2000

Optimization of Gas Well Completion and Production Practices.

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OPTIMIZATION OF GAS WELL COMPLETION AND PRODUCTION PRACTICES

A Dissertation

**Submitted to the Graduate Faculty of the
Louisiana State University and
Agriculture and Mechanical College
in partial fulfillment of the
requirements for the degree of
Doctor of Philosophy**

in

The Department of Petroleum Engineering

by

John H. McMullan

B.S., Louisiana State University, 1976

M.S., Louisiana State University, 1979

May, 2000

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ACKNOWLEDGMENTS

This work represents many years of experience with water-drive gas reservoirs and was made possible through the input of numerous individuals. This includes former colleagues at Celeron Oil and Gas Company and Marathon Oil Company, as well as past and present colleagues at Louisiana State University. Deserving special acknowledgement are the members of the advisory committee: Dr. Zaki Bassiouni (chair), Dr. Adam T. Bourgoyne, Dr. Andrew Wojtanowicz, and Dr. John R. Smith. Dr. Bassiouni deserves particular thanks, because without his untiring support and encouragement over many years, this work would have never been completed.

The Schlumberger Technology Company is acknowledged for the generous contribution of the Eclipse Reservoir Simulation computer software used extensively in this study.

Lastly, all of the members of my family are thanked for their support during the many twists and turns in my long career in the oil and gas business that led to the completion of this work.

TABLE OF CONTENTS

ACKNOWLEDGMENTS	ii
LIST OF TABLES	v
LIST OF FIGURES	vi
ABSTRACT.....	x
CHAPTER 1 - INTRODUCTION.....	1
CHAPTER 2 - LITERATURE REVIEW	4
2.1 Gas/Water Coning in Oil Reservoirs	4
2.2 Water Coning in Gas Reservoirs	6
2.3 Reservoir Considerations	8
CHAPTER 3 - A DISCUSSION OF FLUID FLOW AND CONING	11
CHAPTER 4 - MODEL DESCRIPTION.....	20
4.1 Grid Description and Properties	20
4.2 Fluid Properties.....	24
4.3 Relative Permeability.....	25
4.4 Well Loading and Vertical Flow	29
CHAPTER 5 - BASE CASE.....	33
CHAPTER 6 - IMPACT OF PERFORATED INTERVAL.....	38
CHAPTER 7 - IMPACT OF PRODUCTION RATE.....	43
CHAPTER 8 - ECONOMIC CONSIDERATIONS	51
8.1 Ultimate Produced Water Gas Ratio.....	51
8.2 Time-Value-of-Money	54
8.3 Discounted Cash Flow Analysis	60
CHAPTER 9 - SENSITIVITY ANALYSIS.....	64
9.1 Vertical to Horizontal Permeability Ratio	65
9.2 Fluid Density Contrast.....	66
9.3 Relative Permeability.....	67
9.4 Structural Relief	70
CHAPTER 10 - CONCLUSIONS	80
REFERENCES	82

APPENDIX A – EXAMPLE ECLIPSE DATA DECK	85
APPENDIX B – ECLIPSE VFP INCLUDE FILE	88
APPENDIX C – EXAMPLE ECLIPSE DATA DECK FOR TILTED SYSTEM.....	95
APPENDIX D – ECLIPSE TOPS INCLUDE FILE FOR TILTED SYSTEM SIMULATION RUNS	100
VITA.....	101

LIST OF TABLES

1. Reservoir Properties	22
2. Model Gas Properties.....	25
3. Relative Permeability End Points	28
4. Comparison of Well Life and Recoveries as a Function of Vertical to Horizontal Permeability Ratio	65
5. Comparison of Well Life and Recoveries as a Function of Gas Density	67
6. Comparison of Well Life and Recoveries as a Function of Gas to Water Relative Permeability	68

LIST OF FIGURES

1. A well log section from a typical bottom-water drive gas reservoir. After Bassiouni (1994).	2
2. Schematic of coning in an oil-water system.	11
3. Schematic of expected coning behavior in an oil-water system with perforations extended into the water zone.	12
4. Schematic of expected coning behavior in a gas-water system with perforations extended into the water zone.	13
5. Example gas rate calculations using steady-state radial equation.	16
6. Example water-gas ratio calculations using steady-state radial equations.	19
7. Sketch illustrating the simplified reservoir model.	21
8. Radial cross section with twenty-six, exponentially distributed radii.	23
9. An expanded view of the gas reservoir showing twenty-six exponentially distributed radii and 100, one foot vertical layers.	23
10. Initial water saturation distribution.	24
11. Gas deviation factor used in reservoir simulation model.	26
12. Gas viscosity used in reservoir simulation model.	26
13. Example measured water relative permeability. After Cohen, 1989.	27
14. Example measured gas relative permeability. After Cohen, 1989.	27
15. Simulation model gas-water relative permeability curves.	28
16. Estimated flowing bottom-hole pressure with 500 psia flowing tubing pressure.	32
17. Water saturation profile following two years of production.	34
18. Water saturation profile following four years of production.	34
19. Water saturation profile following six years of production.	35

20. Forecast base case gas and water production rates.	36
21. Forecast base case cumulative gas and water production.	37
22. Forecast base case pressure behavior.	37
23. Impact of the length of perforated interval on cumulative water and gas production.	38
24. Impact of perforated interval and permeability on ultimate gas recovery.	40
25. Impact of perforated interval and permeability on ultimate water production.	41
26. Impact of perforated interval and permeability on producing life.	42
27. Impact of producing rate and permeability on ultimate gas recovery.	44
28. Impact of producing rate and permeability on ultimate water production.	45
29. Impact of producing rate and permeability on well life.	45
30. Gas well "A" response to a drop in flowing tubing pressure.	46
31. Gas well "A" water production response expressed as a water-gas ratio.	47
32. Gas well "B" response to a drop in flowing tubing pressure.	48
33. Gas well "B" water production response expressed as a water-gas ratio.	48
34. Sensitivity of operating costs (expressed as ultimate barrels of water per thousand standard cubic feet of gas) to perforated interval.	52
35. Sensitivity of operating costs (expressed as ultimate barrels water per thousand standard cubic feet of gas) to producing rate.	53
36. Impact of perforated interval and permeability on discounted ultimate gas recovery.	56
37. Impact of perforated interval and permeability on discounted ultimate water production.	56
38. Sensitivity of operating costs (expressed as discounted ultimate barrels of water per thousand cubic feet of gas) to perforated interval.	57
39. Impact of producing rate on discounted ultimate gas recovery.	58

40. Impact of producing rate on discounted ultimate water production.	59
41. Sensitivity of operating costs (expressed as discounted ultimate barrels of water per thousand cubic feet of gas) to producing rate.	59
42. Impact of perforated interval on discounted net present value.	62
43. Impact of production rate on discounted net present value.	63
44. The impact of vertical to horizontal permeability ratio on cumulative water production.	66
45. Relative permeability ratios used in sensitivity simulation runs.	69
46. The impact of water relative permeability on cumulative water production.	69
47. Plan view of tilted simulation model with radial local grid refinement.	72
48. Vertical cross-section of tilted simulation model with radial local grid refinement.	72
49. Initial water saturation distribution for tilted simulation model.	73
50. Water distribution for tilted simulation model following two years of production.	74
51. Water distribution for tilted simulation model following four years of production.	74
52. Water distribution for tilted simulation model following six years of production.	75
53. Impact of perforated interval and permeability on ultimate gas recovery in an example tilted reservoir simulation model.	76
54. Impact of perforated interval and permeability on ultimate water production in an example tilted reservoir simulation model.	76
55. Impact of perforated interval and permeability on well life or an example tilted reservoir simulation model.	77
56. Impact of producing rate and permeability on ultimate gas recovery in an example tilted reservoir simulation model.	78

57. Impact of production rate and permeability on ultimate water production in an example tilted reservoir simulation model.....	78
58. Impact of production rate and permeability on well life for an example tilted reservoir simulation model.....	79

ABSTRACT

In water drive gas reservoirs, wells can be completed with a long perforated interval and produced at high rates to minimize abandonment pressure and maximize recovery. Alternatively, the perforations can be limited to the top of the productive interval and the well produced at a low rate in an effort to prevent coning which results in high abandonment pressures if the strength of the aquifer is adequate to support reservoir pressure. This study uses a reservoir simulation coning model to evaluate these two conflicting completion and production practices. The impact of completion interval, gas production rate, and reservoir permeability were evaluated.

Ultimate gas recovery was found to be largely insensitive to variations in perforated interval and production rate in high permeability systems. Ultimate water production, however, was found to increase at high gas rates and lengthened perforated intervals. In lower permeability systems, ultimate gas recovery was found to increase significantly as production rates were increased, while ultimate water production was actually observed to fall. Sensitivity analysis of vertical to horizontal permeability ratio, fluid density contrast, relative permeability, and formation dip did not alter these conclusions.

The conclusion that elevated production rates can be expected to have no detrimental impact on ultimate gas recovery suggests that gas rates should be maximized in low water disposal cost situations. This finding favors the completion of an interval sufficiently long to maximize production rate and thereby insure that gas recovery and present value of gas reserves are maximized. In high water disposal cost

situations, however, it should be recognized that this strategy might result in elevated water production in high permeability systems.

CHAPTER 1 - INTRODUCTION

Many natural gas reservoirs have some level of pressure support from aquifer encroachment. In gas reservoirs with active water encroachment, it is well known that lowering reservoir pressure with fluid withdrawal rates in excess of aquifer encroachment rates can significantly increase ultimate recovery. An example of a natural gas reservoir that could be expected to have significant aquifer influx is illustrated in Figure 1. This figure is a well log section that clearly shows a clean sandstone interval at a depth of 9,975 feet and approximately 60 feet thick. The top twelve feet of the interval contains gas as evidenced by high resistivity and gas effect on the density-neutron log. The remainder of the permeable interval contains water as indicated by the low resistivity. With the large interval of water underlying the gas, this reservoir would almost certainly have its pressure impacted by expansion of the aquifer as the well is produced.

This type of well could be encountered in either a single well reservoir or in a reservoir developed with multiple wells. If this were a single well reservoir, it would most certainly not be at the very crest of the structure. If the reservoir pressure could be lowered by high withdrawal rates, it would be possible to actually drain up-dip gas that would otherwise be unrecoverable. In a multi-well reservoir situation, drainage and competitive situations could make the decisions on how a well of this type should be completed and produced of paramount importance. In either situation, the possibility of "out-running" the aquifer can significantly add to the ultimate recovery from the reservoir.

**Figure 1 - A well log section from a typical bottom-water drive gas reservoir.
After Bassiouni (1994).**

Unfortunately, the decision to produce a water-drive gas reservoir at high production rates is not as clear-cut as it might seem from the perspective of reservoir engineering. Logic and experience indicate that this type of well will ultimately cease production as the result of excessive water production. It is well known that coning of water will occur if the well is produced at high rates. Clearly, water will be produced sooner as the perforated interval is extended toward the gas-water contact. From this point of view, the prudent course of action would be to delay the occurrence of water

in the well stream by perforating the very top of the interval and producing at a restricted rate.

This investigation had the dual goals of developing guidelines for the selection of optimum perforated interval and production rate in the water-drive gas reservoirs. The system was studied with a commercial reservoir simulation package which has the advantage of allowing the realistic evaluation of any imaginable completion and production scenario for a given reservoir situation. Comparisons of this type are impossible using analytical techniques or through the manipulation and evaluation of actual producing wells.

CHAPTER 2 - LITERATURE REVIEW

Selection of optimum completion and production practices for water-drive gas reservoirs requires an understanding of water coning behavior and the implications of water production on well and reservoir performance. Coning behavior during the production of oil and gas has been extensively investigated. The vast majority of the literature on this subject reports the behavior of water or gas coning into an oil completion. While the object of this research involves the behavior of water coning into gas completions, some insight into coning behavior can be gained with a review of coning into oil completions.

2.1 Gas/Water Coning in Oil Reservoirs

The first significant examination of coning was by Muskat and Wykoff in 1935 and again by Muskat in 1937. This classical analytical treatment of the coning problem investigated the oil production rate above which water would be coned from an underlying aquifer. This rate in an oil water system is known as the “critical” oil rate and was found to be a strong function of the fraction of the productive interval perforated, known as the “penetration ratio,” and the formation thickness for a specific oil and system permeability. The analytical evaluation of critical oil rate was continued (for example, by Arthur in 1944) and also by analog models. Chierici, Ciucci, and Pizzi presented an example of a classical analog model in 1956. This study utilized a potentiometric model to physically investigate the coning phenomenon.

