MAJOR PROJECT REPORT
on
COMPLETION DESIGNING OF AN INJECTOR WELL

UNDER THE MENTORSHIP OF

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SUBMITTED BY

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CERTIFICATE

This is to certify that this project report titled **"Completion Designing of an Injector Well"** submitted to **University of Petroleum and Energy Studies, Dehradun** is a bonafide record of work done by **Mr. Parth and Ms. Nayanshree** under my supervision from **"September 2014"** to **"April 2015"**.

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ABSTRACT

Completion, in petroleum production, is the process of making a well ready for production (or injection). This principally involves preparing the bottom of the hole to the required specifications, running in the production tubing and its associated down hole tools as well as perforating and stimulating as required. Completion is also done foreseeing any future requirements such as workovers, stimulation or artificial lift installation.

This project focuses on analyzing a previously completed well (Well XYZ) and its problem as to recomplete the same with tolerance to future hydro fracturing, if needed.

The initial step for the workflow will be gathering of requisite data and its subsequent analysis. The reason for existing problems and completion design reviewing will be done as the part of streamlining the project towards completion modification.

The last add on to completion designing will focus on adding tolerance for any stimulation jobs if needed in future which being a function of time and reservoir characteristics.

Executive summary

Field XYZ is one of the largest fields in India. With ever demanding thirst for efficient, economical and optimized completion practice, the well **XYZ** was handpicked and considered for recompletion.

This project is meaningfully streamlined , once the workflow is established. The governing set of rules for this project is dictated by the need to place the right amount of water, at the right place with the maximum possible flow rate and minimum injection pressure.
Owing to a set of factors, a more robust and accessible type (tubing less) of completion has been proposed.

The first step forward hereafter, involves establishing the water quality. The assumption takes into account the readiness of client to supply the desired water quality. With HSE running high in blood, barrier check at surface is included in the design to combat any future possibility of uncontrolled flow. The problems of injectivity decline and sand influx is deduced from the available set of data pushing us to propose the relevant mitigation plan.

The project wraps up with certain set of recommendations and future scope which can revolutionize the industry in terms of increasing the sweep efficiency and injectivity together with optimizing perforation.

INTRODUCTION

The major proportion of production technology activities have been concerned with the engineering and installation of the down hole completion equipment. The completion string is a critical component of the production system and to be effective it must be efficiently designed, installed and maintained. Increasingly, with moves to higher reservoir pressures and more hostile development areas, the actual capital costs of the completion string has become a significant proportion of the total well cost and thus worthy of greater technical consideration and optimisation. The completion process can be split into several key areas which require to be defined including:-

(1) The fluids which will be used to fill the wellbore during the completion process must be identified, and this requires that the function of the fluid and the required properties be specified.

(2) The completion must consider and specify how the fluids will enter the wellbore from the formation i.e., whether in fact the well will be open or whether a casing string will be run which will need to be subsequently perforated to allow a limited number of entry points for fluid to flow from the reservoir into the wellbore.

(3) The design of the completion string itself must provide the required containment capability to allow fluids to flow safely to the surface with minimal loss in pressure. In addition however, it would be crucial that the string be able to perform several other functions which may be related to safety, control, monitoring, etc. In many cases the completion must provide the capacity for reservoir management. The completion string must consider what contingencies are available in the event of changing fluid production characteristics and how minor servicing operations could be conducted for example, replacement of valves etc.

Injector wells are of two types :

1.Infill drilling

2. Producer turned injectors

The most important changes when a producer is converted into an injector are :

-Direction of prevalent flow

-Types of flowing fluid

-Type of corrosion

-Access to the formation

-Pressure distribution on the tubular

-Forced load on tubular and packers

-Temperature distribution in wellbore

-Affect on seals

[1]

[1] (Dennis)

Overview of Proposed Well's Completion

On detailed analysis / literature review, economics and flow rate calculations(APPENDIX A), It is proposed that all the injector's completion should have a monobore completion with 4-1/2" production casing utilised for water injection. Risks involved in such well construction/completion are elaborated below:

Uncontrolled Flow : The monobore injectors will not have SCSSV. There is some risk of adverse weather or some natural calamity or war attack which may lead to uncontrolled flow from the well. There is a plan to install one surface shut down valves as part of Xmas tree which will be actuated to close with the HI-LO pilot to be installed downstream of the choke.

Corrosion : There is a risk of internal corrosion to production casing and X-Mas tree because of corrosive nature of injection water, which will be mixture of produced water and Aquifer water, even after treatment due to high velocity of injection water. There is also risk of corrosion of the casing wetted with reservoir fluid due to high CO_2 and low pH produced water. To lower the risk from corrosion it is desired that injection water quality shall be maintained as specified and proper corrosion inhibitor shall be injected. To reduce the corrosion risk further, production casing shall be 1% Cr L80(Appendix A) material to have a long safe life for the well. (The well configuration as of now is of 7" production casing and 4-1/2" completion tubing of carbon steel with GRE lining. However, due to very high well cost & cost of GRE lined tubing and possibility of good quality control on injection water plus added corrosion inhibitor for protection of surface piping, it is being revised to 1% Cr 4- 1/2" casing without any tubing.

Sand Production: There is risk of sand influx in injection wells. Completion and perforation strategy are designed to keep the risk of sand production low. A long rat hole shall be drilled to mitigate the risk of water hammer. The planned well shut down should be slow over a long period of time and efforts should be made to minimise the number of emergency shut downs. There may still be cases of sand production from the wells, resulting in loss of injectivity. (Refer Injectivity loss mitigation-Future scope along with new perforation strategy Appendix A)

Well head Growth: Well cat data and analysis unavailable

Scale formation in casing and on sand face: There is a risk of $BaSO_4$ scale deposition at formation face especially when produced water is mixed with aquifer water for injection. Scale inhibition will be carried out for injection water to prevent the scale deposition. Water quality requirement moulded as per necessity.

Souring of the Reservoir: There is a risk of reservoir souring due to introduction of Sulphate Reducing Bacteria (SRB). Biocide treatment water injection system is planned to prevent the potential souring of the reservoir as well .

WELL DATA PERTAINING WATER INJECTION AND WELL COMPLETION

Field Name Well Name	FIELD XYZ WELL XYZ
Production Type Development	Injection
Number of Deviated Injection Wells	Phase 1 :39 + 4 EOR Demo FM1- 19+ 4 EOR demo (Phase1A : 1) FM2- 10 (Phase 1A : 1) FM3: 4 (Phase 1A : 1) FM4: 3 FM5-3 Phase 2: 14 (Firm Infill) FM1- 6 FM2-8
Formation Name	FM1, FM2 ,FM3, FM4 and FM5
MDBRT Maximum Inclination TVD	1450 M 45 degree 1340 m
Wax Appearing Temperature (in tubing) Wax Dissolution Temperature	63 degree C 79 degree C
TD hole size	6-1/4”
Injectivity Index	~ 10-30 bwpd/day/psi
Maximum expected pore pressure	8.82 ppg
Expected fracture pressure	14.73 -16.68 ppg
Pore pressure gradient (oil leg)	0.356psi/ft

OBJECTIVE

1. To deliver a well bore completion that has long term reliable water injection and does not cause significant loss of injectivity.

2. To provide low frictional losses in production casing for intended injection rates 6000-10,000 bfpd for WELL XYZ in FM3 formation.

