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Mémoire

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Apport de la methode coiled tubing a l'augmentation de la productivite d'un puits Tig 37 krechba petrolier

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DEDICATIONS

I wouldlike to dedicatethismodestwork to the people mostdear to myheart

To mymother, whoalwaysgives me hope to live and who has neverstopped

neverstoppedpraying for me.

To myfather, for his encouragement, his support, especially for his

for his love and his sacrifice sothatnothinghinders the progress of my

the progress of mystudies.

To mydearbrothers.

To all mybigfamily,

To myteachers for their help.

To my best friends and all myclassmates.

To all thosewhom I love and respect.

Thanks

First of all, wethankGodAlmighty for havinggranted us the strength, the courage and the themeans to accomplishthismodestwork .

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To ourdear parents and families for theirprecious help and encouragement continues.

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keywords

bbl/ft = barrels US per foot

bbl/min = barrels US per min

bbl/stroke = barrels US per stroke

BHP = bottom hole pressure

BOH = blow out preventer

TRSSV = Tubing-Retrievable Safety Valve

scf/bbl = Standard cubic feet/ barrels

PPE = personal protective equipment

MSDS = Material Safety Data Sheets

CTU Services = Coiled Tubing Unit Service

RIH $\neq$ pooh

TRSV = Tubing-Retrievable Safety Valve

BPV = BACK PRESSURE VALVE PUMP

POOH = PULL-OUT-OF-HOLE

ABSTRACT

Interventions processes to deal with problems that stop production or hinder production efficiency, the term "well operations" refers to all the provisions applicable to the wells themselves and having as their object, on the one hand, knowledge of the evolution of the state of the wells or the deposit and, on the other hand The maintenance or the adaptation of the wells in order to remain in conditions of use as perfect as possible, out on a well are numerous and can be grouped together in measurement operations, maintenance operations and repackaging or recovery operations, they fall into two categories: light or heavy: Light interventions are cable work operations and pumping operations that based on light unit uses and heavy operations are coiled tubing, snubbing and work over operations that based on the use of multiple units and heavy units (Use drill rig on the work over operation and snubbing unit), Keywords: intervention, measurement, maintenance, wireline, coiled tubing, snubbing. workover.

RÉSUMÉ

Processus d'interventions pour faire face à des problèmes qui arrêtent la production ou entravent l'efficacité de la production, le terme « exploitation des puits » désigne l'ensemble des dispositions applicables aux puits eux-mêmes et ayant pour objet, d'une part, la connaissance de l'évolution de l'état des puits ou le gisement et, d'autre part La maintenance ou l'adaptation des puits afin de rester dans des conditions d'utilisation aussi parfaites que possible, hors sur un puits sont nombreuses et peuvent être regroupées en opérations de mesures, opérations de maintenance et de reconditionnement ou opérations de récupération, elles se répartissent en deux catégories : légères ou lourdes : les interventions légères sont des opérations de travail de câble et des opérations de pompage basées sur des utilisations d'unités légères et des opérations lourdes sont des unités lourdes (Use drill rig on the work over operation and snobbing unit), Mots clés : intervention, mesure, maintenance, filaire, coiled tubing, snub bing. retravailler.

ملخص

عمليات التدخل للتعامل مع المشكلات التي توقف الإنتاج أو تعيق كفاءة الإنتاج ، يشير مصطلح "عمليات البئر" إلى جميع الأحكام المطبقة على الآبار نفسها والتي يكون هدفها ، من ناحية ، معرفة تطور حالة الآبار أو الرواسب ، ومن ناحية أخرى ، صيانة أو تكييف الآبار من أجل البقاء في ظروف الاستخدام المثالية قدر الإمكان ، خارج البئر عديدة ويمكن تجميعها معًا في عمليات القياس وعمليات الصيانة وإعادة التعبئة أو عمليات الاسترداد ، فهي تنقسم إلى فئتين: الخفيفة أو الثقيلة: التدخلات الخفيفة هي عمليات عمل الكابلات وعمليات الضخ التي تعتمد على استخدامات الوحدات الخفيفة والعمليات الثقيلة ، وهي أنابيب ملفوفة ، وعزل ، والعمل على العمليات التي تعتمد على استخدام وحدات متعددة و الوحدات الثقيلة (استخدم جهاز الحفر في العمل فوق وحدة التشغيل والصدم) ، الكلمات الرئيسية: التدخل ، القياس ، الصيانة ، الكابلات السلكية ، الأنابيب الملتفة ، التنفيس بنج. انتهاء العمل

Intruduction General :

Despite the revolution in techniques used up to this point in drilling for the recovery of hydrocarbons the best known problem is the decrease in producio. a horizontal well was a ideal solution for field development, but due to the size of the reservoirs, drilling conventional new horizontal wells were not economically attractive.

Re-entry using boreholes. existing systems using Coiled Tubing Drilling (CTD) has been determined as one of the best options for the development of fields thanks to the equipment and

new techniques which confirm these advantages over conventional drilling.

A montage fast and shorter tripping times and generally result in higher production rates than those obtained using conventional overbalance drilling techniques. Coiled Tubing Drilling "CTD" is one of the newly introduced techniques on the field of Krechba deposit, it combines between the concepts of TC and conventional drilling, There are important differences between these two techniques.

The CTD offers several unique advantages and capabilities over the conventional drilling method, it has there are several drawbacks and usage limitations.

The aim of the work scale is to gain a good understanding of drilling with Coiled Tubing, its applications, its advantages as well as its limitations and to make a study to economize the drilling of CTD and the cleaning conventional.

For this we chose the well drilled in the same area of Krechba deposit fields, the Teg-37 wells conventionally using the Coiled Tubing unit Drilling.

ChapterI:

Description of Coiled Tubing

ChapterI: Description of Coiled Tubing 2

I.1.Intruduction :

Coiled tubing involvespushing a pipe withdownholetoolsattached to its end into an oil or gaswell to carry out workwithoutdisturbing, to complete the existingwell. Althoughthere are disadvantages, there are advantagesthat have encourageditsdevelopment.

I.2.History of Coiled Tubing :

Knowing a little about the history of coiled tubing can help you to understandcurrentperceptions. Althoughcoiled tubing has been in use for more than 30 years in oil and gaswelloperations, itis a “relatively” new type of wellservicingequipment. As withany new technology, the earlydayshadtheirshare of failures aswell as successes. Many times, fishingtools and prayerwererequired to get the tubing out of the hole. Givenpast performances of this type of wellservicing unit, operatorscould not help havingconcernswhentheyhad to runit in a well. However, times and coiled tubing are changing. Whenwe look at the injectorsthatwepreviouslyused and the way the tubing washandled and spooleditbecomesobviousthat changes werenecessary. The following in thismanualwilldiscusseachpiece of equipment and point out why and how the equipment has changed to giveus our modern coiled tubing units.

The learningcurve for coiled tubing surface equipmentiswellintoitspeak. The industryisnowfocusingits attention on tubing strength and tubing life. With the move towardcoiled tubing drillingthatbegan in the early 1990s, wenow face learning the operational habits of bigger surface equipment. Withinjectorsthatcanhandle 100,000 pounds, it’sbecominga whole new game. Not onlyis the surface equipmentchanging, but the steelcoiled tubing itselfmay one daybereplacedwith tubing made fromfiber composites. [2]

I.3.Definition :

Coil Tubing is a long metal pipe thatisspooledaround a large reel. The tube iscontinuousinstead of a jointed pipe. It isnormally 1 to 3.25 in (25 to 83 mm) in diameter and isused for interventions or workoveroperations in wellbores and sometimes as production tubing in depletedgaswells. The tubing pipe isuncurledbeforeitispushedinto a wellbore .

FigureI.1: Coil Tubing unit

I.4. System Overview :

The coiled tubing unit is a portable, hydraulic-powered unit designed to inject and retrieve the coiled tubing workstringsafelyunder pressure to performwell maintenance and remedial services. This isaccomplished by a continuouscoil of pipe that range in sizes of 1, 1 1/4, 1 1/2, 1 3/4, 2, 2 3/8, 2 7/8, and 3 1/2 in. and largerspooled on a hydraulicallydrivenreel.

The system, adaptable to either land or offshore applications, isdesignedsothat components canbetaken off the trailer and placed on a barge for water work.

Tubing Size Range	
80K/100K CTUs	1.50 to 3.50 inch
60K CTUs	1.25 to 2.375 inch
30K Split Bodyload	1.25 to 1.75 inch
15K Single Bodyload	1.0 to 1.50 inch

Table I.1 : Tubing Size

I.5. Coiled Tubing applications :

I.5.1.Pumping applications :

- Starting a wellwithnitrogen,
- Neutralization of a well,
- Removal of sand or sediments,

- Removal ofhydraulicdeposits at high pressure (kerosene, salt ... etc.),
- Stimulation treatments (production column, matrix treatment by: acid, reformate, treated water, xylene)
- Hydraulicfracturing,
- Cement squeeze includingothertreatments for zone isolation (withsand, orpolymer),
- Insulation of zones (to controlproduction),
- Cutting of pipes withfluid.

I.5.2. Mechanical applications :

- ✓ Installation of mechanicalstoppers,
- ✓ Repêchage,
- ✓ Perforation,
- ✓ Logging,
- ✓ Mechanicalremoval of deposits,
- ✓ Mechanicalcutting of tubing **.**

I.5.3. Drilling applications for the unitcoiled tubing :

- ➢ Drilling in Balanced or Underbalanceddrilling mode,
- ➢ Deepening of vertical wells,
- ➢ Re-entry,
- ➢ Realisation of a multi-drainswellfrom the original hole.

I.6. Advantages of Coiled Tubing :

Coiled tubing offers the followingadvantages :

- ➢ Efficiency .
- ➢ Self-Contained unit, requires no rig .
- ➢ Saves time and money--do not have to killwell .
- ➢ Can continuouslypumpfluidsintowellwhilemoving pipe .
- ➢ Land or offshore system designs .
- ➢ No workoverrigrequiredwhenusingcoiled tubing .
- ➢ Reducedpotential damage to formation .
- ➢ Can be and istypicallyused on live wells (no killfluidsintroducedintowell) .
- ➢ Act as tool transport medium for deviated and horizontal wells .

- Performance .
- Computer prepares to optimize job design .
- Fast .
- Tubing Management.
- Advance data acquisition system to monitor key job parameters on tubing management .

I.7. Disadvantages of Coiled Tubing :

- Lowtensilestrength.
- Easy to damage because of itsthickness and flexibility.
- High loadlosses.
- Limitation to maximum pressure.
- Limited service life due to bending forces.
- Pressure differentialshould not exceed 1500 psi to prevent collapse of the Coiled Tubing.
- Risk of corrosion by acidification.
- Shortage of retrievalequipmentthatfitssmallerdiameters, which causes somedifficultiesduring instrumentation operations.
- If the drill string isstuckduring the ascent, the risk of abandoningitis important, because of the lowtensilestrength of the tubing and the lack of rotation.

I.8.Capabilities and limitations of coiled tubing :

coiled tubing offersseveral unique advantages and capabilities over conventionaldrillingmethodsconventionaldrillingmethods. It also has severaldisadvantages and limitations of use .

I.8.1. Coiled Tubing Capabilities :

- Drillingunder pressure,
- Fastmaneuvering (lowering, raising),
- Continuous circulation during the pipe'sadvance,
- High quality and continuousbilateraltelemetrybetween surface and downhole,
- Ability to penetratethrough slim holes,
- Smaller location size,
- More secureworking area.

I.8.2. Limitation of use of coiled tubing :

- No additional rotation,
- Limited draftingcapacity,
- Small diameters,
- Low circulation (in case of smallinnerdiameter of the production case),
- Short pipe life,
- Costcanbe high.

I.9. Characteristics of coiled tubing :

I.9.1. Materials for the manufacture of tubing :

The materialsused to manufacture the Coiled tubing are based on very high performance steel, are rigorouslycontrolled and have a betterresistance to corrosion and hydrogensulfide.

Virtually all CT in use todaybegins as large coils of low-alloycarbon-steelsheet. The coilscanbe up to 55 in. wide and weigh over 24 tons. The length of sheet in eachcoildependsupon the sheetthickness and ranges from 3500 ft for 0.087 in. gauge to 1000 ft for 0.250 in.gauge. The first step in tube makingis to slice flat stripsfrom the coil of sheetusing a slittingmachine **(Figure I.3)**. A specialistcompanyusuallyperformsthisoperation and ships the coilsof strip to the CT mill for furtherprocessing**(Figure I.2)**. The sheet'sthickness sets the CT wallthickness and the strip'swidthdetermines the OD of the finished CT.

In some cases the gauge of the sheetmaterialistapered over a portion of itslength, as isshown in**(Figure I.4)**. This variation in thicknessisused by Quality Tubing to produce CTwith a wallthicknessthat varies alongitslength, known as "True-Taper™".

The CT manufacturer splicesstripswithsimilarpropertiestogetherusingbiaswelds to form asingle continuousstrip the length of the desired CT string. This stripisstored on an accumulatorcalled a "Big Wheel",**(Figure I.5)**Joiningstrips of differentthickness or usingstripswith acontinuallychangingthicknessyields a tapered string. The CT millforms the flat stripinto acontinuous tube and welds the edgestogetherwith a continuous longitudinal seam.

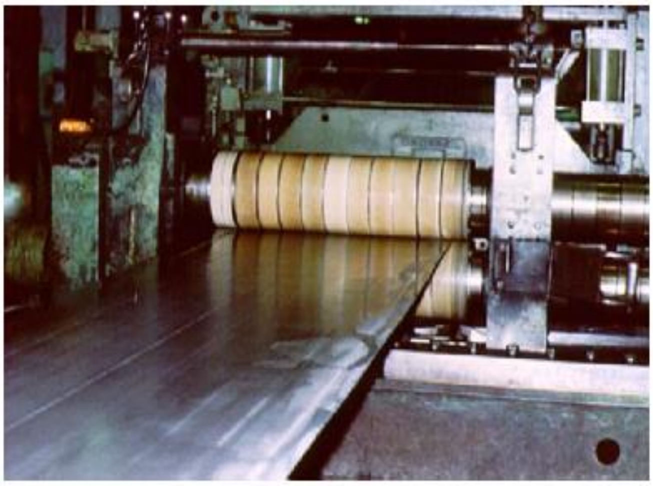


Figure I.2: SlittingSteelSheet for StripFigure I.3 : Rolls of SteelStrips

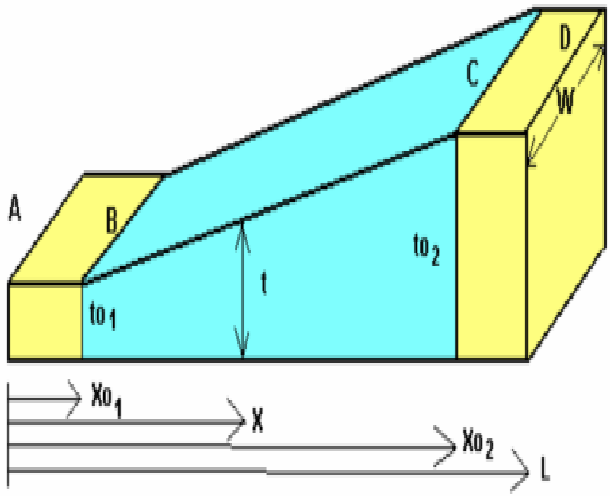


Figure I.4 : True-Taper™Figure I.5 : "Big Wheel" of Flat Strip

I.9.2. Forces applied to Coiled Tubing :

The forces applied to the Coiled Tubing duringits service life are :

- Crushing stresses due to external pressure.
- Bursting stresses due to internal pressure.
- Tensile stresses thatcan cause elongation or rupture of tubing.
- Compressive stresses in deviatedwellsthatcan cause buckling.
- Cyclicbending stresses between the reel and the sprue head.

