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7" Monobore Completion Design for Qatar's Offshore North Field

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Abstract

Producing gas from the Khuff formation in Qatar's offshore North Field presents several completion design challenges. The North Field Khuff formation is a competent limestone / dolomite that is estimated to contain a GIIP of 504×10^{12} scf (504 TCF), which makes it the largest single accumulation of natural gas in the world. The North Field Khuff gas contains hydrogen sulfide and carbon dioxide concentrations of approximately 5,000 ppm and 2.5 mole percent, respectively. Initial condensate yields exceed 40 bbl/MMscf. For design purposes, brine water production was taken into account when making the metallurgical choices for the completion equipment. The producing interval, Khuff K-4 at a datum of 9,400 ft. subsea has a bottom hole temperature of 222°F, and an initial shut-in bottom hole pressure of 5,265 psi. Actual well deviations range from vertical to slightly over 60° from vertical, but all completion equipment was designed and tested to function properly in horizontal wells. The monobore completions have also been designed to accommodate high rate and high volume HCl acid stimulations that are performed during initial completions, and that may be needed throughout the life of the field.

Qatar's North Field monobore completions have been designed to accommodate all of the above well conditions under all expected wellbore load cases, while providing years of trouble free service.

This paper describes the wellbore and equipment design concepts utilized, the equipment innovations made, the equipment installation philosophy and results, and the equipment performance realized to date for the monobore completions in Qatar's offshore North Field.

Introduction

Qatar's North Field is comprised of the Khuff gas accumulation, a Permian - Triassic carbonate sequence, situated offshore Qatar (**Fig. 1**). This gas accumulation was discovered in 1971 with the NWD-1 well. Subsequent to the NWD-1 well, several appraisal wells were drilled with the goal of defining the reservoir limits and gathering reservoir rock and fluid data for potential future development. As a result of this drilling, testing, and subsequent development, Qatar's North Field is now believed to be the largest single accumulation of natural gas in the world.

First Phase Field Development Project. The initial North Field development project was designed for the purpose of providing a reliable domestic supply of natural gas for Qatar. The project is called North Field Alpha or NFA - Phase 1, and consists of 16 wells designed to produce 800 MMscf/d (**Fig. 1**). Each well was designed to produce up to 60 MMscf/d through a conventional packer type completion with a 5-1/2" x 5" CRA tubing string. The first gas production from this project came in July, 1991.

Second Phase Field Development Project. The second North Field development project followed soon after the first project, and was designed for the purpose of providing a reliable supply of LNG to the Far East market. This project is called North Field Bravo or NFB - Phase 2 and the original plan called for 24 wells designed to produce 1,200 Mmscf/d (**Fig. 1**). These wells were all to be conventional packer type completions similar to the previously discussed NFA development. The revised plan of development calls for 20 wells designed to produce 1,200 MMscf/d. Five of the wells are to be completed as originally planned, and fifteen wells are to be completed as 7" monobores. Four wells were dropped from the original plan after satisfactory well performance results were confirmed from several of the initial monobore wells. If needed, the monobore wells are designed to be capable of producing in excess of 100 MMscf/d. This development is still ongoing, as the last five monobore wells are currently being drilled and completed. The first gas production from this project came in July, 1996. The monobore completions that were designed and run, and that are currently producing for this project are the subject of this paper.

Third Phase Field Development Project. The drilling program for the third North Field development project, called NFR, is just now getting underway **(Fig. 1)**. This project is also designed for the purpose of providing a reliable supply of LNG to the export markets. Because of the success of the NFB project, these wells will also be completed as monobores.

Discussion

Monobore designs are typically the most effective method of accomplishing high rate completions, and facilitating reservoir management. Monobore completions utilize the production liner as the non-removable bottom section of the tubing string. The upper part of the tubing string is removable, and is stung into a polished bore receptacle (PBR) in the top of the production liner.

Monobore Advantages. The following are potential advantages of a monobore completion versus a conventional packer type completion.

1. Less complex wellbore design.
2. Can increase tubing size with same casing program, or can maintain tubing size with smaller casing program.
3. Allows for more completion contingencies.
4. Reduces wellbore frictional pressure drop allowing:
   a) Higher flowing tubing pressure at same rate.
   b) Higher well deliverability at same flowing tubing pressure.
   c) Delay of compression.
   d) Improved stimulations through higher pump rates for more effective diversion.
5. Enhances operational efficiency by:
   a) Reducing number of wells needed for field development.
   b) Providing additional production capacity to meet peak demand or in event of loss of well(s).
   c) Providing wellbore flexibility.
   d) Facilitating easier, safer, and more effective:
      i) Water shut off.
      ii) Selective zone testing.
      iii) Selective zone stimulating.
      iv) Thru-bore operations.

Monobore Disadvantages. The following are potential disadvantages of a monobore completion versus a conventional completion.

1. Mechanical loads typically increase.
2. May eliminate a down hole pressure barrier.
3. Liner hanger and liner top isolation packer design are much more critical.
4. Fluid unloading rate is higher for larger tubing.

Production Casing

As stated earlier, the NFB wells were to be completed as conventional 5-1/2" x 5" packer type completions **(Fig. 2)**. The decision to consider monobore completions came late in the well design process, and as a result the casing program was already well established. To meet predetermined LNG delivery schedules, it was mandatory that the monobore completion fit into the predetermined casing plan with only minor changes.

Design Review. The existing casing program was reviewed, resulting in several changes to accommodate the monobore completion. The original casing design used a 9-5/8", 43.5 lb/ft, L-80 x 10-3/4", 55.5 lb/ft, C-90 intermediate string, which was run as a single string and which used a deviation tool to assure an adequate cement job. A 7", 32 lb/ft, L-80 liner with a 7-5/8", 33.7 lb/ft, C-90 tieback string was run as the production casing string. The 7" monobore design required that the intermediate casing perform as the production casing, and eliminated the 7-5/8" tieback casing string **(Figs. 3a & 3b)**. As a result, a review was done to insure that the 9-5/8" x 10-3/4" intermediate casing string could perform acceptably as the production casing.

Stress Design Analysis. The casing design was reviewed using classical stress design and Load and Resistance Design (LRFD). LRFD uses a reliability based design philosophy, that allows the engineer to select the probability of failure that is commensurate with the consequence of failure. For failures that potentially pose a risk to life or the environment, a probability of failure between 1×10^{-5} and 1×10^{-8} was used. Examples of this type of failure are a kick during drilling or a tubing leak during production. For failures that pose no risk to health or the environment, a probability of failure between 1×10^{-2} and 1×10^{-5} was used. Examples of this type of failure are pressure tests and running and cementing.