3. Design life of 15 years.

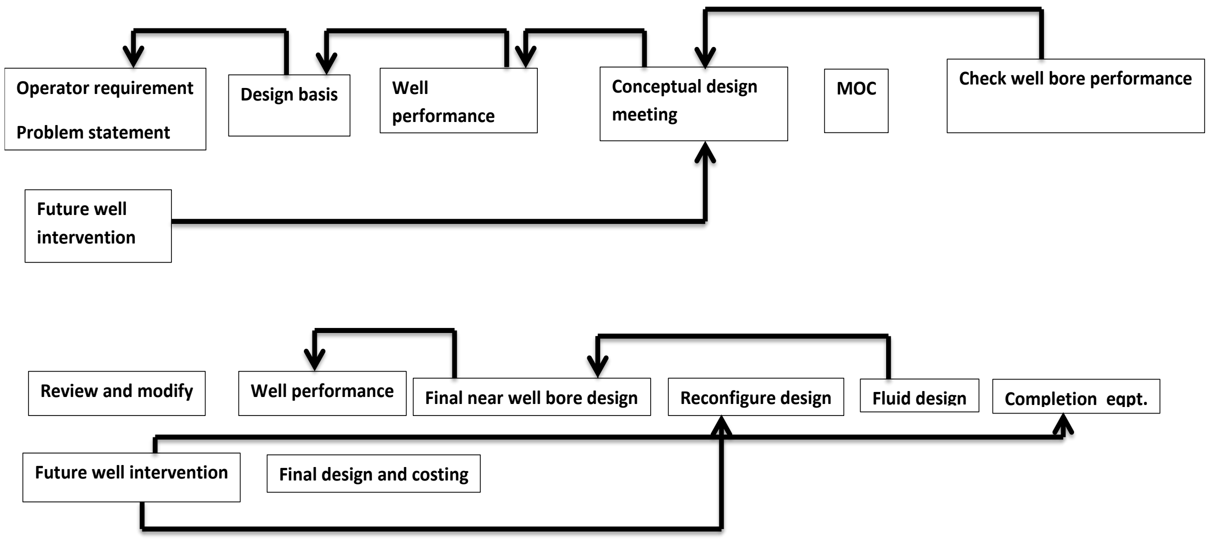
4. To minimise the risk of sand influx by perforation optimisation, avoidance of formation damage.

5.To enable individual layers within the FM sands to be targeted for injection and so improve injection conformance

6. Ability to control the injection profiles in the field.

WORKFLOW

The flow of designing follows a very systematic approach. Since the client provide all the requirements pertaining to injection water quality, the job at hand becomes smoother with lesser number of variables to encounter. The perforation policies are preset as per client.



TIME WEIGHTED AVERAGE PRODUCED WATER PROPERTIES:
(Refer appendix A.1)

pH	7.29
TSS ppm	0.34
TDS ppm	5345
Iron ppm	0.26
D.O ppb	<10
Total Hardness CaCo3ppm	107
Bicarbonate ppm	24.9
Suulphate as So4 ppm	48.8
Chlorides ppm	250
Temperature Degree C	45

General everyday values:

TDS for Well xyz formation water was measured at 9000 mg/l with little sulphate (6.9 mg/l), little strontium (2.8 mg/l) and considerable barium (30 mg/l). High concentrations of CO_2 and HCO_3^- are present.

The aquifer water contains approximately 9300 mg/l total dissolved solids (TDS) with considerable quantities of sulphate (1051 mg/l), little strontium (11 mg/l) and no barium.

DESIRED INJECTION WATER QUALITY

The injected water quality should be maintained as per specifications prepared. Main requirements for injection water treatments shall be:

Parameter	Specification
Solids	Removal of 100% solids greater than 10 microns concentration (max)
Total suspended solids	< 10 mg/litre
Normal Oil Content (Max)	30-40 ppm
Oxygen content	< 10 ppb
Bacteria	Nil
Residual Oxygen Scavenger	1-3 ppm in normal injection

Note:
1. Corrosion inhibitor shall be selected after testing its effect on wettability characteristics of the formation.
2. Screening and selection of suitable scale inhibitor chemicals will be undertaken to prevent plugging of the injection wells with suspended scale. The chemicals should prevent scale nucleation, and not just prevent adherence of the scale
* 3. Injection water has to be heated to 85 degree C before injection for initial injection. Temperature requirement for later injection life shall be decided based on further analysis. (Client requirement)

WELL SERVICE DEGISN REQUIREMENTS

Zonal Isolation	Zonal Isolation would be carried out by cementing the casing across FM1, FM2, FM3,FM4 and FM5
Future Well Service Change	May be flowed back for well cleaning
Maximum Surface Pressures	Maximum anticipated injection pressure is 1750 psi though higher pressure is not ruled out
Targeted injection pressure	during normal matrix injection will be less than 1000 psi
Surface Equipment Pressure Ratings	5000 psi. If the 3000 psi rated wellhead/X-Mas tree saves considerable cost as compared to a 5000 psi rated wellhead/X- Mas tree, 3000 psi rated wellhead/X-Mas tree should be utilized.
Maximum Downhole Pressures (inside completion)	3300 psi. (Injection surface pressure (2000 psi) + Hydrostatic of water at 900 m (1280 psi).Higher pressure may be expected during stimulation and emergency shut downs due to water hammer effect
Well Intervention/Work Over	Following well interventions and work-over are anticipated for the wells: Sand clean-out CT work. If there is a sand build up in the well bore, it will cleaned out using coil tubing Acid Wash with CT: Acid wash with CT may be considered, though not anticipated presently, in wells for injectivity improvement. Formation Fines squeeze: If, depending on the studies, a chemical squeeze in formation is found suitable for controlling the formation fines movement, suitable chemical will be injected into the formation utilizing Coil Tubing. Zone isolation: Bridge plug would be used when bottom zone needs to be isolated. In case upper zone has to be isolated, straddle packer system or cement squeeze technique should be utilized

DRILLING ENGINEERING (FOR INFILL WELLS)

Hole Sizes	8-1/2” and 6-1/4”
Casing Sizes	9-5/8” – 40 ppf, K-55 – 10 m BGL, 7”, K-55, 29/26 ppf, BTC – 450 m , 4-1/2” , ,1% Cr(exact ppf of casing values can't be determined since corrosion data not available), Premium Connection- (upto 1450)
Cementing all strings	For 13-3/8” and 7” casings- Cementation to surface. For 4-1/2” casing- Cementation to 150 meter inside the 7” casing or cementation to surface, whichever is possible, based on formation strength
Casing Material	9-5/8”- Carbon steel, K-55, 40 ppf., BTC , R-3. 7”, 29/26 ppf- 1% Cr. K-55, BTC , R-3 4-1/2”, 1% Cr. L-80, Premium connection, R-3 4-1/2” Injection Casing will have premium connections to minimize leaks during the life of the well. 7” and 4-1/2” casing with extra wall thickness are being used to provide for additional corrosion allowance. (Refer Appendix A.2)

*Trajectory rules: The Deviated injector wells have a maximum of 60 degree deviation with maximum build rate of 3 degrees/100 ft.

**Horizontal injector wells will also be drilled. In these zones, a build rate of 3°/30 meters is sufficient to achieve the horizontal profile, which is again consistent with artificial lift requirements

WELL DESIGN

Casing Material selection
Generally, the casing material selection is based upon following parameters:
Partial pressure of C02 : ~nil
Partial pressure of H2S : ~nil
Chlorides concentrations : 1500-5000mg/l
Corrosion : Existing Possibilities
Selected casing material : L80 1cr (Refer Appendix A.2 for selection)
*ppf of casing couldn't be determined owing to unavailable corrosion rate data.
**Tolerance to Corrosion from future acid soak.

Flow control and safety barriers: 9-Cr material.

