R-00-35

Very deep borehole

Deutag's opinion on boring, canister emplacement and retrievability

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May 2000

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Abstract

An engineering feasibility study has been carried out to determine whether or not it is possible to drill the proposed Very Deep Borehole concept wells required by SKB for nuclear waste disposal. A conceptual well design has been proposed. All aspects of well design have been considered, including drilling tools, rig design, drilling fluids, casing design and annulus isolation.

The proposed well design is for 1168.4 mm hole to be drilled to 500 m. A 1066.8 mm outer diameter (OD) casing will be run and cemented. A 1016 mm hole will be drilled to approximately 2000 m, where 914.4 mm OD casing will be run. This annulus will be sealed with bentonite slurry apart from the bottom 100 m which will be cemented. 838.2 mm hole will be drilled to a final depth of 4000 m, where 762 mm OD slotted casing will be run. All the hole sections will be drilled using a downhole hammer with foam as the drilling fluid medium. Prior to running each casing string, the hole will be displaced to mud to assist with casing running and cementing. The waste canisters will be run on a simple J-slot tool, with integral backup system in case the J-slot fails. The canisters will all be centralised. Canisters can be retrieved using the same tool as used to run them. Procedures are given for both running and retrieving. Logging and testing is recommended only in the exploratory wells, in a maximum hole size of 311.1 mm. This will require the drilling of pilot holes to enable logging and testing to take place.

It is estimated that each well will take approximately 137 days to drill and case, at an estimated cost of 4.65 Meuro per well. This time and cost estimate does not include any logging, testing, pilot hole drilling or time taken to run the canisters.

New technology developments to enhance the drilling process are required in recyclable foam systems, in hammer bit technology, and in the development of robust underreamers.

It is the author's conclusion that it is possible to drill the well with currently existing technology, although it represents one of the biggest challenges to be presented to the drilling industry.

Sammanfattning

En förstudie har gjorts för att avgöra om det är tekniskt möjligt att borra hålen i det föreslagna djuphålskonceptet så att resultatet uppfyller SKB:s krav på hål för deponering av använt kärnbränsle. En konceptuell utformning har föreslagits. Alla aspekter på hålets utformning har beaktats inklusive borrutrustning, utformning av borrigg, typ av borrvätska, utformning av infodring och material för tätning av spalt mellan berg och foderrör.

Det föreslagna borrhålet har en diameter på 1168.4 mm med en infodring på 1066.8 mm (yttermått) ner till 500 m djup, därunder en håldiameter på 1016 mm med en infodring på 914.4 m (yttermått) till 2000 m djup. Spalten mellan foder och berg tätas med bentonitslurry hela vägen utom de nedersta 100 m där cement används. De nedersta 2000 m, ner till 4000 m djup, borras med en diameter på 838.2 mm och förses med en 762 mm (yttermått) infodring. Alla hålsektioner borras med en hammarborrmaskin av typen “down-the-hole” under användande av skum som borrvätska. Innan infodringen installeras byts borrvätskan ut mot en bentonitslurry för att underlätta nersänkning av infodringen och cementarbeten. Kapslarna med det använda kärnbränslet sänks ner med ett enkelt J-slitsverktyg med backupsystem ifall J-slitsen fallerar. Alla kapslar placeras i centrum av hålet. De kan återtas med samma verktyg som används för nersänkning. Tillvägagångssätt vid både nersänkning och återtag presenteras. Undersökning och mätning rekommenderas ske endast i hål med en största diameter av 311,1 mm. Detta betyder att pilothål måste borras om mätning ska kunna göras i läge för ett deponeringshål.

Varje hål beräknas ta 137 dagar att borra och infodra. Kostnaden har uppskattats till 4.65 Meuro per hål. Dessa siffror inkluderar ej pilothålsborrning, loggning, testning i hål eller deponering av kapslar.

Ny teknisk utveckling för att förbättra borrmetoden erfordras beträffande system för recirkulerbart skum, kronor till slagborrmaskin samt robusta upprymmare av igensatta hål.

Författaren bedömer det möjligt att borra deponeringshålen med dagens teknik även om arbetet utgör en av de största utmaningarna för borrningsindustrin.

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1 Introduction

1.1 General

Emplacement of spent nuclear fuel in Very Deep Boreholes means that large holes are drilled to a substantial depth and thereafter filled with buffer and canisters in a stack extending from 2 km depth and downward. At the depth below 2 km the rock itself is assumed capable of isolating the radioactive waste from the biosphere. The ground water conditions are stable and possible movements of the water at depth has limited effect in space and is not expected to be connected with the circulation cells having connections with the biosphere.