While these early studies provided insight into critical rates in oil water systems, they proved to be only marginally accurate as a result of the many

assumptions required by either analytical treatment or through the use of analog models. More importantly, they were limited to the estimation of critical rate and did not provide for a description of behavior following the breakthrough of water. These studies were important, however, because they indicated that critical oil rate is normally uneconomic and is routinely exceeded in actual practice. Long periods of multi-phase production should therefore be expected during the life of a well.

The emphasis of coning studies thus shifted from the estimation of critical rate to the prediction of well behavior following breakthrough. The ability to predict this behavior was made possible by the development of numerical reservoir simulators. While based upon the same fundamental flow equations as the earlier analytical models, the numerical models allow spatial distribution of reservoir properties, multi-phase flow, and the elimination of the requirement to assume unrealistic boundary conditions that is often required in an analytical treatment.

The ability to consider unsteady-state, heterogeneous systems resulted in an abundance of radial coning studies in the 1970's using reservoir simulation. As in the previous analytical and analog models, the emphasis of the vast majority of these studies was water and/or gas coning into oil completions. Aziz and Flores reported an example of an early simulation study in 1974. The findings of many of these studies were summarized by Kabir in 1983, which incidentally, is one of the few investigations of gas-water systems. Kabir reported that oil zone thickness, oil viscosity, horizontal permeability and production rate are the dominating factors controlling water-oil ratio behavior and ultimate recovery. Recent advances in horizontal well drilling technology have made possible the application of horizontal

wells in thin oil columns. These wells are designed to minimize drawdown and thereby control gas and/or water coning and have made a significant contribution to the ultimate recovery of the Prudhoe Bay Oil Field, one of the largest in the world. An example of this type of application to coning theory was presented by Yang and Wattenbarger (1991).

2.2 Water Coning in Gas Reservoirs

Investigations of coning in gas-water systems are much less numerous in the literature. Trimble and DeRose (1977) used the analytical theories of Muskat-Wyckoff and Arthur to successfully evaluate critical gas production rates in the Todhunters Lake Gas Field. Critical gas production rate using reservoir simulation was investigated by Modine and Field in 1971 and analytically by Graue in 1971. Graue applied his evaluation to the Kaybob South Beaverhill Lake Field where the determination of critical gas production rates was important because of the extremely corrosive properties of produced water. As might be expected, Graue determined that for his particular situation, critical height and the ratio of horizontal to vertical permeability were the most important properties when determining the critical gas rate.

Kabir reported the most extensive evaluation of water coning in a gas-water system in 1983. Kabir used a radial reservoir simulation model with 10 blocks logarithmically distributed in the radial direction and 14 layers in the vertical direction. This model was extremely coarse by modern standards. Also, reservoir simulation technology had not yet been developed to allow the inclusion of wellbore friction and loading models.

Kabir produced the reservoir at a constant reservoir voidage rate and water was injected into the aquifer at the outermost radius at the same voidage rate in an effort to simulate a constant pressure aquifer. It is noteworthy that this approach of injection into the outer radius would undoubtedly result, due to transient effect, in an increase in pressure at the outer radius which is in direct disagreement with the stated aim of holding the outer pressure constant. Also, this approach does not allow the average reservoir pressure to fall, which can have a significant impact on ultimate recovery.

In spite of the limitations mentioned above, Kabir was able to identify that coning behavior was mostly governed by horizontal permeability and pay thickness. Grouping permeability and thickness as a product was determined to not be possible because of the implication of gravitational forces over viscous forces in thicker intervals. He also concluded that for the system considered, producing rate, penetration ratio, well spacing, and horizontal to vertical permeability ratio had little bearing on water coning behavior. He also noted that most of the gas was recovered prior to a dramatic increase in water-gas ratio. Finally, the presence of vertical barriers delayed the breakthrough of water but did not impact ultimate recovery.

Uebel attempted an extension of Kabir's work in 1990. Uebel used a radial reservoir simulation model with 15 blocks logarithmically distributed in the radial direction and 16 layers in the vertical direction. Similar to the model used by Kabir in 1983, this model was extremely coarse and the direct inclusion of wellbore friction and loading models was not possible. Uebel attempted to include wellbore phenomenon in an iterative fashion by calculating wellbore loading and friction using a totally separate computer program, resetting production constraints and rerunning

the simulation. This inability to couple wellbore effects automatically to the reservoir model greatly hampered the simulation study.

The largest limitation of the Uebel study, however, was caused by limitations of the simulation program used for the study. Well connections to the model were limited to a maximum of two grid blocks, severely hampering the vertical resolution of the model and making investigation of the impact of perforated interval virtually impossible. Also, material balance residual errors limited production rates to values lower than what are typically encountered in field situations. While the significant impact of drive mechanisms was identified, very little investigation of its effect was reported, presumably due to the limitations of the simulation model.

In spite of these problems and limitations, Uebel was able to make the following conclusions: 1) Time of water breakthrough can be retarded by restricting gas rate but ultimate recovery is not increased. 2) The effect of perforation location is small, provided they are located in the upper half of the productive interval. In a strong water drive, this is the result of downward coning of gas. 3) The vertical to horizontal permeability ratio has little bearing on the water coning behavior.

2.3 Reservoir Considerations

Ultimate recovery from gas reservoirs varies considerably depending upon reservoir properties, drive mechanism, and in some instances, production rate. For the pure depletion drive reservoir, only the abandonment pressure controls ultimate recovery. Abandonment pressure occurs when the well(s) production rate is no longer economic. The reservoir permeability and the completion efficiency of the well(s) control the production rate at these abandonment conditions.

In the situation where partial water drive exists but the reservoir ultimately pressure depletes, production of any water effectively increases the pore volume of the reservoir at abandonment and results in a decrease in ultimate recovery. Cason (1983) reported the actual injection of water into a depletion drive gas reservoir to increase ultimate recovery.

In the case of complete water drive, no loss in reservoir pressure occurs and ultimate recovery becomes a function of the area swept by water and the residual gas saturation. In this situation, the structural position of the well in the reservoir and perhaps the location of the perforations within the productive interval become controlling factors.

In reality, the majority of gas reservoirs are neither completely depletion drive nor completely water drive. In these combination-drive reservoirs that undergo some degree of pressure support from aquifer encroachment, the selection of well locations and the manner in which they are produced become important. Agarwal (1965) specifically identified the benefits of high production rates in water drive gas reservoirs to lower ultimate abandonment pressure prior to the cessation of production as water reaches the production wells. While the volume of residual gas in the reservoir is not significantly different from the volume that could be expected at lower production rates, the abandonment pressure can be lower due to aquifer influx rate being less than the production rate. Lutes et al (1977) and Brinkman (1977) report actual field examples of significant improvement in ultimate gas recovery resulting from increased gas production rates from water drive reservoirs. Chesney et al (1982) and Arcaro and Bassiouni (1987) extended the concept by investigating the intentional

removal of large volumes of water in a process known as co-production. In a manner similar to the accelerated production of gas, production of large volumes of water can result in a lowering of abandonment pressure and an increase in ultimate recovery.

It is clear from the numerous references cited that production rate can have a significant impact on the ultimate recovery from gas reservoirs. In the case of reservoirs that ultimately pressure deplete, production of any water should be avoided and actual waterflooding of the reservoir can be considered as an option to increase recovery. In the case of complete water-drive, the abandonment pressure is not sensitive to withdrawal rates but the production of water resulting from high rates and/or lengthy perforated intervals might result in the premature watering out of wells. Finally, the impact of production rate on recovery in partial water-drive reservoirs is well documented as having a significant impact on recovery. The optimization of completion and production practices for gas reservoirs is clearly an important objective.

CHAPTER 3 - A DISCUSSION OF FLUID FLOW AND CONING

Coning of gas and/or water in an oil system has been studied extensively by the oil and gas industry. Coning results from a difference in the mobility of oil, gas, and water. Figure 2 schematically depicts the coning of water into a well completed in an oil column underlain by bottom water. As indicated by the sketch, water production can be expected if the drawdown resulting from production of oil ($\Delta p_{\max}$) in the well exceeds the gravitational forces acting to maintain the water as a horizontal surface below the oil. The water-oil ratio history can be estimated using one of the numerous methods described in the literature or by using reservoir simulation.

Figure 2 - Schematic of coning in an oil-water system.

Coning in the oil-water system as depicted in Figure 2 has been observed and documented extensively in field examples and has been widely reported in the literature. This observed behavior causes large water production rates as the relatively high mobility water breaks through to the producing well. The knowledge and logic of coning in an oil-water system can be extended to the hypothetical situation where the perforated interval is extended into the water zone as shown in Figure 3. As indicated in the figure, the development of a cone of water through the oil could still be expected to form because of the relative higher water mobility. Water production in this situation would begin immediately and, as in the previous case, high water production rates should be expected.

Figure 3 - Schematic of expected coning behavior in an oil-water system with perforations extended into the water zone.

This investigation focuses on coning behavior in a gas-water system where the underlying water is far less mobile than the overlying gas phase. If a well is perforated at the top of the gas zone in a manner similar to the oil-water system illustrated in Figure 2, a cone of water could be expected to form in a similar manner. In the situation where the perforated interval extends into the water zone, very different behavior from the oil-water system should be expected, however. In this situation, the gas phase is more mobile than the water phase and intuition suggests that gas would cone down through the water as depicted in Figure 4.

The point of this discussion is to identify a difference in coning behavior between oil-water and gas-water systems. For this reason, knowledge and experiences

Figure 4 - Schematic of expected coning behavior in a gas-water system with perforations extended into the water zone.

gained from oil-water systems *should be used with care and perhaps avoided altogether.*

An investigation of basic fluid flow equations can also provide some insight into the relative ability of gas and water flow in a reservoir. Henry Darcy first investigated the flow of fluids through porous media in 1856 using experiments of water flowing through sand filter beds. The fundamental relationship describing the flow of fluids in porous media known as "Darcy's Law" that resulted from these experimental studies is given by:

$$v = - \frac{k dp}{\mu ds} \dots\dots\dots (3.1)$$

This equation states that the *apparent velocity*, v , of fluids flowing in a porous media is proportional to the pressure gradient, dp/ds , and the proportionality constant known as permeability, k , and inversely proportional to the viscosity of the fluid, μ , flowing through the media. The permeability of the media is a rock property and the negative sign results from the direction of fluid flow in a direction opposite the pressure gradient.

Darcy's law is the most fundamental equation used in petroleum reservoir engineering when describing the flow of fluids in hydrocarbon reservoirs. The equation can be integrated for various geometries and extended to multiple flowing phases in a variety of ways. Craft and Hawkins (1959) summarizes many of the basic variations of Darcy's law. Darcy's law used to describe steady-state radial flow of water becomes:

$$q_w = \frac{0.00708 k_w h_w (P_e - P_w)}{\mu_w B_w \ln\left(\frac{r_e}{r_w}\right)} \dots\dots\dots (3.2)$$

where:

- q_w = water flow rate, barrels per day
- k_w = permeability, millidarcies
- h_w = thickness flowing water, feet
- P_e = pressure at outer boundary, psia
- P_w = wellbore pressure, psia
- μ_w = viscosity of water, centipoise
- B_w = water formation volume factor, reservoir
Barrels per surface barrel
- r_e = outer radius, feet
- r_w = wellbore radius, feet

Similarly, the steady-state radial flow of gases can be described using Darcy's law and average gas properties by:

$$q_g = \frac{6.88 \times 10^{-7} k_g h_g (P_e^2 - P_w^2)}{T Z \mu_g \ln\left(\frac{r_e}{r_w}\right)} \dots\dots\dots (3.3)$$

where:

- q_g = gas flow rate, MMCF/day
- k_g = permeability, millidarcies
- h_g = thickness flowing gas, feet
- T = temperature, °R
- Z = gas deviation factor
- μ_g = viscosity of gas, centipoise

These two equations describe steady-state conditions and one-dimensional radial flow of water or gas, and are therefore not adequate to describe the complex three-dimensional, unsteady-state flow of multiple fluids that are the object of this study. These equations do provide an insight, however, into the nature of the relative flow of gas and water.

