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MASTER'S THESIS

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Abstract

Oil and gas are mainly produced from sandstone reservoirs, where sand production may play an important role in the whole reservoir development strategy, not only in terms of optimizing well completion, but in well rate and pressure constraints. Sand screens are a commonly used completion solution in such reservoirs, either as stand alone or in a cased hole, with or without different types of gravel pack. Sand screens are not a perfect completion, they can be damaged by a collapsed borehole, plugged by reservoir fines or be eroded by sand. The idea behind this thesis is to investigate the effects of rate constraints on reservoir performance due to erosion of sand screens in a cased hole. This is done by incorporating an analytical sand screen erosion model with a completion model in NETool and a reservoir model in ECLIPSE. Results show that gravel pack is the most suitable to protect sand screens from erosion while enabling the well to produce at high rate. Analysis have shown that under investigated conditions, gravel pack sand screens completion have highest production potential.

Acknowledgments

I would like to say thanks to my supervisors, Hans Kleppe and Anne Raffn for all their advice and criticism. Thank you for giving me this opportunity. Writing this thesis was a worthy and interesting challenge and I feel I've grown a lot, not just in skill but also in discipline. Special thanks my family for their support and expectations, I will not fail you. At last, I would like to give credit to my girlfriend, without you I would not be able to do it, your support means the world to me.

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Chapter 1 Introduction

1.1 Study Background

It is estimated that 70% of the world's oil and gas reserves are in poorly consolidated reservoirs[1], where sand production is likely to happen. Sand production is the process from failure of the rock to transport of sand grains towards the well and up to the surface. Sand production affects well completion as well as surface facilities. Plugging of perforations, sand screen or production liner, wellbore instability, failure of sand control and collapse of some sections of horizontal well are some of the most common problems associated with sand production. In addition, erosion of pipelines and surface facilities, reduction in productivity, intervention costs and environmental effects adds to the complexity and cost of the field development.

Conventional method of handling sand production is exclusion – preventing sand of entering the wellbore with sand screens as most common tools. Sand screens may be applied in different configurations and together with additional well completions, such as expandable sand screen or gravel pack sand screen. The reliability of such completions must be analyzed in each field application, where screen erosion and productivity is the main issues. Such analysis is performed in this thesis on different cased hole completions, such as expandable sand screen, standalone sand screens and gravel pack sand screens.

1.2 Study Objective

The study is set to complete the following objectives:

a) Introduce the geomechanical mechanisms behind sand production
b) Examine sand control alternatives
c) Investigate the effect of sand screen erosion on well production and recovery.

The results of this study will be a comparative results of sensitivity analysis, as well as a result of analysis of screen service life. Some improvements of the methodology is given, as well as a discussion of applicability of the model in the field.

1.3 Thesis Outline

This thesis consist of 5 chapters. Chapter 1 consist of an introduction to the thesis content, sand production and sand control. Chapter 2 begins with the explanations of geomechanical theory of sand production, then talks about different sand control completion solutions and their failures and ends with a discussion on sand screen erosion. Chapter 3 explains the workflow of the modelling in details. Chapter 4 takes the discussion of the results and recommendations for future works.

Chapter 2 Underlying Theory

2.1. Basic Geomechanics

If the rock is subjected to sufficiently large stresses, it will fail in some manner. The rock will permanently change it shape or fall apart, at the same time as it will lose its original strength. Rock failure is complex mechanism which is not fully understood, and the equations are based on observations, rather than on laws of physics. The following chapters assume homogenous and isotropic rock[2]

2.1.1 Rock Strength

The stress level at which the rock fails is called the rock strength, but neither of them has a straightforward definition. There are different types of rock strengths, depending on the stress geometry. Usually the values for rock strength are found through laboratory experiments, these are then incorporated into failure criteria. Two most common tests used are uniaxial and triaxial tests. In the uniaxial test, experiment is performed a cylindrical specimen of the rock with the ratio of length to diameter r 2:1. Specimen is placed between two pistons in an oil bath. Pistons apply axial stress and the length and the diameter of the specimen is measured. In the triaxial test, confining stress is also applied. Results of the uniaxial is a plot of applied axial stress(σ_z) as a function of axial strain (ε_z). In a triaxial test, confining, and axial stress is applied simultaneously, until a prescribed hydrostatic stress level is reached. Then the axial stress is increased until failure occurs, this is done at different confining pressures. The most common mode of failure observed in such test is shear failure, caused by excessive shear stress, in addition tensile failure, caused by excessive tensile stress, and pore collapse, compression, caused by excessive hydrostatic stress(Figure 1 a) tensile failure b) shear failure c) pore collapse). All the failures are associated with the failure of the rock, that is failure of the solid framework. Therefore stress which causes the failure are called effective stresses and are denoted by σ' to distinguish from total stress σ.

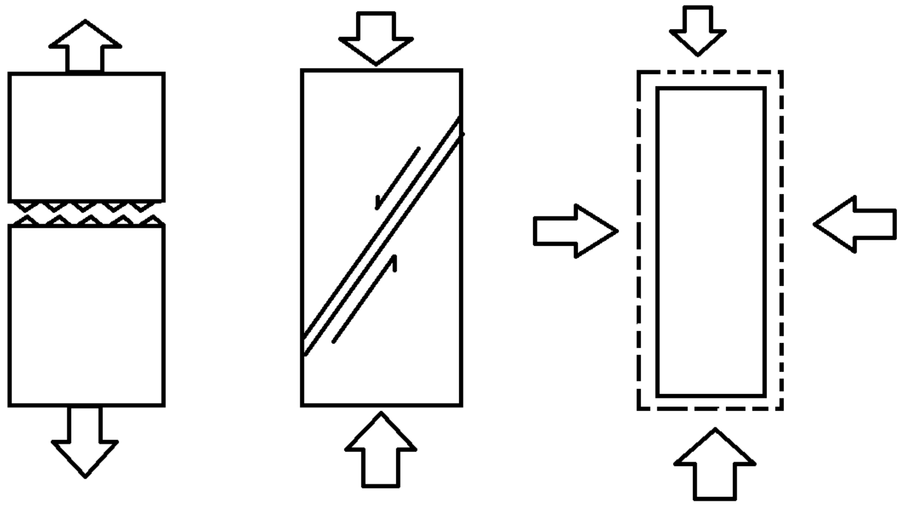

Figure 1 a) tensile failure b) shear failure c) pore collapse

2.1.2 Tensile Failure

Tensile failure occurs then the effective tensile stress across some plane in the sample exceeds a critical limit, tensile strength T_0. Most sedimentary rocks has a low tensile strength, in order of few MPa or less. A sample undergoes tensile failure by splitting in one or very few fracture planes, normal to tensile stress. The fracture plane often originate from preexisting cracks, with largest cracks growing the fastest. The failure criterion of the tensile failure is given by:

$$\sigma' = -T_0 \tag{1}$$

For the isotropic rocks, the condition for tensile failure will always be fulfilled first for the lowest principal stress, so that the tensile failure criterion becomes

$$\sigma_3' = -T_0 \tag{2}$$

2.1.3 Shear Failure

Shear failure occurs then the shear stress along some plane in the sample is sufficiently high.

When the rock fails, a fault zone will develop and the two sides of the plane will move relative to each other in a frictional process. Critical shear stress (τ_{max}) for which shear failure occurs is a function of normal stress (σ') acting over a failure plane:

$$|\tau_{max}| = f(\sigma') \tag{3}$$

This assumption is called Mohr's hypothesis. In the τ-σ′ plane, the function of normal stress describes the limit of safe state of the rock. This line is called failure line or failure envelope. In Figure 2 three principal stresses are indicated, called Mohr's circle, as well as the failure line. If σ'_1 or σ'_3 or both are increased, the Mohr's circle will eventually pass the failure line and the rock will fail. Note that σ'_2 do not influence radius of the circle, thus pure shear failure only depends on minimum and maximum principal stresses.

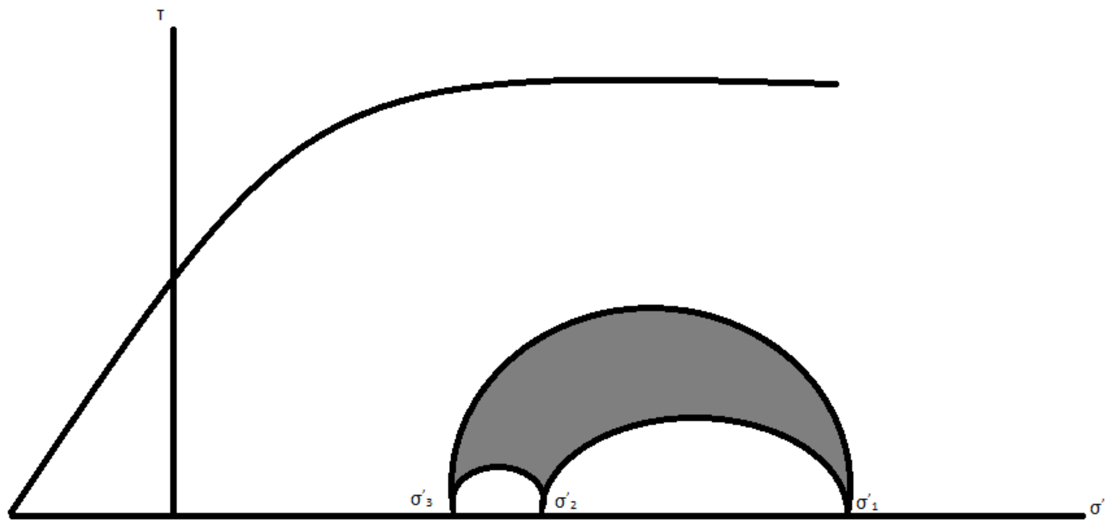

Figure 2 Failure line in the shear stress-normal stress diagram

Functional form of failure line $f(\sigma')$ can be chosen. A constant line, Tresca criterion, being the simplest one, stating that the material will yield when a critical level of shear stress is reached:

$$|\tau_{max}| = \frac{1}{2}(\sigma_1' - \sigma_3') = S_0 \tag{4}$$

Where S_0 is inherent shear strength of the material. Other, more complicated failure criterions exist. The Mohr- Coulomb criterion depend on coefficient of internal friction:

$$|\tau| = S_0 + \mu\sigma' \tag{5}$$

The Griffith criterion depends on the scaled terms of the uniaxial tensile strength T_0.

2.1.4 Pore Collapse

When porous material is compressed, grains may loosen or break and then pushed into the open pore space, thus compacting the rock. Such failures mode is normally observed in a high porosity materials. In sandstones where the size of the pores is of the same order of magnitude as the size of the grains, pore collapse typically consists in reorientation of the grains to better fill the pore space. Pore collapse may occur under pure hydrostatic loading, however microscopically, failure will be due to excessive shear forces acting through grains and grain contacts.

Another mode of pore collapse is grain crushing. When stresses are sufficiently high the grains may be partially crushed at grain contacts and splitting of grains may happen. Such failure mechanisms damage the rock framework permanently and causes yielding, with associated reduction in the stiffness of the rock [2]

2.2. Solids Productions

The problems related to solids production is most pronounce in sandstone reservoirs, but it also may be a problem in chalks and coal reservoirs. [2] Sand production can be classified in three types of severity:

- **Transient sand production**. Sand is produced in a burst at first, following a continuous sand production with declining rate under constant conditions. This kind of sand production is associated with change of production or near-wellbore conditions, change in production conditions or with water breakthrough.
- **Continuous sand production**. Sand is continuously produced at a relatively constant rate
- **Catastrophic sand production**. Where sand is produced at such a high rates, what the well is choked and need a sidetrack or be abandoned.

Sand production cannot occur in intact rock. Rock needs to be damaged or unconsolidated in order to have a potential for sand production. Local stress concentrations which exceed rock strength will fail the rock, but sand may not be produced right away. In order for sand to flow in the well sufficient force from the fluid on particles is needed, still post failure stabilization can occur around the well or in production cavity after some sand is produced. It is also possible for sand to form stable arches on completion equipment, bridging, which allows sand free production until stability conditions are exceeded.

Rock is usually damaged by the effective stress around the well, which depends on far field stress configuration, which may not be homogeneous, pore pressure and geometry of production cavity.

Sand production may be initiated by changes within reservoir and well operations[3]:

- **Completion and drilling operations.** In such operations fluid loss control to reduce formation damage around the well, such as clay swelling, fines migration, wettability changes and emulsions, is done by reducing porous media conductivity as well as rock strength, which enables formation of weak zones. Such weak zones are vulnerable to high pressure gradient, especially in a cased hole, where open flow area are much smaller than in open hole

- **Reservoir in-situ stress state and rock deformation.** As mentioned above sand production can only occur in a damaged rock, where damage may be induced by drilling operations, well completion, well production and operating pressures.
- **Level of pressure drop around the wellbore.** Then producing at higher rates, pressure gradient may be higher than rock strength and failure will occur. Sand will be transported in the well if dragging forces are sufficiently high after rock failure.
- **Reservoir depletion.** Then reservoir pressure depletes, effective stress increases and thus potential for sand production increases.

Fluid flow alone cannot move grains in an intact rock. Consider a production cavity in a well where a grain of diameter $\mathbf{d_g}$ is squeezed between its neighboring grains at the wall of the cavity. The forces needed to remove this grain are sum of shear failures in 4 contact planes at the sides of the grain plus the forces needed to induce tensile failure in the contact plane behind the grain:

$$F_r = \pi(\frac{d_g}{2})^2[4S_o + \mu(2\sigma_z' + 2\sigma_\theta') + T_0] \tag{6}$$

Where

T_0 – tensile strength

S_o – cohesion

μ – coefficient for internal friction

σ_z' - effective axial stress

σ_θ' - effective tangential stress

The sand grain is also pulled by hydrodynamic forces caused by fluid flow. The forces acting from the fluid on the grain can be derived from Darcy's law:

$$F = -A\Delta p_f = \frac{\eta_f}{k} Q\Delta x \tag{7}$$

Were

A – cross sectional area of the element

Δx – is the length of the volume element

Δp_f – pressure drop along the element

k- element permeability

η_f – fluid viscosity

To have an average expression of the force per grain an expression for permeability in a porous rock is used:

$$k = \frac{1}{180} \frac{\phi^3}{(1-\phi)^2} d_g^2 \tag{8}$$

Number of grains N in the volume element is given by volume of solid material in the element divided by the volume of one grain

$$N = \frac{(1-\phi) * A\Delta x}{\frac{1}{6}\pi d_g^3} \tag{9}$$

And the hydrostatic force on one grain is:

$$F_h = \frac{F}{N} = 30\pi\eta_f \frac{1-\phi}{\phi^3} \frac{Q}{A} d_g \tag{10}$$

[2] compares forces on a grain in a very weak rock, and shows that hydrostatic forces remains several orders of magnitude lower than the force needed to remove the grain. Thus rock cannot be destroyed by hydrodynamic forces alone, but such forces are important in moving the grains from damage region and in transporting them in the well.

2.2.1 Shear Failure leading to sand production

In a borehole the largest stress difference is on the borehole wall and the failure will be initiated there. Different borehole orientations in respect to stress field and permeable- impermeable wellbore wall condition give rise to multiple failure criterions and derivation which can be found in [2]. Shear failure of the borehole which leads to sand production depends on horizontal stress configuration, where the stress field can either be isotropic or anisotropic.

For the simplest case where the stress (σ_h') is isotropic consider pore pressure at the cavity wall during production:

$$p_f(R_c) = p_w \tag{11}$$

The smallest principal stress is:

$$\sigma_r(R_c) = p_w \tag{12}$$

And the largest principal stress is

$$\sigma_\theta = (R_c) = 2\sigma_h - p_w - \frac{1-2v_{fr}}{1-v_{fr}}\alpha(p_{fo} - p_f(R_c)) \tag{13}$$

Where

v_{fr} – drained Poisson's ratio

α – Biots poroelastic constant

Failure according to the Mohrs-Coulomb failure criterion is achieved then

$$\sigma_\theta(R_c) - p_f(R_c) = C_0 - (\sigma_r\left(R_c) - p_f(R_c)\right) tan^2\beta \tag{14}$$

Solving the equation in terms of $p_f(R_c) = p_w$ gives the lowest well pressure where failure is initiated.

Expressing minimum well pressure as critical drawdown:

$$p_d^c = p_{fo} - p_{w,min} \tag{15}$$

Where

p_{fo} – far field reservoir pressure

The solution of equation 13 and 14 will be (with $\alpha = 1$) :

$$p_d^c = (1 - v_{fr})(C_0 - 2\sigma_h') \tag{16}$$

Where

$\sigma_h' = \sigma_h - p_{fo}$ – is the effective far field stress.

This model is simplified [2], but reflect a dependency of onset of sand production not only on rock strength and rock properties, but on far field stress and reservoir pressure. Maintaining pressure while depleting reservoir, such as with help of water injection is an important sand production control.

Consider next case, where principal in-situ stresses are all different. Now the stability of a production cavity, or a borehole depends on orientation as well as well pressure. Thorough derivation for this case can be found in [2]. From results it can be found that in a vertical well it is preferable to perforate parallel to minimum horizontal stress, σ_h in order to obtain the largest critical drawdown, while in a horizontal well it is preferred to perforate in a vertical direction, provided that $\sigma_v > \sigma_H$. Note that the field stress around perforations can be disturbed by many factors, such as presence of other perforations, presence of the well and breakouts. Such factors have to be considered when perforating a well for production. Shear failure initiation happens on the borehole wall (Figure 3) which elongates in the same direction (Figure 4). After the rock has failed, grains need to be transported by hydrostatic forces of the flowing fluid. If the force is sufficient the production cavity will have the form seen in Figure 5.

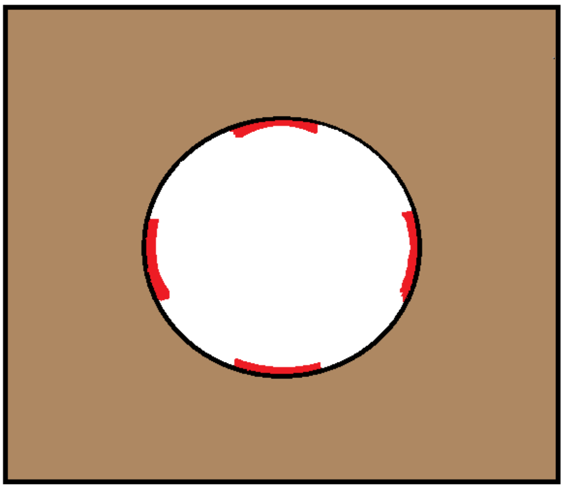

Figure 3 Filure initiation

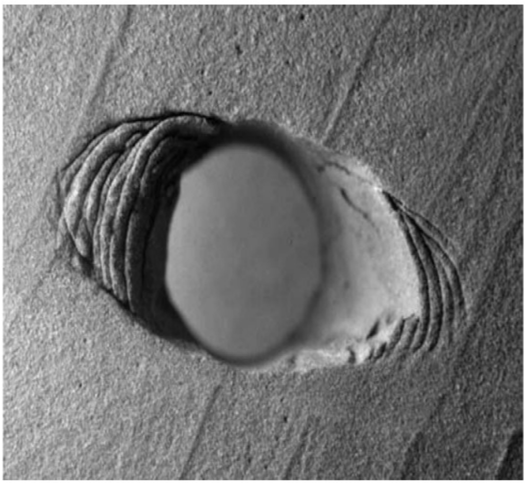

Figure 4 Failure after some time ,[2] figure 4.15

Figure 5 Production cavity after sand production, [4] figure 9

2.2.2 Tensile Failure leading to sand production

Tensile failure may also lead to sand production. Tensile failure will occur then the pore pressure gradient is larger than the radial stress gradient at the cavity wall [2] that is

$$\left.\frac{\partial p_f}{\partial r}\right|_{r=R_c} > \left.\frac{\partial \sigma_r}{\partial r}\right|_{r=R_c} \tag{17}$$

The normalized drawdown pressure gradient is defined as

$$g_{pn} = R_c \left.\frac{\partial \sigma_r}{\partial r}\right|_{r=R_c} \tag{18}$$

The critical drawdown pressure gradient, is the largest normalized pressure gradient without sand failure

$$g_{pn}^c = R_c \left.\frac{\partial \sigma_r}{\partial r}\right|_{r=R_c} \tag{19}$$

And in a cylindrical cavity with isotropic stress the critical drawdown pressure is defined as

$$g_{pn}^c = 2\left[\sigma_h - p_w - (p_{fo} - p_w)\alpha \frac{1 - 2v_r}{2(1 - v_r)}\right] \tag{20}$$

If the tensile strength is larger than zero, this criterion may not be sufficient for tensile failure to occur in the open hole during production. Based on modelling [5] it is found that tensile failure mainly occurs in small holes like perforations. Shear failure will always precede tensile failure in a large hole, but in small cavities with large shear strength tensile failure will occur first, even if it just precedes shear failure. The same happens during startup of the well, when the well pressure is lowered and the pore pressure gradient at the cavity wall will be much larger than radial stress gradient for a short time and tensile can occur. The critical drawdown pressure during well start-up can be found. Even then the tensile failure just precedes shear failure.

Now we have two relations which describe sand production in cylindrical cavity with isotropic stress in terms of critical drawdown pressure for shear failure, equation 16 and tensile failure, equation 20. The resulting expression will limit the pressure gradient for sand free production. Graphically such relations may have the following form (Figure 6):

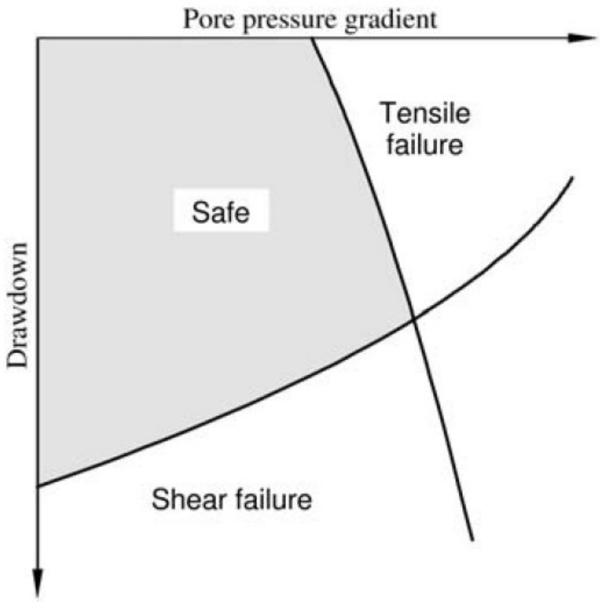

Figure 6 sand free production conditions, from [2], fig. 10.7

2.2.3 Prediction Models

In many applications, stresses are anisotropic, as well as borehole orientation with respect to stresses will vary. Prediction models were developed by various authors [1, 3, 6], where well orientation in respect to stresses, coupling with fluid flow transport of grains and completion effects are recognized.

[1] Presents a numerically coupled geo-mechanical model for sand production in open and cased hole. It uses a finite volume method to predict wellbore and perforation stability and predict sanding based on shear and tensile failure and strain hardening/softening. The paper emphasize that sand production happens in two steps: shear/tensile failure on the surface of production cavity then transport of loose sand into the wellbore. The model is being compared to analytical solutions in two cases: 1) Consolidation problem for poroelastic medium, where a porous medium is subjected a traction and drainage at top plane 2) Stress concentration around hole in elasto-plastic plate, where a hole in center of a plate is subjected to an isotropic far-field stress. A good agreement between a numerical and analytical solutions is observed.

[6] Presents a simple pseudo 3D model to evaluate sand production risks in cased holes with different deviations based on elasticity. Model separates perforation and the wellbore into separate 2D models with the assumption of homogenous isotropic linear elastic rock to simplify calculation. Stresses are calculated analytically and a superposition principle is used to obtain the overall stress distribution. Model is limited to vertical wells, and orientation of perforation and the borehole is not accounted for.

Results are compared to a true 3D numerical code and calibrated showing an average error of 30%.

[3] Presents a mechanical earth model as an input to identify well pressure which makes maximum effective tangential stress higher or equal to rock strength which leads to rock failure. Model needs large input data from logs, reservoir characteristics, stress state regime, well and completion properties as well as laboratory stress data. Critical borehole pressure which leads to rock failure is calculated as the result. The paper concludes that criteria of rock failure is essential in this model, which can be highly sensitive to calculating rock strength with different empirical models based on laboratory analysis.

Modelling of sand production is fundamental in field development and will help to eliminate or mitigate related problems. Choosing different models will affect the result of prediction, making it hard to understand the impact of sand in a well and uncertainty in volume of sand produced. Therefore insuring a good sand control in terms of suitable well completion is an essential step in any field development.

2.3 Sand Control Completions

Different techniques can be deployed without downhole control to reduce or eliminate sand production or some degree of sand can be accepted. As mentioned before modelling can give an answer to critical downhole pressure without sand production with respect to hole and perforation orientations, reservoir pressure and properties. Some techniques are[7]:

- **Water and gas injection**. Such strategies can help to maintain reservoir pressure thus reducing pressure drop in a well, but a possibility of isolated production segment which does not receive pressure maintenance must be considered
- **Selective perforations or oriented perforations**. Perforating in just strongest intervals may reduce sand production potential, but at the same time may lower well productivity, as the most productive intervals are commonly the weakest. Perforating in the direction of largest horizontal stress, thus where the rock is strongest may help delay or avoid sand production. Such techniques will only work in the fields with large stress contrast, where the margin between stresses and thus rock strength.
- **Optimizing perforation density.** It has been confirmed that in stressed regions around perforations overlap with neighboring perforations. The overlapping areas can break out and produce sand depending on overlapping area. Degree of overlapping depends on perforation density, and optimizing it can help to stabilize the rock.

- **Chemical consolidation.** Treating the formation with some kind of material which bonds the sand grains together will increase rock strength and reduce or delay sand production. Before consolidating the formation, formation has to be treated and consolidating chemical has to be injected with a compatible fluid. To ensure long term success of the operation, degree of consolidation should not decrease with time. Some other problems may arise with chemical consolidation, such as HSE problems, damaging permeability and additional well treatment [8].

Some screen less completion are proved to be reliable and cost effective[9], however in most fields failure will occur as reservoir pressure is depleted and as a result the well will produces sand regardless of drawdown[10]. Therefore a well completed with screens will act as a more reliable sand control.

2.3.1 Sand Control Screen Types

A number of different screen types are available and are being deployed in all kinds of formations.

2.3.1.1 Wire Wrapped Screens

Such screens are used alone (Stand Alone Sand Screens) or in gravel packs. WWS consist of predrilled base pipe with welded parallel rods. Single wedge shaped wire is wrapped around the pipe and welded to the rods. The keystone (wedge) insures that the particles are bridged off against the wire or passed through it and produced. Such self-cleaning mechanism provide efficient control against screen plugging, but as a result WWS have a relative low inflow area, f. ex. 5 %, but is still greater than cased and perforated well[7]. In gravel pack completion WWS top the gravel, and fine particles are stopped inside the gravel or produced through the screens.

Figure 7 WIre Wrapped Screens from [7], Figure 3.27

2.3.1.2 Pre-Packed Screens

Pre-Packed Screens are made in a similar manner to WWS with respect to wielded wedge-shaped wires, but are constructed with two screens with a gravel pack between those. Such in-screen gravel-pack provide some degree of filtration, but are prone to plugging [11], do not eliminate annular flow such as annular gravel pack and do not offer protection against screen erosion.

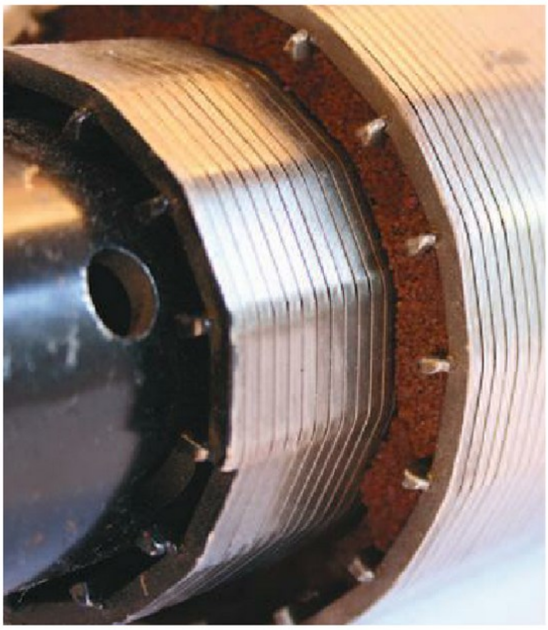

Figure 8 Pre-Packed Screens from [7] figure 3.29

2.3.1.3 Premium screens

There are many different design of premium screens, with a basis of multiple woven screen media wrapped around predrilled basepipe with some kind of outer protecting shroud. Such screens offer a more robust alternative in challenging environments, f. ex. long horizontal wells or compacting reservoirs.

