MECHANISTIC MODELS FOR PREDICTING SAND PRODUCTION: A CASE STUDY OF NIGER DELTA WELLS

A

THESIS

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By

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ABSTRACT

Niger Delta Province is predominantly a friable, unconsolidated sandstone terrain suggesting the expectation of sand production while developing hydrocarbon reserves in such terrain. In this study, a simple and easy-to-use mechanistic model for predicting sand production rate (SPR) in Niger-Delta wells was developed by coupling the static sanding criteria and the dynamic requirement for fluidization of the produced sand. A generic mechanistic model that incorporates the concept of dimensionless quantities associated with sanding was developed; the quantities considered include the loading factor, Reynolds Number, water cut and gas-liquid ratio, GLR. The output from the proposed model is a dimensionless sand production rate (SPR) correlation index. Results indicated that every reservoir has a unique SPR correlation index which represents its propensity to produce sand or its sanding identity.

The developed model was validated by comparing its predictions with field data and the results showed an acceptable maximum deviation of less than 6% in the wells of an onshore asset investigated in the Niger Delta. Compared to existing models, the proposed model predicts better results especially when GLR is significantly high. The applications of this study include reservoir management, completion design, perforation design, sand monitoring strategy, design of surface facilities and pipelines, and analysis of field development plans and economics.

Keywords: mechanistic model, loading factor, Reynolds Number, water cut, gas-liquid ratio, sand production rate (SPR); SPR correlation index.

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DEDICATION

I dedicate this thesis work to Almighty God for giving me the grace to complete it and to my parents for their love and support.

CHAPTER 1

1.0 GENERAL

1.1 INTRODUCTION

Sand production is a common problem in production and injector wells located in weak or poorly consolidated sandstone reservoirs. Recent clastic sediments of the Pliocene and younger Tertiary ages are particularly troublesome and sand production problem maybe expected whenever wells are completed in unconsolidated formations. Sand failures also occurs in older formation when in-situ rock strength is reduced by poor completion and production practice. Identified areas where severe sand production problems are experienced among others include Nigeria, Trinidad, Indonesia, Egypt, Venezuela, Malaysia, Canada tar sands and Gulf of Mexico. The reservoirs in these formations lie between 3,500ft and 10,000ft (Osisanya, 2010).

Extensive research efforts have been expended in developing models for predicting sand production in the past couple of decades. Such models can assist in several aspects of field operations like sand control and management, optimal well completion design and production optimization among others (Chin and Ramos, 2002). Generally the effects of sand production ranges from economics and safety hazards to well productivity and therefore has been an issue of interest to tackle in the petroleum industry. Some of these effects include erosion of downhole and surface equipment, pipeline blockage and leakage, formation collapse, reduction in productivity, increased intervention costs and complexities, increased downtime and other environment effects associated with sand disposal particularly in offshore and swamp locations (Osisanya, 2010). These problems cost the oil industry billions of dollars annually. Therefore, understanding the sand production mechanisms and ability to predict and manage the rate of sand production are beneficial. It is important to predict the possible quantity and particle size distribution of sand, and the frequency of sand produced and transported through the wellbore into the topside facilities. Management of sand production requires an accurate knowledge of ‘‘if the reservoir rock will fail’’, ‘‘when it will fail’’ and ‘‘how much sand will be produced’’ (Oyeneyin, 2014).

Niger-Delta basin rank amongst the world’s most prolific petroleum producing tertiary deltas that account for about 5% of the world’s oil and gas reserves. Its petroleum reserves are estimated at about 39 billion barrels of oil and 278 trillion cubic feet of natural gas. The region ranks 7th in the world production with an average daily production of about 2.4 million barrels

(Mosto, 2013).Major accumulation of hydrocarbons in the Niger-Delta basins are contained in interbedded sands and shale that are deposited primarily in a shallow marine environment lying between 5,000ft and 10,000ft depth part of the Akata-Agbada formation and it is in this range that sanding problems occur. Important structures of the environment are the growth fault and associated rollover anticline which provide the characteristic hydrocarbon traps in the Niger-Delta. Cementation and induration are notably poor and any bonding present is mainly due to silica and calcite. The firm sandstone bed is usually one of poor sorting, with a general average porosity of 30% and permeability ranging as high as 5 Darcies to as low as few tens millidarcy. This friable, unconsolidated sandstone formation constitute a serious sand production challenges. Sand control method employed in Niger-Delta include gravel pack (open-hole, inside casing, and milled-casing under reamed) and sandlocks (Osisanya, 2010).

In order to mitigate problems related to sand production new strategies are being continuously investigated relating to prediction, control and management. The ability to predict when a formation will fail and produce sand is fundamental to deciding whether to use downhole sand control or not and what type of sand control will be most appropriate (Bellarby, 2009). Sand grains are disengaged from the rock matrix structure under physical (earth stress) and chemical action. The mechanism of sand production in terms of rate, volume and sand producing patterns in the reservoir is needed to optimally develop a field. Mechanisms causing sand production are related to the formation strength, flow stability, viscous drag forces and pressure drop into the wellbore (Osisanya, 2010). The critical factors leading to accurate prediction of sand production potential and sand production are: formation strength, in-situ stress, and production rate. Other factors are reservoir depth, natural permeability, formation cementation, compressibility, surface exposed to flow, produced fluid types and phases, formation characteristics, pressure drawdown and reservoir pressure. At present, predicting whether a formation will or will not produce sand is not an exact science and needs more improvement.

Though, there exist a wide variety of empirical, numerical and analytical sanding prediction models in literature which requires lots of rock mechanics input parameter rarely available in field practice and demanding extensive computations (eg. finite element models) that is not practicable in cases when quick sand control decisions is needed, this work intends to develop a simple and easy-to- use mechanistic model for predicting sand production in Niger-Delta wells, however, the derived model would be applicable to any similarly poorly consolidated clastic terrain like the Gulf of Mexico or Indonesia, etc.

1.2 LITERATURE REVIEW

Oyeneyin (2014) worked on sand management solution for guaranteed flow assurance in subsea development, He stated that sand prediction is an element of integrated sand management strategy that involves the evaluation of risk of rock failure. Rock failure leads to other unwanted reactions like sand production and borehole instability. In his view, for an accurate prediction of rock failure and eventual sand production, the strength of the sand at any point is compared with the effective stresses acting, when the effective stresses exceed the strength, the rock fails and sand production can occur. Any sand prediction starts with the evaluation of the time to rock failure and the most important reservoir parameters in sanding prediction are porosity, permeability and geo-mechanical properties. Sand management solution guide provide answers to if and when sand will be produced and how much sand will be produced and transported to topside facilities.

Tiab (2014) identified that clastic formation possessing low porosity shows significant rock strength and proposed that porosity can be used as a qualitative measure of rock strength to predict sand production. He theorized that sand production can be expected if the product of two elastic parameters (i.e. GK_b) is lower than the threshold value of 8E11psi^2, where the shear modulus, G and the bulk modulus, K_b are derived accurately from interpretation of acoustic and density logs.

Osisanya (2010) identified the control of formation sand as the principal producing problem of oil and gas fields producing from recent clastic sediments. Sediments of the Pliocene and younger Tertiary ages are particularly troublesome, and sand production problems may be expected whenever wells are completed in unconsolidated reservoirs. Poor completion and production practices in older formations also result in reducing in-situ rock strength and causing sand failure. The most critical factors to sand production were stated as formation strength, changing in-situ stresses and fluid production rate. Notably sand prediction methods described include production test, well log analysis, laboratory mechanical rock testing, and analogy. To support these methods examples and case studies from the Niger Delta, North Sea and Gulf of Mexico were given. The paper highlighted data required to predict sand production as production test data, formation intrinsic strength, rock dynamics elastic constants, and log data.

Adeyanju and Oyekunle (2010) developed a coupled reservoir geo-mechanical model to predict volumetric sand production and associated wellbore stability in Niger-Delta formation subject to an open-hole completion. The model is based on mixture theory in which mechanics and laws of conservation equation are written for each of the concerned phases: solid matrix, fluidized solid, oil, water and gas phase. Results shows that the magnitude of sand production is strongly affected by the flow rate, the confining pressure, the pressure drawdown and the fluid viscosity.

Azadbakht *et al.* (2012) presented a numerical model for volumetric prediction of sand production in injector wells by postulating that sanding in injector wells is mainly associated with the back-flow and cross-flow generated during shut-in in addition to water-hammer pressure pulsing in wellbore due to fast flow rate changes. A set criteria using geomechanics principles and basic physics of sand production were incorporated into their model for describing conditions required for sanding initiation and propagation. The numerical model accounted the effects of the following parameters on sanding behaviour of injectors: rock strength, water weakening effect and cross-flow effect.

Yi *et al.* (2004) recognized the availability of a wide variety of numerical and analytical sanding onset prediction models in literature which requires large rock mechanics input parameter rarely available in field practice and demanding extensive computations (eg. finite element models) that is not practicable in cases when quick sand control decisions is needed. They developed a simple and easy-to-use analytical sanding onset prediction model to determine the critical drawdown and/or flow rate at which sand production occurs. The model is based on theory of poroelastoplasticity assuming shear failure or tensile stress induced sanding. The only rock mechanics parameter needed in their models include: Biot'sconstant, Poisson's ratio, Uniaxial Compression Strength (UCS) and in-situ stresses. With these data, a critical drawdown pressure for a well can be obtained for any given average reservoir pressure.

Palmer *et al.* (2003) presented a new strategy for predicting and managing sand production by proposing sanding to occur in three stages namely: the onset, transient and steady-state sanding in that order. As drawdown (or depletion) is increased in a well in a sand-prone formation, significant sanding begins at some point (the onset). This is followed by a transient sand burst, which may last hours or days or even months. The sanding eventually declines to a background level (steady-state) in the range 1-100 pptb.

Identified application of their work include: serves as basis to decide if a well can be completed without sand control since it implies a cheaper well installation (completion), higher production rate, and ability to shutoff water; reliable prediction of the volume and concentration of sand produced is required for better design of surface facilities for handling produced sand. They also showed if water injectors can be completed without sand control that completion will allow zonal isolation, avoid inevitable screen or gravel-pack plugging and injectivity loss since it is very difficult to clean or replace a screen economically, in fact the total cost savings can be tens of millions of dollars, or more.

Bai *et al.*(2002) presented a comprehensive geo-mechanical approach in predicting excessive sand production that uses a unified approach that employs multiple methods with complementary objectives: analytical and empirical methods assess the sand production risk under simplified conditions; numerical methods examining stability of sand prevention devices under realistic complex configuration; and experimental methods using laboratory-rock mechanical testing techniques to calibrate the sanding predictions under simulated down-hole conditions.

Willson *et al.* (2002) developed a new model for predicting the rate of sand production by utilizing the non-dimensionalized concepts of Loading Factor, LF (near-wellbore formation stress normalized by strength), Reynolds number (Re) and water production boost factor. They derive an empirical relationship between Loading Factor, Reynolds number and the rate of sand production incorporating the effect of water production. Their proposed definition of sand production rate is SPR = f (LF, Re, water-cut).

Chin and Ramos (2002) proposed a fully coupled sand production model that integrates geomechanics and fluid flow to quantify volumetric sand production during the early drawdown period (a few days), bean-up, as well as in the depletion period (a number of years). They validated the proposed model by comparing simulation results from the proposed model to sand production data from full scale laboratory perforation sanding tests. Key variables that govern volumetric sand production were evaluated to include: rock strength, flow rate, oil viscosity and producing time.

1.3 PROBLEM DESCRIPTION

The tendency for sand to be produced from a clastic sediment increases as the reservoir is been depleted due to a corresponding increase in the effective overburden pressure on the formation with depletion causing the formation to fail at some point. Also as the production rate increases, the drawdown pressure which is the difference between the reservoir pressure and the wellbore flowing pressure increases, this phenomenon tends to draw sand into the wellbore at some point called the critical drawdown pressure. Similarly sand production rate is noted to increase with increasing water cut.

Generally the effects of sand production ranges from economics and safety hazards to well productivity and therefore has been an issue of interest to tackle in the petroleum industry. Some of these effects include erosion of downhole and surface equipment, pipeline blockage and leakage, formation collapse, reduction in productivity, increased intervention costs and complexities, increased downtime and other environment effects associated with sand disposal particularly in offshore and swamp locations (Osisanya, 2010). These problems cost the oil industry billions of dollars annually. Therefore, understanding the sand production mechanisms and ability to predict and manage the rate of sand production are beneficial.

Continuous search for improved means of predicting sand production from clastic sediment is still ongoing for over two decades now. The current practice in the industry involves the determination of the sand production potential and when the formation will fail to know if sand control will be needed and type of well completion. One way employed by production engineers is limiting the production rates such that sand production is avoided. Analogy with other wells in the same area or field and well testing technique – such as Drill Stem Test (DST) – are also used. A known method of predicting sand production is the determination of formation strength mostly from core test analysis and/or log, derived in-situ stresses from leak off test and overburden density data which are applied in a failure mechanism. The applicability and accuracy of some of these models can be confusing. Also, the results from these models may not be representative of production conditions. However, the prediction from these models improves with more accurate input. Predicting sand production is not an exact science, yet and needs more improvement.

Though, there exist a wide variety of empirical, numerical and analytical sanding prediction models in literature, they requires lots of rock mechanics input parameter rarely available in field practice and demands extensive computations (eg. finite element models) that is not practicable in cases when quick sand control decisions is needed, this work seeks to develop a simple and easy-to- use mechanistic model for predicting sand production in Niger-Delta wells, however, the derived model would also be applicable to any similar poorly consolidated clastic terrain like the Gulf of Mexico or Indonesia.

1.4 OBJECTIVES AND APPLICATION OF STUDY

The objectives of this study include:

- To identify critical factors that affects sand production in Niger-Delta wells.
- To develop a simple and easy-to- use mechanistic model for predicting sand production rate (SPR) in Niger-Delta wells.
- To validated the developed model by comparing simulated results of the model with field data of Niger-Delta wells.
- To compare predictability of the developed model to that of existing model
- To develop a more generic normalized SPR model to allow for comparison across analogous field with similar depositional environment and sanding characterisctics.

The application of this study among others include:

- Reservoir Management Strategy
- Completion Design
- Perforation Strategy
- Sand Monitoring Strategy
- Design of Surface Facilities and Pipelines
- Field Economics

1.5 ORGANIZATION OF THESIS

The thesis is divided into six chapters. Chapter one gives a brief introduction and literature review on the subject matter, it also states the objectives and application of the study. Chapter two presents a theoretical background of sand production, control and management**.** Chapter three attempts to provide the formulation of the model for predicting sand production in Niger-Delta wells. Validation of the derived model by comparing the simulated results of the model with field data is shown in Chapter four, while chapter five presents analysis of the model. Chapter six provides conclusions and recommendations of the thesis.

CHAPTER 2

2.0 THEORETICAL BACKGROUND OF SAND PRODUCTION, CONTROL AND MANAGEMENT

2.1 Introduction

Sand production is a problem encountered during the production of oil and gas especially in formations relatively young in geologic age. These rocks are unconsolidated and accounts for majority of the world's reservoirs, therefore most formations are susceptible to sand production. It can be defined as the production of quantifiable amount of sand particles along with reservoir fluids. Sand production is a two-part decoupled phenomenon: sand must be separated from the perforation tunnel (failure), and the flowing fluid must transport the failed sand. Stress, controlled by drawdown and depletion does the first, and rate, also controlled by drawdown does the second (Venkitaraman et al., 2000). Depletion and drawdown fail the medium under either shear or tensile or volumetric failure mechanisms or a combination of them (Nouri et al., 2003). The production of formation sand might start during first flow or later in the life of the reservoir when pressure has fallen or water breaks through. Sand production can erode downhole equipment and surface facilities, production pipeline blockage and leakage, generate additional need for waste disposal which could be a problem in areas of stringent environmental regulations, lead to formation subsidence in severe cases and generate more frequent need for workovers and well intervention. These effects can be viewed as economic and of safety hazards in the oil and gas industry.

2.1.1 Sand Production Effects

The effects of sand production are often detrimental to the productivity of a well in the long run. Downhole equipment might be blocked or damaged and/or surface facilities disabled.

1. Erosion of downhole and surface equipment: sand produced with formation sand at high velocity can erode surface and downhole equipment leading to frequent maintenance to replace such equipment. Blast joints, tubing opposite perforations, screens or slotted liners not packed in the gravel pack installation are potential sites for downhole erosion. If the erosion is severe or occurs over a sufficient length of time, complete failure of surface and/or downhole equipment may occur, resulting in critical safety and environmental problems as well as deferred production. High-pressure gas containing sand particles

expanding through the surface choke is the most hazardous situation. For some equipment failures, a rig assisted workover may be required to repair the damage (William and Joe, 2003)

Figure 2.1: Surface choke failure due to erosion by formation sand (Source: Completion tech., 1995)

Figure 2.2: Eroded piston head (Source: Han et al., 2011)

2. Formation subsidence: the cumulative effect of producing formation sand is collapse of the formation. Over time large volume of sand will be produced at the surface creating a void behind the casing. This void widens as more sand is produced. Formation sand or shale above the void may collapse into it as a result of lack of material for support. The sand grains rearrange to create a lower permeability than was originally especially in formations with high clay content or wide range of grain sizes. Complete loss of productivity is likely in situations where the overlying shale collapses. The collapse of the formation is particularly important if the formation material fills or partially fills the perforation tunnels. Even a small amount of formation material filling the perforation tunnels will lead to a significant increase in pressure drop across the formation near the well bore for a given flow rate(Completion tech., 1995)
3. Sand accumulation in surface equipment: In situations where the production velocity of the reservoir fluid is sufficient to carry sand up the tubing to the surface. Sand particles often settle in surface facilities as separators, heaters, pumps, condensers. As the accumulation builds to appreciable volume in these facilities; equipment(s) clean-up becomes inevitable. This cause deferred production (well is shut-in) and additional cost is inquired as a result of the clean-up activity. Production capacity of the separator is reduced if partially filled with sand. This is as a result of its reduced ability to handle gas, oil and water.
4. Subsurface accumulation: when the production flow velocity is not sufficient to carry the sand particles to the surface. The sand accumulates in the casing or bridges off in the tubing, with time the production interval might be filled with sand. This reduces the production rate for such wells which might eventually cease as the sand accumulation makes it impossible for production to continue. Work-over actives is often required in such occurrences for the well to resume production. If sand production is continuous, well clean out operations may be required regularly. This causes increased maintenance cost and lost production which in turn reduces returns from the well.
5. Sand disposal: This constitutes a problem in formations producing sand especially in areas where there are stringent environmental constraints. Offshore processing systems that do not satisfy anti-pollution regulation of the separated sand is to be transported onshore for disposal constituting additional production cost.

2.1.2 Causes of Sand Production

Factors influencing the tendency of a formation/ well to produce sand can be categorized into rock strength effects and fluid flow effects. Production of sand particles consists of formation fines and load bearing solids. The production of formation fines which is not considered as part of the formations mechanical framework is beneficiary as they can move freely through the formation instead of plugging it. Production rates are often kept to low levels so as to avoid the production of the load bearing particles, in many cases however low production rates are uneconomical. These factors include:

1. Degree of consolidation: The ability to maintain open perforation tunnels is closely tied to how strongly the individual sand grains are bound together. The cementation of sandstone is typically a secondary geological process and as a general rule, older sediments tend to be more consolidated than newer sediments. This indicates that sand production is normally a problem when producing from shallow, geologically younger tertiary sedimentary formations. Such formations are located in the Gulf of Mexico, California, Nigeria, France, Venezuela, Trinidad, Egypt, Italy, China, Malaysia, Brunei, Indonesia and others. Young Tertiary formations often have little matrix material (cementation material) bonding the sand grains together and these formations are generally referred to as being "poorly consolidated" or "unconsolidated". A mechanical characteristic of rock that is related to the degree of consolidation is called "compressive strength". Poorly consolidated sandstone formations usually have a compressive strength that is less than 1,000 pounds per square inch (Completion tech., 1995).
2. Production rate: Increasing the well production rate creates large fluid pressure gradient near the wellbore (perforation) which tends to draw sand into the wellbore. Generally, production of the reservoir fluids creates pressure differential and frictional drag forces that can combine to exceed the formation compressive strength. This indicates that there is a critical flow rate for most wells below which pressure differential and frictional drag forces are not great enough to exceed the formation compressive strength and cause sand production. The critical flow rate of a well may be determined by slowly increasing the production rate until sand production is detected. One technique used to minimize the production of sand is to choke the flow rate down to the critical flow rate where sand production does not occur or has an acceptable level. In many cases, this flow rate is significantly below the acceptable production rate of the well (Completion tech., 1995).
3. Pore pressure reduction: Reservoir fluid production overtime depletes the reservoir pressure resulting in pore pressure reduction. As the reservoir pressure is depleted throughout the producing life of a well, some of the support for the overlying rock is removed. Lowering the reservoir pressure creates an increasing amount of stress on the formation sand itself. (Completion tech., 1995) i.e. the effective overburden pressure

increases. The formation sand particles may be crushed or break loose from its matrix at some time in reservoir life which could be produced along with the reservoir fluids. The formation might subside if the effective stress exceeds the formation strength due to compaction of reservoir rock from reduction in pore pressure.

4. Reservoir fluid velocity: The frictional drag force exerted on the formation sand grains is created by the flow of reservoir fluid. This frictional drag force is directly related to the velocity of fluid flow and the viscosity of the reservoir fluid being produced. High reservoir fluid viscosity will apply a greater frictional drag force to the formation sand grains than will a reservoir fluid with a low viscosity. The influence of viscous drag causes sand to be produced from heavy oil reservoirs which contain low API gravity, high viscosity oils even at low flow velocities (Completion tech., 1995).
5. Increasing water production: Increase in water cut increases sand production or as water production beings sand production beings too. These occurrences can be explained by two mechanisms. In a typical water-wet sandstone formation, some grain-to-grain cohesiveness is provided by the surface tension of the connate water surrounding each sand grain. At the onset of water production the connate water tends to adhere to the water produced, resulting in a reduction of the surface tension forces and subsequent reduction in the grain-to-grain cohesiveness. The stability of the sand arch around the perforation has been shown to be limited greatly by the production of water resulting in the production of sand. An arch is a hemispherical cap of interlocking sand grains that is table at constant drawdown and flow rate preventing sand production (Jon Carlson et al., 1992). A second mechanism by which water production affects sand production is related to the effects of relative permeability. As the water cut increases, the relative permeability to oil decreases. This result in an increasing pressure differential being required to produce oil at the same rate. An increase in pressure differential near the wellbore creates a greater shear force across the formation sand grains. Once again, the higher stresses can lead to instability of the sand arch around each perforation and subsequent sand production (Completion tech., 1995).

