1 Increasing production

The graph below shows the effect of production on the calculation of the well static average pressure. Production has been doubled and therefore pressure drop can be seen here. “The light blue and blue curves” and “green and red curves” are WBP 1 and WBP 4 for two cases.

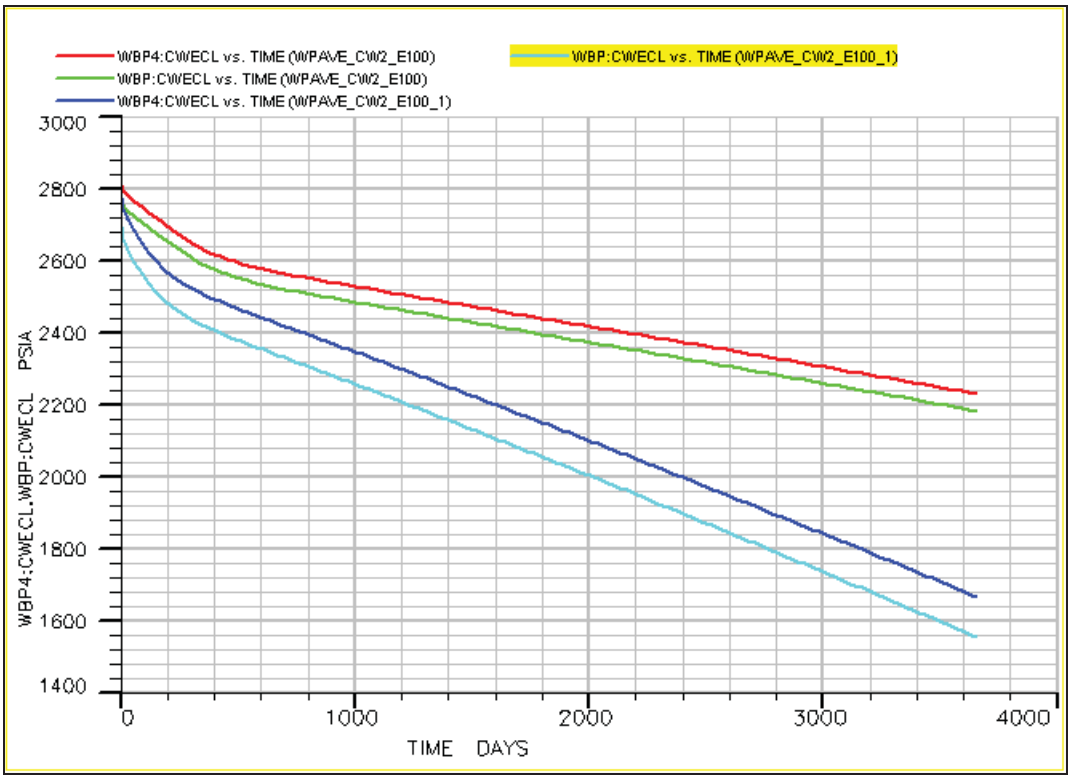

Figure 4-13: The effect of increasing production.

4.5.2 Decreasing the mobility ratio

Decreasing the mobility ratio can be done by changing two factors, one by decreasing the permeability of the reservoir around the well and the other factor is increasing the viscosity of reservoir fluids.

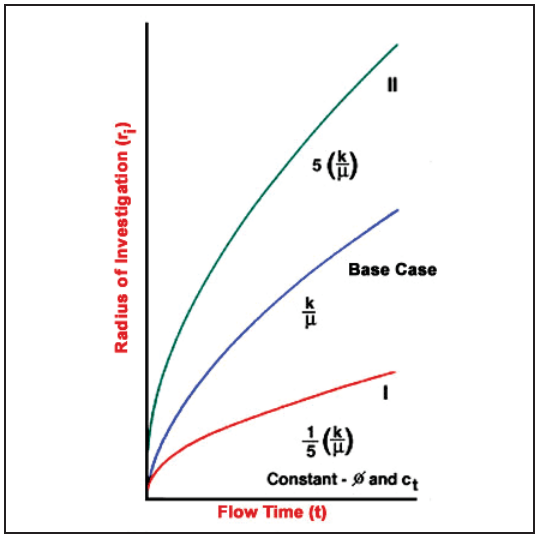

Figure 4-14: The effect of mobility ratio around the well[12].

As it can be seen in the Figure 4-14 the pressure decline profile around the well is changing significantly; and therefore it will definitely affect the calculated pressure.

4.5.3 The effect of Grid Size or Refinement

As we have discussed in previous items, production and mobility ratio play an important role in the variation of the pressure. This effect will be magnified if we use refinement in the reservoir especially around the well. As in these simulations all the data of a grid block belongs to the center of the grid block especially pressure, then by refining the grid, new grid points around the well will jump more into the sink area and therefore the calculated pressure will be lower than the previous case. It is important to mention in both cases reservoir properties were the same.

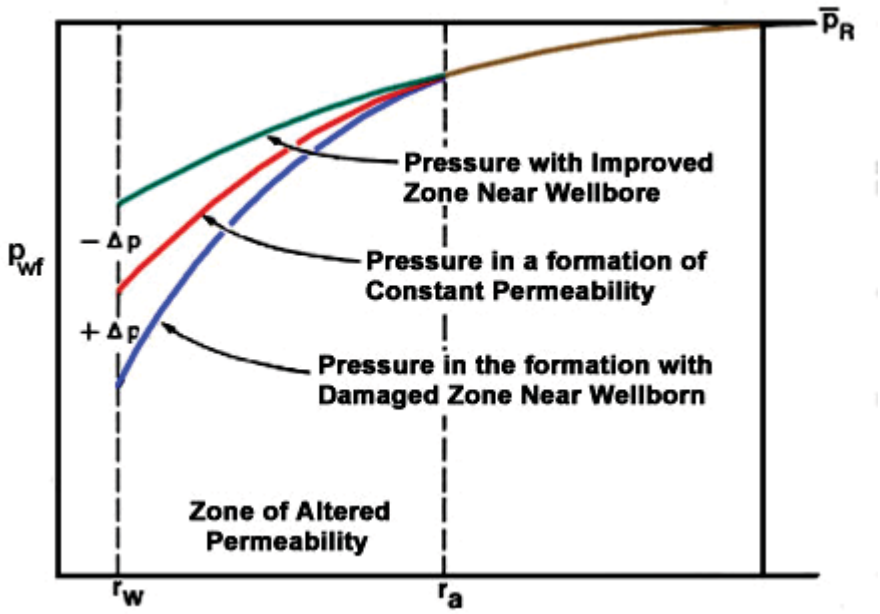

Figure 4-15: pressure decline around the well[12].

In the graph below red curves are for the refinement case; and blue curves are for the normal case.

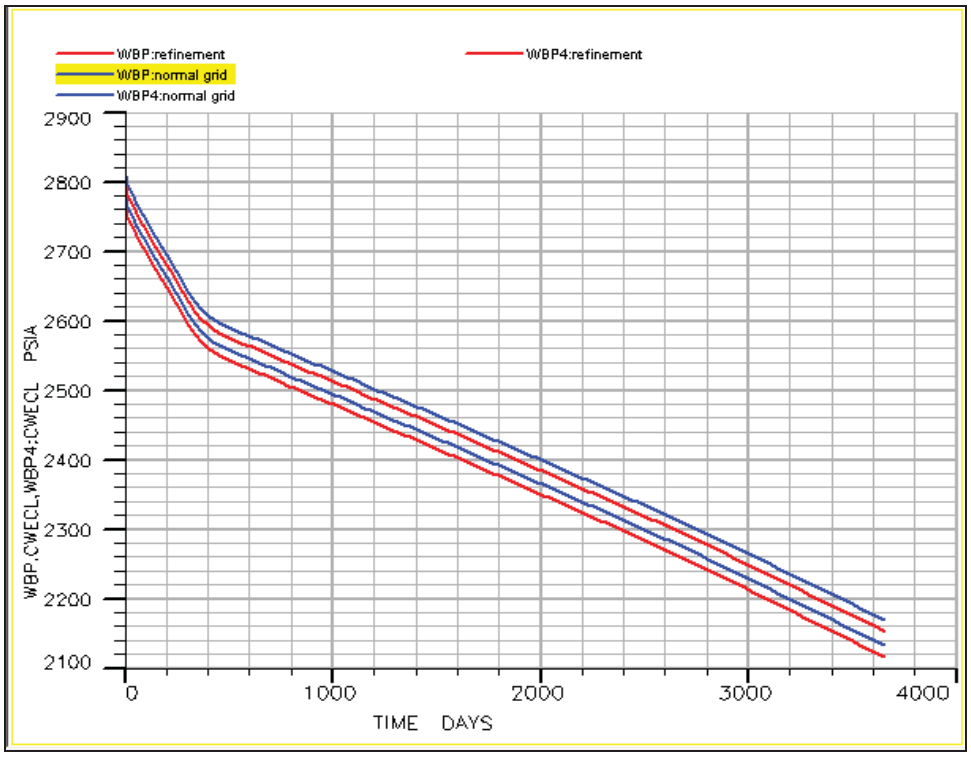

Figure 4-16: variation in pressure due to refinement.

4.5.4 The effect of skin damage

The effect of skin is presented in the figure below. In this graph skin = 0.0 is related to the red curve, skin = +10.0 is related to the blue curve and skin = -3.0 is related to the green curve. The change in the pressure is obvious in this graph. This phenomenon is because the wellbore can not be fed by reservoir in the case of minus skin damage; and positive skin will perform in the opposite way.

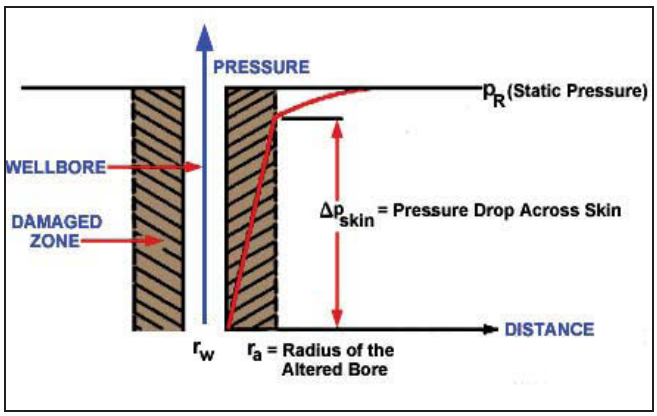

Figure 4-17; The skin damage schematic view[12].

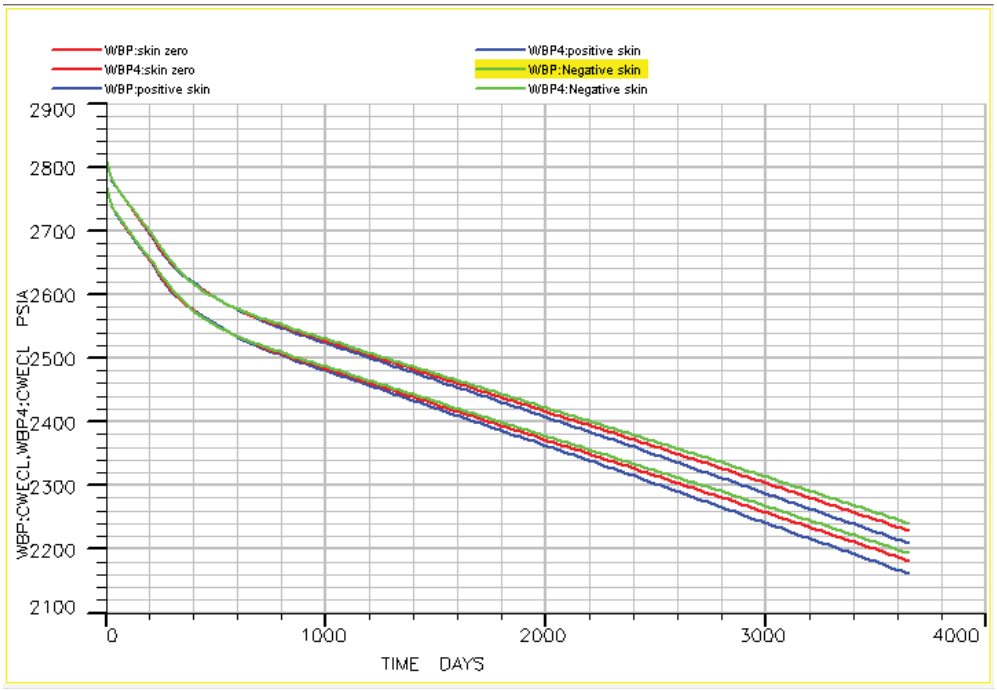

Figure 4-18: The effect of skin on the results, skin=0.0 (red), skin= +10 (blue), skin= -3.0 (green).

