PEOPLE'S DEMOCRATIC REPUBLIC OF ALGERIA
MINISTRY OF HIGHER EDUCATION AND SCIENTIFIC RESEARCH

N° Series: ………./2019

KASDI MERBAH UNIVERSITY - OUARGLA

FACULTY OF HYDROCARBONS, RENEWABLE ENERGIES, EARTH AND UNIVERSE SCIENCES

PRODUCTION DEPARTMENT

FINAL STUDY DISSERTATION

In Order To Obtain The Master Degree

Option: Production

Submitted by :

ACHI Hamza, ZOUABLIA Abdelmadjid

-THEME-

Water injection and gas lift optimization to improve oil rim production in Hassi R'mel field

Presented in : 12 /06/ 2019

President :	Mr. GAREH SALIM	Assistant lecturer
Examiner :	Mr. GHALI AHMED	Lecturer class "A"
Supervisor :	Ms. ROBEI SARRA.	Assistant lecturer class "A"

Academic Year : 2018/2019

Acknowledgments

Throughout the writing of this dissertation we have received a great deal of support and assistance.

We would first like to thank Allah our creator, for the courage and patience given to us to accomplish this work.

Secondly, we would like to express our deep gratitude to our supervisor, Dr. Sarra Robei, whose expertise was invaluable in the formulating of the research topic and methodology in particular.
We would like to acknowledge our colleagues from our internship at Hassi R'mel for their wonderful collaboration. You supported us greatly and were always willing to help me. We would particularly like to single out our supervisor at Hassi R'mel, Ms. R.Habibi, We want to thank you for your excellent cooperation and for all of the opportunities we were given to conduct our research and further our dissertation.
We would also like to thank Mr.Messaoud Kourikar.
You provided us with the intership that we needed to choose the right direction and successfully complete our dissertation.
In addition, we would like to thank our parents for their wise counsel and sympathetic ear. You are always there for us.
Finally, there are our friends, who were of great support in deliberating over our problems and findings, as well as providing happy distraction to rest our minds outside of our research.

Abdelmadjid Zouablia &

Achi Hamza

Dedications

This study is wholeheartedly dedicated to

My beloved parents Belkacem and Noura Abdelmalek, who have been my source of inspiration and gave me strength when I thought of giving up, who believed in me when no one else did, who continually provided their moral, spiritual, emotional, and financial support.

My dear brothers Mohamed Ali and Ahmed Abd el Baste who were always by my side.

All of my relatives especially Abdelnour Abdelmalek and Bouthina Chaouli who shared their words of advice and encouragement to finish this study.

My best friend Abderraouf who supported me throughout the process.

My supervisor Sarra Robei for her valuable advice, feedback, time, expertise and encouragement.

My colleague Hamza Achi for the sleepless nights we spent working on this study.

And lastly, I dedicated this thesis to the Almighty Allah, thank you for the guidance, strength, power of mind, protection and skills and for giving me a healthy life.

Abdelmadjid Zouablia

Dedications

This study is wholeheartedly dedicated to

My beloved parents Rebiai and Hizia Meddour, who have been my source of inspiration and gave me strength when I thought of giving up, who believed in me when no one else did, who continually provided their moral, spiritual, emotional, and financial support.

My dear brothers Youcef, Elbahi , Abdelmalek , Zoubir and their wives, and Lamine(Imad), And our mazouz Bilal and my dear sister Leila and her husband Fares who were always by my side.

My dear nephews Mohamed , Anes and Kais moumen billah and my dear niece Kadar. and my cousins Ghoulem and Tesnim.

My little village Chelia , especially my grandparents, uncles, aunts and cousins.

All of my relatives especially who shared their words of advice and encouragement to finish this study.

My friends who supported me throughout the process.

My supervisor Sarra Robei for her valuable advice, feedback, time, expertise and encouragement.

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Hamza Achi

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List of abbreviations and Symbols

HRM :	Hassi R'mel
CTH :	Oil treatment center (centre de traitement d'huile)
TEG :	TRIAS ARGILO GRESEUX
SSW-NNE:	South South western - North North Eastern
M:	million
ϕ	porosity % .
K	permeability mD
Sw	Water saturation %.
HRS :	Hassi R’mel South
HRE :	Hassi R’mel East
d :	Density
API :	American Petroleum institute
CSTF :	condensate storage center
LPG :	liquefied petroleum gas
SRGA :	Dissolved gas recovery station
CNDG :	North gas distribution center
CTG :	gas treatment center
CTG DJB :	gas treatment center of djbel basaa
MPP :	gas processing plants
P:	pressure bars
T :	Temperature: °C
GC :	Gas condensate T/year
SRGA :	RECUPERATION STATION OF ASSOCIATED GAS
TDT :	Thermal decay time
WOC :	Water Oil contact
GOC :	Gas Oil contact

:

WOR:	Water oil ratio
SPM:	Side Pocket Mandrel
NaCl	Sodium chloride
CaCO3	Calcium Carbonate
CaSO4	Calcium Sulphate
SrSO4	Strontium Sulphate
BaSO4	Barium Sulphate
C:	X valence cation.
A:	Y valence anion
μ :	Ionic strength of the solution.
Ci :	Concentration of each of the ions.
Zi:	Valencia of each of the ions.
PPM :	particle per million
S:	Solubility product
Q_{inj} :	Injected water flow (m3/d)
Q_f :	Reservoir water flow (m3/d)
S_s :	Threshold Salinity (g/l)
S_i :	Injection water salinity (freshwater) (g/l)
S_f :	Reservoir water salinity (g/l)
Wcut:	water cut
GLR :	Gas Lift Rate
PVT:	Pressure, Volume , Temperature
IPR	Inflow Performance Relationship
Pb :	Bubble Pressure
Pr :	Reservoir pressure
J:	production index.
Pwf :	well bore pressure (kg/cm^2)

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VLP:	Vertical Lift Performance Relationship
PSS :	pseudo steady state
Qg injected:	injected gas flow rate (.E3 Sm3/d)
Qgt :	produced gas flow rate (Sm3/d)
$P_{wellhead}$:	wellhead pressure (kg/cm2)
Hu :	reservoir thickness (m)
OD :	outer diameter (in)
ID :	inner diameter (in)
$\vert \Delta P \vert$:	pressure drawdown
Pm :	measured pressure
GLS :	Suspended completion
GLP :	Parallel completion
GLC :	Conventional (mixed) completion
USD :	American dollar
DZD :	Algerian Dinar
CT:	Coiled tubing

:

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INTRODUTION

Oil is a strategic resource, essential energy in many sectors such as transportation, domestic uses and industry. It represents both an economical and a geopolitical asset.

To produce oil, it is not enough to drill a well in the ground and let the oil flow. Studies and equipments are needed to ensure adequate exploitation of underground hydrocarbon reserves.

The production of a well is always accompanied by problems that reduces its effectiveness, therefore decreasing the production rate; and even shutting some wells.

It is the job of production engineers to ensure that the exploitation of a hydrocarbon field (crude oil or natural gas) is optimal, taking the necessary precautions to avoid problems during the exploitation and by attempting to resolve them in the shortest time possible, and make the necessary compromises to maximize production.

A problem that severely obstructs the oil rim production at Hassi R'mel is the formation of salt deposits in the wells, which has a significant impact on the production and the sub-surface and surface installations.

The solution to this problem is the continuous injection of fresh water, whose role is to reduce the salinity of the formation water and bring it below the degree of salinity where the salts do not precipitate; known as "threshold salinity".

The flow rate of the injected water must be optimized to ensure the desalination in the well, and at the same time, to make sure not to weigh too much the hydrostatic column.

The treatment of this problem by injecting water decreases the eruption of the well, and can even cause its flooding. this decline in reservoir pressure requires other activation methods among these methods, gas-lift activation. In this technique, specific quantities of pressurized dry gas are injected into the well to lighten the hydrostatic column and lower the gravity losses and increase the production rate.

Most of the oil wells at HASSI R'MEL field are equipped with completions where the injection of gas and water is done at the same time in the annular space Tubing X Casing (mixed injection). At the beginning, this type of completion has been successful, but with the increase in the proportion of produced water (water cut) and the depletion of the reservoir, frequent clogging with salt (salt saturated water) has become a concern. This has resulted in high expenses due to cleaning operations and costly shutdowns of production.

There are two types of completions that support the separated injection of gas and water, the suspended tubing completion where the gas is injected at the bottom in the annular space between the two tubings 4 "1/2 and the 2" 7/8, and the parallel completion where the gas is injected in the annular space via a 1"660 concentric tubing and the water is injected in the same annular space

This dissertation is divided into three chapters. The first one, presents Hassi R'mel geologically and highlights its major problems then introduces the different completion designs that support the double injection. On the other hand, the second chapter mentions the different salts encountered in oil wells and how to deal with them using the adequate water injection flow rate. The last chapter optimizes gas lift injection flow rate for each completion type and analyses economically the expenses of the parallel completion.

In conclusion and after the comparison between the various completions, some recommendations are proposed in order to improve and to have an optimal production economically and practically in the field of HRM.

Chapter 01 :

Presentation of Hassi R'Mel Field and Choice of Completion

I.1 The geographical position:

Hassi R’Mel field was discovered in early 1956 ,it is located at 550 km South of Algiers between Laghouat and Ghardaïa cities, at an average altitude of 760 m (Figure.I-1).

It is the first natural gas reservoirs, with an estimated initial reserves of 3000 billion standard m^3. It has an oil rim in the eastern area.

Hassi R’mel field is elliptically-shaped. directed South-North /North-East , it extends on a surface area of 3500 Km^2, (70Km from North to South and 50 Km from East to West).

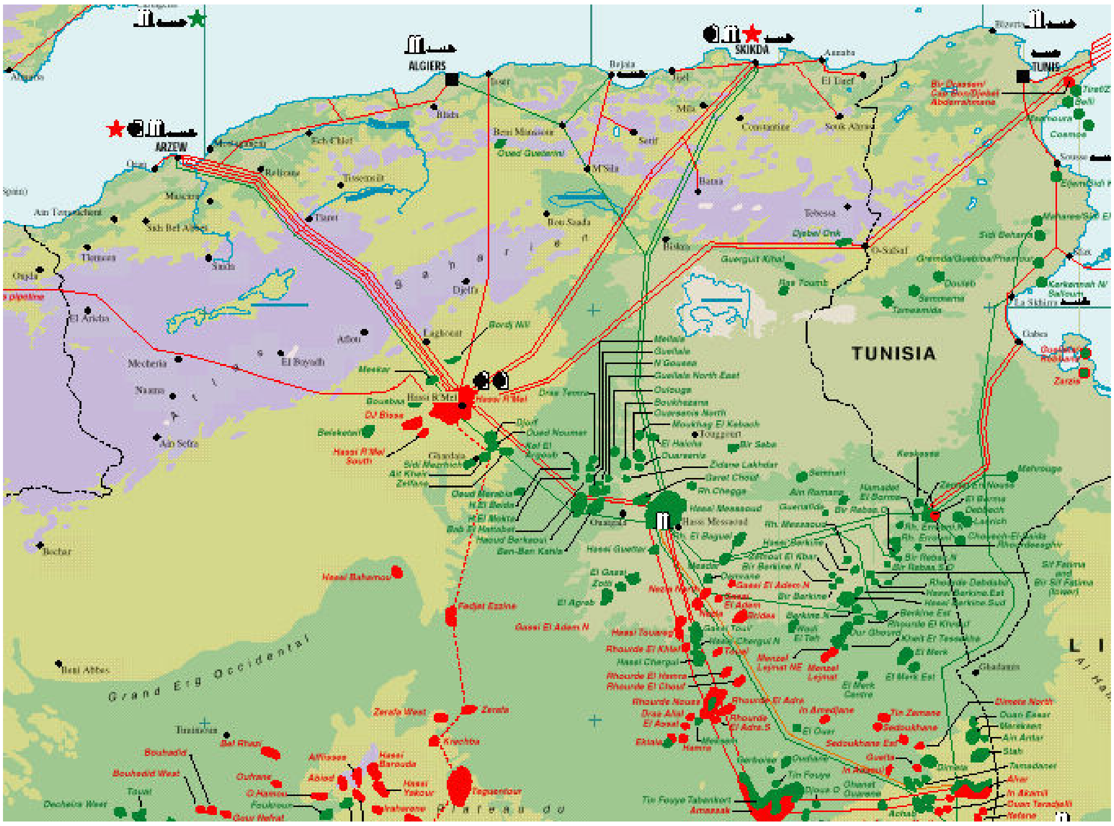

Figure.I-1: Geographical position of hassi r’mel field.

I.2 History of the region:

The first geophysical operation in the region took place in 1951.

In 1952, the first exploration well was drilled near BERRIANE, it highlighted the presence of a Triassic sandstone which possesses the characteristics of an excellent reservoir with a large saliferous Triassic cover.

By the end of 1956, the drilling of HR1, which was achieved a few kilometers to the east of Hassi R'mel water hole, highlighted the existence of a high pressure wet gas reservoir 2123 m deep.

The drillings that followed, had confirmed the existence of an important anticline and permitted a more precise study of the geological levels and characteristics.

From 1957 to 1960, HR2, 3, 4, 5, 6, 7, 8 and 9 were drilled surrounding HR1 in order to explore the northern area of TILGHEMT.

To overcome the natural depletion, and to raise the gas condensate production, many injection wells were implanted North and South of the central zone, with the first one done in 1976.

The presence of oil in Hassi R'mel was detected after the drilling of HR8 well in 1958 in the South Western sector of the field.

In 1978, the exploitation department dealt with the field's limitation. Some wells were implanted on the South Eastern side of the field at DJEBEL BISSA and BOUSBAA, where the well BSB1 gave satisfying oil results (12.2 m^3/d) in the TRIAS ARGILO GRESEUX (TEG) sandstone .

In 1979, the development of HR38 well, implanted on the structure edges, revealed the presence of an oil column with a 9.5 m effective thickness in the level A.

The wells HR (154, 165,166) confirmed the existence of an oil rim.

I.3. Geological overview on the field:

Hassi R'Mel is the biggest gas reservoir towards which the products of different genesis processes, and transformation of hydrocarbons that took place in the grand Oued Mya sedimentary basin, are migrated and trapped after a long trip through the geological times and layers after their expulsion from the bedrocks in which they were formed.

Hassi R'mel geological structure appears as a big wavy anticline, it has a SSW-NNE direction and it is affected by a dense network of gaps.

Two satellite structures are attached to the grand reservoir. In the South-West, **Djebel Bissa's** anticline structure separated from the main structure by a large gas reservoir. In the South, **Hassi R'Mel Sud** is a complex structure that represents an important oil production reservoir.

The reservoir's structural configuration began in the early geological times. The first folds of the Hercynian period aged more than 340M years in the middle of the primary era.

The structure has taken on the look substantially at the end of the Mio-Pliocene age, it is about 2 M years.

The reservoir rock is composed of three levels A,B and C with a thickness reaching 150 m.

I.3.1 Geological position:

Hassi R'mel field is situated on the saharian platform, in the North-Western area of the Triassic basin, behind of IDJERANE M'ZAB and in front of TILGHEMT. It is limited from the North by the ATLAS SAHARIAN chains, from the West by the BECHAR basin, from the East by OUED MYA basin and from the South by AHNET and MOUYDIR basins (Figure.I-2).

Hassi R'mel's tectonic, listed in the global tectonics' frame of the SAHARIAN platform, is marked by two important tectonic cycles:

- Austrian cycle.
- Hercynian cycle.

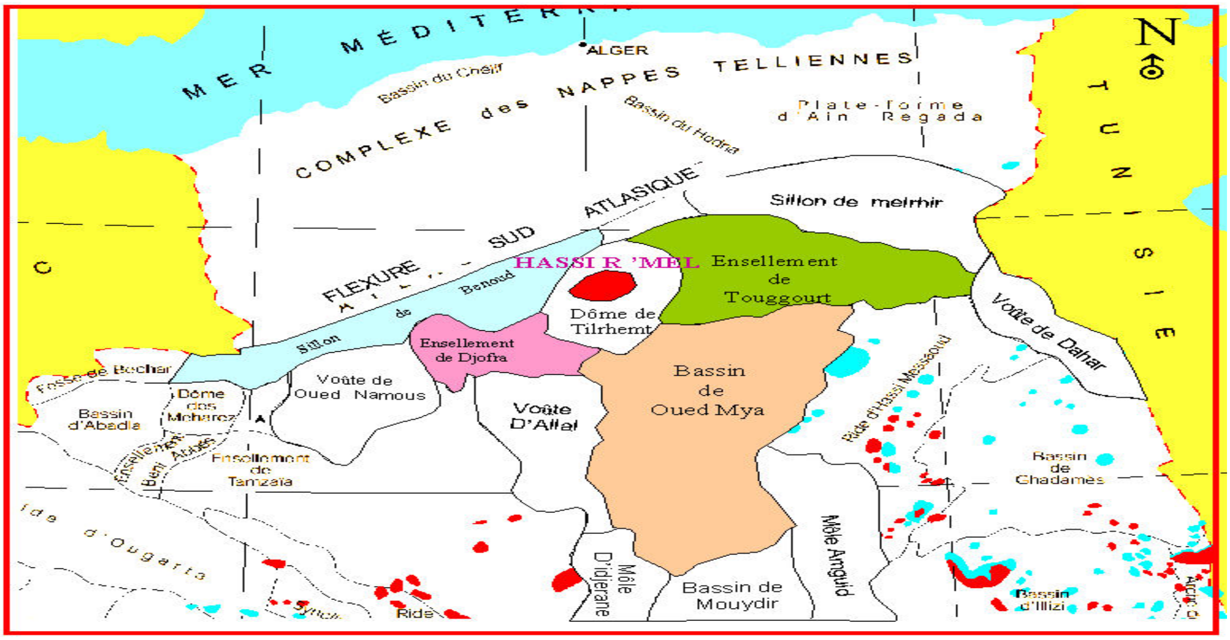

Figure.I-2: Geological situation of the hassi r'mel field.

I.3.2 Stratigraphy of the reservoir:

On the whole structure as shown in (Figure I.4), the series are relatively constant, The stages encountered are the following:

I.3.2.1 Cretaceous: it includes the following stages:

- **Senonian:** has a varying thickness between 30 and 40 meters.
- **Turonian :** it presents a 40 meters thickness.
- **Cenomanian :** it presents a 120 meters thickness.
- **Continental intercalary :** it includes :
  - L'Albian : 200 meters thick.

- L'Aptian : 25 meters thick.
- Barremian : 35 meters thick.
- Neocomian : 300 meters thick.

I.3.2.2 Jurassic: it presents three groups:

- **Malm :** it is composed of **:**
  - Weak sandstone and clay: 300 meters thick.
  - Crystalline limestone, past clay 40 meters thick.
  - Clay with intercalations of friable sandstone: 80 meters thick.
  - Alternations of dolomite and clay: 30 meters thick.
- **Dogger:** it is composed of limestone series alternating with grey-green clay. with a thickness of 230 meters.
- **Lias :** it presents two distinct series :
  - Marny lias 130 meters thick.
  - Carbonated lias 110 meters thick.

I.3.2.3 Triassic: it presents 7 groups:

- Anhydritic Trias: 70 meters.
- Saliferous Trias: 350 meters.
- Dolomitic landmark D1: 4 meters.
- Clay Trias: 70 meters.
- Dolomitic landmark D2: 10 meters.
- Gritty Clay Trias: 120 meters.
- Lower layer of a (0 to 130 meters).

The Triassic reservoir of Hassi R'mel is a set made up of three levels superposition A,B, and C, with clay's intercalation of varying thicknesses. The cover is formed by anhydrite Trias and clay Trias.

I.3.3 PREVIEW OF THE THREE LEVEL RESERVOIRS:

The reservoir of Hassi R'mel is composed of three principal level reservoirs, Triassic aged sandstone named A,B,C separated from each other by clay layers. they lie on the Hercynian surface. The clay trias and the evaporate trias represent the cover (Figure.I-3). They can be connected laterally and vertically as a result of:

- Gaps rejection 5 to 10 meters.
- Fracture development.
- Thin local thickness of clay's intercalation.

I.3.3.1 Reservoir A:

Extension limits: it possesses the biggest extension with a surface of 2640 km^2 and covers practically the majority of Hassi R'mel field except the South- Western zone.

It is composed of fine to very fine sandstone, locally clayey , strongly cemented. Its thickness varies on the whole field from (15 to 30).This layer presents 54% of the reserves in place.

- Average porosity (ϕ) of (10 to 15) %.
- Average permeability (K) of 250 mD.
- Water saturation (S_w) of 24%.

I.3.3.2 Reservoir B:

Extension limits: It has a more limited extension compared to reservoir A, it is limited at the central zone and the Northern zone of the field, representing an area of 1150 km^2.

It is composed of fine sandstone. It is the layer with varying thicknesses, especially in the central zone. The largest thicknesses are found in the North. This layer presents 13% of the reserves in place.

- Average porosity (ϕ):15%.
- Average permeability (K):250 mD.
- Water saturation (Sw) of 28 %.

I.3.3.3 Reservoir C:

Extension limits: It extends on the major part of the field, except in the Southern zone where it bevels. It covers an area of 1780 km^2 and it is able to reach 60 meters thickness in the Northern part .its thickness varies regularly following the North – South direction.

In certain sectors, especially in the center and in the North, it subdivides into 2 or 3 sub-levels, separated from each other by local extension clay benches.

It is composed of medium to fine grains, weakly cemented by conglomerate and of milky white quartz grains, with a variable size, ranging from few mm to few cm, with fine clay passages .

Reservoir C has the best characteristics which are:

- Average porosity (ϕ) of 18%.
- Average permeability (K) of 800 mD.
- Water saturation (Sw) of 13%.

NOTE: Among the three level reservoirs, reservoir C has the best petro physical characteristics, with a permeability of 880 md and a porosity above 18%, and a water saturation reaching 13 %, with reserves in place representing 33 % of total reserves.

I.3.3.4 Inferior series:

It is composed in the meridional area and the occidental area of the central zone by an alternating layer of andesite (efusso- eruptive).In the North as well as in the South, it presents a clayey sandstone layer where (HRS 4-6) wells encountered an accumulation of oil.

I.3.3.5 Cambrian-Ordovician (Paleozoic):

Intermittent under the Trias, it is composed of compact quartzite grains, with a presence of TIGILLITES. The CAMBRIAN-ORDOVICIAN isn't reachable to the totality of Hassi R'mel wells.

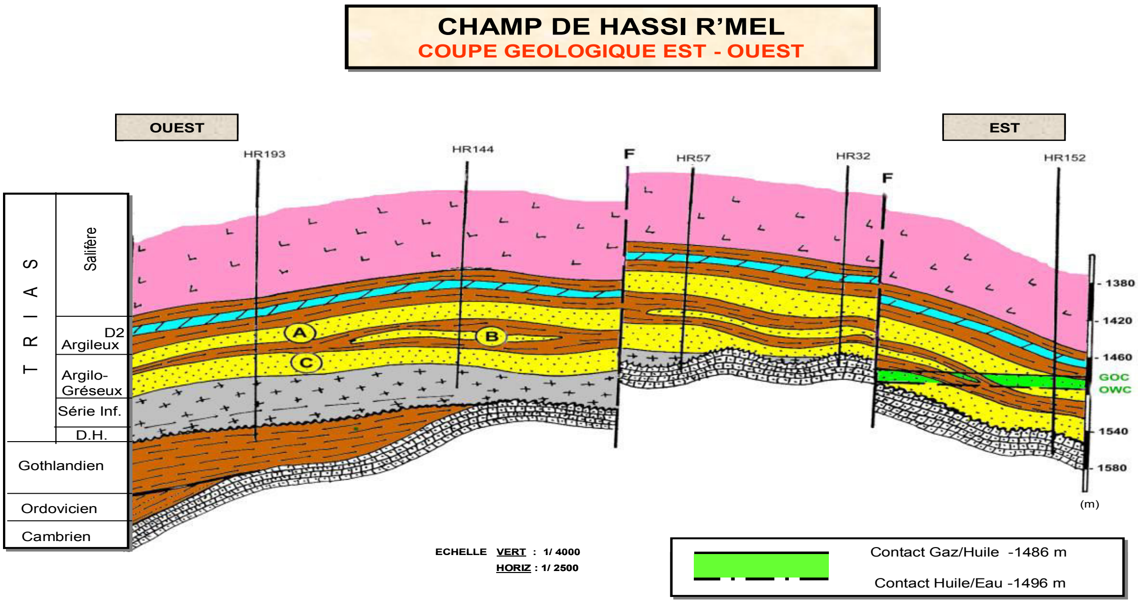

Figure.I-3: East-west geological section of hassi r'mel field.

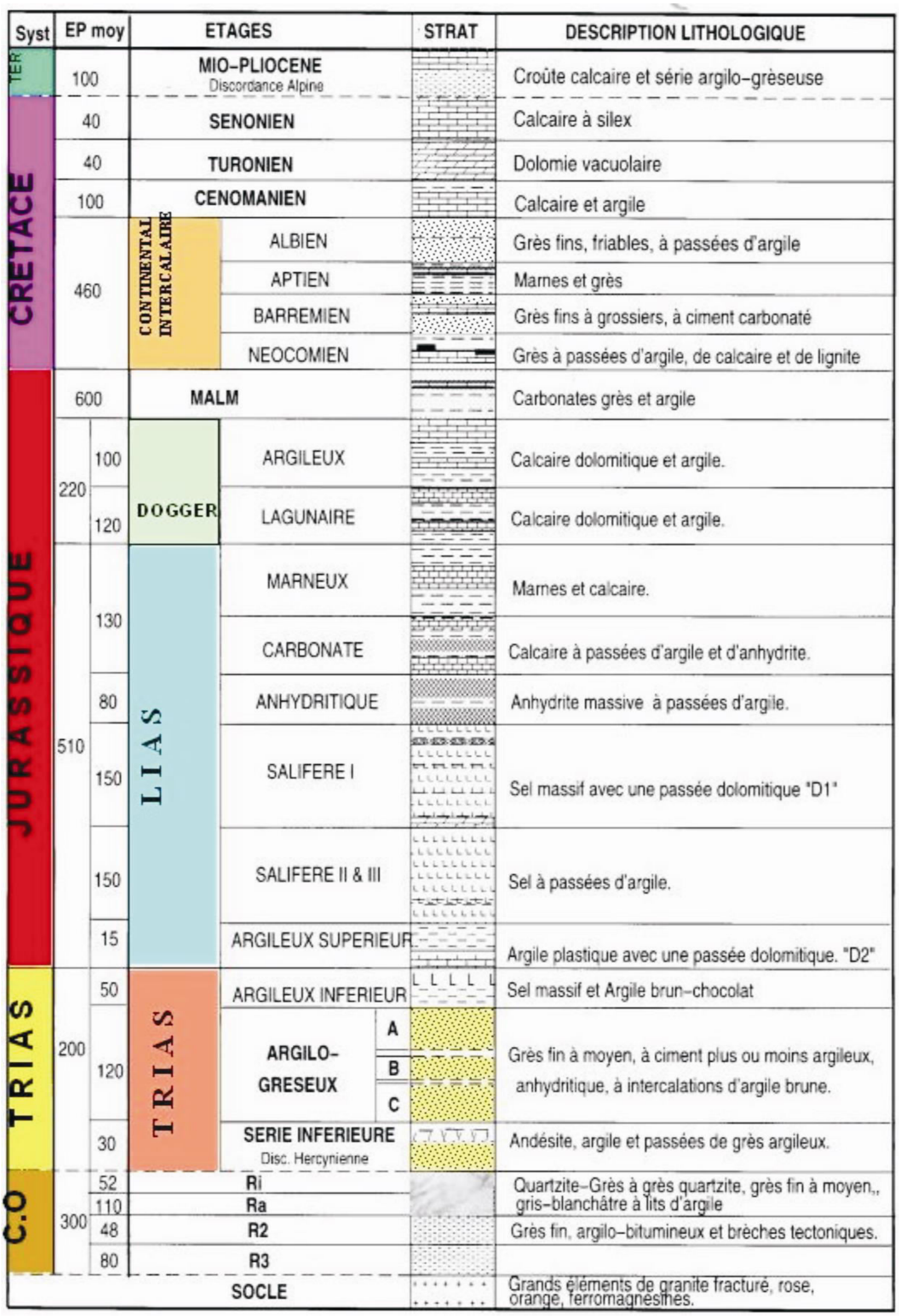

Fig.I-4: Stratigraphic column of hassi r'mel.

I.4.Presentation of oil rim:

I.4.1.Geological frame:

The existence evidence of the oil rim in Hassi R'mel gas field was confirmed, just after the discovery of the gas field, in 1958 with the HR8 well located in the south west of the field, where a thin layer of oil was encountered.

In 1979, the crude oil was exploited. The drilling of the HR38 well and other field delineation wells at the eastern flank eventually resulted in the discovery of an oil rim, where the level A-reservoir sandstone gave a total height of 16 meters (average effective height of the oil rim being 11m); offering a perspective of development and production.

The oil was found at the upper layer (reservoir A), a Triassic-age reservoir, in direct contact with the underlying aquifer, and a large overlying gas cap.

The layer is characterized with quartzite sandstone cemented with anydride clay and Triassic-age carbonated clay. It rests on layers of clay and andesite of the lower series that bevels at the extreme eastern limit to put in direct contact the TAG with the Combro-Ordovician

The average depth at the roof of the horizon 'A' is 2213m. The total thickness varies from 15.4m (HR203) to 37.2m (HR161) with an average of 23.6m.

The oil rim in question extends from North East to South East over a distance of about 65 km for an average width of 4 km.

The oil contained in this rim is light, with a density of 0.81 (42 ° API) in contact and in thermodynamic equilibrium with the condensate gas with an initial bubble pressure, equal to the dew pressure of the gas, 311 kg / cm2.

The qualities of the reservoir ‘A’ on the flank containing the oil rim are characterized by average permeabilities of 250 md. The deposition environment of shallow fluvial type, reflected by a variable sedimentation giving the formation a lateral and vertical heterogeneity more or less pronounced according to the places.

The initial volumes in place estimated are of the order of **90 million m3**.

I.4.2 CHARACTERISTICS OF THE OIL RIM:

Several features are noted on the oil rim and this is related to the mode and the depositional environment where it is noticed in certain sectors. In this case at CTH1 and CTH2 (oil treatment center), the presence of vertical barriers of clay-like permeabilities.

On the other hand, certain sectors do not reveal any barrier. These barriers play a prominent role in the perforation position and the height to be punched delaying the arrival of gas or water.

I.4.3 EXPLOITATION OF THE OIL RIM:

The exploitation of the oil rim since 1981 has led to the production of more than 3.5 million m^3 of oil.

Oil is actively exploited and treated at five treatment centers (CTH1, CTH2 CTH3, CTH4, CTHsouth) and other facilities distributed along the rim, and then pipelined to the north of the country (Figure.I-5).

The history of production wells is related to several factors including the cementation of liners that led to some wells being prematurely flooded with water or premature gas or both.

In addition to this problem, some wells are perforated with insufficient guards or at a shallow depth or with a high production flow.

I.5 ORGANIZATION OF THE FIELD:

The effluent nature and the reservoir homogeneity led to the choice of a development model based on an alternating exploitation pattern, including three exploitation zones (North, Center and South) between which were intercalated two Re-injection areas (Figure.I.6).

- **NORTHERN ZONE**: consists of a gas treatment module (module 3) and the Northern compressor station.
- **CENTRAL ZONE:** consists of modules 0, 1 and 4, the CSTF (condensate storage center and LPG), the SRGA station for the recovery of dissolved gases and the CNDG (gas distribution).
- **SOUTHERN ZONE**: consists of Module 2, South Compressor Station, CTG DJB and CTG-HRSUD.
- The oil treatment centers (C.T.H) are located on the east and south sides.