This report presents the opinions of Das Deutsche Tiefbohr-AG (Deutag) on the general VDH concept as defined by SKB below.

1.2 Analysed concept

A schematic drawing of SKB´s Very Deep Borehole concept is shown in Figure 1-1. The deposition zone is suggested to be located from 2 km depth and down to 4 km.

1.2.1 Drilling technology

SKB assumed that the borehole would be 0.8 m in diameter in the deposition section, which was the largest diameter deemed feasible to drill to the depth of 4 km in 1992 /9/.

Drilling was in 1992 preferred to be made with a bentonite mud as drilling fluid at depth. The required casing was assumed to be of navy bronze but the hydrogen production at reducing corrosion of iron is today known to have a negligible effect, so steel liners may now be considered instead. The casing, however, has to be made sufficiently perforated so that the bentonite can be added in blocks inside the casing and swell through the casing and out into the entire void in the borehole around the canister.

1.2.2 Deposition technology

The principle put forward in /9/ is that the canister is fastened to the drill bit’s position on the drill pipe and pushed down in the casing to the deposition position.

Before this the drilling mud is replaced by a thick bentonite deployment mud, which is as thick as possible although allowing the canister to be pressed through without being damaged. Two or more canisters are assumed to be fitted together in a column with bentonite blocks in between before being pushed down.

Checking of the canister’s position is important as well as checking of the force on the canister in order to be able to verify that the canister is deposited without mechanical overload.