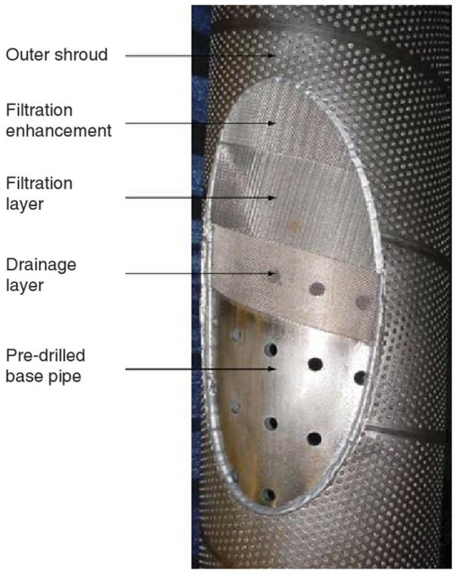

Figure 9 Premium Screens

2.3.1.4 Expandable Sand Screens

When ESS are installed in the well, they are expanded with hydraulic forces to eliminate the annular gap. Such technology offers an additional support in an openhole completion [12] at the same time as eliminating annular flow and increased inflow, compared to conventional screens. In cased hole completions ESS is not recommended[13]. In such application, fluid flows directly in the well only through section of ESS which are in direct contact with perforations and are highly prone to erosion. During production, some perforations are plugged with sand, diverting flow to other open perforations, increasing fluid velocity towards the screen in this sections, further increasing erosion.

2.3.2 Standalone Screens Completion

Low cost and simple installation make standalone screens (SAS) an attractive choice for sand control, but due to their high failure rate they are poorly suited for formations with high risk of solids production. SAS exclude sand particles from entering the well by mechanical retention. Spherical particles will not flow continuously through rectangular slot twice as the diameter of the particle, through circular holes three times their size [14]. Particles will ridge on the screen and allow only fines to pass and be produced. WWS aperture can vary upwards from 0.1mm and it is reasonable to expect that particles up to 50-125 µm to pass the screens. Smaller particles do not contribute either to erosion, or to plugging, as they pass freely through the screens. Sand below 50 micron are non-erosive [15-20]. Problems with screens may arise during completion or during production.[15]. During completion operations failures may arise then placing gravel pack, where erosion, plugging and warp failure are common problems.

During production erosion, plugging or both may fail the screens. Erosion of screens happens by mechanical wear of the retention media, weave or wire, resulting in hole where sand can freely enter the well. Screen plugging during production is due to production of fines which plug the pores in the weave of the screen. Such failure will lead to lower inflow area and increase skin over time.

Placing clean suitably sized gravel pack around the screens allow for a more robust sand control completion. Gravel pack is used to stop larger particle while allowing smaller particles to pass or stop inside the gravel pack (more on gravel pack properties and failure is explained in section 2.3.3 Gravel Pack Completions. Gravel pack installation and use are extensively studied and are primary choice for sand control[14]. ESS can also serve the same purpose, in eliminating annulus and creating larger area for particle filtration. However some limitation for gravel pack and ESS placement exist, in extended reach well and many types of multi-lateral wells [7], and the only option left is to complete such challenging wells with SAS.

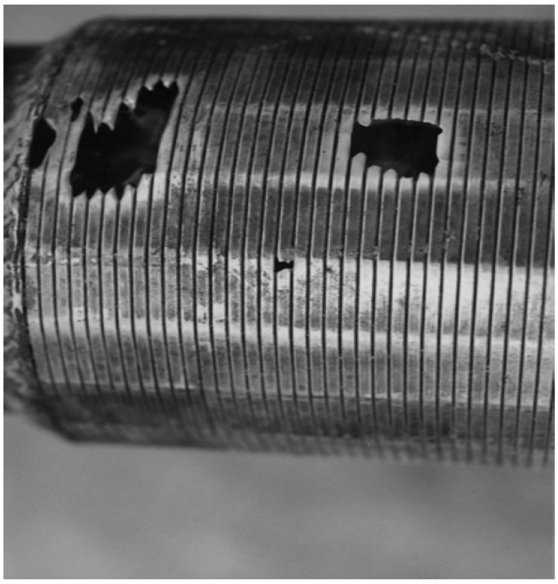

Figure 10 Wire Wrapped screen erosion. Mechanical removal of wires by sand particles lead to formation of holes in the screen where sand can enter the well freely. From [15] Figure 1

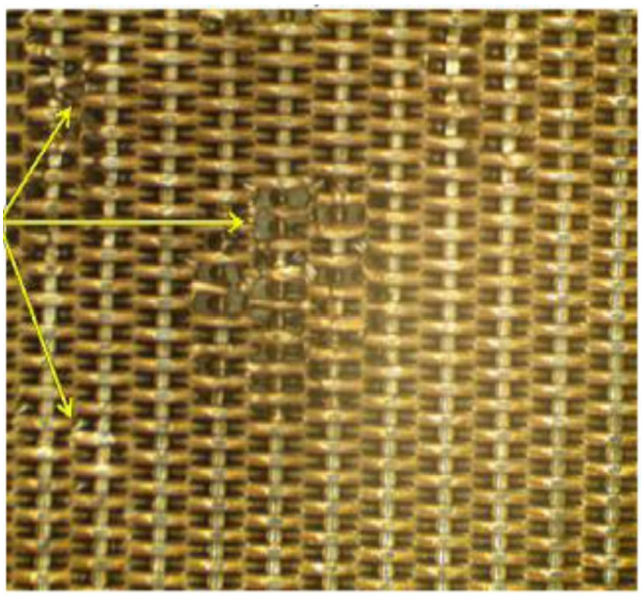

Figure 11 Erosion damage in premium screen weave in a laboratory test. Such microscopic erosion will allow bigger particles, than before erosion, to pass. From [21], Figure 12

Guidelines for SAS application exist[22], where such completion can be considered:

- Low fine content of formation , <5%
- Uniform well sorted sand
- D_{50} >75µm

A problem with such for formations, is that there is not so many sand producing reservoir which are well sorted and have low fines content. Most other sand producing fields are much more challenging, and gravel packing the well is always preferred.

2.3.2.1 Role of annular flow

[22] notes the negative effect of annular flow on standalone screen service life and operators typically use swellable elastomer packers to reduce annular flow or minimise annular gap . Annular flow reduces ability of the sand to bride on the screens, by transporting them in the annulus towards heel of the producing section. Unable to bridge on the screens, sand is directly impact the screen for a longer time, increasing risk of screen erosion. Annular flow also transport clays and fines from shale sections towards the screens, plugging them.

2.3.3 Gravel Pack Completions

Intention with the gravel pack is to pack annular space between the screens and formation or casing. Gravel is pumped in the well to prevent formation collapse and screens are sized to hold gravel in place. Preventing formation collapse can reduce fines production, and gravel itself will hold back larger sand particles is design correctly. However gravel pack can be damaged in many different ways. Scale formation, fines migration and plugging during production and filter cake removal, paraffin and asphaltene deposition will result in skin of 10-300[23].

2.3.3.1 Open Hole Gravel Packs

In long horizontal, extended reach wells high cost and difficulty cementing casing and effective perforations, forces operators to complete such wells as open hole[24]. Open hole completion has a larger inflow area compared to cased hole and have higher productivity and can be used with WWS, pre-packed and premium screens. Open hole gravel packs are installed in two way: circulating pack and alternate path (shunt tubes) pack. For circulating pack, gravel pack operation is done in three stages[25]:

- Injection
- Alpha wave propagation
- Beta wave propagation

During injection fluid-gravel mixture is pumped from the rig until a crossover tool located at the toe of the well where the fluid is directed to the open hole annulus. Larger diameters decreases flow velocity of the mixture and gravel begins to settle on the lower part of the annulus. In alpha wave propagation deposited sand length will propagate until the end of the section, leaving a free channel on the top section of the annulus. When the sand arrives at the end of the section, beta wave propagation begins. Now gravel will begin to deposit in the upper annulus, starting from the end of the section to the crossover tool until all the annular space is filled with gravel. During packing dynamic pressure should be between pore pressure and fracture pressure. If the dynamic pressure is below pore pressure, formation fluid and particles may enter the well, possibly damaging the gravel and increasing risk of screen erosion during last stage of the beta wave, there all fluid is returning through a very small section of screens at extremely high rates. If the dynamic pressure is above fracture pressure, drilling and completion fluid will enter the formation and damage it. During gravel pack operation special care has to be taken in path of the well where, during drilling, drill bit has changed in size, so called "rathole". There will be a short section (10m) with the larger diameter than the rest of the open hole section. Minimum slurry velocity has to be achieved in order to not start beta wave propagation prematurely. Since a larger diameter hole section is exposed with a too low flowrate alpha wave gravel "dune" may be tall enough to block entrance to the open hole and creating beta wave return immediately in the rat hole.

Alternate path pack uses special screens with shut tubes, where slurry is flowing and is deployed to the formation. Tubes allow gravel slurry to bypass any blockage of the annular space, such as collapse formation, packer or gravel bridges in rat holes and zone with high fluid leak off[26].

Before packing the well, gravel has to designed according to formation to effectively stop formation larger (which leads to sand production) and finer grains (which lead to gravel plugging and screen erosion and plugging). There are many different criteria of sizing gravel pack from different authors. Suggestions of using gravel size D_{50} 10, 8-6 times D_{50} of the formation size exist[7] [27], but simple criteria for gravel pack design should be used with care. In addition to mean particle size of formation, other criteria, such as fine content, sand uniformity and sand sorting should also be used.

2.3.3.2 Cased Hole Gravel Packs

Gravel pack in a cased hole serves the same purpose as in open hole, and are used especially where other sand control struggle:

- Laminated sand/shale intervals
- Low permeability formation
- High fines content

Downside with such completion is high complexity and cost in long producing sections. Cased hole gravel pack (CH-GP) is installed in following manner:

- Perforate casing and preferably clean up the perforations
- Run a packer to isolate stagnant volume below perforation and provide latching point for the screens
- Run screens and pack the gravel
- The end result should be tightly packed perforations and annulus.

Chapter 3 Modelling Description

The main part of the thesis is to model performance of sand screen under sand production condition in terms of erosion in different completion settings. A simple numerical reservoir is made in ECLIPSE and run on three production rates scenarios. NETool is used to build completions of the well, and calculate velocity of the producing fluid onto the screens. Calculated velocity is used together with completion and produced particle properties to calculate screen erosion to check if completions are suited for current production rates. Next erosion model is used to calculate safe rates for each completion under different sand properties, i.e. mean size of the particle and concentration. Finally calculated safe rates are used in ECLIPSE and NETool to calculate oil recoveries in order to compare different completion.

3.1 Methodology Workflow

The modeling of sand screen performance in the reservoir is done in two parts. To calculate screen service life in a sand producing reservoir methodology is done by incorporating ECLIPSE , Landmark's NETool well simulator and Procyk's screen erosion model [21] to calculate mass loss of screen during production of 250 m long horizontal cased well in 3 channel reservoir.

Part 1 consist of building a simple reservoir in ECLIPSE and using black oil model to calculate reservoir performance with target liquid production rates of 1000 sm^3/d, 2000sm^3/d and 3000sm^3/d in terms of recovery, bottomhole pressure and oil rates. Reservoir solutions are exported to NETool where completions are build. Four different completion types are investigated in cased hole well:

- Stand alone sand screens
- Expandable sand screens
- Stand alone sand screens isolated with packers
- Gravel pack with screens

For these completions velocity toward screen woven media which serves as sand retainer is calculated in NETool and used in Procyk's screen erosion model to calculate erosion of screens in terms of grams per month. A safe limit in terms of grams of eroded screens is chosen to represent screen service life. The purpose of part 1 is to calculate service life of chosen completions in order to compare them in three base case production scenarios.

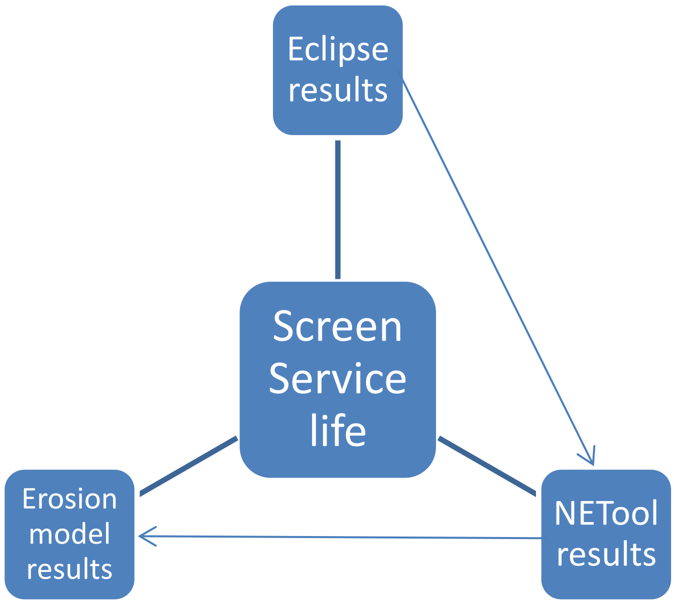

Figure 12 Part 1 of the modelling work. Solution of ECLIPSE reservoir is exported to NETool where fluid velocity onto screens is calculated. Velocity is used in erosion model to calculate service life of different completions.

Part 2 consists of calculating safe production rate with respect to particle size and particle concentration in addition to %open perforations in ESS completion (3.3.2 Expandable Sand Screen Erosion Calculations. Resulting rates are inserted as well control in ECLIPSE model to compare reservoir and well performance for different completions. For gravel pack completion NETool is used to calculate reservoir and well performance with the assumption of 10,30 and 50 skin per year(3.3.5 Gravel Pack - Sand Screens erosion calculations)

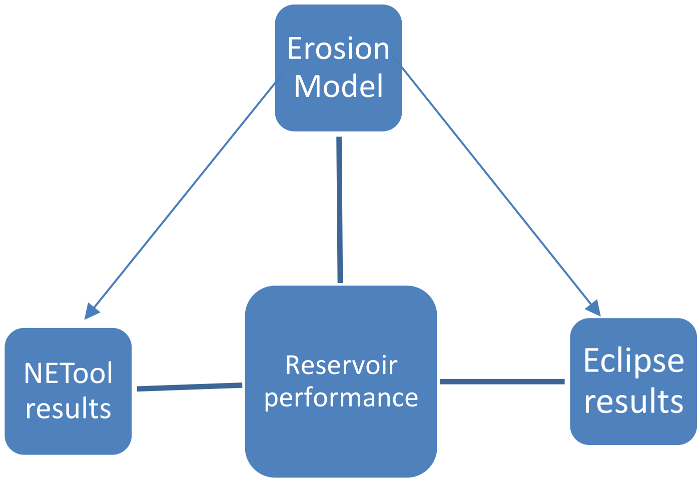

Figure 13 Part 2, Sensitivity Analysis Workflow. Under different conditions, safe rates for each completion is calculated, and safe rates are used as well control in ECLIPSE for each completion to calculate recoveries. For CH-GP NETool is used.

3.2 Description of Reservoir Model

3.2.1 ECLIPSE Reservoir Model

The intention of using this kind of reservoir model, is to model a laminated reservoir with sand channels and impermeable shale between them, where horizontal well would be necessary to obtain good production. Reservoir model have 420 blocks with one layer, where 210 blocks are active, shaped like straight channels, as seen in Figure 14 Horizontal cross-section of the reservoir. There are in total 3 sand channels 35 m wide each. Reservoir parameters are summarized in Table 1 Reservoir parameters

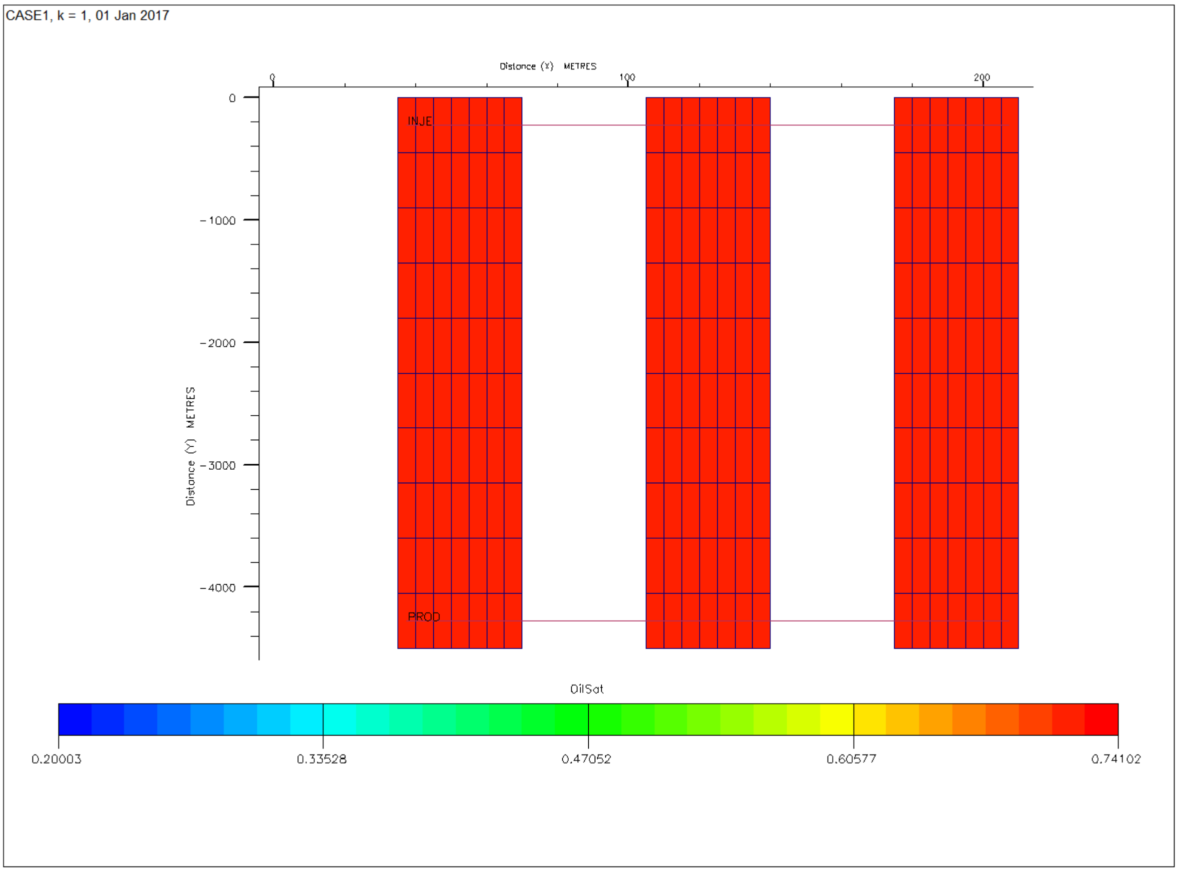

Figure 14 Horizontal cross-section of the reservoir. 3 straight sand channels with shale in between. Observe production and injection well placement.

Parameters	Values
Block length x-direction	5 m
Block length y-direction	450 m
Block length z-direction	50 m
Porosity (in active blocks)	0,2
Permeability x-direction (in active blocks)	1000 mD
Permeability y-direction(in active blocks)	1000 mD
Permeability in z-direction(in active blocks)	100 mD

Table 1 Reservoir parameters. Block geometry, and static reservoir properties.

Relative permeabilities are calculated from Corey functions with normalized saturations:

$$S_{wn} = S_{wn}(S_w) = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{orw}} \tag{21}$$

$$k_{row}(S_w) = K_{row}^0 (1 - S_{wn})^{No} \tag{22}$$

$$k_{r\,w} = K_{rw}^0 S_{wn}^{Nw} \tag{23}$$

With Corey numbers of water and oil, Nw=No=2, and endpoint relative permeability of water $K_{rw}^0 = 1.0$

Relative permeability are given in Table 2 and Figure 15

Sw	So	Swn	Krw	Krow
0,200	0,800	0,000	0,000	1,000
0,300	0,700	0,167	0,028	0,694
0,400	0,600	0,333	0,111	0,444
0,500	0,500	0,500	0,250	0,250
0,600	0,400	0,667	0,444	0,111
0,700	0,300	0,833	0,694	0,028
0,800	0,000	1,000	1,000	0,000

Table 2 Relative Permeabilities of oil and water. Calculated from Corey functions

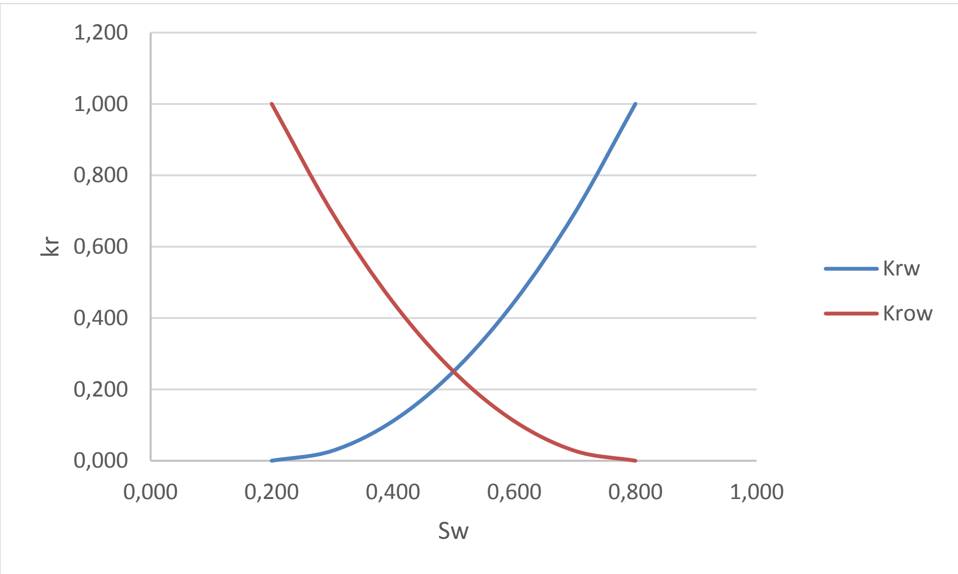

Figure 15 Relative permeabilities as calculated above, presented graphically.

Oil PVT properties are given in Figure 16 and Figure 17, and are essentially constant.

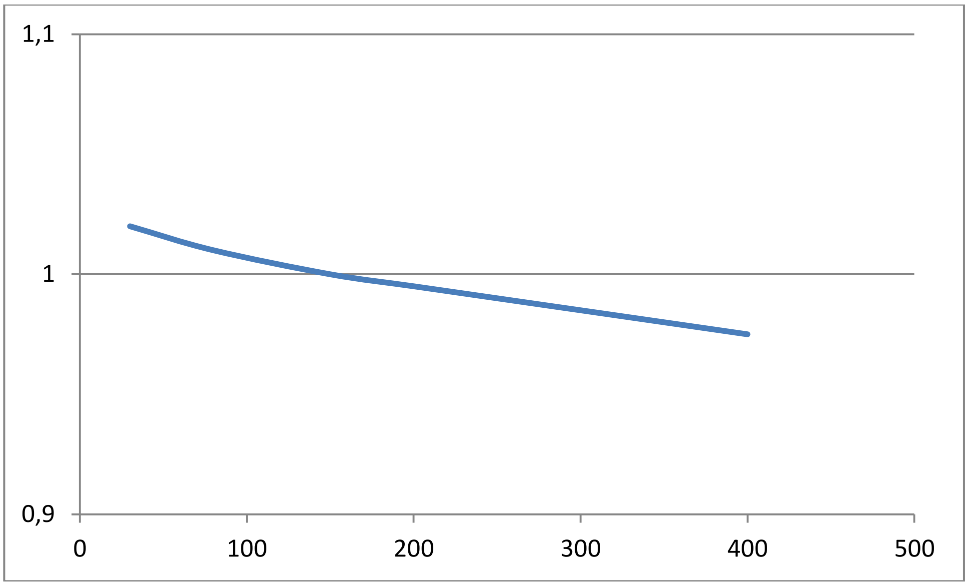

Figure 16 Oil Viscosity

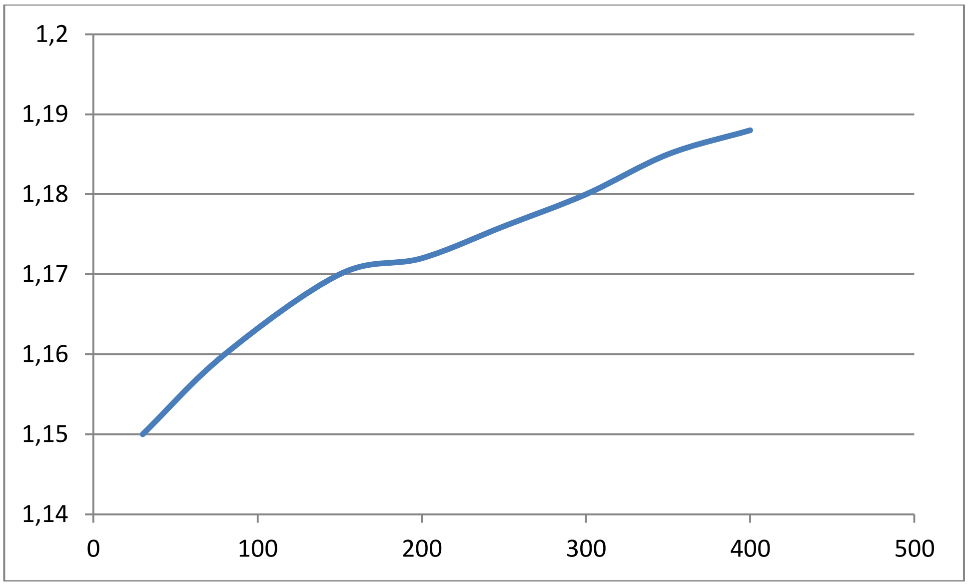

Figure 17 Oil Formation volume factor

Water properties in addition to oil density are summarized in Table 3

Water density at standard conditions	1000 kg/m^3
Oil Density at standard conditions	600 kg/m^3
Water Formation Volume Factor	1.00 rm^3/sm^3
Water compressibility	≈0 1/bar
Water viscosity	1 cP
Water viscosibility	0 1/bars

Table 3 Water and Oil properties

Production is run on three different rate cases with liquid production rate as well control for 60 months: 1000 sm^3/d, 2000 sm^3/d, 300sm^3/D with water injection for pressure maintenance, scheduled to replace void volume, that is to inject as much as it is being produced.

The question to be asked is “What development scenario should we choose under different sand production conditions such that sand screens will not fail?” Highest recovery factor after 60 months is wanted, but formation sand properties are uncertain before production occurs, in terms of erosive fines mean diameter and concentration. In order to find the completion which makes well deliver most oil, the analysis is performed.

3.2.2 NETool Completion and Reservoir model

Result are imported into the NETool as “snapshots” of reservoir properties at different timesteps, such as pressure, oil/water saturation. The program enables user to build completions for the well, such as cemented casing, perforations, sand screen, with different properties. NETool calculates presuredrops and rates according to completion design in nodes representing a piece of completion, from reservoir node to inner tubing.. For more information on NETool see Appendix A

Well path in ECLIPSE model was exported as coordinates from PETREL, so that injection and production wells paths corresponds in both models. The purpose of this study is to investigate effect of sand screen erosion in cased well on oil recover under different completion options in a cased well with perforated cemented liner(casing) in producing intervals. Well completions are:

- Cased Hole Standalone Screens Figure 18 Standalone Sand screens in Cased Hole(Figure 18)
- Cased Hole Standalone Screens with packers (Figure 19)
- Cased hole Sand screens with gravel pack (Figure 20)
- Cased hole Expandable Sand Screens (Figure 21)

Properties of each completion can be found in Appendix B Completion Properties.