Injector Casing Size: 4 1/2 casing (refer friction stats and performance - Appendix A.4)

Surface Piping class: class 900 OD Nominal pipe size 4 O.D 4.5(Appendix A.6)

Water injection wells are expected to have high injectivity indices, and it will be possible to inject large volumes of water through 4½" casing. Heated water will be injected in order to prevent cooling and consequent wax formation in the pore spaces. In Well XYZ the injection volumes required are estimated at approximately 15,000 bwpd maximum per well. Surface injection pressures are expected to be a maximum of 1250 psi for a Field crestal injector, and could be as high as 1750 psi for a deeper injector. However, typically they should be much lower.

Accordingly, a minimum Class 900 surface piping system will be required for water injection to accommodate these expected injection pressures and especially also for anticipated future EOR implementation using a polymer flood, where formation injectivity will reduce.

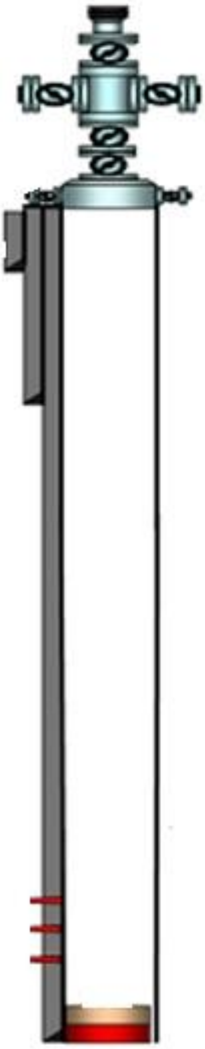
COMPLETION DESIGN REQUIREMENT

Completion Strategy	The wells are planned to be monobore/tubingless completed for the water injection, with about 300 psi underbalance (carrying forward offset well underbalance value)
Perforation Strategy(As per client)	The wells will be completed as monobore perforated completions. Some of the wells shall be perforated with underbalance of about 300 psi while some of the wells will be perforated overbalance and the benefits of underbalance perforation shall be evaluated. If there is marked improvement in injectivity with underbalance perforations, remaining wells will be perforated with underbalance. Overbalanced perforation shall be carried out with wireline casing guns and multiple runs. For this, casing shall be displaced with brine as required for overbalance for safe wireline operations. Dynamic underbalance and StimGun perforation techniques will also be evaluated and may be applied in some wells. Perforation shall be phased and in selective zones. Only high strength zones will be perforated based on the strength calculated with logging techniques. The perforating design for each individual well and layer, considering gun size, charge type, phasing, density and interval length, will be optimized based on advanced technology, further to ensure that the cased and perforated completions deliver sand- free water injection. Perforation zones will have gaps of about 5 m minimum between them to permit future discrete perforation set isolation.
Material Selection	Injection Casing: 4-1/2" ,1 % Cr, L 80 steel (ppf cannot be determined - unavailable corrosion rate data). Wellhead: Unitized/compact, 2 step, class AA or DD , Temp class U. X-Mas Tree: Class AA or DD, Temperature rating U, PSL-2, Material to be low alloy 1% Cr. Elastomer: Nitrile (Will be compatible with the crude, CO_2 service, and injected chemicals)

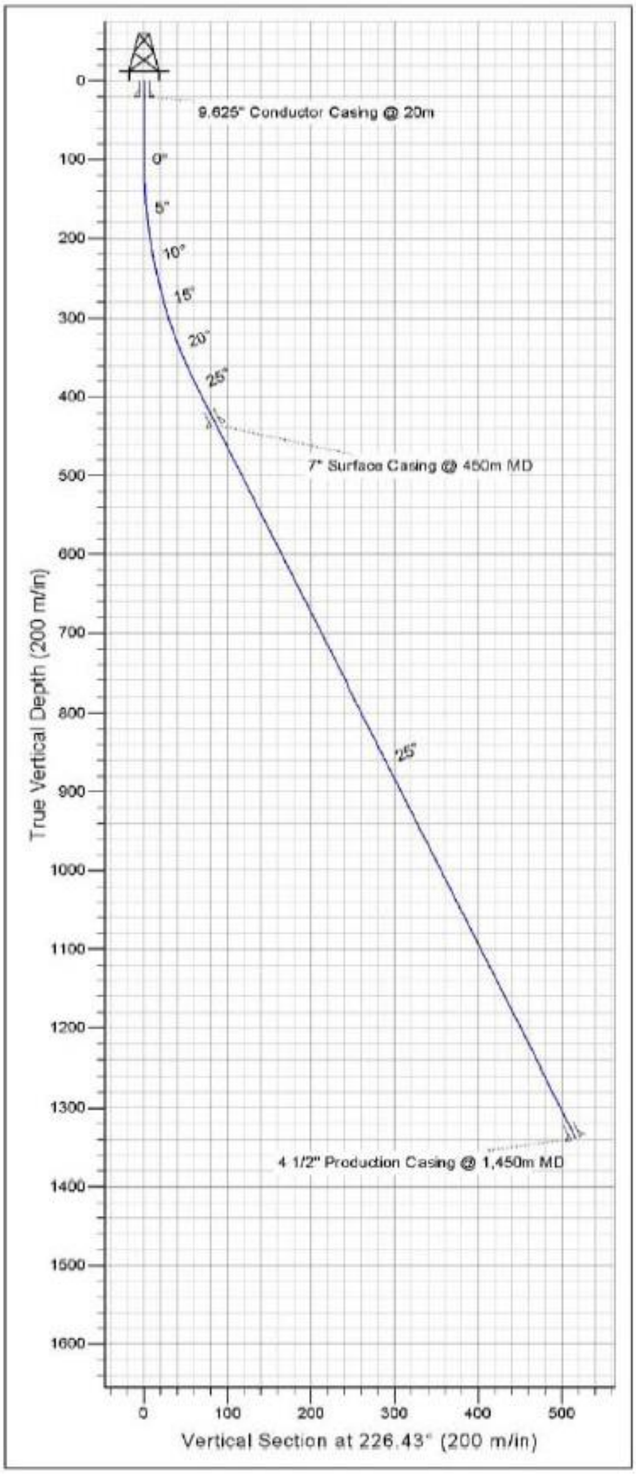
WELLHEAD SELECTION

Maximum working pressure:	A 3000 psi or better rated compact well head and a 3000 psi or better rated stacked X-Mas tree will be used. (If a 3000 psi rated wellhead/X-Mas tree is available at a much lower cost than a 5000 psi rated wellhead/X-Mas tree, it will be chosen)
Material/Cladding	X-Mas tree and the compact well head equipment will be of Class AA , or DD with low alloy, PSL-2 with temperature rating of U. X-Mas tree cladding with suitable CRA will also be considered.
Access	X Mas tree would have a minimum bore of 4"
Well Head Control Systems	X-Mas tree would be stacked tree with one master valve, one swab valve , and one flow wing valve with hydraulic actuator. One manually operated adjustable choke housing would be installed on the flow arm
Flow Back	Since the completion is tubing less, artificial lift for backflow of injectors, if required, shall be by using a coil tubing and nitrogen lift
Chemical Treatment:	Completion is tubing less and no downhole chemical injection is planned for water injector wells (As per available data)
Sampling	One sample collection point would be provided in inlet wing.