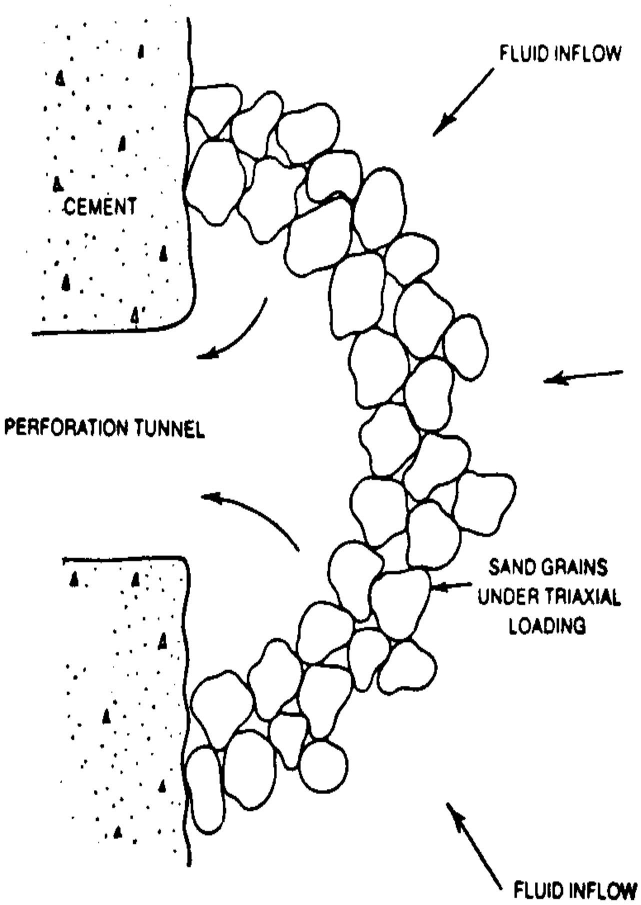


Figure 2.3: Geometry of a Stable Arch Surrounding a Perforation (Source: Completion tech., 1995)

2.2 Sand Prediction

It is important for the completion engineer to know under what conditions a well produce sand to predict if the well will require a method of sand control. Sand prediction is usually done at the initial stage of reservoir development. It involves development of completion design, reservoir management strategy, perforation strategy, sand monitoring strategy, planning of the surface facilities and field economics. This task is not an easy one as the process of sand prediction is more of art than a science. At best performances of nearby offset wells are observed or the well is completed conventionally and flowed to observe if sand production will occur. The many published techniques to predict the onset of sanding can be categorized into four basic approaches: Empirical methods using field observations and well data, Laboratory simulation, Numerical methods and Analytical methods (Qui et al, 2006). Often two or more techniques are used in combination for prediction.

2.2.1 Empirical Methods Using Field Observations and Well Data

This technique uses a correlation between sand production well data and field operational parameters in prediction. Typically one or a group of parameters are used to evaluate the sanding potential and to establish a benchmark for sanding or no sanding. This is due to the practical difficulties of monitoring and recording several year worth of data for all the wells involved in a study (Veeken et al., 1991). Parameters such as Porosity, drawdown or flow rate, compressional slowness etc. are often used. Veeken et al., (1991) presented a list of the parameters that may influence sand production.

Table 2.1: Parameters Influencing Sand Production

FORMATION
Rock
• Strength
• Vertical and horizontal in-situ stresses (change during depletion)
• Depth (influences strength, stresses and pressures)
Reservoir
• Far field pore pressure (changes during depletion)
• Permeability
• Fluid composition (gas, oil, water)
• Drainage radius
• Reservoir thickness
• Heterogeneity
COMPLETION
• Wellbore orientation, wellbore diameter
• Completion type (open hole/perforated)
• Perforation policy (height, size, density, phasing, under/overbalance)
• Sand control (screen, gravel pack, chemical consolidation)
• Completion fluids, stimulation (acid volume, acid type)
• Size of tubular
PRODUCTION
• Flow rate
• Drawdown pressure
• Flow velocity
• Damage (skin)
• Bean-up/shut-in policy
• Artificial lift technique
• Depletion
• Water/gas coning
• Cumulative sand volume

In its simplest form, the field data based sand prediction tool uses only one parameter. Examples include avoiding porosities higher than 30% (Bellarby, 2009), using a cut-off depth criterion for the installation of sand control measures in several deltaic environments: sand control is not installed below a certain depth. A depth of 12,000ft and 7,000ft were mentioned by Tixier et al and Lantz et al respectively. This critical depth is regionally dependent. Another example is applying a compressional sonic wave transit time **(Δt_c)** below which sand control is not required; the limit Δt_c is again field or regionally dependent and may vary from 90 to 120µs/ft (Veeken et al, 1991). Tixier et al., 1975 derived a log based technique using mechanical properties log to predict sanding. A limit value for the sonic and density log derived parameter ratio of G (the dynamic shear modulus) to C_b the bulk compressibility i.e. (G/C_b) was established. When G/C_b exceeds 0.8*10 psi ^{2}, no sanding problem is expected. At ratios less than 0.7*10 psi ^{2} sand influx will occur. This mechanical properties log method works 81% of the time (Osisanya, 2010) but seems to be dependent on regional environment too. The one parameter method is practical but conservative.

The two parameters method considers the depletion of the reservoir pressure (ΔP_{de}) and the drawdown pressure (ΔP_{dd}) not accounted for in the one parameter model. Stein et al., (1972) provided a method to estimate the maximum production sand free rate from density and acoustic velocity log data by relating drawdown to the dynamic shear modulus, E_s. Data from wells producing sand were used to relate to new wells.

$$(P_R - P_W)_C \propto E_s \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots 2.1$$

$$[(P_R - P_w)_C]_Z = [(P_R - P_W)_C]_T \left[\frac{(E_S)_z}{(E_S)_T}\right] \dots\dots\dots\dots\dots\dots 2.2$$

On the basis of data from many fields Veeken et al., (1991) plotted the total drawdown pressure, ($\Delta P_{td} = \Delta P_{de} + \Delta P_{dd}$) versus sonic transit time, Δt_c, for sand and no-producing sand wells. From the plot shown in Figure 2.4, a risk region possible to produce sand was established. To the left of the region, sand-free production can be realistically expected. It was also inferred that increasing total drawdown may trigger sand production. The position of the risk region is field dependent and its position can be determined from sand production tests or routine monitoring.

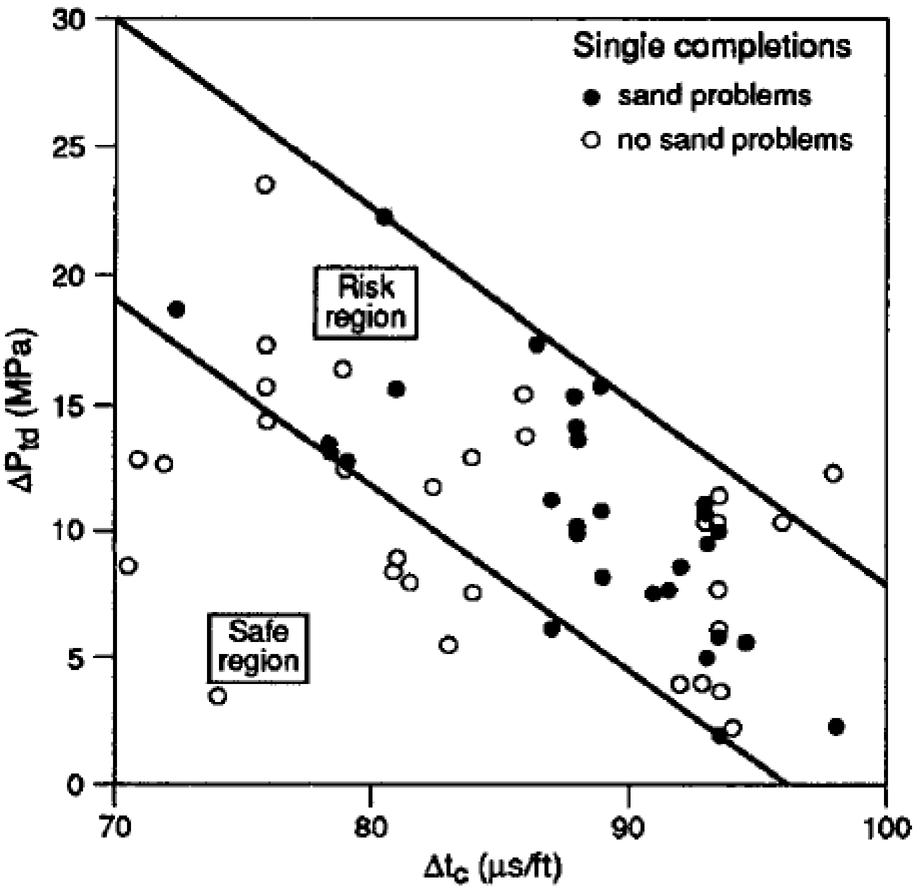


Figure 2.4: Total drawdown versus transit time for intervals with and without Sand problem

To improve the resolution between sand and no sand producers multiple parameter correlation can be used. Fig 2.5 shows the use of the multiple discriminant analysis technique for the data set of Fig. 2.4. Sand production is correlated with a wide range of parameters including depth, sonic transit time, production rate, drawdown pressure, productivity index, shaliness, water cut and gas cut. The sand and no-sand producing wells are well separated. The parameter influencing sand production most in case of Fig. 2.5 is water cut: sand and no sand producers are characterized by an average water cut of 19% and 2% respectively. The discriminant function describing the influence of the various factors is regionally dependent. In a similar analysis, Ghalambor et al., used multiple linear regressions to correlate the critical drawdown pressure observed in water-producing gas wells with seven parameters (Veeken et al., 1991). Extensive data requirement limits the use of the multi-parameter techniques. Empirical methods have the advantage of being directly related to field data and can use easily measurable parameters to provide routine and readily understandable method to estimate sanding risk on a well by well basis. However, revalidation and recalibration of the approach is needed with data from the new environment when transferred from field to field. This necessitates large data acquisition for the new field that may involve field tests and laboratory measurements (Qui et al, 2006).

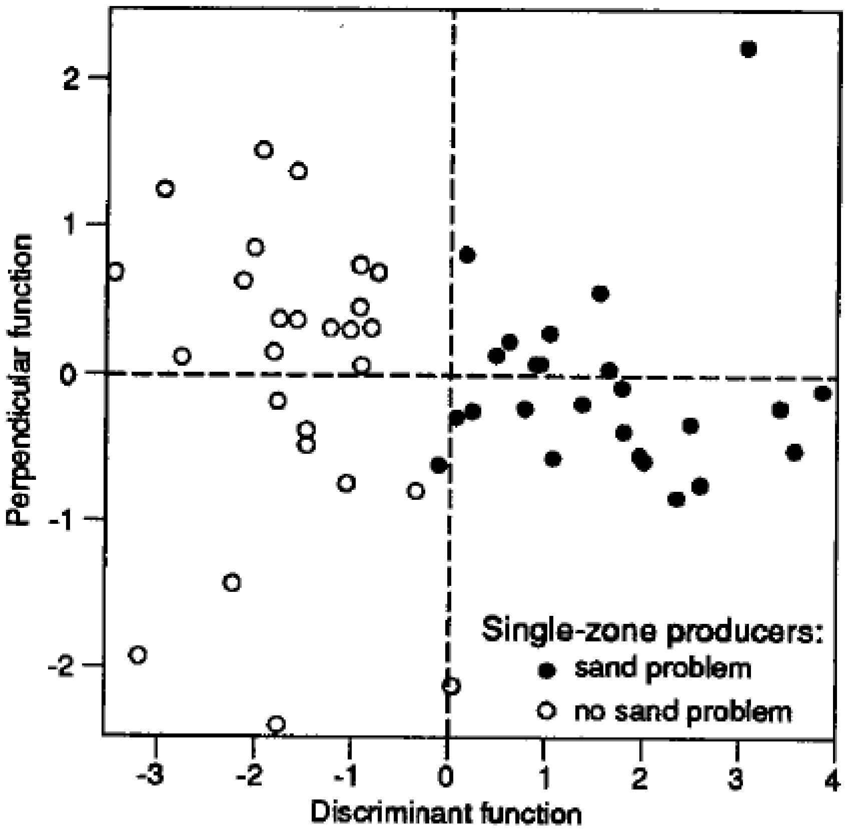


Figure 2.5: Plot Showing Result of Multiple-discriminant Analysis

2.2.2 Laboratory Simulation

This approach is also used widely to establish correlation between the risk of sanding and measurable parameters like stress, flow rate and rock strength and to develop an insight into the mechanism of sanding in the formation involved. Laboratory experiments involve the use of available reservoir core samples or outcrop rock samples (with similar mechanical properties). Two types of laboratory sand production are common: laboratory sand production experiments and hollow cylinder collapse tests (Qui et al, 2006). Typically, laboratory experiments formulates sand production phenomenon in a controlled environment. Laboratory sand production test involves the use of cores to produce a small-scale simulation of flow through perforations or cylindrical cavities contained within a stressed cylindrical core sample. The technique offers the investigation of factors such as drawdowns, stress boundary conditions, flow rates, water cuts and rock properties. Expected conditions during the producing life of the well can be chosen as test parameters. This method is widely used to calibrate and validate predictions from analytical and numerical models. However, considerable number of cores and well equipped facilities are needed for the test.

Thick wall cylinder tests (TWC) are also used for sanding evaluation and calibration, easier to perform than sand production test. In this tests a hollow cylindrical core plug is loaded axially and laterally under increasing hydrostatic stress ($\sigma_1=\sigma_2=\sigma_3$) until collapse occurs in the walls of the cylinder. The hydrostatic stress at which failure initiates in the internal wall is reported as the TWC-internal and the stress that causes external wall failure is called TWC-external or TWC-collapse. The external wall catastrophic failure pressure corresponds to the perforation failure condition that causes continuous and catastrophic sand production. The internal wall failure pressure is less than the catastrophic failure and normally corresponds to the onset of transient sanding. TWC internal can be defined by an increase in fluid volume expelled during constant loading or by monitoring and measuring the internal hole deformation during tests using internal gauged or camera. However, such measures require large plug sizes which are not routinely available (Khaksar et al, 2009). BP reports using plugs that have a 1.5 in. outside diameter (OD), a 0.5 in. internal diameter (ID) and are 3 in. long (Willson et al., 2002), whereas Shell use plugs that have a 1 in. OD, 0.33 in. ID and are 2 in. long (Veeken et al., 1991), (Bellarby, 2009). Results from TWC test can be used to predict the depths and conditions at which sanding might occur in the field, if the stresses corresponding to failure are considered representative of stresses at the sand-face or perforation cavity. Veeken et al, (1991) gave a relationship between the near-wellbore vertical effective stress ($\sigma_{v,w}$) and the TWC collapse pressure (σ_{twc}) from many experiments carried out on friable-consolidated sandstone.

$$\sigma_{v,w} = 0.86 \times \sigma_{\mathrm{twc}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 2.3$$

The results from TWC can however be influenced by sample size/hole size ratio of the hollow cylinder.

Figure 2.6: TWC machine (Source: Bellarby, 2009)

From laboratory experiments important findings as stresses and rock strength are dominant factors controlling sanding initiation and sand production, flowrate only plays a role in in weak and unconsolidated rocks and rocks under excessive stresses, increase in drawdown causes sand production increase, due to changes in boundary conditions (i.e., stresses of fluid flowrate) bursts of sand production are frequently observed after which sand production may gradually decline to some background, there are significant nonlinear scale effects related to the size of a perforation or open hole and their stability against sanding, with smaller diameter cavities being most stable (Qui et al, 2006) have been reached. In the 1970s, Exxon conducted an experiment to establish the relationship between the rock compressive strength and sand production potential of the rock. The studies revealed that the rock failed and began sand production when the fluid flow stresses exceeded the formation compressive strength. As a rule of thumb from the research, sand production or rock failure will occur when the drawdown pressure is 1.7 times the compressive strength. Figure 2.7 shows the equipment used in the test to determine the magnitude of the pressure drops that core samples could withstand before sand production starts. This relationship holds for consolidated formations. Non-destructive test like impact and scratch test are also used for measuring the strength properties of a rock

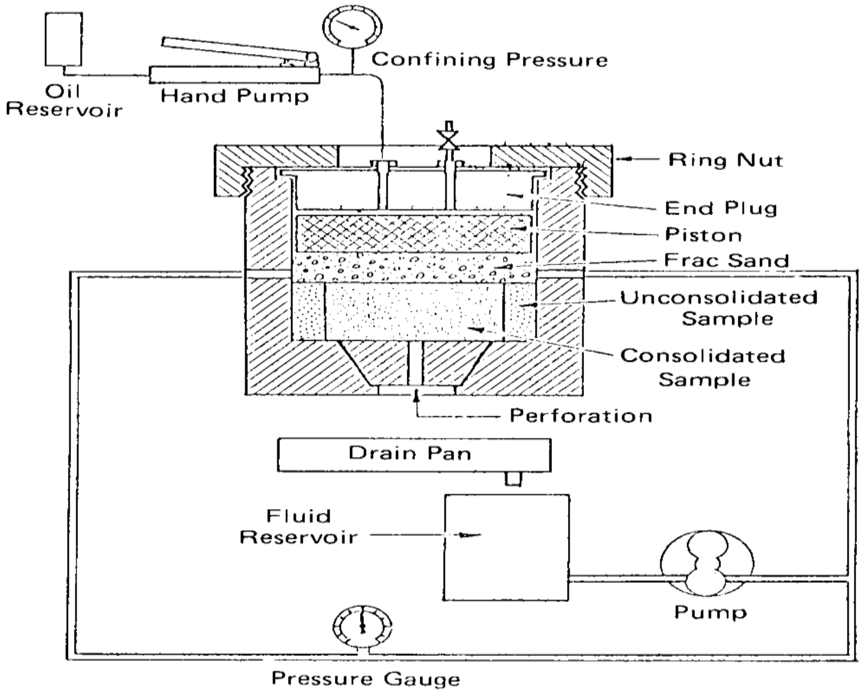


Figure 2.7: Exxon Equipment for Drawdown-to-Rock Failure Test

The main disadvantage of this approach is the amount and availability of core samples needed, time and cost for preparing the core, conducting the experiments, processing and analysing the data from the test. A question of how well a laboratory simulation represents on field scenarios is also raised.

2.2.3 Analytical Methods

This method has gained more popularity in the petroleum industry due to its computational simplicity, readily implementable calculations, and the ease of running multiple realizations to compare many different scenarios. Analytical sand prediction models are based on modeling of perforations and production cavity stability. This tool requires a mathematical formulation of the sand failure mechanism. Production cavity stability under producing conditions is related to the stresses imposed on the formation matrix and the complex manner in which the matrix accommodates these stresses. Stresses imposed are due to overburden pressure, pore pressure, flowing fluid pressure gradient near the wellbore, interfacial tension effects and viscous drag forces. At the mechanical failure of the load bearing sand grain matrix sand is assumed to be produced. Prediction accuracy depends more on how the rock constitutive behaviour is modelled, the failure criterion chosen and whether the materials and other parameters affecting the rock failure are determined precisely. Moore, (1994) highlighted some engineering and geologic parameters shown in Table 2.2 to be considered in a complete evaluation of the sand production potential of a formation based on different sand prediction models and techniques available in the industry. However, no single sand prediction method can accommodate all data highlighted in Table 2.2 reason being that the process of data aquisition is extensive and such information are not available during field development .

Table 2.2: Data Required in a Complete Evaluation for Predicting Sand Production Potential

1. Field data
2. Cyclic loading
3. Directional in-situ stresses
4. Quality of cementation
5. Perforation geometry and spacing
6. Perforation cavities geometry and shot density
7. Cavity evolution effect of varying perforation geometry
8. Well pressure
9. Flow rate (fluid forces)
10. Permeability, viscosity, and relative permeability for two and three phase flow
11. Rock deformation characteristics
12. Rock strength characteristics
13. Flow through porous media where non-Darcy flow is included
14. Log-derived rock mechanical properties
15. Laboratory tri-axial measurements of core samples
16. Regional tectonic forces

The process of sand production starts with the mechanical failure of rock near the wellbore. Sand particles become loose from the formation matrix due to shear opening of the rock and become available to be transported by formation fluid to the wellbore. This process is governed by the formation intrinsic strength and the effective in-situ stresses at that depth in the formation. Once the sand grains are loose, the rate and amount of erosion of the matrix depends on factors such as production rate, the fluid velocity and the fluid viscosity (Navjeet, 2004). The mechanisms responsible for sand production (i.e. sand failure mechanisms) are:

1. Compressive or Shear failure
2. Tensile failure due to pressure drawdown
3. Erosion or Cohesive failure due to cementation degradation

2.2.3.1 Compressive or Shear Failure

Compressive failure refers to an excessive, near cavity wall, tangential stress which causes shear failure of the formation matrix. Compressive failure occurs predominantly in consolidated sandstones (Veeken et al, 1991). Shear failure condition can be triggered by far-field stresses (depletion) and drawdown pressure. Rock strength criterion plays an important role in sand production from shear failure. Shear strength consists of two components; cohesion or physical bonds between the adjoining sand grains and friction. As a result of shear failure, reduction in hole size due to plastic failure near the perforation tunnel might occur. Around the perforation tunnel a stress concentration field is established. This stress concentration field causes the rock to respond either elastically as in strong formation or yield (weak formation), in which case a plastic zone is developed around a perforation tunnel. Large and small sand grains are generated and formation starts deteriorating at the failure plan once shear failure occurs.

