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Enhanced gas recovery using pressure and displacement management

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ENHANCED GAS RECOVERY USING PRESSURE AND DISPLACEMENT MANAGEMENT

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TABLE OF CONTENTS

ACKNOWLEDGMENTS...ii

LIST OF TABLES...v

LIST OF FIGURES...vi

ABSTRACT...viii

1. INTRODUCTION 1

2. CONVENTIONAL RECOVERY FROM GAS RESERVOIRS............................... 3
2.1 Recovery Optimization... 3
2.2 Recovery from Volumetric Reservoirs... 4
2.3 Conventional Recovery from Water-Drive Reservoirs 6
2.4 Enhanced Recovery Techniques for Water-Drive Reservoirs...................... 7

3. WATERFLOODING GAS RESERVOIRS 9
3.1 Comparison of Water Injection in Gas Reservoirs to Oil Reservoirs............ 9
3.2 Injection Volumes and Rates 11
3.3 Timing a Waterflood Project 13
3.4 Investigation of Waterflooding with Simulation 15

4. COPRODUCTION OF GAS RESERVOIRS.. 23
4.1 Comparison to Waterflooding 23
4.2 Water Production Rates and Volumes 24
4.3 Timing a Coproduction Project... 25
4.4 Coproduction Simulation Study... 26

5. COMPUTER MODELING OF THE PDM CONCEPT.................................... 32
5.1 Material Balance Model... 32
5.3 Aquifer Model... 34
5.4 Deliverability Model... 37
5.4.1 Simplified Deliverability Model 41
5.5 Wellbore Model 42
5.5.1 The Cullender and Smith Method... 46

6. ANALYSIS OF FIELD DATA WITH THE PDM APPLICATION 49
6.1 Case Study of Reservoir “S”... 49
6.2 Case Study of Reservoir “T” 55

7. DISCUSSION... 64
7.1 Deliverability Modeling... 64
7.2 Ways to Improve Forecasting Confidence... 66
7.2.1 Acquisition of Pressure Data 67

7.2.2 Understanding and Preserving Conservative Biases.. 68
7.2.3 Alternative Wellbore Models.. 69

8. CONCLUSIONS 71

REFERENCES 73

VITA 76

LIST OF TABLES

Table 3.1 Waterflood simulation model properties……………….………......…...…16

Table 4.1 Coproduction simulation model properties……………………………....…27

LIST OF FIGURES

Figure 2.1 Standard volume of gas remaining in a reservoir..5

Figure 3.1 Injection rate necessary to maintain reservoir pressure...................................13

Figure 3.2 Waterflood simulation model diagram..16

Figure 3.3 Injection rates for waterfloods started in years 4 and 15.................................18

Figure 3.4 Volume injected for waterfloods started in years 4 and 15.............................18

Figure 3.5 Reservoir life for waterfloods started in years 4 and 15..................................19

Figure 3.6 Injection rates to obtain recovery with 19 year reservoir life...........................20

Figure 3.7 Relationship between recovery factor and volume injected for year 4............22

Figure 3.8 Relationship between recovery factor and volume injected for year 15..........22

Figure 4.1 Coproduction simulation model diagram..27

Figure 4.2 Effect of aquifer productivity on recovery...28

Figure 4.3 Comparison of water rates for coproduction begun in years 2 and 5..............29

Figure 4.4 Aquifer behavior for the base case..30

Figure 4.5 Effect of accelerated production rate on coproduction....................................31

Figure 5.1 The material balance equation as a function of pressure.................................33

Figure 5.2 Deviated wellbore diagram..44

Figure 6.1 Top of sand map for reservoir “S”..50

Figure 6.2 History match of reservoir “S”..51

Figure 6.3 Deliverability of well S-9..52

Figure 6.4 Comparison of actual and predicted cumulative production............................54

Figure 6.5 Waterflooding assessment of reservoir “S”...55

Figure 6.6 Top of sand map for reservoir “T”..56

Figure 6.7 History match of reservoir “T”..57

Figure 6.8 Deliverability for wells A-5 and A-6...59

Figure 6.9 Approximate recovery from up-dip well A-6...60

Figure 6.10 Prediction error due to liquid production..61

Figure 6.11 Coproduction assessment of reservoir “T”...62

Figure 6.12 Calculated aquifer history and forecast for reservoir “T”..............................63

Figure 7.1 Houpeurt deliverability plot for well A-5 with all production tests.................65

Figure 7.2 Houpeurt deliverability plot for well A-5 with selected production tests........66

ABSTRACT

The work contained in this thesis combines two previous enhanced gas recovery techniques; coproduction of water and gas from water-drive reservoirs and waterflooding of low pressure gas reservoirs. These two techniques allow the control of reservoir pressure and sweep efficiency through planed production or injection of water. A recovery optimization method, which is applicable to any gas reservoir, was developed using the concept of pressure and displacement management (PDM).

Two simulation studies were conducted, using Eclipse©, to investigate recovery optimization by coproduction and waterflooding. From the coproduction study it was determined that the water production rate needed to optimize recovery increases over time, and that accelerating production rate causes the optimum coproduction rate to increase even faster over time. In the case of the waterflooding study it was concluded that the injection rate necessary to obtain a given recovery factor in a given amount of time, with a limited injection volume goes up significantly over time, and that beginning water injection early in the life of a reservoir can have several advantages to performing a waterflood near abandonment.

In addition, a PDM computer model, that can be used for recovery analysis was developed for Excel. Although this application could be adapted to other programs, Excel allows for fast and effective screening of reservoirs amenable to PDM. Two field cases are analyzed in order to demonstrate the idea of recovery optimization and the versatility of the PDM application.

1. INTRODUCTION

There have been many methods investigated to increase recovery from gas reservoirs. In volumetric reservoirs, compression decreases abandonment pressure, while waterflooding slows or stops pressure decline but decreases the hydrocarbon pore volume (HCPV) at abandonment. In strong water drive reservoirs; practices including accelerating production rate and coproduction of water have been considered to lower the abandonment pressure. These previous methods focused on one particular type of reservoir. All individual techniques can increase recovery in the reservoirs for which they were intended, but are ineffectual in other types of reservoirs.

While these methods do increase recovery, none of them alone can optimize it. For example, compression minimizes the abandonment pressure, but without waterflooding it can still leave a substantial amount of low-pressure gas in the HCPV. Conversely, waterflooding decreases the abandonment HCPV, but leaves the abandonment pressure higher than with compression. Accelerated production rate and coproduction both reduce the abandonment pressure, but can’t minimize it without compression. With or without compression, in order to optimize recovery the aquifer influx should be controlled to reduce the residual gas saturation.

Previous methods fall short of optimization because they are intended to influence only one of the factors that affect recovery, and can only be used in certain types of reservoirs. The majority of gas reservoirs are neither volumetric nor strong water drive, but lie somewhere in between, and the appropriate strategy to optimize recovery and net present value (NPV) is intermediate as well. The theory of Pressure and Displacement Management hypothesizes that the only way to achieve optimum recovery is to minimize both the pressure and HCPV at abandonment, and that this concept should be applicable to any gas reservoir.

Previous studies on coproduction and waterflooding have used mostly classic material balance or reservoir simulation. Simulation is more rigorous, but is time consuming, requires a substantial amount of data and is not available to many small operators. Material balance is much faster and simpler, but does not predict gas production rates or allow direct evaluation of factors like compression, which are necessary to estimate the NPV of reserves.

The purpose of the PDM application is to bridge the gap between material balance and simulation. The application is intended as a screening tool that is fast and easy like material balance, but also predicts production rates and allows incorporation of surface constraints like reservoir simulation. The application is an integrated analytic reservoir model written in Visual Basic for Excel. It consists of reservoir, deliverability and wellbore models that allow the input of constraints like flowing tubing pressure, water injection and production capabilities and aquifer influx. The PDM application is intended as a screening tool to evaluate different production scenarios and techniques of enhancing recovery in order to achieve optimization.

2. CONVENTIONAL RECOVERY FROM GAS RESERVOIRS

2.1 Recovery Optimization

Recovery, at any point in time, can be defined as the percentage of original hydrocarbons that have been produced. Recovery from any natural gas reservoir can be expressed as [1]:

$$G_{pD} = \frac{G_p}{G} = \frac{G - G_a}{G} \qquad \text{2.1}$$

Where:

G_{pD} = Recovery factor, dimensionless

G_p = Cumulative volume of gas produced, MSCF

G = Original volume of gas in place, MSCF

G_a = Volume of gas in place at abandonment, MSCF

If we consider the moles of gas, n, instead of the volume, we can express Equation 2.1 in terms of the real gas law. Assuming reservoir temperature to be constant Equation 2.1 yields:

$$G_{pD} = 1 - \frac{P_a V_a z_i}{P_i V_i z_a} \qquad \text{2.2}$$

Where:

P_i = Initial reservoir pressure, psia

V_i = Initial hydrocarbon pore volume (HCPV), rbbl

P_a = Reservoir pressure at abandonment, psia

V_a = Hydrocarbon pore volume (HCPV) at abandonment, rbbl

Z = Real gas compressibility factor, dimensionless

Since P_i and V_i are fixed, the only way we can increase recovery is to decrease P_a or V_a.

Typically, in volumetric reservoirs, P_a is minimized while V_a remains nearly unchanged. The opposite is true of strong water drive reservoirs, which often see little decrease in pressure while nearly the entire reservoir is swept by the aquifer. In most reservoirs recovery can be increased by minimizing either the pressure or HCPV and neglecting the other factor. However, we can see from Equation 2.2 that in order to truly optimize recovery we must minimize both P_a and V_a.

2.2 Recovery from Volumetric Reservoirs

The main drive energies for volumetric or "depletion drive" reservoirs are gas expansion and formation compaction. Gas expansion is a very efficient drive mechanism. It is common for volumetric reservoirs to obtain recovery factors in the range of 80-90% [2]. Recovery under depletion drive is limited only by the pressure at which we must abandon the reservoir. Abandonment pressure is the reservoir pressure required to maintain the production rate above the economic minimum. Theoretically, if it were possible to bring the abandonment pressure down to zero we could achieve 100% recovery.

Currently the most popular way to increase recovery from volumetric reservoirs is compression. Compressors lower the flowing tubing pressure at the surface, which allows the reservoir to produce to a lower abandonment pressure. While compression does increase recovery by lowering the reservoir pressure, it does not decrease V_a. Since gas saturations can be as high as 80% in volumetric reservoirs, a substantial amount of low pressure gas can still be left at abandonment.

Assuming standard pressure and temperature to be 14.7 psia and 60 ^{o}F, the ratio of reservoir volume to standard volume for a gas can be expressed as:

$$B_g = 5.04 \frac{zT_r}{P_r} \quad \text{...} 2.3$$

Where:

B_g = Formation volume factor, rbbl/MSCF

T_r = Reservoir temperature, ^oR

P_r = Reservoir pressure, psia

Figure 2.1 illustrates the standard volume of gas remaining in a reservoir as a function of pressure for several values of HCPV. For example, at an abandonment pressure of 500 psia, a reservoir with a HCPV of 6.5 MMbbl still contains 1 BCF of gas.

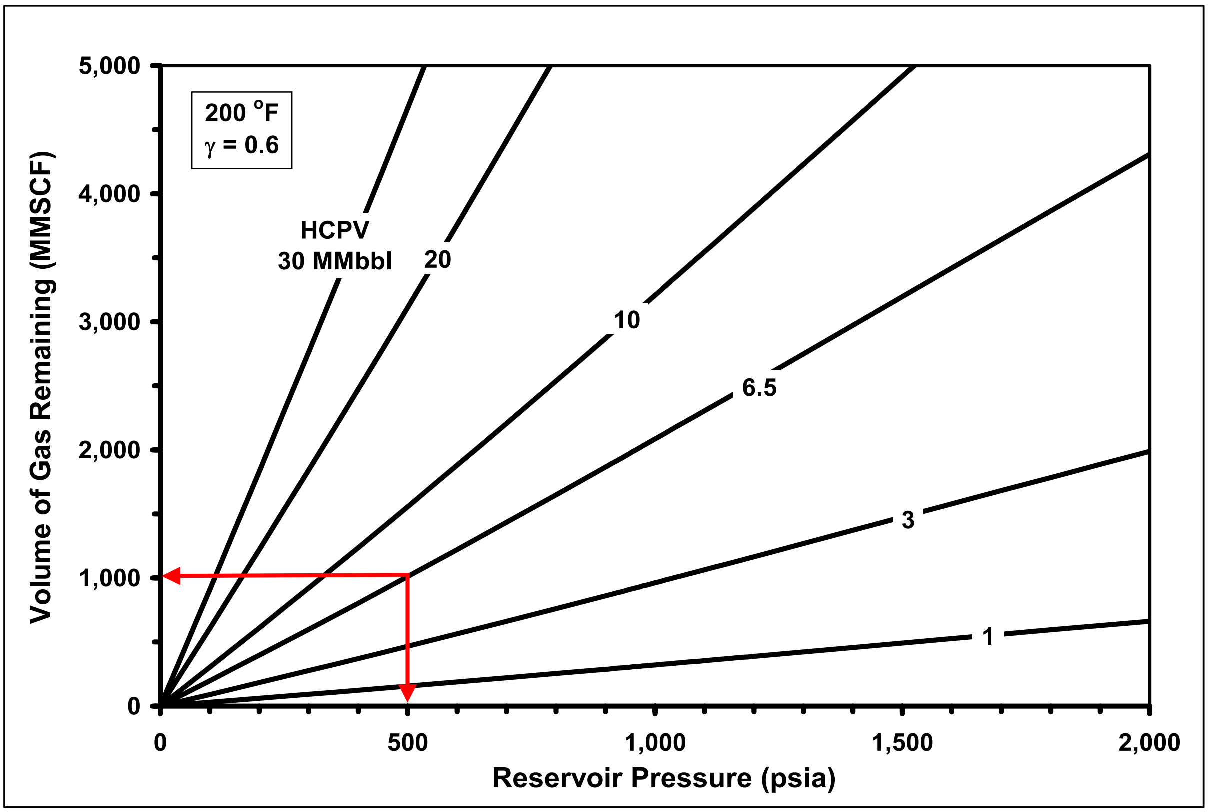

Figure 2.1 Standard volume of gas remaining in a reservoir.

There are limits to how low compression can decrease the abandonment pressure, and it cannot decrease V_a at all. In addition to these shortcomings, both the initial capital investment and operational budget for compression can be high [3]. For these reasons it is desirable to have a method that can be used as a supplement or alternative to compression for enhancing recovery in volumetric or weak water drive reservoirs.

2.3 Conventional Recovery from Water-Drive Reservoirs

The main drive energy for water drive reservoirs comes from aquifer influx. Water influx is not as efficient a drive mechanism as gas expansion. As a result, recovery from water drive reservoirs is typically much lower than depletion drive recovery. A typical range for recovery factors in water drive reservoirs is 45-70%. The most significant factors that affect recovery in water drive reservoirs are production rate and manner of production, residual gas saturation, aquifer properties and volumetric displacement efficiency [4]. Production rate is the only one of these factors that we can control outright. The rest of these factors are physical properties of the reservoir, the aquifer and their fluids.

As a reservoir is swept by an aquifer, most of the gas is displaced from the pore space but some remains as a residual saturation. An experimental study by Geffen et al. [5] indicated that residual gas saturation values could vary from 16-50%, depending on the rock type, and 25-38% for consolidated sandstone. If the aquifer is strong, the residual gas saturation can be permanently trapped at a high pressure. This means that on average about 30% of the pore space in the invaded zone contains immobile, high-pressure gas. Even though the abandoned gas saturation in water drive reservoirs is typically much lower than in depletion drives, the higher abandonment pressure usually results in lower recovery from the water drive.

2.4 Enhanced Recovery Techniques for Water-Drive Reservoirs

In the past, several studies have evaluated the different methods of enhancing recovery from water drive gas reservoirs. These main methods include accelerated production rate, recompletion of existing wells, drilling up-dip wells and coproduction of water. Each of these methods has been implemented in the field, and while analysis techniques vary, each method has been determined to be optimal in different situations. In general, the goal of the reservoir engineer is to optimize recovery while maximizing net present value (NPV).

Accelerated production or “blowdown” attempts to deplete the reservoir faster than the aquifer can respond thereby lowering the abandonment pressure. This method has increased recovery as much as 20-30% when implemented in the field [11], [13]. However, extremely high gas rates are prone to operational problems such as sales contract limits, water “fingering” and sand production. In addition to these operational concerns, once the gas rate is accelerated it cannot be curtailed without a significant loss in recovery [13].

A reservoir simulation study by Hower et al. showed that increasing production rate could cause water coning in key production wells [10]. In fact, the simulation model predicted that to increase recovery the production rate should be lowered rather than accelerated. This anomaly was attributed to improved volumetric sweep efficiency for the lower rate case. The simulation model indicated that coproducing one or two wells could increase recovery by 5-12%, while simply recompleting an existing well could yield a

9.5% increase. Recompletion in conjunction with coproduction was predicted to yield the highest recovery of all. However, recompletion without coproduction was ultimately chosen for implementation because of a higher NPV. The authors noted that the aquifer was of limited extent and that if it had been larger coproduction would have been required to achieve the optimum reservoir performance.

A simulation study by Cohen [12] determined that accelerating production rate could cause some wells to water out prematurely. However, even with this drawback the recovery could still have been increased by about 2.3% over the base case. According to the simulation model, coproduction could have faired slightly better, increasing recovery by 5.6%. Ultimately Cohen concluded that drilling one or two new up-dip wells was the most favorable scenario. He predicted that drilling one new well would increase recovery by 13.3% and that a second well would only yield an additional recovery of 3%.

Optimizing recovery in water drive gas reservoirs is not easy. There are several different options to evaluate, and each one has a different impact on recovery. Furthermore, economics is the most important design criteria, and the method that yields the best recovery may not be the most profitable. The dynamic nature of water drive reservoirs complicates the evaluation and design of enhanced recovery projects even further. If production is continuous, as time elapses the impact that a certain method has on both economics and recovery will change.

3. WATERFLOODING GAS RESERVOIRS

3.1 Comparison of Water Injection in Gas Reservoirs to Oil Reservoirs

Most engineers are familiar with using waterflooding and pressure maintenance in oil reservoirs. Waterflooding is a secondary recovery method that uses water injection to displace remaining movable oil towards production wells. Pressure maintenance is used to keep oil reservoirs above their bubble point, and is not a secondary technique. The benefits of pressure maintenance are that it sustains production rates, keeps producing gas oil ratios down and reduces the need for artificial lift. Although water injection is the underlying mechanism of waterflooding and pressure maintenance, the two practices have different purposes.

Enhanced recovery methods in gas reservoirs must be carried out before depletion, but waterflooding and pressure maintenance can still be used to increase gas recovery. In a gas reservoir, pressure maintenance and waterflooding are more difficult to distinguish. Both the pressure and volumetric sweep efficiency must be considered when designing a water injection project. Reservoir pressure must be kept high enough to deliver an economic production rate while water sweeps the portion of the reservoir that is displaceable.

The two main fluid properties that differentiate the study of gas recovery from oil recovery are mobility and compressibility. When an oil saturated pore space is swept by water, all of the mobile oil is displaced. The oil that is left behind is a residual saturation that will not flow. Gas contained in a residual saturation, on the other hand, will expand if the reservoir pressure is lowered. Conceptually, the ideal gas law tells us that if the pressure is reduced by half then the volume of the gas will double. Critical gas saturation occurs when gas expands enough to form a continuous phase. Once critical saturation is reached, gas will flow much more readily than the liquid phase. This behavior is well documented in oil reservoirs, but can also occur in a gas zone that has been swept by water. However, in water/gas systems this phenomenon transpires differently.