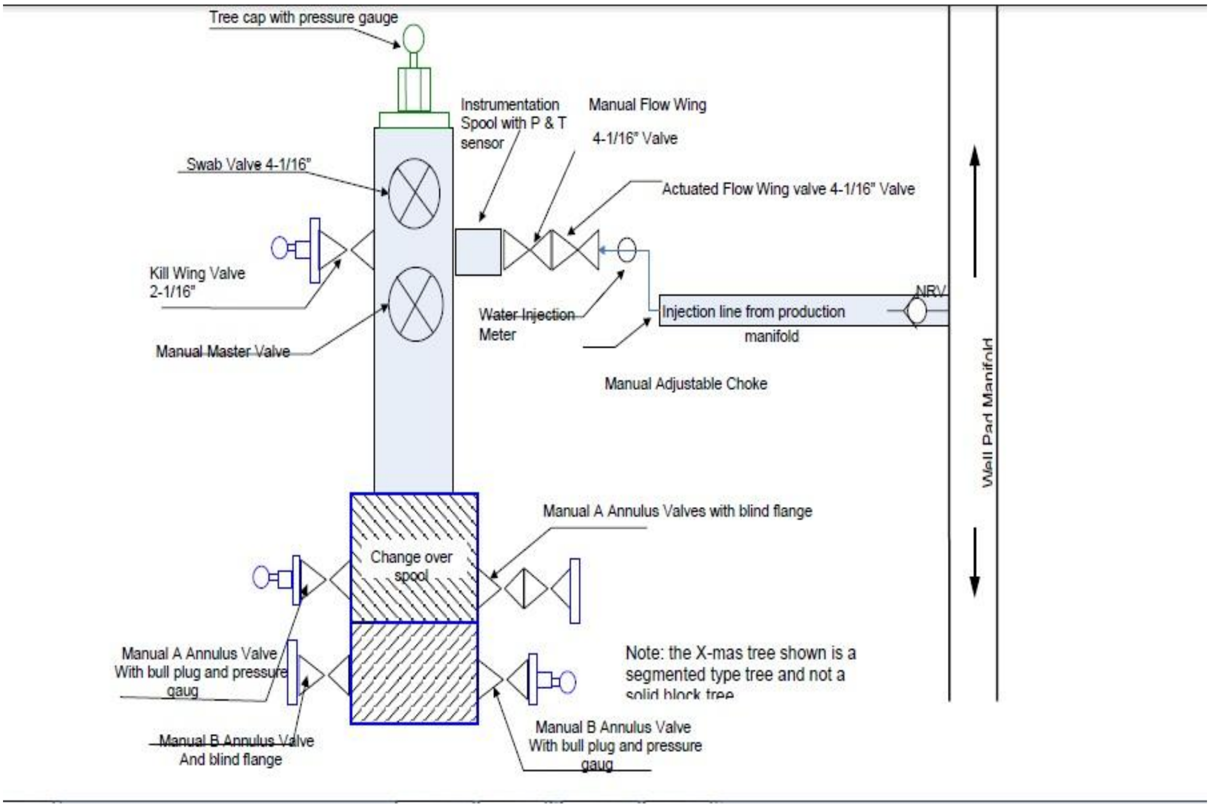
WELL SCHEMATIC

PROPOSED COMPLETION		
	COMPLETION DIAGRAM	MD m
4 1/16" 5K or 3K Wellhead X-Mas		
9- 5/8" casing		18m
7" casing BTC		450m
4-1/2" Casing Premium connection 1cr L-80		1450m

WELL PROFILE



X MAS TREE SCHEMATIC



TALLY

Well xyz					
Elevation Data			Optimum Torque Values N-m		
ORT - GL		Data NA	Casings R3 class	9.625 K55 BTC	9630
RT - GL				7 K55 BTC	7000
GL - WH Top				4.5 1%cr Premium L-80	2710
WH Top - Casing Hgr hang off pt			Make up loss	Data Not available	
ORT - Casing Hgr hang off pt					
RT - Casing hgr hang off pt					
GL-Casing Hanger hang off point 0.8m (assumption)					
Item no	**Description**	**Length (m)**	**Cum length (m)**	**Assy Top Depth (m MDORT)**	
STRING BOTTOM				1450.00	
1	4 1/2 1% cr L-80	10.000	10.00	1440.00	
2	4 1/2 1% cr L-80	10.000	20.00	1430.00	
3	4 1/2 1% cr L-80	10.000	30.00	1420.00	
4	4 1/2 1% cr L-80	10.000	40.00	1410.00	
5	4 1/2 1% cr L-80	10.000	50.00	1400.00	
6	4 1/2 1% cr L-80	10.000	60.00	1390.00	
7	4 1/2 1% cr L-80	10.000	70.00	1380.00	
8	4 1/2 1% cr L-80	10.000	80.00	1370.00	
9	4 1/2 1% cr L-80	10.000	90.00	1360.00	
10	4 1/2 1% cr L-80	10.000	100.00	1350.00	
11	4 1/2 1% cr L-80	10.000	110.00	1340.00	
12	4 1/2 1% cr L-80	10.000	120.00	1330.00	
13	4 1/2 1% cr L-80	10.000	130.00	1320.00	
14	4 1/2 1% cr L-80	10.000	140.00	1310.00	
15	4 1/2 1% cr L-80	10.000	150.00	1300.00	
16	4 1/2 1% cr L-80	10.000	160.00	1290.00	
17	4 1/2 1% cr L-80	10.000	170.00	1280.00	
18	4 1/2 1% cr L-80	10.000	180.00	1270.00	
19	4 1/2 1% cr L-80	10.000	190.00	1260.00	
20	4 1/2 1% cr L-80	10.000	200.00	1250.00	

21	4 1/2 1% cr L-80	10.000	210.00	1240.00	
22	4 1/2 1% cr L-80	10.000	220.00	1230.00	
23	4 1/2 1% cr L-80	10.000	230.00	1220.00	
24	4 1/2 1% cr L-80	10.000	240.00	1210.00	
25	4 1/2 1% cr L-80	10.000	250.00	1200.00	
26	4 1/2 1% cr L-80	10.000	260.00	1190.00	
27	4 1/2 1% cr L-80	10.000	270.00	1180.00	
28	4 1/2 1% cr L-80	10.000	280.00	1170.00	
29	4 1/2 1% cr L-80	10.000	290.00	1160.00	
30	4 1/2 1% cr L-80	10.000	300.00	1150.00	
31	4 1/2 1% cr L-80	10.000	310.00	1140.00	
32	4 1/2 1% cr L-80	10.000	320.00	1130.00	
33	4 1/2 1% cr L-80	10.000	330.00	1120.00	
34	4 1/2 1% cr L-80	10.000	340.00	1110.00	
35	4 1/2 1% cr L-80	10.000	350.00	1100.00	
36	4 1/2 1% cr L-80	10.000	360.00	1090.00	
37	4 1/2 1% cr L-80	10.000	370.00	1080.00	
38	4 1/2 1% cr L-80	10.000	380.00	1070.00	
39	4 1/2 1% cr L-80	10.000	390.00	1060.00	
40	4 1/2 1% cr L-80	10.000	400.00	1050.00	
41	4 1/2 1% cr L-80	10.000	410.00	1040.00	
42	4 1/2 1% cr L-80	10.000	420.00	1030.00	
43	4 1/2 1% cr L-80	10.000	430.00	1020.00	
44	4 1/2 1% cr L-80	10.000	440.00	1010.00	
45	4 1/2 1% cr L-80	10.000	450.00	1000.00	
46	4 1/2 1% cr L-80	10.000	460.00	990.00	
47	4 1/2 1% cr L-80	10.000	470.00	980.00	
48	4 1/2 1% cr L-80	10.000	480.00	970.00	
49	4 1/2 1% cr L-80	10.000	490.00	960.00	
50	4 1/2 1% cr L-80	10.000	500.00	950.00	
51	4 1/2 1% cr L-80	10.000	510.00	940.00	
52	4 1/2 1% cr L-80	10.000	520.00	930.00	
53	4 1/2 1% cr L-80	10.000	530.00	920.00	
54	4 1/2 1% cr L-80	10.000	540.00	910.00	
55	4 1/2 1% cr L-80	10.000	550.00	900.00	
56	4 1/2 1% cr L-80	10.000	560.00	890.00	
57	4 1/2 1% cr L-80	10.000	570.00	880.00	
58	4 1/2 1% cr L-80	10.000	580.00	870.00	
59	4 1/2 1% cr L-80	10.000	590.00	860.00	
60	4 1/2 1% cr L-80	10.000	600.00	850.00	
61	4 1/2 1% cr L-80	10.000	610.00	840.00	
62	4 1/2 1% cr L-80	10.000	620.00	830.00	
63	4 1/2 1% cr L-80	10.000	630.00	820.00	

