Production Performance of Radial Jet Drilled Laterals in Tight Gas Reservoirs in the Netherlands

A Simulation Approach and Economic Analysis

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Abstract

In the Netherlands, a significant number (25+) of small tight natural gas fields are stranded. They are classified, according to the PRMS definition, as contingent resources. The combination of low GIIP and low permeability currently do not allow these fields to be developed economically without stimulation, which is usually required to produce tight gas reservoirs.

The recent change in legislation on hydraulic fracturing increases the need for a more cost effective and politically accepted alternative. Since natural gas has played, and will continue to play an important role in the energy security of the Netherlands, alternative methods are considered to extract these stranded resources. Radial jet drilling could be such an alternative method to develop these reservoirs in a cost effective, environmental friendly and socially acceptable manner.

In this report, a numerical reservoir simulator is used to compare the production performance of a synthetic low permeable homogeneous reservoir based on three development options: a conventional vertical well, a vertical well stimulation through radial jet drilling and one case where the vertical well is stimulated through hydraulic fracturing. The static and dynamic models are based on typical tight gas reservoir properties as found in the Netherlands. The objectives are: to determine the operational scope / boundary conditions for the application potential of radial jet drilling, to identify the reservoir- and well variables that control the effectiveness and production performance, and to evaluate the economics. The comparison of the development option includes a sensitivity and uncertainty analysis of the well and reservoir performance and the impact it has on the economic viability.

The simulations demonstrate that the laterals appear to be most effective in low permeable (0.1 mD) reservoirs, reservoirs with near-well bore formation damage, with lower initial water saturation's, depleted reservoirs and thin reservoirs. The laterals appear less effective in more permeable reservoirs and reservoirs with high horizontal-to-vertical anisotropy.

The application of small diameter laterals generally results in a recovery improvement factor of 2-3.5 compared to a vertical well. The initial gas production improves with a factor 4-7. The small diameter laterals become effective for reservoirs with permeabilities lower than 10 mD. In reservoirs with a permeability lower than 0.1 mD the application results in a recovery factor improvement of at least 2. The lateral length is the well design parameter that has the most profound impact on the recovery factor.

The economics demonstrate that the onshore application of radial jet drilling as a stimulation method is economically feasible and robust whereas a vertical well is economically very marginal. The offshore application of radial jet drilling is only feasible for stranded volumes $>$ 1 BCM in combination with a re-entry scenario.

Acknowledgements

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Contents

Chapter 1

Introduction

The Rotliegend and the overlying Zechstein group contain more than 95% of the (Dutch) natural gas reserves. A small group of fields however have not (yet) been developed due to a variety of reasons and are considered stranded. These stranded fields are defined as not producing sufficient net revenues to make it worth developing at a given time. However, should technical and/or commercial conditions change, such a field may become commercial. In the Petroleum Resource Management System (PRMS) [1] these fields are classified as contingent resources [37]. A recent analysis performed by Energie Beheer Nederland (EBN) shows that the majority of the stranded gas fields are tight and that the largest volumes occur in the upper Rotliegend group. The tight gas portfolio consists of 24 stranded fields with a total Gas Intially In Place (GIIP) of 59.5 Billion Cubic Meters (BCM), of which ca. 55.1 BCM (93%) is located offshore and 4.4 BCM onshore. Approximately 46.7 BCM (73%) is contained in 14 Rotliegend fields of which 9 fields contain less than 1 BCM.

There is not a single definition for tight gas reservoirs, however it is generally accepted that tight gas reservoirs refer to low-permeability sandstones with a porosity $< 10\%$ and a permeability < 0.1 milli-Darcy (mD). The definition used by EBN, is that tight fields cannot produce gas from low-permeability reservoirs in economic quantities without stimulation treatments at current technical and/or commercial conditions [37]. A widely used stimulation method is Hydraulic Fracturing (HF), however in the Netherlands it has been restricted for the time being awaiting legislative authorisation. An alternative method could be Radial Jet Drilling (RJD), which involves jetting multi-laterals from the main well bore in order to increase productivity.

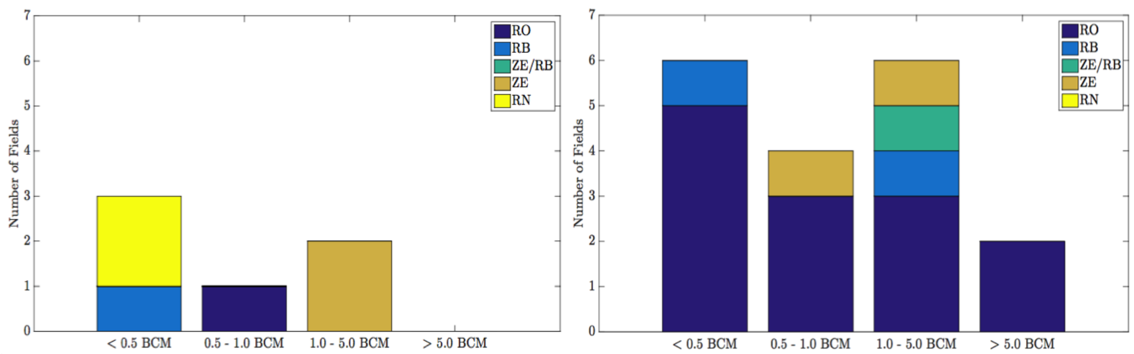


Figure 1.1: Stranded gas volumes in the Netherlands. Left: onshore, right: offshore. RN = Upper Germanic Trias Group, RB = Lower Germanic Trias Group, ZE = Zechstein, RO = Upper Rotliegend Group.

Multi-laterals are horizontal wellbore branches that radiate out from the main (vertical/slanted) wellbore. The drilling of multi-laterals involves conventional horizontal directional drilling techniques, slim hole drilling or coiled-tubing drilling to create a sidetrack [19]. Depending on the level of completions (guidelines described by Technology Advancement Multi Laterals (TAML),

[1] see appendix A.

the multi-lateral wells can be logged, monitored and even controlled with smart well technology.

The laterals that result from RJD will be addressed with a different term as they have not been drilled with conventional bits, cannot be completed, controlled, logged or re-entered due to their limited diameter. Therefore the term SDL will be used throughout this study to refer to the Small Diameter Laterals that are the result of stimulating a well with RJD.

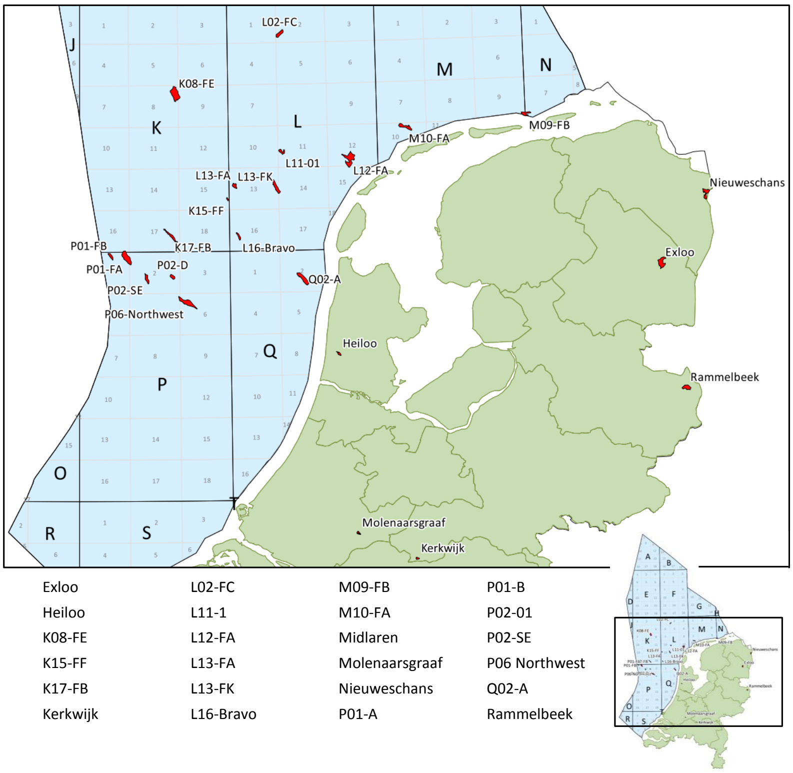


Figure 1.2: All stranded gas fields in the Netherlands that have been classified as tight according to EBN, 2015.

Work has already been performed on multi-lateral wells, and general conclusions that have followed are listed in [19] and many other publications. However, here it is also mentioned that every case is coupled to rigorous economics, which will eventually determine the applicability of individual projects. Study work on RJD however is limited. In studies by [7], [35], [3], [4],[8] and [34] RJD in oil reservoirs, tight gas reservoirs and geothermal applications is discussed.

1.1 Study objectives

Since field tests are scarce, and benefits from RJD are often only described in literature, the need for a more quantitative description has become evident to supply the industry with numbers to work with. The combination of RJD still being considered as new a technique and a lack of understanding of how the technology works does not contribute to the acceptance of this potential attractive stimulation technique.

As in all projects, well and reservoir performance, rigorous economics and political acceptance determine the feasibility of a project. Therefore the study objectives are as follows:

- Understand how much the application of RJD yields in terms of gas production improvement.
- Understand the RJD technology and operating envelope.
- Understand the key parameters that control the well and reservoir performance.
- Evaluate the economic viability of the RJD application on the stranded tight gas fields in the Netherlands, onshore and offshore.
- Raise the interest of operators to take into account RJD as an enabling technology to (re) develop and / or stimulate gas fields.

1.2 Structure of report

The report has been structured as follows. In chapter 2 the reservoir characteristics of tight gas sandstones are described. In chapter 3 the RJD process is explained, the information is based upon literature and interviews with operators and service company staff. Chapter 4 is a combination of chapter 2 and 3, identifying potential production problems that could occur when applying RJD on tight gas reservoirs. The parameters discussed in chapter 2,3 and 4 will be used as input for the simulation models. In chapter 5 the used data, model definition and simulation methods are discussed. In chapters 6 and 7 the simulation results, model validity and the methodology are reviewed. The conclusions and recommendations are summarised in Chapter 8 and 9.

Chapter 2

Tight Gas Reservoirs

Reservoir characterisation is key in determining what factors control production and what parameters are to be used for simulation models. This section describes the general reservoir characteristics of tight gas fields within the Rotliegend group.

2.1 Static properties

Depositional environment

The Rotliegend group comprises clastics and subordinate evaporites which have been buried at depths varying from 2 to ca. 4.5 km where the sediments have been exposed to temperatures between 60°C and 180°C [13]. Within the Rotliegend group, various depositional environments have been recognised, these include alluvial, wadi, aeolian dune, sandflat and playa lake depositional settings in which sedimentary processes were driven by drier and wetter cycles in an arid to semi-arid environment [13].

Diagenesis

Reservoir characteristics, such as porosity and permeability, are dependent on the depositional environment. However, in most tight gas reservoirs, diagenetic processes have a profound secondary effect. Although diagenetic clay minerals form only 3% of the Rotliegend sandstone, its impact on reservoir properties is significant [45]. Due to diagenesis, cements are deposited in the small pore throats of the sandstone, reducing permeability and blocking fluid flow. Impairment of permeability is mainly due to authigenic clays such as illite, kaolinite and chlorite [13]. Illite is the most prominent clay mineral which can seriously reduce the permeability, while hardly affecting porosity [45]. Porosity impairment occurs by pore-filling blocky anhydrite and carbonate cements [13].

Faults and natural fractures

Natural fractures in the Upper Rotliegend group are quite rare and are therefore not considered to have a major control on the reservoir connectivity and gas recovery (see [14] and [27]. The most common natural fracture types are cataclastic and cemented, and can hold significant pressure differences however. Many Rotliegend fields are dissected by faults that depending on their (non-) sealing nature may form baffles or barriers to fluid flow [27].

2.2 Dynamic properties

Swelling

Another cause for permeability reduction is swelling. Two forms of swelling exist: crystalline- and osmotic swelling [2]. The latter involves clay minerals of the smectite group coming into contact with completion fluids. The magnitude of swelling is dependent on the clay type and the contact fluid [44]. Typical threshold entry equivalent radii for tight gas sandstones vary between 0.1-1 microns [1] [5]. The combination of very small pore throats and the water wet rocks (typical for sandstones) have an impact on the capillary pressures that occur in the transition zone.

Permeability jail

The target tight gas sandstones are two-phase systems where the water phase interferes with the gas phase to flow freely (gas being the non-wetting phase). Determining the effective gas permeability is therefore crucial to identify the flow potential of the gas in the presence of water due to the risk of water phase trapping in a so called "permeability jail". There exists a saturation region in which the relative permeabilitys of water and gas are too low for effective fluid flow to take place (see appendix figure A.1). The jail occurs because water is tightly held by capillary forces in the small pore throats of a tight gas sandstone. The smaller the permeability and the pore throats, the larger the permeability jail region [38] and [5]. This region varies per rock type and pore geometry but typically occurs when:

$k_g < 0.05$ mD
$k_{rg} < 2$ % and $k_{rw} < 2\%$
55% - 80% s_w

Water saturation

But also without a permeability jail, gas production in tight sandstones is difficult to achieve. The high water saturation results in low relative gas permeability, which in turn has to be multiplied with the already very low absolute permeability to achieve to effective gas permeability. The associated capillary pressures encountered in tight gas reservoirs studied by [38] suggest that gas columns of 90-300 m are required to achieve acceptable levels of effective permeability to gas.

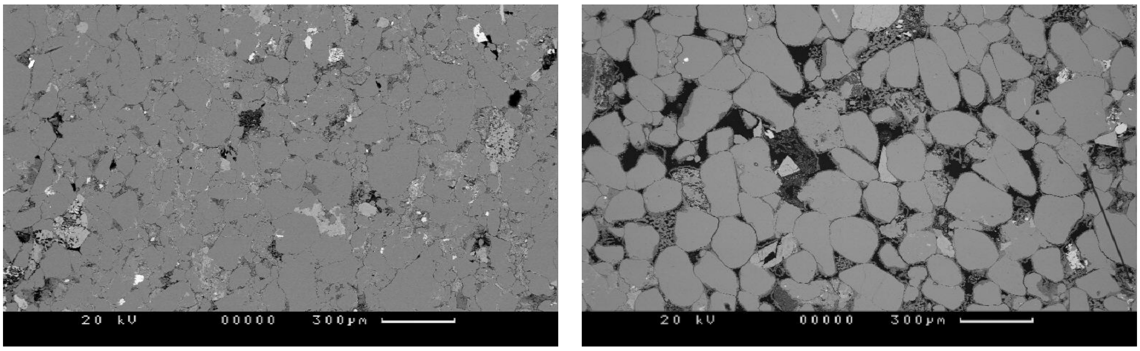


Figure 2.1: Scanning Electron Microscope (SEM) images from the same tight Rotliegend sandstone showing significant variations in pore space and connectivity. Left: low porous and impermeable sandstone. Right: high porous and permeable sandstone. Courtesy of EBN.

Pressure and fluids

In the Netherlands, onshore and shallow offshore (< 1500 meters) reservoir pressures are typically hydrostatic [39]. However in the North-East of the Netherlands, Rotliegend overpressures range from 100 bars above hydrostatic in Groningen and Friesland to about > 200 bars above hydrostatic towards the Dutch Central Graben. Very high overpressures of 400 bars have been observed in block L2, in the southern part of the Dutch Central Graben [40]. The over pressured reservoirs often have complex burial histories that prevent connate pore-fluids to escape and therefore must effectively be sealed of in three-dimensions [20]. The amount of overpressure is influenced by the burial rate, reservoir architecture, sealing capacity of the overlying Zechstein evaporates, compartmentalisation and fault types. Pore fluids and pore-fluid pressures influence the physical and chemical properties of the subsurface. Typical salinity ranges from 150 [g/L] to > 300 [g/L], depending on the geographical location [40].

[1] micron (μm)=10^{-6}m

Chapter 3

Radial Jet Drilling

RJD enables drilling laterals from a mother bore with a high pressure water jet operated via coiled tubing (CT). It can improve oil and gas field production by providing an increased drainage area, reaching unproductive zones, opening up conductive channels through near well-bore formation damage and connecting natural fractures and permeable layers [7] and [11].

RJD can be applied on new wells and on existing wells; active and non-active. However, operations on new- and existing wells are to be differentiated. For new wells, RJD can be incorporated in the regular drilling program (see appendix Radial Jet Drilling), orienting and jetting one lateral every 12 hours. If the tools do not fit through the existing completions (e.g. liner, production tubing, SSSV), a well kill is required to remove the existing completions from the well and install a temporarily work-over tubing through which the RJD operations can take place. In most cases the existing completions are re-newed or interchanged with back-up completions. Especially in the Netherlands, where a lot of wells are aged a work-over rig would be necessary and would make operations more time- and capital intensive. However, even then, RJD could be cost effective due to its low operating costs and potential of improving well performance. The concept is illustrated in figure 3.1.

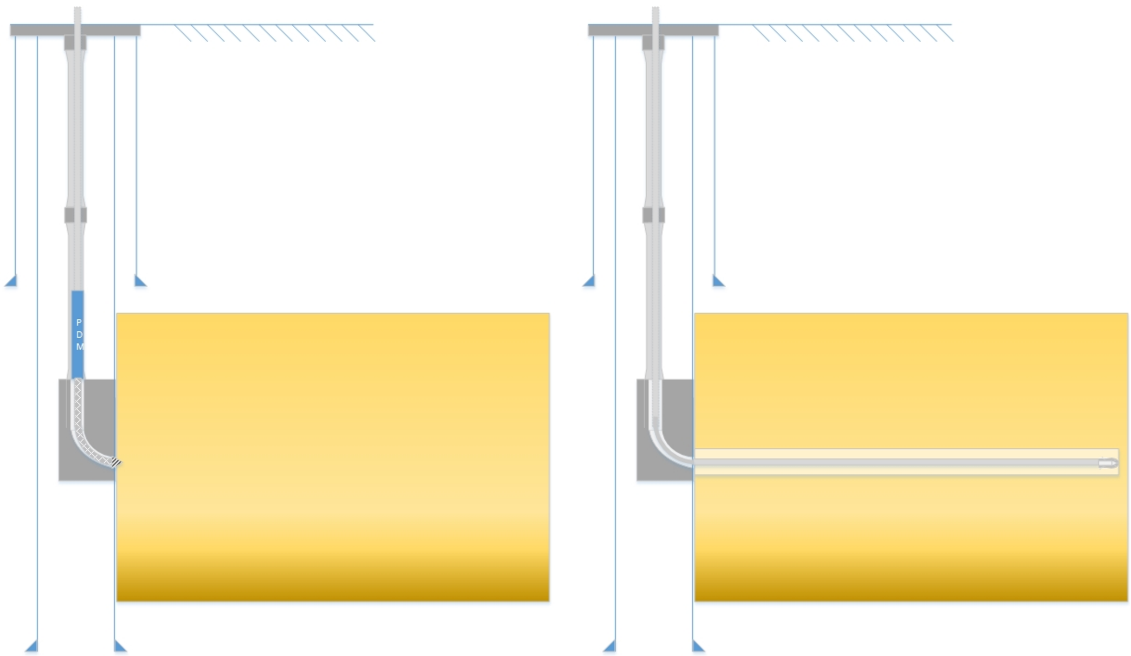


Figure 3.1: Left: The milling process, blue block indicates the Positive Displacement Motor (PDM), the grey block the deflector shoe. Right: the jetting process. Courtesy of the Well Services Group.

3.1 Benefits, limitations and applications

The primary benefits of RJD according to literature are:

- It can be a cost effective method to complete vertical wells to perform like an open hole horizontal completion [4], whereas normal sized multi-laterals require complex drilling techniques and specialised completions.

- The use of a clear jetting fluid reduces formation damage since there is no filter cake build up [7]. In reactive formations, KCl can be added as clay stabilizer [16].

- The environmental footprint of RJD is small compared to hydraulic fracturing units; the water use is significantly smaller, no frac fluids, gels or proppants are required and the surface footprint is negligible [43].

Primary limitations of RJD are:

- No down-hole production management, no Measurement While Drilling MWD and re-entry options [4].

- Directional control is not (yet) possible, meaning that reaching specific targets is challenging [43].

- Laterals can terminate prematurely due to reservoir heterogeneities, loose flow and direction in fractures and faults. [4].

- Since there are no returns to surface (de-consolidated material drops into the rat hole), it is not possible to analyse cuttings and thus retrieve formation data.

Other RJD applications could be guiding acid stimulation, directing hydraulic fracturing or injecting water for geothermal wells [34]. Technological developments will continue to increase the operating ranges. HP/HT wells, live wells and CT through existing production tubing are the main focus areas for most service companies. Offshore operations require capital intensive work-over rigs and a fixed structure to prevent coil/string vibrations.

3.2 Operating conditions and equipment

The general operating conditions as discussed with service companies are listed below.

Property	Field units	SI units	Remarks
Flow rate	4 - 8 gal/min	2.5 - 5 x10^{-4} m3/s	Depends on effective pump pressure
Lateral diameter	2 in	0.0508 m	Depends on formation
Maximum lateral length	328 ft	100 m	Depends on formation and inclination
Operating depth MD	0 - 15000 ft	0 - 4572 m	Not a hard limit. Case specific.
Maximum bottom hole temperature	410 °F	210 °C	Equipment standard.
Wellbore inclination	0 - 40°	0 - 40°	Horizontal wells are possible as well.