4.6 Time_step view of the pressure decline distribution around the well

In this section, one of the simulated examples has been depicted in different time_steps. One quarter of the reservoir has been presented to show the wellbore and reservoir at the same time. This distribution graphs are pressure vs. time steps.

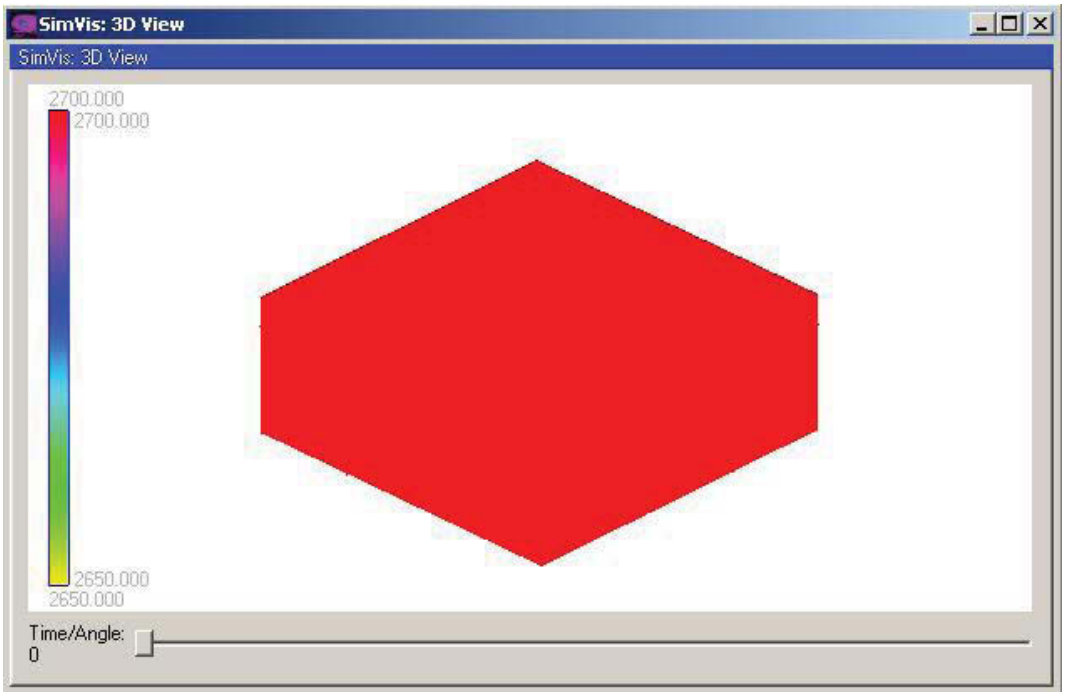

Figure 4-19: initial pressure distribution.

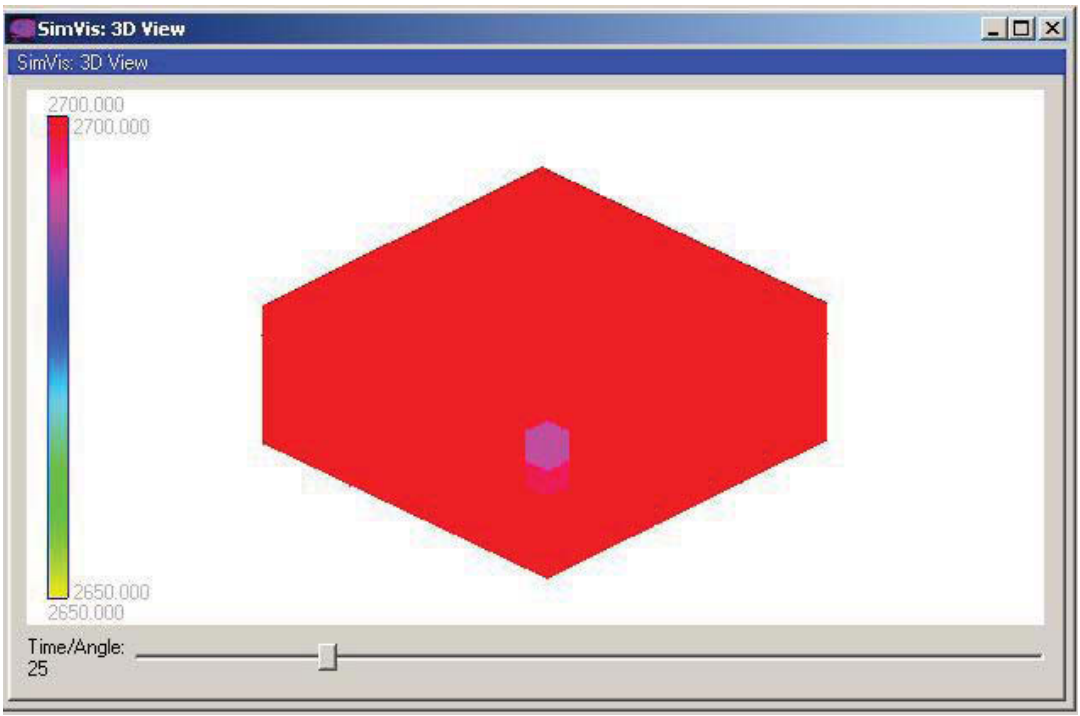

Figure 4-20: pressure distribution at time step 25.

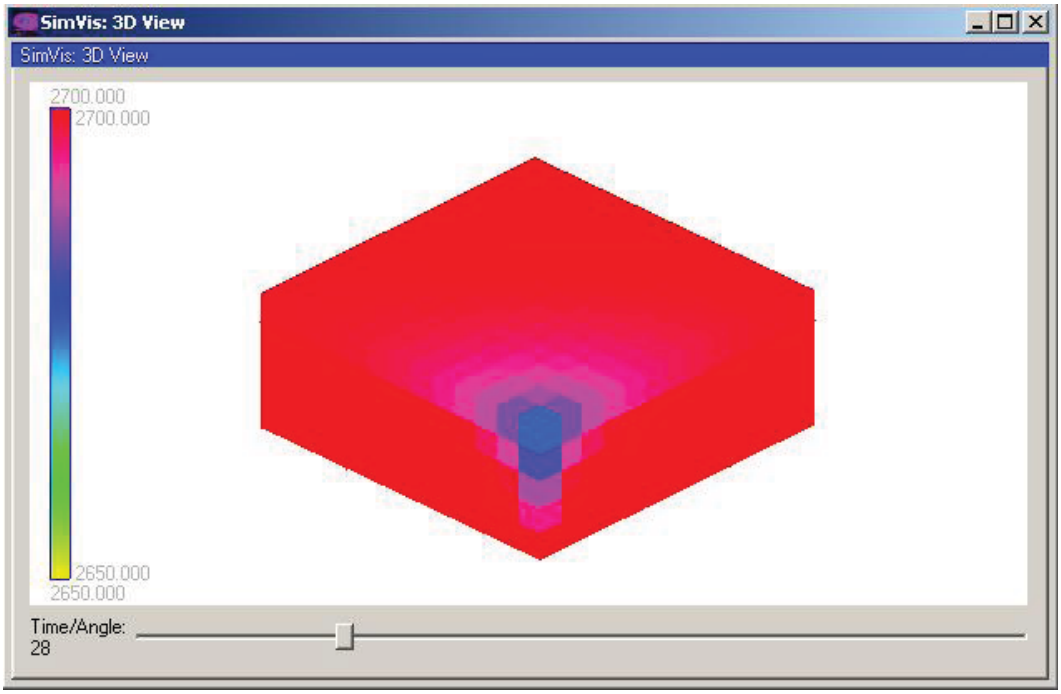

Figure 4-21: pressure distribution at time step 28.

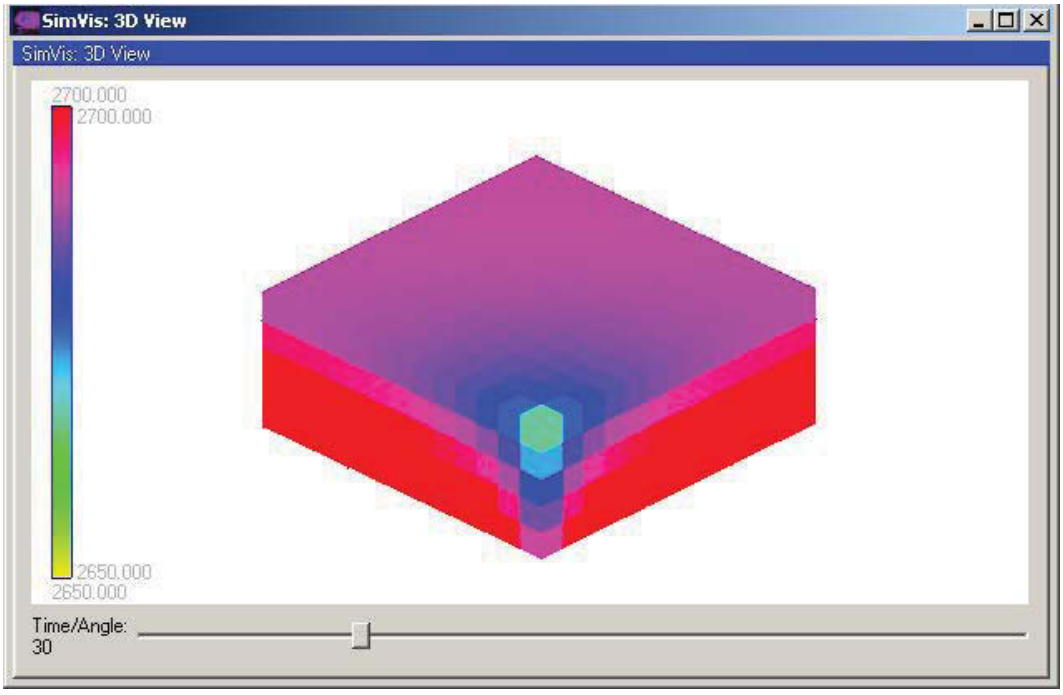

Figure 4-22: pressure distribution at time step 30.

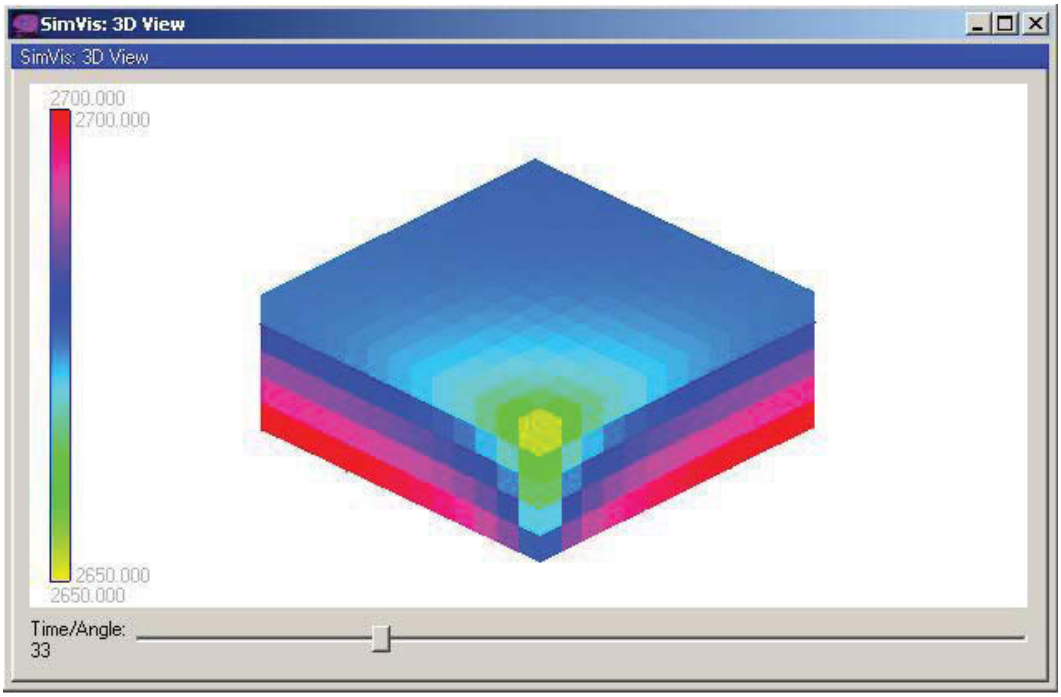

Figure 4-23: pressure distribution at time step 33.