64	4 1/2 1% cr L-80	10.000	640.00	810.00	
65	4 1/2 1% cr L-80	10.000	650.00	800.00	
66	4 1/2 1% cr L-80	10.000	660.00	790.00	
67	4 1/2 1% cr L-80	10.000	670.00	780.00	
68	4 1/2 1% cr L-80	10.000	680.00	770.00	
69	4 1/2 1% cr L-80	10.000	690.00	760.00	
70	4 1/2 1% cr L-80	10.000	700.00	750.00	
71	4 1/2 1% cr L-80	10.000	710.00	740.00	
72	4 1/2 1% cr L-80	10.000	720.00	730.00	
73	4 1/2 1% cr L-80	10.000	730.00	720.00	
74	4 1/2 1% cr L-80	10.000	740.00	710.00	
75	4 1/2 1% cr L-80	10.000	750.00	700.00	
76	4 1/2 1% cr L-80	10.000	760.00	690.00	
77	4 1/2 1% cr L-80	10.000	770.00	680.00	
78	4 1/2 1% cr L-80	10.000	780.00	670.00	
79	4 1/2 1% cr L-80	10.000	790.00	660.00	
80	4 1/2 1% cr L-80	10.000	800.00	650.00	
81	4 1/2 1% cr L-80	10.000	810.00	640.00	
82	4 1/2 1% cr L-80	10.000	820.00	630.00	
83	4 1/2 1% cr L-80	10.000	830.00	620.00	
84	4 1/2 1% cr L-80	10.000	840.00	610.00	
85	4 1/2 1% cr L-80	10.000	850.00	600.00	
86	4 1/2 1% cr L-80	10.000	860.00	590.00	
87	4 1/2 1% cr L-80	10.000	870.00	580.00	
88	4 1/2 1% cr L-80	10.000	880.00	570.00	
89	4 1/2 1% cr L-80	10.000	890.00	560.00	
90	4 1/2 1% cr L-80	10.000	900.00	550.00	
91	4 1/2 1% cr L-80	10.000	910.00	540.00	
92	4 1/2 1% cr L-80	10.000	920.00	530.00	
93	4 1/2 1% cr L-80	10.000	930.00	520.00	
94	4 1/2 1% cr L-80	10.000	940.00	510.00	
95	4 1/2 1% cr L-80	10.00	950.00	500.00	
96	4 1/2 1% cr L-80	10.00	960.00	490.00	
97	4 1/2 1% cr L-80	10.00	970.00	480.00	
98	4 1/2 1% cr L-80	10.00	980.00	470.00	
99	4 1/2 1% cr L-80	10.000	990.00	460.00	
100	4 1/2 1% cr L-80	10.000	1000.00	450.00	
101	7" K55 BTC 45 singles	**9.60**	1432.00	18.00	
102	9 5/8 K50 BTC	12.00	1444	6.00	
103	9 5/8 PUP BTC 2 Singles	2.60	1449.20		0.80
	Assumping GL- Casing hanger spool	0.80	1450.00	0.00	

WELL CLEANUP AND COMPLETION PROGRAMME-OUTLINE

It is particularly important to ensure the completion is clean before the well is put into service.

1. All completion equipment should be jet cleaned and protected before use.

2. During cementation, the casing will be displaced with clean brine with double cement plugs. (as per company's policy)

3. Perforation brine shall be filtered to 2 microns and 50 NTU

4. Under balance perforation with about 300 psi under-balance shall be carried out in some of the wells.

5. The well will be flowed back as quickly as possible after perforation.

6. Coiled tubing with nitrogen assisted lift will be utilized to back flow the well, if well does not flow back naturally

7. Time to time well flow back would be carried out to clean the near well bore and resume re-injection again. This flow back also may need coil tubing and nitrogen.

DETAILED OPERATIONAL PROCEDURES:

Well status:
The well has been drilled and cemented . Proposed injector casing size 4-1/2.
The fluid in the hole is clean brine with double cement plugs.
X- MAS tree is installed and pressure tested to 3000psi.

Monitor Annulus A and B pressure

Pressure test surface shutting valve to 3000 psi

Nipple Down X-Mas tree

Nipple up BOP
Pressure test BOP (Only Blind and Shear Ram against SSV ensuring annulus side is open)

WBCO -WELL BORE CLEAN OUT
BHA : Bit, Bit sub, Downhole magnet, Scraper, Casing brush tool, Filter

RIH WBCO Lower Assembly
Installing Kelly cock and hose 5000psi(if no circulating head available)
Tag float collar and re pick
Close annular BOP and divert mud from choke manifold(not using trip tank now/brine 9.2 packer fluid there to fill up removed volume of iron once requirement arise after total displacement of perforation brine is over)
Circulate water two hole volume + backup 50 bbl to lower down NTU further(Recommended 50-60)
Circulate high vies , alkaline surfactant and again high vies 10-20-35 bbl (client specification for wells with depth 1000-2000m MD)
Kept displacing with drill water until NTU came down to 50-60.
Displace with perforation brine (2 micron and 50 NTU)

POOH Drill pipe and the down hole assembly

PRESSSURE TEST BOP STACK

Wear bushing was retrieved, BOP test assembly with test plug was made up.
Pressure test are as follows:
1) Pipe ram, Manual kill valve and Manual choke valve to 300psi(low)/5 mins and 3500 psi(high) / 10 mins
2) Pipe ram, HCR kill valve and HCR choke valve to 300psi (low)/ 5min and 3500 psi (High)/ 10mins.
3) Pressure tested Annular to 300psi (low) / 5min and 2500psi (high) / 10min
4) Blind ram, Check valve and Choke manifold hose to 300psi (low) / 5min and 3500psi (high) / 10min

RUN IN CBL VDL LOG (along with GYRO if needed/ client specific)(check for micro annulus and cement sheath integrity).

Perforation (to be carried out next as per client).
If flow back does not occur on its own, use nitrogen lift (Complying CTU size to be used).

Check injectivity.
If values are complying with recommended figures, proceed.
Else, try and remove more debris(one more CTU lift followed by testing).
If injectivity still lies low, go with acid treatment (as per client detailing).

SAND CONTROL STRATEGY

Deviated monobore injection wells will employ sand management techniques, initially potential sand ingress would be managed through advance perforation practices, interval selection, flux limitations and general formation damage minimization. Careful consideration will be given to start-up and shut-down procedures as sudden pressure surges can cause unwanted sand ingress. Regular sand tagging operations will be carried. **The rathole length will be maximized to avoid water hammer effect**.

