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EFFECT OF HIGH WATER PRODUCTION ON RECOVERY FACTOR OF MATURE SANDSTONE OIL RESERVOIRS- FIELD CASE STUDY

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Abstract

High water production is one of the biggest production problems causing early abandonment of many oil wells. Excessive water production either coning from the bottom of the reservoir or fingering from the edge of the reservoir decrease the oil relative permeability around the wellbore and hence reduces the ultimate oil recovery from the reservoir. High water movement in the wellbore of unconsolidated sandstone reservoirs creates turbulent flow which enhances the dislodgement of formation sand grains causing formation damage to reservoir rock in the vicinity of the wellbore. The objective of this study is to investigate wellbore and reservoir conditions responsible for early water breakthrough in edge water drive mature sandstone oil reservoirs and their effect on oil recovery factor from these reservoirs. This study was conducting by preparing decline curves for several wells in a strong water drive reservoir which were analyzed in order to calculate the recovery factor for the studied reservoirs. Pressure build up test analysis was also conducted in order to calculate and measure the amount of wellbore damage resulted from the mixing of the intrusion edge water and reservoir fluids in the vicinity of the wellbore. The results of this study indicated that the high water movement in all the studied wells in the reservoir was due to the high oil withdrawal rates resulted from improper perforation density. It was observed that the water movement and the resulted damage near the wellbore was severe in open hole completions compared with cased hole completions. Improper well spacing was also another factor which contributes to an even edge water movement into the reservoir. It was concluded that uncontrollable edge water drive was the main cause of low recovery factor in many unconsolidated Libyan sandstone oil reservoirs.

1. Introduction

Higher water production experienced in many sandstone reservoirs in Sirte basin was due to the higher withdrawal oil production rates from these reservoirs. High water production causes the alteration of wettability around the well bore and reduces K_{ro}. Reversal of rock wettability around the well bore due to turbulence motion caused by high withdrawal rates is one of the main causes of forming water blocks near the well bore which therefore reduces the recovery factor in these wells[1]. Lower perforation settings are one the main causes of high water intrusion into the wellbore. Permeability reduction around the well bore is caused by the organic or inorganic solid precipitation around the well bore caused by the in-situ reaction of formation fluids around the well bore due to reduction in pressure and increase of turbulence caused the increase of flow velocity in the well bore[2,3].

One of the main functions of the reservoir engineer is the prediction of future production rates, which are the fundamental importance to evaluate the performance of the reservoir in the future. Lower recovery factors which are observed in many giant oil reservoirs in Sirte basin are the result of either early water breakthrough due to water injection or natural coning or fingering of aquifer water. The heterogeneous reservoir parameters as well as the presence of complex fracture systems in these reservoirs play an import role in causing early water breakthrough.

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2. Reduction of the flow capacity of the well

2.1. Formation damage resulted from well production operations

The low recovery factor was also attributed to formation damage near the well bore resulted from various well operations. These operations were made on the wells either during the drilling or production phases of the well. Inorganic or organic scales formed, from either the formation water or the oil, in the well bore during the production phase of the well plug the formation pores and hence reduce the permeabity of the formation near the well bore[4]. Corrosion inhibitors, scale inhibitors, or paraffin inhibitors usually cause some permeability reduction if allowed to contact the producing or injection zone. Precipitated scale may plug the wellbore, perforations and formation if an oil or gas well produces water from the normal producing zone, a channel, or a casing leak. Asphalt may be deposited around the wellbore in wells producing relatively high viscosity asphalted oil. Asphalt deposition will cause oil wetting and as a result, emulsions may form around the wellbore. Wells in reservoirs nearing depletion pressure are more susceptible than high-pressure wells to plugging with paraffin or asphalt[4, 5]. The wellbore opposite the producing interval in both carbonate and sandstone wells may become plugged with silt, shale, mud, and fracturing sand or other types of fill. Screens or gravel packs may become plugged with silt, clay, mud, scale, or other debris. Sand-consolidated wells may become plugged with silt, mud, or other debris. In addition, the sand consolidating material will reduce formation permeability to varying degrees[6, 7].

2.2. Wellbore permeability reduction caused from wellbore operations

When cleaning paraffin or asphalt from a well with hot oil or water, the formation and perforations will be plugged unless the melted asphalt or paraffin is swabbed, pumped, or flowed from the well before the wax cools. While cutting paraffin or asphalt from the tubing, if removed particles are circulated down the tubing and up the annulus, a portion of the scraped material will be pumped into perforations and into pores or fractures adjacent the wellbore.