An experiment was conducted by Fishlock et al. [26] where two sandstone cores were waterflooded and then depressurized. The cores had permeabilities of 200 and 1500 md and residual gas saturations of 0.415 and 0.35 respectively. Measurements of Gamma-neutron reaction showed that during blowdown gas saturations had to increase by 0.04 and 0.14 over the residual values in the 200 and 1500 md cores for gas to become mobile again. In a similar experiment Firoozabadi et al. [25] observed that for the three cores used the gas saturation had to increase from the residual value of 0.3 to 0.4 in order for the gas to remobilize. The permeabilities of the cores used by Firoozabadi et al. were 1915, 1445 and 1792 md. The residual gas saturations were determined by history matching the experiments with a simulator rather than direct measurement, but seem to be in fairly close agreement with the data collected by Fishlock et al.

The reasoning for this delayed gas mobilization is that the gas permeability undergoes hysteresis during blowdown, and the relative permeability to gas after imbibition is not the same as it was during primary drainage [26]. Gas permeability was measured by Fishlock et al. at a gas saturation of 0.58 to be 0.001. However, the authors noted that despite low relative permeability, once the gas phase become mobile the fractional flow of gas increased fairly rapidly with further increase in gas saturation. They concluded that the relative permeability to water decreased as a result of gas expansion, and when both relative permeabilities are low the viscosity ratio favors gas flow.

The experiments of Fishlock et al. [26] used cores from a quarry in Scotland. They concluded that the blowdown results were rock dependant, and that the magnitude of the difference between the residual and mobilization saturations might not be typical of reservoir rocks. Their data also provided evidence that the differences between these two saturations are smaller for lower permeability rocks. Experimental data indicates that there is a difference between the residual and remobilization saturations [25], [26]. However, it is important to note that there is no field evidence to corroborate these observations [28]. Furthermore, even if gas saturation must increase 5-15% to become mobile, unless both the residual saturation and trapping pressure are low remobilization should be possible. Consequently, if residual saturation and trapping pressure are low, primary recovery will be high and remobilization might not necessary.

3.2 Injection Volumes and Rates

Water breakthrough at a gas well, especially at low reservoir pressures, could cause the well to "load up" or water out completely. If the reservoir is just above the abandonment pressure injecting water until breakthrough should not decrease the recovery. However, if the average pressure is substantially higher than the abandonment pressure injection should be curtailed before the anticipated breakthrough. It stands to reason that there is some maximum volume of water, V_{max}, which can be injected into a given well or group of wells without affecting the nearest producers.

Near abandonment, V_{max} should be about equal to the displaceable pore volume of a circular injection pattern that has a radius equal to the distance between the injector and producer. While water is being injected, the displacement should be nearly piston like because of the very favorable mobility ratio [4]. If injection is stopped, factors like gas expansion and gravity segregation can cause water to "sag" and spread laterally. This phenomenon should be taken into consideration when determining V_{max} at high reservoir pressures.

Previous studies have investigated waterflooding gas reservoirs at, or near abandonment. The main problem with waiting to begin injection near abandonment is that the compressibility of the gas is nearly as high as it can get. The minimum injection rate needed to maintain reservoir pressure is:

$$I_{\min} = q_g B_g \qquad 3.1$$

Figure 3.1 is a graph of the minimum injection rate verses reservoir pressure for several gas production rates. Even with low production rates, when reservoir pressure falls below 1000 psi the minimum injection rate begins to increase drastically. The example in Figure 3.1 illustrates how I_{min} is inversely proportional to reservoir pressure. In the example, with a production rate of 500 MSCFD reservoir pressure has fallen from 3,000 to 1,000 psia and I_{min} has tripled from 500 to 1500 BPD.

The main benefit of beginning injection before abandonment is that the reservoir pressure does not have to be strictly maintained. There is no immediate threat of falling below the abandonment pressure if the target injection rate is not met. Early in the life of the reservoir, I_{min} is the rate needed to inject V_{max} before the abandonment pressure is reached. If V_{max} is a fixed value then I_{min} increases over the life of the reservoir and reaches its maximum value at abandonment.

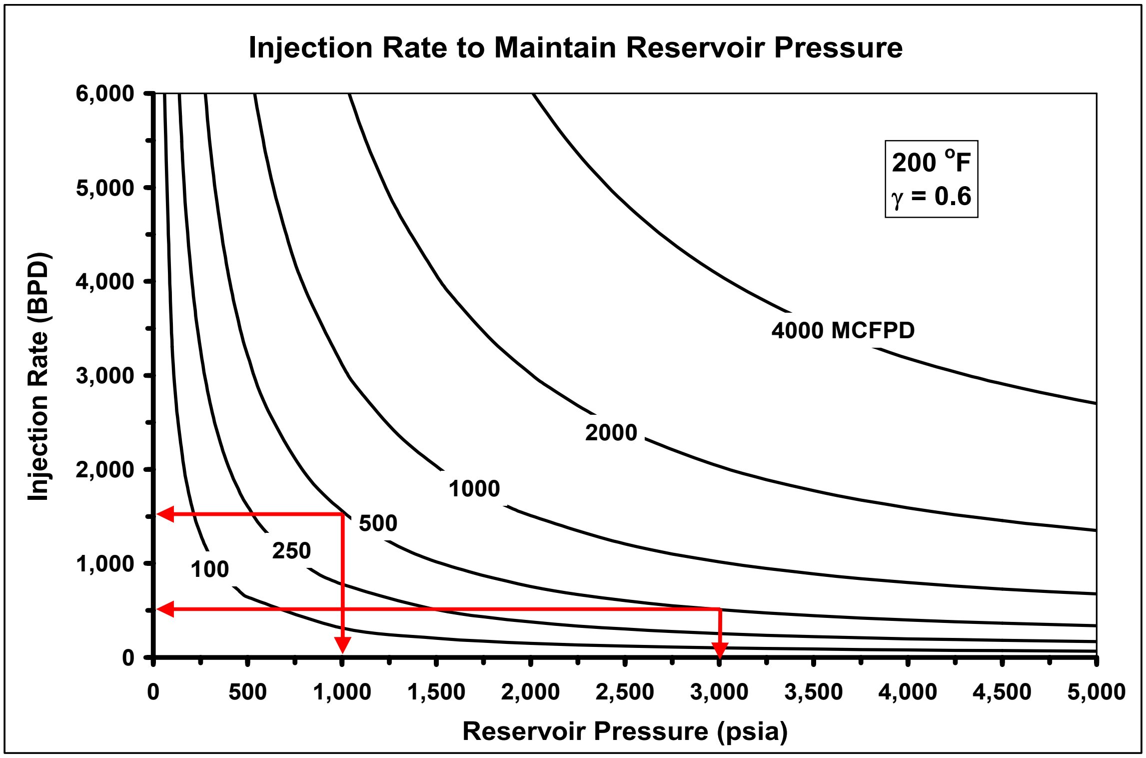

Figure 3.1 Injection rate necessary to maintain reservoir pressure.

3.3 Timing a Waterflood Project

All previous waterflooding studies and field projects have involved gas reservoirs near abandonment. One of the most well documented waterfloods of a gas reservoir took place in St. Martin Parish, Louisiana in the D-1 reservoir of the Duck Lake Field [14]. This venture was primarily an expansion to the fields existing saltwater disposal project. The original gas in place of the D-1 reservoir was estimated to be 681 BCF using a material balance. Using the initial formation volume factor, B_{gi}, given by the author V_i was calculated to be 456 MMrbbl. Over the course of 11 years a volume of water, V_w, equal to 130 MMSTB was injected into the D-1 reservoir. This corresponds to an average injection rate of 33,000 BPD, but a V_w to V_i ratio of only 29%. The author calculated with material balance that water injection was responsible for a 25 BCF increase in production. This incremental recovery is only 3.6% of G, but at $5/MSCF it represents an income of 125 million dollars over 11 years.

While waterflooding near abandonment has been proven to work in the field, high injection rates, large water volumes and long project lives can make it unattractive or impractical. Typically, one or more production wells will have to be converted to injectors to conduct a waterflood. Water injection must be started early enough so that the minimum injection rate is obtainable. Therefore, the number and injectivity of available wells can determine the latest possible starting time for a project. The end of an abandonment waterflood occurs when breakthrough has occurred at all of the production wells. If there is an economic, readily available source of water and the minimum injection rate is achieved this method is relatively low risk. Unfortunately, if the project life is long the abandonment flood will also probably be low reward.

Beginning water injection early in the life of the reservoir has several advantages over an abandonment waterflood. However, there is also much more uncertainty involved in the design. Undoubtedly many people are uncomfortable with the idea of beginning a waterflood in a young gas reservoir. However, the main goal of injection early in a reservoirs life is pressure maintenance rather than displacement. When injection is started early there are many possible production scenarios. Different options can obtain similar recovery results even though the injection rates, volumes and starting times are different.

Since the majority of gas reservoirs have compression installed at some point injection projects should be designed with this in mind. Injecting water for pressure maintenance can decrease production decline and delay compression. Both of these results can increase NPV [15]. After compression is installed, injection can be stopped altogether. This allows the trapped gas to expand as pressure declines and decreases the risk of production wells "loading up" prematurely. Once the reservoir begins to approach abandonment, injection can be resumed as a true waterflood. This strategy incorporates the advantages of both waterflooding and pressure maintenance while minimizing the associated risks.

3.4 Investigation of Waterflooding with Simulation

A reservoir simulation study was done, with Eclipse [27], to investigate the theory and practice of waterflooding gas reservoirs. A diagram and the properties of the simulation model are given in Figure 3.2 and Table 3.1 respectively. The main purpose of this study was to investigate the difference between injecting water early in the life of the reservoir and waiting until it is near abandonment. However, the effects of factors like injection rate, starting time and volume injected on ultimate recovery and production life were also examined.

The reservoir was first produced to abandonment to determine the base recovery and reservoir life. Once the base production life was established an abandonment waterflood was initiated at the last time step. Water injection was continued until the end of the simulation runs for the abandonment flood, because stopping injection caused the production well to fall below the economic limit. For the abandonment waterflood stopping injection at any time resulted in recovery not being optimized. It seems that near abandonment waterflooding a gas reservoir is much like waterflooding an oil reservoir. The drive energy is supplied by the injected water and only the gas that is displaced will be produced.

Table 3.1 Waterflood simulation model properties.		
Reservoir	**Length**	**Grid Blocks**
Radius	4000 feet	20
Thickness	50 feet	10
Theta	45^0	9
Initial Pressure	2000 psi	
Original gas in place	31.6 BCF	
Base Recovery	24.6 BCF	
Base Production Life	15 years	
Economic limit	500 MCFPD	
Depth	2800 feet	
Permeability	100 md	
Porosity	25%	
Aquifer	Fetkovich	
Encroachable water	100 MMBbl	
Productivity	0.1 BPD/psi	

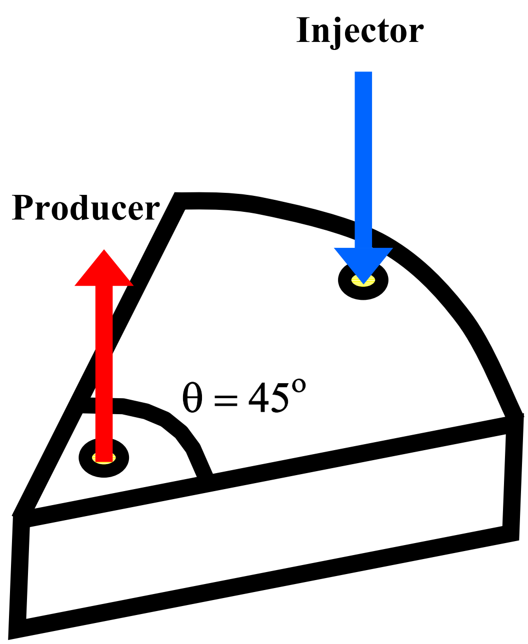

Figure 3.2 Waterflood simulation model diagram.

At every other time in the reservoir's life, the maximum recovery could only be achieved by stopping the injection before production ceased. When injecting before abandonment the swept zone was at a higher pressure than the rest of the reservoir. Essentially, the trapped gas had stored up potential energy much like a spring. When injection was stopped, this energy was slowly released in the form of expansion, which resulted in more production. Utilizing this stored energy always resulted in higher recovery and less water injected than continuing the waterflood until production ceased.

In order to examine these very different behaviors lets compare the behavior of a waterflood in the fourth year of production with the abandonment flood. Figures 3.3 through 3.5 compare the recovery factor, volume injected and production life of the two waterfloods respectively. An injection rate higher than 3,000 BPD is required to yield any additional recovery at abandonment while almost any injection rate can increase the recovery significantly in the fourth year. Having a minimum injection rate could be a serious operational problem in the field. Wells often lose injectivity over time. If this occurred near abandonment, the reservoir would have to be shut in while the affected wells were worked over or the entire project could be in jeopardy.

An injection rate of 3,500 BPD yields identical recoveries for both cases with almost the same volume of water injected. However, the abandonment flood has a production life that is 10 years longer at this rate. In addition, this injection rate is very near the minimum requirement. Injection rates higher than 5,000 BPD for the abandonment flood can achieve an additional 2% of recovery over pre-abandonment floods. Allowing gas expansion to occur before sweeping the reservoir is a much more efficient process than trapping the gas and then allowing it to expand. However, it requires an additional 10-15 MMBbl of water injection and 7-10 years of production.

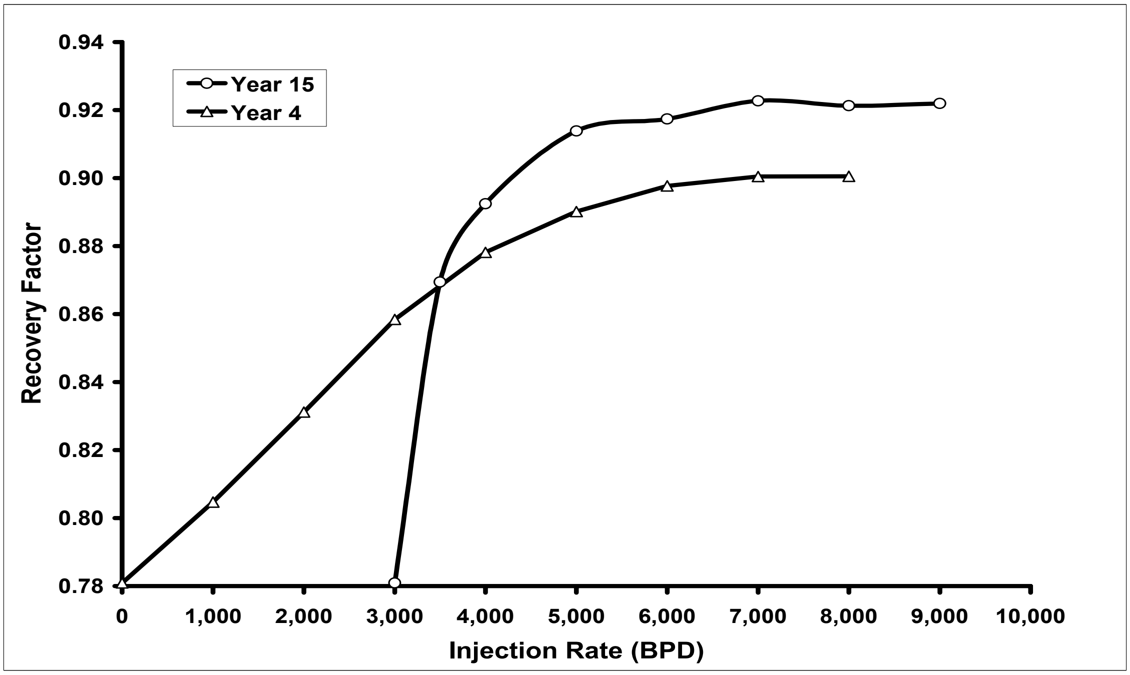

Figure 3.3 Injection rates for waterfloods started in years 4 and 15.

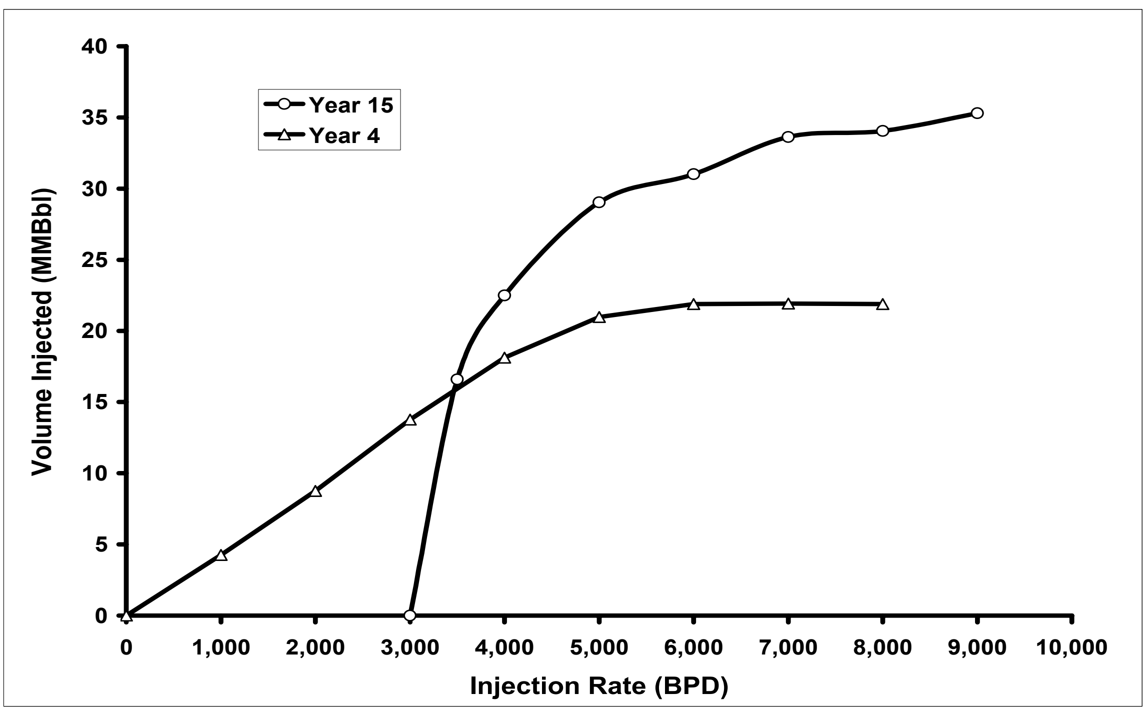

Figure 3.4 Volume injected for waterfloods started in years 4 and 15.

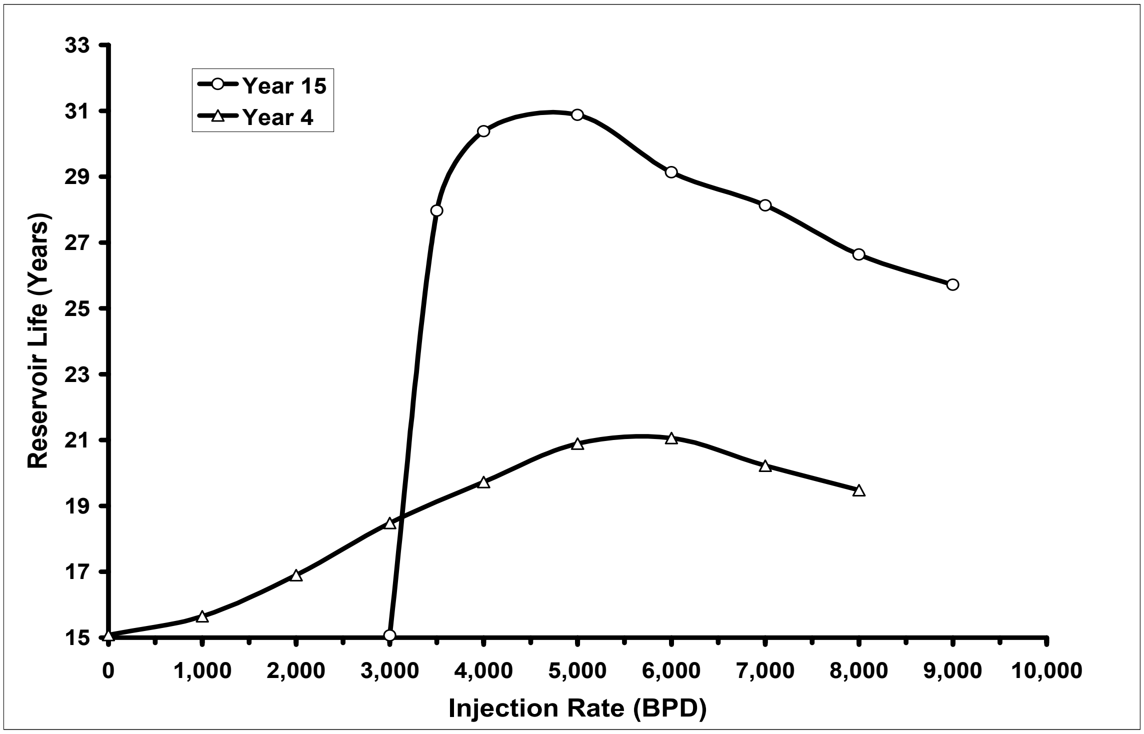

Figure 3.5 Reservoir life for waterfloods started in years 4 and 15.

