Shell P&T - Wells Operated (Europe)

Low UTC Philosophy for Subsea Well Batch Drilling and Completion

Contents

1. INTRODUCTION

Objectives

Our vision in the UK is to sustain the engine by delivering more subsea barrels to market. Our ability to achieve this will be only enabled by an integrated effort to reduce our unit technical costs (UTC) and access a wider portfolio of smaller targets to deliver more value for the UK. Through delivery of more opportunities this offers improved personal development for individuals and making Shell UK Upstream a more rewarding place to work. By applying the standard design to a target, an opportunity team will be able to streamline the activity for delivery on a stable drilling sequence of standard activities and yielding earlier production.

The Standard Design

The Low UTC Team has supported the organisation to identify and mature several improvement themes. These are:

- Standard 4 string casing designs
- Drilling top holes offline
- Standard completions
- Standard hook-ups
- Cleaning-up and flowing the well to host, rather than to the semi-sub

A large proportion of the savings to be delivered are as a result of standardisation and batching activities. Experience has shown within Shell and with our competitors that there are cost savings of up to 30-50% from delivery of a standard solution. We will not reach these kinds of savings unless we are intentional about delivering this standard and continually learning and improving how we deliver our wells.

There will doubtless be examples where delivering a slightly different well might be a bit more valuable for that single opportunity, however we ought to be careful not to treat every opportunity as unique, when in the majority of cases the standard well design will deliver most of the value on offer. Delivering the elements of the standard well described in this document, time and time again, will ultimately lower our costs due to learning curve and NPT reduction, which will in turn prove our ability to deliver lower cost opportunities and therefore unlock otherwise stranded barrels. It should be noted that this document refers to subsea production wells only at this stage.

This document describes the standard well design incorporating drilling and completion phases which will be the base case used to deliver all NPNT subsea development opportunities. For new subsea wells all of the chapters of the document are relevant. However, the document can also be used as a 'menu,' for other types of activities e.g. subsea sidetracks, major workovers etc., where only some of the sections will be used.

We still use our Global Well Delivery process to deliver the standard solution, Well Engineers and Completion & Well Intervention Engineers doing the work will still be guided by the PCAP, however much of the optionality is removed to facilitate a more streamlined approach without compromising process and personal safety.

Workflow

The SWE for front end design supports the Development Engineering part of the opportunity team, by describing how the standard well design can be applied to an opportunity, by employing existing offset reviews and performing a limited amount of modelling work to check how the standard well design can be delivered on a given opportunity. This will include identification of key risks associated with the opportunity and a high level plan for addressing these risks. This will culminate in a feasibility report which will accompany the subsurface data freeze. This feasibility assessment will document any additional work which needs to be carried out to de-risk the opportunity being delivered using the standard well design and will be endorsed by the Well Engineering Design TA2, the Completion & Well Interventions Design TA2, the PT TA2 and the PC TA2.

Once the subsurface part of the Well Functional Spec is frozen, when its position on the rig sequence dictates, the well will be staffed with full time WE and C&WI Engineers to mature the opportunity, defining how the standard well design will be applied to the opportunity, guided by the PCAP Wells Tracker and adhering to the Well Delivery Process.

Potential Savings

Work in the planning phase for standard wells has highlighted a number of potential savings. The change from a five string well to a four string well saves an average of £2.9MM ($4.55MM) per well with a further £385K ($600K) saved using the standard completion design. In addition a further $10MM can be saved per well based on the use of the Top Hole Drilling Vessel, Rig sequencing, Standard CCW hook-up and Flow to Host.

2. DRILLING CIRCLE

The limitations of the four string design need to be evaluated for each field within the CNS. In order to do this, offset information for each field can be used to define the limits of what has already been achieved within the field. This will be represented as a green area on the drilling circle (Figure 1); any targets within the green area can be assumed to be drillable as a 4 string design. The amber area defines the limits of the 4 string design; anything out of this area becomes a 5 string design.

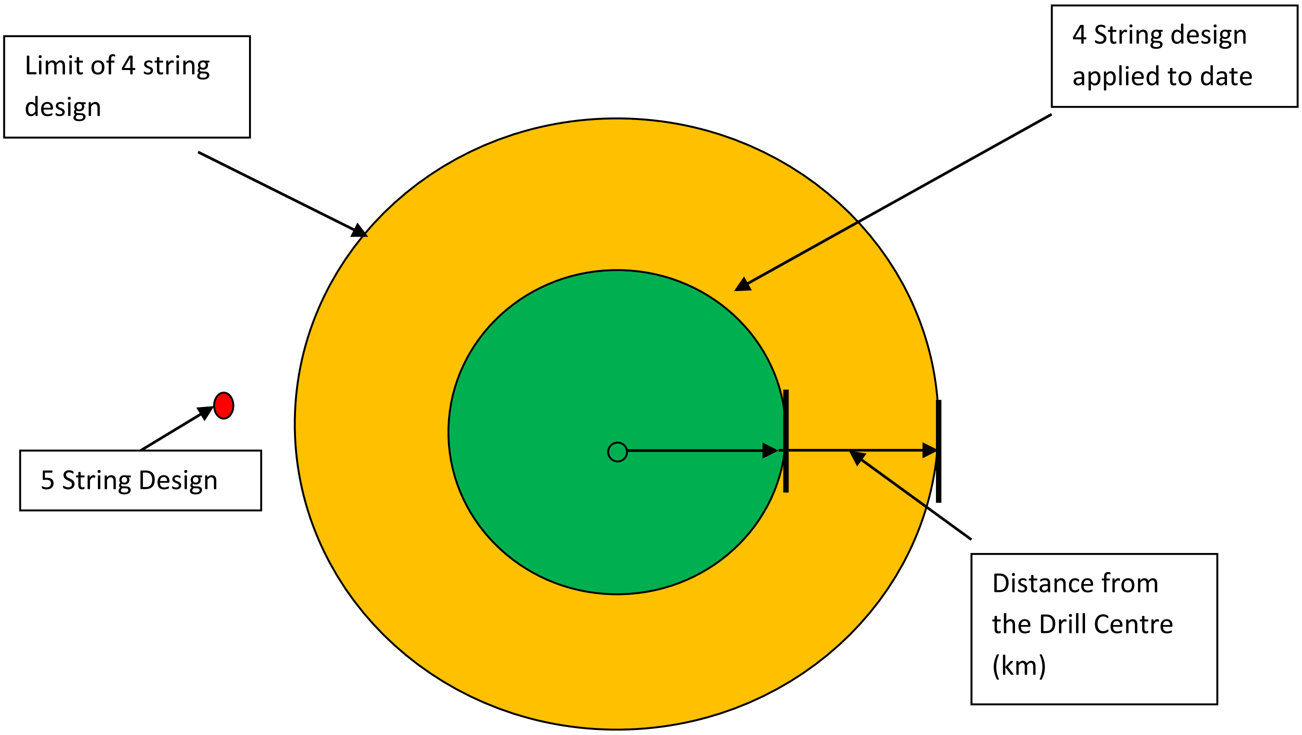


Figure 1 - String design limit chart

Limitations of 4 string design

The limitations on 4 string design are a combination of a number of factors:

1) Wellbore stability
    a. Fracture Gradient
    b. Mud wt
    c. Inclination
    d. Step-out
    e. Well TVD
2) Kick Tolerance
3) Reservoir units (multiple reservoirs may require additional strings)
4) Depletion (function of pore pressure)
5) Combination of depleted and virgin units within a reservoir
6) Sand lenses in the over-burden

Enablers to 4 string design

The use of new / proven technology may help to enable a 4 string design, such as:

1) Wellbore Strengthening
2) Liner drilling

It is possible that due to depletion the green area may shrink for a given field through the effects of depletion. These technologies however are valid technical reasons to maintain a 4 string design. When faced with the possibility of a 5 string design the Staff Engineer may be able to challenge conventional thinking through the use of risk assessments which can promote 4 string designs. Examples of this are Penguin E1 sidetrack and Pierce A12 which were successful in providing assurance on ALARP design, through the use of risk assessment and bow tie assessment.

Example: Howe Main / Howe West Field

There is one production well in Howe Main which is a 4 string design which has a step-out length of 6812ft (2.076Km). During 2012 work started on the design of Howe West which would be a close-coupled well from the Howe Main manifold. Due to its overall complexity Howe West has been designed as a 5 string design and has a step-out of 11550ft (3.52km). We can therefore tell that the limit of the 4 string design is somewhere between 2.076km and 3.52km, but what are the factors that will allow us to define the maximum distance drillable with a 4 string design?

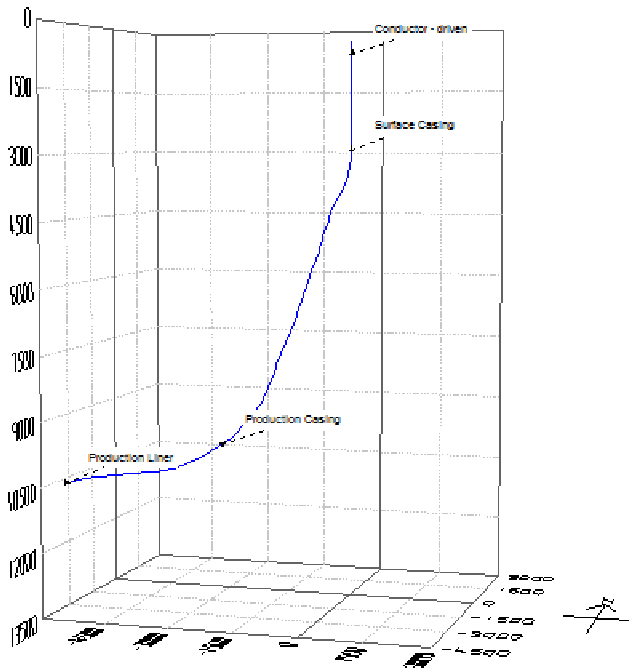


Figure 2 – Howe West Main Producer

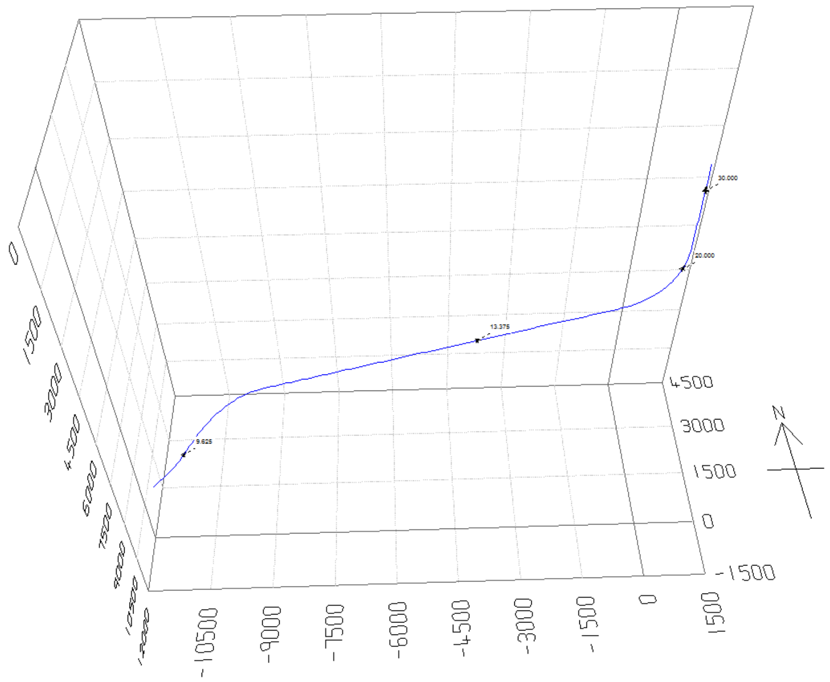


Figure 3 - Howe West: 5 String Design

The key factors when evaluating Howe for the extent of the 4 string design are the LOT at the 13 3/8” shoe, wellbore stability (mud wt selection), kick tolerance and potential hazards in the overburden that would necessitate a casing string.

1) LOT at the 13 3/8” shoe

On Howe Main the leak off below the 13 3/8” shoe was 777pptf EMW at 2950ft TVDrkb and therefore will not be a strong limiting factor in the well design.

2) Wellbore Stability

The 12 ¼” section length will be the limiting factor for the four string design, since the length of the 8 ½” section will be limited by the size of the reservoir and the minimum section length that is required in the well to ensure it is economical. A long 12 ¼” section will therefore have a relatively high inclination (60° to 70°). From the wellbore stability chart we can see that at 60° inclination the mud wt required will be 675pptf at ~5000ft in the sticky shales, the mud wt required then reduces until the Kimmeridge is encountered. Inclinations above 60° will require slightly higher mud wts but with a LOT value of 777pptf it’s clear that this is not a limiting factor and ECD’s in this hole size will be in the order of 20pptf.

There is a limitation on mud wt + ECD in the Balder and Forties formations which may encounter losses between 700pptf and 720pptf; note the Forties formation is water bearing and normally pressured in the Howe Main location. The possibility of losses therefore limit the inclination to ~65°, but will depend on the conservatism of the model and this should be discussed with the wellbore stability focal point and compared to offset experience on other wells.

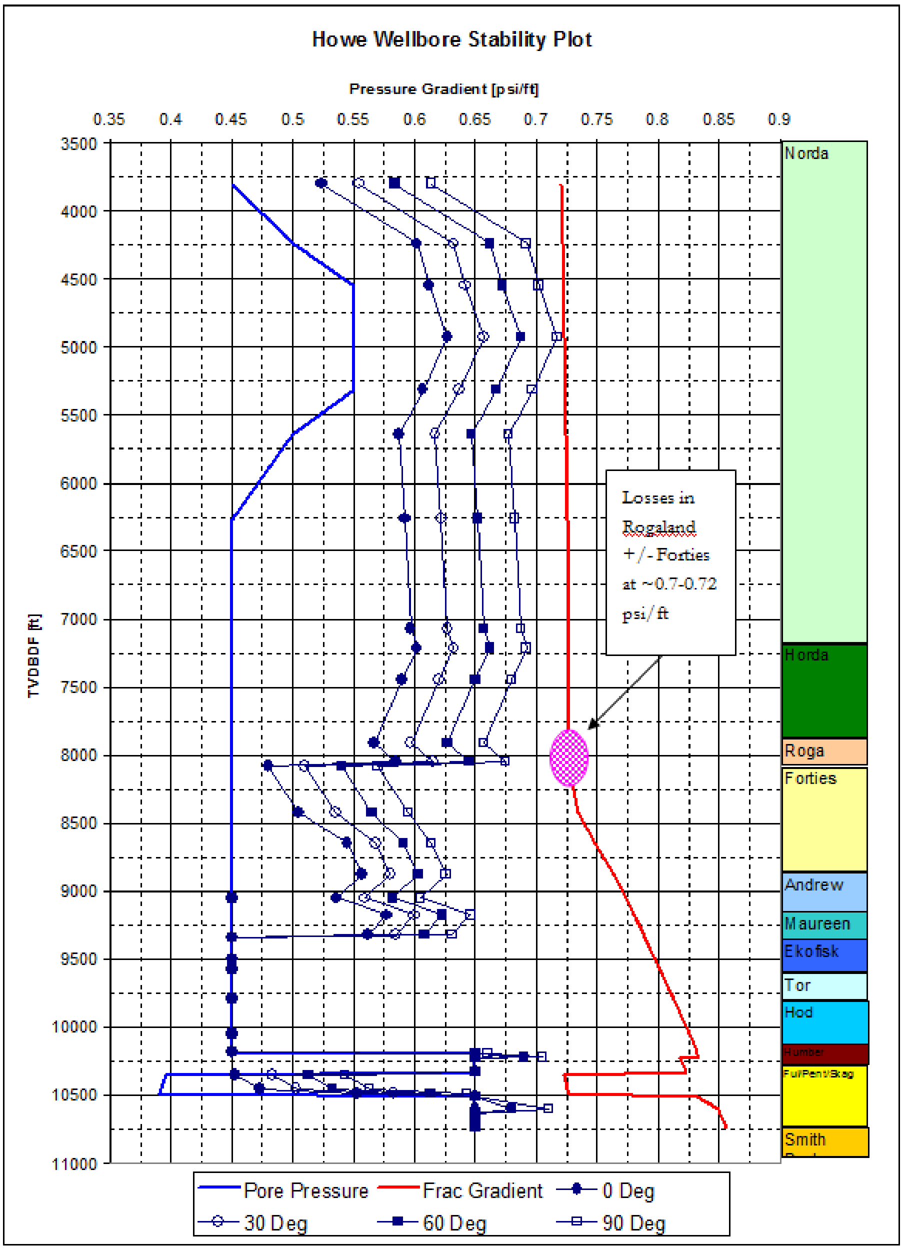


Figure 4 – Wellbore Stability Chart

3) Kick Tolerance

With a LOT of 777pptf and a mud wt of ~675pptf kick tolerance will not be an issue on the 12 ¼" section

4) Potential Hazards in the overburden

TD of the 12 ¼" section on the Howe Main well was in the Tor chalk formation and therefore this will be considered the TD for this design. The Ekofisk and Tor formations are hard chalks and evidence of this can be seen from the drilling performance on the Howe Main wells where ROP's of 3.47ft/hr were achieved in the Ekofisk and 6.67ft/hr was achieved in the Tor.

So far there have been no formations that have a strong requirement to be cased off, however the sticky shales and the Balder can be considered to be time dependant formations (even with the use of OBM), therefore there will be some urgency in completing the section before wellbore stability issues occur. Consideration should also be made of the likelihood of tool failure or the requirement to change a bit when encountering the hard chalk, through the increase in bit wear, stick/slip and vibration. Either way there is a risk of additional open hole time if tripping is required before TD in the Tor.

Maximum Step-Out of the 4 String Design

The key influencing factors in the maximum step out for a four string design are therefore the hole inclination, which drives the mud wt and is limited by the possibility of losses in the Balder and Forties, and the open hole time based on a TD in the Tor formation. Based on this a limit of 9000ft open hole length has been chosen which provides a maximum hole inclination of 64°through the 12 ¼” section and is greater than the 7709ft on the existing well and therefore adds additional but not excessive open hole time. This allows for the 12 ¼” section to TD in the Tor at 9811ft TVDrkb as in the existing well. For this example the 8 ½” reservoir section remains the same as the existing well as shown in Figure 5. The maximum step out of this design is 9183.5ft or 2.799km.

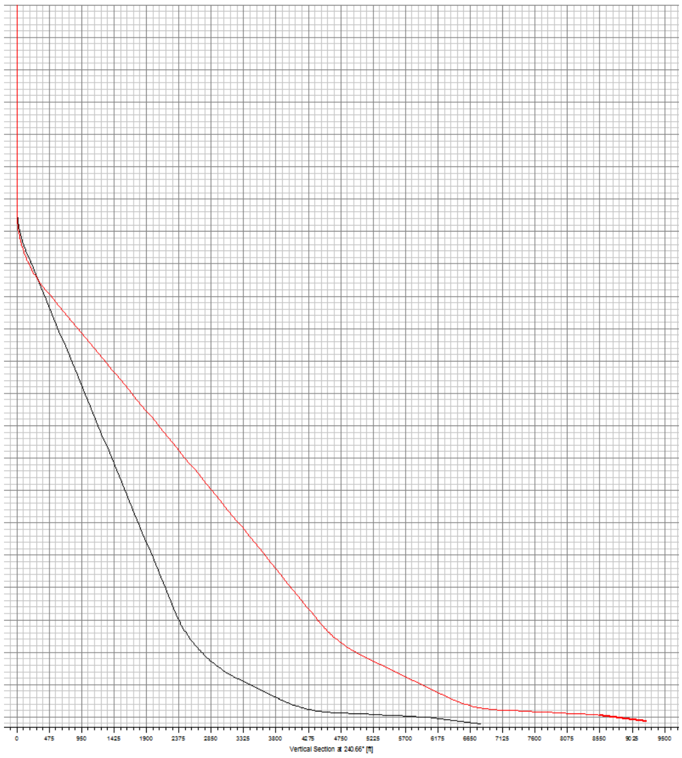


Figure 5 – Existing and Maximum Step-out Well (4SD)

	MD (ft)	CL (ft)	Inc (°)	Azi (°)	TVD (ft)
1	0.00		0.00	0.00	0.00
2	2904.15	2904.15	0.00	0.00	2904.15
3	3004.15	100.00	0.00	0.00	3004.15
4	4303.59	1299.44	39.98	241.60	4200.68
5	10570.64	6267.05	38.98	241.60	9037.82
6	11404.53	833.89	64.00	241.60	9552.92
7	11904.53	500.00	64.00	241.60	9772.11
8	12773.23	868.70	64.00	241.60	10152.92
9	13486.52	713.29	85.08	237.77	10342.06
10	13565.24	78.72	87.29	238.60	10347.29
11	14886.25	1321.01	87.29	238.60	10409.75
12	15037.36	151.11	82.81	237.94	10422.79
13	15751.95	714.59	82.81	237.94	10512.23

Figure 6 – Survey for max step-out design

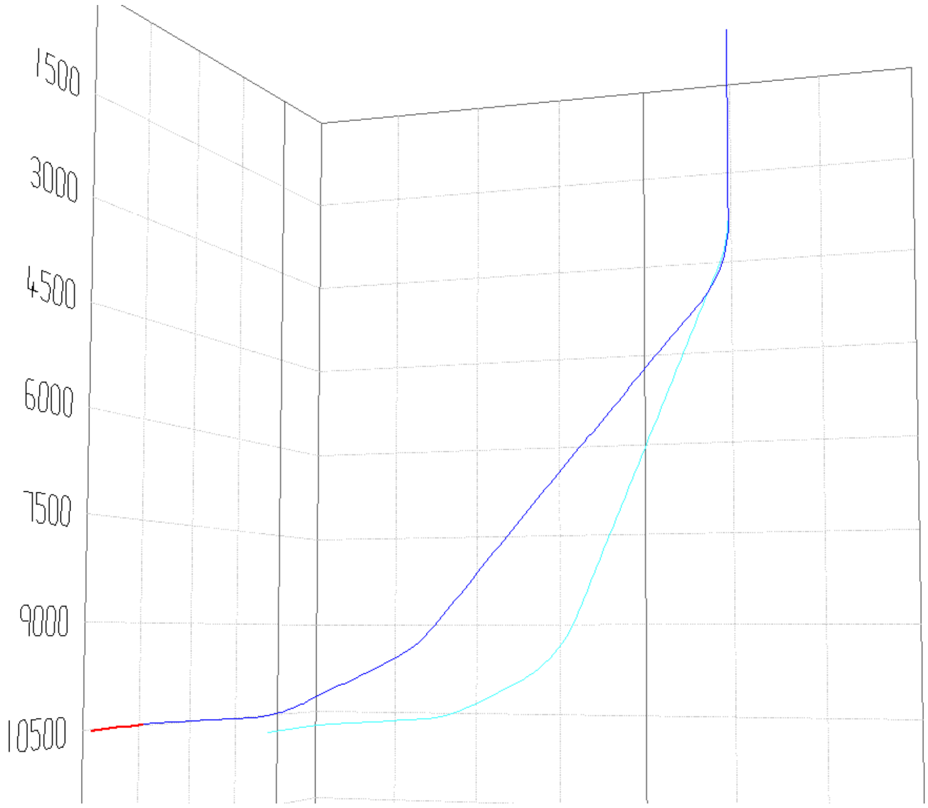


Figure 7– 3D view of the existing and maximum step out well (4SD)

3. 36” HOLE SECTION X 20X30” CONDUCTOR

Objective of the section

The objective of the conductor section is to provide wellbore support of shallow soils, structural support for trawler loads and dynamic bending loads caused by movement of rig BOPs

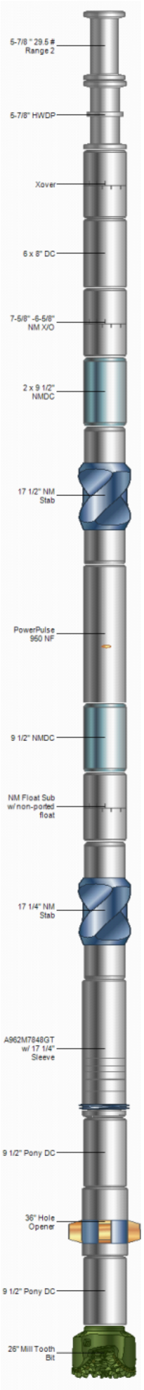
Well Status before this section

- Rig or Top Hole Drilling Vessel on location
- Seabed checked for obstacles

Overview of section operations

- Drill to TD (approximately 640ftBDF) using seawater and bentonite sweeps
  - Shallow gas procedures to be in place
- Displace well to 540pptf kill weight WBM at TD
- POOH
- Run standard DQ-HT3B conductor (As per Figure 5) complete with 60ft 35”x2”wt extension joint and 20” shoe joint.
  - 12ft Stick up if Cocoon type flowbase is to be run, 7ft stickup if non-cocoon type flowbase is to be run
- Cement in place using 13.4ppg RHC + 5% cenospheres with 250% excess cement (if there is a poor record of cement back to surface, then 12.6ppg RHC + 20% cenospheres and 300% excess cement can be utilised)
- WOC and perform top up cement job if required.

Figure 4 shows the typical 36” drilling BHA.