2.3. Reduction of well flow capability resulted from well servicing or workover fluids

Essentially all of the same types of damage associated with initial completion may occur during well servicing or work over. Perforations, formation pores, vugs or fractures may be plugged with solids when killing or circulating a well with mud or unfiltered oil or water. Filtrate invasion by incompatible water, oil or other chemicals may cause water blocks, emulsion blocks, oil wetting the formation, or changes in formation clays. If necessary to pull a packer, mud or other damaging fluids above the packer may be dumped on the producing zones. If a well has been previously hydraulically fractured and propped, any solids entering the fractures will tend to bridge between the sand grains and cause permanent reduction of fracture flow-capacity. Previously acid-etched fractures in carbonate rock may also be plugged by the introduction of clays, barite, or other debris into the fractures[8, 9].

2.4. Lower recovery factors due to early water injection breakthrough

When the energy of the formation is depleted and primary production has dropped to a level where it is no longer economical to continue production from a given reservoir, then the reservoir is usually considered as a candidate for a pressure maintainane program. Pressure maintaince techniques include the injection of either gas or water, and are often referred to as secondary recovery operations. Water injection is usually done to supplement a natural water drive. Water flooding, as this process is called, recovers oil by the water moving through the reservoir as a bank of fluid is pushing oil ahead of it. The recovery efficiency of a water flood is largely a function of the sweep efficiency of the flood and the ratio of the oil and water viscosities[10].

Sweep efficiency is a measure of how well the water contacted the available pore space in the oil bearing zone. Fractures, high permeability streaks and faults are examples of gross heterogeneity, which yield low sweep efficiencies. When water is much less viscous than the oil it is trying to move, the water in this case could begin to finger or channel through the oil. This leads to bypassing of much of the residual oil and lower flooding efficiencies[11, 12]. This concept is called viscous fingering which is an important phenomena in enhanced oil recovery techniques.

3. Figures

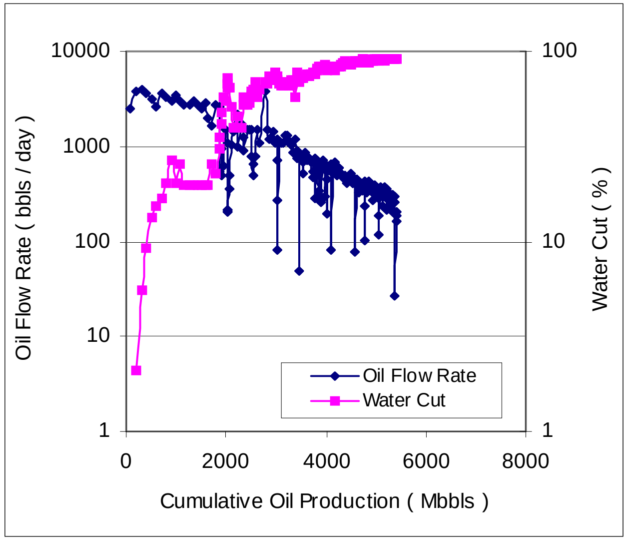

Figure 1: Represents the oil production rate and water cut versus the cumulative oil production for well A 60

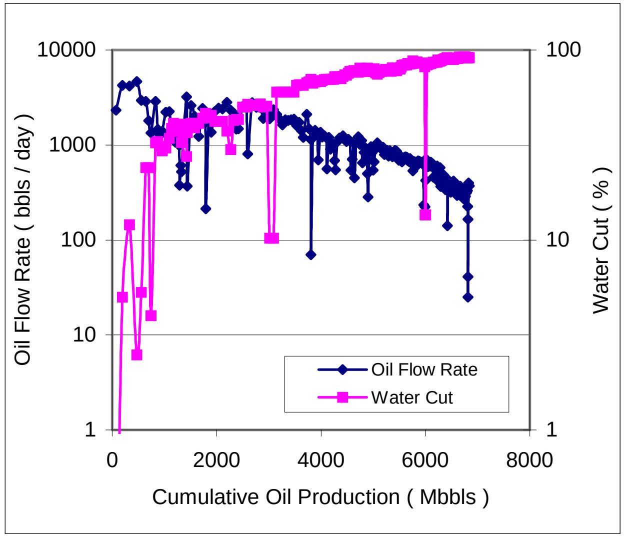

Figure 3: Represents the oil production rate and water cut versus the cumulative oil production for well A 61