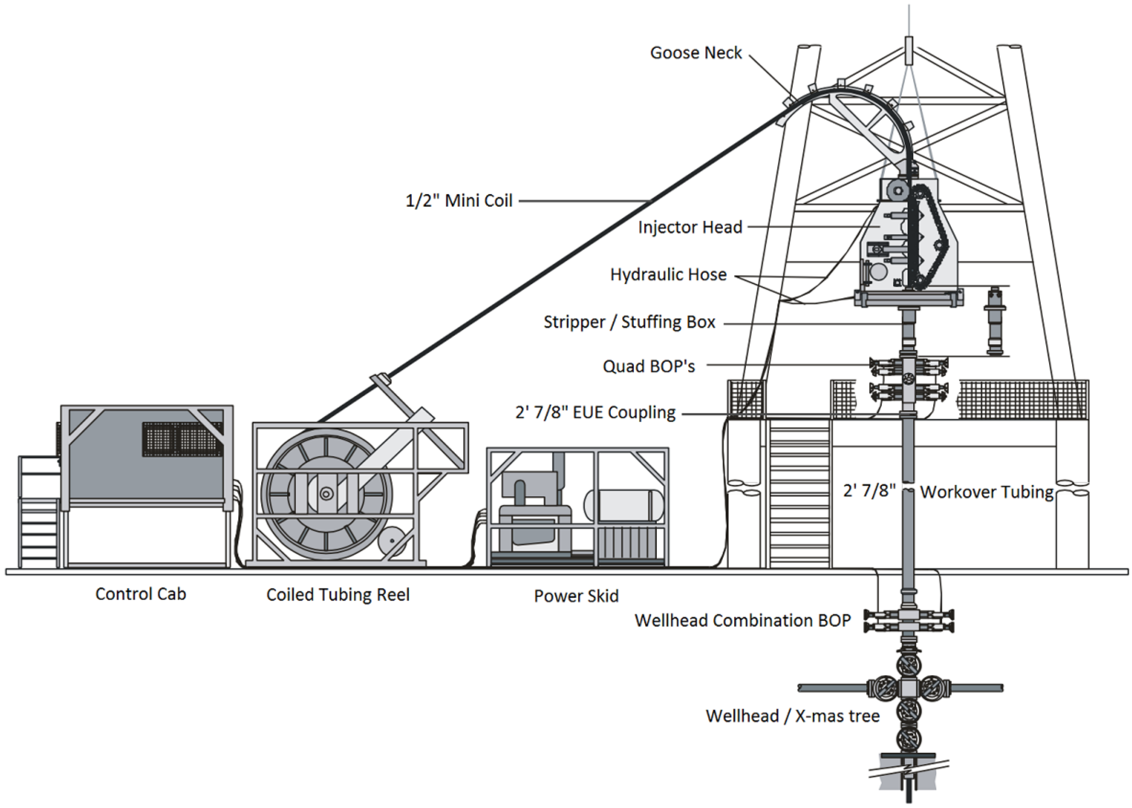


Figure 3.2: Lay-out of work-over rig and coiled tubing unit as used in RJD operations. Courtesy of the Well Academy.

A typical setup for the work-over rig and CT unit is shown in figure 3.2. The goose neck guides the mini coil from the reel to injector head. The injector head inserts/snubs the CT into the stripper. The stripper provides an hydraulic seal around the CT and maintains pressure control during snubbing. The quad Blow Out Preventer (BOP), typically contains a blind, shear, slip and pipe ram. The EUE coupling connects the work-over tubing fixed in the rig slips and the Quad BOP. The wellhead combination BOP contains only a pipe and blind shear ram. The wellhead contains the valves, kill line, choke line and return line. In operations that require a well kill and removal of the production tubing, the kill fluid acts as a primary barrier, the stripper as secondary barrier and the BOPs as tertiary barrier. Note that both the annulus between the casing and the 2 7/8 inch work-over tubing, and the annulus between the work-over tubing and the 1/2 inch mini coil are completely filled with kill fluid. For a more detailed well configuration see figure B.1 in Appendix B.

The equipment is compatible with standard CT. The special parts are the deflector shoe, gyro E-line, milling assembly and jetting assembly. The deflector shoe is located at the end of the CT; it guides the milling- and jetting assembly and ensures reservoir well bore contact via a push pad. The giro E-line is the orientation tool, it sets the orientation of the deflector shoe. The milling assembly consists of a milling bit (dependent on casing API), a torque chain with swivel and a Positive Displacement Motor (PDM). The jetting assembly consists of a nozzle, kevlar hose, mini-coil connection and high pressure connection seals. The nozzle diameter typically varies from 0.5 to 0.75 inches and is approximately 1 inch long [4]. A schematic overview is given in figure 3.3.

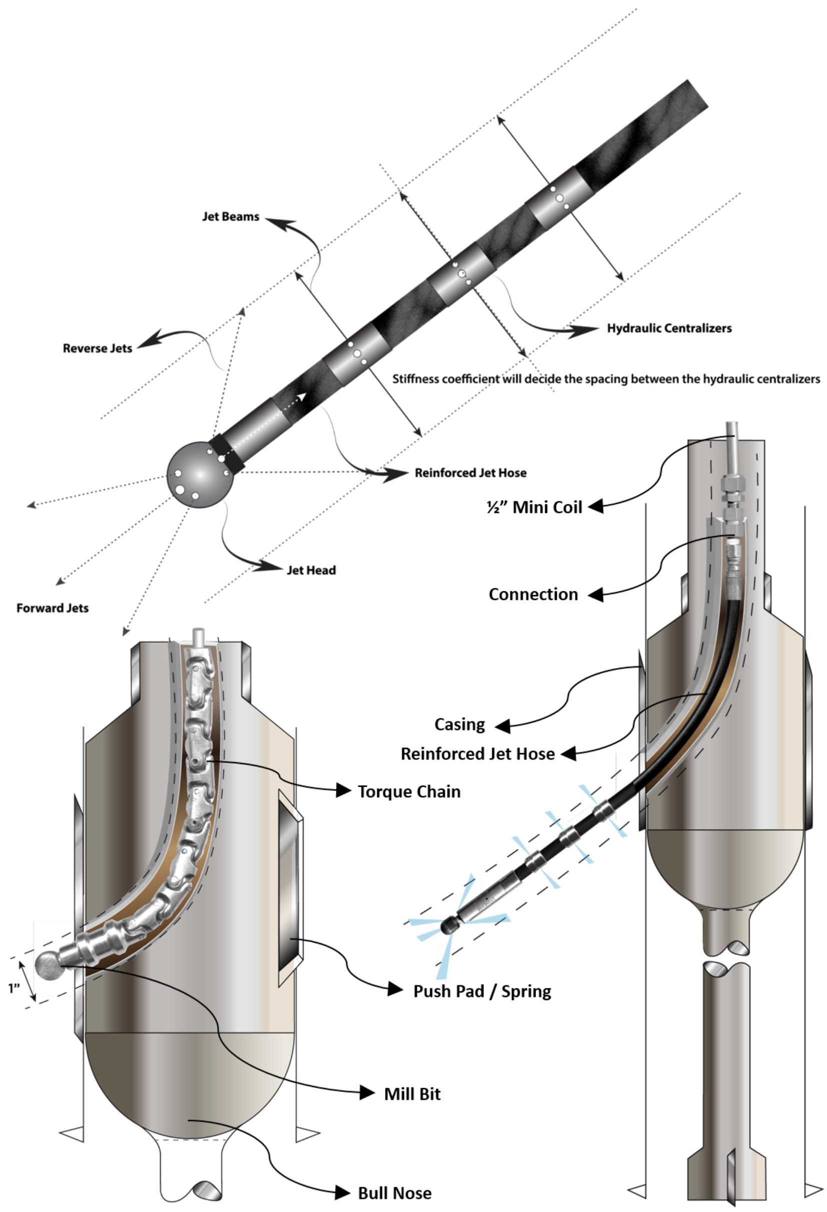


Figure 3.3: The deflector shoe and mill bit (bottom left), the deflector shoe and the jetting assembly (bottom right) and the jet and hose in detail (top). Courtesy of Well Services Group.

Chapter 4

Production Performance

4.1 Tight gas reservoirs and radial jet drilling

This section describes the potential problems associated with tight gas reservoirs and RJD. As with any reservoir type, tight gas sandstones are subject to the normal variety of damage mechanisms caused by drilling and completions. However, the small pore throats and dependency of flow from natural fractures make tight formations extra sensitive for:

- liquid invasion and clay swelling; causing permeability reduction
- plugging of natural fractures (if present); causing loss of well connection

Petro-physical properties

The combination of depositional environment, mechanical compaction and the influence of diagenesis on the micro-structure (grain-size, sorting, presence of clays and cements) of the sandstones control the petro-physical properties of the reservoir and thus its production potential/tightness.

Transition Zone and water phase trapping

The combination of small pore throats and water wet rocks causes the transition zone in tight gas reservoirs to be significant. The high capillary pressures cause the critical water saturation and irreducible water saturation to be high even far above the Free Water Level (FWL). This results in very low effective gas permeability in tight gas reservoirs with high water saturation. In the gas zone, initial water production will probably be low due to a combination of high capillary pressure (water is immobile) and the high horizontal-to-vertical permeability anisotropy.

Formation swelling

The presence of smectites, as mentioned above, implies the use of inhibitors during jetting to prevent clay swelling. A small amount, 7% of Kalium Chlorite (KCL) could potentially be enough [2], [16].

Condensate gas

It could also be possible that when the reservoir- and/or well bore pressure reaches the dew point pressure of a wet gas, condensation occurs and a two-phase mixture is created. The condensates from the gas can have relative permeability effects when occurring in the formation, but it could also cause liquid loading problems when the condensate condenses in the tubing.

Tectonic stress

The tectonic stress regime could be of major influence on the lateral stability. A tectonic active area could result in pre-mature lateral collapse, seriously reducing the long term production. Even normal compaction, which aids gas recovery in the first stages of production (compaction drive) could reduce reservoir permeability and lateral stability in later stages.

Production strategy

In oil reservoirs, water can sweep oil to increase the recovery factors. In gas reservoirs however, water influx from an aquifer could support the reservoir pressure and by-pass the gas. This could result in gas being trapped and lower ultimate recoveries. Mitigation measures involve outrunning the water by producing at high rates [1] and [10].

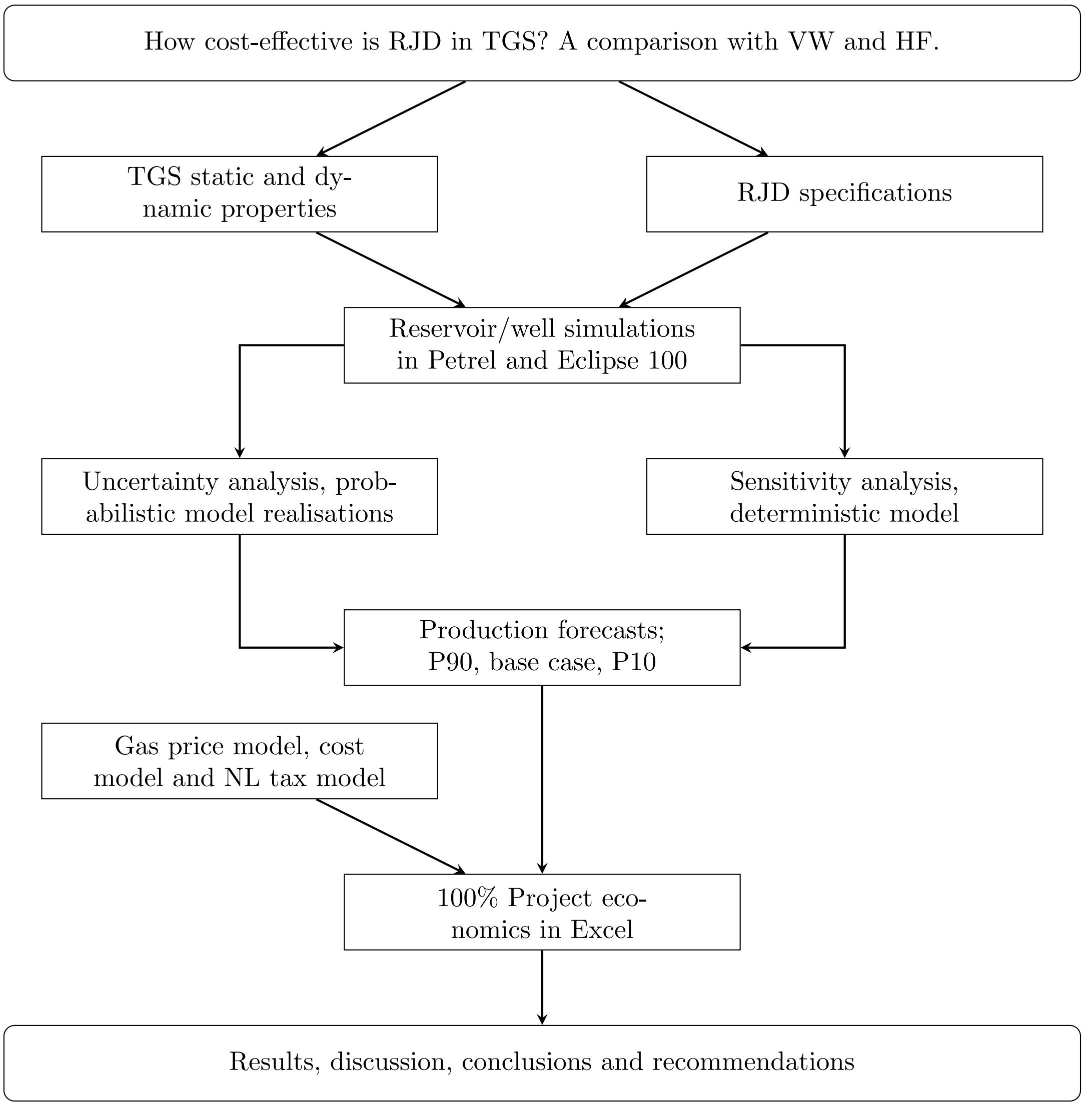
Chapter 5

Method

A full numerical model has been used to study the effect of small diameter laterals in a synthetic reservoir model. The numerical model has been constructed in Petrel using the simple grid option to create a square sector model. The simulations have been run in Eclipse 100. A small high quality data set from EBN has been used to define the most important parameters such as porosity, permeability, water saturation and reservoir pressure. All other unknown values have been assumed to be preset values for consolidated sandstones. The parameters for the small diameter laterals have been supplied by a service company offering RJD. The reservoir has been represented by a homogeneous reservoir to allow comparison between a completion with a vertical well and a completion with a vertical well + small diameter laterals. The data set has been combined with a range of reservoir parameter values supplied by experts within EBN, being representative for tight gas accumulations in the Dutch Rotliegend. The economics have been analysed for 14 development scenario's and are based on simulated production forecasts and a cost model.

The high level method/workflow is illustrated below.

5.1 Workflow



5.2 Data

5.2.1 Reservoir characterisation

The data set is from a Rotliegend Tight Gas Sandstone (TGS) situated in the Southern sector of the Dutch North Sea. The data comprises well logs and 12 core samples that have been analysed with Routine Core Analysis (RCA) and Special Core Analysis (SCAL). The well encountered top reservoir at 3345 m True Vertical Mean Sea Level (TVMSL), GWC at 3440 m TVMSL and FWL at 3515 TVMSL. The average reservoir temperature encountered was 98 °Celsius. The depositional environment consists of sheetfloods, dry sandflats and aeolian dunes. Although the amount of data is limited, the quality is high and is considered to be a good analogue for a typical Rotliegend tight gas reservoir in the Netherlands.

Table 5.1: Overview of log and core sample data from well EBN1. The number of core samples n=12.

Parameter	Min	Mean	Max
Porosity [-]	0.049	0.105	0.175
Permeability [mD]	0.001	0.370	3.050
Water saturation [-]	0.400	0.700	1.000
Reservoir pressure [Bar]	389	396	404
Illite-smectite [%]	1.400	3.100	5.000

The porosity data can be approximated with a truncated normal distribution as shown below. The arguments of the truncated normal distribution are: min=0.030, μ=0.105, max=0.180 and σ=0.033.

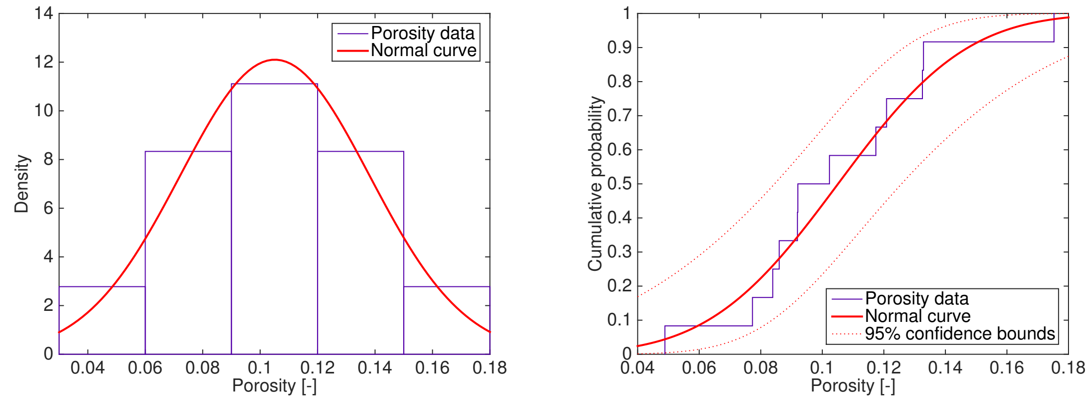


Figure 5.1: Left: porosity density distribution with a bin size of 0.025. Right: cumulative probability distribution.

The porosity has been corrected for logging effects (Archie, Caliper, NMR) and is considered representative for the in-situ porosity. The absolute permeability has been measured in the lab and has also been corrected for in-situ conditions. The porosity and permeability data are shown in figure 5.1, and the porosity-permeability relationship is

$$k = 0.0001e^{56.054\phi} \tag{5.1}$$

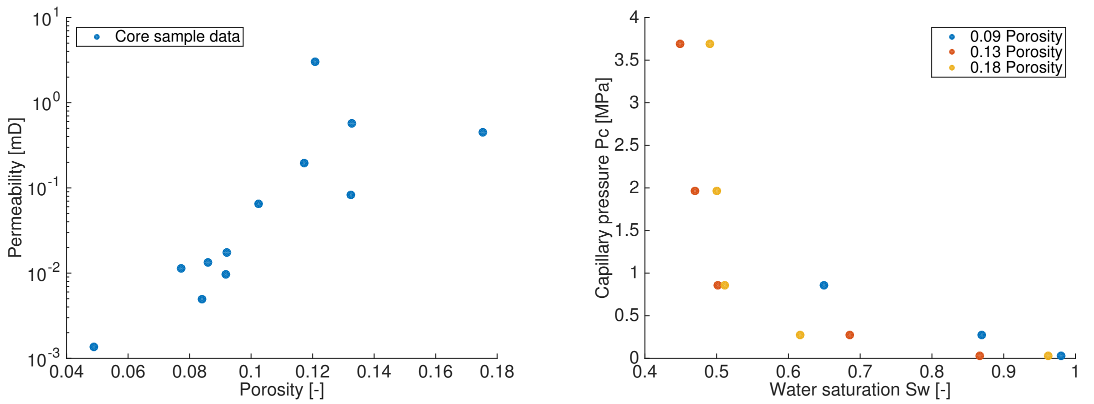


Figure 5.2: Left: porosity and permeability data from the core samples. Right: capillary pressure and corresponding water saturation per porosity class.

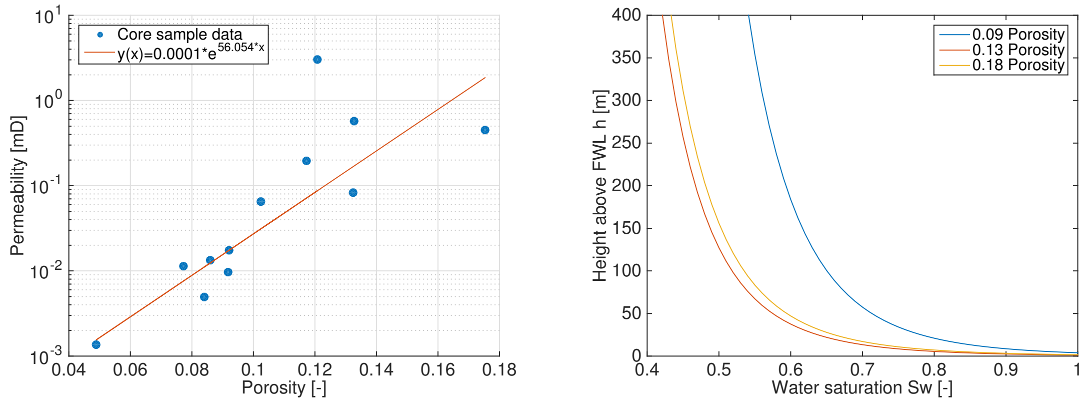


Figure 5.3: Left: porosity-permeability relation from core data. The exponential fit has an $R^2 = 0.672$. Right: The water saturation height functions per porosity class, derived from the capillary pressure data.