Various failure criterions can be used to predict the shear failure mechanism of a rock. Among which are Von Mises, Drucker-Prager, Mohr-Coulomb, Hoek-Brown, Modified Lade and Modified Weibols & Cook. The choice of the failure criterion can be guided by a laboratory experiment to understand behaviour of the rock. The Mohr-Coulomb criterion is the most widely used for shear failure prediction. This criterion considers only the effects of the maximum and minimum principal stresses. It postulates that the failure occurs when shear stress on a given plane within a given plane within the rock reaches a critical value given by:

$$\tau = C + \sigma_n \tan\theta \qquad (2.4)$$

Where, τ is the shear strength, psi

σ_n is the stress normal to the failure plane, psi

C is the cohesive strength, psi

θ is the internal friction angle, degrees

The equation consists of two components; cohesion (C) and friction ($\sigma_n \tan \theta$). Cohesion failure produces the sand particles while shear failure breaks the rock along the shear plane. Assumed material behaviour for shear failure models include: linear elastic brittle, elastic plastic.

2.2.3.2 Tensile Failure

Tensile failure refers to a tensile radial stress exceeding the tensile failure envelope and is triggered exclusively by drawdown pressure. From the tensile failure criterion when a fluid flows into a cavity at high production flow rates, tensile net stresses can be induced near the cavity resulting in formation failure. The mechanism of tensile failure occurs at the perforation tunnel; here the radial stress is controlled by the reservoir pressure and wellbore pressure. Sudden pressure changes can exceed the tensile strength of the formation, causing sand production and subsequent enlargement of the perforation tunnel. Tensile failure may occur at the perforation tip or the perforation wall which is usually penetrating within the plastic zone (Navjeet, 2004). Weingarten and Perkins, 1995 studied the conditions necessary for formation stability around a spherical cavity in weakly consolidated rock. An equation describing tensile failure condition using pressure drawdown, formation rock cohesion and frictional angle was derived. They provided dimensionless curves for determining the pressure drawdown at a specified wellbore pressure.

2.2.3.3 Erosion or Cohesion Failure

Erosion refers to a gradual removal or production of individual sand particle from the cavity surface (perforation tunnel, wellbore surface in open-hole completion etc.). Erosion is controlled by the cohesive strength. Erosion will take place if the drag force exerted on a surface particle exceeds the (apparent) cohesion between surface particles. The frictional drag is directly related to the velocity of the fluid flow. Hence, fluid velocity becomes an important parameter. This is confirmed by field experience: in loosely consolidated formations sand production from open holes tends to be less than from perforated completion: in line with the fact that the fluid velocity at the open hole surface is three orders of magnitude smaller than the velocity at the (intact) perforation surface. Erosion is related to tensile failure, but needs to be considered as a separate mechanism due to its particulate nature (Veeken et al., 1991).Analytical approach captures the mechanisms of sand production, they can be implemented and calibrated more easily compared to numerical. Important aspects of sand production captured by analytical approaches are: stresses, rock strength, in-situ stresses. The time and effort needed for analyses are reduced and overcomes the difficulties of obtaining complex input parameters are overcome by analytical methods.

2.2.4 Numerical Methods

These are finite element analysis models that incorporate the full range of formation behaviour during plastic, elastic and time-dependent deformation. Numerical models provide a detailed description of the stress state and can be accurate. In comparison to other methods of prediction, numerical method is regarded as superior because it accounts for more factors influencing rock failure and sand production. However, the main disadvantage of the method is its complexity and time consumption. Time, resources and data needed for the method might not be available. When properties needed in the numerical modelling are assumed or approximated due to lack or real data, results from the complex modelling are not necessarily more accurate or reliable than that from other approaches that uses simpler easily accessible data.

Another method used in sand prediction is the analogy or historical method. This relies on production experiences such as rate, drawdown, water-cut etc. from other wells in the same reservoir or nearby fields (offset data) to arrive at a choice between sand control and sand prevention. The most critical factors to determine the sand production potential of a reservoir formation are (1) formation strength (2) in-situ stresses (3) production rate. Formation intrinsic strength is however the key information needed. Zhang et al., 2000 developed a simple and efficient approach to evaluate formation strength. They found out to construct a universal failure envelope the only parameter needed is the critical pressure. Conventional logs data (compressional wave velocities) can be used to obtain the failure envelope of a sandstone formation. The generality of their observation is still explored. The failure envelope is constructed from the p_c determined.

$$p_c = 10.086 \times In \frac{(6.789)}{12.322 - V_p} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots . 2.5$$

Where,

$p_c = critical pressure$(psi)

$V_p = compressional\ velocity$ (ft/sec)

2.3 Sand Control

The concept of sand control is based on the absolute exclusion of sand; zero tolerance of sand production at the surface. Problems associated with sand production have provided justification for downhole sand control devices. Once it has been established through sand prediction that at the desired production rate the reservoir will produce sand. The question of the best completion practice to mitigate sand is raised. The choice of the sand control method to be used in a reservoir depends on operating practices, conditions of the field (formation sand characteristics), successful field experiences and economic considerations. Traditionally, the main classes of sand control techniques are mechanical and chemical. Available sand control techniques in the industry include:

1. Rate control or exclusion
2. Non-impairing completion techniques
3. Selective perforation practices
4. Screens (without gravel packs)
    - Slotted liners
    - Wire-wrapped screens
    - Premium screens
    - Expandable screens
    - Pre-packed screens
5. Gravel packs
6. Frac packs
7. Chemical sand consolidation
    - In situ formation consolidation
    - Consolidated gravel

The techniques highlighted above can be further divided into two groups: mechanical exclusion methods and arch stabilization methods (Najveet, 2004). Arch stabilization methods can be further divided into natural arches and reinforced arches. Classification of the above sand control methods given by Najveet, (2004) are presented in table 2.3. The mechanical exclusion methods are designed to prevent sand production through bridging type retention or filter type retention. Bridging type retention allows a certain quantity of sand production until a bridge is formed against a filtration medium such as a screen or sized gravel or the two in combination (e.g. gravel packs). These bridges are disturbed easily by abrupt changes in production rate, resulting in sand production until a new bridge forms. In filter type retention sand production is excluded, and does not depend on the formation of bridges. Filter type sand control is attained simply by further reducing slot size of the screen and size of gravel, below that required for bridging type retention (Najveet, 2004). Mechanical sand exclusion methods highlighted in Table 2.3 are listed in order of effectiveness and reliability in providing filter type sand control.

Table 2.3: Sand Control Methods Classification

Mechanical exclusion (listed in order of increasing effectiveness and reliability)
Consolidated gravel (filling perfs only)
Screens alone
Consolidated gravel (filling perfs & wellbore)
Pre-packed screen
Expandable screen
Gravel packing
Frac packing
Arch stabilization
Natural arches
Non-impairing completion techniques
Selective perforating
Rate control
Reinforced arches
In situ chemical formation consolidation

Arch stabilization depends on the formation of stable arches near the wellbore to prevent sand production. Natural arch stabilization is produced by avoiding arch destabilizing actions that can induce sanding. Stability of natural arches is sensitive to changes in flow rate. Reinforced arches are produced using chemical bonding agents such as plastic resin etc. to create new bonds and strengthen existing ones between adjoining sand grains. Often a combination of techniques is used to ascertain reliability of sand control. Such situation may occur when the parameters of the well exceed the design applicability of a specific control method.

2.3.1 Rate Control or Exclusion Method

Treating the well with care by minimizing shocks to the reservoir is a method used by operators to control sand production. Laboratory and field experience has shown that reducing production rates and pressure drawdown reduces sand influx. Cook et al., (1994) established the influence of flow rate on sand production. The procedure is to slowly and in small increments reduce or increase the rate/drawdown until an acceptable level of sand production is reached or identifying a threshold of rate/drawdown sand can be produced. The objective of this technique is to obtain a maximum flow rate that will allow the formation of a stable arch at the wellbore. Finding a maximum flow rate has to be repeated overtime as reservoir conditions changes (e.g. pressures, fluid saturation). Rate exclusion method is generally more effective when little sand has already been produced.

Rate control is used as both a temporary and a permanent method of sand control. It is used temporarily pending installation of a more effective sand control method, when the value of continually deferring production greatly exceeds the cost of installing an effective sand control method. In the case of high-pressure gas wells, rate control may be utilized temporarily until reservoir pressure has declined to the point where the well control risks which will be incurred during sand control installations are acceptable. Permanent use of sand control as a sand control method usually results when the cost of a more effective sand control method cannot be justified or is not operationally feasible. Rate control may be suitable in situations where production rates must be limited anyway to control water influx or gas coning. A common use of rate control occurs in deep gas wells producing from consolidated sandstones (Navjeet, 2004). The limitation of rate control method in high permeability formation is that flow rates required to enable formation of stable sand arches is often less than the flow potential of the well and may represent not favour well economics in terms of productivity. Rate control is utilized more at the later life of the well when sand production begins largely due to pressure decline and high water cuts.

2.3.2 Non-Impairing Completion Techniques

Drilling and completion activities could damage or impair the new wellbore formation through the influx of drilling of completion fluids etc. into the formation. Indirectly, this technique can be considered a method of sand control especially in marginal sanding situations. High pressure drawdown may lead to premature formation failure in a marginal sand producer. This is because a higher drawdown is needed in impaired formation to produce the same rate of fluid from the reservoir as an unimpaired formation. If a formation is noticed to fail as a result of excessive drawdown, it is fairly often attributed to impaired formation. It has been noted that wells that produced sand during drill stem test, when formation impairment was removed through appropriate completion techniques produced sand free. Completion considerations of significances include the use of clean, filtered non-damaging completion fluids together with proper stimulation design, and treatment. Well stimulation method as acidizing can cause problems if not well designed. In situations where the only method of sand control to be used is passive such as rate control, an unimpaired formation becomes essential in minimizing sand production.

2.3.3 Perforating

Cased and perforated completions are the basis of many fields. Perforating a well is to establish good flow communication between the wellbore and the reservoir. This is more common in onshore fields but also exist in offshore areas. The productivity of a well where applied is largely dependent on the perforation design. Perforation parameters affecting well productivity include perforation dimensions (diameter and penetration), phasing, shot density and charge type. The perforation dimension is a function of the perforating charge/gun design and quality, the position of the gun/charges in the wellbore when they are fired, and well conditions such as temperature, pressure, well fluids, casing size and metallurgy, cement and formation properties (Navjeet, 2004). The aim of most cased-hole completions is to generate the maximum perforation length- deep penetrating charges. Damage caused as a result of perforation impairs productivity. The explosive energy of a perforation creates a hole by outwp7ard pressure. This pressure crushes the cement and rock. The cement and rock are not destroyed in the process, but they, along with parts of the perforation assembly, end up inside the perforation. They must be removed for the perforation to be productive. If not removed it results in a larger pressure drop at the perforations that can contribute to tensile failure.

Most of this debris will be crushed/fractured rock, with minor amounts of charge debris. There are a number of ways of removing this damage. Flowing of the well after perforating will create a drawdown on all the perforations. This will flow some of the debris from some of the perforations (Bellarby, 2009). It is important for perforation impairments to be minimized in order for production stresses which tend to cause sand production are minimized. For sand control further cleanout is imperative prior to gravel packing, frac packing or injecting consolidating chemicals (Completion tech., 1995). The objective in gravel packing is to have large diameter perforations which have been well cleaned, leaving an open cavity where gravel can be placed.

Perforation cleaning is necessary in order to remove perforation damage as a result of formation crushing and compaction, drilling mud, cement, dirty completion fluids and perforating gun debris. Perforation cleaning can be accomplished by underbalanced perforating and perforation washing. Perforating at underbalance allows the production of the sand during the initial stages and thus avoids having to manage transient sand production during later stages of well production (Venkitaraman et al., 2000). Perforation washing is a widely used method for removing perforation damage. It entails pumping through each perforation with sufficient pressure and rate because it is essential to maintain circulation to remove debris from the well. A clean fluid system or fluids with surface filtration systems or a combination of both can be used in washing. In soft rock completions, once communication is established between two or more perforations, debris is removed from the perforations by washing out a void behind casing. In gravel packed completion, this void is subsequently packed with highly permeable gravel. Perforation washing is better suited for long intervals. It is important to remove damage which is not removed by other cleaning processes. A common practice in completions is to acidize the perforations after other perforation cleaning techniques have been used, immediately prior to gravel packing (Navjeet, 2004), frac packing or injecting consolidating chemicals.

2.3.3.1 Selective Perforating

In heterogeneous formations, rock strength varies substantially with depth among the different lithologies present. Avoiding perforating weaker sections of the formation, sand free production rates throughout the life of the well can be maintained. Higher critical drawdown can be gotten perforating the strong zones (have higher degree of cementation). Unfortunately, these weaker sections are often the main productive zones than stronger intervals having lower permeability. To allow draining of the reservoir, the formation should have good vertical permeability such that fluids from the weaker sections can flow to the stronger sections. Both productivity analysis using nodal analysis programs and strength analysis (using cores, logs etc.) need to be carried out prior to making this decision (Venkitaraman et al., 2000).

2.3.3.2 Overbalanced Perforating

This method of perforating simplifies well control because fluid inside the casing overbalances formation pressure and prevents inflow. Perforating through this method holds also holds debris necessitating additional clean-out operation as mentioned above. A new method of extreme overbalanced perforating or surging with resin has been successfully used by Oryx Energy in both their onshore and offshore wells (Navjeet, 2004). This method of extreme overbalanced perforating and stimulation provides a means to sand control. Another advantage is the combination of perforating with sand control as a single operation reduces the completion fluid volume requirements and the average time to complete the well. Extremely overbalanced perforating and stimulation could cause the industry to reconsider the method of perforating wells for sand control. The overbalanced perforating method resin method is used in a wellbore suspected of producing sand in its life and the overbalanced surge resin method is used when the casing has existing perforations in a wellbore suspected of producing sand.

2.3.3.3 Oriented Perforating

Laboratory tests in the past have indicated that the mechanical stability of perforation cavities depends on perforation direction relative to the in-situ stress field. This led to the idea of oriented perforating to minimize the shear stresses acting at the wall of the perforation cavities (Completion tech., 1995). In regions where there is a large contrast between the in-situ stress fields, perforation should be oriented in the direction of the maximum stability. Oriented perforation guns can be used to perforate only in one direction, thereby delaying or avoiding sand production. In extensional stress regimes, for example, many sedimentary basins, the maximum stress will be in the vertical direction (Bellarby, 2009). Oriented perforations in the direction of maximum horizontal stress in a vertical well increase the probability of more stable perforation tunnels for a perforated only completion. Thus, eliminating the need for conventional sand control (Najveet, 2009).

This method can be used successfully in fields with economical constrains. Oriented perforating uses 180° phasing shot in the direction of maximum perforation stability. The use of 180° phasing is believed to reduce the risk of sand production due to a reduced probability of hitting the most unfavourable perforation direction. In case of horizontal completions, the dominant stress field will be vertical or overburden. In this completion, the perforations are directed to the top and bottom of wellbore to the maximum stress field (Najveet, 2009). A challenge is the determination of the maximum horizontal stress direction in a field. There always arises a factor of uncertainty in stress orientation and magnitude as determined in the field.

2.3.4 Screens

All forms of screen can be run in either a cased hole or open hole well with or without gravel packing, although each will have its optimum environment. Screens can also be run into open hole with a pre-installed, pre-drilled liner to provide additional installation protection (Bellarby, 2009). The simplest and oldest sand control method employs only a screen to restrain sand production (Navjeet, 2004). This control method is relatively low-cost. When used alone as sand exclusion devices, the slotted liners or screens are placed across the productive interval and the formation sand mechanically bridges on a slot or opening (Completion tech., 1995) before excessive sand production, screen plugging or erosion occurs. There are several rules available for screen sizing. Normally, the slot width or the screen gauge should be sized to equal the formation sand grain size at the largest 10 % level. Coberly presented this sizing criterion (Navjeet, 2004). The 10^{th} percentile or D_{10} designation denotes the sieve size (screen) which would retain 10 % of the sand grains. The remaining 90 % of the formation sand will be allowed to pass through it. Bridging theory shows that particles will bridge against a hole if the hole diameter does not exceed about three particle diameters. The bridges formed will not be stable and may breakdown from time to time when producing rate is changed or the well is shut-in (William and Joe, 2003).

Bridge break down can cause the formation sand to be resorted (finer sands and silts may be trapped between the coarser grains) which over time tends to result in plugging of the screen. The risk of screen cut-out especially in formations that produces fine sand can be minimized by slowly bringing the well through the critical sand producing rate. Screen-alone applications generally should be limited to the producers that meet the Coberly's criterion and open-hole completions, particularly horizontal wells or wells with extremely long completion intervals (Navjeet, 2004). A non-standard application of screens is for keeping marginal, minor sand influx out of sensitive wells e.g. high-rate gas wells. The main concerns of the application of screen-alone are erosion failure and the plugging of perforation tunnels especially in cased completions. Though the screens alone offers the lowest cost of downhole filtering, the over evaluation in terms of cost should factor in cleanout and workover etc. costs.

2.3.4.1 Slotted Liners

Slotted liners have the largest holes of all the screens. They are usually less costly than wire-wrapped screen, they have smaller inflow area and experience higher pressure drops during production. Slot width usually ranges from 0.012 in. to 0.250 in., these slots are made by a precision saw or mill longitudinally. Slotted liner completion is to guide against hole collapse while maintaining the well productivity (Igbokoyi, 2011). Slotted liners plug more readily than screens and are often used in low productivity wells and where economics cannot support the use of screens. Three types of slotted liners are available:

1. Perforated liner where holes are drilled in the liner.
2. Slotted liner where slots of various width and depth are milled along the liner length.
3. Pre-packed liners for unconsolidated formation.

2.3.4.2 Wire-Wrapped Screens

They have smaller openings than slotted liners. They are used often in gravel pack and standalone completions. They are made up of a base pipe with holes, longitudinal rods and a single wedge-shaped wire wrapped and spot-welded to the rods as shown in fig. 2.8. Wire-wrapped screens do have substantially more inflow area. They are made from stainless steel and are resistant to corrosion and erosion, an advantage over slotted liners. The smallest slot size used is 0.002 in. or 50 microns with 50-70 mesh gravel. As with slotted liners, they are widely used in horizontal wells.

Figure 2.8: Wire-Wrapped Screens (Source: Bellarby, 2009)

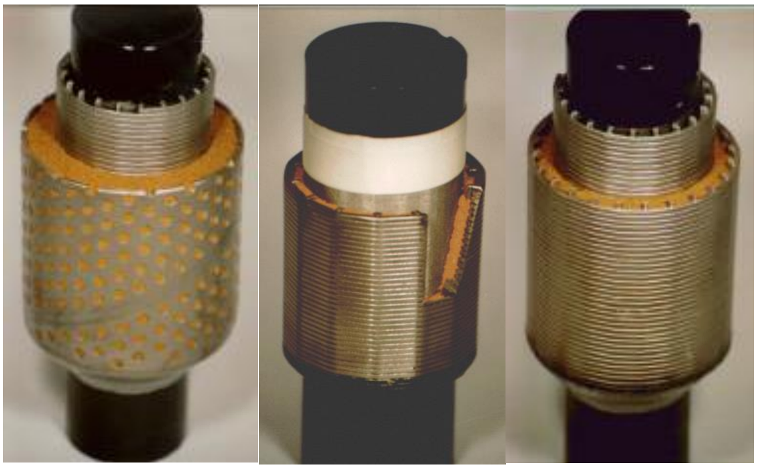
2.3.4.3 Premium Screens

This refers to screens constructed with a woven mesh and some form of shroud for protection. A variety of different designs from vendors exist. Premium screens are made up of multiple woven layers meaning they have non-uniform apertures. They are thinner than pre-packed screens but slightly thicker than wire-wrapped screens. They typically have an inflow of about 30%. Due to their more robust construction they are used in harsh environments- long, horizontal, open-hole wells (Bellarby, 2009). Example of premium screens is presented Figure: 2.9.

Figure 2.9 Example of a Premium Screen (Source: Bellarby, 2009)

2.3.4.4 Pre-packed Screens

These are similar in construction to wire-wrapped screens, but with two screens. Pre-packed screens consist of an inner screen assembly with a layer of resin coated gravel placed around it making up the annulus and an outer screen. The size of the screen slots are made such that they prevent the escape of gravel packed between the screens. Pre-packed screens offer a degree of depth filtration, and the relatively high porosity over 30 % combined with their very high permeability provide minimal pressure drops (Bellarby, 2009). However, they can be prone to plugging due to finer sands embedding between the pore throats. They will plug more easily than a wire-wrapped screen (William and Joe, 2003).



(a) (b) (c)

Figure 2.10: (a) Single-Screen Pre-pack (b) Slim-Pak (c) Dual-Screen (Source Completion Tech.)

2.3.4.5 Expandable Screens

An expandable screen is made up of three layers: (1) a slotted base pipe, (2) a filtration medium and (3) an outer protective shroud.It expands when a cone is pushed through the screen. The design of expandable screens offers it a lot of unique advantages. It offers a lager internal diameter than any other type of screen; ESS eliminates the annular space between the screen and the sandface. Thereby stabilizing the sandface and minimizing sand movement, hence sand production. Productivity of Expandable screens completion is generally superior to other sand control methods especially when deployed in open hole and offer the advantage of near well-bore access for well interventions operations if it becomes necessary during well life (Ayoola, 2009). Expandable screens are widely used in horizontal open-hole completions. Its greatest drawback is its susceptibility to collapse in squeezing formations.