Coil tubing may also be deployed to clean out the sand from the well bore

FUTURE SCOPE - INCREASING INJECTIVITY (Refer data Appendix A.5)

Most of the water injectors in various oil fields worldwide witness injectivity decline during the injection life. The most likely cause of injectivity decline is formation damage and commonly identified damage mechanisms are:

1. Quality of water injected plays a critical role in sustaining the injection rate of the water injectors. Specific water quality metrics include total suspended solids (TSS), particle size distribution of the suspended solids and the amount and type of dissolved minerals in the injection water

2. Compatibility of injection water and formation waters is important part of minimizing formation damage to injection wells. Scale deposits can result due to incompatibility between the two waters

3. Clay swelling in the rock matrix due to contact with fresh or injection water of low salinity can restrict effective pore space in the injection zone

4. Mobilization of formation fines is another widely prevalent formation damage mechanism

5. A dominant plugging agent is iron sulphide slime which is a by-product of the metabolic process of SRB. Iron sulphide and bio-mass of SRB can accumulate on the internal surfaces of iron pipe and be transported with the injection water into the perforations where plugging and decreased injectivity can occur

INCRESING SWEEP

Low Salinity Water Injection
Source : BP
Low salinity enhanced oil recovery involves flooding a sandstone reservoir using water with a specially engineered salinity and ionic composition. The mechanism that it follows is *the **Multi-Ion Exchange*** **Mechanism :** Most Sandstone reservoirs contain a mixture of sand and clay particles, with porous spaces between them holding a mixture of water and oil. Some residual oil droplets are chemically bound to the surface of the negatively charged clay particles, and are not easily displaced by water flooding. Between the surface of each clay particles and the surrounding water is an “electrical double layer” , ions and an outer diffuse layer of mainly negative ions. The adsorbed layer includes divalent ions such as Mg^{2+} and Ca^{2+},which act as tethers between the clay and the oil droplets. Low salinity water involves replacing the conventional injection water in sandstone reservoirs with water whose salinity is close to that of drinking water. When low salinity water is introduced to the reservoir ,the double layer around each clay particle expands, enabling the monovalent ions such as sodium, carried in the injection water to penetrate into the layer. The monovalent ions displace the divalent ions, breaking the tethers between oil droplets. This allows the oil droplets to be swept out of the reservoir. The low salinity injection water has to have a salinity below some limit(TDS < 0.5% or 5000 ppm).

OPTIMIZING PERFORATION

Source : Halliburton

Process of aligning perforations with the maximum principal stress in the producing formation Modular Gun system includes a unique orientation system that does not depend on gravity or unique hole conditions, enabling more accurate orientation of perforations in vertical or deviated wellbores. Gun orientation is verified using a gyro prior to firing. The modular guns are compatible with slickline and/or electric wireline. Modular guns also offer the advantages of long intervals, allowing underbalanced or over balanced conditions as desired with the flexibility of wireline deployment.

Halliburton has continued to advance the technology with new tools and proven technologies making oriented perforating for fracturing and sand control a very cost-effective strategy.

Features and Benefit

Ideal for monobore completions
With the modular gun system, you are able to stack optimum number of guns downhole for perforating the maximum interval.
Several features make the modular gun system your best choice for perforating under a wide range of conditions.
The guns are retrievable or can be left at the bottom of the hole.
The system allows perforating in either underbalanced or overbalanced conditions over the entire interval.
Wide range of gun sizes (2- to 7-in. OD)permits deployment over a wide range of casing, from 3 1/2 to 9 5/8 in.
No rig is required—the system is ideal for rigless completions.
The modular gun system can be deployed via coiled Tubing, electric wireline, or slickline, as well as with conventional tubing or drillstring.

CONCLUSION

This basis of well design is based on the information and data currently available. On the basis of this data, 4-1/2” tubing is required to get the desired injection rates of 10000 BWPD. It has been decided to complete the well with 4-1/2” casing monobore. This decision has been taken to reduce the well construction cost. Wells may need to be flowed back for clean up and coiled tubing with nitrogen will be utilized for this. Considering the fact that injection water will be treated to reduce dissolved CO_2 and Oxygen, also the corrosion inhibitor being added, the corrosion risk is considered to be low and use of 1% Cr, L-80 casing is considered to be optimum for the 4-1/2” monobore considering the probable corrosivity of the injected water. Based on the studies conducted on sand production risk assessment by APA, no sand control mechanism is being adopted for water injection wells. However, perforation strategy (advance oriented perforations)with phased selected zone perforation and efforts to avoid formation damage during completion shall be applied to reduce the risk of sand production in water injection wells. A maximum possible rathole shall be drilled to avoid the effects of water hammer during the emergency shutdowns. Operational guidelines shall be prepared and followed to prevent the shut injection and shutdown which may cause the sand ingress in well bore. Continuous dosing of chemicals like corrosion inhibitor, surfactant, biocide, oxygen scavenger, scale inhibitor etc will be required in the injected water. Injection water shall also be treated to remove dissolved CO_2 to avoid corrosion of surface lines and completion/casing downhole.

APPENDIX A

A.1

	WATER PROPERTIES - INLET AT PROCESSING TERMINAL													
Date / Time	Temp. ºC	pH	Conduc µs/cm	TDS ppm	TSS ppm	D.O ppb	Iron ppm	Total Hardness as CaCO3 ppm	Calcium Hardness as CaCO3 ppm	Magnesium Hardness as CaCO 3 ppm	Bicarbonates ppm	Chlorides ppm	Sulphate as SO_4 ppm	Remarks
	45	7.30	8880	5328	0.37	<10	0.24	-	-	-	-	-	-	
	44	7.33	8900	5340	0.34	<10	0.26	-	-	-	-	-	-	
	45	7.28	8980	5388	0.24	<10	0.31	-	-	-	-	-	-	
	45	7.29	8970	5382	0.26	<10	0.34	-	-	-	-	-	-	
	45	7.30	8940	5364	0.37	<10	0.23	-	-	-	-	-	-	
	45	7.30	8910	5346	0.34	<10	0.25	-	-	-	-	-	-	
	45	7.27	8880	5328	0.28	<10	0.21	-	-	-	-	-	-	
	-	-	-	-	-	-	-	-	-	-	-	-	-	S/D
	44	7.28	8900	5340	0.31	<10	0.34	-	-	-	-	-	-	
	45	7.29	8970	5382	0.35	<10	0.28	-	-	-	-	-	-	
	45	7.28	8890	5334	0.21	<10	0.28	-	-	-	-	-	-	

	45	7.27	8900	5340	0.37	<10	0.25	-	-	-	-	-	-	
	45	7.27	8870	5322	0.31	<10	0.28	-	-	-	-	-	-	
	45	7.35	8910	5346	0.37	<10	0.29	1090	640	450	242	2536	496	
	45	7.31	8900	5340	0.31	<10	0.22	-	-	-	-	-	-	
	45	7.27	8830	5298	0.24	<10	0.19	-	-	-	-	-	-	
	45	7.29	8790	5274	0.27	<10	0.17	-	-	-	-	-	-	
	45	7.32	8780	5268	0.24	<10	0.22	-	-	-	-	-	-	
	45	7.30	8740	5244	0.28	<10	0.20	-	-	-	-	-	-	
	45	7.32	8730	5238	0.20	<10	0.24	-	-	-	-	-	-	
	45	7.29	8760	5256	0.24	<10	0.25	1160	600	560	281	2723	530	
	45	7.27	8780	5268	0.26	<10	0.22	-	-	-	-	-	-	

A.2

API Tubing Grade Guidelines. Source : Petrowiki.org

The following guidelines apply to the use of API tubing grades.