The SCAL capillary pressures and the corresponding water saturations have been measured for different porosity classes in an air-brine system. In figure 5.3 we see the water saturation for different capillary pressures per porosity class. Generally speaking, high porosity implies low capillary force and thus a lower water saturation. However, the water saturation for the 0.18 porosity is higher than that of the 0.13 porosity due to a lower associated permeability. The saturation height functions have been derived by approximating the reservoir rock as a bundle of capillaries where water is the wetting phase.

$$h = \frac{p_c}{(\rho_{brine} - \rho_{gas})g} \tag{5.2}$$

where $\rho_{brine} = 1100$ $[kg/m^3]$, $\rho_{gas} = 0.8$ $[kg/m^3]$ and $g = 9.81$ $[m/s^2]$. h is the height above FWL [m] and p_c is the capillary pressure [Pa]. The resulting saturation height function for the 0.13 porosity class is expressed as

$$h = 1.2348 s_w^{-6.686} \tag{5.3}$$

The saturation height functions that have been calculated with the original capillary pressure data show very high water saturations even far above the FWL. As a result, the associated effective gas permeability's in the reservoir are very low and result in a very small amount of gas production in the simulation model. In combination with the non-availability of relative permeability curves, the few capillary pressure data points per porosity class, it has been decided to only use the porosity-permeability data and the assumption that the gas water contact is equal to the free water level (thus no transition zone). Effectively this means that the gas zone above the GWC is at irreducible water saturation, with gas production only being hampered by the low (absolute) permeability of the reservoir.

To summarise, the parameter ranges from the data set that have been used in the model are the porosity-permeability relationship, the reservoir temperature (100 °C) and the reservoir pressure (40 MPa). All other reservoir parameter ranges have been chosen to be representative for Rotliegend tight gas sandstones in the Netherlands. The minimum, mean and maximum values are shown in table 5.2.

5.3 Model definition

5.3.1 Reservoir model

An important aspect in capturing the effectiveness of small diameter laterals was simulating in relatively small grid blocks. The right balance between accuracy (convergence of the solution with smaller grid blocks), computational speed and data size was determined using a grid study. Cell dimensions of 20x20x10 meters (x,y,z) in a model of 1000x1000x200 meters (x,y,z) was found to be sufficient to capture the production performances for comparison purposes.

The sector model is homogeneous with a horizontal-to-vertical anisotropy (assumed to lie between 1 and 100 [34]), as the the objective is comparison of different production strategy's. A heterogeneous or layered reservoir, which would have been a more realistic representation, would make quantitative comparison much more complicated as the SDL's would then penetrate different layers. Therefore all grid blocks have the same properties in the horizontal and vertical direction.

For modelling purposes, the top of the reservoir is set at 3400 m TVDSS, the GWC at 3500 m TVDSS and the bottom of the reservoir at 3600 m TVDSS. The net-over-gross was fixed at 0.5. The flowing bottom hole pressure was at 100 bar, considering that the export pressures vary between 40-80 bar[1]. The simulated run time is 20 years, with a 30 days time-step. Only in the first month the time-step is reduced to 1 day to prevent simulation convergence problems.

5.3.2 Vertical well (VW) model

The VW model consists of a vertical well completed from top reservoir down to 20m above the GWC. The casing inner diameter is 4.5 inch, the diameter of the perforated zone is 7.5 inch. The skin of the well is assumed to be 5 to reflect the high near wellbore formation damage of most vertical wells in tight gas sandstones.

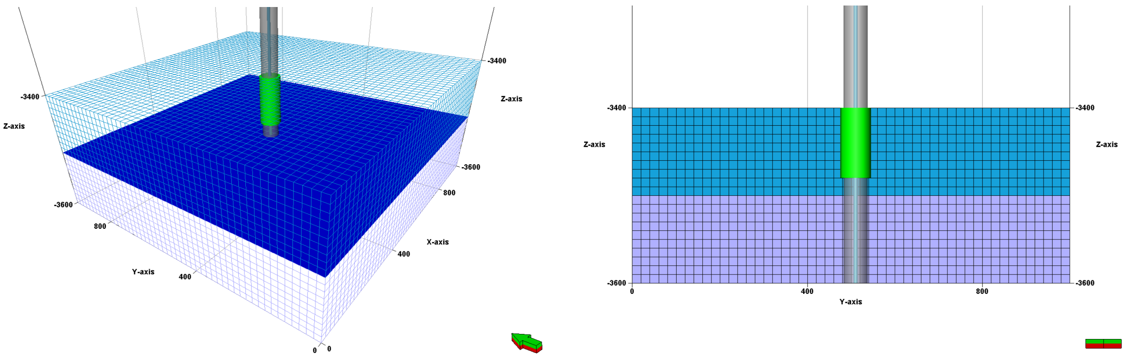


Figure 5.4: Left: Overview of the vertical well model. Right: cross section of the vertical well model. The blue area is the GWC, the green cylinder represents the perforation interval and the grey cylinder the casing. The colour scheme indicates the initial pressure distribution. The illustrations have been scaled vertically with a factor 2.

5.3.3 Small diameter laterals (SDL) model

The SDL model consists of the VW model with four evenly spaced open hole laterals perpendicular to the vertical well. So the SDL model is the VW model stimulated with RJD. The laterals have been modelled using the lateral package (Petrel module), properties such as the diameter required modification in the calculator. The laterals are 100 meters in length and 2 inch in diameter. The kick off point is in the middle of the perforated zone. It is assumed that laterals themselves do not have skin as they have been jetted with brine [7].

[1]Pressure drop over a vertical well is 20-60 bar for flow rates between 100.000-500.000 [m3/d]. Calculated with MATLAB, length 3500 m, tubing size 3 inch, from [22]).

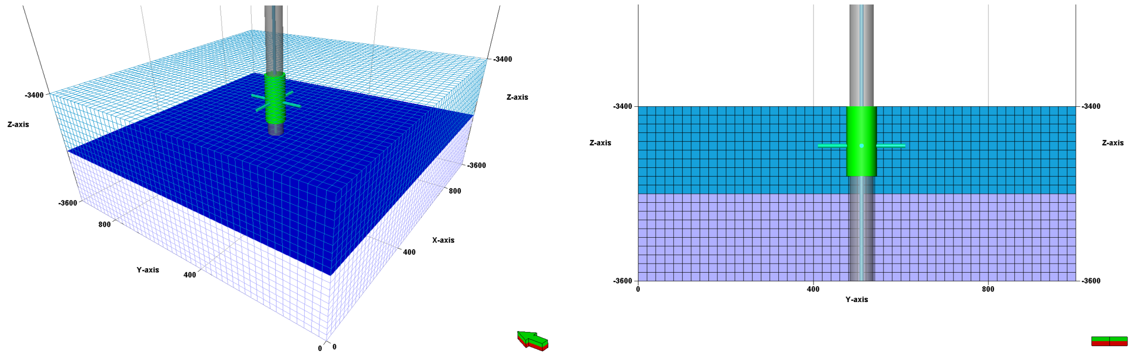


Figure 5.5: Left: Overview of the vertical well model. Right: cross section of the vertical well model. The blue area is the GWC,the green cylinder represents the perforation interval, the grey cylinder the casing and the coloured tubes the laterals. The illustrations have been scaled vertically with a factor 2.

The following reservoir and SDL parameters have been chosen as input for the simulations. The porosity, horizontal permeability and reservoir pressure approximate the values from the data set. The vertical permeability, water saturation and reservoir thickness are representative for the variation encountered in Rotliegend TGS fields. The parameters for the small diameter laterals have been chosen based upon information supplied by a service company offering RJD.

Table 5.2: Range of modelling parameters

	Parameter	Symbol	Min	Mean	Max
Reservoir parameters	Porosity [-]	ϕ	0.04	0.11	0.18
	Permeability xy [mD]	k_h	0.001	0.05	2.4
	Permeability xy/z [mD]	k_h/k_v	1	10	100
	Initial water saturation [-]	s_{wi}	0.2	0.4	0.6
	Reservoir pressure [Bar]	p_r	380	400	420
	Reservoir thickness [m]	h	40	100	160
VW parameters	Skin [-]	s	0	5	10
SDL parameters	Number of laterals [-]	n_l	2	4	6
	Lateral length [m]	l_l	50	100	150
	Diameter [inch]	d_l	1	2	3
	Inclination [°]	θ_l	60	90	90

To summarise, the following assumptions have been made

Assumptions

- Homogeneous transverse isotropic medium
- Single phase gas (dry gas)
- No capillary pressures, thus no transition zone
- Small diameter laterals are open hole completions
- Small diameter laterals do not collapse over time

5.4 Simulation setup

Two simulation sets were built. The first simulation set was used for a sensitivity analysis (based upon the one-variable-at-the-time design [33]) to capture the effect of input (parameter ranges) on the output (production behaviour) for the VW and SDL model. The second simulation set consists of 300 full model realisations to test the probabilistic range of the recovery factor for both the VW and SDL model, keeping well parameters constant.

5.5 Sensitivity production performance

In experimental design simulations input variables (i.e. reservoir parameters and well configuration) are varied to observe changes in the output response (rates, UR, RF). There are two methods: full factorial design and one-variable-at-the-time design. Due to computational constraints, full factorial design was not considered. The drawback of only using one-variable-at-the-time however is that no full interaction effects can be captured. The first simulation set involved running a sensitivity analysis on the minimum, mean and maximum values displayed in table 5.2. The simulation set was executed using the uncertainty and optimisation process in Petrel, varying one-variable-at-the-time automatically. The reservoir thickness (defined by location of the GWC) was coupled to the perforation interval and the location of the lateral kick off point, always honouring a 20 m distance between perforations and the GWC, and the kick off point of the laterals always being in the middle of the reservoir.

5.6 Uncertainty production performance

In order to asses the uncertainties involved, 300 simulation runs have been executed for the vertical case and lateral case using Latin Hypercube Sampling (LHS) in the uncertainty process (600 in total), varying the reservoir parameters within the uncertainty ranges defined in table 5.3. LHS samples more efficient than Monte Carlo (MC) by using a stratified sampling technique, resulting in a quicker approximation of the input distributions. In these simulations the porosity-permeability relationship was honoured (where areas in the one-variable-at-the-time analysis, porosity and permeability were uncoupled). For the other reservoir parameters triangular distributions were defined, see figures 5.6. The vertical and small diameter lateral parameters have been kept constant as these can be controlled in comparison to the reservoir parameters. The arguments used during the uncertainty analysis are:

Truncated normal porosity distribution: min=0.040, μ=0.11, max=0.180 and σ=0.033. Initial water saturation: min 0.2, mode 0.4 and max=0.6, reservoir pressure: min=380, mode=400, max=420. gas water contact min=-3560, mode=-3500, max=-3440.

Table 5.3: Input distributions for the uncertainty analysis

Parameter	Symbol	Distribution
Porosity [-]	ϕ	Truncated normal
Permeability xy [mD]	k_h	Truncated log-normal
Initial water saturation [-]	s_{wi}	Triangular
Reservoir pressure [MPa]	p_r	Triangular
Reservoir thickness [m]	h	Triangular

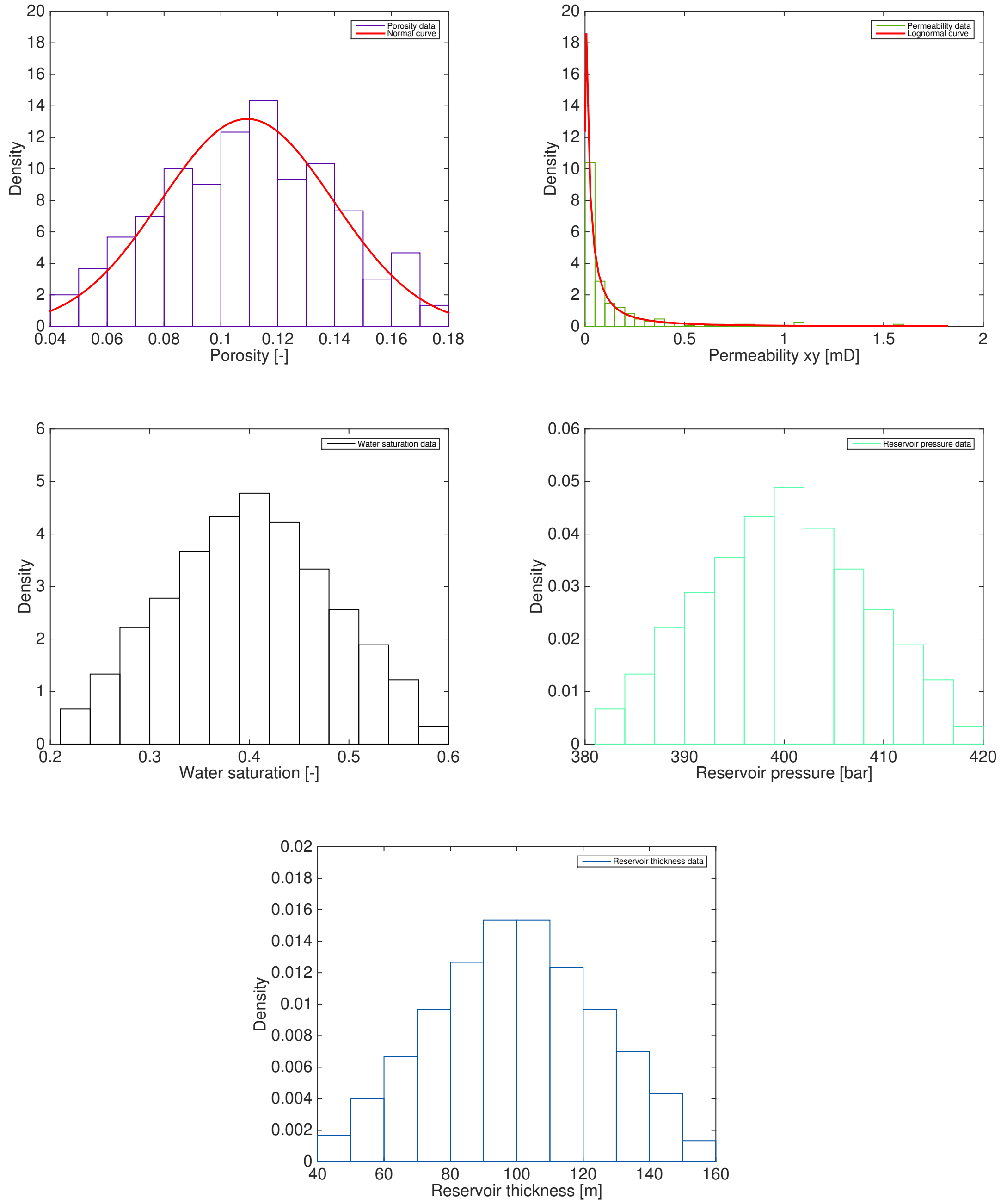


Figure 5.6: Reservoir parameter distributions for 300 simulations

5.7 Economics

The project economics are analysed with a high-level purpose-built spreadsheet that allows combining development options with reservoir models. The input for the project economics consists of production profiles/forecasts and price models. The production profiles come from the reservoir simulations, the price models come from literature and EBN. The key economic indicator for project execution is the Net Present Value (NPV) and Earning Power (EP). The NPV appraises long-term projects against a discount rate. Generally speaking, if NPV>0, projects are considered economic. The EP is the discount rate at which the NPV equals zero, as long EP>r.

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_0 \tag{5.4}$$

where t is the time in years, T is the total number of years, C_t is the Net Cash Flow (NCF) and r is the discount rate (Investopedia).

5.7.1 Development scenarios

The following development scenarios have been analysed. A scenario being defined as a combination between a development option (e.g. well configuration, onshore and offshore) and a reservoir model (e.g. deterministic base case, probabilistic P90 and P10.)

Table 5.4: Overview of development options and reservoir models that have been used for the economic assessment. The reference cases on- and offshore are annotated as **R**

Development Option		Reservoir Model		
		P90 (Low Case)	Deterministic Base Case	P10 (High Case)
Onshore	VW		x	
	Re-entry SDL	x	**R**	x
	New well SDL		x	
	Re-entry HF		x	
	New well HF		x	
Offshore	VW		x	
	Re-entry SDL	x	**R**	x
	New well SDL		x	
	Re-entry HF		x	
	New well HF		x	

The overall assumption for the reference case (deterministic base case + re-entry SDL) onshore/offshore stranded gas fields is the presence of a closed-in appraisal well that may be re-entered, and the absence of production facilities. The deterministic base has the following properties: $\phi = 0.11$, $k_h = 0.05$ mD, $k_h/k_v = 10$, $sw_i = 0.4$, $p_r = 400$ Bar, $h = 100$ m and $GIIP = 0.94$ BCM. The re-entry SDL development scenario has the following properties: $n_l = 4$, $l_l = 100$ m, $d_l = 2$" and $\theta = 90°$.

The economic robustness of the re-entry SDL option has been tested against the P90 reservoir model (based upon the 300 simulations obtained from the uncertainty analysis) whereas the economic upside has been tested against the P10 reservoir model. The other scenarios involve a green field development (assuming exploration has already taken place) where drilling a new vertical well is immediately combined with stimulation through RJD (New well SDL). The VW development option assumes that only a vertical well is drilled. The economics for all scenarios have been tested for onshore and offshore to take into account the substantial cost differences.

The economic analysis uses the production forecasts from the simulations and the financial model components defined below. The three main components are the costs, the gas price and the tax/royalties regime. An economic spreadsheet (see appendix D) has been purpose built to cover the high level project economics, combining important cost aspects with production performance.

5.7.2 Cost model

The cost model is divided into Capital Expenditures (CAPEX) related to wells, facilities and overhead costs, Abandonment Expenditures (ABEX) to restore a well site, and Operational Expenditures (OPEX) required to operate and maintain the wells and facilities. The simplified CAPEX cost model is shown below in table 5.5.

CAPEX

The following CAPEX 5.5 have been assumed for the project economics. Naturally, these are general values and can differ significantly per operator and/or contractor.

Table 5.5: Overview of assumed CAPEX.

CAPEX component	Onshore costs (10^6 eur)	Offshore costs (10^6 eur)
Vertical gas well	6.00	20.0
Work over rig	0.20	0.40
RJD stimulation	0.18	0.25
Modular facility	2.00	20.0
Hook up	1.00	1.50
Pipeline	1.50	15.0
Project overhead	0.50	0.75

- The vertical gas well is a standard design e.g. 16" conductor, 7" casing and 3.5" tubing including cementation and perforations.
- The work over rig is assumed to be a light version able to handle CT operations. It has been assumed that the rig is used for 8 days at a rate of 25k euro/day. Offshore requires 10 days at a rate of 40k euro/day.
- RJD stimulation also requires 8 days (4 laterals, 100m, 2" diameter at 3500m depth) at a rate of 22k euro/day. Offshore requires 10 days at a rate of 25k euro/day.
- Facility costs are based upon skid-mounted modular facilities that can easily be deployed and re-used. They typically include gas processing separation and dehydration facilities.
- Hook up costs involve (re)installing, connecting and completing all field components to get everything up and running.
- Onshore would require approximately 5 km of pipeline at a rate of 300k eur/km, offshore would require 15 km of pipeline at a rate of 1 mln eur/km.
- Project overhead is defined as the costs associated with salaries for company staff and fees for engineering contractors.
- Other services such as completion change outs are assumed cost neutral.

ABEX and OPEX

ABEX requires a provision being set aside every year to pay for the field abandonment at the the end-of-field-life. The total ABEX provision is assumed to be 2 million euro Present Value (PV) for an onshore gas well and 5 million euro (PV) for an offshore gas well. The provision is calculated based on constant payments and interest rate (6%).

OPEX includes fixed and variable expenditures and is expressed as % of the total installed CAPEX. Fixed OPEX predominantly relates to the maintenance, repairs and supervision of the installed wells and facilities. This is approximately 0.7% of the total installed CAPEX. Variable OPEX are the expenditures depending on the volume of gas produced and are mostly limited to tariff costs associated with the gas evacuation, the use of pipelines and gas treatment (7.5 eur/Nm3). Simultaneously, this allows the bulk of the OPEX to be carried in the beginning of the project when most of the gas is produced.

5.7.3 Price model

The gas price is based upon the Title Transfer Facility (TTF) price on the 1st of October 2015. The High Heating Value (HHV) of the gas is based upon the HHV Groninger gas. The assumptions for the price model are listed below in table 5.6.

Table 5.6: Overview of assumed price components.

Price component	Value	Unit
Gas price	18.75	euro/MWh
Gas heating value	35.17	MJ/sm3
Gas price	0.18	euro/sm3
Gas price escalation	2	%/yr

5.7.4 Tax model

The tax/royalty model is mainly based upon documentation from Deloitte [6], describing the tax/royalty regime in the Netherlands. For onshore and offshore production licenses, Corporate Income Tax (CIT) and State Profit Share (SPS) apply. For simplification purposes it has been assumed that the effective tax rate is 50% (CIT+SPS). Normally SPS is paid before CIT and then effectively summed up with CIT to become 50 %. This requires an iterative calculation which has been left out. Since all fields are considered marginal, a 25% Marginal Field Tax Allowance (MFTA) [36] on CIT+SPS is applied for all offshore fields (thus 37.5% tax for offshore marginal fields). New operators in the Netherlands (onshore- and offshore) are not required to pay royalties, therefore the royalties have been assumed to be 0%. The assumed depreciation lifetime of both onshore- and offshore projects is 11 years (onshore can be 5-14 years, offshore 11 years) [6]. Depreciation is an accounting term that is only used to calculate the Earnings Before Tax (EBT).

Table 5.7: Overview of assumed tax, royalties and depreciation lifetime.

Tax/Royalty	Onshore	Offshore
CIT+SPS	50%	37.5%
Royalties	0% revenue	0% revenue
Depreciation lifetime	11 years	11 years

Chapter 6

Results

6.1 Sensitivity production performance

6.1.1 Reservoir parameters

The effect of the variation of a single reservoir parameter on the recovery factor for a VW and SDL is summarised by figure 6.1. The recovery improvement factor (RIF) for SDL compared to VW is illustrated by figure 6.1 on the right.