Results. The casing design review showed that the 10-3/4" casing could be reduced from C-90 grade to L-80 grade. Due to existing inventory and casing wear concerns, it was decided to continue with the C-90 grade.

The casing design review showed that the 9-5/8" casing did not meet the desired level of safety in the event of evacuation of the casing fluid via a tubing leak late in the field life. This scenario was considered to have a low likelihood of occurrence and low consequences. Also, the 7" liner could be run and cemented across the concerned section of 9-5/8" casing as added insurance. Therefore, it was decided to continue with the existing 9-5/8" casing design.

Cementing Review. It was necessary that the deviation tool be eliminated to improve the pressure integrity of the production casing. Elimination of the deviation tool required that the existing cementing program be reviewed.

Three cementing options were identified and discussed as follows.

1. Run the 9-5/8" casing as a liner, and the 10-3/4" casing as

a tieback string (**Fig. 3a**). This option virtually insures that a good cement job is obtained on both the liner and the tieback. The downside to this option is that it requires extra equipment in the form of liner hangers, liner top packers, and seal assemblies. The addition of this equipment increases cost through equipment purchases and added rig time for installation. The tieback system also reduces the pressure integrity of the casing string from that of a single combination string.

2. Attempt to successfully cement the single combination string using conventional cementing techniques (**Fig. 3b**). The risk with this technique is in breaking down weak formations during cementing, and not obtaining a good cement job across the entire casing string. This option is the least costly in terms of both equipment and installation time.

3. Cement the combination string with foam cement. This option is similar in terms of equipment and installation time to Option 2. However, foam cementing techniques are not as well known and as widely used as conventional cementing techniques.

Results. Even with its obvious drawbacks, Option 1 was initially chosen as the preferred method to be used for installation of the production casing. To date most production casing jobs have used this method.

Because of the high potential to encounter very weak formations in this hole section, the probability of success of Option 2 was considered to be lower than Option 1. It was decided to continue to study the feasibility of Option 2, while procuring the necessary equipment to carry out Option 1. As a result of the feasibility study, it was decided to perform a trial of this option. The cement formulations and pumping schedules were optimized to minimize stress on the weak formations. A minimum formation integrity threshold was determined for the weak formations, and a successful formation integrity test was performed prior to attempting the cement job. As a result of the detailed job planning, the ability of the weak zones to withstand the required pressures, and good job execution, the initial job was successful. After the successful test, it was decided to make Option 2 the preferred option contingent on obtaining a successful formation integrity test. Option 1 remained as the back-up, in the event of a failure to obtain an adequate formation integrity test.

Option 3, foam cementing was not seriously considered for this development. The third North Field development is planning to use foam cementing as their preferred technique, but to date no results are available.

Liner Hanger and Liner Top Packer Review. As stated, running the production casing as a 9-5/8" liner with a 10-3/4" tieback string requires a reliable liner hanger and liner top packer system. In addition to being able to handle all load cases of a monobore completion, an additional requirement of the operator was for the tieback seal assembly to have a metal-to-metal primary seal with elastomeric seals as back-up. The requirement to have metal-to-metal sealing has come at a great cost.

Problems and Solutions. The chosen design has the metal-to-metal seal on the nose of the seal assembly. The metal-to-metal seal is energized with compression, and must remain in compression to be effective. This metal-to-metal nose seal precludes the use of a mule shoe, and has resulted in stab-in problems on several wells. One seal assembly could not be stabbed in after cementing, resulting in there being no tieback seals engaged in the PBR. The stab-in problem on subsequent wells was solved by precise placement of centralizers above the seal assembly.

The metal-to-metal nose seal also requires that the seal assembly be bottom locating. When using mandrel casing hangers, the slack-off weight on this nose seal cannot be controlled precisely. There have been cases where the nose seal was over stressed by excessive slack off, causing it to swedge inward forming a restriction in the production casing ID. The reduced ID was discovered after several tieback jobs had been performed, when monobore completion components would not pass the restricted area. A mill was designed, built, and run to open the restriction in these wells to the proper casing ID. To eliminate the possibility of damage to the nose seal on future jobs, a stop was installed on the remaining seal assemblies. This stop allows the metal-to-metal seal to engage, but will not allow the seal to become over stressed.

Connection Review. Connections on the production casing are expected to perform to the design limits of the pipe in internal pressure, external pressure, tension, and compression modes. The original connections on the 10-3/4" and 9-5/8" casings did not meet this criteria. Connections in these exact weights had not been tested, but connections in the same size and grade had been successfully tested. Due to time limitations, additional testing could not be performed on these exact weights. The decision was made to use the connection type that had been successfully tested on the same sizes and grades of pipe.

Monobore Production Liner and Tubing

As stated earlier, the original completion design utilized a conventional CRA packer set about 100' above the top of the productive interval. The packer was set in a 7", 32 ppf carbon steel liner which was run and cemented through the productive interval. In the monobore completions, the production liner acts as the lower non-removable tubing section (**Figs. 3a & 3b**).

Material Selection. The initial packer type completions used 28-Chrome CRA tubing. This CRA was originally selected as the least costly material which could withstand the produced fluids containing H_2S, CO_2, and the potential for formation water production, and the 28% HCl acid stimulations. Believing this earlier selection for tubing material was still valid, 28-Chrome was chosen as the monobore tubing material. Carbon steel liners were acceptable for the packer type completions, because the CRA packer and tubing protected most of the liner from the corrosive produced and treatment fluids. Because the entire monobore liner is exposed to these fluids, the decision was made to use 28-Chrome for the liner material for the monobore wells. It is worth noting that the liner and tubing could be carbon steel, if no formation water production is expected.

Size Selection. A tubing size of 7" was chosen, because it was the largest tubing that could be run while still satisfying the monobore requirement of maintaining a nearly constant tubing ID through all tubing accessories. Larger tubing sizes could be run in the 10-3/4" x 9-5/8" casing, but the down hole safety valve would not be full opening to the tubing ID of larger than 7" tubing sizes.

For the following reasons, it was decided to keep the monobore production liner the same size as the tubing.