Figure 2.11: Expandable screen (expanded) (Source: Bellarby, 2009)

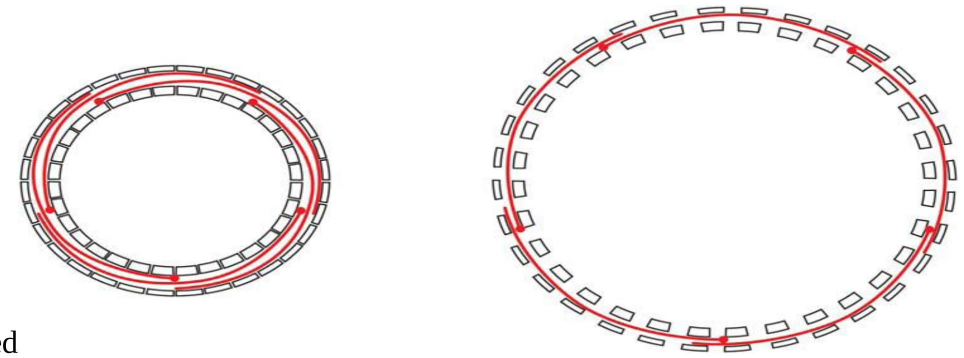


Figure 2.12: Overlapping mesh design for expandable screens (Source: Bellarby, 2009)

2.3.5: Gravel Packing

Gravel packing is the most widely used sand control technique used in the industry. It accounts for about three-quarters of treatments (Jon Carlson et al., 1992). A gravel pack is a downhole filter held in place by a properly sized screen with the gravel pack sand holding the formation. In gravel packing, slurry of accurately sized gravel is pumped into the annular space between a centralized screen and either a perforated casing or open-hole. The gravel pack is designed to prevent the production of formation sand. The flow path of the gravel pack must be small enough to prevent the production of sand but large enough to accommodate well productivity. This technique is a relatively expensive method of sand control, but it is the most effective method of stopping sand movement while permitting production. Gravel packing is not without its drawbacks which are majorly the increased complexity of completion operations and further reducing operating wellbore diameter. Subsequently, downhole operations are complicated and operational flexibility decreases. To obtain an effective gravel pack system, the pack must be properly designed using the correct gravel size, gravel thickness, correctly positioning the liner and placing the gravel.

Selection of the proper gravel size is based on sand sieve analysis on sand samples representing the formation. These can be conventional cores, side-wall cores or sand samples obtained from perforation washing or produced. The early work on gravel packing was done by Coberly and Wagner, (1938) where they suggested using the gravel size of 10 times the D_{10}, of the formation sand (Bellarby, 2009) i.e. using larger sand grains in sizing determination. Another criterion used is the Saucier's based on laboratory experiments. He concluded that between 5 and 7 times the median (D_{50}) particle size, the ratio of gravel pack to sand permeability was a - peak regardless of the permeability sand (Bellarby, 2009). Six times the D_{50} is been used widely in the industry. However, these are not rigid guidelines, testing of formation sample will give the best result. Of importance to optimize the gravel packed completion is the gravel quality, gravel packing fluids, choice of screen or liner selection.

There are three basic methods of gravel packing methods: (1) Inside Casing Gravel pack (ICGP) (2) Milled Casing Underreamed Gravel Pack (MCUGP), and (3) Open Hole Gravel Pack (OHGP). In ICGP, a screen is placed across a perforated interval. The annular space between the casing and screen likewise the perforations tunnels are packed with gravel. With ICGP multiple completion are simplified and workover activities and zone repairs are possible. Inside casing gravel packs have some advantages over milled casing underreamed gravel packs. In highly deviated holes milling problems can occur. Remedial cementing to control Gas Oil Ratio and water influx is not possible once a window has been cut in MCUGP. Influx of formation fines into the gravel and perforation tunnels, causing permeability reduction hence increased drawdown is a main disadvantage of ICGP. This subsequently reduces productivity index (PI).

MCUGP better ensures good productivity by eliminating flow restrictions and increased radial extent of the gravel pack. However, in selecting candidates for MCUGP care must be taken because it can be regarded as a permanent completion. Therefore, gas-oil contact and water-oil contact are of interest and should be isolated by 20ft from the underreamed section. The main advantage of MCUGP is that it offers improved oil flow geometry, increased effective filtration surface due to radial extent gravel, and no perforation debris. For Open-hole gravel packs the casing is placed above the top of the pay zone. They are performed on the bottom zones of the wells especially used for initial completion where the geology of the formation is well known. Open-hole gravel packs completely avoid the difficulties and concerns of perforation packing, and reduce the gravel placement operations to the relatively simple task of packing the screen/open-hole annulus (Completion tech., 1995). Its productivity and reliability is like as in MCUGP. Cased-hole or inside gravel packs now prevail as an accepted industry practice since they offer flexibility, selectivity, and effective zonal isolation and are usually easier to install (Navjeet, 2004).

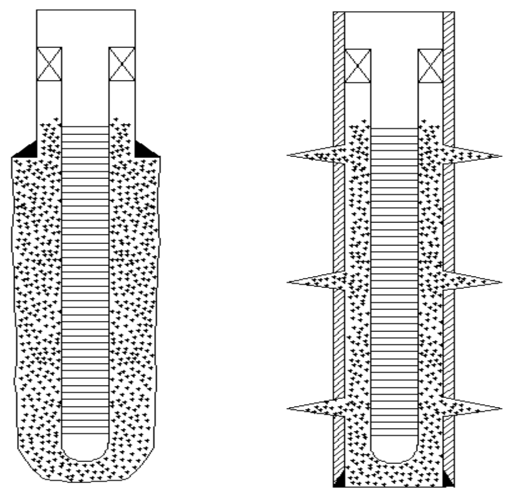


Figure 2.13: Open-Hole and Cased-Hole Gravel Packs (Source: Completion tech., 1995)

2.3.6 Frac Pack

Frac pack is like an internal gravel pack but the pumping is done above the fracture pressure of the formation (Navjeet, 2004). At this pressure the rock splits open generating a fracture which bypasses the near wellbore damage often present in gravel packs. Frac packing helps increase the contact area with the reservoir thereby increasing productivity. Frac packs are poorly suited to intervals close to gas contacts or where cement quality is poor. Compared to cased hole gravel packs, frac packs require more complex fluids, larger volumes, higher pump rates, plus the associated mixing and pumping equipment (Bellarby, 2009). Proppants are used to fill the fracture.

2.3.7 Chemical Consolidation

Chemical consolidation refers to a method that employs a liquid resin which is injected from a well-bore into the unconsolidated rock surrounding the well. The resin is catalytically polymerized to form a porous, permeable rock mass. With most resins, it is necessary to inject a displacement fluid, which is a fluid following the resin which is not miscible with the resin (Talaghat et al., 2009). Three types of commercially available resins include: furans, epoxies, and phenolic resins. Historically chemical consolidation has been used as a low-cost method of stopping sand production in short perforated intervals. It is generally considered a remedial option (Bellarby, 2009). Short intervals with low likelihood of producing sand, low consequence of producing some sand, chemical consolidation can be used as a substitute for screens. The objective in sand consolidation is to increase cementation between the sand grains whilst maintaining permeability. By this, the completion interval behaves like a natural completion without any mechanical sand control equipment obstructing the completion interval. Chemical consolidation can be subdivided into two categories: (1) in-situ consolidation, (2) resin-coated gravel

2.3.7.1 In-situ Consolidation

The formation near the wellbore is treated with resin to cement the sand grains together at their points of contact. This is done by injecting liquid resins through the perforations into the formation and the flushed by a catalyst. The resins used are epoxy, furan and phenolic resins. The success of in-situ consolidation depends on the permeability of the consolidated sand mass to reservoir fluids, the degree of consolidation should not decrease with time. In-situ consolidation treatments are of two types: phase separation systems and overflush systems.

Phase separation systems contain only 15 to 25 % active resin in an otherwise inert solution. Over-flush systems contain a high percentage of resin (Completion tech., 1995). Clays attract the resin; therefore clay concentration hinders the effectiveness of the consolidation process. Clay stabilizers are often used as pre-flush. In-situ consolidation poses less damage to the formation than that can occur from gravel packing. Due to difficulties in achieving effective placement, high cost of resins, likewise compatibility and contamination problems the use of this method of sand control is limited. To decide the best choice of resin for a sandstone experiments should be conducted.

2.3.7.2 Resin Coated Gravel

This is gravel pack sand coated with a thin layer of resin with high permeability. The gravel is circulated typically via coiled tubing inside casing and perforations or open hole and then squeezed to form a plug across the production zone. The resin coating hardens and bonds adjacent particles together strengthening the pack. The bottom-hole temperature of the well or injection of steam causes the resin to cure into a consolidated pack. After curing, the consolidated gravel pack sand can be drilled out of the casing leaving an unobstructed wellbore. The remaining consolidated gravel in the perforations acts as a permeable filter to prevent the production of formation sand (Completion tech., 1995). An advantage of resin-coated gravel is that it doesn't need any special hardware. But a significant additional pressure drop that might affect productivity is created by the pack. This technique is often used in place of regular gravel in gravel packed completions so as to minimize formation or gravel movement. Intervals longer than 20ft are difficult to cover completely. This technique represents about 5% of sand control treatments, mainly concentrated on low-cost onshore markets (Jon Carlson, 1992).

2.4 Sand Management

Sand management refers to an operating concept which does not normally apply the traditional sand control means and production is managed through monitoring and control of well pressures, fluid flow rate and sand influx. More recently sand management is been applied to all processes, technologies and completion techniques meant to address the issue of producing fluids from weak formation (Mathias, 2003). Sand management in conventional oil and gas production has been implemented on a large number of wells in the North Sea and elsewhere. In almost all cases it has proven to be workable, and has led to the generation of highly favourable well skins because of self-clean-up associated with the episodic san bursts that take place (Completion tech., 1995). These wells experience high productivity index and subsequently high production rates. Sand management also cuts the expensive sand control equipment. However, sand management involves risk management. Sand management techniques commonly used in the industry include Rate exclusion, selective perforation practices, orientated perforating (these have been mentioned above under non-exclusive/passive sand control technique) and sand monitoring techniques which include Acoustic transducers, sand detectors, and choke inspection.

CHAPTER 3

3.0 MODEL FORMULATION

3.1 INTRODUCTION

Extensive research efforts expended in developing models for predicting sand production in the past couple of decades identified several factors associated with sand production. The mechanism of sand production in terms of rate, volume and sand producing patterns in the reservoir is needed to optimally develop a field. Mechanisms causing sand production are related to the formation strength, flow stability, viscous drag forces and pressure drop into the wellbore. The critical factors leading to accurate prediction of sand production potential and sand production are: formation strength, in-situ stress, and production rate (Osisanya, 2010). Most existing models for quantifying volumetric sand production may be classified into strain-based, erosion-based and particle-based models (Chin and Ramos, 2002).

Though, there exist a wide variety of empirical, numerical and analytical sanding prediction models in literature which requires lots of rock mechanics input parameter rarely available in field practice and demanding extensive computations. This work is focused in developing a simple and easy-to- use mechanistic model for predicting sand production in Niger-Delta wells, however, the derived model would be applicable to any similar unconsolidated clastic formation.

In other to develop the mechanistic model, factors associated with sand production will be identified from literature, critical ones required in deriving the model will also be identified by critically examining existing developed models for predicting sand production, the mechanistic model will then be develop using existing experimental data and validated for use in the Niger-Delta wells by calibrating with real field data for the Niger-Delta terrain.

3.1.1 Factors Associated With Sand Production in Clastic Sediment

Different authors seem to identification similar factors related to sand production in clastic reservoirs, among others include: formation strength; in-situ stresses; production rate; pressure drawdown; reservoir pressure; reservoir depth; reservoir permeability; reservoir porosity; formation cementation; compressibility; surface exposed to flow; produced fluid properties; formation characteristics; well radius; azimuth; perforation properties (Oyeneyin, 2014; Osisanya, 2010).

3.2 DESCRIPTION OF THE SAND PRODUCTION RATE MODEL

3.2.1 Impact of Stress Concentration Effects

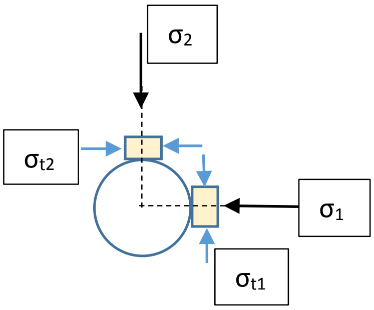


Figure 3.1: Tangential stresses at the wall of a hole/perforation

Given the far field total stresses on a plane perpendicular to the axis of a well-bore perforation or open-hole, σ_1 and σ_2, ($\sigma_1 > \sigma_2$), the tangential stresses on the surface of the hole (σ_{t1} and σ_{t2}) are given by:

$$\sigma_{t1} = 3\sigma_2 - \sigma_1 - P_{wf}(1 - A) - AP_R \dots\dots\dots\dots\dots\dots\dots\dots\dots. 3.1$$

Similarly:

$$\sigma_{t2} = 3\sigma_1 - \sigma_2 - P_{wf}(1 - A) - AP_R \dots\dots\dots\dots\dots\dots\dots\dots\dots. 3.2$$

Where: P_{wf} is the wellbore flowing pressure, P_R is the reservoir pressure, A is a poro-elastic constant given by:

$$A = \frac{(1 - 2v)\alpha}{(1 - v)} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots 3.3$$

$$\alpha = 1 - {}^{c_r}/_{c_b} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots. .3.4$$

Where: α is Biot's constant, v is the Poisson's ratio, c_r and c_b are the grain and bulk rock compressibility respectively.

Substituting equation 3.4 in equation 3.3 gives:

$$A = \frac{(1 - 2v)(c_b - c_r)}{(1 - v)c_b} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots .3.5$$

To avoid sand production the largest effective tangential stress ($\sigma_{t2} - P_{wf}$) should be smaller than the effective strength of the formation, U, next to the hole(Willson *et al*, 2002).

$$that\ is: \sigma_{t2} - P_{wf} \leq U \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots..3.6$$

Substituting equation 3.2 into equation 3.6 and solving for P_{wf} gives:

$$3\sigma_1 - \sigma_2 - P_{wf}(1 - A) - AP_R - P_{wf} \leq U$$

$$3\sigma_1 - \sigma_2 - U - AP_R \leq P_{wf}(2 - A)$$

$$P_{wf} \geq \frac{3\sigma_1 - \sigma_2 - U}{2 - A} - P_R\left(\frac{A}{2 - A}\right) \ldots\ldots\ldots\ldots\ldots..\ldots\ldots..3.7a$$

Thus, the onset of sanding can be established by determining the critical bottom-hole flowing pressure resulting in sand production, $P_{wf,Cr}$

$$P_{wf,Cr} = \frac{3\sigma_1 - \sigma_2 - U}{2 - A} - P_R\left(\frac{A}{2 - A}\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots.3.7b$$

The critical drawdown pressure, CDP, is defined as the drawdown from the reservoir pressure to cause formation fracturing or failure (and possible sand production).

Recall: Drawdown pressure, $DP = P_R - P_{wf} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.3.8$

$$CDP = P_R - P_{wf,Cr} \longrightarrow P_R = CDP + P_{wf,Cr} \ldots\ldots\ldots\ldots...3.9$$

Putting equation 3.7b into equation 3.9, gives:

$$CDP = \frac{1}{2 - A}[2P_R - (3\sigma_1 - \sigma_2 - U)] \ldots\ldots\ldots\ldots\ldots\ldots..3.10$$

$$P_R = {}^1\!/_2\,[3\sigma_1 - \sigma_2 - U + CDP(2 - A)] \ldots\ldots\ldots\ldots..\ldots.3.11$$

Equation 3.10 provides the sanding criterion for the drawdown pressure at which the reservoir fails. However literature theorized that sand production can be expected if the product of two elastic parameters (i.e. GK_b) is lower than the threshold value of 8E11psi^2, where the shear modulus, G and the bulk modulus, K_b are derived accurately from interpretation of acoustic and density logs (Tiab, 2014; Osisanya, 2010). Thus, it is recommended to ensure GK_b is less than 8E11psi^2, before even predicting the sanding rate since sand can only be produced after formation fracturing or failure has occurred.

Note that σ_1 and σ_2 depend linearly on the reservoir pressure, P_R and are not constant values for cases where reservoir depletion effects (production) are considered.

3.2.2 Determination of the Effective Formation Strength, U

In the sanding models employed by BP, the collapse pressure of a so-called thick-walled cylinder test (TWC) is used as the fundamental strength measure for unsupported boreholes and perforations.

A relationship between the effective in-situ strength of the formation, U and the TWC strength is necessary since the TWC test does not directly replicate perforation collapse pressures. This is because the standard TWC test is performed on specimens where the ratio OD/ID = 3, at in-situ conditions, the effective strength would be represented by a TWC strength where OD/ID tends to infinity. Also there is an ID scaling issue too, as perforation tunnels may easily exceed 0.5''diameter when deep penetrating perforating charges are used in low- strength sandstones (Willson *et al,* 2002).

Scaling relationships to account for these effects have been published by Van den Hoek *et al.* They found that for Castlegate sandstone, with an OD/ID ratio of infinity, the maximum size effect factor varies between 3.0 and 3.8, depending upon the amount of post-failure softening. Comparable internal research by BP showed that relative to the collapse pressure of the standard specimen, TWC_{sp}, the equivalent formation strength, U, of a specimen with OD/ID ratio of infinity would be equivalent to:

$$U = 3.10 * TWC_{sp} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots 3.12$$

3.2.3 Concept of a Loading Factor

Having define the expression for predicting the onset of sanding (sanding threshold), it is convenient to non-dimensionalize the stress state acting on a perforation tunnel or borehole by the concept of a ''Loading Factor'', LF, where to be consistent with equation 3.6, LF is defined as:

$$LF = \frac{\sigma_{t2} - P_{wf}}{U} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots 3.13$$

Where: σ_{t2} is the maximum tangential total stress acting on the formation (for open-hole or perforation).

We note that for LF < 1, the formation has not failed, while for LF > 1, the formation has failed and sand maybe produced. To be consistent with the field, putting equation 3.2 and 3.12 in equation 3.13, gives:

$$LF = \frac{3\sigma_1 - \sigma_2 - 2P_{wf} - A(P_R - P_{wf})}{3.10 * TWC} \dots\dots\dots\dots\dots\dots\dots..\dots\dots\dots\dots..3.14$$

3.2.4 Impact of Fluid Flow Effects

The analytical approach adopted to assess fluid flow effects in the sanding model draws on extensive work undertaken to assess required underbalance surge flow-rates for perforation clean-up.

In these previous studies, the removal of shock-damaged and mechanically-weakened debris due to non-Darcy flow or turbulence in the region adjacent to the perforation cavity was correlated with the non-dimensional Reynolds number, defined by:

$$Re = 1.31735E - 12 * \frac{K\beta\rho v}{\mu} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots..\dots\dots\dots.3.15$$

Where:

K is the permeability (in mD); β is the non-Darcy flow coefficient (having dimensions of ft^{-1}); v is the velocity of the fluid crossing the lateral surface of the perforation or well (in inches/second); ρ is the density (in lb/ft^3) and μ is the viscosity (in cP).

Adopting the correlation of Hoven *et al* and Tariq, we have:

$$\beta = {}^{2.65E10}\!/\!_{K^{1.2}} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots.3.16$$

Therefore, by non-dimensionalizing the fluid flow contribution, variations in the formation permeability, fluid flow rate, viscosity, etc. can be easily captured in the analysis. Laboratory studies have shown a value of Re>0.1 is necessary for effective perforation clean-up during under-balance flow. Thus similar high values of Reynolds number are needed for massive sand production rates. At Reynolds numbers less than 0.1, the sanding rate is dominated by the loading factor.

3.2.5 Sources of Experimental Data

An important feature of the prediction model described here is that the sand rate magnitude is established from an empirical interpretation of laboratory sand production tests, rather than relying upon empirically derived relationships from field sanding events. This permits laboratory sanding experiments to be performed on reservoir core to derive field specific sanding relationships.

Using the normalized parameters of loading factor and Reynolds number, a sanding production rate model for dry oil (100% oil, 0% GLR and 0% water-cut) can be derived empirically. To address the impact of water-cut and gas produced on the sand production rate, other sand production experiments that were conducted using three-phase flow were analysed. In this step, the continuous sand production rate at a specified water-cut, varying gas production and stress level was compared with that of a test flowing dry oil only at similar conditions. This permitted the derivation of a ''water-cut boost factor'' and a ''GLR boost factor'' to raise the level of sand production from that evaluated from the function pertaining to no water and gas production (Willson *et al*, 2002).

3.2.6 Final Form of Sand Production Rate Model

- Definition of the Load Factor, LF.
  - LF = f(in-situ stresses, well trajectory, reservoir pressure, drawdown & depletion, TWC strength)
  - $LF = \frac{3\sigma_1 - \sigma_2 - 2P_{wf} - A(P_R - P_{wf})}{3.10 * TWC}; \ A = \frac{(1-2v)(c_b - c_r)}{(1-v)c_b}$
- Definition of Reynolds Number, Re.
  - Re = f(permeability, flow rate per perforation, viscosity, density, perforation number and size)
  - $Re = 1.31735E - 12 * \frac{K\beta\rho v}{\mu}; \quad \beta = {2.65E10}/{K^{1.2}}$
- Definition of Sand Production Rate, SPR.
  - SPR = f(LF, Re, Water-Cut, GLR)
  - $SPR = ae^{(bW + cG)} Re^d LF$ … … … … … … … … … … … … … … … … … . … … … .3.17

Where:

w is the water-cut in fraction; G is the gas-liquid ratio; 'a' has the same unit as SPR called the SPR constant of proportionality and its magnitude depends on the unit of SPR used; 'b', 'c' and 'd' are the SPR correlation index, whose magnitude depends on the terrain investigated and requires real field data and experimental data obtained from cores samples of the desired terrain for their determination.

CHAPTER 4

4.0 MODEL VALIDATION

4.1INTRODUCTION

Proposed model in chapter 3 will be validated by using real field data of sand production in some Niger Delta wells to determine the associated SPR correlation index which is expected to be a unique fingerprint of each well investigated, repeatability of results from the model compared to the real field data will be use as a basis for its validation with an acceptable tolerance of 10% deviation (max) of the predicted results from the observed results.