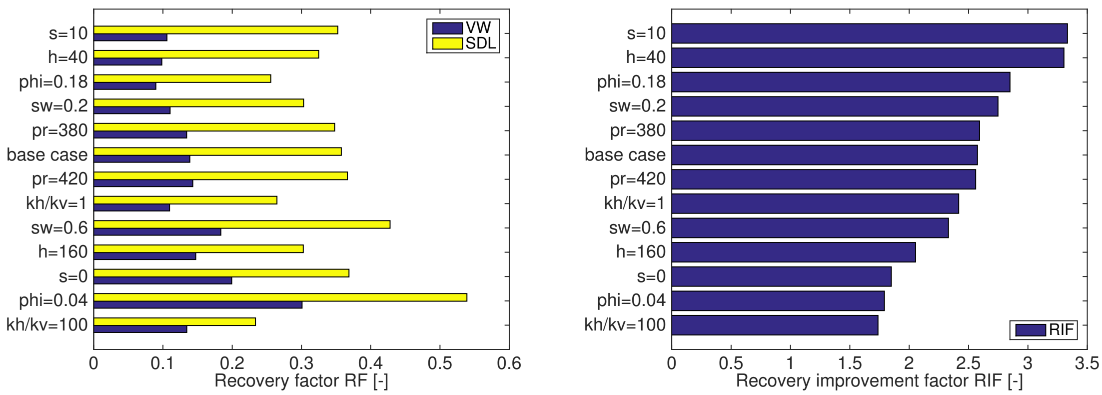


Figure 6.1: Left: Absolute recovery factors for different cases. Right: Relative recovery improvement factor for SDL compared to VW.

The simulation demonstrates that the laterals appear to be most effective in low permeable reservoirs, reservoirs with near well bore formation damage, with lower initial water saturations, depleted reservoirs and thin reservoirs. The laterals appear less effective in high permeable reservoirs and reservoirs with high horizontal-to-vertical anisotropy. The application of SDL generally results in a RIF of 2-3.5 for the simulated cases.

Horizontal permeability k_h

In absolute numbers, the recovery factor increases the most in high horizontal permeability settings when using SDL. This is not surprising as stimulating an already good producing reservoir will only make it perform better. In relative numbers however, expressed in RIF, the low permeable reservoirs gain the most. The low permeability allows only slow flux from the reservoir (high pressure) towards the vertical well bore (low pressure). But by providing a larger effective contact area with a highly conductive lateral, the drainage radius of the vertical well is increased significantly, allowing more production from the matrix in the same amount of time. In figure 6.2 it is clear that the initial gas production between SDL and VW lies between 4-7 units. However, for the high permeable reservoirs the production improvement diminishes quickly and converges to the cumulative gas production of the vertical well. The only benefit is thus acceleration over the first

2-3 years. For the low permeable reservoirs we see not only acceleration but also an improvement in ultimate recovery up to circa 4 times that of a VW.

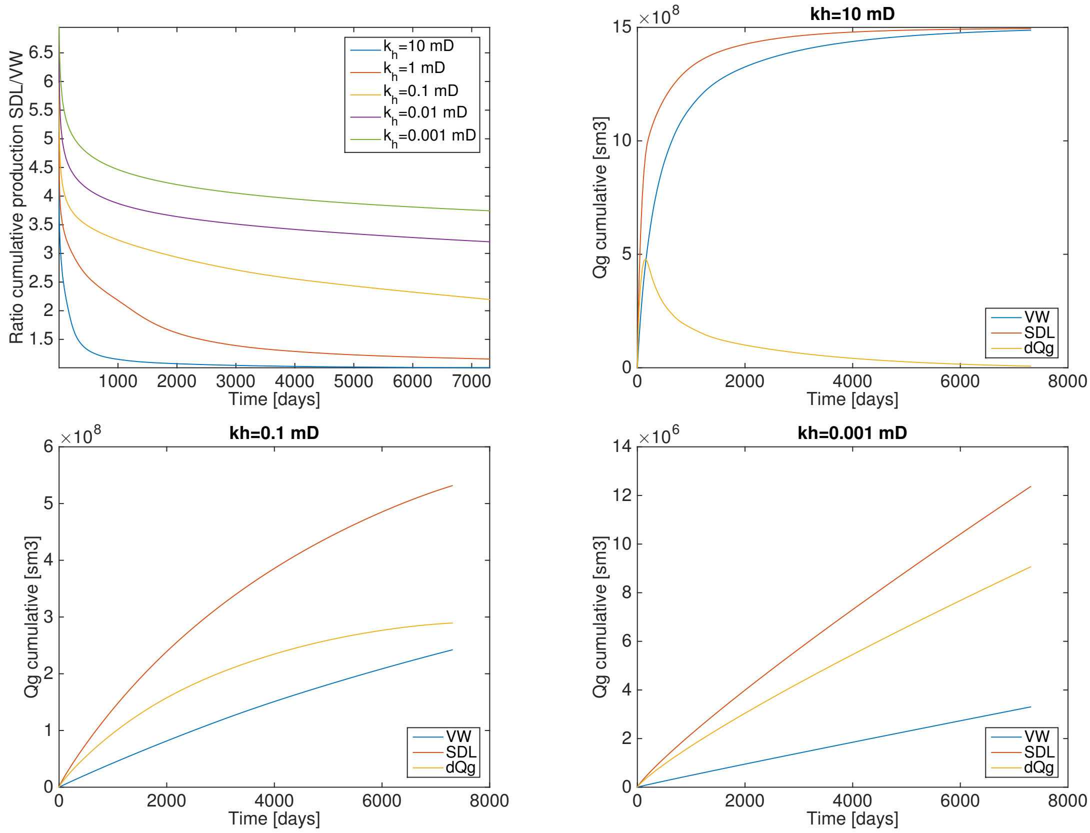


Figure 6.2: Ratio of cumulative gas production SDL/VW and the cumulative gas production profiles for 10mD, 0.1mD and 0.001mD.

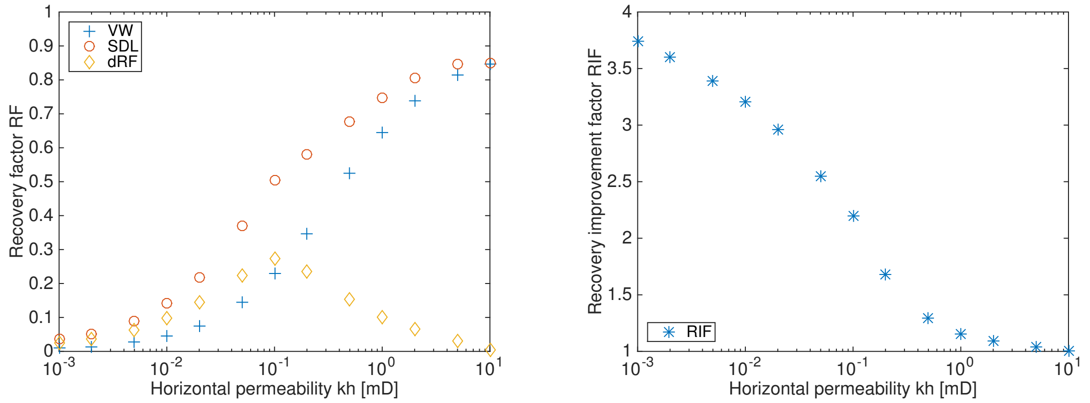


Figure 6.3: Left: Recovery factors for different permeabilities and their differences. Right: Recovery improvement factors for different permeabilities. Horizontal-to-vertical anisotropy is 10.

From figure 6.3 it is clear that RJD could offer a recovery improvement from 5 mD or lower. In reservoirs with a permeability smaller than 0.1 mD the application of SDL results in a recovery factor improvement of at least a factor 2. For even smaller permeability (e.g. 0.001 mD) the recovery improvement factor is > 3.5 compared to the vertical case. However, the absolute average production rates for the first month (< 4000 sm3/day, see figure 6.4) for the SDL case are too low to be economic. The optimum effect of the SDL is around 0.1 mD, the maximum difference in RF (dRF). SDL results in an initial rate improvement of a factor 3-6 compared to a VW and depending on the k_h, see figures 6.2 and 6.4.

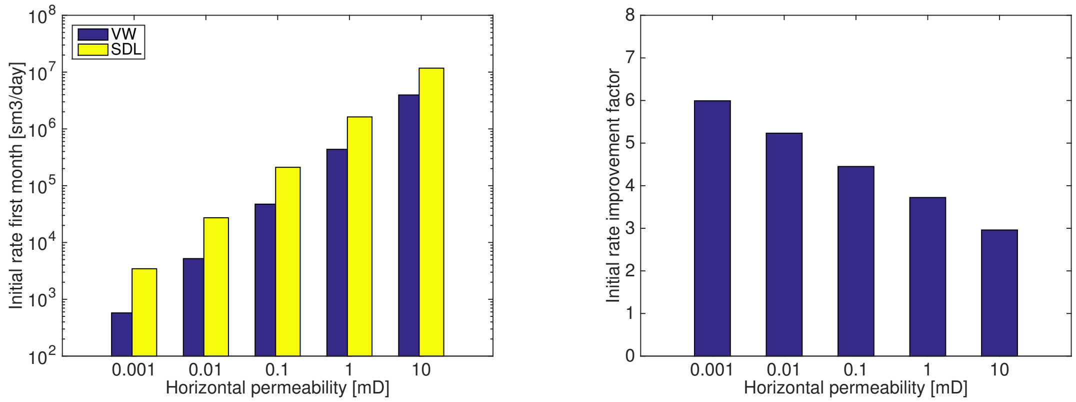


Figure 6.4: Left: Initial day rates first month. Right: Rate improvement factors first month.

Horizontal-to-Vertical Permeability Anisotropy kh/kv

Poor vertical communication reduces the effectiveness of the laterals significantly. Where as a vertical well mostly produces from horizontal flow, laterals also benefit from vertical flow. Good vertical communication however is a risk for early water breakthrough and requires special consideration (see figure 6.5), especially when the distance between the laterals and the GWC is limited.

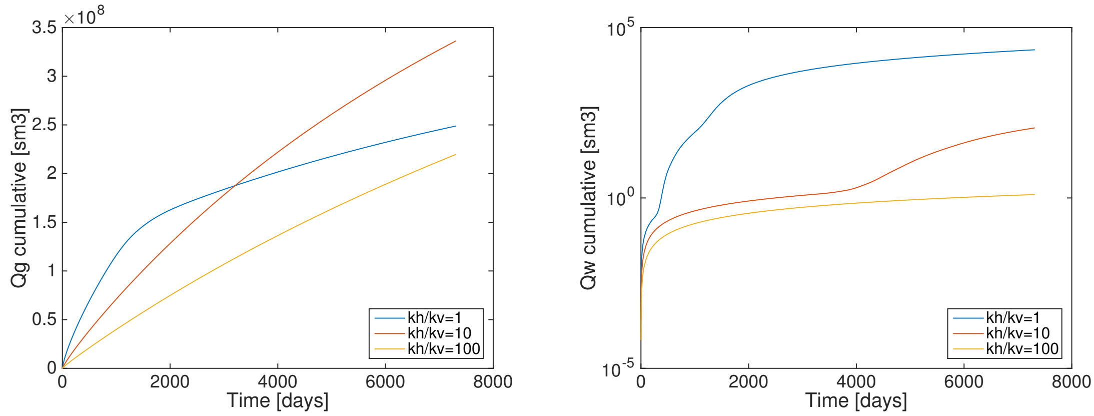


Figure 6.5: Left: SDL case gas recovery for different anisotropy. Right: SDL case water production for different anisotropy.

Initial water saturation

The initial water saturation affects static properties such as GIIP, but more importantly also dynamic properties such as relative permeability. The lower the initial water saturation the higher the GIIP, and the better the relative gas permeability for a given water saturation. In absolute terms, the UR of the sw=0.2 case is higher than that of the sw=0.6 case due to better relative permeability properties. However, the GIIP for the sw=0.2 case is relatively larger compared to it's UR than in the sw=0.6 case, resulting in a higher recovery factor for the sw=0.6 case. In terms of the RIF, the sw=0.2 case outperforms the sw=0.6 case, indicating that the laterals are more effective in reservoirs with low initial water saturation's. See the discussion section on the water saturation model.

Reservoir pressure

The reservoir pressure affects the GIIP and the reservoir energy. Low pressure systems have less GIIP and less driving force than high pressure reservoirs. Especially in tight gas settings, high reservoir pressures are important to achieve large draw down values, acting as the driving force for inflow into the wellbore. The RIF for the laterals improves as the reservoir pressure decreases, indicating that the laterals could be more effective in depleted reservoirs. The laterals enable the gas to enter the highly permeable lateral, requiring less driving force (pressure difference) to move from reservoir to well bore.

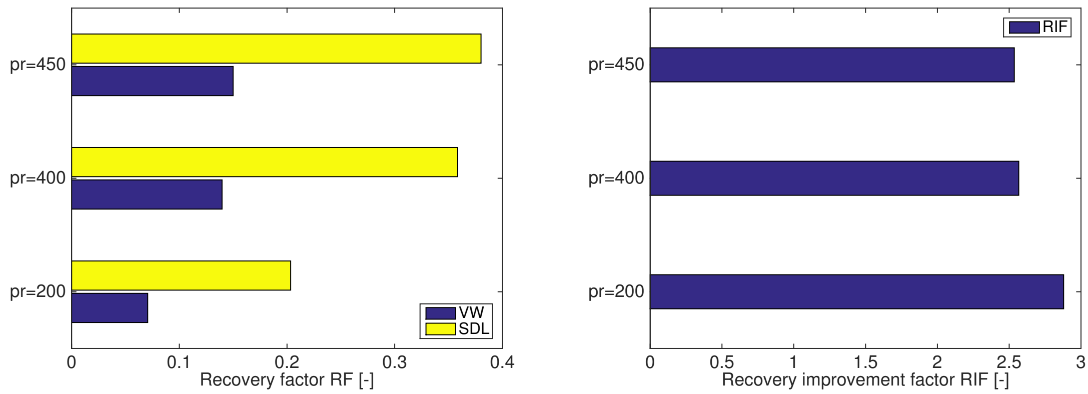


Figure 6.6: Left: Absolute recovery factors for different reservoir pressures. Right: Relative recovery improvement factor for SDL compared to VW for different reservoir pressures.

Reservoir thickness

The reservoir thickness has significant influence on the lateral performance. As already discussed in [19], thin reservoirs, irrespective of horizontal-to-vertical anisotropy, are good candidates for the application of laterals. The simulations also show a significant increase in the recovery factor and the RIF (see figure 6.1. In comparison to the vertical well, the laterals have much more exposure to the thin reservoir than the short perforated interval of the vertical well.

Skin

Skin is a major limiting production factor. Especially in tight gas reservoirs, where near wellbore formation damage is very difficult to avoid and flow rates are naturally low, bypassing skin can offer significant production- and recovery improvement. The RIF for a skin factor of 10 is twice the RIF of a case with a skin factor of 0, implying that in situations of near well bore formation damage, RJD can be used to access unaltered reservoir.

6.1.2 SDL parameters

The SDL parameters; number of laterals, lateral length, diameter and inclination would all be specific per individual reservoir. The number of laterals becomes more important as the permeability decreases, as this would create more exposure. But the absolute effectiveness per lateral would probably decrease due to interference effects. Especially in thick reservoirs, where laterals can be placed above one another, cross flow could occur. This results in production from one lateral flowing back into the other due the pressure differences with depth [19]. Cross flow can only be overcome with smart well equipment that allows individual pressure- and production control per lateral, something not (yet) available for RJD. The lateral length is one of the most important parameters to increase the recovery factor in a homogeneous reservoir, but it could well be that if a vertical well only has skin problems, a shorter lateral would also be sufficient. The Productivity Improvement Factor for SDL versus VW is between 5-6 for the base case reservoir model, see figure 6.8.

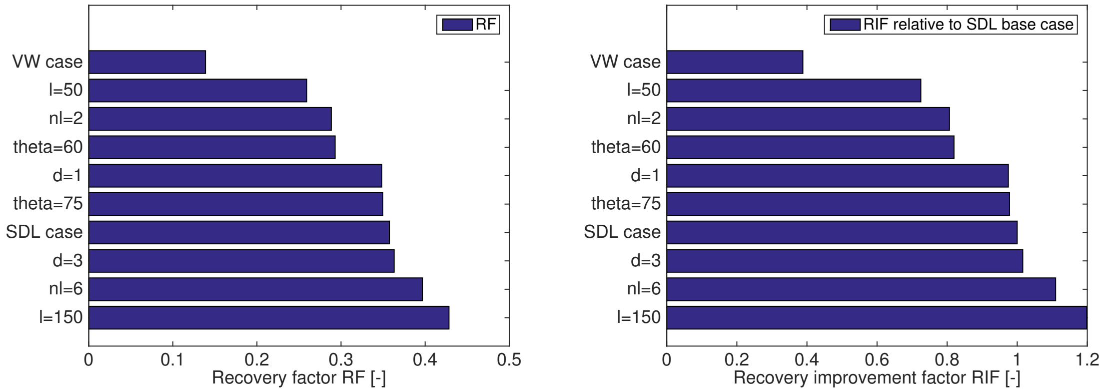


Figure 6.7: Left: Absolute recovery factors for different cases. Right: Relative recovery improvement factor for different cases. The SDL case has $l = 100$ m, $d = 2$ inch and $n = 4$.

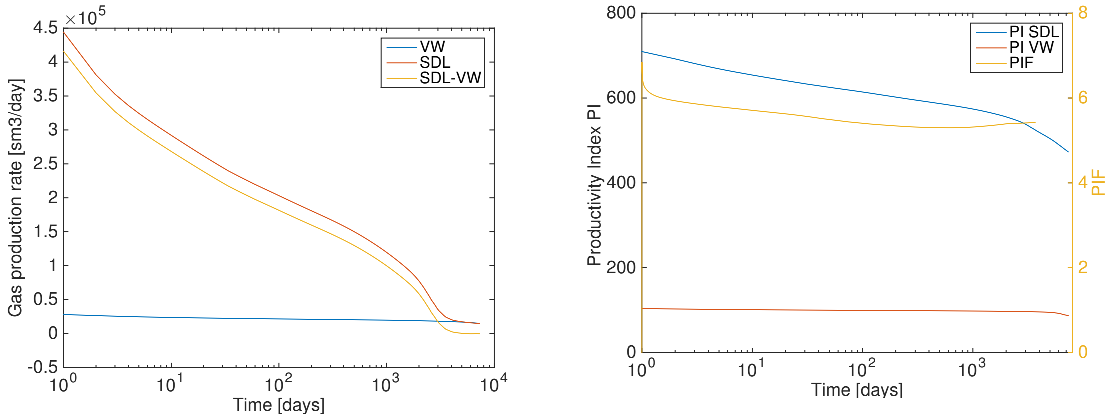


Figure 6.8: Left: Base case gas production rates. Right: Productivity index and productivity improvement factor.

6.2 Uncertainty production performance

The uncertainty analysis comprises 2 x 300 models realisations to test the probability range of the recovery factor for both the vertical and SDL model. The simulation run time is 20 years, the time step 1 month. The probabilistic models have been sorted on ultimate recovery.

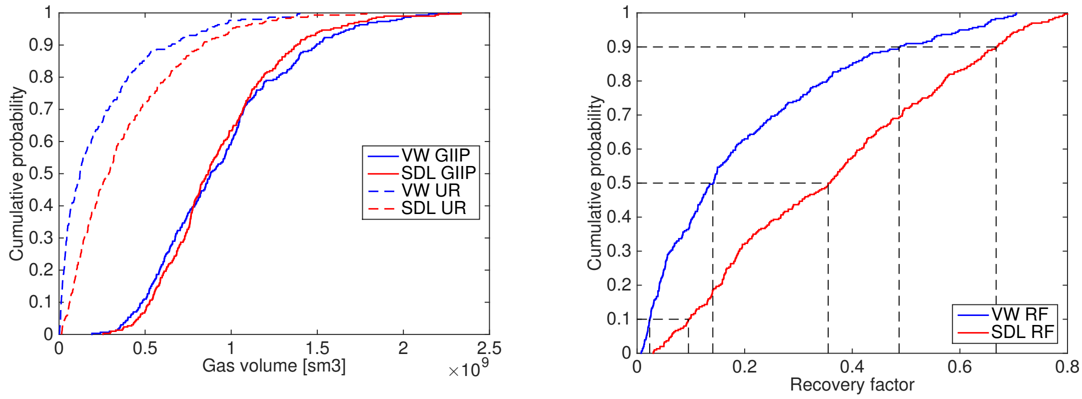


Figure 6.9: Left: GIIP and ultimate recovery for 300 realisations for both the VW and SDL case. Right: Recovery factors for P90, P50, P10 values.

The GIIP distributions for both simulation sets (VW and SDL), although they do not exactly overlay, are very similar as expected. The ultimate recovery and recovery factor for both simulation sets however are very different (see figure 6.9 and table 6.1).

Table 6.1: Recovery factors uncertainty analysis

Model	P90 RF	P50 RF	P10 RF
VW	2.4%	14.1%	48.7%
SDL	9.6%	35.5%	66.7%
SDL/VW	4.0	2.5	1.4

The SDL recovery factor is generally 1.4-4 times the VW recovery factor. In the P50 case the SDL recovery factor is 35.5%, which is 2.5 times the VW recovery factor. In the P90 case, which represents unfavourable reservoir conditions, the SDL recovery is 4 times the VW recovery factor. In the P10 case, which represents the most favourable reservoir conditions, the relative effect of the SDL's is still evident but smaller, resulting in a recovery improvement of a factor 1.4.