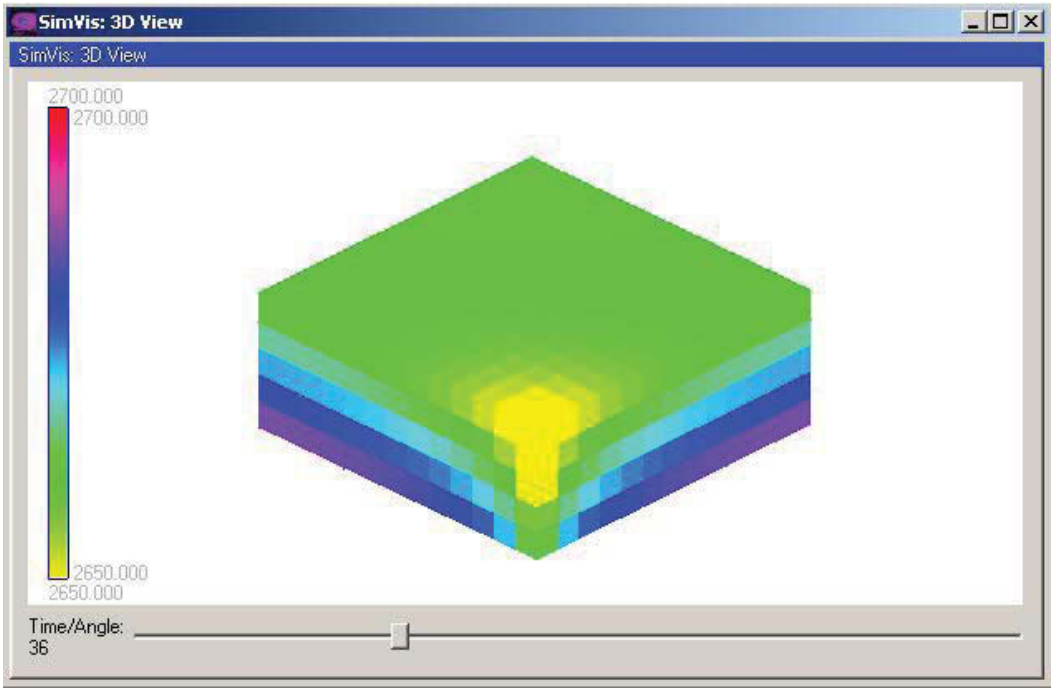

Figure 4-24: pressure distribution at time step 36.

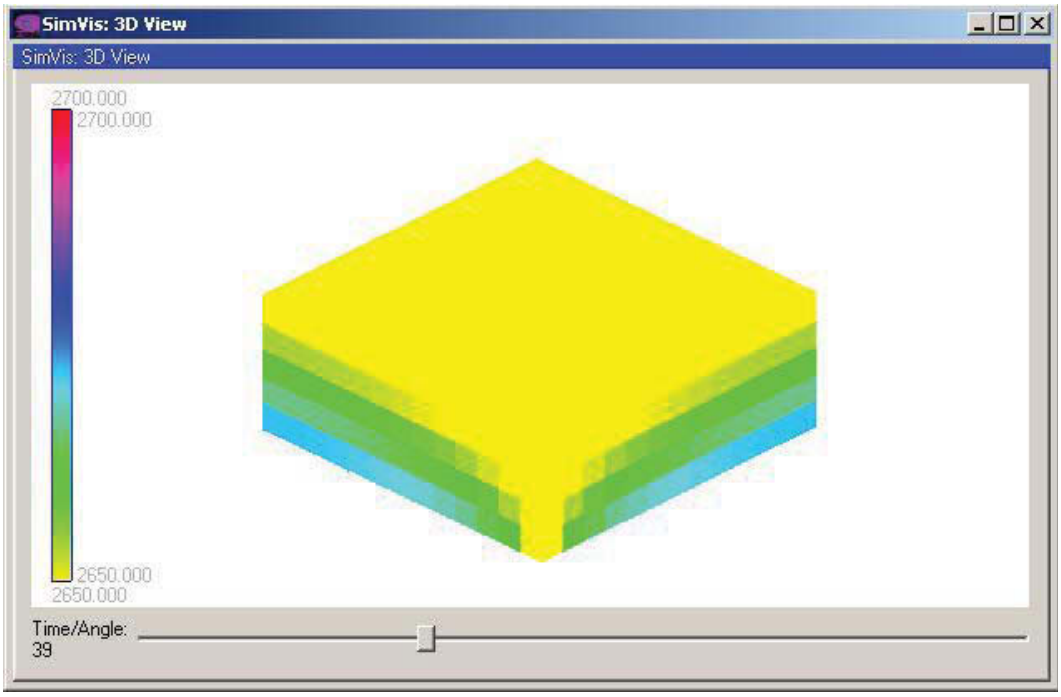

Figure 4-25: pressure distribution at time step 39.

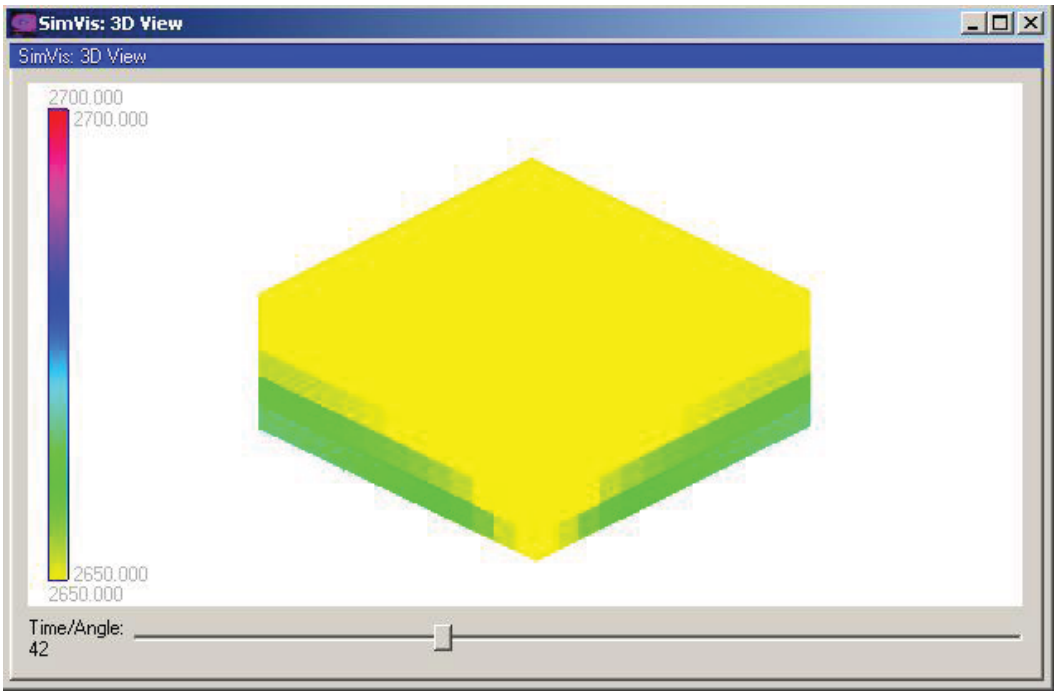

Figure 4-26: pressure distribution at time step 42.

Chapter 5

5 New perspectives for future researches and studies (new averaging method)

5.1 Introduction

This chapter discusses a 2D near-well flow modeling for a vertical well using a flexible grid with discretizations around the wellbore boundary. Using a flexible grid provides a good description for the near-well flow behavior, and the wellbore boundary can be discretized with small grid blocks. A new multipoint and a new two-point flux approximation scheme are presented in this part. These schemes can eliminate flux truncation errors for the calculation of the point-source solution, which is dominant in the well vicinity. Consequently, total flux truncation errors decrease in the near-well region. Compared to the commonly used linear approach, the new multipoint scheme reduces the error, which is important for the near-well flow calculation.

The new approach presented is general and can be used for any kind of grid block. The applications of this technique to PEBI and Triangular grid blocks are presented. Some examples are also presented that show the accuracy and the advantage of the proposed method.

5.2 New numerical schemes for near-well modeling using flexible unstructured grids [4]

The size of the well block, which is defined by gridding the wellbore boundary, ranges from several centimeters (the order of the wellbore radius) to several meters, and only a few gird blocks are used to separate the well block and the general reservoir gird block, which is approximately some tenths to several hundred meters. This is particularly true in field applications. Therefore, the contrast of the gird block size between two neighboring gird blocks might be large in the radial direction. This kind of grid can make the linear numerical scheme inefficient.

Ding et al. proposed a new numerical method that can solve this problem. Theoretically, using numerical methods, based on the linear approach (that is, linear with respect to coordinates of physical space), can give accurate results with the flexible grid, provided that the gird block sizes are small in the whole reservoir. In order to be as accurate as possible, it is necessary to have many small gird blocks in the near-well region. The gird block sizes increase very smoothly toward the far-well region. To obtain a reasonable accuracy with the linear approach, the gird blocks should be smaller than the wellbore radius in the region near the well (this is almost impossible in real reservoir studies).

5.2.1 New Control-Volume Schemes for Near-Well Modeling in Isotropic Media

Solution splitting in the well vicinity makes the analysis of flux truncation errors easy. Because the “singular” flow is dominant in the near-well region, a good numerical scheme should handle this term accurately. To obtain a suitable numerical scheme, we use a coordinate transformation, which transforms the grid system from Cartesian coordinates to polar-type coordinates.

With this change of coordinate, appropriate numerical schemes can be developed in the new coordinate system. For simplicity, the study in this section is limited to

isotropic media with $k = k_x = k_y$. The formulation of Change in the Coordinate System is as follows:

$$\begin{cases} x = e^{\rho} \cos\theta \\ y = e^{\rho} \sin\theta \end{cases} \quad \textbf{5-1}$$

By this a Cartesian grid is changed into a polar type coordinate. The advantage of this transformation is that dominating point-source "singular" flow becomes linear in ρ.

The transformation in Eq. **Error! Reference source not found.** preserves the flux conservation condition: The flux across a curve in the original coordinate system is equal to the flux across the transformed curve in the new coordinate system with:

$$F_i = -\int_{\Gamma_i} k \frac{\partial p}{\partial n} dl = F_i' = -\int_{\Gamma_i'} k \frac{\partial p}{\partial n} dl \quad \textbf{5-2}$$

Where Γ_i= a curve in the Oxy coordinate system, Γ_i' =the corresponding transformation of Γ_i in the $O\rho\theta$ coordinate system, F denotes the flux in the Oxy coordinates, and F' denotes the corresponding flux in the transformed coordinates. Moreover, the flow equation is also elliptic in the new system. We study the numerical schemes for the elliptic operator discretization in this new coordinate system.

With the aforementioned transformation, the polygon gird blocks are transformed into a curved grid system (Figure 5-1). The wellbore boundary, which is a circle in the Oxy coordinate system, becomes a line segment. The condition on the wellbore becomes a boundary condition defined on this line.

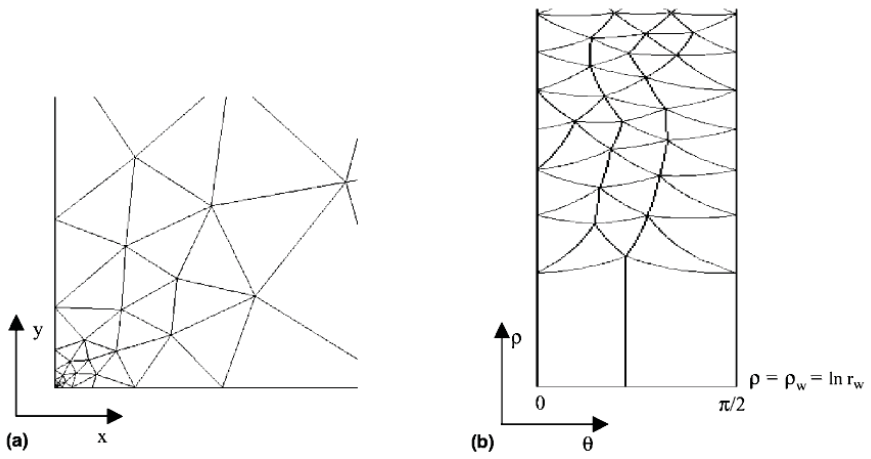

Figure 5-1: An example of gird block transformation, (a) Triangular in Oxy; (b) curved in $O\rho\theta$.