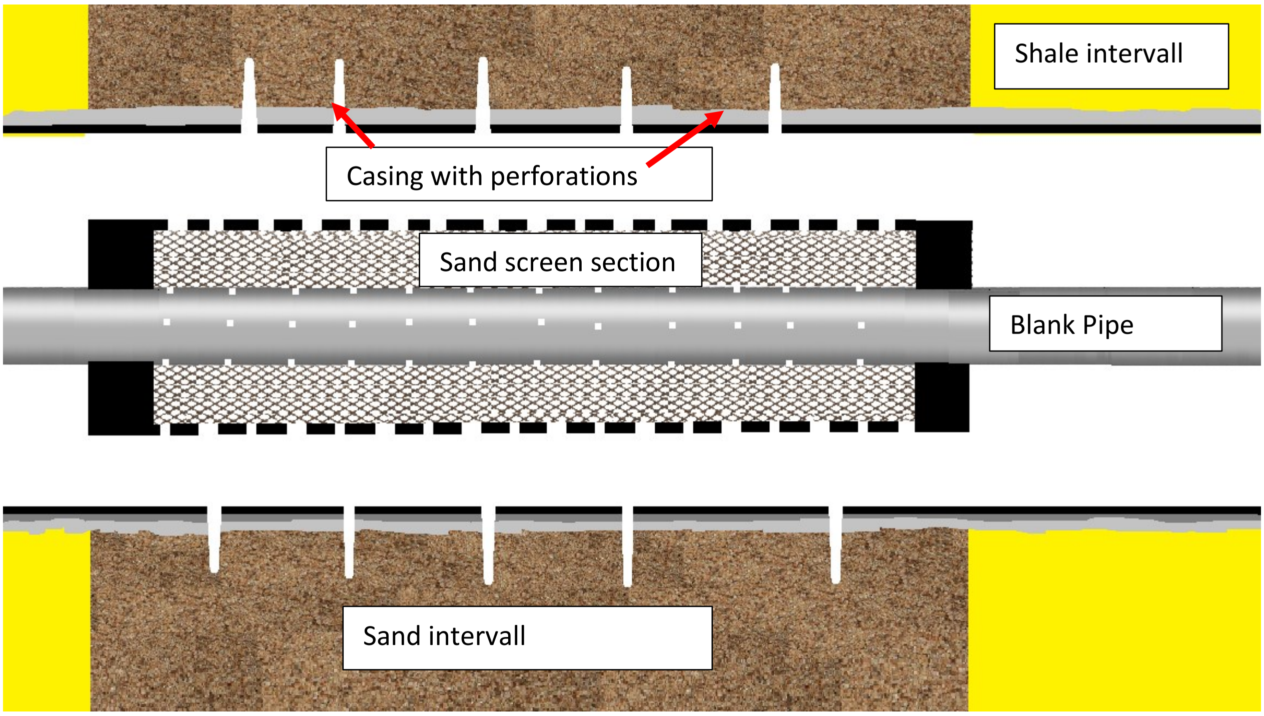

Figure 18 Standalone Sand screens in Cased Hole

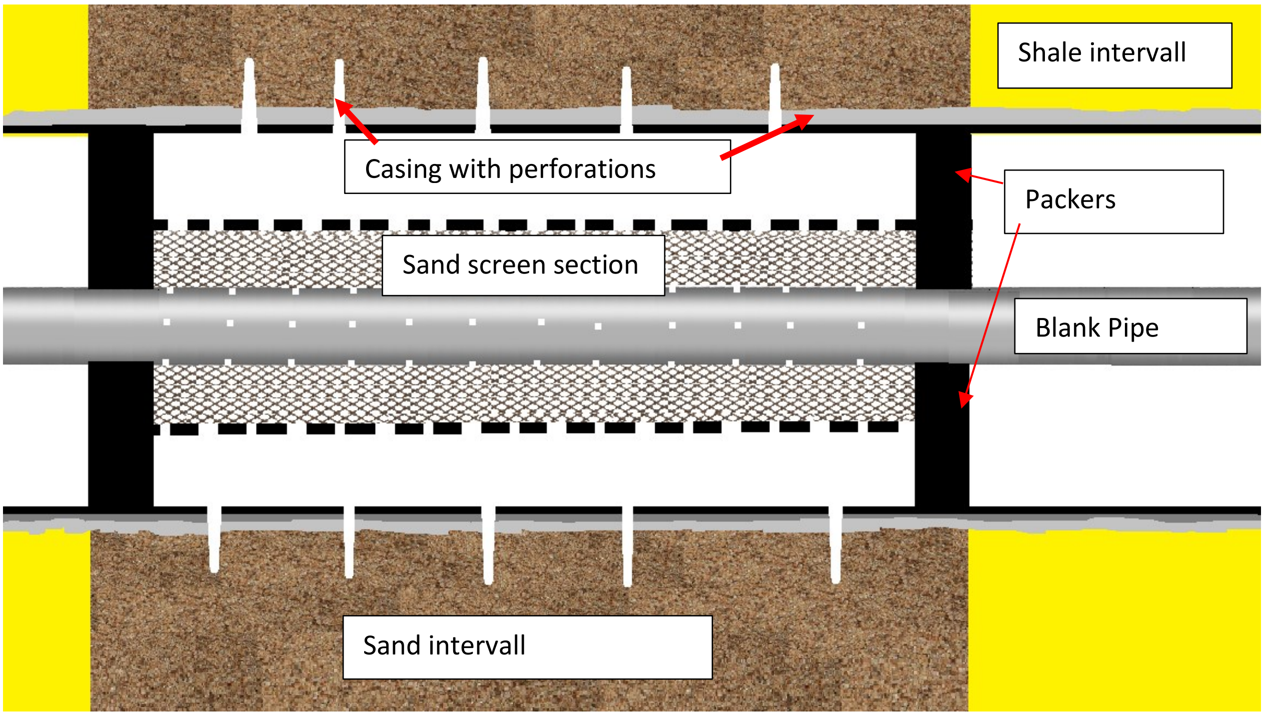

Figure 19 Sand Screens with packer zonal isolation

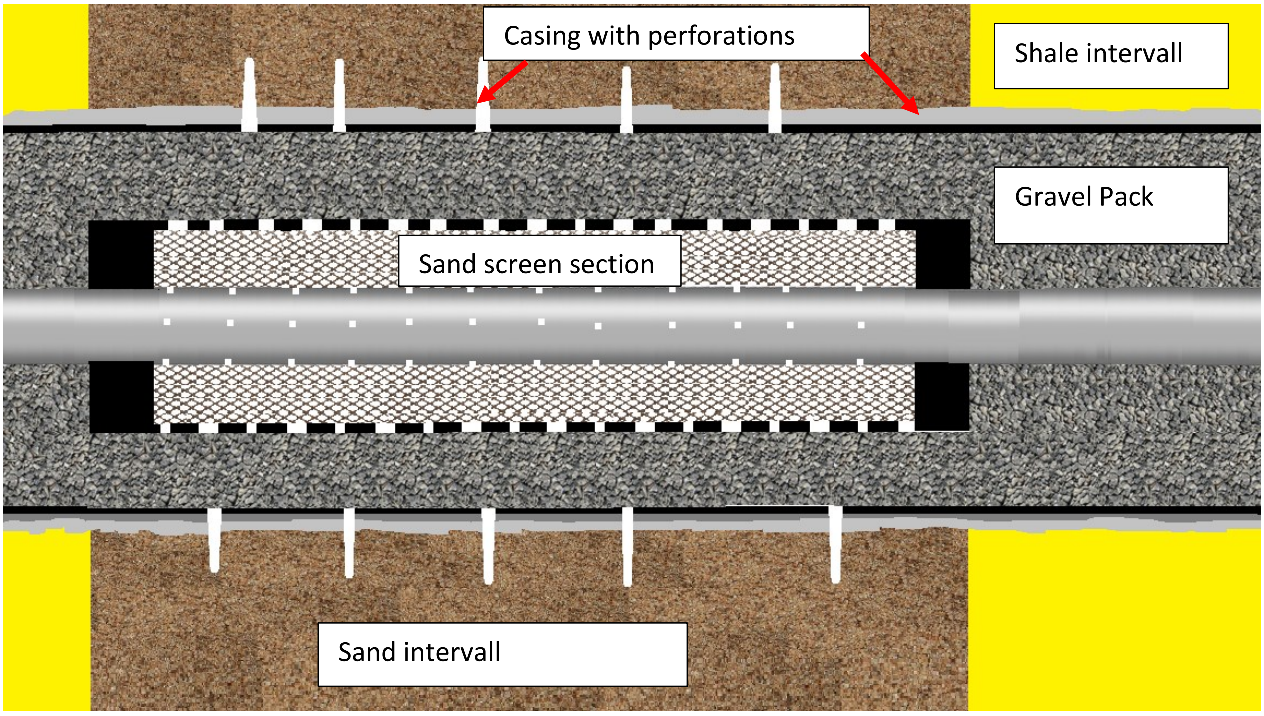

Figure 20 Sand Screens with gravel

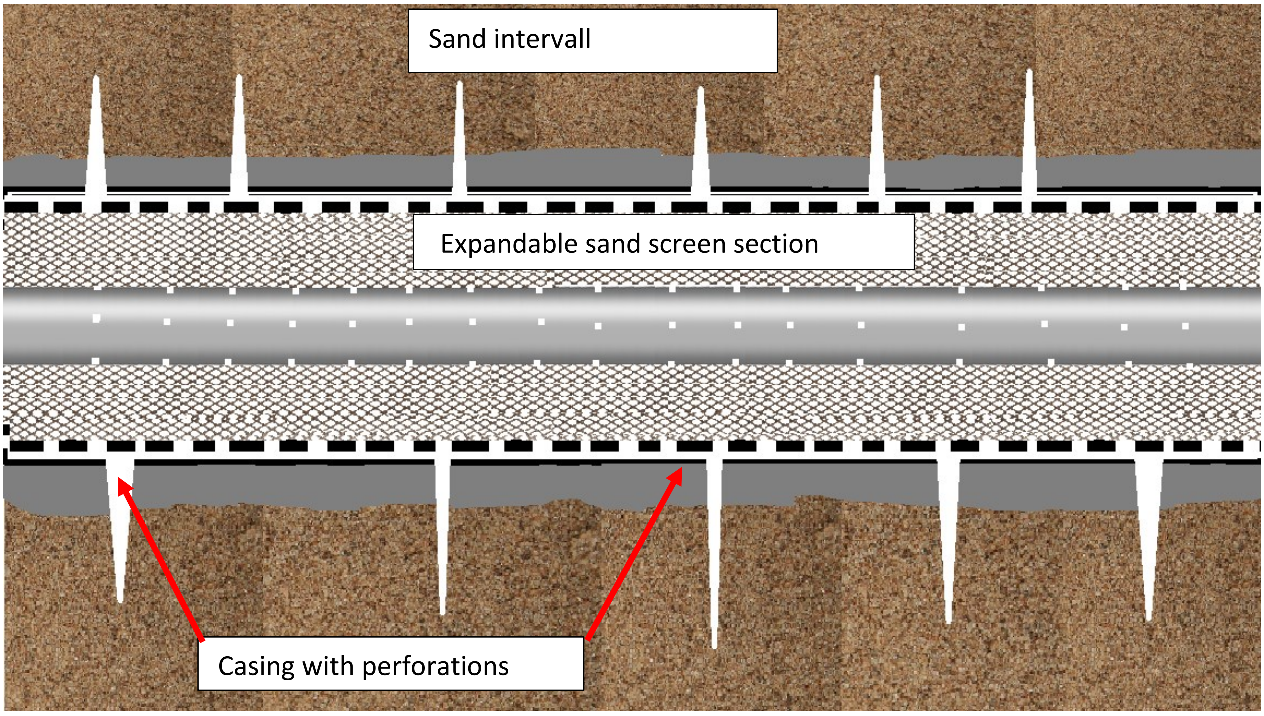

Figure 21 Expandable Sand Screens

3.3 Description of Erosion Calculations

3.3.1 Screen Erosion Model

Basis for calculations of sand screen erosion is an erosion model proposed by Alex Procyk et al [21]. The authors used a cell constructed to imitate a premium screen completion with or without gravel pack. The same test method were used in multiple screen erosion tests [16, 28, 29]. The purpose of the study was to develop a relation between a multi-zone gravel pack screen configuration and erosion with respect to sand volume, sand properties and upstream velocity. The model was based on an idea that the screen configuration is prone to velocity hot spot areas which increases sand screen erosion in those areas, resulting in a higher specific erosion than other models. Those areas are found to be opposite predrilled holes in the liner. The assumption were checked by computational fluid dynamic calculations, which confirmed that the flow will be diverted to the hot spots.
The final model equation is as follows:

$$ER = 1.63e^{-4}x\ F\ x\ HR^{a}x\ d^{b}x\ \left(\frac{SE_r}{V_r^n}\right)x(\frac{V_f}{\epsilon})^{2.7}xV_f * A * T * C * \rho \tag{24}$$

Where
ER – Eroded screen weight loss,g
$1.63e^{-4}$ – conversion factor
F- matching factor, 1.48
V_r – reference velocity for specific erosion
HR – Vickers hardness ratio between particle and screen: SiC/316L = 30GPa/2.9Gpa= 10.3
SE_r- Reference Specific erosion at first data point for 2.4ft/s test, 7.94e-6 g/g
d- mean particle diameter, µm
V_f – Face velocity, ft/s
ϵ- Flow velocity multiplier, 0.22
A – exposed screen area, ft^2
T – time, hrs
C – particle consentration , ppm_w mg/kg
P- carrier fluid density, lb/ft^3

Most of the authors agree that fines which pass through the screen erode them [15-20] with lower eroding particle size limit of 50 micron. Some authors [16, 18, 21] tested screen erosion with smaller sized particles of artificial origin, made from Silicon Carbide, but according to Wentworth Grain Size Classification [28], very fine sand size ranges from 125 micron to 50 micron. Hence using the sizes of artificial sand from laboratory test does not reflect sand sizes which may be found in the reservoirs, and 50 micron sand size is chosen as the smallest sand size used in the model.

With the use of Landmark's NETool Well simulator, velocity of fluid towards sand screen were calculated at each timestep, inserted into the erosion model and eroded screen weight were calculated

The screen configuration in the test cell is shown in figure 5 – Example Multizone Gravel Pack Test Screen Components in [21]. Where the eroding screen media is a 125 micron nominal calendered plain Dutch weave, 316L steel grade. Dimensions of the cell are listed in Table 4. It is assumed that the screen configuration in the test cell can be used to represent screen configuration in the well.

Cell diameter	Cell Screen Area
7.44 inch	0,0280 m^2

Table 4 Test Cell Configuration. Dimensions are taken from [21].

To use the results from [21], there is a need to calculate mass per area by dividing mass of the screen media on area of the screen:

$$Density\ of\ the\ screens = \frac{11{,}18g}{0{,}0280m^2} = 399{,}3g/m\text{^}2 \tag{25}$$

This is the mass not of the whole screen assembly, but the mass of the screen media which protects the well from the sand. The main assumption is if this media fails, the well will start producing sand. Multiple authors report different limits of erosion[16, 21]. It is proposed that the mass loss % of the screens should serve as the limit to safe operation conditions. Procyk[21] concludes that since the screen is prone to local hot spot flow areas, the mass loss limit should be 0.5%. Cameron's[16] limits were 2% and 8%. The limit of 2% is chosen as conservative.

Main assumptions used under calculations area:

- Erosion is calculated for fines >50µm. It is assumed that sand bridging on the screens and in perforations and gravel pack do not affect fine movements and their velocity.
- Specific erosion of the screens in equation 24 is found by from laboratory analysis of different screens. It is assumed that all the screen completions in this thesis is made from the screens and erosion of such screens fails the screens
- Fine particle production concentration is constant throughout the field life.
- Effect of water is incorporated into the equation by average flowing fluid density. As the fraction of water under production changes, so will density and thus erosion.
- It is assumed that gravel will be damaged by fine movements and fine plugging.
- Damaged gravel pack do not affect overall movement of fines in the well

3.3.2 Expandable Sand Screen Erosion Calculations

In a cased well fluid flows in the well from perforations. In an expandable screen assembly, the screens are directly touching the casing, and the annulus is eliminated. In such case all the flow from the reservoir goes from perforations directly onto screens. To calculate velocity of the fluid from volumetric influx, inflow area of the perforations are needed. Using the density of perforations per meter and diameter of perforations from Table 23 fin Appendix B Completion Properties, inflow area can easily be calculated.

$$Inflow\ Area = L_{segments} * PD * PI * r_{perf}^2 \qquad (26)$$

Where:

$L_{segment}$ – length of producing segments

PD- perforation density shots/m

r_{perf} – perforation radius

Perforation densities are varied to model fraction of perforations open to flow. Fluid will only go through the same area as the area of perforations. Calculated Inflow areas and available sand screen areas and mass are then: (Table 5)

%- open flow	Inflow area/ Screen area m^2	Erodible Screen mass g
100%	0,326	130,4
90%	0,293	117,3
70%	0,227	91,0
50%	0,163	65,2
25%	0,081	32,6

Table 5 Calculated open flow area for different fraction of open perforations in CH ESS completion

The input of the equation 24 is fluid velocity, which needs to be calculated from oil and water Influx rates. As the fluid flows from the reservoir towards well, the only available path into the well is through the perforations. The perforation operation can leave some % of perforations plugged as well as perforations will become plugged during production with sand. Fluid will flow with higher velocity to meet the rate target of the well, as more and more perforations become more plugged. The higher the velocity, faster the erosion of the screens. It is assumed the sand particles have the same velocity as the fluid and is carried by both oil and water. To calculate fluid velocity following equation is used:

$$V_f = \frac{3.28ft/m * (Influx\ Oil + Influx\ Water) * L_{prod}}{Inflow\ area(\%open\ screens) * 86400s/day} \qquad (27)$$

Where

Vf – fluid velocity ft/s

Influx oil – oil influx rate $m^3/m/D$

Influx water – water influx rate $m^3/m/D$

L_{prod} – length of production interval

3.28, 86400 – conversion factors

Other constants used in equation 24 used for ESS erosion calculations are summarized in Table 6. Erosion of the screens for three production scenarios are calculated with 200ppm_w fines with mean diameter of 50µm.

Hardness ratio 10,3 Gpa/Gpa
Specific erosion at reference velocity 0,00000794 g/g
Reference velocity 2,4 ft/s
Particle concentration 200 ppm
Carrier fluid density – depending on flowing fractions
Particle D50 50 micron

Table 6 Constants for ESS configuration. Hardness ratio of the particles and steel screens. Specific erosion from laboratory tests. Carrier fluid density is calculated from fractions of oil and water in production stream.

3.3.3 Standalone Sand Screens erosion calculations

In standalone sand screens, an annulus is permitted and is open for flow, and now fluid velocity at different location depends not only on fluid influx from reservoir as in section 3.3.2 Expandable Sand Screen Erosion Calculations but on annular velocity as well. The output from NETool simulation will serve as a source of fluid velocity across the screens, an output example is seen in Figure 22. Such cumulative plots is used to find velocity for each meter of sand screen in all 3 sections of completions. Since rates are constant in each case, fluid velocity will not change throughout field life, as it is assumed that sand build-up on the screens do not affect the movement of sand fines and fluid velocity. Using velocities at each meter of completion, erosion at each meter of completion is calculated using equation 24.

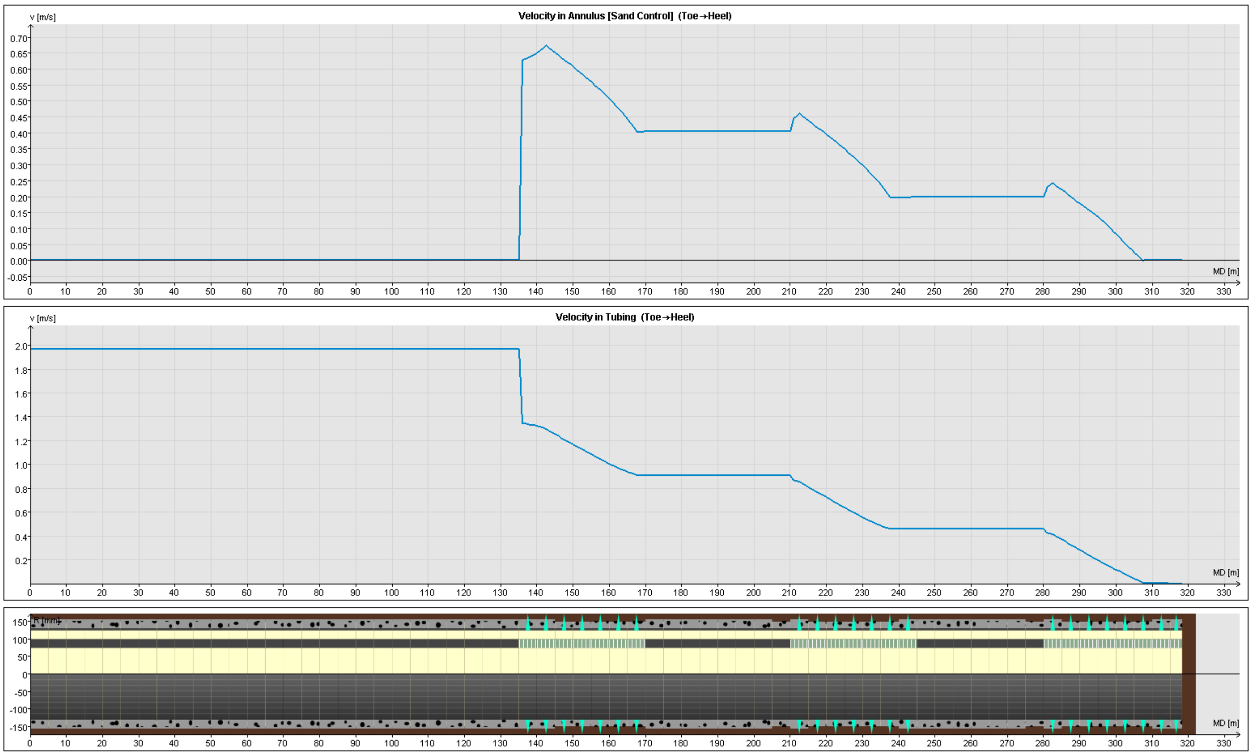

Figure 22 Cumulative fluid velocity in tubing and annulus for 3000m³/d case. Velocity at each meter of completion is found and used in erosion model to calculate screen service life in each completion. Note hoe velocity in tubing, increases in the last segment. It is here all flow from annulus enters the screens and erosion is highest.

Assuming that the outer diameter of the screen assembly from NETool can be used as the outer diameter of the screen media, the total mass of the screen per segment is calculated as

$$Screen\ Mass = mass\ per\ area * screen\ area \tag{28}$$

Where

Screen area - surface area of the screen segment, with 0.1242m as screen radius

$$Screen\ surface\ area = 2\pi * 0{,}1242m * 35m = 27{,}3\ m^2 \tag{29}$$

And the screen mass of one section will be

$$Screen\ Mass = 398{,}60\frac{g}{m^2} * 27{,}3m^2 = 10906{,}08g \tag{30}$$

Mass for three screen sections will then be

$$Screen\ Mass = 10906{,}08g * 3 = 32718{,}25g \tag{31}$$

Screen available area per meter will be

$$Screen\ area\ per\ m = \frac{27{,}3m^2}{35m} = \frac{0{,}78m^2}{m} = 8{,}39ft^2/m \tag{32}$$

And screen mass per meter will be

$$Screen\ mass\ per\ m = \frac{10906{,}08g}{35m} = 311{,}6\ g/m \tag{33}$$

Screen erosion of SAS is calculated per meter in order incorporate different velocities along the completion.

3.3.4 Sand Screens-Packers erosion calculations

Methodology in this analysis follows the methodology in

3.3.3 Standalone Sand Screens erosion calculations taking velocity at each meter of completion from NETool results, erosion of screens are calculated for each case.

3.3.5 Gravel Pack - Sand Screens erosion calculations

In a gravel pack completion an important factor to consider is the damage to the gravel pack. Gravel packs can be damaged in a variety of ways, here it is assumed that it is damaged by fines migration and plugging. Damage of a gravel pack can result in a skin 10-300 [23] and in high permeability formations (above 500 mD) skin factor can range from 20-60 after a year of production [30]. 3 scenarios are chosen for evaluation: 10, 30 and 50 skin per year. Since there is no option for gravel pack skin in NETool, an approach to manually reduce gravel pack permeability is chosen.

According to [23] damaged gravel pack skin can be modelled with the following equation:

$$S_{gp,dam} = \left[\frac{2\pi L_{gp}}{A}\right]\left[\frac{k_{gp}}{k_{gp,dmg}} - \frac{k}{k_{gp}}\right] \tag{34}$$

Where

L_{gp} - linear flow length in the gravel pack

$S_{gp,dam}$ gravel pack damage skin

h – height of the layer

k_{gp} undamaged gravel pack permeability

$k_{gp,dmg}$ gravel pack damage permeability

A area open for flow in for the gravel pack

k – formation permeability

This equation is reversed to calculate gravel pack damaged permeability to use as input in NETool model. With average skin of 10,30,50 per year the gravel pack permeability will exponentially drop (Figure 23, Figure 24 and Figure 25). It is assumed that damage of the gravel pack does not affect overall produced concentration of sand.

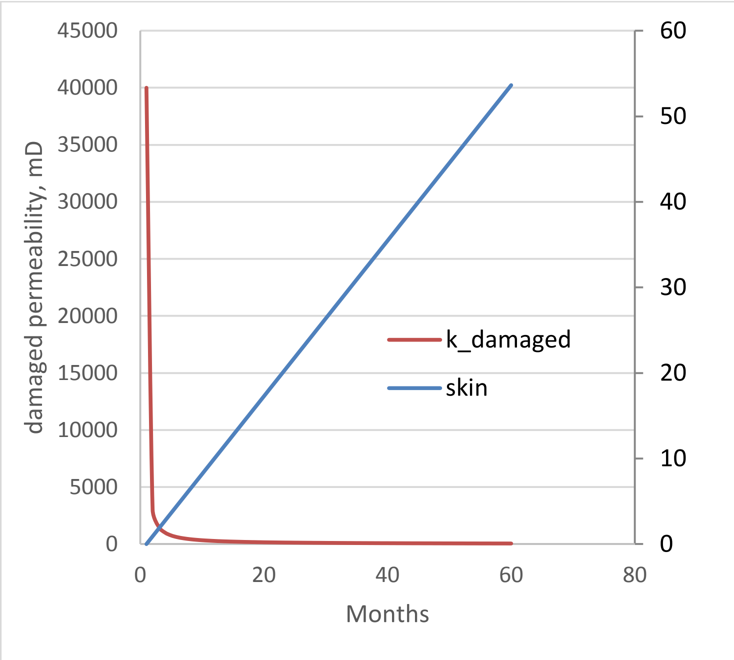

Figure 23 Damaged permeability and skin for 10 per year skin addition

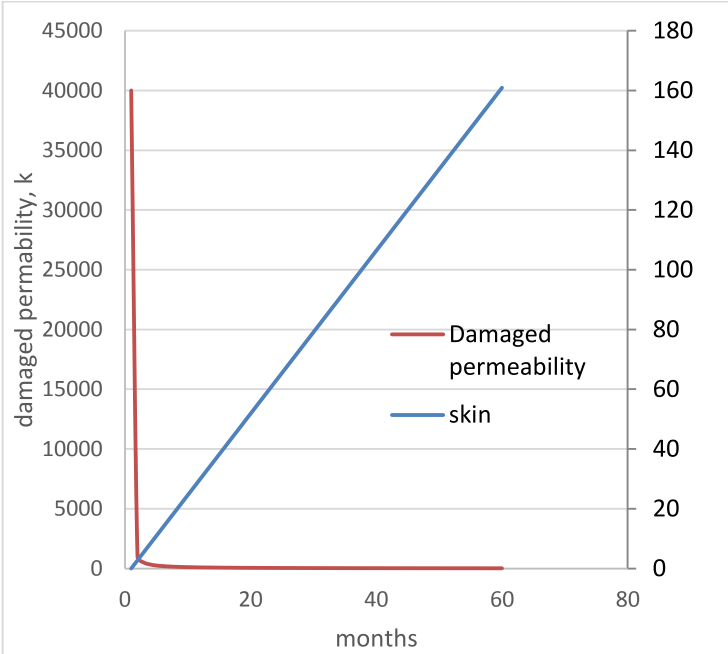

Figure 24 Damaged permeability and skin for 30 per year skin addition

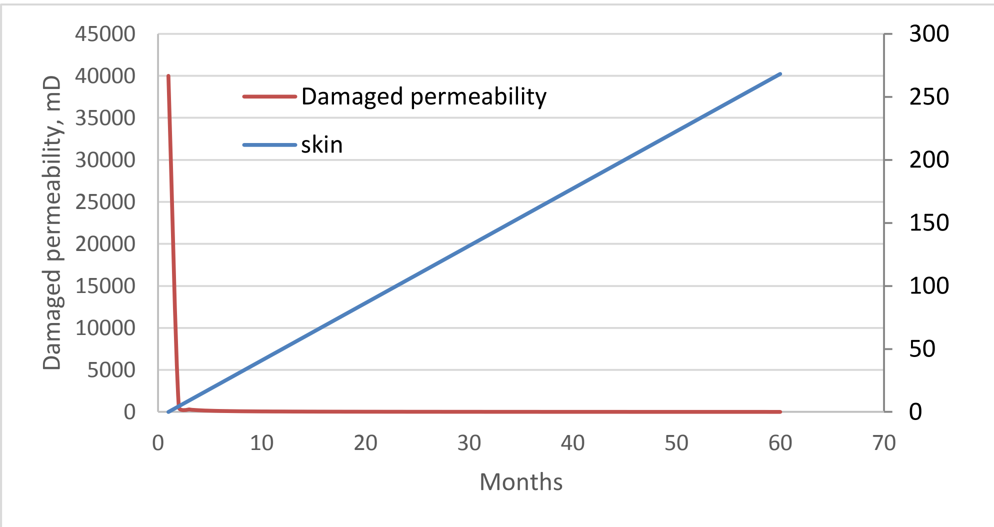

Figure 25 Damaged permeability and skin for 50 skin per year addition

Skin values, translated into permeability of the annular gravel pack is used in calculating velocity onto screens in the gravel pack completion. Mass of the screens and erosion calculation is the same as in

3.3.3 Standalone Sand Screens erosion calculations Damaged permeability value is used to calculate recovery in gravel pack completion.

3.4 Sensitivity Analysis

To find production conditions under which each completion preforms without failing, safe velocity and hence rate are calculated using inverted equation 24. Averaged velocity throughout the field life which only erodes the screen up to the erosion limit of 2% mass loss is then calculated for each completion. Such calculations are done for a number of particle sizes and concentrations. Density of the carrier fluid is assumed to be an average density of 50% oil and 50% water. The used parameters are summarized in Table 7.

Particle size: 50 micron **Particle concentration**: 200 ppm, 400 ppm, 1 000 ppm, 10 000 ppm (1%), 50 000 ppm (5%) **Open Perforations**: 100%-25% **Mass Loss Limit**: 2%
Particle size: 75 micron **Particle concentration**: 200 ppm, 10 000 ppm (1%), 50 000 ppm (5%) **Open Perforations**: 100%-25% **Mass Loss Limit**: 2%
Particle size: 100 micron **Particle concentration**: 200 ppm,10 000 ppm (1%), 50 000 ppm (5%) **Open Perforations**: 100%-25% **Mass Loss Limit**: 2%

Table 7 Summary of sensitivity analysis parameters of produced fines. Mean size diameters used are 50, 75 and 100 micron. Concentrations used are all in ppm_w.