6.3 VW vs SDL vs HF

The HF case consists out of the base case with one square hydraulic fracture in the vertical plane with the vertical well as centre point (-3430 m). The hydraulic fracture extends from the top of the reservoir down to 40 m above the GWC. The half length is 50 meter, the height is 60 meter and the aperture is 0.4 inch. The HF has been modelled as a vertical plane in a local refined grid with a permeability of 10 Darcy.

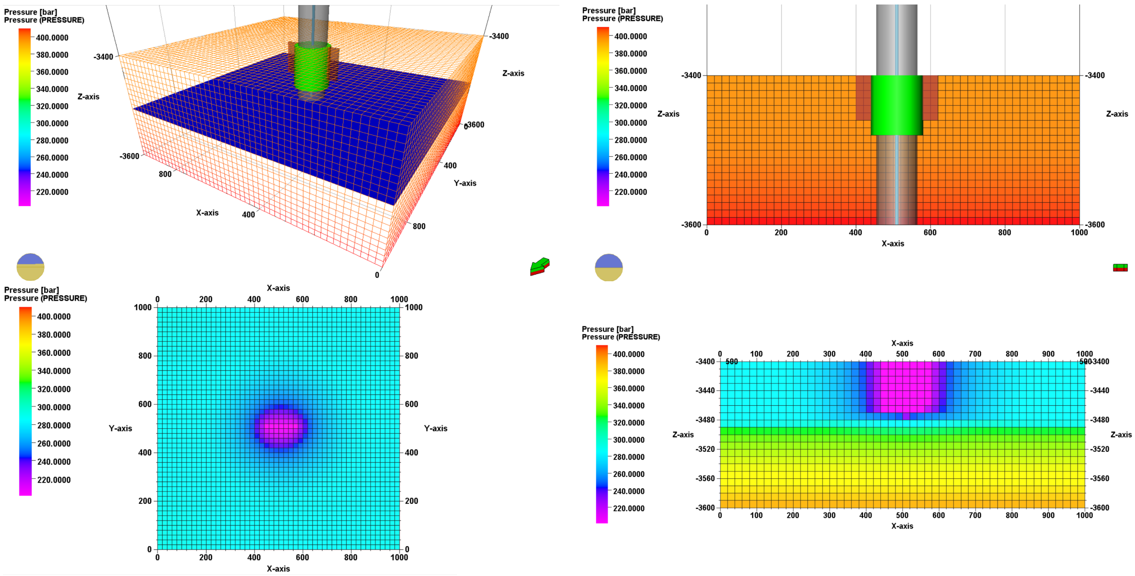


Figure 6.10: The modelled hydraulic fracture and the pressure distribution.

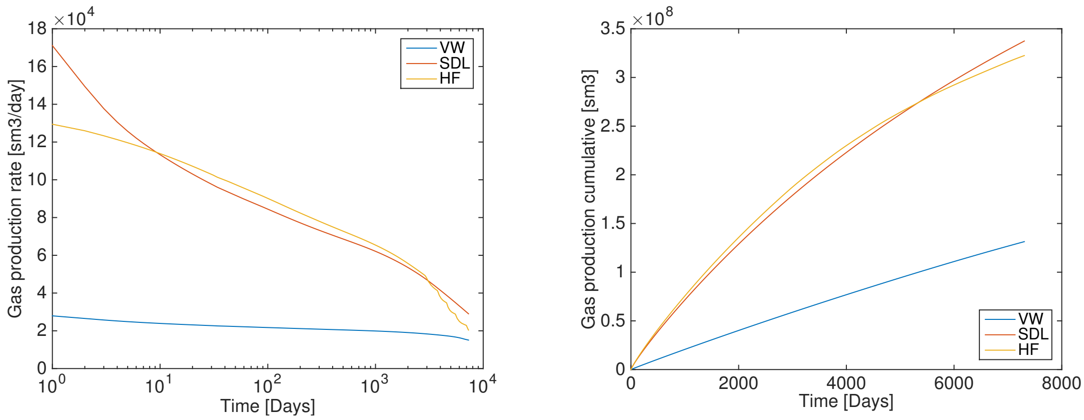


Figure 6.11: Left: GIIP and ultimate recovery for 300 realisations for both the VW and SDL case. Right: Recovery factors for P90, P50, P10 values.

Figure 6.11 and table 6.2 illustrate the similar production performance of the hydraulic fracture and the small diameter laterals.

Table 6.2: Recovery factors for the VW, SDL and HF model.

Model	GIIP [sm3]	UR [sm3]	RF [%]
VW	$9.4\text{x}10^8$	$1.3\text{x}10^8$	14
SDL	$9.4\text{x}10^8$	$3.4\text{x}10^8$	36
HF	$9.4\text{x}10^8$	$3.2\text{x}10^8$	34

This is only a single simulation case however, a more in depth study by experts is recommended. Modeling hydraulic fractures in Eclipse requires specific knowledge to avoid numerical instability and convergence problems.

6.4 Economics

The results of the economic analysis of the various scenarios are summarised below, for more scenario graphs refer to the appendix. The application of RJD in onshore tight reservoirs as modelled appears to be economically attractive (figure 6.12). As will be explained shortly, offshore is a different story. The key indicators are the gas production, Net Cash Flow (NCF) and NCF cumulative (NPV) and Earning Power [1] (EP).

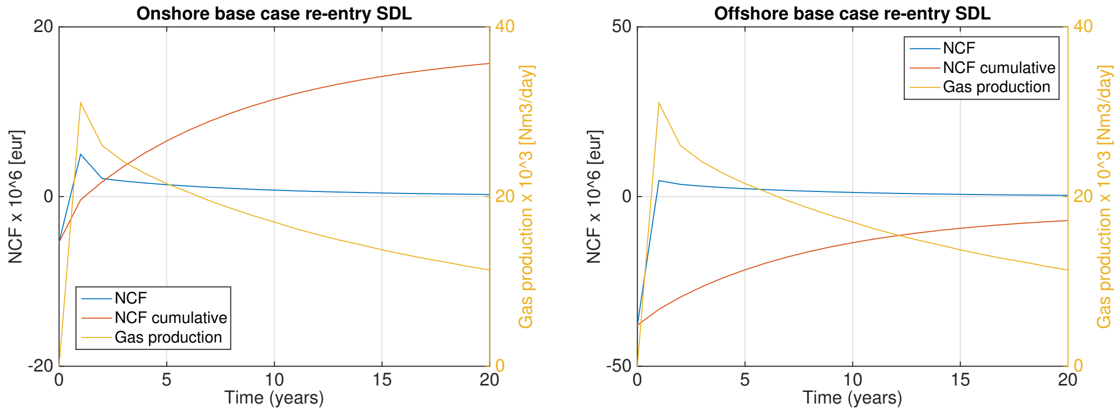


Figure 6.12: Left: Onshore reference scenario (deterministic base case and SDL development). Right: Offshore base case with re-entry SDL. Same production profile, different costs.

Onshore

Seven onshore scenarios have been evaluated. The development options are all NPV positive at a 10% discount rate, except for the P90 re-entry SDL scenario. For the base case reservoir model, the vertical well option is marginally attractive with an NPV of 0.15 mln euro and EP 10%. The re-entry SDL appears very attractive with an NPV of 15.7 mln euro and an EP of 68%. The VW+SDL option is also economically attractive with an NPV of 12.4 mln euro and EP 31%.

The economic robustness of the re-entry SDL development option has been tested against the P90 reservoir model (unfavourable reservoir parameters) and is NPV negative, although the margin (-0.1 mln euro) is small. The P10 case (favourable reservoir parameters) is economically very attractive, but probably is also economic with a VW development only (not tested). Overall, the onshore applications of RJD appear economic robust.

A relatively limited CAPEX is required for RJD stimulation of already existing but non economically producing wells (definition of stranded tight gas reservoirs NL). The SDL development has also been compared to HF. The SDL development option has a higher NPV and EP then the HF development option.

Onshore		Technical Indicators				Economical Indicators	
Reservoir model	Development option	GIIP	Peak rate	UR	RF	NPV	EP
Deterministic base case	VW	992	22.5	138	14	0.15	10
	Re-entry **SDL**	992	85.1	355	36	15.7	68
	New well SDL	992	85.1	355	36	12.4	31
	Re-entry HF	992	66.3	307	31	12.4	43
	New well HF	992	66.3	307	31	9.8	26
P90	Re-entry SDL	392	14.6	64.3	16	-0.1	10
P10	Re-entry SDL	1405	509	880	63	51.9	297

GIIP is in x10^6 sm3, initial rate in x10^3 sm3/day, UR in x10^6 sm3, RF in %, NPV in x10^6 euro, EP in %.

[1] or Internal Rate of Return (IRR)

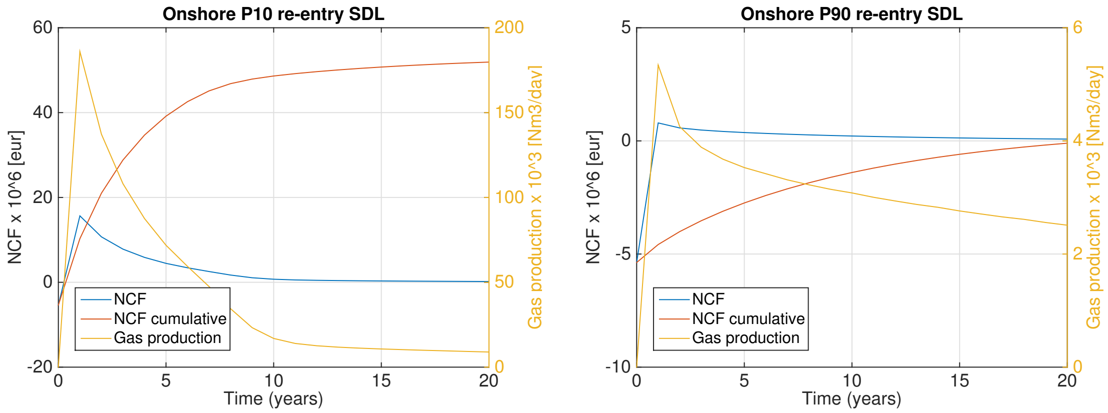


Figure 6.13: Left: Onshore P10 (high) re-entry SDL. Right: Onshore P90 (low) re-entry SDL.

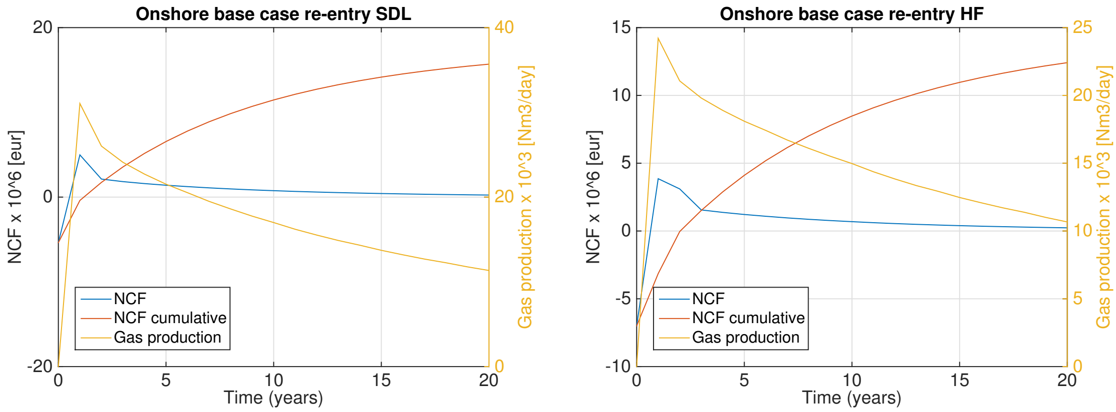


Figure 6.14: Left: Onshore base case re-entry SDL. Right: Onshore base case re-entry HF. Similar production profiles, different costs.

Offshore

The onshore scenarios have also been evaluated for offshore settings. All offshore scenarios are NPV negative, except the re-entry SDL development in combination with the P10 reservoir model. The P10 NPV is 47.7x10^6 eur, the EP is 52%. Note that the NPV of the P10 re-entry SDL cases (onshore and offshore) are similar, although the costs are very different. The similar NPV is due to the Marginal Field Tax Allowance (MFTA) of 25%.

Offshore		Technical Indicators				Economical Indicators	
Reservoir model	Development option	GIIP	Peak rate	UR	RF	NPV	EP
Deterministic base case	VW	992	22.5	138	14	-46.7	-
	Re-entry **SDL**	992	85.1	355	36	-7.1	7
	New well SDL	992	85.1	355	36	-28.4	1
	Re-entry HF	992	66.3	307	31	-14.9	3
	New well HF	992	66.3	307	31	-36.2	-
P90	Re-entry SDL	392	14.6	64.3	16	-35.7	-
P10	Re-entry SDL	1405	509	880	63	47.7	52

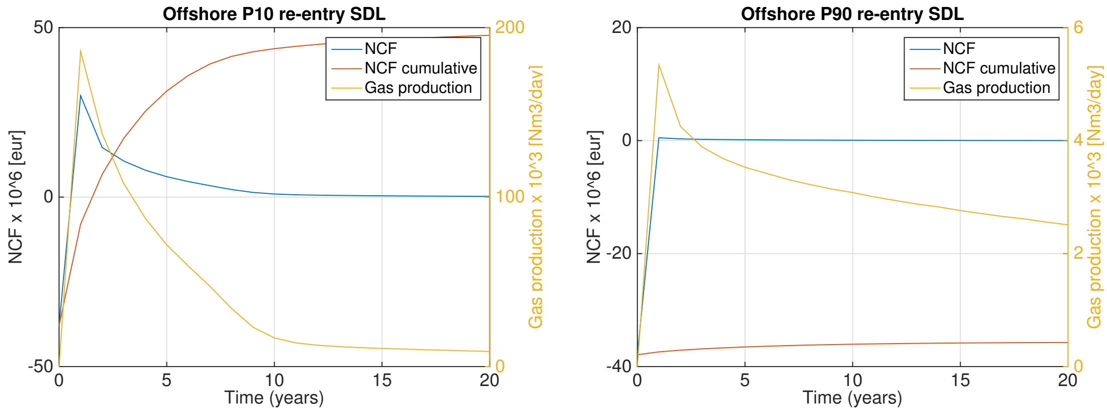


Figure 6.15: Left: Offshore P10 (high) re-entry SDL. Right: Offshore P90 (low) re-entry SDL.

Chapter 7

Discussion

During this study several limitations have been encountered that require explanation. The limitations are the result of assumptions and methods that have been used and are discussed in the sections below.

7.1 Simulation results

Reservoir model

For comparison purposes between VW and SDL within the synthetic model, ease of modelling and the lack of quality data (capillary pressure and water saturation per porosity class) it has been assumed that there is no dependency between porosity and water saturation. The advantage is that a wide range of water saturations can be simulated independent of the porosity which means that high porosity values may be sampled in combination with high water saturations. However, it is realized that this is not realistic, especially in very heterogeneous tight reservoirs.

Another assumption is the non-presence of a transition zone which has an affect on the recovery factor. Normally the GIIP is calculated from top reservoir down the FWL. However, since the model assumes the water saturation is 100% right below the GWC, the GIIP is smaller than the GIIP of a model with a transition zone (depending on the depth of the FWL). This influences the relative permeability's and hence the recovery factors. On the other hand it can be argued that perforating or jetting laterals in the transition zone of tight gas sandstones is not good practice since the higher (mobile) water saturation will hamper gas flow very quickly with increasing water saturation (see relative permeability curves in the appendix).

SDL model

The assumptions is made that there is no pressure drop in the SDLs since we are dealing with low permeability reservoirs. This assumption is also used in the publication of TNO [8]. However, [17] clearly demonstrates that pressure losses in small diameter laterals easily occur when coupled to reservoir inflow. The analytical model has been replicated and the results are described in the appendix. For reservoirs with permeability's over 10 mD, a 2 inch lateral would experience a pressure drop of 70 bar. At higher flow rates also non-Darcy effects come into play.

Another assumption that is subject of discussion is that the laterals have been modelled as straight open hole completions that are open to inflow along the entire length. In reality, parts of the lateral are not connected to permeable parts of the reservoir, causing the gas to concentrate in specific flow paths and entry points. Additionally, the laterals could be subjected to compaction, isolating parts of the lateral and causing a reduction in effective length. In the simulations a production horizon of 20 years is assumed, while in one field test it has been observed that the laterals stop enhancing production after a period of 2 years. However, in tight gas sandstones, which often have been subject to diagenesis/cementation, hole stability problems are not expected unless the SDL penetrates a ductile clay or salt layer.

Production performance

In the simulations it has been assumed that only dry gas is produced, however when producing from wet gas reservoirs the pressure and temperature drop in the tubing (or even the laterals when $p_{wf} < p_{bubble}$) could result in condensate drop-out causing liquid loading of the well [22]. Another problem that might occur is liquid hold-up. In the simulations almost no water was produced due to the tight nature of the reservoir, the horizontal-to-vertical permeability anisotropy and the used relative permeability curves. However, in situations with more water production, liquid-hold up, which results from density and velocity differences between water and gas could hamper production or even cause well shut-in.

The first papers on RJD were published by [7] and show production improvements of 200-1000%. In [35] it is mentioned that maintaining production rates is a challenge, but that initial rates had improved. Most field tests have been analysed in [3] and the overall conclusion is that the technology resulted in a lower production enhancement than predicted. However oil production did increase for most of the wells for a period longer than 12 months. Also in [4] a production increase is observed, and in [3] damaged zone were bypassed successfully. Operation wise, most papers mention easy, quick and relative inexpensive operations. But the major uncertainty is the lack of ability to monitor exactly what is happening downhole and in the subsurface.

Sensitivity production performance

In the one-variable-at-the-time method the single parameters are varied independently. This has limitations because interaction effects are not captured, leading to occasional unrealistic realisations where for example low porosity is combined with high permeability. In the deterministic base model and the probabilistic realisations the dependencies between the parameters are honoured (e.g. porosity-permeability, water saturation and relative permeability).

Uncertainty production performance

The comparison of the production performance of VW and SDL can best be done based on the deterministic model because the reservoir parameters and GIIP are equal and reproducible. A comparison based on probabilistic realisations carries more uncertainty because the sampled reservoir parameters and resulting GIIP can vary. Although the ultimate recovery may be the same, underlying reservoir parameters and GIIP may be different.

The SDL parameters such as the number of laterals, lateral length, inclination and diameter have been assumed fixed in the uncertainty analysis. However there are currently no techniques available that allow measurements and steering while jetting. In combination with the limited field test data, it cannot be verified if the subsurface position, orientation and dimensions are as planned.

Economics

The costs models are high-level and are not broken down into specific cost components. Therefore the uncertainties in the cost model (CAPEX and OPEX) could have an impact on the outcome of the economic analysis. Additionally, the theoretical (read simulated) production forecasts have not been calibrated or verified with actual field data.

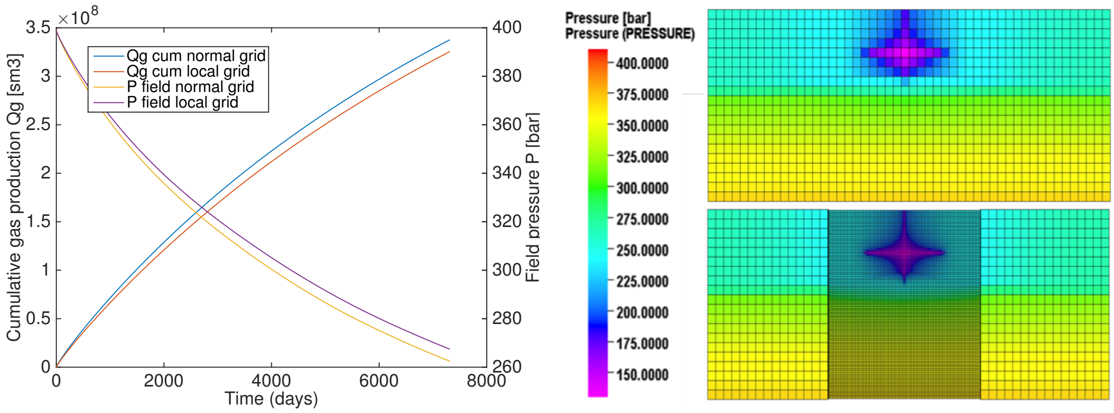


Figure 7.1: Grid used during simulation sets versus the local refined grid. Cumulative gas production decreases on LGR grid decreases compared to normal grid. Field pressure stays higher.

This shows that the results should still be treated with minor caution. The normal grid in this case is 20x20x10 m, while the LGR grid is 4x4x2 m. Modelling reservoir heterogeneities around the wellbore are in the order of 10-100 micro m and would make heterogeneous simulation models very challenging. Additionally, if we want to capture the uncertainty of heterogeneous models, were every cell can have a different value, we would need millions of simulations to approach the input distributions with Latin Hypercube Sampling, let alone Monte Carlo.