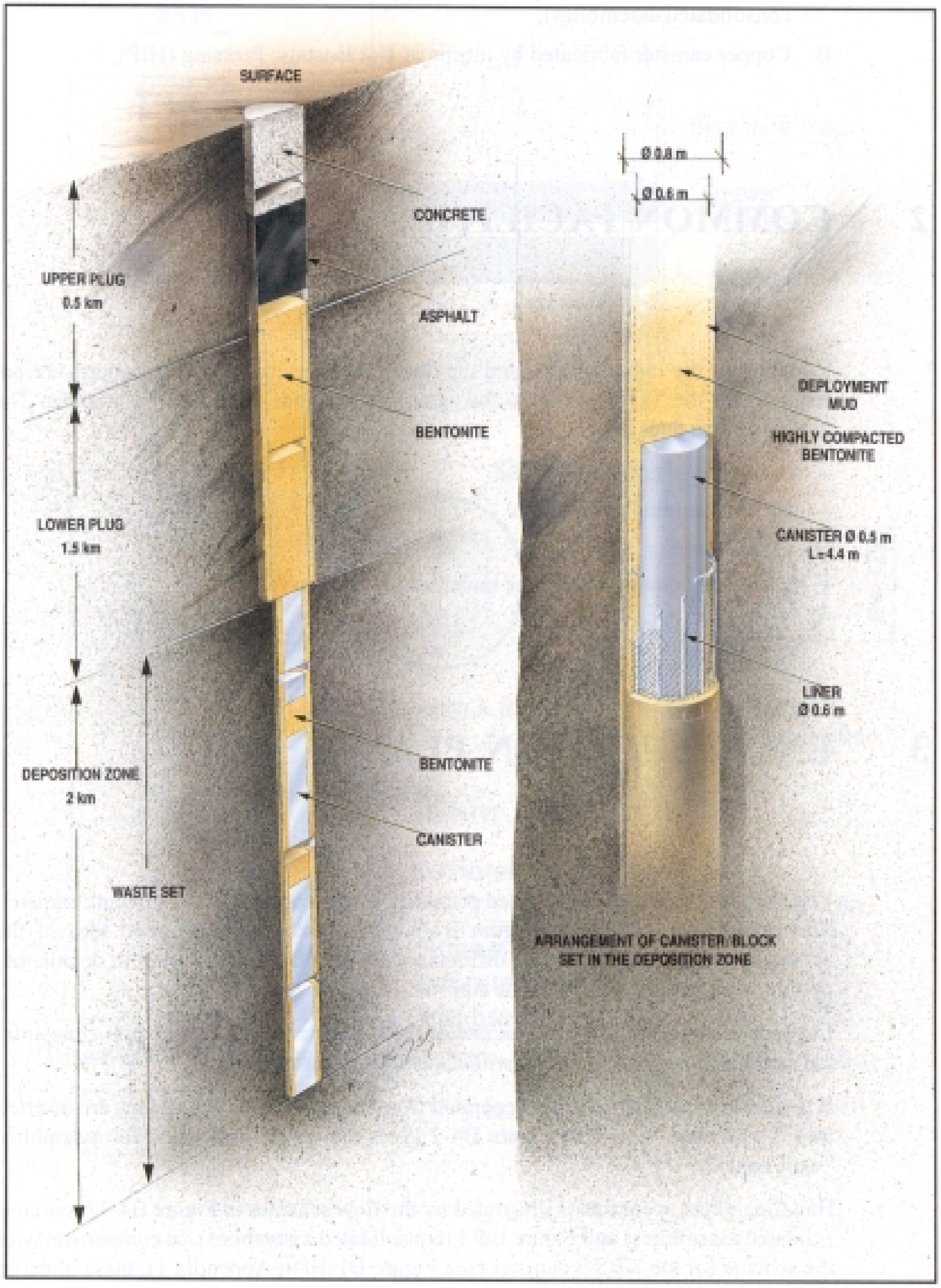

Figure 1-1. *Schematic drawing of VDH concept.*

1.2.3 Retrievability

The possibility to retrieve a deposited canister is not required as a mandatory feature in the Swedish programme, but considered as a major advantage during a short period after the emplacement. This means that the canisters are designed with such a structural strength that they may last intact for the period of time under consideration, which of course includes the strength required for resisting strains imposed during deposition. Once the bentonite has swollen it activates a friction force along the canister that is large enough for keeping the canister in a firm grip.

2 Deutag's background and experience

2.1 Well Engineering Partners

Well Engineering Partners b.v. (WEP) was founded in 1996 by Tom Bakker (formerly head of Offshore Well Engineering with NAM) and the German drilling contractor Deutag with the objective to deliver new technologies and specialist drilling engineering services to the oil and gas industry. In March 2000, it was fully incorporated into Deutag Europe, for whom it is now a business unit. WEP has seven staff members, all of whom are degree qualified, with an average experience of 12 years in drilling operations. The following is a list of the major projects which WEP has completed in the last three years.

Project	Client	Activity
Kashagan	OKIOC (Shell)	ERD Feasibility Study HTHP Casing Design
NAM Blocks A & B	NAM	Shallow ERD Study
Kudu	Shell Namibia E & P	Evaluate Subsea vs. Platform Drilling
Scott Reef	Halliburton (Woodside)	ERD Feasibility Study
E2D Ultra Extended Reach	NAM	State-of-the-Art Report Modelling and Drilling Operations
Coiled Tubing Software	Shell International Exploration and Production (SIEP)	Evaluation and Recommend Software
Brilliant Mole	SIEP	Feasibility Study
Slender Well	SIEP	Deepwater Drilling
Spider Well	Shell Germany (BEB)	Casing Design
Big Loop™	Nedmag	Installation of Continuously Spooled Welded Completion Tubing
Big Loop™	Shell Oman (PDO)	Pre-engineering Study, 7" Big Loop
Rotocavitator™	PDO	Design and implementation of a major sand screen cleanout programme
Water shutoff	PDO	Design, formulation and implementation of novel water shutoff and lost-circulation materials.
Workovers in Salt Mining Well	Nedmag	Integrated Service Workover Engineering Support

Project	Client	Activity
Geotechnical Exploration Wells	Alpetunnel GEIE	Integrated Service Contract Well Design Hard Rock Drilling Continuous Horizontal Coring
Iran	Veba Oil and Gas	Completion Design, Well Design, Budget Preparation
Iran	Shell Exploration and Production International Ventures	Field Development Tender Package Review
Training	Kazakh Oil	Drilling Engineering Course
Training	Deutag	Drilling Engineering Course
Venezuela Rig Move	Deutag	Optimise Planning

The following is a list of the new technologies WEP has assisted in developing during the last three years.

Technology	Partner
Big Loop™	BJ Services
Casing Welding	Deutag and BJ Services
Rotocavitator™	BJ Services and Moscow State University
Soft Torque, Soft Pump and Soft Feed-off (“Soft Drill™”)	Bentec/Deutag
Under Balanced Drilling	Deutag UBD and Northland Energy Services
Casing Running Tool	Deutag and Varco
Continuous Rotary Drilling Machine	Deutag and SIEP
Composite Drillpipe and Coiled Tubing	SIEP
Slender Well Technology	Shell International Deepwater Services and WADO
Spider Wells	BEB, BHI and Plexus
Geothermal Wells	TNO, TU Delft, GFZ, Preussag Energie

2.2 Deutag Europe

Deutag Europe have been involved in only one deep, large bore drilling project. This was the “Kontinentale Tiefbohrprogramm der Bundesrepublik Deutschland (KTB)” super-deep borehole project, between October 1990 and October 1994, where a well was drilled through the top 9000 m of the continental crust in the Rhine Valley. See Figure 2-1.