3.4.1 Calculating Safe Production Rate for Expandable Sand Screen

The calculated safe velocities are translated to production rates as function of % of open perforations using equation 35

$$Q_{safe} = V_{safe} * Inflow\ area(\%open\ screens) \tag{35}$$

Finally safe rates are then used in ECLIPSE as production well constraints to calculate final recovery under different sand production conditions.

3.4.2 Calculating Safe Production Rate for Standalone Sand Screen

Calculating recovery factors for SAS in the sensitivity analysis is done by:

- Inverting equation 24 to calculated safe velocities onto the screens under different conditions listed in Table 7

- Use NETool to find safe rates with matching velocities across the sand screen
- Use the safe rates in ECLIPSE models to calculate recovery factors.

3.4.3 Calculating Safe Production Rate for Sand Screen-Packers

The following analysis uses the same methodology as in 3.4.2 Calculating Safe Production Rate for Standalone Sand Screen

3.4.4 Calculating Safe Production Rate for Sand Screen-Gravel Pack

For the case with highest safe production rate with 0 skin the following analysis uses the same methodology as in 3.4.2 Calculating Safe Production Rate for Standalone Sand Screen. For cases with 10, 30 and 50 skin per year well is producing with damaged gravel pack permeability with safe rate found for a screens with a gravel pack. However under such production condition with increasing pressure drop in gravel, some other well constraint is needed to ensure realistic well operation. During production in base cases, lowest BHP is observed in 3000 sm^3/d case at 76 bar in ECLIPSE and in NETool at 126 bar. Analysis of CH-GP completion performance is done in NETool and minimum BHP allowed is chosen to be 100 bar to ensure realistic well pressure. In ECLIPSE such production schedule with decreased permeability in a small radius around the well is rather tedious to analyze, with respect to local grid refinement around the well and using “restart” option to reduce permeability at each month. For a simple, homogeneous reservoir which is used in this thesis, calculating recovery for gravel pack completion with skin is much easier done in NETool, where permeability in gravel pack can easily be changed in each time step. One other assumption of maximum capacity of surface facilities at 3000 sm^3/d liquid rate is taken in the analysis, resulting in maximum production rate of 3000 sm^3/d, even in the cases where safe production rate for the completion is above that value.

Chapter 4 Results Discussion

4.1 *Methodology Validation*

ECLIPSE and NETool are widely used in the industry, and an analysis performed with such tool can be reliable. Erosion model used in the analysis *"can provide guidance an which well zone to monitor"[21]* but cannot serve as a definite analysis, as laboratory testing cannot accurately represent field conditions in most cases. Completion design must also be optimized for each case and cannot be random. This chapter discuss uncertainty for in erosion model, assumptions in particle flow and optimization in completion design. Then presents findings of the analysis with comparison of completion performance.

4.1.1 Sand screen erosion model

Guidelines exist for preventing sand screen erosion of maximum velocity for different completions[21, 31] as well as different screen erosion model[16, 18, 21]. Procyk's erosion[21] model was chosen based on availability of the data, where other models were lacking, making them impossible to use. Used screen erosion model does account for screen erosion of the fines and screen plugging as well as screen configuration in terms of flow pattern. However it does not take in account presence of bigger particles which may bridge on the screen and filter fines, reducing screen erosion as well as different impact angles of fines.

4.1.2. Assumptions of particle flow

This analysis assumes unhindered fines movement in screens and gravel. However is screens are designed correctly in accordance to formation particle sizes, only 2-3% of sand entering the screen face may be produced[28]. Gravel packs are specially designed to stop formation sand without significant

plugging, but there is a balance between stopping sand and plugging the gravel. Assuming that fines are unhindered by gravel pack is assuming bad design of the gravel pack.
Particle concentration used in the analysis was chosen in accordance to typical sand production found in papers [16, 21, 32]. Some typical values range from few tens of ppm_w to few thousands. However extreme sand production may occur and 5 w% sand may be justified.

4.1.3 Completion design

Sand screens and gravel pack are common form of sand control, but other completions can be considered as well. To reduce annular flow – highest contributor to screen face velocity f. ex. Inflow Control Devices(ICDs) [7] can be used. With an ICD a restriction is placed between the screens and inside of the base pipe, which can reduce the annular flow by evening out screen flow. Results show that SAS suffer from annular flow effect even with swellable packers.

4.1.4 Gravel Pack Completion performance

Under calculations of gravel pack performance a number of assumptions are taken. It is assumed that plugging of the gravel pack is happening regardless of concentration and size of the fines which may not be very reasonable to assume. Gravel pack can be designed to not plug excessively, though such procedure is highly dependent of certain formation size properties analysis, but if the gravel pack is prone to plugging, the more fines produced, the more gravel is plugging. Second assumption under question is an arbitrary limit of BHP for the well. Such development criteria in this analysis is dependent on reservoir pressure making the analysis of the gravel pack performance dependent on reservoir properties and development strategies. Simply put, gravel pack performance depends not only on produced fines properties, but on reservoir properties and well pressure limits.

4.2 *Reservoir Performance*

In ECLIPSE, the reservoir has produced for 60 months with a horizontal injection and a horizontal production wells at each well. There are 3 different production scenarios:

- 1000 m^3/d liquid production rate
- 2000 m^3/d liquid production rate
- 3000 m^3/d liquid production rate

Water injector injects with “void” replacement option, that is, water will be injected as the same rate as the reservoir fluids are produced.

In NETool a standalone sand screen well model is built and set to produce with the same rates as above for 60 months in a corresponding exported ECLIPSE model. Difference in the results originating from difference in computations. ECLIPSE is a numerical black oil simulator where computations of saturation and pressure is performed on reservoir grid. NETool is a nodal numerical simulator of the well completion with one nodal layer for the reservoir (Appendix A NETool). Difference in the results arise from the difference in the size of the simulations and the fact that NETool exports calculated values for pressure and saturation from ECLIPSE model and uses PI-model to calculate rates and well pressures. NETool does not take in account the whole reservoir only the grid-blocks where well is placed, and is a static mode. BHP is calculated based on pressures in the well grid blocks in the static model in one timestep without affecting the pressure values in the static model in the other timestep. Such calculation method result in a somewhat unreasonable BHP which is almost constant throughout the field life. (Figure 29, Figure 33, Figure 37). One other difference may also raise questions, that is difference in shape of the water cut function(Figure 28, Figure 32, Figure 36). NETool is made to export fluid models directly from ECLIPSE and relative permeabilities and hence water cut should have to same shape.

Scenario 1: 1000 m^3/d Liquid Production Rate

ECLIPSE results show an oil production plateau rate is at around 974 sm^3/d, and declines around 1000 days(Figure 26), with the final recovery of 47,5% (
Figure 27) and maximum water cut of 40 % (Figure 28) and minimum BHP of 227.9 Bar (
Figure 29). NETool shows a little different result with lower recovery factor of 43,7% (
Figure 27) and plateau rate of 890 sm^3/d (Figure 28), maximum water cut of 25,1% (Figure 28), BHP of 250,9 bar (
Figure 29).

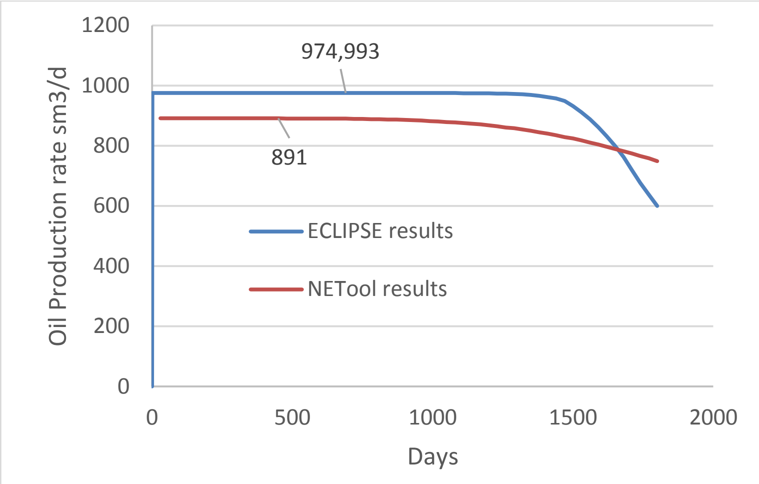

Figure 26 Production rates for Scenario 1 from ECLIPSE and NETool results. ECLIPSE has a higher rate, because of the size of the simulation, while NETool has only one reservoir calculation layer

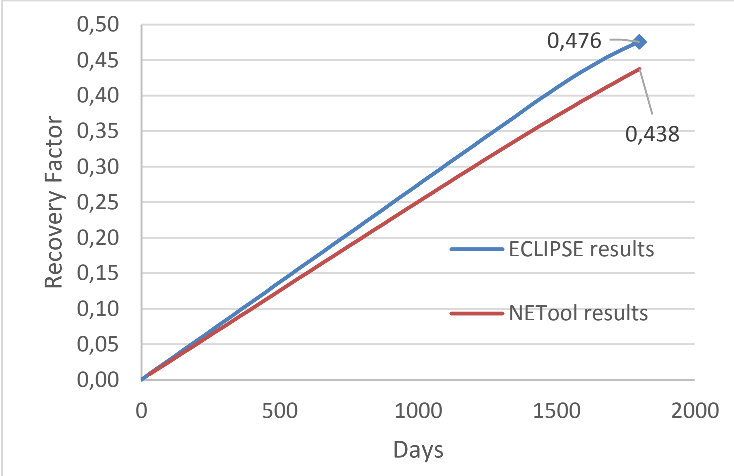

Figure 27 Recovery factor for Scenario 1. ECLIPSE shows a higher recovery then NETool

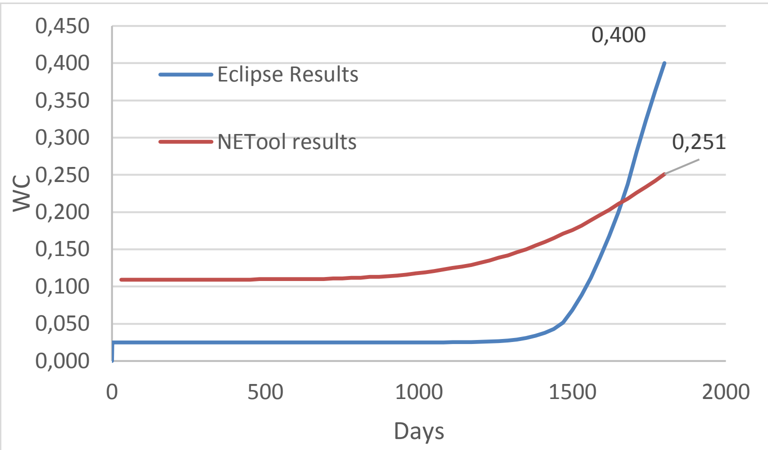

Figure 28 Water Cut for Scenario 1. Difference in computations results in difference between ECLIPSE and NETool results.

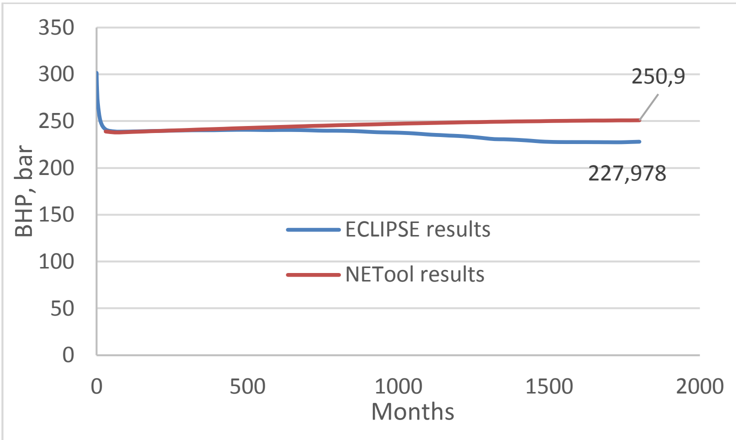

Figure 29 BHP for Scenario 1. NETool has almost constant bottom hole pressure, in fact it is increasing with a constant rate.

Scenario 2: 2000 m^3/d Liquid Production Rate

ECLIPSE results show an oil production rate plateau at around 1949 m^3/d, rapidly declining after 550 days (Figure 31), with the final recovery of 55,8% (Figure 30) and maximum water cut of 88 % (Figure 32) and minimum BHP of 151.4 bar (Figure 33).NETool results show an oil production rate maximum at around 1774 m^3/d, which is declining smoother than ECLIPSE results, resulting in a higher recovery (Figure 31), with the final recovery of 67 % (Figure 30) and maximum water cut of 77,3% (Figure 32) and minimum BHP of 181.8 bar (Figure 33).

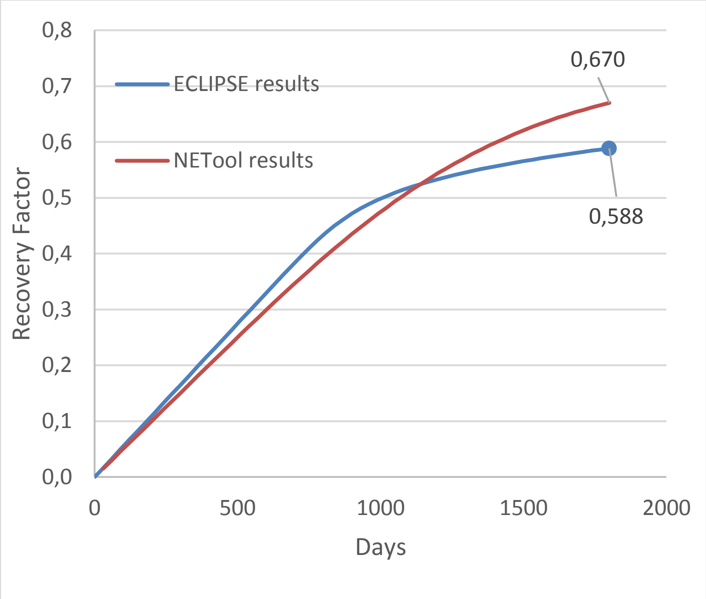

Figure 30 Recovery Factor for Scenario 2 for ECLIPSE and NETool. Difference in the results arise from difference in computations.

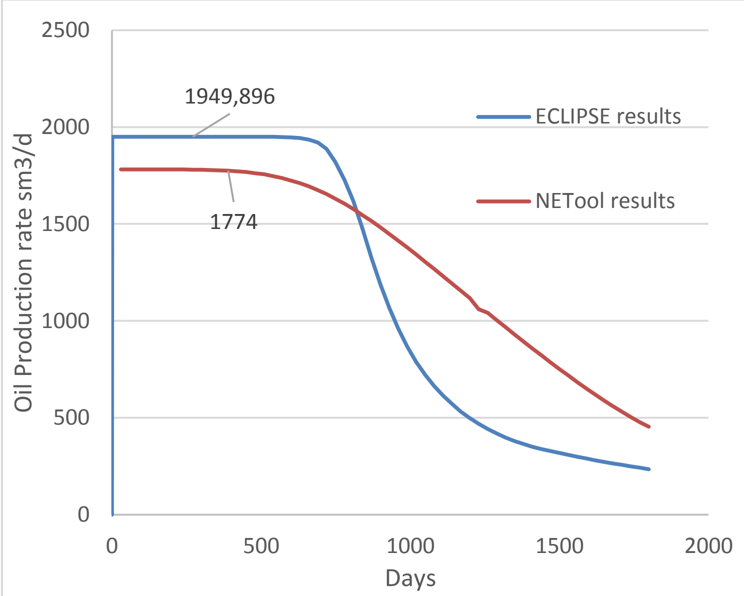

Figure 31 Oil production rates for scenario 2 for ECLIPSE and NETool. Difference in the results arise from difference in computations

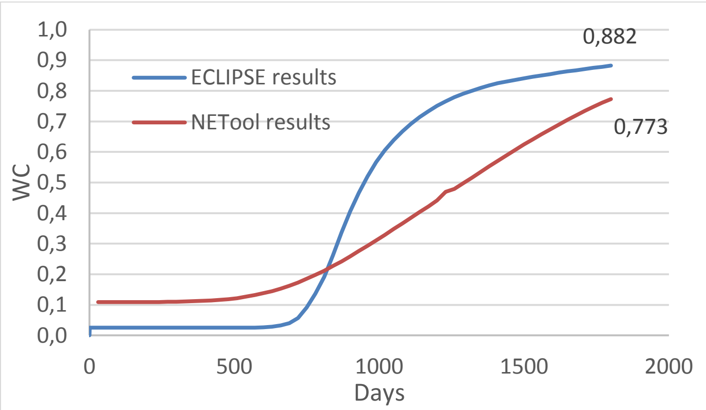

Figure 32 Water Cut for Scenario 2 for ECLIPSE and NETool. Difference in the results arise from difference in computations

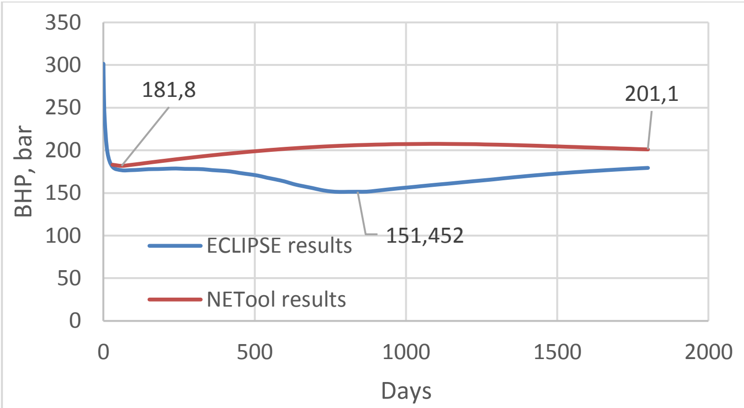

Figure 33 Bottomhole pressure for scenario 2 for ECLIPSE and NETool. Difference in the results arise from difference in computations

Scenario 3: 3000 m^3/d Liquid Production Rate

ECLIPSE results show on oil production rate plateau at around 2924 m^3/d, rapidly declining after 300 days (Figure 34), with the final recovery of 62,6%(Figure 34) and maximum water cut of 94% (Figure 36) and minimum BHP of 76.8 bar (Figure 37). NETool results show an oil production rate maximum at around 2673 m^3/d, which is declining smoother than ECLIPSE results, resulting in a higher recovery (Figure 35), with the final recovery of 72,2 % (Figure 35) and maximum water cut of 94,6% (Figure 36) and minimum

BHP of 126.7 bar (Figure 37).

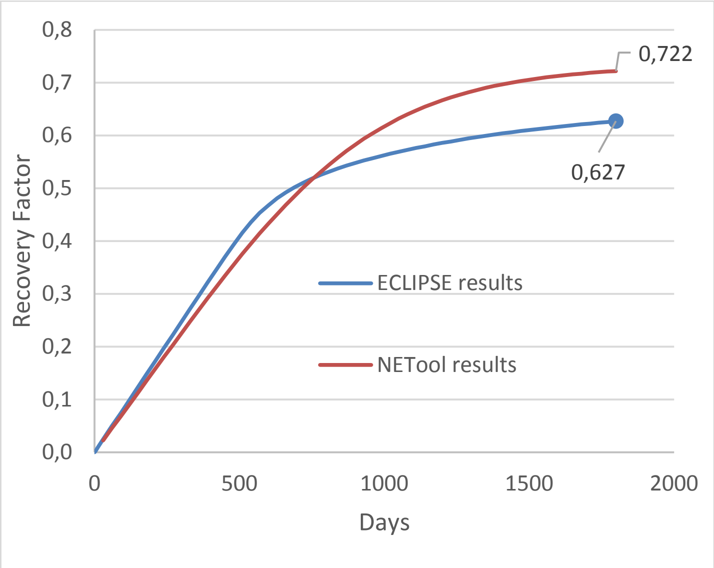

Figure 34 Recovery factor for scenario 3 for ECLIPSE and NETool. Difference in the results arise from difference in computations

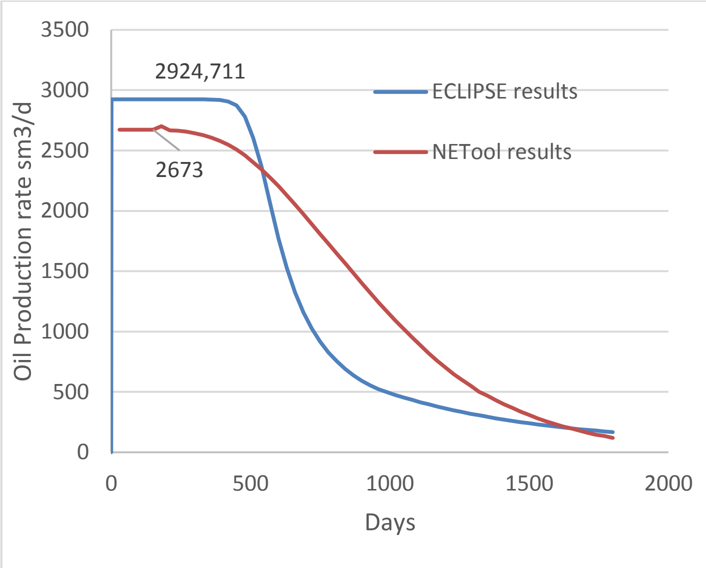

Figure 35 Oil production rate for scenario 3 for ECLIPSE and NETool. Difference in the results arise from difference in computations

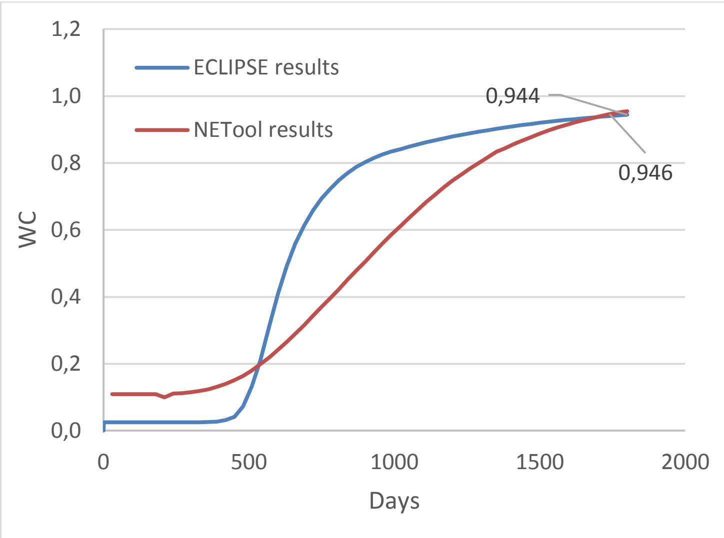

Figure 36 Water cut for scenario 3 for ECLIPSE and NETool. Difference in the results arise from difference in computations

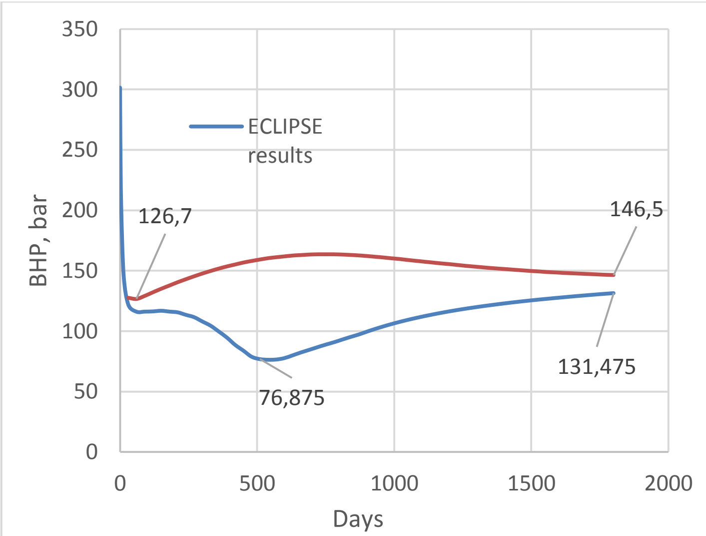

Figure 37 BHP for scenario 3 for ECLIPSE and NETool. Difference in the results arise from difference in computations

4.3.2 Screen Erosion

Erosion model in conjunction with NETool, ECLIPSE, particle properties and completion properties was used to calculate screen erosion for each completion alternative. Results for three base case are presented below with 50 µm D_{50} at 200 ppm_w fines particles properties.

4.3.2.1 ESS Completion

ESS are expanded to the interior of the casing, leaving no annular space. Fluid flows directly towards the screens through perforations, leaving a small inflow area. Perforations tend to plug during production, and such phenomenon is chosen as uncertainty in the analysis. Velocity from perforations towards the screens, for different % of plugged perforations are shown in table Table 8. Velocity towards the screens are low then all perforations are open, 100% and 90% open, but with more plugged perforation velocity increases rapidly, with highest at 3000 sm^3/d with 25% open perforation at 1,39 ft/s.

Open perforations	100%	90%	70%	50%	25%
Face velocity at 1000 sm^3/d; ft/s	0,116	0,129	0,167	0,233	0,466
Face velocity at 2000 sm^3/d; ft/s	0,226	0,252	0,342	0,453	0,906
Face velocity at 3000 sm^3/d; ft/s	0,348	0,387	0,499	0,697	1,39

Table 8 Fluid velocities at different production rates. Velocities are steadily increasing as the open perforations decreases, resulting in a faster erosion of screens.

This velocities are used to calculate screen erosion and thus service life of the screens. Table 9 present calculated screen service life. As expected, at low rate of 1000 sm^3/d, ESS performs well up to 50% open perforations, while at 2000 sm^3/d and 3000 sm^3/d even fully open perforations do not help and screens fail after 16 and 3 months. Figure 38 presents a comparison of different screen configurations at different rates. Figure 39, Figure 39 and Figure 40, present screen erosion as a function of time. As described above, in sand producing formation in a cased hole with ESS, perforations will plug and revert flow to the open perforations. To hold them open, some kind of chemical consolidation must be performed, which adds to the cost and complexity of well completion, and does to guarantee the desired result. At higher rates some other completion alternative must be installed.

Open perforations	100%	90%	70%	50%	25%
Service life at 1000 sm^3/d, months	>60	>60	50	14	12
Service life at 2000 sm^3/d, months	16	11	4	1	<1
Service life at 3000 sm^3/d, months	3	2	1	<1	<<1

Table 9 Expandable sand screens service life. ESS is safe to install at 1000 sm3/d with the condition of all open perforations. At high rates, some other completion must be installed to ensure effective retention of larger sand particles.

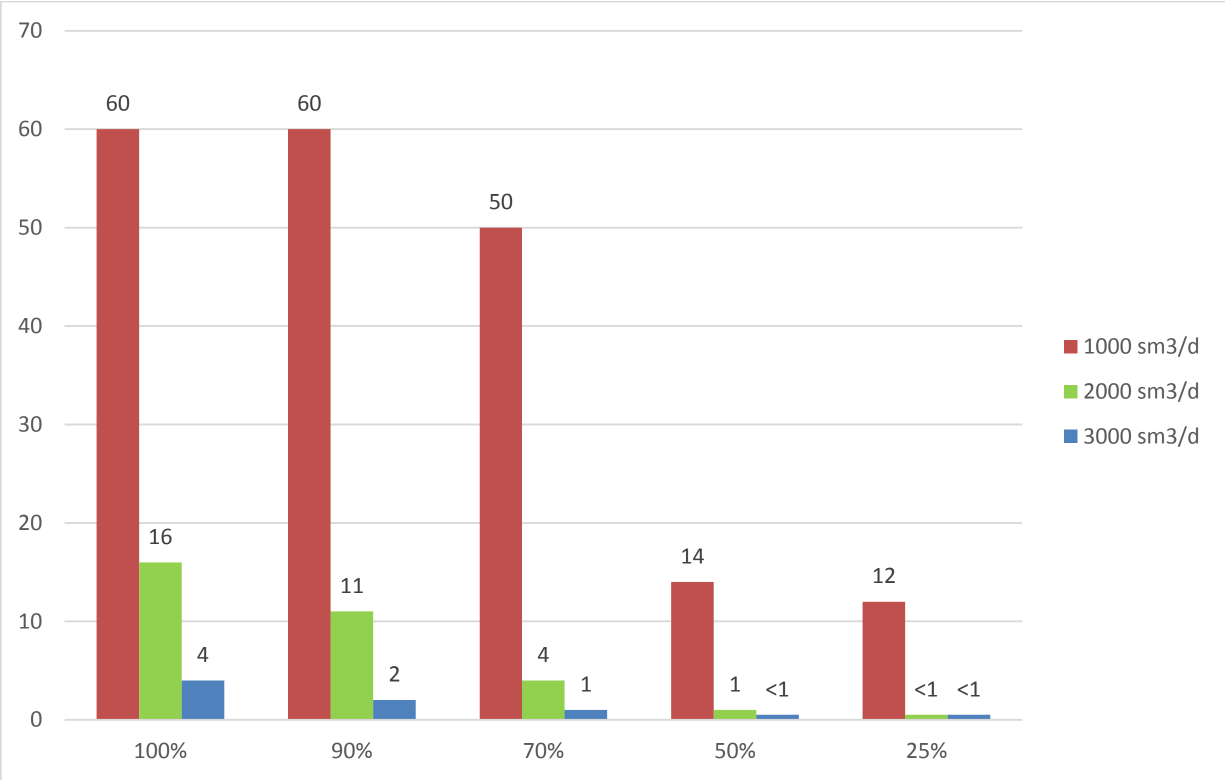

Figure 38 Expandable sand screens service life. Figure presents calculated service life for ESS at different rates as a function of velocity and % of open perforations. Only at 1000 sm3/d at fully open perforations (100% and 90) ESS will perform well.