5.2.1.1 Numerical Schemes in Curved Grid System

We study now the numerical scheme, based on the linear approach in the new coordinate system. A line segment in the *Oxy* coordinate is transformed to a curve in the $O\rho\theta$ system. As the flux is unchanged on the transformed curve (Eq. 5-2), we study numerical schemes for the flux calculation in the new coordinate system $O\rho\theta$. Two schemes, a multipoint and a two-point scheme, are presented.

5.2.1.2 Multipoint Scheme

The multipoint schemes are suitable for flux approximation with flexible grids, especially for nonorthogonal grids. Herein, we give a brief description of the application of the *O*-scheme to arbitrary curved gird blocks in the $O\rho\theta$ coordinate system.

Let us consider the gird blocks as having a common vertex. An example of six gird blocks around the vertex *O* is shown in Figure 5-2, and these blocks are numbered 0, 1, 2, 3, 4, and 5. The midpoints of the common edges of the blocks are denoted by *A, B, C, D, E,* and *F*. To obtain flux approximation over the curved edge *OA*, we establish the *O*-scheme on domain S, the shadow domain shown in Figure 5-2.

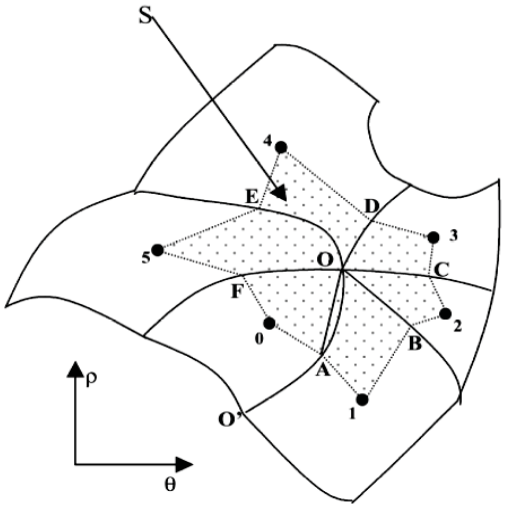

Figure 5-2: *O*_scheme for flux approximation in curved grid system.

The pressure is assumed to be linear in (ρ,θ) on each gird block and is expressed with a linear P_1 finite element function. For example, the pressure on block 0 is expressed by:

$$p(\rho,\theta)=p_0N_0(\rho,\theta)+p_AN_A(\rho,\theta)+p_FN_F(\rho,\theta) \qquad \textbf{5-3}$$

Where in this formula, N_0, N_A, and N_F are linear basis functions defined on the nodes of the triangle *0AF*. N_0 is equal to 1 at point 0, and to 0 at points *A* and *F*. N_A is equal to 1 at point *A*, and to 0 at points 0 and *F*. N_F is equal to 1 at point *F*, and to 0 at points *A* and 0.

The above expression implies pressure continuity at the midpoints of the edges. Then we impose the flux conservation condition on the curved edge to eliminate the degrees of freedom related to the pressure at the midpoint of the edges. For example, the flux conservation over the curve Γ_{AO} is given by:

$$F_{AO,0}=-F_{AO,1} \qquad \textbf{5-4}$$

Where $F_{AO,0}$ represents the flux over the curved edge Γ_{AO} from block 0 to block 1, and $F_{AO,1}$ the flux over the same curved edge from block 1 to block 0. As the pressure is linear on block 0, the flux $F_{AO,0}$ is equal to the flux over the line segment $\overline{AO}$ with:

$$F_{AO,0} = -\int_{\Gamma_{AO}} \overline{\overline{k}}_0.(p_0\nabla N_0 + p_A\nabla N_A + p_F\nabla N_F).\vec{n}dl$$

$$= -\int_{\overline{AO}} \overline{\overline{k}}_0.(p_0\nabla N_0 + p_A\nabla N_A + p_F\nabla N_F).\vec{n}_{AO}dl \qquad \textbf{5-5}$$

$$= -\overline{\overline{k}}_0.(p_0\nabla N_0 + p_A\nabla N_A + p_F\nabla N_F).\vec{n}_{AO}.L_{AO}$$

Where $\vec{n}$ = the normal direction on Γ_{AO} outwards from block 0, $\overrightarrow{n_{AO}}$ = the normal direction on the line $\overline{AO}$ in the same direction, L_{AO} = the length of the segment $\overline{AO}$, and $\overline{\overline{k_0}}$ = the permeability on gird block 0. In the same way, the flux term $F_{AO,1}$ can be written:

$$F_{AO,1} = \overline{\overline{k}}_1.(p_1\nabla N_1 + p_A\nabla N_A + p_B\nabla N_B).\vec{n}_{AO}.L_{AO} \qquad \textbf{5-6}$$

Therefore, the flux conservation condition over the curved edge Γ_{AO} is written by:

$$\overline{\overline{k}}_0.(p_0\nabla N_0 + p_A\nabla N_A + p_F\nabla N_F).\vec{n}_{AO} = \overline{\overline{k}}_1.(p_1\nabla N_1 + p_A\nabla N_A + p_B\nabla N_B).\vec{n}_{AO} \qquad \textbf{5-7}$$

We can also establish the flux conservation equation over the curved edge Γ_{BO}, Γ_{CO}, Γ_{DO}, Γ_{EO}, and Γ_{FO}. In this way, we obtain six flux conservation equations, from which we can eliminate the six unknowns p_A, p_B, p_C, p_D, p_E, and p_F. Finally, the flux over curve Γ_{AO} can be approximated by:

$$F_{AO} = \sum_{j\in V_O} \alpha_j p_j \qquad \textbf{5-8}$$

with V_O the index of the blocks containing the vertex O.

Therefore, the total flux truncation error can be estimated by:

$$\varepsilon_{\rho\theta} \le C \cdot h_{\rho\theta}^2 = O\left(\frac{h_{xy}^2}{r}\right) \qquad \textbf{5-9}$$

Comparing this error (Eq.5-9) and the error given by the commonly used numerical scheme will give this result:

$$\varepsilon_{\rho\theta} = O\left(\frac{h_{xy}^2}{r^2}\right) \qquad \textbf{5-10}$$

We observe that the flux calculation error of the linear scheme can be reduced by a factor of r when using the new scheme. This factor is important in the well vicinity, because r is usually very small close to the well. From this point of view, the new scheme can be considered as an improved numerical scheme for near-well flow modeling.

5.2.1.3 Two-Point Scheme

If the gird blocks are orthogonal in the transformed $O\rho\theta$ system, a two-point scheme is sufficient for accurate well modeling. In particular, if a Cartesian grid is used in the $O\rho\theta$ system as shown in Figure 5-3, the standard two-point finite difference scheme can be applied for the near-well flow approximation. We remark that the Cartesian grid in the $O\rho\theta$ system corresponds to the radial grid in the original *Oxy* system (Figure 5-3).

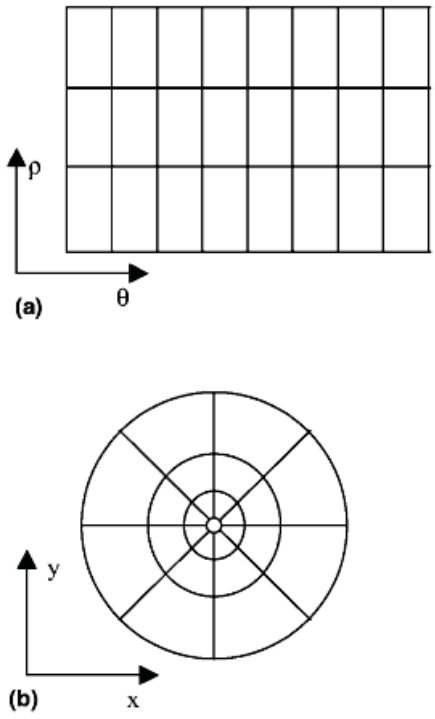

Figure 5-3: Grid transformation between two coordinates.

In general, if the gird blocks are not orthogonal, the two-point scheme is not suitable. But for ease of implementations of the two-point scheme in reservoir simulators, we present in this section a two-point scheme for near-well modeling, which can give good results in most cases.

It can be shown that the flux over a curve Γ_i' can be approximated by the following formula with an error of $O\left(h_{\rho\theta}^2\right)$ (Figure 5-4):

$$F_i' = -\int_{\Gamma_i'} k \frac{\partial p}{\partial n} dl = -k \frac{L_{AB}}{L_{CD}} \left(p_D - p_C\right) \qquad \textbf{5-11}$$

Where p_C and p_D are the pressures defined at points C and D, which are located on the perpendicular bisector of the segment $\overline{AB}$; L_{AB} = the length of the segment $\overline{AB}$; and L_{CD} = the length of the segment $\overline{CD}$. Points C and D can be arbitrary points on the perpendicular bisector. In this paper, we chose the intersection points between the perpendicular bisector and the line $\rho = \rho_0$ and $\rho = \rho_1$.

Because of the point-source "singular" flow being independent on θ, we have therefore $p_C = p_0$ and $p_D = p_i$ for this flow.

Now, we formulate the two-point scheme for near-well flow modeling as

$$F_i = F_i' = -T_i\left(p_i - p_0\right) \qquad \textbf{5-12}$$

with

$$T_i = k \frac{L_{AB}}{L_{CD}} = k \frac{\left|\theta_A - \theta_B\right|}{\left|\rho_i - \rho_0\right|} = k \frac{\Delta\theta_{AB}}{\Delta\rho_{i0}} \qquad \textbf{5-13}$$

where $\Delta\rho_{i0}$ = the distance between the points i and 0 projected in the ρ direction, and $\Delta\theta_{AB}$ = the distance between points A and B projected in the θ direction. This two-point scheme eliminates the flux truncation errors and gives exact calculation for this solution.

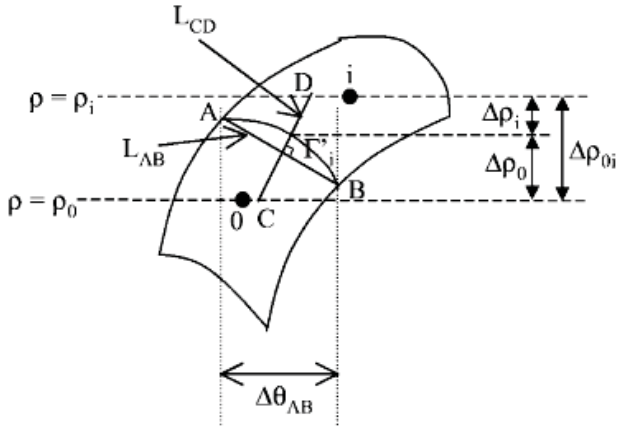

Figure 5-4: New two-point flux approximation scheme.

In heterogeneous media, we use the harmonic average for the calculation of transmissibility (Figure 5-4):

$$T_i = \frac{k_i k_0}{\Delta\rho_0 k_i + \Delta\rho_i k_0} \Delta\theta_{AB} \qquad \textbf{5-14}$$

with k_0 the permeability on the gird block 0 and k_i the permeability on the gird block i.

5.2.2 Examples

5.2.2.1 Example 1: Well Modeling With a PEBI Grid by Ding logarithmic method

An isolated well is considered in an infinite domain with an imposed well flow rate Q=86.4 m^3/D. The reservoir is homogeneous with permeability k=101.3 md. The compressibility is c=0.0001 bar^{-1}, the viscosity is μ=1 cp, and the porosity φ=0.25. The wellbore radius is 10.8 cm. The initial reservoir pressure is 200 bars. This problem is simulated for a period of 1.157 days, and the wellbore pressure is 73.82 bars at the end of the simulation.

A hybrid grid is used as shown in Figure 5-5 The squared gird blocks, with sizes of 50 meters, are used in the general region far from the well, and PEBI gird blocks are used in the well vicinity. All gird blocks satisfy the orthogonal

property[11]. The wellbore boundary is discretized with 10 gird blocks in an angular direction. The well block size in the radial direction is 2 meters, and the block size ratio in radial direction γ is about 2.2. Three numerical methods, the linear approach of Hienemann and Palagi & Aziz that corresponds to a two-point scheme for PEBI gird blocks, the proposed new multipoint scheme, and the proposed two-point scheme, are used in the simulation. The results are compared with the analytical solution.