The combination of all the forces reduces the life span of Coiled Tubing.

I.9.3. The criticaldeformation moment of Tubing during the maneuver :

- At the beginning of the unwinding and winding of the tubing on the drumwhenitgoesfrom the curved state to the straight state and vice versa.

- At the moment of passage on the gooseneckwhen the tubing passes from the straight state to the curved state and vice versa.
- At the moment of passage from the gooseneck to the injection headwhen the tubing passes from the curved state to the bending state to the straight state and vice versa.

A fatigue cycle for a Coiled Tubing isdefined as the set of sequences, fromfromunwinding and rewinding on the drum, to lowering and rewinding on the goose neck. and thisreduces the tensilestrength by about 5 to 10% of itsyieldstrength. of itselasticitylimit.

The service life of a Coiled Tubing isgenerallyconsidered to bearound 80 cycles, withouttakingintoaccount the effects of pressure withouttakingintoaccount the effects of pressure, acidification and weight.

I.10. Conclusion :

In the end itwasdiscoveredthatthere are more benefitsthandisadvantages in usingcoiled tubing services.

ChapterII:

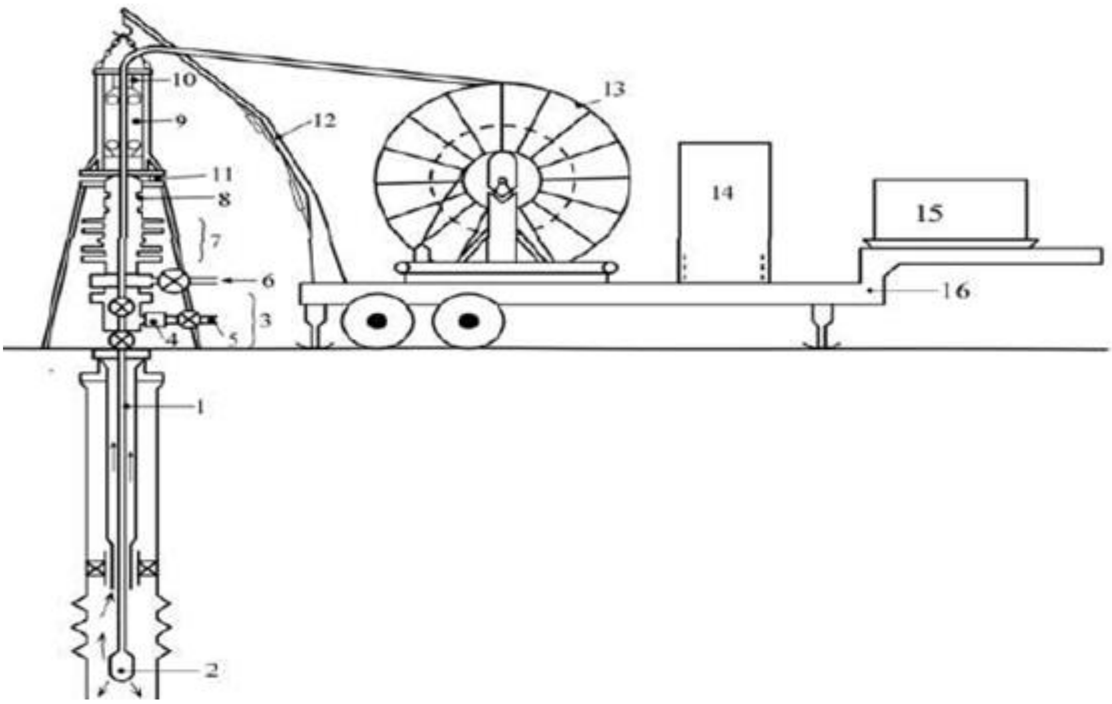
Operating principle of the Coiled Tubing

ChapterII: Operating principle of the Coiled Tubing

II.1.Introduction :

The Coiled tubing is a unit consisting of all the equipmentnecessary for the continuousexecution of tubing lengthoperations in the field. The unit consists of two main parts :

- Surface equipment.
- The bottomtools .



FigureII.1 : coiled tubing equipment

1. Coiled tubing
2. Circulation tool
3. Wellhead
4. Production nozzle
5. Production line
6. Manifold outlet
7. Bop
8. Stripper
9. Injector
10. Rectifier
11. Weightindicator
12. Crane
13. Reel
14. Control cabin
15. Power pack
16. Trailer

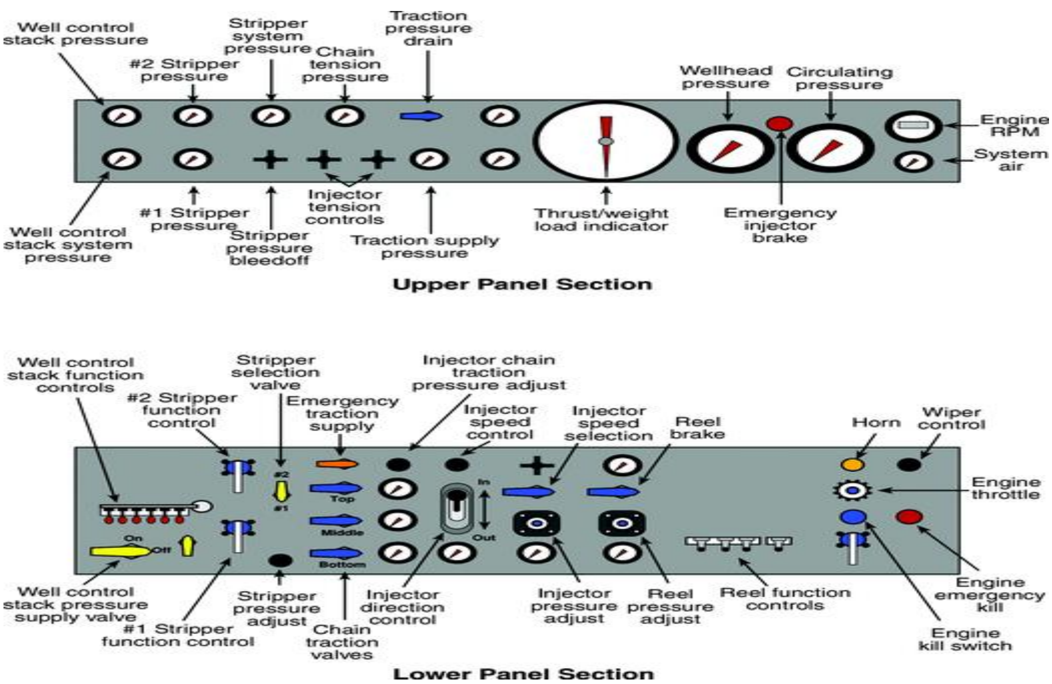
II.2.Surface equipment :

II.2.1Control cabin :

The design of the CT unit control boothmayvaryamongmanufacturers, but normally all controls are located on a remote console panel. A schematic of a typical CT unit control panel isshown in **Figure II.3** . The console assemblyiscompletewith all the controls and gauges needed to operate and monitor all the components used and canbeskid-mounted for offshore use or permanentlymounted as for land-basedunits. The skid-mounted console canbeplacedwherever the operatorwishes at the well site. The reel and injectormotors are activatedfrom the control panel by valves thatdetermine the direction of casing movement and operating speed. Also on the console are the control systemsthatregulate the pressure of the drive string, stripper assembly and variouswell control components...

The operator must have all the necessarycontrols in front of him to operate, control and monitor the followingparameters :

- Circulation pressure
- Wellhead pressure
- Casing weight
- Tooldepth
- Operating speed
- Circulation flow rate
- Pumped volume Winch
- Injection head
- BOP
- Stripper



FigureII.2 : Simplifiedlayout of a console control panel

FigureII.3 : Control cabin

II.2.2. Power unit :

The hydraulic power required to operate the various components and equipment of the Thehydraulic power required to operate the various components and surface equipment of the coiled tubing unit (drum, injection head, BOP, The power unit **(Figure II.4)**isnormallyequippedwith an automatic emergency stop system in case of significanttemperature and oil pressure variations. The hydraulicpumpssupply six circuits used to control the variousfunctions of the coiled tubing unit. functions of the coiled tubing unit whichare :[1]

- the first circuit with a maximum working pressure of 3000 psi issupplied by twopumps (60 and 30 g/min)pumps (60 and 30 g/mn) and drives the injection head.
- the second circuit with a maximum working pressure of 2000 psi drives the winch drum.
- The third circuit, with a maximum working pressure of 2,500 psi, drives the devicethat guides the winding and unwinding of the tubing.
- the fourth circuit is the BOPs circuit whichallows the accumulators to berecharged to a maximum pressure of 3000 psi.
- The fifth circuit iscomposed of storagecylinderspressurized to 2000 psi which, with the help of regulators, performs the followingfunctions and organsfunctions and components by means of the regulators:
    - tensioning the innerchain of the injection head at a pressure of 1500 psi.
    - the tension of the outerchain of the injection head at a pressure of 400 psi.
    - the speed of the injection head at a pressure of 600 psi.
    - the forward/reverse rotation of the injection head at a pressure of 600 psi

- cab position adjustment at 600 psi.
- Hydraulic winch drumbraking system at 350 psi.
- the coiled tubing synchronization system on the drum at a pressure of 2000 psi.
- The system for adjusting the high or low position of the injector at a pressure of 600 psi.

➢ the sixth circuit used to supplyauxiliaryauxiliaryequipment of the coiled tubing unit .

FigureII.4 : Power unit

II.2.3. Winch drum :

The drumis a devicethatallows the coiled tubing to beunwound, rewound and stored as a whole.Inorder to reduce the severebending forces that the coiled tubing undergoesduringitswinding and unwinding, the drum must have a sufficiently large diameter, thestoragecapacitycanbebetween 5000 - 22000 ft .

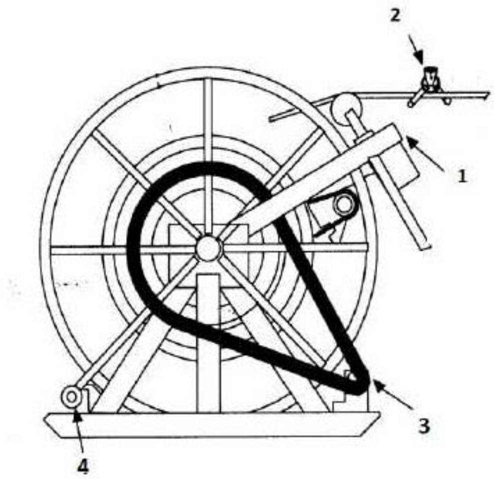
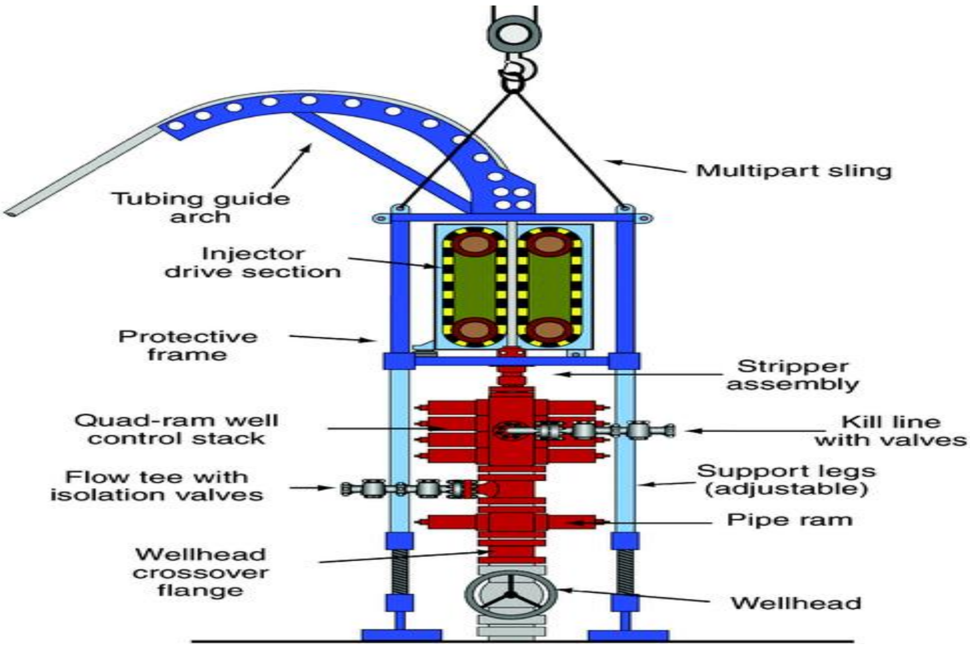


Figure II.5: Simplifiedlayout FigureII.6 : Winch drum
Showing Winch drum

1. Lubrication system
2. Weightindicator
3. Drive motor
4. Braking system

II.2.4. Injection head :

The injection head**(Figure II.7)**is a main component of the coiled tubing unit, used to operatewith the help oftwohydraulicmotorsthat drive twocontinuouschains on which are mountedgrippingelementsthat push or pull the coiled tubing into the wellduringoperations.[4]



FigureII.7 : Injection headassembly

Bothhydraulicmotors are driven by the same pressure source to avoid phase shift between the twothe phase shift between the twochains.

The traction capacity of the injection headis a functionof :

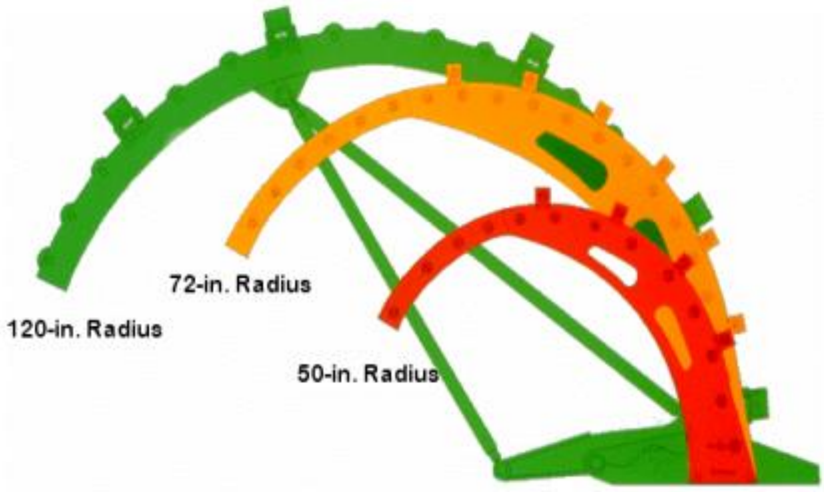
- the size of the injection head.
- the working pressure chosen by the operatorfrom the power unit .
- the chosen speed whichisnormallyaround 125 ft /mn (low speed) and 250 ft/mn (high speed) .

The seizing force isobtained by actuatingthreehydraulic pistons through the inner part of the twochains of the injection head (Inside tension cylinders). This force must besufficient to preventslipping and crushing of the tubing. The outer piston
keeps the twochainsunder tension.

The entire injection headismounted ona substructure equippedwith a tubing weightcellconnected by a hydraulichose to the weightindicator in the operator'scabin. operator'scabin.

II.2.4.1. Gooseneck :

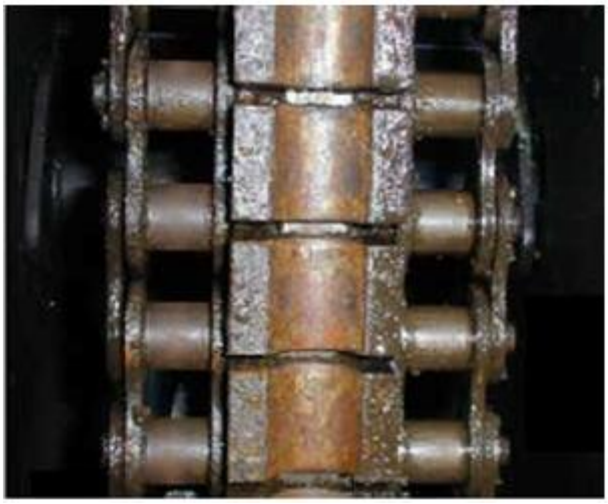
The role of swan neck, to guide and receive the tubing afteritsunwindingfrom the drum, connected to the injection headwith a verysophisticatedsystem**(Figure II.8).**
To obtain the desired radius of the gooseneck, a number of bearings are placed in itscurvature frame with a coiled tubing alignment system.