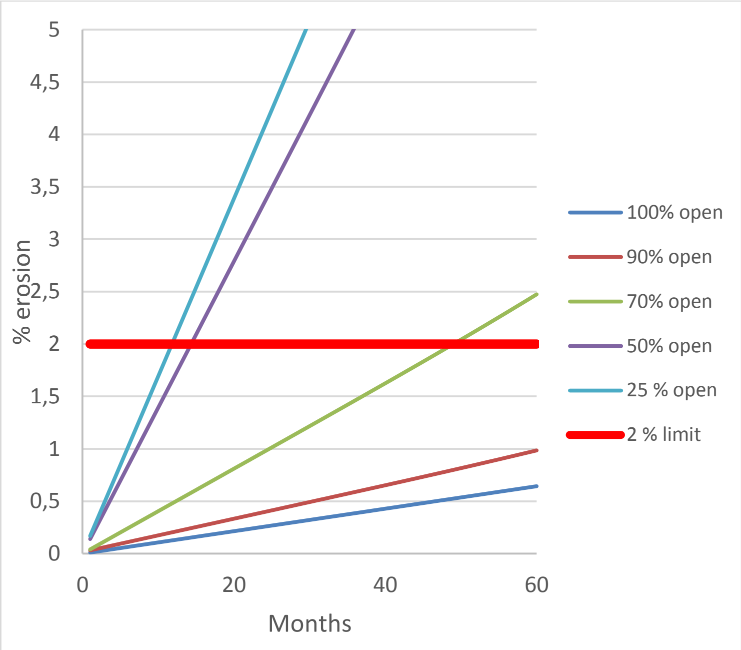

Figure 39 Screen erosion for 1000 sm3/d production as a function of time. 2% limit is marked as a red line. 100% and 90 % open perforations is under 2% at the end of field life.

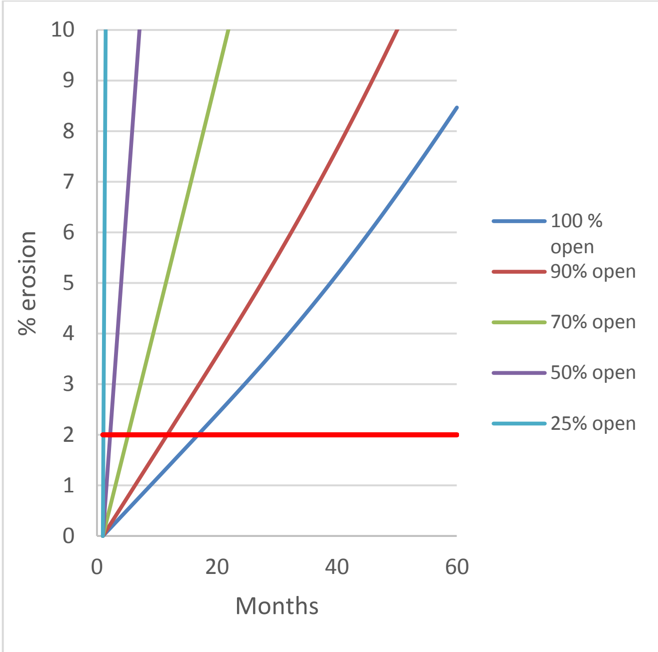

Figure 40 Screen erosion for 2000 sm3/d production rate as a function of time. erosion or 25% open perforations is outside of the chart. 2% erosion limit is shown as a red line. None of the cases perform well under 2000 sm3/d production rate

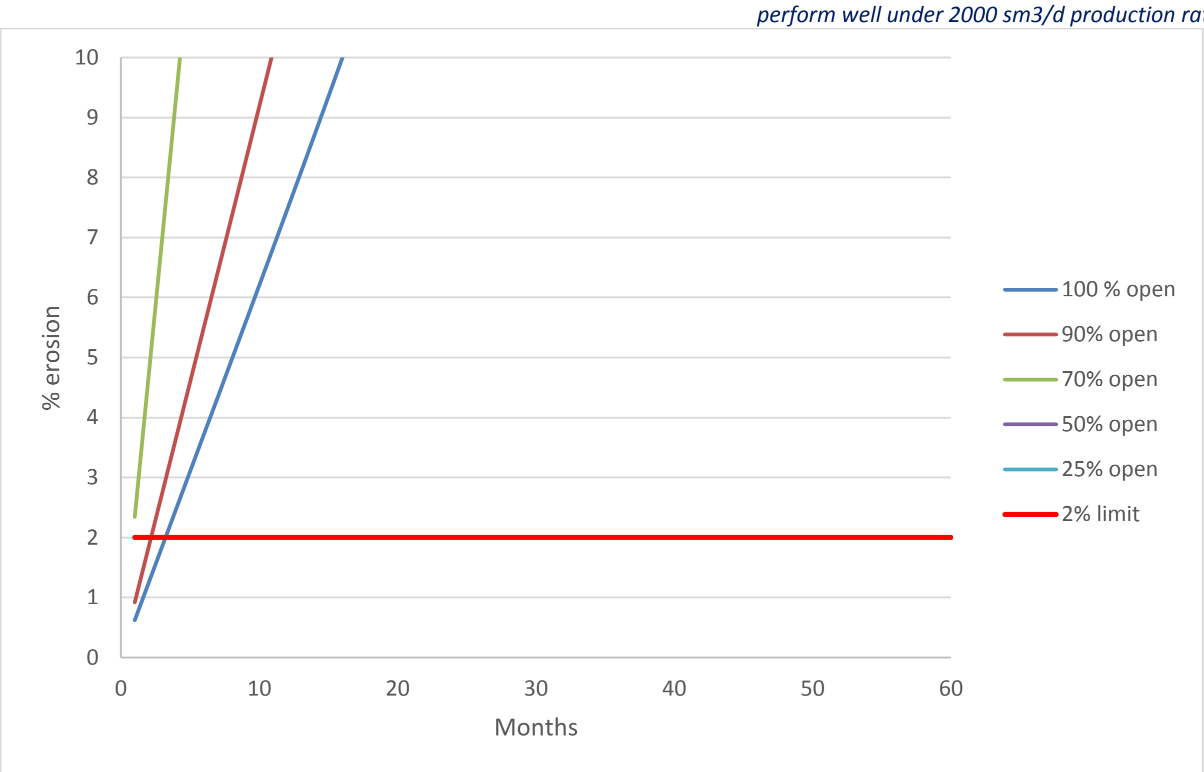

Figure 41 Screen erosion for 3000 sm3/d production rate. Erosion for 25% and 50% open perforations are outside of the chart. 2% limit is shown as a red line. Very fast screen erosion is present for all cases.

4.3.2.2 SAS Completion

Fluid velocities profiles for all three rate cases are shown Figure 42. As seen, velocity onto the screens are highest on the last section of the screen, there all the annular flow is directed inside the well and to the surface. Liquid lubrication effects protect the screen from erosion during annular flow, when particles impede the screens at low angles [16]. Most of the erosion happen then fluid is impacting the screen at 90^0 angle and therefore highest erosion is where all annular flow is directed towards the screens.

Figure 42 Annular and tubular velocity profiles in SAS completion. Highest velocity is at the last section of the screens, resulting in highest erosion there.

Note that liquid production rate is constant throughout the production, resulting in constant velocity throughout field life in SAS completion.

Highest fluid velocities are shown in Table 10(at the last section of the screens). Compared to ESS Table 8 fluid velocities are 70% higher on average. Erosion calculation are performed at each meter of completion. 2% erosion limit result in 6 g/m erosion limit

Highest Face velocity at 1000 sm^3/d ft/s	0,652
Face velocity at 2000 sm^3/d ft/s	1,36
Face velocity at 3000 sm^3/d	2,09

Table 10 Highest fluid velocities at different production rates in SAS completion. This is velocity for the section of the screens there all annular flow is directed towards the screens and inside the inner part of the well.

Screen erosion through time at different production rates are shown in Figure 43, Figure 44, Figure 45. It is observed that screens are eroded well above the limit even before 1st months of production in all cases in the section there all annular flow is directed towards the screens. Result show that some kind of restriction, which reduces or eliminates annular flow is needed. Presented above is ESS, which does eliminate annular flow, but is proved to be prone to screen erosion. Below, one other alternate, swellable packers, which is recommended by [7] on wells with annular flow problems is implemented. SAS completion is proving not to be an effective alternative when subjected to screen erosion

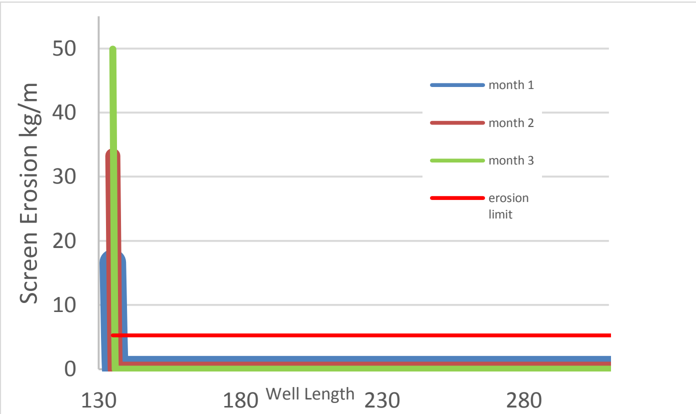

Figure 43 Screen erosion along the well at 1000 sm3/d. Redline is 2%(6g/m) screen erosion. SAS is not a suitable completion alternative

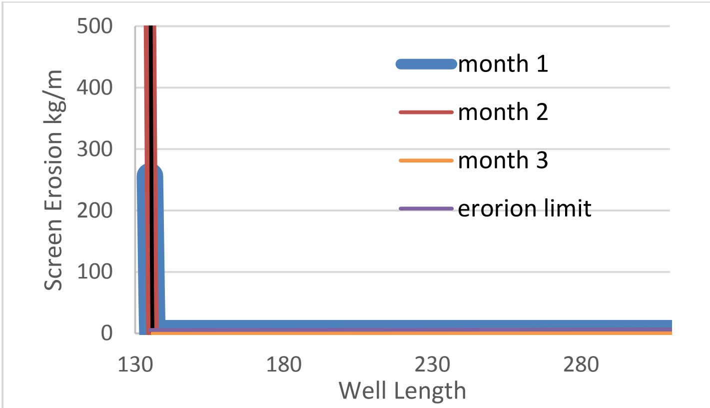

Figure 44 Screen erosion along the well at 2000 sm3/d. SAS screens are eroded drastically after 1 month of production. Black line is erosion after 3 months.

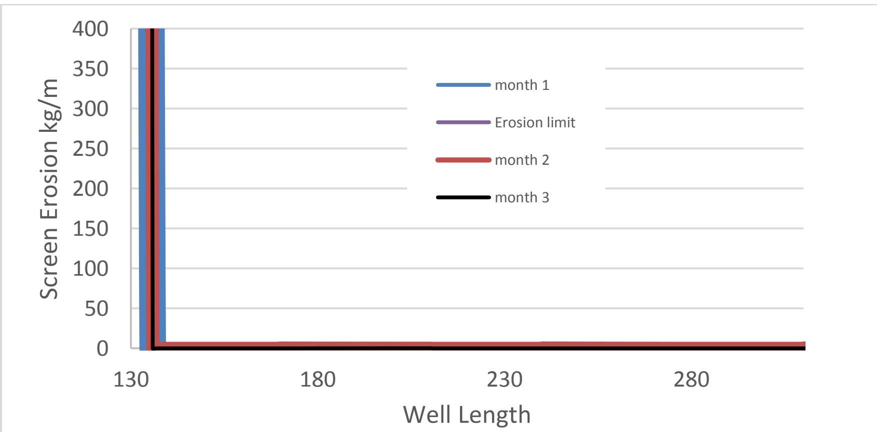

Figure 45 Screen erosion along the well at 3000 sm3/d. SAS erodes well above 2% (6g/m) limit

4.3.2.3 Sand Screens-Packers Completion

Trying to limit annular velocity with swellable packers proved to be ineffective. Same trend of annular velocity pattern as in SAS is observed when packers placed in the well (Figure 46). As seen, packers do not effectively stop annular flow. In fact fluid flows out of the annulus in back in at each production interval, eroding the screen not only at the last interval, but in all sections. Such behaviour may be explained by the fact of high length of production intervals – 35m. Eliminating annular flow and further protecting screens from erosion can be achieved by placing gravel pack around the screens. Such idea is tested in the next section.

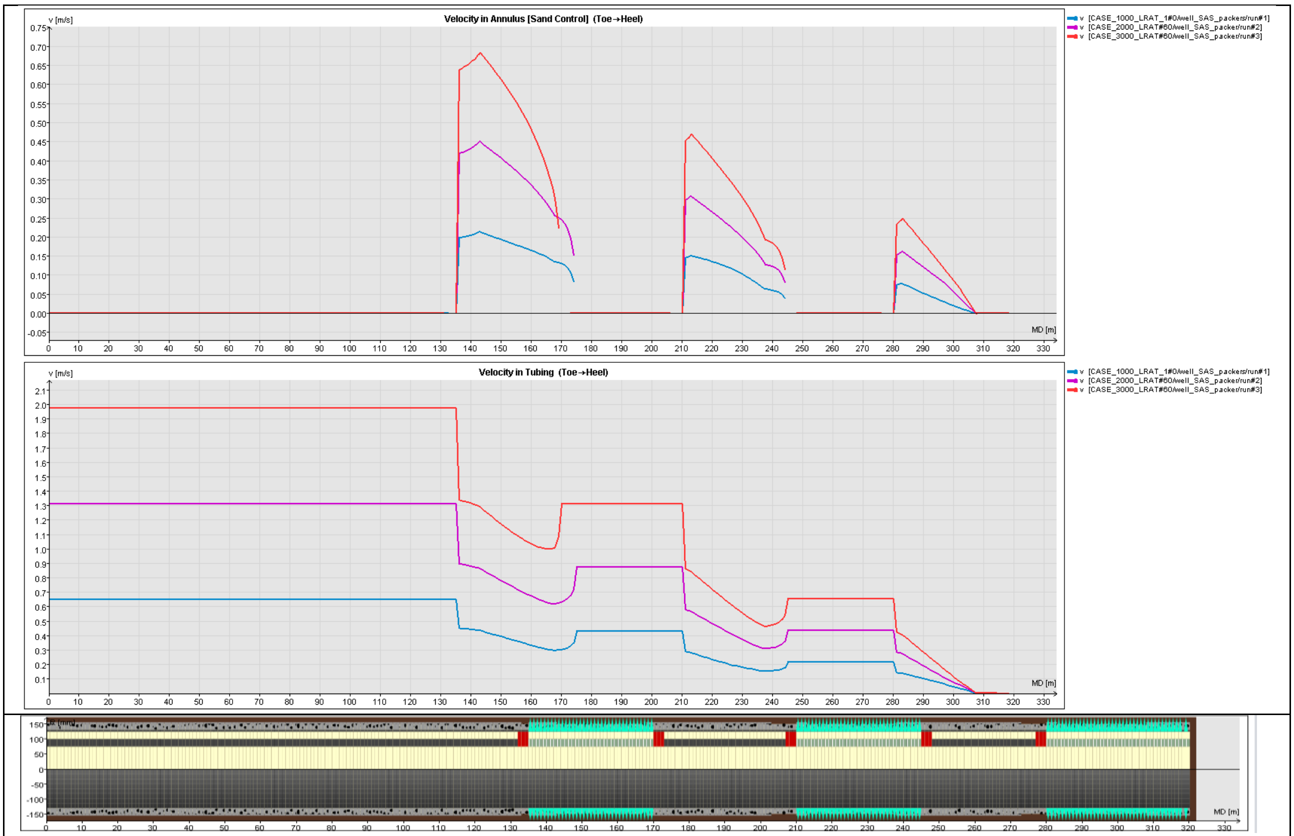

Figure 46 Velocity profile at different production rates in Screens-Packers completion. A seen, flow flows out and back in in the annulus through the screens eroding screens in all production sections.

Highest fluid velocities in each section at different production rates are shown in Table 11. Fluid velocity in the last section is the same as fluid velocity in the last section of SAS completion. Found velocities are used in the erosion model to calculate screen erosion per meter of completion.

Section	1	2	3
Highest Face velocity at 1000 sm^3/d ft/s	0,652	0,461	0,250
Face velocity at 2000 sm^3/d ft/s	1,36	0,9634	0,492
Face velocity at 3000 sm^3/d	2,09	1,47	0,758

Table 11 highest fluid velocities at each section at different production rates. These velocities are used to calculate screen erosion per meter

Screen erosion is shown in Figure 47, Figure 47 and Figure 48. As seen screens are eroded in nearly all section above safe limit before 1 month of production. Screens with swellable packer did not prove to be an effective completion to resist screen erosion.

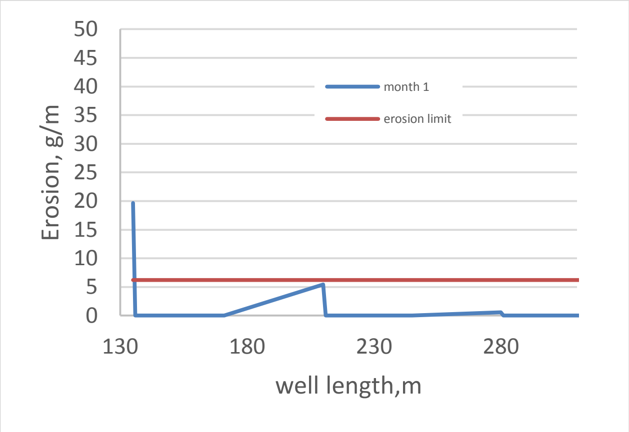

Figure 47 Screen erosion at 1000 sm3/d. Red line I 2% erosion limit. 1st section erodes beyond the limit even before 1 months of production

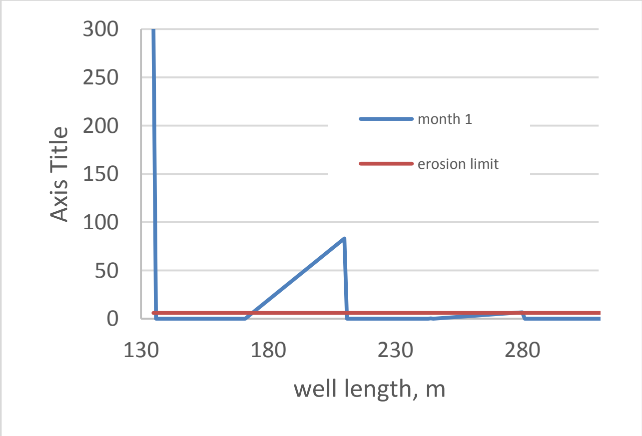

Figure 48 Screen erosion at 2000sm3/d. Red lime is the 2% erosion limit. All section are eroded above the limit after 1 month of production

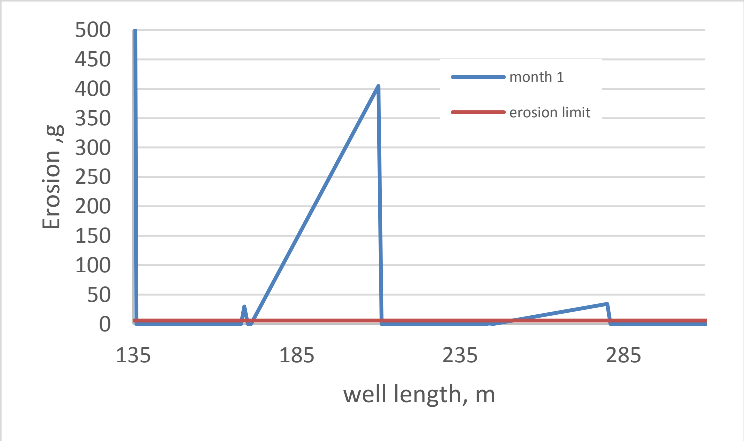

Figure 49 Screen erosion at 3000sm3/d. All sections are eroded well above the limit after 1 month of production

4.3.2.4 Cased Hole Gravel Pack- Sand Screens Completion

With gravel pack placed in the annulus, annular flow is completely eliminated (Figure 50) creating a smooth inflow profile. Gravel pack is proving to be an effective mean to eliminate annulus, thus protecting the screens from erosion.

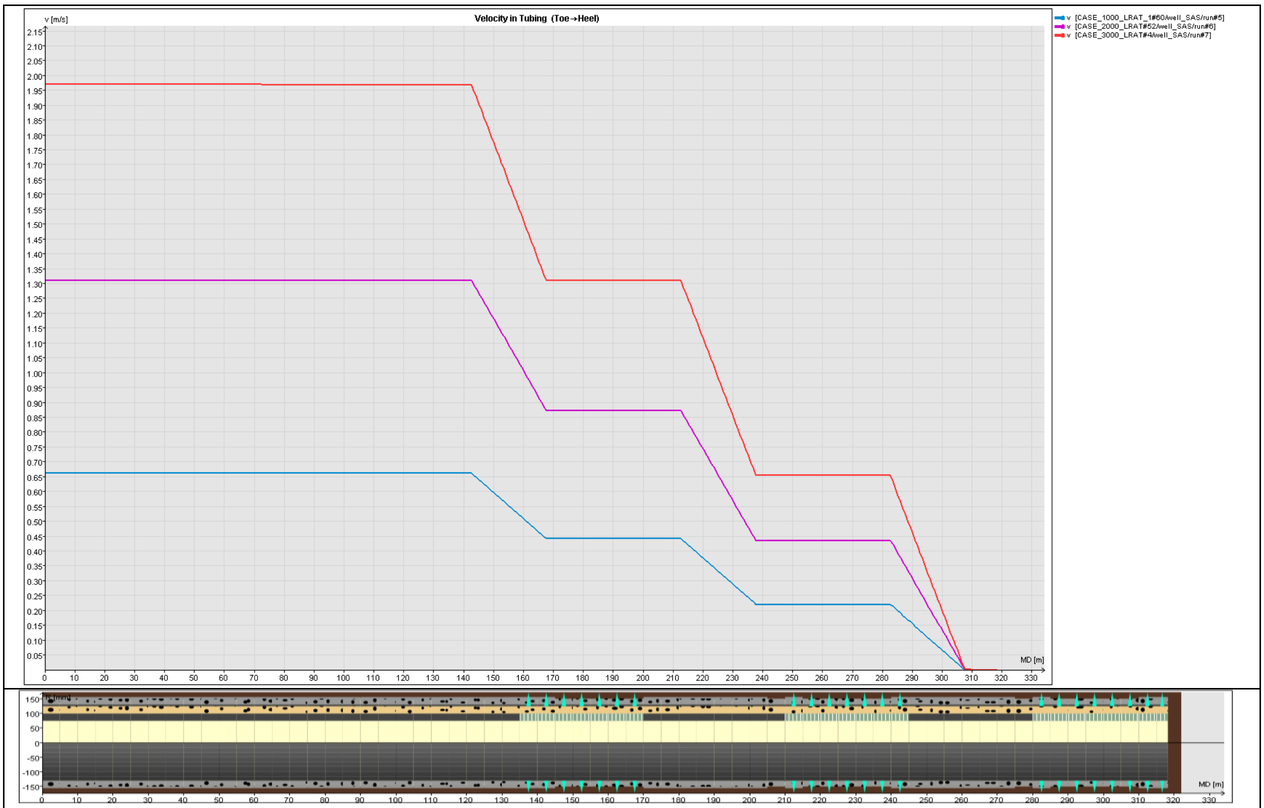

Figure 50 Tubular cumulative velocity profile in a gravel pack, sand screens completion. This velocity is used in erosion model to calculate erosion of the screens in GP completion.

Screen erosion becomes negligible (Figure 51, Figure 52, Figure 53) but the plugging of the gravel pack can create large additional pressure drop, possibly impairing production. Such an effect is investigated in the following chapter.

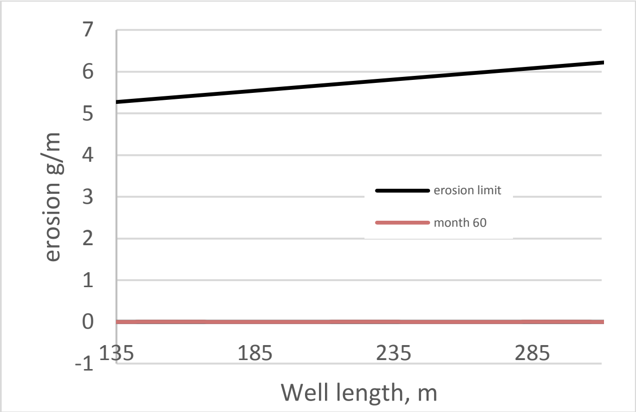

Figure 51 Screen erosion in GP-SS completion at 1000 sm3/d. Even after 60 months screen erosion is negligible. Black line is 2% erosion limit

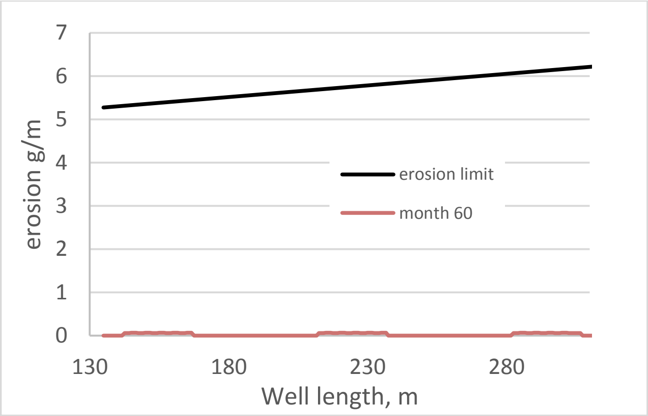

Figure 52 Screen erosion in GP-SS completion at 2000 sm3/d. Even after 60 months screen erosion is negligible and well below erosion limit. Black line is erosion limit.

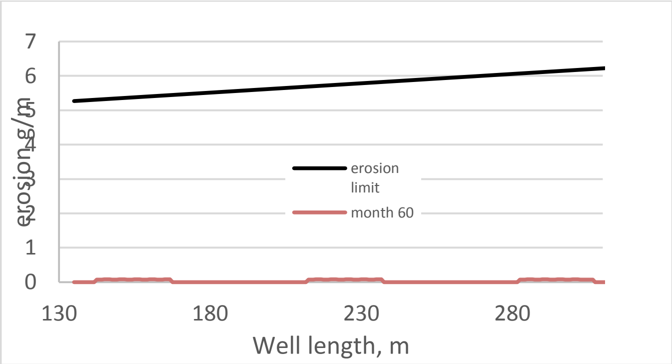

Figure 53 Screen erosion in GP-SS completion at 3000 sm3/d. Even at high rate screen erosion after 60 months is negligible. Black line represent erosion limit.

4.4 Sensitivity Analysis Results

Sensitivity parameters in this analysis were particle size and concentration of produced sand. (Table 7). Analysis was run on all completions in terms of safe velocity, and hence. Found safe rates are put in ECLIPSE model to find recovery and well performance for SAS, Screens with packers and ESS. For gravel pack NETool is used to find recoveries and well performance.

Results show that larger D_{50} particle diameters as well as higher particle concentration have higher risk of screen erosion must be produced at lower rates, giving lower recoveries

4.4.1 50 micron Produced sand

Screen erosion model is inverted and safe velocities are found for each particle properties. In this section particle of 50µm D_{50} at concentrations of 200, 400, 1000, 10 000 and 50 000 ppm_w. safe velocities will be lower for higher concentrations, since at higher concentrations more particles will impact the screen, eroding it more than at lower concentrations.

Particle size(micron)	Particle concentration (ppm)	Velocity limit(ft/s) ESS	Velocity limit (ft/s) SAS	Velocity limit (ft/s) SAS-Packers	Velocity limit (ft/s) Gravel
50	200	0,149	0,149	0,149	0,149
	400	0,124	0,124	0,124	0,124
	1000	0,096	0,096	0,096	0,096
	10 000	0,052	0,052	0,052	0,052
	50 000	0,033	0,033	0,033	0,033

Table 12 Calculated Safe velocities for 50 µm particles. Calculated velocities are equal since density of the screens are equal for all completion and require same erosion volume to erode up to the limit.

The results in Table 12 are used to calculate safe production rate using equation 35. Observe how the safe velocities calculated are the same. This is due to the same density of the screen and the ratio of mass and area in the different completion options. In Table 13 calculated safe production rates are shown. Gravel pack completion protects screen from erosion, resulting in highest safe rates, but being susceptible to plugging, actual productivity will drop. Analysis for gravel pack productivity and recovery was done in NETool, which slightly differ from ECLIPSE results, and are not directly comparable. However different completions can be compared to base cases results from section 4.2 *Reservoir Performance*

Results show that expandable sand screens have higher safe rates than SAS, some even over 1000 m^3/d, even though ESS are not recommended in cased hole well. Well completed with a gavel pack have highest calculated safe rates which are higher than 1000 sm^3/d for all types of sands.

Recoveries for each completion are shown in Figure 13. ESS completion were analyzed in addition in terms of percent open perforations, while effect of plugging in a gravel pack completion is analyzed as well.