Equation 3.3 was used with typical gas properties to construct Figure 5. This figure shows the expected gas flow rate as a function of both the gas permeability-thickness product (known as the capacity) and the difference between the exterior and well pressures (known as the drawdown) for steady-state, radial gas flow. Inspection of this figure suggests that for typical ranges of formation permeability of perhaps 10 millidarcies to 100+ millidarcies, very little formation thickness is required to obtain high flow rates. For example, a flowing interval ten feet thick and 100 millidarcies permeability could be expected to flow in excess of 10 MMCF/Day with a drawdown of only 250 psi. This figure suggests that in the more complex three-dimensional situation that is the target of this study, high gas rates can be expected when only a small portion of the interval is flowing gas.

Figure 5 - Example gas rate calculations using steady-state radial equation.

The water rate calculated using Equation 3.2 can be divided by the gas rate calculated using Equation 3.3 to provide a water-gas ratio, often referred to as the "water yield":

$$BWPM = \frac{q_w}{q_g} = \frac{10,291 k_w h_w T Z \mu_g}{k_g h_g \mu_w B_w (P_e + P_w)} \dots\dots\dots (3.4)$$

Both of these rate equations assume single phase, steady state, radial flow, implying no flow in the vertical direction. Therefore, the resulting equation can not be used directly to describe the relative flow of gas and water when coning occurs. It does, however, suggest an interesting behavior following simplifying assumptions and the expression of the respective interval thicknesses flowing gas and water as a fraction of the total interval:

$$\text{Let: } k_w = k_g$$

$$B_w = l$$

f_w = fraction of the total interval flowing water, then:

$$h_w = f_w h_t$$

$$h_g = f_g h_t = (1 - f_w) h_t$$

Equation 3.4 then simplifies to:

$$BWPM = \frac{10,291 T Z \mu_g f_w}{\mu_w (P_e + P_w) (1 - f_w)} \dots\dots\dots (3.5)$$

Even though this equation does not accurately describe coning behavior, it does strongly suggest that low water-gas ratios can be expected until well over the majority of a producing interval is flowing water. Equation 3.5 was used with typical gas

properties to construct Figure 5. Inspection of this figure indicates that for this example case, the high gas mobility relative to water results in a low water-gas ratio until perhaps 80 to 90 percent of the interval is flowing water. It also suggests little sensitivity to well drawdown.

While the proceeding discussion does not allow for the impact of vertical flow and coning, it is reasonable to assume that once the water contact moves into the perforated interval, gas would tend to form a cone through the water as illustrated in Figure 4. This would suggest that the producing water-gas ratio would be even lower than the values suggested in Figure 5. While actual well behavior in the multi-phase, multi-dimensional system can only be accurately predicted through reservoir simulation, analysis of the one dimensional, single phase equations suggests:

- 1) High gas rates can be expected when only a thin interval is flowing gas,
- 2) Water-gas ratio should be low until the vast majority of the perforated interval is flowing water, and
- 3) Water-gas ratio is relatively insensitive to the pressure drawdown between the wellbore and the reservoir.

Figure 6 - Example water-gas ratio calculations using steady-state radial equations.

CHAPTER 4 - MODEL DESCRIPTION

The coning phenomenon in the production of oil and gas has been studied extensively over the years. However, nearly all of the interest has been directed toward the production of oil with the coning of water or gas. Very little interest has been directed toward the phenomenon of water coning during the production of gas in gas-water systems.

The coning phenomenon has been studied using both analytical methods and with reservoir simulation. Analytical methods normally consider a steady-state situation with fixed boundary conditions and are therefore limited to simplified predictions like breakthrough time. Reservoir simulation, however, is much more suited when reservoir performance through depletion is of interest. The emphasis of this study is on the impact of coning on ultimate recovery. For this reason, reservoir simulation was selected as the method used to model reservoir behavior in this study. Other requirements include a fully implicit solution of the flow equations by the reservoir simulator and the ability to couple well-bore hydraulics with the well and reservoir models. For these reasons, the full-featured reservoir simulator Eclipse (a product of the Schlumberger Technology Company) was selected to conduct this investigation. An example Eclipse simulation data deck is included in Appendix A.

4.1 Grid Description and Properties

A sketch of the simplified reservoir model used in the majority of this investigation is illustrated in Figure 7. The “layer cake” type model consisted of a gas reservoir of approximately 63 BCF (61 million reservoir barrels) underlain by an

aquifer of approximately 700 million barrels of water. The gas reservoir was 100 feet thick and had an outer radius of 2,500 feet. The gas reservoir was underlain by an aquifer 200 feet thick with an outer radius of 5,000 feet, or 2,500 feet larger than the gas reservoir. The size of the aquifer relative to the gas reservoir was exaggerated by multiplying the porosity in the aquifer by a factor of ten in the area of the aquifer not overlain by the gas reservoir.

Figure 7 - Sketch illustrating the simplified reservoir model.

Fluid and rock properties were chosen to represent a typical, high porosity Gulf Coast gas reservoir. The top of the reservoir was set at 5,000 feet and a reservoir temperature and initial pressure typical for this depth were used. Although the value of horizontal permeability was varied extensively in this study, a base case of 100

millidarcies was used. Vertical permeability is normally assumed to be less than horizontal permeability due to the influence of bedding planes and laminations in the reservoir. Except in the simulation cases intended to test the sensitivity of this parameter, a reduction in vertical permeability to 10% of the horizontal permeability was used. The general reservoir properties used in the simulation study are summarized in Table 1.

A reservoir simulation grid was constructed consisting of 100 one foot vertical layers in the gas zone, with nine 10 foot and one 110 foot layer representing the water zone. Twenty-six radial grids were distributed exponentially as illustrated in Figure 8 (dimensions are in feet). Since it is not possible to illustrate the 100 one foot layers of the gas zone at this scale, an expanded view of the gas zone is illustrated in Figure 9. This expanded view of the model, with the grid lines removed to improve clarity, are used in all subsequent grid illustrations. An example view with the grid lines removed is shown in Figure 10 and illustrates the initial water saturation distribution.

Table 1 - Reservoir Properties

Depth to top of Reservoir = 5,000 feet

Initial Pressure = 2,500 psia

Temperature = 120° F

Porosity = 25%

Horizontal Permeability = 100 millidarcies

Vertical Permeability = 10 millidarcies

Rock Compressibility = 10×10^{-6} psi⁻¹

Figure 8 - Radial cross section with twenty-six, exponentially distributed radii.

Figure 9 - An expanded view of the gas reservoir showing twenty-six exponentially distributed radii and 100, one foot vertical layers.

Figure 10 - Initial water saturation distribution.

4.2 Fluid Properties

Fluid properties for gas and water have been investigated extensively and can be accurately estimated using correlations available in the literature. Water viscosity and density were estimated using correlations published by Numbere et al (1977). A 40,000 ppm sodium chloride solution was assumed which yielded a specific gravity of 1.026 and a viscosity of 0.68 centipoise at reservoir temperature and pressure.

The correlation presented by Standing (1977) was used to estimate gas critical temperature and pressure assuming a 0.6 specific gravity natural gas. The correlation presented by Dranchuk et al (1974) was then used to estimate the gas deviation factor over the pressure range required for the reservoir simulation model. Finally, viscosity for the 0.6 specific gravity gas was estimated using the correlation developed by Lee et al (1966) and extended by Gonzalez et al (1968) over the same pressure range. The

resulting gas deviation factor and viscosity are summarized in Table 2 and graphically presented in Figures 11 and 12.

Table 2 - Model Gas Properties

<u>Pressure (psia)</u>	<u>Z Factor</u>	<u>Viscosity (centipoise)</u>
100	0.989	0.0122
300	0.967	0.0124
500	0.947	0.0126
700	0.927	0.0129
900	0.908	0.0133
1,100	0.891	0.0137
1,300	0.876	0.0141
1,500	0.863	0.0146
1,700	0.853	0.0151
1,900	0.845	0.0157
2,100	0.840	0.0163
2,500	0.837	0.0177
2,700	0.839	0.0184

4.3 Relative Permeability

Oil-water and gas-oil relative two-phase relative permeabilities have been treated at great length in the literature. Very little gas-water two-phase relative permeability data has been reported, however. Cohen (1989) reported laboratory data from a gas field in Germany and this data has been reproduced in Figures 13 and 14. These data were used with the representative relative permeability end points listed in Table 3 to construct the relative permeability curves used in this study and illustrated in Figure 15. The selection of the water permeability curve was patterned after the highest water relative permeability curves reported by Cohen, thereby maximizing the ability to produce water, the offending phase.

Figure 11 – Gas deviation factor used in reservoir simulation model.

Figure 12 - Gas viscosity used in reservoir simulation model.

Figure 13 – Example measured water relative permeability. After Cohen, 1989.

Figure 14 – Example measured gas relative permeability. After Cohen, 1989.

Table 3 – Relative Permeability End Points

Irreducible Water Saturation (S_{wir}) = 30%

Residual Gas Saturation (S_{gr}) = 20%

Relative Permeability to Gas (K_{rg}) at $S_{wir} = 0.9$

Relative Permeability to Water (K_{rw}) at $S_{gr} = 0.29$

Figure 15 - Simulation model gas-water relative permeability curves.

Relative permeability is a source of much uncertainty in reservoir simulation and, as previously mentioned, little data is reported in the literature for gas-water systems. It is common practice in the industry to use oil-water relative permeability for gas-water systems when no measured data is available. A commonly used method for estimating oil-water relative permeability using empirical correlations was developed by Honarpour et al (1982). A comparison of the gas relative permeability

used in this study compares favorably with estimates using the Honarpour correlations assuming water-wet sandstone. The water relative permeability calculated using Honarpour is roughly half the values used in this study suggesting that this study will conservatively overestimate water production rates.

In addition to relative permeability, capillary pressure is the other saturation dependent rock property and that can influence fluid flow in the reservoir. The impact of capillary pressure is diminished as the difference in gas and water densities increase. As is a common practice in the reservoir simulation of gas-water systems, capillary pressure was ignored in this study.

4.4 Well Loading and Vertical Flow

In addition to the description of fluid flow within the reservoir and from the reservoir to the wellbore, an accurate evaluation of the recovery from gas-water reservoirs also requires the calculation of frictional and hydrostatic losses in the wellbore. This is necessitated by the fact that in actual operating situations, fluid flow from a well is not controlled at the wellbore but rather at the surface. Furthermore, a gas well producing from a water-drive reservoir will ultimately cease production as a result of a combination of excessive liquid production and low gas flow rates. Increasing amounts of produced water result in an increasing flowing bottom-hole pressure. This increase in bottom-hole pressure ultimately reduces the gas rate to the point where the velocity of the gas in the tubing string is no longer high enough to remove additional water from the well. The water eventually settles in the wellbore and the well “loads” with water and ceases production. Unless the flowing surface

pressure is reduced or the tubing is replaced with a smaller diameter, the well is no longer capable of production and has reached abandonment conditions.

The minimum gas flow rate that provides continuous removal of liquids from gas wells was investigated extensively by Turner et al (1969). This study compared both a continuous film and entrained liquid drop model to an extensive database of actual field data. It was observed that the entrained drop model more accurately predicted the onset of liquid loading but still required adjustment to agree with field data. Flow area and pressure were determined to be the primary controlling factors and a set of equations and a nomograph were presented to allow the estimation of the minimum unloading rate for a particular situation.

A loading rate was estimated using the Turner equations for a flowing tubing pressure of 500 psia and 2.441 inch internal diameter. These conditions were selected as typical Gulf Coast values and resulted in a loading gas rate of 1.22 million standard cubic feet per day. This condition was treated as the point where loading occurred and production ceased for all of simulation runs in this study.

Specifying a target parameter and operational constraints controls production from a well in a reservoir simulation model. In a gas-water simulation, the target parameter is typically a gas production rate or a well operating pressure while the constraints are typically water rates, water-gas ratios, and/or minimum pressures. At each simulation time step, the simulator attempts to produce the well at the target value while verifying that none of the specified constraints is violated. If any of the specified constraints is violated while attempting to operate at the target parameter, the target is abandoned and the worst offending violated constraint becomes the new

target. This process is repeated at each time step and often results in well control switching between the various specified constraints several times during the life of a well.

Production from each simulation run in this study was controlled first with a specified gas production rate target, and then by either a minimum flowing tubing pressure or maximum water production rate constraint. The application of a flowing tubing pressure constraint requires a calculation of the hydrostatic and frictional losses in the tubing string. If the specified gas production rate results in a flowing tubing pressure less than the specified value, control of the gas production rate switches to the flowing tubing pressure constraint.