1. Strict adherence to the monobore philosophy of a single ID from surface to total depth.
2. Standardized and minimized tubular inventory.
3. Minimized connection testing.
4. Standardized wireline plugs and tools

Weight Selection. To minimize cost, the monobore liner and tubing weights were optimized based on expected stresses and the ability to thread with a premium connection. Classical stress design criteria was used for the analysis, and 7", 26 ppf, 110 ksi minimum yield pipe was selected for the project. Although the 26 ppf casing was over designed from a stress design perspective, it was chosen as the lightest weight and lowest cost tubing / liner that could still be reliably threaded with a premium connection.

Thread Selection. As with the production casing connection, the tubing connection is expected to perform to the design limits of the pipe body in internal pressure, external pressure, tension, and compression. Additionally, it is expected to maintain a seal during a rapid cool down such as an acid job or well kill. The tubing connection testing program was designed to test all of these cases, and to test the sensitivity of the connection to damage from galling during repeated make-ups and break-outs.

Initially, four premium connections from four different manufacturers were evaluated for possible use in this project. These connections had all been tested in the required size and weight, but in a different material and yield strength. Therefore, a minimum amount of additional testing was required to fully qualify any of these connections. Based on the past testing and field performance, it was believed that all of these connections had a very high probability of passing the additional testing required for this project. For reasons specific to each, two of the four manufacturers chose not to participate in the additional testing.

To promote competition, one additional connection was chosen for possible testing. This connection had a much more limited testing history than the other connections. Therefore, it was necessary to perform more detailed testing to qualify this connection for this project.

As expected, the original two connections passed the additional testing. Rather unexpectedly, the final connection chosen never successfully completed the testing phase.

No single pipe manufacturer could deliver the required quantity of pipe within the required time. Therefore, the pipe order was split and pipe was purchased with both qualified connections.

Liner Hanger, Liner Top Isolation Packer with Anchor Latch, and Production Seal Assembly

As stated earlier, the monobore liner becomes the non-removable lower section of tubing. In conventional packer completions it is normal for the produced fluids to flow through a liner until they enter the bore of the packer and subsequently the tubing. The monobore completion eliminates the conventional production packer. The produced fluids are routed up the production liner, through the bore of the liner hanger and the liner top isolation packer, and then into the tubing.

The liner hanger and liner top isolation packer are an integral part of the completion pressure vessel, and thus must be design for this service. The liner hanger and liner top isolation packer must also be capable of handling the normal pressure and mechanical loads required of them as liner equipment, as well as the mechanical loads induced by the tubing movement.

An additional requirement of this project was that the production seals could not move during any normal production operation. Stress analysis showed that sufficient slack-off weight could not be applied to keep the seals static during acidizing and well killing operations. Therefore, an anchor latch system was required for the seal assembly.

Supplier Selection. Liner hangers, liner top isolation packers, and seal assemblies are not regulated by accepted oil and gas industry regulations. Therefore, a two step supplier selection process was carried out.

Supplier Audit. The first step consisted of supplier quality audits by two independent third party auditors. These inspectors were charged with independently performing supplier audits whereby the suppliers were graded according to a weighted scoring system. The independent grades were then combined and averaged. This grading system narrowed the potential suppliers to three.

Equipment Qualification. The second part of the supplier selection process required the suppliers that passed the supplier audits to submit proof of design qualification, including stress analysis and finite element analysis on critical components and assemblies

All suppliers were also required to either successfully pass functional testing of their equipment to North Field well conditions, or show proof that their equipment had already passed testing that met or exceeded the required testing. This part of the supplier selection process proved to be very difficult, and not every supplier that passed the audit ultimately passed the functional tests.

Specific Seal Tests. Each manufacturer was required to prove that all components containing sealing elements could pass the following test.

1. Pressure test at down hole temperature and differential pressure for 72 hours.
   a) Temperature cycled from down hole temperature to room temperature every 24 hours.
   b) Pressure reversed from one side to the other side of the sealing element every 12 hours.
   c) Elements to remain bubble tight during entire test.
2. Stroke test of all seal assemblies equal to four strokes of 20 feet each, at down hole temperature and full differential pressure.
   a) Elements to remain bubble tight during entire test.

System Tests. Each manufacturer was required to prove that their system could pass the following functional test requirements when set in 9-5/8", 43.5 lb/ft casing at an angle from vertical of 65° or greater.

1. Force down of 100,000 lbs from below and force down of 200,000 lbs from above at down hole temperature and 6,330 psi differential pressure.
   a) Pressure held for 1 hour.
   b) Seals to remain bubble tight during entire test
2. Force down of 50,000 lbs from below and force up of 200,000 lbs from above at room temperature and 6,330 psi differential pressure.
   a) Pressure held for 1 hour.
   b) Seals to remain bubble tight during entire test
3. Verification of anchor latch shear release at 200,000 lbs.
4. Verification of anchor latch release by right hand rotation.
5. Verification of collet indication at 20,000 lbs in both up and down directions. The collet is used for tubing space out.

Equipment Characteristics. As expected, the systems submitted for testing from each manufacturer were quite different. Some manufacturers attempted to use conventional liner hanger and liner top isolation packer equipment modified to meet the specific requirements, while others submitted equipment designed specifically for monobore applications. As would be expected, the equipment designed specifically for monobore application performed much better in the functional testing than systems adapted from drilling applications.

Liner Hanger Features. The liner hanger system that was selected for use has the following features.

1. Hydraulic top set system.
2. One direction slips designed to hold liner weight.
3. Lower tieback seal receptacle.
4. ID with seals installed matches tubing ID.
5. Burst rating equivalent to burst rating of tubing.
6. Collapse rating exceeds burst rating of production casing.
7. All CRA (28-Chrome) flow wetted parts.
8. Carbon steel (AISI 4130) non-flow wetted parts.
9. Qualified premium connections.

Liner Top Isolation Packer Features. The liner top isolation packer that was selected for use has the following features.

1. Weight set system.
2. Top locating lower seal assembly.
3. Lower seal assembly uses proprietary "Bullet" type seals.
4. Bi-directional slips.
5. Upper seal bore receptacle with anchor latch (200,000 lbs).
6. ID with seals installed matches tubing ID.
7. Burst rating equivalent to burst rating of tubing.
8. Collapse rating exceeds burst rating of production casing.
9. All CRA (28-Chrome).
10. Qualified premium connections.