The relationships between starting time, injection rate, recovery and project life are complex to say the least. There are many possible strategies, and the engineer must decide how starting time, injection rate and producing life affect the value of a project. In order to understand them better, it is useful to hold some of the values constant. A series of simulation runs started injection in different years, and 20 MMBbl was injected before year 14 for each run. The injection rate was adjusted until all of the runs ended during year 19 and the recoveries were as close to the same as could be achieved. The injection rates and recovery factors are shown in Figure 3.6. The required injection rate tripled from year 2 to year 10 while the recovery went down by 0.5% and the project life increased by half a year.

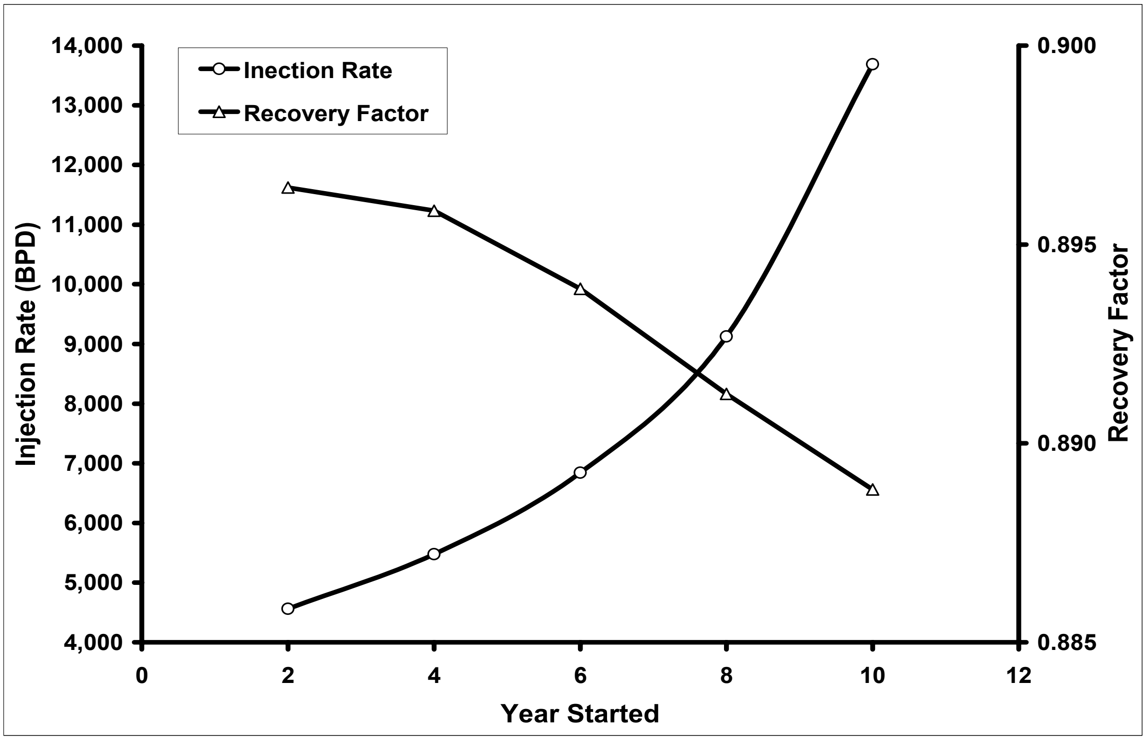

Figure 3.6 Injection rates to obtain recovery with 19 year reservoir life.

The injection rate necessary to obtain a given recovery factor in a given amount of time, with a limited injection volume goes up significantly over time. The main lesson that can be learned from this study is that waiting is harmful because time is not on our side. Unless we act in the early part of a reservoir's life a trade off will have to be made. A high injection rate will be necessary in order to ovoid having to settle for less recovery or a longer production life. If we wait until abandonment we might be able to get more recovery, but there will still be a trade off with rate, volume, project life or all three.

There was a strong linear relationship between recovery factor and the volume of water injected when the waterflood was started in year 4, shown in Figure 3.7, this behavior was typical up to year 10. Near abandonment, this relationship became quadratic in nature, shown in Figure 3.8. These two graphs seem to suggest that the amount of water injected is the factor most directly related to recovery. However, it is important to remember that before abandonment, a waterflood must have an associated "blow down" phase in order to reach this optimal recovery.

The ideal injection volume is more or less constant for most of the reservoir life. You can see in Figure 3.4 and Figure 3.7 that for the simulation model the ideal volume was about 20 MMBbl. At any point in time there is a minimum rate that will hit this injection target with enough time to "blow down" before production ceases.

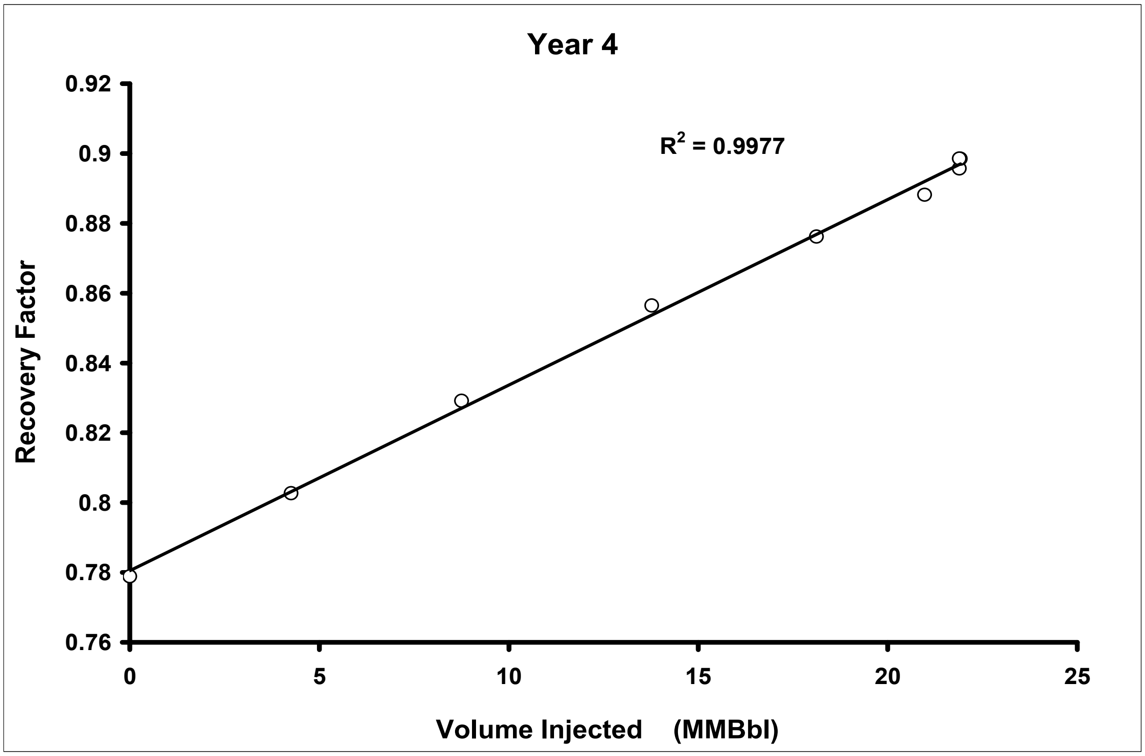

Figure 3.7 Relationship between recovery factor and volume injected for year 4.

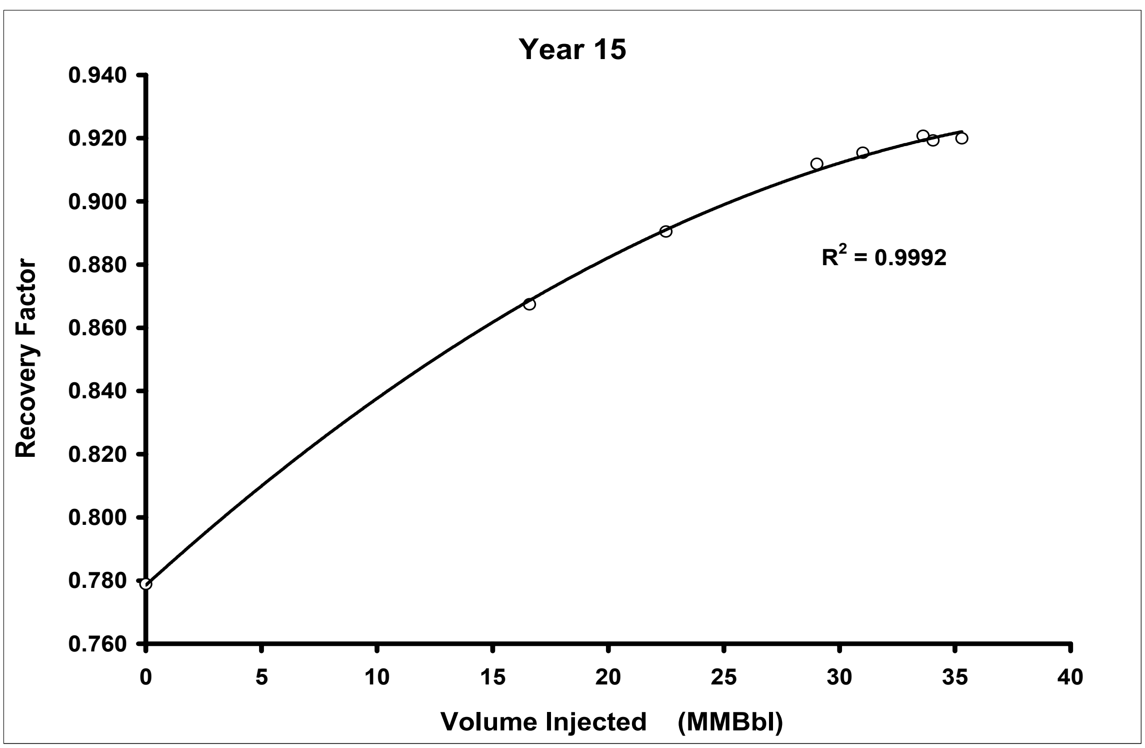

Figure 3.8 Relationship between recovery factor and volume injected for year 15.

4. COPRODUCTION OF GAS RESERVOIRS

4.1 Comparison to Waterflooding

Superficially, coproduction and waterflooding may not seem to have very much in common. However, the goal of both methods is to allow the engineer to manage the pressure of the reservoir and its displacement by water. If we think of the aquifer as an injection well, the similarity between the two techniques is easier to see. Since we cannot directly control the rate or volume of water that the aquifer "injects" into the reservoir, the only way to reduce the influx from the aquifer is to produce water. Theoretically, if the water production rate is equal to the rate of water influx then the reservoir has effectively been converted to a depletion drive. In practice, well geometry and water production capabilities may be inadequate to completely stop influx from the aquifer. However, recovery in many reservoirs can still be increased significantly by coproduction.

While decreasing the strength of an aquifer may increase the recovery in a reservoir, a substantial amount of gas can remain in the upswept region at abandonment. The easiest way to recover this gas is to displace it with water. If we are able to keep the aquifer in check enough to reach abandonment pressure, we may then waterflood the reservoir by allowing the aquifer to invade it. We still cannot control the rate or volume of influx, but if we have some idea of the aquifers properties we can determine the best time to stop coproduction. This "aquifer flood" may not be as effective as a designed waterflood where we control the injection rate, but since no additional equipment is needed and the water is free, it will be less expensive.

4.2 Water Production Rates and Volumes

If we assume that the ideal goal of coproduction is to control the aquifer influx, then to understand the water production rates required for coproduction we need a relationship for aquifer influx. The generalized rate equation for aquifer influx proposed by Fetkovich [15] is:

$$q_w = J_{aq}(P_{aq} - P_R)^m \qquad \text{4.1}$$

Where:

q_w = Aquifer flow rate, rbbl/day

J_{aq} = Aquifer productivity index, rbbl/day/psia

P_{aq} = Average aquifer pressure, psia

P_R = Pressure at the aquifer-reservoir boundary, psia

m = 1 (when Darcy's law applies)

Equation 4.1 is an idealized expression for the water production rate that is necessary to "hold back" the aquifer. The aquifer productivity is based on Darcy's law and can be derived for many different geometries and flow conditions. While the ideal coproduction rate is proportional to aquifer productivity, Equation 4.1 suggests that it is mostly a function of the difference between average aquifer pressure and the aquifer-reservoir boundary pressure. If the aquifer pressure declines slower than reservoir pressure, the rate of water influx will go up over time.

Since the highest value of aquifer pressure is the initial one, and abandonment pressure is the lowest that the boundary pressure can get, the maximum possible influx rate is:

$$q_{\max} = J_w(\mathrm{P}_i - \mathrm{P}_{ab}) \qquad \text{4.2}$$

Theoretically, if the aquifer is infinite acting so that its pressure does not decline, the value of q_{max} can be enormous. However, if the aquifer is infinite acting, unless its productivity is small coproduction might not be able to significantly increase recovery [8].

The overall volume of water that must be produced during a coproduction project is related to the aquifer properties and the production life of the reservoir. The life of the reservoir is either the time it takes to reach abandonment pressure or the time it takes the aquifer to water out all of the production wells. Typically, the maximum coproduction rate will be limited by the design and number of water producers or water processing capabilities. If the water production rate is constant, the total volume of water produced is the coproduction rate times the anticipated production life.

4.3 Timing a Coproduction Project

Ideally, coproduction should be started simultaneously with gas production. This would require intentionally drilling a "dry hole" into the aquifer, which is not a very practical option. In most cases, it would be preferred to coproduce with gas wells as they water out. If there are no gas wells near the gas/water contact, then a significant amount or water influx can occur before coproduction begins. In this situation, a water production rate higher than q_w would be desirable, and might be necessary depending on the amount of influx. This high water rate would allow us to "catch up" with the aquifer and possibly liberate some of the trapped gas from the invaded zone [7].

Time is one of the crucial factors that determine the feasibility of coproduction projects, and it always works against us. The longer we wait to begin coproduction, the higher the water rate will have to be to increase the recovery by the same amount. If we wait for gas wells to water out, then we should try to minimize the turnaround time it takes to turn a gas well into a water well. The best way to do this is to identify coproduction potential early in the life of the reservoir and design wells with coproduction in mind. Wells that are drilled nearest to the gas/water contact can be completed with larger tubing and gas lift mandrels. This not only saves time, but also eliminates the expense of working over the wells and replacing the tubing.

The rate of water production not only determines the feasibility of a coproduction project, it also determines its economic feasibility. On land, disposing of produced water can be a considerable expense. Even offshore, where disposal is free, produced water must still be processed. The volume of a processing system is fixed and having a portion of it occupied by water reduces its capacity to handle hydrocarbons. Economic analysis of a coproduction project must consider the cost of handling produced water in addition to tangible expenses like well completions.

4.4 Coproduction Simulation Study

In order to investigate the principle of coproduction a reservoir simulation study was conducted using Eclipse [27]. A diagram of the model and its properties are given in Figure 4.1 and Table 4.1. In many ways, it is identical to the model used in the waterflooding study; only the permeability and aquifer properties were changed. The three main goals of the study were to:

1. Determine how aquifer productivity affects recovery
2. Establish how project timing changes water production requirements
3. Understand what affect accelerated production rate has on coproduction

Table 4.1 Coproduction simulation model properties.		
Reservoir	**Length**	**Grid Blocks**
Radius	4000 feet	20
Thickness	50 feet	10
Theta	45^0	9
Initial Pressure	2000 psi	
Original gas in place	31.6 BCF	
Base Production Rate	5 MMCFPD	
Base Recovery	26.2 BCF	
Economic limit	500 MCFPD	
Depth	2800 feet	
Permeability	400 md	
Porosity	25%	
Aquifer	Fetkovich	
Encroachable water	1000 MMBbl	
Productivity	20 BPD/psi	

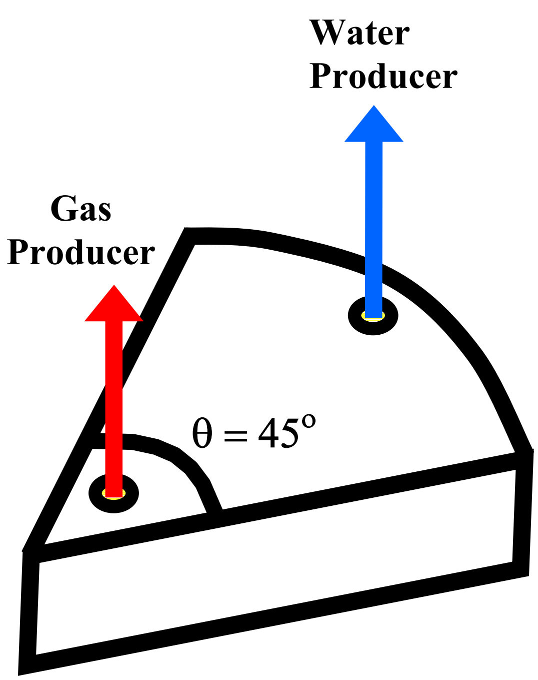

Figure 4.1 Coproduction simulation model diagram.

Initially the model was produced conventionally with just the gas well. The aquifer productivity values were varied in order to determine the effect that a large range of values had on recovery. The results can be seen in Figure 4.2. Given these results and the results from the waterflooding study, it seems reasonable to conclude that if an aquifer is just the right size or productivity we may not need to do anything special in order to get good recovery. For this simulation model it appears that waterflooding could increase the recovery when the aquifer productivity is less than 3, and coproduction can increase the recovery when the productivity is greater than 10. Based on these conclusions an aquifer productivity of 20 was chosen to conduct the coproduction study.