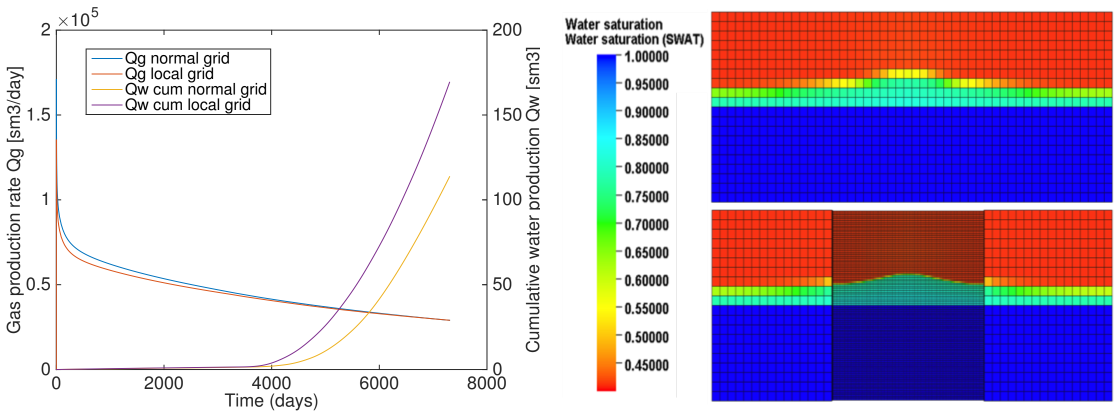


Figure 7.2: Grid used during simulation sets versus the local refined grid. Water production increases, gas production decreases.

The model represents production in a tight gas reservoir that has been perforated above the GWC and far above the FWL, thus only gas is produced. In reality the irreducible water saturations and critical water saturations can be significantly different, hampering the gas production to very low production levels.

Wellbore stability can be of significant impact on the production performance of the SDLs. As mentioned in earlier in [3] and [35], the lifetime of the SDLs ranges from a few months to a few years depending on the reservoir formation and type. This has not been included in the reservoir simulations and economics.

7.2 Water saturation model

Without transition zone - model 1

The saturation model has been simplified by assuming that there is no transition zone below the GWC (-3500 m). Instead of a transition zone it has been assumed the water saturation below the GWC is 1.0. Above the GWC the water saturation has been assumed 0.4, that represents the irreducible- and critical water saturation. The consequence of this assumption is a high relative permeability for water at the GWC, see figure 7.3. However, the net effect is that there is predominantly gas production and that the dynamics below the GWC are not correctly captured.

With transition zone - model 2

A more realistic saturation model takes into account a full transition zone with the water saturation as a function of height above FWL. The simulator initialises the saturation height in the equilibration process based on water saturation and the corresponding capillary pressure data. The water saturation decreases from FWL (Sw=1) to a specific Sw at GWC depending upon the distance to FWL.

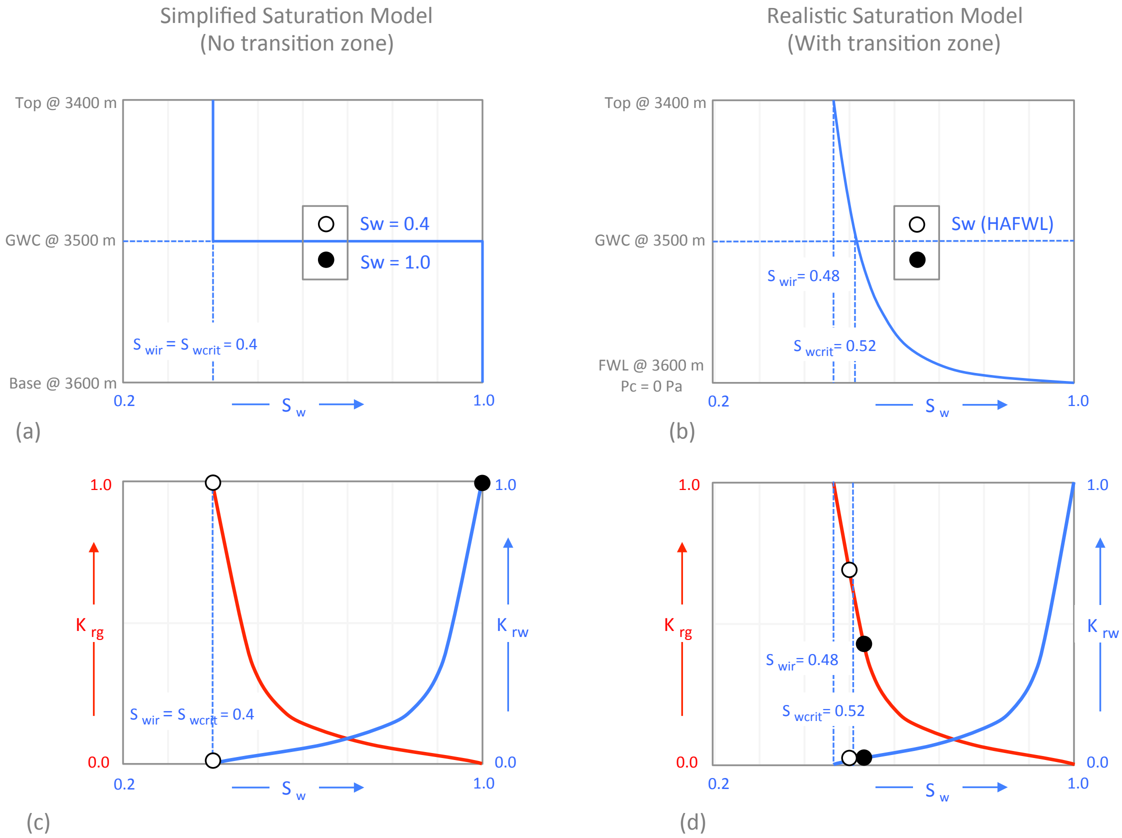


Figure 7.3: Water saturation model without transition zone versus water saturation model with transition zone and the associated relative permeability curves.

GIIP

GIIP is usually calculated from top reservoir down to FWL. This implies that the GIIP in the model 1 is significantly smaller than that of model 2. Although the UR of model 2 will increase compared to that of model 1, the GIIP change is much larger resulting in a significantly lower RF. However, it can be argued that in transition zones mobile water very quickly starts hampering gas production (lowering the relative gas permeability) and thus one always perforates or places SDL's above the GWC, as modelled.

The difference between the base case deterministic model 1 (no transition zone) and model 2 (with transition zone), in terms of GIIP, UR and RF is summarised in table 7.1.

Table 7.1: The differences between model 1 and model 2.

Model	GIIP sm3	UR sm3	RF %
1 - without transition zone	9.4×10^8	3.4×10^8	36
2 - with transition zone	1.3×10^9	3.6×10^8	28

Although the recovery factor for model 2 is lower than for model 1, the ultimate recovery is very similar. The implication is that the economics are also very similar.

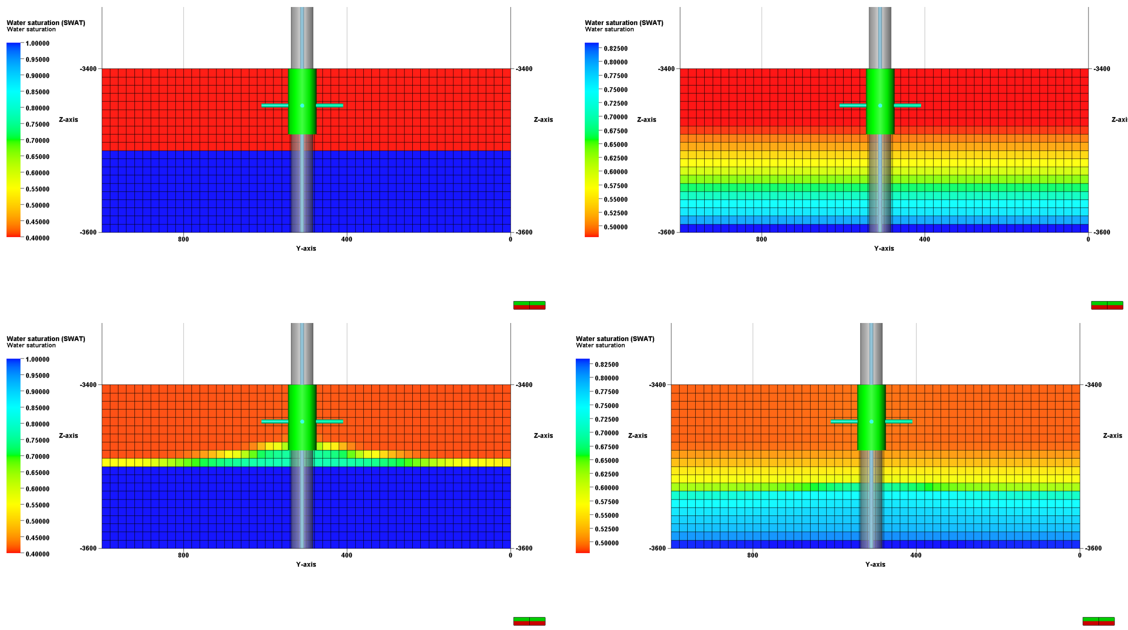


Figure 7.4: No transition zone versus transition zone.

During this study the reservoir behaviour above the GWC has been simulated correctly. However, the relative permeability dynamics below the GWC contact may result in earlier water breakthrough. This naturally depends on the relative permeability curves and the horizontal-to-vertical anisotropy.

Chapter 8

Conclusions

The following conclusions have been drawn from this study:

- The simulations demonstrate that the laterals appear to be most effective in low permeable reservoirs, reservoirs with near-well bore formation damage, with lower initial water saturation's, depleted reservoirs and thin reservoirs. The laterals appear less effective in high-permeable reservoirs and reservoirs with high horizontal-to-vertical anisotropy. The application of small diameter laterals generally results in a recovery improvement factor of 2-3.5 compared to a vertical well for the simulated cases. The initial gas production ratio between SDL/VW is between 4-7.

- SDLs are effective i.e. yield a recovery improvement from 10 mD or lower. In reservoirs with a permeability lower than 0.1 mD the application results in a recovery factor improvement of at least a factor 2.

- The lateral length is one the most important SDL parameter that increases the recovery factor in low-permeable homogeneous reservoirs.

- The SDL recovery factor is generally 1.4-4 times the VW recovery factor. In the P50 case the SDL recovery factor is 35.5%, which is 2.5 times the VW recovery factor. In the P90 case, which represents unfavourable reservoir conditions, the SDL recovery is 4 times the vertical well recovery factor. In the P10 case, which represents the most favourable reservoir conditions, the relative effect of the SDL is still evident but smaller, resulting in a recovery improvement of a factor 1.4.

- The economics demonstrate that the onshore application of radial jet drilling as a stimulation method are feasible and robust (except for the P90 reservoir model). A vertical well development is very marginal for the simulated cases.

- The economics demonstrate that the offshore application of radial jet drilling as a stimulation method is only feasible for stranded volumes $>$ 1.5 BCM in combination with a re-entry scenario.

- The simulated production performance of the small diameter laterals could be just as effective as a single hydraulic fracture. RJD's smaller environmental footprint and lower costs could make the technology an attractive alternative to hydraulic fracturing.

Chapter 9

Recommendations

Simulation model

It is recommended to verify the synthetic simulation results by making a comparison with actual field production data (when available) to gain a better understanding of the modelling issues and the actual system (reservoir/RJD interaction) response. Multi-segment well models could be implemented to provide a more detailed fluid flow/pressure drop in the horizontal wellbore and modelling with other wells in vicinity would change the pressure behaviour due to interference effects.

Stimulation comparison

In this study RJD has been compared with a vertical well completion to imitate stimulating an existing vertical well with skin. But in terms of stimulation techniques it is recommended to compare RJD with hydraulic fracturing in a more extensive manner. Especially the way hydraulic fractures are modelled in the simulation is an important consideration when comparing production performance of RJD versus HF.

Lateral stability

Several fields tests have shown that the SDL's production enhancement deteriorate after a certain period of time, ranging from a few days to several years. This probably depends on the formation instability overburden and tectonic stress regime. The actual lifetime of the SDL's is unknown and difficult to verify. Since the lateral lifetime controls the incremental production it is recommended to investigate the possibilities of monitoring or testing the SDL lifetime in different formations and stress regime's.

Lateral skin

It has been assumed that skin of the laterals is zero because the jetting fluid is a brine. However, in situations where the well needs to be killed or reactive clays are present, the jetting fluid could cause formation damage. Especially when injecting brine in tight gas sandstones, which have small pore throats and thus strong capillary forces, injecting water under high pressure could result in water phase trapping.

Well testing

Conventional well testing determines reservoir characteristics and pressures from build-up tests. In tight gas reservoirs however, the shut-in time is often not adequate to look far enough into the reservoir as the pressure transient does not diverge quick enough [12]. Reservoirs with a high permeability e.g. 100 mD require well tests of a few hours or days (depending on the size of the reservoir) to reach the boundaries. Low permeable reservoirs e.g. 0.01 mD, require 10^4 times more production time before outer boundaries can be recognised from transient data, which is very unrealistic. In [32] it is suggested that hydraulic fractures must be incorporated in the well testing scheme. The application of RJD is a cheaper method and can be directly incorporated in the drilling scheme and hence makes tight reservoir testing feasible and cost effective. Offshore, there is no need for hydraulic stimulation vessel and extra rig time which significantly reduces the costs for tight gas reservoir well testing. If the formation still proves to be too tight, hydraulic stimulation can always be added.

Oil applications

It is believed that the application of RJD technology to oil may improve the well and reservoir performance even better than for gas. A similar study on oil could be performed.

Appendix A

Tight Gas Reservoirs

The product of the absolute (rock) permeability k and the relative gas permeability k_{rg} is the effective gas permeability k_{eff}. In tight gas sandstones, the combination of low absolute permeability and high water saturation (low relative permeability) results in low effective gas permeability and thus slow gas production.

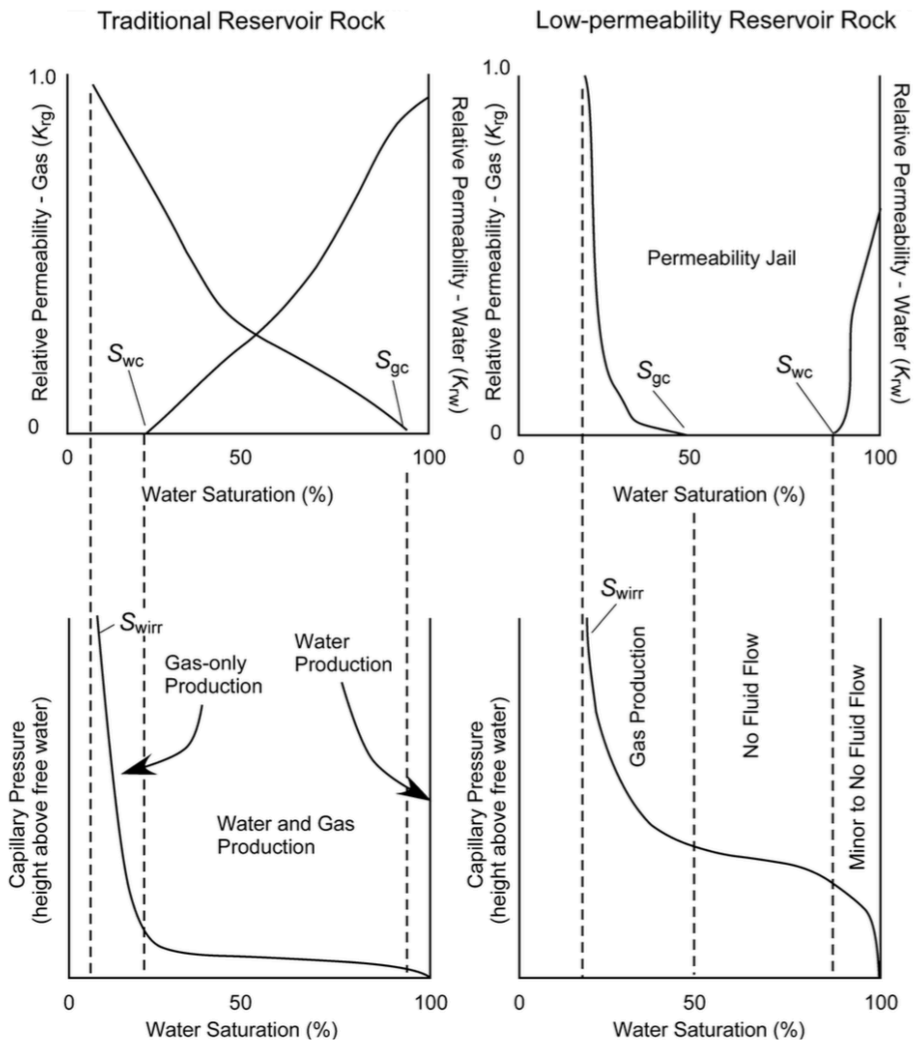


Figure A.1: The concept of permeability jail as explained in chapter 2. Tight gas reservoirs only produce gas within a limited range of water saturations. Courtesy of [38]

The Petroleum Resources Management System (PRMS)

		Production		Resource cat.
Discovered	Commercial	Reserves	On production	1
			Approved for development	2
			Justified for development	3
	Sub-commercial	Contingent Resources	Development pending	4
			Development unclarified or on hold	5
			Development not viable	6
		Unrecoverable		
Undiscovered		Prospective Resources	Prospect	8
			Lead	9
			Play	10
		Unrecoverable		

EBN 2015

Figure A.2: The Petroleum Resource Management System as used within EBN.

Appendix B

Radial Jet Drilling

B.1 Dimensions

The laterals used in the simulation model are 100 m long, have a diameter of 0.05 m, an outer surface area of 16 m2 and a volume of 0.20 m3. Four laterals in total thus have an effective contact area with the reservoir (assuming 100% open hole completion) of 62.84 m2 and a volume of 0.80 m3.

B.2 Operation procedure

A typical program involves a 5 man team, consisting out of 4 operators and 1 gyro expert per shift. Work-over procedures vary depending on the needs, but typically the entire job, from killing the well to restarting the well, requires 8 full days. For a live well the working procedure is as described below [43]

1. Well is killed by pumping in completion fluid via the kill line. The killing method depends on the well and the completions present.

2. The work over rig and the BOP are installed. All completions are pulled (production tubing, packers, SSSV, nipples etc.).

3. The deflector shoe is installed on the pre-determined depth with a work over tubing, the work over tubing is set into the work overs rig slips.

4. A gyro orientation tool is run into the tubing and orientates the deflector shoe towards the target zone.

5. After retrieving the gyro orientation tool the milling assembly is run in hole with a mini coil and the milling assembly. The mill bit is energised with a PDM and mills a hole in the casing.

6. The milling assembly is pulled out and disconnected. Then the jetting assembly is attached to the mini coil and run in hole again.

7. The lateral is jetted up to a pre-determined length, all return material falls into the rat hole. There are no returns to the surface.

8. Depending on the number of planned laterals, the tubing can be rotated (thus rotating the connected deflector shoe) and the steps 5 7 can be repeated. The gyro orientation is repeated when very accurate orientation is necessary, otherwise the work over tubing can be rotated at the surface, torque is transferred.

9. Once all laterals have been placed, the rig will pull the tubing and deflector shoe and re-install the production tubing and all other completions. One day contingency is included.

Note that gyro tool can also be used for initial placement, leaving the other laterals on azimuthal placement with the work-over tubing. This would reduce operating time but comes at expense of accurate SDL placement.

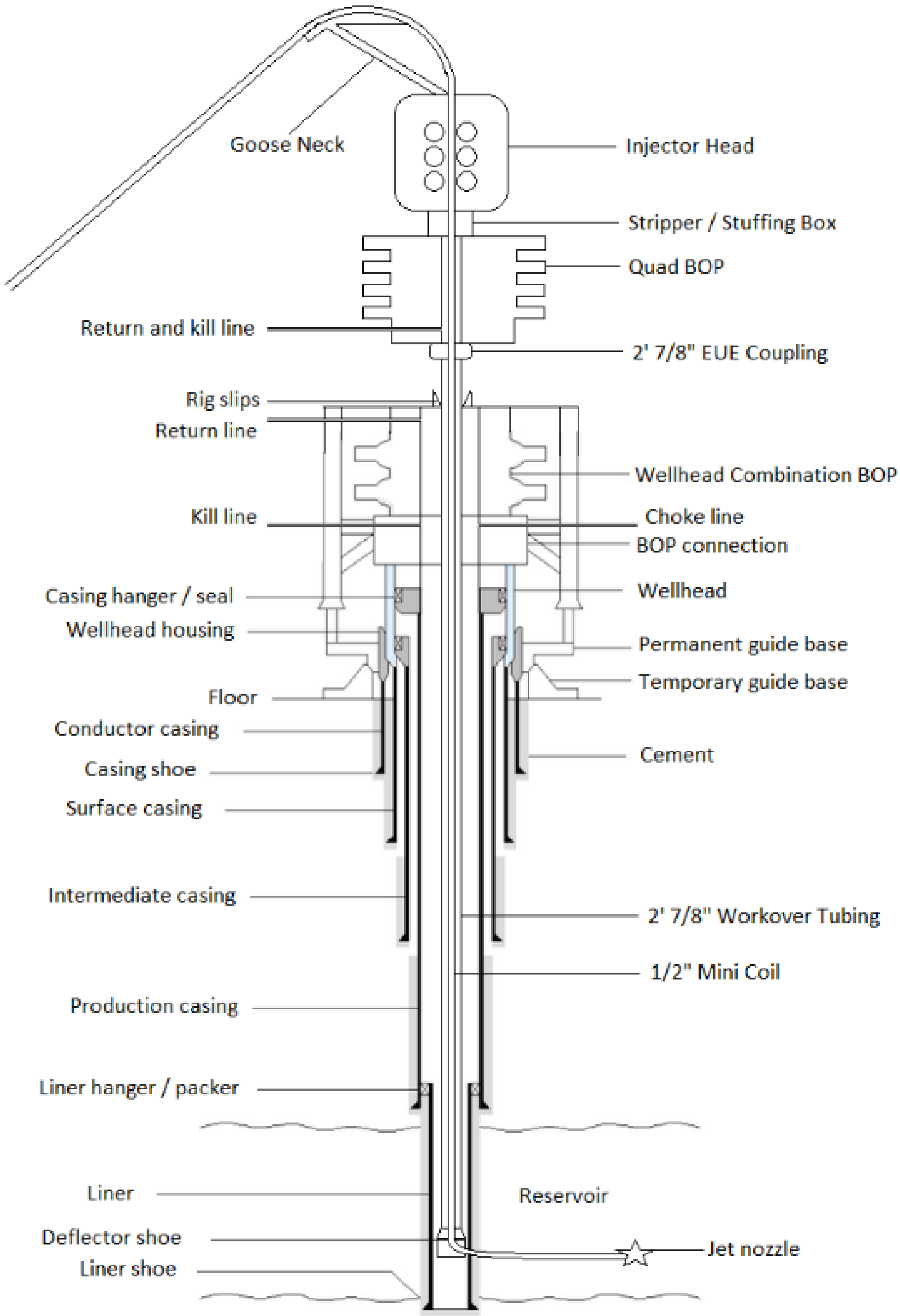


Figure B.1: Cross section of a typical well configuration during RJD. Naturally this varies per well.