Production Seal Assembly Features. The production seal assembly that was selected for use has the following features:

1. Premium Chevron type A-Ryte seal stacks.
2. All CRA (28-Chrome).
3. Qualified premium connections.
4. Anchor latch to mate with latch in liner top isolation packer.

Equipment Installation. Once the equipment selection process was complete, the focus immediately turned to insuring that the equipment would perform in the field as required.

Detailed Procedures. Work was begun to develop detailed well site installation procedures. An attempt was made to get as many people as possible involved in the process of developing the installation procedures. It was believed that getting input from everyone involved would result in the best procedures possible. It was also believed that it would result in more complete buy-in to the procedures to be used, which would minimize second guessing offshore during installation.

The detailed procedures were the result of the combined input of drilling and completion engineers and operations personnel of the operator, design engineers and operations personnel of the manufacturer, rig site personnel from both the operator and the manufacturer, and from consultants used on this project. To facilitate discussion, and efficient and immediate decision making, all of these people met for several days and developed the detailed procedures. Once there was agreement on the procedures, representatives of the operator, manufacturer, and consultants signed off on the final procedures.

Rig Site Checklists. Because input was solicited and obtained from everyone involved in the project, there was a belief that the procedures were very good. However, everyone believed that there was no substitute for actually running a system and that procedural changes would result once rig operations began.

In anticipation of possibly needing to make procedural changes during the initial rig operations, the representatives involved in writing the detailed procedures were on location for the first monobore completion. Fortunately, the detailed procedures proved to be very complete and accurate. Unfortunately, they proved to be quite long and complex to follow on the rig floor. As a result, the detailed procedures were compressed into checklist form for rig site use. These checklists have proven to be an invaluable rig site aid. They are distributed to all relevant personnel on the rig, and are kept as a permanent part of the well records for future reference.

Rig Experience. To date, ten monobore wells have been drilled and completed in this project, and installation problems have been minimal. The following is a summary of the atypical experiences so far with the monobore completions.

1. While circulating on bottom, a monobore liner hanger running tool released prematurely. The monobore liner was set on bottom and cemented in place with no difficulty, but it was never known if the liner hanger had set properly. It was not a concern, because the liner top isolation packer has bi-directional slips and therefore no loads are transmitted to the liner hanger.
2. The flexibility of the monobore concept was proven early in the project, when a leak occurred between the 10-3/4" tieback seal and the 9-5/8" hanger PBR at approximately 5,300' MD. Normally the monobore liner hanger is set at approximately 10,300' MD, or approximately 400' above the 9-5/8" shoe. To cover the leak, the monobore liner hanger was set above the leak and the liner was cemented in place. The removable tubing string was then stung into the liner top isolation packer at approximately 5,300' MD rather that 10,300' MD.

Neither of these problems were directly related to the monobore completion, but were instead problems with systems that support the monobore completions. The ability to overcome these problems shows the flexibility of the monobore concept.

Subsurface Safety Valve

Qatar has no governmental regulations requiring the installation of subsurface safety valves in offshore wells. However, it is an accepted industry practice to install a subsurface safety valve as a safety device to guard against loss of life and property, and to minimize potential environmental damage. Due to the high productivity of the North Field wells and the corresponding potential for high risk to personnel, property, and the environment, installation of subsurface safety valves was considered to be essential for this project.

Safety Valve Features. Unlike liner hanger and liner packer equipment, subsurface safety valves are regulated by accepted oil and gas industry regulations. As such, valves for this project were required to be certified to API 14A (8^{th} Edition). In addition, the valve selected for this project has the following features.

1. Tubing retrievable versus wireline retrievable.
   a) Higher reliability as reported by North Sea Study (SINTEF).
   b) Higher reliability as reported by internal partner study.
2. All CRA (Inconel 925 & Inconel 718) design.
3. Metal-to-metal flapper design with low pressure Viton seal.
4. Rod piston actuated.
5. Through the flapper self equalizing.
6. Maximum OD of 9.200 inches.
7. Minimum ID of 6.059 inches.
8. Maximum rated working pressure of 5,000 psi.
9. Burst rating of 7,500 psi.
10. Collapse rating of 5,000 psi.
11. Temperature rating of 20° to 300°.
12. Capability to accommodate a self equalizing wireline retrievable insert valve.

Protection of Safety Valve from Acid Attack. As a result acid attack, the previous NFA project has experienced several failures of wireline retrievable safety valves. The Khuff formation requires acidization in order to produce to its full capability. Therefore, the monobore safety valves for the NFB project were supplied with sealing separation sleeves to protect the valve during acidizing and the subsequent post-acidizing flow back. These separation sleeves lock into the nipple profile above the safety valve.

After several acidizing jobs had been performed with the separation sleeve in place, it was discovered that the separation sleeve had evidence of acid attack on the OD. This indicated that the separation sleeve seals had leaked and acid was allowed between the separation sleeve and the safety valve.

Metallurgical testing showed that the safety valve would not incur damage from acid attack if the acid was properly inhibited, and the exposure time and temperature were limited. However, trapping acid behind the separation sleeve was believed to pose a greater corrosion risk than allowing contact of the safety valve with acid. The concern was that acid would get trapped behind the separation sleeve during the acid job, and would then be heated up during the subsequent acid flow back. The trapped hot acid could potentially be very corrosive.

It was decided to no longer use the separation sleeve, but to flush the safety valve after both the acid job and the acid flow back. The flushing procedure consists of the following.

1. Close the safety valve and bleed off 500 psi from above the flapper.
2. Allow the safety valve to self equalize.
   a) This will flush the equalizing section of the safety valve, with sea water after the acid job and with gas after acid flow back.
3. Open and close the safety valve eight (8) times.

a) This is an attempt to flush out any acid that may be behind the flow tube.

4. Repeat step #2.

Protection of Safety Valve from Mechanical Damage. According to one safety valve manufacturer, the leading cause of valve failure is damage incurred during wireline and electric line operations. As a result, a safety valve protection sleeve was supplied with the safety valves. This sleeve locates on the nipple profile above the safety valve, and is held in place with a collet. It is believed that the protection sleeve has provided some measure of protection, because the ID of the protection sleeve has sustained damage in the form of wire tracks or grooves. Had the protection sleeve not been installed, there is a chance that the grooves would be on the ID of the safety valve.

Installation and Operation. There is nothing unique about the installation and operation of the monobore tubing retrievable self equalizing subsurface safety valve. The control line is Incolloy 825, and is protected with encapsulation. Cross coupling protectors are used at all couplings to further protect the control line against abrasion during running and production cycles.