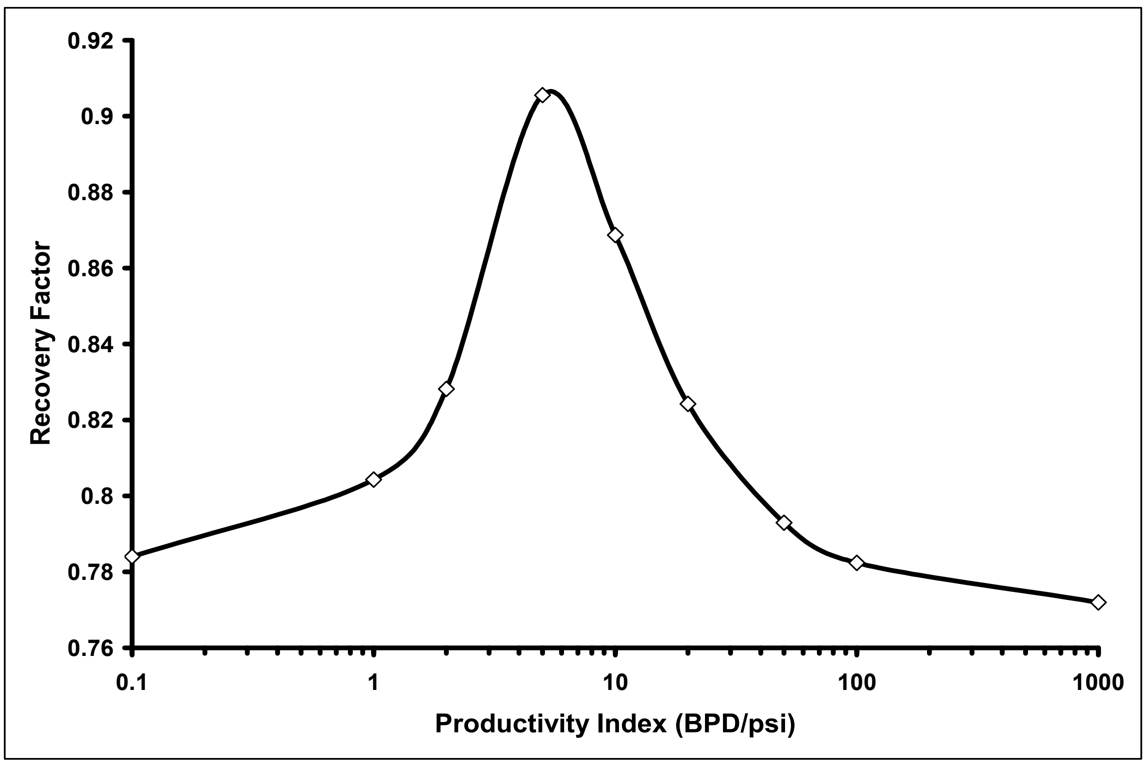

Figure 4.2 Effect of aquifer productivity on recovery

The base recovery of the model was established to be 82.7% of *G* with a gas production rate of 5 MMCFD. Coproduction was initiated at different points in time and was carried out at varying water production rates. Figure 4.3 illustrates a comparison between starting coproduction in year 2 versus year 5. The water production rate necessary to increase recovery 8% is only 4,000 BPD in year 2. By year 5 it to obtain the same incremental recovery the water production rate has doubled to 8,000 BPD. When we examine the aquifer behavior, it is not difficult to see why.

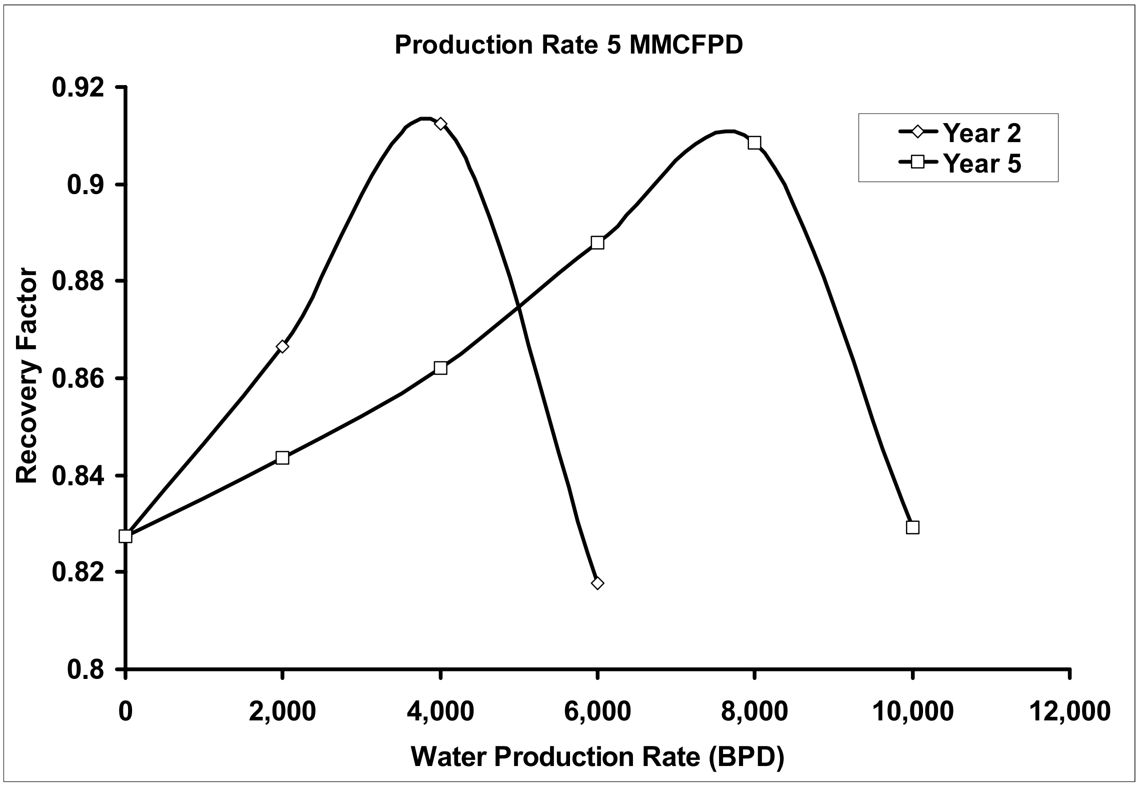

Figure 4.3 Comparison of water rates for coproduction begun in years 2 and 5.

Figure 4.4 shows the aquifer flow rate and cumulative influx. After the first year the rate of water influx is 1,700 BPD. By the end of the second year the aquifer flow rate is over 3,000 BPD. The optimum coproduction rate is higher than the aquifer rate because 1.26 MMBbl of water have already invaded the reservoir. In a sense, the aquifer has a head start and we have to "catch up" to it. As gas production decreases the reservoir pressure, the rate of water influx continues to climb. By the fifth year, 5.75 MMBbl of influx have occurred and the aquifer flow rate is 4,600 BPD. At this point, the optimum coproduction rate is nearly twice the influx rate. The good new is that the reservoir pressure begins to decline slower after year 5, which means the influx rate increases more slowly. Even though we are just one third of the way trough the life of the reservoir, recovery optimization is becoming less and less possible due to increasing water production rates.

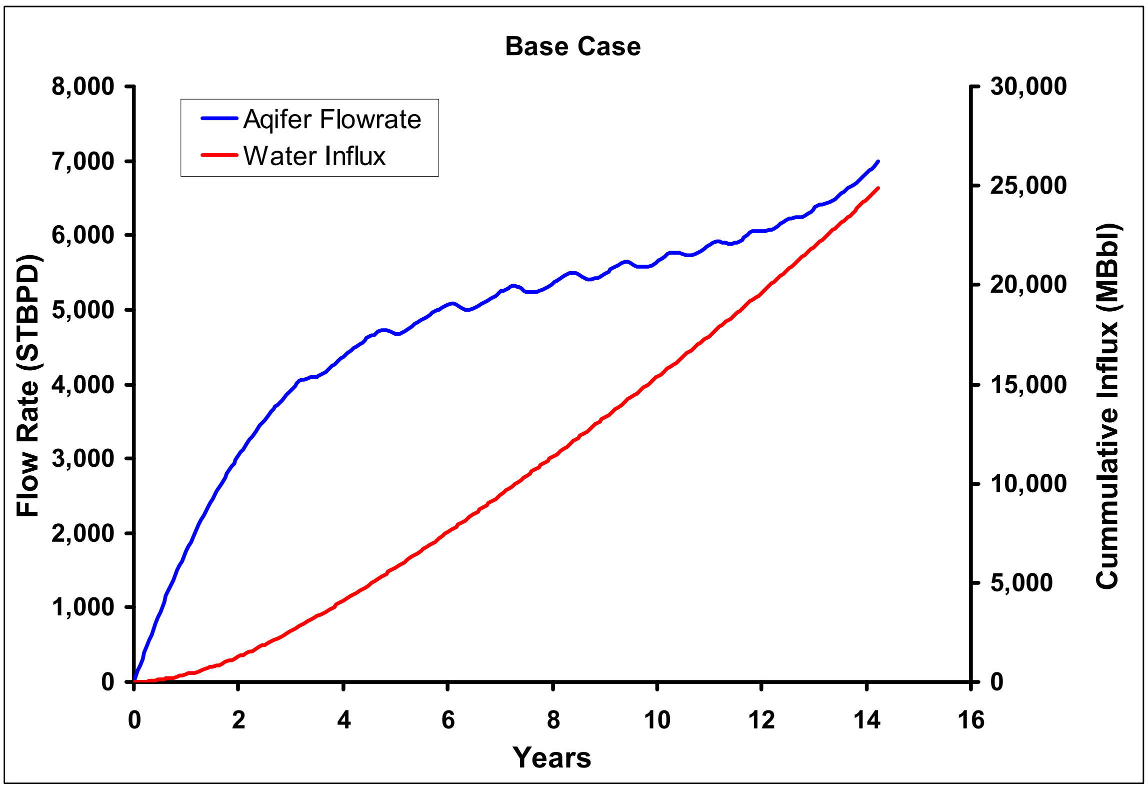

Figure 4.4 Aquifer behavior for the base case.

Accelerating gas production rate is a well-know method for increasing recovery in water drive reservoirs [11], [13]. In order to find out how higher production rates affect the coproduction technique, the gas production rate of the model was doubled to 10 MMCFPD then the previous procedure was repeated. Figure 4.5 shows the results of this exercise. As expected, increasing the gas rate yielded a better recovery than the base case.

Unfortunately, it also made it more difficult to increase the recovery further with coproduction. Essentially the higher production rate made the aquifer respond faster and harder. The increased response time is noticeable in the second year because the optimum coproduction rate is 1,000 BPD higher than the lower gas rate case. The magnitude of the aquifer influx necessitates a coproduction rate of 14,000 BPD in the fifth year! It is clear from these results, that high production rates can have a very adverse affect on efficiency of a coproduction project.

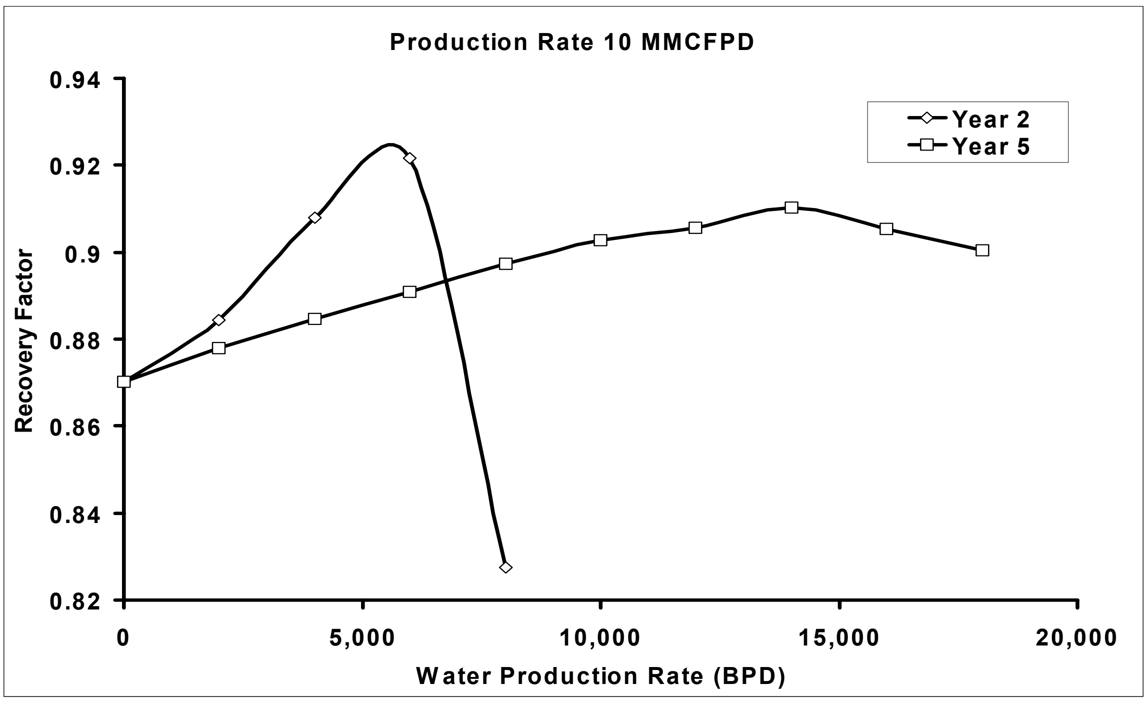

Figure 4.5 Effect of accelerated production rate on coproduction.

While it might be possible for an aquifer to be the perfect size or productivity to give us very good recovery without any extra effort, it is not very likely. Engineers should evaluate water drive reservoirs for coproduction as early in their lives as possible. This will increase the probability of coproduction being feasible and economic by minimizing the water production rates.

5. COMPUTER MODELING OF THE PDM CONCEPT

5.1 Material Balance Model

Material balance is the balance of fluid flow in and out of a control volume, which is defined by the original HCPV. The underlying assumption is that the sum of the net fluxes in gas, formation and water volumes is zero. The material balance concept is represented by the expression:

Remaining =Initial – Production + Change in HCPV…………………………..……...5.1

The general material balance equation (MBE) for a gas reservoir is:

$$G(B_g - B_{gi}) + GB_{gi}\left[\frac{c_w S_w + c_f}{1 - S_w}\right]\Delta P_{ave} + W_e = G_p B_g + B_w W_p \quad \text{.....................5.2}$$

If we let:

$$C_t = \frac{c_w S_w + c_f}{1 - S_w}$$

Equation 5.2 becomes:

$$G(B_g - B_{gi}) + GB_{gi} C_t \Delta P_{ave} + W_e = G_p B_g + B_w W_p \quad \text{.............................5.3}$$

Equation 5.3 can be rearranged as:

$$G(B_g - B_{gi}) + GB_{gi} C_t \Delta P_{ave} + W_e - G_p B_g - B_w W_p = 0 \quad \text{.........................5.4}$$

Where:

G = Original gas in place, MSCF

G_p = Cumulative production, MSCF

c_t = Total water and rock compressibility, psi^{-1}

c_w = Water compressibility, psi^{-1}

c_f = Formation compressibility, psi^{-1}

S_w = Water saturation, fraction

W_e = Water influx, reservoir barrels (rbbl)

B_g = Gas formation volume factor, rbbl/MCF

ΔP_{ave} = Change in average reservoir pressure, psia

W_p = Water production, stock tank barrels (STB)

B_w = Water formation volume factor, rbbl/STB

All terms on the left hand side (LHS) of Equation 5.4 are functions of reservoir pressure. Furthermore, at the correct value of pressure the LHS should be equal to zero. This means that for a given production history the reservoir pressure can be calculated every time step using an iterative approach. A graph of the absolute value of the LHS of Equation 5.4 is shown in Figure 5.1. The root of Equation 5.4 can usually be found within a few iterations by using the Secant method.

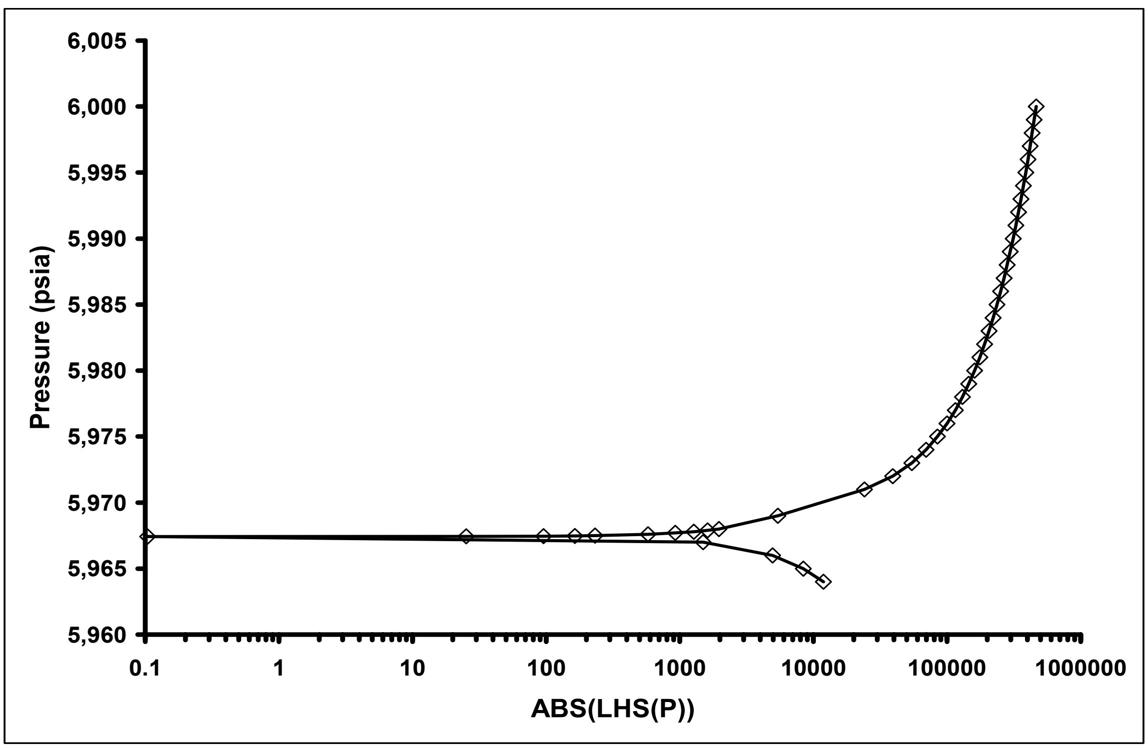

Figure 5.1 The material balance equation as a function of pressure

The average pressure for a time step is calculated using the water influx from the previous time step. The water influx and average aquifer pressure for the current time step is then be calculated using the average reservoir pressure from the previous and current time steps. Usually the MBE is used to calculate water influx at the points in time were there are measured pressure points. The advantage of solving the MBE with this iterative approach is that we can calculate the average pressure and influx for any given time step. This aids in achieving a better history match, and makes it possible to predict future behavior.

5.3 Aquifer Model

The reservoir model of the PDM application uses material balance in conjunction with a Fetkovich aquifer to calculate the average reservoir pressure and water influx. The Fetkovich aquifer model [15] approximates the Van Everdingen and Hurst unsteady-state aquifer model [16]. While the Van Everdingen and Hurst model is more accurate, the Fetkovich model was chosen for its computational speed and the fact that it can be directly used in many commercial reservoir simulators.