The Eclipse reservoir simulation program allows the use of flowing tubing pressures as a constraint through a multi-dimensional interpolation process that requires elaborate arrays of pressure and flow rate values calculated prior to the actual reservoir simulation. The process of calculating these values requires the selection of one of the numerous two-phase flow correlations available in the literature. The majority of these correlations were developed for oil, water, and gas flow. For purposes of this study, a more recent procedure reported by Reinicke et al (1984) was utilized. This procedure was one of the few reported in the literature that considered gas and water flow and utilized data collected from numerous actual flowing gas wells. The array of values calculated with this procedure and applied in all reservoir simulation runs in this investigation is graphically depicted in Figure 16. These calculations assumed a 500 psi flowing tubing pressure and 2.441 inch internal tubing diameter to be consistent with the loading calculation. Furthermore, a vertical depth of

5,000 feet was assumed. Figure 16 was constructed using families of water-yield for presentation purposes. The actual Eclipse data referred to as “VFP” tables is included in Appendix B.

Figure 16 - Estimated flowing bottom-hole pressure with 500 psia flowing tubing pressure.

CHAPTER 5 - BASE CASE

This section describes the results from a typical reservoir simulation run using the model geometry depicted in Figure 7 and a perforated interval of 50 feet at the top of the gas zone. The base case assumes a maximum gas production constraint of 20 million standard cubic feet per day, and a minimum flowing tubing pressure of 500 psia. The maximum water production rate was constrained to 2,000 barrels of water per day and each simulation was terminated when liquid loading was assumed at a gas rate of 1.22 million standard cubic feet per day. The base case reservoir permeability was assumed equal 100 millidarcies in the horizontal and 10 millidarcies in the vertical direction.

Figure 10 illustrates the initial water saturation profile for the simulation with the simulation grid removed to improve clarity. The wellbore is located at the far left and the gas/water contact is located at 5,100 feet. The completion interval of 50 feet and the wellbore are also identified on Figure 10. Figures 17, 18, and 19 show the movement of the gas/water contact and the development of a water cone into the well after two, four, and six years of production. As illustrated in Figure 17, a water cone is beginning to form and is nearing the completion interval after two years of production. Figure 18 shows that the water cone has reached the completion interval after four years of production and the gas/water contact has moved vertically to sweep nearly half of the productive interval. Finally, Figure 19 shows the reservoir nearing depletion. The water cone covers approximately 80% of the completion interval and a similar proportion of the reservoir has also been swept with water.

Figure 17 - Water saturation profile following two years of production.

Figure 18 - Water saturation profile following four years of production.

Figure 19 - Water saturation profile following six years of production.

Figure 20 illustrates the gas and water production history of the example reservoir simulation case. The maximum production rate of 20 MMSCF/Day is maintained for nearly six years after which time the limiting flowing tubing pressure is reached and production rate falls abruptly. Significant water production begins after the third year and increases exponentially. In addition to the actual production rates, the ratio of barrels of water per MMSCF is also plotted on Figure 20. When expressed as a ratio, significant water production does not occur until after the sixth year even though the vast majority of the completion interval has been covered with the water cone. This observation is consistent with the behavior suggested by the simplified horizontal fluid flow equations discussed in Chapter 3 and graphically illustrated in Figure 6.

Figure 20 – Forecast base case gas and water production rates.

Figure 21 illustrates the cumulative recovery of gas and water from the example reservoir simulation as a function of total time. This figure is significant in that it illustrates that nearly all of the gas has been recovered prior to the rapid increase in water production after the sixth year. Finally, Figure 22 shows the reservoir, bottom-hole, and flowing surface pressures for the simulation over the life of the well. As indicated by the figure, the minimum flowing surface pressure constraint of 500 psi is reached after approximately 5 ½ years and, as expected, production rates fall from that point on. The slight increase in tubing pressure occurring near the end of the life of the well results from reaching the maximum water production rate constraint of 2,000 barrels of water per day (as can be seen in Figure 20).

Figure 21 - Forecast base case cumulative gas and water production.

Figure 22 - Forecast base case pressure behavior.

CHAPTER 6 - IMPACT OF PERFORATED INTERVAL

The radial reservoir simulation model was used to evaluate the impact of the length of perforated interval on recovery and well behavior from water-drive gas reservoirs. The cumulative gas and water recoveries from three simulation runs are illustrated in Figure 23. In addition to the 50 foot perforated interval discussed previously, this figure shows the results from a 10-foot perforated interval at the top of the 100-foot gas zone as well as a simulation run with the entire 100-foot interval perforated. Aside from the change in perforated interval, all model properties and production constraints were identical for all three simulation runs.

Figure 23 – Impact of the length of perforated interval on cumulative water and gas production.

As indicated by the figure, the length of the perforated interval for this particular reservoir system does not significantly impact ultimate gas recovery. Ultimate water production varies by approximately a factor of two. While this increase in water production is significant, it is perhaps far less than what would be expected for an order of magnitude increase in the length of the perforated interval. Also of significance is the increase in the life of the production between the 10-foot and the 50 and 100-foot simulation runs. This increase is the result of a shorter production period at the maximum flat production rate of 20 MMCFPD and a longer period of production decline. This increase in life has a significant economic impact when the present value of the production is considered.

The behavior illustrated in Figure 23 could be expected to vary significantly with changes in reservoir permeability. To evaluate the impact of permeability and perforated interval, a series of thirty simulations were run at permeabilities ranging from 1 to 1,000 millidarcies. Perforated intervals of 10, 25, 50, 75, 100, and 110 feet were evaluated. Note that the 110-foot interval includes ten feet below the original gas/water contact.

The ultimate gas recovery to abandonment for these runs is illustrated in Figure 24. For permeabilities of 100 and 1,000 millidarcies, the indicated ultimate gas recovery is insensitive to perforated interval. In both these cases the reservoir is essentially completely swept with water but the recovery in the 100 millidarcy case is slightly higher than the 1,000 millidarcy case due to a higher abandonment pressure. A reduction in the system permeability to 10 millidarcies results in an increase in recovery with the larger completion intervals. This results from a reduction in aquifer

influx at the lower permeability with a subsequent reduction in abandonment pressure while still sweeping essentially the entire reservoir with water. At smaller perforated intervals, however, the reduction in perforated interval results in loss of well productivity with well loading rates reached before the entire reservoir is swept with water. As permeabilities are reduced further, the amount of perforated interval (and hence well productivity) completely dominates the predicted recovery. Of significant interest is that in all instances, decreasing the perforated interval never increases ultimate recovery and can significantly reduce recovery in low permeability systems.

Figure 24 – Impact of perforated interval and permeability on ultimate gas recovery.

Figure 25 illustrates the forecast ultimate water production from the same series of simulation runs. As expected, increases in perforated interval increase ultimate water production as the perforations are extended toward the original

gas/water contact. The amount of water production, however, is far less sensitive to the order of magnitude change in perforated interval than might be expected.

Of significance from an economic point of view is the impact of the perforated interval on well life. Figure 26 illustrates the well life from reservoir simulations run at the same range of permeabilities and perforated intervals. At the higher permeabilities, the length of perforated interval does not significantly impact well life because the well produces at the maximum rate for nearly the entire life of the well. At lower permeabilities, a reduction in perforated interval increases well life as the lower well productivity shortens the duration of the flat, maximum production rate period. At the lowest permeability considered the increase in the life of the well results from a significant increase in ultimate recovery as seen in Figure 24.

Figure 25 - Impact of perforated interval and permeability on ultimate water production.

The simulation runs discussed in this chapter used a maximum gas production rate constraint of 20 MMSCF/day. The cases considering permeabilities of five millidarcys or less were not capable of producing initially at this rate even when the entire productive interval was perforated. The 10 millidarcy case required a 75 foot perforated interval to produce initially at 20 MMSCF/day. Only the 100 and 1,000 millidarcy cases were capable of producing at the maximum rate constraint with a 10 foot perforated interval, the smallest considered. Variability in production rate can have a pronounced impact on water and gas recovery and is addressed in detail in the following chapter.

Figure 26 - Impact of perforated interval and permeability on producing life.

CHAPTER 7 - IMPACT OF PRODUCTION RATE

Maximum gas production rate in the previous sections was constrained to 20 million standard cubic feet per day. A series of simulations were run with a 50-foot perforated interval while varying this production constraint. The forecast ultimate gas recovery for these simulations is illustrated in Figure 27. At the maximum permeability of 1,000 millidarcies, aquifer influx was adequate to maintain pressure and ultimate gas recovery was not influenced by withdrawal rate. When a permeability of 100 millidarcies was used in the simulation, an increase in recovery was forecast that resulted from a lowered abandonment pressure as aquifer influx was unable to completely replace reservoir voidage. This trend was repeated for all of the permeabilities and was most pronounced in the 5 millidarcy simulation. At a permeability of 2 millidarcies, recovery was impacted only slightly due to very limited aquifer influx and pressure depletion dominating the recovery. The significant conclusion that can be drawn from this series of simulations is that curtailing the production rate never results in an increase in ultimate recovery and can significantly reduce recovery.

The impact on ultimate water production from the same series of simulation runs is illustrated in Figure 28. For a permeability of 1,000 millidarcies, high production rates result in earlier water production and an increase in ultimate water production. In all other cases, however, ultimate water production either falls or is largely unaffected by increasing the maximum gas production rate constraint. The fall

in ultimate water production rate for the intermediate permeability cases is the result of greatly shortened well life.

Production rate can be expected to significantly impact the producing life of a well. Figure 29 dramatically shows the impact production rate can have on the well life. In reservoirs with permeability large enough to allow high production rates, curtailing rate can result in an order of magnitude increase in well life. The economic consequences of delayed recovery are significant and are discussed in detail in the next chapter.

Figure 27 – Impact of producing rate and permeability on ultimate gas recovery.

Figure 28 – Impact of producing rate and permeability on ultimate water production.

Figure 29 – Impact of producing rate and permeability on well life.

If curtailing gas production rate can not be expected to increase ultimate gas recovery and can actually result in a significant loss in recovery in low permeability systems, the logical extension is that increasing gas production rate in an existing well can be expected to possibly improve ultimate recovery. Actual experience with increasing production rate has had mixed result, however. Figure 30 illustrates recent well test data from a deep, South Louisiana gas reservoir. Gas production rate begins a gradual fall beginning with the onset of water production in late 1995. Gas production rates and tubing pressures continued to fall until mid 1998 when compression was installed resulting in a drop in flowing tubing pressure from over 700 psi to less than 500 psi. The gas production responded with a significant increase in rate while water production actually fell. If water production is expressed on the basis of barrels of water per million standard cubic feet of gas as shown in Figure 31, the drop in water production rate is very dramatic.

Figure 30 – Gas well “A” response to a drop in flowing tubing pressure.

Figure 31 – Gas well “A” water production response expressed as a water-gas ratio.

The production behavior for a second deep, South Louisiana gas well example is illustrated in Figure 32. This well produced a relatively stable gas and water production rate at a flowing tubing pressure of approximately 2,300 psi. In July of 1999, the choke was opened in an effort to increase the gas production rate. While the gas rate did temporarily increase, there was a disproportional increase in water production rate. When plotted on the basis of barrels of water per millions of standard cubic feet as shown in Figure 33, the increase in water production is dramatic. Water disposal costs for this well are quite high and the effort to increase income from this well by increasing the choke size was deemed a failure.

Figure 32 – Gas well "B" response to a drop in flowing tubing pressure.

Figure 33 – Gas well "B" water production response expressed as a water-gas ratio.

The water production behavior of the two gas well examples in response to a reduction in flowing tubing pressure is radically different. This difference in behavior can be explained by examination of the differences in the two reservoirs. Both wells produce from thick, relatively high permeability intervals and have produced for several years. In the first example, gas well "A", the reservoir pressure has been significantly depleted. With the combination of high rate and low reservoir pressure, a large pressure drawdown exists for this well which likely results in gas coning as depicted schematically in Figure 4. An increase in drawdown should be expected to decrease the flow rate of water relative to gas.

In the second example, gas well "B", the large gas reservoir was produced by several wells for many years with an active water-drive. Very little loss in reservoir pressure occurred suggesting the reservoir is extremely high permeability. The high flowing tubing pressures in conjunction with the high water production rates indicate the well is producing with a very high bottom-hole pressure and very little drawdown. With extremely small pressure drawdown, little tendency for coning exists and the relative flow of gas and water could be expected to approach the radial behavior as discussed in Chapter 3. Furthermore, the high water-gas ratio suggests that the vast majority of the perforated interval is covered with water. Since water production rate is proportional to the pressure drawdown and gas production rate is proportional to the difference in the squares of the well and reservoir pressure, an increase in water production could be expected. While this increase in water production is detrimental from an operating cost perspective, the results of the simulation study suggests that ultimate recovery should not be affected.