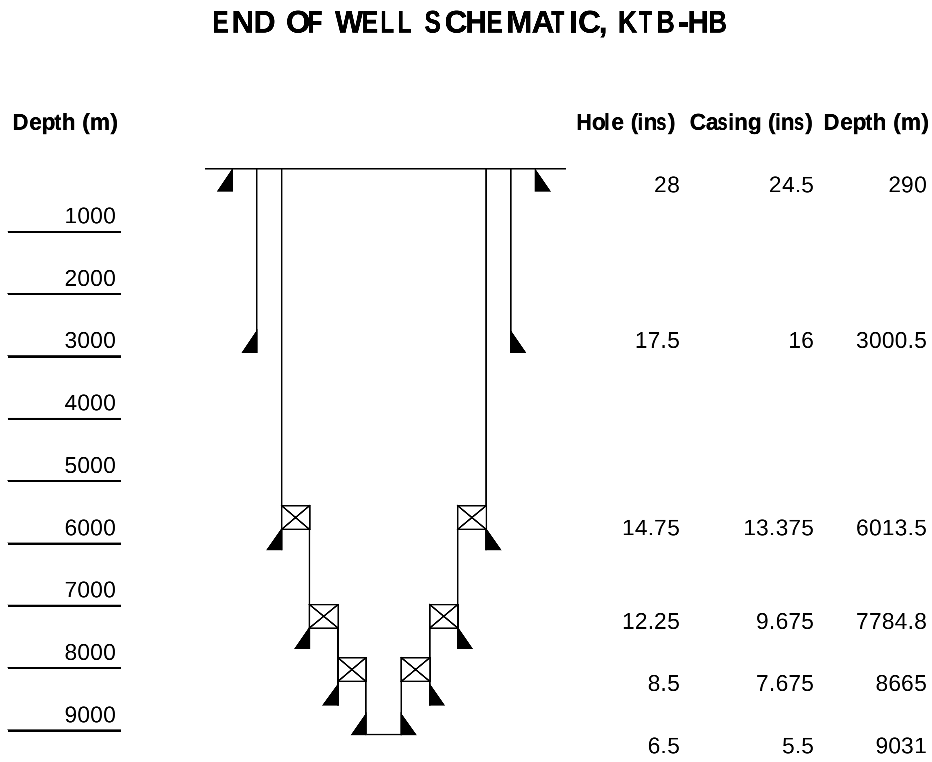

Figure 2-1. *End of well schematic, KTB-HB.*

The main technological achievement for the Deutag during the drilling of this well was the building and management of the world's largest land drilling rig, UTB-1 GH 3000 EG (shown in Figure 2-2). The rig, with a total weight of 2500 tonnes, a depth rating of 12000 m and a maximum installed capacity of 12900 HP, was purpose-built for the project. The rig also incorporated novel environmental features, such as low sound emission fully electric drive, and on-site conditioning of drilling waste.

The drilling operations were managed by Deutag on a day-to-day basis on behalf of the customer, GeoForschungsZentrum (GFZ), providing manning of the rig and wellsite drilling engineering. Some specifications of the rig are given below:

Derrick

Manufacturer	Noell
Base	11.5 m x 11.5 m
Clear height	63 m
Number of lines	10–16
Maximum hookload	8500 kN
Nominal gross capacity	10550 kN
Racking capacity	12000 m 5" drillpipe, plus collars

Substructure

Manufacturer	Deilmann
Rig floor	13 m x 13 m
Height	11.75 m
Clear height	9.5 m
Load capacity	12000 kN

***Figure 2-2**. Deep drilling rig UTB-1 GH 300 EG.*

Drawworks

Manufacturer	Wirth
Maximum power input	2200 kW
Maximum line pull	750 kN
Maximum line speed	20 m/s
Drill line diameter	1.75”
Feed-off control	0–30 m/h

Mud pumps

Manufacturer	Wirth
Number of units	2
Maximum power input	1240 kW
Manufacturer	Continental Emsco
Number of units	1
Maximum power input	620 kW

Drive system

Manufacturer	AEG
Mains	2 x 20 kV / 7000 kVA
Number motors	9 x DC
Manufacturer	Siemens
Maximum power output	740 kW each

Pipe handling
Pipe handler

Manufacturer	Varco
Height	53 m
Maximum capacity	150 kN
Maximum drill pipe stand	40 m
Dual elevator system	Varco
Pipe conveyor	Deilmann
Pipe boom	Deilmann

Blowout preventers

Manufacturer	Shaffer
Number of units	4 x ram, 1 x annular
Opening	18.75”
Rating	700 bar

Mud tank system

Manufacturer	ITAG
Active tank volume	150 m^3
Reserve tank volume	300 m^3

3 Drilling technology

3.1 State-of-the-art

3.1.1 Introduction

Large diameter boreholes (>17.5” outer diameter (OD), or 444.5 mm) are drilled in the oil industry for setting surface casing. It is established industry practice to drill as small a hole as the well design will allow, because of the expense of the operation. Large diameter holes are commonly drilled in civil engineering and mining. Civil engineering projects typically only drill to a maximum depth of approximately 20 m, and frequently use downhole hammers. The mining industry also employs large bore drilling techniques, again either using hammers, or raise drilling from an established adit. Drilling large boreholes from the surface down is unusual in the mining industry.