Schlumberger

Field Name	UK 02 1/30 Guillemot A	Borehole Name	GUA-P5	Hole Size (in)	36.000
Structure Name	Guillemot A	BHA Name	14May13 OOL DRAFT 36"x26" BHA MOTOR GUA P5	Depth In (ft)	0.00
Well Name	GUA-P5			Depth Out (ft)	0.00

	Desc.	Manu.	Serial Number	OD (in) ID (in)	Max OD (in)	Bot Size (in) Top Size (in)	Bot Type Top Type	Bot Gender Top Gender	FN OD (in) FN Length (ft)	Length (ft)	Cum. Length (ft)	Cum. Weight (1000 lbm)
1	26" Mill Tooth Bit	Generic		9.750 3.750	26.000	 7.625	 Regular	 Pin	0.000 0.00	2.60	2.60	2.6
2	9 1/2" Pony DC	Schlumberger		9.500 3.000	9.500	7.625 7.625	Regular Regular	Box Pin	0.000 0.00	5.00	7.60	3.7
3	36" Hole Opener	Generic		10.000 2.875	36.000	7.625 7.625	Regular Regular	Box Pin	0.000 0.00	14.50	22.10	7.0
4	9 1/2" Pony DC	Schlumberger		9.500 3.000	9.500	7.625 7.625	Regular Regular	Box Pin	0.000 0.00	5.00	27.10	8.0
5	A962M7848GT w/ 17 1/4" Sleeve	Schlumberger		9.625 7.850	17.250	7.625 7.625	Regular Regular	Box Box	0.000 0.00	32.02	59.12	14.4
6	17 1/4" NM Stab	Schlumberger		9.500 3.000	17.250	7.625 7.625	Regular Regular	Pin Box	0.000 0.00	6.00	65.12	15.7
7	NM Float Sub w/ non-ported float	Schlumberger		9.500 2.500	9.500	7.625 7.625	Regular Regular	Pin Box	0.000 0.00	5.00	70.12	16.8
8	9 1/2" NMDC	Schlumberger		9.500 3.000	9.500	7.625 7.625	Regular Regular	Pin Box	0.000 0.00	31.00	101.12	23.5
9	PowerPulse 950 NF	Schlumberger		9.500 5.900	9.680	7.625 7.625	Regular Regular	Pin Box	0.000 0.00	24.80	125.92	28.2
10	17 1/2" NM Stab	Schlumberger		9.500 3.000	17.500	7.625 7.625	Regular Regular	Pin Box	0.000 0.00	5.00	130.92	29.3
11	2 x 9 1/2" NMDC (2 joints)	Schlumberger		9.500 3.000	9.500	7.625 7.625	Regular Regular	Pin Box	0.000 0.00	62.00	192.92	42.7
12	7-5/8" -6-5/8" NM X/O	Rig		8.000 3.000	8.000	7.625 6.625	Regular Regular	Pin Box	0.000 0.00	5.00	197.92	43.4
13	6 x 8" DC (6 joints)	Rig		8.000 3.000	8.000	6.625 6.625	Regular Regular	Pin Box	0.000 0.00	192.00	389.92	71.5
14	Xover	Rig		9.500 3.250	9.500	6.625 5.875	Regular XT57	Pin Box	0.000 0.00	5.00	394.92	72.6
15	5-7/8" HWDP (3 joints)	Rig		5.875 4.000	7.000	5.875 5.875	XT57 XT57	Pin Box	0.000 0.00	93.00	487.92	77.9
16	5-7/8 " 29.5 # Range 2	Rig		5.875 5.045	7.000	5.875 5.875	XT57 XT57	Pin Box	0.000 0.00	31.00	518.92	78.8

Total Length (ft)	518.92
Total Weight in Air (1000 lbm)	78.8
Total Buoyant Weight (1000 lbm)	78.8
Buoyant Weight Below Jar (1000	
Weight in Air Below Jar (1000 lbm)	

BHA Comments

Mud Properties	
Mud Weight (lbm/gal)	
Mud Type	
PV (cP)	
YP (lbf/100ft2)	

Sensor Offset from Bit (ft)	
GR	111.02
D+I	113.14

Stabilizer Summary		
Blade Mid-Pt to Bit (ft)	Blade OD (in)	Blade Length (ft)
10.100	36.000	3.000
29.450	17.250	1.500
61.620	17.250	2.000
127.420	17.500	2.000

Bend Summary	
Bend Angle (deg)	Bend to Bit (ft)

BHA Nozzle Summary			
Bit Nozzle		Reamer Nozzle	
Count	ID (1/32 in)	Count	ID (1/32 in)
		TFA (in2)	
		PD Flow Restrictor (1/32 in)	
TFA (in2)		Rotor By Pass Nozzle (1/32 in)	0.000

Date	14-May-2013
Designed By	DIROOladoyin
Approved By	

Figure 4 - Typical 36" drilling BHA

Typical casing schematic for this section

The typical conductor schematic is shown in Figure 5. For more information, also visit:

- Conductor Schematic: https://sww-knowledge-epe.shell.com/teamepns/livelink.exe/open/40312021
- Component Details:https://sww-knowledge-epe.shell.com/teamepns/livelink.exe/open/40309212

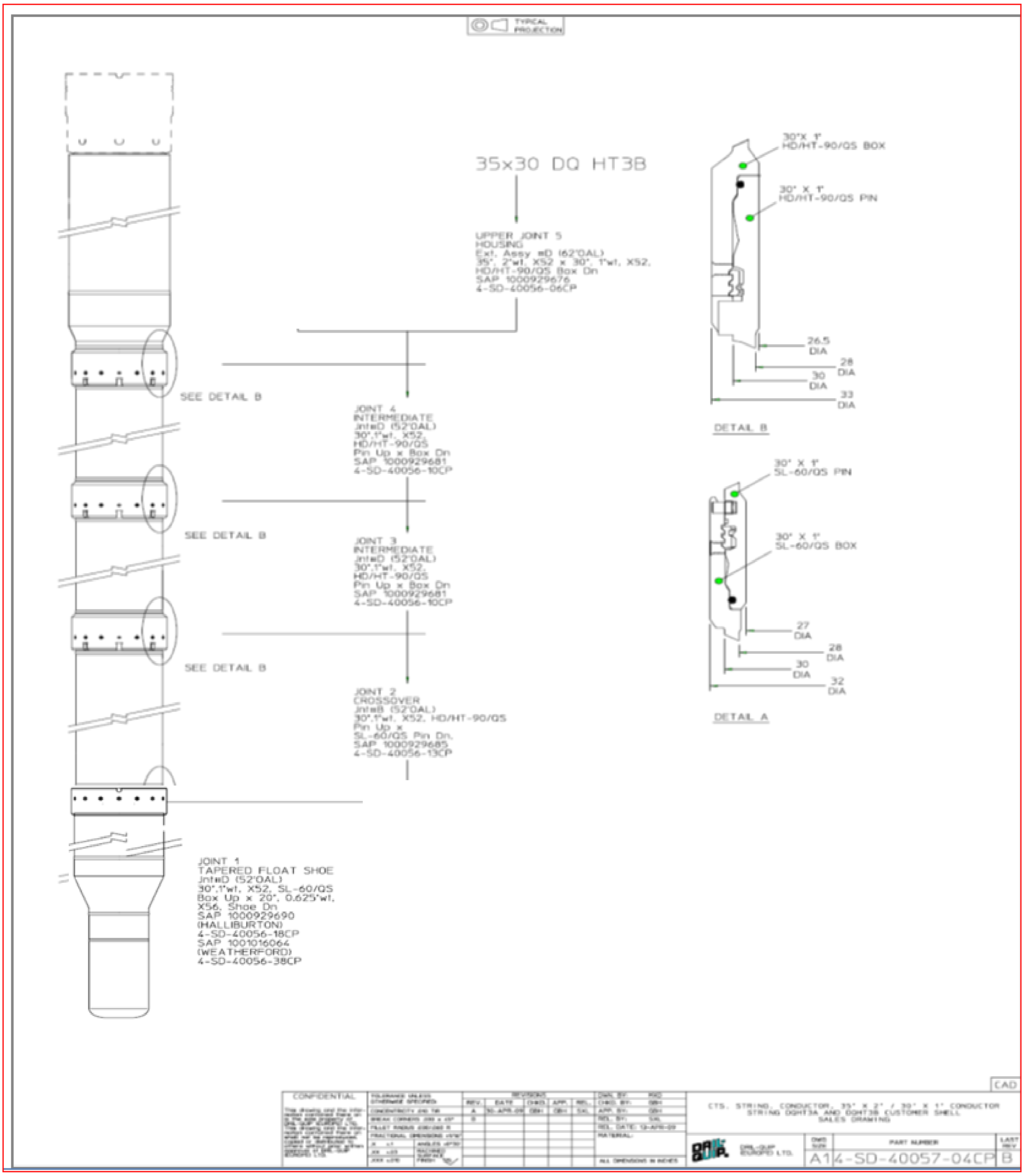


Figure 5 - Typical 30" conductor schematic

Factors limiting the design of this section

Set hole section length

The total length of the conductor assembly is set and it is equal to 268ft. TD is therefore calculated as follows:

TD = conductor assembly length – stick up + water depth + DFE

Where:

- Stick Up is 12ft in case the cocoon is installed, and 7ft in case of no cocoon;

- Water Depth (MSL-ML) is typically around 300ft for CNNS but this needs to be updated based on location;
- DFE is typically 86.5ft but this needs to be checked based on the rig.

Drilling fluid

The 36” hole is drilled with seawater and bentonite sweeps. An alternative to bentonite sweeps is hi-vis pills made from Guar Gum which has been used successfully where logistics were an issue in the supply of prehydrated bentonite. However, if there is a risk of excessive washout whilst drilling due to presence of unconsolidated sands then bentonite should be used for its enhanced plastering effect compared to guar gum. Silicate pills can also be used in extreme cases eg no history of cement returns to seabed. At TD the hole is to be displaced to 540pptf kill weight mud.

Casing Design

The Standard conductor string is the HT3B design, to include a 60ft extension joint in order to cover the softest soil conditions in CNS as per the OAP Conductor Design Study. Figure 6 describes the conductor string specifications. The suffix H, M, S refers to hard, medium or soft formation. A, B, C refer to the thermally induced compressive load that the conductor must support. HT3B has been chosen to cover all realistic load cases.

Design Case	Conductor String	Soil Profile	Thermal Load Case
HT1A-HB	HT1A 40'	Hard	B (1,500.000 lbs)
HT2A-HC	HT2A 40'	Hard	C (2,700,000 lbs)
HT2B-MA	HT2B 60'	Medium	A (500,000 lbs)
HT3B-MB	HT3B 60'	Medium	B (1,500,000 lbs)
HT4B-MC	HT4B 60'	Medium	C (2,700,000 lbs)
HT3B-SA	HT3B 60'	Soft	A (500,000 lbs)
HT4B-SB	HT4B 60'	Soft	B (1,500,000 lbs)

Figure 6 - Conductor string specifications

Cementing Design

The conductor is cemented using a single Rapid Hardening Cement (RHC) with 5% Cenosphere’s at 13.4ppg. Excess in the order of 250% is standard, with the aim of observing cement returns to surface (if these are not obtained, a top up job is required).

Where surface soil conditions are weak as seen on offset wells (Pierce and Guillemot for example) a lighter 12.6ppg slurry can be formulated using 20% Cenospheres. This can be used in combination with silicate liquor sweeps while drilling and Cemnet fibres (or other vendors’ equivalent products) to reduce the risk of having to carry out a top-up job which typically causes 12hrs of NPT. It is also recommended to increase excess to 300% in these situations.

Procurement

The well engineer must ensure that the following items are booked in time. For more information and advice, refer to the Wells Materials Guidelines Wiki:

http://sww.wiki.shell.com/wiki/index.php/Wells_Material_Ordering_Guidelines_%28WMOG%29

Casing and accessories

Book the following items in SAP at least 12 weeks prior to spud. For more advice, contact Shauna Skillander. Also see the list at the following address:

https://sww-knowledge-epe.shell.com/teamepns/livelink.exe/open/41463565

Item	Material	Plant	Requirement qty	Base Unit	Pr...	It...	R..	Stor. Location	BOM ex...	Description
0020	1001016064	GB01	2.00	EA		N	3	1021		JOINT ASSY,FLSH,DRILQUIP,4-SD-40056-38CP
0030	1000929681	GB01	3.00	EA		N	3	1021		COJ,X52,HD/HT-90/QS,30.0x1.0,50ft
0040	1000929685	GB01	2.00	EA		N	3	1021		XOCO,X52,30x1.0HD/HT-90Px30X1.0SL-60P
0050	1001138270	GB01	2.00	EA		N	3	1021		ASSY,WHHS,35.0x30.0,A50383-22,VETCOGRY

Drilling services

Quotations need to be collected from the vendors for all drilling services (except for Cementing and Fluids). These quotes are then to be provided to the Cost Controllers.

4. 17 1/2” HOLE SECTION X 13 3/8” SURFACE CASING

Objective of the section

The objective of the 17 1/2” section is to allow 13 3/8” casing to be run so that weak shallow formations are secured and to ensure a robust shoe strength for the proceeding 12 ¼” section. The 13 3/8” casing also provides structural integrity for the well against bending loads caused by BOP loading and trawler loading. For gas lifted wells, the B-annulus contained by the 13 3/8” casing and the casing shoe provides a secondary barrier to gas lift operating pressures. The shoe strength should also allow for leak-off of TITAP in order to prevent collapse of the 9 5/8” casing.

Well Status before this section

- The top hole will have been already installed by the Top Hole Drilling Vessel or conventional drilling rig.

- 35” x 30” Conductor set +/- 250ft below mud line as per the Standard Conductor design with 540pptf kill weight bentonite mud in hole

Overview of section operations

- Tag TOC inside conductor and drill out with 17 ½” assembly

- Continue drilling to section TD of 3500ftTVDBDF with seawater and bentonite sweeps
    - Shallow gas procedures to be in place

- At TD displace well to 540pptf mud.
    - For some wells the WBS model will show early onset of over-pressured/sticky shales as shallow as 3000ftTVDBDF. For these wells, advice from the wellbore stability focal point will be required since it may be necessary to displace the well to a higher weight bentonite spud mud and additional inhibition. In one example, at TD Guillemot P5 was displaced to 580pptf WBM with the base 500ft of the well displaced to Silicate Water Based Mud (WBM) containing 40ppb KCL and 8% silicate liquor to mitigate wellbore instability from sticky shales.

- POOH

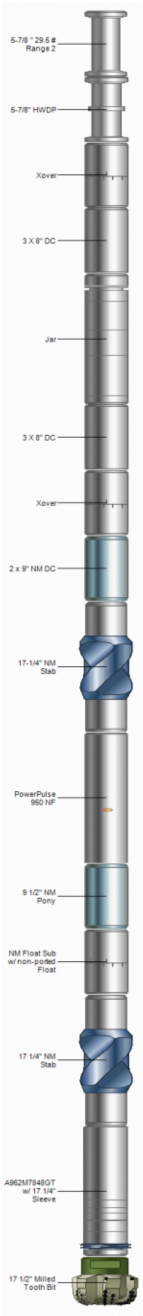
- Run the standard DQ-RB2B surface casing assembly (Figure 8) complete with a DQ THM90 quick connect from 13 3/8” casing to 29ft 20” wellhead extension x Vetco MS-700 18 ¾” Wellhead Housing.
    - The 20” x 0.625”, X80 crossover swage at the base of the DQ THM90 is only rated to 4375psi (302bar). For wells on Pierce where gas lift pressures can potentially be much higher than this consider welding a Vam Top connection directly to the 18 ¾” WHH or using the Vetco RL-3M connector.

- Cement to surface using a 12.5ppg (650pptf) lead and 500ft of 16ppg (832pptf) tail using Class G+35% Silica. The recommended excess slurry volume is 100%.

- WOC

- Run Production Flowbase (Cocoon or Non-cocoon type)

Figure 7 shows a typical 17 ½” drilling BHA.



Schlumberger

Field Name	UK 021/30 Guillemot A	Borehole Name	GUA-P5	Hole Size (in)	17.500
Structure Name	Guillemot A	BHA Name	14May13 OOL DRAFT 17 1/2" BHA MOTOR GUAP5	Depth In (ft)	0.00
Well Name	GUA-P5			Depth Out (ft)	0.00

	Desc.	Manu.	Serial Number	OD (in) / ID (in)	Max OD (in)	Bot Size (in) / Top Size (in)	Bot Type / Top Type	Bot Gender / Top Gender	FN OD (in) / FN Length (ft)	Length (ft)	Cum. Length (ft)	Cum. Weight (1000 lbm)
				9.750					0.000			
1	17 1/2" Milled Tooth Bit	Generic		3.750	17.500	7.625	REG	Pin	0.00	2.06	2.06	1.0
				9.625		7.625	Regular	Box	0.000			
2	A962M7848GT w/17 1/4" Sleeve	Schlumberger		7.850	17.250	7.625	Regular	Box	0.00	32.02	34.08	7.4
				9.500		7.625	Regular	Pin	0.000			
3	17 1/4" NM Stab	Schlumberger		3.000	17.250	7.625	Regular	Box	0.00	6.00	40.08	8.7
				9.500		7.625	Regular	Pin	0.000			
4	NM Float Sub w/non-ported Float	Schlumberger		3.000	9.500	7.625	Regular	Box	0.00	5.00	45.08	9.8
				9.500		7.625	Regular	Pin	0.000			
5	9 1/2" NM Pony	Schlumberger		3.000	9.500	7.625	Regular	Box	0.00	10.00	55.08	11.9
				9.500		7.625	Regular	Pin	0.000			
6	PowerPulse 950 NF	Schlumberger		5.900	9.680	7.625	Regular	Box	0.00	24.80	79.88	16.6
				9.500		7.625	REG	Pin	0.000			
7	17-1/4" NM Stab	Schlumberger		3.000	17.250	7.625	REG	Box	0.00	5.00	84.88	17.7
				9.250		7.625	REG	Pin	0.000			
8	2 x 9" NM DC (2 joints)	Schlumberger		2.500	9.250	7.625	REG	Box	0.00	60.00	144.88	30.3
				9.500		7.625	Regular	Pin	0.000			
9	Xover	Rig		3.250	9.500	6.625	Regular	Box	0.00	5.00	149.88	31.4
				8.000		6.625	Reg	Pin	0.000			
10	3 X 8" DC (3 joints)	Rig		2.500	8.000	6.625	Reg	Box	0.00	90.00	239.88	45.2
				7.750		6.625	REG	Pin	0.000			
11	Jar	Rig		3.000	7.750	6.625	REG	Box	0.00	33.00	272.88	48.7
				8.000		6.625	Reg	Pin	0.000			
12	3 X 8" DC (3 joints)	Rig		2.500	8.000	6.625	Reg	Box	0.00	90.00	362.88	62.5
				9.500		6.625	Regular	Pin	0.000			
13	Xover	Rig		3.250	9.500	5.875	XT57	Box	0.00	5.00	367.88	63.6
				5.875		5.875	XT57	Pin	0.000			
14	5-7/8" HWDP (3 joints)	Rig		4.000	7.000	5.875	XT57	Box	0.00	93.00	460.88	68.9
				5.875		5.875	XT57	Pin	0.000			
15	5-7/8 " 29.5 # Range 2	Rig		5.045	7.000	5.875	XT57	Box	0.00	31.00	491.88	69.8

Total Length (ft)	491.88
Total Weight in Air (1000 lbm)	69.8
Total Buoyant Weight (1000 lbm)	69.8
Buoyant Weight Below Jar (1000	45.2
Weight in Air Below Jar (1000 lbm)	45.2

BHA Comments

Mud Properties	
Mud Weight (lbm/gal)	
Mud Type	
PV (cP)	
YP (lbf/100 ft2)	

Sensor Offset from Bit (ft)	
MWD GR	64.98
D+I	67.10

Stabilizer Summary		
Blade Mid-Pt to Bit (ft)	Blade OD (in)	Blade Length (ft)
4.410	17.250	1.500
36.580	17.250	2.000
81.380	17.250	2.000

Bend Summary	
Bend Angle (deg)	Bend to Bit (ft)
0.780	9.840

BHA Nozzle Summary			
Bit Nozzle		Reamer Nozzle	
Count	ID (1/32 in)	Count	ID (1/32 in)
		TFA (in2)	
		PD Flow Restrictor	
		(1/32 in)	
		Rotor By Pass Nozzle	
TFA (in2)		(1/32 in)	

Date	14May2013
Designed By	DIR\OOladoyin
Approved By	

Figure 7 - typical 17 1/2" BHA

Typical casing schematic for this section

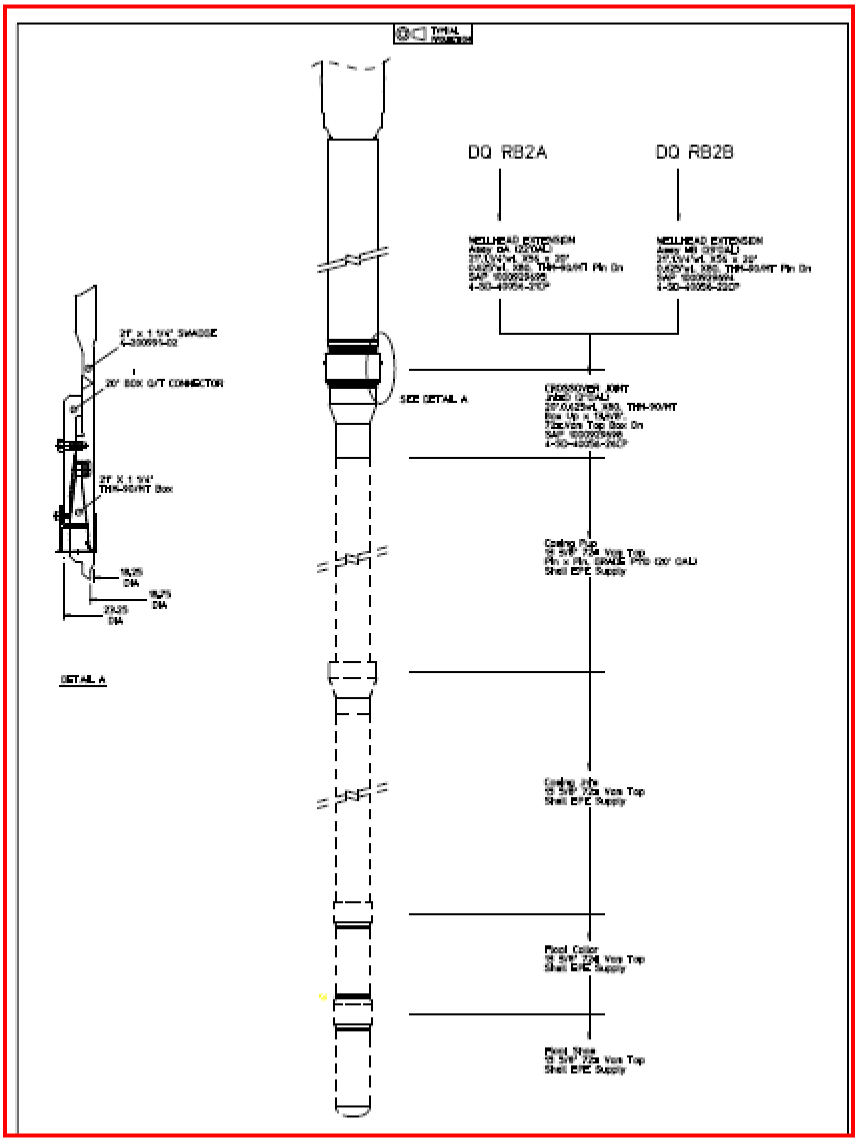


Figure 8 - Typical 13 3/8" casing schematic

Factors limiting the design of this section

Hole section length

This is fixed at 3500ftTVDBDF as limited by onset of sticky/over-pressured shales (Lark). Early onset of sticky/over-pressured shales is to be mitigated as described Drilling fluid section on page 21.

Sticky Shale (Lark) limit

The depth of the Lark formation varies across the CNS and represents the on-set of over-pressure in the overburden. There is therefore a risk of wellbore stability when drilling with seawater and sweeps followed by the displacement to a 540pptf spud mud. An offset analysis performed on twenty CNS wells has shown that although these wells are drilled below the recommended mud wt (as per the wellbore stability charts) it is very uncommon to have any issues running casing with a 540pptf spud mud wt. One reason for this is that the charts are based on a very small amount of actual data since the majority of wells drilled to these depths are done so riser less. There is however limited information on drilling wells to 3500ft into the top of the Lark and therefore for this reason it is recommended that the wellbore stability focal point is contacted to provide advice on the spud mud wt.

Cap & Contain limitations

If hydrocarbons are expected in the next section (12 1/4" hole), the open hole section should be able to withstand full evacuation to hydrocarbons. The LOT at the 13 3/8" shoe must therefore be considered in the planning of the well based on the PPP. The Reservoir Engineer (RE) will provide either a gas or oil gradient to use in the evaluation. In the case where cap and contain requirement is not met, a risk analysis will be carried out to ensure that there is sufficient mitigation for evacuation to hydrocarbons occurring. Figure 9 shows the standard bow-tie model risk analysis as used for Pierce A12; also see:

https://sww-knowledge-epe.shell.com/teamepns/livelink.exe/open/55907995/

	PREVENTION								RECOVERY			
Barrier / PPP Scenario	TD in Sele	MW Over-balanced	Wellbore stability & ECD Management	Wellbore strengthening	LCM strategy	Under-balanced after total Losses	Pump SW / sub-hydro-static		Low case Kick tolerance with SW	Well is shut in, well kill, plug back	Tertiary – C&C	Tertiary - Relief Well
Absolute Max (558pptf)		680pptf MW overbalancing 544pptf Real High PPP & 555pptf virgin	ECD< Minimum FBP static MW>MHS	MHS+800psi ensures that FBP>ECD	effective	Moderate losses required	Significant SW volumes to under-balance	KICK	>20bbls	Practises & Procedures in place	C&C v. unlikely to be robust	Relief Well Plan in place
Real High (544pptf)–Exp									>45bbls			
Expected (490pptf)									155bbls		C&C unlikely to be robust	
Exp-Real Low (364pptf)					Less effective	Significant losses required	Sub hydrostatic P_p<450pptf		Unlimited for P_p<386pptf		P_p>386pptf C&C may not be robust	
Real Low-Abs Min (125pptf)			Uncontrollable losses, LCM less effective			Significant losses required	Sub hydrostatic		Unlimited		C&C robust	

Figure 9 - standard bow-tie model risk analysis as used for Pierce A12

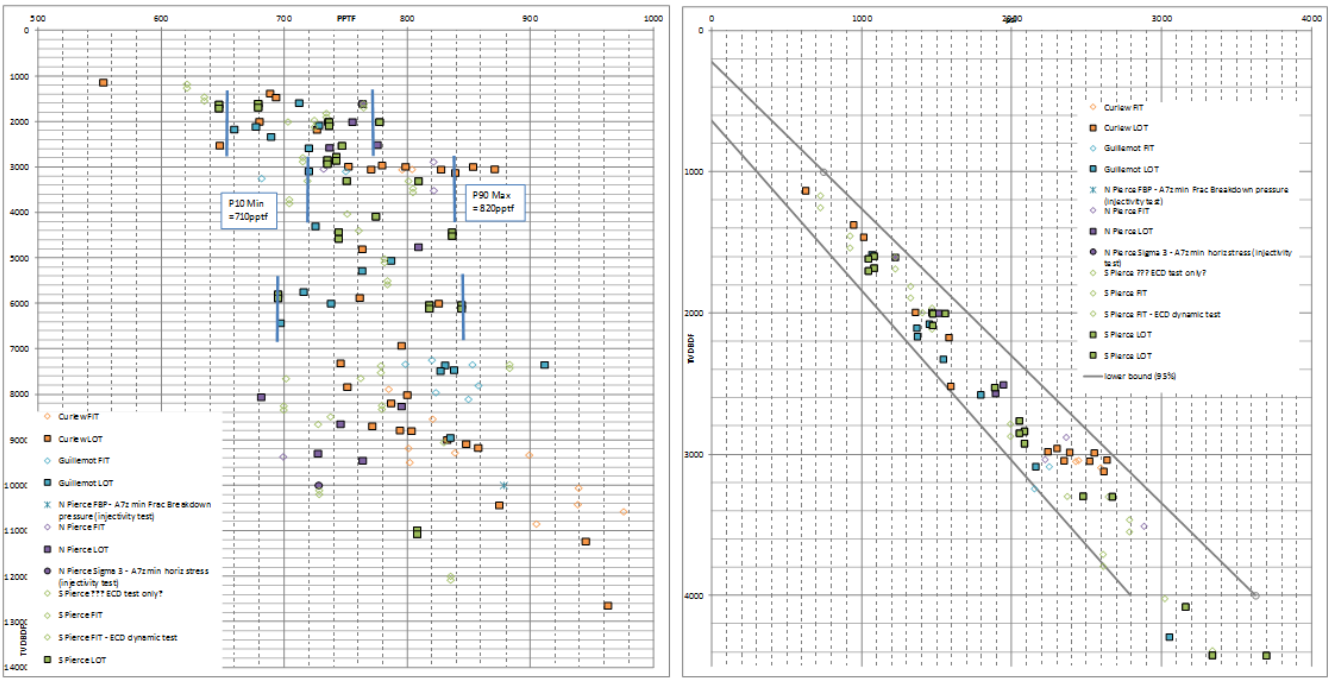


Figure 10 - CNNS LOT database

Figure 10 shows data from the CNNS LOT Database, which is available at:

https://sww-knowledge-epe.shell.com/teamepns/livelink.exe/open/60857039

Directional limitations

The 13-3/8" casing shoe will be at maximum inclination of 25 degrees. The section will be drilled to section TD with a maximum dogleg severity of 2 degrees / 100ft. Maximum inclination in this section will be restricted by wellbore stability, recommended mud weight to drill the section and estimated ECD. A typical BHA is shown in Figure 7.

Kick Tolerance limitations

This is another factor that needs to be taken into consideration though not a boundary; it may affect the maximum drilling depth depending on the drilling contractor's policy. As a guide, the 13 3/8" casing shoe strength should be able to withstand circulating out 25bbl swabbed gas kick (in case any of the formations to drill are expected to contain hydrocarbons). Wellplan will be used to model Kick Tolerance and is based on a swabbed gas kick. Mud weight is therefore used in this determination which is in the most part driven by wellbore stability.

Drilling fluid

The 17 1/2" hole is drilled with seawater and bentonite sweeps. At TD the well will typically be displaced to a 540pptf kill weight mud. An alternative to bentonite sweeps is hi-vis pills made from Guar Gum which has been used successfully where logistics were an issue in the supply of prehydrated bentonite. However, if there is a risk of excessive washout whilst drilling due to presence of unconsolidated sands then bentonite should be used for its enhanced plastering effect compared to guar gum. Silicate pills can also be used in extreme cases eg no history of cement returns to seabed. For wells with early onset of sticky/over-pressured shales the well should be displaced at TD to a mud weight up to 580pptf kill weight (determined by the Wellbore Stability Focal Point). The bottom 100ft-500ft should be displaced to Silicate WBM containing 40ppb KCL + 8% silicate. Since this is both a mud design and wellbore stability issue the Wells Fluid Team should also be contacted for their recommendations on this.