FigureII.8 : Gooseneck

II.2.4.2. Drive Chains and Tensioners :

The drive system consists of twohydraulicmotorstypicallyconnected and synchronized by a control system. The direction and speed of rotation of thesemotorsiscontrolled by a 4-position hydraulic control valve located at the power pack.



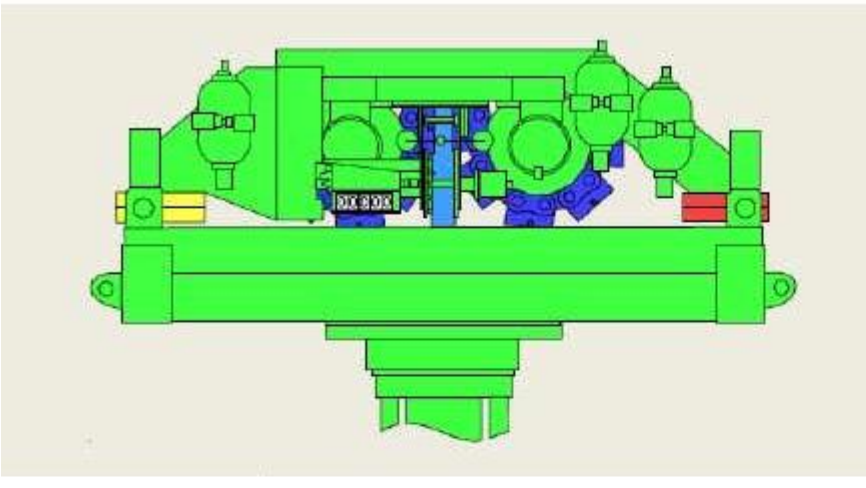
FigureII.9 : Chains and Tensioners

II.2.4.3. Chain component :

FigureII.10: Chain component

1. Axes de liaison
2. Gripper
3. Chaîne à rouleaux
4. Goupilles fendues

II.2.4.4. Weightindicator :



FigureII.11 : Weightindicator [1]

II.2.5. Packer (stripper) :

The stripper **(Figure II.12)**is a sealingelementwhichisinstalledunder the injection headvery close to the grippingelements of the injection headchain in order to prevent the coiledtubingfrombucklingduring the operation.

The stripper is the primarybarrierwhen the coiled tubing is in the well, itensures a perfectsealaround the coiled tubing like the gland in cableoperations.

There are three types of stripper on the market :

- the conventional stripper
- the conventional stripper
- radial stripper

The operating principle of all types of strippers is the same, itconsists of hydraulicallymoving a piston to directly or indirectlycompress a seal, whichhydraulically move a piston to directly or indirectlycompress a seal, which in turnsealsaround the coiled tubing.[4]

FigureII.12: stripper

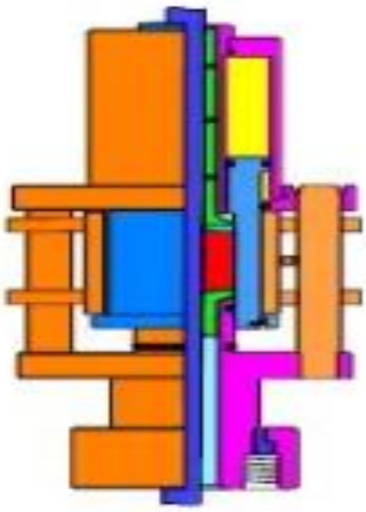
II.2.5.1. The conventional stripper :

In the conventionalstripper **(Figure II.13)** the hydraulic pressure appliedpushes the piston upwardswhich in turn moves the lower fur to compress the packeragainst the upper fur.

The pressure at the top of the well tends to keep the stripper closedduring the intervention operation, which

The wellhead pressure tends to keep the stripper closedduring the intervention operation, thusreducing the hydraulic pressure in the lowerchamber of the stripper.

The twoupper and lowersleeves help guide and center the tubing in the packer. seal. A ring mountedbetween the uppersleeve and the sealprevents the sealfrombeingforcedbetween the uppersleeve and the seal. A ring mountedbetween the uppersleeve and the sealprevents the sealfrombeingforcedbetween the sleeve and the Coiled Tubing.



FigureII.13 : conventional stripper

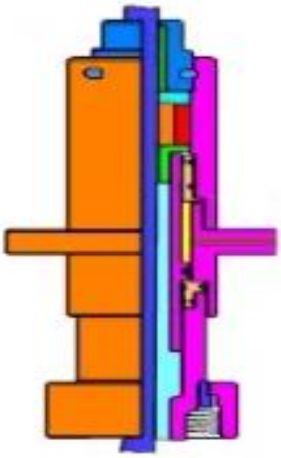
II.2.5.2. The lateral stripper :

The operating mechanism of the sidedoor stripper **(Figure II.14)**isreversedcompared to the conventional stripper.

In the sidedoor stripper system, the hydraulic pressure pushes the piston down, which in turn moves the upper liner, which presses the packeraround the tubing against the lower liner.

The hydraulic pressure applied to the piston must begreaterthanthat of the wellhead and must bemaintainedduring the entire intervention operation.

The table below shows the characteristics for each type of stripper:

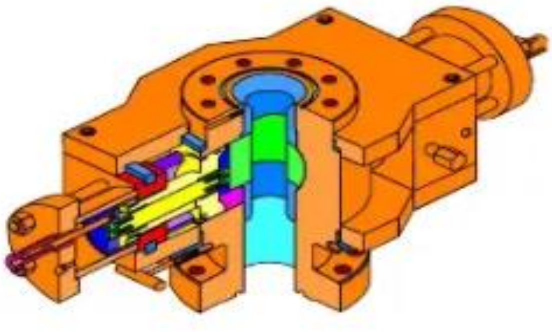


FigureII.14 :lateral stripper [4]

II.2.5.3Radial stripper :

The Radial Stripper **(Figue II.15)**is a stripper withjawsdesignedspecifically for Coiled Tubing stripping. It wasdeveloped to overcome the problemsencounteredduring the use of conventional strippers (single or double).

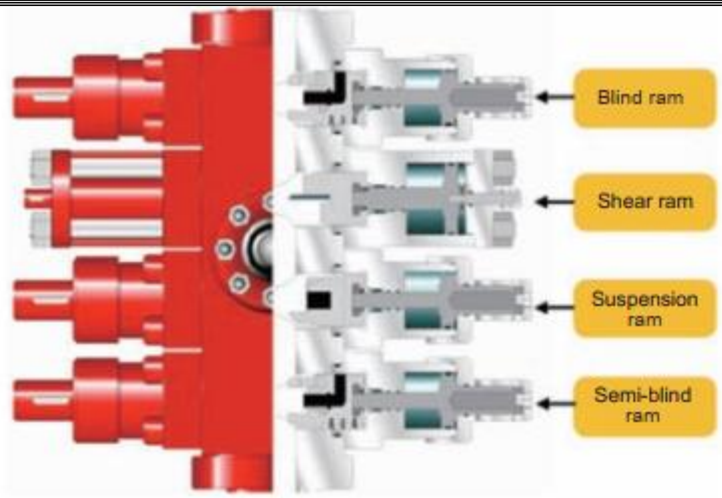
The radial stripper has a reducedheight, ease and simplicity of change of elastomerscompared to the conventional stripper.



FigueII.15 : Radial stripper

II.2.6.BlowoutPrevention System (BOP) :

The blowoutprevention system mainlyincludes BOP, blowout box and lubricator. As the well control equipment of oil and gaswells, the blowoutprevention system functionsmainly in sealing the pressure in wells and preventingblowout accidents etc. duringfieldoperationswith the coiled tubing unit.

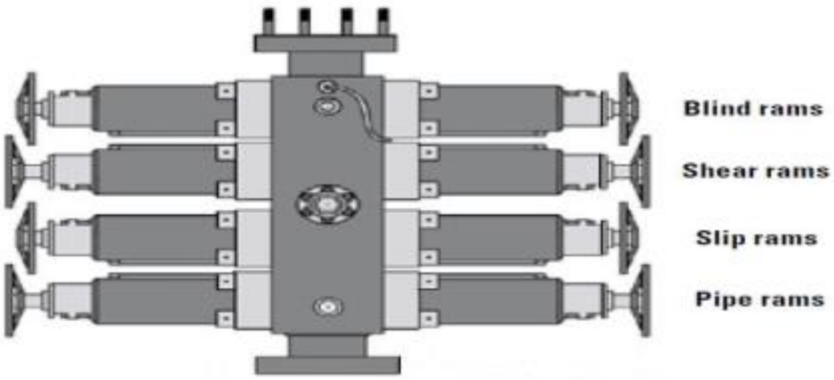


FigureII.16 : BOP [3]

II.2.6.1Quadruple BOP :

This type of standard stackingis the most responsive of the BOPsused in Coiled Tubing, itis a solid block composed of four rams arranged**(Figure II.17)**from top to bottom as follows .

- A blind rams plug: Usedonly to seal on an emptyhole.
- A shear rams plug: used to cutCoiled Tubing / Coiled Tubing withlogging cableinsidewithoutsealing.
- A slip rams packer: used to suspend the tubing in the wellwithoutsealing.
- A pipe rams plug : used to obtain a positive sealagainst the tubing .



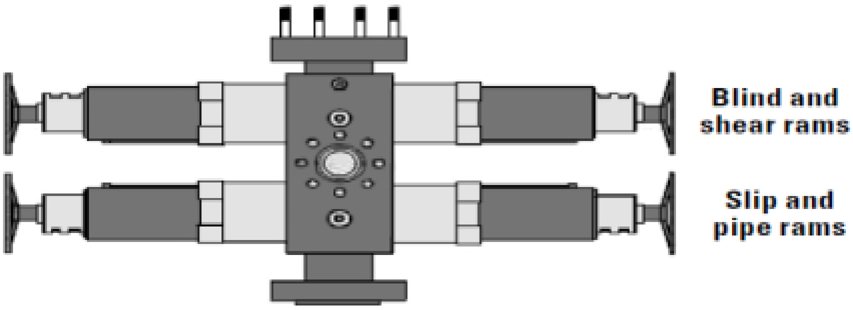
FigureII.17 : Quadruple BOP

II.2.6.2. Combinaison BOP :

The BOP COMBINE **(Figure II.18)**is a double shutterwhichfulfils the samefunctions as the BOP QUAD but withonlytwo rams, itiscomposed of :

- A Blind/Shear rams top plug, used to cut the tubing and seal on an emptywheel.
- A lower pipe/slip rams plug, used for hanging and sealing on the tubing.

Each valve isequippedwith a pressure equalization valve. A kill line inletlocatedbetween the thetwoobturatorswhichallows to pumpinside the tubing if necessary.



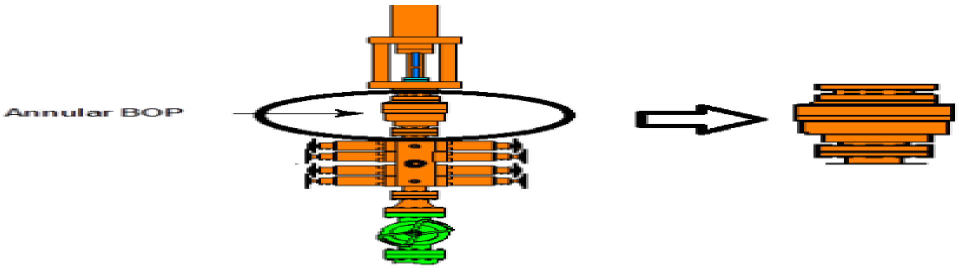
FigureII.18 : Combinaison BOP

II.2.6.3Annular BOP :

The Annular BOP isused more frequently in specialoperations at the Coiled Tubing, for example the assembly of very long tool strings thatrequire the use of a deployment system. The main purpose of using an annular stopper in a CoiledTubing stackis to be able to close stackis to be able to close tightly on differentdiameters of Coiled Tubing and tooling.

Its position in the stackdepends on the nature of the work to bedone. above Quad, below the deployment system, the ring shuttercanbeused as a back up as a back up for the stripper if necessary.

The characteristics of the annularshutter must besimilar to those of the clamshellshutterswith the with the additionalpossibility of closing on an empty ho

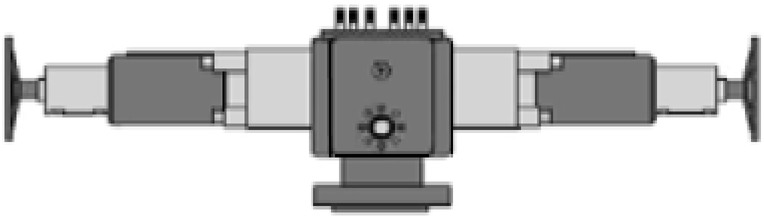


FigureII.19 : Annular BOP

II.2.6.4Shutters (shear/seal) :

In some countries wheresafetyregulations are very strict, an additionalshear/seal rams **(Figure II.20)** must beinstalledbetween the production head and the BOP assembly, and isused as a tertiarybarrier if necessary.

This type of valve requires a large volume of hydraulicfluid, whichiswhy an independenthydraulic unit (koomey) isrequired. The working pressure of the koomey unit isusuallybetween 1500 and 3000 psi .



FigureII.20 : Shutters (shear/seal)

II.2.7. Deployment system :

In Coiled Tubing operations, the distance between the production wellhead and the stripper determines the maximum length of the tool string. If this maximum distance isexceeded, itbecomesnecessary to use a control barrierwhichcanbe the DHSV or the deployment system.

In general, there are several types of deploymentsystems on the market**(Figur II.21/ II.22)** which have the same operatingprinciple as the multi-ram BOP .

The stackingcanbecomposed of :

- one shear/seal rams on top and one pipe rams on bottom.
- a tubing /slip rams plug at the top and pipe rams to guide the tubing at the bottom.