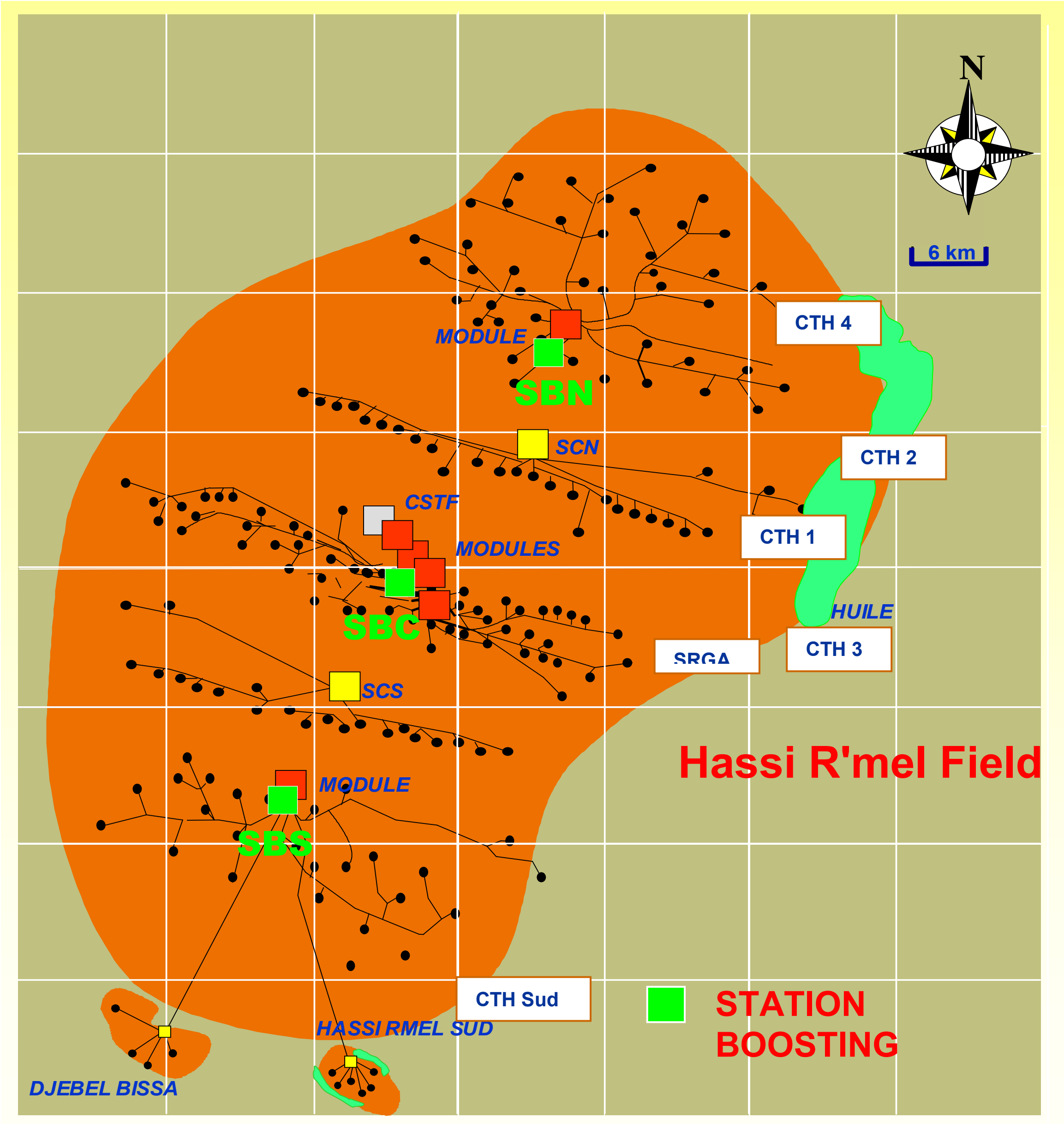

Figure.I-5: presentation of the oil rim.

I.6 DEVELOPMENT OF THE HASSI R'MEL FIELD:

The development of the Hassi R'Mel field was carried out in several stages:

- 1961- 1969: Exploitation of 06 gas treatment units with a capacity of 04 billion m3 per year.
- 1972-1974: Exploitation of 06 additional units to reach a capacity of 14 billion m3 per year.
- 1975-1980: Implementation and realization of a plan for a gigantic development program aimed at the following objectives:

- Increase in processing capacity from 14 to 94 billion m3 per year by setting up five gas treatment plants which are :
  - ~ 3 factories located in the central zone : $MPP_{0,}$ MPP_1, $MPP_{4\,;}$
  - ~ 1 factory located in the Northern zone: MPP_3 ;
  - ~ 1 factory located in the Southern zone : MPP_2 ;

  Four of the five gas processing plants (module 1, 2, 3 et 4) have a treatment capacity 20.10^6 m^3/day, the fifth (MPP_0) has a capacity of 30.10^6 m^3/day.

- Maximization of liquid hydrocarbons recovery condensate and LPG by partial cycling of the gas from the installation of two (2) compressor stations (North & South), used for the reinjection of dry gas into the deposit, to ensure the maintenance of the reservoir pressure for as long as possible and thus increase the life of the reservoir and also agitate it to recover more heavy components (LPG and Condensate).
  The reinjection capacity of each unit is $90.10^6 m^3$/day.

Operating characteristics of the compressor station:

- ~ Entry pressure of the station 68,14 bars.
- ~ Entry temperature of the station 45°C.
- ~ Exit pressure of the station 350 bars.
- ~ Exit temperature of the station 100°C.

- 1981 – 1993: The fact that the Hassi R'Mel reservoir also contains an oil rim (Figure.I-7) on the eastern periphery (an elliptical anticline initially constituting an average thickness of 11m) has generated the installation of five oil treatment centers (CTH1, CTH2, CTH3, CTH4, & CTHSud) giving a production of 2500 m3/day. The first CTH was installed in 1981.
- 1985: Realization and commissioning of a unit for the recovery of flared gases and the production of LPG modules 0 and 1.
- 1987 and 2000: The southern HR field, with its 130 km2 area, has led to the construction and commissioning of DJEBEL BISSA and HR-SUD gas treatment centers :
  The HRsud gas treatment center was built with a capacity of:
  - Dry gas 2,2 10^9 m^3/year.

- Gas Condensate 440 000 T/year.
- Flared gas 350 .10^6 m^3/year.

The DJEBEL BISSA center has a capacity of 6.$10^6 m^3$/day.

- 1991: Drilling and putting into production HRZ1, thus becoming the first horizontal well in Algeria and announcing the beginning of the exploitation of the field by horizontal drilling.
- 1995 – 1999: Commissioning of SBAA (ADRAR) and IN SALAH gas dehydration units.
- 1999: Realization and commissioning of a gas recovery plant for the associated gases coming from the oil treatment centers: The facilities built did not allow the gas produced to be used, the gas was flared and burned automatically at each CTH. This is no longer the case since, for economical and especially environmental reasons, gas is totally recovered thanks to a compressor installation called "RECUPERATION STATION OF ASSOCIATED GAS" (SRGA).
- 2004: Commissioning BOOSTING stations: In order to keep production facilities running at full capacity and optimize liquid recovery, a project called "BOOSTING HR" was launched in 1999, planning:
  - ~ Drilling of 59 additional wells.
  - ~ Dimensioning of the collection network.
  - ~ Construction of three BOOSTING stations.

I.7.FINAL PRODUCTION CAPACITY INSTALLED:

The final development of the field made it possible to reach the following production capacities:

- ~ 100 billion cubic meters of gas per year.
- ~ 12 million tons of condensate per year.
- ~ 3.5 millions of tons of LPG per year.
- ~ 700 thousand tons of crude oil per year.

The continuous exploitation of Hassi R'Mel reservoir has resulted in a progressive pressure drop (Initial Pressure = 310 bar), current pressure about 195 bar.

The Hassi R'mel field contains about 450 wells is divided into four categories:

- ~ Gas production wells.
- ~ Oil production wells.
- ~ Injection wells.

~ Various wells (abandoned, observation, quagmires, etc ...).

I.8.Problems encountered within the exploitation of the oil rim:

During the oil rim exploitation the producers encountered several problems due essentially to the shallow depth of the reservoir, the petro physical parameters of the reservoir (k = 270md, $\Phi = 0.2$), and the aquifer activity and the high formation water salinity.

Among these problems there are:

☞ **The rise of the water :**

The rise of water in Hassi R'mel is very fast (active aquifer) because of good vertical and horizontal permeability which can reach up to 270 md.

The interpretations of various logging tests (PDK, TDT, RST) demonstrated that the ascent is very fast especially in the zone not influenced by gas reinjection.

Since the thickness of Hassi R'mel oil rim is only 10 to 12 m, oil producing wells may soon drown.

☞ **Water coning :**

The phenomenon of coning is related to the deformation of the interface between two fluids the water-oil contact (WOC) and the gas-oil contact (GOC).

The low efficient thickness of the oil rim (10m) and the good petro physical properties favor the inflow of water.

Gas inflow is preferable to water inflow: water weighs down the column on the other hand, the gas is an auto-gas-lift.

This is a real calamity for producers, since the coning phenomenon is responsible for:

- Decrease in oil production.
- The need to use gas-lift with large gas flows due to high water-cut.
- Formation of salt deposits due to the high salinity of reservoir water, which reaches up to 360g / l.

☞ **Salt deposits** :

The oil-producing layer in Hassi R'mel has the particularity of being thin (10 m in some places), and the majority of the wells have a considerable WOR (water-oil ratio); knowing that the reservoir water is salty saturated at the bottom conditions (330 g / l), the salt dissolved in it crystallizes and settles in the tubing during production and this follows the drop in pressure and temperature, leading to a decrease in the salt solubility in water. This deposition of salt can reduce the diameter of the flow until it completely blocks the tubing, as well as surface installations and collection.

☞ **The weight of the hydrostatic column** :

The various mineral deposits, the rise of the water level and the presence of coning water increase the density of hydrocarbons, which implies a heavier hydrostatic column and a drop in head pressure.

To fix this problem gas lift is injected to lighten the column.

☞ **The Hydrates :**

Hydrates are ice-like crystals that are formed under certain conditions of temperature and pressure in the presence of hydrocarbons (mainly methane, ethane, propane or butane), carbon dioxide, hydrogen, sulfide , and in the presence of liquid water.

Hydrates are their own catalyst and have a very great adhesion to the walls, hydrate formation in a structure leads quickly to the total obstruction of the pipes and to the pure and simple interruption of the production.

The method of combating the hydrates formation which is usually at the collection level consists to inject an inhibitor into liquid water, methanol or glycol at most times. This process is called hydrate inhibition.[11]

(Table.I.1):The situation of wells implant in the hrm field.

status	Northern area	Central area	Southern Area	TOTAL
Gas wells	HR 078, 080, 081, 091, 092, 101, 102B, 103, 104, 105, 106, 107, 108, 109, 110, 111, 112, 113, 114, 115, 116, 117, 118, 119, 121, 122, 123B, 124B, 125, 126, 128, 129, 130, 131, 149, 159, 501, 502, 504, 505, 506, 507, 508, 509, 518, 519, 520, C001, C002, C003, C004, C009, C010, C011, C015, C016, C017, C022, C023, C024, C055, C056, C057,	HR 007, 010, 011, 015, 016, 017, 018, 019, 020, 021, 022, 023, 024, 025, 026, 027, 028, 029, 030, 031, 032, 033, 034, 035, 036, 037B, 039, 040, 041, 042, 043, 044, 045, 046B, 047, 048, 049, 050, 051, 052, 053, 054, 055, 056, 057, 058, 059, 060, 061, 065, 095, 096, 097, 098, 099, 100, 134, 135, 214, 216, 217, 510, 511, 512, C005, C006, C007, C008, C012, C013, C014, C018, C019, C020, C021, C025, C026, C027, C028, C029, C030, C031, C032, C033, C034, C045, C046, C047, C048, C049, C050, C051, C052, C053, C054,	DJB001B, DJB002, DJB005, DJB006, HR006B, HR012, HR062, HR063, HR064B, HR066, HR067, HR068, HR069, HR070, HR071, HR072, HR073, HR074, HR075, HR076, HR077, HR082, HR083, HR084, HR085, HR086, HR087, HR088, HR089, HR093B, HR136, HR137, HR141, HR156, HR157, HR158, HR192, HR200, HRD001, HRD003, HRD004, HRD005, HRD006, HRD013, HRD015, HRD016, HRD018, HRD019, HRD020, HRD021, HRD022, HRS001, HRS002, HRS003, HRS011, HRS021,	243
Oil wells	HR 167, 170, 189, 205, 208, 210, 211, 215, 218, 219, E200, E201, E202, E204, E205, E206, E207, E208, E400, E402, E403, E404, E405, E406, E407, E408, Z002, Z003, Z004, Z007, Z008, Z009,	HR 038, 152, 154, 161, 164, 166, 168, 184, 185, 188, 196, 197, 199, 202, 206, 209, 213, E100, E103, E104, E106, E107, E108, E109, E111, E112, E113, E300, E302, E303, E304, E305, E306, E307, Z001, Z005, Z010, Z011, Z012, Z013,	HR162, S008, S013, S014, S015, S017, S020, S022,	92
injector wells	HR 014, I025, I026, I027, I028, I029, I030, I031, I032, I033, I034, I035, I036, I037, I038, I039, I040, I041, I042, I043, I044, I045, I046, I047, I048B, I049, I050, I051, I052,		HR002, 013, 079, I001, I002, I003, I004, I005, I006, I007, I008, I009, I010, I011, I012, I014, I016, I017, I018, I019, I020, I021, I022, I023, S004, SI001, SI002, SI003,	62
Others (abandoned closed, observators)	HR003, HR004, HR090, HR090B, HR102, HR120, HR123, HR124, HR127, HR132, HR133, HR147, HR160, HR169, HR172, HR173, HR174, HR175, HR176, HR178, HR179, HR180, HR183, HR186, HR191, HR198, HR203, HR204, HRE203, HRE401, HRI048, ONS001, TR001,	BE001, DAO001, HR001, HR009, HR037, HR046, HR144, HR145, HR146, HR148, HR150, HR151, HR165, HR181, HR195, HR212, HRE101, HRE102, HRE301, HRP001,	BLH001, BSB001, BSB002, DJB001, DJB001L, DJB003, DJB004, DJB007, DJB008, DJB009, DJB010, DJB011, DJBW001B, GHA001, HKL001, HR006, HR008, HR054, HR093, HR094, HR138, HR139, HR140, HR142, HR143, HR153, HR155, HR163, HR171, HR177, HR182, HR187, HR190, HR193, HR194, HR201, HR207, HRS005, HRS006, HRS007, HRS009, HRS010, HRS012, HRS016, HRS018, HRS019, HRS024, HST001, MSK001, NL001, NL002, NL003, NL004, OEH001,	192
Total				589

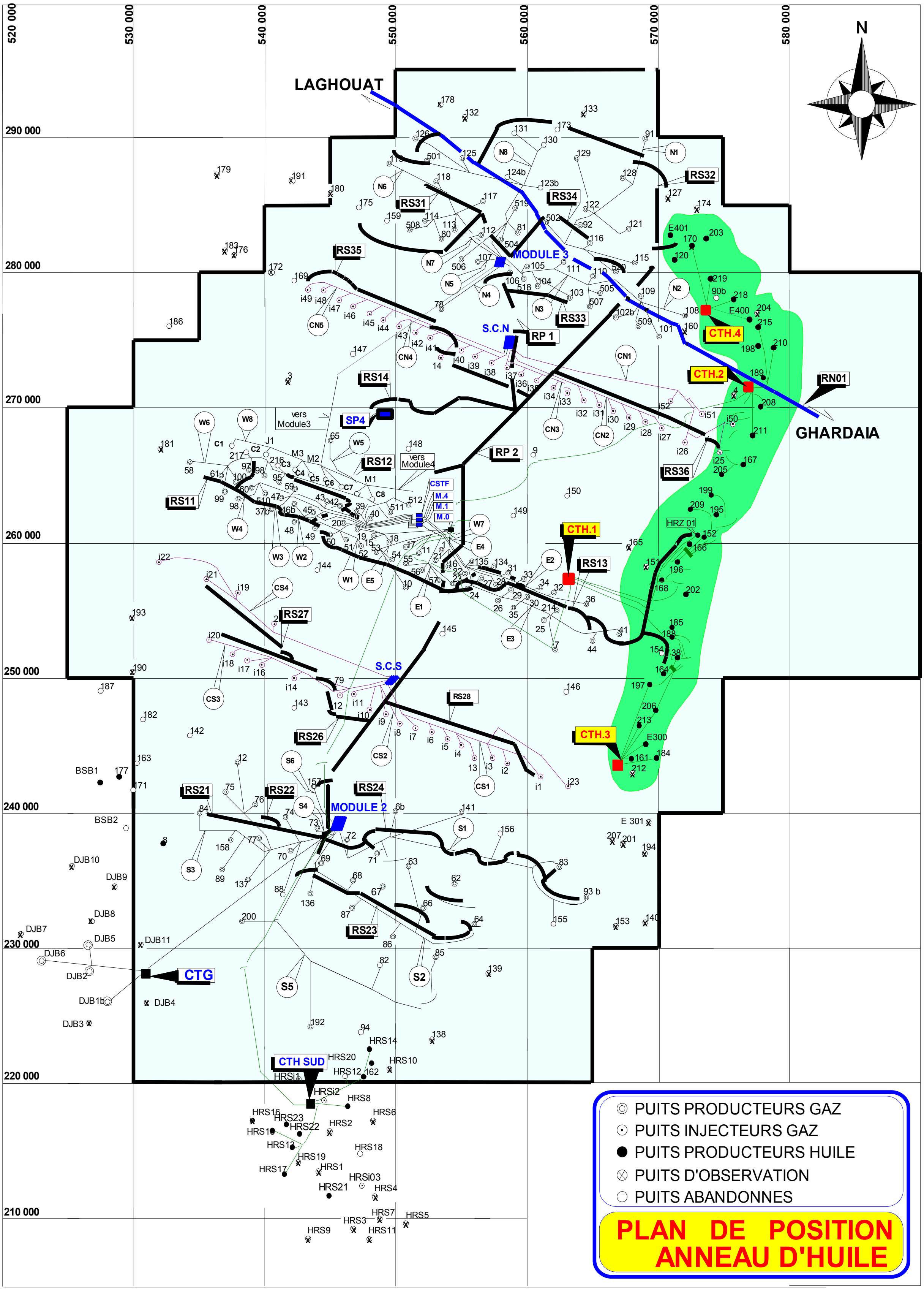

Figure.I-7: Oil rim position plan.

Hassi R'mel is a rich gas and oil field that has been put into production since 1956. Unlike the trouble-free production of gas, oil production has faced several problems such as: formation of hydrates, salt deposits and the natural depletion. The latter two are the most irritating ones.

In order to overcome these difficulties, different activation and desalting procedures were employed, among them water injection and gas lifting.

In cases where both problems occur, simultaneous water injection and gas lifting are required. To achieve this purpose, special types of completions are used, such as: conventional completions, gas lifting completions and water injection completions.

I.9. Types of completions:

Completion systems are the components necessary to complete the well after being drilled and prepared for production. [5]

I.9.1. Parallel completion:

It enables the well to start with the available pressure of the compressor station; the gas is injected through a gas-lift valve called the operating valve. It allows emptying the well of the completion fluid and, thus, lightening the hydrostatic column, therefore the bottom pressure pushes the effluent from the reservoir to the injection point, the gas mixes with the effluent and decreases its density so the well begins to produce (Figure.I-8).

Gas circuit: The gas is injected by the Macaroni 1 "660 and passes through the tubing through the gas-lift valve housed in the" SPM ".

Desalting water circuit: the water is pumped into the annular 7 "x tubing using a pump driven by gas, then passes from the annular to the well bottom, through two valves placed in series access valve and injection valve respectively. First, the water passes through the gas-operated valve, which lets the water flow to the injection valve.

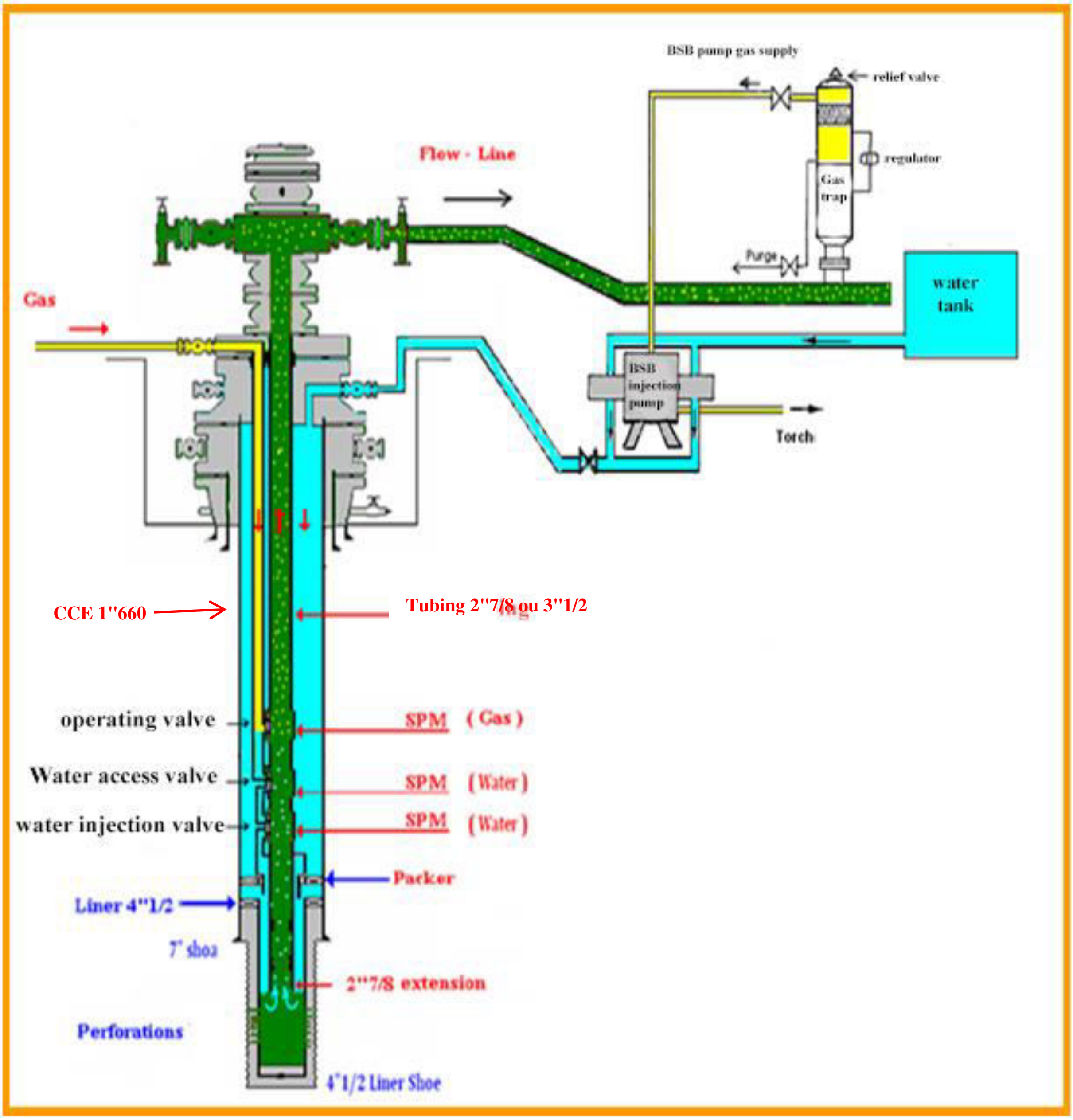

Figure.I-8. Gas-lift completion with desalination system at the bottom.

I.9.1.1. Desalination system

The desalination system at the bottom of a GLP completion consists of two valves:

1) **Water access valve.**
2) **Water injection valve.**

The water access valve or "Switching valve" is a safety valve controlled by the injection gas pressure. This valve is calibrated in the laboratory at a predetermined pressure to close in case of gas interruption. Its purpose is to prevent the reservoir from being flooded to the annulus water. The water injection valve is used to inject the water at the bottom of the well at a constant rate, through the Packer (Figure I.9). [1]

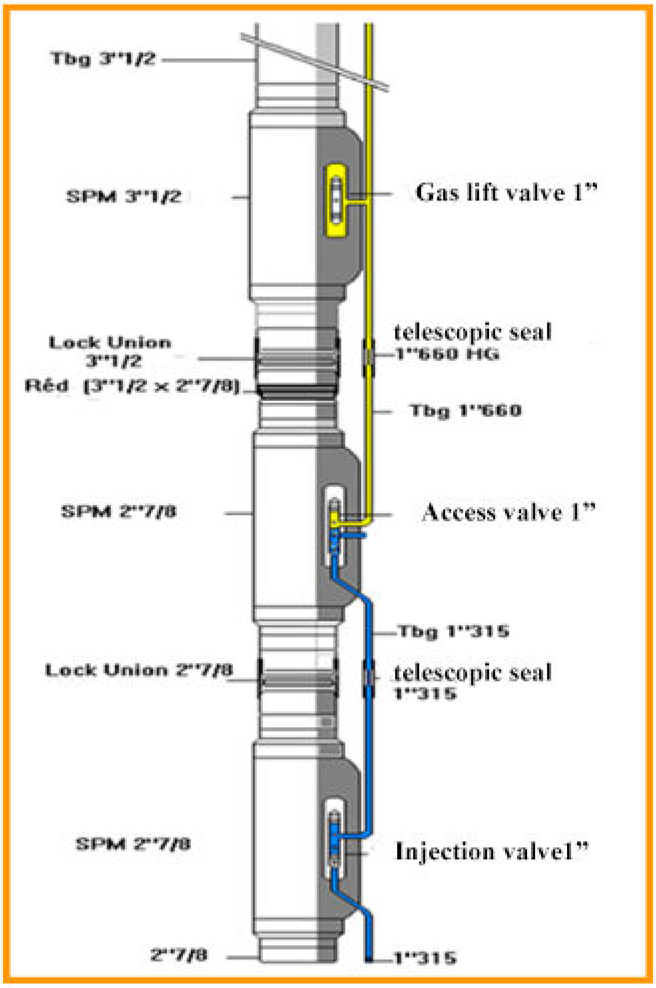

Figure.I.9: Desalination system.

Advantages:

- ✓ Isolated annulus.
- ✓ Separates the injection water from the gas-lift for better desalting and to avoid ice formation.
- ✓ Avoid the problem of stopping the BSB pump due to the high gas injection pressure, because the gas is injected through the concentric 1 "660.
- ✓ Reduce production pauses due to salt plugs.
- ✓ Reduce coiled tubing operations.
- ✓ Avoid flooding the well with desalination water in the case of gas-lift shutdown (bottom safety system)
- ✓ No reduction in fluid passage and therefore no production losses.
- ✓ Possibility of wire-line control in both tubings.

Disadvantages:

- ✓ Constraints in the choice of diameters of the two tubings; it must be ensured that the sum of the outer diameters of the tubings is smaller than the internal diameter of the casing in order to be able to incorporate them.
- ✓ The recovery of these wells requires a heavy apparatus.
- ✓ Complete modification of the wellhead and packer.

I.9.2. Suspended tubing completion:

This completion allows the continuous injection of water into the well; (…) separates it from the gas lifting. It is based on creating a second annulus using a hanging 2"7/8 tubing which is attached to the orifice and put inside the old 4"1/2 tubing, The new annulus allows the injection of gas lift while the old 7" annulus is used to inject desalination water, and the production is made through the 2"7/8 tubing (Figure.I-10). [10]

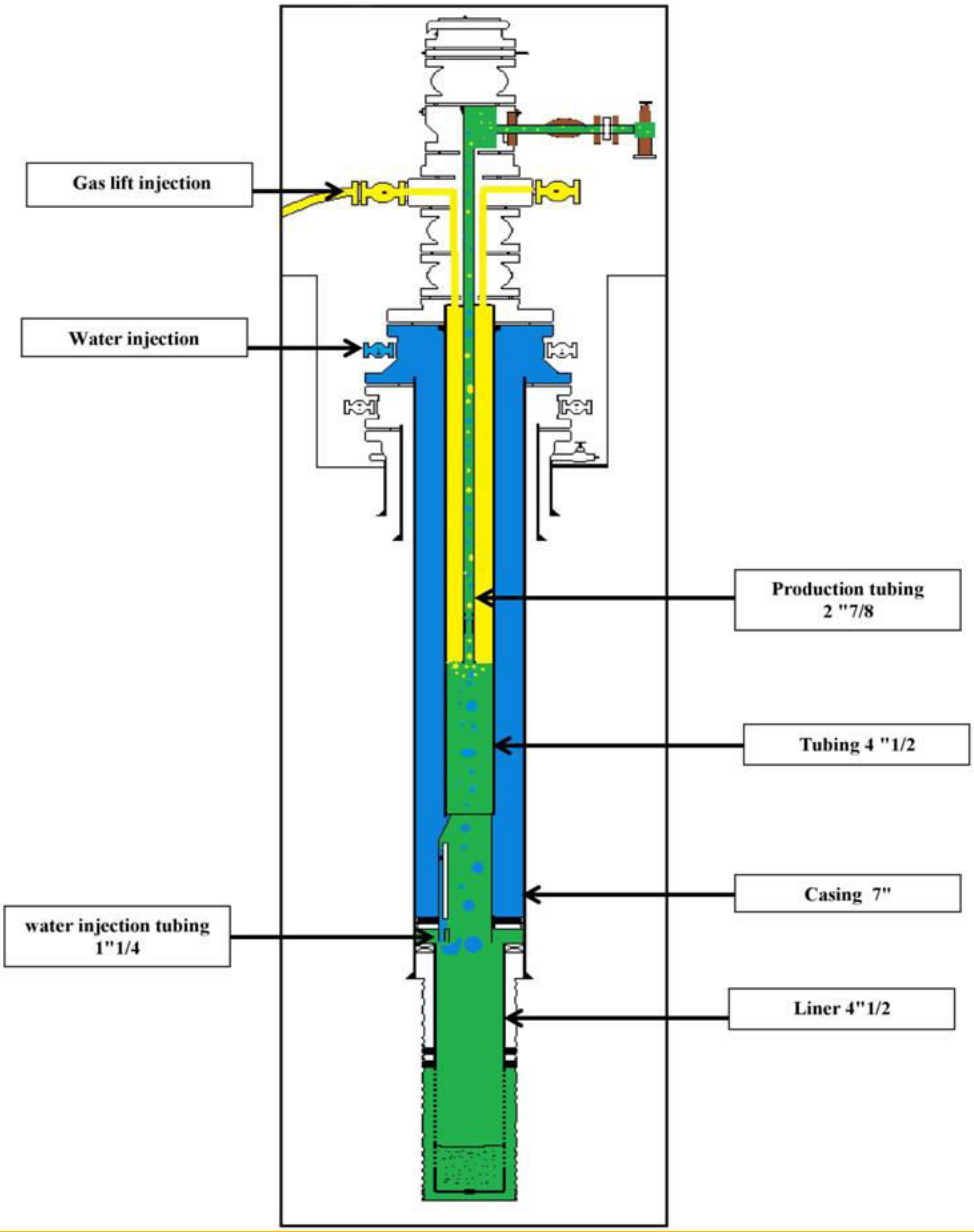

Figure.I.10. suspended tubing completion.

Advantages:

- ✓ Injection of the water inside the tubing, washing the open area.
- ✓ The stopping level of the Macaroni is chosen according to the height of the sediments and the zone supposed to produce water.
- ✓ Possibility to access the wire line at the open area and control the bottom.

Disadvantages:

- ✓ Loss of production by reducing the cross section of the effluent and increasing pressure losses (of the order of 4 to 10%).
- ✓ Equipment limited to tubings larger than 3 "1/2 in diameter.
- ✓ Difficult wire-line operations, with the risk of jamming or breaking the cable.
- ✓ Impossibility to perform Amerdas measurements (diameter 1 "050 to exclude).
- ✓ No way to control the tubing-Macaroni space.
- ✓ Difficult circulation of large flow fluids.

I.9.3.Double injection completion (mixed injection):

This type of completion was not planned to be used, it was used after the delay made to provide the Macaroni for the suspended and parallel completions, it was used as a temporary solution in the wells already equipped with SPMs.

It has a simple principle, which is to inject both water and gas from the annulus into the same SPM (Figure.I-11). [12]

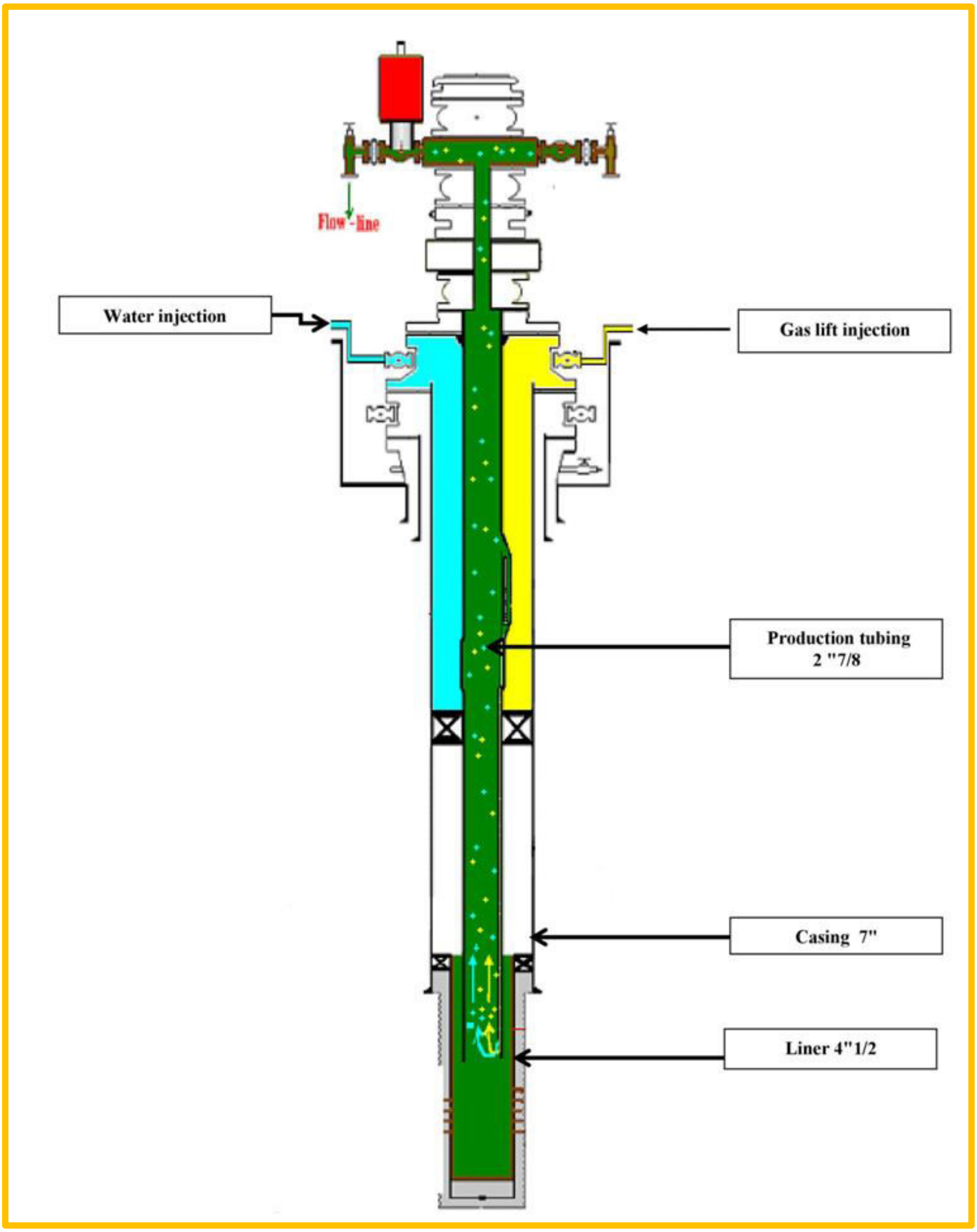

Figure I.11: Mixed injection tubing.