For the linear approach of Hienemann and Palagi & Aziz the error on the wellbore pressure calculation reaches 6.58%. However, this error can be reduced to 0.271 and 0.268% respectively with the proposed new two-point scheme and new multipoint scheme. This improvement is significant. The near-well field pressure calculation errors are presented in Figure 5-6. It shows that errors for the near-well field pressure calculation are large using the linear approach with a maximum error of 4.8 bars (Figure 5-6 a). However, the field pressure calculation errors are much smaller when using the new approaches with a maximum error of 0.4 bars (Figure 5-6 b and c). This example shows that the linear approach is not very accurate for near-well flow modeling, while the proposed new methods give much better results. The proposed new two-point scheme and new multipoint scheme have almost the same accuracy.

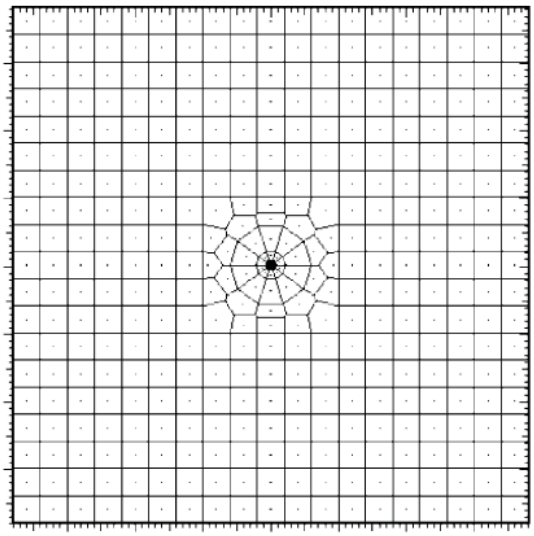

Figure 5-5: Using PEBI grid for near-well modeling.

The method presented in this paper is not limited to radial type PEBI gird block. It

is general and can be used for any kind of gird blocks. In the following example, we present well modeling using a triangular grid.

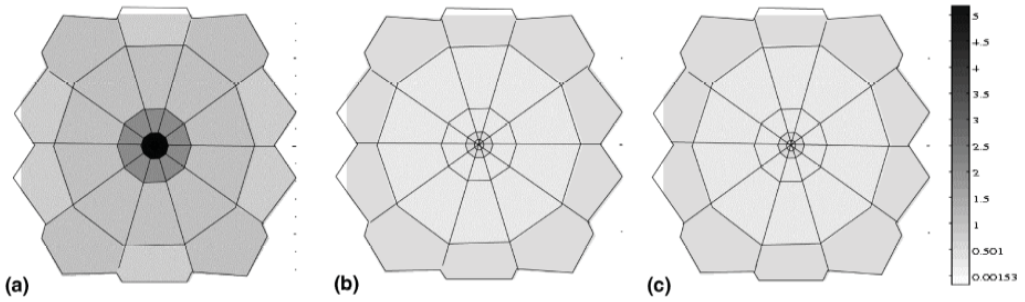

Figure 5-6: Errors in field pressure calculation in the well vicinity; (a) using the linear conventional method, (b) multi-point scheme, (c) two-point scheme.

5.2.2.2 Example 2: Well Modeling With a Triangular Grid

The reservoir properties and the well condition are the same as in Example 1. A triangular "coarse" grid is used for the near-well flow modeling, as shown in Figure 5-7 a. In this example, only a quarter of the geometry is considered. The well block size in the radial direction is 0.8 meters, and the gird block size progress with a ratio $\gamma = 2$ in the vicinity of the well. The *O*-scheme of Avatsmark et al., which is based on linear approximation, is first used on the triangular grid for flow simulation. The simulation results of the linear *O*-scheme are then compared with the proposed new multipoint and two-point schemes, which are based on logarithmic approach. Errors on wellbore pressure calculation are given in Table 5-1, and errors on near-well field pressure calculation are presented in Table 5-2.

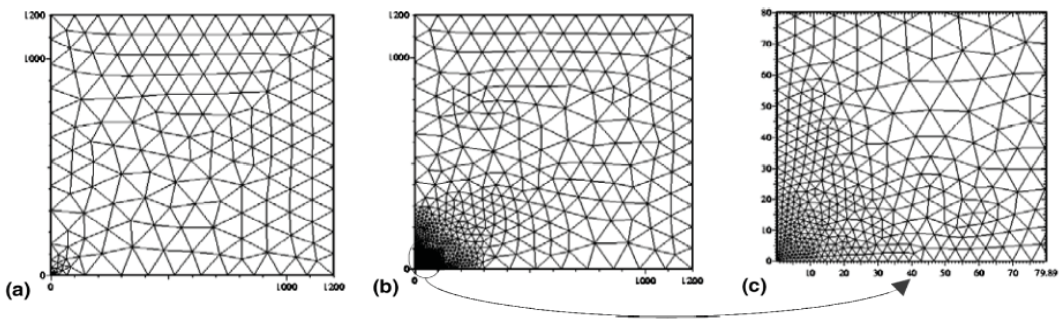

Figure 5-7: Triangular grid blocks for near-well modeling; (a) Normal grid blocks around a well (a quarter of the reservoir), (b) Fine grid blocks around the wellbore, (c) Coarser grid blocks.

Table 5-1: Error in wellbore pressure in example 2.

	Gridblock		Error (bars)		
	Wellblock size (m)	Gridblock size ratio γ	Linear O-scheme	New two-point scheme	New multipoint scheme
Coarse grid	0.8	~ 2	6.13%	0.27%	0.266%
Fine grid	0.8	~ 1	2.05%		

Table 5-2: Error measurements on near-well in field pressure example 2.

	Gridblock		Error (bars)	
	Wellblock size (m)	Gridblock size ratio γ	Linear O-scheme	New two-point scheme
Coarse grid	0.2	~ 2.	4.7	0.42
	0.8	~ 2.	5.9	0.5
	3.2	~ 2.	7.2	0.62
Fine grid	0.8	~ 1.	0.8	

As discussed in the preceding section, the linear approach is not suitable for this kind of gird block. The wellbore pressure calculation error reaches 6.13% with the linear *O*-scheme. However, this error can be reduced to 0.27 and 0.266% respectively when using the new two-point scheme and the new multipoint scheme. Similar results are obtained for the near-well field pressure calculation (Figure 5-8). The errors when using the linear *O*-scheme are large, with a maximum error of 5.9 bars, while the errors, when using the new methods, are much smaller, with a maximum error of 0.5 bars. The efficiency of the proposed new methods is evident. Again, in this example, the results given by the new two-point scheme and the new multipoint scheme are very similar, while the new two point scheme is less CPU time-consuming. The advantage of the new multipoint scheme can be revealed in more complex cases in which the gird blocks are greatly deformed in the vicinity of the well. In these cases, the two-point scheme might be inefficient as shown in the example given by Ding and Jeannin for the point sink/source modeling. However, for the grid geometry in the examples presented in this paper, using the two point scheme is sufficient.

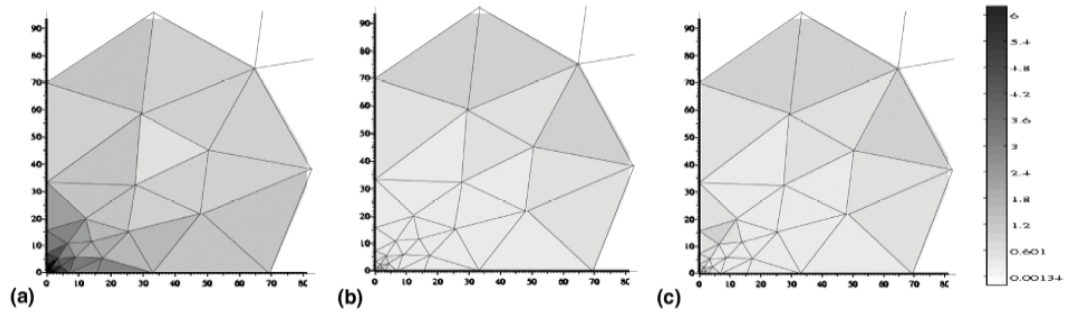

Figure 5-8: Pressure calculation errors in the well vicinity; (a) Linear scheme, (b) Multi-point scheme, (c) Two-point scheme.

The figure (Figure 5-9) below can magnify the errors in pressure calculation that occur during the linear *O* scheme. This is one quarter of an example reservoir in which the well is located in the down left side of the figure.

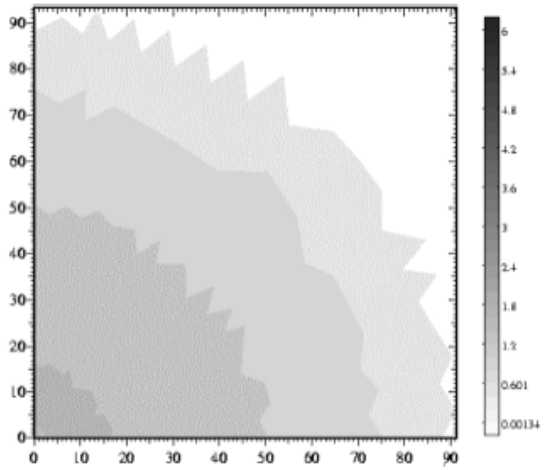

Figure 5-9: pressure calculation error using linear approach with fine grid blocks.

5.2.3 Some conclusions and recommendation regarding logarithmic approach

1. Method presented by Ding et al. is not limited to radial type of PEBI grid block. It is general and can be used for any kind of grid blocks.
2. For commonly used flexible grids in reservoir simulations, the grid blocks in the vicinity of the well are usually not small enough compared to the

wellbore radius, especially in field applications. Moreover, the grid block sizes usually increase geometrically in the radial direction outward from the well. This kind of grid makes the commonly used linear approach (linear in coordinates of physical space) inefficient for near-well flow modeling. Although the linear numerical scheme is accurate with very small grid block sizes (h<<rw) in the vicinity of the well, it is impossible to use this kind of grid in real applications. New numerical schemes have been proposed to improve the linear approach for near-well modeling[4].

3. In particular, two numerical schemes, a multipoint and a two-point scheme, are proposed for the near-well flow calculation. The multipoint scheme is an accurate one, whereas the two-point scheme is an approximate one, which is not consistent in the finite-volume sense for nonorthogonal grid blocks. This scheme can give satisfactory results in most cases. The examples presented show the limitations of using the linear approach with the commonly used flexible grid blocks for the near-well modeling. These examples illustrate two problems when using the linear approach: The problem of the well block size, which is usually large with respect to the wellbore radius, and the problem of the grid block size progressing geometrically outward from the well. The methods proposed in this paper can accurately handle these problems. The results show that the linear approach is not accurate enough with the commonly used grid blocks such as the ones in the examples, while the proposed methods give quite satisfactory results not only on the wellbore boundary but also in the near-well field. In these examples, the proposed two-point scheme is efficient. It gives almost the same accuracy as the proposed multipoint scheme, and it is less CPU time-consuming. The multipoint scheme might be required in the case of greatly deformed near-well grid blocks, where the two-point scheme is not efficient. The proposed schemes have been successfully applied to model near-well formation damage attributable to drilling fluid[4].

Chapter 6

6 Summary and Recommendations

6.1 Summary and Conclusions

This thesis work showed the state of the art methods for calculating the static bottom hole pressure in the contemporary reservoir simulators. Their limitations and applicability of these methods were discussed and monitored. Three methods that have been investigated were ECLIPSE®, SURE® and HRC.

The HRC method for Well Static bottom hole pressure is presented in this thesis work. This method has been programmed By FORTRAN 90 in the HRC. The applicability and concept of the presented method has been tested and confirmed. The Code has been tested by a number of examples and by at least 50 different cases in these examples.

Examples can be listed as: a homogeneous reservoir and a heterogeneous reservoir, each of them with and without cross flow between the layers and examples with special features around the well. All of the tested cases showed good and comparable results with the-state-of-the-art commercial software.

A number of examples were object oriented to magnify any possible error or bug in the code. Investigations showed that by changing the settings of the keywords, increasing production, decreasing the mobility (increasing viscosity or decreasing permeability) and changing the size of grids, the calculated average pressures will vary significantly. Even refining a coarse grid reservoir (changing the grid size of

the same reservoir) showed a big difference in the results.

Variation of the measured values within a spectrum, clearly presents unreliability on the results. By changing the weighting factors, an engineer can produce any arbitrary value within a spectrum.

Results will have big differences with a possible buildup test which gives the correct static pressure. These results opened a new perspective for further researches.