Result show that highest recovery factor is achieved for all concentration for a gravel pack completion compared to other completion alternatives.

Only if the gravel is excessively plugged, ESS with fully open perforations have a higher recovery factor for 200-1000 ppm_w .With zero skin at concentrations of 200-1000 ppm_w gravel pack completion have recovery of 72,2%, same as the highest recovery in base cases at 3000 sm^3/d. Second highest recovery at low concentrations is 52,9 % at 200 ppm_w for ESS at 100% open perforations. For SAS highest recovery is only 12,7% at 200 ppm_w.
Results show that for a gravel pack completions, it is essential to design the gravel pack such it does not extensively plug. With small degree of plugging(at 10 skin per year), gravel pack completion only loses 2.3%, 4.9% and 0 percent of recovery for 200-1000 ppm_w, 1000 ppm_w and 50 000ppm_w compared to a clean gravel pack. With high degree of plugging recovery is lost at 35.4%, 26.2% and 7.5% for 200-1000 ppm_w, 1000 ppm_w and 50 000ppm_w compared to a clean gravel pack. For ESS it is essential to keep perforations open, where recovery is lost at 37.1%, 36.1%, 30.7%, 16.5% and 10.7% for respective concentration when perforations is only 25% open compared to fully open perforations. However even at low open inflow area ESS performs better than SAS and SAS with packer at 200-10000 ppm_w that is 3.1%, 2%, 0.8% increase in recovery at respective concentrations. At 50 000 ppm_w SAS/SAS-packers perform 1,2 % better than lowest recovery for ESS. Chemical consolidation may be performed to stop plugging of perforations thus consolidating the formation, but will add unnecessary complexity to well completion, where other forms of sand control may be easier to install, i.e gravel pack.

Graphical comparison of completions from NETool and ECLIPSE results are shown in Appendix C Completion Performance Comparison

Particle Size (micron)	50				
Particles concentration(ppm)	200				
% open perforations	100%	90%	70%	50%	25%
Safe Production Rate(m^3/d) ESS	1283	1154	896	641	320
Safe Production Rate (m^3/d) SAS	258				
Safe Production Rate (m^3/d) SAS-Packers	258				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	6333				
Particles Concentration (ppm)	400				
%Open Perforations	100%	90%	70%	50%	25%
Safe Production Rate (m^3/d) ESS	1064	957	743	532	266
Safe Production Rate (m^3/d) SAS	226				
Safe Production Rate (m^3/d) SAS-Packers	226				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	5222				
Particles Concentration (ppm)	1000				
%Open Perforations	100%	90%	70%	50%	25%
Safe Production Rate (m^3/d) ESS	830	747	580	415	207
Safe Production Rate (m^3/d) SAS	192				
Safe Production Rate (m^3/d) SAS-Packers	192				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	4111				
Particles Concentration (ppm)	10 000				
%Open Perforations	100%	90%	70%	50%	25%
Safe Production Rate (m^3/d) ESS	445	401	311	222	111
Safe Production Rate (m^3/d) SAS	127				
Safe Production Rate (m^3/d) SAS-Packers	127				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	2200				
Particles Concentration (ppm)	50 000				
%Open Perforations	100%	90%	70%	50%	25%
Safe Production Rate (m^3/d) ESS	288	259	201	144	72
Safe Production Rate (m^3/d) SAS	97				
Safe Production Rate (m^3/d) SAS-Packers	97				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	1430				

Table 13 Calculated safe Rates for particles with D50 of 50 micron. Wells completed with a Gravel pack show highest calculated safe rate.

Particle Size (micron)	50				
Particles concentration(ppm)	200				
BASE CASE Recovery factors. From ECLIPSE at 3000 sm3/D	0,626				
BASE CASEs Recovery factors from NETool at 3000 sm3/D	0,722*				
% open perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,529	0,510	0,438	0,316	0,158
Ultimate Recovery Factor SAS	0,127				
Ultimate Recovery Factor) SAS-Packers	0,127				
Skin factor per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,722*	0,699*	0,499*	0,368*	
Particles Concentration (ppm)	400				
%Open Perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor (m^3/d)	0,492	0,462	0,367	0,262	0,131
Ultimate Recovery Factor SAS	0,111				
Ultimate Recovery Factor SAS-Packers	0,111				
Skin factor per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,722*	0,699*	0,499*	0,368*	
Particles Concentration (ppm)	1000				
%Open Perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,409	0,369	0,286	0,205	0,102
Ultimate Recovery Factor SAS	0,094				
Ultimate Recovery Factor SAS-Packers	0,094				
Skin FActor per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,722*	0,699*	0,499*	0,368*	
Particles Concentration (ppm)	10 000				
%Open Perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,219	0,198	0,153	0,109	0,054
Ultimate Recovery Factor SAS	0,062				
Ultimate Recovery Factor SAS-Packers	0,062				
Skin Factor per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,599*	0,550*	0,410*	0,337*	
Particles Concentration (ppm)	50 000				
%Open Perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,142	0,128	0,099	0,071	0,035
Ultimate Recovery Factor SAS	0,047				
Ultimate Recovery Factor SAS-Packers	0,047				
Skin per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,546*	0,546*	0,534*	0,472*	

*Table 14 Recovery factor for 50 µm particles. Wells completed with a gravel pack shows highest recovery, though effectivity of such completions are dropped with high degree of plugging. * NETool simulation results.*

4.4.1 75 micron Produced sand

Screen erosion model is inverted and safe velocities are found for each particle properties. In this section particle of 75µm D_{50} at concentrations of 200, 10 000 and 50 000 ppm_w.

Particle size(micron)	Particle concentration (ppm)	Velocity limit(ft/s) ESS	Velocity limit (ft/s) SAS	Velocity limit (ft/s) SAS-Packers	Velocity limit (ft/s) Gravel
75	200	0,133	0,133	0,133	0,133
	10 000	0,046	0,046	0,046	0,046
	50 000	0,030	0,030	0,030	0,030

Table 15 Calculated safe velocities for 75 µm particles. Calculated velocities are equal since density of the screens are equal for all completion and require same erosion volume to erode up to the limit.

The results in Table 15 are used to calculate safe production rate using equation 35. In Table 19 calculated safe production rates are shown. Same trend is observed with 75 µm particles as for 50µm particles. Calculated safe rates for 75 µm particles are nearly 10% lower than for 50 µm particles with corresponding drop in recoveries, proving that larger fines have a negative effect on production. Results follows the same trend in respect to gravel pack being the most suitable completion in terms of recovery.

Recoveries for each completion are shown in Table 19. With zero skin at concentrations of 200 ppm_w gravel pack completion have recovery of 72,2%, same as the highest recovery in base cases at 3000 sm^3/d. Second highest recovery at low concentrations is 50,9 % at 200 ppm_w for ESS at 100% open perforations. For SAS highest recovery is only 11,8% at 200 ppm_w.

With small degree of plugging (at 10 skin per year), gravel pack completion only loses 2.3%, 0.4% and 0 percent of recovery for 200-50000 ppm_w, compared to a clean gravel pack. Such losses are slightly lower than in the case in the previous section, which is an effect from lower safe rate. With high degree of plugging recovery is lost at 35.4%, 22.2% and 6.2% for 200-50000 ppm_w compared to a clean gravel pack. For ESS it is essential to keep perforations open, where recovery is lost at 36.8 %, 14.9%, and 9.6% for respective concentration when perforations is only 25% open compared to fully open perforations. However even at low open inflow area ESS performs better than SAS and SAS with packer at 200 and 10000 ppm_w that is 2.3% and 1% increase in recovery at respective concentrations. At 50 000 ppm_w SAS/SAS-packers perform 0,9 % better than lowest recovery for ESS.

Graphical comparison of completions from NETool and ECLIPSE results are shown in Appendix C Completion Performance Comparison

Particle Size (micron)	75				
Particles concentration(ppm)	200				
% open perforations	100%	90%	70%	50%	25%
Safe Production Rate(m^3/d) ESS	1150	1034	803	575	287
Safe Production Rate (m^3/d) SAS	239				
Safe Production Rate (m^3/d) SAS-Packers	239				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	5888				
Particles Concentration (ppm)	10 000				
%Open Perforations	100%	90%	70%	50%	25%
Safe Production Rate(m^3/d) ESS	399	359	279	199	99
Safe Production Rate (m^3/d) SAS	119				
Safe Production Rate (m^3/d) SAS-Packers	119				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	2000				
Particles Concentration (ppm)	50 000				
%Open Perforations	100%	90%	70%	50%	25%
Safe Production Rate(m^3/d) ESS	258	232	180	129	64
Safe Production Rate (m^3/d) SAS	90				
Safe Production Rate (m^3/d) SAS-Packers	90				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	1285				

Table 16 Calculated safe rates for 75 µm particles. Calculated rates are slightly lower than for 50 µm. Sill a gravel pack completion have highest safe rates because such completion protects screens from erosion.

Particle Size (micron)	75				
Particles concentration(ppm)	200				
BASE CASE Recovery factors. From ECLIPSE at 3000 sm3/D	0,626				
BASE CASEs Recovery factors from NETool at 3000 sm3/D	0,722*				
% open perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,509	0,485	0,396	0,284	0,141
Ultimate Recovery Factor SAS	0,118				
Ultimate Recovery Factor SAS-Packers	0,118				
Skin factor per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,722*	0,699	0,499*	0,368*	
Particles Concentration (ppm)	10 000				
%Open Perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,197	0,177	0,137	0,098	0,048
Ultimate Recovery Factor SAS	0,058				
Ultimate Recovery Factor SAS-Packers	0,058				
Skin factor per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,588*	0,584*	0,443*	0,366*	
Particles Concentration (ppm)	50 000				
%Open Perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,127	0,114	0,088	0,063	0,031
Ultimate Recovery Factor SAS	0,044				
Ultimate Recovery Factor SAS-Packers	0,044				
Skin factor per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,530*	0,530*	0,523*	0,468*	

Table 17 Recoveries for 75 µm particles. Calculated recoveries are slightly lower than for 50 µm case. Gravel pack completion have highest recovery factors, event thorugh such completion may be susceptible to plugging.

4.4.1 100 micron Produced sand

Screen erosion model is inverted and safe velocities are found for each particle properties. In this section particle of 75µm D_{50} at concentrations of 200, 10 000 and 50 000 ppm_w.

Particle size(micron)	Particle concentration (ppm)	Velocity limit(ft/s) ESS	Velocity limit (ft/s) SAS	Velocity limit (ft/s) SAS-Packers	Velocity limit (ft/s) Gravel
100	200	0,133	0,133	0,133	0,133
	10 000	0,046	0,046	0,046	0,046
	50 000	0,030	0,030	0,030	0,030

Table 18 Calculated safe velocities for 100 µm particles. Calculated velocities are equal since density of the screens are equal for all completion and require same erosion volume to erode up to the limit.

The results in Table 18Table 15 are used to calculate safe production rate using equation 35. In Table 19 calculated safe production rates are shown. Same trend is observed with 100 µm particles as for 50µm and 75 µm particles. Calculated safe rates for 100 µm particles are nearly 10% lower than for 75 µm and nearly 20% lower than 50 µm particles with corresponding drop in recoveries. Results follows the same trend in respect to gravel pack being the most suitable completion in terms of recovery.

Recoveries for each completion are shown in Table 19. With zero skin at concentrations of 200 ppm_w gravel pack completion have recovery of 72,2%, same as the highest recovery in base cases at 3000 sm^3/d. Second highest recovery at low concentrations is 49.2 % at 200 ppm_w for ESS at 100% open perforations. For SAS highest recovery is only 11,1% at 200 ppm_w.

With small degree of plugging (at 10 skin per year), gravel pack completion only loses 2.3%, 0 and 0 percent of recovery for 200-50000 ppm_w, compared to a clean gravel pack. Such losses are slightly lower than in the case in the previous section, which is an effect from lower safe rate. With high degree of plugging recovery is lost at 36.1%, 13.7% and 8.9% for 200-50000 ppm_w compared to a clean gravel pack. For ESS it is essential to keep perforations open, where recovery is lost at 36.8 %, 14.9%, and 9.6% for respective concentration when perforations is only 25% open compared to fully open perforations. However even at low open inflow area ESS performs better than SAS and SAS with packer at 200 and 10000 ppm_w that is 2% and 1% increase in recovery at respective concentrations. At 50 000 ppm_w SAS/SAS-packers perform 1.3 % better than lowest recovery for ESS.

Graphical comparison of completions from NETool and ECLIPSE results are shown in Appendix C Completion Performance Comparison

Particle Size (micron)	100				
Particles concentration(ppm)	200				
% open perforations	100%	90%	70%	50%	25%
Safe Production Rate(m^3/d) ESS	1064	957	743	532	266
Safe Production Rate (m^3/d) SAS	226				
Safe Production Rate (m^3/d) SAS-Packers	226				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	5222				
Particles Concentration (ppm)	10 000				
%Open Perforations	100%	90%	70%	50%	25%
Safe Production Rate(m^3/d) ESS	369	332	259	184	92
Safe Production Rate (m^3/d) SAS	112				
Safe Production Rate (m^3/d) SAS-Packers	112				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	1857				
Particles Concentration (ppm)	50 000				
%Open Perforations	100%	90%	70%	50%	25%
Safe Production Rate(m^3/d) ESS	239	215	167	119	59
Safe Production Rate (m^3/d) SAS	85				
Safe Production Rate (m^3/d) SAS-Packers	85				
Safe Production Rate (m^3/d) SAS-Gravel (with 0 skin)	1150				

Table 19 Calculated Safe for 100 µm particles. Gravel pack, compared to other completion will deliver at higher rates under all particle concentrations.

Particle Size (micron)	100				
Particles concentration(ppm)	200				
% open perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,492	0,462	0,367	0,262	0,131
Ultimate Recovery Factor SAS	0,111				
Ultimate Recovery Factor SAS-Packers	0,111				
Skin Per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,722*	0,699*	0,499*	0,368*	
Particles concentration(ppm)	10 000				
%Open Perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,182	0,177	0,127	0,090	0,045
Ultimate Recovery Factor SAS	0,055				
Ultimate Recovery Factor SAS-Packers	0,055				
Skin per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,579*	0,579*	0,473*	0,394*	
Particles Concentration (ppm)	50 000				
%Open Perforations	100%	90%	70%	50%	25%
Ultimate Recovery Factor ESS	0,118	0,106	0,082	0,058	0,029
Ultimate Recovery Factor SAS	0,042				
Ultimate Recovery Factor SAS-Packers	0,042				
SKin per year	0	10	30	50	
Ultimate Recovery Factor SAS-Gravel	0,509*	0,509*	0,509*	0,469*	

Table 20 Ultimate Recovery Factors for 100 µm particles. Gravel pack will generally deliver most oil, but if great plugging occurs, at low concentrations, ESS will deliver most oil (provided all perforations are open) compared to greatly plugged GP.

Chapter 5 Summary and Future Work

In this thesis an investigation sand erosion of sand screens in different cased hole well completions and consequent effect on field recoveries is performed. An erosion model were used to calculate screen erosion by different sized particles at different concentrations. Next rates at which completion could handle inflow of sand were calculated at resulting oil recoveries were found using ECLIPSE and NETool models.

5.1 Summary and Conclusion

a) Placing a gravel pack around sand screens greatly increases sand screen service life in terms of protection from erosion. Such completion alternative ensures high oil recoveries even under scenarios there severe plugging occurs.

b) Expandable sand screens in cased well requires fully open perforations in order to serve as a competent sand retainer in regard to screen erosion at low rates. Such a requirement may never be fulfilled, as produced sand will almost certainly fill perforation as well is being produced. Chemical consolidation may be performed to stop sand production thus consolidating the formation, but will add unnecessary complexity to well completion, where other forms of sand control may be easier to install.

c) Standalone sand screens is found to be least effective sand control in a cased hole under investigated conditions. High annular velocity serves as the cause of excessive screen erosion, and reducing it with the gravel pack was found to be highly successful in terms of protecting the screens from erosion. One other traditional mean of reducing annular velocity, swellable packer was implemented without success, possibly caused by too long production intervals.

d) Investigating effect of particle sizes and concentrations on rates where screens do not experience excessive erosion showed that completion with a gravel pack will perform best under all investigated conditions. Expandable sand screens and standalone sand screen do not offer effective resistance against sand erosion.

e) Larger particles at higher concentrations erode the most, requiring a more robust sand control.

5.2 Future Work

a) Only some types of completion, ESS, SAS and GP were investigated in this thesis. It may prove useful to investigate other sand control methods or additional devices, such as ICDs

b) Single erosion model used is based on laboratory work with synthetic sand. Investigating other erosion models as well as trying to investigating industry standards will be useful. Creating a model based not only on laboratory data, but on field data as well may also prove suitable for screen erosion investigation.

c) Arbitrary sand concentrations were used in this analysis. Using a fully geomechanical model under different stress conditions and well orientations may add reliability to screen erosion analysis. Coupling a geomechanical model with erosion model may assist in understanding the role of well completion on oil recovery.

d) Performing such analysis on real reservoir and using real sand screen properties will be of great interest.

Appendix

Appendix A NETool

Introduction

NETool is a nodal numerical model based on user input of: reservoir, completion,fluid and simulation setup information. Numerical model is built by user input and individual components are organized into nodes linked by flow connection, as illustrated in Figure 54 . This Appendix presents a short summary of the simulator, as well as a main modelling equation for elements used in this thesis. For an in depth description, reader is advised to go through “ NETool^{tm} 5000.0.4.1 User Guide” and “NETool^{tm} 5000.0.4.x Technical manual” [33, 34]

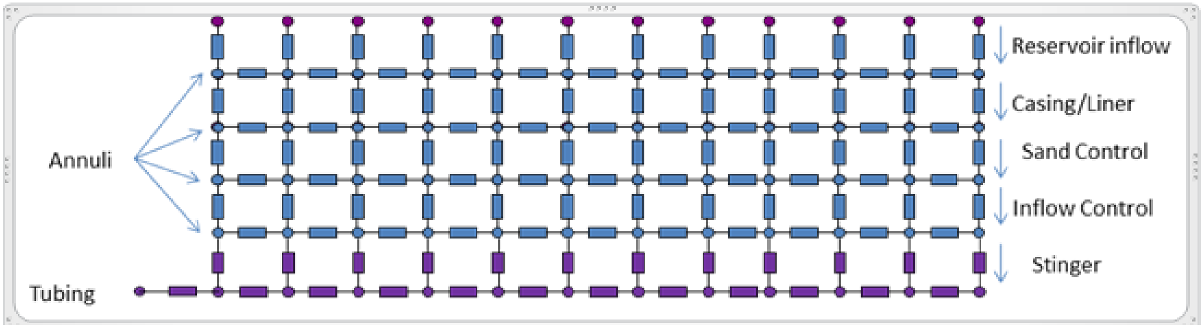

Figure 54 NETool computational nodes, from [34]

As seen in Figure 54 a NETool model is divided into layers of computational nodes. The uppermost layer represent reservoir nodes, and the lowermost represent inner production tubing. The layers in between depend on the completion types. The fluid performance between annuli and tubing layer can be modeled, by changing and configuring the completion type.

NETool is based on conservation of mass and momentum of oil, gas and water components where general momentum balance equations are replaced by correlation which calculate pressure drop based on volumetric flow rate, fluid properties, phase fraction, and flow geometry. Basic assumptions in NETool are:

- 3-phase flow
- Steady state and sub-sonic conditions
- Flow within the well is locally one dimensional, the flow is averaged across the cross-section between the nodes
- Pressure drop calculations within the annulus and the tubing are general momentum balance equations (Bernoulli) including friction, compressibility and hydrostatic phenomenon
- Linear Darcy flow equation is annulus is filled with gravel or collapsed rock.

- Reservoir flow performance is based on PI-Models, which are based on local averaging of reservoir properties
- Pressure drop calculations across completions are based on respective correlations and models

Work process

NETool uses a wizard to guide a user through building a well model.

1. **Importing a new or opening existing reservoir model**

User can define reservoir properties by using log information or importing a model from ECLIPSE. Reservoir properties can be imported with different time step solution, such that NETool can model well behavior in different time step of the reservoir solution.

2. **Define well path within the reservoir**

Defining well trajectory by deviation survey data or UTM coordinates. Defining sub-laterals is also possible, as well as importing well trajectory from other file formats, f. ex. Petrel Deviation File

3. Specify segments by adding nodes to the well path

Defining well nodes lengths, where reservoir and completion properties are defined and are constant throughout the whole segment length.

4. **Define well type, active phases, simulation target etc.**

A general settings tab is used to define:

well type: producer, gas or water injector

Phase mode: fluid liquid phases in the well

Boundary condition: Target flow rates at S.C or R.C. or target pressure at reference MD etc.

Model options: checkboxes to enable or disable additional simulation features, f. ex.

Thermal model, enabling temperature dependent PVT modelling

5. **Define PI**

Choosing a fitting PI model for the well

6. **Specify PVT**

Specifying liquid PVT properties if they are not imported with the reservoir model from ECLIPSE

7. **Specify Relative Permeability**

Specifying relative permeability of each phase, if they are not imported with the reservoir model from ECLIPSE

When a reservoir model is exported from an ECLIPSE reservoir, the fluid model, reservoir properties and relative permeabilities are also exported in a NETool model, but it is also possible to enter PVT properties in NETool using tables, correlations, or ECLIPSE format keywords.NETool supports multiple features of an ECLIPSE model, such as, 3 phase flow, Endpoint Scaling, API tracking, VFP curves, temperature effect, etc.

PI Models

Flow of fluids are modeled in NETool with the help of PI models. The simplest one being:

$$Q = PI * \Delta P \tag{36}$$

Where

Q – well flowrate

PI – productivity index, based on local upscaling

ΔP – pressure drop between reservoir and the well

PI for a vertical well in a homogeneous reservoir in a simple radial model:

$$PI = \frac{2\pi k_{eff} L}{\mu \left[\ln\left(\frac{r_e}{r_w}\right) + S \right]} \tag{37}$$

Where

K_{eff} – effective upscaled permeability for flow perpendicular to the wellbore

L – segment length

μ – average fluid viscosity

r_w –wellbore radius

S- skin

Averaging of fluid properties is done by weighted average of flowing fluid phase reservoir volume fraction.

The individual components of flowing fluid is calculated as follows:

$$q_o = PI * \frac{1}{B_o} * \frac{\frac{k_{ro}}{\mu_o}}{\frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w}} (p_e - p_w) = \frac{2\pi k_{eff} L}{\ln\left(\frac{r_e}{r_w}\right) + s} \frac{k_{ro}}{B_o \mu_o} (p_e - p_w) \tag{38}$$

$$q_w = PI * \frac{1}{B_w} * \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w}} (p_e - p_w) = \frac{2\pi k_{eff} L}{\ln\left(\frac{r_e}{r_w}\right) + s} \frac{k_{rw}}{B_w \mu_w} (p_e - p_w) \quad (39)$$

$$q_g = PI * \frac{1}{B_g} * \frac{\frac{k_{rg}}{\mu_g}}{\frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w}} (p_e - p_w) = \frac{2\pi k_{eff} L}{\ln\left(\frac{r_e}{r_w}\right) + s} \frac{k_{rg}}{B_g \mu_g} (p_e - p_w) \quad (40)$$

The equation used to calculate flow from reservoir to the well in Netool is:

$$\frac{Q}{T * M} + H * Q^2 = \Omega * (P_{res} - P_{well}) \quad (41)$$

Where

M- mobility. Effect of fluid and saturation function on fluid flow.

T- transmissibility

H- high velocity coefficient

Ω- Condensate banking/gas break out adjustment coefficient. This coefficient accounts for large pressure drops near the well due to relative permeability effects from condensate banking or gas breakout.

Mobility is used to calculate flow of each phase from reservoir into wellbore:

$$Q_i = M_i * T * (P_{reservoir} - P_{annulus}) \quad (42)$$

Where

Q_i is phase flowrate

M_i – phase mobility $= \frac{k_{r,i}}{\mu_i}$

Mobility can be defined in 3 ways in NETool: from relative permeability, from phase flowing fraction or manually

Transmissibility reflects the rock properties (permeability), well geometry, reservoir drainage geometry and conditions. Transmissibility can be defined in 3 ways in NETool: from PI model, manually by formula coefficients, and manual values.

Permeability upscaling is done by the formula:

$$K_{ups} = \frac{ln\frac{r_o}{r_w}}{\int_{r_w}^{r_o}\frac{dr}{K(r)r}} \tag{43}$$

Where r_w is equivalent wellbore radius and r_o is the upscaling radius. First reservoir grid is stretched to the vertical direction, such that the inflow area is converted from the elliptical to a circular one. Next, NETool calculates how radius r intersects grid blocks and makes several radial segments where permeability is constant. This is done in angular and radial directions. The final value is a normalized inverse sum of permeabilities in surrounding grid segments.

There are other PI models used in NETool, depending on well type and location in the reservoir.

The basis- equation for the PI models are a simple radial PI model, where the coefficient f is varied depending on the model used:

$$PI = M\frac{2\pi k_h}{\ln\left(\frac{r_e}{r_w}\right) + f + s} \tag{44}$$

Where

M- phase mobility

K_h – horizontal permeability

R_e- radial extent of the reservoir

r_w – Wellbore radius

S – skin factor

L – segment length

There are: an option to match productivity index to match production or injection rates and two PI models. One can match global well PI multiplier, or match per segment transmissibility multiplier. The PI model is adjusted as follows:

$$PI = C_{well} * C_{segment} * T * M \tag{45}$$

Where

C_{well} is a global PI multiplier

$C_{segment}$ is the per segment transmissibility multiplier

The two Pi models are the Joshi PI model and Babu and Odeh PI model. The difference between them is how the models model reservoir geometry, well location in the reservoir and the pressure in the reservoir.

The Joshi model is based on a solution where a 3D model is divided into two 2D flow models, which are added later. That is one model is parallel to the well, the other is perpendicular to the well. The geometry of the model is based on the well located symmetrically in the reservoir where the constant pressure boundary forms an ellipse. The reservoir should have the same relationship between well length, reservoir length and reservoir width. If the pressure at reservoir boundary, p_0 is constant, the flowrate in the model is given as:

$$Q = PI * (p_0 - p_w) \tag{46}$$

Where p_w is the pressure in the well and PI is a function of $K_{upscaled}=\sqrt{\frac{K_h}{K_v}}$, h,a,$K_h$, r_w, and L. L is the length of the well, a is a half length of the ellipse.

Since the model can only 3d symmetrical flow, the well placed close to the boundary, will give lower rates, since the boundary near the well naturally have lower pressure than the boundary farther away, but the model supports only constant pressure boundary.

The Babu and Odeh PI model uses a rectangular box reservoir with a horizontal well parallel to the sides. Compared to the Joshi model, Babu and Odeh model:

-Can handle cases where the well is not centered in the box

- is based on semi-steady state assumption with no-flow boundaries with flowrate defined as

$Q = PI * (p_{av} - p_w)$ where p_{av} is the average pressure in the reservoir

- It is a genuinely 3D analytical model

Since the reservoir pressure in Babu and Odeh model is taken as the average reservoir pressure, this pressure will always be lower than initial reservoir pressure.

The two models are sensitive in what pressure is used. NETool is often used together with a reservoir simulator for model calibration.

For gas wells, NETool uses a model similar to backpressure equation:

$$q_g = C(p_r^2 - p_{wf}^2) \tag{47}$$

In the injection wells, Injectivity index is used. It is similar to PI:

$$II = \frac{Q}{(p_{res} - p_{well})} \tag{48}$$

NETool uses two models to calculate flow from a injecting well, II in regular mode and II in advanced mode:

Regular mode:

$$II = \frac{T}{\mu(P_{res})B(P_{res})} \tag{49}$$

Where

μ - fluid viscosity

B- formation volume factor

T – segment transmissibility

Advanced mode:

A radial near wellbore model is used: Area around the wellbore is split into rings, and μ and B are calculated for each ring

$$II = \frac{1}{N}\sum_{n=1}^{N}\frac{T}{\mu(P_{res}^n)B(P_{res}^n)} \tag{50}$$

Completions in NETool

Completion types are selected for each segment and can be fully mixed and varied along the well. Flow correlations are provided for several completion types, including:

- Cased hole, screens, Gravel pack.

Completion layers are divided in 4 layers:

- Casing/Liner
- Sand Control
- Inflow Control
- Stinger

Each completion layer has different completion types, where stinger is innermost layer and casing/liner is the outermost. Layers cannot overlap, but can have no annulus.

Completion specification is done manually in NETool for each segment, where first a user is choosing the completion type, then specifying its parameters. Here only completion types, parameters and modelling equations are discussed that are relevant for this thesis' work.

Perforated cemented liner

The required items to describe the liner/casing and perforation are:

- Casing ID
- Casing OD
- Hole diameter – diameter of perforation
- Shot density – number of shots per foot
- Length of perforation – length of perforation as measured from outer diameter of the casing

In addition one must choose a skin model to calculate additional pressure drop in the well due to perforation. There are two models for perforation skin, model #1 which is based on work of Karakas and Tariq [35] and model #2 which is based on work of Furui, Zhu, and Hill [36] .

Model #1 assumes laminar flow in perforations and was originally developed for vertical wells, and is adapted for horizontal wells. Orientations of perforations are not considered. Model #2 assumes single phase incompressible flow, where properties of the multiphase flow are averaged. Model also assumes negligible pressure drop inside the perforation in addition to considering the effect of perforation orientations

Screens

There are 3 types of skin available: Generic, perforated pipe and wire wrapped. All screens can have sand pack or filter cake in the annulus.