Advantages:

- ✓ Practically no production losses by reduction of the effluent passage section.
- ✓ Ability to descend tools in the open area for control.
- ✓ Possibility of removing the injection valve with retrieval tools.

- ✓ The injection valve can be calibrated which allows to maintain the desired pressure in the annulus.

Disadvantages:

- ✓ At great depths, the injection valve deteriorates rapidly.
- ✓ Extensive experience in cable work is required to install and remove the injection valve.
- ✓ Instable flow of water and gas at the injection point.
- ✓ Limited water injection efficiency.

I.10. Conclusion

In order to pick the best completion, different simulations are made in the goal of evaluating the optimal injection rate for both water and gas lifting, The results of these simulations shows the completion that gives the best production rate.

CHAPTER 02 :

SALTS AND WATER CALCULATIONS

II-1- INTRODUCTION:

During the exploitation of a well, the extraction of fluids causes a change in volume. This results in significant drops in pressure and temperature, causing some of oil and water to evaporate and, crystallization of mineral salts that cling to the pipelines and stack, causing clogging of canalization and areas like: valves, pumps, chokes..

II-2- Salts encountered in oil wells:

II-2-1- Sodium chloride (NaCl):

Water can contain up to 350 g / l of sodium chloride, and thus be so close to saturation that a very small temperature variation or a low evaporation of water due to the pressure drop, causes a significant precipitation of NaCL .

These are the least troublesome salt deposits because the solubility of sodium chloride is high enough which a simple fresh water injection prevents the formation of its deposits.

II-2-2- Calcium Carbonate ($CaCO_3$):

The precipitation of salt is conditioned by the equilibrium between Carbonates and Bicarbonates, according to equation (1) :

$$Ca(HCO_3)_2 \leftrightharpoons CaCO_3 + CO_2 + H_2O \tag{1}$$

A pressure drop promotes the release of CO_2, shifts the equilibrium in direction 1 and causes the precipitation of insoluble $CaCO_3$.

II-2-3- Calcium Sulphate ($CaSO_4$):

It is a relatively soluble salt (about 2 g / l) but also sufficient that it is at a concentration close to its solubility limit to cause hard and encrusting deposits.
A main reason of $CaSO_4$ formation is pressure drop of the effluents during the ascent to the surface which causes a partial water evaporation and leads to the super saturation of the Calcium Sulphate and therefore to a fast precipitation thereafter.

Finally, the precipitate can be formed by incompatibility of two waters.

II-2-4- Strontium Sulphate ($SrSO_4$):

It is much less soluble than Calcium Sulphate and has a decrease in solubility according to the temperature. Precipitation of $SrSO_4$ can occur by water evaporation, temperature rise, or incompatible waters mixture. Deposits of SrSO4 are practically insoluble, even by acids.

II-2-5- Barium Sulphate ($BaSO_4$):

As a rule, Barium Sulphate deposits are formed from the incompatibility of two waters.

The reservoir waters may contain Barium ions and are exposed to either wash or pressure-holding waters that contain Sulphate ions.

This is the most troublesome salt deposit because the solubility limits are very low and the deposits are hard and compact.

The solubility of Barium Sulphate (for example) is one hundred times lower than that of Calcium Sulphate. However, the solubility of BaSO4 increases with the ionic strength of the water.

An excess of Sulphate ions tends to coagulate the precipitate while an excess of Barium ions tends to disperse it.

The saturation level is an important element that regulates the rate of crystallization for Barium Sulphate. The higher the level of supersaturation, the faster the precipitation. [8]

II-3-Law of salinity:

The mass law of action governs the solubility of the salts; the dissociation equilibrium of a salt of the $CnAm$ type is as equation (2) demonstrates:

$$CnAm \rightleftarrows nC^{x+} + mA^{y-} \tag{2}$$

C: X valence cation.

A: Y valence anion

(NX=MY)

The dissociation constant is written in equation (3) as follows:

$$\frac{[C^{x+}]^n \times [A^{y-}]}{[C_n A_m]} = constant \tag{3}$$

(According to given thermodynamic conditions)

The values in square brackets refer to activities that, in the case of low salt solutions, are equivalent to the considered ion concentrations. Moreover, the activity of insoluble species (case of C_nA_m) is unitary. In these conditions, equation (3) becomes equation (4):

$$[C^{x+}]^n \times [A^{y-}] = S \quad (4)$$

S is solubility product, it is characteristic of salt and thermodynamic conditions.

II-4-Deposit Formation Conditions:

The saturation state of the water may be due, among other things, to an ion exchange in the rock. nevertheless, the pressure drop between the deposit and the bottom of the well produces a partial evaporation of this water, which oversaturates and precipitates crystals.

Many studies have proposed an explanation based on electric charges, the water droplets containing crystalline germs must carry a positive electrical charge, and have a dielectric constant greater than that of the crude in which they swim. The rock is negatively charged due to the presence of clays; similarly, the flow currents in the pipes carry it to a negative potential.

Hence attraction and fixation on the asperities. The crystals that have their own polarity are retained electrically and mechanically. Their growth is subsequently easy to conceive. [3]

II-5-Influence of various parameters

II-5-1-Temperature:

It has a very important action on solubility, as a rule, a rise in temperature increases the solubility, but there are exceptions like: $CaCO_3$, $CaSO_4$, which are less soluble when heated.

II-5-2-Pressure:

In general, the pressure has little influence on the solubility of salts, however, the variations of the pressures cause variations in concentration of dissolved gas, and in this case equilibrium displacements which can modify the precipitation conditions. (Deposits of Calcium carbonate may appear this way).

II-5-3-Salinity:

In the case of diluted solutions, the activities of the various present ions can be assimilated to their concentrations. For waters loaded with salts, these ions are close enough to exert non negligible electrostatic interactions between them, it is characterized by the ionic strength as in equation (5) which is the half sum of the concentrations of each of the ions multiplied by the squares of their charges:

$$\mu = \frac{1}{2} \sum C_i \, Z_i{}^2 \tag{5}$$

μ : Ionic strength of the solution.

C_i : Concentration of each of the ions.

Z_i: Valencia of each of the ions.

The ions are more marked that the ionic strength of solution is important, it follows that the solubility of a salt is increased by addition of another salt if the two cohabiting salts do not contain ions common.

The (Figure II.1) and show solubility curves for some solids and gases as a function of temperature. [2]

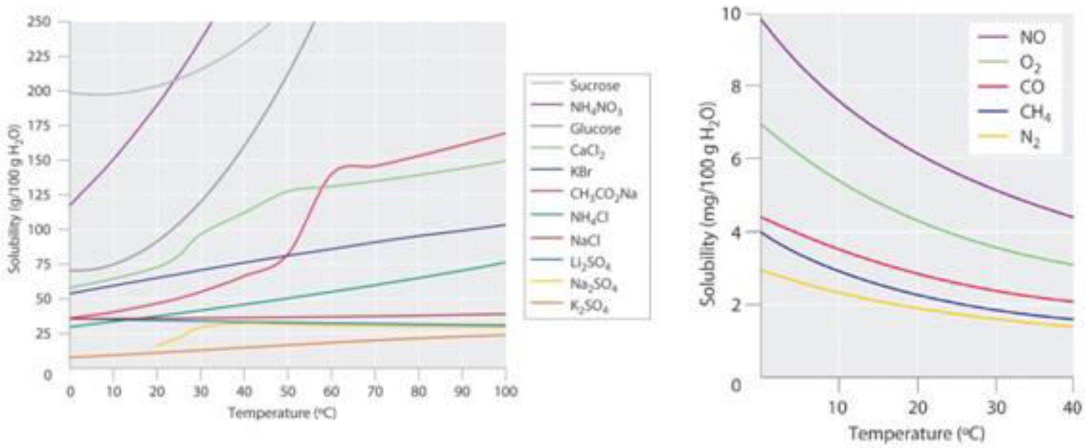

Figure II.1 Solubility in water as a function of temperature.

II.6.Localization of deposits :

For Sodium Chloride (the salt most encountered at the oil rim of the Hassi R'mel region), the solubility varies in the same direction as the temperature and the pressure as (Figure II.2) and (Figure II.3) demonstrate:

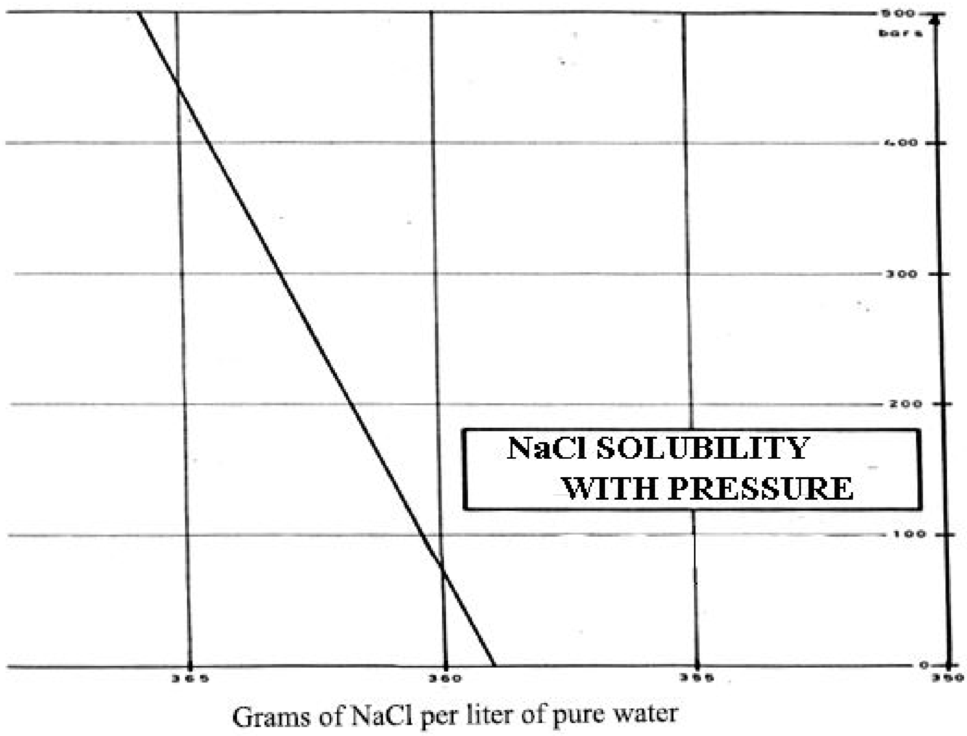

Figure II.2 Solubility of NaCl as a function of pressure.

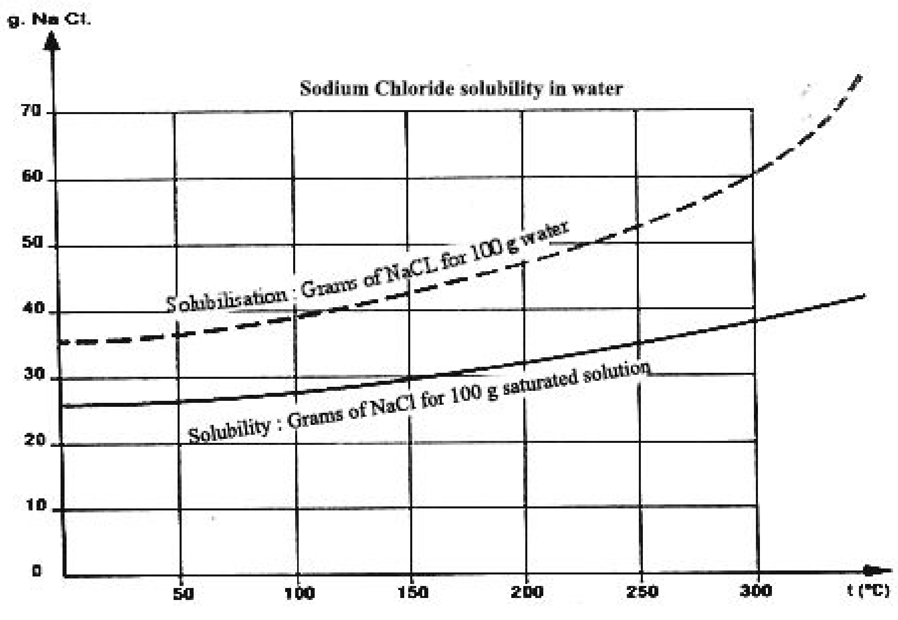

Figure II.3 Solubility of NaCl as a function of temperature.

The Figure II.2 and Figure II.3 illustrate that the salt crystallizations occur preferably in areas subjected to severe drops in temperature and / or pressure; the passage from the reservoir to the well, the passage of the bubble point, the surface installations ... ..

This does not mean that deposits necessarily occur in these places. Indeed, for there to be deposits, it is necessary in addition that the local conditions are favorable, that is to say, for example:

- Rough walls that allow the hanging.
- Turbulence favoring the contact of the crystals with the walls.
- Electrical potential of the walls of opposite sign of that of the droplets of water loaded with crystals.
- Moderate flow rate allows crystal deposits when they have reached a certain size, ...

It is therefore not possible to predict, by reasoning only, where these deposits occur.

II-7-Detection and monitoring of deposits:

Once completed and connected to the production network, the best production conditions must be ensured. For this, constant monitoring of the various production parameters is necessary (daily monitoring or at least two times a week).

At the well head, the production team, at each round, raises the following parameters:

- ✓ Head pressure.
- ✓ Line pressure (downstream of the choke).
- ✓ Temperature of the effluent.

In addition during the monitoring of these wells, they proceed to:

- ✓ Examination of annulus pressures
- ✓ Verification of the proper operation of the desalination water injection systems.
- ✓ The state of the cheats (possibly).

It is in case of non-correspondence of the results that can be detected the presence of a clogging (when the head pressure drop is important). [12]

II-8-Means of destruction and prevention:

The fight against salt deposits consists in eliminating as much as possible the aqueous phase by a suitable treatment and dissolving the salt crystals in external water.

The existing means to fight against salt deposits are:

II-8-1-The work with the cable (wire-line):

This method implements the lightest and fastest means of intervention.

The cable-working equipment is used to scrape tubing and down hole equipment, break up the salt plugs encountered and control the well to the bottom.

II-8-2-The fresh water wash:

It can be used in the both ways; continuously (preventive objective) or discontinuous (curative objective).

II-8-2-1-The periodic wash:

It is a curative treatment of already formed deposits. It does not require any modification in equipment, but requires the interruption of production.

The operation consists of sending water caps to the well bottom.

A treated volume of soft water (up to 10 m³ or sometimes more) is pumped at the wellhead (closed well), while monitoring the pressure in the head so as not to drown the well. The cap descends by gravity through the tubing dissolving with its passage salt bridges encountered. The cap usually pierces after 8 hours. After that, the well is returned to production by disgorging the water cap from the torch.

II-8-2-2-The continuous injection:

It is needed when accumulations are important. The principle is to pump a small amount of water (the minimum necessary) to the well bottom to reduce the concentration of the reservoir water.

This operation has the advantage of not interrupting production.

- For low flow rate wells, the water is injected through a small section tube lowered into the production tubing.
- For high flow rate wells, water is brought to the well bottom by tubing and production is provided by the annulus.

II-8-2-2-1 The different completions for the continuous injection of water:

A) Parallel tubings completion.

. B) Suspended tubing completion .

C) Conventional side pocket injection (mixed injection) .

II-8-3-Coiled tubing:

This operation allows for quick intervention on the well. It involves circulating soft or processed water through the tubing of the coiled tubing unit to dissolve deposits and salt plugs in the tubing.

The operation can take a few minutes, and even hours, depending on the size of the salt plug.

II-8-4-The chemicals:

Which can be divided into two groups :

- Filmogens whose role is to coat the metal walls with a film that reduces their roughness. They can also be attracted to the surfaces of the crystals: they then prevent them from agglomerating.

-Crystal morphology modifiers, such as cadmium, lead or ferrocyanide salts.

There is also as a chemical solution the use of anti depots. These are compounds with concentrations below stoichiometry. Inhibition of deposit formation has begun since 1930 by a first application, which is the use of 1 to 10 ppm of sodium hexametaphosphate to prevent the precipitation of a Calcium Carbonate supersaturated solution.

Since then, polyphosphates have been widely used to prevent the formation of Calcium salt deposits.

Recently new types of molecules have appeared such as: Polycarboxylic acids, Phosphonates, Aminophosphonates. Fatty amines. The use of these chemicals is done by squeeze in the formation, and very rarely, by sticks or pellets placed at the well bottom by gravity where they dissolve slowly.

***II-8-5-The injections (squeezes) of soft water in the rock*:**

Where it can dissolve salt crystals if there are any; but it acts mainly because it remains partly water adsorbed in the rock and serves as diluents of the reservoir water after production. The effect of this operation can take a long time. [6]

NOTE: This operation carries the risk of flooding the well and hence, it should be avoided.

II.9 Water injection equipments:

II.9.1. Subsurface equipments:

II.9.1.1. Injection packer:

- Side pocket mandrel :

It is designed for the activation of gas lift wells, this special piece equips a few number of eruptive wells.

The side pocket is equipped with a manikin (DUMMY) to allow circulation.

The mandrels are used to inject gas, water, anti-emulsion products and corrosion inhibitors through the annulus. This is achieved by equipping the injection valve mandrels, often by pressurizing the annulus to a certain pressure value

- Injecting valve :

These valves are similar to gas-lift valves with the only difference that they do not work with an opening and closing system, its role is to ensure a direct connection between the annulus and the production column.

Commonly known as the "orifice valve".

- An extension tube:

Through which water can flow from the valve to the desired injection point under the packer. This tube guarantees the seal between the annulus and the tubing.

II.9.1.2. The injection of water through a macaroni:

This completion is simple and does not require an injection valve. The injection is made through a reduced diameter tube called 'Macaroni or Velocity String' suspended at the wellhead. At the end of the Macaroni (Figure II.4) is a non-return valve. [2]

This type of completion is not used too much because of the disadvantages it presents.

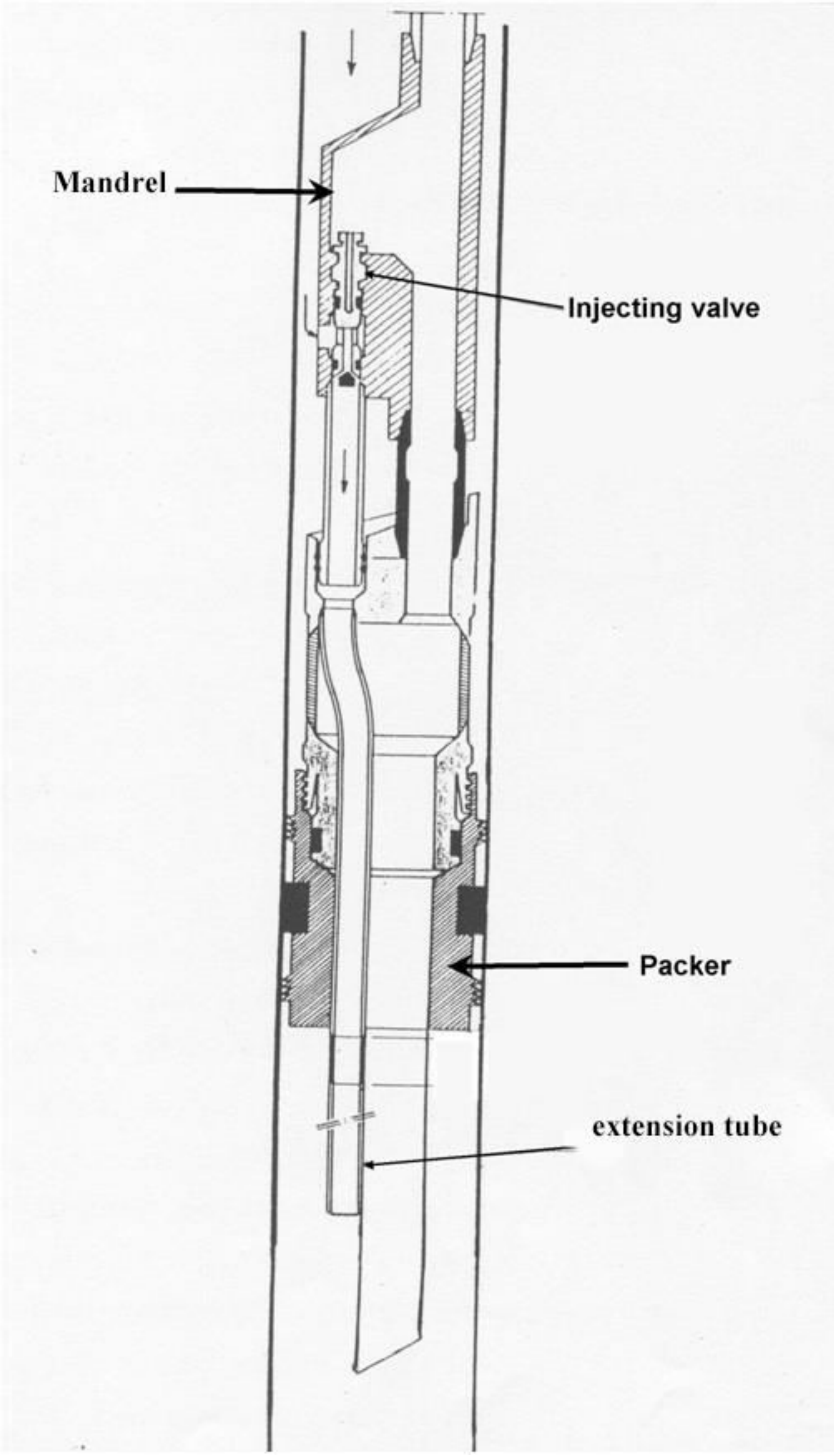

Figure II.4 Bottom equipment for packer water injection.

II.9.2 Surface equipment:

The surface equipment consists of a BS&B pump (pump + pneumatic + BS&B) ,a gas trap (scrubber), 3-way valve, automatic valve, decent valve, a soft water tank.

***A water tank* :**

Uniform capacity is generally about 50m^3. It is usually placed outside the safety perimeter and is periodically filled by water tank or connected to a water system.

***One (or more) discharge pump (s)*:**

The pumps used are of the BSB type, 1"1 / 2 or 2 " (Figure II.5) depending on the flow rate to be injected. They are continuously supplied with gas by the scrubber.

Figure II.5 Discharge pump.

The scrubber (gas trap) :

The effluent produced by the well runs from the bottom to the head through the tubing and from the head to CTH through the production line.

The scrubber (Figure II.6) is placed on this line, it serves to trap a portion of the gas produced. It's made of :

- Two rooms: gas chamber (upper chamber) to feed the automatic valve and water injection pumps (BSB); and mixing chamber (lower).
- Purge valve.
- Regulator.
- Full flange: For isolation of both chambers.
- Isolation valve: To avoid contact of the gas chamber and the mixing chamber.

Figure II.6 Scrubber.

The gas is trapped first in the mixing chamber, as quantities of water and oil are entrained, a passage to the upper chamber through a filter allows the best separation, then it passes to feed the automatic valve through an outlet and the water injection pumps through the second outlet.

The (Figure II.7) resumes the surface and subsurface continuous injection installation.

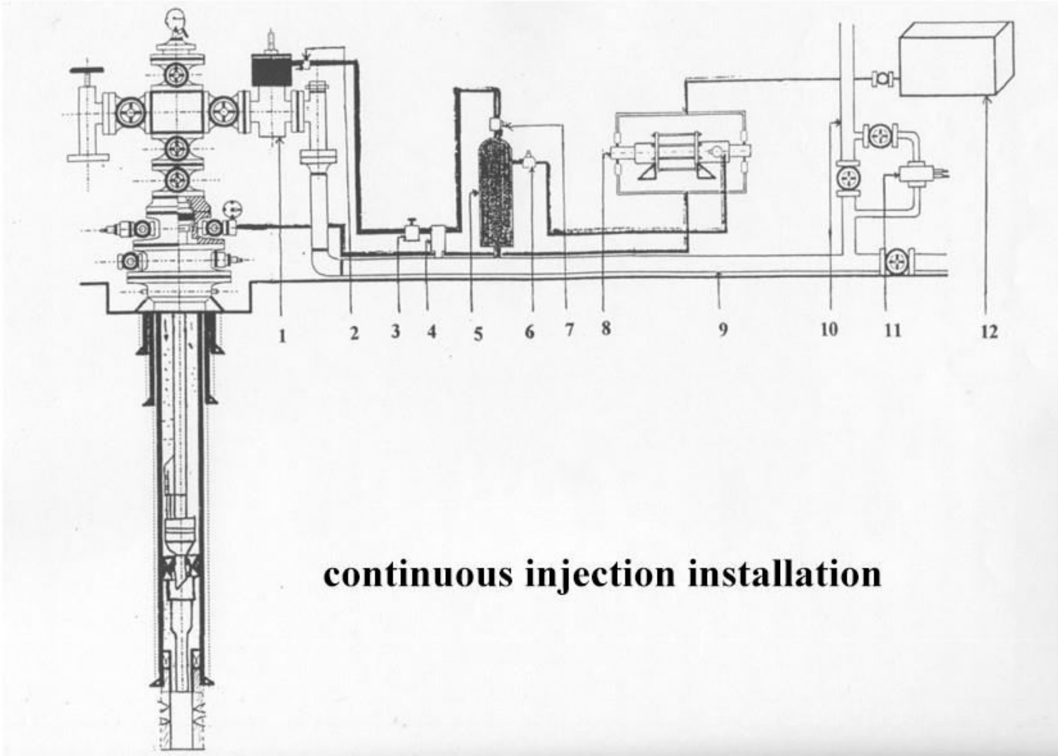

Figure II.7 Continuous injection installation.

II.10. Evolution of reservoir pressure and Watercut:

II.10.1.Evolution of the reservoir pressure decline :

The reservoir pressure is the only energy source that pushes the fluid out of the reservoir, and when this source decreases, the production decreases, which requires the use of enhanced recovery. There are many methods to activate the well, gas lifting is the first method to resort to.

In addition, the reservoir pressure directly affects several important parameters in the production system such as: wellhead pressure (Duse), tubing diameter, which are optimized based on it.

The (Figure II-8) shows the evolution of the reservoir pressure at the Hassi R'mel field.

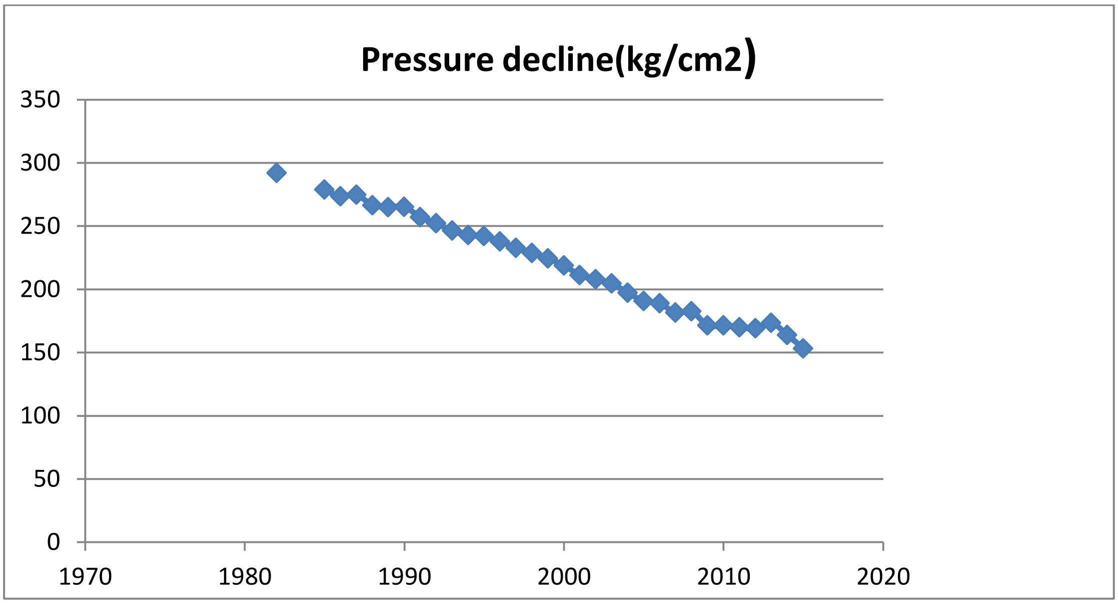

Figure II-8. Evolution of reservoir pressure.

II.10.2. Evolution of water-cut:

The initial level of water oil contact (WOC) in the Hassi R'mel field was predicted at (1500m), during the production, the WOC level rises in the reservoir, which increases the water flow in the wells.

The (Figure.II-9) illustrates the variation of Water cut for each CTH. [11]

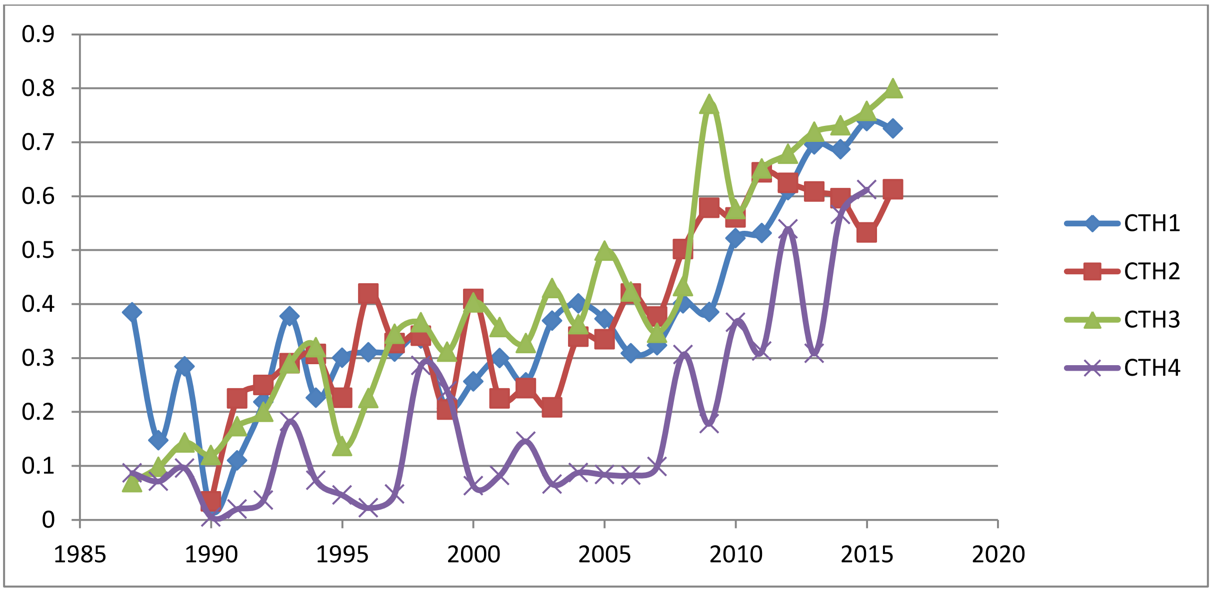

Figure.II-9. Evolution of Water cut in CTH.

II.11. Calculation of the desalination water flow:

II.11. 1. Solubility law:

To avoid salt deposits in the tubing, the quantity of water injected must ensure a salinity of the mixture (reservoir water + injected water) lower than the threshold solubility.

The threshold solubility is the degree of salinity beyond which the reservoir water no longer dissolves the salt. This is when salt deposits begin to form.

Knowing that NaCl is the predominant salt, the solubility curve (Figure II-10) of the NaCl is used to determine the threshold salinity at the temperature 0 ° C which is the worst case.