In term of CPU time, there has not been a big difference in the overall CPU time, since the method is easy and without any specific iteration.

6.2 Recommendations

The presented method here in this thesis work is prone to further development as it is only applicable for Cartesian gird. Further development should be done for all kind of unstructured grid.

Further investigation should be done to make the method independent of size and type of gridding. An example of refining grid clearly showed this weakness in the method.

A brief discussion has been presented in the last chapter about a logarithmic approach for near well modeling and pressure calculation around the well. This recent research has opened a new perspective to work on.

Chapter 7

7 Nomenclature

Superscripts:

CVFE	= Control Volume Finite Element
n	= time step level
n + 1	= time step level
v	= iteration level

Subscripts:

c	=Component
c	=Connection
cur	=Current
h	=Horizontal direction
i	=Grid block number
ij	=Grid block interface between nodes i and j
ini	=Initial
i; j; k; l	=Counters in summation terms
j	=Grid block number
l	=Local coordinate
p	=Phase
p	=Phase
r	=Radial direction
tot	=Total
θ	=Angular direction
θ	= space variable in transformed coordinates system

x =x-axis

x' =x-axis in local coordinate system

y =y-axis

y' =y-axis in local coordinate system

z =z-axis

Other symbols:

2D =Two dimensions/dimensional

3D =Three dimensions/dimensional

A =Control-Volume surface area, m 2

A =Accumulation term

B =Formation volume factor

CVFE =Control volume finite element

CVFD =Control volume finite difference

FC =Flux Continuous

GPEBI=Generalized perpendicular bisector

PEBI =Perpendicular bisector

R =Rotation matrix

S =Saturation, fraction

Tij =Interblock transmissibility (geometric factor part), m 3

V =Volume, m 3

Vp =Pore volume, m 3

WI =Production index

c =Compressibility

d =Intersection point

d =Distance, m

e =Edge point locations

μ =Viscosibility, Pa.s/Pa

i =ith node in x-direction

j =jth node in y-direction

k =kth node in z-direction

k =Permeability or tensor, m2

kr =Relative permeability, fraction

hxy	=grid block size in Oxy coordinates system
$h_{\rho\theta}$	=grid block size in $O\rho\theta$ coordinates system
Lij	=length of the segment joining the points i and j
O(.)	=equivalent order, depends on both the grid block size
np	=Number of phases
nc	=Number of connections
$\vec{n}$	=Normal vector
p	=Pressure, Pa
pwell	=Well bottom hole pressure, Pa
pana	=analytical pressure solution
pcal	=calculated pressure
pinit	=initial reservoir pressure
pw	=wellbore pressure
q	=Production of phase p, m 3 /s
rw	=Well radius, m
r	=Radial distance, m
$\vec{s}$	=Vector pointing from node i towards node j
t	=Time, s
w	=Width, m
v	=Darcy velocity, m/s
Δ	=Triangle
Δ x	=Grid block length in x-direction, m
Δ y	=Grid block length in y-direction, m
$\vec{\nabla}\Phi$	=Potential gradient, Pa/m
Φ	=Potential, Pa
Φ'	=Potential gradient, Pa/m
α	=Angle, radian
λ	=Mobility, 1/m 3 .Pa.s
μ	=Viscosity, Pa.s
ρ	=Mass density, kg/m 3
$\overline{\rho}$	=Mass density at standard conditions, kg/m 3

ϕ	=Porosity, fraction
γ	=grid block size ratio in the radial direction
Γ	=curve or boundary of a domain
ΓR	=reservoir boundary
Γw	=wellbore boundary
Δ θ ij	=distance between the points i and j projected to the θ direction
Δ ρ ij	=distance between the points i and j projected to the ρ direction
Δ θ , Δ ρ	=distance in $O\rho\theta$ system[2]
ε	=flux truncation error
$\overline{P}_R$	= average pressure for reservoir
P_i	= average pressure for Well i
V_i	= the drainage volume of Well i
γ	= specific gravity of fluid.
ΔH	= the vertical distance between the point at which the pressure was measured and the datum depth, ft.
F1	= weighting factor
F2	= weighting factor between well index weighted pressure and pore volume weighted pressure
WBP n	= keyword defining the number of neighboring blocks.
RES	= pressure will be depth corrected by reservoir fluids
WELL	= pressure will be depth corrected by wellbore fluids
NONE	= pressure will not be depth corrected
OPEN	= only open perforations will be contributed in calculations
ALL	= all of the perforations will be contributed in calculations