To date, there have been no installation problems or failures in service associated with the monobore subsurface safety valves.

Monobore Plug Systems

At some time in their life, most wells are expected to need some form of tubing isolation or other related intervention. Monobore wells are not expected to be different in this respect.

Plug Systems. Two different plug systems were evaluated for this project. They were the nipple plug system and the nippleless plug system. Ultimately, both the nipple and the nippleless plug systems were used in this project.

Nipple System. The nipple plug system requires a landing nipple profile in the tubing string, and a mating lock on the plug devices. This concept is similar to conventional lock profile systems, except the monobore landing nipple is full opening to the tubing drift diameter.

A landing nipple is installed in the bottom of each tubing string, and mating plug devices are available to accommodate tubing isolation and hanging off of bottom hole pressure gauges.

Performance Testing. All nipple systems considered for this project were required to pass the following performance testing.

1. Tools run, set, and retrieved in at least 55° from vertical with wireline.

a) Verification tests at 250°F.

b) Tools passed through a 6.000" ID and set in nipple profile.

c) Tools pressured to 5,000 psi for seven days and remained gas tight.

d) Tools retrieved by wireline and removed through a 6.000" ID in less than 2 hours.

2. Tools capable of being run at moderate speed without compromising performance.
3. Tools equalize with wireline at rated differential pressure.
4. Tools have sufficient fluid by-pass to facilitate circulation while running.
5. Must be able to wash over top of plug prior to retrieving.
6. Elastomers qualified and manufactured to API 14A 8th Edition, Sections 5.25 and 3.3 at bottom hole temperatures.
7. Plugs and associated running and pulling tools capable of being redressed on location.
8. Tool designs have consideration to prevent premature setting.

Additional Requirements. In addition to passing the above functional testing, the nipple systems used in this project meet the following requirements.

1. API Monogram where applicable.
2. Capable of setting and pulling on wireline or coiled tubing.
3. Incoloy 925 nipple and plug devices.
4. Nipple ID of 6.160" (tubing drift 6.151").

Nippleless System. The nippleless plug system does not require a mating locking system, and thus the plug can be set anywhere in the tubing string or liner via slips that bite into the tubing or liner ID. Nippleless plug systems were designed to accommodate tubing isolation and hanging off of bottom hole pressure gauges.

Performance Testing. All nippleless systems considered for this project were required to pass the same performance testing described above for the nipple systems.

Additional Requirements. In addition to passing the above functional testing, the nippleless systems used in this project meet the following requirements.

1. Capable of setting and pulling on wireline, electric line, or coiled tubing.
2. Incoloy 925 plug devices.

Plug Experience. In just over one year of production, neither the nipple nor the nippleless plug system have been used.

Wellhead and Christmas Tree System

The wellhead system used for the monobore completions is not unique, but is essentially identical to the system used for the conventional packer completions (**Fig. 4**). Except for the obvious size difference, the monobore trees are identical to the trees used for the conventional completions.

Wellhead. The wellhead utilizes a lower housing and the lower end of a compact spool to house the 18-5/8", 13-3/8", and 10-3/4" casings. The upper end of the compact spool houses either the monobore tubing or a contingency 7-5/8" casing string. If the contingency 7-5/8" casing string is required, a string of 5-1/2" x 5" tubing can be landed in an add-on contingency tubing spool. The production casing hanger utilizes an all metal-to-metal seal system.

This wellhead system has proven to be very reliable in service, but several problems have been encountered during installation. The installation problems have been associated with misalignment of the 10-3/4" casing hanger in the wellhead, and the inability to get a proper set and test of the 10-3/4" casing hanger metal seal assembly. The compact wellhead system has very tight tolerances, and the 10-3/4" casing hanger running tool was modified to more accurately guide the hanger through the wellhead. The 10-3/4" casing hanger metal seal assembly installation problems have been resolved through proper alignment of the 10-3/4" casing hanger in the wellhead, and by improved installation procedures and better training of personnel involved in the installation.

Christmas Tree and Tubing Hanger. The tree used on the monobore completions is a 6-3/8", 6,500 psi WP solid Y-block Inconel 625 clad tree. The lower master gate valve is manually operated, while the upper master gate valve is fitted with a wire cutting hydraulic actuator. The flow wing is fitted with one manual gate valve and one hydraulic actuated gate valve. The kill and swab gate valves are manually operated.

The mandrel tubing hanger is solid Inconel 718, and utilizes an all metal-to-metal seal system. It has a premium box tubing connection on bottom, and running threads on top. The hanger is prepared with a lock profile for a wireline set back pressure valve. The subsurface safety valve control line is continuous through the hanger and into the outlet of the compact spool. Control line communication is maintained until the hanger is landed and locked into place.

The only problem experienced to date with the installation of the tubing hanger was as a result of improper installation of the 10-3/4" casing hanger metal seal assembly, as discussed above. The monobore trees have performed well in service.

Summary

Monobore completion technology has been around for years, but still it is not well understood by most drilling and completion personnel. Also, there is currently a paucity of equipment designed specifically for monobore completions. As a result, the application of this technology has been very slow to develop.

To date, monobore technology has been limited mainly to niche developments such as very hostile high pressure/high temperature wells and other wells where very high rate completions are needed. Projects of these types can usually support the up front monobore development costs, with the expectation that the monobore completion will pay back these extra development costs through overall lower project development costs or through higher revenue streams.

Like any other emerging technology, as monobore completions become more common there will be more monobore equipment readily available. As the equipment becomes more available, serious consideration should be given to using monobore completion technology on even the most routine wells.