- H40—Although an API grade, H40 is generally not used in tubing sizes because the yield strength is relatively low and the cost saving over J55 is minimal. Suppliers do not commonly stock this grade.

- J55—A commonly used grade for most wells when it meets the design criteria. Some operators recommend it be full-length normalized or normalized and tempered after upsetting when used in carbon dioxide or sour service (ring-worm corrosion problems); however, such heat treatments increase costs. J55 has been the "standard" grade for tubing in most relatively shallow (< 9,000 ft) and low-pressure (< 4,000 psi) wells on land.

- C75—No longer an official API grade and generally not available. It was developed as a higher-strength material for sour service but was replaced by L80 tubing.

- N80—A relatively old grade with essentially open chemical requirements. It is susceptible to H_2S-induced SSC. It is acceptable for sweet oil and gas wells when it meets design conditions. The quenched-and-tempered heat treatment is preferred. The N80 grade is normally less expensive than L80 grades.

- L80—A restricted yield-tubing grade that is available in Type 1, 9 Cr, or 13 Cr. Type 1 is less expensive than 9 Cr and 13 Cr but more subject to weight-loss corrosion. L80 Type 1 is used commonly in many oil and gas fields because of higher strength than J55. L80 is satisfactory for SSC resistance in all conditions but may incur weight-loss corrosion. Though popular in the past for CO_{2-} and mild H_2S-contaminated wells, Type 9 Cr largely has been replaced by Type 13 Cr. L80 13 Cr tubing has gained popularity because it has good CO 2 -induced weight-loss corrosion resistance properties; however, it is more costly. Type 13 Cr may not be suitable in sour service environments. Typically, the H_2S partial pressure should be less than 1.5 psi for safe use of L80 Type 13 Cr. The user should consult National Assn. of Corrosion Engineers (NACE) MR-01-75.

- C90—A relatively new API grade with two different chemical requirements: Type 1 and Type 2. Only Type 1 is recommended for use in sour service. Typically, this grade must be special ordered; its use has been generally supplanted by T95.

- T95—A high-strength tubular grade that has different chemical requirements: Type 1 and Type 2. Only Type 1 is recommended for sour service. T95 is SSC resistant but not weight-loss resistant.

- P110—The old P105 tubing grade, which allowed a normalized and tempered heat treatment, was discontinued, and the casing P110 grade, which is restricted to quench-and-tempered heat treatment, was adopted. This high-strength tubing typically is used in deep sweet oil and gas wells with high pressures. This grade is sensitive to SSC failures unless the temperatures are relatively high (> 175°F). The P110 grade is slightly more expensive than L80 Type 1 but usually less expensive than the C90 and T95 API restricted-yield grades.

- Q125—Although not a specific API tubing grade, users can order Q125 API tubing. Type 1 chemistry is preferred.

A.3
Injection Pressure determination (averaging values) :

Given MD of well xyz=1450 m MDBRT

Taking a maximum inclination of 45 degree TVD=1350 cos45=1350x1/√(2)=1025 meter

<u>From well data,</u>

Injection pressure: 1200-1800psi **Temp=70-90 deg C** **flow rate Q=4000-8000 bfpd**

Injection fluid viscosity: 8.4ppg

	AvgMangInj values	
WHP	1338	psi
WHT	78	deg C
Qi	6881	bwpd
Density	8.4	ppg
Viscosity	Depends on shear rate and rpm	cp

Sensitivity		
Case 1	**Case 2**	**Case 3**
1200	1500	1800
70	80	90
4000	6000	8000
8.4		

Maximum expected pore pressure=8.82 ppg

Expected fracture pressure =14.73 -16.68 ppg

P_{res}=0.052x8.82x1025x3.281=1542 psi

P_{frac}=0.052x14.73x1025x3.281=2576 psi

Hydrostatic head=0.052x8.4x1025x3.281=1469

$P_{friction}$=100 psi

$P_{res}<P_{inj}+P_{hyd}-P_{friction}<P_{frac}$

$1542<P_{inj}+1469-100<2400$

$\boxed{173\ \text{psi}<P_{inj}<1031\ \text{psi}}$

A.4

psi Loss per 100 Feet of Pipe (psi/100 ft.)