Many large-diameter wells were drilled in Nevada for nuclear testing purposes during the 1960s and early 1970s. Typically, these reach true depth (TD) at approximately 1500 m, with a final diameter of 1625 mm. Almost all were drilled with downhole hammers. Detailed information on these wells is currently lodged with the US Department of Energy, and was unavailable for this project.

One well, completed in April 2000 on behalf of MHP, is of interest to this project. It was drilled in New York State as a gas storage well. Details are given in the following table:

Table 3-1. MHP well configuration.

Hole size (mm)	Casing size (mm)	Depth (m)	Total days on location	Drilling method
990.6	914.4	30.4	No data	Mine shaft drilling rig in overburden
863.6	762	228.6	75	Reverse circulation
723.9	660.4	701	95	Air / mist hammer drilling
609.6	508	1257	107	Air / mist hammer drilling

The last two hole sections of the well were drilled with a 283 m^3 / minute air package supplied by Weatherford ADS, the downhole hammers and bits were supplied by Numa. Lithologies were relatively benign (shale, limestone, salt) and no diamond enhancement was used on the bits. It is reported that the operator is planning to drill a second similar well to a depth of approximately 1525 m.

The key factor in the decision process when choosing between rotary and percussion drilling in very large borehole sizes is usually made on the basis of the rock properties, notably the compressive strength. The choice of the drilling fluid is strongly dependent on both the rock properties (consolidated, unconsolidated, risk of groundwater or hydrocarbon flow, risk of loss of circulation, etc.). The fluid medium can be air (treated in this instance as a fluid), mist (dispersed water droplets in an air or nitrogen medium), stiff foam, stable foam, aerated non-newtonian fluid, aerated newtonian fluid, and water or other clear brine. Each of these methods will be discussed in the subsequent text. In all cases, however, the fluid medium must serve two basic purposes: it must be circulated at sufficient velocity so as to be able to effectively remove the drilled cuttings from the hole, and it must be able to cool and lubricate the drill bit during the drilling process. Other key functions of a non-newtonian fluid (i.e. mud) are to maintain a positive pressure balance over the formation's hydrostatic pressure (thus preventing uncontrolled influxes of formation fluids and the potential collapse of the borehole) and the lubrication of the drillstring in inclined boreholes.

Naturally, the choice of drilling equipment available and the type of drilling rig to be used varies with the choice of the fluid medium. In addition, the choice of rotary or percussion drilling is not restricted to the fluid medium chosen, as they can be used in either medium. The choice of drilling method is usually made on the basis of the hardness of the rock, the depth to which the hole will be drilled, the risks of the downhole loss of drilling fluid and the effects on the formation of the drilling fluid.

When considering the current scope of the project, much of the current oil and gas drilling technology can be ignored because it is focussed on rocks significantly softer than those which will be encountered in this project. Most of the formations which are drilled in the oil and gas industry have a compressive strength less than 138 MPa. These formations are, typically, mudstones, shales, moderately to poorly cemented sands, and limestones. Traditional rotary drilling methods have evolved to cope with these rocks. Hydrocarbons are not generally found in high compressive strength rocks.

3.1.2 Determining the drilling method

The choice between rotary and percussion drilling can be made on the basis of the energy efficiency of the drilling process. In its simplest form, this can be considered as the amount of energy required to remove a certain unit of rock. This relationship can be simply defined for rotary drilling in the following equation:

The energy required to remove 1 cm^3 of rock can be defined in the following manner:

$$E_s = 0.9518 \cdot S_c + 104.38 \qquad \text{(equation 3-1)}$$

E_s : Specific Energy per volume of rock (J/cm^3)

S_c : Compressive strength of rock (MPa)

The total energy available at the bit can be calculated using the following relationship:

$$E_b = \frac{P}{V_t} \qquad \text{(equation 3-2)}$$

E_b : Work done by bit (J/cm^3)

P : Power supply to the bit (J/s)