Acknowledgments

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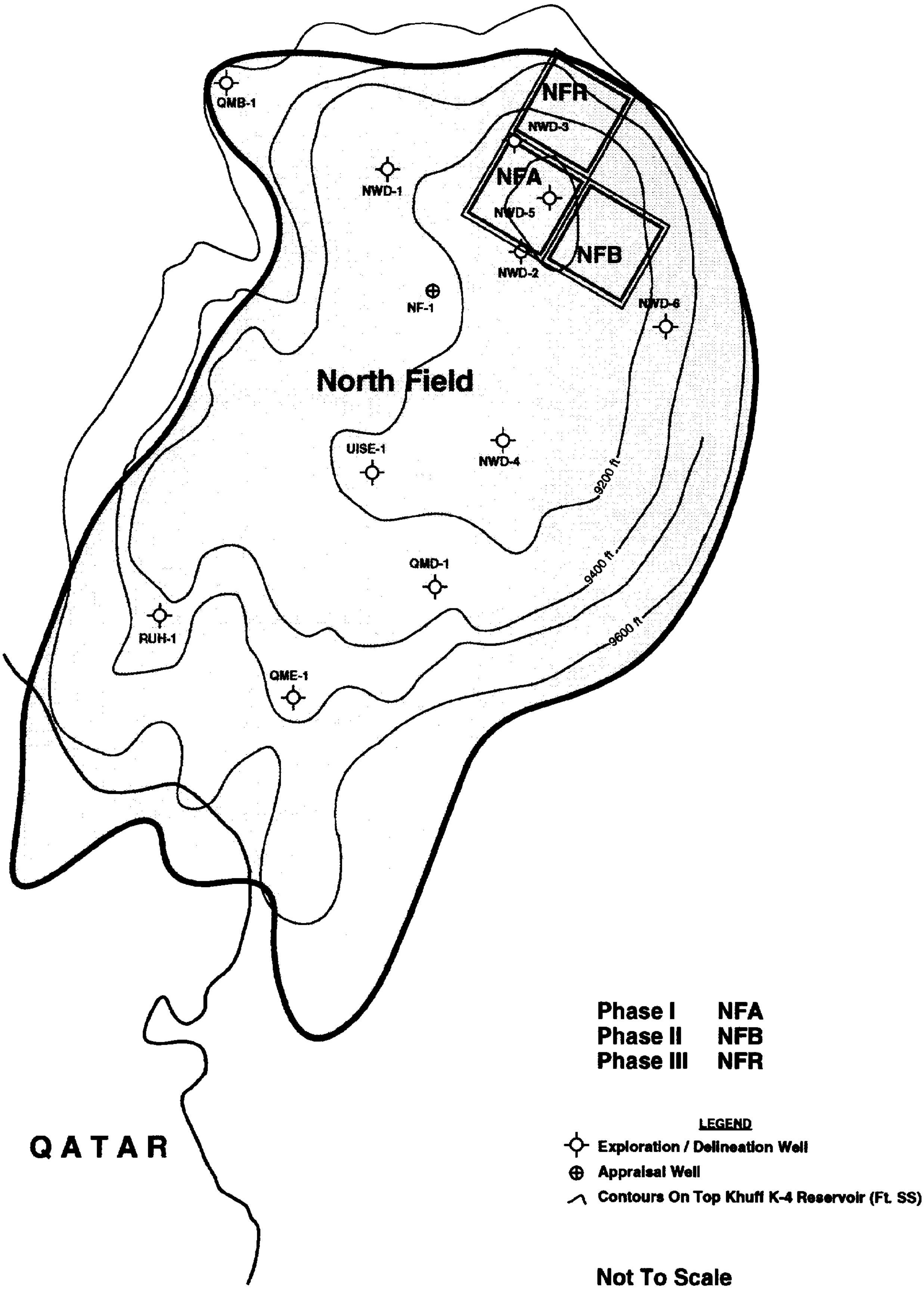

Fig. 1 - North Field Showing Location of Phase I, II and III Developments.