Chapter 8

8 Reference:

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Appendix 1

1 New routine in the research code

This appendix presents the routine which carry the basic part of static pressure calculations in the HRC. There were several routines which were manipulated for this project, but the main routine was *"cvar11_o.f"*. This routine is nicely equipped by comments for future investigations.

```
!IBM* SOURCEFORM (FREE(F90))
!DIR$ FREE
!MS$FREEFORM

  SUBROUTINE CVAR11_o(NPARE1,NPARE2,LL,NWELL,NBAREA    & !in
   &,  LIMIZ,NPDOM,LIMIZP,IDOM,NDOM1,NPVT              & !in
   &,  Yfim_opt,ICLUST)                                  !in

!*****************************************************************************************************
!  Name   :                C V A R 1 1 _ o                                                           *
!  Release: H5 V.1.1                                                                                 *
!  Package: H5 UNIT2                                                                                 *
!  Date   : JUL-2006                                                                                 *
!  All rights reserved, no parts of this material may be reproduced                                  *
!*****************************************************************************************************
!@ Function of the routine: CVAR11_o                                                                 *
!@ ================================                                                                  *
!@ Calculation of ECLIPSE type static well pressure                                                  *
!*****************************************************************************************************
!  VERS|AUTHOR    |   DATE  |       COMMENT                                                          *
!  1.01|HZ/HADI   |10-JUL-06| new                                                                    *
!  1.02|HZ/HADI   |06-AUG-07| calculation of Eclipse type static well pressure                       *
!  1.03|HZ/HADI   |11-SEP-07| finalizing  of Eclipse type static well pressure                       *
!                                                                                                     *
!*****************************************************************************************************
!EH-^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+
!EA-^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+

  USE BLOCK_Variables                                  !replaces INTB,TT,TTW,TS,TTN           @
  USE WELL_Variables                                   !modul for block and well variables

  USE M_MESSAGE
  USE AXCREAL                                          !compositional data
  USE TDDATA,  ONLY : DEC                              !general TDD storage module
  USE ROCK,    ONLY : IDOPT

  IMPLICIT NONE

  INTEGER,INTENT(IN) :: NPARE1,NPARE2
  LOGICAL,INTENT(IN) :: Yfim_opt
  INTEGER,INTENT(IN) :: LL,NWELL,NBAREA,NPVT
  INTEGER,INTENT(IN) :: NPDOM,IDOM,NDOM1

  INTEGER,DIMENSION(0:4,NPDOM) ,INTENT(IN) :: LIMIZP
  INTEGER,DIMENSION(NPDOM)     ,INTENT(IN) :: ICLUST

  INTEGER,DIMENSION(0:NBAREA+1,3) ,INTENT(IN) :: LIMIZ
```

```
  LOGICAL :: YWGATH
  INTEGER :: IWEL,N,L,IZ,INJ,J,ICOMP
  INTEGER :: IEPT,IAVA,NTIP,NTYPE,IOPR,NGL,KIND
  INTEGER :: IP

  INTEGER :: I,JZN,JZ,NJ,NJJ,NMAX,NUMBKJ,NUMBKJ1,NUMBKJ2,LIB1,IDUAL,K,IDD,IIZ,NBKJ
  LOGICAL :: YFRAC,YY
  REAL(4),DIMENSION(0:9) :: PC
  INTEGER,DIMENSION(0:100) :: JJZ,IJJ
  REAL(4) :: EPS=1.E-6,PRING,PAV_con,PAV_vol,PPERF,PVOL,F1
  REAL(4),ALLOCATABLE,DIMENSION(:) :: SPAVRV              !sum_of_pressure_for_volume averaging
  REAL(4),ALLOCATABLE,DIMENSION(:) :: SBLVOL              !sum_of_block_volumes
  REAL(4),ALLOCATABLE,DIMENSION(:) :: SPAVRC              !sum_of_pressure_for_connection averaging
  REAL(4),ALLOCATABLE,DIMENSION(:) :: SPINDX              !sum_of_productivity_indices

!START---+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+

 ALLOCATE(SPAVRC(0:1),SPINDX(0:1),SPAVRV(0:1),SBLVOL(0:1)) !proform
!---^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+
! Calculation of ECLIPSE type static well pressures       !HZ070806
!:::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::

 Well_2: DO IWEL = 1,NWELL                                !loop over the wells

   IF(.NOT.WW(IWEL)%ywpave)     CYCLE Well_2              !no static pressure will be calculated for this well
   IF(IDOM /= WW(IWEL)%IDOM)    CYCLE Well_2              !The well is outside the domain
                                                          !in normal proceding (no parallel domains) IDOM=WW(IWEL)%IDOM = 0
    IZ  = WP(IWEL)%IZPERF(1)                              !sno.of 1st perforation block

    IF(IZ < LIMIZ(NPARE1,1).OR.                         & !if the well does not belong to the area
     & IZ > LIMIZ(NPARE2,2))  CYCLE Well_2                !calculated in the actual cycle

    IF(Yfim_opt) THEN                                     !HZ070806  -- not used now
     DO IP = 1,NPDOM
     IF(IZ >= LIMIZP(1,IP).AND.                         & !IP = sno.of the domain, the intervall is
      & IZ <= LIMIZP(4,IP)) EXIT                          !outside of the actual domain
     ENDDO
     IF(ICLUST(IP) /= 0) THEN
       DO L = 1,N                                         !loop over the perforations
         WP(IWEL)%P2(L) = ABS(WP(IWEL)%P2(L))
       ENDDO
       CYCLE Well_2
     END IF
    END IF

    CALL RWCODE(WW(IWEL)%IWOP,IEPT,IAVA,NTIP,NTYPE,IOPR,NGL,KIND)
    INJ = WW(IWEL)%INJC                                   !sno.of quality definition
```

```
YWGATH = WW(IWEL)%IWGATH > 0                          !gathered well bore

N = WW(IWEL)%NPERF                                    !no.of perforations for layered well

DEALLOCATE(SPAVRC,SPINDX,SPAVRV,SBLVOL)
ALLOCATE(SPAVRC(0:N));    SPAVRC = 0.;                !sum_of_pressure_for_volume averaging
ALLOCATE(SPINDX(0:N));    SPINDX = 0.;                !sum_of_block_volumes
ALLOCATE(SPAVRV(0:N));    SPAVRV = 0.;                !sum_of_pressure_for_connection averaging
ALLOCATE(SBLVOL(0:N));    SBLVOL = 0.;                !sum_of_productivity_indices

Perfs_2: DO L = 1,N                                   !loop over the perforations

 WP(IWEL)%WPAVE(L) = -999.999

 IF(WW(IWEL)%perfcode == 0.AND.           &           !only open perforations considerd
  & WP(IWEL)%EF(L) <= 0.) CYCLE Perfs_2               !the actual perforation is closed

 IZ  = WP(IWEL)%IZPERF(L)                             !sno.of the perforation block
 LIB1 = INTBB(IZ)%LIB1                                !sno.of rock region
 IDUAL= IDOPT(LIB1)                                   !flag for dual option
 YFRAC= IDUAL == 1.OR.IDUAL == 3                      !0 ... single porosity block
 IDD = 1                                              !for single porosity block
 IF(YFRAC) IDD = 2                                    !for dual fracture block

 NUMBKJ = 0                                           !counter for blks forming the ring
 PRING = 0.                                           !arithmetric average pressure of the rings

 JJZ = 0;   JJZ(0) = IZ
 NMAX = INTBB(IZ)%NMAX                                !no.of normal cartesian neigbors to block IZ
                                                      !registrate blocks of the 1st ring (4 blks in cartesian)

 first_ring: DO NJ = 1,NMAX                           !loop over the normal neighbors
  JZ = INTBB(IZ)%JZ(NJ)                               !sno. of the neighbor
  LIB1 = INTBB(JZ)%LIB1                               !sno.of rock region
  IDUAL= IDOPT(LIB1)                                  !flag for dual option
  IF(IDUAL == 1.OR.IDUAL == 3) IDD = 2                !0 ... single porosity block

  IF(ABS(IZ-JZ) <= IDD) CYCLE first_ring              !vertical neighbors are not considered
  NUMBKJ = NUMBKJ+1
  JJZ(NUMBKJ) = JZ
  IJJ(NUMBKJ) = INTBB(IZ)%IJ(NJ)                     !pointer to the transmissibility
 ENDDO first_ring

 NUMBKJ1 = NUMBKJ                                     !NUMBKJ1 = no.of blocks in the 1st ring

 A2: DO NJ = 1,NUMBKJ1                                !loop over the 1st level ngbs
                                                      !loop over the 2nd level nbrs should find the "diagonal" nbrs
```

```
JZ = JJZ(NJ)                                  !sno. of the block in 1st ring
LIB1 = INTBB(IZ)%LIB1                         !sno.of rock region
IDUAL= IDOPT(LIB1)                            !flag for dual option
YFRAC= IDUAL == 1.OR.IDUAL == 3               !0 ... single porosity block
IDD = 1                                       !for single porosity block
IF(YFRAC) IDD = 2                             !for dual fracture block

NMAX = INTBB(JZ)%NMAX                         !no of 2nd level neigbors (nbrs of normal nbrs)
A1: DO NJJ = 1,NMAX                           !loop over the 2nd nbrs, registrate their all lateral nbrs
    JZN = INTBB(JZ)%JZ(NJJ)
    DO K = 1,NUMBKJ1
    IF(JZN == JJZ(K)) CYCLE A1
    ENDDO
    IF(JZN == IZ)          CYCLE A1
    IF(ABS(JZN-JZ) == IDD) CYCLE A1           !vertical neghbors are not considered
    NUMBKJ = NUMBKJ+1
    JJZ(NUMBKJ) = JZN
    IJJ(NUMBKJ) = INTBB(JZ)%IJ(NJJ)
  ENDDO A1
ENDDO A2

A3: DO I = NUMBKJ1+1,NUMBKJ
  DO J = I+1,NUMBKJ
    IF(JJZ(I) == JJZ(J)) CYCLE A3
  ENDDO
  JJZ(I) = 0
ENDDO A3

A5: DO I = NUMBKJ,1,-1
  DO J = I-1,1,-1
    IF(JJZ(I) == JJZ(J)) JJZ(I) = 0
  ENDDO
ENDDO A5

J = NUMBKJ
A4: DO I = NUMBKJ1+1,NUMBKJ
  DO WHILE (JJZ(I) == 0)
    DO K = I,J
    JJZ(K) = JJZ(K+1)
    IJJ(K) = IJJ(K+1)
    ENDDO
    J = J-1
    IF(J == I) EXIT A4
  ENDDO
ENDDO A4
NUMBKJ  = J-1
NUMBKJ2 = NUMBKJ
```

```
!-^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+
!Calculation of block potentials
!PRS calculate the potential if with constant
!Hadi: write here wery detailed how ECLIPSE correct the pressure and why we do it in an other way!
!:::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::
  DO J = 0,NUMBKJ                                      !loop over all involved blocks
   IIZ = JJZ(J)                                        !sno.of the block (JJZ(0) = IZ)
   IF(WW(IWEL)%rocode == 0) THEN                       !flag for depth correction density = 0 (keyword NONE;
    PC(J) = P(IIZ)                                     ! no correction
   ELSE                                                !determine the potential
    YY = WW(IWEL)%rocode == 1                          !1 - Constant density  (input is keyword 'WELL');
                                                       !2 - REServoir density (input is keyword 'RES' )
    CALL POTED2_o(IIZ,IIZ,YY,NPVT,WW(IWEL)%dwpave)     !calculate th potential
    PC(J) = POTE(IIZ)
  END IF
 ENDDO
!-^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+
!Calculation of the average pressure connection based
!:::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::
 NUMBKJ = WW(IWEL)%nblock                              ! HZ,HH,070917 provisorical only for cartesian, make it suitable &
                                                       ! &for unstructured grid too
 SELECT CASE(NUMBKJ)
   CASE (1);  NBKJ = 0;  F1 = 1.0                      !WBP1 -> "N neighbore"=0, weifgting should be only by well block (F1=1.)
   CASE (4);  NBKJ = 4;  F1 = 0.0                      !WBP4 -> "N neighbore"=4, weifgting should be only by neighboring blocks (F1=0.)
   CASE (5);  NBKJ = 4;  F1 = WW(IWEL)%F1              !WBP5 -> "N neighbore"=4 + wellblock, normal weifgting by a factor (F1=??.)
   CASE (9);  NBKJ = 8;  F1 = WW(IWEL)%F1              !WBP9 -> "N neighbore"=8 + wellblock, normal weifgting by a factor (F1=??.)
 END SELECT

 PRING = 0
 IF(WW(IWEL)%F1 >= 0.) THEN                            !calculate the arithmetic avr.press. of the blocks in rings
  DO J = 1,NBKJ                                        !NBKJ = 4 or 8 for cartesian
    PRING = PRING+PC(J)                                 !sum of the pressure of block in ring
  ENDDO
  PRING = PRING/(FLOAT(NBKJ)+EPS)                       !arithmetic average
  PPERF = F1*PC(0)+(1.-F1)*PRING                        !weighting averaging with perf.block

 ELSE                                                  !WW(IWEL)%F1 < 0, means the avr.pressure is volume weighted

  PRING = PC(0)*AFI(IZ)
  PVOL  = AFI(IZ)
  DO J = 1,NBKJ                                        !NBKJ = 4 or 8 for cartesian
    JZ = JJZ(J)                                         !sno.of the block
    PRING = PRING+AFI(JZ)*PC(J)                         !sum of the presure
    PVOL  = PVOL +AFI(JZ)                               !sum of the presure
  ENDDO
  PPERF = PRING/(PVOL+EPS)
 END IF
```

```
SPAVRC(L) = SPAVRC(L)+WP(IWEL)%OWSS(L)*PPERF           !OWSS = 0 for closed perforations
SPINDX(L) = SPINDX(L)+WP(IWEL)%OWSS(L)
SPAVRC(0) = SPAVRC(0)+WP(IWEL)%OWSS(L)*PPERF           !OWSS = 0 for closed perforations
SPINDX(0) = SPINDX(0)+WP(IWEL)%OWSS(L)

!-^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+
!Calculation of the average pressure volume based (see TDD Manual Eq.  XXXXXX)
!::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::

 SELECT CASE (NUMBKJ)
  CASE (1)                                             !only well block considered
    SPAVRV(L) = SPAVRV(L) +AFI(IZ)*PC(0)
    SBLVOL(L) = SBLVOL(L) +AFI(IZ)
    SPAVRV(0) = SPAVRV(0) +AFI(IZ)*PC(0)
    SBLVOL(0) = SBLVOL(0) +AFI(IZ)
  CASE (4)                                             !only first ring is considered
    DO J = 1,4                                         !NUMBKJ = 4 or 8 for cartesian
     JZ = JJZ(J)                                       !sno.of the block
     SPAVRV(L) = SPAVRV(L) +AFI(JZ)*PC(J)
     SBLVOL(L) = SBLVOL(L) +AFI(JZ)
     SPAVRV(0) = SPAVRV(0) +AFI(JZ)*PC(J)
     SBLVOL(0) = SBLVOL(0) +AFI(JZ)
    ENDDO
  CASE (5)                                             !perf.block and first ring considered
    DO J = 0,4                                         !NUMBKJ = 4 or 8 for cartesian
     JZ = JJZ(J)                                       !sno.of the block
     SPAVRV(L) = SPAVRV(L) +AFI(JZ)*PC(J)
     SBLVOL(L) = SBLVOL(L) +AFI(JZ)
     SPAVRV(0) = SPAVRV(0) +AFI(JZ)*PC(J)
     SBLVOL(0) = SBLVOL(0) +AFI(JZ)
    ENDDO
 CASE (9)                                              !perf.block and 2 rings considered
    DO J = 0,8                                         !NUMBKJ = 4 or 8 for cartesian
     JZ = JJZ(J)                                       !sno.of the block
     SPAVRV(L) = SPAVRV(L) +AFI(JZ)*PC(J)
     SBLVOL(L) = SBLVOL(L) +AFI(JZ)
     SPAVRV(0) = SPAVRV(0) +AFI(JZ)*PC(J)
     SBLVOL(0) = SBLVOL(0) +AFI(JZ)
    ENDDO
 END SELECT

ENDDO Perfs_2

                                                       !avr.block press.for all open perfs,weighted by prod.index
DO L = 1,N                                             !(in ECL nomenclature: by connection transmissibility)
 IF(WW(IWEL)%perfcode == 0.AND.                      & !only open perforations considerd
  & WP(IWEL)%EF(L) <= 0.) CYCLE                        !the actual perforation is closed
 PAV_con = SPAVRC(L)/(SPINDX(L)+EPS)                   !avr.pressure, connection (ProdIndex) weighted
```

```
   PAV_vol = SPAVRV(L)/(SBLVOL(L)+EPS)                    !average pressure, volume weighted
   WP(IWEL)%WPAVE(L) =  WW(IWEL)%F2 *PAV_con             & !Averaging the two kind of avr. pressure for the perforation
    &           +(1.-WW(IWEL)%F2)*PAV_vol
  ENDDO

                                                          !avr.block press.for all open perfs, weighted by prod.index
   PAV_con = SPAVRC(0)/(SPINDX(0)+EPS)                    !avr.pressure, connection (ProdIndex) weighted
   PAV_vol = SPAVRV(0)/(SBLVOL(0)+EPS)                    !average pressure, volume weighted
   WW(IWEL)%WPAVE =  WW(IWEL)%F2 *PAV_con                & !Averaging the two kind of avr. pressure for the perforation
    &           +(1.-WW(IWEL)%F2)*PAV_vol
  ENDDO Well_2

!---^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+----^----+
  RETURN
  END SUBROUTINE CVAR11_o
```

Appendix 2

2 Schedule input file, SCAL input file and PVT input file for ECLIPSE® examples

2.1 Schedule input file for ECLIPSE®

The schedule file is one of the obligatory include files in the simulation with Eclipse. It provides the dynamic changes which are applied to the reservoir. It specifies the operations that are needed to be simulated like production, injection and constraints of the wells and reservoir.

```
-- ------------------------------------------------------------------------
-- Office Schedule (SCHED) Data Section Version 2005A Apr 19 2005
-- ------------------------------------------------------------------------
-- File: wpave_cw2_sch.inc
-- Created on: 15-Sep-2007 at: 13:04:58
-- ************************************************************************
-- *                          WARNING                                     *
-- *                THIS FILE HAS BEEN AUTOMATICALLY GENERATED.           *
-- *          ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.    *
-- ************************************************************************
ECHO
RPTSCHED
'FIP=2' 'WELLS=5' /
RPTRST
'BASIC=2' 'NORST=0' /
WPAVE
2* 'WELL' 'OPEN' /
WELSPECS
'CWECL' 'WG_PROD' 13 13 6250 'OIL' 1* 'STD' 'SHUT' 'YES' 1 'SEG' 3* 'STD'
/
 /
COMPDAT
'CWECL' 13 13 1 5 'OPEN' 1 1* 0.583 1* 0 0.04025 'Z' 1* /
 /
WCONPROD
'CWECL' 'OPEN' 'ORAT' 100 8* /
 /
DATES
1 'FEB' 1980 /
/
```

```
RPTSCHED
'FIP=2' 'WELLS=5' /

RPTRST
'BASIC=2' 'NORST=0' /


WPAVE
2* 'WELL' 'OPEN' /

DATES
1 'MAR' 1980 /
/

RPTSCHED
'FIP=2' 'WELLS=5' /

RPTRST
'BASIC=2' 'NORST=0' /


WPAVE
2* 'WELL' 'OPEN' /

DATES
1 'APR' 1980 /
/

RPTSCHED
'FIP=2' 'WELLS=5' /

RPTRST
'BASIC=2' 'NORST=0' /


WPAVE
2* 'WELL' 'OPEN' /


.................
```

[Continue for ten years …]