V_t : volume of rock removed per time unit (cm^3/s)

$$P = T \cdot \omega \qquad \text{(equation 3-3)}$$

T : Torque applied to the bit (Nm)

ω : rotary speed (rad/s)

$$\omega = RPM \cdot \frac{2\pi}{60} \qquad \text{(equation 3-4)}$$

RPM : rotary speed (rev/min)

$$V_t = ROP \cdot \frac{\pi \cdot D^2}{144} \qquad \text{(equation 3-5)}$$

ROP : Rate of penetration (m/hr)

D : Bit diameter (cm)

Formula to estimate torque from WOB (or use Top Drive manufacturers graph)

$$T = a \cdot WOB \cdot \frac{D}{100} \qquad \text{(equation 3-6)}$$

T : Torque supplied to bit (Nm)

a : dimensionless range of ratios expected for rotary drilling with 0.10 being typical for tri-cone bits and 0.15 for polycrystalline diamond composite (PDC) bits.

WOB : Weight on bit (N)

D : Bit diameter (cm)

Combining equation 3-2 to equation 3-6 yields

$$E_b = \frac{0.048 \cdot a \cdot WOB \cdot RPM}{ROP \cdot D} \qquad \text{(equation 3-7)}$$

E_b : Energy done by bit (J/cm^3)

Combining equation 3-1 and equation 3-7 gives the efficiency of the bit:

$$\varepsilon_b = \frac{E_b}{E_s} \qquad \text{(equation 3-8)}$$

Assume granite has compressive strength Sc = 220 Mpa

ROP	(m/h)	2.5	2	1.5	1	0.5
RPM	(rev/min)	70	70	70	70	70
Dbit	(cm)	914	914	914	914	914
Es	(J/cm3)	21857	21857	21857	21857	21857
Bit constant	(-)	0.1	0.1	0.1	0.1	0.1
Vt	(cm3/s)	45563.78	36451.03	27338.27	18225.51	9112.757
WOB	(kN)	148638.9	118911.2	89183.36	59455.58	29727.79
T	(kNm)	135856	108684.8	81513.59	54342.4	27171.2

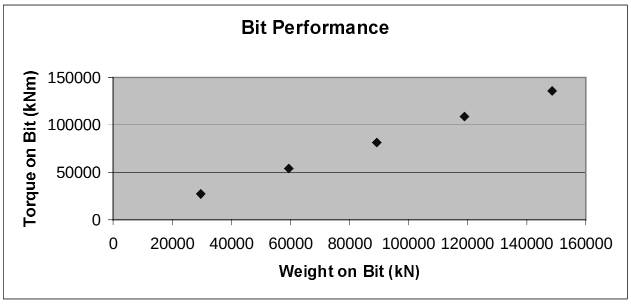

Figure 3-1. *Example of torque / weight on bit relationship, rotary, drilling in granite.*

These can be combined in graphical form to show that, given the compressive strength of granite, either an unreasonably high weight on bit or an extremely high bit RPM is needed. See Figure 3-1.

Weight on bit of anything above 310 kN is considered excessive for conventional rotary oilfield drill bits. Bit RPMs of over 500 can easily be achieved by the use of a downhole turbine, but these are quite simply not available in the hole sizes proposed to be drilled. Therefore, it is recommended that only percussion (hammer drilling) be adopted as a technique for drilling the deep wells.

3.2 Well design

For the sake of calculations and the preparation of technical quotations, the following generic well design was assumed. It is important to note that this well design does not take into account the as-yet unknown effects of the deep geological conditions, and may change.

Table 3-2. Proposed well configuration for SKB well.

Hole size (mm)	Section TD (m)	Casing OD (mm)
1168.4	500	1066.8 mm
1016	2000	914.4 mm
838.2	4000	762 mm

3.2.1 Casing design

The following properties of the casing have been calculated using the formulae given in /1/:

Internal yield (burst) in psi, $P_Y = 0.875\left[\frac{2Y_P t}{D}\right]$ psi　　Equation 3-9

Yield strength collapse in psi, $P_{Y_P} = 2Y_P\left[\frac{(D/t)-1}{(D/t)^2}\right]$ psi　　Equation 3-10

Tensile yield strength, $P_Y = 0.7854(D^2 - d^2)Y_P$ pounds　　Equation 3-11

Where:

P_Y is the pipe body yield strength (pounds).

P_{Y_P} is external pressure required to generate minimum yield stress (psi).

Y_P is specified minimum yield strength for the pipe (psi).

D is pipe body outer diameter, inches.

d is pipe body inner diameter, inches.

t is wall thickness, inches.

In selecting the casing for the proposed design, many casing wall thicknesses and grades were looked at. The main selection criterion was a requirement for a minimum casing inner diameter (ID) of 700 mm (approximately 27.5”). These are shown in Attachment 1.