In summary, the behavior of the two gas well examples is consistent with the results of the simulation study. The first well is under a significant pressure drawdown and can be compared to the low permeability cases in the simulation study that showed an increased recovery with increased gas production rate and a reduced water production. The second well with little drawdown or loss in reservoir pressure can be compared to the high permeability cases of the simulation study that showed no impact on ultimate gas recovery while water production increased as gas rates were increased.

CHAPTER 8 - ECONOMIC CONSIDERATIONS

An economic evaluation of a well producing gas and water is impossible to accomplish without a detailed knowledge of the product price, drilling and completion costs, facility costs, pipeline costs, and operating costs (including water disposal). In practice, all of these factors vary widely due to such factors as location, existing infrastructure, and reservoir depth, size and geometry resulting in every well having a unique economic profile. Because of this uniqueness, an economic evaluation cannot be directly applied to the multiple simulation forecasts reported in this study. An attempt was made, however, to economically evaluate the forecasts by adopting simplified approaches. This economic analysis consists of three components: 1) the expression of operating costs as a cumulative produced water gas ratio, 2) an evaluation of the impact of producing life using "time discounted" production values, and 3) a simple discounted cash-flow analysis.

8.1 Ultimate Produced Water Gas Ratio

Water production from the numerous forecasts in this study can be expressed by dividing the ultimate water production to abandonment by the ultimate gas production to abandonment. This value, which incidentally becomes dimensionless if multiplied by a constant, can be considered as an indicator of the portion of a well's operating cost attributable to water production over the life of a particular forecast. This type of calculation has the advantage of allowing the comparison of forecasts where both the total water and gas production are impacted by a change in operating conditions.

The ultimate water-gas ratio was calculated for the various simulation forecasts evaluating the impact of perforated interval and production rate. Figure 34 illustrates the ultimate water-gas ratio as a function of perforated interval. This figure was constructed by dividing the ultimate water production illustrated in Figure 25 by the values of ultimate gas recovery illustrated in Figure 24. Inspection of the figure indicates that as perforated interval is lengthened, cumulative undiscounted operating costs attributable to water disposal increase. The increase in operating costs is perhaps less than might be expected, however. Except in the low permeability cases that have low water-gas ratio at all perforated intervals, an order of magnitude increase in the length of the perforated interval has a far lesser impact on the ultimate produced water-gas ratio.

Figure 34 – Sensitivity of operating costs (expressed as ultimate barrels of water per thousand standard cubic feet of gas) to perforated interval.

The same procedure was applied to the simulation runs that considered the impact of production rate and the results are illustrated in Figure 35. This figure was constructed by dividing the values of ultimate water production illustrated in Figure 28 by the ultimate gas recovery illustrated in Figure 27. It is worth noting that in all cases considered, the cumulative water to gas ratio remains under 0.06 barrels per MCF. For all cases except the highest permeability considered, operating costs expressed as an ultimate water-gas ratio were found to decrease with increased rate. The highest permeability case was found to have lower ultimate water-gas ratio values at low production rates as a result of delayed water breakthrough at low production rates. All other cases experienced immediate water breakthrough at the commencement of production.

Figure 35 - Sensitivity of operating costs (expressed as ultimate barrels water per thousand standard cubic feet of gas) to producing rate.

8.2 Time-Value-of-Money

Economic analysis in the oil and gas industry normally includes a calculation that “discounts” the cash flow from a project for the “time-value-of-money.” This discounting stems from the fact that a dollar to be received in the future is worth less than a dollar currently in possession. At least in theory, a dollar currently in possession can be invested and by the time a future dollar is received, its value would have grown to over the original dollar. Discounting a future revenue stream for the impact of time yields what is known as the “present value” of a cash flow. For a detailed discussion of the economic evaluation of investments, refer to the text by Franklin and John Stermole.

A discounted cash flow analysis normally divides the continuous income stream into time periods, usually months or years. A “discount factor” is calculated for each of the periods using the following formula:

$$\text{Discount Factor} = \frac{1}{(1+i)^n} \dots\dots\dots (8.1)$$

Where n is the time to the midpoint of the time period and the interest rate per time period, or discount rate, is given by i .

The use of discounting for the time value of money is normally applied to the final cash flow in a detailed economic analysis to arrive at a present value. This approach is not practical to evaluate the forecasts in this study for the reasons mentioned in the beginning of the chapter. A unique method was devised, however, to provide a method of evaluating the economic impact of time. This method applied

discount factors against gas and water production volumes as opposed to the final cash flow. A discount rate of 10% per year was selected as a value typically used in industry and required for present value reporting by the Securities and Exchange Commission for all publicly traded oil and gas companies. This discount rate was used to calculate a discount factor at the midpoint of each simulation time step (typically one month). The discount factor was multiplied by the production during the period and all of the periods in each forecast were summed to yield a time “discounted” volume.

This discounting procedure was applied to all of the simulation runs that evaluated the impact of perforated interval. The results of the numerous calculations are summarized graphically in Figures 36, 37, and 38. Figure 36 illustrates the discounted ultimate gas recovery and can be compared to the undiscounted values previously presented in Figure 24. As expected, both figures yield the same conclusion that increasing perforated interval can result in increased gas recovery in lower permeability systems and does not detrimentally impact recovery in any system considered. Figure 37 illustrates the same discounting procedure applied to the ultimate water production from the same forecasts. The equivalent undiscounted values were presented previously in Figure 25. As before, this analysis indicates a limited increase in ultimate water production can be expected as the perforated interval is lengthened.

Figure 36 - Impact of perforated interval and permeability on discounted ultimate gas recovery.

Figure 37 - Impact of perforated interval and permeability on discounted ultimate water production.

The discounted ultimate water production illustrated in Figure 37 can be divided by the discounted gas recovery illustrated in Figure 36 to provide a discounted ultimate water-gas ratio. As discussed in the previous section, this value can allow the relative comparison of water production (and hence water disposal costs) between the various simulation forecasts. The use of discounted values adds the impact of time to the calculation. This procedure was applied to the forecasts that evaluated perforated interval to create Figure 38. Recall the undiscounted values of ultimate water-gas ratio were illustrated in Figure 34. The result of this analysis confirms the conclusion drawn from Figure 34 that an increased perforated interval length results in a limited increase in ultimate operating costs when expressed on the basis of barrels of ultimate water production per ultimate gas recovery.

Figure 38 - Sensitivity of operating costs (expressed as discounted ultimate barrels of water per thousand cubic feet of gas) to perforated interval.

The impact of time using the discounting method was also applied to the simulation runs that evaluated the impact of producing rate. Figure 39 illustrates the impact of producing rate on discounted ultimate recovery. The similar illustration using undiscounted values is shown in Figure 27. As expected, the impact of rate on recovery becomes significant when discounting is applied to the recoveries. This figure clearly indicates that high rates improve recovery in all cases considered.

Figure 40 illustrates the impact of discounting on the ultimate water recovery for the forecasts evaluating the impact of production rate. The undiscounted values can be found on Figure 28. While the lowest rates result in lower discounted ultimate water production, the values quickly approach a constant for all but the highest permeability case. A similar trend is observed when the discounted water-gas ratio is plotted in Figure 41, undiscounted values can be found on Figure 35.

Figure 39 – Impact of producing rate on discounted ultimate gas recovery.

Figure 40 – Impact of producing rate on discounted ultimate water production.

Figure 41 - Sensitivity of operating costs (expressed as discounted ultimate barrels of water per thousand cubic feet of gas) to producing rate.

8.3 Discounted Cash Flow Analysis

A discounted cash flow analysis requires the calculation, at each time period, of the difference between the income derived from the sale of product and cash outlays for royalty, operating costs, and capital investments. For a producing gas well, this calculation can be simply expressed as follows:

$$\begin{array}{r} \text{Income from Gas Sales} \\ + \text{Income from Condensate Sales} \\ - \text{Royalty and Severance Tax} \\ - \text{Operating Costs} \\ - \text{Capital Investments} \\ \hline = \text{Net Cash Flow for Period} \end{array}$$

As mentioned previously, each gas well is unique which requires individual and specific economic analysis. For purposes of discussion, however, simplifying assumptions can be made to allow an approximate economic analysis. First, it can be assumed that the income from condensate sales offsets the royalty burden and severance taxes. Secondly, it can be assumed that water disposal costs make up the vast majority of operating costs. And finally, initial capital investments can be ignored, a so-called “point forward” economic evaluation. While these assumptions are admittedly not accurate for all situations and could not be used for actual decision analysis, they do allow for the easy calculation of a discounted cash flow, which provides insight into the relative economics of the individual forecasts presented in this study. Rewriting the calculation of cash flow with these assumptions yields:

$$\begin{aligned}
& \text{Gas Production in Period} \times \text{Gas Price} \\
& - \text{Water Production in Period} \times \text{Water Disposal Cost per Barrel} \\
\hline
& = \text{Net Cash Flow for Period}
\end{aligned}$$

Gas and water production volumes per time period are obviously available for all of the forecasts reported in this study. In addition, a relatively accurate gas price can be obtained by consulting recent historical spot prices for domestic gas. For example, the spot gas price for Louisiana severance tax calculations averaged approximately \$2 per MMBTU for the six months ending July 1999. This is equivalent to \$2/MCF if a calorific value of 1,000 BTU per standard cubic foot is assumed.

Water disposal costs, however, vary widely from location to location and no single value can be assumed as approximately representative. For this reason, several different water disposal costs were considered in the discounted cash flow analysis of the production forecasts reported in this study. Costs of \$0.10, \$1, and \$2 per barrel were chosen to represent low, moderate, and high water disposal costs.

Discounted cash flow analyses for all of the simulation forecasts considering the impact of perforated interval and production rate were calculated using a gas price of \$2 per MCF and the range of water disposal costs mentioned above. In a manner consistent with financial reporting requirements of the Security and Exchange Commission, gas price and water disposal cost per barrel were not escalated with time and a discount rate of 10% per year was used. Net present values that resulted from the discounted cash flow analyses using the "moderate" water disposal cost and the simulation forecasts considering the impact of perforated interval are illustrated in

Figure 42. While numerous simplifying assumptions were required to arrive at this figure, it is reasonable to conclude from the figure that discounted cash flow can be expected to significantly improve with increased perforated interval length in lower permeability systems. Furthermore, increased perforated interval in high permeability systems appears to have an insignificant impact on the discounted cash flow.

The discounted cash flow analysis procedure was repeated using the moderate water disposal cost for the simulation forecasts that considered the impact of production rate. The net present values resulting from these analyses are illustrated in Figure 43. This figure clearly indicates that a dramatic improvement in net present value can be expected at accelerated production rate over all permeability ranges.

Figure 42 – Impact of perforated interval on discounted net present value.

The discounted cash flow analyses were repeated for all of the forecasts illustrated in Figures 42 and 43 using the “low” and “high” water disposal cost scenarios. The net present value calculations were marginally impacted by the variation in water disposal cost. This can be explained by the revenue from gas production greatly exceeding water disposal costs, even in the high water disposal cost scenarios.

Figure 43 - Impact of production rate on discounted net present value.

CHAPTER 9 - SENSITIVITY ANALYSIS

The conclusions drawn from this study can be sensitive to many of the parameters that were held constant in the previous simulation runs. The parameters most likely to have an impact are those factors that impact the relative flow of gas and water. These include: 1) the vertical permeability that could influence water coning, 2) the density contrast between gas and water that controls vertical segregation of the two phases, and 3) the relative permeability of the two phases. Conspicuously absent from the above list is the viscosity of the two phases. Since the viscosity of water and gas are well known, sensitivity analysis of viscosity differences within the reasonable narrow ranges possible was unnecessary.

Non-darcy flow (or rate sensitive skin damage) occasionally occurs in high rate gas wells and is the result of turbulent flow at the wellbore. It should be recognized that non-darcy gas flow would result in a reduction of gas flow rate relative to water for a given well drawdown. Sensitivity analysis of this parameter was not undertaken due to the infrequent occurrence of non-darcy flow and the uniqueness of the individual well behavior when it does occur.