4.2 FIELD DATA OF SOME NIGER DELTA WELLS

Table 4.1 through Table 4.6 presents some data used in this work from two onshore wells in Niger Delta terrain.

Table 4.1: Some Required Field Information of All Wells Investigated

Average Oil Density	35^0API (53.03 lb/ft)
Average Oil viscosity	0.8cP
Wellbore Diameter @600ft	17-1/2’’
Wellbore Diameter @4227.5ft	12-1/4’’
Wellbore Diameter @8500ft	8-1/2’’
Perforation Diameter	4-5/8’’
Perforation Density	4 SPF
Perforation Interval	80ft

Table 4.2: Some Rock Mechanics Data of A64 Well

Depth(ft)	Overburden (psi/ft)	Pore Pressure (psi/ft)	Min Horizontal Stress(psi/ft)	Max Horizontal Stress(psi/ft)	poissons ratio	youngs modulus(Mpsi)	friction angle(deg)	shale content(%)
5694	0.8211	0.43	0.715	0.765	0.28	0.115	25.40	0.113
5782	0.8321	0.43	0.723	0.773	0.28	0.115	25.40	0.113
5868	0.8401	0.43	0.742	0.792	0.28	0.115	25.40	0.214
5954	0.849	0.43	0.761	0.811	0.28	0.243	26.11	0.214
6040	0.861	0.43	0.768	0.818	0.28	0.243	26.11	0.214
6280	0.882	0.43	0.772	0.822	0.28	0.243	26.11	0.214
6687	0.902	0.43	0.790	0.840	0.28	0.312	27.54	0.532
6931	0.962	0.42	0.813	0.863	0.28	0.312	27.54	0.221
7123	0.981	0.42	0.841	0.891	0.28	0.107	27.54	0.221
7809	0.981	0.41	0.842	0.892	0.28	0.107	27.82	0.221

Table 4.3: Some Rock Mechanics Data of A65 Well

Depth(ft)	Overburden (psi/ft)	Pore Pressure (psi/ft)	Min Horizontal Stress(psi/ft)	Max Horizontal Stress(psi/ft)	poissons ratio	youngs modulus(Mpsi)	friction angle(deg)	shale content(%)
5843	0.821	0.471	0.6136	0.6636	0.28	0.115	25.40	0.113
5980	0.832	0.422	0.6297	0.6797	0.28	0.115	25.40	0.113
6060	0.840	0.426	0.6431	0.6931	0.28	0.115	25.40	0.113
7201	0.849	0.391	0.6811	0.7311	0.28	0.243	26.11	0.377
7271	0.861	0.402	0.7245	0.7745	0.28	0.243	26.11	0.377
7345	0.882	0.397	0.7431	0.7931	0.28	0.243	26.11	0.377
7484	0.902	0.392	0.7461	0.7961	0.28	0.312	27.54	0.221
7575	0.962	0.369	0.8125	0.8625	0.28	0.312	27.54	0.221
7638	0.981	0.383	0.8411	0.8911	0.28	0.107	27.54	0.102

Table 4.4: Extraction from Production Data of Reservoir D4 in Well A-64

UniqueId	Date	Date	Sand	Oil	Water	Gas	Bean	THP
		Days	PPTB	bbl/m	bbl/m	Mscf/m		psi
A-64-D4	01-Nov-07	27	40	13081	36322	5919	64	290
A-64-D4	01-Jun-06	30	34	17137	14032	82393	64	426
A-64-D4	01-Jan-07	31	33	15323	11686	2899	64	375
A-64-D4	01-Dec-06	31	33	14850	10520	19075	64	435
A-64-D4	01-Nov-06	30	33	19788	14790	14550	64	435
A-64-D4	01-Oct-06	29	33	18150	13607	15624	64	435
A-64-D4	01-Sep-06	30	33	18615	13327	5813	64	435

Table 4.5: Extraction from Production Data of Reservoir D2 in Well A-64

UniqueId	Date	Date	Sand	Oil	Water	Gas	Bean	THP
		Days	PPTB	bbl/m	bbl/m	Mscf/m		psi
A-64-D2	01-Apr-05	30	3	8688	4313	8193	30	456
A-64-D2	01-Jun-05	26	2	6184	4598	12934	30	519
A-64-D2	01-Aug-05	30	2	3930	2947	23332	30	495
A-64-D2	01-Nov-05	30	8	1436	1115	38364	28	206
A-64-D2	01-Jan-06	31	2	7275	10625	2920	28	206
A-64-D2	01-Mar-06	29	3	9242	8133	35	28	735
A-64-D2	01-Apr-06	30	4	15047	14277	3557	28	206
A-64-D2	01-May-06	12	5	5453	7029	9372	28	265

Table 4.6: Extraction from Production Data of Reservoir D8 in Well A-65

UniqueId	Date	Date	Sand	Oil	Water	Gas	Bean	THP
		Days	PPTB	bbl/m	bbl/m	Mscf/m		psi
A-65-D8	01-Jun-07	29	2	54279	31	11063	36	600
A-65-D8	01-Feb-09	13	0	21540	8	9525	36	524
A-65-D8	01-Jan-10	15	1	13506	5814	5550	36	334
A-65-D8	01-Feb-10	4	1	3646	1497	1024	36	334
A-65-D8	01-Mar-10	30	2	39280	16440	7541	36	334
A-65-D8	01-Apr-10	26	2	38743	7399	6933	36	334
A-65-D8	01-May-10	16	2	23049	4228	4778	36	334

An attempt to estimate the associated water-cut and GLR is shown in Tables 4.7, 4.8 and 4.9.

Table 4.7: Estimations from Production Data of Reservoir D4 in Well A-64

Sand	Oil	Water	Water-cut	Gas	GLR
PPTB	bbl/m	bbl/m	%	Mscf/m	scf/bbl
40	13081	36322	74	5919	120
34	17137	14032	45	82393	2643
33	15323	11686	43	2899	107
33	14850	10520	41	19075	752
33	19788	14790	43	14550	421
33	18150	13607	43	15624	492
33	18615	13327	42	5813	182

Table 4.8: Estimations from Production Data of Reservoir D2 in Well A-64

Sand	Oil	Water	Water-cut	Gas	GLR
PPTB	bbl/m	bbl/m	%	Mscf/m	scf/bbl
3	8688	4313	33	8193	630
2	6184	4598	43	12934	1200
2	3930	2947	43	23332	3393
8	1436	1115	44	38364	15043
2	7275	10625	59	2920	163
3	9242	8133	47	35	2
4	15047	14277	49	3557	121
5	5453	7029	56	9372	751

Table 4.9: Estimations from Production Data of Reservoir D8 in Well A-65

Sand	Oil	Water	Water-cut	Gas	GLR
PPTB	bbl/m	bbl/m	%	Mscf/m	scf/bbl
2	54279	31	0	11063	204
0	21540	8	0	9525	442
1	13506	5814	30	5550	287
1	3646	1497	29	1024	199
2	39280	16440	30	7541	135
2	38743	7399	16	6933	150
2	23049	4228	15	4778	175

4.2.2 Determination of Average Permeability of the Pay-Zone of the Investigated Wells

Using Archie's equation, the initial water saturation (S_{wi}) will be determined from log data (which is not presented here because the size of log data is enormous), obtained S_{wi} will then be used to estimate the permeability (K) of the pay-zone using the Timur's correlation for determining permeability and the average permeability of the pay-zone will then be obtained by considering the geometric mean (due to the degree of heterogeneity of reservoir's permeability).

$$S_{wi}^{n} = \frac{aR_w}{\emptyset^2 R_t} \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 4.1$$

Due to lack of appropriate Petrophysical data, we will assume:

$$n = 2 \; and \; a = 1; \;\; thus \; S_{wi} = \sqrt{\frac{R_w}{\emptyset^2 R_t}} \dots \dots \dots \dots \dots \dots \dots 4.2$$

$$K = 8581 \frac{\emptyset^{4.4}}{S_{wi}^{2}} \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 4.3$$

Where: K is in md; $\emptyset \; and \; S_{wi} \; are \; in \; fraction$

For Well A-64, K_{ave} = 105.19md while for Well A-65, K_{ave} = 98.20md

4.2.3 Determination of the Formation Strength, U of the Investigated Fields

Ideally, the formation strength is determined from the TWC test in the laboratory, due to leak of relevant data, we will estimate the formation strength by obtaining the average of the fracture gradient of the pay-zone of the formation determined using the Ben Eaton's correlation for fracture gradient. Estimated formation strength is shown in Table 4.10 and Table 4.11.

$$F = \left(\frac{S - P}{D}\right)\left(\frac{\Upsilon}{1 - \Upsilon}\right) + \frac{P}{D} \dots \dots \dots \dots \dots \dots \dots \dots \dots 4.4$$

Where:

F is the fracture gradient at the true vertical depth of interest.

S is the overburden pressure at the true vertical depth of interest.

P is the pore pressure of the formation (reservoir pressure) at the true vertical depth of interest.

D is the true vertical depth of interest.

Υ is the Poisson's ratio at the true vertical depth of interest.

Table 4.10: Formation Strength for Well A-64

Depth(ft)	Overburden (psi/ft)	Pore Pressure (psi/ft)	Reservoir Pressure (psi)	Poissons Ratio	Fracture Gradient(psi/ft)	Formation Strength(psi)
5694	0.821	0.43	2448	0.28	0.58	3314
5782	0.832	0.43	2486	0.28	0.59	3390
5868	0.840	0.43	2523	0.28	0.59	3459
5954	0.849	0.43	2560	0.28	0.59	3530
6040	0.861	0.43	2597	0.28	0.60	3610
6280	0.882	0.43	2700	0.28	0.61	3804
6687	0.902	0.43	2875	0.28	0.61	4103
6931	0.962	0.42	2911	0.28	0.63	4372
7123	0.981	0.42	2992	0.28	0.64	4546
7809	0.981	0.41	3202	0.28	0.63	4936

Table 4.11: Formation Strength for Well A-65

Depth(ft)	Overburden (psi/ft)	Pore Pressure (psi/ft)	Reservoir Pressure (psi)	Poissons Ratio	Fracture Gradient(psi/ft)	Formation Strength(psi)
5843	0.821	0.471	2752	0.28	0.61	3548
5980	0.832	0.422	2525	0.28	0.58	3478
6060	0.840	0.426	2580	0.28	0.59	3556
7201	0.849	0.391	2812	0.28	0.57	4096
7271	0.861	0.402	2925	0.28	0.58	4222
7345	0.882	0.397	2918	0.28	0.59	4303
7484	0.902	0.392	2934	0.28	0.59	4418
7575	0.962	0.369	2795	0.28	0.60	4542
7638	0.981	0.383	2927	0.28	0.62	4703

4.2.4 Determination of Reynolds Number of each Reservoir Investigated

Combining equations 3.15 and 3.16 gives:

$$Re = \frac{0.03491\rho v}{\mu K^{0.2}} \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 4.5$$

From Table 4.1:

$\rho = 53.03\, lb/ft$; $and\ \mu = 0.8cP$; Thus:

$$Re = \frac{2.3141v}{K^{0.2}} \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 4.6$$

Recall, through the perforations:

$$q = nAv \ldots\ldots 4.7$$

Where:

n is the total number of the perforations while A is the average cross-sectional area of each perforation, (for simplicity, we assume half of the perforations to be effective).

From Table 4.1:

$n = 320\ shots;\ and\ A = 16.8in^2$; Thus:

$$v = 3.7202E - 04 * q \ldots\ldots 4.8$$

Putting equation 4.8 in equation 4.6, gives:

$$Re = \frac{8.609E - 04 * q}{K^{0.2}} \ldots\ldots 4.9$$

Recall: In Well A-64, K_{ave} = 105.19md while for Well A-65, K_{ave} = 98.20md; Thus:

InWellA-64, $Re = 3.3927E - 04 * q$; for WellA-65,$Re = 3.4397E - 04 * q \ldots 4.10$

Where: q is in in^3/sec.; Recall: 1bbl/month = 3.743E-03in^3/sec.

4.3 Determination of Sanding Potential of the Investigated Well

Sanding potential of the Wells investigated will be confirmed by comparing the product of the shear modulus and the bulk modulus with the threshold for sanding established in literature. Recall sand production can be expected if the product of two elastic parameters (i.e. GK_b) is lower than the threshold value of 8E11psi^2, where the shear modulus, G and the bulk modulus, K_b are derived accurately from interpretation of acoustic and density logs (Tiab, 2014; Osisanya, 2010). Thus, it is recommended to ensure that GK_b is less than 8E11psi^2, before even predicting the sanding rate since sand can only be produced after formation fracturing or failure has occurred. The estimated sanding potential of both Wells based on Petrophysical properties is presented in Table 4.12 and Table 4.13

Recall:

$$G = \frac{E}{2(1 + v)}\ and\ K_b = \frac{E}{3(1 - 2v)} \ldots\ldots 4.11$$

Where:

E is the Young Modulus, v is the Poisson’s ratio.

Table 4.12: Sanding Potential of Well A-64

Depth(ft)	Overburden (psi/ft)	Pore Pressure (psi/ft)	Min Horizontal Stress(psi/ft)	Max Horizontal Stress(psi/ft)	poissons ratio	youngs modulus(Mpsi)	Shear Modulus, G (Mpsi)	Bulk Modulus, K_b (Mpsi)	GK_b (psi^2)
5694	0.8211	0.43	0.715	0.765	0.28	0.115	0.0449	0.0871	3.91E+09
5782	0.8321	0.43	0.723	0.773	0.28	0.115	0.0449	0.0871	3.91E+09
5868	0.8401	0.43	0.742	0.792	0.28	0.115	0.0449	0.0871	3.91E+09
5954	0.849	0.43	0.761	0.811	0.28	0.243	0.0949	0.1841	1.75E+10
6040	0.861	0.43	0.768	0.818	0.28	0.243	0.0949	0.1841	1.75E+10
6280	0.882	0.43	0.772	0.822	0.28	0.243	0.0949	0.1841	1.75E+10
6687	0.902	0.43	0.790	0.840	0.28	0.312	0.1219	0.2364	2.88E+10
6931	0.962	0.42	0.813	0.863	0.28	0.312	0.1219	0.2364	2.88E+10
7123	0.981	0.42	0.841	0.891	0.28	0.107	0.0418	0.0811	3.39E+09
7809	0.981	0.41	0.842	0.892	0.28	0.107	0.0418	0.0811	3.39E+09

Table 4.13: Sanding Potential of Well A-65

Depth(ft)	Overburden (psi/ft)	Pore Pressure (psi/ft)	Min Horizontal Stress(psi/ft)	Max Horizontal Stress(psi/ft)	poissons ratio	youngs modulus(Mpsi)	Shear Modulus, G (Mpsi)	Bulk Modulus, K_b (Mpsi)	GK_b (psi^2)
5843	0.821	0.471	0.6136	0.6636	0.28	0.115	0.04492	0.08712	3.91E+09
5980	0.832	0.422	0.6297	0.6797	0.28	0.115	0.04492	0.08712	3.91E+09
6060	0.840	0.426	0.6431	0.6931	0.28	0.115	0.04492	0.08712	3.91E+09
7201	0.849	0.391	0.6811	0.7311	0.28	0.243	0.09492	0.18409	1.75E+10
7271	0.861	0.402	0.7245	0.7745	0.28	0.243	0.09492	0.18409	1.75E+10
7345	0.882	0.397	0.7431	0.7931	0.28	0.243	0.09492	0.18409	1.75E+10
7484	0.902	0.392	0.7461	0.7961	0.28	0.312	0.12188	0.23636	2.88E+10
7575	0.962	0.369	0.8125	0.8625	0.28	0.312	0.12188	0.23636	2.88E+10
7638	0.981	0.383	0.8411	0.8911	0.28	0.107	0.04180	0.08106	3.39E+09

The product of the shear modulus and the bulk modulus of the formations investigated in both cases for all depth considered is less than the threshold value of 8E11psi^2, this suggest the possibility of formation failure in the production life of the reservoir and sanding when the critical drawdown and flow rate required for fluidizing the fractured formation is met.

4.4 Determination of Loading Factor of the Investigated Wells

Relationship for the loading factor (equation 3.13 and 3.14) will be used in its determination, the required Poro-elastic constant is firstly determined using equation 3.5 and substituted in equation 3.14 to obtain the Loading Factor.

Recall:

$$C_b = \frac{1}{K_b} = \frac{3(1-2v)}{E} \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 4.12$$

Where: C_b is the rock bulk compressibility.

The estimated Loading Factor of both wells are shown in Table 4.14 and Table 4.15

Table 4.14: Loading Factor of Well A-64

Depth(ft)	Overburden (psi/ft)	Pore Pressure (psi/ft)	Min Horizontal Stress(psi/ft)	Max Horizontal Stress(psi/ft)	Poissons Ratio	Youngs Modulus (Mpsi)	Bulk Compressibility (1/psi)	Poro-elastic Constant	Formation Strength (psi)	Loading Factor
5694	0.821	0.43	0.715	0.765	0.28	0.115	1.15E-05	0.46	3314	**1.45**
5782	0.832	0.43	0.723	0.773	0.28	0.115	1.15E-05	0.46	3390	**1.48**
5868	0.840	0.43	0.742	0.792	0.28	0.115	1.15E-05	0.46	3459	**1.55**
5954	0.849	0.43	0.761	0.811	0.28	0.243	5.43E-06	0.29	3530	**1.64**
6040	0.861	0.43	0.768	0.818	0.28	0.243	5.43E-06	0.29	3610	**1.67**
6280	0.882	0.43	0.772	0.822	0.28	0.243	5.43E-06	0.29	3804	**1.69**
6687	0.902	0.43	0.790	0.840	0.28	0.312	4.23E-06	0.20	4103	**1.80**
6931	0.962	0.42	0.813	0.863	0.28	0.312	4.23E-06	0.20	4372	**1.86**
7123	0.981	0.42	0.841	0.891	0.28	0.107	1.23E-05	0.47	4546	**1.89**
7809	0.981	0.41	0.842	0.892	0.28	0.107	1.23E-05	0.47	4936	**1.98**
									AVERAGE	1.70

Table 4.15: Loading Factor of Well A-65

Depth(ft)	Overburden (psi/ft)	Pore Pressure (psi/ft)	Min Horizontal Stress(psi/ft)	Max Horizontal Stress(psi/ft)	poissons ratio	youngs modulus (Mpsi)	Bulk Compressibility (1/psi)	Poro-elastic Constant	Formation Strength (psi)	Loading Factor
5843	0.821	0.471	0.6136	0.6636	0.28	0.115	1.15E-05	0.46	3548	**1.04**
5980	0.832	0.422	0.6297	0.6797	0.28	0.115	1.15E-05	0.46	3478	**1.20**
6060	0.840	0.426	0.6431	0.6931	0.28	0.115	1.15E-05	0.46	3556	**1.25**
7201	0.849	0.391	0.6811	0.7311	0.28	0.243	5.43E-06	0.29	4096	**1.62**
7271	0.861	0.402	0.7245	0.7745	0.28	0.243	5.43E-06	0.29	4222	**1.74**
7345	0.882	0.397	0.7431	0.7931	0.28	0.243	5.43E-06	0.29	4303	**1.80**
7484	0.902	0.392	0.7461	0.7961	0.28	0.312	4.23E-06	0.20	4418	**1.83**
7575	0.962	0.369	0.8125	0.8625	0.28	0.312	4.23E-06	0.20	4542	**2.04**
7638	0.981	0.383	0.8411	0.8911	0.28	0.107	1.23E-05	0.47	4703	**2.03**
									AVERAGE	1.62

Values of Loading Factor for both wells at all depths (being greater than 1) further confirms that the poorly consolidated formation has the potential of sanding.

4.5 Validation of Proposed Model

Linearization of the model by taking the logarithm of both sides aids the determination of the associated SPR correlation indices. That is:

$$SPR = ae^{(bW+cG)}Re^{d}LF \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.17$$

$$\ln SPR = \ln a + bW + cG + d\ln Re + \ln LF \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots 4.13$$

SPR (lb/m) = Sand Concentration (pptb) * Oil Rate (1000 bbl/m)……………..…… 4.14

Using appropriate equations (4.10 and 4.14) on Tables 4.7, 4.8, 4.9 aids the determination of the correlation indices for all the reservoirs investigated. Tables 4.16, 4.17 and 4.18 shows the Reynolds number and SPR data of the investigated data.