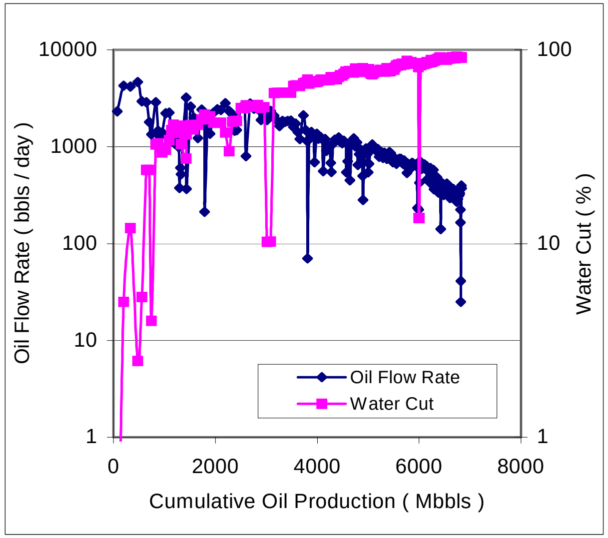

Figure 5: Represents the oil production rate and water cut versus the cumulative oil production for well A 62

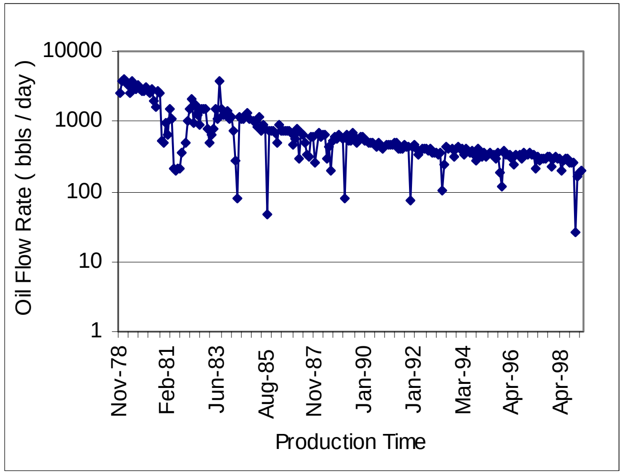

Figure 2: Represents the oil production rate versus the production time for well A 60

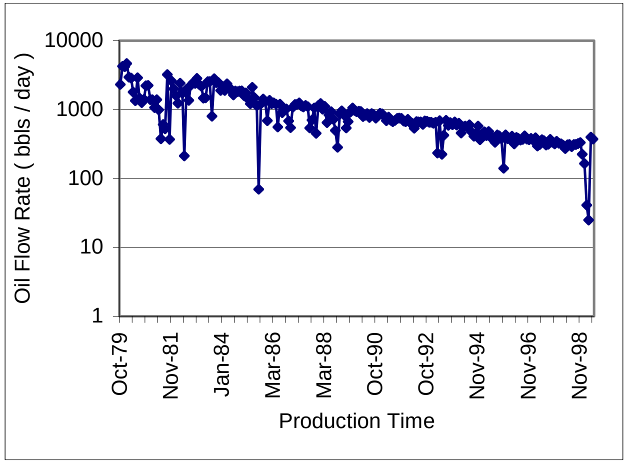

Figure 4: Represents the oil production rate versus the production time for well A 61

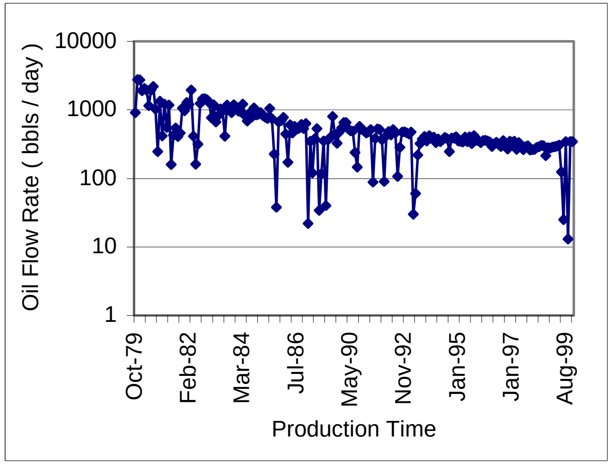

Figure 6: Represents the oil production rate versus the production time for well A 62