The advantage of using the deployment system under the QUAD or the COMBI is to be able to to assemble the different sections of a relatively long toolpathwhenlowering and to assemble themwhenraising of a relatively long toolpath in completesafety.[4]

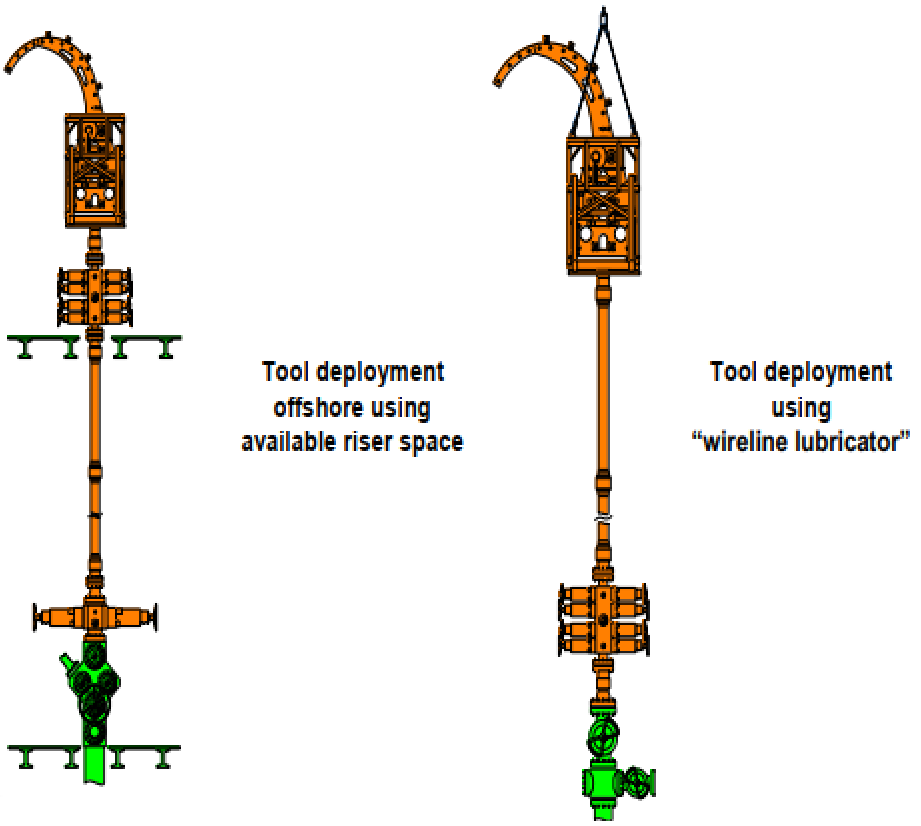
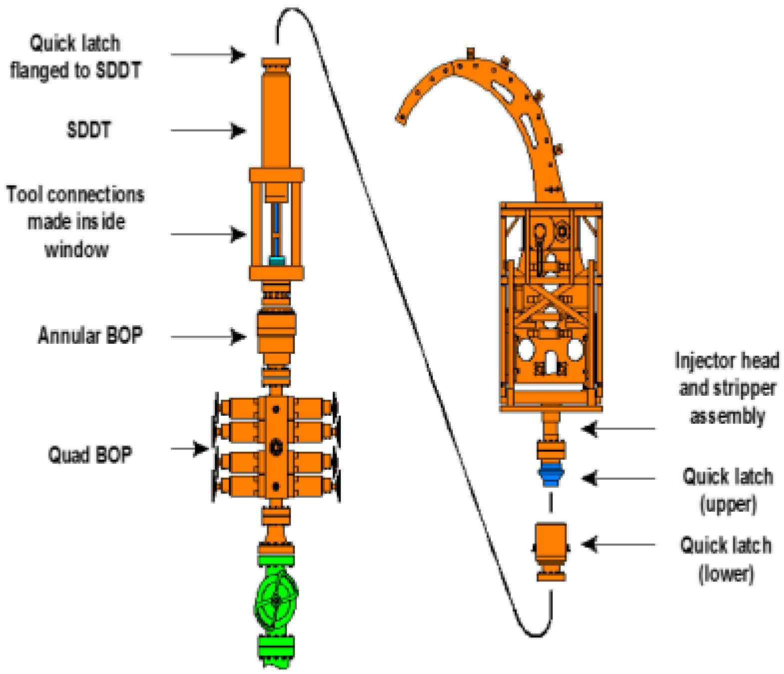


Figure II.21 : offshore deployment



FigureII.22 : onshoredeployment

II.3. The bottomtools :

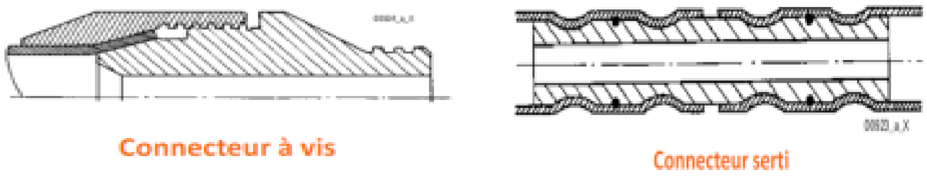
It is a set of parts thatconstitutes the main element of coiled tubing (the train or the probe of coiled tubing).

The coiled tubing train isvalid for the differentcoiled tubing operations, such as cleaning, re-drilling, stimulation, acidification ... etc, attached to the end of tubing. The main elements are:

II.3.1. Fitting (connector) :

Coiled Tubing fittings**(Figure II.23)** are used to couple variousdownholetools to the end of the Coiled Tubing. There is a widevariety of fitting types and sizes on the market. There are three types of fittingsused for coiled tubing:

Bite fittings, screw/holefittings and internalfittings.



FigureII.23 : types des connecteurs

II.3.2. Check valve :

The probability of reverse circulation withCoiled Tubing isverylow, so the use of check valves in the the use of check valves **(Figure II.23)** in the Coiled Tubing train becomesnecessary .

Generally the check valve isplaced at the top of the BHA, immediatelybelow the load bars.

Check valves canbeball or flap valves and are considered the primarybarrierduring the intervention at the Coiled Tubing.

If the check valve fails, the Coiled Tubing must bereassembledwith circulation to preventwellfluidfrom passing into the Coiled Tubing.

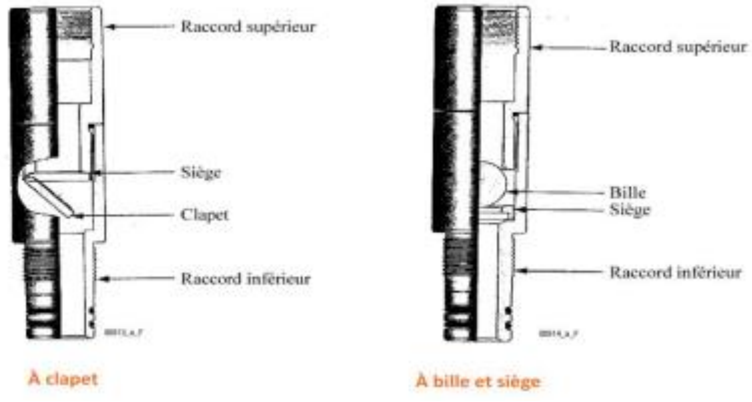
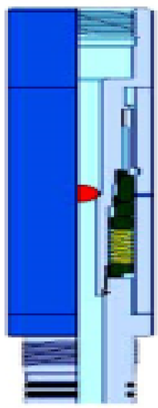


Figure II.24 : check valve

II.3.3. Hydraulicdisconnector :

Hydraulicdisconnector**(Figure II.24)**is a shearloweredwith the tool train to release the Coiled tubing in case of jamming, the principle of use of the Boss is to pump a ballinside the Coiled tubing and continue to rise in pressure untilshearing the pins of the disconnectors and release the Coiled Tubing.[4]



FigureII.25 : disconnector

II.3.4. Centerers :

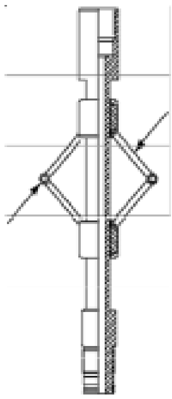
The centeringdevices are securelymounted in the coiled tubing tool set to keep the tools or the thetools or the tip awayfrom the walls of the tubing material.

- **Elasticbladecenteringdevice :**

Elasticbladecentering machines usually have three flexible curvedblades. The elasticity of the bladesallows for effective centeringwithin a certain range of insidediameter.

- **Rigidcenteringdevice :**

Rigidcenteringdevicesusually have three or four fins mounted on a central sleeve. sleeve. The outsidediameter of these fins isslightlysmallerthan the smallestinsidediameterencountered in the diametersencountered in the packing throughwhichitis to belowered.



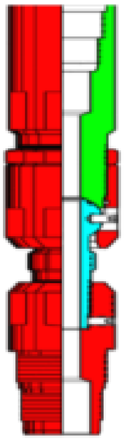
FigureII.26 : Centerers

II.3.5. The load bars :

Used to increase the train size (length), and center the assembly in the empty area betweenpacker and betweenpacker and liner.

II.3.6. Patella :

The ball-and-socket joint **(Figure II.26)**minimizes the effects of coiled tubing bends and gives the BHA the flexibility to centralizeheavy components.



FigureII.27:Patella

II.3.7. The tool :

There are several types of tools**(Figure II.27)**used, depending on the operationwemake the choice (of tool). The cuttingtool, the cleaningtool, and fishing ... etc.[4]

FigureII.28 : differenttools

II.4. Conclusion :

We note that the coiled tubing group consists of manyequipment on the surface as well as the bottom, whichmakesit more advantageous, coordinated and efficient than the rest of the groups, and thishelps the drillingprocess and gives a distinctive result.

III.1INTRODUCTION :

Teg-37 was drilled and completed by KCAD T220 on 10th November 2012, The well was put on production on the 5th April 2013, and after 15 days flowing the well started to be loaded with production fluid (heavy fluid) and caused the dead of the well , The static Gradient surveys analysis indicated that the top of this heavy fluid is at 2500 m, and this fluid has a pressure gradient of 0.4 psi/ft, above this fluid we have a dry gas with SG = 0.628 and 9.2 mol % CO2.

The 4-1/2” Slotted liner is this well is not is installed properly deep in the well and is suspended completely inside the 7” Casing, as you can see below Schematic, This was due to a problems encountered during the completion of the well.

Mud losses were observed during the drilling of the 6” Hole, Estimated quantity of OBM lost is as below.

A fish was left inside the 4-1/2” Slotted line during the completion of the well, dimensions of the fish are mentioned below .

III.2. Objectives :

Teg-37isbeingdrilledtobecompletedasverticalgaswelllocatedintheInSalahfield.Acleanup operation is planned to be performed on this well, therefor JV-Gas has requested fromHalliburtontounloadthewell.

ThewellisnewdrilledGaswellandwasputonproductiononthe5thApril2013,Butjustafter15 days the well started to be loaded with production fluid (heavy fluid) and caused the deadof the well , The static gradient surveys analysis indicated that the top of this heavy fluid is at2500 m, and this fluid has a pressure gradient of 0.4 psi/ft, above this fluid we have a dry gaswithSG= 0.628.

Thisproposaldescribestheprocedure,materialandequipmentrequiredtoperformthisjob.
To kickoff the well with N2 and flow it until it is clean from hydrocarbon liquid using Schlumberger Well Test Unit and HES Coiled tubing unit, The aim of the displacement is to recover all liquids from the well and draw the well to lowest possible FWHP and get measurement of the Condensate Gas Ratio (CGR) in the end of the clean up, All clean up fluids will be taken to the flare pit and burned / evaporated .

III.3. Program Overview :

RU with Slick-line and drift tubing and Tag HUD with appropriate drift size, use 3.35" fluted drift (1-3/4" CT will be used), then rigged down with Slick line, RU with Schlumberger Well Test equipments and Pressure test surface equipment, Coiled Tubing will then be rigged up and run in hole, and the well will be unloaded using N2. The aim is to run the coil to inflow the well and clean up. After the well observed flowing continuously in the flare pit, pull out of the hole while circulating at low N2 flow rate to surface, continue flowing the well until confirming the well is cleaned up from liquids.

III.4. Presentation of the krechbafield :

III.4.1INTRODUCTION :

The Krechba deposit is located in the northern part of the In Salah region**(figureIII.1)**. The deposit was discovered in 1957 by drilling KB1 which returnedcountered the Tournaisian Carboniferous and Siegenian – Gedinnian reservoirs of theLesser Devonian at a depth of 1,700 to 3,350 meters. The different drilled wells produced gas flows in all three reservoirs.1This deposit constitutes, with those of Teg and Reg and, further south, those of theIn Salah region (HassiMoumen, Garet el Befinat, Gour Mahmoud and the struc-ture of In Salah), a large gas complex operated as part of the tionSonatrach – BP – Stat Oil. After treatment, the gas produced is transported to HassiR'mel located 450 km north of Krechba

(FigureIII.2). [5]

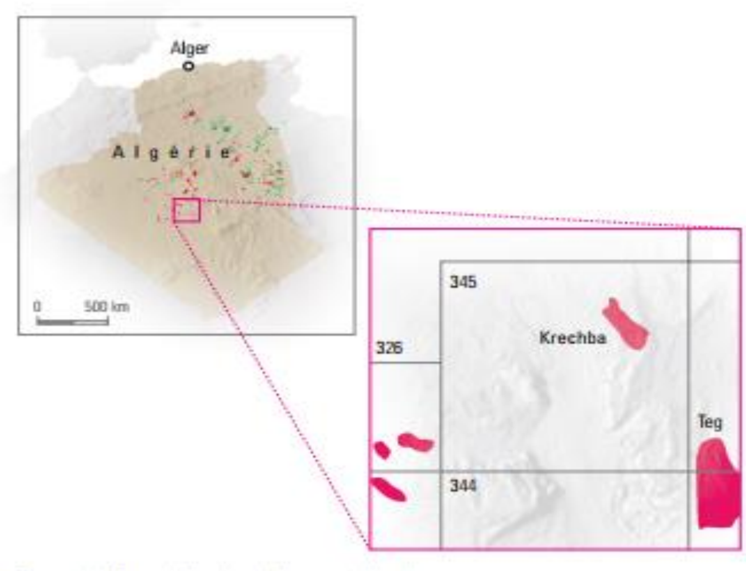


Figure III.1: Situation map of the Krechba deposit.

III.4.2.structurally of Geology :

The Krechba deposit appears to be a large anticlinal structureclosed, structurally simple. The current architecture of the Krechba was modeled at the end of the Carboniferous during the "Hercynian orogeny born ". This is an anticline that developed as a result of cutbacks deep in the base. These were accompanied by a network of north-south faults intersecting, to the west of the deposit, the formations of the Ordovician and the Silurian.

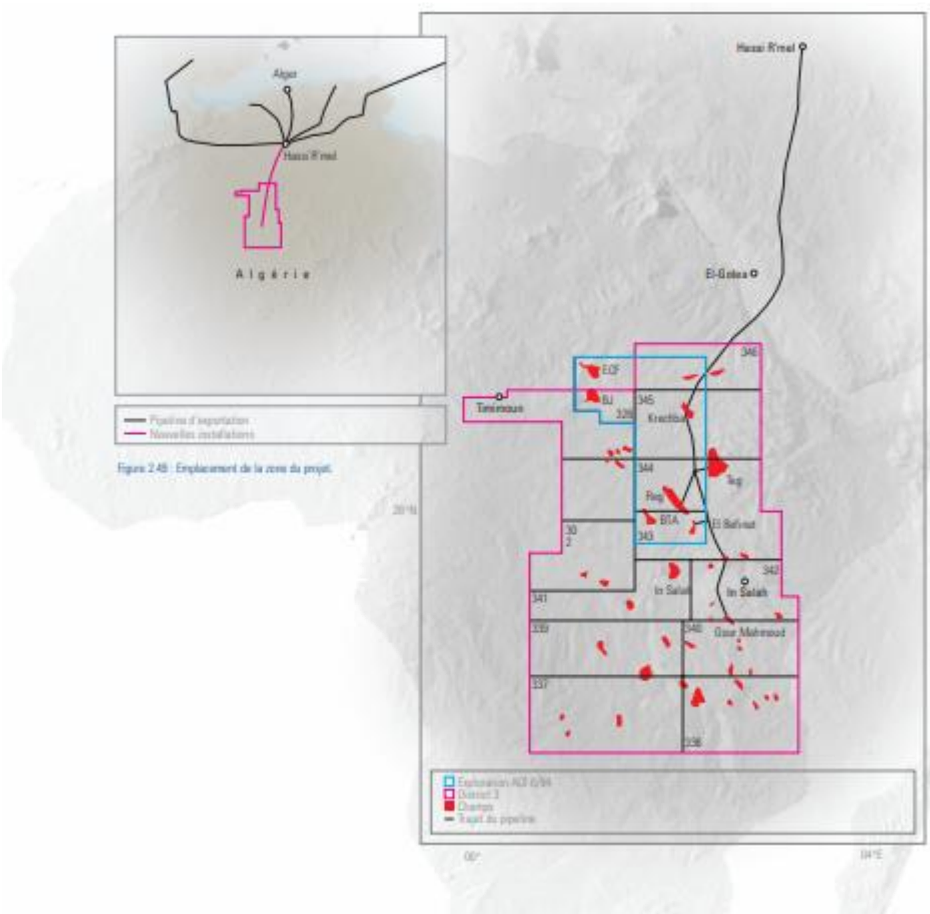


Figure III.2: Location of Project Area

The location of the paleovalley, in which the sandstones of the Tournaisien were deposited, was influenced very presumably by these flaws. The structure of Krechba underwent post-hercynians. The structural map of the Krechba deposit has was established on the basis of the interpretation of the seismic 3D carried out in 1998, the three reservoir horizons having then been mapped in detail. The interpretation shows an elongated submeridian NNO-SSE anticline with fer-metures with steep sides **(FigureIII.3).** Figure 2.51 shows the stratigraphic column as well as the nomenclature adopted in the series.