Table 4.16: SPR Data determined from Production Data Reservoir D4 in Well A-64

Sand	Oil	Re	Water	Water-cut	Gas	GLR	Observed SPR
PPTB	bbl/m		bbl/m	%	Mscf/m	scf/bbl	lb/m
40	13081	**1.6611E-02**	36322	74	5919	120	**523**
34	17137	**2.1763E-02**	14032	45	82393	2643	**583**
33	15323	**1.9459E-02**	11686	43	2899	107	**506**
33	14850	**1.8858E-02**	10520	41	19075	752	**490**
33	19788	**2.5128E-02**	14790	43	14550	421	**653**
33	18150	**2.3048E-02**	13607	43	15624	492	**599**
33	18615	**2.3639E-02**	13327	42	5813	182	**614**

Table 4.17: SPR Data determined from Production Data of Reservoir D2 in Well A-64

Sand	Oil	Re	Water	Water-cut	Gas	GLR	Observed SPR
PPTB	bbl/m		bbl/m	%	Mscf/m	scf/bbl	lb/m
3	8688	**1.1033E-02**	4313	33	8193	630	**26**
2	6184	**7.8527E-03**	4598	43	12934	1200	**12**
2	3930	**4.9911E-03**	2947	43	23332	3393	**8**
8	1436	**1.8232E-03**	1115	44	38364	15043	**11**
2	7275	**9.2390E-03**	10625	59	2920	163	**15**
3	9242	**1.1736E-02**	8133	47	35	2	**28**
4	15047	**1.9108E-02**	14277	49	3557	121	**60**
5	5453	**6.9241E-03**	7029	56	9372	751	**27**

Table 4.18: SPR Data determined from Production Data of Reservoir D8 in Well A-65

Sand	Oil	Re	Water	Water-cut	Gas	GLR	Observed SPR
PPTB	bbl/m		bbl/m	%	Mscf/m	scf/bbl	lb/m
2	54279	**6.8928E-02**	31	0	11063	204	**109**
0	21540	**2.7353E-02**	8	0	9525	442	**0**
1	13506	**1.7151E-02**	5814	30	5550	287	**14**
1	3646	**4.6299E-03**	1497	29	1024	199	**4**
2	39280	**4.9881E-02**	16440	30	7541	135	**79**
2	38743	**4.9200E-02**	7399	16	6933	150	**77**
2	23049	**2.9269E-02**	4228	15	4778	175	**46**

Using data provided in Tables 4.16, 4.17 and 4.18, generated linearized systems of equations was solved using MATLAB to determine SPR correlation indices of each well investigated. Summary of the results obtained is presented in Table 4.19

Table 4.19: SPR Correlation of the Investigated Wells

WELL	SPR CORRELATION INDICES			
	a(lb/m)	b	c(bbl/scf)	d
A-64/D4	7938.66	0.5657	1.22E-05	0.8957
A-64/D2	196.12	6.8081	3.28E-05	1.2771
A-65/D8	912.78	0.1407	5.27E-04	1.015

4.5.1 SPR Model for the Investigated Wells

- For A-64/D4

$$SPR = 7938.66 * Re^{0.8957} * LF * exp(0.5657w + 1.22E - 05G) \ldots\ldots\ldots\ldots\ldots\ldots 4.15$$

- For A-64/D2

$$SPR = 196.12 * Re^{1.2771} * LF * exp(6.8081w + 3.28E - 05G) \ldots\ldots\ldots\ldots..\ldots\ldots 4.16$$

- For A-65/D8

$$SPR = 912.78 * Re^{1.015} * LF * exp(0.1407w + 5.27E - 04G) \ldots\ldots\ldots\ldots\ldots...\ldots 4.17$$

4.6 . Comparison of Predicted SPR based on Developed Model with Actual SPR in Investigated Wells

Tables 4.20 through 4.22 shows tabular comparison of predicted SPR and the observed SPR of A-64/D4, A-64/D2 and A-65/D8 respectively, while Figure 4.1 through 4.9 attempts to present graphical representations of this comparison for easy visualisation and interpretation. The model seems to accurately predict quantitatively the rate of sand produced in the investigated wells with a maximum deviation of less than 8% in all case but one analysed which is below the tolerance of 10% deviation suggested in the modelling.

Table 4.20: Comparison of Predicted SPR with Observed SPR of A-64/D4

Sand	Oil	Re	Water	Water-cut	Gas	GLR	Observed SPR	Predicted SPR	% Deviation
PPTB	bbl/m		bbl/m	%	Mscf/m	scf/bbl	lb/m	lb/m	%
40	13081	1.6611E-02	36322	74	5919	120	523.2	521.8	0.28
34	17137	2.1763E-02	14032	45	82393	2643	582.7	583.3	0.11
33	15323	1.9459E-02	11686	43	2899	107	505.7	506.6	0.17
33	14850	1.8858E-02	10520	41	19075	752	490.1	491.4	0.27
33	19788	2.5128E-02	14790	43	14550	421	653.0	637.6	2.36
33	18150	2.3048E-02	13607	43	15624	492	598.9	590.9	1.35
33	18615	2.3639E-02	13327	42	5813	182	614.3	598.3	2.60

Table 4.21: Comparison of Predicted SPR with Observed SPR of A-64/D2

Sand	Oil	Re	Water	Water-cut	Gas	GLR	Observed SPR	Predicted SPR	% Deviation
PPTB	bbl/m		bbl/m	%	Mscf/m	scf/bbl	lb/m	lb/m	%
3	8688	1.1033E-02	4313	33	8193	630	26.1	27.0	3.59
2	6184	7.8527E-03	4598	43	12934	1200	12.4	13.0	4.82
2	3930	4.9911E-03	2947	43	23332	3393	7.9	7.9	0.73
8	1436	1.8232E-03	1115	44	38364	15043	11.5	10.9	5.10
2	7275	9.2390E-03	10625	59	2920	163	14.6	15.3	5.15
3	9242	1.1736E-02	8133	47	35	2	27.7	27.6	0.29
4	15047	1.9108E-02	14277	49	3557	121	60.2	58.8	2.36
5	5453	6.9241E-03	7029	56	9372	751	27.3	27.6	1.18

Table 4.22: Comparison of Predicted SPR with Observed SPR of A-65/D8

Sand	Oil	Re	Water	Water-cut	Gas	GLR	Observed SPR	Predicted SPR	% Deviation
PPTB	bbl/m		bbl/m	%	Mscf/m	scf/bbl	lb/m	lb/m	%
2	54279	6.8928E-02	31	0	11063	204	108.6	109.0	0.43
0	21540	2.7353E-02	8	0	9525	442	0.0	48.4	
1	13506	1.7151E-02	5814	30	5550	287	13.5	14.5	7.36
1	3646	4.6299E-03	1497	29	1024	199	3.6	4.1	12.45
2	39280	4.9881E-02	16440	30	7541	135	78.6	78.9	0.482
2	38743	4.9200E-02	7399	16	6933	150	77.5	77.0	0.646
2	23049	2.9269E-02	4228	15	4778	175	46.1	46.0	0.190

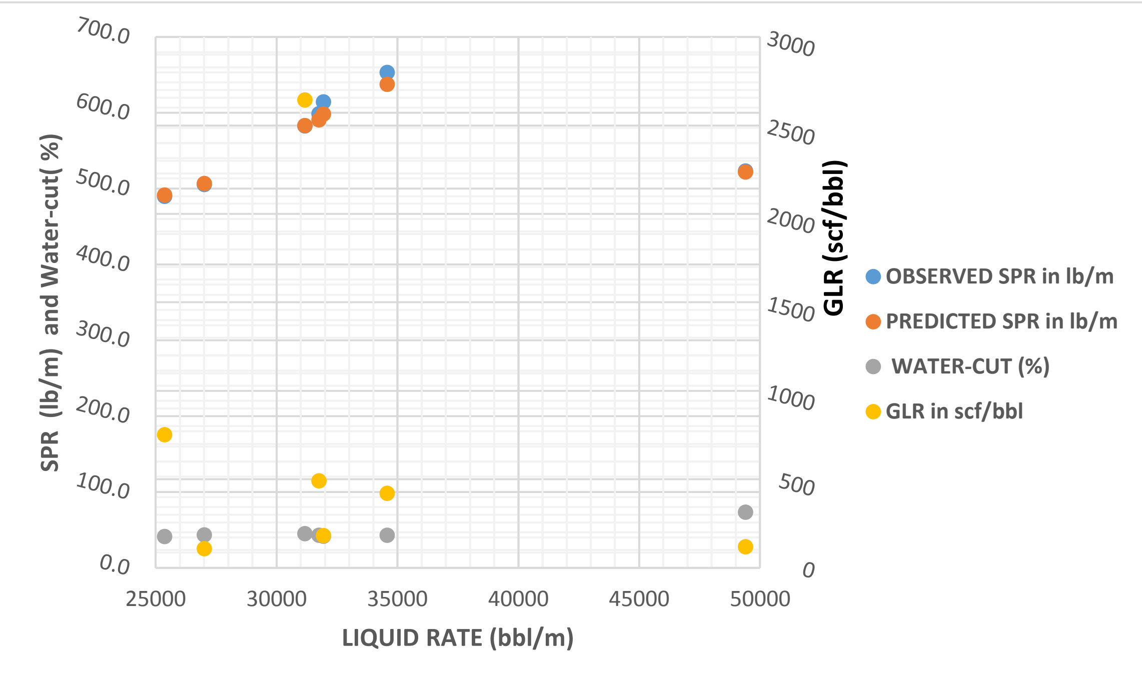


Figure 4.1: Predicted and Observed SPR of A-64/D4 at different Total Liquid Rate.

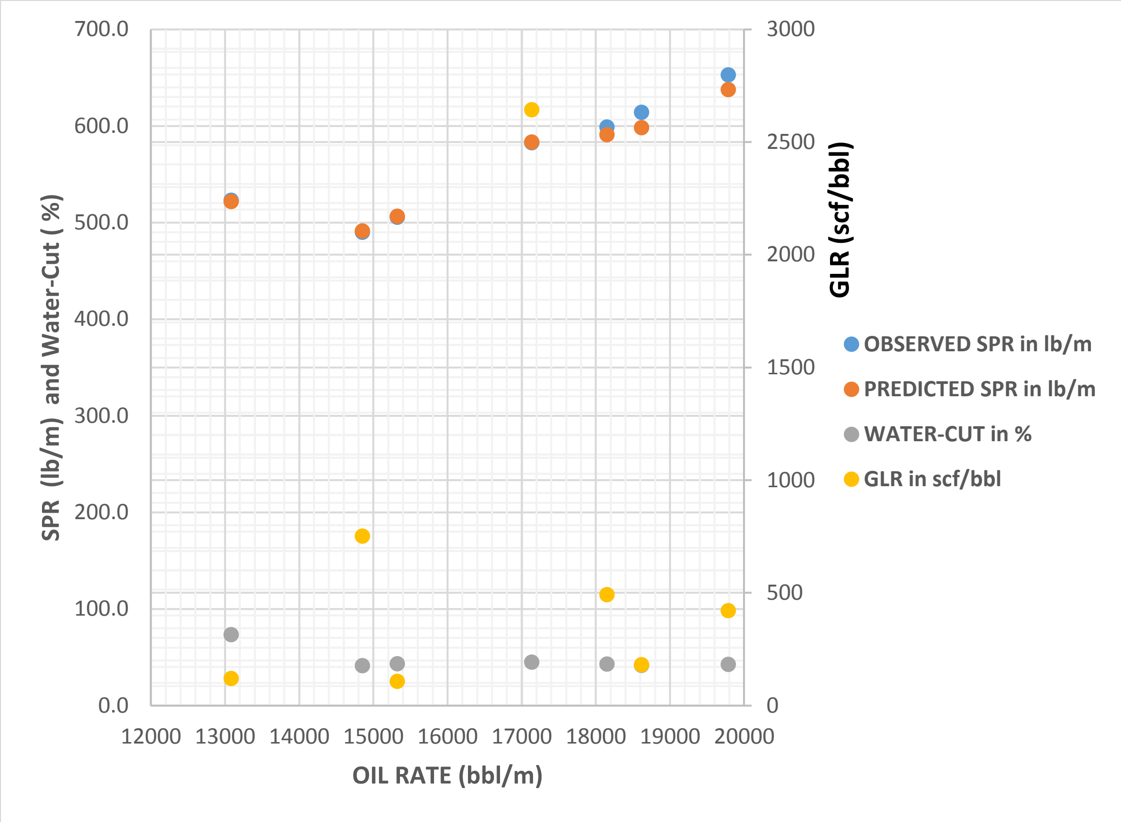


Figure 4.2: Predicted and Observed SPR of A-64/D2 at different Oil Production Rate.

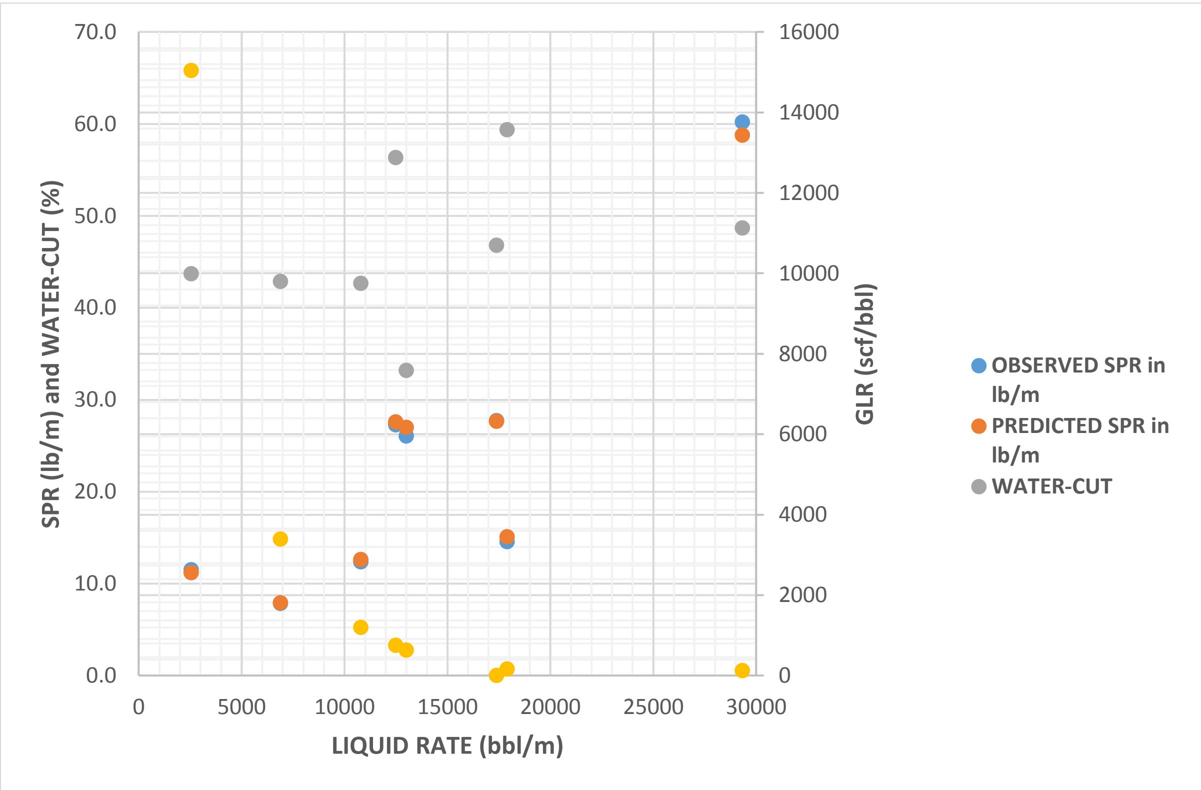


Figure 4.3: Predicted and Observed SPR of A-64/D2 at different Total Liquid Rate.

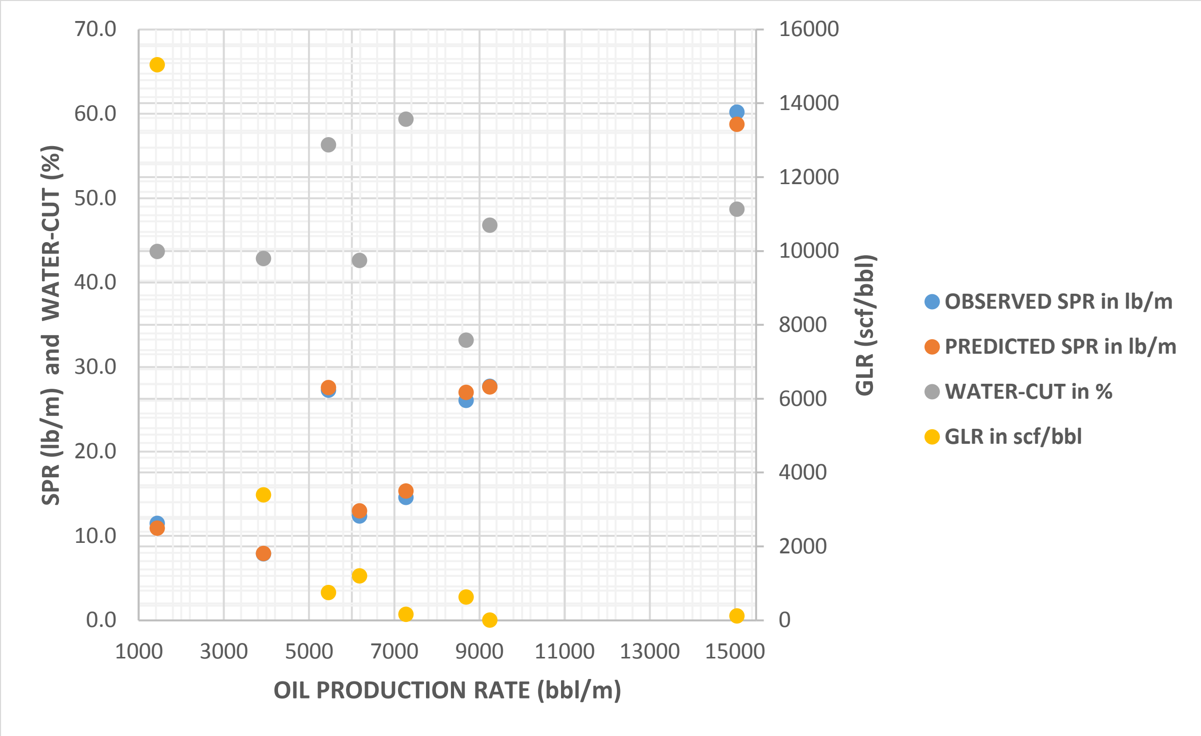


Figure 4.4: Predicted and Observed SPR of A-64/D2 at different Oil Production Rate.

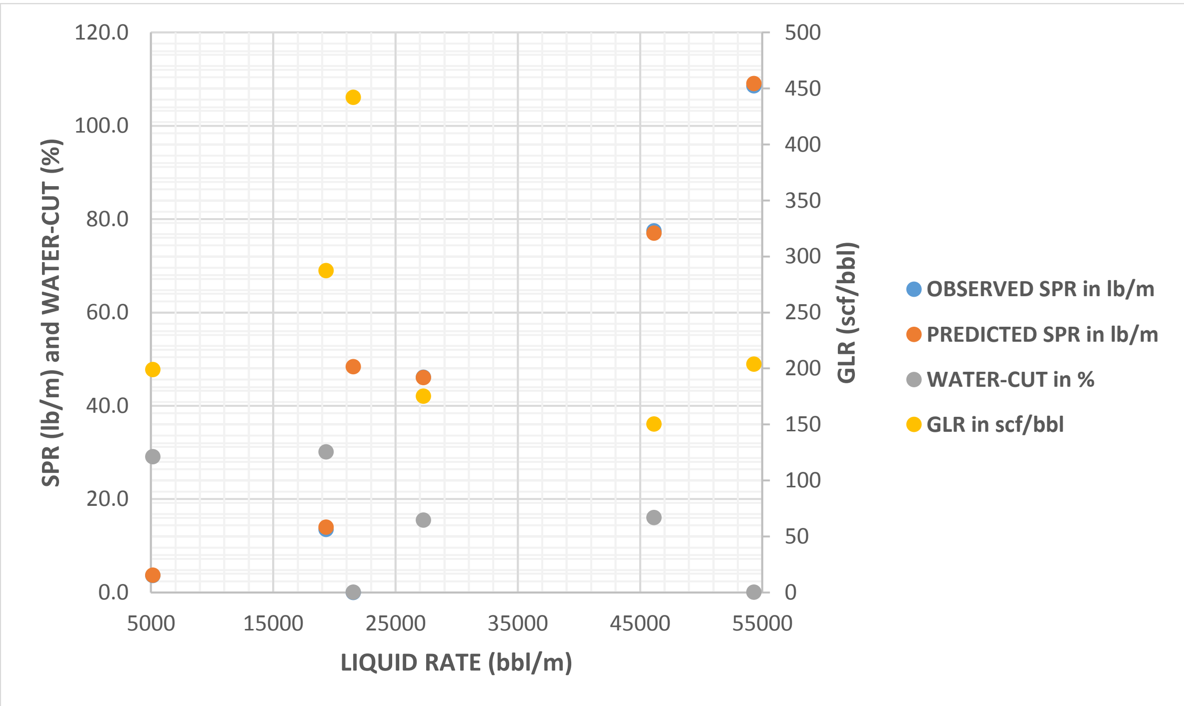


Figure 4.5: Predicted and Observed SPR of A-65/D8 at different Total Liquid Rate.

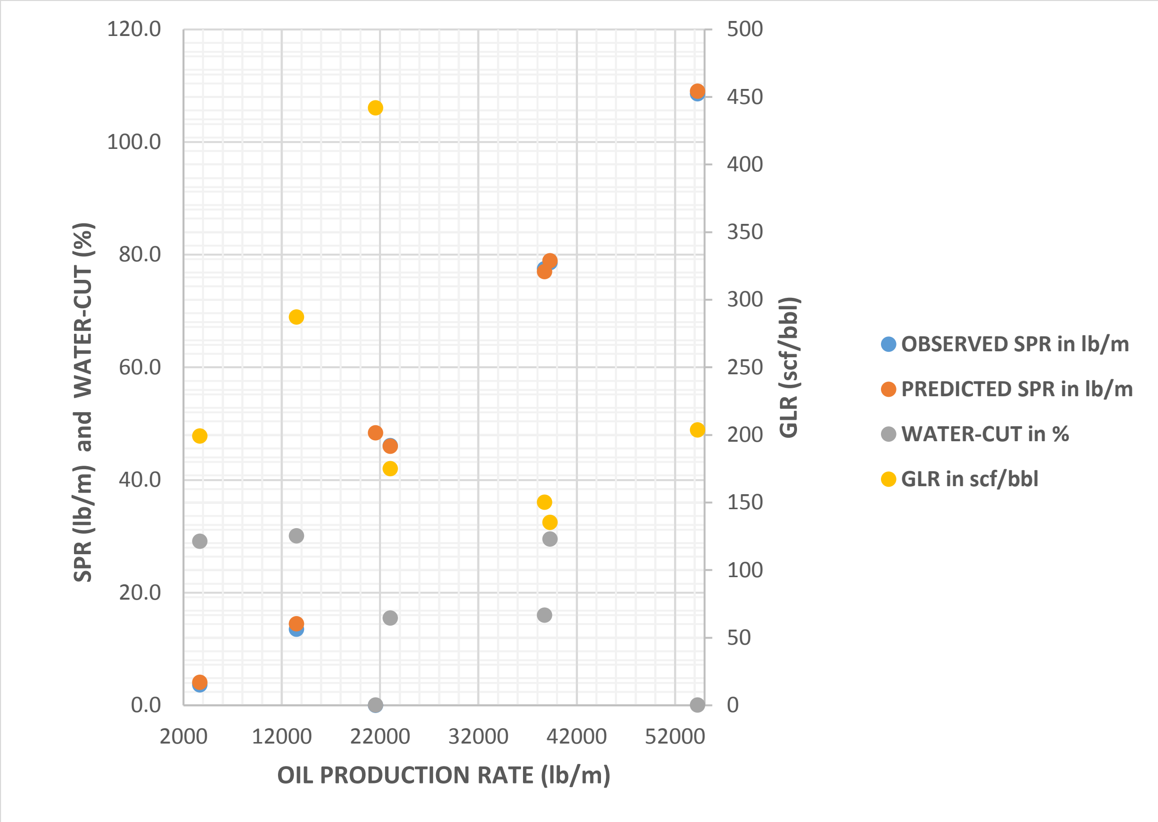


Figure 4.6: Predicted and Observed SPR of A-65/D8 at different Oil Production Rate.