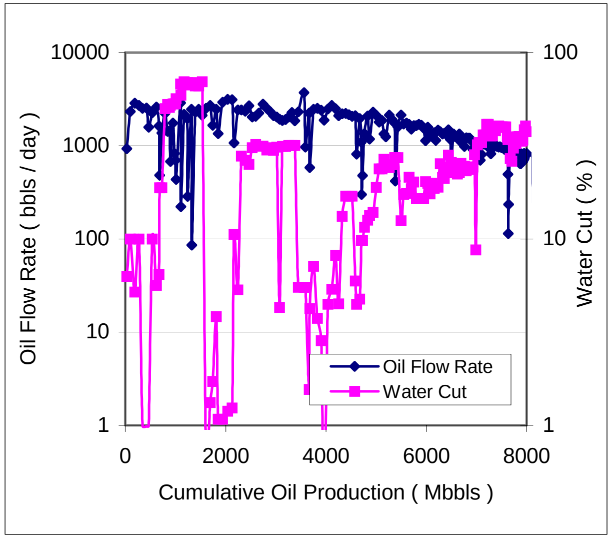

Figure 7: Represents the oil production rate and water cut versus the cumulative oil production for well A 63

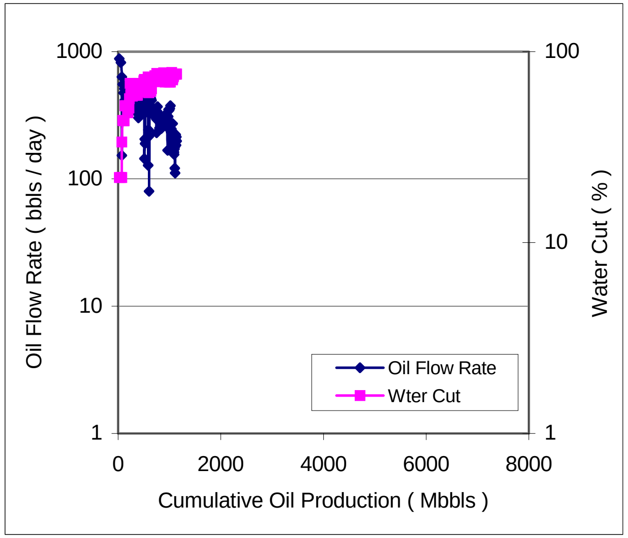

Figure 9: Represents the oil production rate and water cut versus the cumulative oil production for well A 65

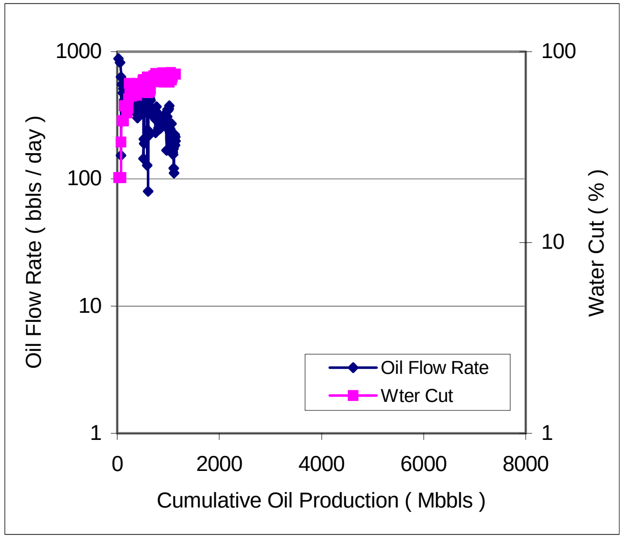

Figure 11: Represents the oil production rate and water cut versus the cumulative oil production for well A 66