2.2 SCAL input file for ECLIPSE®

Relative permeability and capillary pressure measurements from core analyses will be given to the reservoir. These curves will be assigned to the grid cells on the basis of rules which have been set up. This data is a crucial part of reservoir properties.

```
-- ------------------------------------------------------------------------
-- Office SCAL (SCAL) Data Section Version 2005A Apr 19 2005
-- ------------------------------------------------------------------------
-- File: wpave_cw2_scal.inc
-- Created on: 12-Sep-2007 at: 12:15:34
-- ************************************************************************
-- *                              WARNING                                 *
-- *                THIS FILE HAS BEEN AUTOMATICALLY GENERATED.           *
-- *          ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.    *
-- ************************************************************************
-- OFFICE-SCAL-HEADER-DATA
-- Off SCAL Saturation Tables:          1          1
-- Off SCAL  "Saturation 1"
-- Off SCAL End Point Tables:          1          1
-- Off SCAL  "End Points 1"
-- Off SCAL Petro Elastic Tables:          1          1
-- Off SCAL  "Petro-elastic 1"
ECHO
SGOF
--
-- Gas/Oil Saturation Functions
--
             0           0           1           0
          0.43        0.32           0          1*
         0.759          1*          1*    5.656472
/

SWOF
--
-- Water/Oil Saturation Functions
--
         0.241           0           1    5.676035
       0.70883          1*           0          1*
         0.722       0.172          1*          1*
             1          1*          1*           0
/
```

2.3 PVT input file for ECLIPSE®

This file contains the PVT functions necessary for the simulation. Gas Z factor, gas viscosity in the PVT tables are functions of pressure. And oil FVF, oil viscosity and pressure are functions of the solution gas in oil. The other data provided are constants. The PVT tables used in the ECLIPSE® examples are shown here. It is important to notice that rock compressibility is provided here.

```
--
-- ------------------------------------------------------------------------
-- Office PVTN (PVTN) Data Section Version 2005A Apr 19 2005
-- ------------------------------------------------------------------------
--
-- File: wpave_cw2_pvt.inc
-- Created on: 2007-Sep-14 at: 11:26:46
--
-- ************************************************************************
-- *                                WARNING                               *
-- *              THIS FILE HAS BEEN AUTOMATICALLY GENERATED.             *
-- *          ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.    *
-- ************************************************************************
--
-- OFFICE-PVTN-HEADER-DATA
-- Off PVTN PVT Tables:          1          1
-- Off PVTN  "PVT 1"
-- Off PVTN Rock Tables:          1          1
-- Off PVTN  "Rock Compact 1"
ECHO
PVTO
--
-- Live Oil PVT Properties (Dissolved Gas)
--
      0.009864      14.7       1.1       1.2 /
      0.098926     307.3     1.132     0.747 /
      0.187857     599.9     1.164     0.706 /
      0.276784     892.5     1.196     0.669 /
      0.364069    1185.1     1.228     0.636 /
      0.441215    1477.6     1.261     0.605 /
      0.519706    1770.2     1.294     0.577 /
      0.601076    2062.8     1.328     0.551 /
      0.685884    2355.4     1.364     0.529 /
       0.77366      2648     1.399     0.519
                    3148     1.385     0.519 /
/

PVTW
--
-- Water PVT Properties
--
        2948     1.019 2.66e-006     0.489         0
/
```

```
,
PVZG
--
-- Dry Gas PVT Properties (using Z-factors)
--
     170.1
/
        14.7       0.9     0.008
       307.3  0.861171    0.0101
       599.9  0.822341    0.0122
       892.5  0.783512    0.0142
      1185.1   0.74355    0.0164
      1477.6  0.702168    0.0194
      1770.2  0.678726     0.023
      2062.8  0.672157    0.0269
      2355.4  0.676744    0.0308
        2648   0.69495    0.0345
/

DENSITY
--
-- Fluid Densities at Surface Conditions
--
       52.24     62.46    0.0711
/
ECHO
ROCK
--
-- Rock Properties
--
        2948 1.1001e-015
/
```

Appendix 3

3 TDD input file, PVT input file and rock input file for HRC examples

3.1 TDD input file

The core of the general TDD files that have been used for the example is printed here. Special outputs are being written out for these examples. The commands for these outputs are presented in the TDD file.

```
------------------------------------------------------------
RELEASE 6.0
TITLE                   wpave center well
DATEFORM                year_month_day
UNITS                   inpu_f outp_f
INITIAL  DREF=6250

# Dates of start and end of simulation
DATEINIT  1980/01/01
DATEEND   1990/01/01

# General file addresses for HRC code to use
FILEDEF error       FILENAME wpave_cw.err
FILEDEF SUREGrid    FILENAME ref/wpave_cw.sgr.work/BASIC
FILEDEF restart_out FILENAME wpave_cw.res
FILEDEF rockfunc    FILENAME wpave_cw.rck
FILEDEF pvtfunc     FILENAME wpave_cw.pvt
FILEDEF postproc    FILENAME results
FILEDEF lisfile     FILENAME wpave_cw.lis

INFORM  resume      FILENAME wpave_cw.rsm
INFORM monitor      FILENAME wpave.mon

# presenting the PVT tables in the LIS file
INFORM ctabs pvttab
```

```
INFORM wells

# files to be written out for post processors
POSTPROC sgdistri spproduc
POSTPROD perfor

# Output of the simulation will be written out for these days (also timesteps)
OUTPUT    1980/01/01    perfor
OUTPUT    1980/02/01    perfor
OUTPUT    1980/03/01    perfor
OUTPUT    1980/04/01    perfor
……
…… [For every month] ……
……
OUTPUT    1989/10/01    perfor
OUTPUT    1989/11/01    perfor
OUTPUT    1989/12/01    perfor
OUTPUT    1990/01/01    well_p perfor matbal gasfvf
#Well Definition
GROUP_NAME WG_PROD
GROUP WG_PROD  << cw1

#well specification
WELLDEF WG_PROD oilprd netrat Dupuit

PERFSPEC 1980/01/01 cw1 allperfs FLOWEF 1.0

WTARGET cw1   100.

########      HRC      ########
## HRC reference depth correction for pressure
 WPAVEDEP forall  6250

## pressure monitoring around cw1 for the remaining years by "HRC solution"
WELLSPEC  1980/01/01  cw1  wpave F1 0.1  F2 1.0 RES OPEN wbp 5 drefwpave 6250
WELLSPEC  1981/01/01  cw1  wpave F1 -0.3 F2 1.0 RES OPEN wbp 5 drefwpave 6250
WELLSPEC  1982/01/01  cw1  wpave F1 0.5  F2 0.0 RES OPEN wbp 5 drefwpave 6250
WELLSPEC  1983/01/01  cw1  wpave F1 0.5  F2 1.0 WELL OPEN wbp 5 drefwpave 6250
WELLSPEC  1984/01/01  cw1  wpave F1 0.5  F2 1.0 RES ALL wbp 5 drefwpave 6250
WELLSPEC  1985/01/01  cw1  wpave F1 0.5  F2 1.0 RES OPEN wbp 1 drefwpave 6250
WELLSPEC  1986/01/01  cw1  wpave F1 0.5  F2 1.0 RES OPEN wbp 4 drefwpave 6250
WELLSPEC  1987/01/01  cw1  wpave F1 0.5  F2 1.0 RES OPEN wbp 5 drefwpave 6250
WELLSPEC  1988/01/01  cw1  wpave F1 0.5  F2 1.0 RES OPEN wbp 9 drefwpave 6250
```

3.2 Rock input files

This file contains the saturation tables and capillary pressure curves for the simulation. For minimizing the effect of saturation curves in the softwares, endpoints have been entered.

```
#S A T U R A T I O N   O P T I O N   F O R   R O C K   R E G I O N S
#^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^
# Select here the saturation option for the defined rock regions. The
# first input value is taken as default value. For a missing definition
# of the ISOPT for rock regions the default value will be assigned.
#
 (1X,I5)
 (1X,I5,4I6)
#NROCK            no.of rock regions
     1
#   NR ISOPT IROPT IDOPT saturation option (ISOPT) for rock regions (NR)
     1     0     0     0
 (1X,I5,2X,E10.4)
#   NR         CFI  rock compressibility [1/psi]
     1  1.1001e-15
#
#S E G R E G A T E D   F L O W   D A T A
#^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^
# Input data for chosen SF regions for ISOPT=08,18,28. The first set of
# SF data is set as default value. For missing SF data for defined regions
# (no input in the list) the default values are assigned.
#
 (1X,I5,5(2X,E10.4))
 (6X,7(2X,E10.4))
#   NR         cfi         Swc        Sorw         Sgc        Sorg
#         krw(Sgc)    krg(Swc)   krw(Sorw)    krg(Sfr)    kro(Swc)  kro(Swc,Sgc)    Pcow(Swc)
     1  1.1001e-15      0.2410      0.2780      0.0000      0.3290
            1.0000      0.3200      0.1720      0.3200      1.0000      1.0000     56.7603

#P E R M E A B I L I T Y   F U N C T I O N S
#^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^^
# Input saturation functions for chosen ISOPT=00,01,02,03,04,10,
# 11,12,13,20,21,22,23. Input saturation functions for reference
# rock regions first. (Number of ACTUAL NROCK = REFERENCE NROCK)
# Saturation functions for rock regions can also be defined by
# giving the endpoints only and relate them to the given functions
# of a reference rock region (those rock regions are called
# related rock regions): ACTUAL NROCK > REFERENCE NROCK!
#
######################## These are only linear rel-perms. ########################
 pcowd      1     1
#         S  Function
    0.241000   5.6760349
    1.000000   0.0000000
 pcgfd      1     1
#         S  Function
    0.241000   5.6564720
    1.000000   0.0000000
 krwi       1     1
#         S  Function
    0.241000    0.000000
    0.722000    0.172000
 krgd       1     1
#         S  Function
    0.000000    0.000000
    0.430000    0.320000
 krowi      1     1
#         S  Function
    0.278000    0.000000
    0.759000    1.000000
 krogd      1     1
#         S  Function
    0.329000    0.000000
    0.759000    1.000000
```

3.3 PVT input files

This file contains the PVT functions necessary for the simulator. Gas Z factor, gas viscosity, oil FVF, oil viscosity and solution gas in oil, in the PVT tables are functions of pressure. The other data provided are constants. The PVT tables used in the HRC examples are shown here.

```
#-------------------------------------------------------------------------
 RELEASE  6.0
 inpu_f
 NPVT   1
#-------------------------------------------------------------------------
 start_PVT   1
#----------------- ------------------------------------------------------
#$PHASES 1         # --> Parameter                                    | metric |  field    | labor   |
 PINIT   2948      # --> Pressure (PINIT,PB,PRESS,ZPB,PPC)            |bar     |psia       |bar      |
 TINIT   170.1     # --> Temperature (TINIT,TEMP1,TEMP2,ZTEMP,TPC)|K       |F          |K        |
 DINIT   6250      # --> Depth                                        |m       |ft         |m        |
 RHOW   62.46      # --> Density (RHOW,RHOO,RHOG)                     |kg/m3   |lbm/ft3    |kg/m3    |
 RHOO   52.24      # --> Density (RHOW,RHOO,RHOG)                     |kg/m3   |lbm/ft3    |kg/m3    |
 RHOG   0.0711     # --> Density (RHOW,RHOO,RHOG)                     |kg/m3   |lbm/ft3    |kg/m3    |
 WOC   6250        # --> Phase contacts (WOC,GOC,WGC)                 |m       |ft         |m        |
 PB   2648         # --> Pressure (PINIT,PB,PRESS,ZPB,PPC)            |bar     |psia       |bar      |
 MUW   0.489       # --> Viscosity (MUW,MUO,MUG)                      |cp      |cp         |cp       |
 CW   2.66e-06     # --> Compressibility (CW,CO)                      |1/bar   |1/psia     |1/bar    |
 COBP 2.00143E-05  # --> oil Compressibility

 start_table   PVT_Func?
      PRESS     ZFACT       MUG        BO       MUO        RS?
       14.7       0.9     0.008       1.1       1.2     9.864?
      307.3  0.861170    0.0101     1.132   0.74569    98.931?
      599.9  0.822341    0.0122     1.164   0.70607   187.864?
      892.5  0.783511    0.0142     1.196   0.66934   276.795?
     1185.1  0.743549    0.0164     1.228    0.6355    364.18?
     1477.6  0.702168    0.0194     1.261   0.60457   441.189?
     1770.2  0.678726     0.023     1.294   0.57653   519.659?
     2062.8  0.672156    0.0269     1.328   0.55139   601.047?
     2355.4  0.676743    0.0308     1.364   0.52915   685.848?
       2648   0.69495    0.0344     1.399   0.51911   774.031?
       2898   0.71239  0.037699     1.428    0.5098   835.931?
       2948   0.71579  0.038204     1.433   0.49355   851.031?
       3148   0.72801  0.040611     1.461    0.4798   905.831?
 end_table?
#-------------------------------------------------------------------------
 end_PVT   1
```