Figures illustrating the design limitations

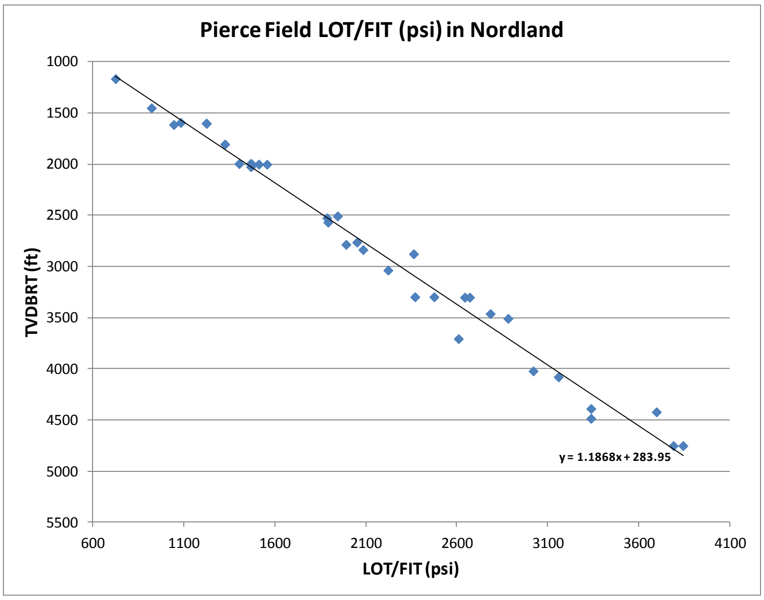


Figure 11 - Pierce field LOT/FIT in Nordland formation

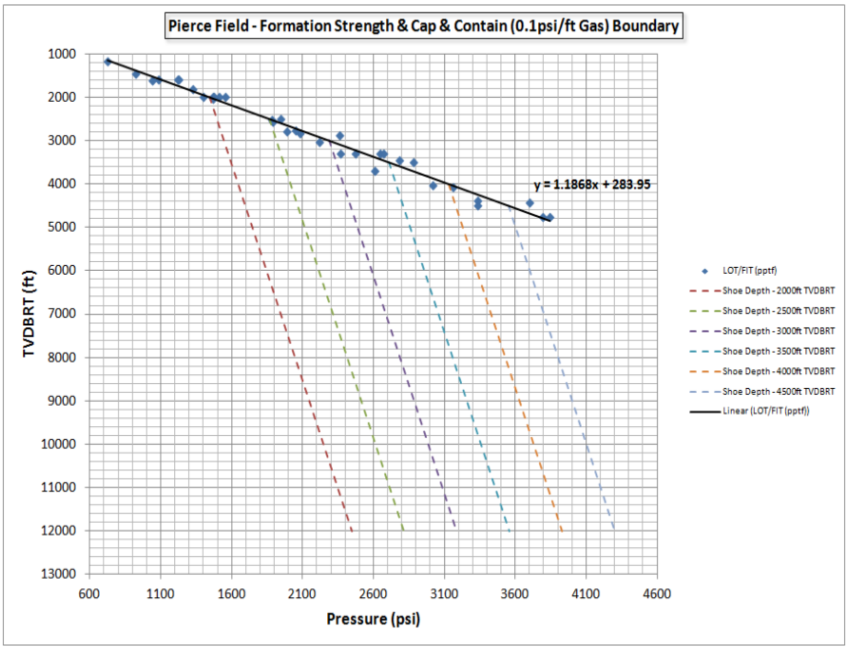


Figure 12 - Cap and contain lines for gas gradient

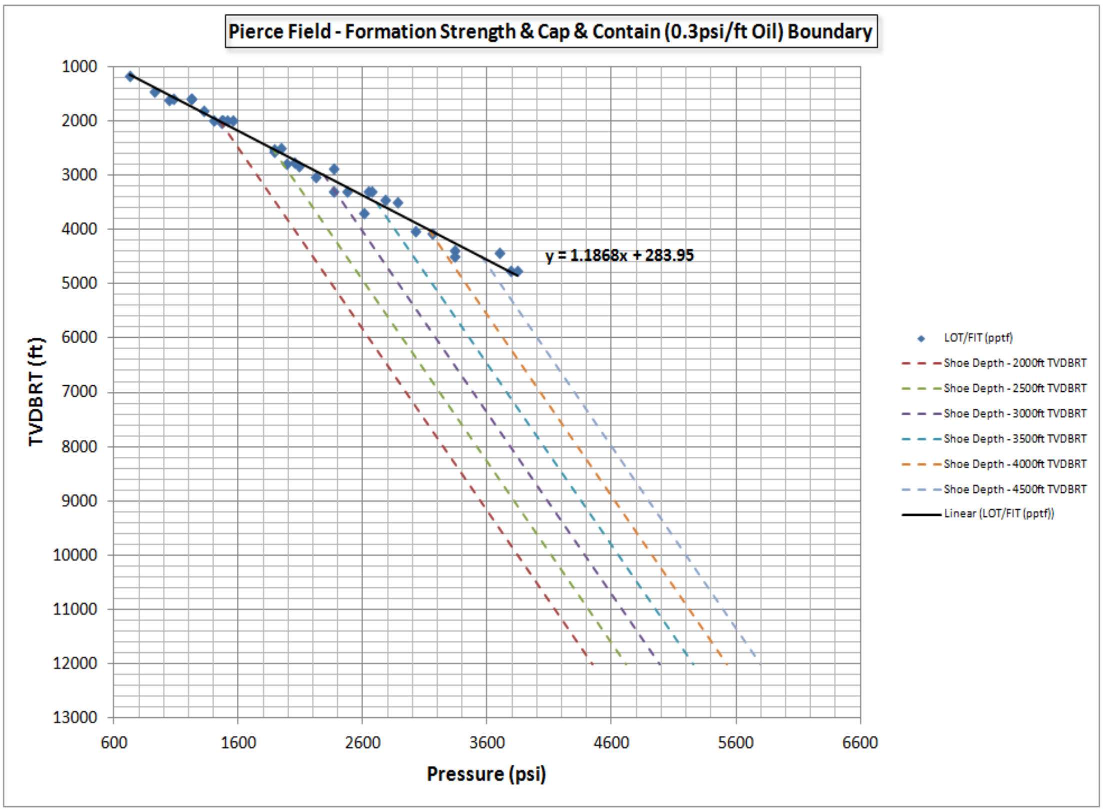


Figure 13 - Cap and contain lines for oil gradient

Casing Design

The Surface casing to be used is 13 3/8", 72ppf, P110. It should be noted that

1. The maximum allowable instantaneous gas lift pressure must be <250bar. Operating Gas lift pressure is advised by the asset and is checked against the well design. A Leak Off Test at the shoe will confirm the

maximum allowable operating gas lift pressure and is expected to be between 710pptf and 860pptf (as per Figure 10. See below for max allowable gas lift pressures:

	min	max
(a) Leak off at shoe	710pptf	860pptf
(b) TVDBDF (b)	3500ft	3500ft
(c) Leak off strength at shoe	2485psi	3010psi
(d) Max gas Lift pressure at wellhead c-(b-400ft)*0.1	2175psi (150bar)	2700psi (186bar)

2. SSC risk is medium if Partial Pressures in the proceeding hole section falls within Region 0.

Cementing Design

The main objectives of the cementation of the surface casing are to provide long term isolation to prevent communication between distinct permeable zones and surface and to assure a good hydraulic seal between casing and formation in order to achieve FIT or LOT at the casing shoe to drill through the next section. Cement to surface is also critical for ensuring structural integrity of the surface casing against bending loads from BOPs and Trawlers.

Cement to be used is Class G+35% Silica. Schedule is 650pptf extended lead slurry and 500ft of 832pptf tail to surface using dye in order to indicate cement to surface. A minimum of 100% excess is recommended as per the Shell UIE Cementing Operations Manual and Standards. Note however that some fields have a history of poor surface cementations; On Pierce and Guillemot the recommendation is 175% excess on the lead and 50% excess on the tail.

The cement slurry is dependent on static bottom hole and simulated production temperature profile, Class G slurry can be used for BHT less than 230^{0}F and for temperatures greater than 230^{0}F Class G + 35% Silica blend slurry should be used. For ease of cement inventory management, all non-conductor cement jobs will use Class G + 35% Silica blend slurry.

Because the hole section is vertical, one centralizer per two joints is sufficient centralization.

Procurement

The well engineer must ensure that the following items are booked in time. For more information and advice, refer to the Wells Materials Guidelines Wiki:

http://sww.wiki.shell.com/wiki/index.php/Wells_Material_Ordering_Guidelines_%28WMOG%29

Casing and accessories

Book the following items in SAP 12 at least 12 weeks prior to spud. For more advice, contact Shauna Skillander. Also see the list at the following address:

https://sww-knowledge-epe.shell.com/teamepns/livelink.exe/open/41463565

Op...	BO...	Material	Plant	Requirement qty	Ba...	I...	R..	Sto...	Description	SortStrg
0020	0070	1001106712	GB01	1.00	EA	N	3	1021	FLSH,X65,BW,20.000x0.625	
0020	0080	1001106718	GB01	1.00	EA	N	3	1021	FLCO,X65,BW,NR,3k,20.000x0.625	
0020	0090	1000929698	GB01	2.00	EA	N	3	1021	XOCO,X80,20x0.625THM-90Bx13.3/8-72VAM-TB	
0020	0100	1001227008	GB01	2.00	EA	N	3	1021	WHHS,VETCOGRY,18.750in,MS700,A50421-4	
0030	0011	1001129938	GB01	1,175	M	N	3	1021	CSG,P110,R3,VAM-T,SD,13.3/8-72.0,PSL1	
0030	0020	1000676649	GB01	1.00	EA	N	3	1021	SEAL,MS-1,18.3/4,15k,PSL 2-4 ,MS-700	
0030	0030	1000676650	GB01	1.00	EA	N	3	1021	SEAL,SG-TPR,18.3/4,15k,PSL 2-4 ,MS-700	
0030	0040	1000532350	GB01	2.00	EA	N	3	1021	FLSH,P110,VAM-T,CONVENT ,13.3/8-72.0	
0030	0050	1000490627	GB01	2.00	EA	N	3	1021	FLCO,P110,VAM-T,NON-ROT. ,13.3/8-72.0	
0030	0070	1000411031	GB01	40.00	EA	N	3	1021	CEST,HOLE 17.1/2,STA4,PIPE 13.3/8	
0030	0080	1000411114	GB01	40.00	EA	N	3	1021	STCO,JSH,13.3/8	
0030	0090	7000000008	GB01	2.00	EA	N	3	1021	13 3/8" x 20" Top Only MidBore SSR Plug,	
0030	0100	1000509758	GB01	2.00	EA	N	3	1021	CGPJ,P110,13.3/8-72.0,VAM-T,SD , 3ft	
0030	0110	1000441826	GB01	2.00	EA	N	3	1028	CGPJ,P110,13.3/8-72.0,VAM-T,SD ,10ft	
0030	0120	1000493315	GB01	2.00	EA	N	3	1021	CGPJ,P110,13.3/8-72.0,VAM-T,SD ,15ft	
0030	0130	1001178642	GB01	2.00	EA	N	3	1021	DART,TOP,WEATHERF,1285900,5TO5.7/8in	

Wellhead components

Book the following items in SAP 12 at least 12 weeks prior to spud. QAQC by Calum Dines required. Figure 14 shows the wellhead schematic.

SAP	Component	Description
1001227008	Vetco 18 ¾" MS700 Wellhead Housing x 2	15k wellhead
1000676649	MS-1 Seal assembly x 2	Provides a seal between the casing hanger and the wellhead bore while providing lock down for the casing hanger
1000676650	Seal SG TPR x 1	backup to the MS-1 with elastomeric seals to be used when the seal areas have severe damage
1000676651	Dummy 13 3/8" Casing Hanger x 2	Dummy 13 3/8" Casing Hanger (to be ordered in 12 ¼" section)

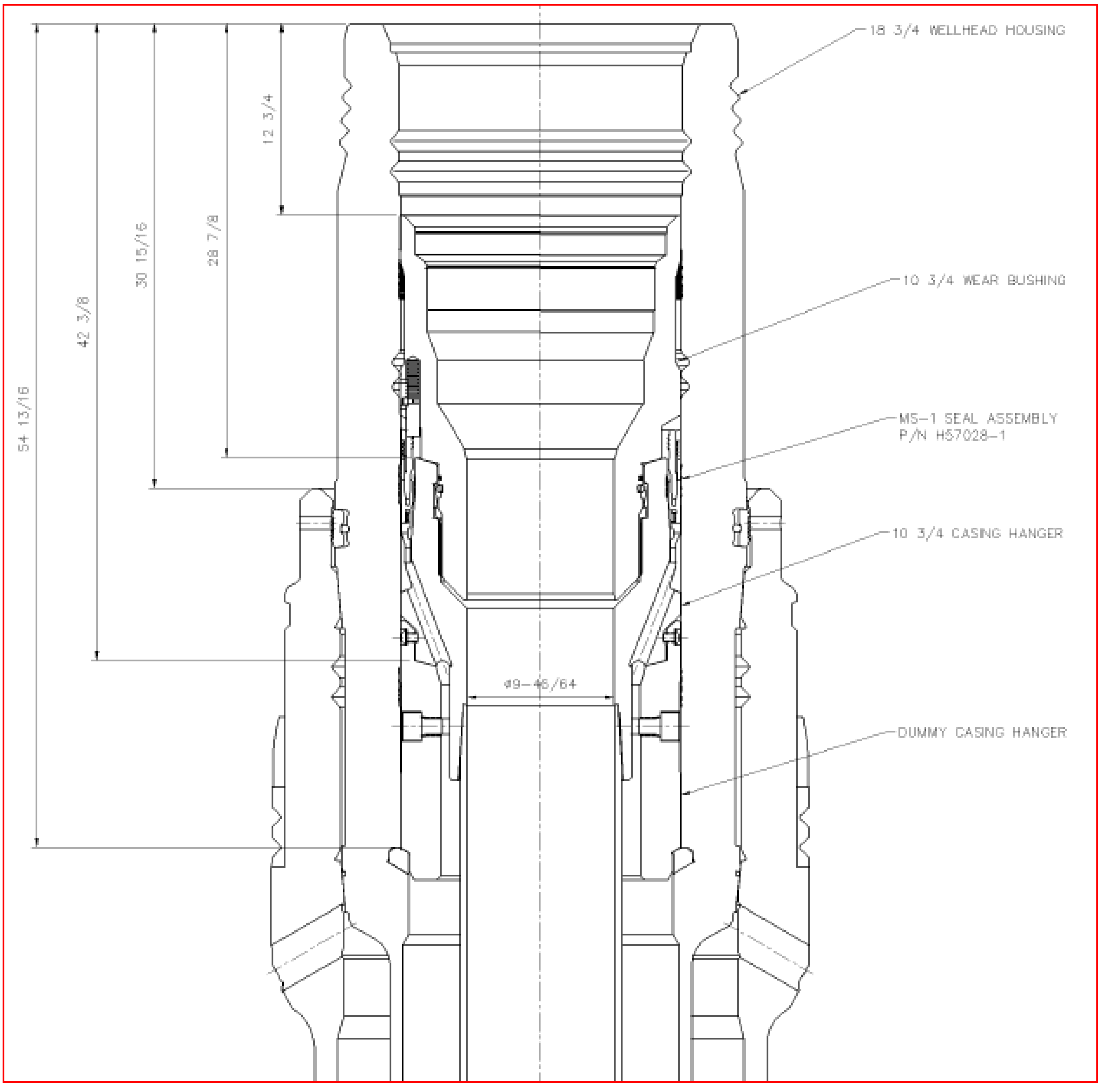


Figure 14 – 18 ¾" MS700 Slim Bore Wellhead schematic

Xmas Tree

The Tree should have been ordered by the subsea team. Tree information can be found at https://sww-knowledge-epe.shell.com/xtrnshell/livelink.exe/open/3120843/

Flowbase

Determine whether the flowbase needs to be cocoon-type or non-cocoon type. This will depend on whether the location has existing trees that are non cocoon style or not. More information can be found at

https://sww-knowledge-epe.shell.com/xtrnshell/livelink.exe/open/3120843

or refer to Subsea Tree Fishing Protection Policy doc no. EP200507210420. There is also a Shell Standard Close Coupled Well Subsea Tie-In Design Document doc no. EP201311201592. The flowbase will be run after landing and cementing the 13 3/8” casing. Running the flowbase will be last operation with the top hole drilling vessel if the top hole drilling vessel has been utilized.

Figure 15 shows flowbase schematic for the non cocoon (left) and cocoon type (right) flowbases.

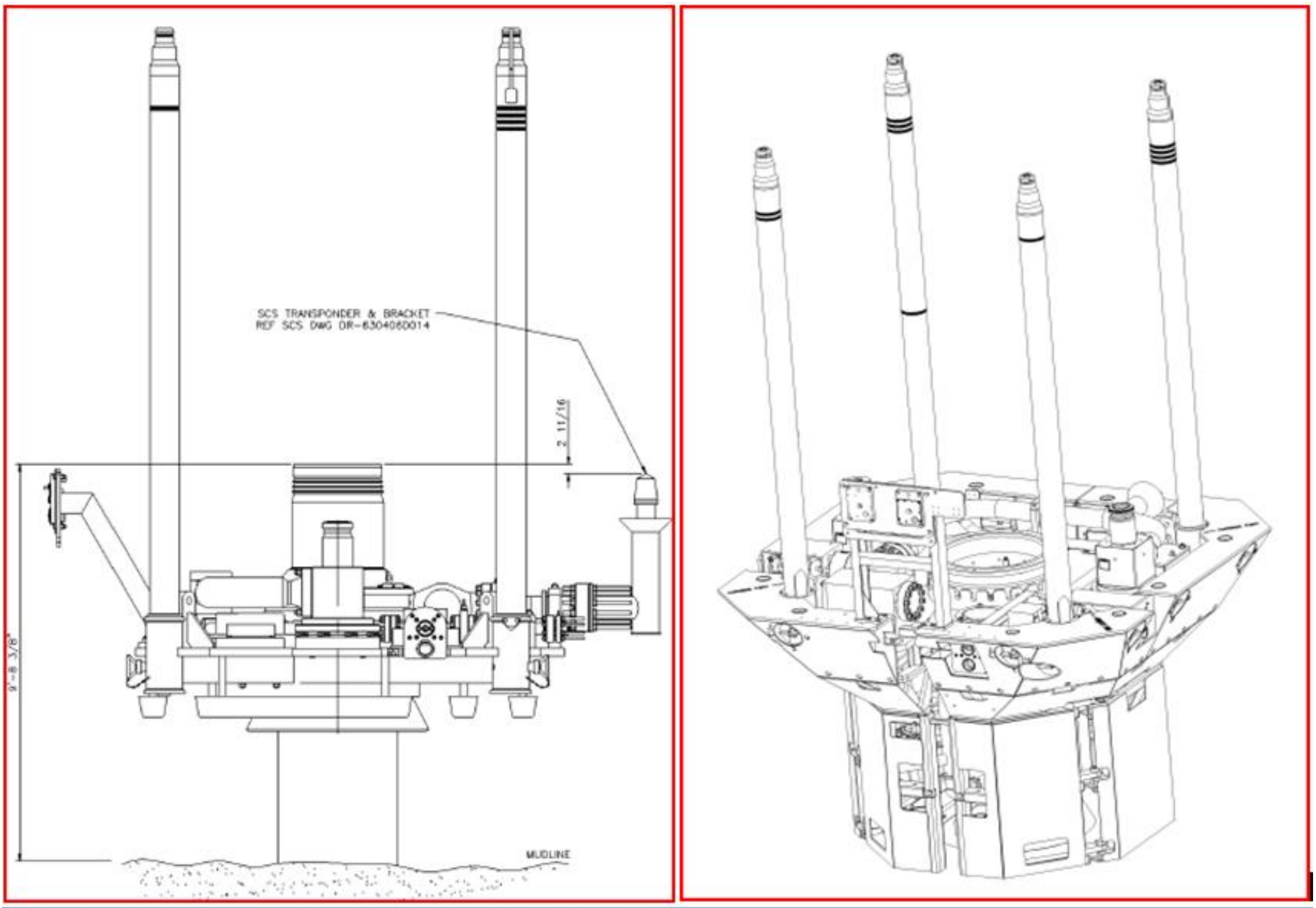


Figure 15 - Flowbase schematic

Drilling services

Quotations need to be collected from the vendors for all drilling services (except for Cementing and Fluids). These quotes are then to be provided to the Cost Controllers.

5. 12 ¼" HOLE SECTION / PRODUCTION CASING

Objective of the section

The objective of the 12-1/4" section is to drill to top reservoir or into the reservoir and cement 10-3/4" x 9-5/8" casing to facilitate drilling the reservoir in the next hole section.

Well Status before this section

- The top hole will have been already installed by the Top Hole Drilling Vessel
- 36" x 30" Conductor set +/- 250ft below mud line as per the Standard Conductor design
- 20" x 13-3/8" Surface Casing set and cemented above, or just into the sticky shales in the Nordland group
- 20" x 13-3/8" Casing pressure tested with seawater in hole
- Flowbase installed
- Corrosion cap installed
-

Overview of section operations

The 12-1/4" section will commence by removing the corrosion cap, running and testing BOPs after rig arrival on location. 12-1/4" directional BHA will be run in hole to drill out the shoe track while displacing the well to OBM. The shoe track, rathole and 15ft of new formation will be drilled and a leak-off test conducted to confirm enough shoe strength to drill to section TD. This section will typically be drilled using a rotary steerable system and MWD/LWD. OBM weight will be determined by wellbore stability and predicted pore and fracture pressures. 10-3/4" x 9-5/8" casing will be run and cemented with shoe above or just into the target reservoir section. Top of cement will be determined by depth of shallowest permeable zone, production packer setting depth and future well abandonment considerations.

Typical 12 ¼" shoe setting depths are shown below and in Figure 16.

Reservoir Target	**Shoe**
Tay Target	Horda
Oden Target	Horda
Forties	Sele
Andrews	Sele
Fulmar/Skagerak	Chalk-Valhall or Heather
Fulmar/Skagerak (opportunity case)	Heather or Kimmeridge

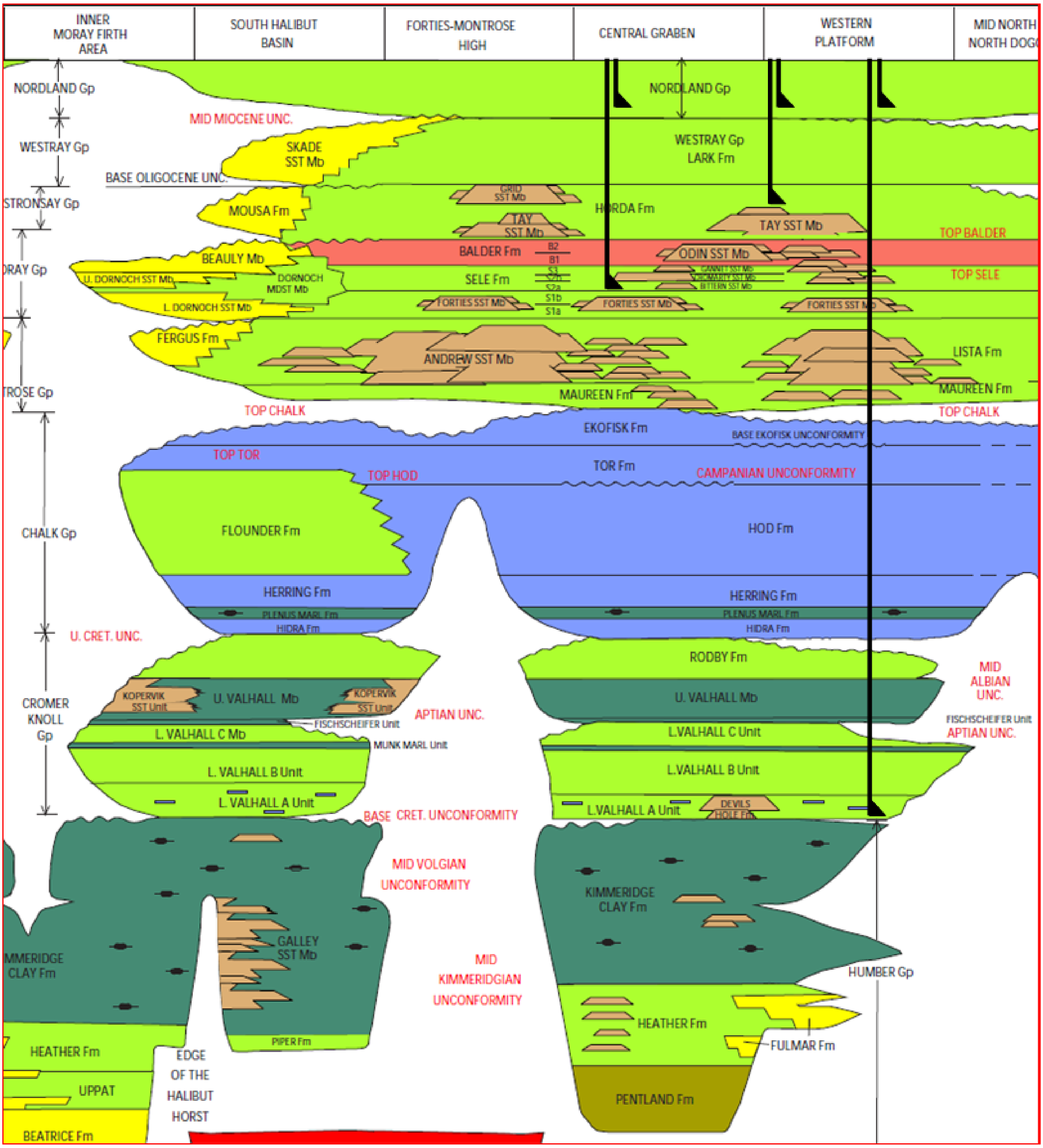


Figure 16 - 12 1/4" section typical setting depths

Factors limiting the design of this section

Maximum hole section length

The maximum recommended section length is 9000ft; this is in addition to the use of the “Drilling Circles” which determines maximum achievable step out. Figure 17 and Figure 18 give a summary of section lengths that have been achieved in Pierce and Curlew as a guide.

Cap & Contain limitations

If hydrocarbons are expected in this section (12 1/4” hole), the open hole section must be able to withstand full evacuation to hydrocarbons. The LOT at the 13 3/8” shoe must therefore be considered in the planning of the well based on the PPP. The RE will provide either a gas or oil gradient to use in the evaluation. In the case where cap and contain requirement is not met, a risk analysis will be carried out to ensure that there is sufficient mitigation for evacuation to hydrocarbons occurring. The preference when designing a four string standard well is to avoid hydrocarbons by setting the shoe above the reservoir; however in some instances this is not possible.

Figure 19 shows a plot of leak-off and limit data in the Nordland group using Pierce as an example; Figure 20 and Figure 21 give cap and contain lines for different gas gradients.

The trend line has been used to generate a chart for maximum drilling depth for estimated shoe strength based on 13-3/8” casing setting depth and predicted pore pressure at TD. Note that cap and contain is not a boundary as this can be risk assessed even if the well design does not meet this requirement.

In some fields such as Gannet there can be multiple thin reservoirs and a careful assessment of the shoe setting depths must be made since setting the shoe above the shallowest reservoir may lead to wellbore stability problems for the next hole section.

Oil Based Drilling Fluid

This section will be drilled with OBM to eliminate the incidence of chemical instability in the reactive shale that will be encountered. Typical drilling fluid properties which are dependent on the fluid weight driven mostly by inclination and wellbore stability are shown in Figure 22.

Historically water based mud were considered for 17 ½” sections with a 5 string design. When drilling this hole size with OBM, the large amount of cuttings and high flow rate associated with this hole size has resulted in a significant amount of NPT due to issues with cuttings processing equipment and crane and skip movements.

OBM has been selected as the default fluid for the standard well design (4 string design) for the following reasons:

- Quantity of cuttings and reduced flow rate compared to a 5 string design (12 ¼” hole vs. 17 ½” hole) results in less strain on cuttings containment equipment
- Enhanced wellbore stability compared with WBM
    - No pore pressure penetration
- Lower ECDs (lower mud weight required compared to WBM) therefore reduced risk of losses
- Better hole cleaning at high angles compared to WBM
- More tolerant fluid system to extended open hole time which is important if we consider potential for equipment failures (eg pump liner failures – see Fram Ocean Guardian experience) and the industry problem of declining competency

<u>Production Casing Shoe Setting Formation Fluid considerations:</u>

For an Open Hole completion, if there is a choice between setting production casing in top reservoir or shale above, then we should set in top reservoir. However Cap and Contain must be considered for the Standard Well Design:

- Higher mud weight will normally be required to hold back shale
    - The increase in mud weight could be as much as 60pptf – for example we may need 620pptf for Sele but only 560pptf for reservoir shales if Sele cased off
    - 60pptf at 10,000ft TVD means additional 600psi Hyd P on reservoir which can increase spurt loss and fluid loss into reservoir which causes formation damage
    - 620pptf OBM has more solids than 560pptf OBM therefore if the screens are suspended in 620pptf then risk of impairment to screens is higher
    - Similarly, increased solids content in the OBM is detrimental to flow to host opportunity – solids can cause erosion and have negative impact on oil in water separation

Hydraulic Limitations

Typical flow rates for drilling the section is 900 - 1000gpm. This is usually limited by maximum surface pressure of ~ 4500psi and ECD constraints depending on fracture pressure prediction.

Drilling window, wellbore stability and pore pressure prediction ("Well Integrity Plot") limitations

Please refer to the 8 ½" hole section.

Directional limitations

The 13-3/8" casing shoe will be at maximum inclination of 25 degrees. The section will be drilled to section TD with typical planned dogleg severity of 3 degrees / 100ft. Maximum inclination in this section will be restricted by wellbore stability, recommended mud weight to drill the section and estimated ECD. Consideration will also be given to production packer setting depth and the ability to deploy wire line which may limit inclination above packer setting depth to 65 degrees. The maximum DLS is 3 deg/100 ft. A typical BHA is shown in Figure 23.

Kick Tolerance limitations

This is another factor that needs to be taken into consideration though not a boundary; it may affect the maximum drilling depth depending on the drilling contractor's policy. As a guide, the 13-3/8" casing shoe strength should be able to withstand circulating out 25bbl swabbed gas kick. Wellplan will be used to model Kick Tolerance and is based on a swabbed gas kick. Mud weight is therefore used in this determination which is in the most part driven by wellbore stability.