B.3 Fluids and rock penetration mechanism

The fluid consumption is limited, the mill bit is driven by a PDM, approximately 1 cubic meter (depends on casing API) of fluid is required to mill through the casing. Jetting one 100 meter lateral requires approximately another cubic meter of fluid. For a typical job of 4 laterals, 8 cubic meters are required [43]. The jetting fluid used is water or brine, additives (KCL) can be added to prevent clay swelling or other formation reactions as long as the nozzle does not clog up. There are two primary mechanisms that penetrate the rock in RJD [4]:

- Surface erosion: The jet erodes the formation by pumping water under high pressure through small nozzles , the force resulting from the high velocity and mass erodes the rock. The more porous the rock, the easier the erosion due to the smaller back pressure.
- Pore-elastic tensile failure: pore-elastic tension occurs when high pressure water enters the pore space, increasing the pore pressure and causing the rock to fracture. The sudden increase in pore pressure de-consolidates the rock.

However, rock breaking performance is influenced by bottom hole confining pressure, the higher the confining pressure, the lower the eroded depth [41]. This implies that deep targets require more jetting time than shallow targets. The jet de-consolidates single grains and dissolves the matrix, only quartz particles remain and fall into the rat hole. The self-propelled force of the jet bit is studied in [24]. The number, diameter and orientation of the orifices are important design parameters for the optimal configuration. The forward orifices crush the rock in front of the bit by high pressure impact, and possibly cavitation [26]. The backward orifices generate the self-propelled force and expand the radial hole [24].

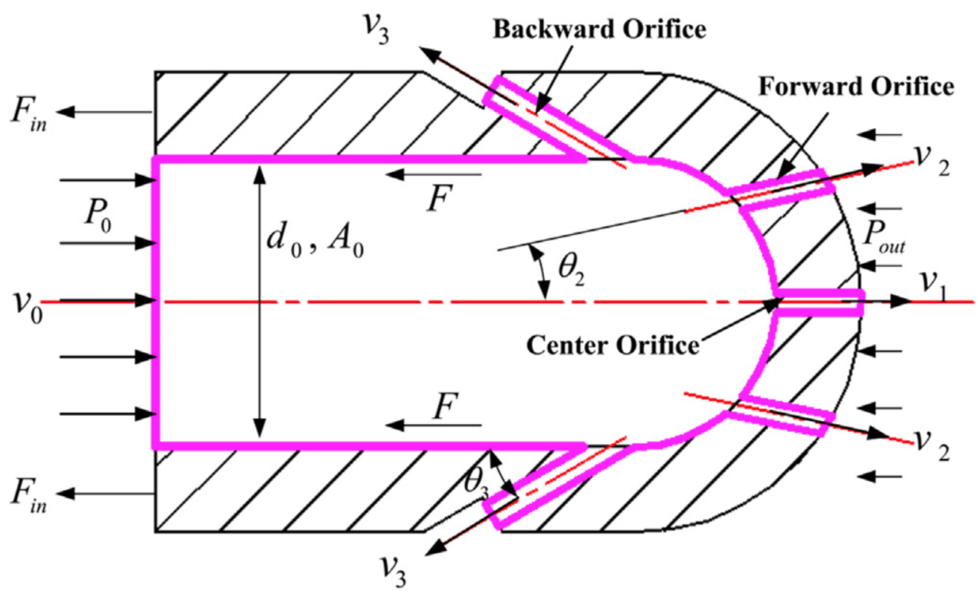


Figure B.2: Cross section of the physical model of a multi-orifice nozzle as used during RJD. Courtesy of [24].

B.4 Coiled tubing friction

The operating depth of CT (RJD) operations is limited by the frictional pressure drop caused by the fluids running through the coil. No matter what length of coil is run in hole, the fluids will always have to travel through the entire coil, reducing the effective pressure significantly due to frictional losses. If we only take into account gravity and friction for a single phase fluid (water), the pressure drop per unit length over a vertical CT string can be calculated with

$$\frac{dp}{ds} = -\rho g \sin(\theta) - \frac{\rho}{2d} f v^2 \tag{B.1}$$

for ρ=1000 kg/m3, g=9.81 m/s2, θ=90°, d=0.0127 m, f=0.0223 and v=3 m/s this would result in a pressure drop per unit length of approximately 1.67x10^4 Pa/m (0.167 bar/m).

B.5 Wellbore friction

In this chapter the pressure drop in lateral gas wells is discussed by comparing a regular pipe flow calculation with the more extensive analytical model of [17] which couples inflow from the reservoir with friction effects in the lateral. The goal is to get a feeling for typical dimensions associated with small diameter laterals in tight gas reservoirs. A small sensitivity analysis is included to define the parameters controlling pressure drop.

In several cases, the pressure drop in a lateral is negligible compared with the drawdown. This allows ignoring the pressure drop and assuming a constant pressure along the length of the lateral. Literature states that in the case of tight gas reservoirs the effect of inflow on the lateral pressure drop needs no explicit consideration and allows using an analytical solution or even an approximation with fully developed pipe flow [19]. However, when dealing with small diameter laterals (< 3 inch), frictional forces can become significant and reduce or even neutralise the effective drawdown. This is especially important when working with SDL's and (highly) permeable reservoirs.

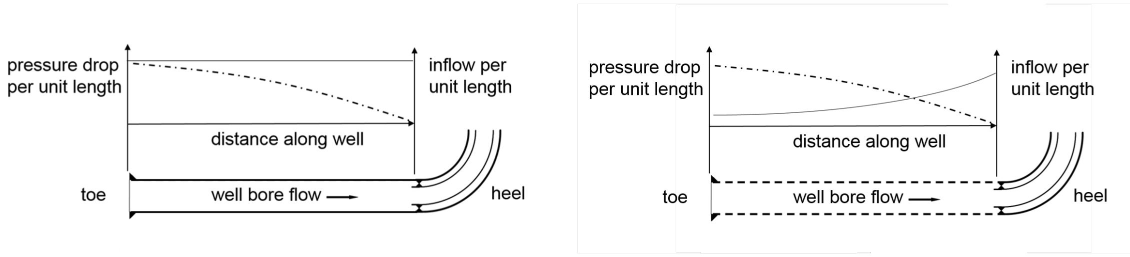


Figure B.3: Left: Regular pipe flow pressure drop. Right: Pressure drop with inflow from the reservoir.

As a simple reference case, the flow through a lateral can be modelled as fully developed flow in a circular pipe that is open only at the ends, so no inflow along the length occurs. This allows using the Moody friction factor f_M (or Darcy-Weisbach friction factor), which is non-dimensionally related with the Reynolds number and the relative pipe roughness in the Moody diagram. For typical open holes, the surface roughness ϵ can vary from 0.003 to 0.012 m, depending on rock formation type and the completions [28].

Table B.1: Properties used for flow example in a regular pipe

Property	Value	SI units	Value	Field units
d_h	0.0508	m	2	in
ϵ	0.0060	m	0.2362	in
l	100	m	328	ft
μ	2x10^5	$Pa.s$	0.01	cP
ρ	0.8	kg/m^3	0.499	lbm/ft^3

The pressure drop in a pipe can be expressed as

$$\Delta p = f_M \frac{L}{d_h} \frac{\rho u^2}{2} \tag{B.2}$$

Where f_M is the Moody friction factor, L is the length, d_h is the diameter, ρ is the fluid density and μ is the viscosity.

The main parameters that determine the friction factor are the surface roughness, the diameter and the flow rate. For turbulent flows, the friction factor and the Reynolds number are related through the Colebrook equation. Increasing flow rates result in higher Reynold numbers, implying that the viscous forces are becoming negligible in comparison to the momentum forces. This results in a decreasing friction factor with higher velocity. Note that this does not imply in an actual decrease of the *friction force* with increasing velocity. In the case of the laterals, flow rate will be the major control since the roughness and diameter will be assumed constant once producing.

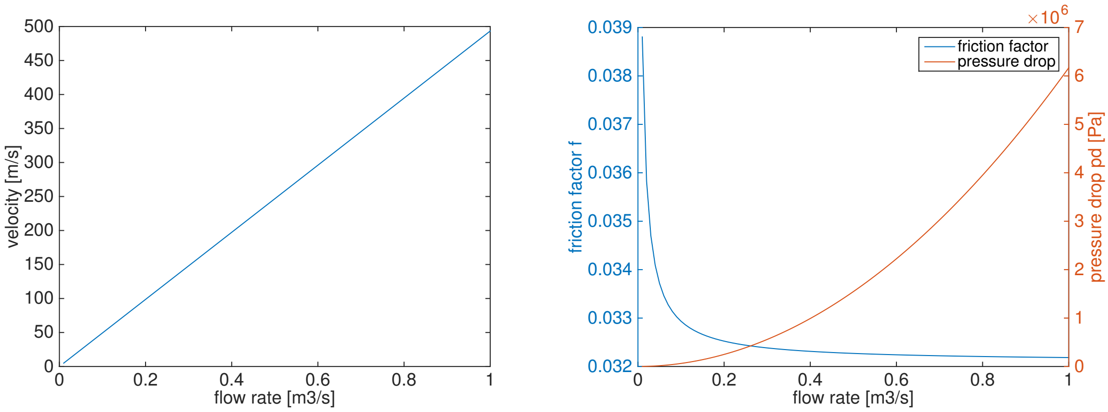
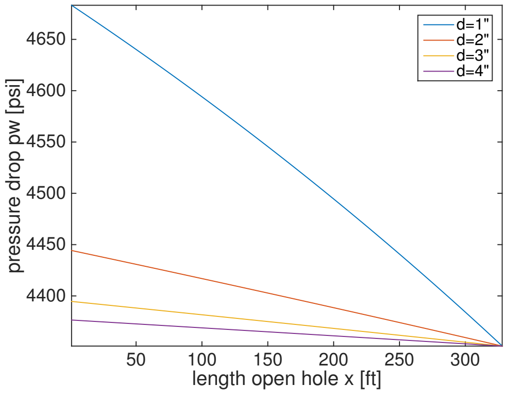


Figure B.4: Left: Pressure drop for different diameters. Right: Pressure drop for different permeability's.

Guo[17] has developed an analytical equation to calculate the pressure drop in a horizontal well coupled with reservoir flow. Friction increases significantly when open hole diameter becomes smaller. Open hole surface area and diameter are related exponentially, if the diameter decreases a factor 2, the surface area decreases a factor 4. If gas production is kept constant, a 1 inch diameter lateral would experience a fluid velocity 4 times higher than a 2 inch diameter lateral, increasing friction. Figures B.5 show the effect of diameter and permeability (kh/kv=10) on the pressure drop in the lateral. The flow rate in the lateral is 590.000 ft3/day (16000 sm3/day), and results in a pressure drop of 93 psi (6.4 bar) over a length of 328 ft (100 m) for a 2 inch (0.0508 m) diameter lateral. As long as the pressure drop is < 10% of the drawdown, it can be neglected. However, for higher permeability's, the pressure drop increases significantly with the associated flow rates.

Table B.2: Properties used in pressure drop calculations.

Property	Value	SI units	Value	Field units
d_h	0.0508	m	2	in
h	100	m	328	ft
k_h	9.87 x 10^{-17}	m^2	0.1	mD
k_v	9.87 x 10^{-18}	m^2	0.01	mD
ϵ	0.0060	m	0.2362	in
l	100	m	328	ft
μ	2 x 10^5	$Pa.s$	0.02	cP
ρ	0.8	kg/m^3	0.499	lbm/ft^3
p_r	400 x 10^5	Pa	5800	psi
p_{wH}	300 x 10^5	Pa	2900	psi
r_w	0.0254	m	1	in
S	5	-	5	-
T	393	K	653.4	$^\circ R$
y_b	500	m	1640	ft
y_g	0.55	-	0.55	-
Z	0.95	-	0.95	-



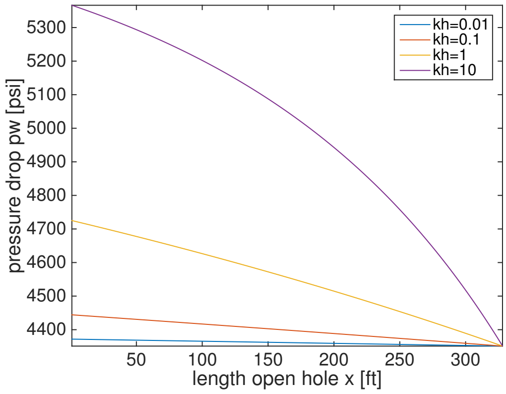


Figure B.5: Left: Pressure drop for different diameters. Right: Pressure drop for different permeability's.

Guo Parameters Field

```
close all
clear all
clc

% % Field
% h=50; %ft
% yb=5000; %ft
% kh=10; %md
% kv=5; %md
% s=0;
% Z=0.95;
% mug=0.02; %cP
% T=600; %Rankine
% pr=3000; %psi
% rw=0.328; %ft
% dh=1; %inch
% pwH=1000; %psi wellhead = assumed pwf
% L=100; %ft
% yg=0.7; %SG
% e=0.01; %in
```

Pressure Drop Function

```
function output =
pressure_drop_function(h,yb,kh,kv,s,Z,mug,T,pr,rw,dh,pwH,L,yg,f)
%UNTITLED Summary of this function goes here
%   Detailed explanation goes here

Iani=sqrt(kh/kv);

Jspg=kh/(1424*mug*Z*T*(Iani*log(h*Iani/(rw*(Iani+1)))+(pi*yb/(h))-
Iani*(1.224-s)));

C1=(140.86/Jspg)*(sqrt(pwH*dh.^5/(f*yg*T)));
C2=(L*(3/C1).^(2/3))+3/pr*((pr-(1/3)*(pr-pwH))/(pr-pwH)).^(1/3);

for x=1:L
a=((pr/3)*(C2-x*(3/C1).^(2/3))).^3;
pw(x)=pr*(1-(1/(a+(1/3))));
end

output=pw;
end
```

Pressure Drop Diameter

```
close all
clear all
clc

%% determine input units, output is always in field units.
unit=2; % set units in field(1) or SI(2).
```

Figure B.6: Matlab script for calculating pressure drops in laterals coupled with reservoir inflow.

```
if unit==1;
% import parameters in field units
run('Guo_parameters_field.m')
else
    run('Guo_parameters_SI_to_field.m')
end

%% set dh_new
dh_new=[1 2 3 4];

%% for loop to run pressure function
for i=1:4
    dh=dh_new(i);
f=0.25*(1/(1.74-2*log(2*e/(dh))))^2;
pw=pressure_drop_function(h,yb,kh,kv,s,Z,mug,T,pr,rw,dh,pwH,L,yg,f);
plot(pw); hold on

dp_psi(i)=pw(1)-pw(round(L));
dp_psi_per_diameter(i)=dp_psi(i);
dp_Pa_per_diameter(i)=from_psi_to_Pa(dp_psi(i));

% production
Iani=sqrt(kh/kv);
Jspg=kh/(1424*mug*Z*T*(Iani*log(h*Iani/(rw*(Iani+1)))+pi*yb/h-
Iani*(1.224-s)));
% QgH_Furui_ft3d=zeros(1,i);
QgH_Furui_ft3d(i)=Jspg*L*(pr^2-pwH^2)*1000; % scft3/d
QgH_Furui_m3d(i)=from_ft3_per_d_to_m3_per_d(QgH_Furui_ft3d(i)); % m3/d

fs=18;
htext=findall(gcf,'type','text');
set(htext,'Interpreter','none','FontSize',fs);
haxes=findall(gcf,'type','axes');
set(haxes,'TickLabelInterpreter','none','FontSize',fs);
legend('d=1"','d=2"','d=3"','d=4"')

xlabel('length open hole x [ft]');
ylabel('pressure drop pw [psi]');
axis tight

end

%production
QgH_Furui_ft3d(i)=Jspg*L*(pr^2-pwH^2)*1000
QgH_Furui_m3d(i)=from_ft3_per_d_to_m3_per_d(QgH_Furui_ft3d(i)) % m3/d

% pressure drop in numbers
dp_psi_per_diameter
dp_Pa_per_diameter=from_psi_to_Pa(dp_psi_per_diameter)
```

Figure B.7: Matlab script for calculating pressure drops in laterals coupled with reservoir inflow.

Appendix C

Simulations

C.1 Grid Study

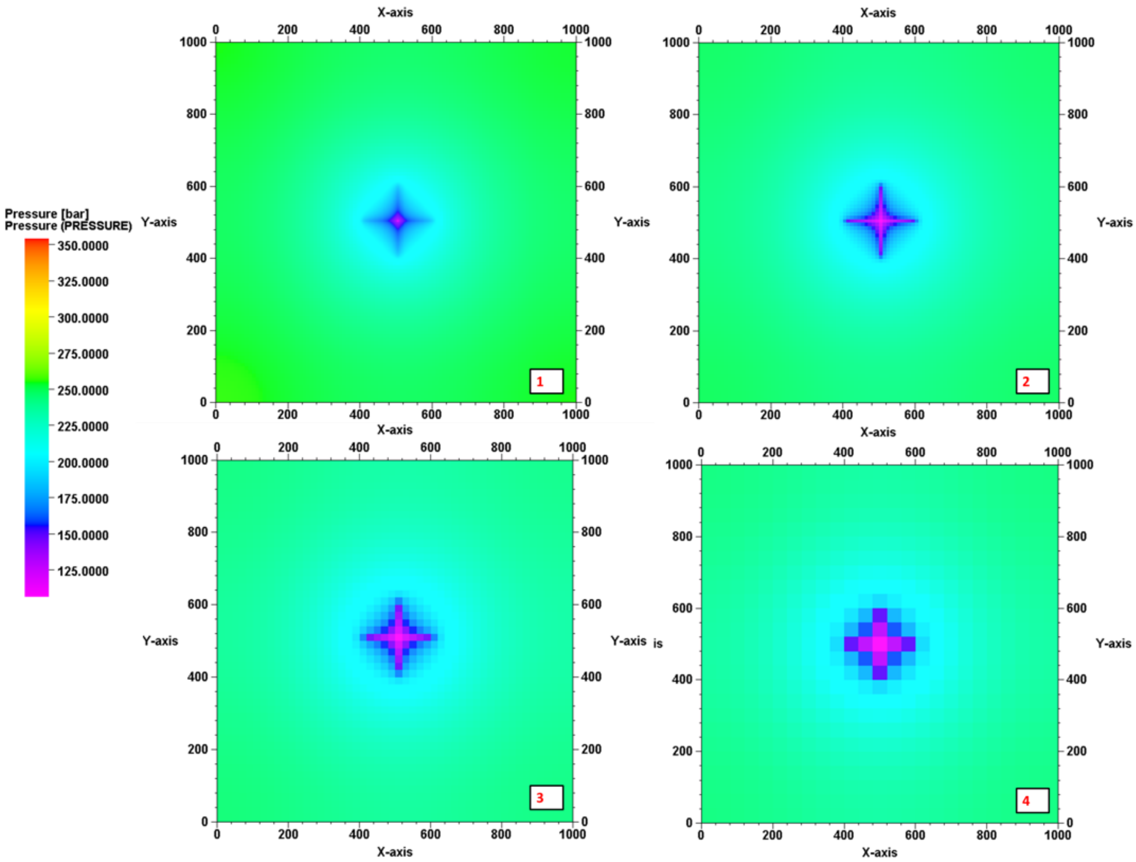


Figure C.1: Effect of grid refinement. Figure 1: 5x5x2.5, figure 2: 10x10x5, figure 3: 20x20x10, figure 4: 40x40x20

C.2 VW pressure profile

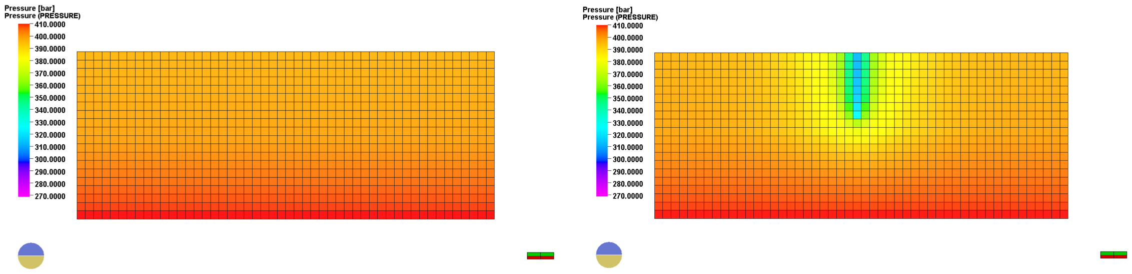


Figure C.2: Left: Initial pressure distribution for the vertical base case. Right: pressure distribution after 6 months.