Generic

This type of screen represents an ideal screen with large inflow area and no pressure drop. There are no input parameters.

Perforated pipe

Represent a pipe with holes, inputs are perforation density and perforation diameter. Orifice equation is used to calculate pressure drop.

Wire-Wrapped screens

This completion uses two layers, annulus and tubing. The WWS includes options such as Collapsed Annulus and filter cake built on the outside of the screen

The following items are needed to specify WWS:

- Sand Control ID – inner diameter of screen base pipe
- Sand Control OD – outer diameter of the screen
- Perforation diameter – diameter of the perforations in the screen base pipe
- Perf. Density – density of perforations in the screen base pipe
- Width of flow Channel—the width of the space radially between the longitudinal wires of the screen. “w” in the Figure 55
- Thickness of flow channel walls—width of the longitudinal wires (those first laid on the base pipe). “s” in Figure 55
- Height of flow channel—thickness of the longitudinal wires (those first laid on the base pipe). “d” in Figure 55
- Wire Width—width of the outer wires of the screen (those that hold back the sand). “W_w” in Figure 55
- Wire Thickness—thickness of the outer wires of the screen. “h” in Figure 55
- Spacing between wires—the gap between the outer wires of the screen. “y” in Figure 55

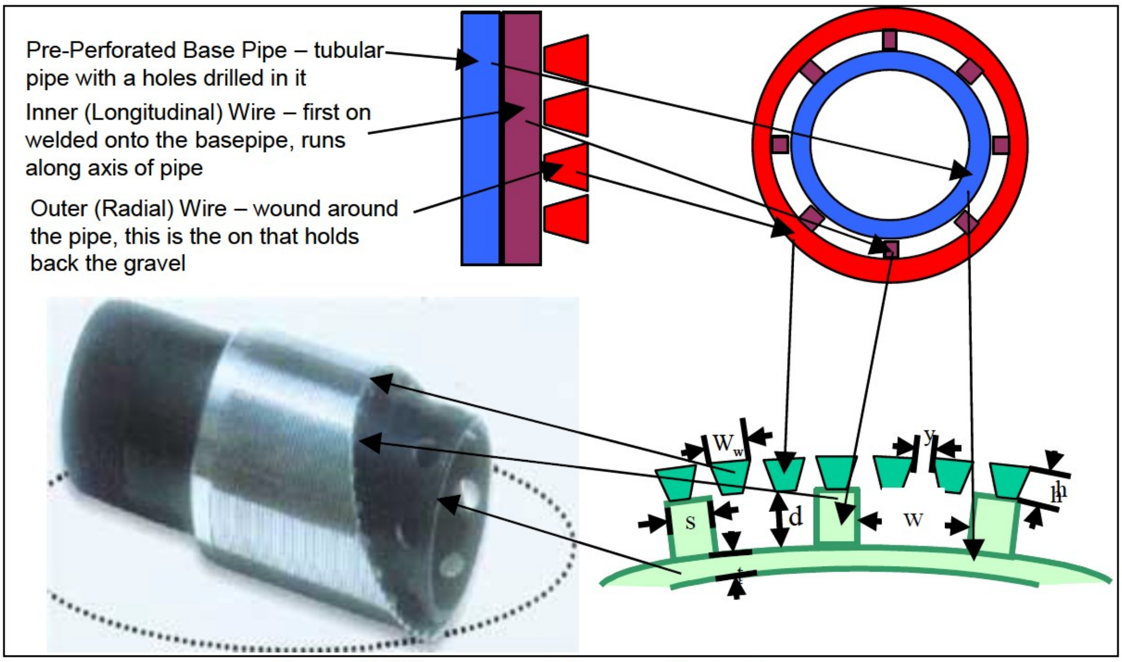

Figure 55 WWS in NETool, from [34]

Filter Cake/Annulus input

WWS has the option to model a buildup of formation on the screens and its effect on well productivity. The filter cake option can also be used to model gravel pack in the well, but without the slip between gas and fluids, as this effect can be modelled separately in the gravel pack option.

The necessary inputs for the filter cake options are:

- Sand Pack thickness – thickness of the filter cake built up on screens or completely filled annulus
- Sand pack permeability – can be entered manually or calculated from input of sand pack porosity and particle shape factor
- Sand grain diameter – average diameter of the sand grains in the filter cake

Cemented blank pipe

The cemented blank pipe is used to model absents of annulus. The only input parameter required is inner diameter of the liner/casing.

Packer

This is a short completion segment which blocks annular space. NETool models a non-leaking packer as a cemented blank pipe, but the packer can also be modelled to have a gap.

LOG and Production logging tool

Exporting well completion to a reservoir model

Simulation results

NeTool simulation results are presented in a separate window, where both graphical and numerical results are presented. A summary of the simulation run is seen first, where the whole oil, gas and water rates are presented, as well as GOR, WC(Water cut) and pressure at first node. There are other parameters presented in the result file: pressures, Stock tank rates, Downhole rates, velocities, permeability, Saturations, relative permeability, mobility, transmissibility, Skin, productivity index, IPR, PVT properties, Rock Fluid properties. IT is also possible to directly compare the results of two or more separate runs.

Appendix B Completion Properties

B-1Expandable Sand Screens.

Completion properties of ESS types are listed in Table 21

Top MD	No of segments	Casing/Liner	Sand control
0	26	Cemented Blank pipe	-
135	7	Perf. Cemented Liner	Generic Sand screen
170	8	Cemented Blank pipe	-
210	7	Perf. Cemented liner	Generic Sand Screen
245	7	Cemented Blank Pie	-
280	7	Perf. Cemented Liner	Generic Sand screen

Table 21 Completion Sections of Expandable Screen Assembly

The properties of individual completion component are listed in Table 22, Table 23 and Table 24

Wellbore diameter (Whole well) 300 mm
Casing/Liner ID 250 mm
Pipe Roughness 15.0

Table 22 Properties of cemented blank pipe

Perforation diameter 13.0 mm
Shot density 10/9/7/5/2.5 perforations/ft
Length of perforations 700 mm

Table 23 Properties of perforations

Sand Control OD 248,4 mm in ESS*;
Sand Control ID 150 mm in ESS;
Screen type : Generic**

Table 24 properties of Generic Sand Screens

* NETool does not allow 0 annulus between screens and casing, the smallest clearance has to be no less than 1/16 inch. It is assumed that this clearing is negligible

** Generic type assumes simplest form of the screens with negligible pressure drop between annulus and tubing

B-2 Stand Alone Sand Screens.

Top MD	No of segments	Casing/Liner	Sand control
0	26	Cemented Blank pipe	-
135	7	Perf. Cemented Liner	Generic Sand screen
170	8	Cemented Blank pipe	-
210	7	Perf. Cemented liner	Generic Sand Screen
245	7	Cemented Blank Pie	-
280	7	Perf. Cemented Liner	Generic Sand screen

Table 25 Completion Sections of Standalone Screen Assembly

The properties of individual completion component are listed in Table 26, Table 27and Table 28

Wellbore diameter (Whole well) 300 mm
Casing/Liner ID 250 mm
Pipe Roughness 15.0

Table 26 Properties of cemented blank pipe

Perforation diameter 13.0 mm
Shot density 10 perforations/ft
Length of perforations 700 mm

Table 27 Properties of perforations

Sand Control OD 200 mm;
Sand Control ID 150 mm;
Screen type : Generic

Table 28 properties of Generic Sand Screens

B-3 Stand Alone Sand Screens with packers

Top MD	No of segments	Casing/Liner	Sand control
0	131	Cemented Blank pipe	-
131	3	Cemented Blank Pipe	Packer
135	35	Perf. Cemented Liner	Generic Sand screen
170	3	Cemented Blank Pipe	Packer
173	34	Cemented Blank pipe	-
207	3	Cemented Blank Pipe	Packer
210	35	Perf. Cemented liner	Generic Sand Screen
245	3	Cemented Blank Pie	Packer*
248	32	Cemented Blank Pipe	-
280	35	Perf. Cemented Liner	Generic Sand screen

Table 29 Completion Sections of Standalone Screen Assembly
** Non leaking packer.*

The properties of individual completion component are listed in Table 30, Table 31, Table 32.

Wellbore diameter (Whole well) 300 mm
Casing/Liner ID 250 mm
Pipe Roughness 15.0

Table 30 Properties of cemented blank pipe

Perforation diameter 13.0 mm
Shot density 10 perforations/ft
Length of perforations 700 mm

Table 31 Properties of perforations

Sand Control OD 200 mm;
Sand Control ID 150 mm;
Screen type : Generic

Table 32 properties of Generic Sand Screens

B-4 Stand Alone Sand Screens with Gravel pack

Top MD	No of segments	Casing/Liner	Sand control	Annulus
0	26	Cemented Blank pipe	-	Gravel pack
135	7	Perf. Cemented Liner	Generic Sand screen	Gravel pack
170	8	Cemented Blank pipe	-	Gravel pack
210	7	Perf. Cemented liner	Generic Sand Screen	Gravel pack
245	7	Cemented Blank Pie	-	Gravel pack
280	7	Perf. Cemented Liner	Generic Sand screen	Gravel pack

Table 33 Completion Sections of Standalone Screen Assembly with gravel pack
** Non leaking packer.*

The properties of individual completion component are listed in Table 30, Table 31, Table 32.

Wellbore diameter (Whole well) 300 mm
Casing/Liner ID 250 mm
Pipe Roughness 15.0

Table 34 Properties of cemented blank pipe

Perforation diameter 13.0 mm
Shot density 10 perforations/ft
Length of perforations 700 mm

Table 35 Properties of perforations

Sand Control OD 200 mm;
Sand Control ID 150 mm;
Screen type : Generic
Gravel pack original permeability. 40000 mD

Table 36 properties of Generic Sand Screens

Appendix C Completion Performance Comparison

C-1 50μm particles

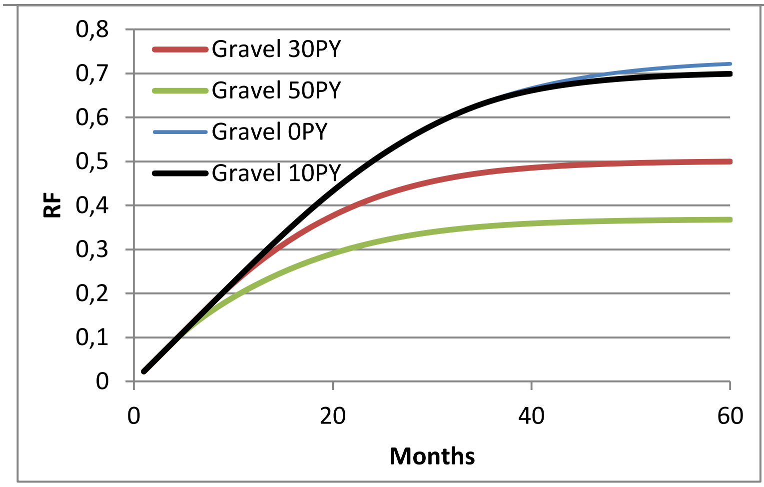

*Figure 56 Comparison of recoveries in a gravel pack completion for 200 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.*

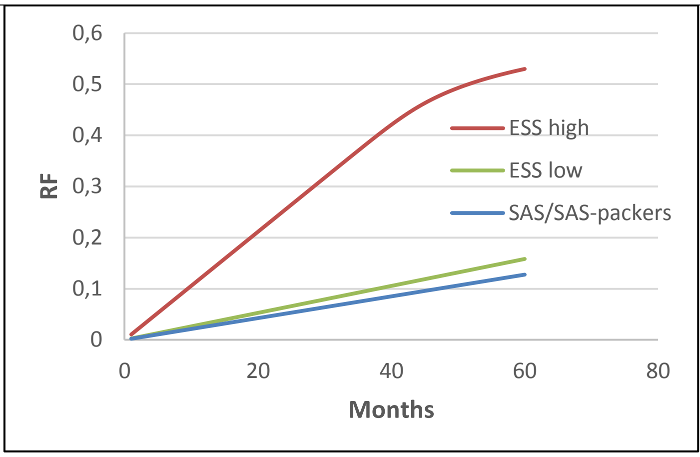

Figure 57 Comparison of recoveries of ESS and SAS completions for 200 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

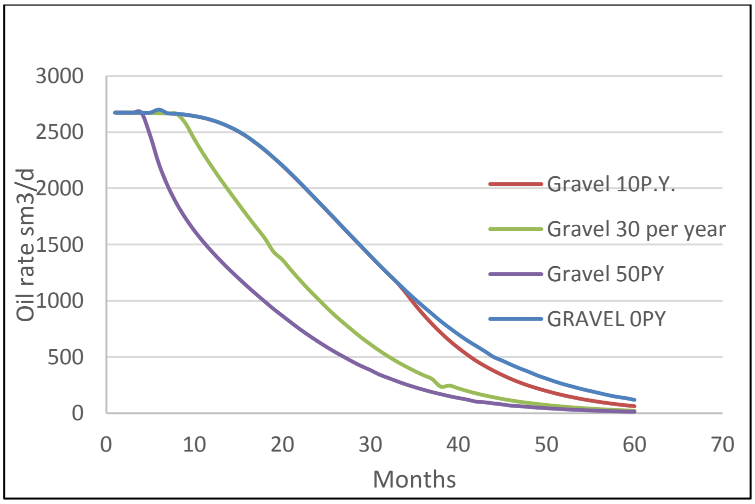

Figure 58 Oil production rates of gravel pack under different skin per year (PY) under 200 ppm sand

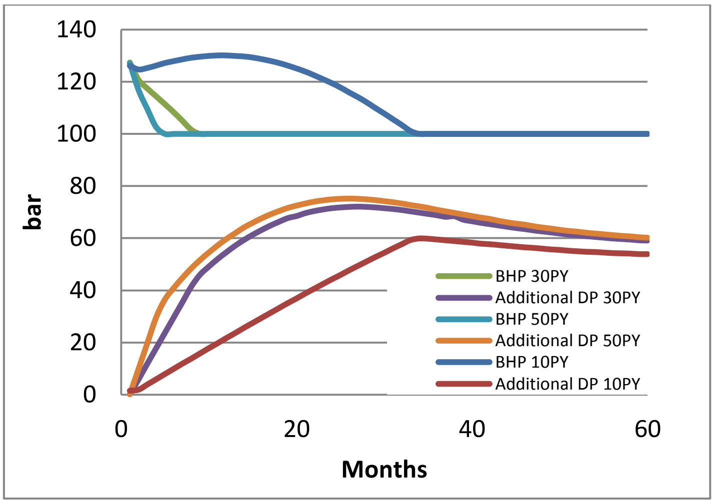

Figure 59 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 200 ppm sand under different skin per year (PY)

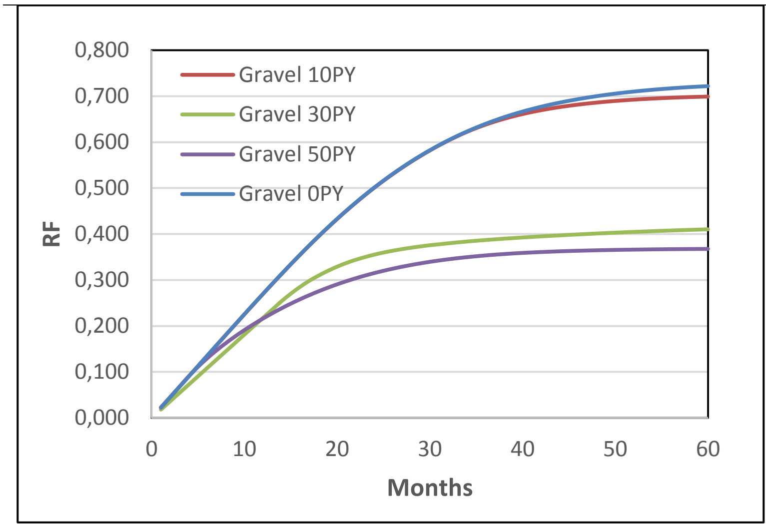

*Figure 60 Comparison of recoveries in a gravel pack completion for 400 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.*

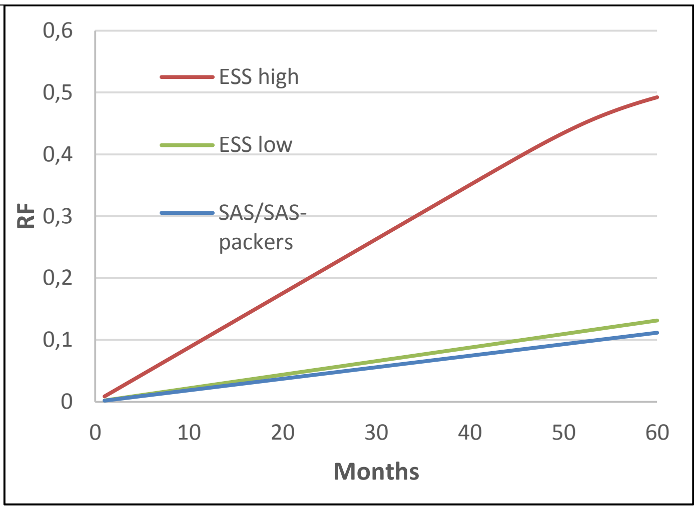

Figure 61 Comparison of recoveries of ESS and SAS completions for 400 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

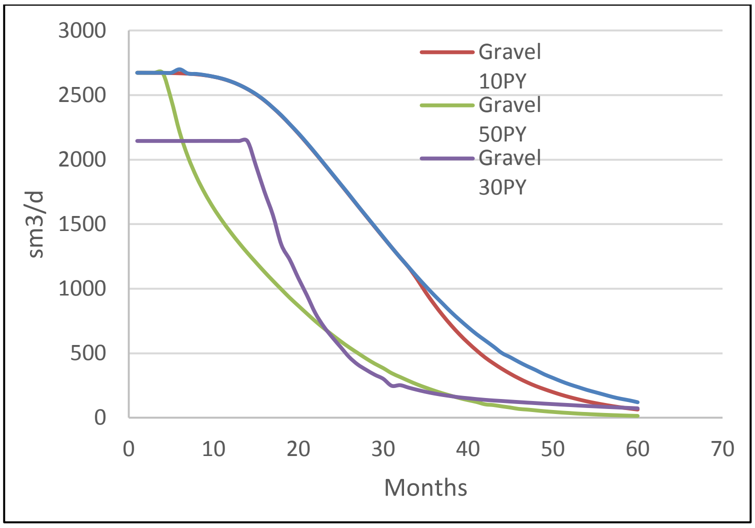

Figure 62 Oil production rates of gravel pack under different skin per year (PY) under 400 ppm sand

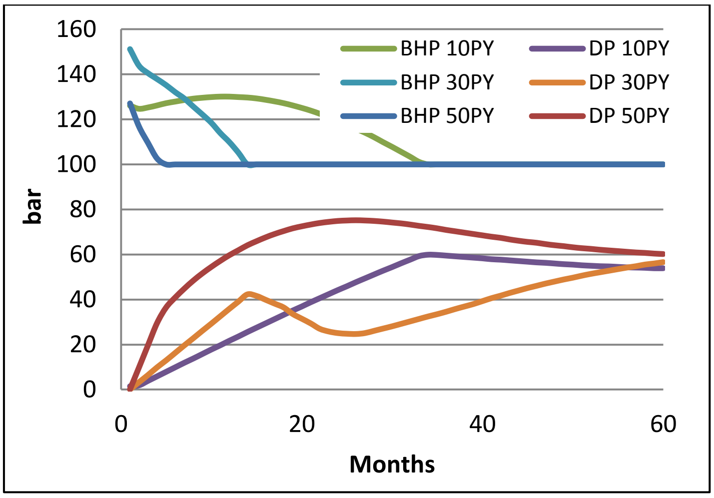

Figure 63 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 400 ppm sand under different skin per year (PY)

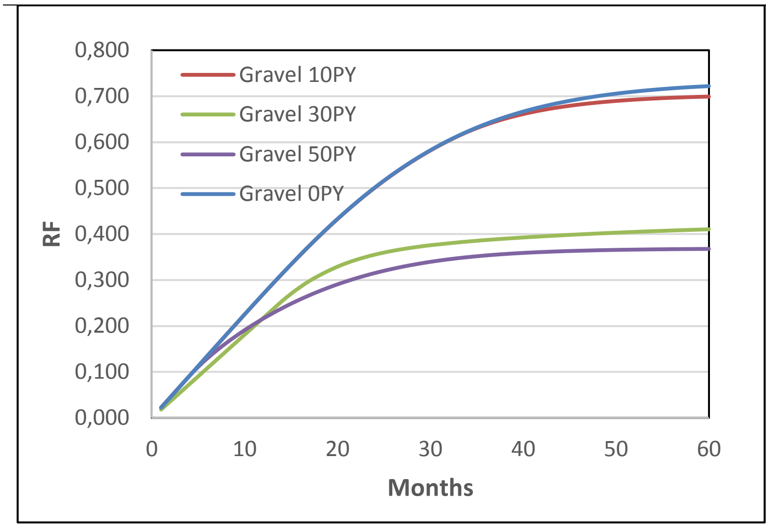

Figure 64 Comparison of recoveries in a gravel pack completion for 1000 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.

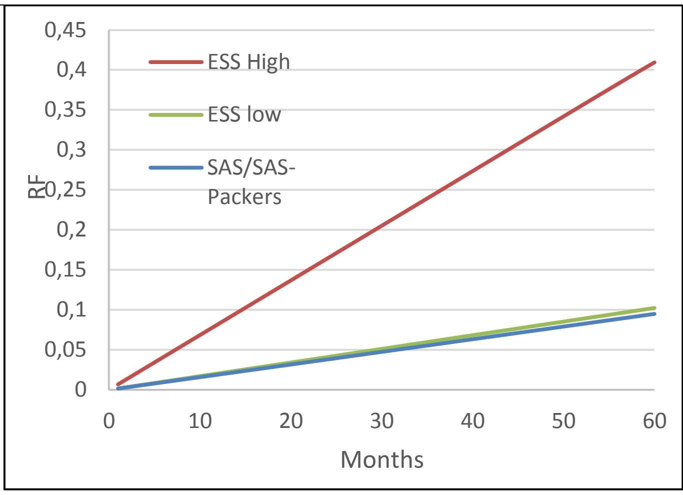

Figure 65 Comparison of recoveries of ESS and SAS completions for 1000 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

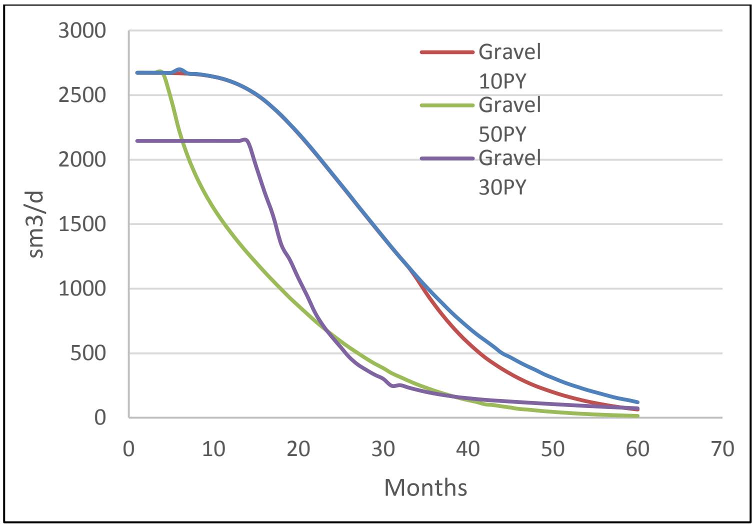

Figure 66 Oil production rates of gravel pack under different skin per year (PY) under 1000 ppm sand

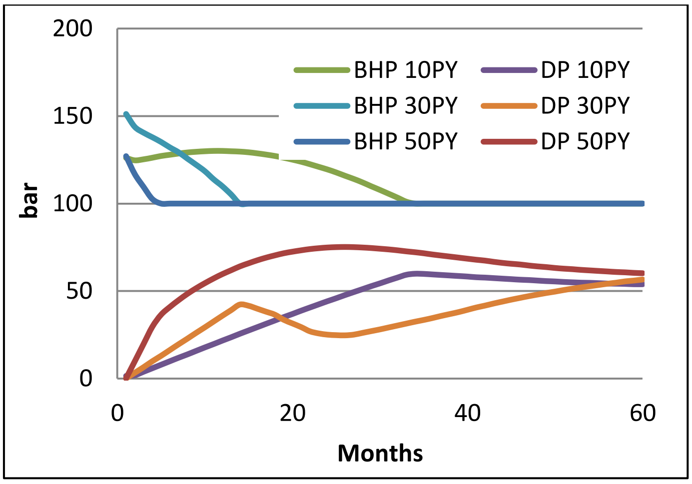

Figure 67 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 1000 ppm sand under different skin per year (PY)

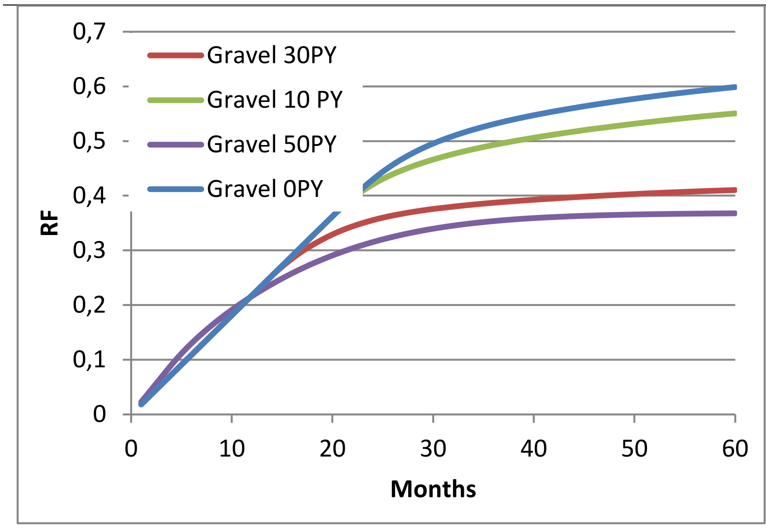

*Figure 68 Comparison of recoveries in a gravel pack completion for 10000 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.*

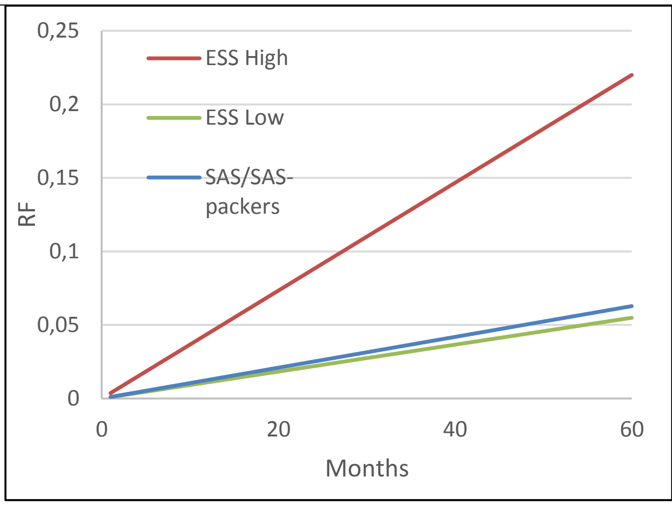

Figure 69 Comparison of recoveries of ESS and SAS completions for 10000 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

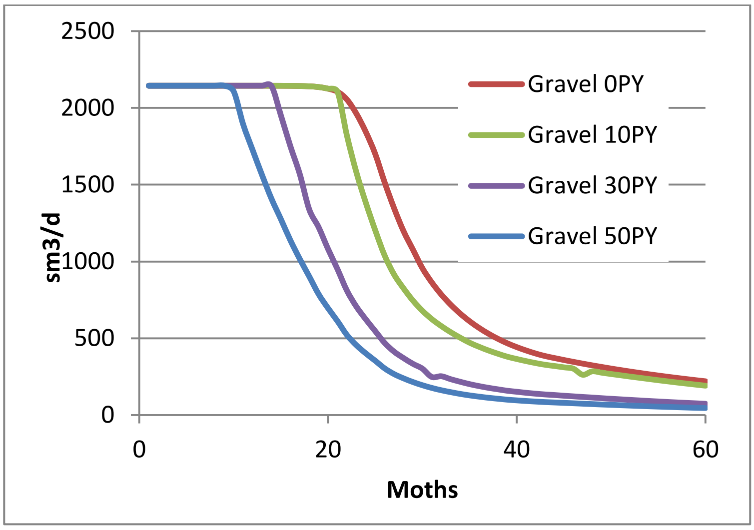

Figure 70 Oil production rates of gravel pack under different skin per year (PY) under 10000 ppm sand.