Fetkovich defined a generalized rate equation for an aquifer that is independent of the flow geometry:

$$q_w = J_{aq}(P_{aq} - P_R)^m \qquad \text{5.5}$$

Where:

q_w = Aquifer flow rate, rbbl/day

J_{aq} = aquifer productivity index, rbbl/day/psia

P_{aq} = Average aquifer pressure, psia

P_R = Pressure at the aquifer-reservoir boundary, psia

m = 1 (when Darcy's law applies)

Next, he derived a material balance equation for the aquifer, assuming constant water and formation compressibility. Using material balance, the average aquifer pressure can be expressed as:

$$P_{aq} = P_{ia}\left[1 - \frac{W_e + (W_p - W_i)B_w}{P_{ia}V_{aq}(c_w + c_f)}\right] \quad \text{5.6}$$

Where:

P_{ia} = Initial aquifer pressure, psia

W_e = Cumulative water influx, rbbl

W_p = Water production, STB

W_i = Water injection, STB

B_w = Water formation volume factor, rbbl/STB

V_{aq} = Aquifer pore volume, rbbl

c_w = Water compressibility, psi^{-1}

c_f = Formation compressibility, psi^{-1}

Fetkovich also defined the term "maximum encroachable water", which is the amount of water the aquifer could supply if its pressure were dropped to zero.

$$W_{ei} = P_{ia}V_{aq}(c_w + c_f) \quad \text{5.7}$$

Substituting Equation 5.7 into Equation 5.6 yields:

$$P_{aq} = P_{ia}\left[1 - \frac{W_e + (W_p - W_i)B_w}{W_{ei}}\right] \quad \text{5.8}$$

By using Equations 5.5 and 5.8, after much manipulation, Fetkovich arrived at an expression that describes the cumulative water influx from an aquifer.

$$W_e = \frac{W_{ei}}{P_{ia}}\left(P_{ia} - P_R\right)\left[1 - \exp\left(-\frac{J_{aq} P_{ia} t}{W_{ei}}\right)\right] \quad \text{……………………………………5.9}$$

Equation 5.9 assumes that both the average and boundary pressure of the aquifer are constant. In reality, both of these pressures are changing with time. In order to apply Equation 5.9 the principal of superposition would have to be used. Fetkovich showed that by calculating the water influx and associated pressures over a short time step superposition is not necessary. The following equations are used to calculate the water influx for a given time step, *n*:

$$\Delta W_{en} = \frac{W_{ei}}{P_{ia}}\left(\overline{P}_{n-1} - \overline{P}_{Rn}\right)\left[1 - \exp\left(-\frac{J_{aq} P_{ia} \Delta t_n}{W_{ei}}\right)\right] \quad \text{……………………5.10}$$

$$\overline{P}_{n-1} = P_{ia}\left[1 - \frac{W_e + (W_p - W_i)B_w}{W_{ei}}\right] \quad \text{……………………………………………………5.11}$$

$$\overline{P}_{Rn} = \frac{P_{Rn-1} + P_{Rn}}{2} \quad \text{…………………………………………………………………5.12}$$

Where:

$\overline{P}_{n-1}$ = Average aquifer pressure at the end of the previous time step, psia

$\overline{P}_{Rn}$ = Average aquifer-reservoir boundary pressure during current time step, psia

P_{Rn-1}= Average reservoir pressure from previous time step, psia

P_{Rn} = Average reservoir pressure from current time step, psia

Δt_n = time step, days

The cumulative water influx then:

$$W_e = \sum_{0}^{n} \Delta W_{en} \quad \text{...5.13}$$

5.4 Deliverability Model

The generalized diffusivity equation for the radial flow of a real gas through a homogeneous, isotropic, porous medium is:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{p}{\mu_g z}\frac{\partial p}{\partial r}\right) = \frac{\phi\mu \mathrm{c}_t}{0.0002637k_g}\frac{p}{\mu_g z}\frac{\partial p}{\partial t} \quad \text{...5.14}$$

Because viscosity and compressibility are both functions of pressure, Equation 5.14 is a non-linear partial differential equation. Al-Hussainy et al. [18] introduced a variable transform that takes care of most of the non-linearity. This transform is known as real gas pseudo-pressure, m(p). Pseudopressure is defined as:

$$m(p) = 2\int_{p_b}^{p} \frac{p}{\mu z} dp \quad \text{...5.15}$$

Where:

P_b = Arbitrary base pressure, psia

We can differentiate Equation 5.15 with respect to pressure, radius and time. The chain rule can then be applied in order to rewrite Equation 5.15 in terms of pseudo pressure as:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial m(p)}{\partial r}\right) = \frac{\phi\mu_g c_t}{0.0002637k_g}\frac{\partial m(p)}{\partial t} \quad \text{...5.16}$$

Equation 5.16 is linear with respect to m(p) but, μ_g and c_t are still dependent on pressure. However, the remaining non-linearity is usually of little consequence, and most of the time μ_g and c_t can be evaluated at their average values.

The transient flow solution of Equation 5.16 is:

$$m(P_s) - m(P_{wf}) = \frac{50{,}300 P_{sc} T q_{sc}}{T_{sc} k_g h}\left[1.151 \times \log\left(\frac{k_g t}{1{,}688 \phi \mu_g c_t r_w^2}\right) + S'\right] \text{........................} 5.17$$

The pseudosteady-state solution of Equation 5.16 is:

$$m(P_{ave}) - m(P_{wf}) = \frac{50{,}300 P_{sc} T q_{sc}}{T_{sc} k_g h}\left[1.151 \times \log\left(\frac{10.06 A}{C_A r_w^2}\right) - \frac{3}{4} + S'\right] \text{.........................} 5.18$$

Where:

q_{sc} = Flow rate, MSCFD

P_s = Static bottomhole pressure prior to the well test, psia

P_{ave} = Average reservoir pressure, psia

P_{wf} = Flowing bottomhole pressure, psia

P_{sc} = Standard pressure, psia

T = Reservoir temperature, ^oR

T_{sc} = Standard temperature, ^oR

h = Reservoir thickness, feet

t = Time, hours

r_w = Wellbore radius, feet

S' = Total Skin factor, dimensionless

A = Well drainage area, ft^2

C_A = Well drainage area shape factor, dimensionless

μ_g = Gas viscosity, cp

k_g = Relative permeability to gas, md

Both Equations 5.17 and 5.18 assume that Darcy's law applies. However, at high flow rates gas velocities can reach the threshold for turbulence near the wellbore. Forchheimer [22] observed this nonlinear behavior between flow rate and pressure drop. He attributed this behavior to inertial losses in the pore space, and observed that it seemed to be proportional to the density times the velocity squared. Forchheimer also proposed a second proportionality constant, β, to describe the rate dependant pressure drop. He then added a term onto Darcy's Law to correct for the extra pressure loss. This modified version of Darcy's law is known as the Forchheimer equation.

$$\frac{\partial p}{\partial L} = \frac{\mu_g \vec{v}}{k} + \beta \rho \vec{v}^{\,2} \quad \text{......} 5.19$$

The non-Darcy component is usually only significant near the wellbore, and is generally incorporated in fluid-flow equations as an additional skin factor that is rate dependant. The total skin factor, S', which is determined from pressure transient analysis, includes the mechanical skin damage, S, and the non-Darcy skin effects, so that:

$$S' = S + Dq \quad \text{......} 5.20$$

For an open-hole, fully penetrating completion:

$$D = \frac{2.715 \times 10^{-15} \beta k_g M P_{sc}}{h r_w T_{sc} \mu_g} \quad \text{......} 5.21$$

If we substitute Equation 5.20 into Equations 5.17 and 5.18, they become:

$$m(P_s) - m(P_{wf}) = \frac{50{,}300 P_{sc} T q_{sc}}{T_{sc} k_g h}\left[1.151 \times \log\left(\frac{k_g t}{1{,}688 \phi \mu_g c_t r_w^2}\right) + S + Dq_{sc}\right] \quad \text{......} 5.22$$

$$m(P_{ave}) - m(P_{wf}) = \frac{50{,}300 P_{sc} T q_{sc}}{T_{sc} k_g h}\left[1.151 \times \log\left(\frac{10.06 A}{C_A r_w^2}\right) - \frac{3}{4} + S + Dq_{sc}\right] \quad \text{......} 5.23$$

Equations 5.22 and 5.23 are both quadratic in terms of gas flow rate. For convenience, Houpeurt [24] wrote these equations as:

$$\Delta m(p) = m(P_s) - m(P_{wf}) = a_t q_{sc} + b q_{sc}^2 \quad \text{5.24}$$

$$\Delta m(p) = m(P_{ave}) - m(P_{wf}) = a q_{sc} + b q_{sc}^2 \quad \text{5.25}$$

Where:

$$a_t = \frac{50{,}300 P_{sc} T}{T_{sc} k_g h}\left[1.151 \times \log\left(\frac{k_g t}{1{,}688 \phi \mu_g c_t r_w^2}\right) + S\right] \quad \text{5.26}$$

$$a = \frac{50{,}300 P_{sc} T}{T_{sc} k_g h}\left[1.151 \times \log\left(\frac{10.06 A}{C_A r_w^2}\right) - \frac{3}{4} + S\right] \quad \text{5.27}$$

$$b = \frac{50{,}300 P_{sc} T}{T_{sc} k_g h} D \quad \text{5.28}$$

The values of a_t, a and b can be calculated using Equations 5.26 through 5.28. However, the necessary values are generally not known with much certainty. A more practical approach is to determine these values directly from well test data.

Most wells spend the majority of their producing life in pseudosteady-state flow. Since we are primarily interested in predicting future behavior, the deliverability model of the PDM application uses Equation 5.25. The values of a_t and b can be determined from transient flow data but at least one stabilized point is needed to determine the value of a. Dividing Equation 5.25 through by q_{sc} yields:

$$\frac{\Delta m(P)}{q_{sc}} = b q_{sc} + a \quad \text{5.29}$$

A plot of Equation 5.29 should yield a straight line with a positive slope of b and an intercept of a. An alternate approach is to graph Equation 5.25, which should generate a quadratic equation that goes through the origin. In either case a program like Excel can fit a line or polynomial to the data and determine the correlation coefficient. Once the values of *a* and *b* are determined the flow rate can be calculated with the quadratic equation.

$$q_{sc} = \frac{-a + \sqrt{a^2 + 4b\Delta m(P)}}{2b} \quad \ldots\ldots 5.30$$

5.4.1 Simplified Deliverability Model

The PDM application was designed so that it could be used with only publicly available data. Public data is often incomplete or its accuracy is questionable. Production tests are the most common source of data to determine the deliverability of a well. Generally the average reservoir pressures and flowing bottom-hole pressures have to be calculated, and things like tubing diameter or true vertical depths may not be known. This can make it difficult to describe the deliverability using the Houpeurt equation[1]. For these reasons it is often useful to express well deliverability in terms of a simplified inflow equation.

If we begin with Darcy's law in field units:

$$q_{sc} = -0.001127 \frac{k\,A}{\mu\,B_g} \frac{dp}{dL} \quad \ldots\ldots 5.4.1$$

Where:

$$B_g = \frac{p_{sc}\,T\,z}{5.615\,p\,T_{sc}} \quad \ldots\ldots 5.4.2$$

Substituting yields:

$$q_{sc} = \frac{-0.006328\,k\,T_{sc}\,A\,p}{\mu\,p_{sc}\,T\,z} \frac{dp}{dL} \quad \ldots\ldots 5.4.3$$

[1] The details of this discrepancy are discussed in Chapter 7.

Separating variables and integrating gives us:

$$\int_0^L \frac{q_{sc}}{A}\, dL = \frac{-0.006328\, k\, T_{sc}}{p_{sc}\, T} \int_{p_o}^{p_L} \frac{p}{\mu\, z}\, dp \quad \text{...} 5.4.4$$

For radial flow:

$$q_{sc} = \frac{19.88 \times 10^{-6}\ T_{sc}\, k\, h}{P_{sc}\, T\, Ln\, (r_e / r_w)} \left[m(P_e) - m(P_{wf}) \right] \quad \text{...} 5.4.5$$

Note that this is a steady state equation. For pseudo-steady state, Equation 5.18 can be rearranged in the form:

$$q_{sc} = \frac{19.88 \times 10^{-6}\ T_{sc}\, k\, h}{P_{sc}\, T \left[Ln\, (r_e / r_w) - 0.75 + S \right]} \left[m(P_e) - m(P_{wf}) \right] \quad \text{..} 5.4.6$$

Both Equation 5.4.5 and 5.4.6 can be written as:

$$q_{sc} = C \Delta m(P) \quad \text{...} 5.4.7$$

If non-Darcy flow is negligible a plot of Equation 5.4.7 should yield a straight line that goes through the origin. This simplified inflow equation typically describes well deliverability adequately when there are many potential sources of error.

5.5 Wellbore Model

The wellbore model calculates flowing bottomhole pressures based on the gas flow rate and pressure observed at the surface. As most methods used to calculate bottomhole pressures, it is based on the mechanical energy balance equation. The differential form of the steady-state mechanical energy balance equation is:

$$\frac{144}{\rho_g} dP + \frac{g}{g_c} dZ + \frac{v}{g_c} dv + dF = dw_s \quad \text{...} 5.31$$

Where:

ρ_g = Fluid density, lbm/ft^3

dP = Incremental change in pressure, psia

g = Gravitational acceleration, 32.2 ft/sec^2

g_c = Mass-to-force conversion factor, 32.17 ft-lbm/sec^2-lbf

dZ = Incremental change in elevation, ft

v = Velocity of fluid, ft/sec

dv = Incremental change in velocity, ft/sec

dF = Incremental energy loss per unit mass, ft-lbf/lbm

dW_s = Incremental shaft work per unit mass, ft-lbf/lbm

For gas flow in the wellbore, we can assume that there is no shaft work done by the system. In addition, the change in kinetic energy is generally much smaller than the other terms and is usually neglected. If we apply these assumptions Equation 5.31 becomes:

$$\frac{144}{\rho_g}dP + \frac{g}{g_c}dZ + dF = 0 \quad \text{...5.32}$$

Equation 5.32 is the generalized equation that describes liquid flow in the wellbore. Now we must express it in terms of the gas properties in which we are interested. The Moody equation for energy loss in pipes due to friction is:

$$dF = \frac{fv^2}{2g_c d'}dL \quad \text{...5.33}$$

The density of a gas can be written in terms of the real gas law as:

$$\rho_g = \frac{0.01875\gamma_g P}{Tz} \quad \text{...5.34}$$

For a real gas in a pipe of constant area, the average velocity at any point can be written:

$$v = \frac{q}{A} = \frac{1{,}000\, q_{sc} T P_{sc} z}{86{,}400\, T_{sc} P z_{sc}} \frac{4}{\pi d'^2} = \frac{4.152 \times 10^{-4}\, T z q_{sc}}{P d'^2} \quad \text{......5.35}$$

Where:

T_{sc} = 520 °R

P_{sc} = 14.65 psia

For a deviated well, shown in Figure 5.2:

$Z = L\cos(\theta)$ ……5.36

And:

$dZ = \cos(\theta)\, dL$ ……5.37

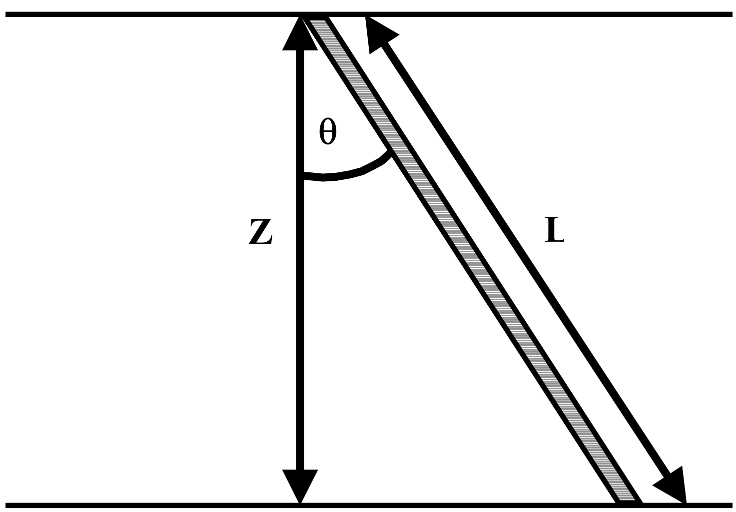

Figure 5.2 Deviated wellbore diagram.

Finally, we note that:

$$\frac{g}{g_c} = 1\frac{lbf}{lbm} \quad \text{......5.38}$$

Substituting Equations 5.33, 5.34, 5.35, 5.37 and 5.38 into Equation 5.32 yields:

$$\frac{53.33Tz}{\gamma_g}\frac{dP}{P} + \cos(\theta)dL + \frac{f}{2g_c(d/12)}\left(\frac{4.152 \times 10^{-4} Tzq_{sc}}{P(d/12)^2}\right)^2 dL = 0 \qquad 5.39$$

Equation 5.39 can be rearranged as:

$$\frac{53.33Tz}{\gamma_g}\frac{dP}{P} + \cos(\theta)dL + \frac{6.67 \times 10^{-4} f}{d^5}\left(\frac{Tz}{P}\right)^2 q_{sc}^2 dL = 0 \qquad 5.40$$

Where:

T = Temperature, °R

z = Real gas compressibility factor

γ_g = Gas specific gravity, dimensionless

P = Pressure, psia

θ = Deviation angle measured from vertical, degrees

L = Measured depth (MD), feet

f = Moody friction factor, dimensionless

d = Pipe diameter, inches

q_{sc} = Gas flow rate, MSCFD

Equation 5.40 is the basis for all methods that predict bottomhole pressure based on surface measurements in gas wells. It can be integrated using a variety of techniques, but the Cullender and Smith (C&S) method remains one of the most accurate. One reason for this is it makes no simplifying assumptions about temperature or "*z* factor" in the wellbore. It also achieves greater accuracy by allowing the calculations to be done over as many wellbore elements as desired. The C&S method was developed for "dry gas" applications. It does not account for the gravitational or frictional pressure losses due to water and condensate in the wellbore. While there is a method available to correct the C&S calculations for water and condensate production, the decrease in error is only 3.4% [20]. For this application, the added accuracy was not deemed worth the increase in calculation time necessary to achieve it. For this reason the wellbore model of the PDM application uses the classic "dry gas" version of the C&S method.

5.5.1 The Cullender and Smith Method

Starting with Equation 5.40 and separating variables yields:

$$\frac{\frac{\mathrm{T}\, z}{P}}{\cos\theta + \frac{6.67\times 10^{-4}\ \mathrm{f}\ q_{sc}^{2}}{d^{5}}\left(\frac{\mathrm{T}\, z}{P}\right)^{2}}\, dP = -\frac{\gamma_g}{53.33}\, dL \quad \ldots\ldots 5.41$$

Dividing the numerator and denominator on the LHS of Equation 5.41 by $\left(\frac{\mathrm{T}\, z}{P}\right)^{2}$, then rearranging and integrating both sides gives us:

$$\int_{P_{\mathrm{tf}}}^{P_{\mathrm{wf}}} \frac{\frac{P}{\mathrm{T}\, z}}{\left(\frac{P}{\mathrm{T}\, z}\right)^{2}\cos\theta + \frac{6.67\times 10^{-4}\ \mathrm{f}\ q_{sc}^{2}}{d^{5}}}\, dP = \int_{0}^{L} \frac{\gamma_g}{53.33}\, dL \quad \ldots\ldots 5.42$$

Where:

P_{wf} = Flowing bottomhole pressure, psia

P_{tf} = Flowing tubing head pressure, psia

By reversing the limits of integration, we were able to get rid of the negative sign on the RHS of Equation 5.41 and can easily evaluate the integral:

$$\int_{0}^{L} \frac{\gamma_g}{53.33} dL = 0.01875\gamma_g L \qquad \text{5.43}$$

The RHS of Equation 5.43 is a constant, we'll call this value α so that:

$$\alpha = 0.01875\gamma_g L \qquad \text{5.44}$$

Unfortunately, the LHS of Equation 5.42 contains both pressure and temperature dependant variables, which makes the exact evaluation of the integral difficult. C&S integrated the LHS of Equation 5.43 numerically using the trapezoidal rule, such that:

$$\int_{P_{tf}}^{P_{wf}} \frac{\frac{P}{Tz}}{\left(\frac{P}{Tz}\right)^2 \cos\theta + \frac{6.67\times 10^{-4} fq_{sc}^2}{d^5}} dP \approx \frac{\left(I_{mp} + I_{tf}\right)\left(P_{mp} - P_{tf}\right)}{2} + \frac{\left(I_{wf} + I_{mp}\right)\left(P_{wf} - P_{mp}\right)}{2} \qquad \text{5.45}$$

The subscripts *tf*, *mp* and *wf* indicate tubing flowing, midpoint and well flowing respectively. *I* is the integrand defined by:

$$I = \frac{\left(\frac{P}{Tz}\right)}{\left(\frac{P}{Tz}\right)^2 \cos\theta + \Omega} \qquad \text{5.46}$$

The friction term Ω is defined by:

$$\Omega = \frac{6.67\times 10^{-4} fq_{sc}^2}{d^5} \qquad \text{5.47}$$

The Wellbore Model Calculation Procedure

1. Compute α

2. Compute Ω

    a. Compute μ_g at P_{tf} and T_{tf}

    b. Compute Reynolds number

    c. Compute the Moody friction factor

3. Compute I_{tf}

4. Assume $I_{mp} = I_{tf}$

5. Compute $P_{mp} = P_{tf} + \dfrac{\alpha}{I_{mp} + I_{tf}}$

    a. Compute I_{mp}

    b. Iterate Step 5 until P_{mp} converges.

6. Assume $I_{wf} = I_{mp}$

7. Compute $P_{wf} = P_{mp} + \dfrac{\alpha}{I_{wf} + I_{mp}}$

    a. Compute I_{wf}

    b. Iterate Step 7 until P_{wf} converges.