To calculate the flow of water to be injected, equation (6) will be used:

$$\boxed{S_s(Q_{inj} + Q_f) = Q_{inj} \times S_i + Q_f \times S_f} \quad (6)$$

Q_{inj} : Injected water flow (m3/d)

Q_f : Reservoir water flow (m3/d)

S_s : Threshold Salinity (g/l)

S_i : Injection water salinity (freshwater) (g/l)

S_f : Reservoir water salinity (g/l)

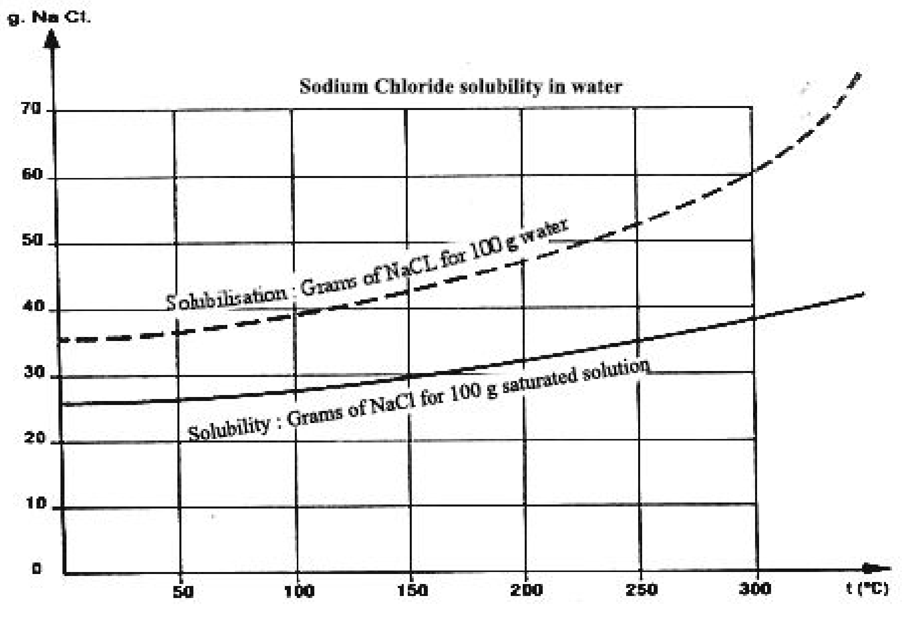

Figure II-10. NaCl solubility curve as a function of temperature

According to the (Figure.II-10) which represents the variation of the solubility in a saturated solution as a function of the temperature, the salinity threshold at **0 ° c** is equal to **258g / l.** The salinity of the formation water varies from a well to another and the salinity of the injection water (fresh water) is 4g / l**.**

II.11.2. Calculation of water quantity:

Based on equation (6), the water flow is determined as follows in equation (7):

$$Qinj = Qf\ \frac{(Sf-Ss)}{(Ss-Si)} \quad (7)$$

In this calculation, the injected flow rate is increased by a safety factor of "1.05". [3]

II.11.3. Estimation of the water-cut resulting from the injection:

The determination of the water-cut is necessary for the optimization of the injected gas flow rate for the activation of the wells. In this case, the flow rate of water injected is taken into consideration in the calculation of the water cut .

Water-cut is the ratio between the water flow and the sum of water and oil flow rates as demonstrates equation (8).

$$Wcut = \frac{Qw}{(Q0+Qw)} \quad (8)$$

Qw: This is the sum of the water flow of the formation and the injected water

$Qw = Qinj + Q\ f$ **(m3/d)**

Q0: Produced oil flow (m3/d). [6]

***II.11.4 Calculations* :**

Using the water and the salinity data in the (Table.II-1) and applying it in the equations (6,7,8), the calculation of the desalination water injection flow rate for each well is as follows:

Table.II-1. Injected water salinity data .

Well	Q_{inj}(m3/d)	Q_f(m3/d)	S_s (g/l)	S_i(g/l)	S_f(g/l)
HR162	5	43.20	258	4	342
HRE111	7.08	10.67	258	4	342
HR189	1.72	38.48	258	4	265
HR202	4.24	37.26	258	4	368
HRS020	17	87	258	4	333
HRE 207	8.34	37.70	258	4	315
HRE104	6.58	61.12	258	4	381

Calculation example: (HR189)

$$\boxed{Q_{inj} = Q_f \frac{(S_f - S_s)}{(S_s - S_i)}}$$

$$\boxed{Q_{inj} = 38.48 \frac{(265 - 258)}{(258 - 4)}}$$

$$\boxed{Q_{inj} = 1.06 \text{ m}^3/\text{j}}$$

$$\boxed{Wcut = 65 \%}$$

Following the same calculation steps as shown for HR189 well, the results obtained for each well are put side by side with the current measured data in the (Table.II.2):

Table.II-2. Injection water flow optimization results.

parameter / Well	Salinity		Qinj (m3/d)		Wcut (%)	
	Before	**after**	**Current**	**calculated**	**current**	**Calculated**
HR162	342	258	7.08	3.52	20	20.6
HRE111	342	258	5	14.28	62	68
HR189	265	258	4.72	1	60	58
HR202	368	258	4.24	16.13	64.7	70
HRS020	333	258	17	25.68	59.12	61
HRE 207	315	258	8.34	8.46	55.91	57
HRE104	381	258	6.58	29.59	76.5	78

Note: For some wells the current Qinj is lower than the calculated one. In this case the desalting is not 100% effective. an increase in the flow of injected water is needed.

II.12.CONCLUSION :

To have a perfect efficiency, it is necessary to study with precision the flow rate of injected water. A studied flow rate makes possible to get rid of the mineral deposits and thus not having to intervene again in the well. In some cases, the injected water weighs down the hydrostatic column, which requires an activation method.

This is one of the two objectives of this work. That is, optimize the flow of water that would prevent the formation of deposits, the other objective is to optimize the flow of gas lifting to preserve the well eruptivity.

CHAPTER 03 :

GAS LIFT OPTIMIZATION AND ECONOMIC STUDY

III.1. OPTIMIZATION OF GAS LIFTING:

III.1.1. INTRODUCTION TO PRESSURE LOSSES:

During the fluid flow from the reservoir to the wellhead, its initial energy will be lost in the form of pressure losses (Figure.III.1) . These pressure losses are the sum of two factors:

- friction losses of the effluent on the walls of the tubing.
- the hydrostatic weight of the effluent (gas, water and oil) in the tubing.

Injecting gas lift into the tubing through the deepest point increases the well production by reducing pressure losses.

This will have two opposite effects:

- An increase in friction losses **(negative effect).**
- A decrease in the weight of the column **(positive effect).**

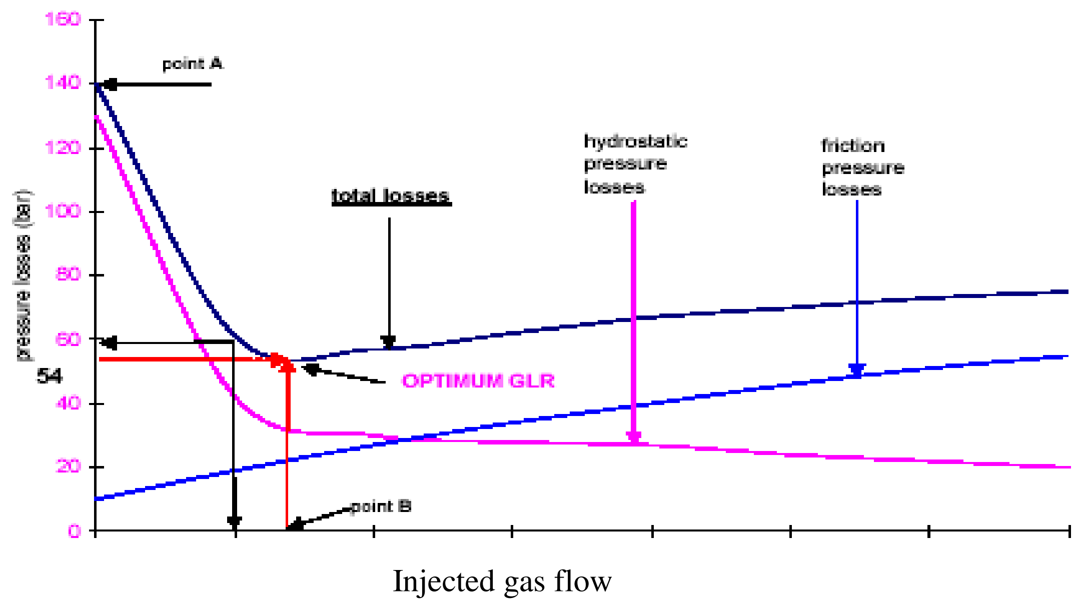

Figure.III-1.Evolution of the pressure losses as a function of the injected gas flow.

The figure.III.1 gives the evolution of the pressure losses according to GLR, it is divided into two zones :

- The first zone, the increase in GLR decreases the total pressure losses, and gravitational pressure losses**,** despite the increase in friction losses.

- The second zone, the total pressure loss increases with the decrease of the gravitational losses, and the increase of friction losses, despite the increase in GLR.

The minimum of the total pressure loss corresponds to an optimum GLR.

The injection of large volumes of gas causes problems in lines and surface installations. This gas must be transported to the station and must be separated. It therefore adds pressure losses in pipelines that can disturb neighboring producing wells. In addition, when the volume of available gas on a field is limited, it must be shared judiciously between all the wells to produce the maximum oil .All wells will not be at their "optimum GLR " but at their "economic GLR".[4]

Thence it is necessary to determine the amount of gas to inject to obtain optimal production using a PIPESIM software.

III.1.2. REVIEW ABOUT PIPESIM SOFTWARE:

PIPESIM is a software used to analyze well performance. It allows to:

- Optimize production.
- Improve well performance.:
  - Analyze the production system.
  - Determine pressure gradients.
  - Optimize gas-lifting.

PIPESIM includes all known correlations of pressure losses, in the reservoir (inflow), in the production column (outflow) with PVT correlations.

The creation of a model using PIPESIM requires a certain amount of data, and to have the best out of this software ,the maximum amount of data must be provided.

The necessary data for the use of PIPESIM are:

- ✓ Geological report data.
- ✓ Well completion report data.
- ✓ Well test data.
- ✓ The gauging data.

PIPESIM software was used to optimize the production flow rate of the following wells (HR162, HRE202, HRE111, HR189, HRS20,HRE 207,HRE104).

III.1.3. Optimization procedure:

The purpose is to determine the flow rate of injected gas in order to have maximum oil flow.

In the course of the pressure losses according to GLR; At the beginning, the pressure losses continue to decrease as the GLR increases up to a point where any increase in injection rate increases the pressure losses; this point corresponds to the optimal GLR.

The steps that must be followed to arrive at determining the optimal GLR are:

- Insertion of data into PIPESIM.

- Manipulating the box "System analysis" allows to insert different values of gas flow, which allows to have different outflow curves and therefore several different operating points.
- Redoing the previous step with other values in order to have more representative points.
- A curve is drawn: oil flow produced as a function of injected gas flow.
- The optimal gas flow is the one that gives the maximum value of this curve.

And finally, to have a better gas lift optimization, the most appropriate correlations must be used. So it is essential to choose the correlations well. [7]

Choice of correlations:

a) IPR curve (inflow):

The equations used to draw the curve of the IPR are :

- The monophasic flow equation (DARCY) for Pb < Pr.
- The biphasic flow equation (VOGEL) for Pr <Pb.

In this case Pr < Pb, the pseudo steady state equation with the correction of VOGEL will be used, which is written in formula (1) :

$$\boldsymbol{q = \frac{J*P}{1.8}\left[1 - 0.2\left(\frac{Pwf}{P}\right) - 0.8\left(\frac{Pwf}{P}\right)^2\right]} \qquad (1)$$

Furthermore the oil flow is selected Qo for Qo<Qomax and the corresponding dynamic bottom pressures Pwf will be determined, then the points obtained are drawn on the graph Pwf = f (Qo) which is shown in (FIGURE.III.2) :

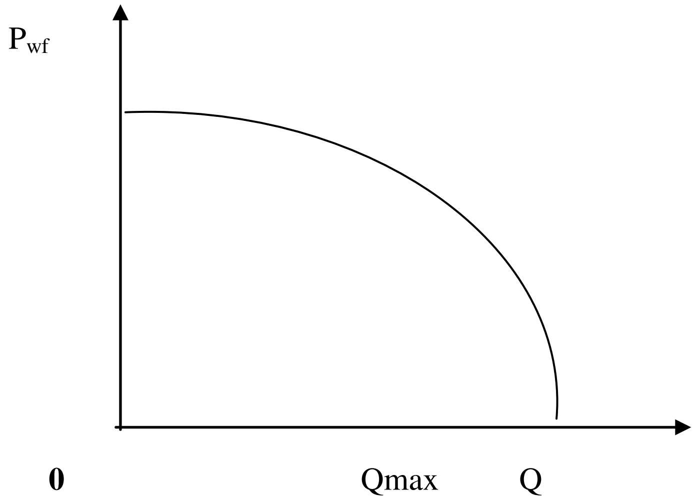

Figure.III.2 The IPR curve (inflow).

b) The VLP curve (outflow):

Numerous correlations have been established for biphasic flows in the tubing, some of which are general and others are limited to a small area of application. Among the correlations used in the PIPESIM software:

- Mukherjee and Brill ;
- Orkiszewski ;
- Hagedorn & Brown ;
- Beggs&Brill.
- Duns & Ros

The goal is to choose a correlation that yields the closest results to those measured.

Due to the lack of data especially the values of dynamic bottom hole pressure, the availability of well head pressure data will be used. And these steps will be followed to determine the suitable correlation:

1) Insert well data by placing the node at the well bottom.
2) Use the pseudo steady state equation PSS combined with Vogel for Pres< Pb.
3) Vary tubing correlations **«vertical wellbore correlation**", and retaining the one of reservoir the same (**PSS+ Vogel**).
4) A value of well head pressure is given for each correlation.
5) The most appropriate correlation gives a well head pressure close to that measured. [9]

III.1.4. Gas-lift optimization HR162:

The well was drilled and put into production in 1991 in level A. Recently, It has experienced frequent disturbances such as salt deposits formation in the tubing and production facilities.

*III.1.4.1.*Matching data with the measured data (suspended tubing) :

After collecting data from the well database and the latest test results, the well data needed for calculations (Table.III.1) and the reservoir data (Table.III.2) and the completion data (Table.III.3). [11]

Table.III.1. HR 162 well data.

$P_{wellhead}$ (kg/cm^2)	Qo (Sm^3/d)	Qg_t (Sm^3/d)	Qw (Sm^3/d)	GOR_f (Sm^3/m^3)	Wcut (%)	Qg injected (.E3 Sm3/d)
44.64	94.6	4765	59.20	51	38.74	20

Table.III.2. HR 162 reservoir data.

P_{res} (kg/cm^2)	K (mD)	Drainage radius (m)	Hu (m)
207	89	375	3.2

Table.III-3. HR 162 completion data.

Depth (m)	Type	OD(in)	ID(in)
2164	Casing	9.625	8.755
2266	Casing	7.000	6.184
2055.11	Tubing	4.500	3.958
2031.2	Concentric	2.875	2.441

A.2) Choice of correlation:

Inserting HR162 data into PIPESIM results the different pressure gradient graphs for each correlation (Figure.III.3).

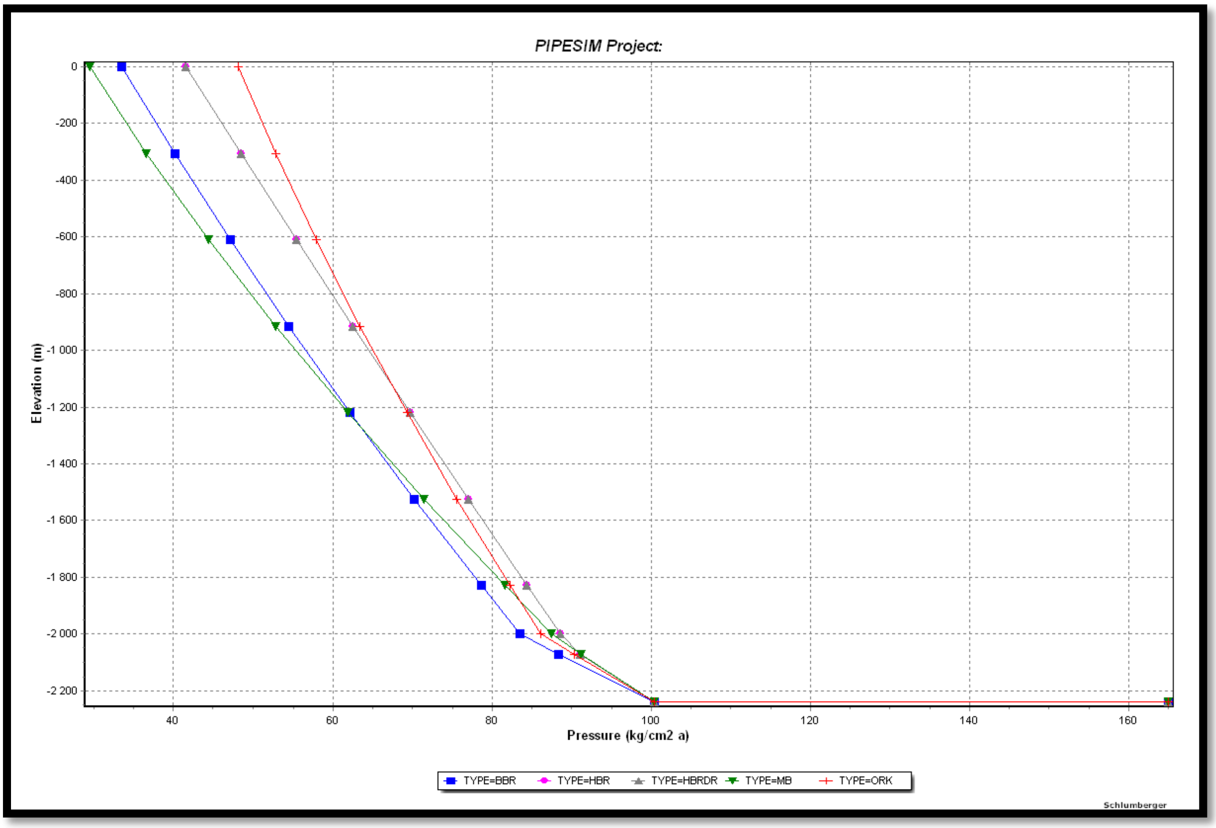

Figure.III-3. Choice of the Correct Correlation for Calculating Pressure Losses HR162.

The results are taken (Figure.III.3) and put side by side to be compared in (Table.III.4).

Table.III-4. the well head pressure curves results (HR162 well)

	Beggs&Brill	Hagedorn & Brown	Duns & Ros	Mukherjee and Brill	Orkiszewski
$P_{wellhead\ measured}$ (kg/cm2)	44,64	44,64	44,64	44,64	44,64
$P_{wellhead\ calculated}$(kg/cm2)	36,7568	44,6215	32,5085	35,7591	48,5539
$\lvert \Delta P \rvert$ /Pm (%)	19,98	0,53	11,18	29,45	15,10

Note that the value of the well head pressure obtained by the correlation of **Hagedorn and Brown** ($P_{wellhead\ calculated}$= 44.62 Kg/cm2) is the closest to the one measured ($P_{wellhead\ measured}$= 44,64 Kg/cm2).

Therefore Hagedorn and Brown equation is chosen to calculate the pressure losses in the tubing of HR162 well.

A.3) Determination of the operating point:

The operating point is the different parameters presented in this study are based on nodal analysis using PIPESIM software (Figure.III-4).

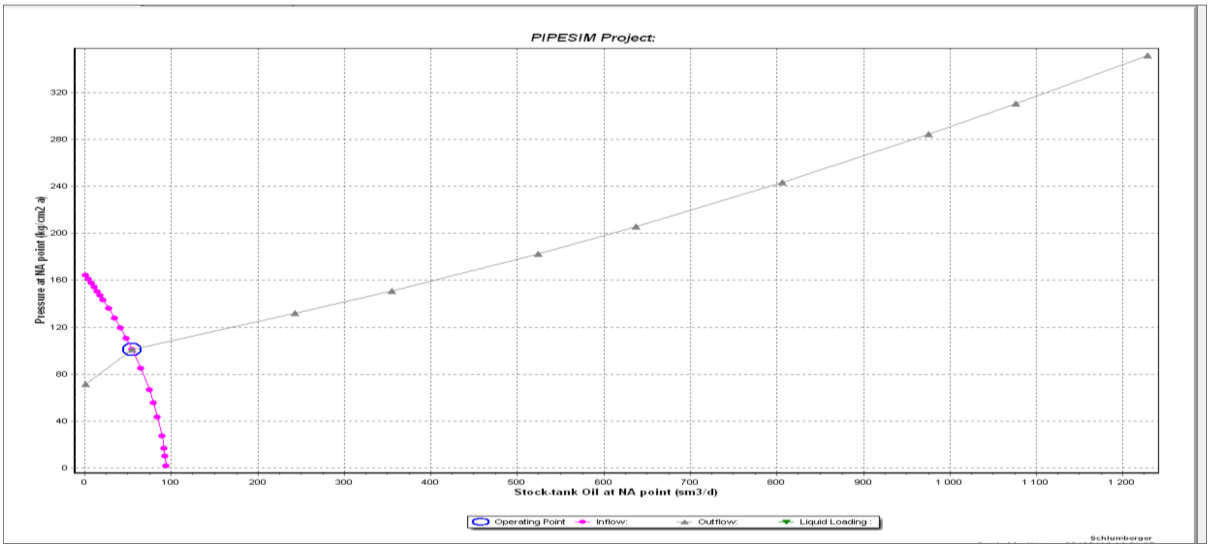

Figure.III-4. Operating point (VLP, IPR curves)

So the operating point is: **Qo = 94.71 (Sm3/d)** with a bottom hole pressure **P_{wf}= 138.49 (Kg/cm^2)**.

Note that this flow is close to that measured **Qo =94.6 (Sm3/d).**

Moreover, HR162 well data is modeled. The following work consists of optimizing the injection gas flow rate and optimizing the depth of the injection point in the $2^{7/8}$ tubing.

III.1.4.2 Optimization with the current completion (suspended tubing):

B.1. Determination of the optimum gas lifting flow rate:

Adding a quantity of gas generates an increase in friction losses, since the gas injection increases the flow speed of effluent. On the other hand it decreases the density of the effluent and thus reduce the gravitational losses. These two inverse effects have an optimum point the GLR $_{optimum}$. The optimum injection point corresponds to the point at which the increase in injected gas flow becomes unnecessary or even drop production if the flow is very strong; in other words the ratio (production gain / injection rate) becomes smaller**.**

The various operating points for different injection rates build the curve that characterizes the evolution of production as a function of the injected gas flow. Indeed the optimal injection point will be the point of intersection between the curve and its tangent (Figure.III.5).

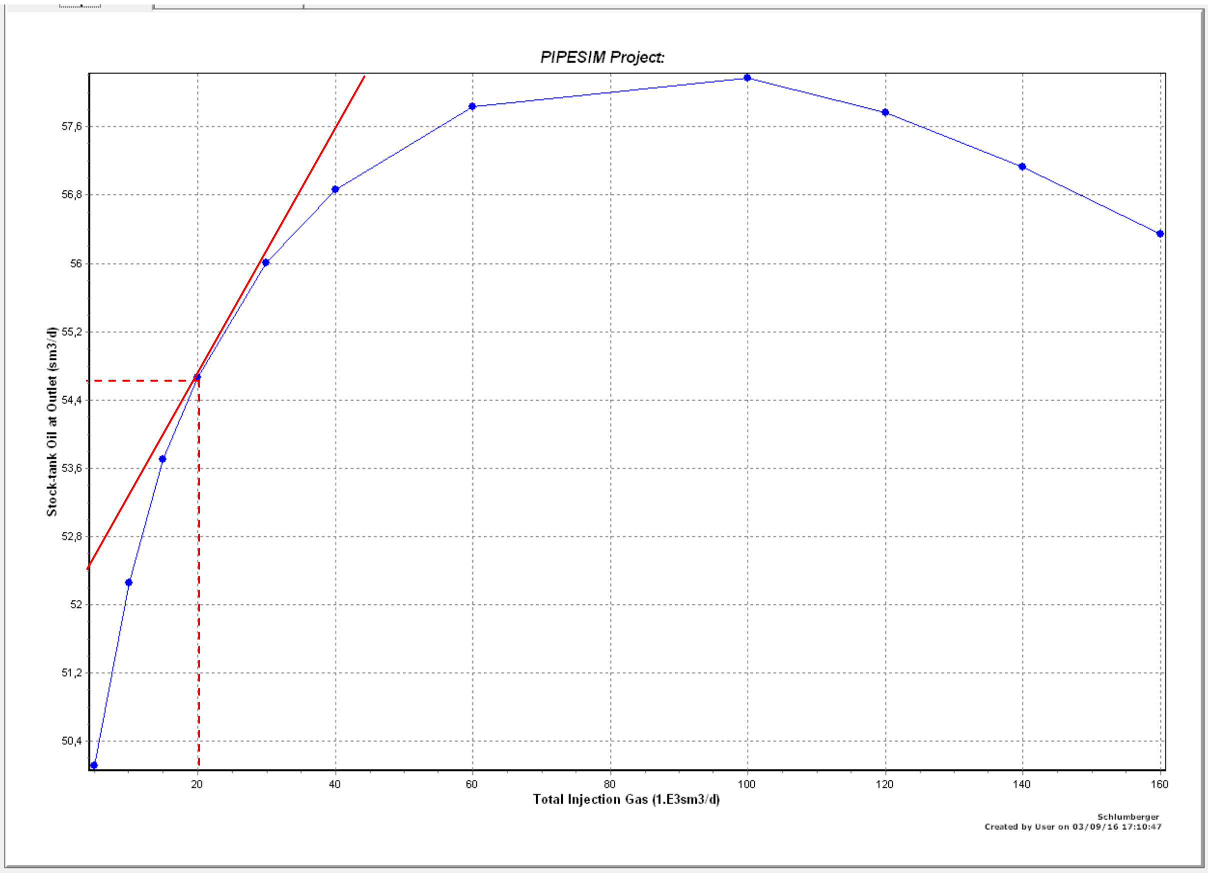

Figure.III-5. Performance curve of different gas injection rates.

According to the curve, the increase in injected gas flow increases the oil flow, but with different proportions. Also , beyond an injection rate of **23(.E3Sm3/d)** the contribution of the gas lift is negligible. Therefore the optimum production is Qo **= 94.71Sm3/d**.

B.2. Optimization of production tubing diameter:

Table.III-5 and Figure.III..6 illustrate the results of the simulation for the choice of optimum tubing diameter for a depth of 1900 m.

Table.III-5. Optimization of tubing diameter.

Tubing diameter	2"3/8	2"7/8
Oil flow (m3/d)	83,5811	94,71

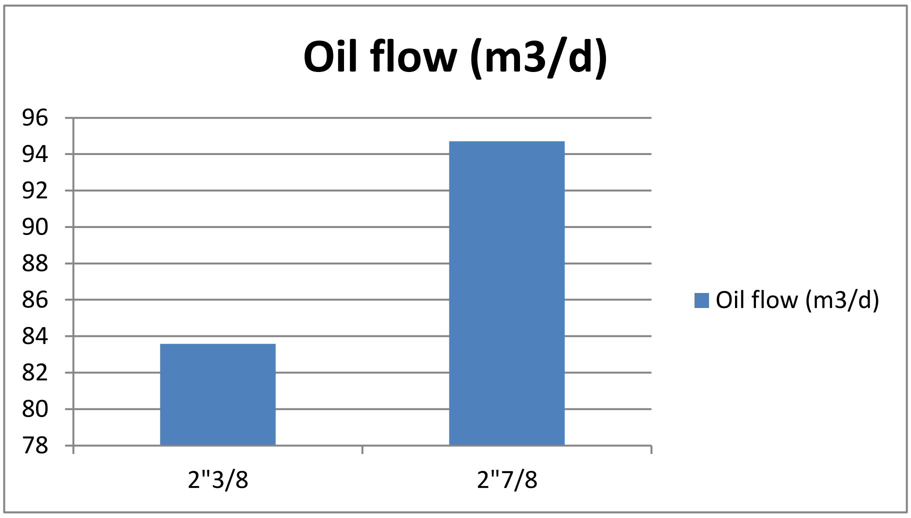

Figure.III-6. Choice of optimum tubing diameter.

In conclusion, the obtained results show that the well operates with the optimal parameters: tubing 2"7/8, Qginj = 23 (.E3 Sm3/d), Qo = 94.71 (Sm3/d).

B.3. the effect of pressure decrease and water-cut on production:

Pressure decrease :

The variation of the oil flow as a function of the reservoir pressure (Table.III.6) (Figure.III.7).

Table.III.6. The variation of production according to reservoir pressure decrease

	2''7/8	
P_r(Kg/cm2)	Qo (Sm3/d)	Pwf (Kg/cm2)
207	94.7102	138.49
200	91,7226	137.8
194	88,8771	137.2
189	84,049	136.56
184	80,2024	136.09
180	76,4909	135.85
170	72,8192	135.05
160	69,2566	134.82
150	65,8007	134.13
140	61,4176	133.3
130	57,8384	133.12
120	54,5219	132.84
110	52,5274	132.08
100	47,5657	131.53

The (Table.III.6) shows that a pressure decline of 5 (Kg/cm2) corresponds to a drop in production of 3.84 (m3/d).

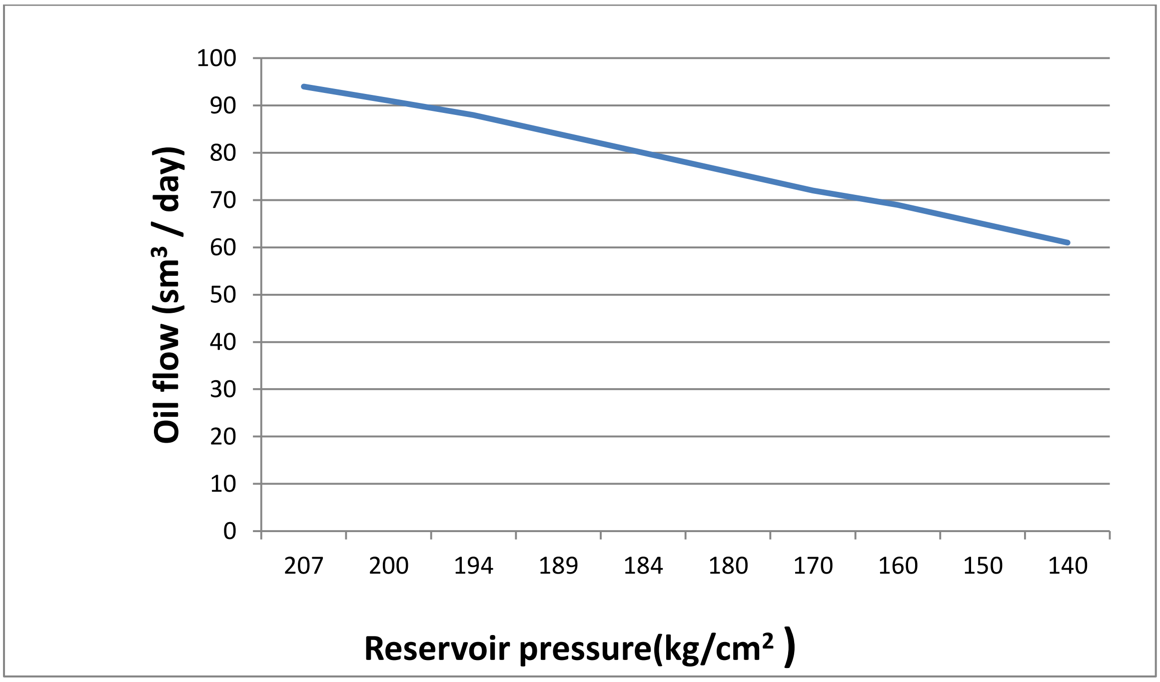

Figure.III.7. HR162 well production rate depending on the reservoir pressure.

- **Water cut:**

In the oil rim of Hassi R'mel, the coning phenomenon is a serious problem, because the producing layer is considered as thin, and it causes an untimely water income for the producing wells. These comings play a negative role in the production, because it increases the density of the effluent, so the production column gets heavier; which forces to inject a large amount of gas.

The well history (Figure.III.8) shows a tendency of water flow to increase and a drop in oil flow, this reflects the rise of the water level.

Over time, the water cut will increase following the rise of the water level in the formation, for that the evolution of the production according to Wcut will be predicted.