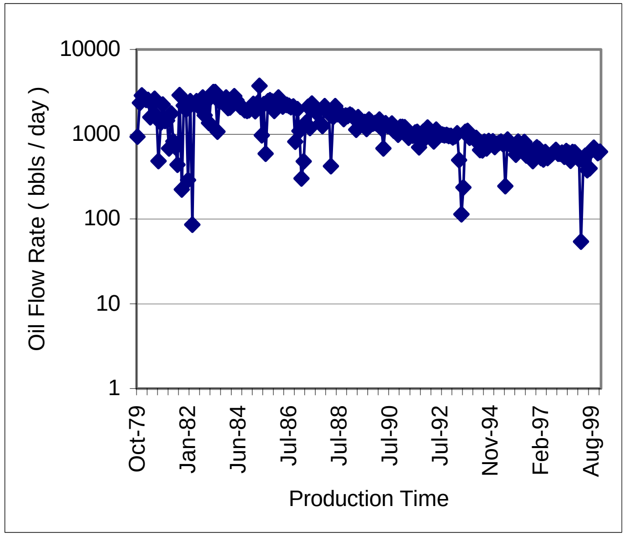

Figure 8: Represents the oil production rate versus the production time for well A 63

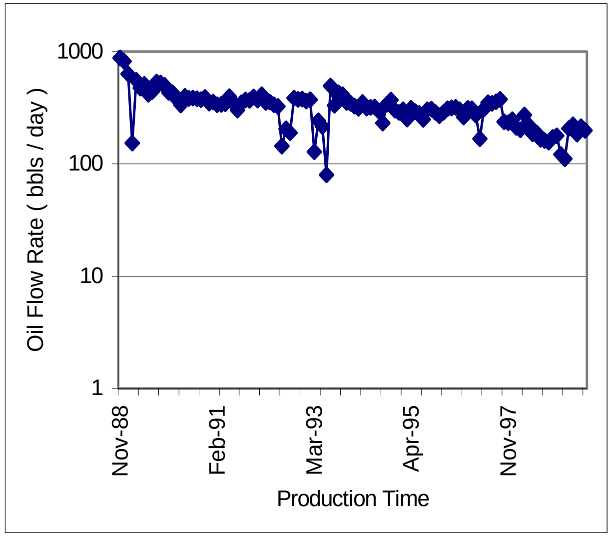

Figure 10: Represents the oil production rate versus the production time for well A 65

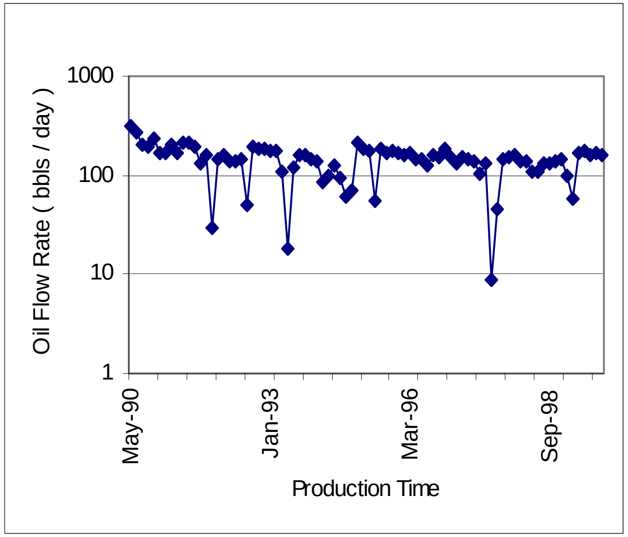

Figure 12: Represents the oil production rate versus the production time for well A 66

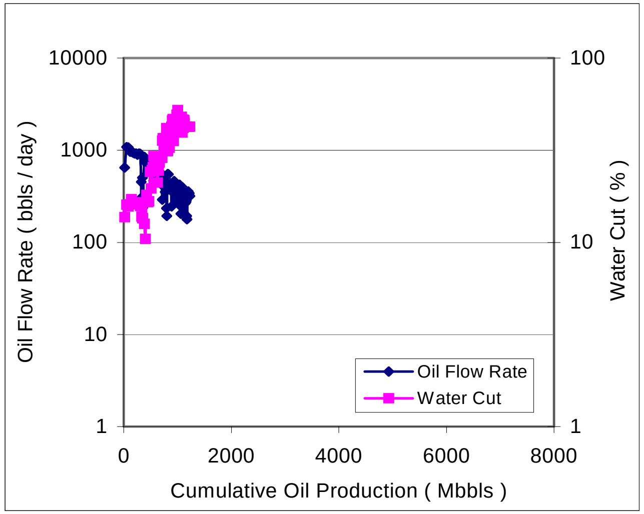

Figure 13: Represents the oil production rate and water cut versus the cumulative oil production for well A 67