8. Use Simpson's rule to refine the answer $P_{wf} = P_{tf} + \dfrac{6\alpha}{I_{tf} + 4I_{mp} + I_{wf}}$

9. Let $P_{wf} = P_{tf}$ for the next element and return to Step 1.

6. ANALYSIS OF FIELD DATA WITH THE PDM APPLICATION

6.1 Case Study of Reservoir "S"

Reservoir "S" is a gas formation located in the High Island area of offshore Texas. The reservoir, shown in Figure 6.1, is an anticline structure with one major fault that runs north and south. The original gas water contact was at –2920 feet and is shown on the figure with a dotted line. The two wells were both completed in June 1983, but early production was very sporadic. The S-9 only produced one day for the first six months and the two wells combined produced at less than 2 MMCFD until May 1985, even though each well was capable of producing about 25 MMCFD. The reason for this is not known, but presumably there were mechanical or contract problems. Judging from the available production tests compression was installed sometime between May and November 1988. Apparently there was a fair amount of aquifer influx, and the down dip well, S-6, watered out in March 1991. The S-9 well was still producing as of March 2004, but appears to have been near abandonment. The reported cumulative production at that time was 32.64 BCF of gas, 1.16 MMSTB of water and 2 MBbl of condensate.

The S-6 was abandoned after it watered out, and it is unknown whether or not the operator considered any other options. However, it is decision points like this that offer the greatest potential for optimizing recovery in a gas reservoir. The S-6 might have been useful as a water producer or injector if it could increase the recovery of the S-9. The cost of recompleting the S-6 or installing surface equipment would have been offset by not having to plug and abandonment it. The purpose of this study is to demonstrate the use of the PDM application by evaluating the recovery optimization of reservoir "S" at the time the S-6 well watered out.

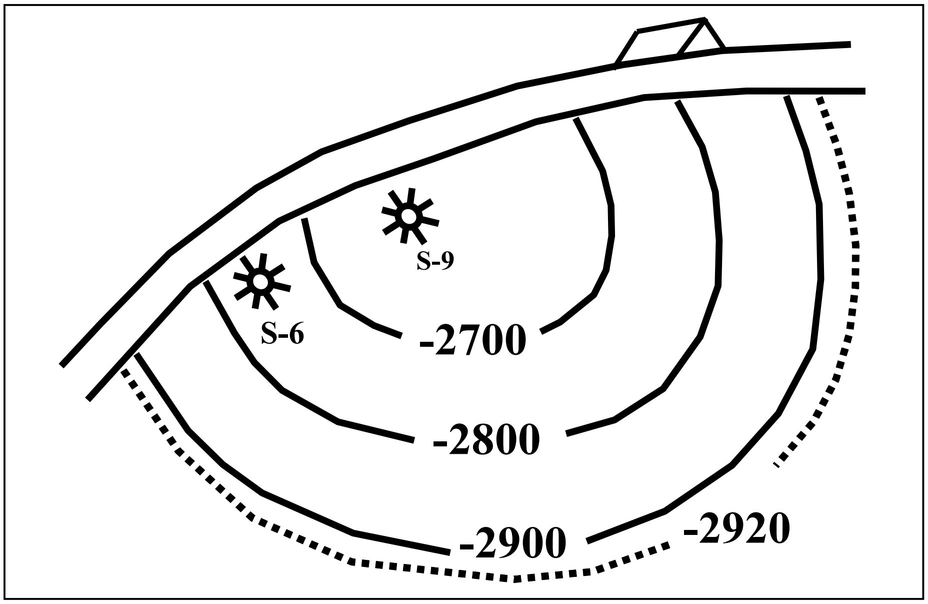

Figure 6.1 Top of sand map for reservoir “S”

The history match of reservoir “S” is shown in Figure 6.2. There are only five measured pressure values to compare to the calculated history due to the unusually low production prior to year 2. In addition, the low production rates did not induce much of a response from the aquifer until year 5. These two factors that make it difficult to obtain a good history match with material balance. To decrease the amount of uncertainty in the model, and reduce the risk of getting a non-unique solution, estimates of the aquifer productivity were calculated, using the finite, constant boundary pressure, radial flow equation given by Fetkovich [16]. Assuming an aquifer permeability of 1 Darcy and r_e/r_w values of 2 and 4, the aquifer productivity was estimated to be between 100-200 BPD/psi. By narrowing the range of possible productivity values, we reduce the number of parameters for the history match, which makes it easier obtain one and yields higher confidence in the results.

In order to begin forecasting production we need to determine the values that the PDM application uses in its calculations. The deliverability of well S-9 was determined using the simplified steady state model, discussed in Chapter 5; the results are shown in Figure 6.3. Ordinarily the suction pressure of the compressor would be known, but in this case its not. The data available says that the flowing tubing pressure of S-9 went up and down over the production life and that it was 150 psi in 2002 and 2003, which raises concerns about the accurate modeling of that well constraint. The average value of the available data was about 500 psi, and that seems like a reasonable assumption, so 500 psi was the tubing pressure used to forecast with.

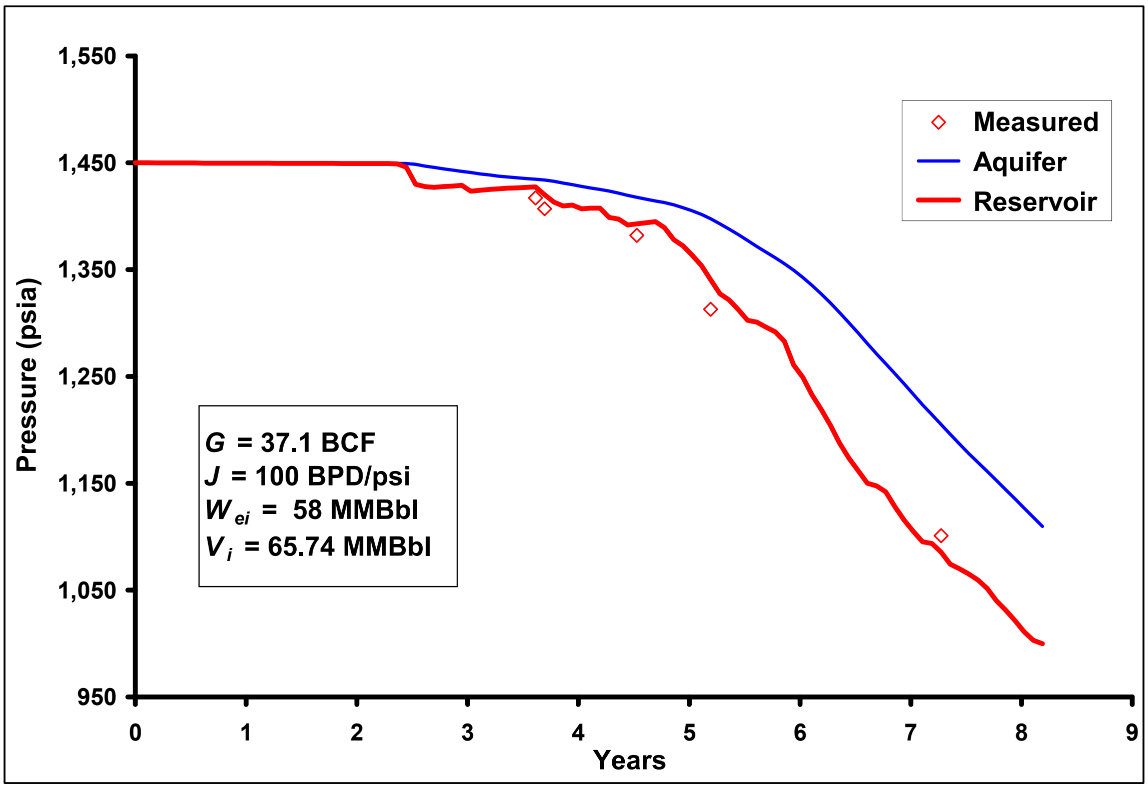

Figure 6.2 History match of reservoir “S”.

In addition to values for calculations the PDM application has several parameters that can be used to control wells. The tubing pressure we will use, 500 psi, is really lower than the actual one at the beginning of the forecast. If we specify a maximum gas rate the program will control production with this rate until the average reservoir pressure is too low to deliver it. At that point the gas rate will decline with the reservoir pressure. We must also specify two values to let the program know when to shut the well in. One of these is the economic limit; the other is the maximum net water influx, W_{emax} that can occur before the S-9 waters out. The maximum net water influx is the cumulative influx from the aquifer plus the water injected or minus the water produced.

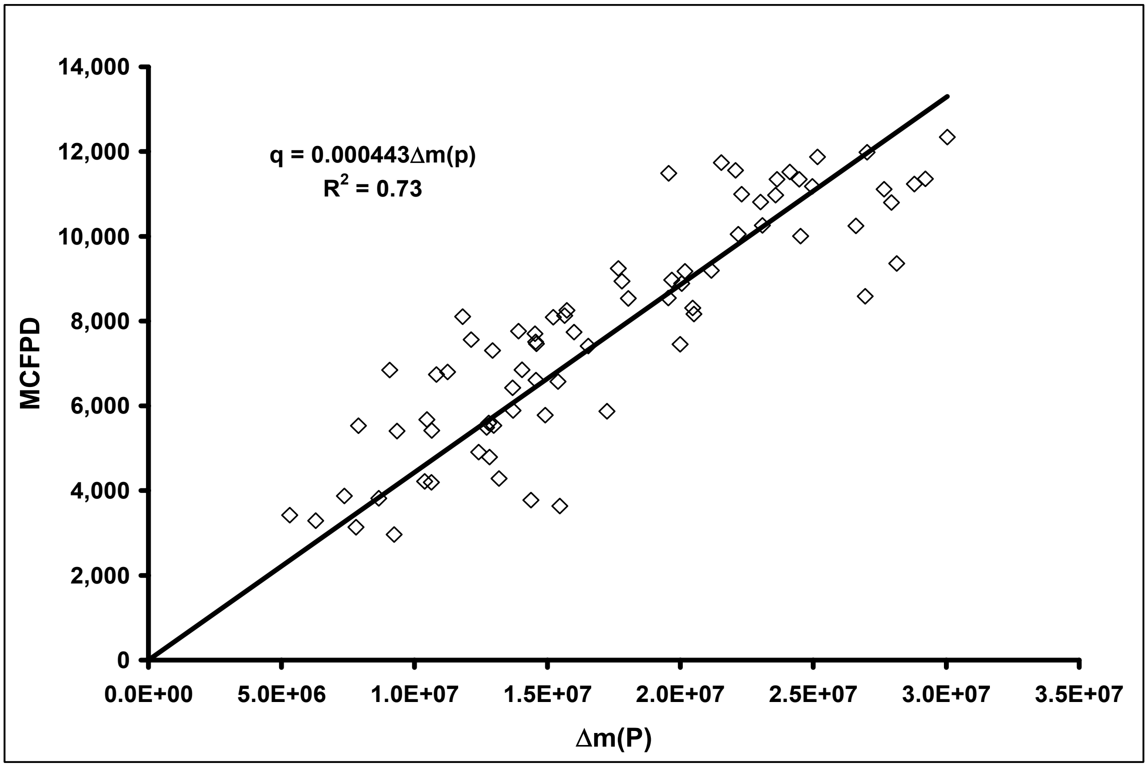

Figure 6.3 Deliverability of well S-9.

The flow rate of the S-9 was about 10 MMCFPD the month after the S-6 watered out, and it declined more or less smoothly afterwards so that will be the maximum gas rate for the forecast. We will assume an economic limit of 500 MCFPD, which is a typical value. The maximum water influx is not as easy to determine. According the history match, the S-6 watered out after 13.6 MMBbl of water influx. Since we only have a top of sand map and we don’t know the porosity or saturations accurately calculating

W_{emax} would be difficult. From a history match on the entire life of reservoir "S" it was determined that at the last reported production point the cumulative aquifer influx was 39.5 MMBbl. This is about 42% of our history matched V_i and since the S-9 is located near the top of structure this seams like a reasonable enough estimate for W_{emax}.

The analysis is begun by predicting a base case, in order to determine what kind of recovery we can expect to get if the S-6 is abandoned and the S-9 continues to be produced on compression. The PDM application predicts that 32.45 BCF of gas would be recovered by January 2001. In real life 32.64 BCF was recovered in March 2004, however the real S-9 was shut in for 30 months between 1991 and 2004. The comparison between predicted and actual production is illustrated in Figure 6.4. One of the reasons for the difference between the initial slopes of the two curves is that we did not have an accurate tubing pressure trend. The PDM application is a constant tubing pressure model. Since we didn't know the suction pressure of the compressor, or have any extra constraints, it is quite likely that the tubing pressure was underestimated. Even so, the main purpose of the PDM application is to calculate recovery. If in fact the ultimate recovery is 32.64 BCF, it means despite having sparse and arguably poor quality data available, the PDM application predicted the base recovery of reservoir "S" to within 0.6% of the actual value.

We now have an estimation of what the base recovery from reservoir "S" will be, but a decision about what to do with well S-6 still needs to be made. Since S-6 watered out it may seem like producing water would be beneficial. However, according to the history match the reservoir has a HCPV of 65.74 MMBbl while the aquifer only has 57.98 MMBbl of encroachable water. It is not clear whether we should inject water or produce water, but one of the advantages of the PDM application is that it allows different scenarios to be investigated with no additional work.

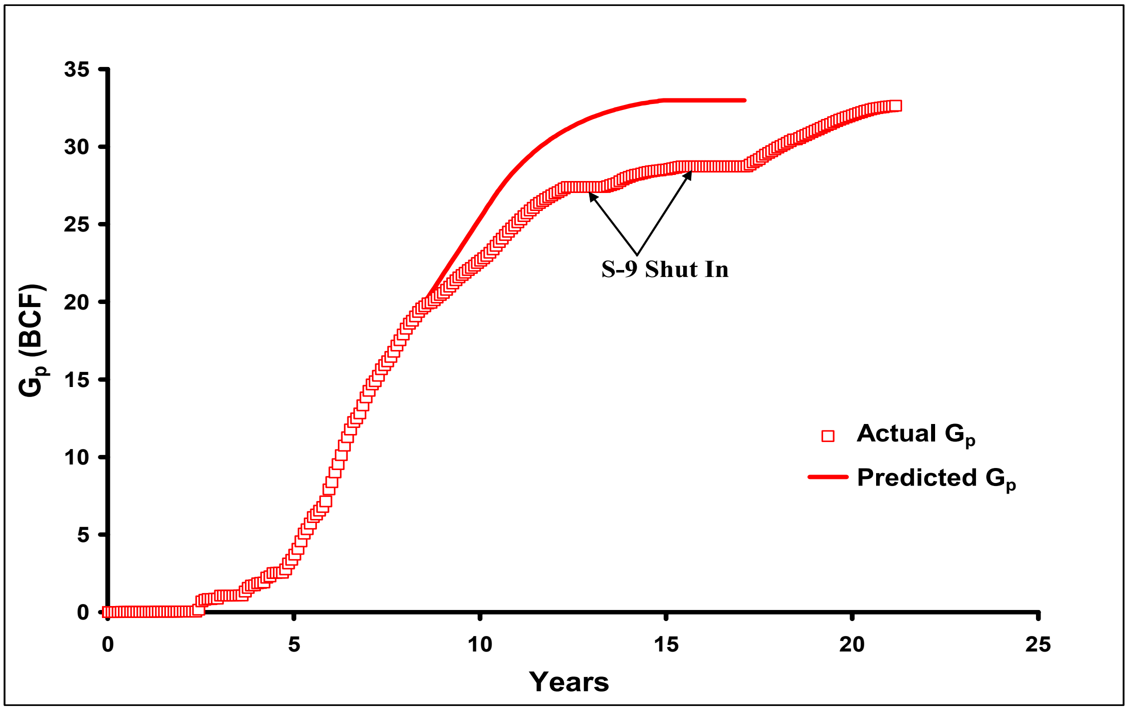

Figure 6.4 Comparison of actual and predicted cumulative production.

Using the values and constraints that it was given, the PDM application determined that S-9 should reach its economic limit before being watered out. This means that in order to increase the recovery we should inject water. In reality the geometry of the reservoir is not very conducive to water injection because S-6 and S-9 are a little closer together than we would like them to be, but the PDM application uses a lumped model that does not know this, so for demonstration purposes we will pretend that the geometry is favorable. Figure 6.5 illustrates the water injection rates necessary to optimize recovery and the resulting production life of the reservoir.

According to the analysis if we inject 2.1 MMSTB at 1,000 BPD we could increase recovery by about 1.5% or 560 MMSCF. This corresponds to 0.267 MSCF per barrel of water injected. At a gas price of $5/MSCF that translates to an income of $1.34 per barrel injected. Since the reservoir is offshore it seems unlikely that this water injection project would be feasible. However, if the reservoir were on shore, it might be possible to increase the profit margin by saving money on water disposal, or perhaps even charging other companies to dispose of their water. The base forecast predicted a recovery of 88% so regardless of where the reservoir is located there is just not very much optimization that can be done in this case. The only recommendation that seems appropriate is to plug and abandon the S-6 well.

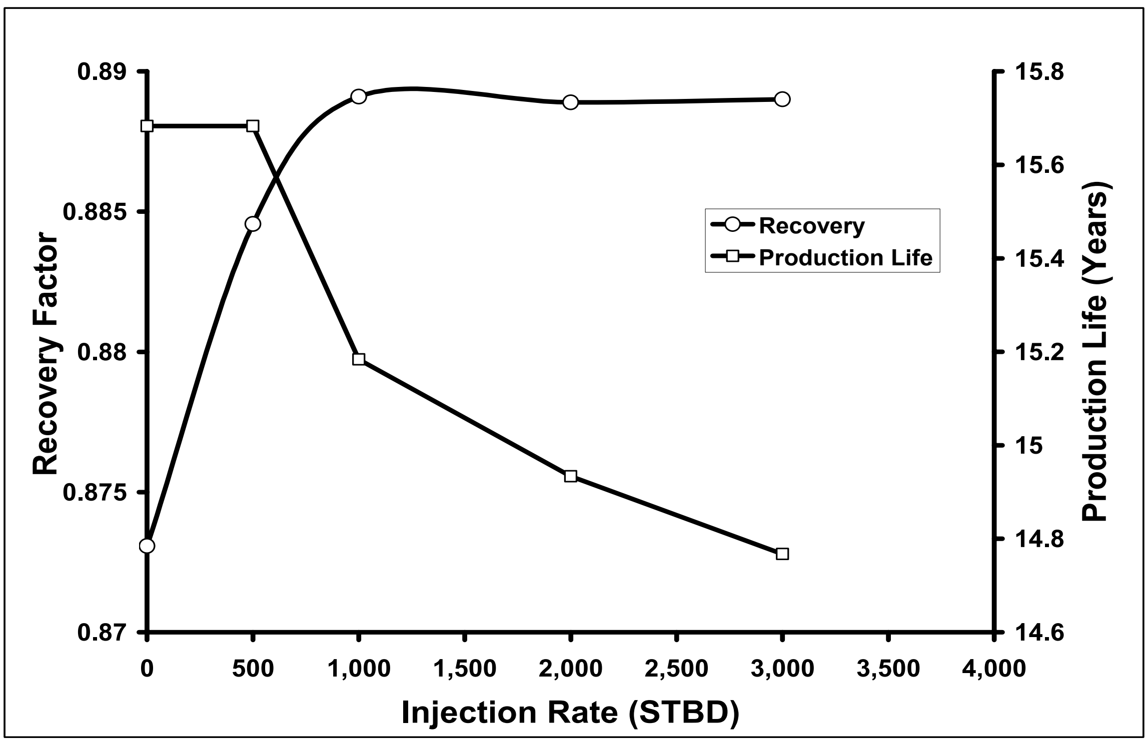

Figure 6.5 Waterflooding assessment of reservoir "S".