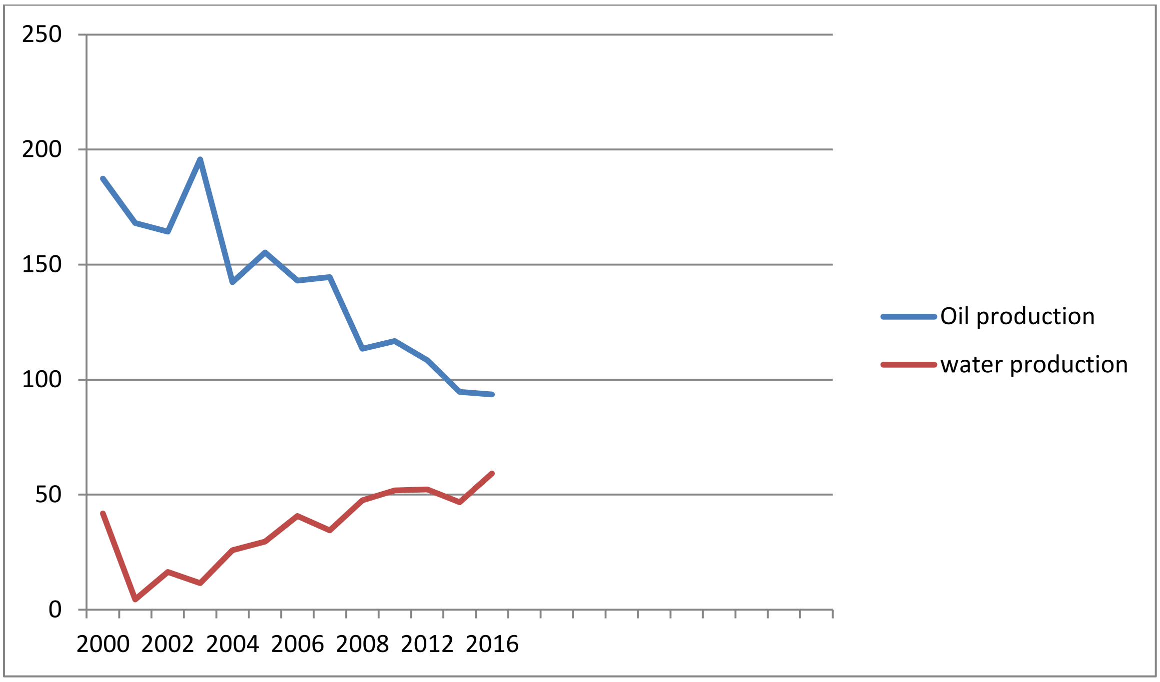

Figure.III-8. HR 162 well production history.

The different operating points given by the software, based on the optimal injection rate Qginj = 23 (.E3 Sm3/d), for each value of water cut (Table.III-7).

Table.III-7. The variation of the production according to the water-cut.

Water cut (%)	Qo (Sm3/d)
90	48,202
80	56,012
70	63,727
60	69,418
50	76,229
40	83,128
30	89,195
23	**94,762**

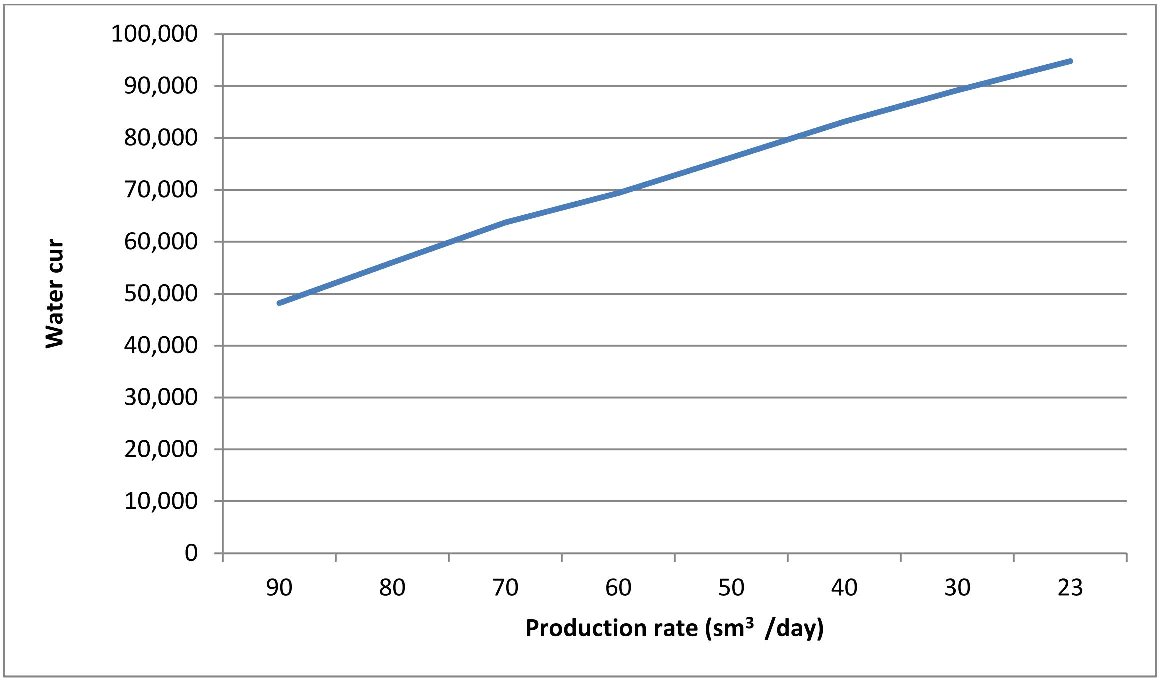

Figure.III-9. HR162 Variation of production as a function of water cut

According to the graph(Figure.III.9), a WC increase of about 10% brings the production down to about 6 m^3/ d. this result shows the influence of WC on production.

B.4.Optimization of the injection point depth:

The (Table.III.8) shows the different oil flow rates as a function of depth. The optimal depth is 2031.32 m.

Table.III.8. Optimization of the injection point depth.

Depth (m)	Qo (Sm3/d)
1500	92,2337
1600	92,6243
1700	92,9649
1800	93,4553
1900	94,1522
2031.32	**94,71**
Diameter	**2''7/8**

III.1.4.3.Optimization with the new completion (parallel completion):

- Optimization of production tubing diameter:

The (Table.III.9) shows the different oil flow rates as a function of tubing diameter. For a valve placed at a depth of 2031.32 m the optimum diameter is the 2"7/8.

Table.III.9. Optimization of tubing diameter.

Tubing diameter	**Qo(Sm3/d)**
3"1/2	90,353
2"7/8	96,501
2"3/8	93,6543

- Determination of optimal gas lift injection rate :

The (Table.III.10) shows the different oil flow rates as a function of gas lifting injection. The optimal flow rate is = 96.501 (Sm3/d) which corresponds to an injection of Qgl = 20 (.E3 Sm3/d) of gas lift

Table.III.10. Optimization of gas lift injection rate.

Qginj	Qo(**Sm3/d**)
5	91,2519
10	92,2534
15	93,5829
20	**96,501**
30	97,7168
40	98,4962
50	97,0117
60	96,3471

- Variation of production as a function of :
  - Pressure decline

The (Table.III.11) shows the variation of oil flow rate as a function of pressure decline.

Table.III.11. Oil flow rate as a function of pressure decline.

Pr (Kg/cm2)	Qo (Sm3/d)
207	96,5009
200	92,6526
194	88,8898
189	84,971
184	81,0948
180	77,3353
170	73,66
160	70,0903
150	66,6174
140	63,2487
130	59,8384
120	56,2523
110	53,0233
100	49,9567

- **Water cut**

  The (Table.III.11) shows the variation of production as a function of water cut:

Table.III.12. Oil low rate as a function of water cut.

Wcut (%)	Qo(Sm3/d)
20	96,501
30	91,0072
40	84,8323
50	77,9104
60	70,6828
70	64,4751
80	56,5391
90	48,3251

III.1.4.3.Summary:

A comparison between pressure decline and water cut effects on both completions are shown in (Figure.III.10) and (Figure.III.11) respectively.

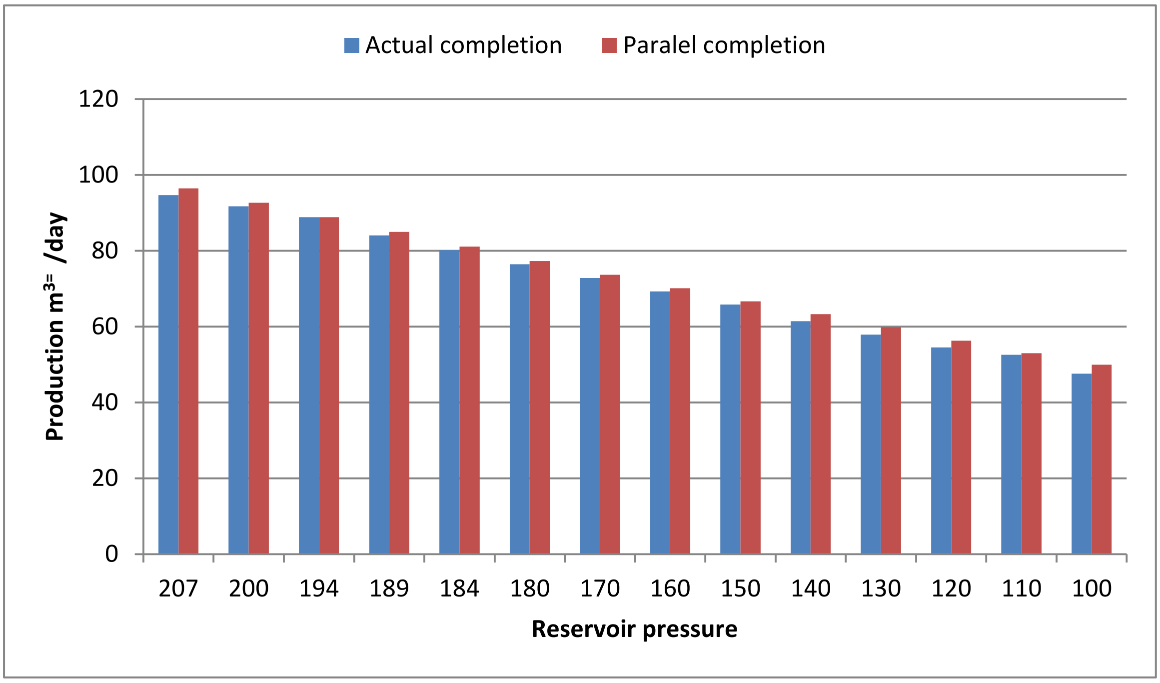

Figure.III-10. Variation of production as a function of pressure decline (HR162)

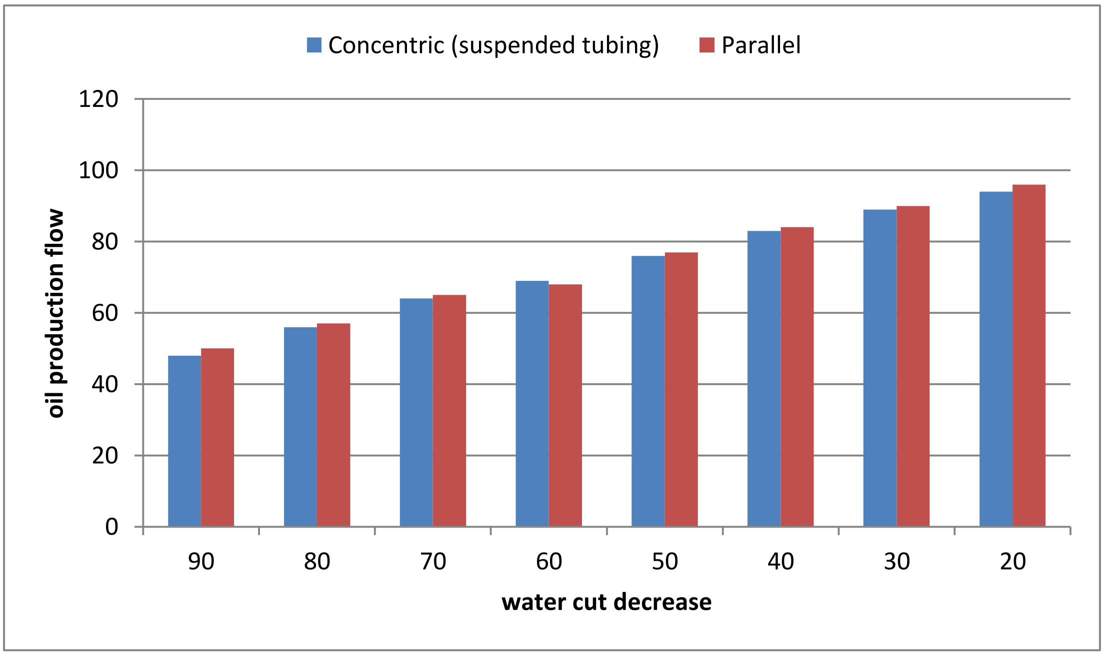

Figure.III-11. Variation of production as a function of Water-cut (HR162)

Table.III.13 and Figure.III.12 a comparison between the oil flow rate and the gas lift injection rate for each completion.

Table.III-13. Comparison between different completions (HR162)

Completion	Tubing optimum diameter	Qg inj (.E3/Sm3/d)	Qo(Sm3/d)
Concentric (suspended tubing)	2"7/8	23	94.71
Parallel	2"7/8	20	96.50

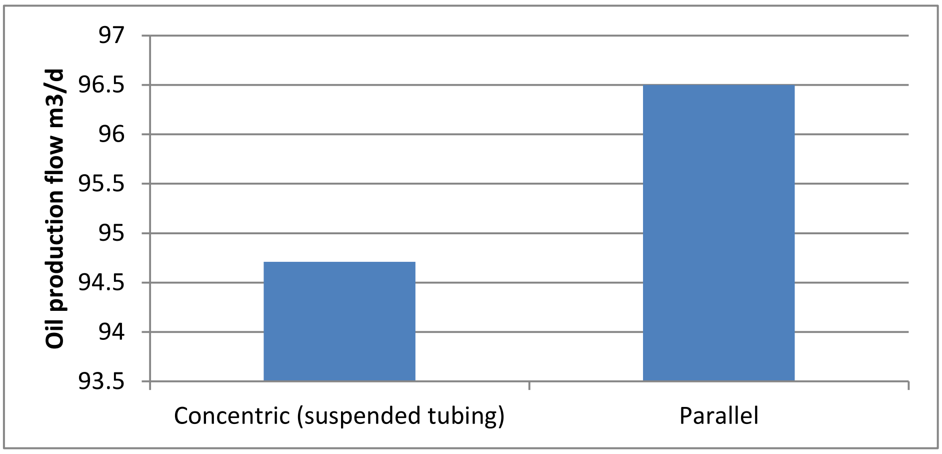

Figure.III-12. Production for each completion (HR 162)

III.1.5 Gas-lift Optimization HRE111:

Using well data from Annex A and B the optimization of HRE111 is as follows:

A) Determination of the operating point:

The operating point is : Qo = 22,71 (Sm3/d), Pwf = 99,22 (Kg/cm2).

B) Optimization with current completion (mixed injection)

❖ Optimization of production tubing diameter

The (Table.III.14) shows the different oil flow rates as a function of tubing diameter. Due to the low reservoir pressure, preferring to keep the same diameter 2"7/8.

Table.III.14. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
3"1/2	23,5492
2"7/8	22,7117
2"3/8	18,0429

❖ Gas lift injection flow optimization:

The (Table.III.15) shows the different oil flow rates as a function of gas lifting injection. The optimum production rate is Qo = **23,47**(Sm3/d) for a gas injection flow Qgl = 15 (.E3 Sm3/d).

Table.III.15. Optimization of gas lift injection rate.

Qgl (.E3 Sm3/d)	**Qo (Sm3/d)**		
5	21,9373	21,3879	17,6446
10	23,5492	22,7117	18,0429
15	**24,6455**	**23,4794**	**18,1005**
20	25,4298	24,0069	18,0564
30	26,4356	24,5478	17,4715
40	26,979	24,7295	16,5528
50	27,2321	24,6816	15,4401
60	27,3307	24,4324	14,1665
Diameter	**3"1/2**	**2"7/8**	**2"3/8**

C) Optimization with Special Completion (suspended tubing).

❖ Optimization of the depth and diameter of production tubing:

The (Table.III.16) shows the different oil flow rates as a function of depth and tubing diameter.

Table.III.16. Optimization of the injection point depth and tubing diameter.

Depth (m)	**Qo(Sm3/d)**	
1500	23,8903	18,2859
1600	23,5783	18,0903
1700	23,2205	18,0199
1800	22,8921	17,9424
1900	22,6003	17,9083
2000	22,3859	17,9082
2100	22,23	17,9683
Diameter	2"7/8	2"3/8

The optimum diameter is the 2"7/8 and the optimal depth is at 1500m, but for reasons of start of well in case of intervention or neutralization it must be as low as possible in this case at 2000m.

- Determination of optimal gas lift injection rate:

The (Table.III.17) shows the different oil flow rates as a function of gas lifting injection. The optimum flow rate is Qo = 23.71 (Sm3 / d) which corresponds to an injection of 15 (.E3 Sm3 / d) of lift gas.

Table.III.17. Optimization of gas lift injection rate.

Qgl (.E3 Sm3/d)	**Qo (Sm3/d)**	
5	23,0805	16,9484
10	23,4724	17,6031
15	**23,7098**	**18,0197**
20	23,8903	18,2859
30	24,1444	18,5348
40	24,2894	18,526
50	24,3591	18,3271
60	24,3692	17,9727
Diameter	**2"7/8**	**2"3/8**

D) Optimization with the new completion (Parallel completion)

- Optimization of the tubing diameter

The (Table.III.18) shows the different oil flow rates as a function of tubing diameter. The diameter 2"7/8 is the optimum for a 2130 m depth.

Table.III.18.Optimization of tubing diameter.

Tubing diameter	**Qo (Sm3/d°**
3"1/2	23,8518
2"7/8	22,3173
2"3/8	17,8835

❖ Optimization of gas lift injection rate

The (Table.III.19) shows the different oil flow rates as a function of gas lifting injection. The optimal production rate is Qo = 22,87 (Sm3/d) for a gas lift injection rate of : Qgl = 15 (.E3 Sm3/d).

Table.III.19. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	3"1/2	2"7/8	2"3/8
5	21,0819	20,6141	17,0911
10	22,8578	21,9972	17,5371
15	**23,9488**	**22,8723**	**17,6224**
20	24,7628	23,3848	17,5868
30	25,8033	23,9546	17,0243
40	26,3653	24,0851	16,1259
50	26,6288	24,1358	15,0207
60	26,7353	23,8717	13,7419

E) Summary

Table.III.20 shows a comparison between the oil flow rate and the gas lift injection rate for each completion.

Table.III-20. Comparison between different completions (HRE111)

Completion	Optimum tubing diameter	Qg inj (.E3/Sm3/d)	Qo(Sm3/d)
Current (mixed injexion)	2"7/8	15	23,47
Special (suspended tubing)	2"7/8	15	23,71
New (parallel completion)	2"7/8	15	22,87

The obtained flow by the parallel completion is inferior to the current completion. As the pressure decreases and the increase in the water cut, the two completions mixed and suspended give good results but the suspended tubing completion is chosen due to its efficient desalting system.

III.1.6. Gas-lift optimization HR189:

Using well data from Annex A and B the optimization of HR189 is as follows:

A) Determination of the operating point:

The operating point is: Qo = 24,76 (Sm3/d, Pwf = 94,67 (Kg/cm2).

A. Optimization with current completion (mixed injection)

- Optimization of production tubing diameter

The (Table.III.21) shows the different oil flow rates as a function of tubing diameter. The optimum diameter is 2"7/8.

Table.III.21. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
2"7/8	24,76801
2"3/8	22,70873

- Gas lift injection flow optimization

  The (Table.III.22) shows the different oil flow rates as a function of gas lifting injection. The optimum production flow rate is Qo = 24.74 (Sm3 / d) which corresponds to an injected gas flow rate Qginj = 20 (.E3 Sm3 / d).

Table.III.22. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	Qo(Sm3/d)	
5	24,5170	22,5567
10	24,6081	22,6172
15	24,6824	22,6780
20	**24,7413**	**22,7002**
30	24,8150	22,6950
40	24,8434	22,6361
50	24,8378	22,5331
60	24,8059	22,3937
Diameter	2"7/8	2"3/8

B. Optimization with special completion (suspended tubing)

- Optimization of production tubing diameter

The (Table.III.23) shows the different oil flow rates as a function of tubing diameter. The optimum diameter is 2"7/8.

Table.III.23. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
3"1/2	27,43386
2"7/8	**25,66867**
2"3/8	23,25406

- Optimization of optimal tubing depth

The (Table.III.24) shows the different oil flow rates as a function of depth. The optimal depth is 2037 m.

Table.III.24. Optimization of the injection point depth.

Depth (m)	Qo (Sm3/d)	
1500	25,5812	22,79862
1600	25,59746	22,80749
1700	25,61376	22,8167
1800	25,63009	22,82645
1900	25,6464	22,83687
2000	**25,66367**	**22,84792**
2037	**25,66867**	**22,85216**
Diameter	**2"7/8**	**2"3/8**

- Gas lift injection flow optimization

The (Table.III.25) shows the different oil flow rates as a function of gas lifting injection. The optimum production flow rate is Qo = 25.92 (Sm3 / d) which corresponds to an injected gas flow rate Qgin = 15 (.E3 Sm3 / d).

Table.III.25. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	**Qo(Sm3/d)**		
5	27,5971	25,7613	23,4930
10	27,6466	25,8508	23,5354
15	**27,6875**	**25,9255**	**23,5560**
20	27,7215	25,9620	23,5581
30	27,7823	26,0007	23,5149
40	27,8386	26,0007	23,4192
50	27,8896	25,9966	23,2795
60	27,9351	25,9440	23,1014
Diameter	3"1/2	2"7/8	2"3/8

C. Optimization with the new GLP Completion (Parallel Completion)

❖ Optimization of production tubing diameter

The (Table.III.26) shows the different oil flow rates as a function of tubing diameter. The optimum tubing diameter is 2 "7/8 for a depth of 2041 m.

Table.III.26. Optimization of tubing diameter.

Diameter	**Qo(Sm3/j)**
3"1/2	24,0917
2"7/8	22,9299
2"3/8	19,2068

❖ Determination of optimal gas lift injection rate:

The (Table.III.27) shows the different oil flow rates as a function of gas lifting injection. The optimum flow rate is Qo = 24.68 (Sm3 / d) which corresponds to an injected gas flow rate of Qgin = 20 (.E3 Sm3 / d).

Table.III.27. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/j)	Qo(Sm3/j)		
5	25,3666	24,1537	20,3704
10	25,5674	24,3693	20,5920
15	25,7546	24,5439	20,7424
20	**25,8691**	**24,6864**	**20,8356**
30	26,0608	24,8972	20,8957
40	26,1791	25,0326	20,8317
50	26,2483	25,1013	20,6770
60	26,2825	25,1406	20,4479
Diameter	3"1/2	2"7/8	2"3/8

D. Summary

(Table.III.28) shows a comparison between the oil flow rate and the gas lift injection rate for each completion.

Table.III-28. Comparison between the different completions (HR189)

Completion	Optimum tubing diameter	Qg inj (.E3/Sm3/d)	Qo(Sm3/d)
Current (mixed injection)	2"7/8	20	24.74
Speciale (suspended tubing)	2"7/8	15	25.92
Parallel	2"7/8	20	24.68

III.1.7. Gas-lift optimization HR 202:

Using well data from Annex A and B the optimization of HR 202 is as follows:

A) Determination of the operating point:

The current operating point: Qo = 50.88 (Sm3 / d), Pwf = 139.07 (Kg / cm2).

B) Optimization of the current completion (mixed completion)

- Optimization of production tubing diameter

The (Table.III.29) shows the different oil flow rates as a function of tubing diameter. The optimal diameter is the 2"7/8.

Table.III.29. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
2"7/8	50,8893
2"3/8	43,9986

- Gas lift injection flow optimization

The (Table.III.30) shows the different oil flow rates as a function of gas lifting injection. The optimum production rate is Qo = 50,5 (Sm3 / d) which corresponds to an injection of 20 (.E3 Sm3 / d).

Table.III.30.Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	Qo(Sm3/d)	
5	45,5742	39,9345
10	48,1372	41,6956
15	49,6213	42,8309
20	**50,5095**	**43,6616**
30	51,7948	44,7729
40	52,7220	45,4357
50	53,4102	45,8378
60	53,9286	46,0546
Diameter	2"7/8	2"3/8

A. Optimization with special completion (suspended tubing)

- Optimization of production tubing diameter

The (Table.III.31) shows the different oil flow rates as a function of tubing diameter. The optimum diameter is 2"7/8.

Table.III.31. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
2"7/8	52,4247
2"3/8	45,6521

- Optimization of optimal tubing depth

The (Table.III.32) shows the different oil flow rates as a function of depth. The optimal depth is 2059 m.

Table.III.32. Optimization of tubing depth.

Depth (m)	**Qo (Sm3/d)**	
1500	49,4817	43,4122
1600	50,0304	43,8042
1700	50,5801	44,2018
1800	51,7286	44,6030
1900	51,6914	45,0069
2000	52,2541	45,4142
2059	**52,5864**	**45,6521**
Diameter	**2"7/8**	**2"3/8**

- Gas lift injection flow optimization

The (Table.III.33) shows the different oil flow rates as a function of gas lifting injection. The optimum production flow rate is Qo = 50.15 (Sm3 / d) which corresponds to an injected gas flow rate Qgin = 20 (.E3 Sm3 / d).

Table.III.33. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	**Qo (Sm3/d)**	
5	45,2464	39,8057
10	47,8058	41,4760
15	49,2831	42,5585
20	**50,1556**	**43,3451**
30	51,4200	44,3907
40	52,3324	45,0134
50	53,0095	45,3901
60	53,5190	45,5962
Diameter	**2"7/8**	**2"3/8**

B. Optimization with the new GLP Completion (Parallel Completion)

- Optimization of production tubing diameter

The (Table.III.34) shows the different oil flow rates as a function of tubing diameter. The valve is placed at a depth of 2031 m, the optimum diameter of tubing is 2 "7/8.

Table.III.34. Optimization of tubing diameter.

Diameter	**Qo(Sm3/j)**
3"1/2	53,4891
2"7/8	51,7196
2"3/8	45,7389

- Determination of optimum flow rate of gas lift :

The (Table.III.35) shows the different oil flow rates as a function of gas lifting injection. The optimum flow rate is Qo = 51.83 (Sm3 / d) which corresponds to an injection of 20 (.E3 Sm3 / d) of lift gas.

Table.III.35. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/j)	**Qo(Sm3/j)**		
5	51,3782	49,7277	43,9484
10	51,6064	50,4834	44,6031
15	51,8172	51,0585	45,0197
20	**51,9452**	**51,8371**	**45,2859**
30	52,1194	52,2096	45,5348
40	52,2188	52,6963	45,526
50	52,2715	52,0404	45,3271
60	52,3	52,2782	44,9727
Diameter	3"1/2	2"7/8	2"3/8

C. Summary

Table.III.36 shows a comparison between the oil flow rate and the gas lift injection rate for each completion.

Table.III-36. Comparison between the different completions (HRE202)

Completion	optimal tubing diameter	**Qg inj (.E3/Sm3/d)**	**Qo(Sm3/d)**
Special (suspended tubing)	2"7/8	20	52,58
MIXED GLC	2"7/8	20	50,50
Parallel GLC	2"7/8	20	51,83

III.1.8. Gas lift optimization HRS20

Using well data from Annex A and B the optimization of HRE111 is as follows:

A) Determination of the operating point:

The operating point from (Figure.III.13) is : **Qo = 42,04911 (Sm3/d), Pwf = 85.74827 (Kg/cm2).**

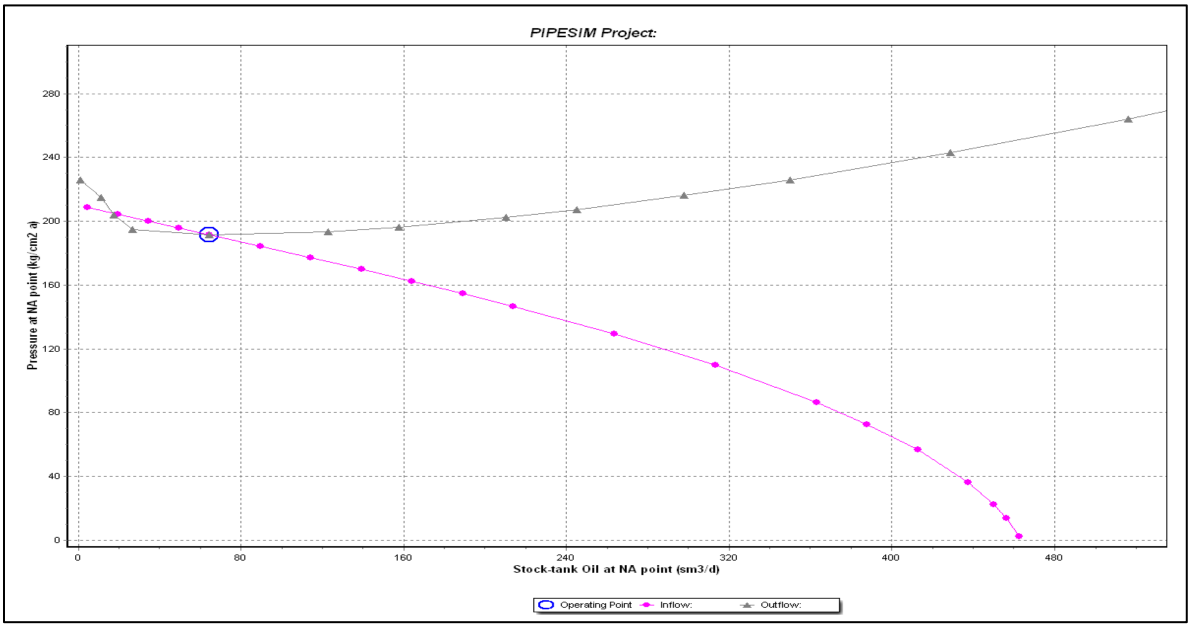

Figure.III-13. well operating point HRS20

B. Optimization with the current completion (mixed injection)

- Optimization of production tubing diameter and injected gas

The (Table.III.37) shows the different oil flow rates as a function of tubing diameter and injected gas flow rate. The optimal flow is Qo = **42.0767 (Sm3/d)** which corresponds to an injection of **30 (.E3 Sm3/d)** of lift gas for a tubing diameter of 3"1/2.

Table.III.37. Optimization of the injection flow rate and tubing diameter.

Qginj (.E3 Sm3/d)	**Qo(Sm3/d)**		
5	11,2992	16,8841	17,8108
10	32,2494	29,2321	31,7324
15	37,0258	32,7715	37,782
20	38,4355	37,6341	39,9405
30	**42,0781**	**43,348**	**43,5199**
40	45,3645	47,5949	47,1389
50	61,5602	53,4505	52,6245
60	63,0213	61,1693	59,4631
Diameter	**3"1/2**	**2"7/8**	**2"3/8**

A. Optimization with Special Completion (suspended tubing)

❖ Optimization of production tubing diameter

The (Table.III.38) shows the different oil flow rates as a function of tubing diameter. The optimum diameter is 2 "7/8.

Table.III.38. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
2"7/8	47,2748
2"3/8	40,327

❖ Gas lift injection flow optimization

The (Table.III.39) shows the different oil flow rates as a function of gas lifting injection. The optimal flow is **Qo = 44.2748 (Sm3/d)** which corresponds to a gas injection of **Qgl = 30 (.E3 Sm3/d)** for a tubing diameter **2"7/8.**

Table.III.39. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	Qo(Sm3/d)	
5	16,2642	18,6917
10	35,3252	19,3556
15	40,6178	26,2502
20	43,2748	39,327
30	**44,2748**	**42,8071**
40	42,6414	44,3529
50	43,3072	46,7754
60	41,9496	49,5025
Diameter	**2"7/8**	**2"3/8**

B. Optimization with the new GLP (parallel completion)

❖ Determination of optimal tubing diameter and gas lift injection rate

For a **1962 m** depth:

The (Table.III.40) shows the different oil flow rates as a function of gas lift injection rates and tubing diameter. the optimal flow is **Qo = 47.6086 (Sm3/d)** which corresponds to a gas lift injection rate of **Qgl=30 000 (Sm3/d)** for a **3"1/2** diameter.

Table.III.40. Optimization of the injection flow rate and tubing diameter.

Qginj (.E3 Sm3/d)	Qo (Sm3/d)		
5	12,156	11,9695	11,69
10	15,9903	13,5198	12,4771
15	23,0086	27,5051	17,7312
20	34,0897	32,3896	25,7297
30	**47,9843**	**38,8689**	**32,5267**
40	55,4901	40,9155	33,4871
50	60,7534	43,6458	36,4391
60	64,0595	46,2852	39,7551
Diameter	**3"1/2**	**2"7/8**	**2"3/8**

E.Summary

Table.III.41 shows a comparison between the oil flow rate and the gas lift injection rate for each completion.

Table.III-41. Comparison between different completions (HRS20)

Completion		Tubing diameter	Qg inj (.E3/Sm3/d)	Qo(Sm3/d)
Current	**Without GL**	3"1/2	-	23.01
	With GL	3"1/2	30	42.04
special (suspended tubing)		2"7/8	30	44.27
Parallel		3"1/2	30	47.9

By comparing the results obtained for each completion, it is found that the parallel completion feasible only with a tubing 2 "7/8, gives a flow rate of 47.9 (Sm3 / d) which is higher than that obtained for the other completions.