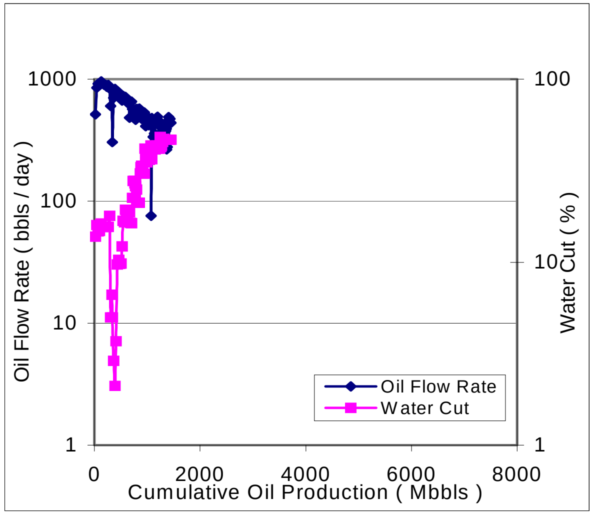

Figure 15: Represents the oil production rate and water cut versus the cumulative oil production for well A 68

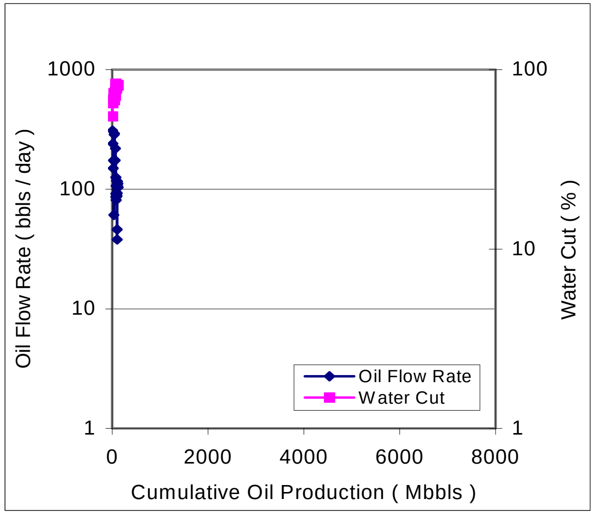

Figure 17: Represents the oil production rate and water cut versus the cumulative oil production for well A 70

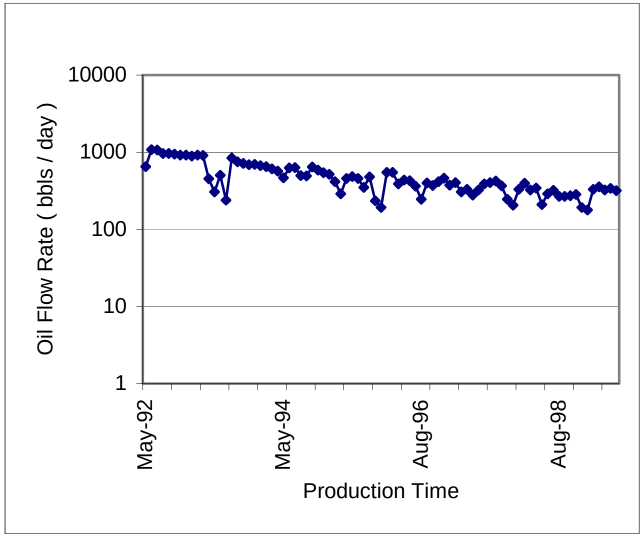

Figure 14: Represents the oil production rate versus the production time for well A 67

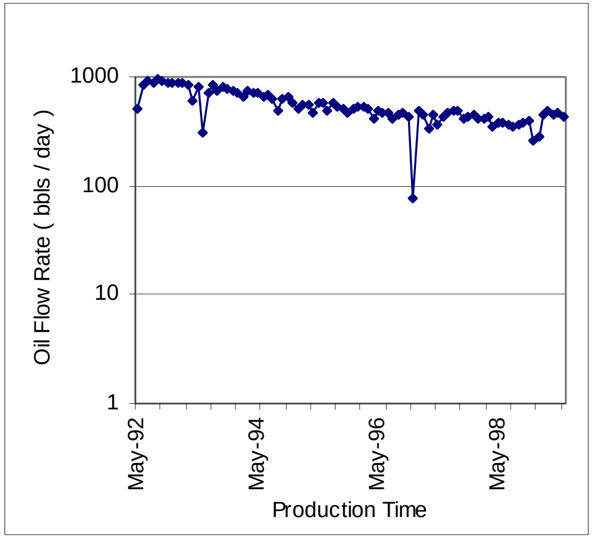

Figure 16: Represents the oil production rate versus the production time for well A 68