6.2 Case Study of Reservoir "T"

Reservoir "T" is located in the same field, offshore Texas, as reservoir "S". The reservoir, shown in Figure 6.6, is a structural trap that lies between a fault and a discontinuity. The original gas water contact was at –5634 feet and is shown in the figure by a dotted line. The A-5 well was completed in June of 1985, and produced 8.51 BCF before it was watered out in April 1988. The History match of reservoir "T" is shown in Figure 6.7. Like reservoir "S", reservoir "T" has only a few pressure points to compare the calculated values with. However, because of the large aquifer response it was much easier to obtain a history match and to have confidence in the results. This is another situation where the operator must have been surprised by water influx. There was rapid pressure loss during the first year and half of production, but the aquifer came in very strongly after that. It only took about four months for the well to water out once it started making water.

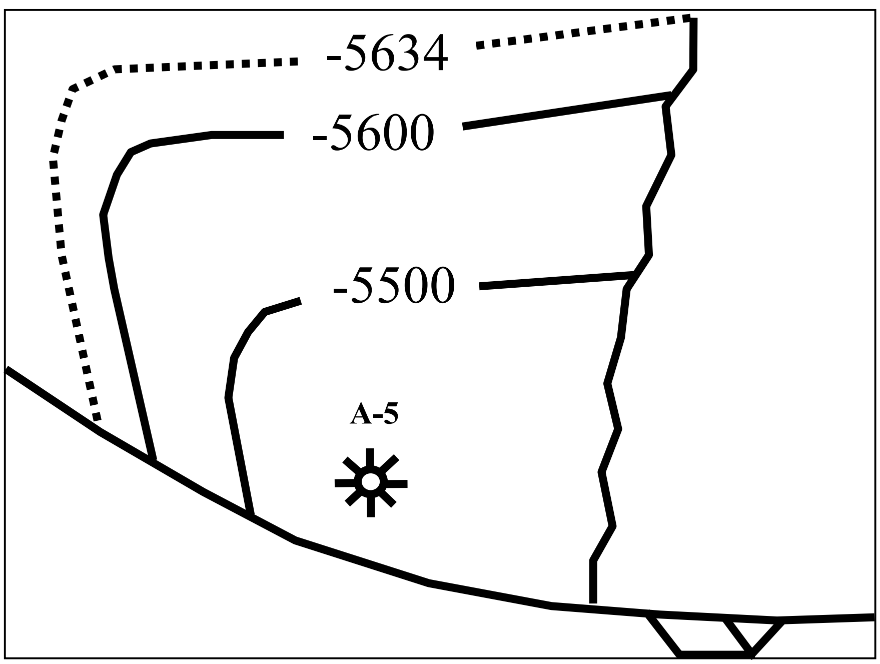

Figure 6.6 Top of sand map for reservoir "T".

It seems like the operator has only two real choices: abandon the reservoir or try and drill a well up dip of A-5. If we assume that 90% of G is recoverable, less the 8.5 BCF already recovered, there could be up to 2.9 BCF remaining. This is a generous assessment, but if the best possible scenario is not worth drilling a well, the operator should abandon the reservoir. According to the history match, the reservoir has a V_i of about 11.68 MMBbl, and A-5 watered out after about 6.4 MMBbl of influx. Approximately 10 to 15% of the HCPV is above the A-5 structurally so it should take about 1.17 to 1.75 MMBbl of more influx to water out a new well. It seems that if we go to the expense of drilling a new well, and we have another well available, it might be advantageous to coproduce. According to Halford [8], if a reservoir has a water drive index, I_w, greater than 90% coproduction will not be effective.

$$I_w = \frac{W_e - W_p}{G_p B_g} \quad \text{...6.1}$$

The I_w of this reservoir was calculated to be 70%, so we will at least investigate coproduction.

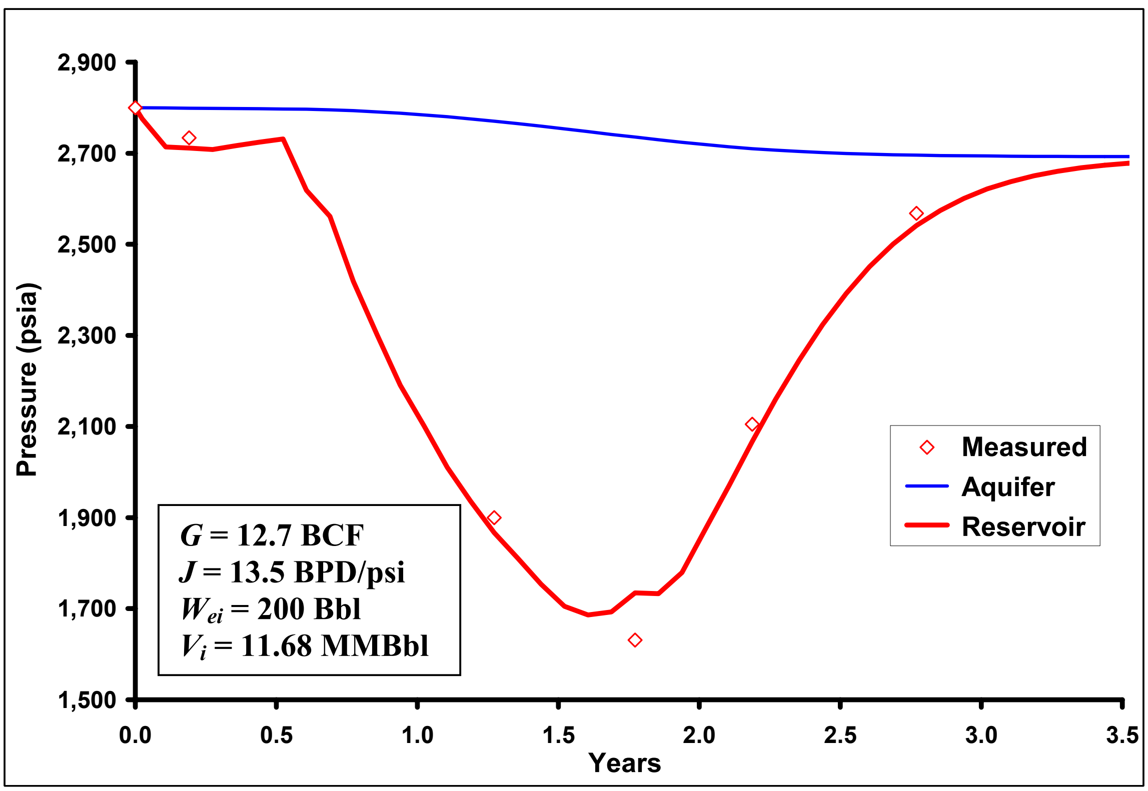

Figure 6.7 History match of reservoir "T".

To begin the analysis we must set up the program like we did for reservoir "S". In order to evaluate the possibility of drilling an up-dip well with the PDM application, we need a deliverability model. Well A-5 should be fairly analogous since the two wells would be completed in the same reservoir, just a few thousand feet from each other. The deliverability relationship for A-5 is shown in Figure 6.8. Notice that the data is much "noisier" than the data for the S-9 well. The spread is due to both liquids production and the fact that reservoir pressures were calculated over a much wider range, and both calculations went into determining the deliverability. There was no compression installed on the A-5 and the flowing tubing pressure was somewhere in the neighborhood of 1150 psi. I decided on an economic limit of 1 MMCFD because 500 MCFD did not seem conservative enough. The maximum flow rate was chosen as 20 MMCFD even though A-5 would probably be able to make more than that. Once again however the main concern is to accurately determine W_{emax}. For this study we will use low and high estimates of 7.53 and 8.14 MMBbl for W_{emax} so we can determine how sensitive the project is to it.

Figure 6.9 illustrates how much production could be obtained from an up dip well, as a function of W_{emax}. It indicates that the production from A-6 for our low and high estimates of W_{emax} are 1.77 BCF and 2.21 BCF, and that if W_{emax} is really only 1 MMBbl we could still get 1.58 BCF of production. Granted, we are making some pretty big assumptions here about water influx and production. One of the assumptions is that the well A-6 will make 20 MMCFD. If A-6 has the same deliverability as A-5 achieving that rate should not be a problem. The reservoir has re-pressurized enough to make that flow rate possible. The other two main assumptions that we are making are about influx and water production. If the well waters out earlier than planned we will definitely fall short of our projected production. If the well starts making a significant amount of liquids we could also miss our target significantly.

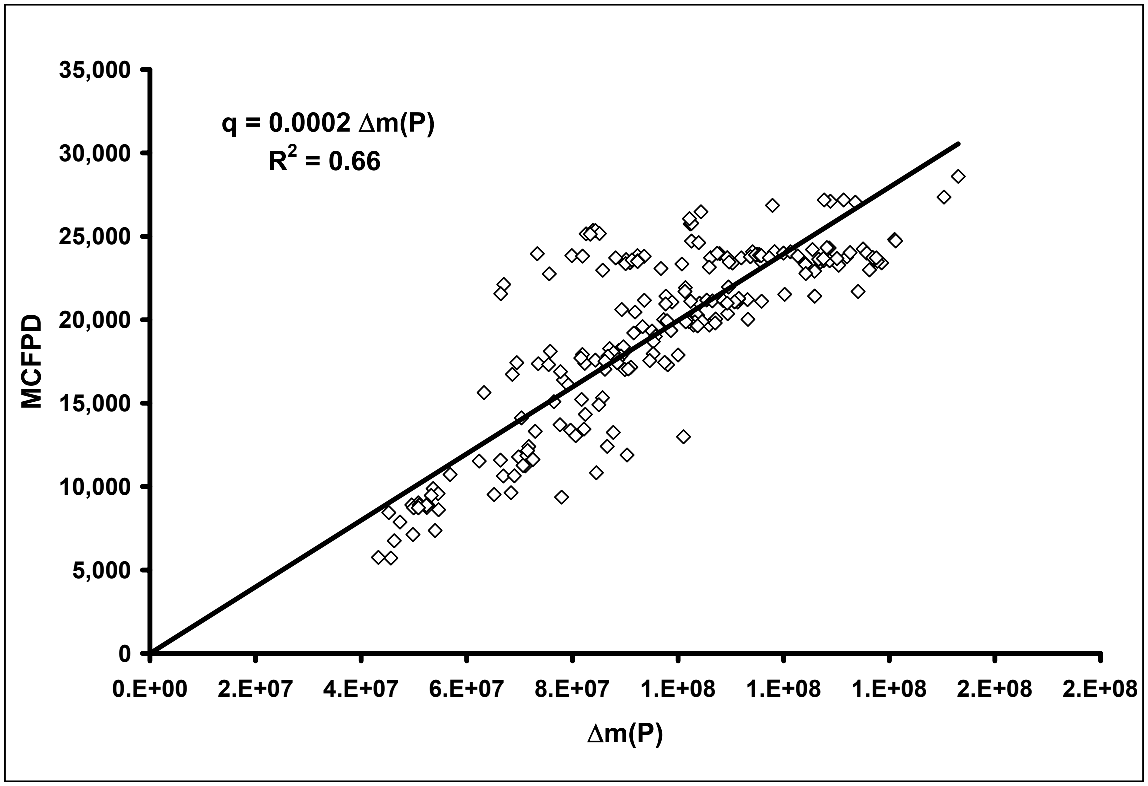

Figure 6.8 Deliverability for wells A-5 and A-6.

Since the PDM application doesn't account for liquids production during its forecast, we should investigate the amount of error this can introduce. Figure 6.10 shows the results from a forecasting run to predict the history of the A-5 well. Notice, that the answers are very close until about year 1.5, then the calculated behavior deviates from the real behavior. There could be other factors involved, but liquid production seems to be the most consistent with the observed behavior. We can not be completely sure that this the source of all the error because the monthly production data that was available did not report much water, but 200 of the production tests reported at least 100 BWPD, and for the last few months 200 BCPD. The highest liquid to gas ratio (LGR) was 57 BPMMCF which was calculated from the last available production test done in April 1987, year 1.85. We have no way of knowing what it was after that, but we do know the LGR was increasing fast at that time. The error introduced by liquid production was only 8.5% in this case, and that is an acceptable margin for many applications. However, it is clear that the wellbore model of the PDM program does have limitations when it comes to the production of liquids.

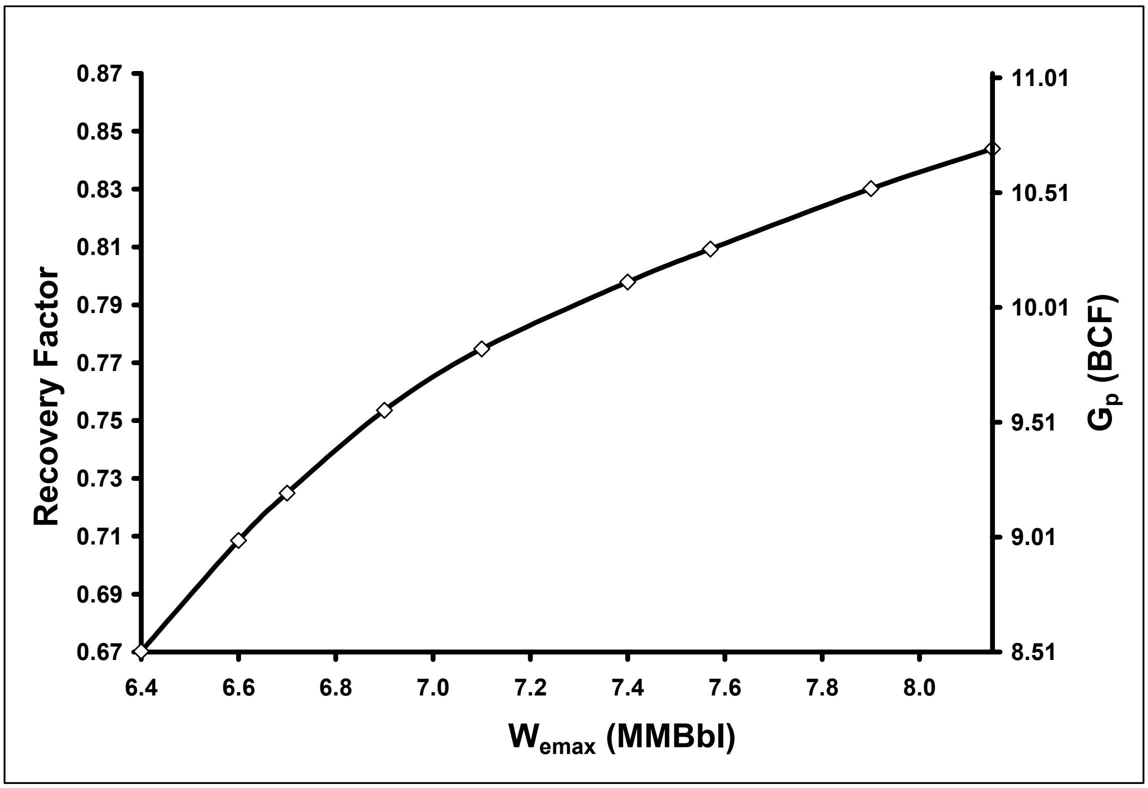

Figure 6.9 Approximate recovery from up-dip well A-6.

The next phase of this study is to determine the impact that coproduction could have on the recovery of well A-6. Since the amount of influx that could occur was assumed, the recovery from A-6 was evaluated at different water production rates for both the low and high estimates of W_{emax}. Results of the coproduction evaluations are shown in Figure 6.11. In order to increase recovery the of A-6 by 1% water production rates of 3000 BPD and 5000 BPD are necessary for W_{emax} values of 7.53 MMBbl and 8.14 MMBbl. This is indicative of the fact that the lower W_{emax} is, the more A-6 stands to benefit from coproduction.

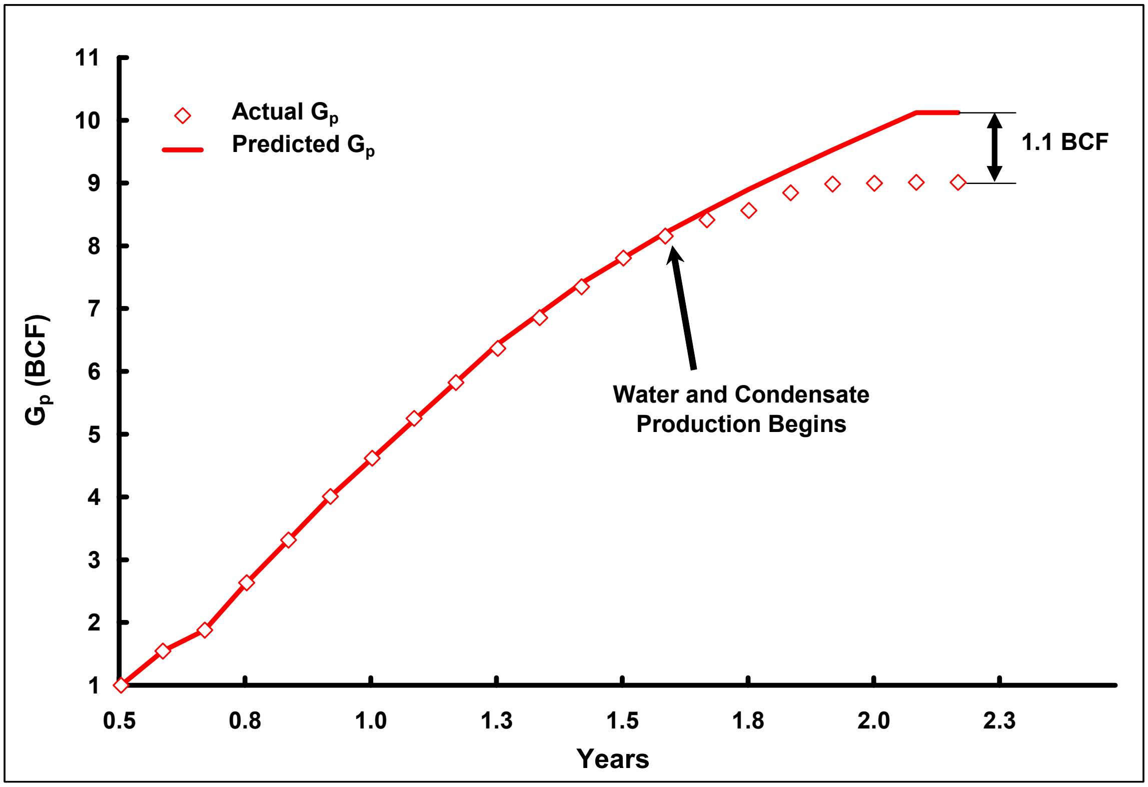

Figure 6.10 Prediction error due to liquid production.

Increasing the recovery by 1% yields an extra 127 MMSCF of production. At a gas price of $5/MSCF the extra production generates 635 thousand dollars. The project would last about six months, so water volumes of 547 and 912 MBbl would be produced for the 3,000 and 5,000 BPD cases. The income generated by coproduction is $1.16 per barrel of water produced for the 3,000 BPD case and $0.70 per barrel for the 5,000 BPD case. This means that coproduction has little value on its own at this point. However, since water production in the A-6 is a major concern, coproduction could have value by helping A-6 achieve its base production for either case.