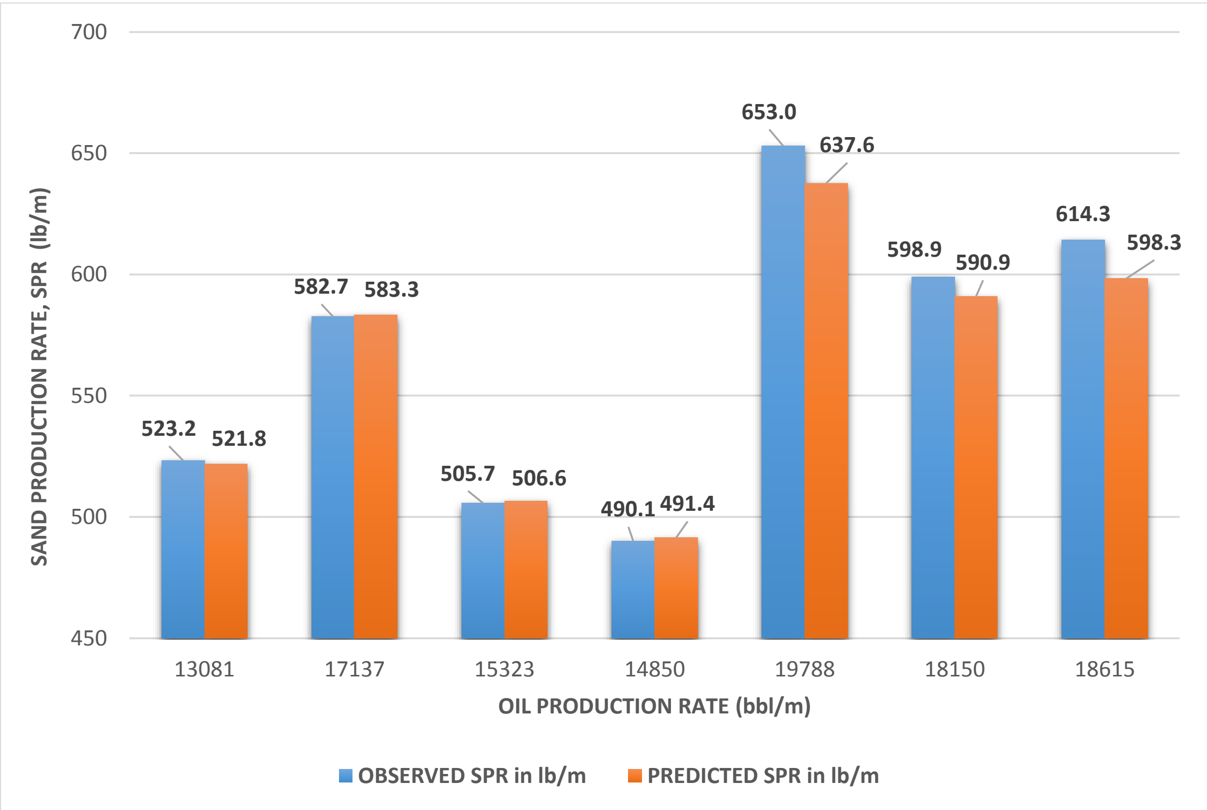


Figure 4.7: Predicted and Observed SPR of A-64/D4 at different Oil Production Rate.

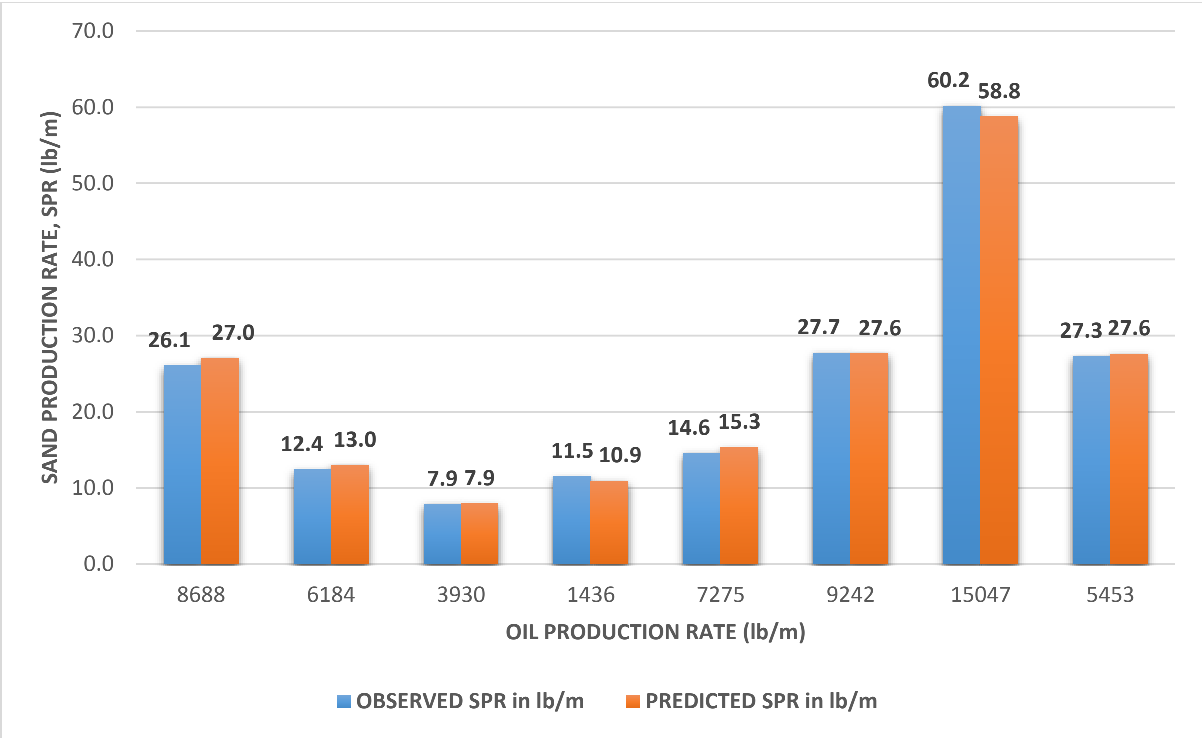


Figure 4.8: Predicted and Observed SPR of A-64/D2 Well at different Oil Production Rate.

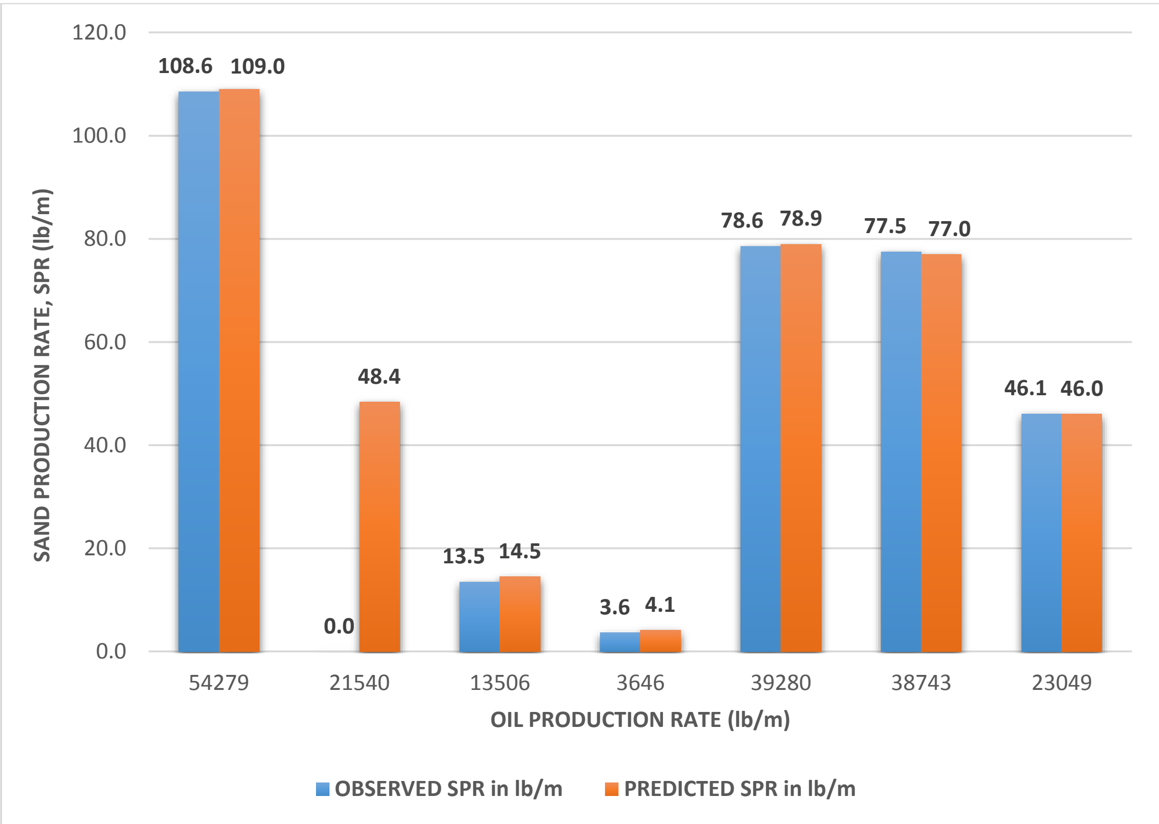


Figure 4.9: Predicted and Observed SPR of A-65/D8 Well at different Oil Production Rate.

CHAPTER 5

5.0 ANALYSIS OF DEVELOPED MODEL

5.1 Normalization of the Developed SPR Model of the Investigated Reservoir

The developed SPR model of the investigated reservoir will be normalized by comparing the SPR values with the standard condition for sand production that is when LF equals unity, Re equals 0.1, water-cut and GLR equals zero as the basis. Resulting values of SPR are then divided by the value at this standard condition to establish a dimensionless SPR that corresponds to that sanding condition, thus sanding of different reservoir can be easily compared.

- **Normalized SPR= SPR_N** **SPR_N= SPR/SPR_0**

5.1.1 Normalization of A64/D4

Basis: LF = 1, Re = 0.1, W = 0 and G = 0. Thus: SPR_0= 1009.36lb/m

5.1.2 Normalization of A64/D2

Basis: LF = 1, Re = 0.1, W = 0 and G = 0. Thus: SPR_0 = 10.36lb/m

5.1.3 Normalization of A65/D8

Basis: LF = 1, Re = 0.1, W = 0 and G = 0. Thus: SPR_0 = 88.18lb/m

Figure 5.1 through 5.3 present graphical representation of comparison of the normalized observed SPR (SPR_N) with the normalized predicted SPR_N.

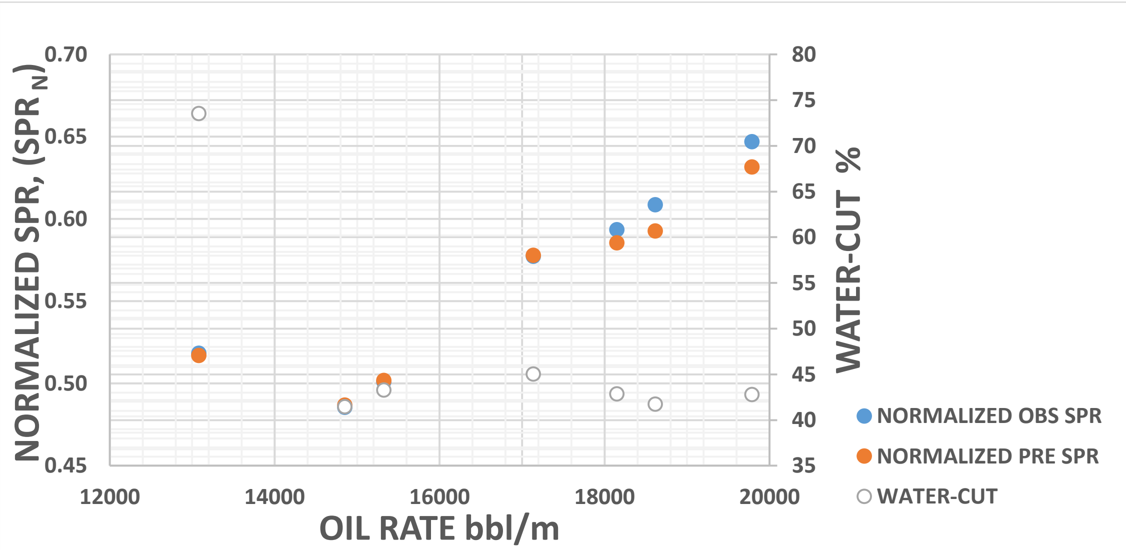


Figure 5.1: Normalized SPR for A64/D4 as a function of oil rate and water-cut

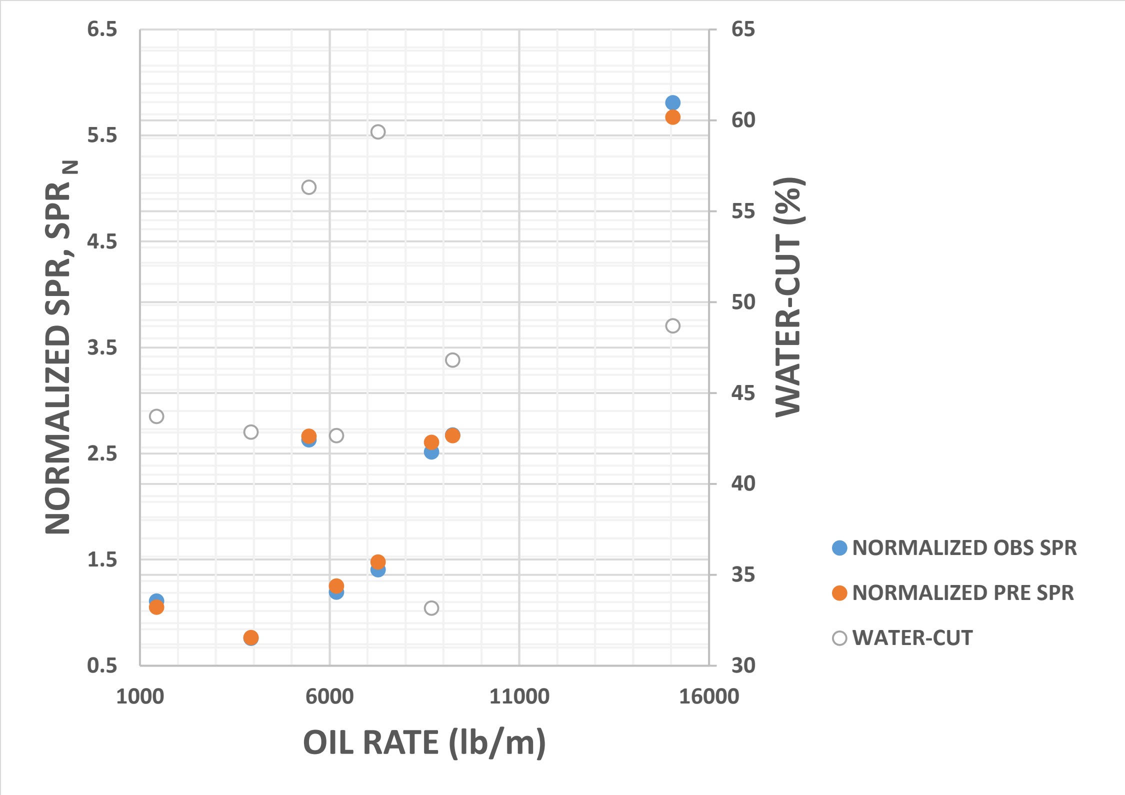


Figure 5.2: Normalized SPR for A64/D2 as a function of oil rate and water-cut

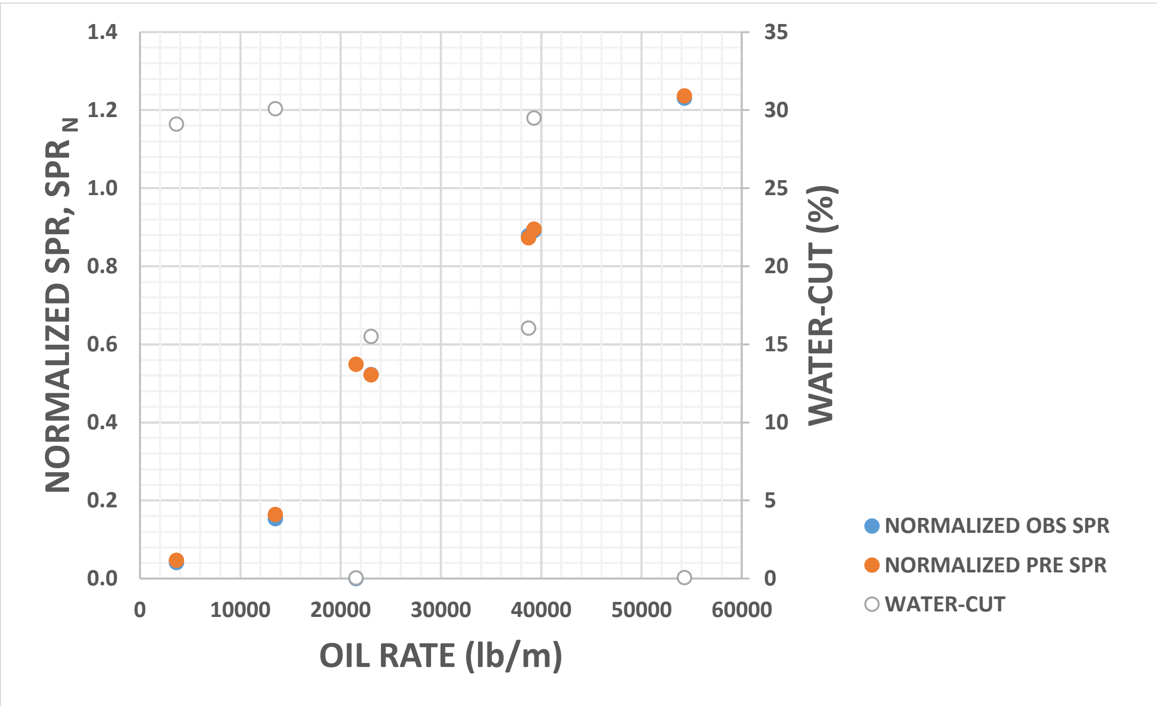


Figure5.3: Normalized SPR for A65/D8 as a function of oil rate and water-cut

5.2 COMPARISON OF DEVELOPED MODEL AND WILLSON *ET AL* MODEL

Table 5.1 through 5.3 and Figure 5.4 through 5.6 attempts to compare the accuracy of the developed model with the existing Willson *et al* model to ascertain if the contribution of the GLR term is significant or not in the prediction of SPR of the investigated reservoir.