Figures illustrating the design limitations

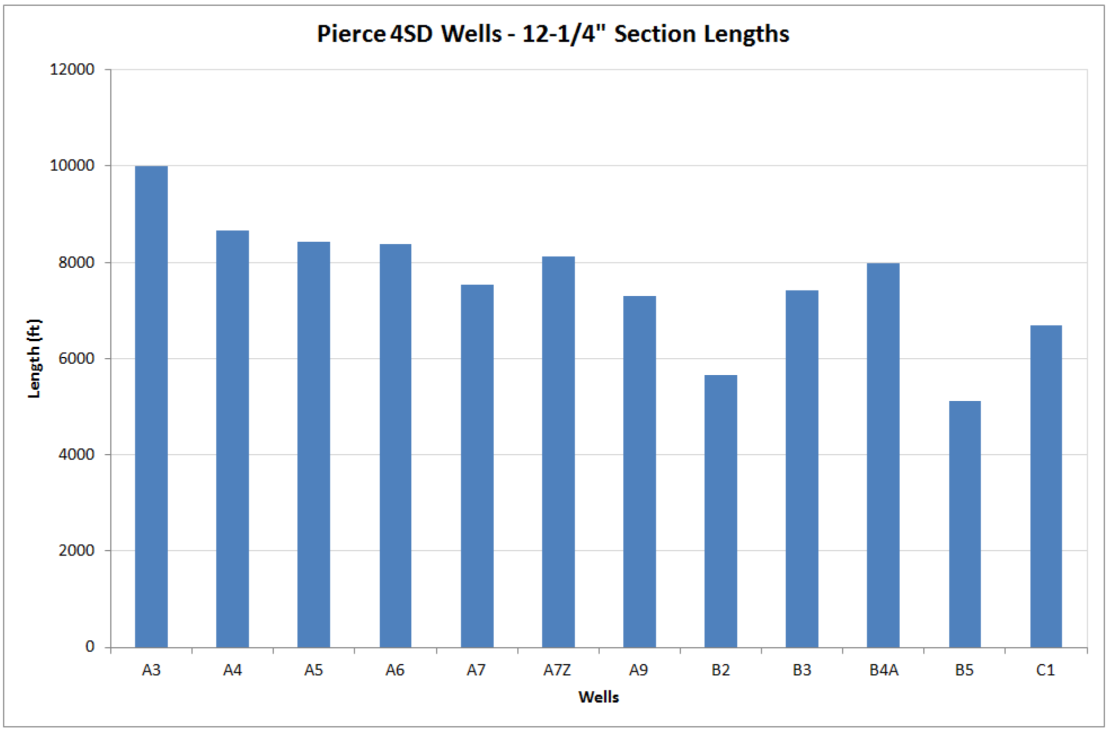


Figure 17- Section lengths in Pierce 4DS wells

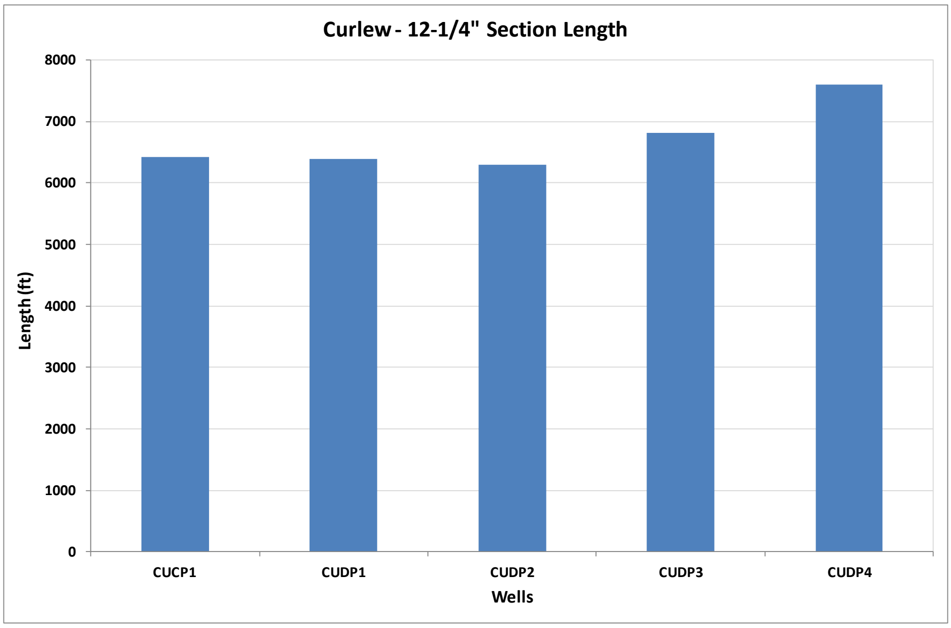


Figure 18 - Section lengths in Curlew wells

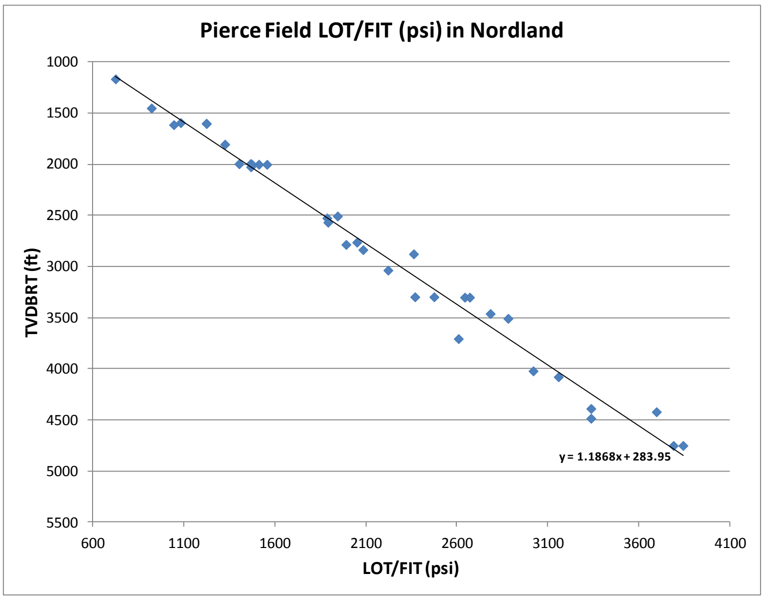


Figure 19 - Pierce field LOT/FIT in Nordland formation

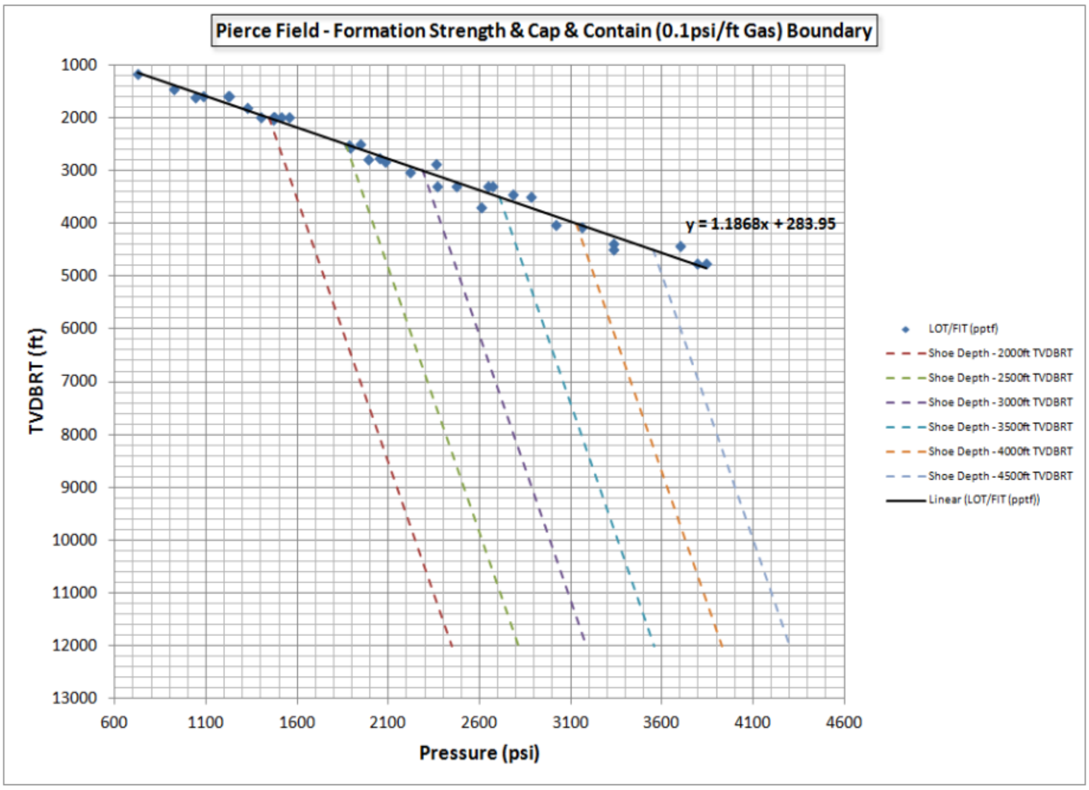


Figure 20 - Cap and contain lines for gas gradient

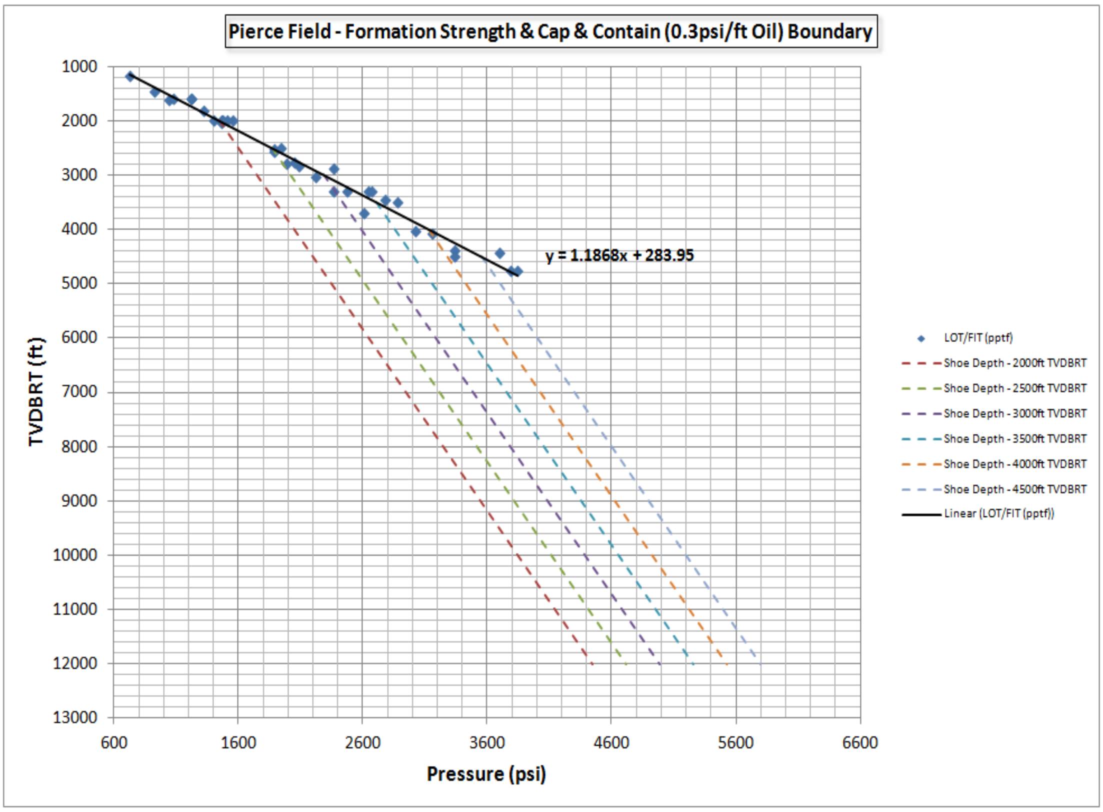
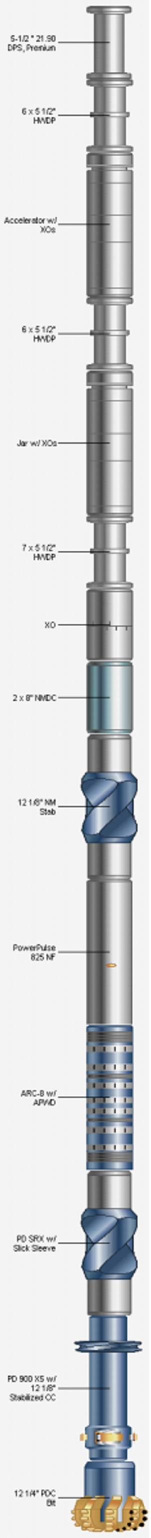


Figure 21 - Cap and contain lines for oil gradient

Drilling Fluid Properties		Drilling Fluid Formulation		
Mud Weight (ppg)	700	DF-1 Base Oil	Continuous phase	0.431 bbl
PV (120 °F)	<40 or ALAP	Water	Discontinuous phase	0.281 bbl
YP (120 °F)	20 - 28	CaCl2 (82-85%)	Salinity	30.4 ppb
6 RPM (120 °F)	12 - 16	Bentone 920	Viscosifier	6.5 ppb
Gels (10s / 10m) (120 °F)	5 - 15 / 15 - 30	VERSACLEAN CBE	Emulsifier Package	10.0 ppb
HTHP FL (270 °F)	< 3.0 ml			
ES (Volts)	> 400	Lime	Alkalinity	10.0 ppb
WPS Chlorides (g/l)	160 - 200	M-I BAR UFG	Weighting agent	288.0 ppb
Excess Lime (ppb)	> 2	Versatrol M	Fluid Loss	2.0 ppb
O/W Ratio	60/40 - 70/30			
LGS %	< 6			

Figure 22 - Typical 12 1/4" section drilling fluid



Schlumberger

Field Name	UK 023 Pierce	Hole Size (in)	12.250	Depth In (ft)	0
Well Name	23/22a-C1	BHA Name	12 1/4" BHA	Depth Out (ft)	0

#	Description	Vendor	Serial #	OD/ID (in)	Max OD (in)	Connection (Bottom/Top) (in)	Gender (Bot/Top)	Fish Neck (OD/Leng (in)(ft)	Length (ft)	Cum. Length (ft)	Cum. Weight (klbm)
1	12 1/4" PDC Bit	Generic		8.000 / 3.250	12.250	6 5/8 REG	Pin	0 / 0	1.44	1.44	0.4
2	PD 900 X5 w/ 12 1/8" Stabilized CC	Schlumberger		9.000 / 5.125	12.125	6 5/8 REG / 6 5/8 FH	Box / Box	0 / 0	13.8	15.24	2.9
3	PD SRX w/ Slick Sleeve			8.250 / 2.813	9.000	6 5/8 FH / 6 5/8 FH	Pin / Box	0 / 0	5	20.24	3.7
4	ARC-8 w/ APWD	Schlumberger		8.250 / 2.810	9.100	6 5/8 FH / 6 5/8 FH	Pin / Box	0 / 0	18	38.24	6.5
5	PowerPulse 825 NF	Schlumberger		8.250 / 5.109	8.410	6 5/8 FH / 6 5/8 Regular	Pin / Box	0 / 0	24.7	62.94	10.1
6	12 1/8" NM Stab			8.250 / 2.813	12.125	6 5/8 Regular / 6 5/8 Regular	Pin / Box	0 / 0	5	67.94	10.9
7	2 x 8" NMDC (2 joints)			8.000 / 2.500	8.000	6 5/8 Regular / 6 5/8 Regular	Pin / Box	0 / 0	60	127.94	20.1
8	XO			8.000 / 3.000	8.000	6 5/8 Regular / 5 1/2 FH	Pin / Box	0 / 0	3	130.94	20.5
9	7 x 5 1/2" HWDP (7 joints)			5.500 / 3.500	7.250	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	217	347.94	33.9
10	Jar w/ XOs	HE		8.000 / 3.000	8.160	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	32	379.94	37.4
11	6 x 5 1/2" HWDP (6 joints)			5.500 / 3.500	7.250	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	186	565.94	48.9
12	Accelerator w/ XOs	HE		8.000 / 3.000	8.160	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	32	597.94	52.5
13	6 x 5 1/2" HWDP (6 joints)			5.500 / 3.500	7.250	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	186	783.94	63.9
14	5-1/2 " 21.90 DPS, Premium			5.366 / 4.778	7.000	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	31	814.94	64.7

BHA Comments

Total Length (ft)	814.94
Total Weight in Air (klbm)	64.7
Total Buoyant Weight (klbm)	52.9
Buoyant Weight Below Jar (klbm)	27.8
Weight in Air Below Jar (klbm)	33.9

Stabilizer Summary

Blade Length (ft)	Blade Mid-Pt to Bit (ft)
1.167	12.21
2.000	17.74
2.000	65.44

Bend Summary

Bend Angle (deg)	Bend to Bit (ft)

Sensor Summary

Type	Distance to Bit (ft)
PD GR	9.000
APWD	25.140
RES	27.490
ARC GR	27.660
MWD GR	48.140
D+I	50.260

BHA Nozzle Summary

Bit Nozzle Count	Bit Nozzle 1/32 in	Reamer Nozzle Count	Reamer Nozzle 1/32 in
8	14.000		
		TFA (in2)	
		PD Flow Restrictor (1/32 in)	0.000
TFA (in2)	1.203	Rotor By Pass Nozzle (1/32 in)	

Mud Properties

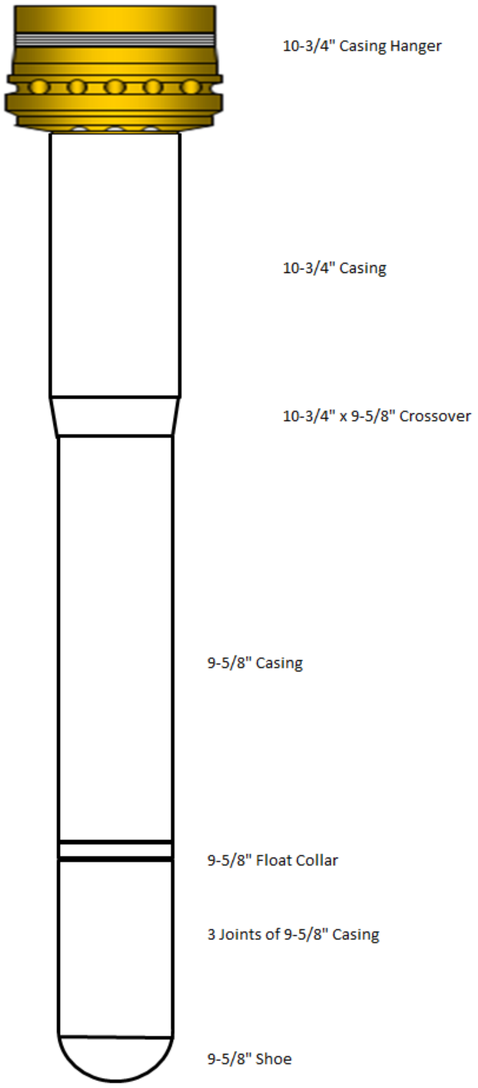
Mud Weight (lbm/gal)	13.5	YP (lbf/100ft2)	
Funnel Viscosity (s)		PV (cP)	

Date	24Aug2011
Designed By	EUR\NWibbelmann
Approved By	

Figure 23 - Typical 12 1/4" BHA

Casing Design

Typical casing schematic is as shown below:



Cementing Design

The main objectives of the cementation of the production casing are to provide long term isolation to prevent communication between reservoir, distinct permeable zones and surface and to assure a good hydraulic seal between casing and formation in order to achieve FIT or LOT at the casing shoe to drill through the reservoir section (if applicable).

The following are considerations for production casing cementation, also illustrated in Figure 24. The well engineer has to double check, for each well, that these guidelines still apply, based on the TS12.

1. 660ft (200m) minimum column of competent cement above production packer setting depth is required in the 9-5/8" casing annulus. Note that a 100ft (33m) column of good cement is required if logged (see figure 24 below). "Logged good cement", is defined as >80% Bond Index with no channeling.
2. 660ft minimum column of competent cement or 100ft column of good cement if logged above any hydrocarbon, gas or water-bearing zones that require isolation and prevent annular pressure build-up (see figure 24 below).
   The plan will be for a minimum of 1000ft of cement in this section or if H/C's are present the plan will be 1000ft of cement above the shallowest H/C bearing zone. If losses occur or the job was critical, cement evaluation log will be acquired with the aim of achieving a minimum of 33m (100ft) of cement with a bond index >80%. This would be good for production of the well. For abandonment purposes we would need 2 x 33m of cement or failing this we would have to mill casing to achieve it.
3. Recommended excess volume of 20% over open hole should be pumped unless offsets indicate otherwise. If caliper volume is available, 10% excess over caliper volume should be pumped.
4. Casing centralization up to desired top of cement is recommended with a minimum stand-off of 70% assuming gauge hole should be achieved. Typical centralizer programme to achieve > 70% bond index is 2 centralizers per joint for the shoe track and one centralizer per joint up to planned TOC.
5. The minimum length of shoe track should be three joints.
6. When considering well abandonment it is possible that the final abandonment of the well by setting abandonment plugs will result in plugs below the production packer setting depth. This needs to be established and recorded in the WFS. Cemented liner laps can only be accepted where there is evidence of good quality cement (inflow test, pressure test or log).

Depending on formation strength, lead and tail slurries (14.5ppg & 16ppg) will be utilised or a single 15.6ppg to 16ppg slurry. If ECD margins are low, 14.5ppg Class G tail slurry with micro-silica can be considered following consultation with the Well Fluids Team and Subject Matter Expert (SME).

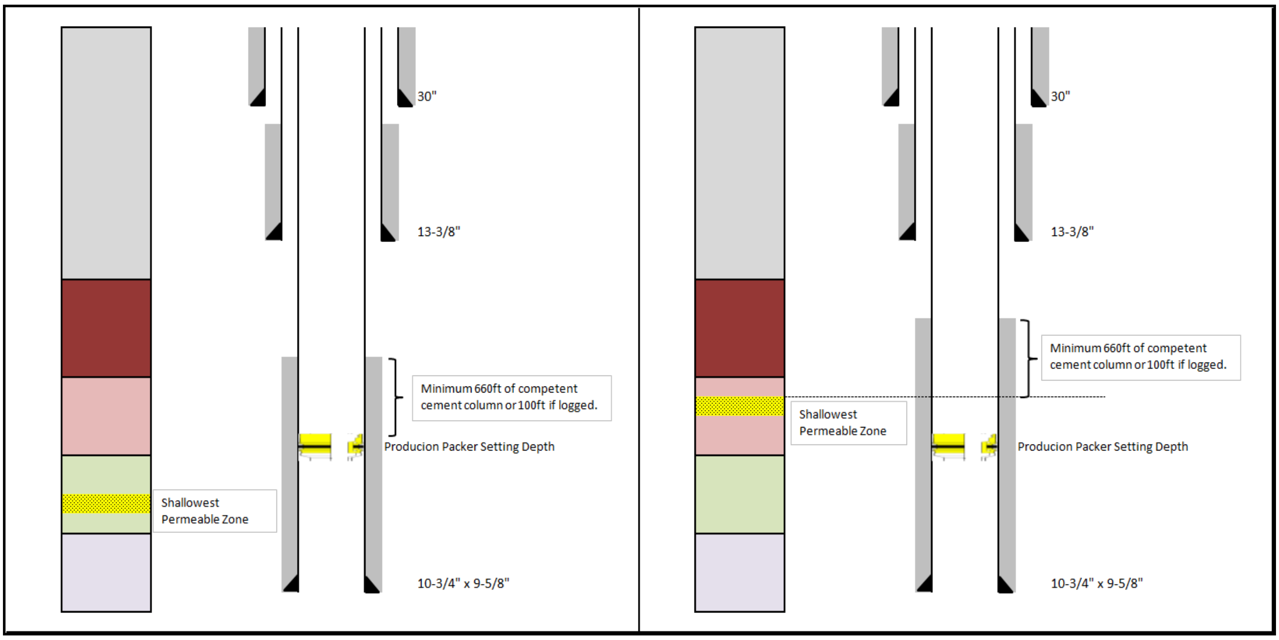


Figure 24 - Typical cementation requirements for 9 5/8" casing

Procurement

The well engineer must ensure that the following items are booked in time. For more information and advice, refer to the Wells Materials Guidelines Wiki:

http://sww.wiki.shell.com/wiki/index.php/Wells_Material_Ordering_Guidelines_%28WMOG%29

Casing and accessories

Book the following items in SAP 12 at least 12 weeks prior to spud. For more advice, contact Shauna Skillander. Also see the list at the following address:

https://sww-knowledge-epe.shell.com/teamepns/livelink.exe/open/41463565

Item	Material	Plant	Requirement qty	Ba...	Pr...	I...	R...	Sto...	Description
0031	1001129939	GB01	410	M		N	3	1021	CSG,L80,R3,VAM-T,SD,10.3/4-55.5,PSL1
0040	1000676651	GB01	2.00	EA		N	3	1021	CGHG,DUMMY,18.3/4 x 13.3/8 , MS-700
0060	1000676649	GB01	1.00	EA		N	3	1021	SEAL,MS-1,18.3/4,15k,PSL 2-4 ,MS-700
0080	1000678826	GB01	2.00	EA		N	3	1021	XO3P,L80,P10.3/4-55.5V-TxP9.5/8-53.5V-T
0090	1000586278	GB01	2,400	M		N	3	1021	CSG,VM95SS,R3,VAM-T,SD,9.5/8-53.5
0100	1000510752	GB01	2.00	EA		N	3	1021	FLCO,Q125,VAM-T,NON-ROT. ,9.5/8-53.5
0110	1001136030	GB01	2.00	EA		N	3	1021	CEPLS,9.5/8x10.3/4,787194,WEATHERF
0130	1001106739	GB01	2.00	EA		N	3	1021	DART,SSR,BTM,5.1/2,734162,WEATHERF
0140	1000609339	GB01	150.00	EA		N	3	1021	STCO,J10S/BEVELLED, 9.5/8
0150	7000000008	GB01	2.00	EA		N	3	1021	9 5/8" Float Shoe, Model 303AM, Ledgerid
0160	7000000008	GB01	75.00	EA		N	3	1021	9 5/8" SpiraGlider SC Spiral Rigid Centr
0170	1000609000	GB01	2.00	EA		N	3	1021	CGP,J,VM95SS,VAM-T,SD,9.5/8-53.5,3ft
0180	1000610125	GB01	2.00	EA		N	3	1021	CGP,J,VM95SS,VAM-T,SD,9.5/8-53.5,10ft
0190	1000513008	GB01	2.00	EA		N	3	1021	CGP,J,VM95SS,VAM-T,SD,9.5/8-53.5,15ft
0200	1000533169	GB01	2.00	EA		N	3	1021	CGP,L80,VAM-T,10.3/4-55.5,10ft
0210	1000610106	GB01	2.00	EA		N	3	1021	CGP,L80,VAM-T,10.3/4-55.5,15ft
0220	1001178642	GB01	2.00	EA		N	3	1021	DART,TOP,WEATHERF,1285900,5TO5.7/8in
0230	1000676648	GB01	2.00	EA		N	3	1021	ASSY,CGHG,VETCOGRY,A50782-10,10.75x10.75
0240	1000493298	GB01	2.00	EA		N	3	1021	CGP,VM95SS,VAM-T,SD,9.5/8-53.5,20ft
0250	1001229457	GB01	2.00	EA		N	3	1021	CGP,L80,VAM-T,SD,10.3/4-55.5,20ft

Please note that the items circled will change depending on well depth and WellCat design based on CITHP, temperature and sour service. Refer to chapter on WellCat.

Contact person: Adebola Ogunremi

6. 8 1/2” HOLE SECTION X 5 ½”X7” PRODUCTION LINER

Objective of the section

The objective of the 8-1/2” section is to directionally drill through the reservoir to well TD and set 7” x 5-1/2” production liner. In the case of standalone screens lower completion, the well will be displaced to low solids PST specification oil based mud after drilling to TD.

Well Status before this section

- 10-3/4” x 9-5/8” Casing set above or just into the reservoir section
- OBM in hole

Overview of section operations

The 8-1/2” section will commence by running 8-1/2” BHA in hole to drill out the shoe track while displacing the well to reservoir drilling OBM, this may likely be of lower weight than OBM used for drilling the 12-1/4” section. The shoe track, rat hole and 15ft of new formation will be drilled and a leak-off or limit test conducted to confirm enough shoe strength to drill to well TD in the case where the shoe is set above the reservoir section and shoe strength required is greater than ECD observed in the 12-1/4” section. This section will typically be drilled using a rotary steerable system and MWD/LWD. OBM weight will be determined by wellbore stability and predicted pore and fracture pressures. 7” x 5-1/2” liner will be run and cemented with shoe at 5 ft above well TD. Top of cement will typically be planned to be 500ft above top of liner with drill pipe in place.

Factors limiting the design of this section

Maximum hole section length

The maximum recommended section length is 6000ft for cased and perforated liner, this is limited by TCP and FFGS and 3000ft for open hole lower completion (sand screens); this is in addition to the use of the “Drilling Circles” which determines maximum achievable step out.

Drilling fluid and hydraulics

This section will normally be drilled with OBM unless the lower completion is a gravel pack. Typical drilling fluid properties which are dependent on the mud weight in use are shown in Figure 25. Typical flow rates for drilling the section is 450 - 550gpm. This is usually limited by maximum surface pressure of ~ 4500psi and ECD constraints depending on fracture gradient.