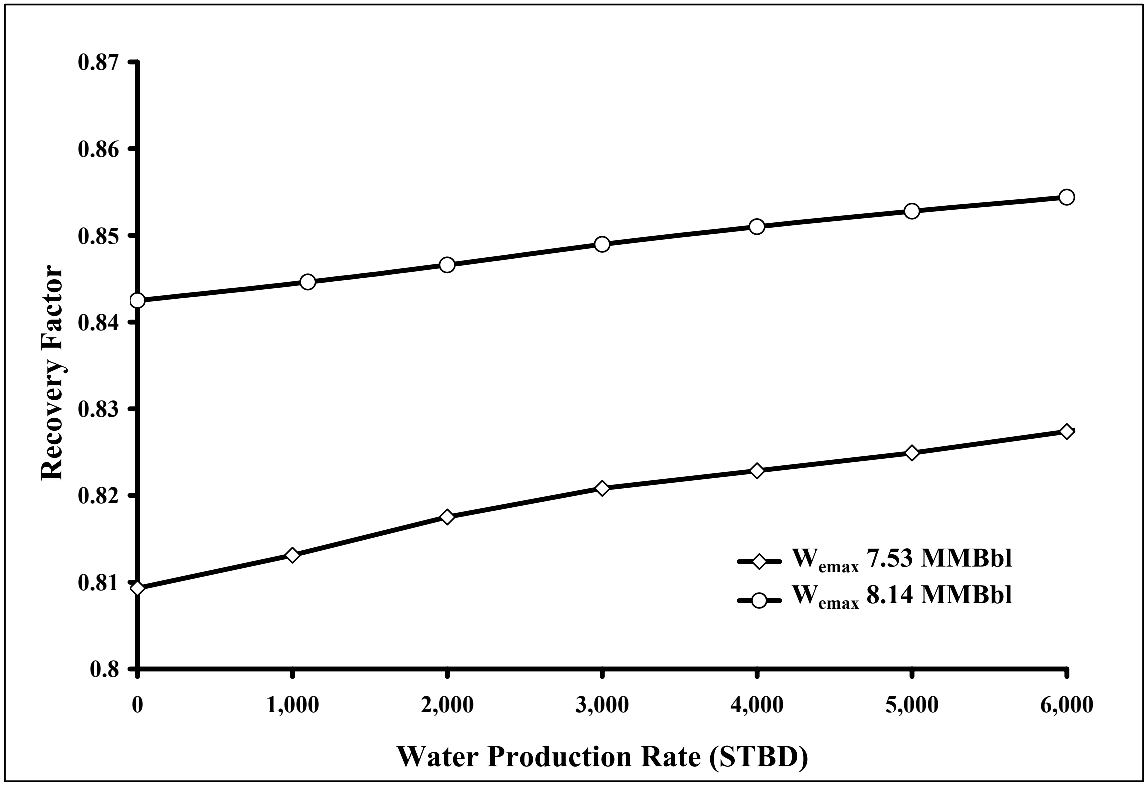

Figure 6.11 Coproduction assessment of reservoir "T".

In addition to the various design constraints the timing aspect of this project is also very important. Although we are not producing anymore, the aquifer continues to invade the reservoir. Figure 6.12 shows the cumulative influx and aquifer flow rate over the life of the reservoir until pressure stabilization. When the A-5 watered out the Aquifer flow rate was about 8,700 BPD. According to the projections of the reservoir model the lower W_{emax} value of 7.56 MMBbl will be reached in about nine months. This puts another constraint on a project design that was already very restricted. The previous analysis was a "best case" scenario. It was done assuming that the project could be implemented the following month. Of course in real life that is virtually impossible unless there already happened to be a drilling rig on site. Since even the best case is marginal it is unlikely that this project would be economically viable. The best recommendation appears to be that reservoir "T" should be abandoned.

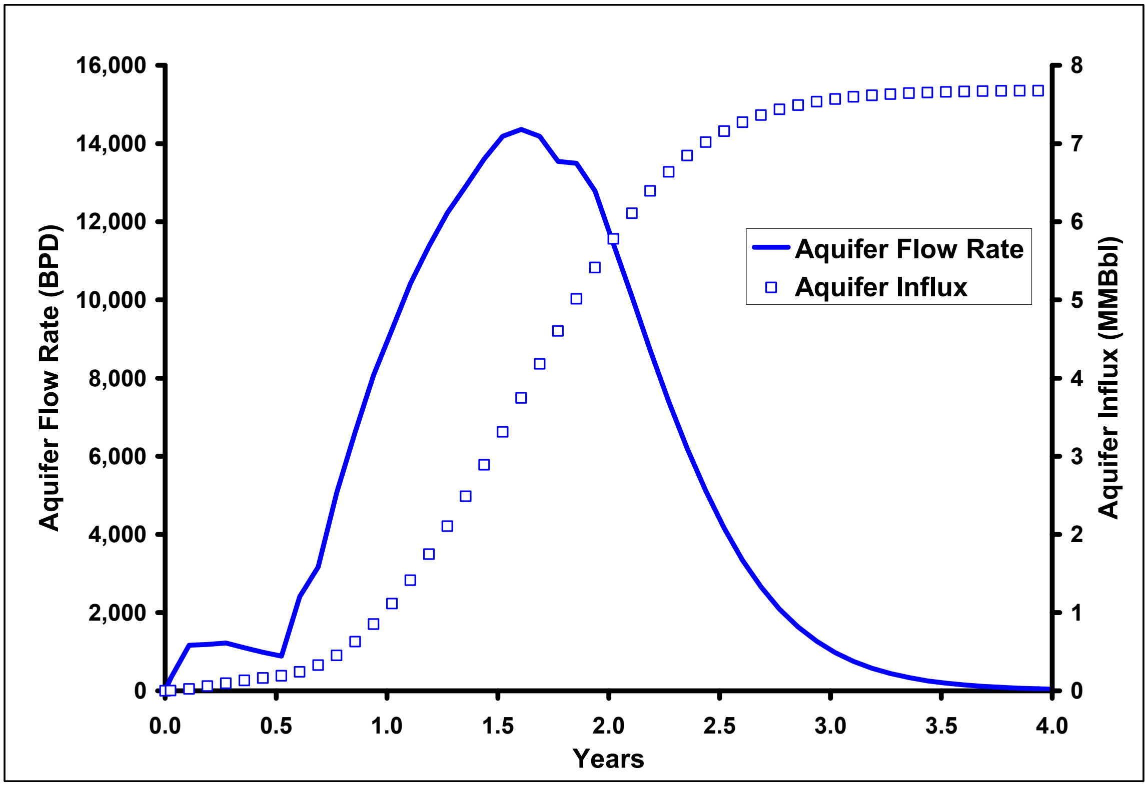

Figure 6.12 Calculated aquifer history and forecast for reservoir "T".

7. DISCUSSION

7.1 Deliverability Modeling

The Houpeurt equation [24] is more representative of actual flow in the reservoir than the simplified inflow expressed by Equation 5.4.7. Houpeurt analysis is the preferred method to determine deliverability from well test data. However, because the Houpeurt equation requires that two coefficients be used to describe deliverability it is more sensitive to error than the simplified inflow equation.

The margin of error associated with measuring flowing tubing pressure can easily be a few percent depending on the type of gauge used. In addition to measurement error, if there is production of liquids the wellbore model will introduce more error. There is also error generated by the assumption that reservoir pressure is a constant value during each month. This means that if production tests are used to estimate deliverability some values of $\Delta m(P)$ can contain a substantial amount of error. This is especially true at the beginning and the end of a wells production life. When a well first come on line there is a period of "clean up" during which damage caused by drilling fluids affects the deliverability. Towards the end of a well's life liquid production causes the PDM wellbore model to under estimate the flowing bottomhole pressure, which results in over estimation of deliverability.

The two field cases studied both showed non compliance with the Houpeurt equation when all available production tests were included in the analysis. Figure 7.1 shows all the deliverability data for well A-5 graphed on a Houpeurt plot. Notice that it yields a negative value for *b*, which is physically impossible. If we remove the first three months and the last half of the production tests from the data set the results are much more realistic. Figure 7.2 shows this limited data set on the same Houpeurt plot. Not only is the value of *b* positive, but the value of *a* corresponds to a simplified inflow coefficient of 0.000231. This is in close agreement with the value of 0.0002 shown in Figure 6.8.

While it is possible to determine a Houpeurt relationship for well A-5 by excluding or weighting certain data points, whether it is necessary or wise to do so is debatable. The highest flow rates that we predicted for well A-6 were 20 MMCFPD. Assuming that the quadratic relationship is accurate, at 20 MMCFPD the q^2 term is 14.5% of the q term, which is significant. However, by including all of the data and using the simplified inflow equation we obtain a more conservative deliverability model. It was known from the error analysis shown in Figure 6.10 that over prediction caused by liquid production was the major concern. Therefore the simplified deliverability model was chosen to provide a more conservative estimate.

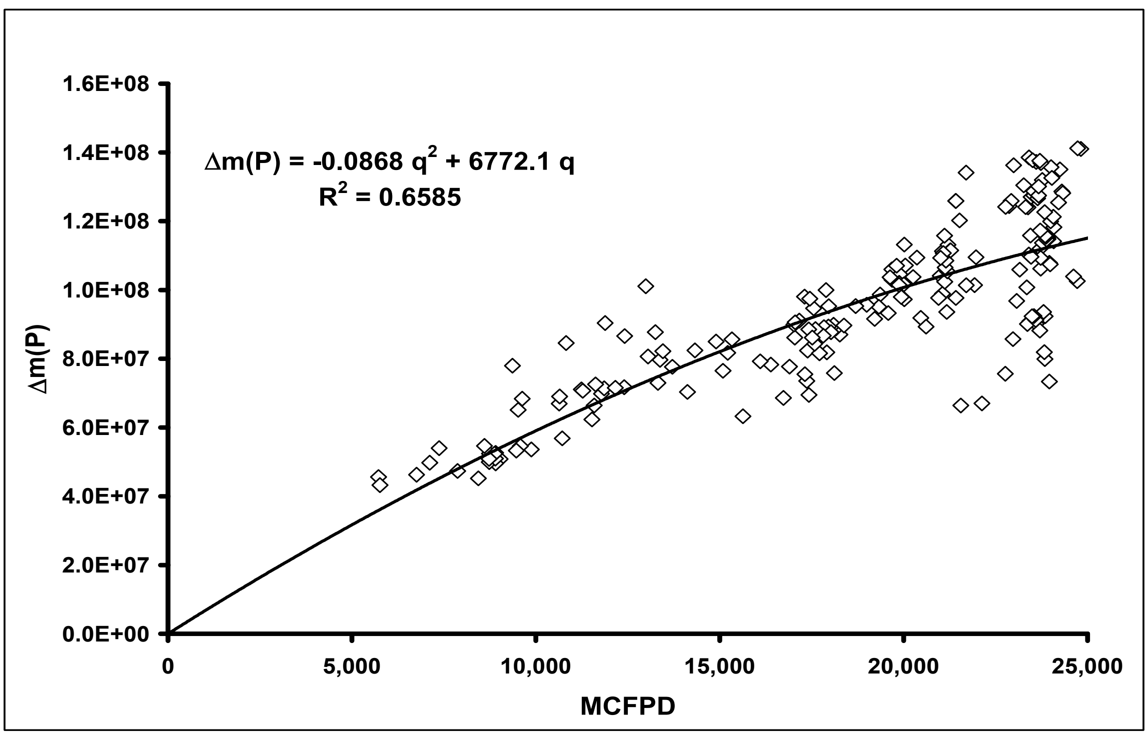

Figure 7.1 Houpeurt deliverability plot for well A-5 with all production tests.

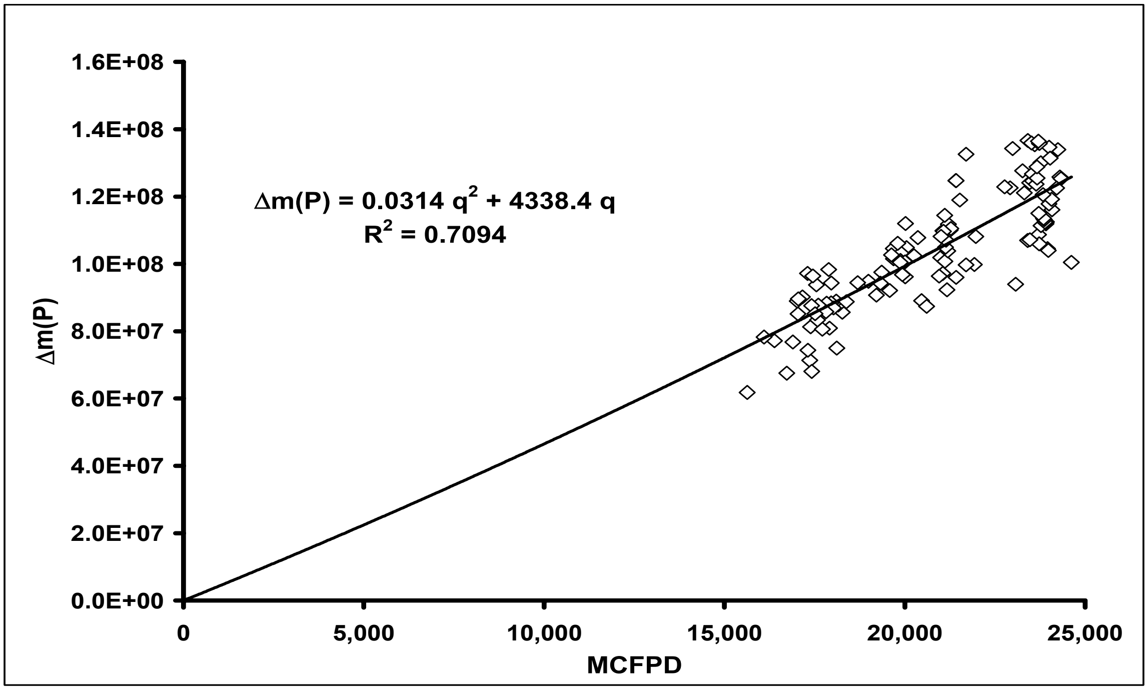

Figure 7.2 Houpeurt deliverability plot for well A-5 with selected production tests

7.2 Ways to Improve Forecasting Confidence

The greatest source of potential error within the PDM application is the wellbore model. It is based on the Cullender and Smith method for dry gas and does not account for gravitational or frictional pressure losses due to liquid production. Significant liquid production affects the production forecasts of the PDM application in two ways. The accuracy of the forecasts can be affected by well deliverability, but only if the inflow data is obtained using the wellbore model. The wellbore model itself can have a direct effect on the production forecasts by underestimating bottomhole pressure during the prediction phase.

If there is significant liquid production and the wellbore model is used to calculate flowing bottomhole pressures for inflow modeling some data points will appear to have higher deliverability than they actually do. The error this introduces into the deliverability coefficients should be relatively small if the majority of the data has reasonably low LGR. In real wells, liquid production causes an increase in flowing bottomhole pressure. During forecasting the bottomhole pressures calculated by the wellbore model will be lower than they should be if there is liquid production. This can cause over estimation of production and recovery from wells that produce at high LGR or water out.

The remainder of this chapter discusses different methods to increase confidence in the forecasts of the PDM application. These methods fall into three main categories.

1. Determining the magnitude of possible error with pressure measurements
2. Understanding and preserving the conservative biases of the program
3. Using alternative wellbore models

7.2.1 Acquisition of Pressure Data

When a well produces a significant amount of liquids some error is introduced into the forecasts of the PDM application. For the case of well A-5 in reservoir “T” this error was 1.1 BCF or about 8.5% of *G*. The LGR increased rapidly and last known value was about 50 Bbl/MMSCF. This amount of liquid production is well out side the limits of a dry gas wellbore model, which is evident from the significant error in the predicted recovery. While the analysis of reservoir “T” helps us understand how this error occurs, and gives us some general idea of the magnitudes that can be expected, it does not help us determine how this error can affect other wells. One way to determine the error caused by liquid production is by directly measuring the flowing pressure gradient in a well.

Installing permanent down-hole pressure gauges is becoming a common completion practice for some companies. Permanent down-hole gauges generate a vast amount of useful data such as well tests, deliverability and static reservoir pressures. This data can be used to improve the accuracy of virtually every aspect of the PDM application. However, the most important contribution that a permanent pressure gauge has on the accuracy of forecasts is to provide constant surveillance on the flowing bottomhole pressure. If a well starts to make a significant amount of liquid a permanent gauge will not only allow us to determine how much error is generated in the wellbore model and correct for it, but it will allow us to keep track of it in real time. Real time assessment is by no means necessary, but if liquid production becomes a concern a simple flowing pressure survey could help correct some of the error.

7.2.2 Understanding and Preserving Conservative Biases

There are two main conservative biases within the PDM application. The first is that condensate production is not predicted. Condensate has become very valuable in recent years and fetches a premium price. While condensate production can cause overestimation of gas recovery, if condensate recovery is substantial the economic error introduced by liquid production will be offset. The second internal bias is that when evaluating coproduction the application does not account for gas production from the water producer. In many situations this will result in neglecting a substantial amount of gas production [29]. The effect of neglecting gas rates associated with coproducers results in a conservative estimation of recovery. This implies that projects which evaluate as marginal might be worth further investigation. Furthermore, if a coproduction project evaluates favorably it is almost certainly worth a more detailed study.

There are other tactics that can be used to impose conservative biases on the program. As touched on in Section 7.1, by using the simplified inflow equation we can include early production data in the deliverability model. This data typically exhibits lower deliverability characteristics which shift the deliverability coefficient toward a more conservative number. If there is liquid production, having a conservative estimate of deliverability helps offset some of the error associated with the wellbore model. Another tactic that influences the wellbore model is increasing the absolute roughness in order to raise the calculated bottomhole pressures. This technique is more effective if there are pressure measurements with which to correlate the results.

7.2.3 Alternative Wellbore Models

The previous sections focused on ways to work within the limitations of the program. However, one of the more direct ways to increase the accuracy of the PDM application is to incorporate a more robust wellbore model that can compensate for water and condensate production. In addition to using an alternate wellbore model, by including some method to approximate water and condensate production rates the forecasts of the PDM application could be greatly improved. For example, a technique similar to the Dykstra-Parsons method [33] could be employed to estimate water production rates.

Any alternate wellbore model should calculate higher pressures than the Cullender and Smith method. One candidate is the corrected version of Cullender and Smith [20]. In vertical wells the Gray correlation [30] would be good choice; however its validity is subject to the following limitations.

1. Flow velocities less than 50 feet per second
2. Nominal tubing sizes less than 3.5 inches
3. Condensate gas ratios less than 50 Bbl per MMSCF
4. Water gas ratios below 5 Bbl per MMSCF

If the limitations of the Gray correlation are exceeded there are many two-phase flow correlations available. Although it was intended for oil/gas flow, the Duns and Ros correlation should be the most accurate all around [31]. The authors noted that since dimensionless groups were used and surface tension and liquid density were accounted for the same correlations should apply to gas/water flow. Indeed, the Duns and Ros correlation is reported to yield relatively accurate results in the mist flow regime, and in the presence of water production [32]. These are the two most important factors that apply to gas wells. However, other correlations could be more accurate in special circumstances and alternate wellbore models should be chosen on a case by case basis.

8. CONCLUSIONS

The intent of this thesis was to achieve three main goals. The first goal was to establish which parameters affect recovery optimization. The second goal was to use reservoir simulation to investigate the relationship between these parameters and determine how they could be controlled in order to achieve optimization. The last goal was to create a computer model for Excel that could be used as a fast and versatile screening tool to analyze recovery optimization.

Gas recovery is only optimized when both the pressure and hydrocarbon pore volume at abandonment are minimized. Previous methods to enhance gas recovery have concentrated on minimizing one of these parameters while neglecting the other. Because of this, they do not optimize recovery and are only applicable in certain types of reservoirs. The pressure and displacement management concept unifies previous approaches and can analyze recovery potential in any gas reservoir.

One theme that occurred in both simulation studies was that time is the enemy of optimization. As an aquifer invades a water-drive reservoir, or the pressure declines in depletion drive, the rate at which water must be produced or injected in order to optimize recovery without making some sort of trade off increases. In some reservoirs, optimizing recovery may not be profitable from the beginning because it requires drilling additional wells or installing surface equipment. However, even in reservoirs where optimization is economically viable, there is a window of opportunity that can shut during the production life.

Optimizing recovery is a surprisingly difficult task. There are many different methods of enhancing recovery from which to choose. Even after the appropriate strategy is determined, the timing of implementation can affect the design parameters. Different combinations of water rates, volumes and starting/stopping times can achieve similar recoveries, but affect the project life and therefore NPV differently. Optimization is complicated further by the fact that the effect of these different combinations on the results is generally not proportional. The dynamic nature of optimization virtually necessitates an iterative design approach.

The PDM application is a versatile tool that allows many different production scenarios to be evaluated in a short amount of time. The program is designed to require only publicly available information and can be set up quickly. Once all the necessary data is obtained and entered, the application is capable of evaluating the impacts of compression, coproduction and injection on recovery without any additional preparation time. This allows the engineer to evaluate many possibilities, and to revisit designs based new information or constraints.

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