III.4.3.The Carboniferous:

Carboniferous sandstones, deposited in an environmentofpaleovallée, are located at a depth of 1,700 m. These sandstones are well developed (up to 24 m thicktotal) over a large part of the deposit, but are absent in parts of western and southern field. The Carboniferous sandstones are of good quality, with porosities up to 22% and permeabilities up to 200 mD. The body of water at the level of Carboniferous is at the level of –1 330 mss, which gives a closed area of 130 km2. This body of water was confirmed by pressure measurements and recorded tests.

III.4.4.The Devonian :

The Devonian reservoirs are located at a depth between 2850 and 3350 m; they come under the form of alternating sandstone levels separated byc lay levels. These sandstones are of "little marinedeep ”to“ marginal sailor ”. Gedinnian sandstones (D30 to D10) have a significant lateral extension and are of medium quality, with porosities up to 15% and permeabilities reaching 150 mD. The sandstone from the Siegenien (D40) are of poorer quality does diagenesis; porosities are generallyless than 10%. In the Devonian levels (D40,D30 and D20), the trapping mechanism is complex.The area of the roof closure of the D40 is 100 km2 with a structural closure of 65 m. However, for the two tanks D40 and D30-20, the gas columninterpreted from the logs exceeds the height of the structural closure. For D40, the trapping mechanism is probably mixed, structural or stratigraphic / diagenetic. Gas / water contact has been confirmed at -2,420 mss by tests and pressure measurements. [6]

III.4.5. Well testing and reservoir fluids :

The results of the tests carried out on the Carboniferous and Lower Devonian look like this:

- Tank C10.2
- The DSTs of existing wells, despite their short lifetimes, show variation in productivity from one well to another. This variation in flow rate is a function of reservoir qualities and is an indicator of its heterogeneity. [7]

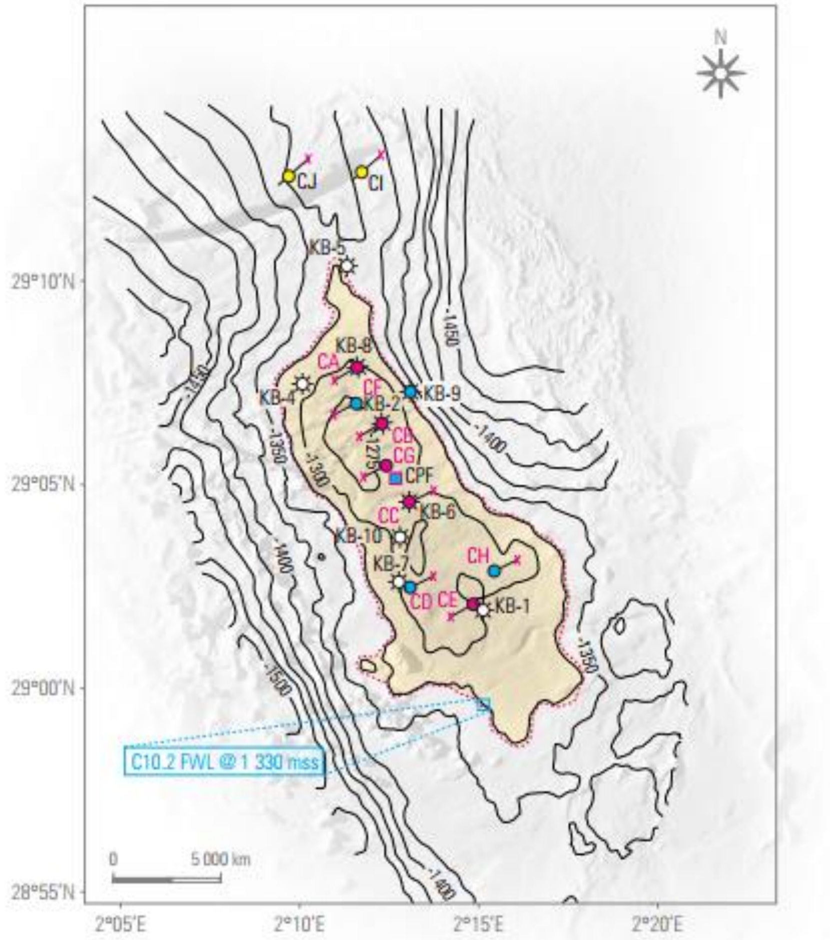
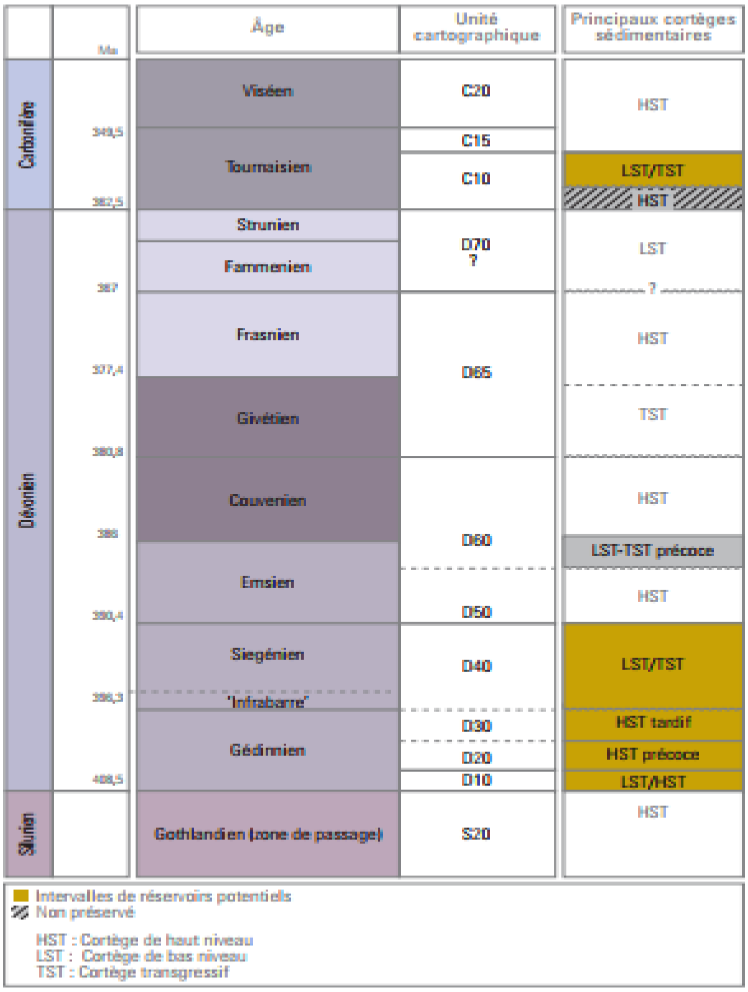


Figure III.3 : Structure of the Krechba deposit.

The results indicate maximum production in wells not damaged, which varies from 300,000 m3 / d on the sides to 700,000 m3 / d in the center of the structure. Analysis of the fluids collected indicates a variation in the gas composition, with a maximum condensate content of 11.2 m3 / million m3 obtained on the KB-9z well. The maximum condensate flow obtained has summer of 1.4 m3 / d.

D30 tank The test results show a variation in the production rate. TheFlow rates obtained from the wells in the north of the field were greater.

Some wells provided appreciable flows. The flow variation is directly linked to the qualities of thereservoir and indicates its heterogeneity. The production of water observed during certain tests confirms the complexity of the body of water in this reservoir. We will note other share the high concentration of CO_2 (9%) obtained on the effluent of the KB10 well.



FigureIII.4 : Stratigraphic column

III.4.6. Well Data: [7]

Production Rate: 50 mmscfd @ 56 barg (During last clean up)

Max Deviation: Vertical Well.

Min ID: 3.725” RN Nipple @ 2592.5 m MDbrt

Last DownholeOps:Drift HUD and performed SBHPS (Static bottom hole pressure surveys)On 27-April-2013, Tagged HUD at 2757m(WL)

Target Reservoir: D40 Lower sand

kh 4229 md-ft

Reservoir pressure from initial build up1987 psi at 2969 mtvd

Estimated Mud losses 946 bbl of OBM (during drilling 6" Hole)

♦ ***Fish dimensions:*** The fish was left during running the 4-1/2" Liner, and was tagged during Slick line job with 3.35" fluted drift at 2757 m (WL).Lost tools string composed by.

- *Flapper Valve shifting tools (0.67 m)*
- *2-7/8" EU Pin / Pin XO (0.27 m)*
- *No-Go Sub (0.35 m)*
- *2-7/8" string shoe (3 m)*

III.5. Service Companies Responsibilities :

III.5.1. Responsibilities of Schlumberger Well Test crew :

- Function test methanol injection pumps at the choke manifold prior to start of test.
- Tie cable/clamps will be used in all upstream lines. Swamp weight shall be used on the flare lines.
- Ensure that gas detection equipments will be on site, and functioning.
- Function test the ESD, from all shut down points check the set pilots low and high
- All pressure testing will be with appropriate permits, and test area barricaded
- The material safety data sheets for all chemicals stored on-site during testing operations will be made available.
- Thickness testing of the flow lines should be conducted every 1-2 hrs, during the clean up Periods, If significant amounts of solids are lifted, then the thickness measurements of the pipes should be more frequent (less then 1 - 2 hours), paying particular attention when there is an increase in flow rate and when the slotted liner is being jet blasted
- Withdraw all hot work permits before start of the test.

III.5.2. Responsibilities of Halliburton Coiled tubing crew

- If only one stripper is supplied with the CT spread there must be two pipe rams. This is to comply with two barrier policy. If two strippers are used then the upper stripper is the one which should be used when carrying out the CT operation. When shear seals are employed all connections to the tree or wellhead must be flanged and double valve isolated, thereby excluding elastomers from connections beneath these BOP’s. Ref: BP DWOP (BPA-D-001- Section 23. Coiled Tubing Operations).
- BOP must be flanged to X-mass tree.
- Confirm crane is capable to lift the injector head

III.6.TECHNICALINFOANDWELLBORESCHEMATIC :

III.6.1.CustomerWellboreschematic :

Table III.1 :completionSchematic

FINALCOMPLETIONSCHEMATIC — **FIELD:TEGUENTOURINE** — **WELLNUMBER:Teg-37**

WELLDATA

WellType:	7x5"Prod	**Endofstring:**	2603m	**OriginalRTE:**	9.15
OriginalDrillingRig:	KCADT220	**AnnulusFluid:**	NaClBrine	**NewRTE:**	N/A
NewDrillingRig:	N/A	**AnnulusFluidWt:**	1.03	**MinimumstringID:**	3.502in.
FirstCompleted:	10-Nov-12	**CompletionFluid:**	NaClBrine	**WellTD:**	2999mDDbrt
WorkoverNumber:	N/A	**CompletionFluidWt:**	1.03	**MaxDLS(°/30m):**	0.9
WorkoverDate:	N/A				

CASINGDATA

Size(in.)	Weight	Grade	Thread	MD(m)	TVD(m)
30	310ppf	X56	Welded	5	5
18⅝	87.5&100.5ppf	K55	Buttress	77	77
13⅜	68ppf	K55	Buttress	908	908
10¾(w/ 9⅝)	55.5ppf	L80	VamTop	91	91
9⅝	47ppf	L80	VamTop	1865	1865

WELLHEADDATA

	SUPPLIER	TYPE	RATING	TOPCONNECTION
XMASTREE CAP	Cameron	6.3/8"FLS	5M	9.1/2"OTIS Quick Union
XMASTREE	Cameron	6.3/8"FLS	5M	71/16"APIStudded
2STAGEWELLHEAD	Cameron	SSMC	5M	135/8"Flangelock
TUBINGHANGER	Cameron	135/8"	5M	

LINERDATA

Size(in.)		Weight	Grade	Thread	MD(mDD)	TVD(m)
7"Liner	1794	29ppf	L80	VamTop	2868	2868
4½"SlottedLiner	2600.8	12.6ppf	L80	VamTop	2793.8	2794

ADDITIONALCOMPLETIONINFORMATION

KCADRTE tohangoffpoint(m):	**9.39** 0.47

COMMENTS/ NOTES:
X-masTree:S/N:112183945004P/N:2205085-01
AGV: S/N:112184092-004P/N:2230971-01

PACKER:

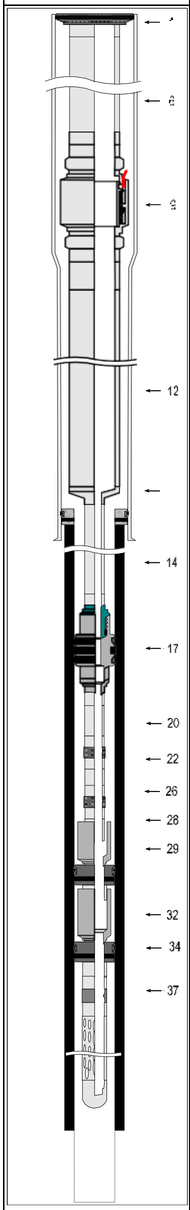
TopofPackertomidelement(mBRT):	0.90
MHPPackermidelement(mBRT):	**2557.43**
Nearest7"Casingcouplings(mBRT):	2572.5
Gapfrom7"x5" Crossoverto9-5/8"x 7"TOL	21.3
Gapfromendofproductionstringtothe topoflinerPBR	3.90
Maximuminclinationbeforebottomnipple	0º
Endofstring including calculated stretch (m):	

RESERVOIRZONES:

			T(ºc)	P(psia)
D40	2937.5mDDbrt	2937.5mDDbrt	144°C	2195Psia

CONTROLLINES:
TRSV:1/4"InconelEncapsulatedControllinewith1/4"Swadgelokfittings.
6x CannonstandardcableclampsusedbetweenTRSVand Hanger.(SAP:372272)
1xCannonSpecialcableclampaboveTRSV.(SAP:477984)