Drilling Fluid Properties	
Mud Weight (ppg)	580
PV (120 °F)	<30 or ALAP
YP (120 °F)	18 - 25
6 RPM (120 °F)	8 - 12
Gels (10s / 10m) (120 °F)	5 - 15 / 15 - 30
HTHP FL (270 °F)	< 3.0 ml
ES (Volts)	> 400
WPS Chlorides (g/l)	160 - 220
Excess Lime (ppb)	> 2
O/W Ratio	80/20 - 85/15
LGS	<6%

Figure 25 - Typical drilling fluid properties for the 8 1/2" hole

Drilling window, wellbore stability and pore pressure prediction ("Well Integrity Plot") limitations

Due to reservoir depletion future in-fill drilling can only occur if a drilling window exists or in the case where limited or no drilling window exists, that it can be created using wellbore strengthening. In order to establish the available drilling window a "Well Integrity Plot", needs to be created (Figure 26). From the plot is can be established whether there is a positive drilling window, a limited drilling window where for instance a Low-ECD mud system (combined with a LCM strategy) would be utilised to reduce ECD while drilling (Pierce A11 and C1) or wellbore strengthening should be considered. The drilling window is assessed based on the difference between the predicted ECD and the minimum horizontal stress (Sh_{min}) based on Possible Real Low Pressure as provided by the RE on the Pore Pressure Prediction (PPP). To assess the likelihood of success of applying wellbore strengthening, 800psi is added to the depleted Sh_{min} and is displayed on the right hand side of the plot. For more information on wellbore strengthening and the Well Integrity plots refer to the Wellbore Strengthening Guidance Document (available as a link from the PCAP).

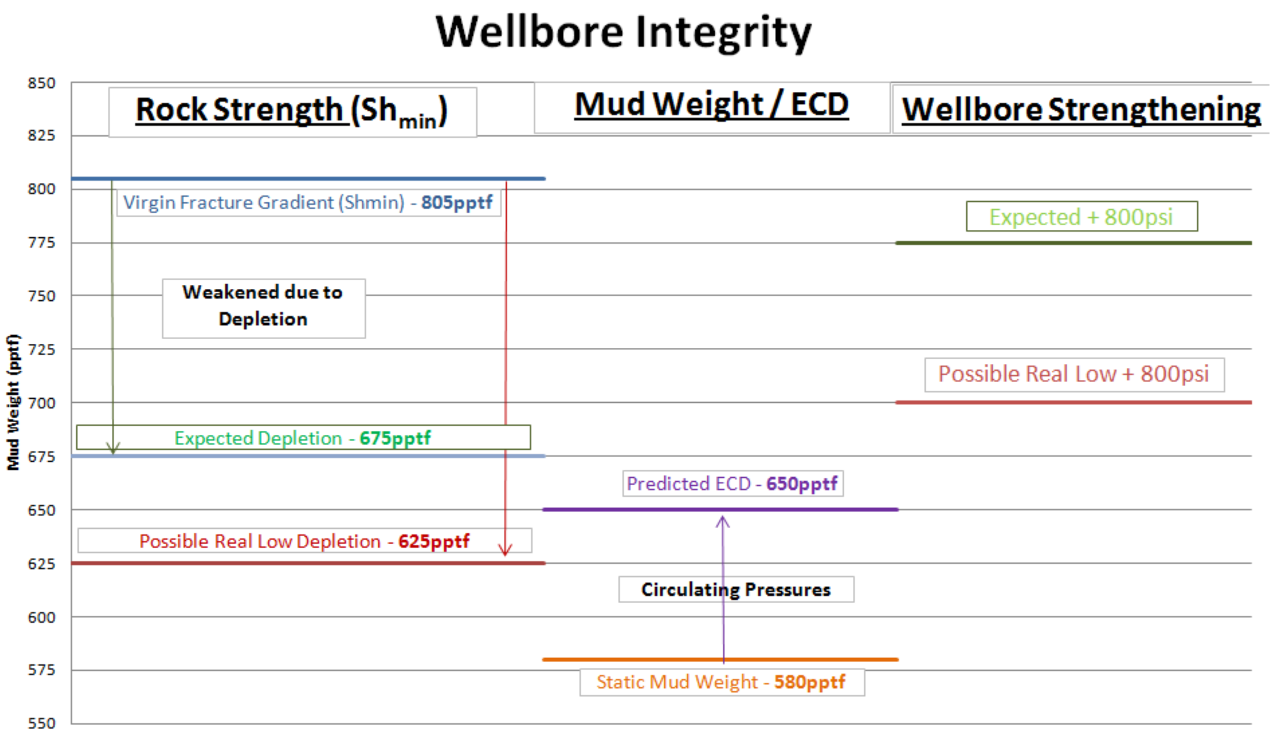
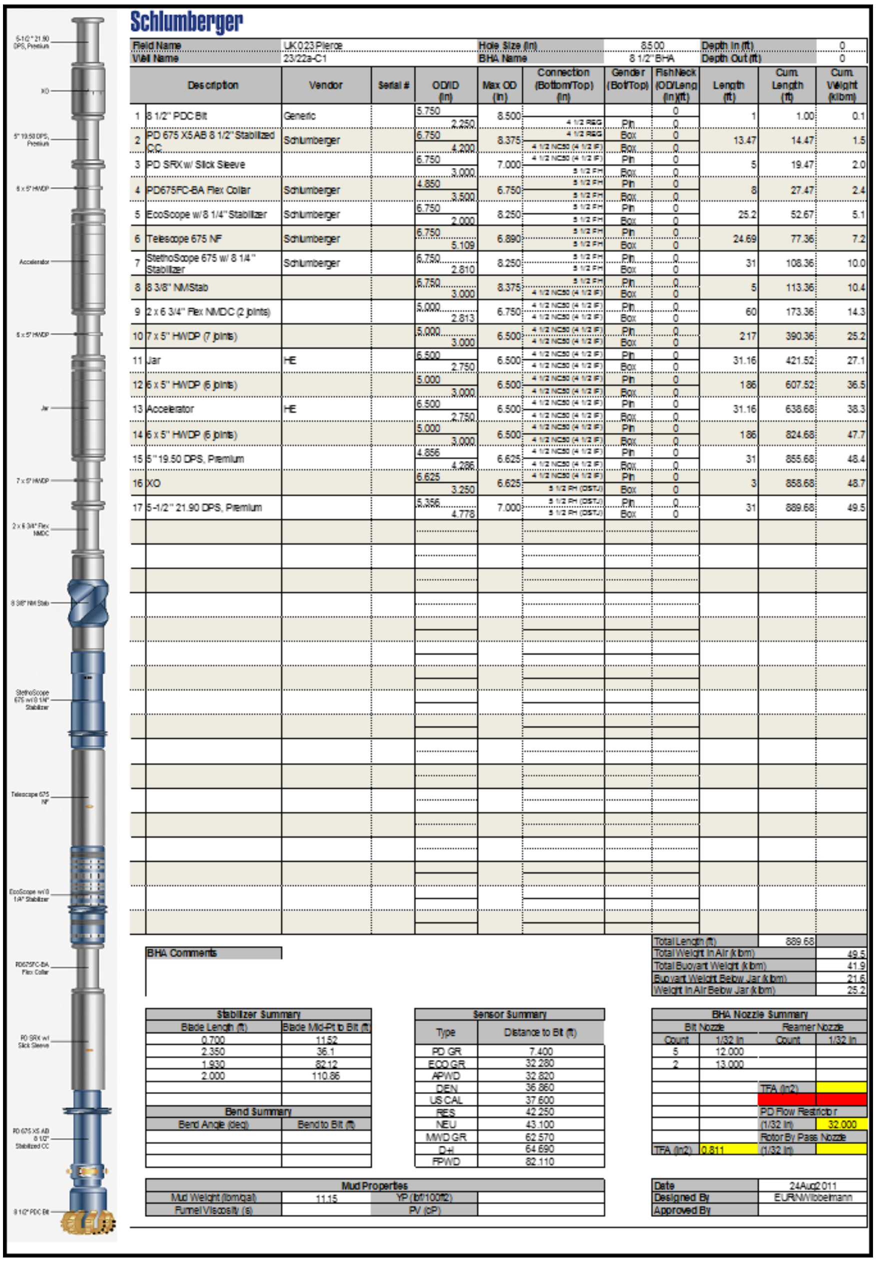


Figure 26 - Typical Wellbore Integrity Diagram for 8 1/2" hole section

Directional limitations

This section will typically be drilled at high inclination through the reservoir section or to cut through stratigraphy. Typical dogleg severity in this section is 3 degrees / 100ft and excessive doglegs should be avoided especially for open hole lower completion. A typical BHA is shown in Figure .



Schlumberger

Field Name	UK023 Pierce	Hole Size (in)	8.500
Well Name	23/22a-C1	BHA Name	8 1/2" BHA
Depth In (ft)	0	Depth Out (ft)	0

#	Description	Vendor	Serial #	OD/ID (in)	Max OD (in)	Connection (Bottom/Top) (in)	Gender (Bot/Top)	FishNeck (OD/Leng (in)(ft)	Length (ft)	Cum. Length (ft)	Cum. Weight (klbm)
1	8 1/2" PDC Bit	Generic		5.750 / 2.250	8.500	/ 4 1/2 REG	/ Pin	0 / 0	1	1.00	0.1
2	PD 675 X5 AB 8 1/2" Stabilized CC	Schlumberger		6.750 / 4.200	8.375	4 1/2 REG / 4 1/2 NC50 (4 1/2 IF)	Box / Box	0 / 0	13.47	14.47	1.5
3	PD SRX w/ Slick Sleeve			6.750 / 3.000	7.000	4 1/2 NC50 (4 1/2 IF) / 5 1/2 FH	Pin / Box	0 / 0	5	19.47	2.0
4	PD675FC-BA Flex Collar	Schlumberger		4.850 / 3.500	6.750	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	8	27.47	2.4
5	EcoScope w/ 8 1/4" Stabilizer	Schlumberger		6.750 / 2.000	8.250	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	25.2	52.67	5.1
6	Telescope 675 NF	Schlumberger		6.750 / 5.109	6.890	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	24.69	77.36	7.2
7	StethoScope 675 w/ 8 1/4" Stabilizer	Schlumberger		6.750 / 2.810	8.250	5 1/2 FH / 5 1/2 FH	Pin / Box	0 / 0	31	108.36	10.0
8	8 3/8" NMStab			6.750 / 3.000	8.375	5 1/2 FH / 4 1/2 NC50 (4 1/2 IF)	Pin / Box	0 / 0	5	113.36	10.4
9	2 x 6 3/4" Flex NMDC (2 joints)			5.000 / 2.813	6.750	4 1/2 NC50 (4 1/2 IF) / 4 1/2 NC50 (4 1/2 IF)	Pin / Box	0 / 0	60	173.36	14.3
10	7 x 5" HWDP (7 joints)			5.000 / 3.000	6.500	4 1/2 NC50 (4 1/2 IF) / 4 1/2 NC50 (4 1/2 IF)	Pin / Box	0 / 0	217	390.36	25.2
11	Jar	HE		6.500 / 2.750	6.500	4 1/2 NC50 (4 1/2 IF) / 4 1/2 NC50 (4 1/2 IF)	Pin / Box	0 / 0	31.16	421.52	27.1
12	6 x 5" HWDP (6 joints)			5.000 / 3.000	6.500	4 1/2 NC50 (4 1/2 IF) / 4 1/2 NC50 (4 1/2 IF)	Pin / Box	0 / 0	186	607.52	36.5
13	Accelerator	HE		6.500 / 2.750	6.500	4 1/2 NC50 (4 1/2 IF) / 4 1/2 NC50 (4 1/2 IF)	Pin / Box	0 / 0	31.16	638.68	38.3
14	6 x 5" HWDP (6 joints)			5.000 / 3.000	6.500	4 1/2 NC50 (4 1/2 IF) / 4 1/2 NC50 (4 1/2 IF)	Pin / Box	0 / 0	186	824.68	47.7
15	5" 19.50 DPS, Premium			4.856 / 4.286	6.625	4 1/2 NC50 (4 1/2 IF) / 4 1/2 NC50 (4 1/2 IF)	Pin / Box	0 / 0	31	855.68	48.4
16	XO			6.625 / 3.250	6.625	4 1/2 NC50 (4 1/2 IF) / 5 1/2 FH (DSTJ)	Pin / Box	0 / 0	3	858.68	48.7
17	5-1/2" 21.90 DPS, Premium			5.356 / 4.778	7.000	5 1/2 FH (DSTJ) / 5 1/2 FH (DSTJ)	Pin / Box	0 / 0	31	889.68	49.5

BHA Comments

Total Length (ft)	889.68
Total Weight In Air (klbm)	49.5
Total Buoyant Weight (klbm)	41.9
Buoyant Weight Below Jar (klbm)	21.6
Weight In Air Below Jar (klbm)	25.2

Stabilizer Summary

Blade Length (ft)	Blade Mid-Pt to Bit (ft)
0.700	11.52
2.350	36.1
1.930	82.12
2.000	110.86

Bend Summary

Bend Angle (deg)	Bend to Bit (ft)

Sensor Summary

Type	Distance to Bit (ft)
PD GR	7.400
ECO GR	32.280
APWD	32.820
DEN	36.860
US CAL	37.600
RES	42.250
NEU	43.100
MWD GR	62.570
D+I	64.690
FPWD	82.110

BHA Nozzle Summary

Bit Nozzle Count	Bit Nozzle 1/32 in	Reamer Nozzle Count	Reamer Nozzle 1/32 in
5	12.000		
2	13.000		
		TFA (in2)	
		PD Flow Restrictor (1/32 in)	32.000
TFA (in2)	0.811	Rotor By Pass Nozzle (1/32 in)	

Mud Properties

Mud Weight (lbm/gal)	11.15	YP (lbf/100ft2)	
Funnel Viscosity (s)		PV (cP)	

Date	24Aug2011
Designed By	EUR/NWibbelmann
Approved By	

Figure 27 - Typical 8 1/2" hole BHA

Casing Design

The production liner string includes 9-5/8” x 7” Liner Hanger, approximately 140ft of 7” Liner before crossing over to 5-1/2” Liner, as shown in Figure . The typical liner lap over-all length (7” and 5 ½” liner) is 300ft as described below. See the Completions section for the background reasoning behind the selection of 140ft length.

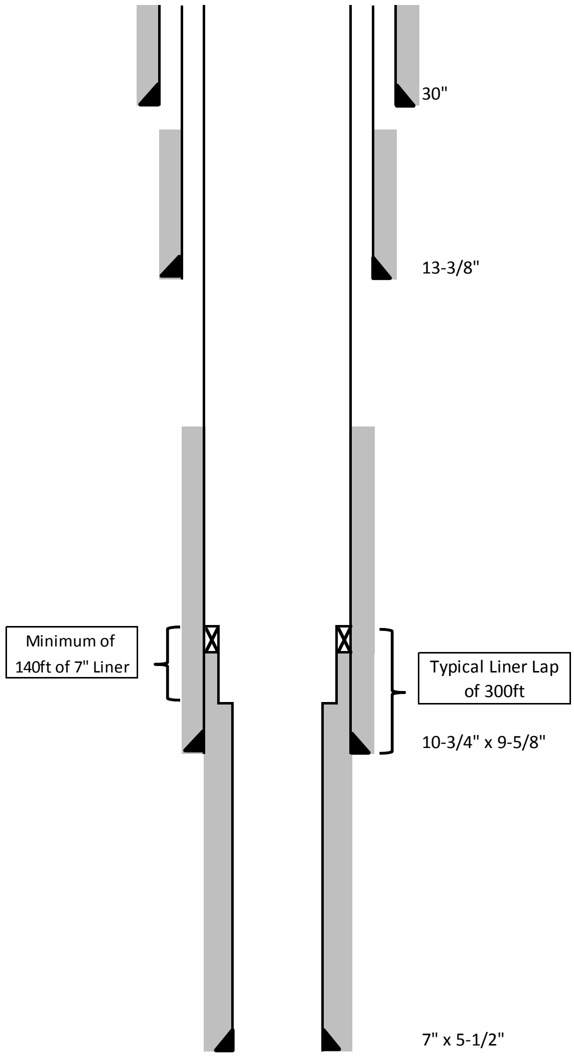


Figure 28 - Typical 5 1/2" x 7" liner design

Cementing Design

The main objectives of the cementation of the production liner is to provide zonal isolation between permeable and hydrocarbon bearing zones and surface to allow optimal completion

The following are considerations for production casing cementation.

1. Recommended excess volume of 10% over open hole should be pumped unless offsets indicate otherwise with sufficient volume to obtain 500ft above top of liner with drill pipe in place. If caliper volume is available, the requirement for 10% excess can be ignored.
2. Liner centralization with a minimum stand-off of 70% assuming gauge hole is recommended.
3. The minimum length of shoe track should be three joints.

Typical slurry weight will be 16ppg with low fluid loss and may require to be gas tight and have zero free water. In depleted reservoir, or if ECD margins are low, a 14.5ppg slurry can be considered, however in horizontal wells the cement density will have little effect on the job.

Procurement

The well engineer must ensure that the following items are booked in time. For more information and advice, refer to the Wells Materials Guidelines Wiki:

http://sww.wiki.shell.com/wiki/index.php/Wells_Material_Ordering_Guidelines_%28WMOG%29

Casing and accessories

Book the following items in SAP 12 at least 12 weeks prior to spud. For more advice, contact Shauna Skillander. Also see the list at the following address:

https://sww-knowledge-epe.shell.com/teamepns/livelink.exe/open/41463565

Contact person: Adebola Ogunremi

7. WELLBORE CLEAN UP

Objective of the section

The aim of the wellbore clean up is to efficiently displace the drilling fluid from the wellbore leaving the casing/liner free of solids and “water wet”, before displacing the well to completion fluid (inhibited sea water, brine or base oil). The detailed process for a cased hole clean up may vary but generically follows on from drilling a reservoir section, running and cementing a liner or casing or running and installing sand screens or gravel pack followed by cleaning the surface and sub-surface equipment prior to commencing the running of a completion string.

Industry wide data has shown that a surprising amount of completion NPT has been caused by dirt and debris being pumped back down the well post clean up. Areas that also need to be cleaned are the drill floor, mud pits and circulation system. If a well is not cleaned up successfully, the remaining debris can lead to significant problems and associated costs. These problems range from formation damage to mechanical failure of isolation valves and completion equipment. Wellbore solids are typically mud solids – clay, barite, mill/scale rust from the tubular and fines from drilling the formation and cement. The aim of the wellbore clean up is to have a solids content of the seawater / brine of ≤ 0.05% by volume.

<u>Cased Hole Wellbore Clean Up</u>

Well Status

- The 7”x 5 ½” Production Liner has been set, cemented and pressure tested in OBM.

Operation Steps and descriptions

<u>Step # 1 - Clean Riser, Jet Wellhead and BOP’s in Oil Based Mud</u>

The riser and BOP cavities are cleaned to remove debris / cuttings that can later contaminate the completion fluid. This operation is performed in the OBM used to drill the reservoir. The typical BHA for this run is given in Figure below

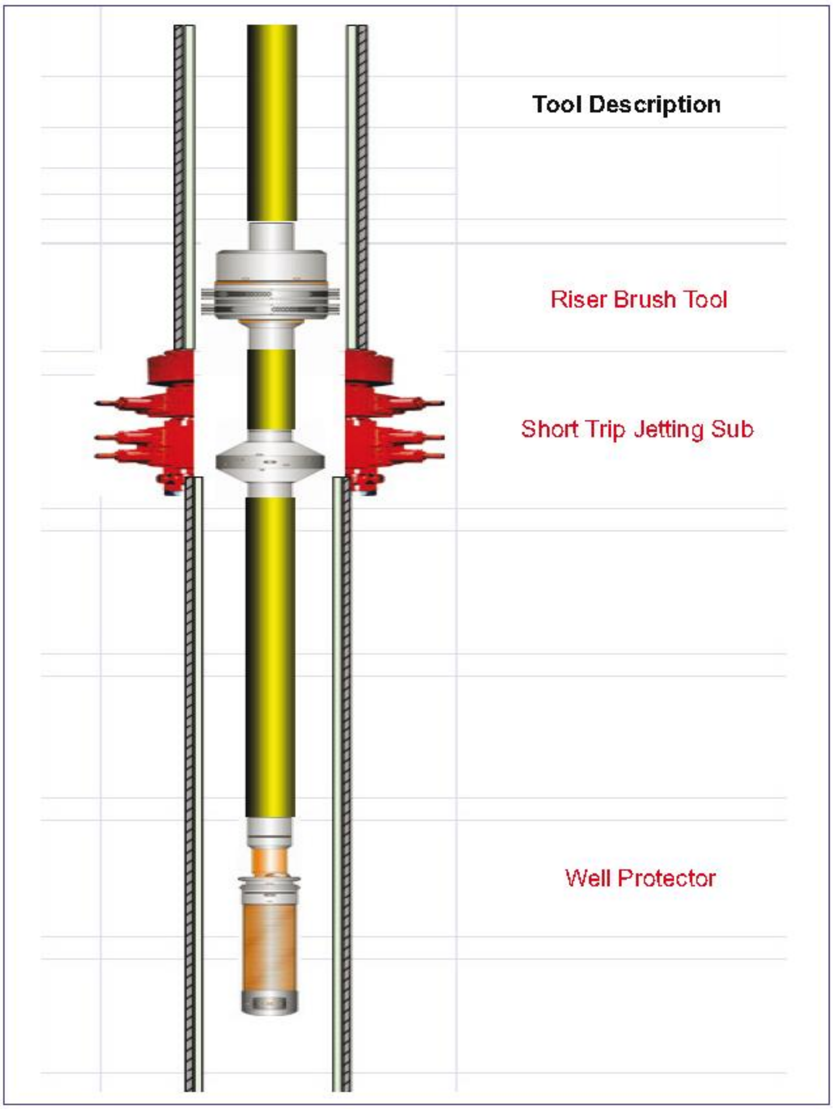


Figure 29 - Typical BHA design for cleaning riser and jetting wellhead & BOP's

<u>Tool Description</u>

WELL PROTECTOR	Prevents debris from the BOP cavities entering the well by filtering debris through a wire screen filter
SINGLE-ACTION BYPASS SUB JETTING TOOL (SABS-JT)	Used to remove drill cuttings, mud-cake, and other debris that drilling deposits on the riser, blowout preventer (BOP), and wellhead walls. The tool removes these contaminants completely to ensure clean and effective cementing and completions operations.
BRISTLE BACK – RISER BRUSH TOOL	Surface wellhead brushing/jetting tool is designed to ensure that the multiple profiles of surface wellheads are clean prior to the completion. The tool effectively brushes and jets surface wellheads simultaneously and reduces the downtime caused by clogged up wellheads.

Overbalanced Well

In these wells, the perforating method is shoot and pull (Example: Pierce C-1). The Casing / Liner lap will be pressure tested from above in OBM prior to the commencement of the Wellbore Clean Up and no Inflow Test will be required. The well will never be underbalanced until the production packer has been set and tested.

Underbalanced well

In these wells a Well Commissioner will be run as part of the wellbore clean up string in order to inflow test the liner lap and shoetrack without displacing the entire well to a lighter fluid. The well is monitored via a side-entry sub for the duration of the inflow test with fluid returns plotted on a Horner Plot. A normal inflow test is conducted over 4hrs but if showing a trend to zero and a residual flow of <15US gallons/hr, then the inflow test can be accepted after a minimum of 1hr.

Step #2 – Tag 5 ½" Landing Collar and Condition Oil Based Mud

RIH with the clean up assembly, note 2 7/8" drill pipe cannot be rotated, and instead a motor assembly will be used to ensure the mill reaches the landing collar. Operations include scraping the 9 5/8" packer setting area, pressure testing the liner top (confidence test on wells utilising shoot and pull) and conditioning the OBM.

Step #3 – Combined Inflow Test and Wellbore Clean Up

Over-balanced Wells – Displace OBM to inhibited brine

Under-balanced Wells – The well will be inflow tested using the Well Commissioner tool using a horner plot by displacing the string to base oil. Prior to commencing the wellbore clean up, bottoms up will be circulated to check for gas before the well goes under-balanced.

The typical BHA for this run is given in Figure 30 below

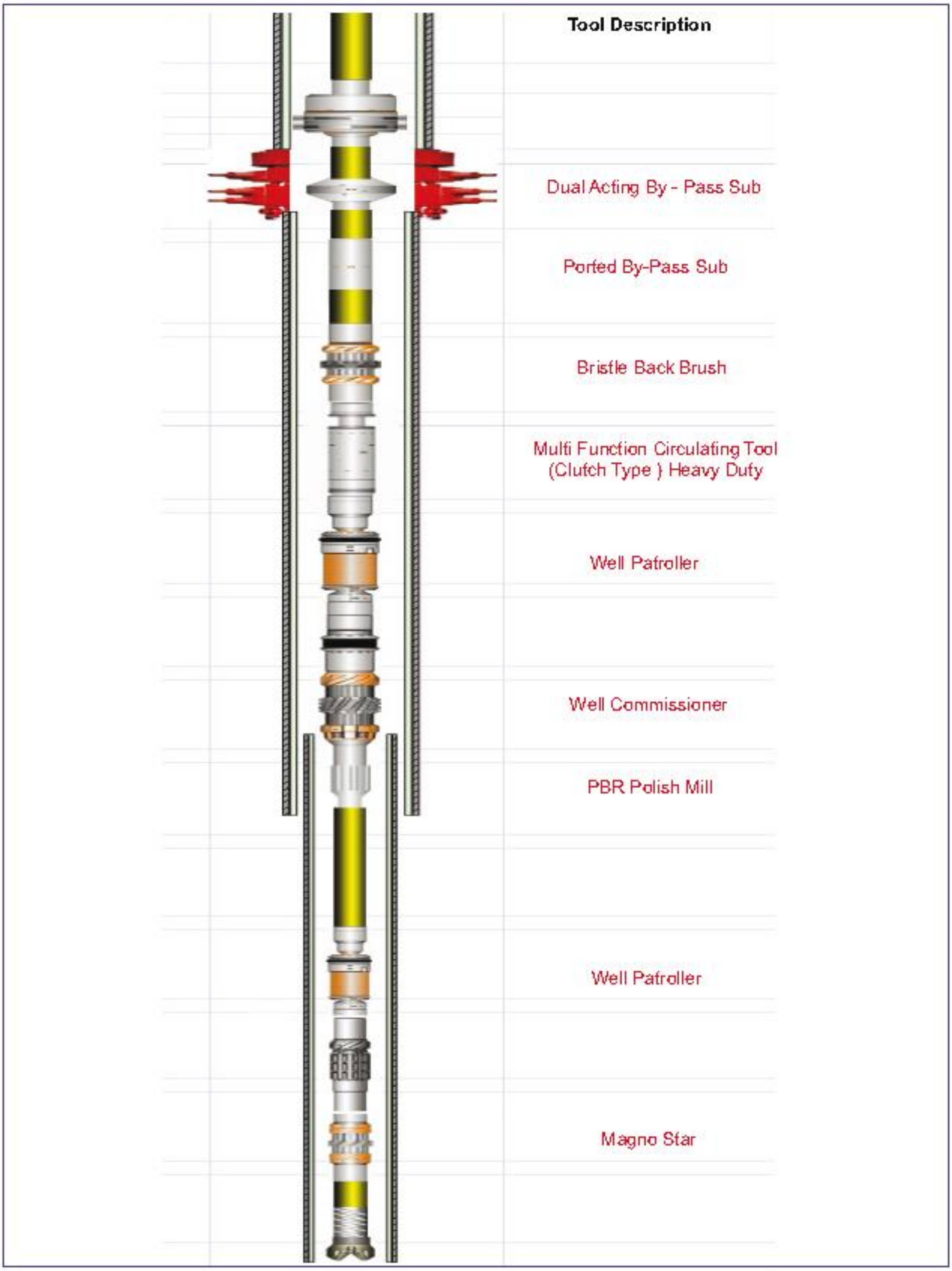


Figure 30 - Typical BHA for cleanup train run

The typical OBM displacement train consists of:

- A Base oil spacer between the mud and the aqueous pill.
- A weighted and viscosified Push Pill to perform the displacement.
- A wash pill to water wet the casing
- And a viscosified sweep pill to carry and support solid debris.

The key elements of the clean-up train are:

a) The base oil which is the most effective clean up chemical
b) The contact time (≥ 10minutes) that the surfactants have with the casing
c) The pump rate at which the clean-up is pumped. Volumes pumped will therefore be related to both circulation rate and contact time.

Displacement of the liner and casing will be in 2 stages. Liner displaced first through circ sub just above mud motor / bit if required (5 ½" liners or smaller will require a motor/ bit on 2 7/8" DP which cannot be rotated. 7" liners will have 3 ½" DP which can be rotated, so no motor is required). MFCT opened and casing can be displaced whilst rotating the string for an efficient clean up. The displacement will continue until the clean-up specifications are met. The Well Patroller will be checked when back at surface for solids / debris – it may be necessary to repeat the clean-up if the Well Patroller is >80% full. If well is to be displaced to an underbalanced fluid the liner lap must be inflow tested again after displacement is completed. If the well is to be underbalanced to base oil then the wellbore clean-up is first conducted in seawater then displaced to base oil under controlled conditions and a final inflow test performed before POOH. Once the inflow test is successful circulate bottoms up to check for gas prior to POOH.

Step #4 – Jet Wellhead and BOP's

- This step is initially performed utilising a wear bushing pulling tool and a Well Patroller. The Well Patroller will avoid any debris falling down the well when recovering the wear bushing. The Well Patroller will remain on the string for the next assembly

- The second run will include a Full bore Jetting Tool and the Well Patroller. Jet the BOP cavities and wellhead area prior to running the completion.