The following oil industry standard design factor has been used in the casing design:

Tension　1.35

The following worst case installation loads have been considered for the two main casing strings:

36” casing

Burst:　Not considered

Collapse:　Not considered

Tension:　Installation load

30" casing

Burst: Not considered

Collapse: Not considered

Tension: Installation load

The burst and collapse loads have not been considered because of the logic for drilling the holes: the area for waste disposal is a homogeneous, stable granite mass, not subject to fractures or overpressures. Hydrocarbons and high-pressure water flows cannot be expected and, therefore, the only load to consider is during installation (i.e. tensile loading). Additionally, the deep casing string (762 mm pipe body OD) will be slotted or perforated in some manner, thereby rendering it incapable of retaining internal and external pressure. The ability of the casing to withstand some minor wellbore instability (e.g. rockburst) is considered to be sufficient given its wall thickness.

The casing designs and material available for selection are presented in Attachment 1 of this report.

The casing tensile loads during installation have been calculated as follows:

String weight in air $W_S = W_C L$ Equation 3-12

Buoyed weight in mud $W_B = W_S \left(1 - \left(\frac{W_M}{65.44}\right)\right) - W_S$ Equation 3-13

Axial tension due to bending $T_A = DLS \times W_C \times D \times 63$ Equation 3-14

Shock loading $S = 150 \times V_C \times \frac{\Pi}{4} \times \left(D^2 - d^2\right)$ Equation 3-15

Total installation load is the sum of Equations 3-12 to 3-15, and is expressed in pounds.

Where:

W_C is the weight of the casing string in air, pounds.

L is the length of the casing string, feet.

W_M is mud weight, pounds per gallon.

DLS maximum dog-leg severity in wellbore, degrees per 100 ft.

D is pipe body outer diameter, inches.

d is pipe body inner diameter, inches.

V_C is running speed of the casing ins/sec (taken here as maximum value of 33).

To summarise the results in Attachment 1, any of the casing grades conforming to API Specification 5L /2/ shown in these tables for any of the casing sizes (30”, 36” and 42” casing) are suitable for use in the waste disposal wells. Industry standard sizes typically have wall thicknesses of 0.406” (10.31 mm) and above. The effect of temperature and cementing / sealing the annulus with bentonite on the casing strings is shown in Attachment 2. There is a small increase in the axial load on each casing string, but the effect is negligible. The casing strings still remain within the design limits shown in Attachment 1.

The calculations above have been made on the basis of full strings of casing running from section TD to surface. Consideration was also given to the casing strings being installed as liners. Liner hangers are of a robust enough design that one could have been manufactured for either the 36” or the 30” casing. The weight of these casing strings would exceed the tensile yield of any API drillpipe, and a running string of heavy-walled 9-5/8” or 10-3/4” casing would have to be used. Cementation of the liner string would certainly be a problem due to the large volumes involved. The tensile loading on the liner hanger slips themselves would be so large as to approach the tensile yield of the casing, so unless the casing were set on bottom prior to the liner hanger being set, there would be a severe risk of the external (supporting) casing parting when any load was applied. Such a load could come from drilling (for example drilling out the casing shoe) or even the additional pressure exerted during circulation. However, since the waste canisters would eventually have to be deployed through the restriction in ID of a liner hanger, even with an inverted guide lip at the top of the 30” hanger there was considered to be too high a risk of snagging the canister. Therefore, a full-bore design has been adopted.

The wellhead design would have to be capable of sustaining the combined loads of the casings. Assuming the proposed casing strings in Table 3-3 are used, a combined load of approximately 1370 tonnes will be exerted on the wellhead (including the weight of a blow out preventing – BOP – stack). Including buoyancy forces, this reduces to approximately 970 tonnes. The casing cannot be set on bottom because the load would cause the casing to buckle and collapse.

Table 3-3. Proposed casing for SKB well.

Section TD (m)	Casing OD (mm)	Casing weight (kg/m)	Casing wall thickness (mm)
500	1066.8 mm	330.2	0.500
2000	914.4 mm	229.5	0.406
4000	762 mm	187.7 (slotted)	0.500

3.3 Drilling fluids and deployment fluids

As discussed above, there are a number of fluid media which can be used for the drilling of the waste disposal boreholes. Each of these will be discussed briefly in the following section, and a recommendation will be made.

3.3.1 Dry air drilling

This is the simplest method of cleaning the hole and is well suited to percussion drilling. Air is compressed and pumped either down the drillstring or, less commonly down the annulus. The method, however, suffers from two main drawbacks: inability to cope with water influxes greater than 5 m^3/hr, and compressor requirements in large hole sections.