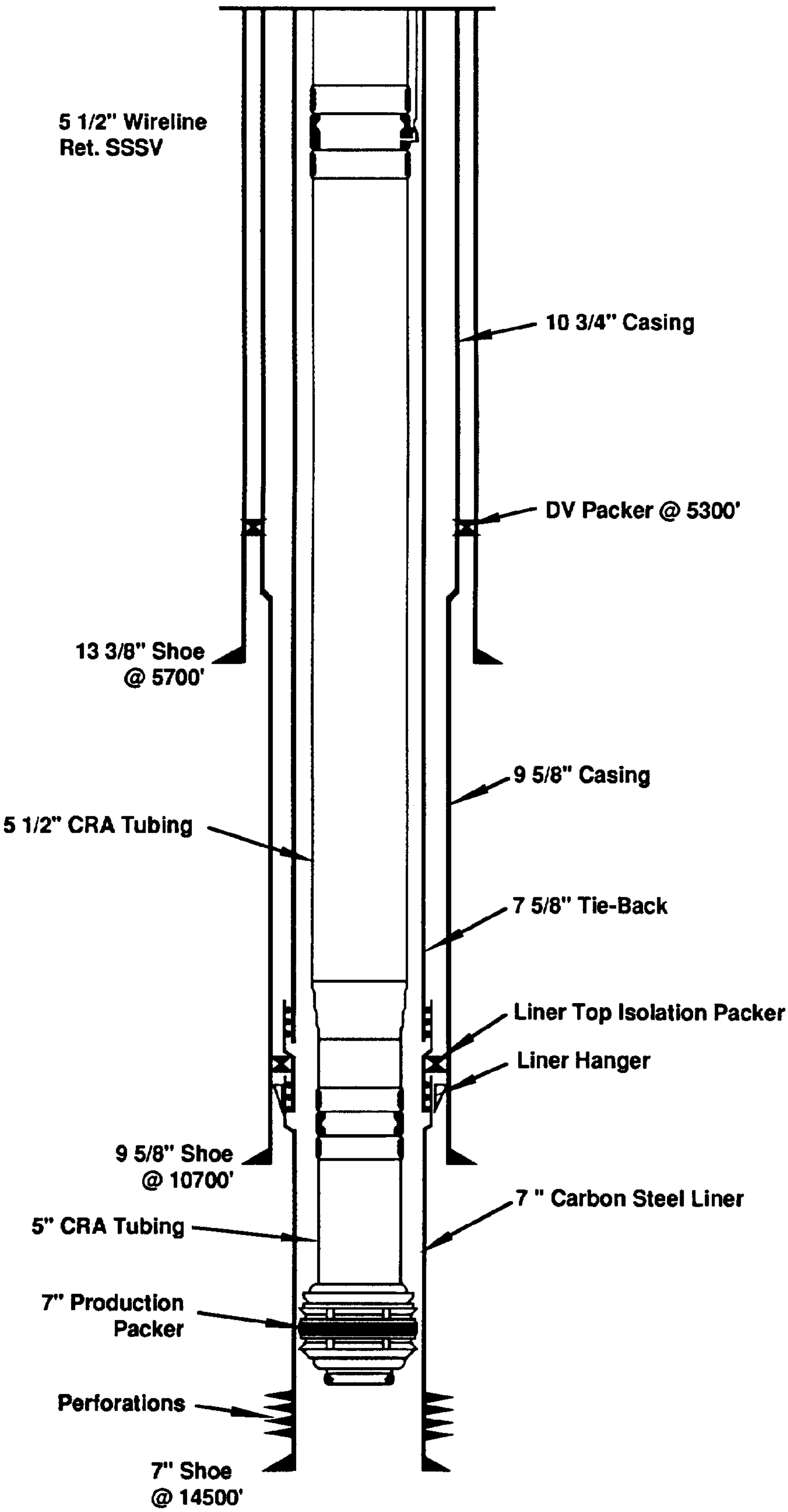

Fig. 2 - Original 5 1/2" x 5" Completion Schematic

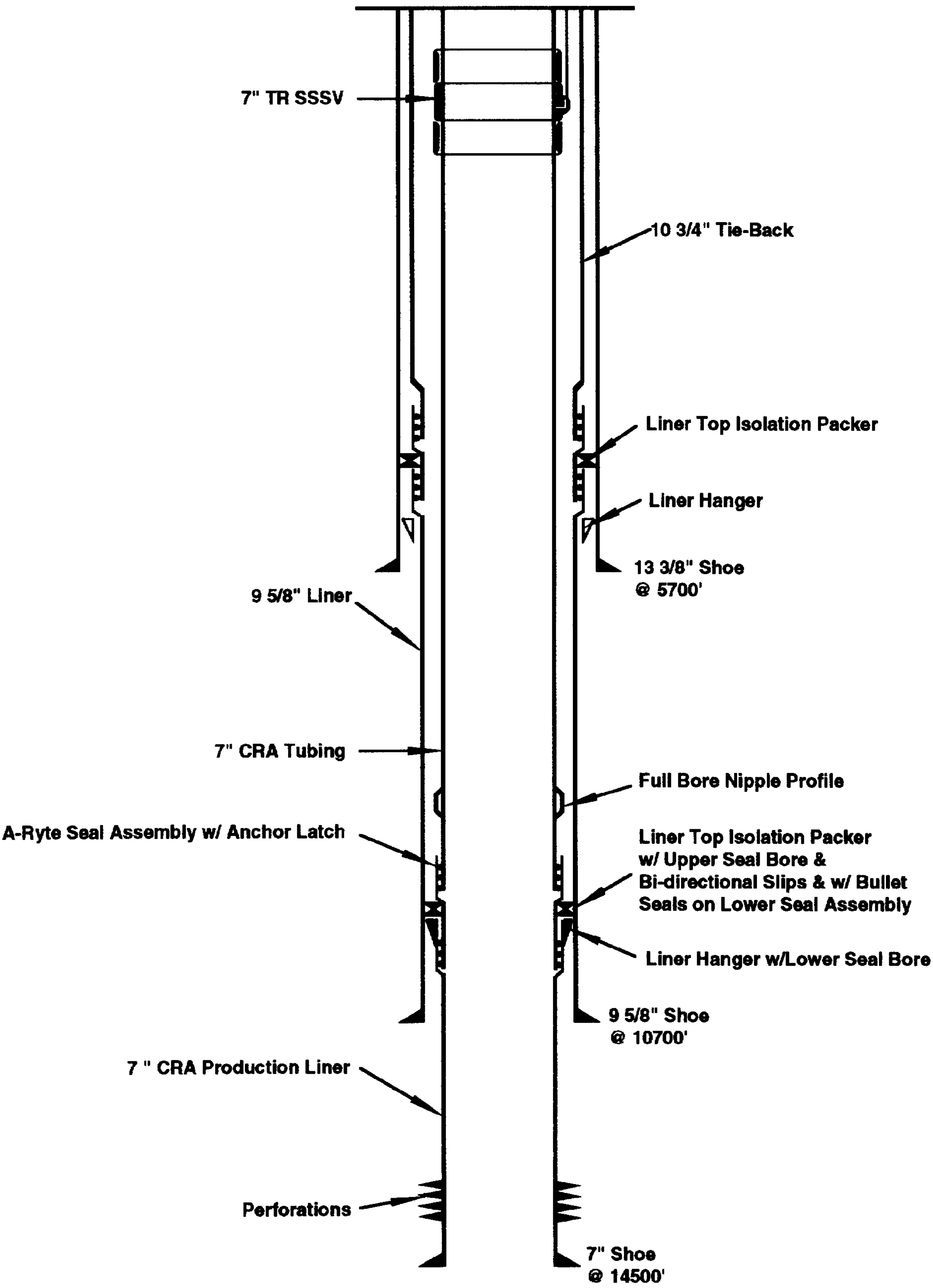

Fig. 3a - Monobore Completion Schematic with 9 5/8" Liner and 10 3/4" Tie-Back