WELL SCHEMATIC



ITEMNUMBER	DESCRIPTION	LENGTH (m)	TOPITEM(mBRT)	ID (inches)	OD (inches)	THREAD	MODULE/No. Joints	SUPPLIER	Volume (bbl)
	CorrectionforRTE(Workover only)		0.0						
1	**TubingHangerbelowHOP** Partnumber:2180000-04-02 Serialnumber:HM6000	0.250	8.92	6.276	14.080	VamTop B	TbgHanger	Cameron	0.0
2	7"PupJoint,26ppf,13CrL80	1.589	9.17	6.276	7.677	VamTop PxP		Cameron	0.2
3	7"Tubing, 26ppf,13CrL80	12.029	10.76	6.276	7.677	VamTop BxP	1	ISG	1.7
4	7"PupJoint,26ppf,13CrL80	1.724	22.79	6.276	7.677	VamTop BxP	1	ISG	2.0
5	7"PupJoint,26ppf,13CrL80	3.096	24.51	6.276	7.677	VamTop BxP	1	ISG	2.3
6	7"Tubing, 26ppf,13CrL80	36.102	27.61	6.276	7.677	VamTop BxP	3	ISG	6.9
7	7"PupJoint,26ppf,13CrL80	3.100	63.71	6.288	7.587	VamTop BxP	ISG-310	ISG	7.3
8	7"FlowCoupling,13Cr,L8026ppf. Part number : 428758SerialNumber:1912 443-3	1.780	66.81	6.221	7.603	VamTop BxP		Halliburton	7.5
9	**TRSV,SPValve,7",SelfEqualizing,13CRWith5.963"'RPT'InternalLockProfile** Part number: 101412309 SerialNumber: 1937674-1	3.283	68.59	5.963	9.231	VamTop BxP		Halliburton	7.9
10	**7"FlowCoupling,13Cr,L8026ppf.** Partnumber:428865SerialNumber: 1855564	1.782	71.87	6.258	7.606	VamTop BxP		Halliburton	8.1
11	7"PupJoint,26ppf,13CrL80	1.939	73.66	6.289	7.579	VamTop BxP		ISG	8.3
12	7"Tubing, 26ppf,13CrL80	1697.097	75.59	6.276	7.677	VamTop BxP	132	ISG	221.4
13	**X-over,7"26ppfx5"15ppf,13CrL80**	0.512	1772.69	4.408	7.677	7" Vam Top Bx 5"VamTopP	1	ISG	221.4
14	5"Tubing, 15ppf,13CrL80	779.660	1773.20	4.276	5.577	5"18#VTBxP	65	ISG	266.8
15	5"PupJoint,15ppf,13CrL80	2.930	2552.86	4.423	5.481	VamTop BxP	ISG-300	ISG	267.0
16	**Ratchet-LatchLocatorSSR(RotaretoReleaseLatch)** Part number:142137 SerialNumber: 2340702-08	0.740	2555.79	3.956	5.484	VamTopB		Halliburton	267.0
17	**7"23-32#MHRPacker,13Cr** Part Number:101481488SerialNumber:2340702-08	1.815	2556.53	3.930	5.857	NewVAMB, 5"18ppf		Halliburton	267.1
18	**ReducingAdapter,5"18ppfNewVamx5"15ppfVamTop,13Cr** PartNumber:141837 SerialNumber:2278088	0.155	2558.35	4.273	5.018	NewVAM5"Px5" VamTopP		Halliburton	267.1
19	5"PupJoint,15ppf,13CrL80	1.869	2558.50	4.472	5.483	VamTop BxP		ISG	267.3
20	5"Tubing, 15ppf,13CrL80	11.969	2560.37	4.408	5.470	VamTop BxP	1.0	ISG	268.0
21	5"PupJoint,15ppf,13CrL80	2.985	2572.34	4.380	5.448	VamTop BxP	ISG-306	ISG	268.2
22	**3.813"'R'LandingNipple** Partnumber:137354SerialNumber:2297261	0.400	2575.33	3.813	5.525	VamTop BxP		Halliburton	268.2
23	5"PupJoint,15ppf,13CrL80	1.914	2575.73	4.439	5.457	VamTop BxP		ISG	268.3
24	**5"Tubing,15.0ppf,13CrL80,R3**	11.979	2577.64	4.408	5.470	VamTop BxP	1.0	ISG	269.1
25	5"PupJoint,15ppf,13CrL80	2.925	2589.62	4.397	5.468	VamTop BxP	ISG-307	ISG	269.2
26	**3.813"'RN' LandingNipple** PartNumber:137319SerialNumber:2297262-07	0.415	2592.54	3.725	5.525	VamTop BxP		Halliburton	269.3
27	5"PupJoint,15ppf,13CrL80	2.044	2592.96	4.398	5.459	VamTop BxP		ISG	269.4
28	5"Tubing,15.0ppf,13CrL80,R3,c/w1/2muleshoe	8.000	2595.00	4.408	5.000	VamTop BxP	1.0	ISG	269.9
	BottomofString		2603.00						
29	PolishedBoreReceptacle7"x5"20-35#PBR	3.450	2600.80	5.710	5.775			Weatherford	0.4
30	LinerTopPacker-CTSP4R7"x5"29-32#	1.590	2604.25	5.870	5.920	VamTopP		Weatherford	0.5
31	SeatStem	0.980	2605.84	5.220	5.930	VamTop BxP		Weatherford	0.6
32	PolishedBoreReceptacle7"x5"20-35#PBR	5.000	2606.90	3.958	4.937			Weatherford	0.2
33	LinerTopPacker-CTSP4R7"x5"29-32#	1.080	2611.90	4.330	5.910	VamTopP		Weatherford	0.3
34	HydraulicNonRotatingLinerHanger Assy.CTH	1.610	2612.98	4.330	5.910	VamTop BxP		Weatherford	0.4
35	5"Tubing,15.0ppf,13CrL80,R3	13.022	2614.59	4.408	5.470	VamTop BxP	1.0	ISG	1.2
36	5"x-overpupjoint,15ppf,L80	2.940	2627.61	4.408	5.470	5" Vam Top B x5"NewVamP		ISG	1.4
37	**FlapperValve(KOIV),L-80,13Cr** Part number: 812EGF7505-F / 101755785SerialNumber:	0.830	2630.55	3.502	4.937	5" Vam TopBx41/2"Vam Top P	FV-1	Halliburton	1.4
38	4.5"x-overjoint,12.6ppf,L80	1.950	2631.38	3.958	4.960	VamTop BxP		ISG	1.5
39	4.5"slottedliner,12.6ppf,L80 Note:4.5"Stinger Packoffat3014m.ID1.50".	160.500	2633.33	3.958	4.960	VamTop BxP		ISG	9.5
	BottomofStringc/wGuideShoe		2793.83						

Initial: OzgurOzbay26/10/2012Updated:JudeEronmwon05/11/201

III.6.2SuspensionSchematic

Rig Name:KCAD
T220RTE:9.15m
RTEtohangoffpoint: **9.39**

Teg-37

SuspensionSchematicFina

Note:AlldepthsreferencedtoKC D220RTE=9.15mAGL

WellData:

Hole Size	Depth(mDDbrt)
24"	77
17-1/2"	910
12¼"	1868
8½"	2874
6"	2999

Casing	Depth(mDDbrt)
30"	5.0
18⅝"	76.8
13⅜"	908.0
10¾"x9⅝"CrossOver	91.0
9⅝"	1865.0
7"LinerPBR Top	1794.0
7"LinerShoe	2868.0
4½"SlottedLiner PBR Top	2606.9
4½"SlottedLiner Shoe	2793.8

Completion Summary:	Depth(mDDbrt)
7"TRSV	68.6
"5.963"'RPT'ProfileonTRSV	68.6
X-over 7"x5"	1772.7
RatchetLatch-RotateType	2555.8
7"MHRPacker	2556.5
3.813"R Nipple	2575.3
3.813"RNNipple	2592.5
Bottomof5"Tubing	2603.0

Reservoir Isolation

FlapperValve	2630.6

SuspensionDetails:

TRSVclosed
BPVset in tubinghanger

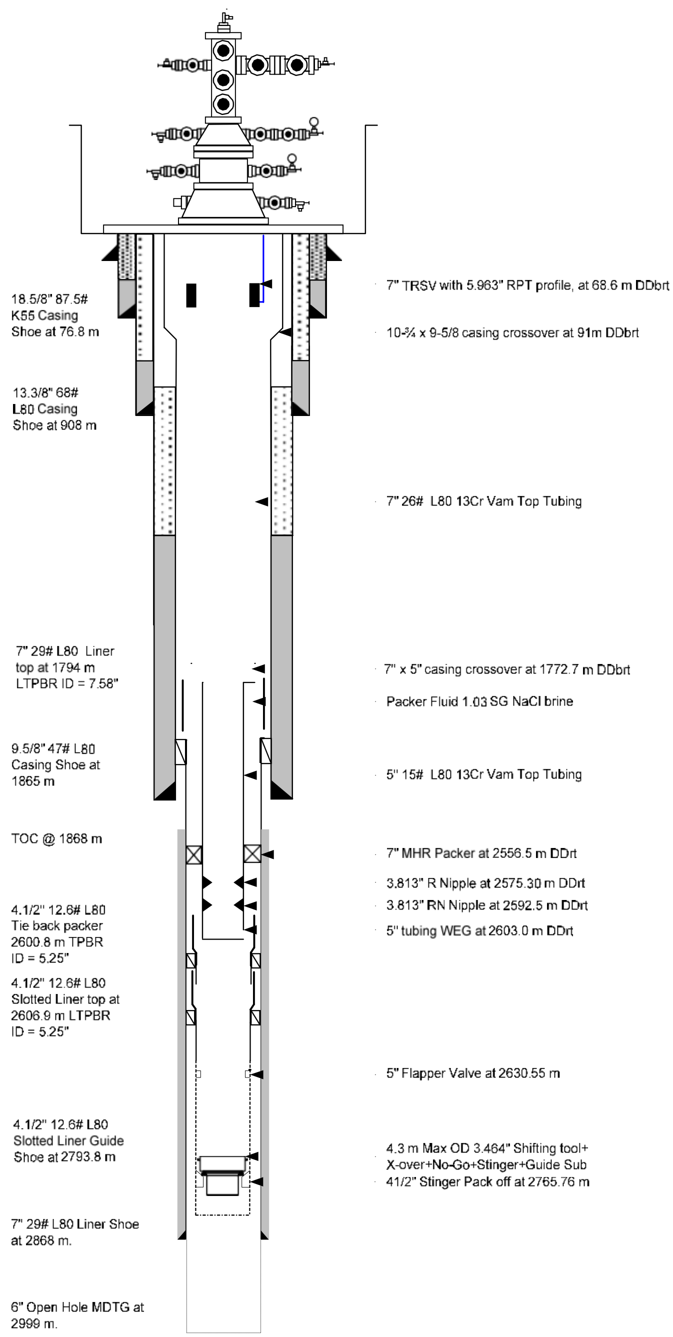
ReservoirSections

LowerD40	Top	2937.5mDDbrt

Reservoirconditionsattopofreservoir

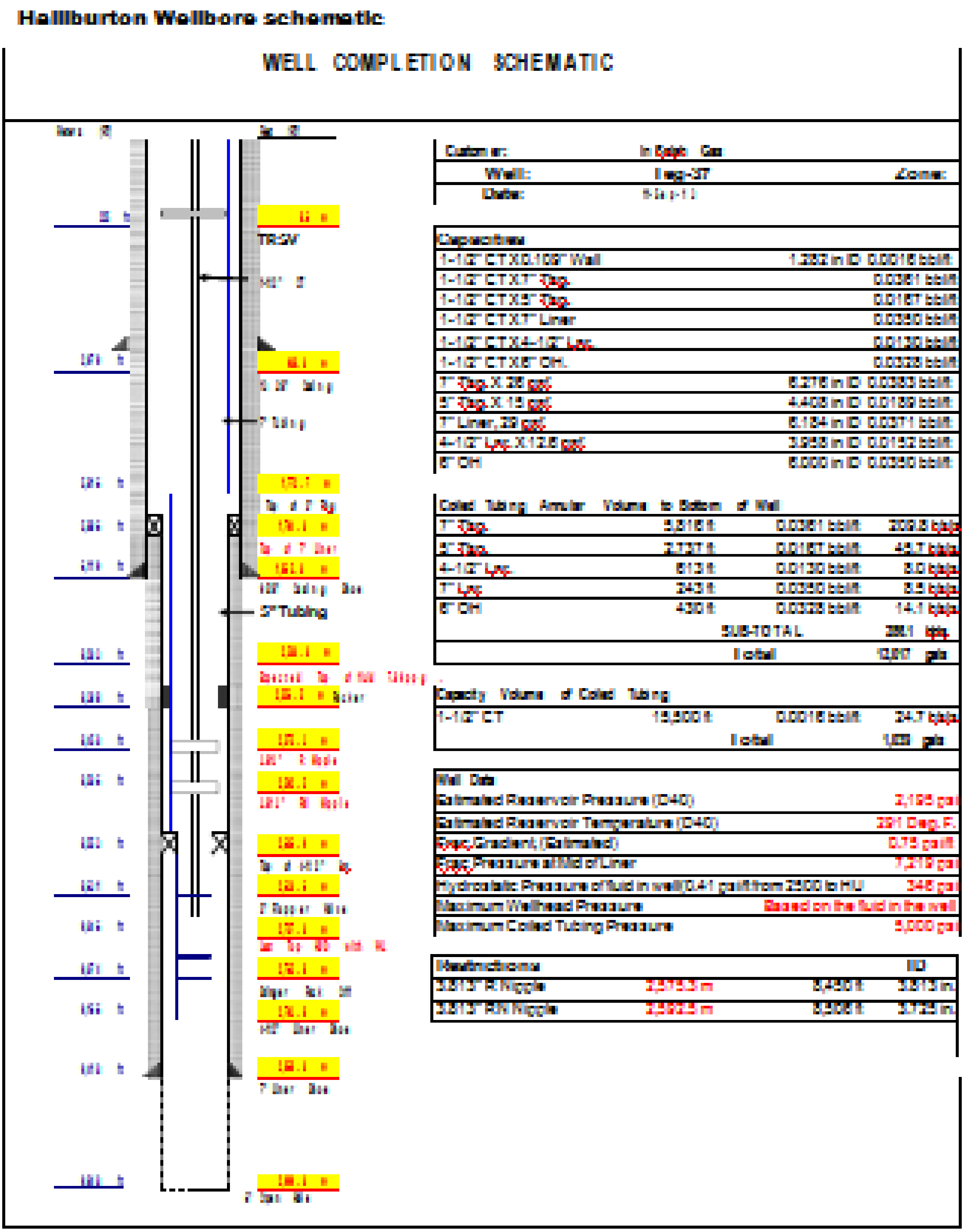
D40

Pressure	2317PsiaTBC
Temperature	144°C



Initial: OzgurOzbay
26/10/2012Updated:JudeEronmwon0
5/11/2012

FigureIII.5 : Teg-37SuspensionSchematic-Final



III.7. JOBPARAMETERS :

III.7.1.Wellbore Teg-37 :

Tubing1	0ft	to	5,816ft	7"	X	26	PPF	X	6.276"ID
Tubing2	5,816ft	to	8,553ft	5"	X	15	PPF	X	4.408"ID
Casing	0ft	to	6,119ft	9-5/8"	X	47	PPF	X	8.681"ID
Liner	8,553ft	to	9,840ft	41/2"	X	12.6	PPF	X	3.958"ID
Packer	8,388ft								

III.7.2.Reservoir :

EstimatedReservoirPressure(D40)

2,19

5 psiEstimatedReservoirTemperature(D40)

291

Deg.F.FracGradient,(Estimated)

0.75

psi/ft

FracPressureatMidofLiner 7,219

psiHydrostaticPressureoffluidinwell(0.41psi 346

psiMaximumWellheadPressure Basedonthe

fluidinthewell

MaximumCoiledTubingPressure 5,000psiEquipementLimitation

III.7.3 Fluids :

FreshWater 1,389gals

Nitrogen 7m3

FreshWater requiredfortheoperationwillbesuppliedbyclient

III.7.4 EquipmentRequired :

1ea. 1-1/2" x 0.109" Wall Thickness, QT - 900 Coiled Tubing Unit1ea. ClamMixingUnitwithHT-400Pump

1ea. Nitrogen Pumping Unit with 10 m3 N2 storage tank1ea. 26m3Nitrogentransport

III.7.5.BHA :

1ea ServiceConnector

1ea DoubleFlapperCheckValve

1ea HydraulicDisconnect

1ea KnuckleJoint

1ea 1MeterStraitJoint

1ea WashNozzle

III.8. JOBPROCEDURE :

Table III.2 : job procedures Represents

Teg-37:WellUnloading

Stage No.	StageVolume(bbl)	Fluid	StagesDescription	Stage Clean Volume (gals)	StageN2 Volume (liters)	Total Clean Rate (bpm)	Stage Time (min)	Job Time (min)
1			**Conductsafetymeeting,ensureinvolvedpeopleandcompanymanarepresent.**				15min	15min
2			Rig up CT , pumping & N2 units, Rig up surface lines to CT Function test BOP. **(See Note#5below).**				100min	115min
3	25	FreshWater	FillcoiledtubingandsurfacelineswithFreshWaterforpressuretesting.	1,039		1.20	21min	136min
4		Nitrogen	CooldownNitrogenunit.		1,000			136min
5	2	FreshWater	Pressure test CT against swab valve and N2 pumping lines separately to 500/4000psi for 5/10mnrespectively.	100			45min	181min
6	6	FreshWater	OpenSwabvalve,Openwingvalveandcirculatetoseefluidreturns	250		1.20	5min	186min
7		Nitrogen	UseN2toDisplaceFreshWaterfromCTtotheflarepit		600		20min	206min
8			Open well (make sure TRSSV is open) and start RIH at **20 fpm** until pass the **TRSV (68.6 m/225 ft).**				11min	217min
9			ContinuRIHto**2,300m@65fpm,**saferunningspeedwithoutpumpingN2.Performcheck weightevery**2,000ft.**				116min	333min
10		Nitrogen	ContinuRIHto**2,745m@30fpm**whilepumpingN2at**20l/mn**		973		49min	382min
11		Nitrogen	StopCT at**2,745m**,Pump**0.5m3**ofliquidNitrogenathighrate(40-60lpm)		500		10min	392min
12		Nitrogen	Slowdownnitrogenratetothe20-25lpm,makesureallthefluidabovethisdepthhasbeendisplaced,untillonlyN2observedonsurface.		800		40min	432min
13		Nitrogen	ContinuepumpingNitrogenat20-25lpm,untilwellstartstoflowandcansustaintheproduction onitsown.Adjustnitrogenrateifneeded.		1,000		33min	465min
14		Nitrogen	POOHtosurface,whilemaintainingN2circulationatminimumrate15lpmifneeded.		1,350		90min	555min
15			Close the swap valve,secure the wellandrigdownInjector.				60min	615min
16			Leavethewellflowingforcleanup.					615min
Totals	**33.1bbl**			**1,389**	**6,223**			**10.2hrs**

Note

1) Thewellneedstobeequippedwithaflarelineandanadjustablechokerunningasafedistancefromthewell.