However, the optimum oil flow rate is close to that of parallel completion (47.6 (Sm3 / d).) Therefore, it is advisable to provide a parallel tubing completion for the HRS20 since the desalting system is more efficient

III.1.9. Gas-lift optimization HRE207:

Using well data from Annex A and B the optimization of HRE207 is as follows:

A) Determination of the operating point:

The operating point is: Qo = 29,75 (Sm3/d, Pwf = 92,97 (Kg/cm2).

A. Optimization with current completion (mixed injection)

- Optimization of production tubing diameter

The (Table.III.42) shows the different oil flow rates as a function of tubing diameter. The optimum diameter is 2"7/8.

Table.III.42. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
2"7/8	29,75872
2"3/8	24,28479

- Gas lift injection flow optimization

The (Table.III.43) shows the different oil flow rates as a function of gas lifting injection.The optimum production flow rate is Qo = 29.51 (Sm3 / d) which corresponds to an injected gas flow rate Qginj = 20 (.E3 Sm3 / d).

Table.III.43. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	Qo(Sm3/d)	
5	27,8546	22,4444
10	28,5347	23,1800
15	29,0759	23,7135
20	**29,5170**	**24,1026**
30	30,1817	24,5745
40	30,6234	24,7471
50	30,9095	24,6998
60	31,0663	24,4775
Diameter	2"7/8	2"3/8

B. Optimization with special completion (suspended tubing)

- Optimization of production tubing diameter

The (Table.III.44) shows the different oil flow rates as a function of tubing diameter. The optimum diameter is 2"7/8.

Table.III.44. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
2"7/8	30,57587
2"3/8	25,43178

- Optimization of optimal tubing depth

The (Table.III.45) shows the different oil flow rates as a function of tubing depth. The optimal depth is 2000 m.

Table.III.45. Optimization of tubing depth.

Depth (m)	**Qo (Sm3/d)**	
1500	30,03155	24,81952
1600	30,14358	24,94227
1700	30,25738	25,06428
1800	30,36528	25,1899
1900	30,47108	25,31052
2000	30,57587	25,43178
Diameter	**2"7/8**	**2"3/8**

- Gas lift injection flow optimization

  The (Table.III.46) shows the different oil flow rates as a function of gas lifting injection. The optimum production flow rate is Qo = 30.40 (Sm3 / d) which corresponds to an injected gas flow rate Qgin = 20 (.E3 Sm3 / d).

Table.III.46. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	Qo(Sm3/d)	
5	28,9058	23,8128
10	29,5141	24,4731
15	30,0037	24,9620
20	**30,4088**	**25,3163**
30	31,0164	25,7434
40	31,4311	25,9345
50	31,7016	25,8822
60	31,8549	26,6322
Diameter	2"7/8	2"3/8

C. Optimization with the new GLP Completion (Parallel Completion)

❖ Optimization of production tubing diameter

The (Table.III.47) shows the different oil flow rates as a function of tubing diameter. The valve is placed at a depth of 2041 m, the optimum tubing diameter is 2 "7/8.

Table.III.47. Optimization of tubing diameter.

Diameter	**Qo(Sm3/j)**
3"1/2	32,0917
2"7/8	29,7088
2"3/8	25,2068

❖ Determination of optimal gas lift injection rate:

The (Table.III.48) shows the different oil flow rates as a function of gas lifting injection. The optimum flow rate is Qo = 29.68 (Sm3 / d) which corresponds to an injected gas flow rate of Qgin = 20 (.E3 Sm3 / d).

Table.III.48. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/j)	Qo(Sm3/j)		
5	30,3666	29,1537	24,3704
10	30,5674	29,3693	24,5920
15	30,7546	29,5439	24,7424
20	**30,8691**	**29,6864**	**24,8356**
30	31,0608	29,8972	24,8957
40	31,1791	30,0326	24,8317
50	31,2483	30,1013	24,6770
60	31,2825	30,1406	24,4479
Diameter	3"1/2	2"7/8	2"3/8

D. Summary

Table.III.49 shows a comparison between the oil flow rate and the gas lift injection rate for each completion.

Table.III-49. Comparison between the different completions (HR207)

Completion	Optimum tubing diameter	Qg inj (.E3/Sm3/d)	Qo(Sm3/d)
Current (mixed injection)	2"7/8	20	29.51
Special (suspended tubing)	2"7/8	20	30.40
Parallel	2"7/8	20	29.68

III.1.10. Gas-lift optimization HRE104:

Using well data from Annex A and B the optimization of HRE104 is as follows:

A) Determination of the operating point:

The operating point is: Qo = 17.25 Sm3/d, Pwf = 83.36 (Kg/cm2).

B. Optimization with current completion (suspended tubing)

- Optimization of production tubing diameter

The (Table.III.50) shows the different oil flow rates as a function of tubing diameter. The optimum diameter is 2"7/8.

Table.III.50. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
2"7/8	17,76801
2"3/8	16,70873

- Optimization of optimal tubing depth

The (Table.III.51) shows the different oil flow rates as a function of tubing depth. The optimal depth is 1835 m.

Table.III.51. Optimization of tubing depth.

Depth (m)	**Qo (Sm3/d)**	
1500	16,5812	15,79862
1600	16,59746	15,80749
1700	16,91376	15,8167
1835	**17,21009**	**15,82645**
1900	17,6464	15,83687
Diameter	**2"7/8**	**2"3/8**

- ❖ Gas lift injection flow optimization

The (Table.III.52) shows the different oil flow rates as a function of gas lifting injection. The optimum production flow rate is Qo = 17.51 (Sm3 / d) which corresponds to an injected gas flow rate Qginj = 20 (.E3 Sm3 / d).

Table.III.52. Optimization of gas lift injection rate.

Qginj (.E3 Sm3/d)	Qo(Sm3/d)	
5	17,5170	15,5567
10	17,6081	15,6172
15	17,7824	15,6780
20	**17,5113**	**15,7002**
30	17,8150	15,6950
40	17,8434	15,6361
50	17,8378	15,5331
60	17,8059	15,3937
Diameter	2"7/8	2"3/8

A. Optimization with the new completion (parallel completion):

- ❖ Optimization of production tubing diameter

The (Table.III.53) shows the different oil flow rates as a function of tubing diameter. For a valve placed at a depth of 1835 m the optimum diameter is the 2"7/8.

Table.III.53. Optimization of tubing diameter.

Tubing diameter	Qo(Sm3/d)
3"1/2	19,76801
2"7/8	17,5308
2"3/8	16,6543

❖ Determination of optimal gas lift injection rate :

The (Table.III.54) shows the different oil flow rates as a function of gas lifting injection. The optimal flow rate is = 17.53 (Sm3/d) which corresponds to an injection of Qgl = 20 (.E3 Sm3/d) of gas lift

Table.III.54 Optimization of gas lift injection rate.

Qginj	Qo(**Sm3/d)**
5	12,5170
10	14,6081
15	15,7824
20	**17,5383**
30	18,5850
40	18,0155
50	17,8378
60	17,8059

B. Summary

Table.III.55 shows a comparison between the oil flow rate and the gas lift injection rate for each completion.

Table.III-55. Comparison between different completions(HRE104).

Completion	**tubing optimum diameter**	**Qg inj (.E3/Sm3/d)**	**Qo(Sm3/d)**
Concentric (suspended tubing)	2"7/8	23	17.25
Parallel	2"7/8	20	17.53

Based on the results achieved earlier using Pipesim software, the parallel completion tend to give superior or the same production rate as the other two completions,

The more efficient desalting system in this completion makes it a better choice, yet it is not enough reason for it to be chosen, to decide better an economic study should be done.

III.2. Economic study:

III-2.1. Goal of the study:

The purpose of this economic study is to have an idea about the estimated cost and the projected gain in the case of planning parallel GLC completions on HRM field wells in the future.

The calculations below are based on the following data:

- Barrel price : 56.81 $, Conversion rate: 1 USD = 110 DZD
- Cost of renting a Workover rig: 2 058 198 DZD/Day
- Average cost of a Coiled tubing cleaning operation : 872 770 DZD
- Coiled tubing cleaning + Kick-off : 1 280 965 DZD
- Average cost of pumping water: 170 000 DZD/D, in average, 09 wells are treated per day, so the estimated pumping cost for a well is approximately 18 889 DZD.

III-2.2. Estimated Cost of implementing a Parallel Completion:

The (Table.III.56) represents the different equipments needed in the parallel completion prices.

Table.III-56. Cost of the equipment of the new completion

Equipment	Quantity	Unit price (DZD)	Total price (DZD)
Tubing head « dual string »	1	854562.26	854562.26
Tubing hanger « dual string »	1	467 173.90	467 173.90
Lock union 2 7/8	2	231819.64	463639.28
Tubing 2"7/8	200	23671.25	4734250
Concentric 1 660	200	**65705.57**	**13 141 114.00**
Telescopic seal 1 315	2	208184.8	416 369.60
SPM (Injection valve GL)	1	728559.99	728 559.99
Gas-lift valve	1	19 974.82	19 974.82
SPM (Switching valve). SBRO. 1SW	1	728559.99	728 559.99
Switching valve	1	93315.72	93 315.72
Dummy valve	1	20553.2	20 553.20
SPM (injection valve)	1	728559.99	728 559.99
Water injection valve	1	103528.08	103 528.08
Pulling Tool	1	57228.19	57 228.19
Kick over Tool	1	595026.51	595 026.51
Total			**23 152 415.53**

- Expenses of a Workover rig:

Estimated number of days for resumption of a well = 30 days

Total price = 30 * 2 058 198 = 61745 940 DZD

- Overall estimated cost:

Total cost = (Rig expenses + equipment cost)

= (61745 940 + 23 152 415.53)= **84898355.5 DZD**

If the servicing charges for the Workover are estimated at 20% of the total cost, the final cost of setting up a parallel GLC completion is equal to:

Total price = (84 898 355.5 DA)*1.2 = **101 878 026.6 DZD**

III-2.3. Calculation of cleaning operations expenses:

Frequent cleaning operations with Coiled tubing or water pumping are performed to dissolve the salt plugs and restore well production with the current HRM completions. The number of cleaning operations varies from one well to another depending on the frequency of salt clogging, which depends on the salinity and the amount of salty water produced. To illustrate the charges related to the cleaning operations (Table.III.57) and (Figure.III.15), five of the wells previously mentioned in the optimization part will be taken as example.

Table.III-57. Expenses related to cleaning operations

Wells	**Cleaning with CT**			**Pumping**			**Total cost (DA)**
	Number/year	Unit cost (DZD)	Total (DZD)	Number/year	Unit cost (DZD)	Total (DZD)	
HR162	6	872 770	**5 236 620**	48	18 889	**906 672**	**6 143 292**
HR202	7	872 770	**6 109 390**	120	18 889	**2 266 680**	**8 376 070**
HRE111	5	872 770	**4 363 850**	84	18 889	**1 586 676**	**5 950 526**
HR189	14	872 770	**12 218 780**	84	18 889	**1 586 676**	**13 805 456**
HRS20	24	1 280 965	**30 743 160**	-	-	-	**30 743 160**

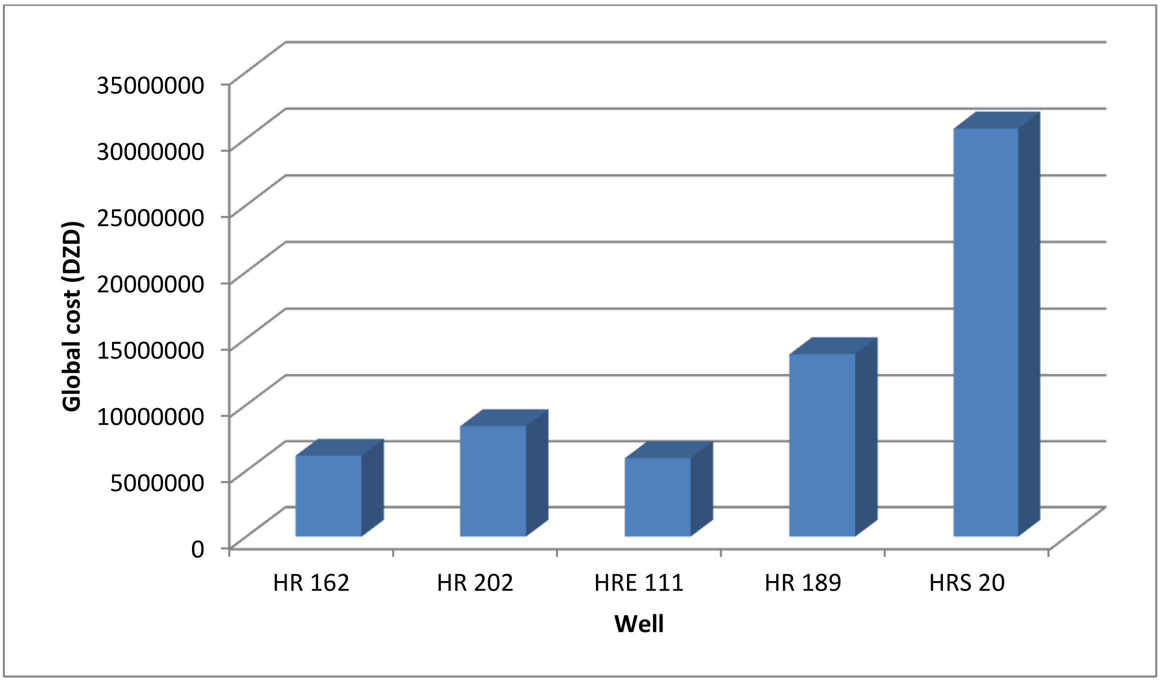

Figure.III-14. Annual expenses related to cleaning operations

According to this graph, the charges are high for the well HR189 and excessively high for the well HRS20. Activation of the HRS20 well with gas-lift in the future and the choice of parallel completion most likely will reduce these expensive cleaning operations with Coiled tubing

III-4.Calculation of production losses due to salt clogging :

Using the data collected from the engineering departement, the annual losses of each well is represented in (Table.III.58) and illustrated in (Figure.III.15) :

Table.III-58. Annual production losses

Wells	Production (m3/D)	Revenues ($/D)	Revenues (DZD/D)	Annual pauses (days)	Annual losses (DZD)
HR162	54.8	19 551	**2 150 590**	116	**249 468 471**
HRE202	26.6	9 490	**1 043 900**	174	**181 638 540**
HRE111	22.6	8 063	**886 922**	75	**66 519 170**
HR189	25.2	8 991	**988 958**	139	**137 465 102**
HRS20	66.4	23 689	**2 605 825**	155	**403 902 830**

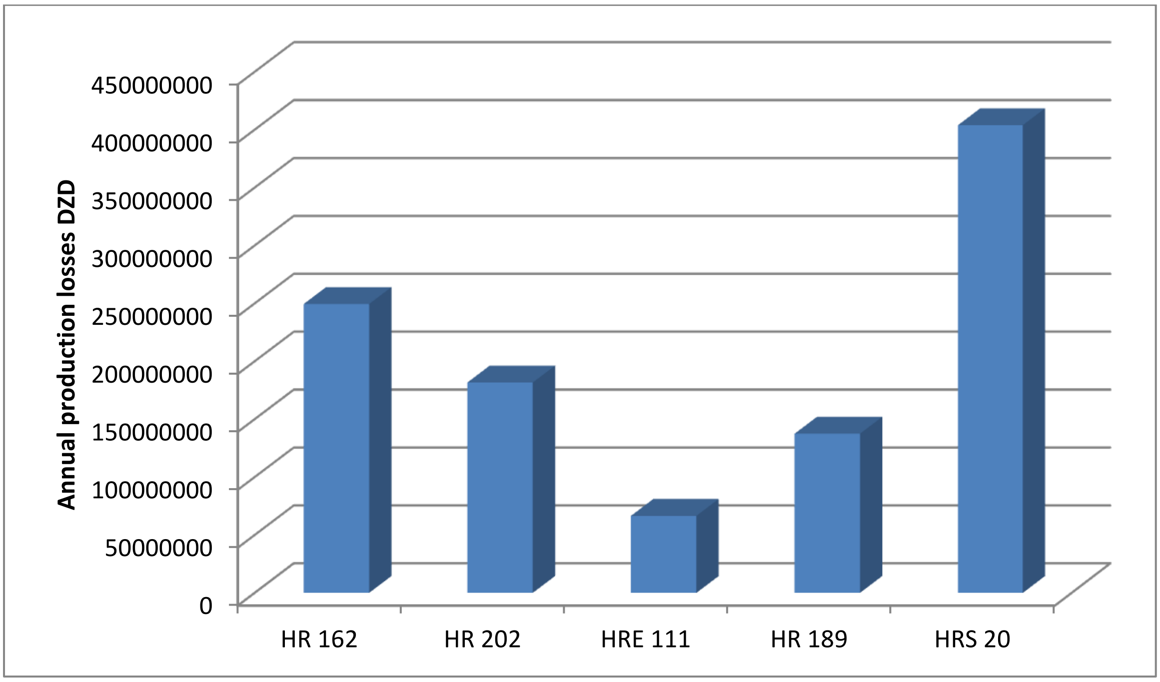

Figure.III-15. Annual production losses due to salt clogging.

III-2.5. The contribution of the new parallel completion:

Although the contribution in terms of production is not important by comparing the new parallel GL completion with the current completions (mixed injection & suspended tubing), the parallel completion offers the advantage of efficient desalting while reducing costly cleaning interventions and pauses due to salt plugging. For example, if the implementation of the new completion will reduce these annual charges by 60%, the probable annual gains are calculated in (Table.III.59) and compared in (Figure.III.16):

Table.III.59 Annual gains

Well	Estimated Cost of a Parallel Completion (DZD)	Current annual losses + charges (DZD)	Annual Gains (DZD)
HR162	101 878 027	255 611 763	153 367 058
HR202	101 878 027	190 014 610	114 008 766
HRE111	101 878 027	72 469 696	43 481 818
HR189	101 878 027	151 270 558	90 762 335
HRS20	101 878 027	434 645 990	260 787 594

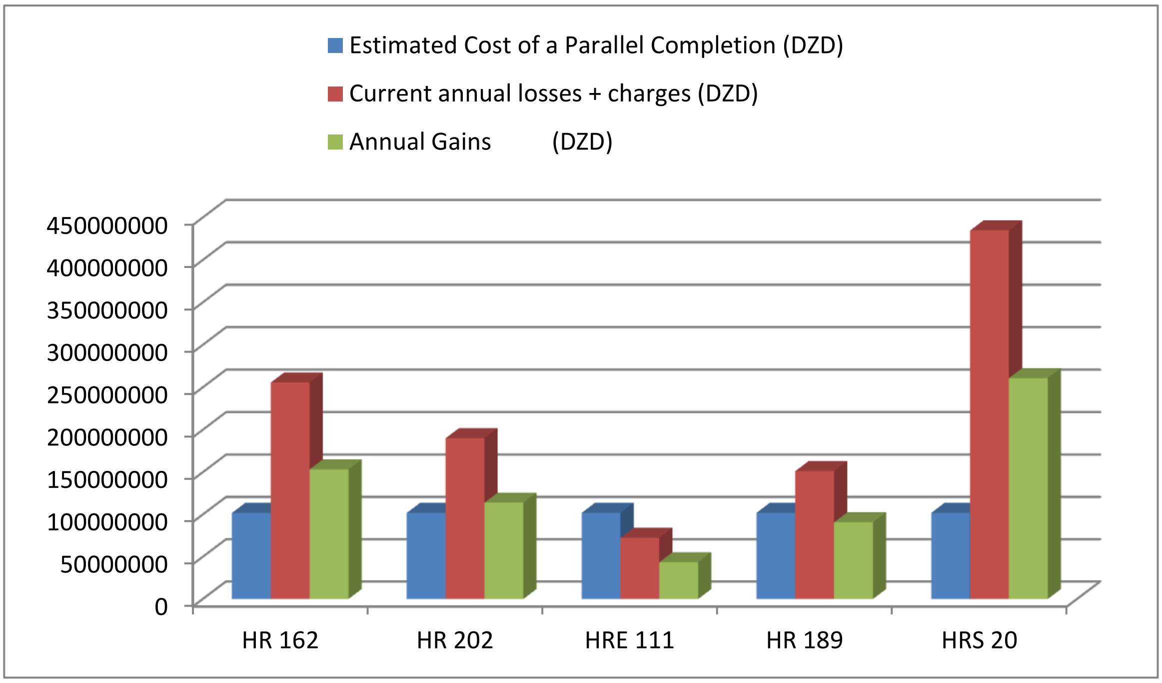

Figure.III-16. Presentation of the charges and gains returned by the implementation of parallel completions.

The annual gains from the clean-up operations and the current production losses almost cover the cost of a parallel completion except HRE111 and HR189 which have low potentials. The gain is remarkable for the HRS20 which has a good potential.[11]

III.2.6.Conclusion:

The cost of setting up a new parallel completion is similar to that of the Work over currently carried out at HRM for the implementation of a standard completion (suspended tubing). The advantages of parallel completion will be more and more significant if they are applied to oil wells of the South field after gas lift activation as shown by the example of well HRS20.

CONCLUSION AND RECOMMENDATIONS :

Conclusion

Based on the results obtained in the optimization study, the following conclusions are made :

- The desalination water flow rate is insufficient for some wells, which favors their clogging with salt. The calculation of these flows must be based on the salinity law and adjusted according to the behavior of the well.
- Parallel completion offers the advantage of efficient desalting by reducing costly cleaning operations and preventing shutdowns due to clogging. It also allows the BSB pumps to function properly since it avoids the problem of hydrates formation and the counter pressure caused by the high gas injection pressure.
- The difference in production rates between parallel and current completions is insignificant yet parallel completion ensures a more stable production due to the separation of gas and water injections.
- The optimization results show that the optimal tubing is 2 "7/8 for the majority of the oil rim wells, but the 3" 1/2 gives better results for the South field wells where the pressure of the deposit is relatively high.
- The parallel completion has two dimensions: 2 "7 / 8x1" 660 and 3 "1 / 2x1" 660, however the suspended tubing completion is limited to only 2 "7/8 tubing.
- The cost of a Parallel Completion Workover is not expensive and is close to the cost of a special completion currently used for separate injection.
- The economic study shows that the cost of a parallel completion can be covered in less than a year in good potential wells.

Recommendations

- Provide parallel completions for the southern area wells for their better desalination system.
- Measure dynamic parameters consistently to achieve better results.
- Optimize desalination water flow rates to avoid salt deposits .
- Select BSB injection pumps with good efficiency, to inject predetermined water flow rates.
- Increase the frequency of tests on the well for more data..
- Regular maintenance operation

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APPENDIX :

Appendix A : Well data

HRE 111

- **Data**

Well data :

$P_{reservoir}$ (Kg/cm2)	P_{tete}(Kg/cm2)	K (mD)	Hu (m)	Qo (Sm3/d)	Qe (Sm3/d)	GOR	Qginj (.E3 Sm3/d)	Wcut (%)
136	37.68	55	4	22.6	41.5	1347	10	64.7

- **Current completion**

Depth (m)	type	OD(in)	ID(in)
2218	casing	9.625	8.755
2163	Tubing	2.875	2.441
2238	Liner	7.000	6.184

- **Choice of correlation**:

	Beggs&Brill	Hagedorn & Brown	Duns & Ros	Mukherjee and Brill
$P_{\text{wellhead measure}}$ (kg/cm2)	37,68	37,68	37,68	37,68
$P_{\text{wellhead calculated}}$ (kg/cm2)	37,29	43,45	41,95	34.41
$\lvert \Delta P \rvert$ /Pm (%)	1.035	15,31	11,33	8,67

HR 189

- Well data:

$P_{reservoir}$ (Kg/cm2)	P_{tete}(Kg/cm2)	K (mD)	Hu (m)	Qo (Sm3/d)	Qe (Sm3/d)	GOR	Qginj (.E3 Sm3/d)	Wcut (%)
164	41.69	24.5	3.2	25.66	47.67	2465	23	65

- Current completion:

Depth (m)	Type	OD(in)	ID(in)
2117	Casing	7.000	6.184
2199.37	Tubing	2.875	2.441
2283	Liner	4.5	3.92

- Choice of correlation :

	Beggs&Brill	Hagedorn & Brown	Duns & Ros	Mukherjee&Brill	Orkiszewski
$P_{wellhead}$ me (kg/cm2)	41,69	**41,69**	41,69	41,69	41,69
$P_{wellhead}$ cal (kg/cm2)	39.31	**40,60**	51,62	36.27	34,57
$\vert\Delta P\vert$/Pm (%)	6,78	**2,61**	23,81	13	17,07

HR 202

- Data

$P_{reservoir}$ (Kg/cm2)	$P_{welhead}$(Kg/cm2)	K (mD)	Hu (m)	Qo (Sm3/d)	Qe (Sm3/d)	GOR	Qginj (.E3 Sm3/d)	Wcut (%)
230	43.34	60	2.5	52,58	166,53	394	23	76

- Current Completion

Depth (m)	Type	OD(in)	ID(in)
2147.5	Casing	7	5,92
2194.85	Tubing	2.875	2.441
2270	Liner	4,892562	5,785124

- Correlation choice

	Beggs&Brill	Hagedorn & Brown	Duns & Ros	Mukherjee and Brill
$P_{wellhead}$ measured (kg/cm2)	43.34	43.34	43.34	43.34
$P_{wellhead}$ calculated (kg/cm2)	35.83	43.36	44.87	30.16
$\vert \Delta P \vert$ /Pm (%)	7.51	0.02	1.53	13.18

The pressure obtained by the **Hagedorn & Brown** correlation is the closest.

HRS 20

Data matching :

$P_{wellhead}$(Kg/cm2)	Qo (Sm3/d)	Qw (Sm3/d)	GOR	Wcut (%)
21.09209	30.1	91.52	42	62.2

Reservoir data :

P_{res} (kg/cm^2)	K (mD)	Rayon drainage (m)	Hu (m)
218.8	29	500	3.25

- Current completion data

Depth (m)	Type	OD(in)	ID(in)
2077	Casing	7.000	6.184
1977.13	Tubing	3.500	2.75
2204	Liner	4.5	3.92

- Choice of correlation

	Beggs&Brill	Hagedorn & Brown	Duns & Ros	Mukherjee and Brill	Orkiszewski
Pwellhead measured (kg/cm2)	21.09209	21.09209	21.09209	21.09209	21.09209
Pwellhead calculated(kg/cm2)	21.264	21.120	21.4624	21.591	21.655
$\vert \Delta P \vert$ /Pm (%)	0,004	0,0004	0,0096	0,0036	0,022

HRE 207

- Well data:

$P_{reservoir}$ (Kg/cm2)	P_{tete}(Kg/cm2)	K (mD)	Hu (m)	Qo (Sm3/d)	Qe (Sm3/d)	GOR	Qginj (.E3 Sm3/d)	Wcut (%)
124	39.02	39	6.3	29.7	37.9	1366	23	56

- Current completion:

Depth (m)	Type	OD(in)	ID(in)
2207	Casing	9"5/8	8.393701
2199.37	Tubing	2.875	2.441
2280	Liner	7	6.004
2222,7	PLUG		

- Choice of correlation :

	Beggs&Brill	Hagedorn & Brown	Duns & Ros	Mukherjee&Brill	Orkiszewski
$P_{wellhead}$ me (kg/cm2)	39.02	**39.02**	39.02	39.02	39.02
$P_{wellhead}$ cal (kg/cm2)	35.66	**39,30**	42,46	34.90	54,73
$\lvert\Delta P\rvert$/Pm (%)	8,61	**0,71**	8,81	10,55	40,26

CASINGS/LINERS

	Section type	Name	From MD	To MD	ID	OD	Roughness
			m	m	in	in	in
1	Casing	Casing	0	2207	8,393701	9,64567	0,001
2	Liner	Casing 1	2093	2222,7	6,004	7	0,001

TUBINGS

	Name	To MD	ID	OD	Roughness
		m	in	in	in
1	Tubing	2000	2,441	2,875	0,001
2	Tubing 1	2199	3,92	4,5	0,001

TUBING

Name: Tubing

Grade: N80

Density: 8147,019 kg/m3

HRE104

- Well data:

$P_{reservoir}$ (Kg/cm2)	P_{tete}(Kg/cm2)	K (mD)	Hu (m)	Qo (Sm3/d)	Qe (Sm3/d)	GOR	Qginj (.E3 Sm3/d)	Wcut (%)
140	83.36	13.3	5.75	17.1	61.12	1445	23	78

- Current completion:

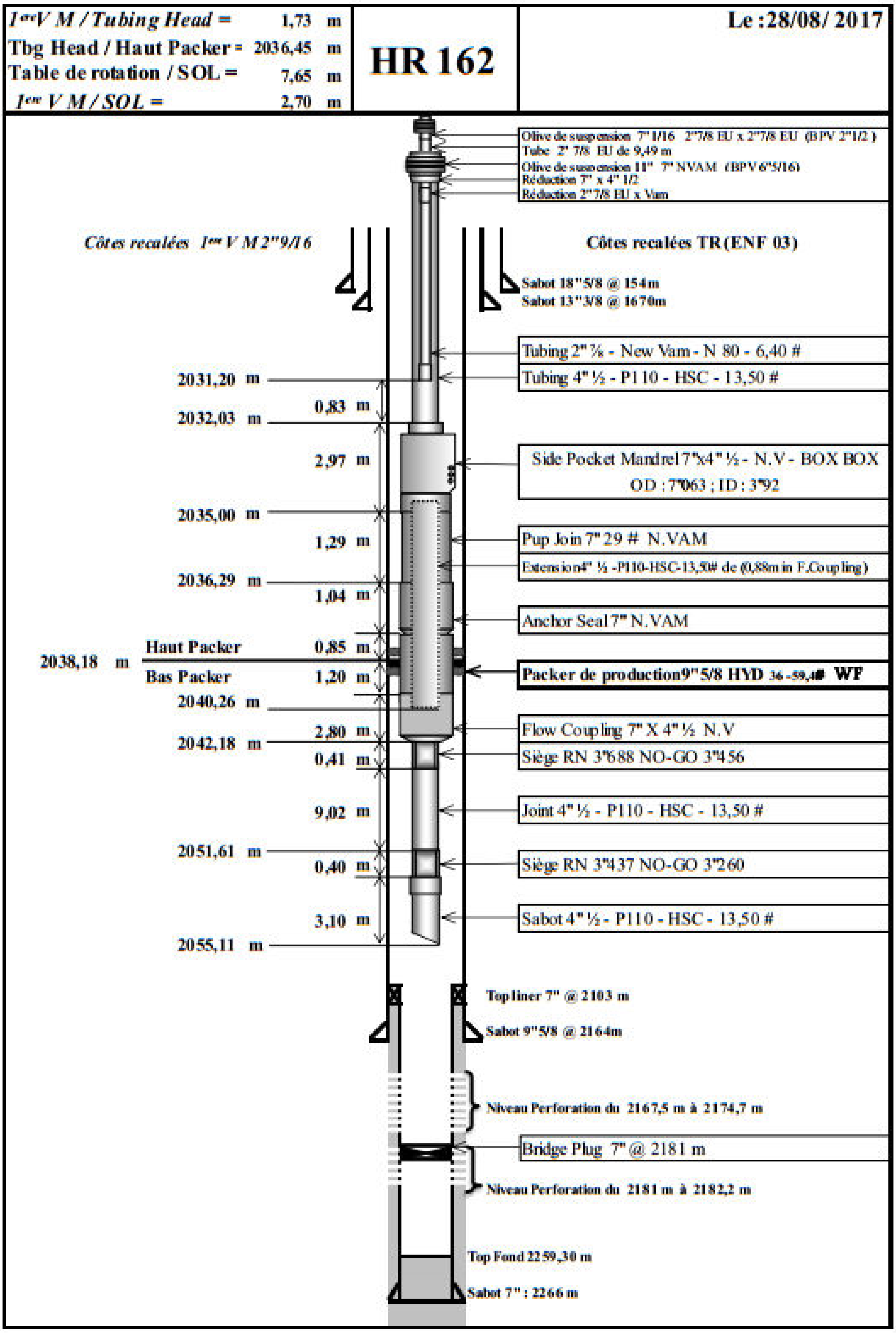
Depth (m)	Type	OD(in)	ID(in)
2218	Casing	7.000	6.184
1903	Tubing	2.875	2.441
2273	Liner	4.5	3.92

- Choice of correlation :