Finally, the impact of structure would certainly play a role in the behavior of wells producing from water-drive gas reservoirs. While the forecasts reported to this point in this study assume the well is located at the top of the structure, this situation in actuality occurs only occasionally. The impact of structural position was investigated in a series of reservoir simulation runs.

9.1 Vertical to Horizontal Permeability Ratio

Logic would suggest that the vertical flow of bottom-water could be significantly impacted by the selection of the vertical to horizontal formation permeability. All the previous reservoir simulation runs assume a vertical to horizontal ratio of 0.1. While this is a commonly used value in reservoir simulation studies, this ratio could vary significantly in actual situations.

To consider the sensitivity of this parameter, the base case forecast was repeated with vertical to horizontal permeability ratios of 0.5 and 1. Vertical permeability equal to the horizontal permeability is likely the upper limit of this ratio in all but the most unusual situations. The life and ultimate gas and water recoveries from these runs are compared to the base case in Table 4.

As indicated by Table 4, ultimate gas recovery and well life are not significantly impacted by the vertical to horizontal permeability ratio. The ultimate water recovery is influenced significantly, however. Figure 44 illustrates the

Table 4 - Comparison of Well Life and Recoveries as a Function of Vertical to Horizontal Permeability Ratio

	<u>Vertical to Horizontal Permeability Ratio</u>		
	<u>0.1</u>	<u>0.5</u>	<u>1.0</u>
Life (years)	7.16	7.41	7.57
Ultimate Gas (BCF)	46.34	46.14	46.13
Ultimate Water (Millions of Barrels)	0.94	1.41	1.64

cumulative water production behavior for the three cases considered. Note that the time scale begins after 3 years of production, or nearly half the ultimate life of the forecasts. Inspection of the figure indicates that while an increase in the vertical to horizontal permeability ratio increases ultimate water production, the majority of this increase occurs late in the life of the well. Except in cases of extreme water disposal costs, the economic impact of this increase in water production is diminished significantly when the time-value of money is considered.

9.2 Fluid Density Contrast

The density contrast between gas and water and the influence of gravity act to suppress the coning of water in water-drive gas reservoirs. The density contrast

Figure 44 - The impact of vertical to horizontal permeability ratio on cumulative water production.

between the phases can be expected to have some impact on the results of the reservoir simulation forecasts reported in this study. To investigate this impact, the base case simulation case was repeated with twice and half the gas density of the base case. This effectively models the situation where the system pressure is halved and doubled. The life and ultimate gas and water recoveries from these runs are compared to the base case in Table 5. As indicated by the table, well life and fluid recoveries are insensitive to density variations.

9.3 Relative Permeability

As discussed in Section 4.3, relative permeability is one of the greatest uncertainties in this study. To investigate this impact, the base simulation case was repeated with twice and half the original water relative permeability of the base case. The values of relative permeability are often compared by plotting the ratio of gas to

Table 5 - Comparison of Well Life and Recoveries as a Function of Gas Density

	<u>Variation of Gas Density</u>		
	<u>Half</u>	<u>Base</u>	<u>Double</u>
Life (years)	7.16	7.16	7.07
Ultimate Gas (BCF)	46.31	46.34	46.40
Ultimate Water (Millions of Barrels)	0.96	0.94	0.90

water relative permeability as indicated in Figure 45. The life and ultimate gas and water recoveries from runs using these relative permeability curves are compared to the base case in Table 6.

As indicated by the table, ultimate gas recovery and well life are impacted insignificantly by the variation in relative permeability. The ultimate water recovery is influenced significantly, however. Figure 46 illustrates the cumulative water production behavior for the three cases considered. Note that the time scale begins after 3 years of production, or nearly half the ultimate life of the forecasts. Inspection of the figure indicates that while an increase in water relative permeability increases ultimate water production, the majority of this increase occurs late in the life of the well. Except in cases of extreme water disposal costs, the economic impact of this increase in water production is diminished significantly when the time-value of money is considered.

Table 6 - Comparison of Well Life and Recoveries as a Function of Gas to Water Relative Permeability

	<u>Variation in Gas to Water Relative Permeability Ratio</u>		
	<u>Half</u>	<u>Base</u>	<u>Double</u>
Life (years)	7.24	7.16	7.24
Ultimate Gas (BCF)	46.20	46.34	46.38
Ultimate Water (Millions of Barrels)	1.36	0.94	0.65

Figure 45 - Relative permeability ratios used in sensitivity simulation runs.

Figure 46 - The impact of water relative permeability on cumulative water production.

9.4 Structural Relief

All of the reservoir simulation runs considered to this point used the "layer cake" model depicted in Figure 7. This geometry was selected because of its ability to accurately model water coning through the use of a fine vertical and a logarithmically distributed, horizontal radial grid. The selection of this symmetric, radial grid required the well to be completed in the center of the reservoir at the top of the productive interval. In actual situations, however, reservoirs have structural dip and the wells are rarely completed at the structurally highest position. This limitation of the radial grid system is an unfortunate compromise that is required to accurately model coning behavior with small grids.

Simulation of dipping reservoirs is normally accomplished through cartesian or corner-point gridding systems. While these types of grids can accurately model the shape and dip of a reservoir, the large grid block size and orthogonal orientation of the grids make them poorly suited for the modeling of wellbore phenomenon such as coning. To overcome this problem, a method known as "local grid refinement", or LGR, was employed. This simulation technique allows the subdivision of a vertical column of grid blocks into a subset of grid blocks that have a radial distribution in the horizontal direction. Vertical layers can also be subdivided into thinner thicknesses if desired.

The LGR technique was utilized to construct an example simulation model to investigate the impact of formation dip and any changes in behavior observed by the radial model. Figure 47 is a plan view (XY) of the cartesian grid used with a well located in the upper third of the figure. An exploded view of the radial grid refinement

illustrates the eight exponentially distributed radial grids and four quadrants of the radial LGR. The geometry of the system was selected to provide roughly the same initial gas in place as the radial model. The global grid consisted of 11 by 30 horizontal square grids, 345 feet on each side. Vertical layering consisted of 30, ten feet thick grids. All rock and fluid properties were identical to those used in the radial model simulations. The initial gas water contact was set at a depth of 5,100 feet resulting in an initial gas in place of 62.6 billion standard cubic feet. An infinite acting aquifer was simulated by increasing the porosity in the cells at the outer, down-dip boundary to an extremely large value. The producing well was located approximately in the center of the productive portion of the reservoir.

It should be emphasized that while this model was used to describe an example case where the reservoir has a tilting structure, no model can be constructed to describe the "typical" geometry of the reservoirs encountered in nature. The shape, dip, size, and thickness of every reservoir is unique and varies widely. Furthermore, the placement of the well in the reservoir also impacts the predicted recovery. These many parameters will influence the ultimate gas and water production rates and ultimate recovery. In the simple radial model case with the well located at the top and geometric center of the reservoir, the entire reservoir was effectively swept with water in all cases considered except for the low permeability cases that pressure depleted. Recovery in these cases became predominately controlled by abandonment pressure. In cases considering complex geometries, the added factor of widely varying sweep efficiency significantly complicates the predicted reservoir recoveries.

Figure 47 – Plan view of tilted simulation model with radial local grid refinement.

Figure 48 – Vertical cross-section of tilted simulation model with radial local grid refinement.

The initial water saturation distribution in the dipping system is illustrated in Figure 49. The grid lines have been removed from this figure for clarity. As indicated by the figure, a significant amount of gas is located structurally up-dip from the production well. An additional feature of this model is the influence of water encroachment as an edge water drive. The impact of this deviation can be observed in Figures 50, 51, and 52 illustrating the position of the water movement for an example simulation case after two, four, and six years of production, respectively. Abandonment for this simulation case occurred shortly after six years resulting in a significant volume of unrecovered up-dip gas opposite the direction of water encroachment.

Figure 49 – Initial water saturation distribution for tilted simulation model.

Figure 50 – Water distribution for tilted simulation model following two years of production.

Figure 51 – Water distribution for tilted simulation model following four years of production.

Figure 52 – Water distribution for tilted simulation model following six years of production.

Investigation of the impact of perforated interval for a wide range of permeabilities was studied using the tilted simulation model in the same manner as the radial model discussed in Chapter 6. Figure 53 illustrates ultimate gas recovery, Figure 54 illustrates ultimate water production, and Figure 55 illustrates well life for a variety of formation permeabilities and lengths of perforated interval. Inspection of these figures indicates a behavior similar to the results observed in the radial model simulation runs. Increased length of perforated interval results in an increase in ultimate gas recovery and an increase in ultimate water production. Increased length of perforated interval results in a decrease in well life in all but the low permeability cases. The increase in life for the low permeability cases is a consequence of the greatly increased ultimate recovery.

Figure 53 - Impact of perforated interval and permeability on ultimate gas recovery in an example tilted reservoir simulation model.

Figure 54 - Impact of perforated interval and permeability on ultimate water production in an example tilted reservoir simulation model.

Figure 55 - Impact of perforated interval and permeability on well life for an example tilted reservoir simulation model.

The impact of producing rate was also investigated with the tilted reservoir simulation model and a 50 feet thick perforated interval in a manner similar to the radial simulation study discussed in Chapter 7. Figure 56 illustrates the ultimate gas recovery, Figure 57 illustrates ultimate water production, and Figure 58 illustrates well life for a variety of formation permeabilities and maximum production rates. While not as consistent as the radial simulation study, Figure 56 indicates that ultimate gas recovery generally improves with increasing production rate. Figure 57 suggests that increased rate results in a decrease in ultimate water production in all but the highest permeability case, largely the result of the shortened well life illustrated in Figure 58. All of these results are consistent with the radial simulation study, particularly if the time-value-of-money is considered.

Figure 56 - Impact of producing rate and permeability on ultimate gas recovery in an example tilted reservoir simulation model.

Figure 57 - Impact of production rate and permeability on ultimate water production in an example tilted reservoir simulation model.

Figure 58 - Impact of production rate and permeability on well life for an example tilted reservoir simulation model.

CHAPTER 10 - CONCLUSIONS

State of the art reservoir simulation, coupled with two-phase flow wellbore and loading models were utilized to rigorously investigate completion and production practices from water-drive gas reservoirs. These results were compared with field experience and simplified analytical analysis to arrive at the following conclusions:

1. Analytical analysis indicates that bottom water-drive gas reservoirs can be expected to flow with a small water-gas ratio until nearly the entire perforated interval is flowing water. Furthermore, the extremely low viscosity of gas results in the ability to produce high gas rates from very thin flowing intervals at reasonable, Gulf Coast values of reservoir permeability.
2. Simulation analysis of the impact of perforated interval length indicates that ultimate gas recovery is never detrimentally impacted with increased length. Ultimate water production can be expected to increase in high permeability systems, however.
3. Analysis of the impact of gas withdrawal rate indicates that elevating gas rates should also never detrimentally impact ultimate gas recovery. In lower permeability systems, increasing rate was found to significantly improve ultimate gas recovery.
4. Maximized gas withdrawal rates can be expected to increase ultimate water production in high permeability systems and to decrease ultimate water production in low permeability systems.
5. Economic analysis strengthens the case for maximizing gas production rate.
6. Sensitivity analysis of vertical to horizontal permeability ratio, fluid density contrast, relative permeability, and formation dip does not alter the above conclusions.

7. These findings favor the completion of an interval sufficiently long to maximize production rate and thereby insure that gas recovery is maximized. In high water disposal cost situations, however, it should be recognized that this strategy might result in elevated water production in high permeability systems.

8. When considering a rate change in an existing well, this study indicates that an improvement in gas-water ratio can be expected if the gas production rate is increased in a well experiencing a significant drawdown. In high permeability systems that can typically be identified by low drawdown, an increase in rate can result in a disproportionate increase in water production, however. This increase in water production rate should have no detrimental impact on ultimate gas recovery.