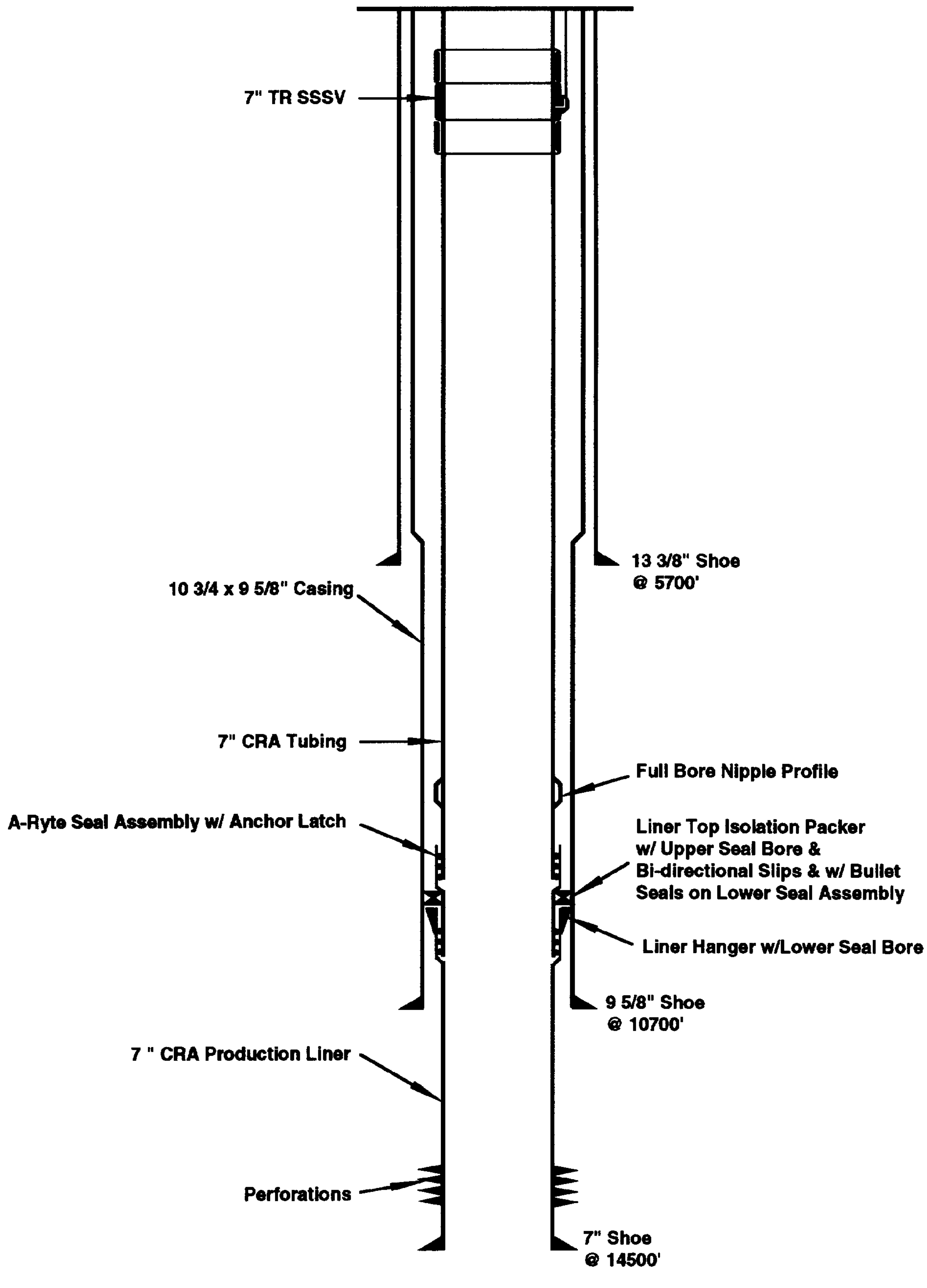

Fig. 3b - Monobore Completion Schematic with 9 5/8" x 10 3/4" Combination String

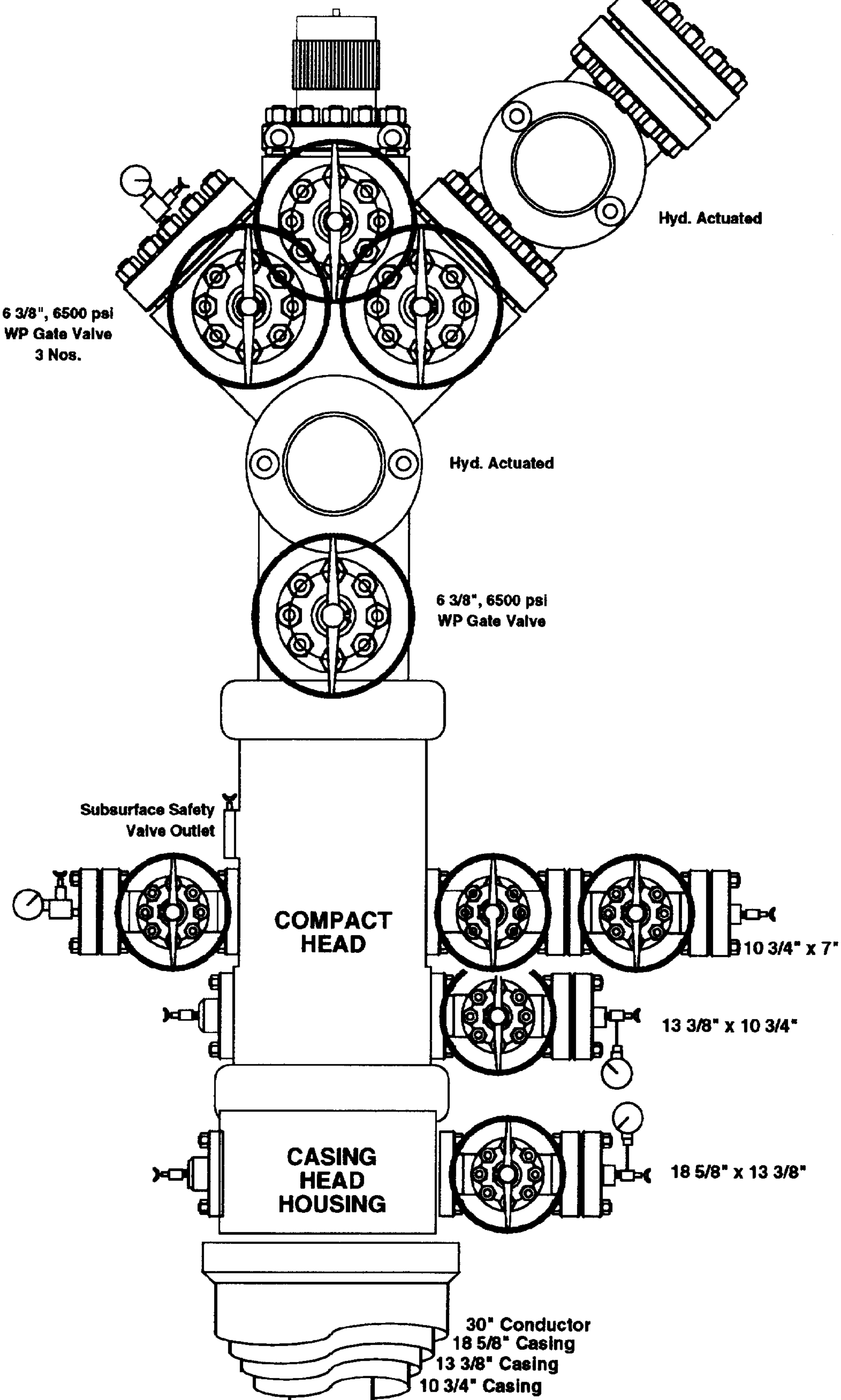

Fig. 4 - Monobore Wellhead & Christmas Tree