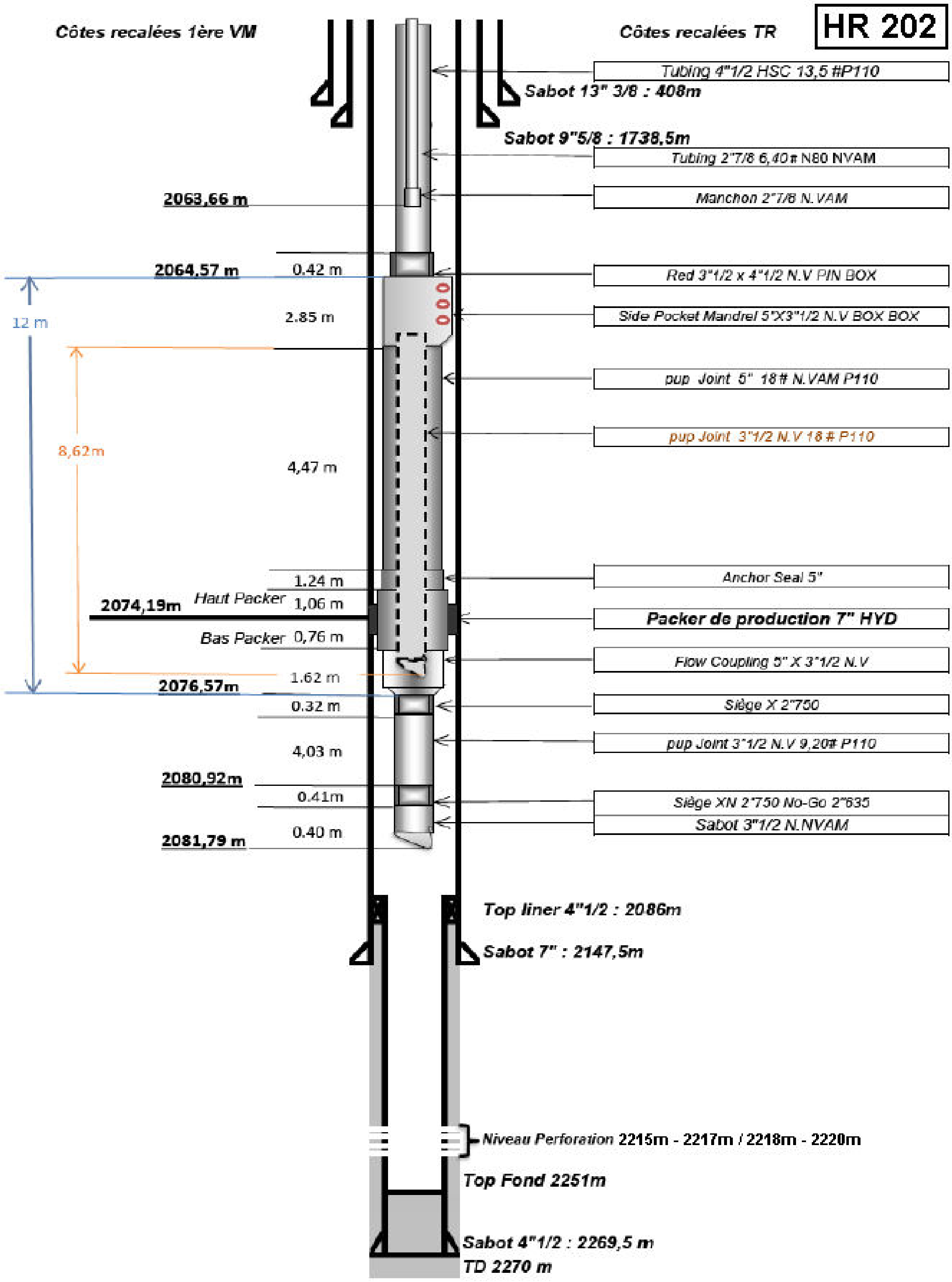
	Beggs&Brill	Hagedorn & Brown	Duns & Ros	Mukherjee&Brill	Orkiszewski
$P_{wellhead}$ me (kg/cm2)	83.36	83.36	83.36	83.36	83.36
$P_{wellhead}$ cal (kg/cm2)	81.31	**82,90**	91,62	78.27	76,57
$\lvert\Delta P\rvert$/Pm (%)	6,78	**2,61**	23,81	13	17,07

APPENDIX B : COMPLETION

HR 162

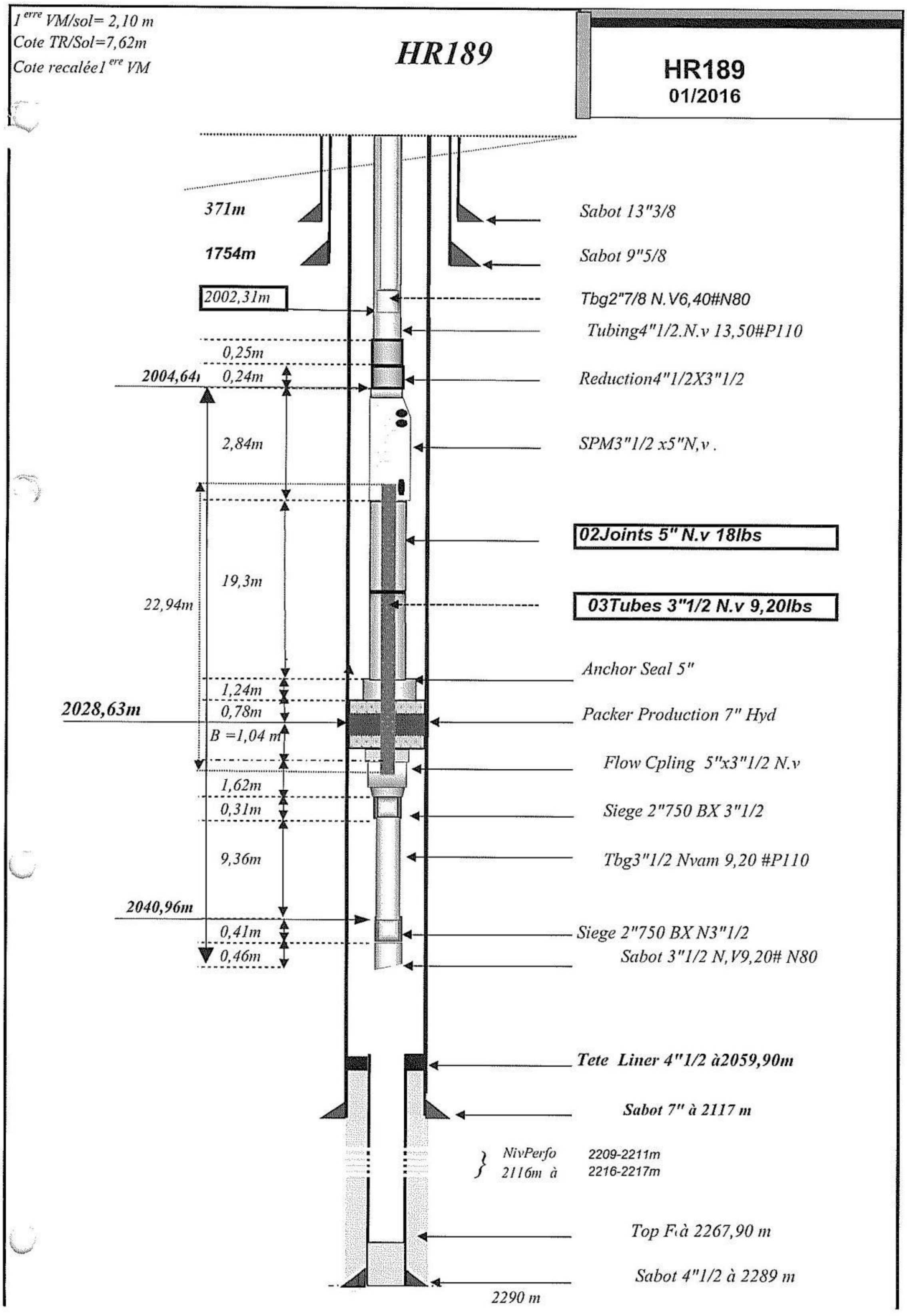


HR 202



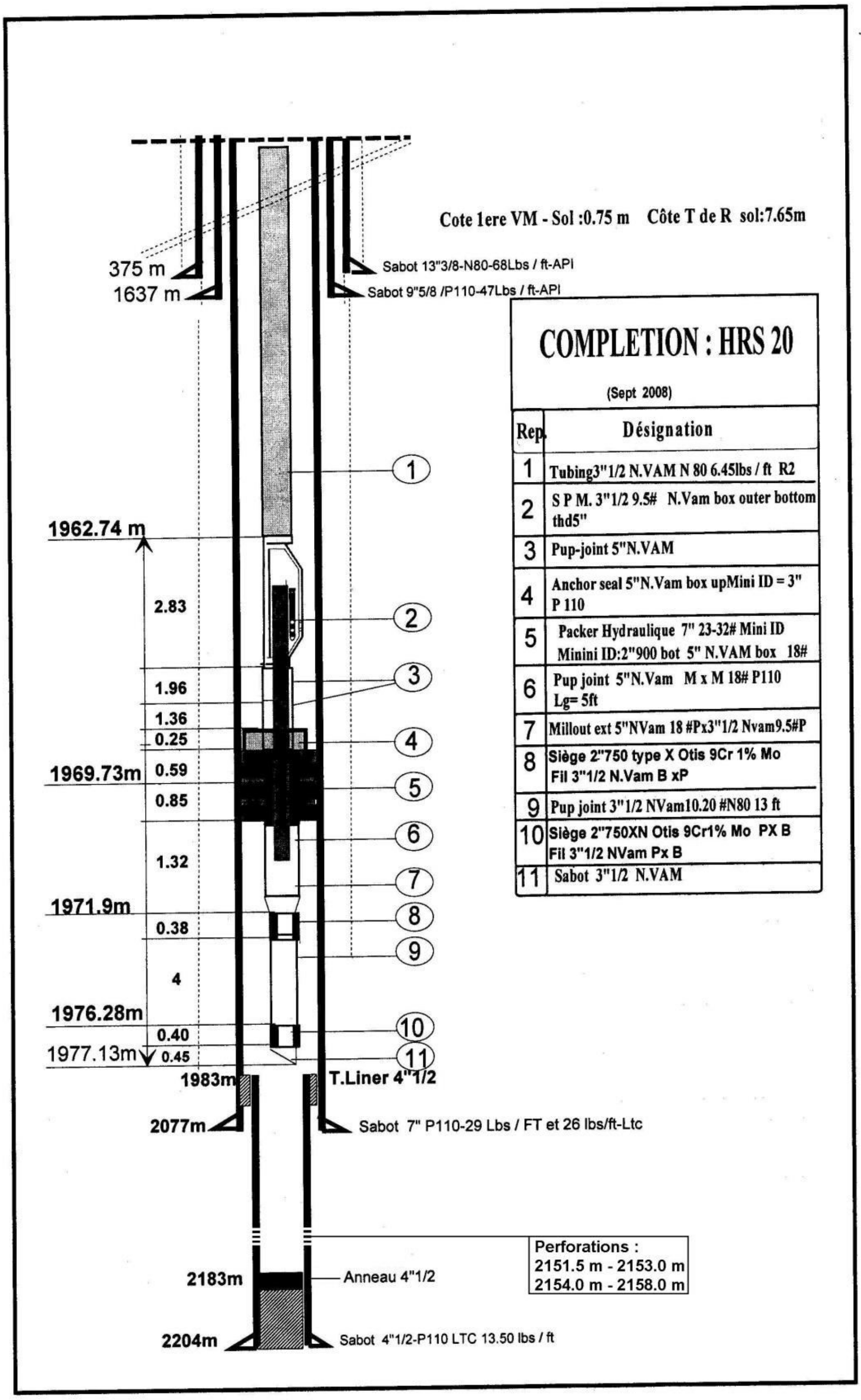
Côtes recalées 1ère VM
Côtes recalées TR
HR 202
Tubing 4"1/2 HSC 13,5 #P110
Sabot 13" 3/8 : 408m
Sabot 9"5/8 : 1738,5m
Tubing 2"7/8 6,40# N80 NVAM
2063,66 m
Manchon 2"7/8 N.VAM
2064,57 m
0.42 m
Red 3"1/2 x 4"1/2 N.V PIN BOX
12 m
2.85 m
Side Pocket Mandrel 5"X3"1/2 N.V BOX BOX
pup Joint 5" 18# N.VAM P110
8,62m
pup Joint 3"1/2 N.V 18 # P110
4,47 m
1.24 m
Anchor Seal 5"
2074,19m
Haut Packer
1,06 m
Packer de production 7" HYD
Bas Packer
0,76 m
Flow Coupling 5" X 3"1/2 N.V
1.62 m
2076,57m
0.32 m
Siège X 2"750
4,03 m
pup Joint 3"1/2 N.V 9,20# P110
2080,92m
0.41m
Siège XN 2"750 No-Go 2"635
0.40 m
Sabot 3"1/2 N.NVAM
2081,79 m
Top liner 4"1/2 : 2086m
Sabot 7" : 2147,5m
Niveau Perforation 2215m - 2217m / 2218m - 2220m
Top Fond 2251m
Sabot 4"1/2 : 2269,5 m
TD 2270 m

HR189



1erre VM/sol= 2,10 m
Cote TR/Sol=7,62m
Cote recalée1ere VM
HR189
HR189
01/2016
371m
1754m
2002,31m
0,25m
2004,64
0,24m
2,84m
19,3m
22,94m
1,24m
2028,63m
0,78m
B =1,04 m
1,62m
0,31m
9,36m
2040,96m
0,41m
0,46m
Sabot 13"3/8
Sabot 9"5/8
Tbg2"7/8 N.V6,40#N80
Tubing4"1/2.N.v 13,50#P110
Reduction4"1/2X3"1/2
SPM3"1/2 x5"N,v .
02Joints 5" N.v 18lbs
03Tubes 3"1/2 N.v 9,20lbs
Anchor Seal 5"
Packer Production 7" Hyd
Flow Cpling 5"x3"1/2 N.v
Siege 2"750 BX 3"1/2
Tbg3"1/2 Nvam 9,20 #P110
Siege 2"750 BX N3"1/2
Sabot 3"1/2 N,V9,20# N80
Tete Liner 4"1/2 à2059,90m
Sabot 7" à 2117 m
NivPerfo
2116m à
2209-2211m
2216-2217m
Top F. à 2267,90 m
Sabot 4"1/2 à 2289 m
2290 m

HRS 20



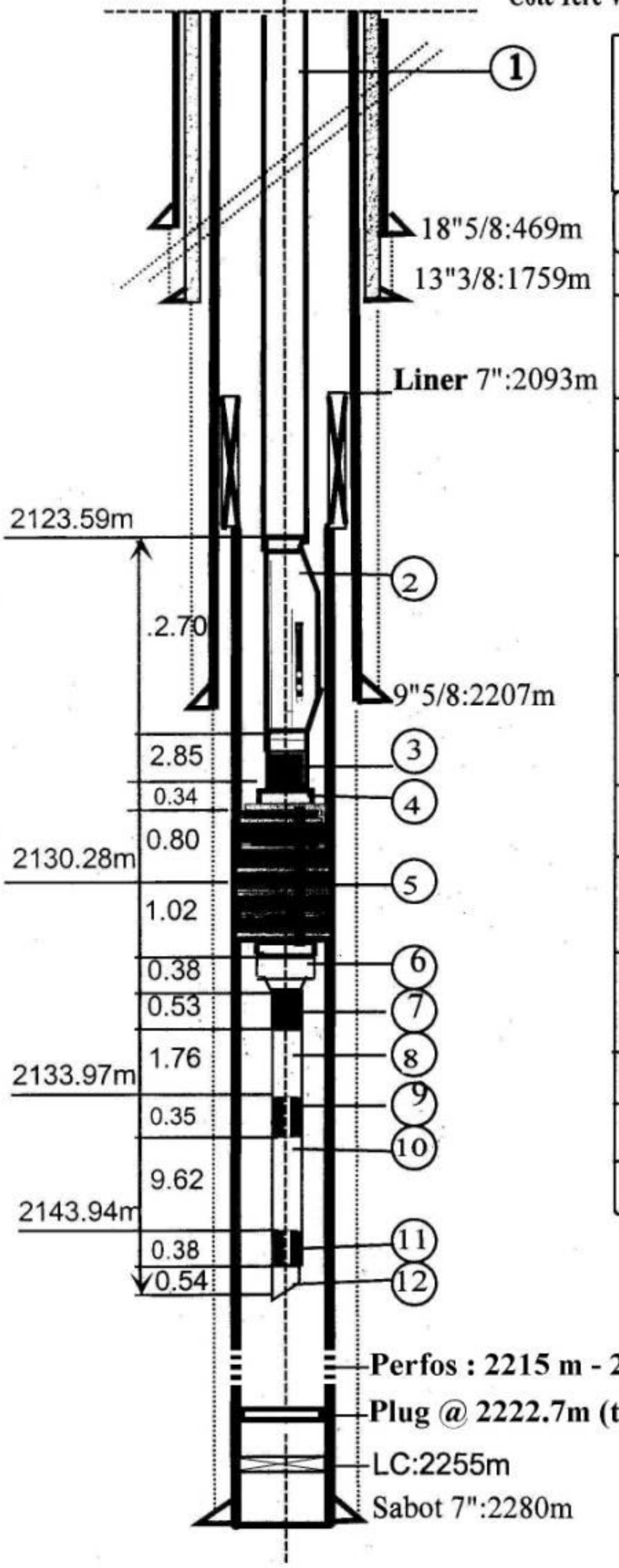
COMPLETION : HRS 20

(Sept 2008)

Rep.	Désignation
1	Tubing3"1/2 N.VAM N 80 6.45lbs / ft R2
2	S P M. 3"1/2 9.5# N.Vam box outer bottom thd5"
3	Pup-joint 5"N.VAM
4	Anchor seal 5"N.Vam box upMini ID = 3" P 110
5	Packer Hydraulique 7" 23-32# Mini ID Minini ID:2"900 bot 5" N.VAM box 18#
6	Pup joint 5"N.Vam M x M 18# P110 Lg= 5ft
7	Millout ext 5"NVam 18 #Px3"1/2 Nvam9.5#P
8	Siège 2"750 type X Otis 9Cr 1% Mo Fil 3"1/2 N.Vam B xP
9	Pup joint 3"1/2 NVam10.20 #N80 13 ft
10	Siège 2"750XN Otis 9Cr1% Mo PX B Fil 3"1/2 NVam Px B
11	Sabot 3"1/2 N.VAM

HRE 207

Côte 1ere VM-Sol :1.16 m   Côte T de R sol:7.62m



DIR/EP/PREP/MAT/PUITS

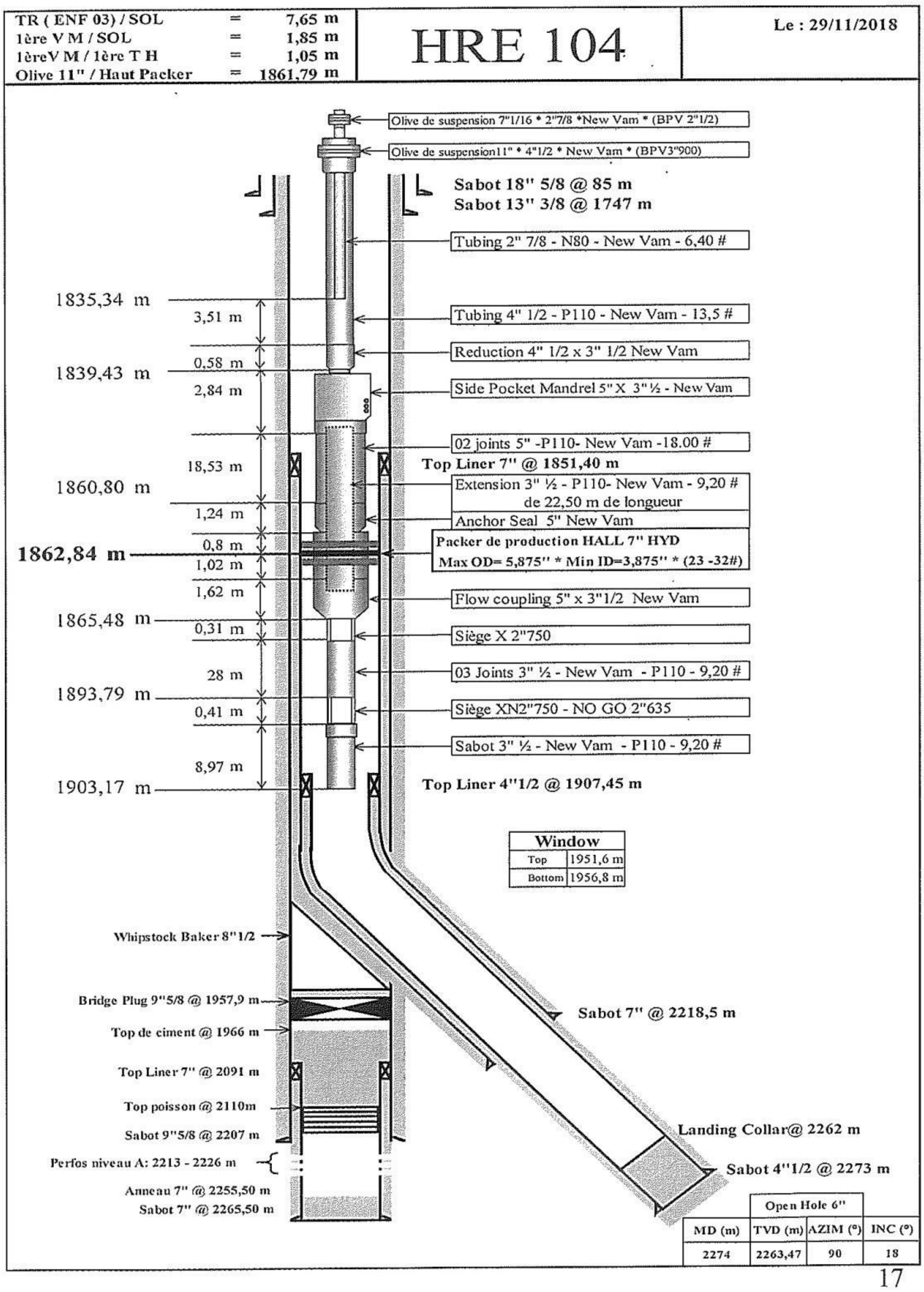
COMPLETION : HRE207

PUITS-D,HUILE - INJD,EAU S/PACKER. Jan 04

Rep.	Désignation
1	Tubing 2"7/8 N.VAM N80 6,40lbs/ft R2
2	S P M. Hallib. 2"7/8 SFO-2H injection Mandrel 2"7/8 6,40 # N.VAM box x 4"1/2 N.VAM box 12,60 #.
3	Pup-joint 4"1/2 N.VAM 12,60# pin x pin.
4	Ratch-latch 'RLN' locator-sub OD.5"250 ID.3"938 fil. 4"1/2 N.VAM box
5	Packer Hallib. 7" 23-32 # x 5.000 (hydraulic) 4"1/2 N.VAM 12,60# x 5" N.VAM 18# Box x box OD.5"875 ID. 3"881.
6	Réduction 5" N.VAM F x 4"1/2 N.VAM F
7	Pup-joint 4"1/2 N.VAM 12,60# pin x pin.
8	Flow-coupling adapter 4"1/2 N.VAM 12,60# Box x 2"7/8 N.VAM 6,40# pin OD. 4"911 ID. 2"360.
9	Siège Hallib 2"313 type X Fil 2"7/8NV M x F maxi OD. 3"260 mini ID. 2"313 Mat. 9Cr 1Mo Réf. 711X23150.
10	Tubing 2"7/8 N.VAM 6,40 # N80
11	Siège Hallib 2"313 type XN Fil 2"7/8NV Pin x box OD 3"260 ID2"205mat 9Cr1Mo
12	Sabot 2"7/8 Vam

HRE 104

FICHE TECHNIQUE PUITS HRE 104



APPENDIX C: GAS LIFT

Artificial Lift Methods:

Most oil reservoirs are of the volumetric type where the driving mechanism is the expansion of gas when reservoir pressure declines because of fluid production. Oil reservoirs will eventually not be able to produce fluids at economical rates unless natural driving mechanisms (e.g., aquifer and/or gas cap) or pressure maintenance mechanisms (e.g., water flooding or gas injection) are present to maintain reservoir energy. The only way to obtain a high production rate of a well is to increase production pressure drawdown by reducing the bottom-hole pressure with artificial lift methods.

Approximately 50% of wells worldwide need artificial lift systems. The commonly used artificial lift methods include sucker rod pumping, Gas lift and Electrical submersible pumping.

Each method has applications for which it is the optimum installation. Proper selection of an artificial lift method for a given production system requires a thorough understanding of the system.

GAS LIFT:

Gas Lift is one method of artificial lift, where Gas is injected continuously or intermittently at selected location(s). Resulting in a reduction in the natural flowing gradient of the reservoir fluid, thus reducing the hydrostatic component of the pressure difference from the bottom to the top of the well.

The basic objective of gas-lift design, as stated by McWilliams in the discussion of Lake's paper, is to ‘’ equip our wells in such a manner as to compress a minimum amount of gas to produce a maximum amount of oil. ’’Lake (1927) noted that oil production by gas lift can be controlled by changing gas volumes, injection depth, wellhead pressure, and tubing size.

PRINCIPAL OF GAS LIFT:

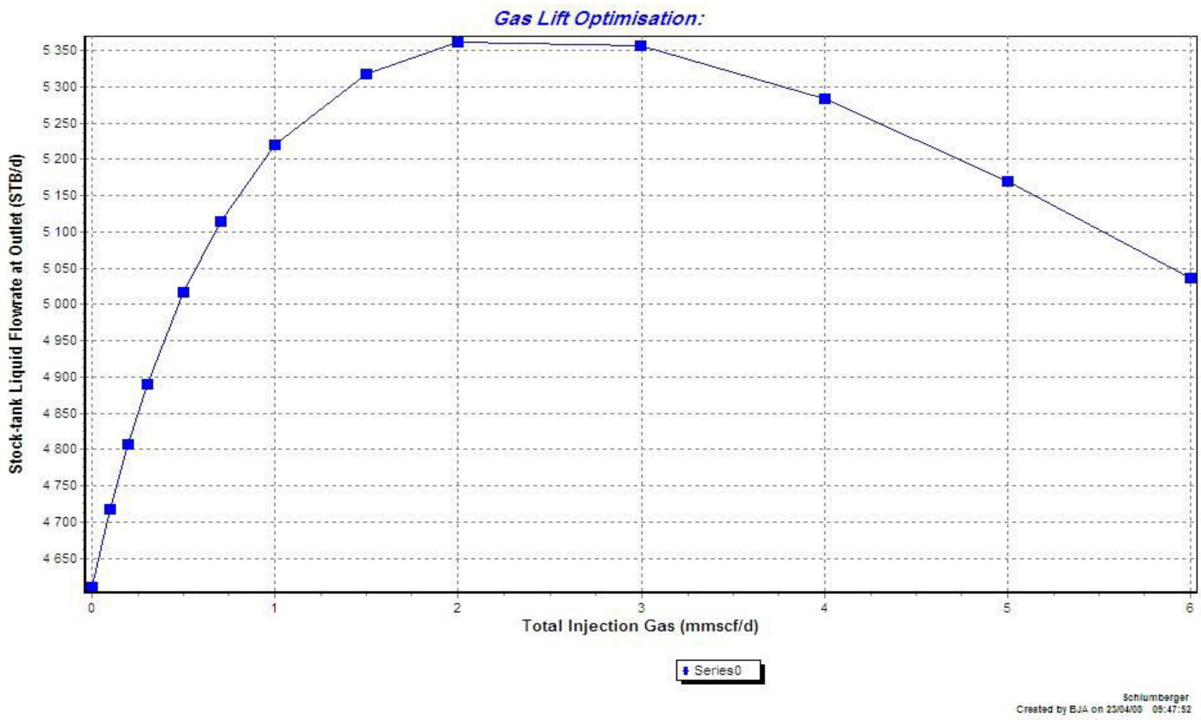
Gas lift technology increases oil production rate by injection of compressed gas into the lower section of tubing through the casing–tubing annulus and an orifice installed in the tubing string. Upon entering the tubing, the compressed gas affects liquid flow in two ways:

(a)the energy of expansion propels (pushes) the oil to the surface .

(b)the gas aerates the oil so that the effective density of the fluid is less and, thus, easier to get to the surface.

Gas lift technology has been widely used in the oil fields that produce sandy and grassy oils. Crooked/deviated holes present no problem. Well depth is not a limitation. It is also applicable to offshore operations. Lifting costs for a large number of wells are generally very low.

Two other considerations must enter the design. First, large amounts of gas injected into the well will affect the separation facilities at the top. Second, there exists a limit gas-liquid ratio (GLR) above which the pressure difference in the well will begin to increase because the reduction in the hydrostatic pressure will be offset by the increase in the friction pressure



TYPES OF GAS-LIFT:

According to the injection mode

There are two basic types of gas lift used in the oil industry. The continuous flow gas lift and the intermittent gas lift

- **Continuous gas lift** :

  A continuous gas lift operation is a steady-state flow of the aerated fluid from the bottom (or near bottom) of the well to the surface. In continuous flow a continuous volume of high pressure gas is introduced into the production tube to aerate or lighten the fluid column until reduction of the bottom hole pressure will allow a sufficient differential across the sand face, causing the well to produce the desired rate of flow. To accomplish this, a flow valve is used that will permit the deepest possible injection point of available gas lift pressure in conjunction with a valve that will act as a changing or variable orifice to regulate gas injected at the surface depending upon tubing pressure. This method is used in wells with a high productivity index and a reasonably high bottom hole pressure relative to well depth.

- **Intermittent gas lift** :

  Intermittent gas lift operation is characterized by a start-and-stop flow from the bottom (or near bottom) of the well to the surface. Intermittent flow involves expansion of a high pressure gas ascending to a low-pressure outlet. A valve with a large port permits complete volume and pressure expansion control of gas entering into the tubing, thus either regulating lift of the accumulated fluid head above the valve with a maximum velocity to minimize slippage or controlling liquid fall back, fully ejecting it to the tank with minimum gas. Generally used in conjunction with a surface time cycle controller, intermittent lift is used on wells that have the following characteristics:

1. High PI with low bottom hole pressure ;or
2. Low PI with low bottom hole pressure.

   In intermittent lift, gas is injected at regular intervals by the controlling (a motor valve operated by a connecting timing device that permits selective cycling with controlled gas injection into the casing annulus). The cycling is regulated to coincide with fluid fill-in rate from the producing formation into the well bore.

Note: Continuous gas lift method is used in wells with a high PI (0:5 stb=day=psi) and a reasonably high reservoir pressure relative to well depth. Intermittent gas lift method is suitable to wells with (1) high PI and low reservoir pressure or (2) low PI and low reservoir pressure.

Depending on the surface injection circuit:

The gas used comes either from the formation gas of the oil reservoir considered, or neighboring gas wells, and we distinguish:

a) Gas - lift in closed circuit :

Most gas lift systems are designed to recirculate the gas. The low-pressure gas from the production separator is piped to the suction of the compressor station. The high-pressure gas from the discharge of the compressor station is injected into the well to lift the fluids from the well.

b) Gas-lift in open circuit:

The gas used for the gas lift is burned with a torch or marketed after use. In this case, the injected gas comes from another gas field.

c) Auto–gas lift

If the completion of the well permits, the reservoir oil is lifted by the gas produced from a gas reservoir located above and penetrating into the production column by perforation and injection device between two packer.

N.B: For the exploitation of the oil rim of Hassi R'mel, the type of gas-lift used in the majority of the activated wells is a continuous open circuit gas-lift.

APPLICATIONS OF GAS-LIFT:

Gas lift offers many applications and about 20% of production wells in the world are involved in this mode of activation.

1. **To increase production rates in flowing wells*:***

For wells suffering from a decline in pressure but still able to produce without resorting to activation, and which are characterized by a GOR or GLR naturally lower than the average, the gas lift will increase their production compared to natural production.

2. **To enable wells that will not flow naturally to produce. *:***

In the case of a well unable to discharge its own energy (depleted), the gas lift, causes a reduction in the bottom pressure and facilitates the circulation of the effluent to the surface.

3. **To unload a well that will later flow naturally*:***

Sometimes eruptive wells cannot restart after neutralization. They must then be activated in order to regain their eruptivity. If these wells were originally equipped with mandrels, then they can be restarted with high pressure gas.

THE MAIN PARAMETERS OF GAS-LIFT

a) Pressure at the wellhead:

The lower the head pressure, the less gas will be required to produce the same amount of fluid. In addition, a small volume of injected gas makes it possible to have few compact surface installations, thus decreasing the pressure of the collections.

b) Injected gas pressure:

The pressure of the injected gas affects the number of discharge valves. Thus, a high pressure can make it possible to operate without a single point discharge valve. This greatly simplifies well design, operations and maintenance.

When the available pressure is low, it is recommended to increase it for a few hours from 10 to 15 bars to kick off the well.

c) Depth of gas injection

A deep injection point brings a marked improvement in well production, especially for wells with high PI.

To improve the efficiency of the injected gas, there are three main parameters: Injection pressure, injection rate and injection depth. The latter is determined from the pressure gradient of the flow, the deeper the point of injection is, the more the injected gas is effective.

d) High PI and Skin effect:

The productivity of a well depends directly on the draw-down. And thus the bottom pressure. Gas-lift activation reduces this pressure.

Skin effect is the damage of the first centimeters of the reservoir. The effect of skin has the direct effect of reducing the PI and must be fought by one of many known processes such as acidification, re-perforation, etc… A well with a low PI needs a larger amount of gas.