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APPENDIX A - EXAMPLE ECLIPSE DATA DECK

```

Runspec
Title
    Sensitivity to Perforated Interval Run - 100 md, 50 feet perforated
MESSAGES
    6* 3*5000 /
Radial
Dimens
    -- NR      Theta      NZ
       26      1        110      /
Gas
Water
Field
Regdims
    2      /
Welldims
    -- Wells      Con
       1        100      /
VFPPDIMS
    10 10 10 10 0 1 /
Start
    1 'Jan' 1998 /
Nstack
    100 /
Unifout
-----Grid
Tops
    26*5000 /
Inrad
    0.333 /
DRV
    0.4170 0.3016 0.4229 0.5929 0.8313 1.166
    1.634 2.292 3.213 4.505 6.317 8.857
    12.42 17.41 24.41 34.23 48.00 67.30
    94.36 132.3 185.5 260.1 364.7 511.4
    717.0 2500 /
DZ
    2600*1
    234*10
    26*110
/
Equals
    'DTHETA'      360      /
    'PERMR'       100      /
    'PERMTHT'     100      /
    'PERMZ'       10       /
    'PORO'        0.25     /
    'PORO'        0        26 26 1 1 1 100 /
    'PORO'        10       26 26 1 1 101 110 /
/
INIT
--RPTGRID
--1 /
-----PROPS
DENSITY
    45      64      0.046      /
ROCK
    2500    10E-6      /
PVTW

```

```

2500      1      2.6E-6    0.68      0      /
PVZG
-- Temperature
120      /
-- Press      Z      Visc
100      0.989    0.0122
300      0.967    0.0124
500      0.947    0.0126
700      0.927    0.0129
900      0.908    0.0133
1100     0.891    0.0137
1300     0.876    0.0141
1500     0.863    0.0146
1700     0.853    0.0151
1900     0.845    0.0157
2100     0.840    0.0163
2300     0.837    0.0167
2500     0.837    0.0177
2700     0.839    0.0184
/
--Saturation Functions
--Sgc =      0.20
--Krg @ Swir =      0.9
--Swir =      0.3
--Sorg =      0.0
SGFN
--Using Honarpour Equation 71
--      Sg      Krg      Pc
0.00     0.000    0.0
0.20     0.000    0.0
0.30     0.020    0.0
0.40     0.081    0.0
0.50     0.183    0.0
0.60     0.325    0.0
0.70     0.900    0.0
/
SWFN
--Using Honarpour Equation 67
--      Sw      Krw      Pc
0.3      0.000    0.0
0.4      0.035    0.0
0.5      0.076    0.0
0.6      0.126    0.0
0.7      0.193    0.0
0.8      0.288    0.0
0.9      0.422    0.0
1.0      1.000    0.0
/
-----REGIONS
Fipnum
2600*1
260*2
/
-----SOLUTION
EQUIL
5000      2500      5100      0      5100      0      /
RPTSOL
6* 2 2 /
-----SUMMARY
SEPARATE
RPTONLY
WGPR
/

```

```

WWPR
/
WBHP
/
WTHP
/
WGPT
/
RPR
1 2 /
TCPU
-----SCHEDULE
NOECHO
INCLUDE
  'GWVFP.VFP' /
ECHO
RPTSCHED
  6*      2      /
RPTRST
  4      /      restarts once a year
TUNING
  0.0007  30.4  0.0007  0.0007  1.2  /
  3* 0.00001  3* 0.0001  /
  2*      100  /
WELSPCS
  'P' 'G' 1 1 5000 'GAS' 2* 'STOP' 'YES' /
/
COMPDAT
  'P' 1 1 1 50 'OPEN' 2* 0.666 /
/
WCONPROD
  'P' 'OPEN' 'THP' 1* 2000 20000 2* 600 500 1 /
/
WECON
  'P' 1* 1220 4* 'YES' /
/
TSTEP
  48*30.4      /
TSTEP
  48*30.4      /
TSTEP
  48*30.4      /
TSTEP
  48*30.4      /
TSTEP
  48*30.4      /
TSTEP
  48*30.4      /
TSTEP
  48*30.4      /
End

```


APPENDIX B - ECLIPSE VFP INCLUDE FILE

```

-- Gas Water Coning Study VFP Tables
-- John McMullan
-- Fall 1999
--
--TABLE DIMENSIONS:  RATES-10    THP- 7    WFR- 8    GFR- 1    ALQ-1
--VFP TABLE        1

VFPPROD

    1      5.00000E+03    'GAS'    'WGR'    'OGR'
/

    5.00000E+02    1.00000E+03    2.50000E+03    5.00000E+03
    7.50000E+03    1.00000E+04    1.50000E+04    2.00000E+04
    2.50000E+04    3.00000E+04
/

    1.00000E+02    2.50000E+02    5.00000E+02    7.50000E+02
    1.00000E+03    1.50000E+03    2.00000E+03
/

    0.00000E+00    1.00000E-01    2.00000E-01    3.00000E-01
    5.00000E-01    7.50000E-01    1.00000E+00    2.00000E+00
/

    0.00000E+00
/

    0.00000E+00
/

    1      1      1      1      1.20672E+02    1.44269E+02    2.49890E+02    4.54176E+02
                                6.63321E+02    8.71983E+02    1.28442E+03    1.69021E+03
                                2.09117E+03    2.49024E+03
/

    1      2      1      1      1.98848E+02    2.42908E+02    3.97820E+02    6.44042E+02
                                9.09626E+02    1.19316E+03    1.77829E+03    2.36966E+03
                                2.96875E+03    3.58206E+03
/

    1      3      1      1      2.16794E+02    2.50508E+02    4.18504E+02    7.65954E+02
                                1.14182E+03    1.52637E+03    2.30276E+03    3.09262E+03
                                3.90880E+03    4.76314E+03
/

    1      4      1      1      2.31640E+02    2.66463E+02    4.87042E+02    9.29204E+02

```

				1.39468E+03	1.86737E+03	2.82736E+03	3.82126E+03
				4.87204E+03	5.99862E+03		
/							
1	5	1	1	2.66086E+02	3.28744E+02	6.57535E+02	1.26698E+03
				1.90238E+03	2.54724E+03	3.88794E+03	5.34484E+03
				6.96453E+03	8.77119E+03		
/							
1	6	1	1	3.19895E+02	4.19953E+02	8.73915E+02	1.69228E+03
				2.53375E+03	3.40229E+03	5.29436E+03	7.48496E+03
				1.00354E+04	1.29720E+04		
/							
1	7	1	1	3.82156E+02	5.19538E+02	1.09338E+03	2.10912E+03
				3.16071E+03	4.27992E+03	6.84776E+03	9.97298E+03
				1.37192E+04	1.81095E+04		
/							
1	8	1	1	6.90124E+02	9.73085E+02	1.96708E+03	3.75344E+03
				5.87158E+03	8.45262E+03	1.52028E+04	2.30000E+04
				2.30000E+04	2.30000E+04		
/							
2	1	1	1	2.81404E+02	2.92146E+02	3.55468E+02	5.18082E+02
				7.06913E+02	9.04081E+02	1.30390E+03	1.70292E+03
				2.09997E+03	2.49672E+03		
/							
2	2	1	1	4.07842E+02	3.89206E+02	4.89037E+02	7.06513E+02
				9.58657E+02	1.23161E+03	1.80268E+03	2.38616E+03
				2.98077E+03	3.59168E+03		
/							
2	3	1	1	4.36917E+02	4.12627E+02	5.28068E+02	8.48709E+02
				1.20574E+03	1.57490E+03	2.33235E+03	3.11270E+03
				3.92439E+03	4.77668E+03		
/							
2	4	1	1	4.61776E+02	4.48990E+02	6.06351E+02	1.01265E+03
				1.45776E+03	1.91605E+03	2.85869E+03	3.84477E+03
				4.89257E+03	6.01664E+03		
/							
2	5	1	1	5.21384E+02	5.29332E+02	7.69372E+02	1.33403E+03
				1.94601E+03	2.57889E+03	3.90974E+03	5.36483E+03

				6.98283E+03	8.78891E+03		
/							
2	6	1	1	6.07773E+02	6.40764E+02	9.84294E+02	1.74471E+03
				2.56333E+03	3.42222E+03	5.30865E+03	7.49898E+03
				1.00490E+04	1.29858E+04		
/							
2	7	1	1	7.02270E+02	7.60546E+02	1.20707E+03	2.15771E+03
				3.18645E+03	4.29612E+03	6.85840E+03	9.98255E+03
				1.37286E+04	1.81181E+04		
/							
2	8	1	1	1.09491E+03	1.25181E+03	2.07296E+03	3.79125E+03
				5.89157E+03	8.46727E+03	1.52149E+04	2.30000E+04
				2.30000E+04	2.30000E+04		
/							
3	1	1	1	5.58554E+02	5.63910E+02	5.98336E+02	7.04836E+02
				8.50832E+02	1.01826E+03	1.38183E+03	1.76046E+03
				2.14469E+03	2.53266E+03		
/							
3	2	1	1	7.53823E+02	6.96883E+02	7.08584E+02	8.75109E+02
				1.10350E+03	1.35700E+03	1.89911E+03	2.46313E+03
				3.04352E+03	3.64296E+03		
/							
3	3	1	1	7.93278E+02	7.47771E+02	7.91654E+02	1.02965E+03
				1.34300E+03	1.68683E+03	2.41539E+03	3.17876E+03
				3.97808E+03	4.82072E+03		
/							
3	4	1	1	8.39288E+02	8.02856E+02	8.77760E+02	1.18784E+03
				1.58237E+03	2.01144E+03	2.92237E+03	3.89126E+03
				4.92793E+03	6.04558E+03		
/							
3	5	1	1	9.40783E+02	9.20082E+02	1.05714E+03	1.51102E+03
				2.06727E+03	2.66842E+03	3.96531E+03	5.40243E+03
				7.01026E+03	8.81051E+03		
/							
3	6	1	1	1.07420E+03	1.07215E+03	1.28853E+03	1.92183E+03
				2.68055E+03	3.50699E+03	5.35998E+03	7.53351E+03
				1.00748E+04	1.30075E+04		

/

3	7	1	1	1.20650E+03	1.22301E+03	1.51930E+03	2.33041E+03
				3.29818E+03	4.37642E+03	6.90662E+03	1.00156E+04
				1.37546E+04	1.81421E+04		

/

3	8	1	1	1.65284E+03	1.74156E+03	2.35846E+03	3.93672E+03
				5.98765E+03	8.53770E+03	1.52591E+04	2.30000E+04
				2.30000E+04	2.30000E+04		

/

4	1	1	1	8.38994E+02	8.42486E+02	8.65356E+02	9.40492E+02
				1.05214E+03	1.18925E+03	1.50843E+03	1.85863E+03
				2.22398E+03	2.59883E+03		

/

4	2	1	1	1.07932E+03	1.01537E+03	1.00056E+03	1.11317E+03
				1.29727E+03	1.51975E+03	2.02301E+03	2.56577E+03
				3.13316E+03	3.72406E+03		

/

4	3	1	1	1.13916E+03	1.08653E+03	1.09791E+03	1.27197E+03
				1.53325E+03	1.83993E+03	2.52276E+03	3.26048E+03
				4.04383E+03	4.87568E+03		

/

4	4	1	1	1.20493E+03	1.16100E+03	1.19755E+03	1.43355E+03
				1.77157E+03	2.16191E+03	3.02667E+03	3.97038E+03
				4.99159E+03	6.09868E+03		

/

4	5	1	1	1.34142E+03	1.31256E+03	1.39935E+03	1.76169E+03
				2.25419E+03	2.81418E+03	4.06498E+03	5.47831E+03
				7.07161E+03	8.86151E+03		

/

4	6	1	1	1.50712E+03	1.49535E+03	1.64691E+03	2.17103E+03
				2.86069E+03	3.64578E+03	5.45561E+03	7.60747E+03
				1.01348E+04	1.30566E+04		

/

4	7	1	1	1.65869E+03	1.66334E+03	1.88156E+03	2.57150E+03
				3.46966E+03	4.50898E+03	7.00014E+03	1.00889E+04
				1.38137E+04	1.81889E+04		