Table 5.1: Comparison of Developed SPR model and the Willson *et al* SPR model for Predicting Sanding in A64/D4

Sand	Oil	Water-cut	GLR	Observed SPR	Predicted SPR	% Deviation (P)	Willson	% Deviation (W)	NORMALIZED	NORMALIZED	NORMALIZED
PPTB	bbl/m	%	scf/bbl	lb/m	lb/m	%	SPR (lb/m)	%	Obs SPR	Pre SPR	Willson SPR
40	13081	74	120	523.2	521.8	-0.28	521.0	-0.43	0.518	0.517	0.516
34	17137	45	2643	582.7	583.3	0.11	564.8	-3.07	0.577	0.578	0.560
33	15323	43	107	505.7	506.6	0.17	505.9	0.04	0.501	0.502	0.501
33	14850	41	752	490.1	491.4	0.27	486.9	-0.65	0.486	0.487	0.482
33	19788	43	421	653.0	637.6	-2.36	634.3	-2.86	0.647	0.632	0.628
33	18150	43	492	598.9	590.9	-1.35	587.3	-1.94	0.593	0.585	0.582
33	18615	42	182	614.3	598.3	-2.60	597.0	-2.82	0.609	0.593	0.591

Table 5.2: Comparison of Developed SPR model and the Willson *et al* SPR model for Predicting Sanding in A64/D2

Sand	Oil	Water-cut	GLR	Observed SPR	Predicted SPR	% Deviation (P)	Willson	% Deviation (W)	NORMALIZED	NORMALIZED	NORMALIZED
PPTB	bbl/m	%	scf/bbl	lb/m	lb/m	%	SPR (lb/m)	%	Obs SPR	Pre SPR	Willson SPR
3	8688	33	630	26.1	27.0	3.59	26.4	1.47	2.516	2.606	2.552
2	6184	43	1200	12.4	13.0	4.82	12.5	0.77	1.194	1.251	1.203
2	3930	43	3393	7.9	7.9	0.73	7.1	-9.88	0.759	0.764	0.684
8	1436	44	15043	11.5	10.9	-5.10	6.7	-42.06	1.108	1.052	0.642
2	7275	59	163	14.6	15.3	5.15	15.2	4.59	1.404	1.477	1.469
3	9242	47	2	27.7	27.6	-0.29	27.6	-0.30	2.676	2.668	2.668
4	15047	49	121	60.2	58.8	-2.36	58.5	-2.74	5.809	5.672	5.650
5	5453	56	751	27.3	27.6	1.18	26.9	-1.28	2.631	2.662	2.598

Table 5.3: Comparison of Developed SPR model and the Willson *et al* SPR model for Predicting Sanding inA65/D8

Sand	Oil	Water-cut	GLR	Observed SPR	Predicted SPR	% Deviation (P)	Willson	% Deviation (W)	NORMALIZED	NORMALIZED	NORMALIZED
PPTB	bbl/m	%	scf/bbl	lb/m	lb/m	%	SPR (lb/m)	%	Obs SPR	Pre SPR	Willson SPR
2	54279	0.06	204	108.6	109.0	0.43	97.923	-9.80	1.231	1.236	1.111
0	21540	0.04	442	0.0	48.4		47.680		0.000	0.549	0.541
1	13506	30.09	287	13.5	14.5	7.36	14.364	6.35	0.153	0.164	0.163
1	3646	29.11	199	3.6	4.1	12.45	4.073	11.72	0.041	0.046	0.046
2	39280	29.50	135	78.6	78.9	0.482	78.589	0.04	0.891	0.895	0.891
2	38743	16.03	150	77.5	77.0	0.646	76.607	-1.13	0.879	0.873	0.869
2	23049	15.50	175	46.1	46.0	0.190	45.746	-0.76	0.523	0.522	0.519

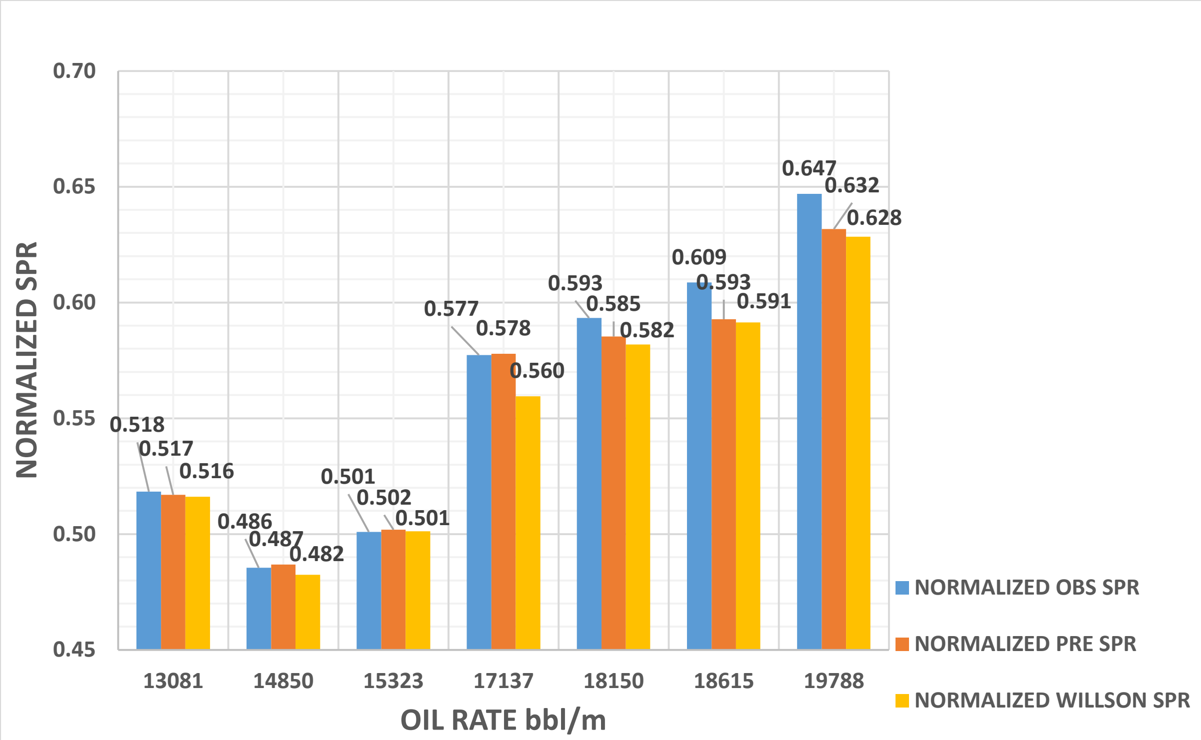


Figure 5.4: Comparison of Developed SPR model and the Willson *et al* SPR model for Predicting Sanding in A64/D4

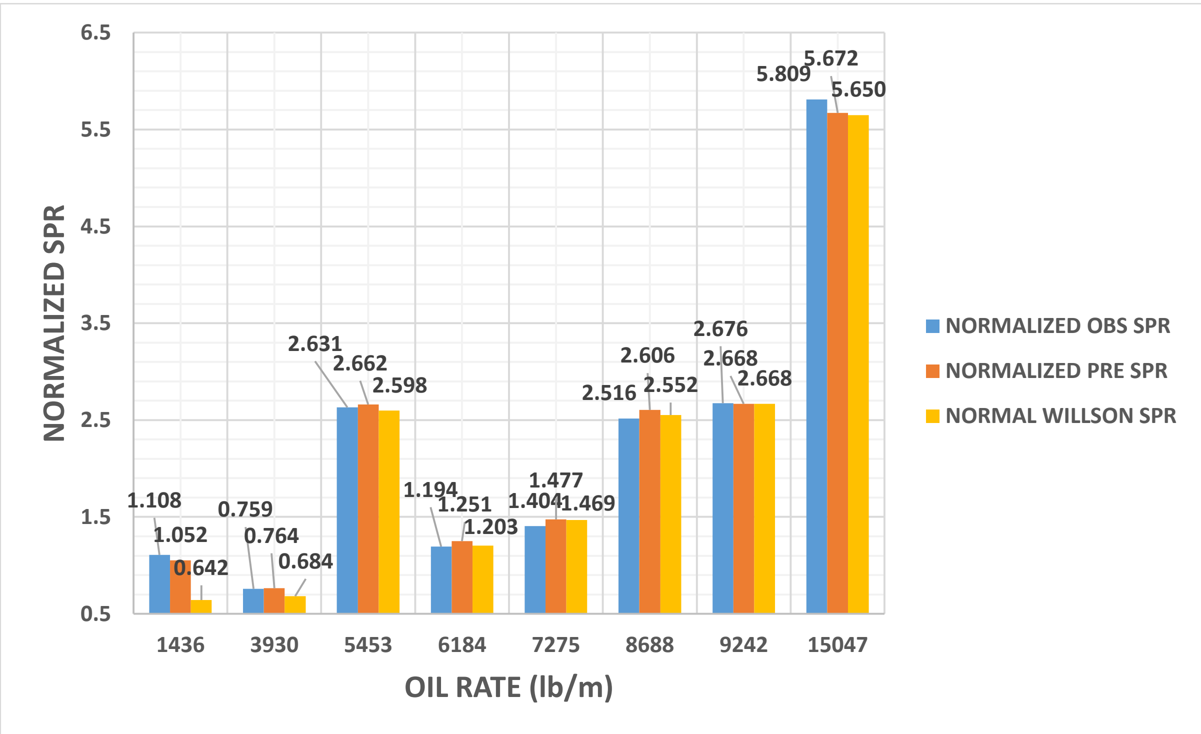


Figure 5.5: Comparison of Developed SPR model and the Willson *et al* SPR model for Predicting Sanding in A64/D2

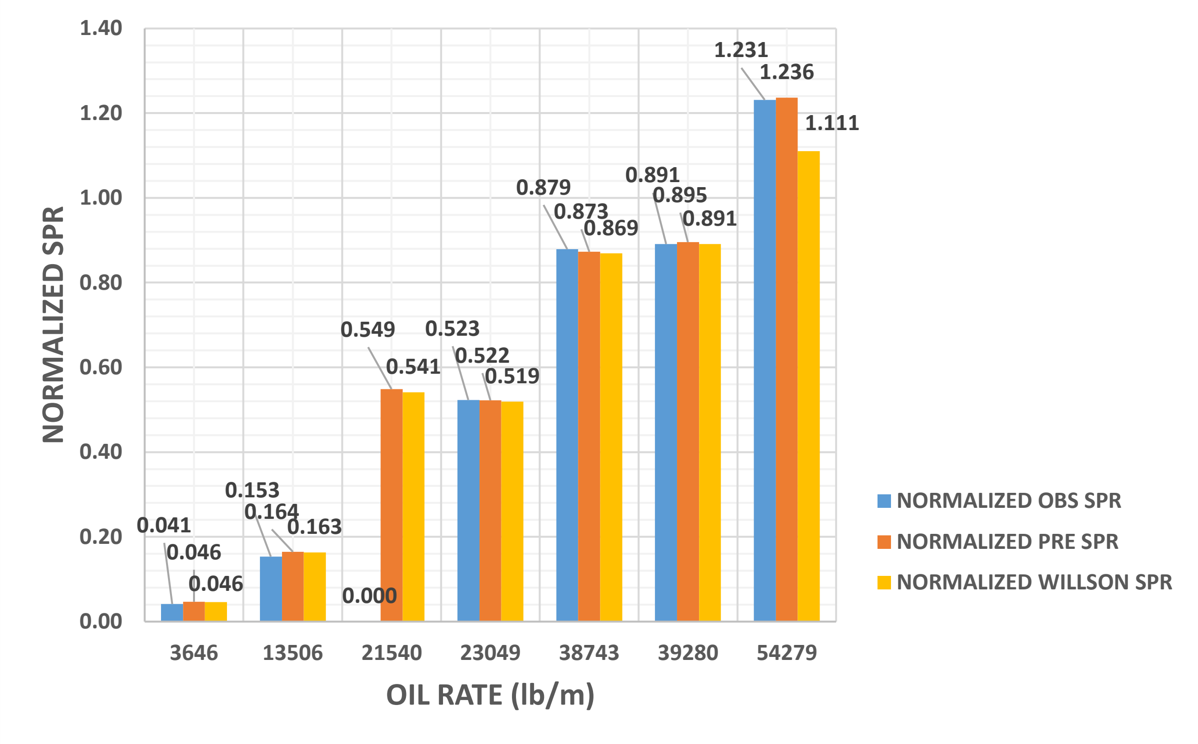


Figure 5.6: Comparison of Developed SPR model and the Willson *et al* SPR model for Predicting Sanding in A65/D8

Tables and Figures above shows that for all investigated reservoirs, neglecting the contributions of GLR seems to underestimate the predicted SPR and the effect is more obvious when the GLR is significantly high. Thus for a more accurate SPR prediction especially when the value of GLR is significant, it is advisable to use the developed SPR model.

5.3 SENSITIVITY ANALYSIS

Reservoir A64/D4 is selected for the sensitivity analysis of the normalized developed model. That is: $\boldsymbol{SPR = 7938.66 * Re^{0.8957} * LF * exp(0.5657w + 1.22E - 05G)}$ … … **4.15**

$$\boldsymbol{SPR_{normalized} = (10Re)^{0.8957} * LF * exp(0.5657w + 1.22E - 05G)} \text{ … … … . . } \mathbf{5.1}$$

5.3.1 Effect of Load Factor on Predicted SPR

Assuming LF spans from 1 to 10 and taking Re = 0.1, GLR (G) = 0 with W spanning from 0 to 95%. Equation 5.1 becomes:

$$\boldsymbol{SPR_{normalized} = LF * exp(0.5657w)} \text{ … … … … … … … . … … … … . . … … … … . … … } \mathbf{5.2}$$

The sanding response as a function of load factor thus determined is shown in Figure 5.7. As expected SPR increases linearly with increasing LF for all values of W and G because LF increases with increasing effective stresses which causes the more failure in the formation sand.

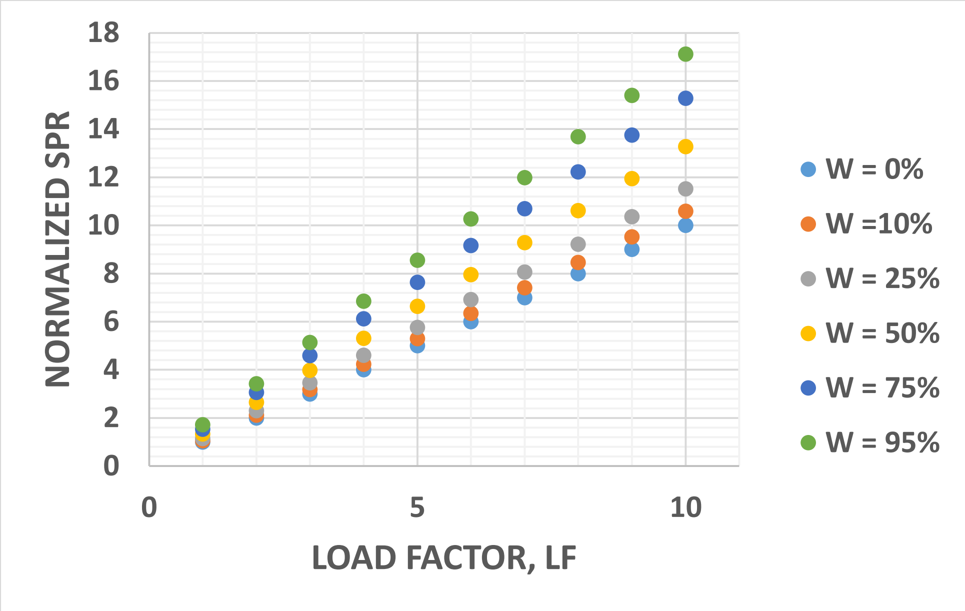


Figure 5.7: Effect of Load Factor on Predicted SPR of A64/D4

5.3.2 Effect of Oil Rate on Predicted SPR

Assuming Oil flowrate spans from 0 to 1000000 bbl/m, taking water-cut (W) = 0 and

GLR (G) = 0 with LF spanning from 1 to 5. Equation 5.1 becomes:

$$SPR_{normalized} = (10Re)^{0.8957} * LF \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots 5.3$$

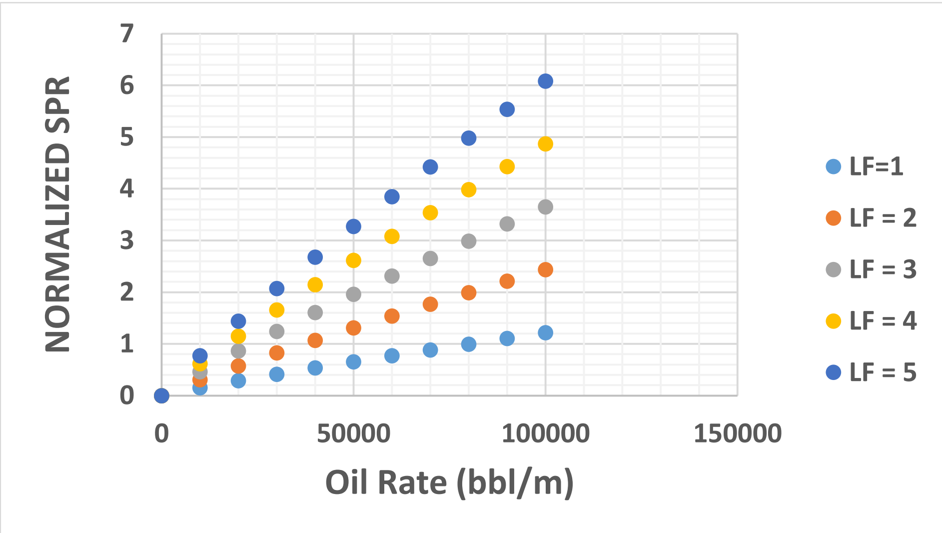


Figure 5.8: Effect of Oil Rate on Predicted SPR of A64/D4

Figure 5.8 presents the effect of oil rate on SPR of A64/D4, the expected trend is that as oil rate increases the SPR also increases because the carrying ability of a fluid generally increases with increasing velocity of the fluid above the critical velocity required to fluidized the failed formation.

5.3.3 Effect of Water-Cut on Predicted SPR

Similarly the effect of water-cut on the developed SPR model is established by assuming water-cut spans from 0 to 95% while LF spans from 1 to 3, taking Re = 0.1, GLR (G) = 0 . Equation 5.1 becomes:

$$\boldsymbol{SPR_{normalized} = LF * exp(0.5657w)} \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \mathbf{5.2}$$

The sanding response of water-cut thus determined is as shown in Figure 5.9. As expected SPR increases with increasing water-cut for all values of LF and G because capillary pressure of the formation decreases with increasing water saturation resulting in weaken the grain to grain cohesive force of the formation and an increase in quantity of formation failure. It also causes a decrease in oil relative permeability requiring an increased drawdown to maintain the same oil rate thereby increasing the effective stresses which causes the more failure in the formation sand.

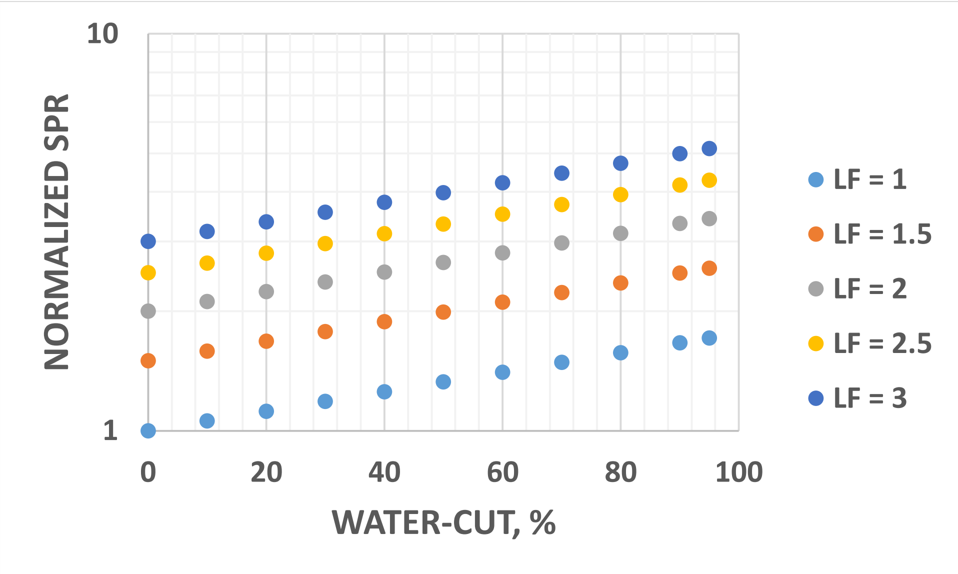


Figure 5.9: Effect of Water-cut on Predicted SPR of A64/D4

5.3.4 Effect of GLR on Predicted SPR

Similarly the effect of GLR on the developed SPR model is established by assuming GLR spanning from 0 to 5E+04 while LF spans from 1 to 3, taking Re = 0.1, W = 0 . Equation 5.1 becomes:

$$\boldsymbol{SPR_{normalized} = LF * exp(1.22E-05G)} \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \mathbf{5.4}$$

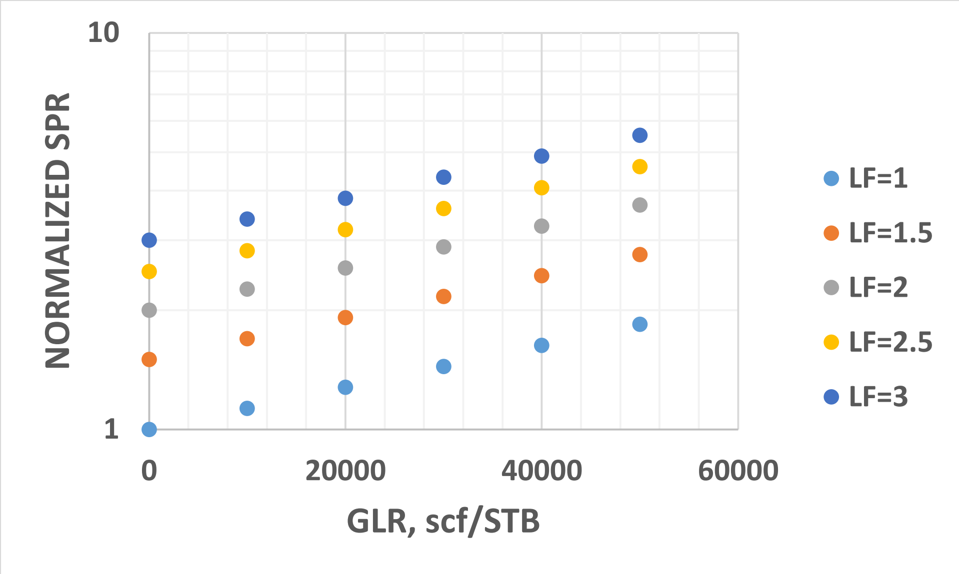


Figure 5.10: Effect of GLR on Predicted SPR of A64/D4

Figure 5.10 presents the effect of Gas-Liquid Ratio on predicted SPR of A64/D4, the expected trend is that as GLR increases the SPR also increases because the resulting multiphase fluid has a higher carrying ability and thus better fluidizes the failed formation.

CHAPTER 6

6.0 CONCLUSION AND RECOMMENDATION

6.1 Conclusions

Based on this study, the following conclusions were made:

- A simple and easy-to-use mechanistic model for predicting SPR in Niger Delta wells was developed
- Every reservoir has a unique SPR correlation indices which represent its propensity to sanding or its sanding identity.
- The developed model is reliable since the maximum deviation between observed and predicted SPR is less than 6% in most cases investigated.
- Compared to existing models, the proposed model predicts better results, especially when GLR is significantly high.
- A more generic normalized SPR model was also developed to allow for comparison across analogous fields with similar depositional environment and sanding characteristics.
- Predictions with this model will aid planning capital sanding related investments such as postponement of sand control installation, recompletion schedule, drilling disposal wells, and installation (or cancellation) of capacities of sand handling facilities.

6.2 Recommendations

The following recommendations are suggested to highlight areas of additional research to improve the formulation of the model developed in this work:

- Additional dataset from various depositional environments within the ND should be used in validating the developed SPR model
- Future study should incorporate the variability of rock mechanics properties of the investigated reservoir
- Thick-Wall-Cylinder (TWC) test should be carried out to have a more accurate measure of the formation strength

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