2) Theaboveisaguideline.Adjustrates&volumesasneededtosuitethejobrequirement.

3) Attempt tostabilizeN2rateandCTspeedtounloadthewell fluidat 500scf/bbl

4) Thechokeshouldbeproperlyadjustedtomaintainbackpressureinthewellandavoidexcessivedrawdown

5) Plantoperformofflinethefollowingtest:piggingCT,pressuretestsofblindandpiperams.

III.9. Procedure :

1. Conductsafetymeeting,ensureinvolvedpeopleandcompanymanarepresent.
2. RigupCT,pumping&N_2units,RigupsurfacelinestoCTFunctiontestBOP.(SeeNote#5below).
3. FillcoiledtubingandsurfacelineswithFreshWaterforpressuretesting.
4. CooldownNitrogenunit
5. PressuretestCTagainstswabvalveandN2pumpinglinesseparatelyto500/4000psifor5/10mnrespectively.
6. OpenSwabvalve,Openwingvalveandcirculatetoseefluidreturns
7. UseN_2toDisplaceFreshWaterfromCTtotheflarepit
8. Openwell(makesureTRSSVisopen)andstartRIHat20fpmuntilpasstheTRSV(68.6m/225ft).
9. Continu RIH to 2,300 m @ 65 fpm, safe running speed with out pumping N_2. Perform check weight every2,000ft.
10. ContinuRIHto2,745m@30fpmwhilepumpingN_2at20l/mn
11. StopCTat2,745m,Pump0.5m3ofliquidNitrogenathighrate(40-60lpm)
12. Slowdownnitrogenratetothe20-25lpm,makesureallthefluidabovethisdepthhasbeendisplaced,untillonly N_2observedonsurface.
13. ContinuepumpingNitrogenat20-25lpm,untilwellstartstoflowandcansustaintheproductiononitsown.Adjustnitrogenrateifneeded
14. POOHtosurface,whilemaintainingN_2circulationatminimumrate15lpmifneeded.
15. Closetheswapvalve,securethewellandrigdownInjector.
16. Leavethewellflowingforcleanup.

III.9.1 Note:

1-Thewellneedstobeequippedwithaflarelineandanadjustablechokerunningasafedistancefromthewell.

2-Theaboveisaguideline.Adjustrates&volumesasneededtosuitethejobrequirement.3-AttempttostabilizeN2rateandCTspeedtounloadthewellfluidat500scf/bbl .

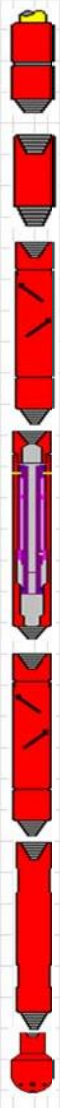
4-Thechokeshouldbeproperlyadjustedtomaintainbackpressureinthewellandavoidexcessivedrawdown .

III.10. CTBOTTOMHOLEASSEMBLY:

BOOTS & COOTS
A HALLIBURTON SERVICE

STANDARD WASH BHA SCHEMATIC

Customer:	JV-Gas	Customer Rep:	
Field:	ISG	Well Type:	Gas
Well Nos:	Teg-37	HES Rep/s:	
Rig Type:		HES Office:	
Installation:		Service Order:	
Location:	In Salah/ khrechba	DATE	September 11, 2013



Tool String	Item Nos	O.D. (inches)	I.D. (inches)	Length (Inches)	Description of Item	Top Conn	Bottom Conn
	1	1.750		1.50	Roll on connector		
	2	2.000		4.75	Bump Sub		
	3	1.700	0.72	10.50	Double Flapper Valve		
	4	1.810	0.54	12.00	Hydraulic Disconnect		
	5	1.760	0.50	15.50	Knuckle Joint		
	6	1.690		23.75	Straitgh Bar		
	7	2.000		6.00	Wash Nozzle		
				74.00 in			

Figure III.6:Standard wash BHA shematic

Note:AlllengthsandODsneedtobecheckedandnotedbeforerunningtheBHA.

III.11.RIGLAYOUT :

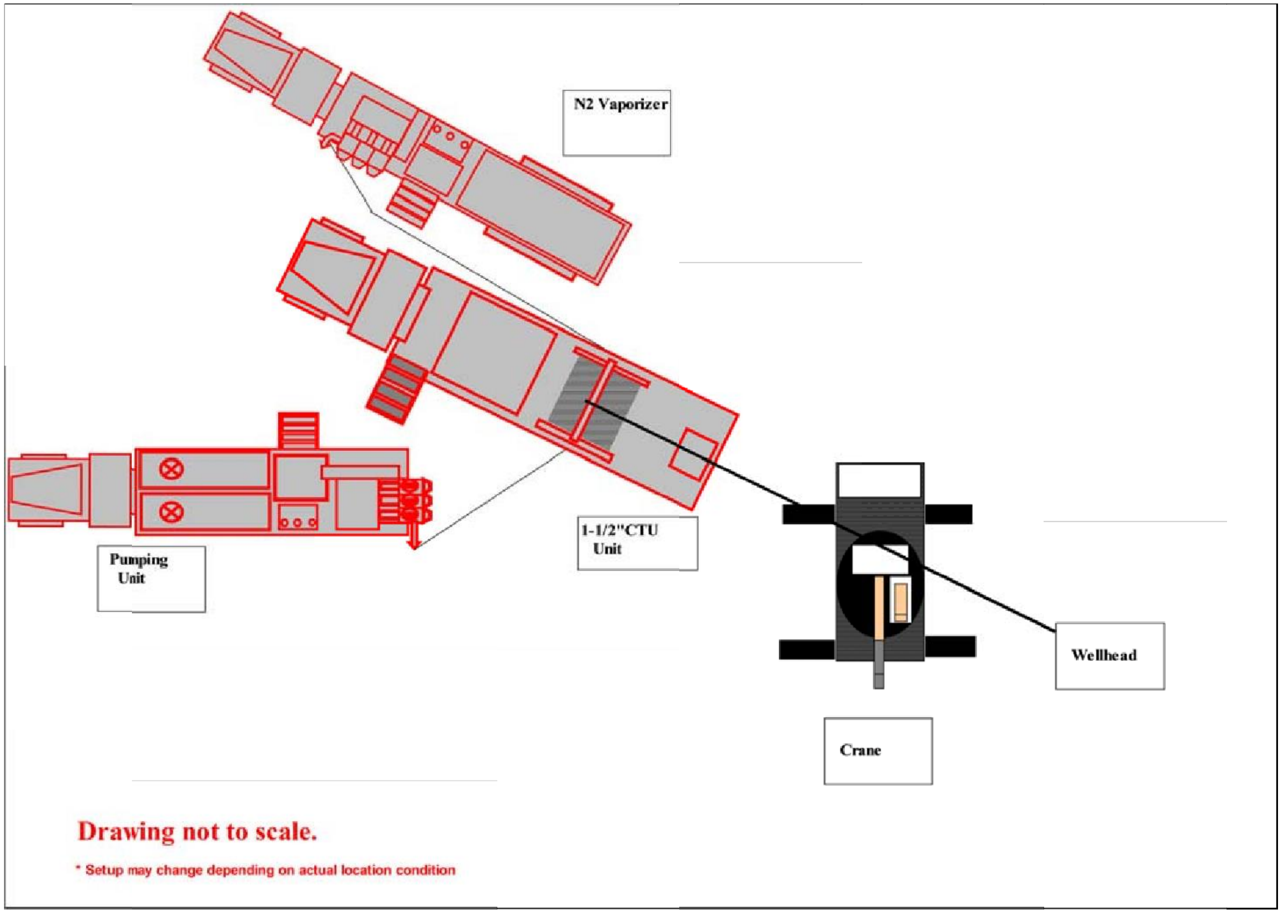


Figure III.7 :RigLayoutRepresents

III.12.STACKUPDIAGRAM :

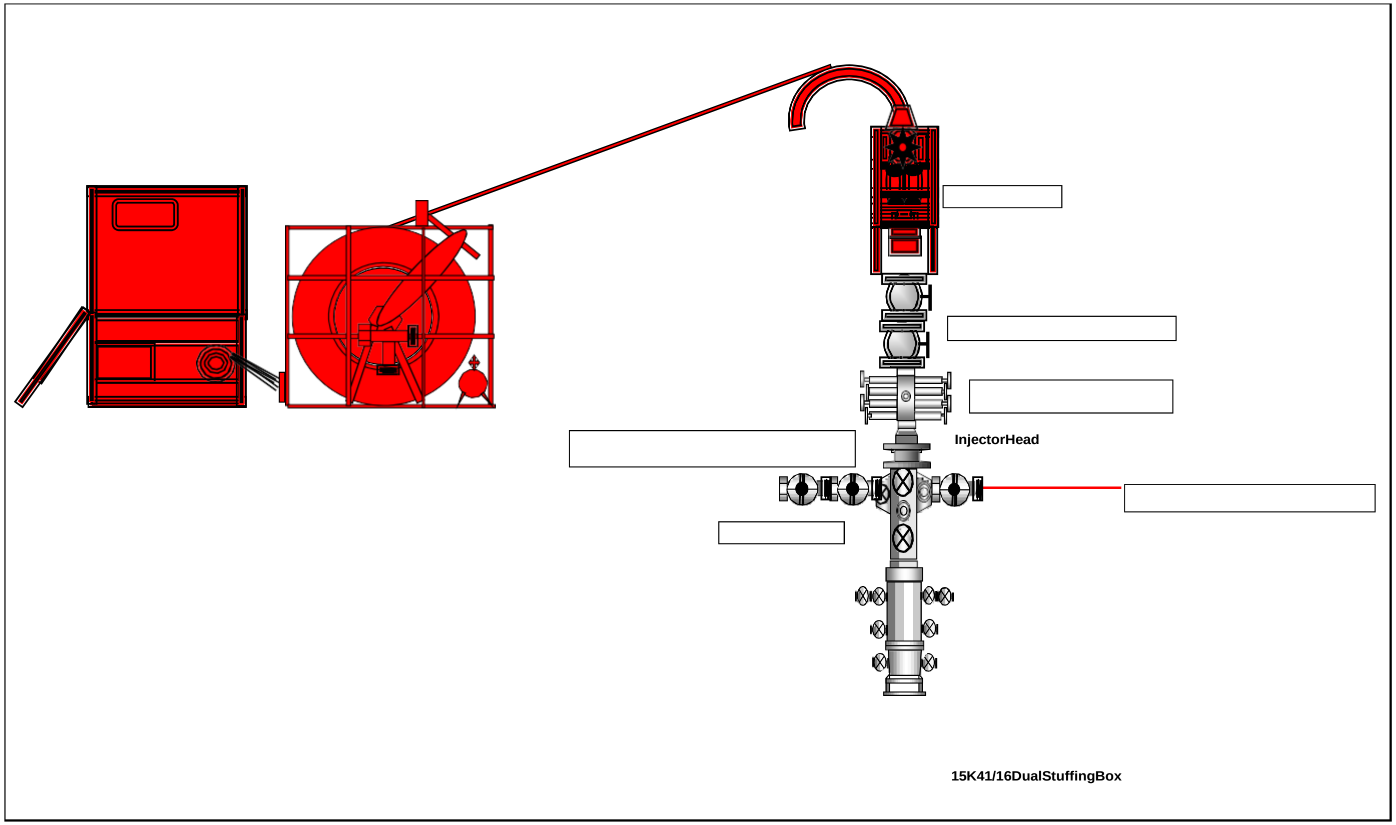


Figure III .8 :STACKUPDIAGRAM

III.13. Slick Line and Clean Up Operations step by step :

III.13.1.Day 1: Slick Line WORK :

Drifting To Total Depth (HUD) :

- With the well shut-in at the choke and manual wing valve, make up a 3.3 " sized tubing drift/gauge (1-3/4" CT will be used in N2 lift), and attach to the wire line tool string.
- Connect the lubricator, and pressure test.
- Open the UMV. Slowly open the Swab Valve (SV) to expose the lubricator assembly to full well pressure. Note the shut-in tubing pressure.
- When 5 m below DHSV POOH slowly to confirm DHSV is open. If hanging up stop and evaluate. Cont to RIH to establish HUD. POOH
- Take note of any restrictions or over pulls encountered while making the drift run in the well.
- Close UMV and SV on Xmas Tree, bleed-off pressure, break lubricator and remove the drift tool, Inflow test / tree valves and grease if needed.

III.13.2.Day 2 :RU of Schlumberger Test Equipment :

Well Test Equipment Rig-up :

- Obtain a work permit prior to commence the job.
- Prior to any operations hold a safety meeting with all personnel involved, and ensure that all safety signs are in position and well test area is enclosed by barrier tape.
- Ensure the manual production wing valve, UMV and LMV is locked in the closed position.
- Rig up the Schlumberger ESD to hydraulic WSSV.
- Rig up Schlumberger surface test equipment to Schlumberger ESD and out to the flare pit.
- Ensure to avoid 90 degrees elbows in the rig-up as much as possible to avoid unnecessary erosion. It is particularly important not to have an elbow on the outlet of

the choke manifold The flare line should be chocked up so it can be screwed straight onto this outlet.

- All lines to choke manifold tested to 3500 psi. And all lines down stream the manifold must be tested to 1200 psi .And the area must be cleared when that pressure test is ongoing.
- Ensure that there are no intrusive probes in any of the upstream or downstream lines (thermo wells, etc) especially during the clean-up period. Rocks can damage these probes and cause leaks if not sealed in. Any intended in-line probes in the lines must only be inserted after the well has been cleaned up, Risk Assessed, and ensured to have a positive and rated pressure seal (needle valve, gauge, etc).