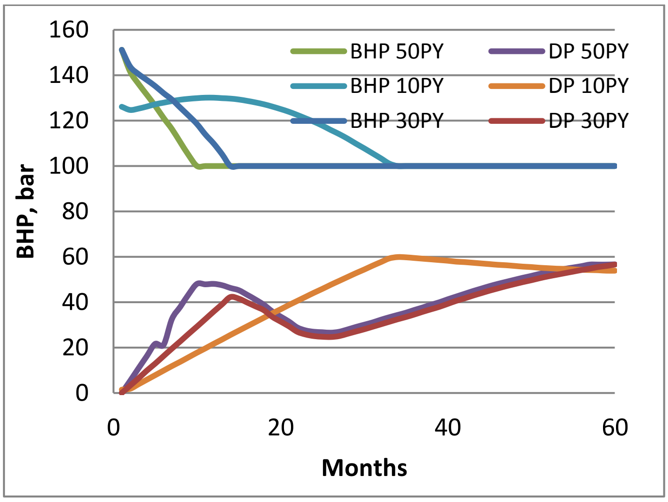

Figure 71 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 10000 ppm sand under different skin per year (PY).

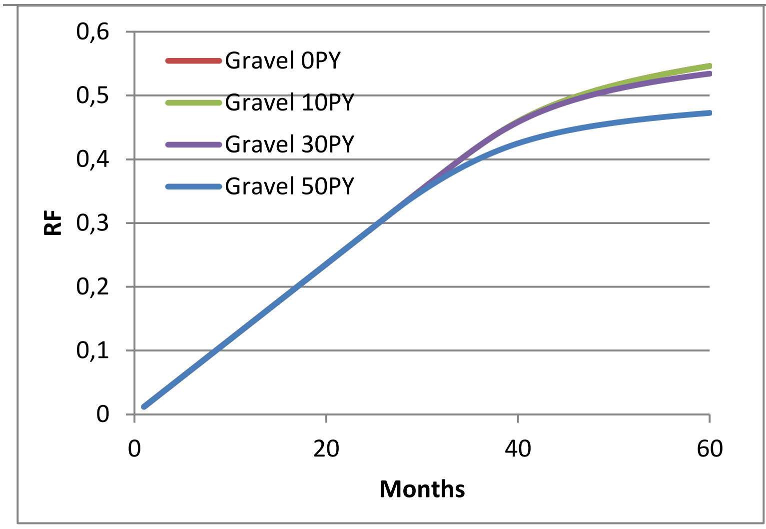

*Figure 72 Comparison of recoveries in a gravel pack completion for 50000 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.*

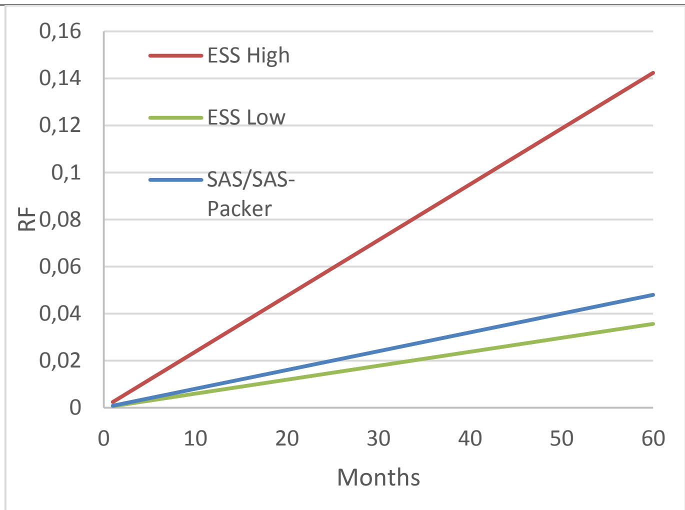

Figure 73 Comparison of recoveries of ESS and SAS completions for 50000 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

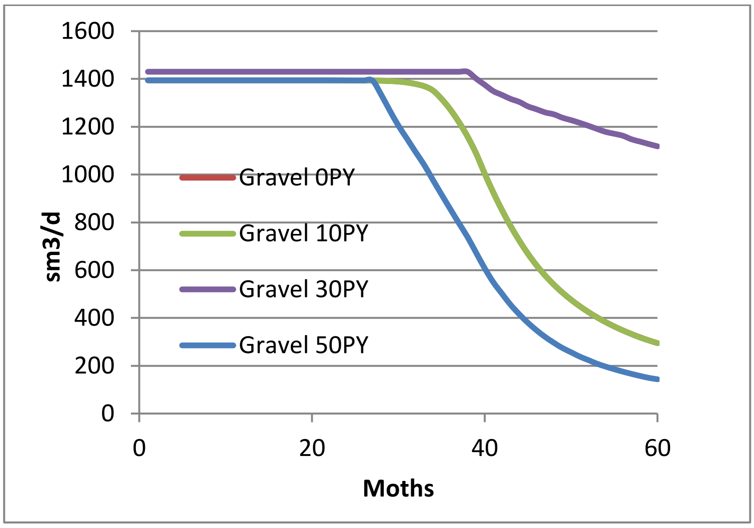

Figure 74 Oil production rates of gravel pack under different skin per year (PY) under 50000 ppm sand.

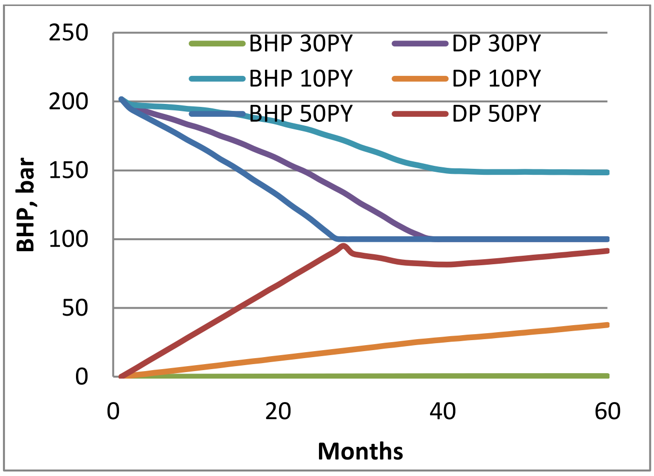

Figure 75 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 50000 ppm sand under different skin per year (PY).

C-1 75μm particles

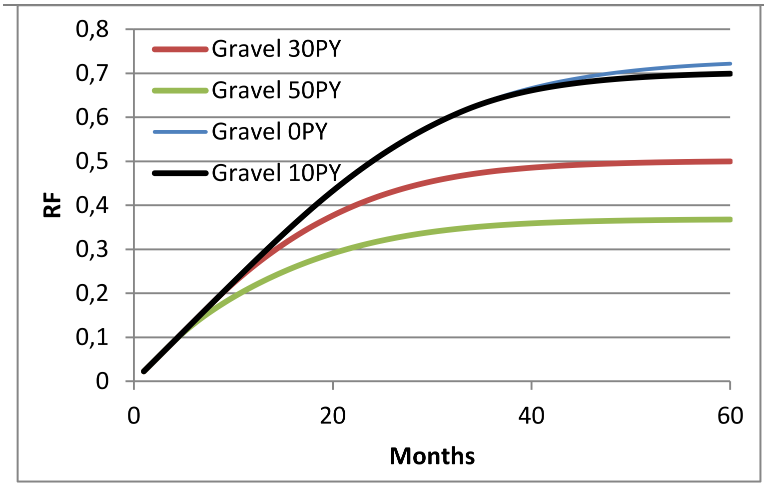

*Figure 76 Comparison of recoveries in a gravel pack completion for 200 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.*

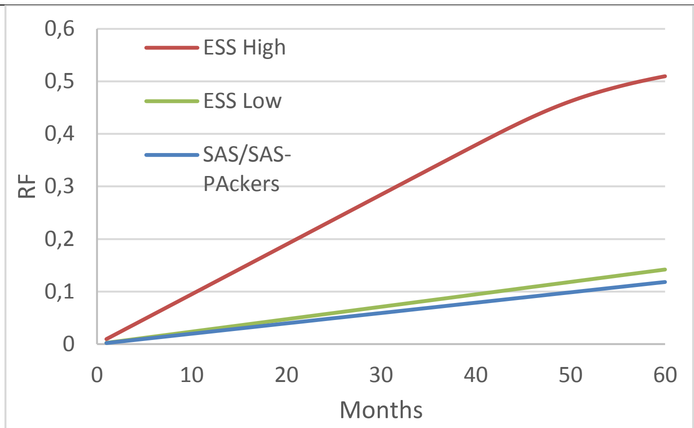

Figure 77 Comparison of recoveries of ESS and SAS completions for 200 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

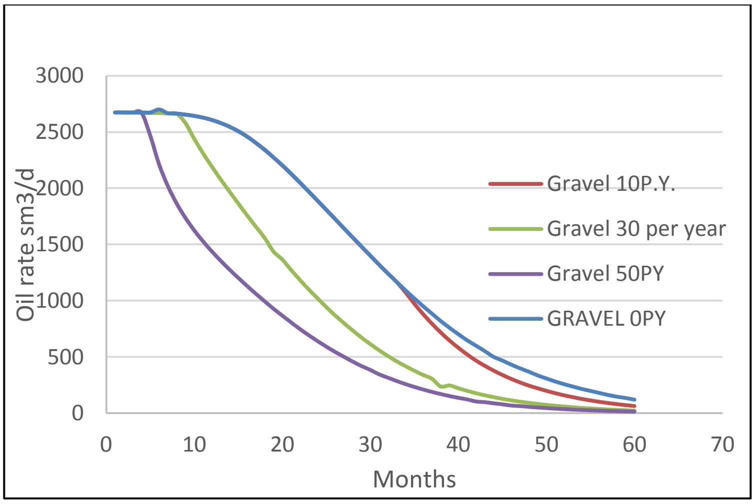

Figure 78 Oil production rates of gravel pack under different skin per year (PY) under 200 ppm sand

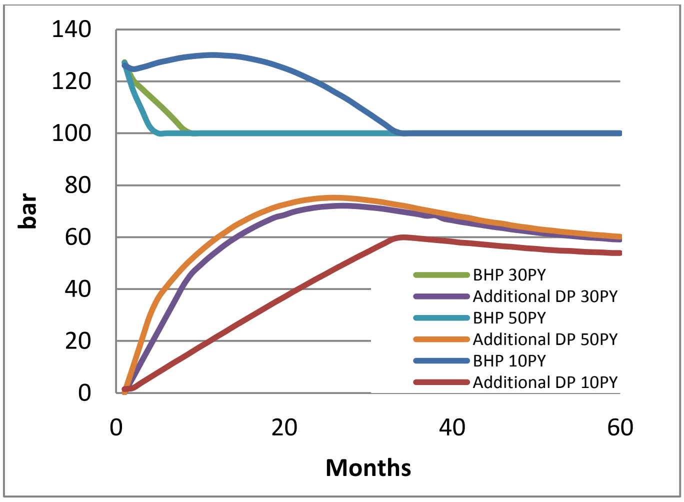

Figure 79 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 200 ppm sand under different skin per year (PY)

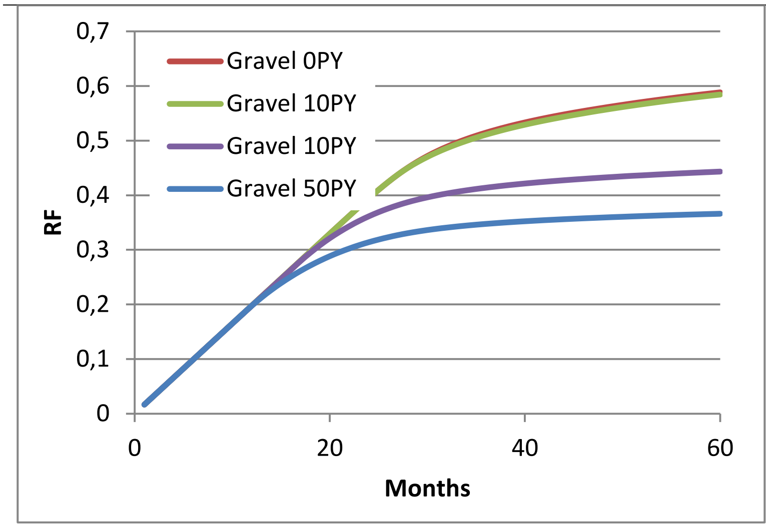

*Figure 80 Comparison of recoveries in a gravel pack completion for 10000 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.*

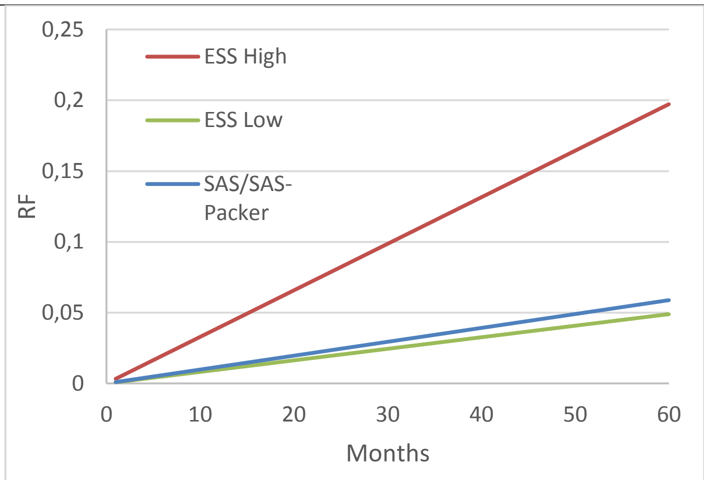

Figure 81 Comparison of recoveries of ESS and SAS completions for 10000 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

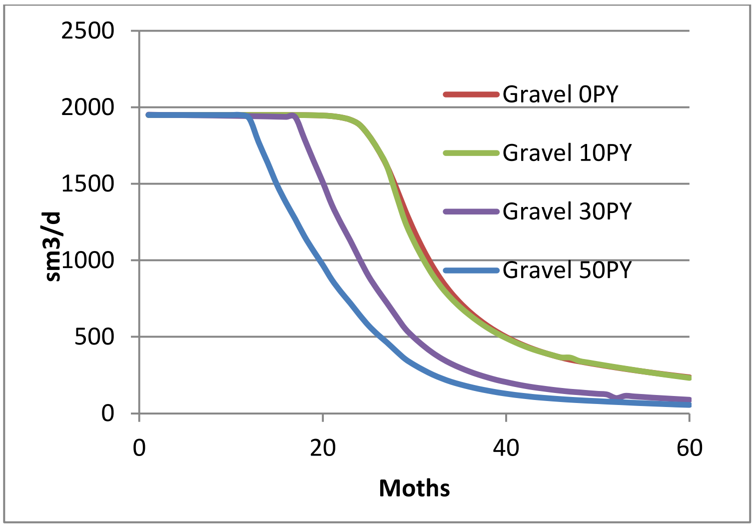

Figure 82 Oil production rates of gravel pack under different skin per year (PY) under 10000 ppm sand

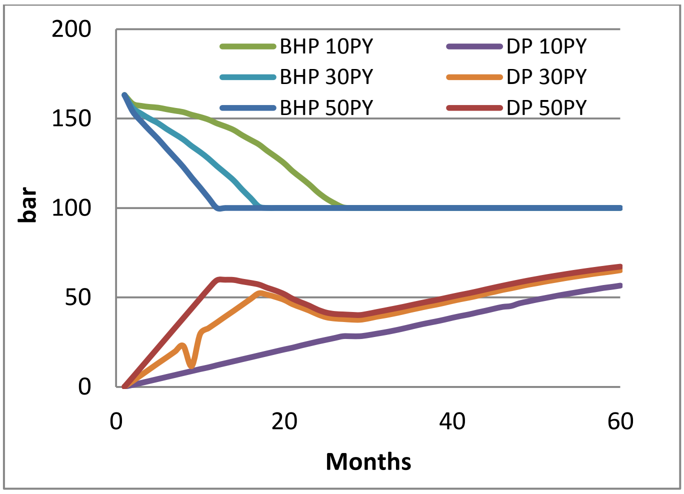

Figure 83 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 10000 ppm sand under different skin per year (PY)

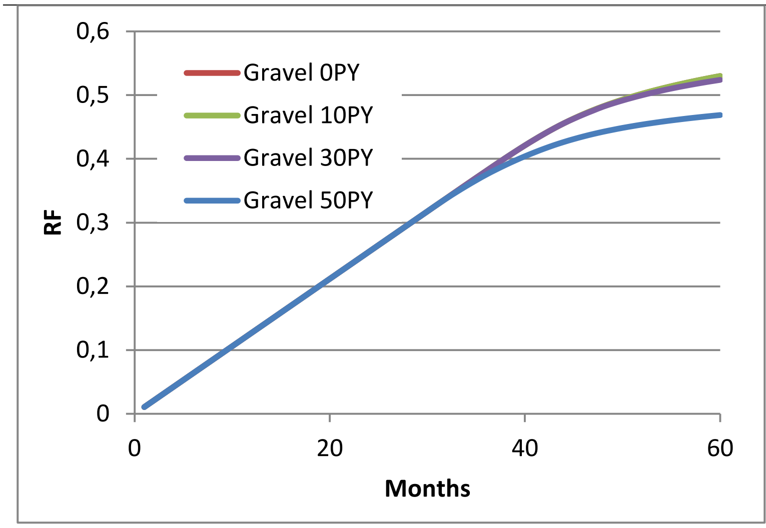

*Figure 84 Comparison of recoveries in a gravel pack completion for 50000 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.*

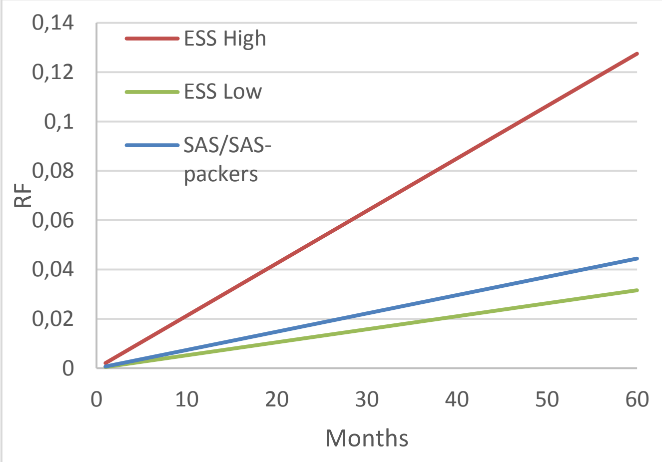

Figure 85 Comparison of recoveries of ESS and SAS completions for 50000 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

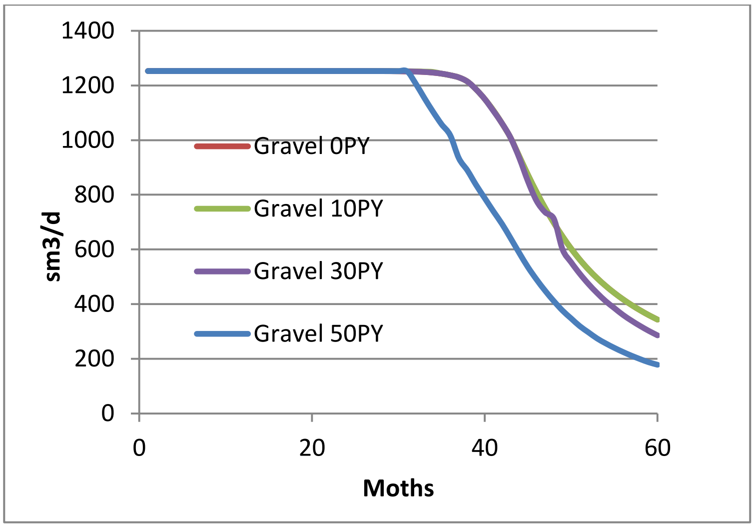

Figure 86 Oil production rates of gravel pack under different skin per year (PY) under 50000 ppm sand

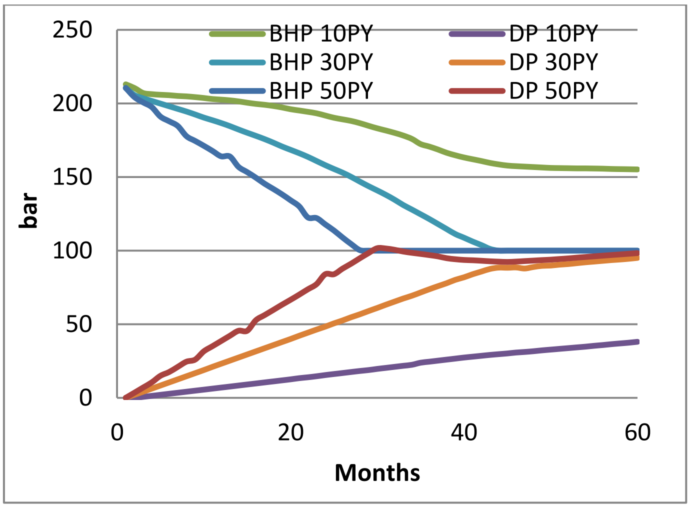

Figure 87 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 50000 ppm sand under different skin per year (PY)

C-1 100μm particles

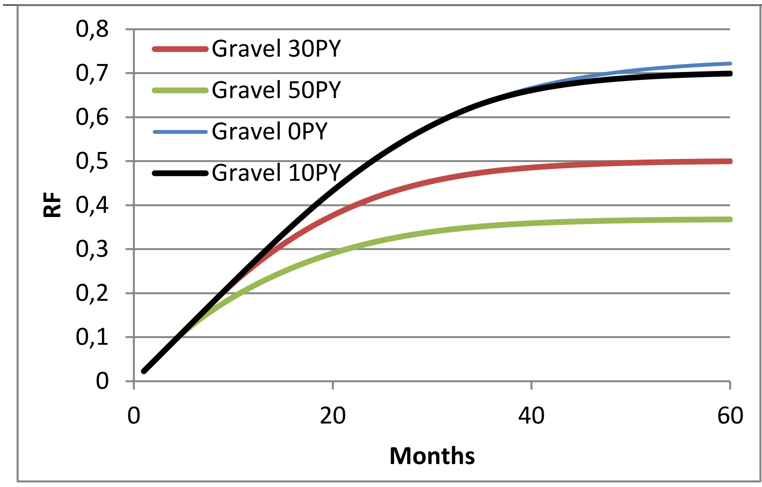

*Figure 88 Comparison of recoveries in a gravel pack completion for 200 ppm. **PY – skin value per year. As seen a low addition of skin have a small impact on recovery factor while high skin reduces recovery dramatically.*

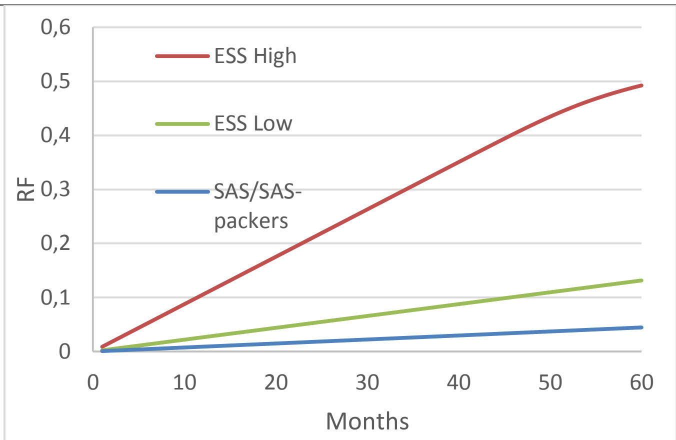

Figure 89 Comparison of recoveries of ESS and SAS completions for 200 ppm sand. Even at low inflow areas, ESS performs better than SAS completions.

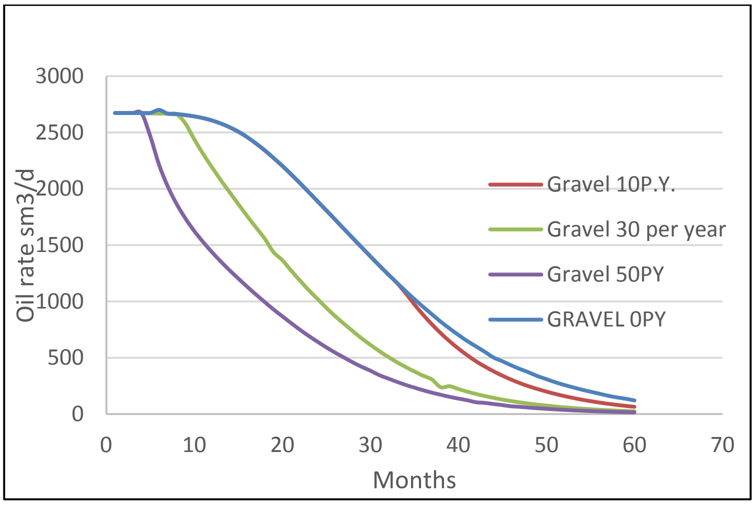

Figure 90 Oil production rates of gravel pack under different skin per year (PY) under 200 ppm sand

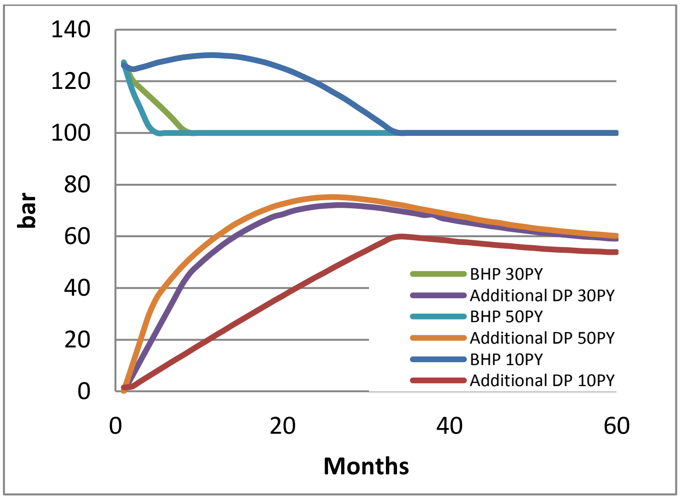

Figure 91 BHP pressure and additional pressure drop(DP) due to skin in gravel pack completion in 200 ppm sand under different skin per year (PY)

Unfortunately, production data for 10000-50000 ppm_w was lost in a damaged USB-Drive and will not be shown here.

Nomenclature

$\sigma' - effective\ stress$
$T_0 - tensile\ strength$
$\sigma_3' - lowest\ principal\ stress$
$\tau_{max} - critical\ shear\ stress$
$\sigma_1' - highest\ principal\ stress$
$S_0 - inherent\ shear\ strength$
$\mu - coefficient\ of\ internal\ friction$
$F_r - force\ needed\ to\ induce\ faliure\ behinde\ the\ grain$
σ_z' - *effective axial stress*

σ_θ' - *effective tangential stress*

A – *cross sectional area of the element*

Δx – *is the length of the volume element*

Δp_f – *pressure drop along the element*

k- *element permeability*

η_f – *fluid viscosity*

$\phi - porosity$

d_g - *diameter of the grain*

Q – *Fluid flow rate*

$\sigma_h' - smallest\ horizontal\ effective\ far\ field\ stress$

$p_f - pore\ pressure\ at\ the\ cavity\ wall$

$p_w - well\ pressure$

$R_c - radius\ of\ the\ cavity$

v_{fr} – drained Poisson's ratio

α – Biots poroelastic constant

$C_0 - uniaxial\ compressive\ strength$

$p_{fo} - far\ field\ reservoir\ pressure$

$\sigma_v - vertical\ stress$

$\sigma_r - radial\ stress$

$p_f - pore\ pressure$

$g_{pn}^c - critical\ drawdown\ pressure\ gradient$

D_{50} – *mean particle grain size*

$S_{wn} - normalized\ water\ saturation$

$S_w - water\ saturation$
$S_{wi} - initial\ water\ saturation$
$S_{orw} - oil\ water\ reduced\ saturation$
$k_{row} - \ oil\ water\ relative\ permeability$
$No - correy\ oil\ number$

$k_{rw} - water\ relative\ permeability$
$Nw - correy\ water\ number$
ER – Eroded screen weight loss
$F - matcing\ factor$
V_r – reference velocity for specific erosion
HR – Vickers hardness ratio between particle and screen3
SE_r- Reference Specific erosion
d- mean particle diameter
V_f – Face velocity
ϵ- Flow velocity multiplier
A – exposed screen area
T – time
C – particle consentration
P- carrier fluid density
a – matching factors
b – matching factors
$L_{segment}$ – length of producing segments

PD- perforation density

r_{perf} – perforation radius

Vf – fluid velocity

L_{gp} - linear flow length in the gravel pack

$S_{gp,dam}$ gravel pack damage skin

h – height of the layer

k_{gp} undamaged gravel pack permeability

$k_{gp,dmg}$ gravel pack damage permeability

A area open for flow in for the gravel pack

k – formation permeability

$Q_{safe} - safe\ production\ rate$

$V_{safe} - safe\ fluid\ velocity$

Q – well flowrate

PI – productivity index, based on local upscaling

ΔP – pressure drop between reservoir and the well

K_{eff} – effective upscaled permeability for flow perpendicular to the wellbore

L – segment length

μ – average fluid viscosity

r_w –wellbore radius

S- skin

M- mobility.

T- transmissibility

H- high velocity coefficient

Ω- Condensate banking/gas break out adjustment coefficient

Q_i is phase flowrate

M_i – phase mobility $=\frac{k_{r,i-relative\ phase\ permeability}}{\mu_i - phase\ viscosity}$

$K_{ups} - upscaling\ permeability$

r_w is equivalent wellbore radius

r_o is the upscaling radius

M- phase mobility

K_h – horizontal permeability

R_e- radial extent of the reservoir

r_w – Wellbore radius

S – skin factor

L – segment length

C_{well} is a global PI multiplier

$C_{segment}$ is the per segment transmissibility multiplier

$II - injectivity\ index$

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