Advantages and Limitations of Gas Lift:

- Advantages:

- ✓ Well suited to medium or high flow rates.
- ✓ Well suited to wells has good IP and relatively high background pressure.
- ✓ Applicable for wells with a relatively high GLR.
- ✓ Initial costs may be low if a source of high pressure gas is available (as in the case of HRM where there is no need to install compressors).
- ✓ Possibility of injecting an additive (corrosion inhibitor for example) at the same time as the gas.
- ✓ Start and control of surface production
- ✓ A crouched\deviated holes present no problem: current reliability of gas lift equipment on wells with a deflection up to 50 °.
- ✓ Durable with few moving parts

-Limitations:

- ✗ It requires gas within or near the oil fields; Gas volumes may be excessive for wells with a high percentage of water.
- ✗ Not applicable in casing in bad condition.
- ✗ Handling of high pressure gas, which can be expensive and carries risks (safety).
- ✗ Foaming problems that can be increased.
- ✗ Low efficiency in deep wells.
- ✗ Requires treatment in case of formation of hydrates, where gas needs to be treated either by dehydration or by injection of methanol.

- Corrosive gas can increase the cost of gas lift operations if it is necessary to treat the dry gas before use, or implement special steel completions.

Gas-lift equipments:

Most gas lift systems are designed to re-circulate the gas for lifting.

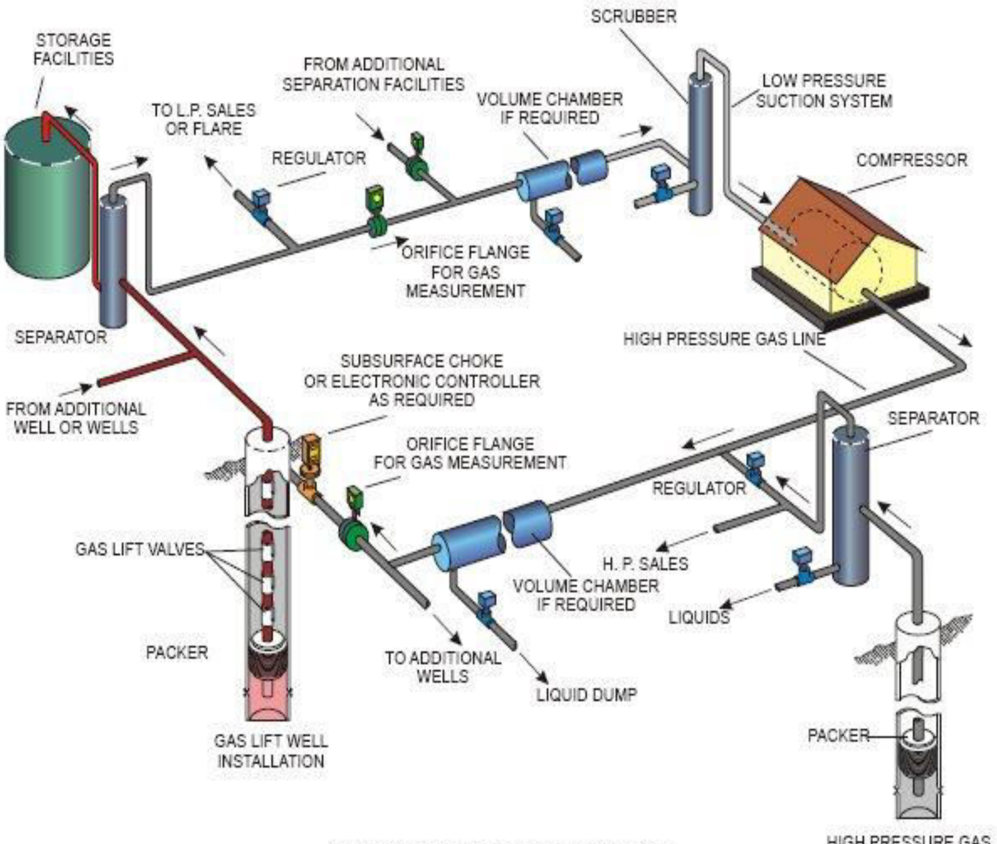
The low pressure gas coming from the stations is compressed to be partially re-injected in wells for lifting purposes.

- Equipments are divided into two categories :

A/ Surface equipments

B/ Subsurface equipments

SURFACE EQUIPMENTS:



Basic Components for a Gas Lift System

Surface equipments consist of:

1. Compression plant.
2. A high pressure distribution network.
3. Metering and control equipments (gauges and flow regulators, block valves, etc.)
4. Low pressure fluids gathering network.
5. Dehydration equipment.

N.B: In Hassi R'mel the gas pressure coming from the pumping station is very high (150bars), so compression plants are not needed.

a) compression plant :

The low pressure gas coming from crude oil gathering station is compressed and sent to the high pressure network distribution, the compressor can be centrifugal (turbine) or reciprocating compressor,

Reciprocating compressors are more commonly used due to their flexibility to work under changing conditions and their applicability to smaller volumes; they size up to 20000 hp and pressure varying from vacuum pressure at the suction to more than 30000 psi at the discharge.

They are not sensitive to changes in gas composition and density

b) A high pressure distribution network :

It consists of a pipe system that can work at very high pressures; this system distributes gas for all wells connected to this system.

c) Metering and Control Equipment

- There are different types of gas metering instruments:

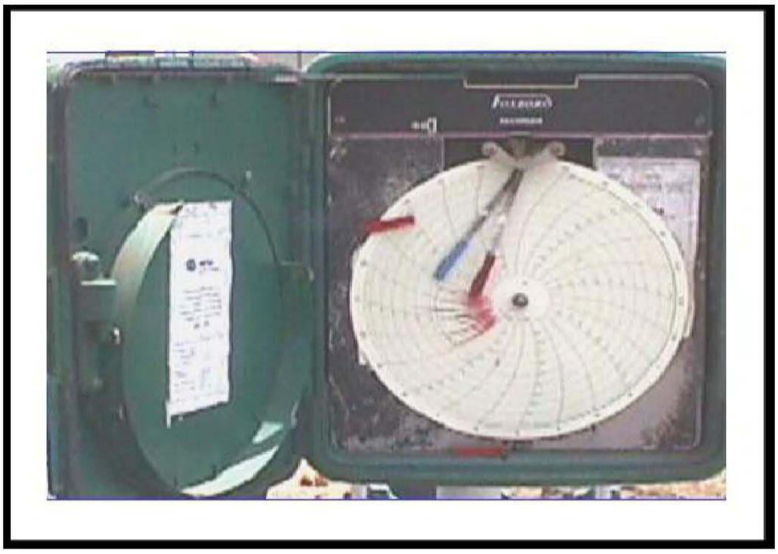
✓ The device used worldwide to measure injection gas is the orifice plate

✓ The orifice meter is an instrument of differential metering to measure gas and liquid with an error of 2% and consists of two pressure measurements: static pressure and differential which are connected to a flange or orifice fitting.

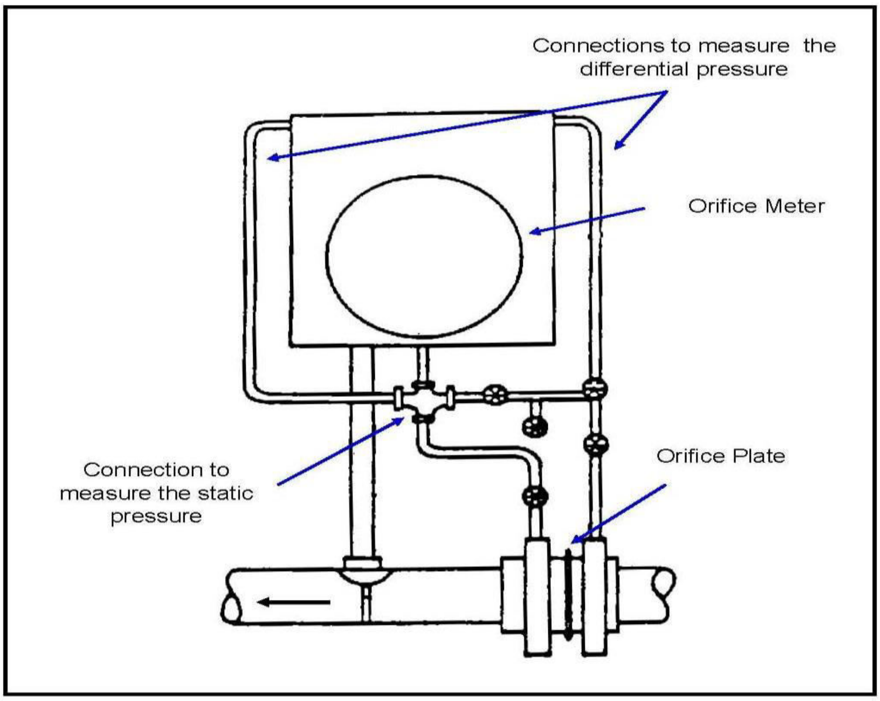
- The orifice meter uses two types of charts:

1- Standard orifice meter chart where the differential and static pressure is directly read.

2- Square root chart: very popular in gas lift, it uses logarithmic scale and allows the operator to determine the volume of gas using the orifice meter equation.FIG



- It has a surface gauge with two indicator needles through which the injection and production pressures are measured.- It also has the block valves to control the back flow that can be generated In Hassi R'mel, an electronic flow measurement system is



used to send the flow records through radio waves (the SCADA system).

d) Low pressure gas gathering network:

It is comprised by flow lines that transport the produced fluids to the separator; where, the liquid phase is separated and transported to the storage tanks, the gas phase is sent to the compression plant.

e) **Dehydration Equipment:**

Natural gas has important quantities of water vapor due to the presence of connate water in the reservoir. The gas capacity to contain water in the vapor phase will depend greatly on the gas pressure and temperature. As gas cools down, it loses its property to contain water in the vapor state: this property is reduced as temperature increases. Subsequently, the water vapor must be removed from the gas used for lifting to prevent formation of liquids in the gas distribution system.

The presence of liquids in the gas distribution system can cause formation of hydrates, which are solid compounds resulting from the reaction between the natural gas and the water. A hydrate is formed by 10 % hydrocarbon and 90% water approximately, and it can plug valves, lines and orifices.

In distribution systems that have fractions of acid gases, such as CO_2 and H_2S , the formation of liquids needs to be avoided as much as possible since these can accelerate corrosion in gas distribution facilities, well casing and production tubing.

Dehydration of natural gas can be performed through absorption and adsorption process. The absorption process implies that the gas current will pass through a liquid desiccant having a strong affinity for water.

In the adsorption process, the gas flows through a bed of granulated solids called solid desiccants.

The dehydration system most commonly used in the oil industry, especially in artificial gas lift operations, is the absorption process. The desiccant used in these systems is generally a solution of one glycol, generally Diethylene glycol (DEG) or Triethylene glycol (TEG).

NOTE: In the case of an intermittent gas lift, the surface equipment requires the presence of an intermittent which allows:

• The adjustment of the periodicity of the injections.

• Setting the duration of the injection.

SUBSURFACE EQUIPMENT:

- Comprised basically of Mandrels and the gas lift valves.
- Numbers of Mandrels will depend on the depth of the well and the injection pressure available at surface.

a) **Mandrels for Gas Lift Valves:**

The mandrel is a specially designed pipe with the objective of allowing the valve to settle it has threaded ends so it can be connected to the well production string and be an integral part of it, there are two basic types of mandrels for gas lift valves and each one has two different variants in turn.

a)1- **Tubing retrievable mandrels :**

They have external supports to install the gas lift valve. This mandrel is threaded to the production tubing, like a short pipe, being an integral part of the production tubing. It is necessary to pull the tubing string to remove the valve.

a)-2- **Pocket mandrels:**

They have an inner pocket that allows the gas lift valve to seat and to be retrieved with the use of special wireline-operated tools.

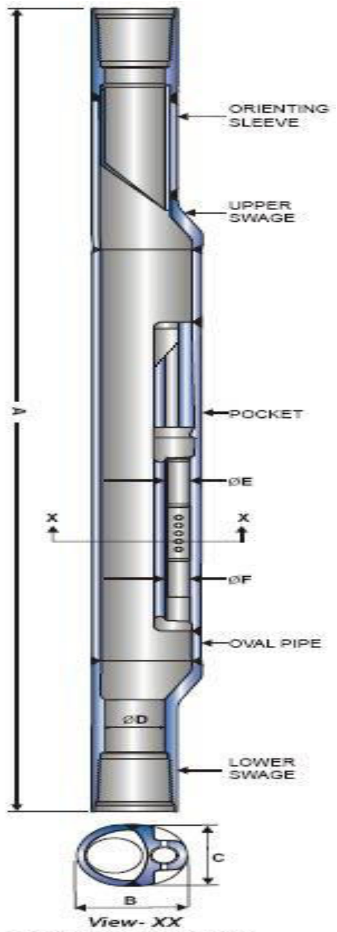
This type of mandrel was introduced by Camco, in 1957.

The mandrel has pockets with different designs.

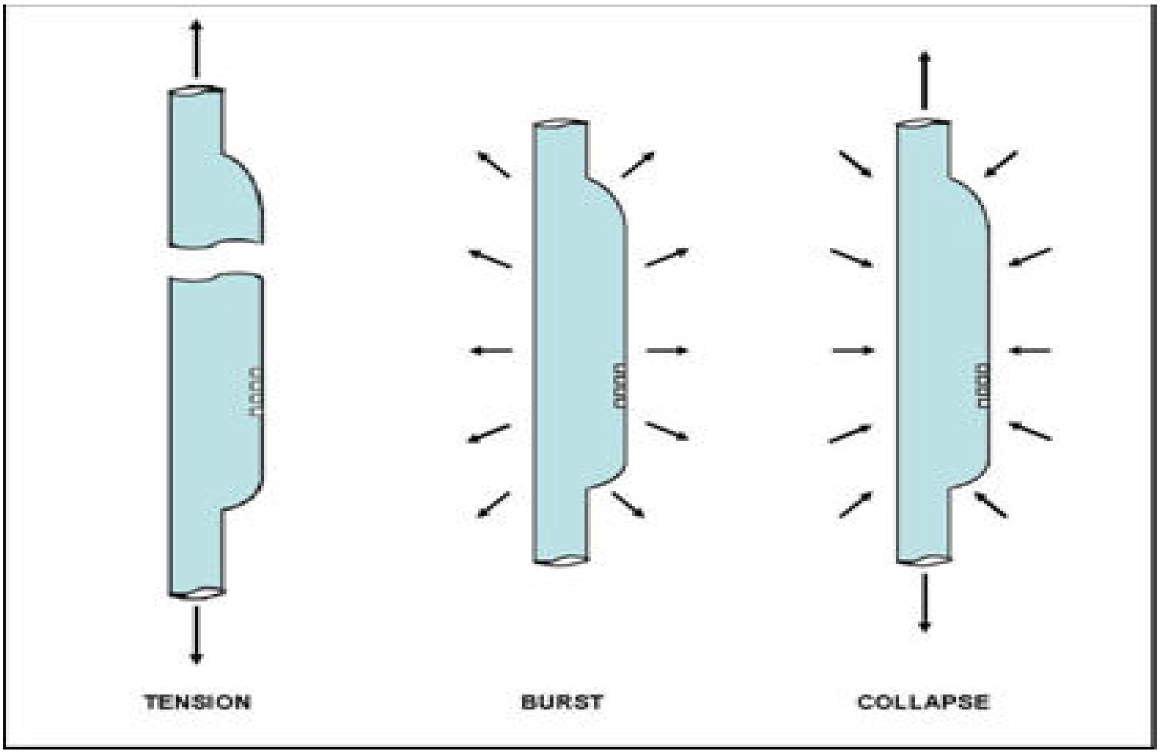
The mandrel size will depend on the diameter of production tubing. Commonly, the diameters of production tubing used are: 2 3/8'', 2 7/8 '' and 3 ½ ''. The mandrels are classified depending on the size of the valve: ''K'' series mandrels for valves with 1''

OD; ‘’M’’ series mandrels for valves with 1 ½’’ OD (recommended the most to lift high production rates).

Due to the different stresses the mandrels are subjected to, their design must be failure proof against tension (caused by excessive weight on the string), burst (caused by an excessive inner pressure) and collapse (caused by the combination of weight on the string and external pressure).



View- XX
TP Series Mandrel for 1-1/2" OD Valve (Welded Swages)



b) Gas Lift Valves:

The valves are very important elements in the gas injection system; their function is to regulate gas passage. The gas volume that passes through the orifice will depend on the differential pressure existing. The orifice size ranges between ¼ ‘’ to 1 ‘’ in diameter. The mechanical principle of valves is identical in wells flowing through the annulus and the tubing. Gas lift valves are classified according to the pressure that has the greatest effect on their opening. Under continuous flow, the valve that is used must be sensitive to the tubing pressure when it is open. Under intermittent flow, any type of valve can be practical.

b) 1. Operating principle:

The operating principle of a gas lift valve can be perfectly compared to a pressure regulator. The valve and the regulator have in common a load element, a reaction element, a drive element, a body and an orifice. If we compare both devices, the only difference would be the elongated shape of the valve needed for the borehole installation. However, in terms of the basic components, the valve and the regulator are the same.

Load element: Generally, a bellows loaded with gas (nitrogen). However, many valves are designed and built using springs as load elements .Some valves also use a combination of springs and bellows as load elements

Drive element: All gas lift valves use bellows as the drive element, even when the load element is a spring. The bellows are made of two or three monel folds and they are designed to act like springs. Most bellows have a protection, such as liquids, plastic rings or other mechanisms to prevent deformation or flattening.

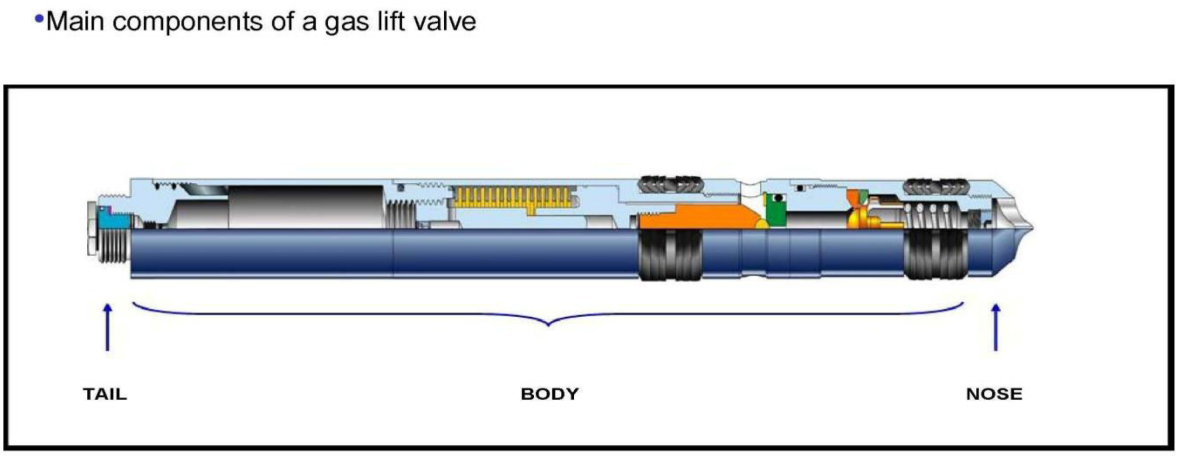
Element of reaction: Generally constituted by a spring

Body of valve: Manufactured with monel or stainless steel.

Stem and seat: Generally manufactured with stainless steel, although they can be of tungsten carbide to increase their resistance to wear and extend their working life.

Components of a gas lift valve:

The gas lift valve consists of:

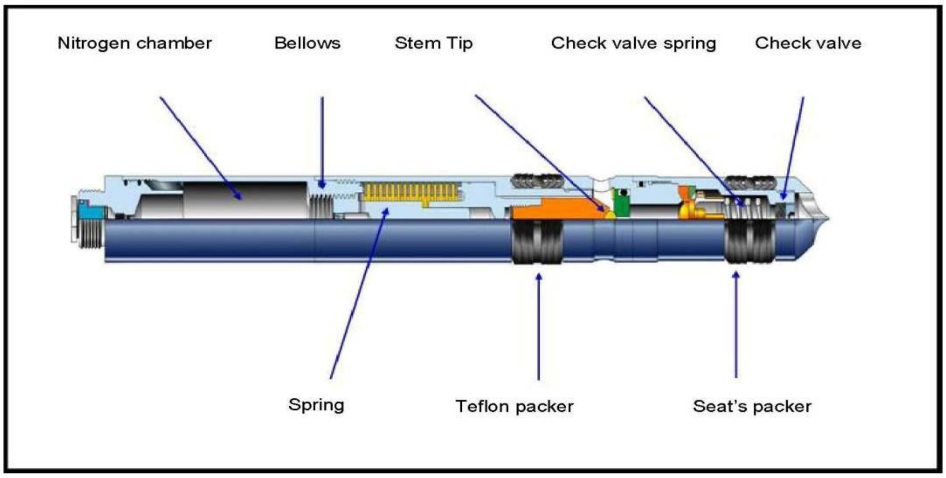


Tail: It has a coupling device for its coupling or decoupling from the mandrel through wireline operations.

Body: admits gas from the annulus, and through the pressure control, transports it to the nose towards the production tubing.

Nose: allows the injection gas to flow the valve body to the production tubing through the gas outlet orifices.

- Internal components of a Gas Lift Valve



The gas-lift valve is composed of:

Nitrogen chamber: chamber or dome loaded with pressured nitrogen. It allows the ball, located at the tip of the stem, to stay over the valve seat closing the gas flow from the annulus to the production tubing.

Bellows: It has a spring shape and its expansion allows the ball to be coupled to the seat. Sometimes, a spring is used as the load element, operating similarly to a loaded dome.

Stem: establishes the connection between the bellows and the ball.

Ball: located at the tip of the stem, it is a tungsten carbide structure that hermetically seals the seat.

Seat: orifice acting with the ball controls the injected gas from the annulus to the production tubing.

Check valve: Used in fluid operated valves, it closes the fluid flow from the production tubing to the annulus.

Seat's packer and teflon ring: They act as a seal between the valve and the mandrel, preventing possible leaks of the high pressure gas to the production tubing. They are resistant to high temperatures.

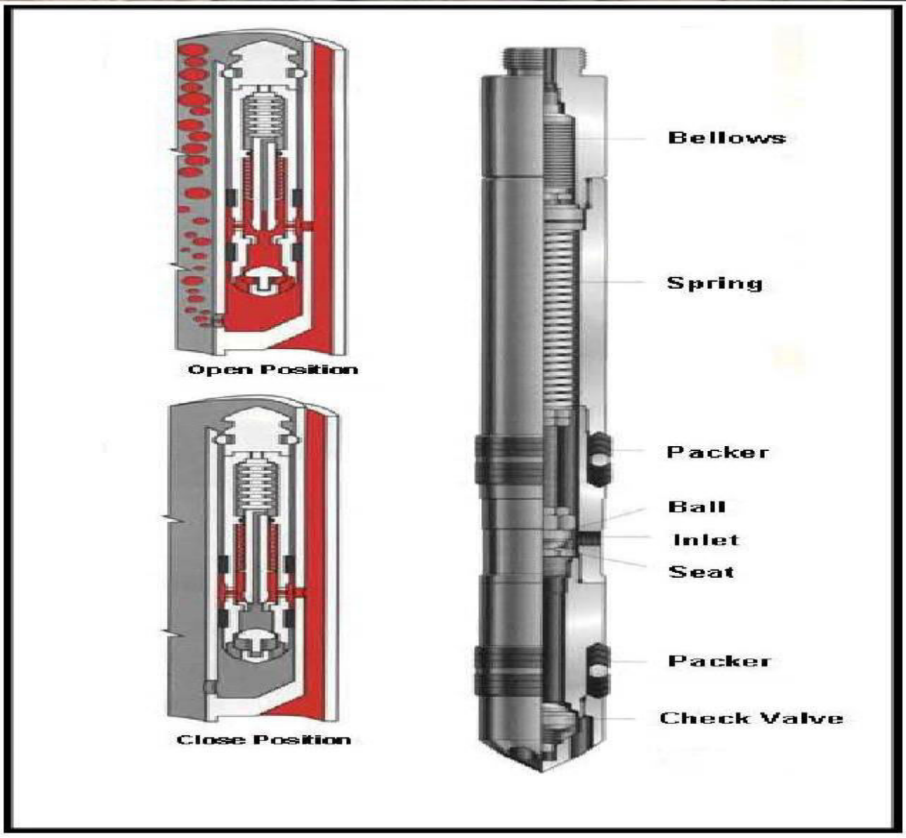
Types of gas lift valves:

There are two main types of gas lift valves:

Casing operated valves:

They are also known as fluid pressure operated valves, these valves are 50 to 100 % sensitive to pressure in the tubing in their closed position. However, these valves are 100 % sensitive to pressure in tubing in their open position. Subsequently, these valves need a pressure increase in the tubing to open, and a decrease to close.

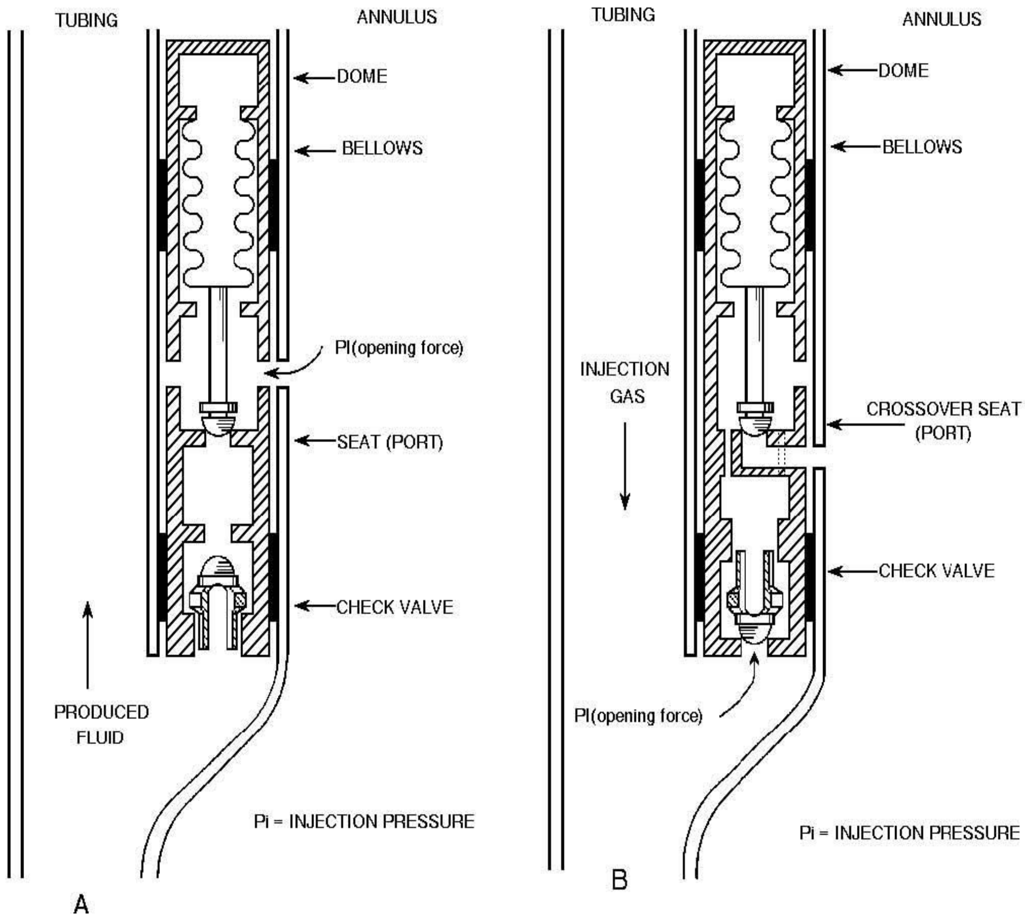
This type of valves is subdivided into: spring valve, dome unloaded valve, dome loaded valve, springless valve and combined valve. Some of them use chokes or internal orifices to control gas passage to the eductor . Ideal for wells capable of having continuous flow for a short period of time before the reservoir energy becomes depleted and the wells go into intermittent flow.



They have a principle of opening and closing which is very simple:

It is necessary that

Opening forces Fo = Fc closing forces



Tubing operated valves:

They are sensitive to the pressure of the effluent (in the tubing). The annular pressure intervenes only for the opening of the valve, while the tubing pressure is applied on the bellows transmitter of strengths. As a result, the casing pressure effect is much less important than the tubing effect for opening. In addition, since the valve orifice was previously cleared, when the pressure of the tubing reaches the opening pressure, the bellows are compressed and the ball of the valve is moved from its seat, thus allowing the gas to flow through the valve orifice.

These valves are difficult to control because it is difficult to estimate the pressure on the tubing side.

Other types of valves:

- **Throttle valves :**

Also known as “continuous flow valves or proportional valves “. Present a very similar response to valves operated by gas pressure in the annulus when in closed position .But in their open position, these valves are sensitive to the pressure in the tubing.

- **Combined valves:**

This type of valve requires a pressure increase in the tubing to open and a pressure decrease in the annulus or the tubing to close.

- **Blind valves :**

Also known as ‘’Dummy’’, It is used with the only purpose of blocking the communication between the annulus and the production tubing

Orifice valve:

It does not have opening and closing devices, so it allows for a direct injection of the gas to the production fluid, as is the case of Hassi R'mel, where water and gas are injected using this type of valves .It has a check valve at the nose with the objective of preventing leaks of the production fluid to the annulus. It is designed to keep a constant gas injection volume.

- **Pilot valve : (operating valve) :**

This type of valve was developed based on the design of wells with intermittent gas lift. This valve has large orifices (1/4’’ to 1’’ in diameter) depending on the design of completion which sometimes limits the physical dimensions of the valves that can be installed in a specific well. The large orifices guarantee the instantaneous flow of gas when the valve is opened, increasing the efficiency of the artificial lift system with intermittent gas injection.

- **Valves for production by casing:**

The valves with annular production (inverse gas-lift) are similar to the valves with production in the tubing (gas-lift direct). They are laid to the cable in a mandrel or screwed to the tubing. We find the same components: bellows, spring, seat, ball and check valve. Similarly, they can be operated by the pressure of the injected gas or by the pressure of the effluent.

ملخص:

يعد حقل حاسي الرمل مصدرا لكميات كبيرة من الغاز الطبيعي والنفط بفضل تركيبته الجيولوجية المميزة. في شرق وجنوب الحقل تتواجد بنية حلقية منتجة للنفط والتي تواجه آبارها مشاكل تقنية. أبرزها ترسب الملح الذي يؤثر سلبا على الإنتاجية. يعد ضخ المياه العذبة الحل الأكثر فاعلية لهذه المشكلة ولكنه يثقل العمود الهيدروستاتيكي. من أجل تخفيف العمود الهيدروستاتيكي وزيادة معدل تدفق النفط، يتم ضح غاز الرفع. في هذه الحالة ، تُقترح تصميمات اكمالات(تجهيزات) جديدة تسمح بالضخ المزدوج للمياه ورفع الغاز في وقت واحد. يسمح برنامج PIPESIM باختيار الإكمال المناسب. بالإضافة إلى ذلك ، يعمل على تحسين خصائص الاكمالات (تجهيزات) مثل معدل الضخ الأمثل لرفع الغاز والعمق الأمثل وقطر الإنتاج الأمثل. بصرف النظر عن PIPESIM ، و باستخدام البيانات التي تم جمعها ، يتم تحديد تدفق المياه الأمثل يدويا.

كلمات مفتاحية: الملح,غازالرفع ,ضخ المياه, الاكمالات (تجهيزات) , PIPESIM.

Abstract

Hassi R'mel field is a source of significant quantities of natural gas and oil due to its distinctive geological structure. In the east and the south of the field there is an oil-producing rim whose wells are known to face technical problems. The most irritating of these problems are salt deposits that severely affect the productivity. Injection of fresh water is the most effective solution to this problem yet it weighs down the hydrostatic column. In order to alleviate the hydrostatic column and increase the oil flow rate, gas lift is injected. For this case, new completion designs that allow the double injection of water and gas lift simultaneously are proposed. PIPESIM software allows to choose the adequate completion. In addition, it optimizes the configuration of each completion such as the optimal gas lift injection rate, the optimal depth and the optimal production tubing diameter. Apart from and using the collected data, the optimal desalination water flow is determined PIPESIM, manually.

Keywords: salts, gas lift, water injection, completions, PIPESIM.

Résumé

Le champ de Hassi R'mel est une source de quantités importantes de gaz naturel et de pétrole grâce à sa structure géologique distinctive. À l'est et au sud du champ se trouve un anneau d'huile dont les puits ont rencontré des problèmes techniques. Les plus irritants de ces problèmes sont les dépôts de sel qui affectent gravement à la productivité. L'injection d'eau douce est la solution la plus efficace à ce problème, mais elle alourdit la colonne hydrostatique. Pour alléger la colonne hydrostatique et augmenter le débit d'huile, un gaz lift est injecté. Dans ce cas, des nouvelles complétions permettant la double injection simultanée d'eau et de gaz lift sont proposées. Le logiciel PIPESIM permet de choisir la complétion adéquate. En outre, il optimise la configuration de chaque complétion, notamment le débit optimal d'injection de gaz sous pression, la profondeur optimale et le diamètre de tubing de production optimal. En outre PIPESIM, et en utilisant les données collectées, le débit optimal d'eau de dessalage est déterminé manuellement.

Mots clés: sels, gaz lift, injection d'eau, complétions, PIPESIM.