PRESSURE TEST EQUIPMENT :

- Move in rig up Schlumberger pump unit
- Get 2 radios to communicate between pump operators and well test chief operator.
- Barrier off area.
- Discuss test procedure with pump operator and all the other personnel involved highlighting risks.
- Make sure all valves to flare are open before flushing lines.
- Start flushing lines at pumping rate of 1.5 bbl/min with centrifuge pump. Once clear returns are observed at flare line end, stop pumping.
- Install 6” 206 Test plug on flare line with valve on test plug open.
- Flush again lines at low pumping rate with centrifugal pump.
- Stop flushing and isolate flare line (close valve on test plug).
- From SLB Unit apply 300/1200 for 5/10 min. (Record all pressure test on chard recorder)
- Close downstream valves on choke manifold.
- Bleed off at the 6” test plug at flare end and remove plug.
- Confirm to pump operator that the pug has been removed.
- Apply 300/3500 for 5/10 min against downstream valves on choke manifold.
- Close upstream valves on choke manifold.
- Open downstream valves.

- Apply 300/3500 for 5/10 min against upstream valves on choke manifold.
- If the pressure test passes, bleed off pressure from surface lines and secure the well area before leave the well.

III.13.3.Day 3: Coiled tubing Rig Up and Unloading the Well:

Check weather forecast for the well location for the time period when hydrocarbons will be first produced to surface. If acceptable weather conditions are anticipated for the beginning of the test, proceed with the test programme. Unacceptable conditions are high winds particularly ones blowing toward rig, blowing sand, and low visibility.

- Ensure to have a valid flaring permit in place before commencing the job, Inform the OLC and the military prior to start the flare.
- Carry out gas check prior to moving CT unit to the well.
- Confirm tree valve status.
- Spot and rig up the CT unit and associated equipment as per HES's standard operating procedures and JVGAS regulations.
- Prepare N2 equipment.
- M/U BOP and CT nozzle (CT tools string composed by, Roll on Connector 1.75", Bomb Sub 2", Dual Flapper check valve 1.7" , Hydraulic disconnect 1.81", Straight bar 1.69", Wash Nozzle 2 ").
- Ensure hydraulic disconnect will work if needed to release CTand also use an appropriate bull size.
- P/T to 500/4000psi for 5/10 minutes for CT PCE and surface lines..
- Open TRSSSV using Enerpac hand pump. Keep it open at 300 to 320 bars.
- Open Swab valve and UMV. Record WHP.

Ensure that the TRSSV is kept open all the time when CT is down hole..

- Start RIH. Take extra care when running through X-mas tree valves and TRSSSV. Once through TRSSSV come on line with N2 at minimum rate. Get weight. checks every 500 m while RIH
- Open the well at choke manifold on adjustable choke (128/64") to flare pit.
- RIH with the Coiled Tubing not faster than 6 m/min.

Visually inspect the line-up from the tree to the burners and check that all valves are in the correct position. The Intervention Supervisor and the Well Test Supervisor should witness this.

- Once clear of the TRSSV increase RIH speed to 15 to 20 m/min and start pump N2 at minimum rate, When at depth below 2500 m, start injecting nitrogen at a minimum of 500 scf/min
- Insure that “A” and “B” annulus are monitored during the flow period to ensure they do not exceed maximum allowable pressures, No more then 500 psi.
- Conduct pull test every 250 m and compare weights with calculated weights. Slow down running speed going through the landing nipples and the top of liner, returns are to be taken to the flare pit. Monitor fluid returns closely for any signs of gas, Ensure that the pilots are lit.
- Continue RIH in steps of 250 m each parking the coil for 5/10min maintaining nitrogen rate at 500 scf/min until the well starts flowing or until the end of the coiled tubing is at 2745 m (Last HUD-10 m), continue to pump nitrogen until the hydrocarbon liquid (Top of hydrocarbon liquid proximately 2500 m)has been displaced with nitrogen.
- N2 has to be shut in prior to closing the well for the not frac the formation,
- Once it is confirmed that the well will flow without N2, POOH with CT into the lubricator and close the Swab valve. Clean up the well at the highest rate possible and at lowest possible FWHP
- Monitor the flow line for signs of erosion, especially if solids are produced. Record Ultrasonic thickness measurements.
- If there is any indication of flow line erosion, well must be secured and lines have to be opened and inspected.
- Flow the well until all of the hydrocarbon liquid has been flared
- The length of the clean up period is a judgment call of the well site OPS Intervention Supervisor.
- Bleed off and maintain annulus pressure below 500 psi during the clean up. Record the volume and type of fluids recovered and report on the OPS daily report and Well test report.
- Obtain pressures at various choke settings with estimated flow rate at the Data Acquisition Unit, and reported in well test reporting.
- Obtain condensate gas ratio (CGR) measurement in the end of the clean up operation.

III.14.4.Day 4: Rig Down of Well test equipments :

This step is to be done after confirming the well iscleaned up and not necessary in the 4thday .

- With the UMV, Manual Wing Valve, Actuated Wing Valve, and Kill wing closed, open the swab valve and bleed down the pressure through the choke manifold and inflow test of tree-x.
- Open the kill wing valve keep all valve closed and flush the Schlumberger test equipment with fresh water.
- Rig down ESD from the WECO connection. necessary
- Rig down Schlumberger test equipment.
- Open the kill wing valve to bleed any trapped pressure and then close it again.
- Remove the 2-1/16” flange x 2” 1502 WECO from the kill wing.
- Pressures test the companion flange to 5000 psi with a hydraulic hand pump against the kill wing valve.
- With the Wing Valve, Actuated Wing Valve, and Kill wing closed, open the swab valve and close the swab needle valve.
- Function test of WSSV and close it
- Slowly open the UMV to test the tree cap installation**,** the tree cap flange and cap needs to be tested to 5k. All pressure tests should be recorded and retained.
- Close the UMV and bleed off the pressure above the UMV through the swab needle valve.
- Close the swab valve..
- After rig down of all equipment, check the site to verify it is as clean as before the operation.
- Notify the Area Authority and Teg Operations Superintendent that the cleanup is complete and sign off on the permit.

III.15.CALCULATIONS :

III.15.1.Weight of Gas Column to 2500 m (Top of hydrocarbon liquid) :

- WHP = 85 bars (1232 .5 psi)
- Correction factor for gas with SG : 0.628 = 1.181
- HP = 1.181 X 1232,5 = ***1456 psi***

III.15.2.Weight of Hydrocarbon liquid from 2500 m to (HUD – 10 m) :

- Hydrocarbonliquid gradient = 0.4 psi / ft
- HUD = 2757 m
- HP = 0.4 x (247 X 3.28) = ***324 psi***

Total weight of Gas column and hydrocarbon column to (HUD – 10 m) = 324 + 1456 = ***1793 psi.***

III.15.3.Wight of hydrocarbon column from (HUD – 10 m) to top perforation (at 2930 m) :

- Length of the hydrocarbon column = 2930 -2747 = 183 m
- HP = 0.4 X (183 X 3.28) = ***240 psi***.

III.15.4.Total weight of Wellbore fluid column to top perforation (at 2930 m) :

Total weight = 240 + 324 + 1456 **= 2020 psi.**

- Reservoir pressure = ***1961 psi*** (June 2012) (From SOR of Teg-37).
- Bottom hole pressure at Gauge depth (at 2750 m WL) = ***1848 psi*** (***Pressure Gradient Surveys Job on the 27/04/2013***).

III.16.*Diagrams and*Scenario *Schematics:*

III.16.1.1st Scenario: 55 mmscf/d (Shlumberger Simulation) :

2 Well Test Layout

2.1 Pfd Drawing

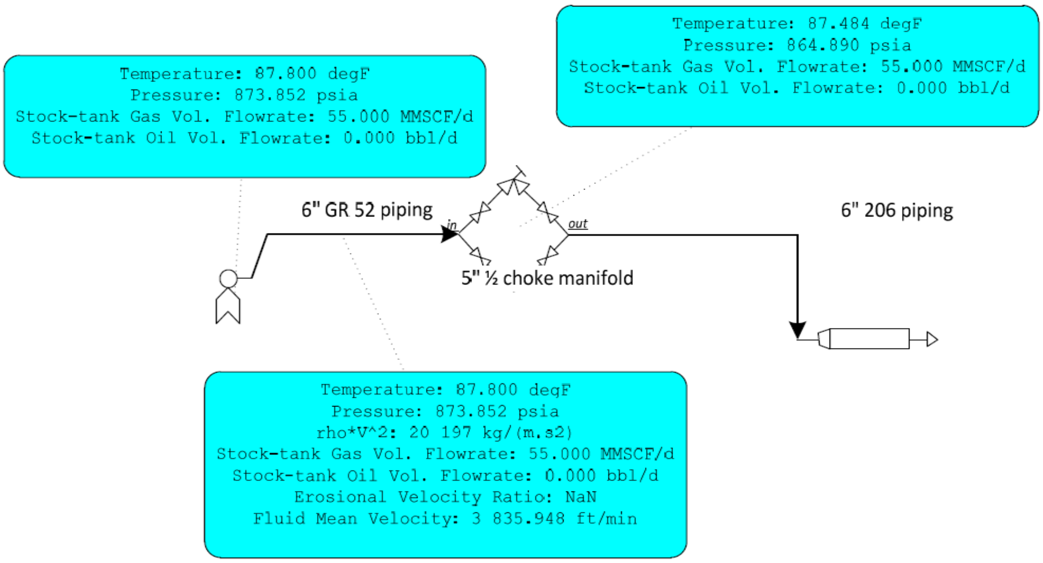


Figure III .9:Scenario well test Layout 1

III.16.2.*2nd Scenario : 14 mmscfd*(Shlumberger Simulation) :

2.1 Pfd Drawing

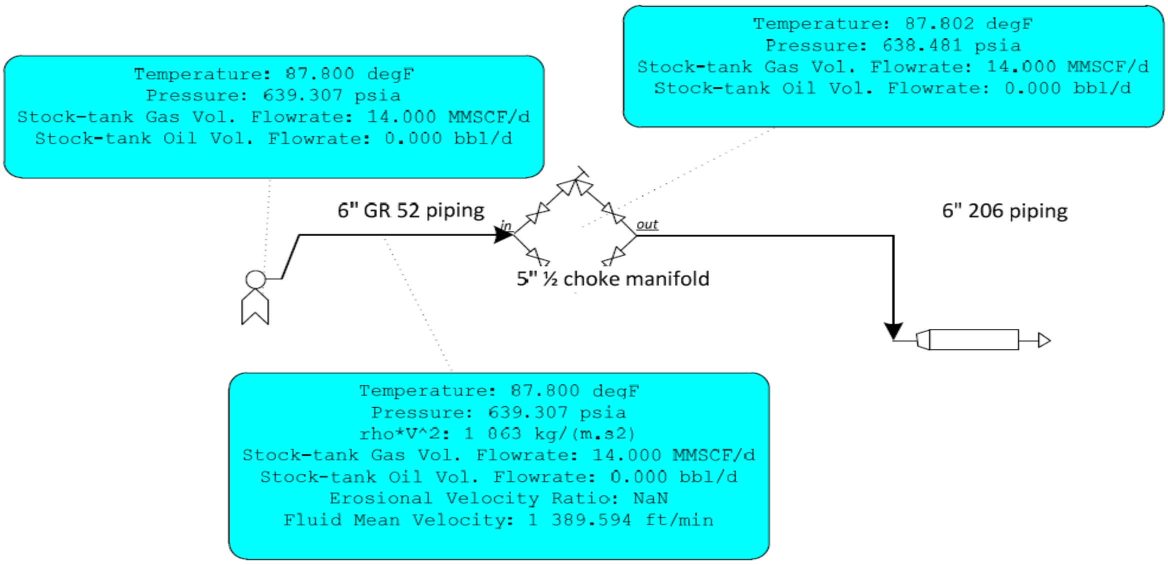


Figure III .10 :Scenario well test Layout 2

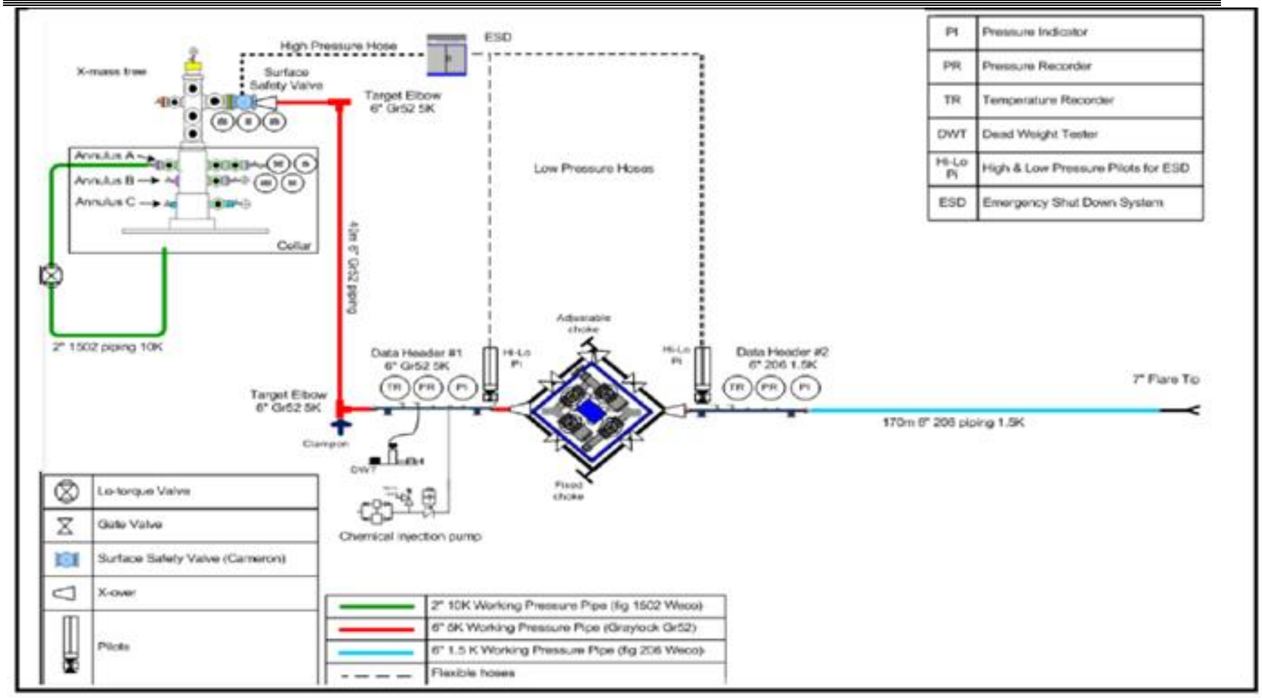


Figure III.11 : surface testing equipment layout

III.17. conclusion :

In each case study couled tubing is used to solve the problems posed or to maintain the well and to save the production but in the other cases we will change the parameters of well operations as another hole layer link is created. and all these interventions are successful without problem but each operation is expensive so the transition after the problem creates continuity in productivity .

Reservoir pressure is less then column weight by about ***60 psi.***

CT and Clean up will be able to reduce bottom hole pressure by 324 psi maximum from the 2020 psi (Total weight of the column in the Wellbore to top perforation.

ConclusionGeneral :

According to the present study and before highlighted the importance and the effectiveness of the couled tubing interventions the wells, with all the advantages to the intervention on the wells is production. Among the advantages can be Technological development in terms of dealing with problems. impede production processes (Tools and calves treatment programs and the establishment of modern processes to restore, protect and increase productivity, New chemicals more effective than those currently used

✓multiesed tool multiesmultized in the same process increases the success rate

✓Specific transition between interventions due to specific problems of some disadvantages such as

✓The development of the mechanism used in the interventions creates a price increase

✓Different techniques of intercreation of hemutations of result options of multivariate of the multifier several new products chSimiques creates new problems that cannot be solved

✓The disruption of safety during new interventions in the pilot phase of the primary

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