Open Hole Wellbore Clean up

Well Status

- 8 ½" open hole reservoir section drilled to TD.

PST spec RDF and LSOBM

The default OBM system that will be used on a Standard Well Design is PST spec RDF, however a risk assessment is required to ensure this is the appropriate system for the well. This risk assessment will take place with the Wells Fluids Team and Production Technology to discuss whether PST spec RDF or Low Solids Oil Based Mud (LSOBM) is the correct choice for the well. LSOBM if used will be used to displace the PST spec RDF at TD of the section and will not be used for drilling the well.

Scenario 1 Full Circulating system in PST spec

- POOH and pick up BOP / Riser clean up string (see below)

Scenario 2 Circulating System is NOT in PST spec

- Pull back to previous casing shoe and pick up shallow clean up tool string, jet function BOP's to remove debris
- Carry out PST conditioning with bit inside 9 5/8" casing shoe
- PST conditioning inside open hole should not be carried out due risk washing out formation and continually generating cuttings/fines
- Run back to TD and displace open hole (plus required excess) to PST OBM RDF
- POOH to pick up shallow wellbore clean up (WBCU) tools

WHY PST Spec OBM RDF?

- PST OBM will be used and displaced into open hole section for the running of the screens, it will be production screen tested for the ability to flow back through the installed screens.
- PST OBM spec will be achieved whilst drilling to / or after TD is reached. By circulating to PST mud whilst drilling will reduce the need to prepare another mud system which would result in the time reduction / exposure of the open hole section before the installation of the lower completion.

WHY LSOBM?

- LSOBM is an OBM system where barite has been eliminated and replaced by a combination of calcium carbonate and higher density brine
- It's use depends on a number of factors -including when there is a low permeability reservoir properties, screen aperture size, duration of suspension before clean up, non-uniform clean-up of the open hole eg heel cleans up in preference to the toe of the well

Operation Steps

- Drill open hole section to TD using PST spec Reservoir Drilling Fluid (RDF). Attempt to achieve PST spec before section TD or shortly thereafter.
- POOH with drill string and run BOP / Riser clean up string (**Error! Reference source not found.**31).

  Carried out at this stage so any debris/cuttings in BOP area can be cleaned out thoroughly before displacing casing volume to PST OBM

- Pick up WBCU tools and run to casing shoe and clean-up to PST spec OBM**.**
- Scraper to be run prior to lower completion primarily to avoid any debris from falling on top of the fluid isolation device (FID) during this process. Any debris on top of FID may affect the correct functioning of the device.
- Packer setting areas will be scraped prior to setting as per Vendors guidelines.
- Clean up run performed in OBM to give best lift capabilities for removing debris.

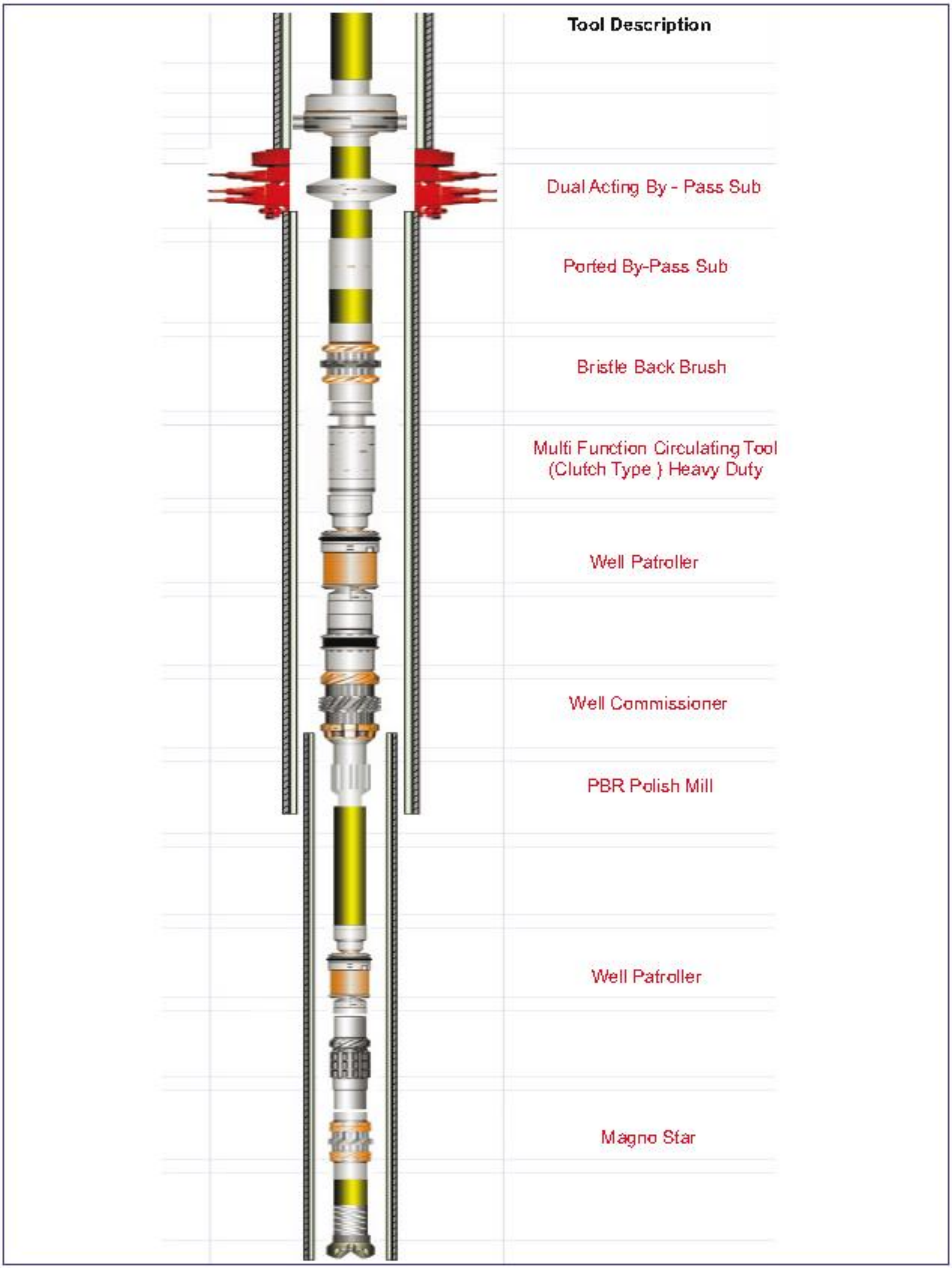


Figure 31 - Typical Scraper Clean up Toolstring

HEAVY DUTY RAZOR BACK CASING CLEANING TOOL (HDRB)	The HEAVY DUTY RAZOR BACK CCT comprises a high-strength, one-piece mandrel and carries a higher rpm

9 5/8” Scraper	and weight-on-bit rating than the standard RAZOR BACK CCT.
WELL PATROLLER	Filters any remaining debris from the annulus and through a wire screen filter.
MAGNOSTAR	Magnet was designed specifically for large-volume cleanup applications in high-torque strings. MAGNOSTAR magnet provides high-volume ferrous debris extraction when circulation alone is insufficient.
PORTED BYPASS SUB	Used to equalize pressure and fluid flow around the tool. Specifically, the PORTED BYPASS SUB establishes communication between the fluids in the drill pipe pressure and fluid flow in the drillstring. Typically, it is run above the WELL PATROLLER* tool to provide an additional means of equalizing pressure and fluid flow around the tool, should it fill with debris while pulling out of hole.
RAZOR BACK CCT 10 ¾” Scraper	Run as an integral part of the drill to scrape the casing as the pipe is run in hole. It can be run as part of most drilling/milling/polishing assemblies as a stand-alone device. More often, it is run with circulating tools and the WELL PATROLLER debris recovery tool as part of a total cleanup system. It can be rotated and reciprocated without damaging the casing or tool itself.

- Run Lower Completion with FID

  If required displace ID of Screens to a lower weight PST OBM to assist flow of the well during flow to host.

- Perform a wellbore clean-up above the FID to completion fluid (Figure 33).

  The wellbore clean up string will be run above the closed FID to displace from PST OBM to the over-balanced completion fluid. The key to a successful wellbore clean up with this type of design is to remove solids from the wellbore above the FID without a) accidentally opening the FID and b) leaving debris in the well that will impede the functionality of the FID. In order to ensure proper space out, the string will be spaced out to land off on a bearing sub against the 7” x 5 ½” x-over keeping the bottom of string above the FID. Note: At this point the drilling debris inside the casing will have been cleaned up and removed on the previous scraper run.

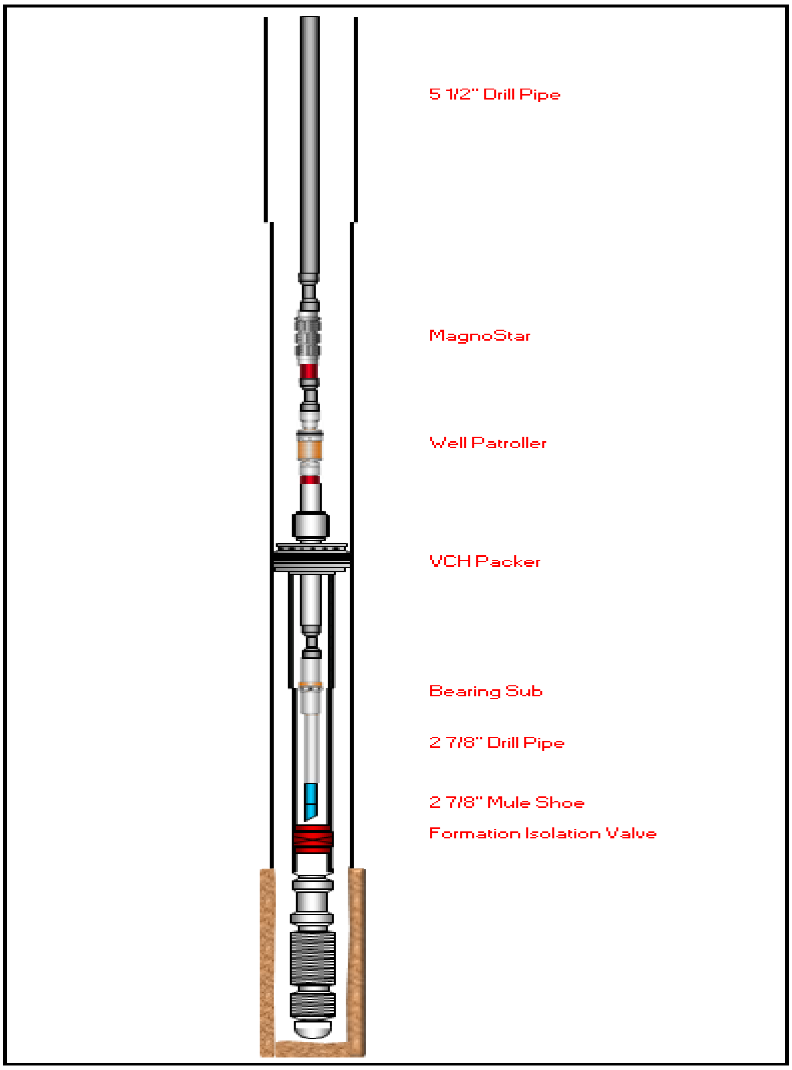


Figure 32 - Typical Displacement Toolstring

MULESHOE – 2 7/8”	The muleshoe is run on drill pipe inside the 5 ½” lower completion above FID.
BEARING SUB	Acts as a “no-go” for landing on internal-diameter restriction. (7” x 5 ½” X Over in lower completion). Crossed over to 3 ½” drill pipe inside the 7” section of lower completion

8. INSTALLATION OF OPEN HOLE LOWER COMPLETION

Objective of the section

The objective of this stage of operations is to select an appropriate open hole lower Completion design that will allow the well to have the following;

- An adequate sand control design
- An adequately tested primary well barrier
- An adequate anchor point for the lower Completion

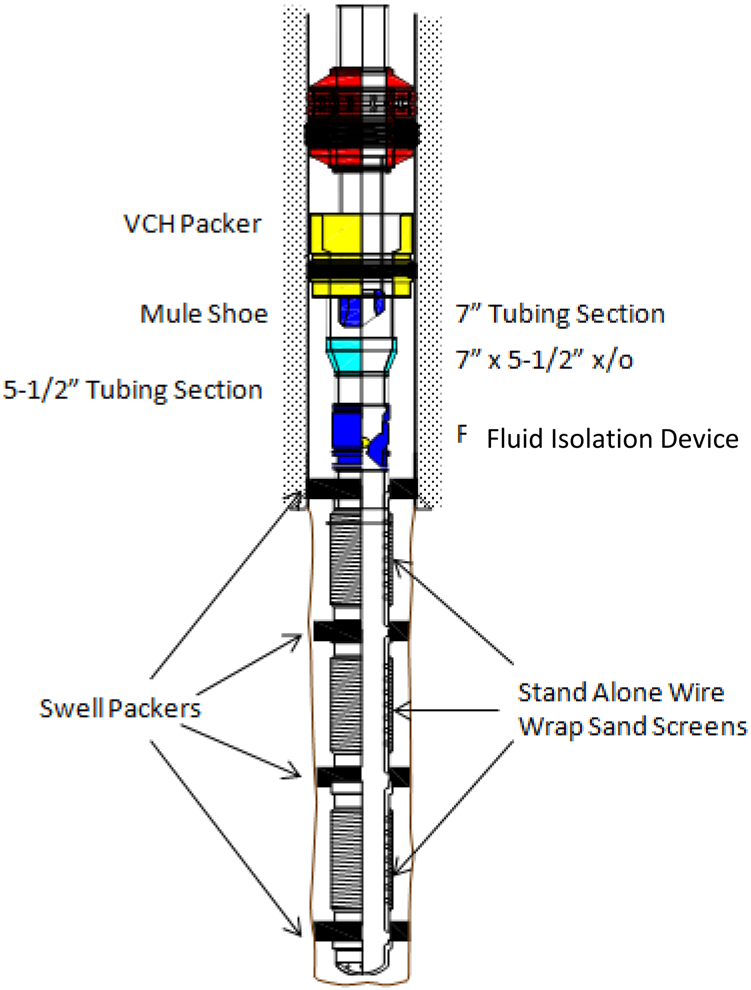
Well Status before this section

- The 8 ½" hole section has been drilled.
- The drilling mud has been conditioned to PST specifications.
- A clean up string has been deployed to scrape the production casing – especially at the Production Packer setting depth.

Overview of section operations

The lower Completion will be deployed and set at the desired depth. The VCH Packer will be tested in Drilling mud before the wash-pipe is pulled out of the lower Completion. The shifting tool attached to the end of the wash-pipe will close the Fluid Isolation Device (FID). Following this, a pressure test will be conducted on the VCH Packer and FID in Drilling mud. If this test has been successful, the well will be displaced to Completion fluid and the upper Completion deployed. Following this, the VCH Packer and FID will be tested in Completion fluid and if successful, it will form part of the primary well barrier.

Typical Lower Completion Schematic: Figure 33



Factors limiting the design of lower completion and of its installation

Ensure that the loads exerted on the VCH Packer fall within the VCH Packer performance envelope (Figure 34).

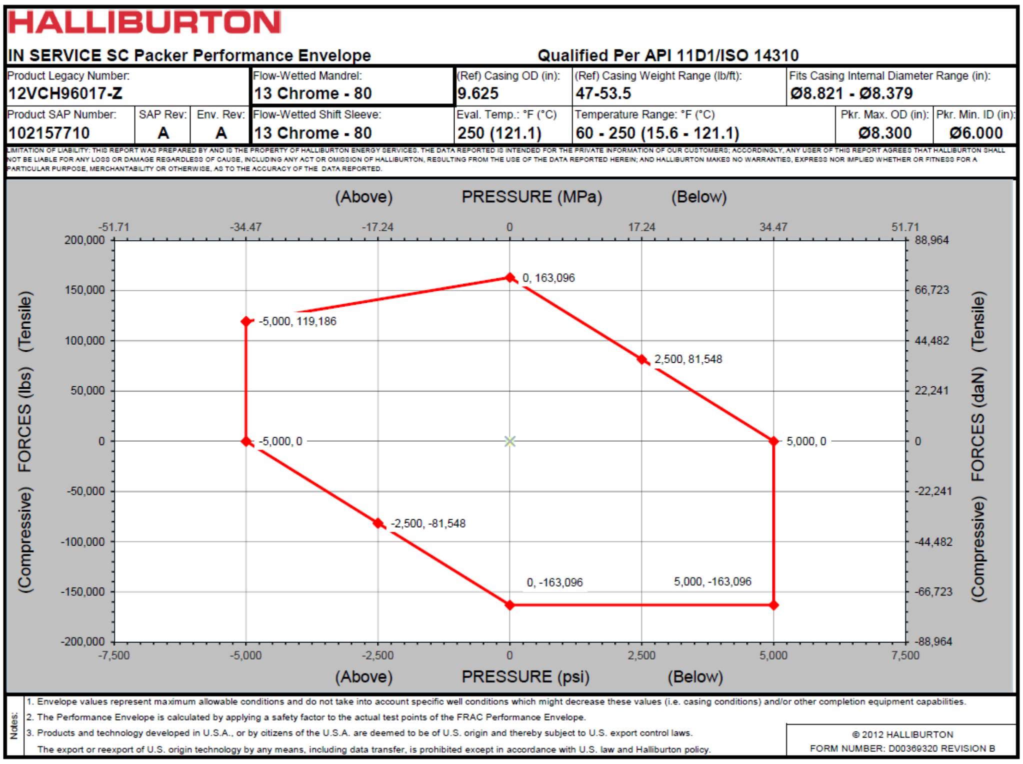


Figure 34 - Packer performance envelope

Lower Completion Design

VCH Packer

- The recommended liner hanger of the open hole lower Completion is the Halliburton VCH Packer. This will act as the anchor point of the lower Completion and will also form part of the primary well barrier.

7” Section of Lower Completion

- The standard lower Completion design is to have a 7” x 5 ½” design. This has been chosen as base case for the following reasons:
    1. A monobore (5-1/2”) well allows easier passage in and out of the well for through-tubing standard equipment such as plugs, straddles, tractors and logging tools (PLT/RST/calliper).
    2. Enable standard plugs / straddles to be used as opposed to high expansion plugs / straddles. High expansion plugs / straddles generally have a reduced pressure differential rating, and as such, will not be as robust.
    3. Increase the likelihood of stable production rates as the well will not have large ID variations.
- The standard section of 7” tubing is 13Cr L80 29ppf tubing with VAM TOP HT connections.

9-5/8” Casing Corrosion Mitigation

- The standard 9-5/8” casing design will not be 13Cr casing. As a result, there will be a section of 9-5/8” casing located between the VCH Packer and the Production Packer that may be exposed to produced reservoir fluids and thus be at risk of corrosion (see Figure 3).
- In order to minimise this risk of corrosion, the tailpipe of the upper Completion will need to be a minimum of 120ft MD inside the lower Completion. This prevents the exposed section of 9-5/8” casing from being flow wetted and therefore minimise the risk of corrosion.
- It is recommended that the length of the 7” tubing section be no less than 140ft MD in order to account for this corrosion. However, this length should also not be greater than 140ft MD (refer to Location of Cross Over section below), because this will avoid wireline tool strings falling on the low side of the exposed 7” tubing section and not being able to enter the 5-1/2” tubing section of the lower Completion. It is therefore recommended that the length of the 7” tubing section be 140ft MD.
- The 5-1/2” tubing in the tailpipe is special clearance tubing, where the OD of the coupling is reduced to 5.89” in order to ensure that there is sufficient clearance for the upper Completion tailpipe to enter the lower Completion. Refer to Chapter 9: Upper Completion Design for more information.

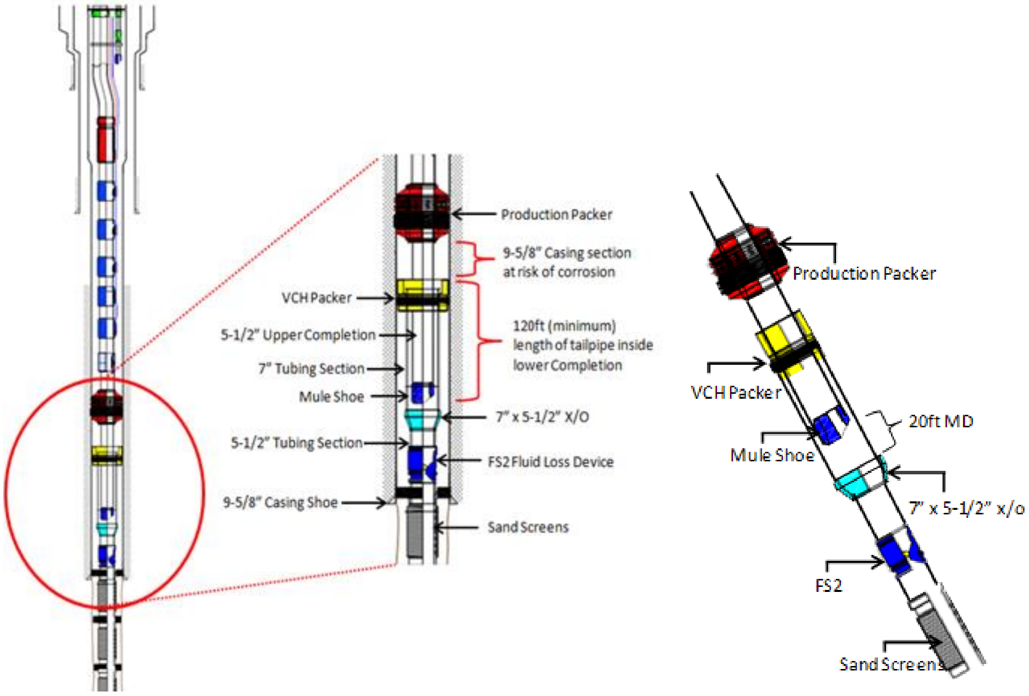


Figure 35 - 9 5/8" casing section at risk of corrosion and distance between mule shoe and cross over

Component	Maximum OD (inches)
Mule Shoe	5.940
5-1/2” 13Cr L80 17ppf Tubing*	5.89

*special clearance

Figure 36 - Upper completion tailpipe maximum ODs

7” x 5 1/2” Cross Over

- A 7” x 5-1/2” Cross Over will be incorporated into the lower Completion design in order to allow the well to be monobore (5-1/2”).

  Location of Cross Over

- The location of the Cross Over with respect to the upper Completion Mule Shoe is critical. If the Mule Shoe is too close to the Cross Over, then there is little room for error when it comes to spacing out the upper Completion. Conversely, if the Mule Shoe is too far away from the Cross Over, then it can (especially in highly deviated wells) result in wireline tool strings falling on the low side of the exposed 7” tubing section and not being able to enter the 5-1/2” tubing section of the lower Completion.
- It is therefore recommended that the Mule Shoe of the upper Completion be positioned 20ft MD above the 7” x 5-1/2” Cross Over (Figure 25).
- Since it is recommended that 120ft MD of the upper Completion tailpipe be inside the lower Completion (as mentioned above), it is thus recommended that the 7” tubing section length be no longer than 140ft MD (120ft MD + 20ft MD). This will prevent wireline tool strings falling on the low side of the 7” tubing section (because generally wireline toolstrings are / can be made to be longer than 20ft) and still give sufficient room for space out errors.

  Wellbore Clean Up

- Following the deployment of the lower Completion, a wellbore clean up displacement string will be deployed in order to displace the Drilling mud to Completion fluid. The displacement string is planned to no-go on the 7” x 5-1/2” Cross Over. By no-going against the Cross Over, this will simplify the deployment of the displacement string and allow it to reach target depth more easily.
- The general 7” x 5-1/2” Cross Over that Halliburton supply has a 5.5^{O} internal taper. This angle is not sufficient for the displacement string to no-go against it. In view of this, Halliburton have provided a modified Cross Over that has a 10^{O} internal taper, which will sufficiently ensure that the displacement string no-go’s against the Cross Over. This modified 10^{o} internal taper Cross Over will be the standard 7” x 5-1/2” Cross Over.

5 1/2” Tubing Section

- The standard section of 5-1/2” tubing is 13Cr L80 17ppf tubing with VAMTOP HT connections (i.e. identical to the standardised upper Completion tubulars).

  Length of 5-1/2” Tubing Section

- Space out of the 5-1/2” tubing section is critical when running the lower Completion.
- When making up the lower Completion assemblies on the Drill Floor, the assembly that requires the longest time to make up is the VCH Packer, which may take up to 6 hours to make up.
- If a Well Control incident took take place during this period, then in order for the Variable Bore Rams to be effective, the sand screens should be spaced out in order to be located below the BOPs and the 5-1/2” blank tubing located across the BOPs.
- Due to Shell’s CNS assets having an average distance of approximately 370-390ft TVD from the Drill Floor to the mud line, it is recommended (where practical) that there is at least 400ft MD between the VCH Packer and the top of the sand screens.
- As a result, in the event of a Well Control incident while the VCH Packer is being made up, the sand screens will be located below the BOPs and the blank 5-1/2” tubing will be across the BOPs. Thus, the Variable Bore Rams can be closed and Well Control Procedures followed without the need to use the Shear Rams.
- Due to the recommended length of the 7” tubing section being 140ft MD, the recommended length of the 5-1/2” tubing section prior to reaching the sand screens is at least 260ft MD (400ft MD – 140ft MD = 260ft MD).

Formation Isolation Device (FID)

- The standard Fluid Isolation Device is the Halliburton FS2, but other manufactures can be considered. The FID is run in the open position into the well as part of the lower Completion and is located between the 7” x 5-1/2” cross over and sand screens.
- The purpose of having a FID in the lower Completion is to be;
    - An isolation between the Completion fluid and Drilling mud in order to minimise the risk of emulsions forming in the well.
    - A pressure containing platform in order to set the Production Packer hydrostatically.

- A pressure containing platform in order to test the upper Completion.
- Part of the primary well barrier (when nippling down BOPs and nippling up Xmas Tree).

Location of the FID

- During a well workover / abandonment, in order to gain the necessary well barriers to ND Xmas Tree and nipple up NU BOPs, a Bridge Plug is set and tested in the upper Completion tailpipe. This plug combined with the Production Packer will form part of the primary well barrier.
- However, in the event that the Production Packer fails to hold pressure, the only available option that would prevent a single barrier workover / abandonment is to set a plug in the lower Completion (between Cross Over and FID) and attempt to test the VCH Packer & plug in order for it to form part of the primary barrier.
- In view of this, it is recommended that there should be a minimum of 40ft MD of 5-1/2" tubing section between the 7" x 5-1/2" Cross Over and the FID in order to allow space to set a Bridge Plug for workover / abandonment purposes.

Opening Remotely

- Just prior to the well being fully opened in order to unload, the FID is functioned open remotely through a series of hydraulic pressure cycles from surface. This eliminates the need to make an intervention on the well, thus reducing operational time and cost.
- For the Halliburton FS2 device each pressure cycle consists of applying a minimum tubing pressure of 3,000psi and holding it for a minimum of 3 minutes before bleeding it down to 0 psi within 5 minutes. A total of 10 pressure cycles are applied from surface in order fully open the FS2. As these pressure cycles are applied, the valve's indexing mechanism moves through each of the predetermined cycles to de-support the internal latch.
- The valve will only open after the well pressure has been reduced to 0 psi on the 10^{th} pressure cycle, in order to prevent surging of well fluids into the formation. The opening of the valve is facilitated by the valve's power springs and boost piston, which provides the necessary force to fully open the valve.
- In the event that the FID has not been fully opened via hydraulic pressure cycles from surface, the redundant option is to deploy the BS1 Coiled Tubing Shifting Tool (CTST). The BS1 CTST is a flow activated shifting tool that requires CT circulation to activate the keys.

Testing the lower completion

- To confirm that the VCH Packer has fully set, a 20,000lbf set down weight is applied followed by a 20,000lbf pick up weight. The VCH Packer is pressure tested to well design pressure in order for it to be;
    1. A pressure containing platform in order to set the Production Packer hydrostatically.
    2. A pressure containing platform in order to test the upper Completion.
    3. Part of the primary well barrier when ND BOPs and NU Xmas tree.
- Once the VCH Packer has been set, it is pressure tested (based on well design test pressure e.g. 3,000psi) from above via the DP annulus for 15 minutes. At this stage of the operations, the VCH Packer is tested in Drilling mud and thus is not classed as forming part of the primary well barrier when ND BOPs and NU Xmas Tree.
- Following this, the wash pipe is POOH resulting in the BS1 Shifting Tool closing the FID. The VCH Packer and FID will then be tested again in Drilling mud for 15 minutes.
- Following this, the well will be displaced to Completion fluid and the upper Completion deployed.
- Once the tubing hanger has been set, the HHC Production Packer will be set Hydrostatically by pressuring up against the VCH Packer and FID.
- The VCH Packer and FID will then be tested (via the Salvo Test method) for 15 minutes to Design Test Pressure.
- If this final test in Completion fluid is good, the VCH Packer (along with the FID) can be classed as forming part of the primary well barrier when ND BOPs and NU Xmas Tree.