Sizes 1/2" through 6" Flow 1 through 600 gpm

Size	1/2"		3/4"		1"		1 1/4"		1 1/2"		2"		2 1/2"		3"		4"		6"	
O.D.	0.840		1.050		1.315		1.660		1.900		2.375		2.875		3.500		4.500		6.625	
I.D.	0.622		0.824		1.049		1.380		1.610		2.067		2.469		3.068		4.026		6.065	
Wall Thk	0.109		0.113		0.133		0.140		0.145		0.154		0.203		0.216		0.237		0.280	
Flow gpm	Velocity fps	psi Loss	Velocity fps	psi Loss	Velocity fps	psi Loss	Velocity fps	psi Loss	Velocity fps	psi Loss	Velocity fps	psi Loss	Velocity fps	psi Loss	Velocity fps	psi Loss	Velocity fps	psi Loss	Velocity fps	psi Loss
1	1.06	0.91	0.60	0.23	0.37	0.07	0.21	0.02	0.16	0.01	0.10	0.00	0.07	0.00	0.04	0.00	0.03	0.00	0.02	0.00
2	2.11	3.28	1.20	0.83	0.74	0.26	0.43	0.07	0.32	0.03	0.19	0.01	0.13	0.00	0.09	0.00	0.05	0.00	0.03	0.00
3	3.17	6.94	1.80	1.77	1.11	0.55	0.64	0.14	0.48	0.07	0.29	0.02	0.20	0.01	0.13	0.00	0.08	0.00	0.05	0.00
4	4.22	11.81	2.41	3.01	1.48	0.93	0.86	0.24	0.64	0.12	0.38	0.03	0.26	0.01	0.17	0.01	0.10	0.00	0.06	0.00
5	5.28	17.85	3.01	4.54	1.86	1.40	1.07	0.37	0.80	0.18	0.48	0.05	0.33	0.02	0.22	0.01	0.13	0.00	0.08	0.01
6	6.34	25.01	3.61	6.37	2.23	1.97	1.29	0.52	0.96	0.25	0.57	0.07	0.40	0.03	0.26	0.01	0.15	0.00	0.10	0.01
7	7.39	33.27	4.21	8.47	2.60	2.62	1.50	0.69	1.12	0.34	0.67	0.10	0.46	0.04	0.30	0.01	0.18	0.00	0.11	0.02
8	8.45	42.59	4.81	10.84	2.97	3.35	1.72	0.88	1.28	0.43	0.76	0.12	0.53	0.05	0.35	0.02	0.20	0.00	0.13	0.04
9	9.50	52.96	5.41	13.48	3.34	4.16	1.93	1.10	1.44	0.53	0.86	0.15	0.59	0.06	0.39	0.02	0.23	0.01	0.14	0.05
10	10.56	64.35	6.02	16.38	3.71	5.06	2.15	1.33	1.60	0.65	0.96	0.19	0.66	0.08	0.43	0.03	0.25	0.01	0.16	0.08
11	11.61	76.76	6.62	19.54	4.08	6.04	2.36	1.59	1.76	0.77	1.05	0.22	0.73	0.09	0.48	0.03	0.28	0.01	0.18	0.11
12	12.67	90.17	7.22	22.95	4.45	7.09	2.57	1.87	1.91	0.91	1.15	0.26	0.79	0.11	0.52	0.04	0.30	0.01	0.19	0.14
14	14.78	119.93	8.42	30.53	5.20	9.43	3.00	2.48	2.23	1.21	1.34	0.35	0.92	0.14	0.61	0.05	0.35	0.01	0.22	0.24
16	16.89	153.53	9.63	39.08	5.94	12.07	3.43	3.18	2.55	1.55	1.53	0.45	1.06	0.18	0.69	0.07	0.40	0.02	0.26	0.38
18	19.01	190.91	10.83	48.59	6.68	15.01	3.86	3.95	2.87	1.92	1.72	0.55	1.19	0.22	0.78	0.08	0.45	0.02	0.29	0.57
20			12.03	59.05	7.42	18.24	4.29	4.80	3.19	2.34	1.91	0.67	1.32	0.27	0.87	0.10	0.50	0.03	0.32	0.00
22			13.24	70.44	8.17	21.76	4.72	5.73	3.51	2.79	2.10	0.80	1.45	0.33	0.95	0.12	0.55	0.03	0.35	0.00
24			14.44	82.74	8.91	25.56	5.15	6.73	3.83	3.28	2.29	0.94	1.58	0.38	1.04	0.14	0.60	0.04	0.38	0.00
26			15.64	95.94	9.65	29.64	5.58	7.81	4.15	3.80	2.49	1.09	1.71	0.44	1.13	0.16	0.66	0.04	0.42	0.00
28			16.85	110.04	10.39	34.00	6.01	8.95	4.47	4.36	2.68	1.25	1.85	0.51	1.22	0.18	0.71	0.05	0.45	0.00
30			18.05	125.02	11.14	38.62	6.44	10.17	4.79	4.95	2.87	1.42	1.98	0.58	1.30	0.21	0.76	0.06	0.48	0.00
35					12.99	51.37	7.51	13.53	5.58	6.59	3.35	1.89	2.31	0.77	1.52	0.28	0.88	0.07	0.56	0.00
40					14.85	65.76	8.58	17.32	6.38	8.43	3.82	2.43	2.64	0.98	1.74	0.36	1.01	0.09	0.64	0.00
45					16.71	81.78	9.65	21.53	7.18	10.48	4.30	3.02	2.97	1.22	1.95	0.44	1.13	0.12	0.72	0.00
50					18.56	99.37	10.73	26.17	7.98	12.74	4.78	3.66	3.30	1.48	2.17	0.54	1.26	0.14	0.80	0.00
55							11.80	31.21	8.78	15.20	5.26	4.37	3.63	1.77	2.39	0.64	1.39	0.17	0.88	0.00
60							12.87	36.67	9.57	17.85	5.74	5.14	3.96	2.08	2.60	0.75	1.51	0.20	0.96	0.00
65							13.94	42.52	10.37	20.70	6.21	5.95	4.29	2.41	2.82	0.87	1.64	0.23	1.04	0.00
70							15.02	48.77	11.17	23.74	6.69	6.83	4.62	2.77	3.04	1.00	1.76	0.27	1.12	0.00
75							16.09	55.40	11.97	26.98	7.17	7.76	4.95	3.14	3.25	1.14	1.89	0.30	1.20	0.00
80							17.16	62.43	12.77	30.40	7.65	8.74	5.28	3.54	3.47	1.28	2.02	0.34	1.28	0.00
85							18.23	69.84	13.56	34.01	8.13	9.78	5.60	3.96	3.69	1.43	2.14	0.38	1.36	0.00
90							19.31	77.63	14.36	37.80	8.61	10.87	5.93	4.40	3.91	1.59	2.27	0.42	1.44	0.00
95									15.16	41.77	9.08	12.02	6.26	4.87	4.12	1.76	2.39	0.47	1.52	0.00
100									15.96	45.93	9.56	13.21	6.59	5.35	4.34	1.93	2.52	0.52	1.60	0.00
110									17.55	54.79	10.52	15.76	7.25	6.38	4.77	2.31	2.77	0.61	1.76	0.00
120									19.15	64.36	11.47	18.51	7.91	7.50	5.21	2.71	3.02	0.72	1.92	0.00
130											12.43	21.47	8.57	8.69	5.64	3.14	3.28	0.84	2.08	0.00
140											13.39	24.62	9.23	9.97	6.08	3.60	3.53	0.96	2.25	0.00
150											14.34	27.97	9.89	11.33	6.51	4.09	3.78	1.09	2.41	0.00
160											15.30	31.52	10.55	12.77	6.94	4.61	4.03	1.23	2.57	0.00
170											16.25	35.26	11.21	14.28	7.38	5.16	4.28	1.38	2.73	0.00
180											17.21	39.19	11.87	15.87	7.81	5.74	4.54	1.53	2.89	0.00
190											18.17	43.32	12.53	17.54	8.25	6.34	4.79	1.69	3.05	0.00

* Pfric in the above exzmple based on this chart

A.5

Injectivity Test Data

TEST	TEST DURATION	RATE OF THP RISE	II ESTIMATE
1.	10 days(cool water injection trial)	Sustained THP at 1500 psi. Inj rate declined from 10-12 kbwpd to 2 kbwpd	Declined from 20 b/d/psi to 2 b/d/psi
2.	14 days(hot water injection trial)	Increase from 70-1250 psi (75 psi/day	Declined from 20 b/d/psi to 2 b/d/psi
3.	7 days(hot water	Increase from 70-140	Decline from 50-

	injection after re perf)	psi (10 psi/day)	60 to 18-20 b/d/psi
4.	Step Rate Test (6 hours	Increased from 970-1040 psi	17-18 b/d/psi

A.6

Surface piping classes

Source: http://www.engineeringtoolbox.com/pipe-flanges-gaskets-dimensions-d_863.html

Nominal Pipe Size	Gasket Inside Diameter (ID) *(inch)*	Gasket Outside Diameter (OD) *(inches)*			
		Class 150	Class 300	Class 400	Class 600
1/2	0.84	1.875	2.125	2.125	2.125
3/4	1.06	2.25	2.625	2.625	2.625
1	1.31	2.625	2.875	2.875	2.875
1 1/4	1.66	3	3.25	3.25	3.25
1 1/2	1.91	3.375	3.75	3.75	3.75
2	2.38	4.125	4.375	4.375	4.375
2 1/2	2.88	4.875	5.125	5.125	5.125
3	3.50	5.375	5.875	5.875	5.875
4	4.50	6.875	7.125	7.00	7.625
5	5.56	7.75	8.50	8.375	9.50
6	6.62	8.75	9.875	9.75	10.50
8	8.62	11	12.125	12.00	12.625

Nominal Pipe Size	Gasket Inside Diameter (ID) *(inch)*	Gasket Outside Diameter (OD) *(inches)*			
		Class 150	Class 300	Class 400	Class 600
10	10.75	13.375	14.25	14.125	15.75
12	12.75	16.125	16.625	16.50	18.00

A.7
Casing Connection Reference

1. API Spec. 5B, Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads, 14th edition. 1996. Dallas: API.

A.8
COUPLINGS

The standard types of API threaded and coupled connection are:

- Short thread connection (STC)
- Long thread connection (LTC)
- Buttress thread connection (BTC)

The API standards recognize three length ranges for casing:

Range 1 (R-1): 16 – 25 ft

Range 2 (R-2): 25 – 34 ft

Range 3 (R-3): > 34 ft

Connection design limits

The design limits of a connection are not only dependent upon its geometry and material properties, but are influenced by:

- Surface treatment
- Phosphating
- Metal plating (copper, tin, or zinc)

- Bead blasting
- Thread compound
- Makeup torque
- Use of a resilient seal ring (many companies do not recommend this practice)
- Fluid to which connection is exposed (mud, clear brine, or gas)
- Temperature and pressure cycling
- Large doglegs (e.g., medium- or short-radius horizontal wells