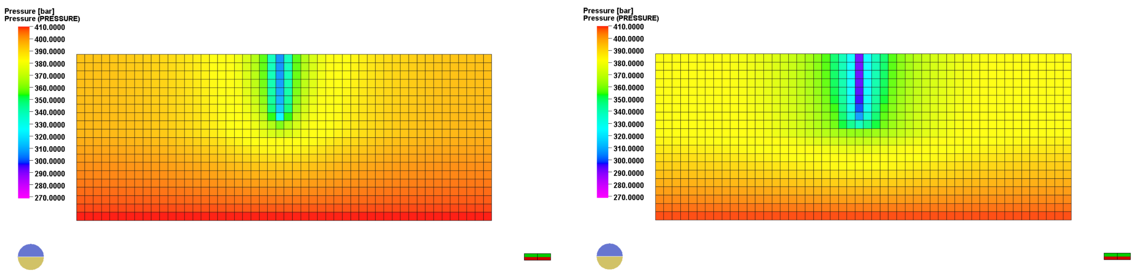


Figure C.3: Left: pressure distribution after 1 year. Right: pressure distribution after 5 years.

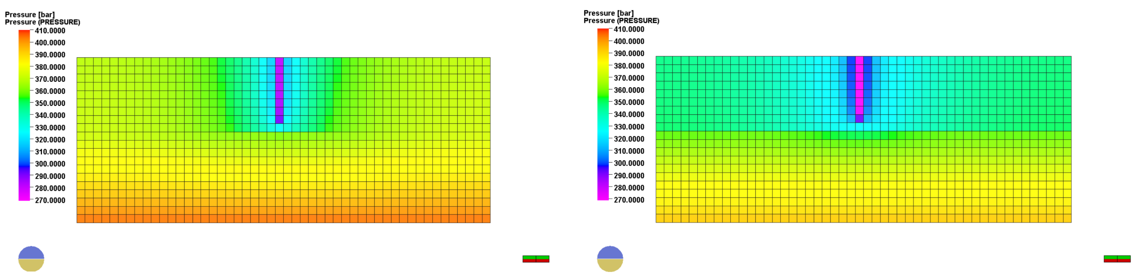


Figure C.4: Left: pressure distribution after 10 years. Right: pressure distribution after 20 years.

C.3 SDL pressure profile

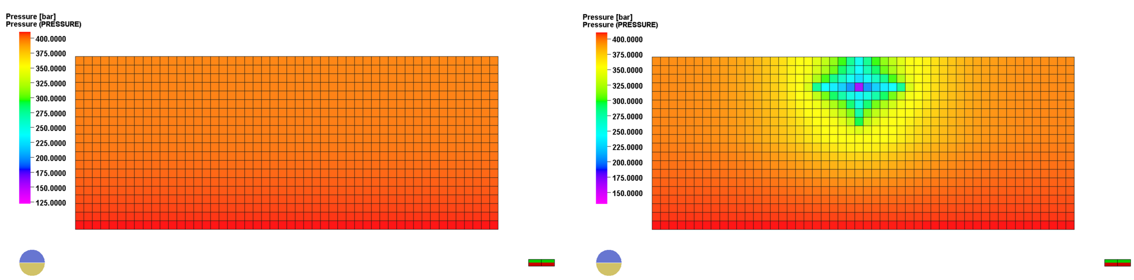


Figure C.5: Left: Initial pressure distribution for the small diameter lateral case. Right: pressure distribution after 6 months.

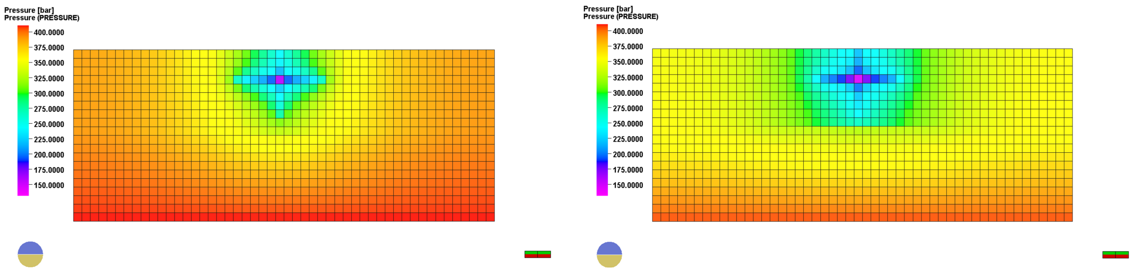


Figure C.6: Left: pressure distribution after 1 year. Right: pressure distribution after 5 years.

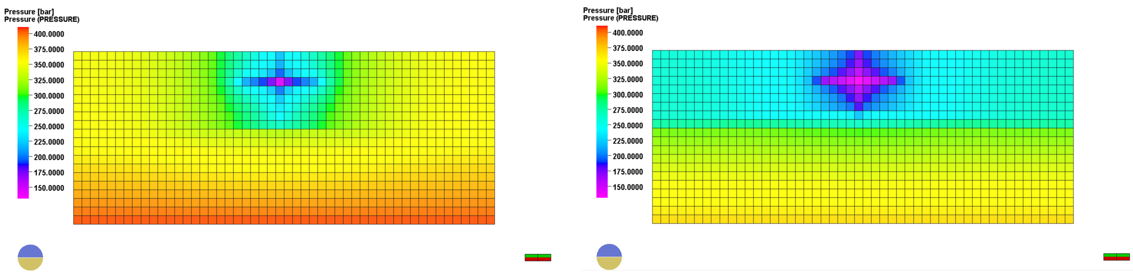


Figure C.7: Left: pressure distribution after 10 years. Right: pressure distribution after 20 years.

C.4 Tornado charts

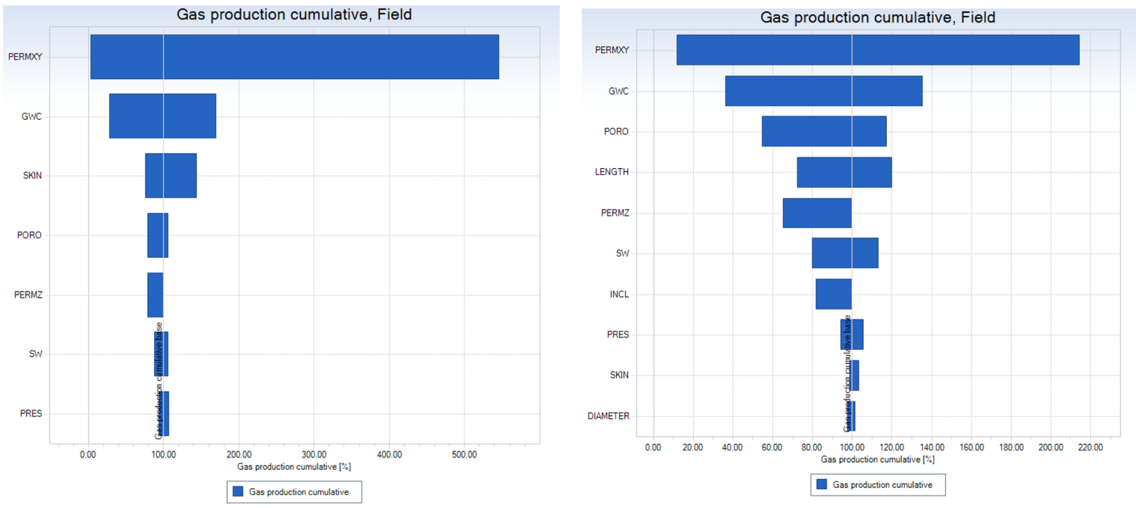


Figure C.8: Left: VW cumulative gas production is 130x10^6 sm3, recovery factor is 0.14. Right: SDL cumulative gas production is 336x10^6 sm3, recovery factor is 0.36

Appendix D

Economics

D.1 Results economics

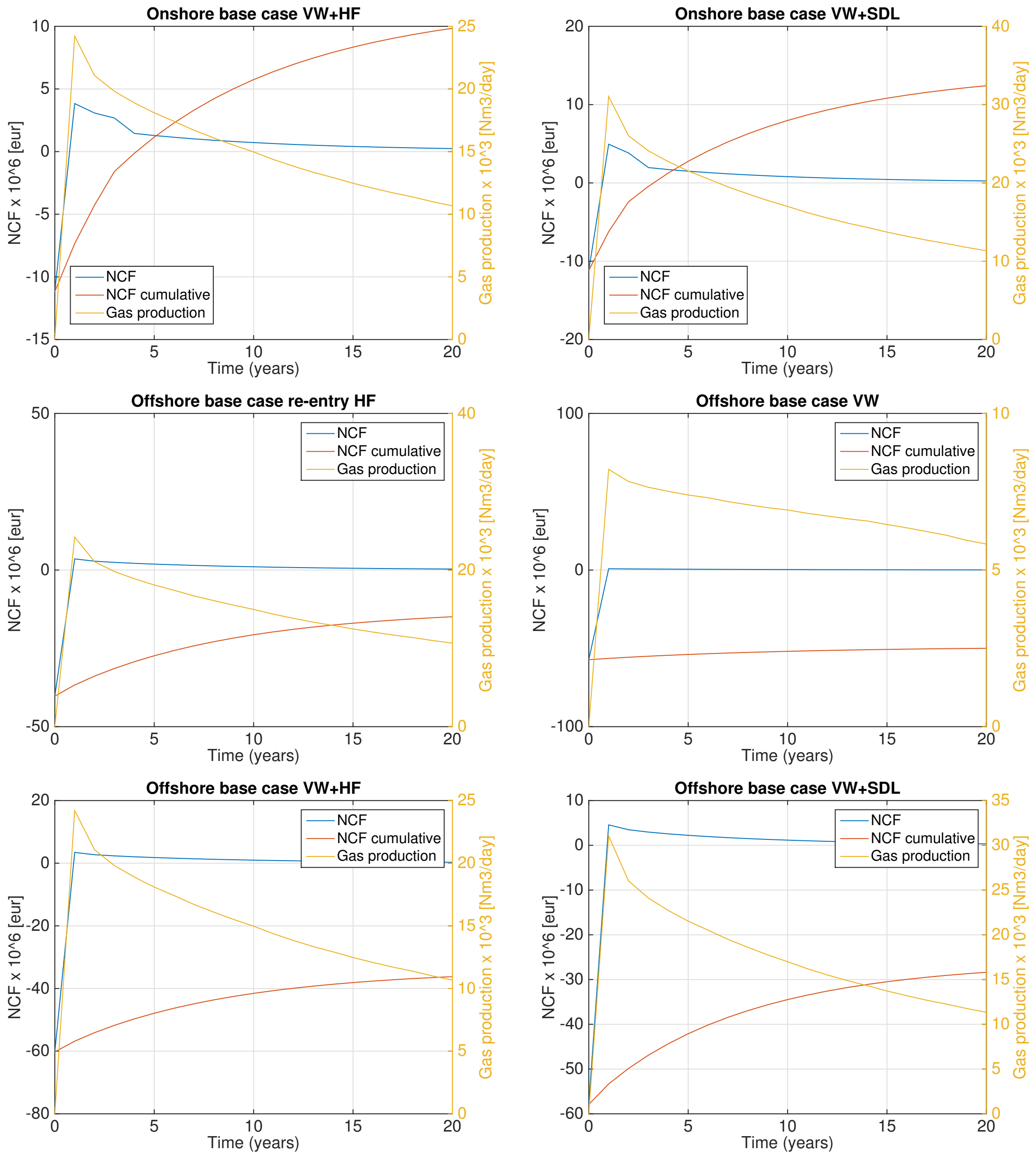


Figure D.1: Key economic indicators NCF and gas production rate.

General Project Information			Country	Onshore/Offshore	Author: Stefan Peters		Calculation Model Revision 23-11-2015
Field Name	Stranded Tight Gas	Tax Regime	Netherlands	Onshore			INPUT CELL, OUTPUT CELL, MANUAL CELL, PERFORMANCE
Reservoir Model	Base Case	Development Option	Re-entry SDL				

Production Forecast

Gas-Initially-In-Place (GIIP)	992,15	10^6 Nm3
Recovery Factor (RF)	36%	
Ultimate Recovery (UR)	354,68	10^6 Nm3
Peak Production	85,06	10^3 Nm3
Production Start	1	yr
Production End	20	yr

Gas & Oil Price

Gas Price (energy based)	18,75	eur/MWh
Gas High Heating Value (HHV)	35,17	MJ/Nm3
Gas Price (volume based)	0,183	eur/Nm3
Gas Price Escalation	2%	

CAPEX

		Number	Total Unit Cost Onshore (10^6 eur)	Total Unit Cost Offshore (10^6 eur)	Costs (10^6 eur)	Remarks
Wells	Gas Well	0	6,00	20,00	0,00	Vertical well, 16" conductor, 7" casing, 3,5" tubing
	Work Over Rig Rental	1	0,20	0,40	0,20	Onshore 8 days @ 25k €/d, Offshore 10 days @ 40k €/d
	RJD Stimulation	1	0,18	0,25	0,18	Onshore 8 days @ 22k €/d, Offshore 10 days @ 25k €/d
	HF Stimulation	0	2,00	3,00	0,00	Single hydraulic fracture, 50 m half length, 60 m height, 0.4 inch aperture
Facilities	Modular Skid	1	2,00	20,00	2,00	Onshore light modular skid, offshore additional rig space/mono pile
	Hook up	1	1,00	1,50	1,00	Costs to get everything up and running
	Pipeline	1	0,30	1,00	1,50	Onshore 5 km @ 300k eur/km, Offshore 15 km @ 1*10^6 eur/km
Overhead	Overhead,Project Management	1	0,50	0,75	0,50	Onshore 500 days @ 1000 €/d, offshore 750 days @ 1000 €/d
Total CAPEX					5,38	
Total installed CAPEX					11,38	Total installed CAPEX also includes existing wells and facilities

Tax and Royalties

Concession Area	10	km^2
Surface Rights	700	eur/km^2/yr
CIT+SPS	50%	
Tax (CIT+SPS) Relief	0%	

Depreciation & Multipliers

Discount Rate	10%	
Discount Rate ABEX	6%	
Depreciation Lifetime	11	yr
Capex Multiplier	1	
Cost Escalation (Capex & Opex)	2%	

ABEX	Well Abandonment Costs	1,00	2,00	5,00	2,00	Discounted ABEX is included as a yearly provision. It is not part of CAPEX.
				FV =	2,97	Future value ABEX
				PMT =	0,08	PMT calculates loan payments based on constant payments and interest rate

OPEX

Fixed OPEX	% of total installed	0,66%	0,08	10^6 eur/yr	100k per year
Variable OPEX	Gas evacuation and treatment	0,01	0,01	eur/Nm3	7,5 eur/k Nm3, treatment included to dehydrate gas etc.

Date	Time (Year)	Production (10^6 Nm3)	Production (10^3 Nm3/day)	Gas Price (eur/Nm3)	Revenue (10^6 eur)	License Fees (10^6 eur)	CAPEX (10^6 eur)	CAPEX Multiplier (10^6 eur)	Depreciation	OPEX (10^6 eur)	ABEX provision (10^6 eur)	EBT (10^6 eur)	EBT Cumulative (10^6 eur)	Tax (CIT+SPS in 10^6 eur)	Cash flow (10^6 eur)	Cash flow Cumulative (10^6 eur)	NCF (10^6 eur)	NCF Cumulative (10^6 eur)
01/01/15	0	0,00	0,00	0,00	0,00	0,00	5,38	5,38	0,00	0,00	0,00	-5,38	-5,38	0,00	-5,38	-5,38	-5,38	-5,38
01/01/16	1	31,05	85,06	0,19	5,80	0,01	0,00	0,00	0,47	0,31	0,08	4,93	-0,45	0,00	5,48	0,10	4,98	-0,39
01/01/17	2	26,02	71,28	0,19	4,96	0,01	0,00	0,00	0,39	0,28	0,09	4,19	3,74	2,10	2,58	2,68	2,13	1,73
01/01/18	3	24,10	66,04	0,19	4,69	0,01	0,00	0,00	0,37	0,27	0,09	3,95	7,69	1,98	2,43	5,11	1,83	3,56
01/01/19	4	22,71	62,23	0,20	4,50	0,01	0,00	0,00	0,34	0,27	0,10	3,79	11,49	1,90	2,34	7,45	1,60	5,16
01/01/20	5	21,52	58,97	0,20	4,35	0,01	0,00	0,00	0,33	0,26	0,10	3,66	15,14	1,83	2,26	9,70	1,40	6,56
01/01/21	6	20,52	56,22	0,21	4,23	0,01	0,00	0,00	0,31	0,26	0,11	3,55	18,69	1,77	2,19	11,90	1,24	7,80
01/01/22	7	19,50	53,42	0,21	4,10	0,01	0,00	0,00	0,30	0,25	0,11	3,43	22,12	1,72	2,13	14,02	1,09	8,89
01/01/23	8	18,60	50,97	0,21	3,99	0,01	0,00	0,00	0,28	0,25	0,12	3,33	25,45	1,67	2,07	16,09	0,97	9,85
01/01/24	9	17,75	48,64	0,22	3,89	0,01	0,00	0,00	0,27	0,25	0,13	3,23	28,69	1,62	2,01	18,11	0,85	10,71
01/01/25	10	17,00	46,57	0,22	3,80	0,01	0,00	0,00	0,26	0,25	0,14	3,15	31,83	1,57	1,97	20,07	0,76	11,47
01/01/26	11	16,20	44,40	0,23	3,69	0,01	0,00	0,00	0,25	0,24	0,14	3,05	34,88	1,52	1,91	21,99	0,67	12,14
01/01/27	12	15,52	42,52	0,23	3,61	0,01	0,00	0,00	0,24	0,24	0,15	2,97	37,85	1,48	1,87	23,86	0,60	12,73
01/01/28	13	14,88	40,78	0,24	3,53	0,01	0,00	0,00	0,23	0,24	0,16	2,89	40,74	1,45	1,83	25,69	0,53	13,26
01/01/29	14	14,32	39,24	0,24	3,46	0,01	0,00	0,00	0,22	0,24	0,17	2,82	43,56	1,41	1,80	27,50	0,47	13,74
01/01/30	15	13,72	37,59	0,25	3,38	0,01	0,00	0,00	0,21	0,24	0,18	2,75	46,31	1,37	1,76	29,26	0,42	14,16
01/01/31	16	13,19	36,14	0,25	3,32	0,01	0,00	0,00	0,20	0,24	0,19	2,68	48,99	1,34	1,73	30,99	0,38	14,54
01/01/32	17	12,69	34,77	0,26	3,26	0,01	0,00	0,00	0,19	0,24	0,21	2,61	51,60	1,31	1,70	32,70	0,34	14,87
01/01/33	18	12,25	33,57	0,26	3,21	0,01	0,00	0,00	0,19	0,24	0,22	2,56	54,16	1,28	1,68	34,38	0,30	15,18
01/01/34	19	11,77	32,24	0,27	3,14	0,01	0,00	0,00	0,18	0,24	0,23	2,49	56,64	1,24	1,65	36,03	0,27	15,45
01/01/35	20	11,34	31,07	0,27	3,09	0,01	0,00	0,00	0,17	0,24	0,24	2,43	59,07	1,21	1,63	37,66	0,24	15,69
	Total	354,68			77,99	0,14	5,38	5,38	5,38	5,05	2,97	59,07	59,07	29,76	37,66	37,66	15,69	15,69
															15,69			

Economic Performance Indicators

Discount Rate	0,00	0,05	0,10	0,15	Development Costs	0,02	eur/Nm3	Earning Power (IRR)	68%	
Project Net Present Value (PNPV, 10^6 eur)	37,66	23,42	15,69	11,10	Lifting Costs	0,01	eur/Nm3	UTC	0,03	eur/Nm3

Figure D.2: Purpose built economic spreadsheet

List of Figures

Glossary

ABEX Abandonment Expenditures.

API American Petroleum Institute.

BOP Blow Out Preventer.

CAPEX Capital Expenditures.

CIT Corporate Income Tax.

CT Coiled Tubing.

EBN Energie Beheer Nederland.

EBT Earnings Before Tax.

EP Earning Power.

FWL Free Water Level.

GWC Gas Water Contact.

HHV High Heating Value.

MFTA Marginal Field Tax Allowance.

MWD Measurements While Drilling.

NCF Net Cash Flow.

NMR Nuclear Magnetic Resonance.

NPV Net Present Value.

OPEX Operational Expenditures.

PDM Positive Displacement Motor.

RCA Routine Core Analysis.

RF Recovery Factor.

RJD Radial Jet Drilling.

SCAL Special Core Analysis.

SDL Small Diameter Lateral.

SPS State Profit Share.

SSSV Sub Surface Safety Valve.

TGS Tight Gas Sandstone.

TTF Title Transfer Facility.

TVMSL True Vertical Mean Sea Level.

UR Ultimate Recovery.

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