Well Life Cycle Integrity

- The VCH Packer is not tested during routine well integrity testing during the life cycle of the well. This is due to the VCH Packer not forming part of the well barriers for Production.

Sand Control Design

The standardised open hole lower Completion sand control design is to use Petro Guard Wrap Screens. These screens are stand alone wire wrap sand screens that will have 5-1/2” 13Cr L80 17ppf base pipe with VAM TOP HT connections.

Sand screens

- The slot sizing of the sand screens is a critical step in the lower Completion design and will be selected by the Production Technologist (PT). If the slot size is too small, there is an increased risk of the screens plugging and thus significantly impacting production rates.
- Conversely, if the slot size is too large, then there is an increased risk of sand production resulting in the erosion of downhole components (e.g. SCSSSV, Production choke) and the interruption of topside process facilities (e.g. separators). In addition, presence of sand in the well may restrict downhole access. The slot sizing of the sand screens is driven by the Particle Size Distribution (PSD) of the formation sand.
- An example PSD of Gannet F Field is given in Figure ; as can be seen, there is a significant range in the PSD, ranging between approximately 35 – 2,500µm, with the majority of the sand grains being between 90 - 500µm.
- With this range in the PSD, it is not possible to select a slot size that will isolate all the sand grains without plugging off the screens. As a result, a balance will need to be struck where the majority of the sand grains are isolated without plugging off the screens, yet some fine sand grains are produced without causing any damage to downhole components and topside facilities.
- The appropriate slot size is determined by using the following;
  - Field experience of slot sizing with similar formations. Has there been any sand production / plugging issues experienced?
  - Select either the D10 PSD or 2x D50 PSD, whichever size is smaller.
- In the example shown in Figure , the D10 PSD is approximately 300µm and the D50 PSD is approximately 175µm (therefore 2 x D50 = 350µm). With no other field experience, the recommended slot size for this example would be 300µm.

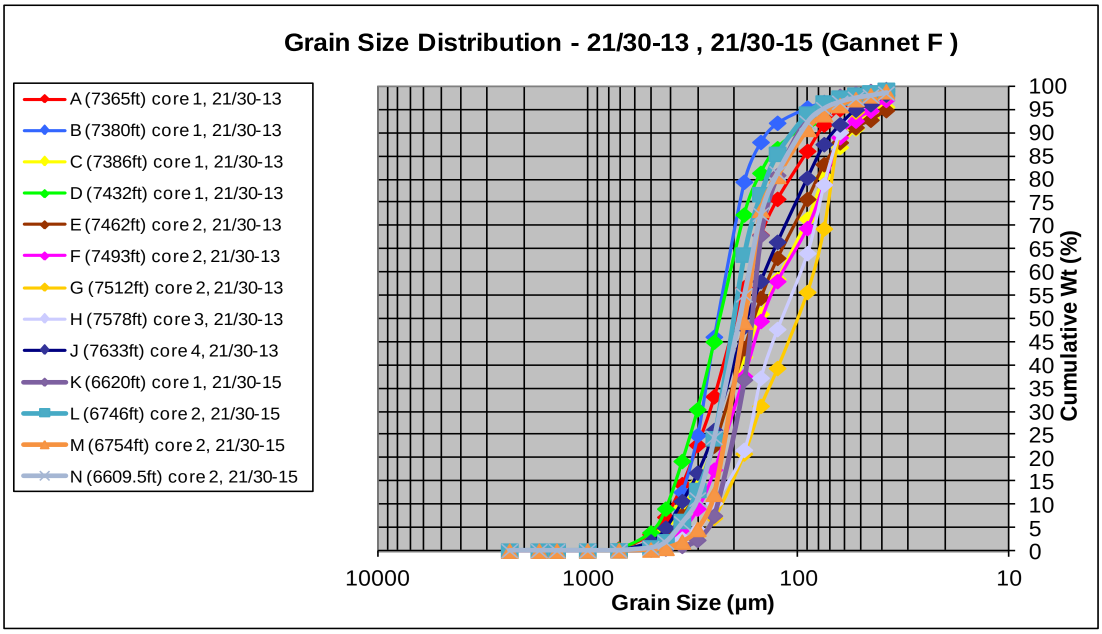


Figure 37 – Particle Size Distribution in Gannet F field

- During the manufacturing stage of the sand screens, it is not entirely possible to obtain the desired slot sizes precisely; there will always be a machining error that will result in the slot sizes either being slightly oversized or undersized.
- As with the slot sizing, a fine balance will need to be struck when selecting the degree of over sizing and under sizing of the screens (this is known as the slot tolerance). If a very small slot tolerance is selected (for example 100% of slots have to be within +/- 5µm of desired slot size), this will most likely result in the manufacturing process taking significantly longer due to more screens being rejected for not meeting this small tolerance. This will also in turn lead to increased costs.

- Conversely, if a very large slot tolerance is selected (for example 100% of slots have to be within +/- 100µm of desired slot size), this will most likely result in a relatively quick manufacturing process time, but will increase the likelihood of sand production / screens plugging.
- The key objective is to ensure that the selected slot tolerance does not significantly increase the manufacturing time / cost of screens, but also not increase the likelihood of sand production / screens plugging. Based on the above considerations, the recommended slot tolerance of the sand screens is as followed:

  1. 90% of all slots to be +/- 25 microns of the desired slot size.
  2. 100% of all slots to be +/- 50 microns of the desired slot size.

Base pipe

- The standard base pipe for the sand screens will be 5-1/2" 13Cr L80 17ppf tubing with VAM TOP HT connections (i.e. the same as the standardized upper and lower Completion tubulars). This will allow the well to be monobore. Since water shut-off is often seen as critical in some fields having a monobore completion is essential when setting straddles.
- This base pipe will have 32 perforations per foot, with the perforation hole size being 0.375" in diameter, equating to an open area of $3.53 in^2/ft$.

Swell Packers

- Swell Packers are incorporated into the lower Completion design in order to provide reservoir segregation. This will thus give the benefit of allowing watered out / pressure depleted zones to be isolated through the deployment of plugs / straddles and therefore improve well production performance. In addition, Swell Packers are deployed in order to protect the screens from shale collapse.
- The standard Swell Packers are the Halliburton Easywell Packers.
- When selecting the OD of the Swell Packers, it is dependent on the following factors;
  - Hole size (for the Standard Well Design it is 8-1/2")
  - Reservoir Pressure / Temperature
  - Differential Pressure
  - Required Swell Time
  - Drilling Mud
  - Base pipe Size (for Standard Well Design it is 5-1/2")
  - Type of Swell Packer (for Standard Well Design it is oil swelling, in order for it to commence swelling as soon it makes contact with drilling mud).
- With the exception of Swell Packer type and hole and base pipe sizes, the other parameters will vary from well to well. It is therefore critical that Halliburton conduct the necessary models using the SwellSim software in order to provide the recommended Swell Packer OD and the associated swell times.

Procurement

The Completion Engineer must ensure that the Lower Completion items are ordered in time. For more information and advice, refer to the Wells Materials Guidelines Wiki:

http://sww.wiki.shell.com/wiki/index.php/Wells_Material_Ordering_Guidelines_%28WMOG%29

Openhole Lower Completion Components

Order the following items in SAP at least 40 weeks prior to spud. For more advice, contact Marcel Oolderink.

Item	Material	Plant	Requirement qty	Ba...	P...	I..	R..	St...	BOM ex...	Description
0650	1001631281	GB01	2.00	EA		N	3	1058		FLUID LOSS DEVICE,FS2-L,8.015,4.625,13Cr
0660	1001631286	GB01	2.00	EA		N	3	1058		PACKER,9.5/8,47.0-53.5,13Cr,6.000,6.7/8
0670	1001631285	GB01	2.00	EA		N	3	1058		SUB,BOTTOM,7.15/16-6 STUB ACx7.5/8-29.7
0680	1001631276	GB01	2.00	EA		N	3	1058		EXT,UPPER,MCS,7.5/8-29.7,13Cr,VAM-TOP-HT
0690	1001631284	GB01	2.00	EA		N	3	1058		COUPLING,RED,7.5/8-29.7x7-32,VAM-TOP-HT
0700	1001631283	GB01	2.00	EA		N	3	1058		SUB,MAKE-UP,7-32.0,VAM-TOP-HT,13Cr,PxP
0710	1001631282	GB01	2.00	EA		N	3	1058		ADAPTER,RED,7-32.0x5.5-17,VAM-TOP-HT
0720	1001631278	GB01	2.00	EA		N	3	1058		EXT,SEAL BORE,4.5,96.05,5.1/2-17.0
0750	7000000765	GB01	8.00	EA		N	3	1058		Swellpacker Type: SP OS L 5.5in x 8in x
0770	7000000765	GB01	2.00	EA		N	3	1058		BS1 Seal Bore Snap In-Snap Out Collet Sh
0780	7000000765	GB01	2.00	EA		N	3	1058		Halliburton Sand Control Float Shoes, 6.
0810	1001273312	GB01	6.00	EA		N	3	1055		LATCH,PETTECH,RM,AN51114,INC 718,1.5in
0820	7000000765	GB01	6.00	EA		N	3	1058		PGW Std screen 38.5ft long 28ft Coverage

All the above mentioned components of the open hole lower Completion are recommended products from Halliburton. Quotations need to be collected from the Halliburton focal point and these quotes are then to be provided to the Cost Controllers. The Halliburton focal point is;

Steven Laidlaw, Technical Professional, Halliburton

E-Mail steven.laidlaw@halliburton.com, Tel: +44 1224 884594, Mobile: +44 7767 334 809

9. UPPER COMPLETION

Objective

The objective of this section is to give an overview of the components to be used during the installation of a standard upper completion

Well Status before this section

- The wellbore clean up has taken place and mechanical barriers have been confirmed
- Inhibited Seawater, Brine or Base oil is in the well with <0.05% solids

Typical upper completion schematic

Tubing Hanger	TBC
Short String	
2-3/8" 4.6# Vam Top Pup Joint 6ft Pin x Pin, 13Cr-80	1001189839
2-3/8" 4.6# Vam Top Pup Joint 6ft, 13Cr-80	1001009838
Otis Landing Nipple with Btm NO-Go 1.781in	1000901285
2-3/8" 4.6# Vam Top Pup Joint 4ft, 13Cr-80	1001009837
Muleshoe Guide	1000901283
Production String	
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 20ft Pin x Pin Pup Joint	1001176899
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 6ft Pup Joint	1001009818
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 16ft Pup Joint	1001009818
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 6ft Pup Joint	1001009815
SP Tubing Retrievable Safety Valve	1001062587
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 8ft Pup Joint	1001009816
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 16ft Pup Joint	1001009818
5 1/2" 17# Vam Top HT Box x Box L-80 13Cr Coupling	1000997473
5 1/2" SGM NPQG/NHQG Multidrop-W, Tubing/Tubing Vam Top HT Pin x Pin 13Cr	1001637892
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 8ft Pup Joint	1001009816
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 16ft Pup Joint	1001009818
5 1/2" 17# Vam Top HT Box x Box L-80 13Cr Coupling	1000997473
5 1/2" SGM for NPQG/NHQG/NDPG Single Gauge. 17# Vam Top HT Pin x Pin. 420 Mod; 13Cr	1001531099
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 8ft Pup Joint	1001009816
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 16ft Pup Joint	1001009818
Halliburton Sliding Side Door	1001209315
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 8ft Pup Joint	1001009816
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 16ft Pup Joint	1001009818
Polished Bore Receptacle	1001705042
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 8ft Pup Joint	1001009816
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 16ft Pup Joint	1001009818
9 5/8" HHC Hydrostatic Set Retrievable Packer	1001013350
5 1/2" 17# Vam Top HT Box x Pin L-80 13Cr 8ft Pup Joint	1001009816
5 1/2" 17# Vam Top HC Box x Pin L-80 13Cr 8ft Pup Joint Perforated	1001203759
5 1/2" 17# Vam Top HC Box x Pin L-80 13Cr 16ft Pup Joint	1001203760
Halliburton Self Aligning Mule Shoe Guide	1001147011

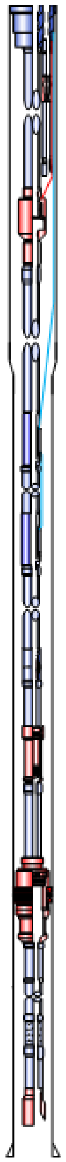


Figure 38 -Typical upper completion schematic

Completion design and components

Tubing Hanger

MS-700 Dual Bore tubing hanger

- 5 ½" 17# Vam Top HT
- 2 3/8" 4.6# Vam Top HT
- 6 Ports
- Carbon steel with Alloy 625 cladding
- Vendor: Vetco

2 3/8" String

- 1 x 6ft 2 3/8" 4.6# Vam Top SC-80 Pin x Pin. Shell SAP: 1001185539
- 1 x 6ft 2 3/8" 4.6# Vam Top SC-80 Box x Pin. Shell SAP: 1001009838
- 1 x 1.781" RN Nipple 2 3/8" 4.6# Vam Top Box x Pin. Shell SAP: 100901285
- 1 x 4ft 2 3/8" 4.6# Vam Top SC-80 Box x Pin. Shell SAP: 1001009837
- 1 x 2 3/8" 4.6# Vam Top SC-80 Box x Half Muleshoe. Shell SAP: 1000901283

5 ½" String

- 1 x 20ft 5 ½" 17# Vam Top HT Pin x Pin. Shell SAP: 1001176899
- 2 x 6ft 5 ½" 17# Vam Top HT Box x Pin. Shell SAP: 1001009815

Dual Hanger String Clamp – Shell SAP: 1000883917

- 5 ½" x 2 3/8" Dual clamp
- Installed on the dual string below the tubing hanger to keep the 5 ½" and 2 3/8" together
- Vendor: Schlumberger. Part Number: A03820

Tubulars

Standard tubing to be:

- 5 ½" 17# Vam Top HT 13CrTubing String – Shell SAP Number: 1000997407
- 2 3/8" 4.6# Vam Top SC-80 Tubing for Annulus

Shell Standard for assemblies is 16ft pup joint on top and 8ft pup joint on bottom:

- 16ft 5 ½" 17# Vam Top HT 13Cr Pup Joint for top of Assembly – Shell SAP Number: 1001009818
- 8ft 5 ½" 17# Vam Top HT 13Cr Pup Joint for bottom of Assembly – Shell SAP Number: 1001009816
- Standard for tubing will be 13Cr unless specific well conditions require different spec i.e. H_2S. This would be identified within the WFS.
- 4 ½" Vam Top HT 13CrTubing String has been looked at but brings very little benefit in extending the life of the well so has been discounted.
- Future may bring the opportunity to run 5 ½" VAM 21 but this currently is not an option.
- Link to current Tubular Specification Sheets
- https://sww-knowledge-epe.shell.com/teamepns/livelink.exe?func=ll&objId=57437688&objAction=browse&sort=name
- Link to current Tubular Stock – 'Green Items' https://sww-knowledge-epe.shell.com/teamepns/livelink.exe?func=ll&objId=41463565&objAction=browse&sort=name

Safety Valve

Shell SAP Number: 1001062587

Component	Max OD (inch)	Top Seal Bore Min ID (inch)	Bottom Seal Bore Min ID (inch)	Closure Type	Max Working Pressure (psi)	Service	Temperature (Deg F)
Safety Valve	8.22	4.625	4.625	Flapper	6000	H2S	20 - 300

5 ½” Self equalising TRSSSV c/w 4.625” nipple profile.

Setting depth variables:

- Set inside 10 ¾” Casing to allow larger nipple size over slim-line design
- Ensure control line fluid compatibility with other wells in the field
- Annulus fluid / Setting depth of valve – Maximum setting depth has to be above the depth where heavy annulus fluid has the potential to open the valve in the event the integrity of the control line is compromised.
- Hydrate formation
- Cratering
- Vendor: Halliburton. Part Number: 78001950-BEN

Gas Lift (SPM / GLV’s)

Where gas lift is required PTC Gas Lift Valves will be utilised and installed as per Production Technologist

- PTC is currently the best design as the seal faces are designed to be protected from flow erosion thus reducing the risk of leak path compared to other available designs
- RM Latches – Hold the Gas Lift Valve in-place. Designed for installation in an ‘A Type’ profile mandrel i.e. Has a 360 degree profile for the location of the locking dogs
- SPM (Side Pocket Mandrel) to be set in maximum of 65deg inclinations
- SPM depth to allow optimal well un-loading / well displacement
- If the SPM is to be used for unloading the well then the valve must be changed to dummy valve before handing well back to production. In addition the maximum flow rate must be specified.
- Solid body SPM – Currently using 3 Piece welded mandrels. Advantage of solid body mandrel is no ID change thus reduced risk of stuck tools / plugs.

Component (Schlumberger)	Max OD (inch)	Min ID (inch)	Drift (inch)	External Working Pressure (psi)	Internal Working Pressure (psi)	Control Line Internal
Welded Gas Lift Mandrel	7.780	4.595	4.570	6245	7715	No
Solid Body	8.150	4.735	4.653	7200	8000	Yes

Gauges

Shell SAP: 1001531099

Component	Max OD (inch)	Min ID (inch)	Drift (inch)	Casing Range (lb/ft)	Internal Working Pressure (psi)	External Working Pressure (psi)	Service	Temperature (Deg F)
Gauge Mandrel	6.650	4.798	4.767	36 – 59.4	6200	6300	CO_2	40 - 300

Component	Max cable length (km)	Max cable length between gauges (km)	Connection Type	Working Pressure (psi)	Tubing Pressure	Annulus Pressure	Temperature (Deg C)
Single Gauge	10	1	EDMC-R	16000	Yes	No	150

As per section 10 of the WRM (Well & Reservoir Management Standard):

'All new wells that develop more than 1 MMBOE should have a PDHG as a base case, unless it can be demonstrated that this is not cost-effective and data of equivalent quality can be obtained safely, by alternative means'

- Gauge Mandrels – 5 ½" Vam Top HT Pin x Pin.
- Max Working Pressure 6200psi @ 150 degC
- Vendor: Schlumberger. Part Number: 100896877
- 5 ½" Vam Top HT Coupling – Shell SAP: 1000997473
- Single Tubing Pressure Gauge: Max Temp 150 deg C. Working Pressure 16000psi
- 1 sec sample rate for both pressure and temperature
- Shell SAP: 1000794776
- Vendor: Schlumberger. Part Number: P497157
- Dual Gauges – Gives redundancy with a second gauge should 1 gauge fail – Not full redundancy as both gauges share single cable (Any damage to the down-hole cable would result in communication with both gauges being lost). Additional $250k for cost of gauge mandrel, gauge. Also rig time for second splice (average 6 - 8hrs)
- Flowatcher – Allows for metering of individual wells where more than 1 producing well flows into a single pipeline with no-way to meter individual well production without shutting in neighboring wells - Additional $400k+ for equipment cost. Also rig time for second splice (average 6 - 8hrs). Restriction in tubing string from Venturi which will result in higher intervention costs due to extra time for retrieving / running of the Venturi during the intervention.
- The additional costs associated with the running of either dual gauges / Flowwatcher comes down to sales equipment / rig time for additional splices – services charge costs are almost identical for all three scenarios.

The base case going forward will be for single gauge as per above requirement and well specific justification for additional data to be argued in.

Sliding Side Door

Shell SAP Number: 1001209315

Component	Max OD (inch)	Seal Bore Min ID (inch)	Shifting Direction	Max Working Pressure (psi)	Service	Temperature (Deg F)
Sliding Side Door	6.860	4.562	Down to Open	7100	STD / CO2	325

Consideration Points for SSD:

- 4.562" Profile
- SSD in a Gas well – No SPM so have the ability to set a 'Side Door Choke' across the SSD in the event of not being able to achieve pressure sealing capabilities
- SSD in an Oil Well – With SPM the ID's does not allow the sleeve (4.650" OD) to be RIH and as such a straddle will have to be set in the event of not being able to achieve pressure sealing capabilities
- 162" flow area through SSD
- 0.1932" flow area through GLV (1/2" Orifice)
- Max flow rate through a SPM is 1-1.5bpm - Unsuitable flow rate for time efficient displacement
- Vendor: Halliburton. Part Number: 921RPD45604-G

For optimal well displacement the standard will be to run an SSD - (This may be revised should under balanced completions be endorsed)

PBR

Shell SAP Number: 1001013350

Component	Max OD (inch)	Min ID (inch)	Seal bore Min ID (inch)	Casing Range (lb/ft)	Max Working Pressure (psi)	Service	Temperature (Deg F)	Stroke (inch)
PBR	8.20	4.791	6.000	36 – 59.4	6290	STD / CO2	40 - 350	240

- 20ft Stroke
- Allows for end of well abandonment without the need to cut packers / tubing or milling of packers
- Allows for more cost effective workover by only having to recover the tubing string without having to cut / mill packer
- Any restriction in the tubing above the packer i.e. stuck plug in a SPM – Allows for a more time efficient and cost effective workover
- Have to consider the pull available taking into account weight of completion, landing string, tubing selected and the life of the well timeframe to give % of tensile strength lost due to tubing deterioration when selecting shear ring size.
- Shear Ring size currently – 90k, 120k, 135k, 150k. Shear Ring requirement confirmed during WellCat. During shear ring selection weight of tailpipe and packer setting pressure also have to be taken into consideration.
- The PBR shear rating should be designed so that it can be sheared out when recovering the upper completion, however it should not be able to shear during the production lifecycle of the well as confirmed by WellCAT. The reason behind this is that it is not desirable to have dynamic seals as part of the production tubing barriers.
- Vendor: Halliburton. Part Number: 912PBS60078

Packer

Shell SAP: 1001013350

Component	Max OD	Min ID	Drift (inch)	Casing	Max	Service	Temperature

	(inch)	(inch)		Range (lb/ft)	Working Pressure (psi)		(Deg F)
HHC Packer	8.310	4.785	4.767	43.5 – 53.5	6290	H2S / CO2	325

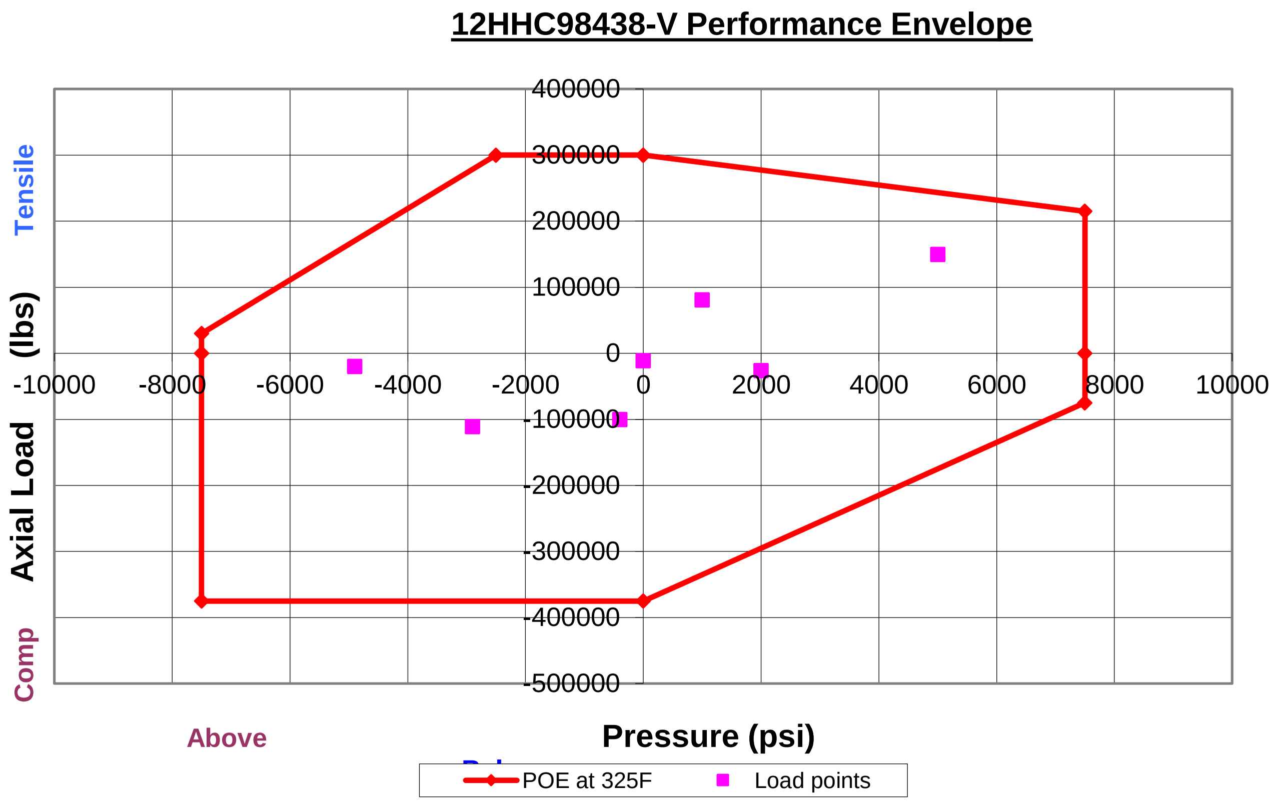


Figure 39 - Packer performance envelope

9 5/8” HHC Hydrostatic Packers set against an FID

- 9 5/8” 43.5# - 53.5# Casing
- Hydrostatic Packers eliminate the need for running / pulling plugs.
- Packer setting depth has to take into account well integrity – 100ft below good logged TOC & 1000ft below unlogged TOC (Technical Standards 03). Abandonment criteria 100ft below good logged TOC & 660ft below unlogged TOC (TS 12)
- Packer to be set +/- 100ft above the liner top but within 65deg inclination.
- Less than 65deg inclination at setting depth to limit the need for any intervention other than standard wireline i.e. No tractors or coil tubing required.
- Cut-To-Release to aid removal if required
- Vendor: Halliburton. Part Number: 12HHC98438-V

Shoot and Pull Completion Packer

Shell SAP: 1001013350

- HHC Hydraulic Set packer
- Same packer as Hydrostatic Set packer. This packer set up would be run where it is not possible to pressure up the well to set a hydrostatic packer.
- Hydraulic setting requirement captured during make-up meeting and changes made during assembly make-up – no special engineering work involved
- Vendor: Halliburton. Part Number: 12HHC98438-V

Tailpipe

Shell SAP: 1001138268 / Perforated Pup Shell SAP: 1001203759

- 13Cr tailpipe inside Lower Completion min 100ft to avoid flow wetting casing
- No seals to prevent creating trapped annulus between top of VCH packer and Bottom of HHC packer
- Perforated pup to allow pressure to reach hydrostatic setting packer in the event of plugging of the tailpipe annulus
- 5 ½" 17# Vam Top HC tubing c/w special clearance coupling
- 5 ½" 17# Vam Top HC Perforated Pup Joint – 8ft
- Link below to Tubing Data Sheet: https://sww-knowledge-epe.shell.com/teamepns/livelink.exe?func=ll&objId=57437688&objAction=browse&sort=name
- See Extract from TS-03 below:

3.3. DECISION CHART

Clarifications and supplements to CTDM:

- Guidance exists within UIE relating to "dead zone" criteria, specifically acceptance or otherwise of the use of carbon steel casings / liners in place of their CRA equivalents in nominally corrosive environments. In summary:
    - Where production or injection of corrosive fluids is anticipated, the "dead zone" criteria shall be achieved using a minimum of 100ft "overlap". e.g. with a production packer set within a 9.5/8" production casing, a 100ft of 13%Cr [or other CRA as applicable] completion tailpipe overlapping within a 7"x13%Cr [or other CRA as applicable] liner results in a "dead zone" immediately below the production packer, allowing carbon steel 9.5/8" casing [from below the production packer to top of liner] to be used.
    - Where production or injection of corrosive fluids is not anticipated, the "dead zone" criteria may be relaxed.

Muleshoe

Shell SAP: 1001147011

SAG:

- Essential in a well with any deviation which causes issues when trying to stab into Lower Completion / Liner Top as Rotation of string not recommended with gauge cable in the hole.
- Current option has Special Clearance Box to allow 5 ½" 17# Vam Top HT connection max OD of 5.940"
- Shell SAP Number: 1001147011
- Vendor: Halliburton. Part Number: 212SDG25-F

Short String W.E.G

Shell SAP: 1000901283

- 2 3/8" 4.6# 13Cr Vam Top
- Vendor: Halliburton. Part Number: 912G27505

Nipple / Plugs

The standard upper completion design will be to run with no nipple in the 5 ½" 17# Vam Top HT string and use retrievable bridge plugs if intervention required.

- A plug TBC, suitable for 5 ½" 17# Tubing (assessment currently ongoing to determine this)
- Junk Catcher available
- With no nipple profile less flow turbulence
- Eliminate the risk of trying to set plugs in nipples with scale during intervention
- No restriction in tubing string which will limit the scope of intervention during the life of the well.
- SAP: TBC
- Vendor: Interwell

The standard will be to run with a nipple in the 2 3/8" 4.6# Vam Top string.

- 2 3/8" Vam Top 1.781" RN Nipple
- Vendor: Halliburton. Part Number: 911RN17805
- Shell SAP: 1000901285

Hydrostatic packers are preferred option for the Low UDC wells and as such would be set against the FID in the well. In the event of the FID not holding sufficient pressure to set the packer an Interwell plug could be utilised therefore limited use for having a nipple installed.