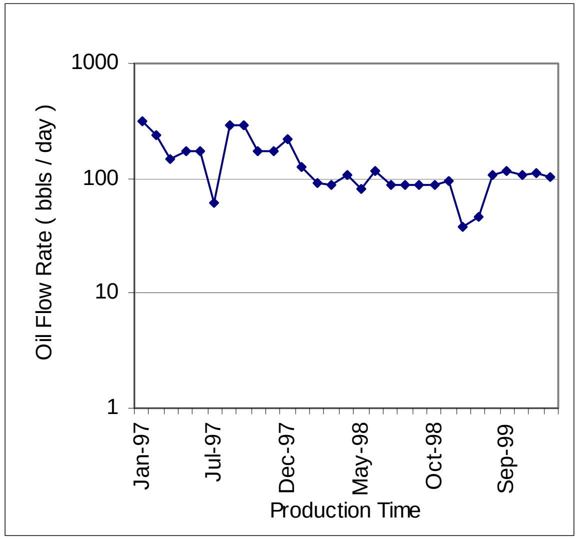

Figure 18: Represents the oil production rate versus the production time for well A 70

4. Results and Discussion

Figures 1, 3, 5, 7, 9, 11, 13 and figures 2, 4, 6, 8, 10, 12, 14 represent the oil flow rate and the water cut versus the production time and the cumulative oil production for selected oil producing wells from the studied sandstone reservoir respectively. The analysis of the oil production decline for all these selected wells indicate that the decline rate is low and stable in all the studied wells early in their production life. After few years of production, the oil rate has decreased and the water cut has jumped sharply as indicted in the early portions of these decline curves. The shape of the decline trend evidenced in these reservoirs differ from one well to another depending on the activity of the aquifer or the completion history of the well or the water injection scheme in the reservoir.

The analysis of the production rate versus production time figures 2, 4, 6, 8, and 10 and for the selected wells indicate that an exponential oil production decline rate exists in these wells. The figures indicate that there exist three decline trends, the first trend starts from the beginning of the production at year 1970 and it ends at year 1981. The first decline is believed to be due to a natural reservoir decline pressure. The second decline starts from year 1984 to year 1990 and this decline is also believed to be due to a work over activities conducted in the wells. The third decline starts from year 1990 to year 1999 and this decline shows stabilized production due to pressure maintenance exists in these wells.

The figures 1, 3, 5, 9, 11, and 17 of wells A60, A61, A62, and A66 respectively indicted that the increase early of water cut was also due to the lower completion of these wells near the water table in the reservoir. The results of the decline curve analysis of these wells indicate that the increased water cut in the reservoir has substantially reduced the reservoir oil recovery factor which is dependent on the expected oil recovery from individual wells. The results of this study indicated that the high water movement in all the studied wells in the reservoir was due to the high oil withdrawal rates resulted from improper perforation density. The calculated skin values obtained from the studied wells in the field indicated that positive skin values were reported for these wells which were responsible for lowering the relative permeability and hence lowering the oil recovery factor in these wells.

5. Conclusions

1. Lower recovery factors observed in some of the giant sandstone reservoirs in Sirte basin are caused by early water breakthrough caused by high oil withdrawal rates from these reservoirs.
2. Formation damage caused by the turbulence flow around the well bore due to the high withdrawal rate and increased water saturations in the wellbore is another factor contributing to the lowered recovery factors in these reservoirs.
3. The delay of implementing pressure maintainance in these reservoirs is one of the causes of low reported recovery factor in these reservoirs.
4. It is believed that the selection of the best production lifting mechanism also plays an important factor in increasing the recovery factor in these reservoirs.
5. Recovery factors are also caused by the untreated production problems evidenced in may wells in these reservoirs.
6. Open hole and lower perforation completions cause water coning problems evidenced in some of the high water producing wells in these reservoirs.
7. It is concluded that if these reservoirs are not managed early, the expected recovery factors will become lower and the treatment cost of these reservoirs will be higher.

6. Acknowledgments

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7. References

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