/

4	8	1	1	2.10671E+03	2.17369E+03	2.68172E+03	4.13861E+03
				6.13697E+03	8.66037E+03	1.53522E+04	2.30000E+04
				2.30000E+04	2.30000E+04		
/							
5	1	1	1	1.12159E+03	1.12415E+03	1.14101E+03	1.19774E+03
				1.28549E+03	1.39785E+03	1.67408E+03	1.99257E+03
				2.33519E+03	2.69356E+03		
/							
5	2	1	1	1.39957E+03	1.33254E+03	1.30354E+03	1.38314E+03
				1.53102E+03	1.72093E+03	2.17527E+03	2.68659E+03
				3.23391E+03	3.81104E+03		
/							
5	3	1	1	1.47919E+03	1.42387E+03	1.41804E+03	1.54967E+03
				1.76733E+03	2.03740E+03	2.66899E+03	3.37546E+03
				4.13880E+03	4.95705E+03		
/							
5	4	1	1	1.56269E+03	1.51642E+03	1.53251E+03	1.71745E+03
				2.00596E+03	2.35675E+03	3.16890E+03	4.08200E+03
				5.08417E+03	6.17847E+03		
/							
5	5	1	1	1.72630E+03	1.69533E+03	1.75500E+03	2.05138E+03
				2.48550E+03	3.00244E+03	4.20069E+03	5.58584E+03
				7.16216E+03	8.94054E+03		
/							
5	6	1	1	1.91180E+03	1.89738E+03	2.01332E+03	2.45669E+03
				3.08215E+03	3.82404E+03	5.58568E+03	7.71309E+03
				1.02254E+04	1.31365E+04		
/							
5	7	1	1	2.07132E+03	2.07208E+03	2.24671E+03	2.84622E+03
				3.67960E+03	4.67866E+03	7.12736E+03	1.01947E+04
				1.39055E+04	1.82698E+04		
/							
5	8	1	1	2.50224E+03	2.55957E+03	3.00489E+03	4.36901E+03
				6.31889E+03	8.81638E+03	1.54807E+04	2.30000E+04
				2.30000E+04	2.30000E+04		
/							

6	1	1	1	1.69115E+03	1.69279E+03	1.70361E+03	1.74069E+03
				1.80005E+03	1.87939E+03	2.08767E+03	2.34638E+03
				2.64074E+03	2.96127E+03		
/							
6	2	1	1	2.02821E+03	1.96065E+03	1.91878E+03	1.96195E+03
				2.06324E+03	2.20404E+03	2.57035E+03	3.01476E+03
				3.51343E+03	4.05502E+03		
/							
6	3	1	1	2.14137E+03	2.08690E+03	2.06600E+03	2.14974E+03
				2.30778E+03	2.51858E+03	3.05217E+03	3.69012E+03
				4.40641E+03	5.19157E+03		
/							
6	4	1	1	2.25128E+03	2.20653E+03	2.20475E+03	2.33104E+03
				2.54892E+03	2.83300E+03	3.54165E+03	4.38702E+03
				5.34466E+03	6.40842E+03		
/							
6	5	1	1	2.44830E+03	2.41912E+03	2.45437E+03	2.67203E+03
				3.01908E+03	3.46086E+03	4.55444E+03	5.87792E+03
				7.41587E+03	9.16829E+03		
/							
6	6	1	1	2.64910E+03	2.63550E+03	2.71799E+03	3.06280E+03
				3.59053E+03	4.25626E+03	5.92254E+03	7.99806E+03
				1.04785E+04	1.33676E+04		
/							
6	7	1	1	2.80758E+03	2.80740E+03	2.94000E+03	3.42775E+03
				4.16143E+03	5.08926E+03	7.45506E+03	1.04786E+04
				1.41621E+04	1.85064E+04		
/							
6	8	1	1	3.19259E+03	3.24207E+03	3.62300E+03	4.86622E+03
				6.73888E+03	9.19108E+03	1.58062E+04	2.30000E+04
				2.30000E+04	2.30000E+04		
/							
7	1	1	1	2.26173E+03	2.26293E+03	2.27087E+03	2.29818E+03
				2.34248E+03	2.40279E+03	2.56654E+03	2.77918E+03
				3.03121E+03	3.31501E+03		
/							

7	2	1	1	2.63909E+03	2.57442E+03	2.52911E+03	2.55472E+03
				2.63013E+03	2.74032E+03	3.04208E+03	3.42831E+03
				3.87932E+03	4.38321E+03		
/							
7	3	1	1	2.77716E+03	2.72612E+03	2.70086E+03	2.76111E+03
				2.88472E+03	3.05638E+03	3.51355E+03	4.08874E+03
				4.75731E+03	5.50671E+03		
/							
7	4	1	1	2.90295E+03	2.86207E+03	2.85459E+03	2.95123E+03
				3.12720E+03	3.36562E+03	3.99095E+03	4.77299E+03
				5.68513E+03	6.71600E+03		
/							
7	5	1	1	3.11389E+03	3.08818E+03	3.11419E+03	3.29111E+03
				3.58470E+03	3.97313E+03	4.98021E+03	6.24550E+03
				7.74460E+03	9.46988E+03		
/							
7	6	1	1	3.31410E+03	3.30277E+03	3.37111E+03	3.66405E+03
				4.13037E+03	4.74069E+03	6.32704E+03	8.35388E+03
				1.08031E+04	1.36703E+04		
/							
7	7	1	1	3.46393E+03	3.46471E+03	3.57881E+03	4.00689E+03
				4.67653E+03	5.55145E+03	7.84723E+03	1.08304E+04
				1.44879E+04	1.88135E+04		
/							
7	8	1	1	3.80826E+03	3.85472E+03	4.20500E+03	5.37857E+03
				7.19755E+03	9.61450E+03	1.61889E+04	2.30000E+04
				2.30000E+04	2.30000E+04		
/							

APPENDIX C – EXAMPLE ECLIPSE DATA DECK FOR TILTED SYSTEM

```

Runspec
Title
    Tilted - 100 md - 50 ft perforated
Dimens
    11      30      30      /
Gas
Water
Field
Welldims
-- Wells      Con
    1          400      /
VFPPDIMS
    10 10 10 10 0 1 /
Start
    1 'Jan' 1998 /
Nstack
    200      /
LGR
    1 9000 /
Unifout
MESSAGES
    6* 4*50000 1* 10 /

-----
Grid
NOGGF
Include
    'tops.inc' /
DX
    9900*344.75 /
DY
    9900*344.75 /
DZ
    9900*10 /
Equals
    'PERMX'      100      /
    'PERMY'      100      /
    'PERMZ'      10       /
    'PORO'       0.25     /
    'PORO'       1e10     1 11 30 30 1 30 /
/
INIT
Gridfile
    2 /
Radfin
    'Well' 6 8 1 10 8 4 20 /

Inrad
    0.333      /
--DRV

```



```

--      0.4170  0.3016  0.4229  0.5929  0.8313  1.166
--      1.634   2.292   3.213   4.505   6.317   8.857
--      12.42   17.41   24.41   34.23   48.00  /

```

Endfin

--RPTGRID

--1 /

PROPS

DENSITY

45 64 0.046 /

ROCK

2500 10E-6 /

PVTW

2500 1 2.6E-6 0.68 0 /

PVZG

-- Temperature

120 /

```

-- Press      Z      Visc
  100      0.989  0.0122
  300      0.967  0.0124
  500      0.947  0.0126
  700      0.927  0.0129
  900      0.908  0.0133
 1100      0.891  0.0137
 1300      0.876  0.0141
 1500      0.863  0.0146
 1700      0.853  0.0151
 1900      0.845  0.0157
 2100      0.840  0.0163
 2300      0.837  0.0167
 2500      0.837  0.0177
 2700      0.839  0.0184

```

/

--Saturation Functions

--Sgc = 0.20

--Krg @ Swir = 0.9

--Swir = 0.3

--Sorg = 0.0

SGFN

--Using Honarpour Equation 71

```

--      Sg      Krg      Pc
  0.00  0.000  0.0
  0.20  0.000  0.0
  0.30  0.020  0.0
  0.40  0.081  0.0
  0.50  0.183  0.0
  0.60  0.325  0.0
  0.70  0.900  0.0

```

/

SWFN

--Using Honarpour Equation 67

```

--      Sw      Krw      Pc
  0.3  0.000  0.0
  0.4  0.035  0.0
  0.5  0.076  0.0

```

0.6	0.126	0.0
0.7	0.193	0.0
0.8	0.288	0.0
0.9	0.422	0.0
1.0	1.000	0.0

/

SOLUTION
EQUIL
5000 2500 5100 0 5100 0 /
RPTSOL
6* 2 2 /

SUMMARY
SEPARATE
RPTONLY
WGPR
/
WWPR
/
WBHP
/
WTHP
/
WGPT
/
WWPT
/
FPR
TCPU

SCHEDULE
NOECHO
INCLUDE
'GWVFP.VFP' /
ECHO
RPTSCHED
6* 2 /
RPTRST
4 / restarts once a year
TUNING
0.1 30.4 0.01 0.015 1.1 0.2 /
3* 0.0001 3* 0.00001 /
2* 200 /
TUNINGL
0.1 30.4 0.01 0.015 1.5 0.1 /
3* 0.0001 3* 0.00001 /
20 1* 200 1* 20 /
WELSPECL
'P' 'G' 'Well' 1 1 5000 'GAS' 2* 'STOP' 'YES' /
/
COMPDATL
'P' 1 1 1 10 'OPEN' 2* 0.666 /
'P' 1 2 1 10 'OPEN' 2* 0.666 /
'P' 1 3 1 10 'OPEN' 2* 0.666 /

98

[illegible]

APPENDIX D – ECLIPSE TOPS INCLUDE FILE FOR TILTED SYSTEM SIMULATION RUNS

Tops										
4980	4980	4980	4980	4980	4980	4980	4980	4980	4980	4980
4985	4985	4985	4985	4985	4985	4985	4985	4985	4985	4985
4990	4990	4990	4990	4990	4990	4990	4990	4990	4990	4990
4995	4995	4995	4995	4995	4995	4995	4995	4995	4995	4995
5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000
5005	5005	5005	5005	5005	5005	5005	5005	5005	5005	5005
5010	5010	5010	5010	5010	5010	5010	5010	5010	5010	5010
5015	5015	5015	5015	5015	5015	5015	5015	5015	5015	5015
5020	5020	5020	5020	5020	5020	5020	5020	5020	5020	5020
5025	5025	5025	5025	5025	5025	5025	5025	5025	5025	5025
5030	5030	5030	5030	5030	5030	5030	5030	5030	5030	5030
5035	5035	5035	5035	5035	5035	5035	5035	5035	5035	5035
5040	5040	5040	5040	5040	5040	5040	5040	5040	5040	5040
5045	5045	5045	5045	5045	5045	5045	5045	5045	5045	5045
5050	5050	5050	5050	5050	5050	5050	5050	5050	5050	5050
5055	5055	5055	5055	5055	5055	5055	5055	5055	5055	5055
5060	5060	5060	5060	5060	5060	5060	5060	5060	5060	5060
5065	5065	5065	5065	5065	5065	5065	5065	5065	5065	5065
5070	5070	5070	5070	5070	5070	5070	5070	5070	5070	5070
5075	5075	5075	5075	5075	5075	5075	5075	5075	5075	5075
5080	5080	5080	5080	5080	5080	5080	5080	5080	5080	5080
5085	5085	5085	5085	5085	5085	5085	5085	5085	5085	5085
5090	5090	5090	5090	5090	5090	5090	5090	5090	5090	5090
5095	5095	5095	5095	5095	5095	5095	5095	5095	5095	5095
5100	5100	5100	5100	5100	5100	5100	5100	5100	5100	5100
5105	5105	5105	5105	5105	5105	5105	5105	5105	5105	5105
5110	5110	5110	5110	5110	5110	5110	5110	5110	5110	5110
5115	5115	5115	5115	5115	5115	5115	5115	5115	5115	5115
5120	5120	5120	5120	5120	5120	5120	5120	5120	5120	5120
5125	5125	5125	5125	5125	5125	5125	5125	5125	5125	5125

/

VITA

John H. McMullan was born and attended grade school in Baton Rouge, Louisiana, graduating from Lee High School in 1972. He enrolled at Louisiana State University and received Bachelor of Science and Master of Science degrees in Petroleum Engineering in 1976 and 1979. He remained at L.S.U. as an instructor and assistant professor in the Petroleum Engineering Department from 1979 through 1983. Since that time, he has worked in a variety of domestic and international locations for both independent and major oil companies. John has experience in oil and gas fields in every major producing province in the lower 48 United States, Alaska, North Sea, and Russia, with an emphasis on reservoir engineering and simulation. In addition to black oil and dry gas reservoir simulation, John has also completed field studies for gas cycling and thermal recovery projects. He returned to L.S.U. in January, 1998 to complete a doctoral degree begun many years before.

DOCTORAL EXAMINATION AND DISSERTATION REPORT

Candidate: John H. McMullan

Major Field: Petroleum Engineering

Title of Dissertation: Optimization of Gas Well Completion and
Production Practices

Approved:

Major Professor and Chairman

Dean of the Graduate School

EXAMINING COMMITTEE:

Adam T. Bourgeois

Andrew K. Al-Farhan

John R. Smith

Thomas G. Ruff

Date of Examination:

December 15, 1999