Tubing Hanger Plugs

Currently standard wireline plugs.

Clamps

Cross Coupling Clamps – Shell SAP: 1001635913

- For 5 ½” 17# Vam Top HT Tubing
- Cross-coupling clamp to be installed across every coupling above gauge mandrel
- Slot for gauge line and safety valve line
- Additional 10% to be ordered to allow for damage
- Vendor: Schlumberger. Part Number: 101122330

Safety Valve Stand-Off Clamp – Shell SAP: 1001635879

- Offers protection to the gauge line from below as it passes the large OD of safety valve
- Offers protection to both the gauge and safety valve lines above the safety valve
- Vendor: Schlumberger. Part Number101093790

Procurement

Longest lead items for standard completion items are approximately 52 weeks +/- for tubing hangers.

- Lead time for 25% Cr tubing /completion components for water injections wells approximately 60 weeks +/-.

For completion components procurement allow the following for lead times:

- 18 weeks through to 29 weeks for Halliburton equipment, up to 36 weeks for Schlumberger equipment.

10. PERFORATING

Objectives of this activity

The primary aims from a perforating job are to maximise the production or injection by minimising the skin damage caused. Improve well site efficiencies wherever possible and to eliminate any secondary operations such as re-perforating.

For the four string casing design there are a few designs that can be implemented. The design of these will be driven by what is best for the well in terms of penetration and clean-up of perforating tunnels, cost and efficiency. The primary purpose of this document is to reduce complexity and where possible introduce a standard design.

Well Status before this section

- The wellbore clean-up has occurred
- Depending on the perforating strategy there is the possibility of using underbalanced fluids
- Appropriate perforating selection will be chosen for the well characteristics

Parameters to consider for the perforation strategy

Reservoir properties that are important to perforating are as follows and all will have an effect of perforating performance.

- Permeability
- Porosity
- Existing Depletion
- Unconfined Compressive Strength
- Fluid Type and Properties
- Formation Pressure
- Temperature
- Stresses and their directions
- Casing size

The relative productivity of a given reservoir is primarily dependent on the near wellbore pressure drop. This is governed by drilling damage, perforation parameters and stimulation operations.

Perforation material selection

Charge

The choice of charge whether Deep Penetrating (DP) or Big Hole (BH) will be dependent on the reservoir characteristics. Figure 39 shows the components of a shaped charge.

DP charges are typically powdered metal liners that give deep penetration and small entrance hole diameters. BH charges are designed to give a shallower penetration but much larger entrance hole size and are used for sand control and fracture stimulation.

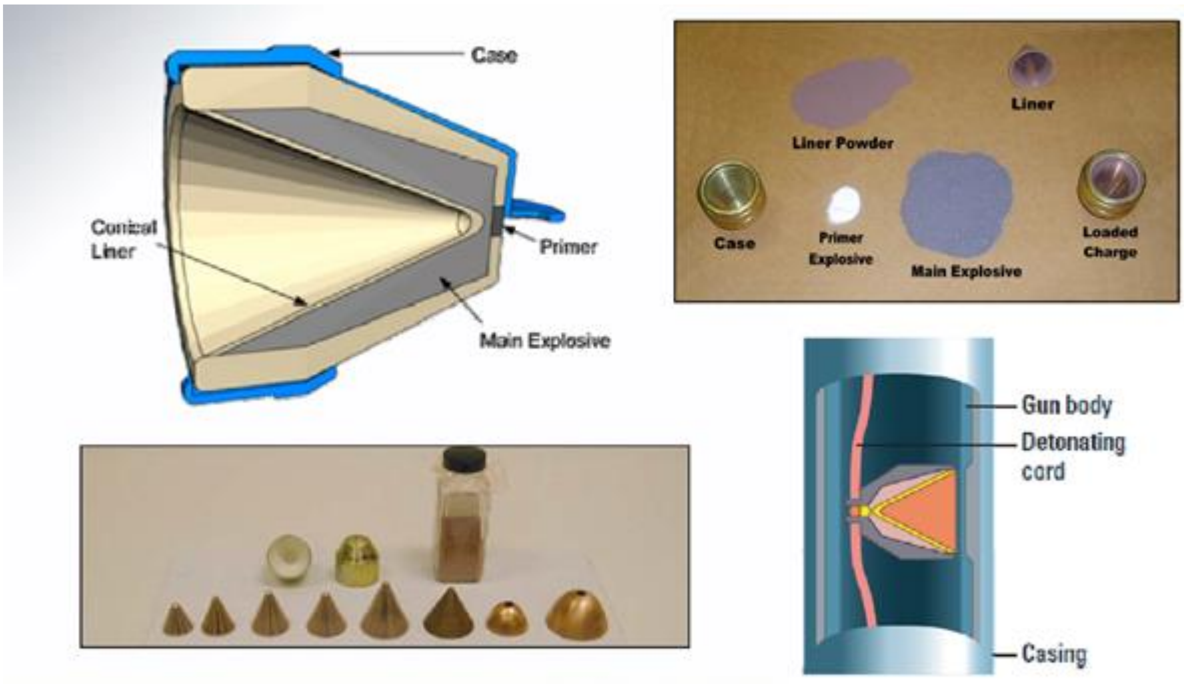


Figure 40 - Components of a shaped charge

Explosive

Temperature affects the rate of reaction, combustion pressure and the sensitivity of explosives. Consequently, maximum safe operating temperatures are defined for all explosives. Exceeding the temperature rating can result in reduced performance and the time aspect needs to be reviewed in the planning of the perforating job.

It is important to review the time that the perforating equipment will be downhole and if problems are anticipated then explosive choice may need to be changed.

See Figure and Figure for more details. It should be noted that for most NPNT wells, HMX will be utilised.

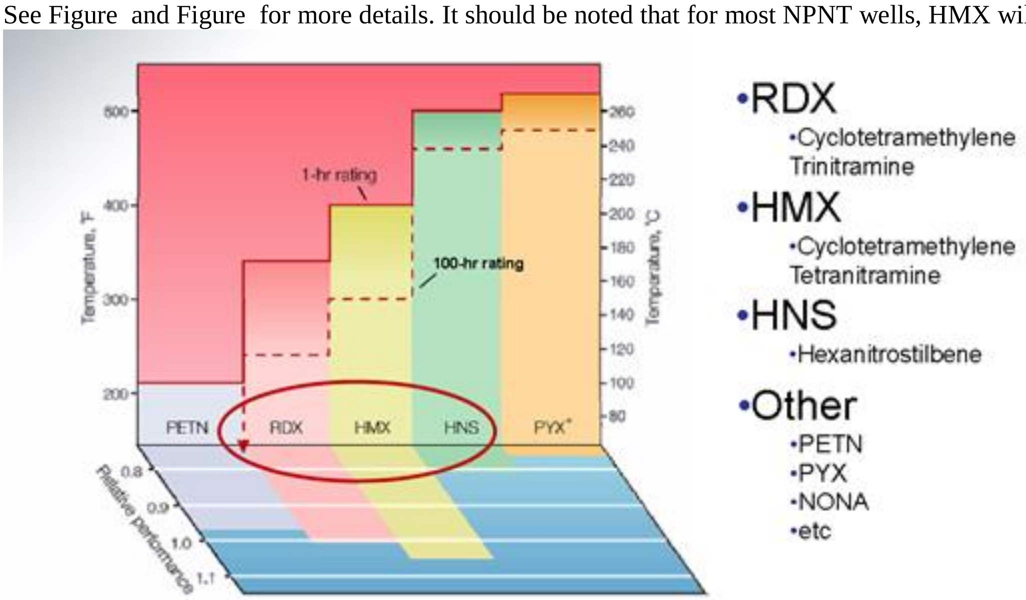


Figure 41 - Energetic materials

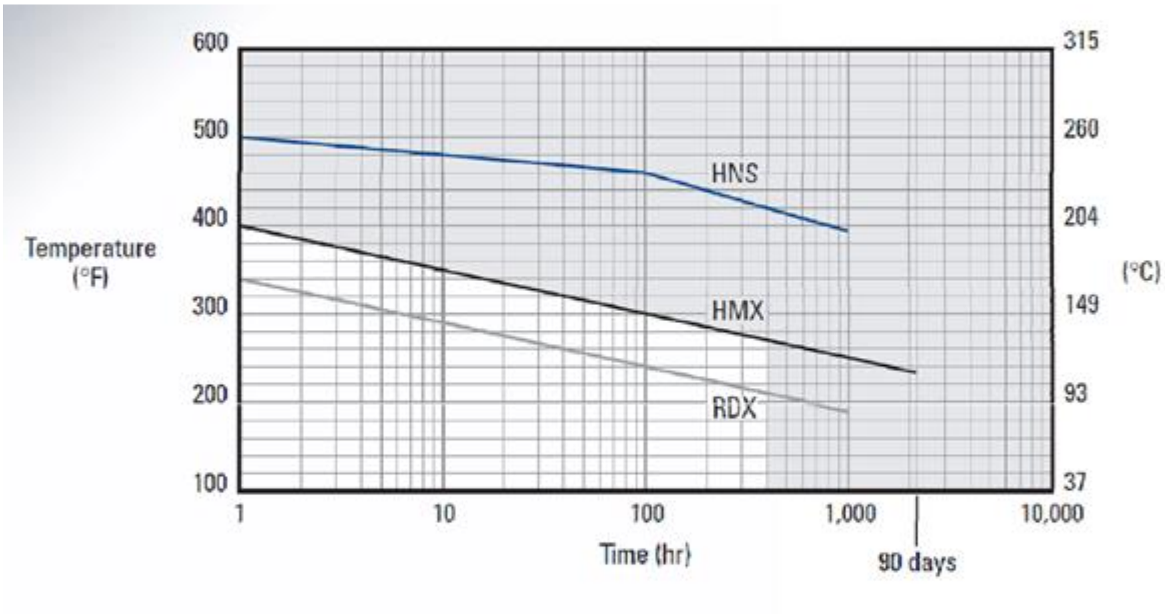


Figure 42 - Time-temperature ratings

Perforating options

Figure 43 illustrates the perforating options that need to be considered for a standard well.

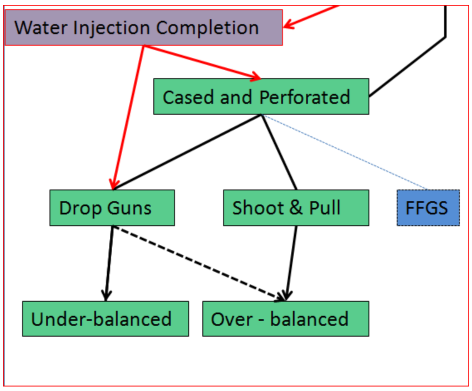


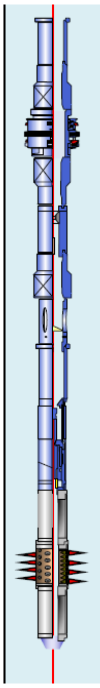
Figure 43 - Perforating options

Auto-Drop guns on end of completion

Running guns on the end of the completion (Figure 44) is suitable where there is no major deviation (although this has been performed up to 80°) and there is available sump to allow the guns to drop to the sump following release from the SXAR (automatic release) A WEG is left following release of guns an no intervention is required

This TCP design has PURE chambers (which allow dynamic underbalance to take place through the control of internal air volume) top and bottom of the gun string to maximise dynamic underbalance, and also to minimise gun shock.

This design would be applicable in both production and injection wells and can be used in both under-balanced an over-balanced operations. The design may include additional free gun volume in order to achieve the necessary dynamic under-balance if perforating in an over-balanced environment.

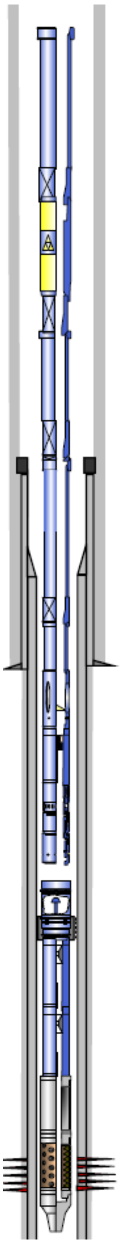


4-1/2 12.6 # VAM Top Tubing	4.500	3.958		TBC			TBC
X-Over (box X pin)				TBC			TBC
Production Packer				TBC			TBC
X-Over (box X box)				TBC			TBC
TDP-2 587 x 300 Glass Plug	5.870	3.000	4-1/2" 12.6# VAM Top Pin 4-1/2" 12.6# VAM Top Pin	5.348			
X-Over (box X pin)	4.500	2.400	4-1/2" 12.6# VAM Top Box 2-7/8" EUE Pin	2			Schlumberger
Long Slot Debris Sub	3.670	2.400	2-7/8" EUE Box 2-7/8" EUE Pin	2			Schlumberger
Tubing Joint with redundant HDF fill sub inside	3.670	n/a	2-7/8" EUE Box 2-7/8" EUE Pin	31			Schlumberger
2-7/8" SXAR Above drop point with HDF Release Housing WEG	3.670	2.441	2-7/8" EUE Box 335 Acme Box	2.00			Schlumberger
2-7/8" SXAR Below Drop point Explosive Automatic Release	3.670	n/a	335 Acme Pin API Acme Pin	1.00			Schlumberger
2 7/8" - PURE Chamber	4.500	n/a	API Acme Box API Acme Pin	60			Schlumberger
2 7/8" Guns	4.500	n/a	API Acme Box API Acme Pin	150			Schlumberger
2 7/8" - PURE Chamber	4.500	n/a	API Acme Box API Acme Pin	60			Schlumberger
Bullnose	4.500	n/a	API Acme Box N/A	0.75			Schlumberger

Figure 44- Auto-drop guns on end of completion

Setting Guns on auto-release gun hanger

MAXR (automatic release gun anchor) set with drillpipe (Figure 45). Setting tool activated via HDF (Hydraulic Delay Firing Head). Intervention free firing system eFire 1000hr (pulses sent to firing head that has 1000hr battery). Allows for completion to be installed several hundred feet above anchored guns if required and on release allows full monobore. Can be run either under-balanced or over-balanced . In order to maximize perforation tunnel clean-up in over-balanced situation, may need additional free gun volume (surge chambers) to increase dynamic underbalance.

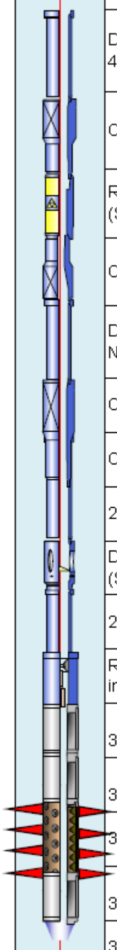


5 1/2" DSTJ-FH Drill Pipe	7.000	3.500	5 1/2" DSTJ-FH	5 1/2" DSTJ-FH	10340.00			
Crossover: TRD 12477 5-1/2" DSTJ-FH to 3-1/2" IF	7.050	2.281	5 1/2" DSTJ-FH	3 1/2"IF	2.00			SLB
R.A. Marker Sub (Top toTag)	5.000	2.250	3 1/2" IF	***	0.98			SLB
R.A. Marker Sub (Tag to Bottom)	5.000	2.250	***	3 1/2"IF	0.69			SLB
Crossover: TRD 38109 3-1/2" IF to 5-1/2" DSTJ-FH	7.100	2.250	3 1/2"IF	5 1/2" DSTJ-FH	2.00			SLB
5 1/2" DSTJ-FH Drill Pipe (1 std)	7.000	3.500	5 1/2" DSTJ-FH	5 1/2" DSTJ-FH	90.00			
Crossover: TRD 16487 5 1/2" DSTJ-FH to 2-7/8" HT-PAC	7.050	1.500	5 1/2" DSTJ-FH	2 7/8" HT-PAC	2.00			
Top of 7" Liner	*7.000*	*6.094*						
7" x 5-1/2" Liner X-over	*5.500*	*4.670*						
2-7/8" HT-PAC Drill Pipe	2.880	2.441	2 7/8" HT-PAC	2 7/8" HT-PAC	600.00			
Crossover: UCL 1641 2-7/8" HT-PAC to 2-7/8" EUE	3.125	2.438	2 7/8" HT-PAC	2-7/8" EUE	2.00			
2-7/8" EUE PupJoints	3.610	2.441	2-7/8" EUE	2-7/8" EUE	6.00			SLB
Ported Debris Sub	3.610	2.441	2-7/8" EUE	2-7/8" EUE	1.76			SLB
HDF/EOF Fill Sub c/w EOF HDF-D	3.610	***	2-7/8" EUE	SLB MOD	6.88			SLB
CPST Setting Tool	3.680	***	SLB MOD	***	6.43			SLB
MAXR Setting Sleeve	4.250	***	***	***	1.50			SLB
5.5" MAXR (Top to Slips)	4.250	***	***	***	7.54			SLB
5.5" MAXR (Bottom to Slips)	4.250	***	***	3.00 S.A.	2.22			SLB
eFire Fill Sub c/w 1000 hr. eFire F/Head	3.680	***	3.00 6 S.A.	3.00 6 S.A.	14.77			SLB
eFire Fill Sub c/w 1000 hr. eFire F/Head	3.610	***	3.00 6 S.A.	3.00 6 S.A.	14.77			SLB
3.31" Safety Spacer	3.310	***	3.00 6 S.A.	2.25'' S.A.	10.00			SLB
3.31" 2906 PJN PURE + Bull nose	3.310	***	2.25'' S.A.	2.25'' S.A.	0.00			SLB

Figure 45 - MAXR automatic gun hanger set with drillpipe

Shoot and Pull

Shoot and Pull scenario with hydraulic actuation firing heads (Figure 46). Requires run in and to pull out of hole on drill pipe or tubing. Run packer-less therefore require to be perforated overbalance with a Perf Pill to prevent losses. Option to use Drill Stem Test Tools to perforate the well under-balanced but well will be require to be killed prior to pulling out of hole with test string and guns. Shoot and Pull within the context of the Standard Well Design is a stop-gap technology until Full Flow Gun System (FFGS) technology can be utilized.



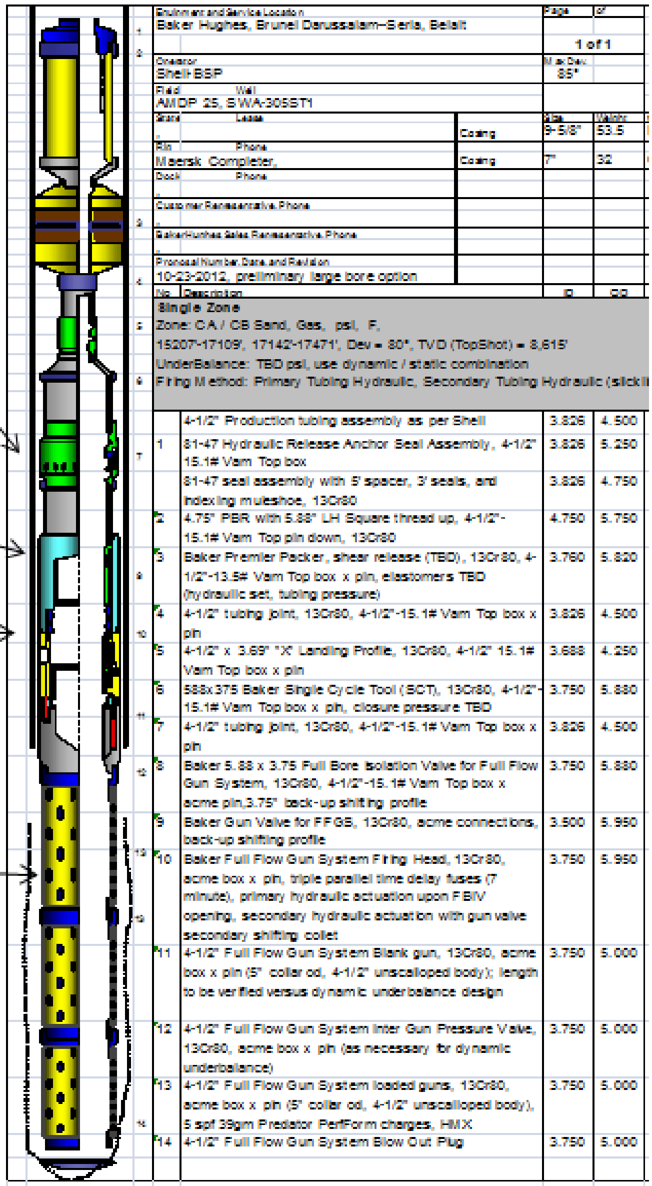
Tool	Description			Connection	Length	Depth (MD)		Supplier
		in	in		feet	Top	Bottom	
	Drill Pipe (XXXjoints) 4" NC40 EIS VAM Box	5.000	2.563	4" NC40 EIS VAM Box 4" NC40 EIS VAM Pin	15060.00	164.49	15224.49	
	Crossover	5.000	2.563	4" NC40 EIS VAM Box 3.5" IF Pin	3.75	15224.49	15228.24	
	RA sub (SN11061)	3.500	2.440	3.5" IF Box 3.5" IF PIN	1.71	**15228.24**	**15229.95**	Schlumberger
	Crossover	5.000	2.563	3.5" IF Box 4" NC40 EIS VAM Pin	4.15	15229.95	15234.10	
	Drill Pipe 4" NC40 EIS VAM Box	5.000	2.563	4" NC40 EIS VAM Box 4" NC40 EIS VAM Pin	1221.96	15234.10	16456.06	
	Crossover (TRD25987)	5.000	2.310	4" NC40 EISVAM Box 3.5" IF Pin	2.58	16456.06	16458.64	Schlumberger
	Crossover (UCL2288)	3.090	2.440	3.5" IF Box 2.88" EUE Pin	1.83	16458.64	16460.47	Schlumberger
	2 7/8" EUE Tubing	3.680	2.440	2.88"EUE Box 2.88" EUE Pin	30.35	16460.47	16490.82	Schlumberger
	Debris Sub (SN00017)	3.680	2.440	2.88"EUE Box 2.88" EUE Pin	1.76	16490.82	16492.58	Schlumberger
	2 7/8" EUE Tubing	3.680	2.440	2.88"EUE Box 2.88" EUE Pin	30.35	16492.58	16522.93	Schlumberger
	Redundant Firing Head HDF/TCF Run in Place Side x Side	3.680	N A	2.88" EUE Box 335 adaptation Box	14.99	16522.93	16537.92	Schlumberger
	3 3/8" - Safety Spacer	3.375	N A	335 adaptation Pin	10.76	16537.92	16548.68	Schlumberger
	3.38" - PURE Chamber	3.375	N A		61.32	16548.68	16610.00	Schlumberger
	3 3/8" HMX PURE gun	3.375	N A		550.00	**16610.00**	**17160.00**	Schlumberger
	3 3/8" PURE Chamber	3.375	N A		9.84	17160.00	17169.84	Schlumberger
	3 3/8" Bullnose	3.375	N A		0.93	17169.84	17170.77	Schlumberger

Figure 46 - Shoot and Pull scenario with hydraulic actuation firing heads

Full Flow Gun System (FFGS)

Perforating technology that can be utilised instead of shoot and pull (Figure 47). FFGS is run as a permanent part of the completion and is a technique which has the potential to save a considerable amount of rig time, by eliminating tripping operations. The system consists of gun valve, firing head, perforating guns and blow out plug. The FBIV will be cycled open to expose the firing head and pressure applied to fire the guns. Following successful firing of the guns, charges and internal components are reduced to fine acid soluble powder, which is expelled from gun. Full-bore access to formation immediately after firing allowing intervention tools to be set in ID. Option to run swellable packers with system to isolate sections. No rat hole required. Well can be brought on immediately after perforating.

- Full Bore Isolation Valve (FBIV)
- Gun Valve
- FFGS firing Head
- FFGS guns and charges



No.	Description	ID	OD
	4-1/2" Production tubing assembly as per Shell	3.826	4.500
1	81-47 Hydraulic Release Anchor Seal Assembly, 4-1/2" 15.1# Vam Top box	3.826	5.250
	81-47 seal assembly with 5' spacer, 3' seals, and indexing muleshoe, 13Cr80	3.826	4.750
2	4.75" PBR with 5.88" LH Square thread up, 4-1/2"-15.1# Vam Top pin down, 13Cr80	4.750	5.750
3	Baker Premier Packer, shear release (TBD), 13Cr80, 4-1/2"-13.5# Vam Top box x pin, elastomers TBD (hydraulic set, tubing pressure)	3.760	5.820
4	4-1/2" tubing joint, 13Cr80, 4-1/2"-15.1# Vam Top box x pin	3.826	4.500
5	4-1/2" x 3.69" "X" Landing Profile, 13Cr80, 4-1/2" 15.1# Vam Top box x pin	3.688	4.250
6	588x375 Baker Single Cycle Tool (SCT), 13Cr80, 4-1/2"-15.1# Vam Top box x pin, closure pressure TBD	3.750	5.880
7	4-1/2" tubing joint, 13Cr80, 4-1/2"-15.1# Vam Top box x pin	3.826	4.500
8	Baker 5.88 x 3.75 Full Bore Isolation Valve for Full Flow Gun System, 13Cr80, 4-1/2"-15.1# Vam Top box x acme pin,3.75" back-up shifting profile	3.750	5.880
9	Baker Gun Valve for FFGS, 13Cr80, acme connections, back-up shifting profile	3.500	5.950
10	Baker Full Flow Gun System Firing Head, 13Cr80, acme box x pin, triple parallel time delay fuses (7 minute), primary hydraulic actuation upon FBIV opening, secondary hydraulic actuation with gun valve secondary shifting collet	3.750	5.950
11	4-1/2" Full Flow Gun System Blank gun, 13Cr80, acme box x pin (5" collar od, 4-1/2" unscalloped body); length to be verified versus dynamic underbalance design	3.750	5.000
12	4-1/2" Full Flow Gun System Inter Gun Pressure Valve, 13Cr80, acme box x pin (as necessary for dynamic underbalance)	3.750	5.000
13	4-1/2" Full Flow Gun System loaded guns, 13Cr80, acme box x pin (5" collar od, 4-1/2" unscalloped body), 5 spf 39gm Predator PerfForm charges, HMX	3.750	5.000
14	4-1/2" Full Flow Gun System Blow Out Plug	3.750	5.000

Figure 47 - Full Flow Gun System (FFGS)

11. UNDERBALANCED COMPLETIONS

Benefits

Underbalanced completion operations offer a number of operational and lifecycle cost benefits. These include completion brine savings, operational savings through simplification and improved reservoir performance due to lower skin from damaging brines in the cased hole scenario. However underbalanced completions require TA1 approval on a case by case basis.

Establishing barriers

Cased Hole Underbalanced Completion

In the cased and perforated completion scenario, the sequence of operations for installing the completion underbalanced is as follows:

- Run and cement the production liner and set the ZX Packer
- Pressure test the liner in mud
- With the clean up assembly in the well, inflow test the liner using a Well Commissioner or similar packer - the drill pipe is displaced from mud to base oil to achieve the required under-balance to inflow test the well

Failure to confirm well barriers during either the pressure test or inflow test will result in an investigation into the leak path and the setting of a bridge plug in the liner or a tie-back packer. Once the liner lap has been successfully inflow tested and the barriers confirmed, the wellbore clean up can take place displacing the mud to seawater with the aid of surfactant and hi-viscosity pills (ref '*Wellbore Cleanup*' section). The well is then displaced to seawater or base oil under controlled conditions and a final inflow test performed. The well is then pressure tested to the maximum shut-in pressure + 10% to confirm the barriers before POOH with the clean-up assembly to run the completion. As an additional check on the integrity of the well, consider circulating bottoms up prior to POOH to check for gas. TCP guns can then be run with the completion to allow for underbalanced perforating and flow to host. Note: a fluid isolation device (FID) is not run for cased and perforated completions.

Open Hole Underbalanced Completion (Requires TA1 Approval)

In the open-hole scenario, after the lower completion screens have been run in PST spec OBM and the fluid loss device closed, the Well Commissioner or similar packer is used to inflow test the FID in a similar manner to the liner lap in the cased hole scenario. If during the inflow test a leak is detected, it would first need to be established whether the screen hanger packer or the FID was leaking. The backside test conducted after setting the screen hanger packer should give confidence as to whether the packer is holding or not. If it is established that the FID is leaking, a tie-back screen packer with an FID would need to be run. After testing the tie-back packer and FID, the wellbore cleanup can then be performed as above (ref '*Wellbore Cleanup*' section) and the well displaced to base oil to aid flow to host. At this point, primary well control is provided by the inflow-tested FID, the fluid column is no longer a barrier. Secondary well control is provided by the BOPs and all fluids must be circulated on a closed system. Note: for gas wells capable of natural flow, a small gas leak past the FID may go undetected in base oil. For sub-hydrostatic gas wells where an inflow test of the FID is not possible, a pressure test from above (in base oil) would be the only way of proving the primary barrier. Also, if the FID is compromised/opened, the well will flow. The well should remain lined up to the trip tank and fluid levels monitored throughout completion running. It is possible to mechanically shift the FID to a partially open position once it has been closed if the collets are engaged in some manner. Following the inflow test of the FID, the upper completion is run (ref '*Upper Completion'* section).

At present, underbalanced completions in the open hole scenario require **TA1 approval**. Clarification on well control standards from the new Well Control Manual is required before underbalanced completions are technically endorsed.