Any significant fluid influx into the well (>5 m^3/hr) during air drilling will result in the conversion of the dust of drilled cuttings converting into mud, which forms rings in the annulus in areas where pressure drops occur (e.g. borehole irregularities, changes in drillstring OD). These can quickly result in the hole packing off and can result in the drillstring getting stuck. The water influxes are either cured by squeezing cement, or overcome by converting to another drilling method. Cement squeezes in large holes will be very expensive because the equipment is not currently available. Given the western maritime climate of Sweden, it is unlikely that the wells can be drilled without encountering significant water influxes.

The second drawback of air drilling in large holes is the volume of air required. Angel /3/ calculated that in order to clean the hole effectively, an air injection rate equivalent to a surface annular velocity of 914 m/minute is required. This is relatively easy to achieve in small hole sizes, but with the proposed well geometry for the waste disposal project, compressors with an output totalling well over 1360 m^3/min will be required, plus the additional boosters. Considering a normal oil well to 3000 m will require compressors totalling 85 m^3/minute, this represents a significant additional expense in rental equipment and fuel.

Noise levels from the compressors and boosters will need to be evaluated very closely, and significant (expensive) additional soundproofing may be required. Additionally, noise and dust levels at the blooie line (the surface air return line down which air and cuttings are expelled) will be very high.

A typical air drilling layout is shown in Figure 3-2.

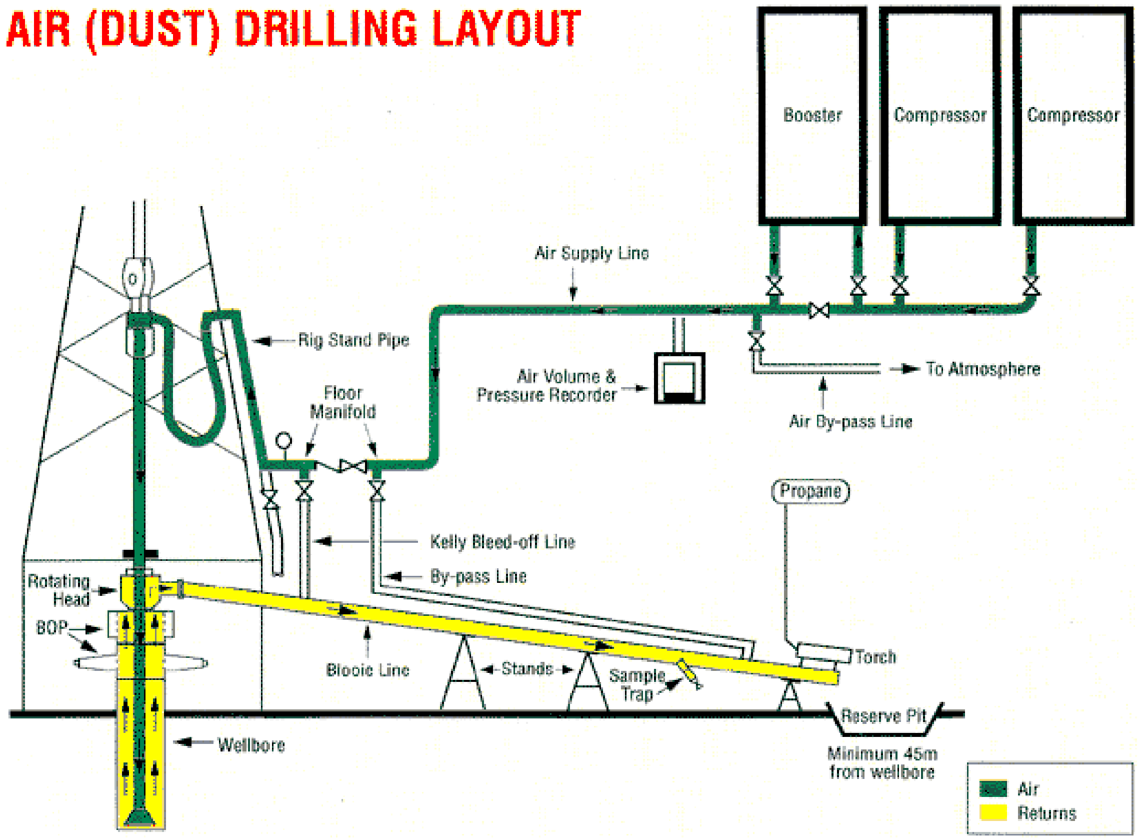

Figure 3-2. Typical air drilling layout.

3.3.2 Mist drilling

Mist drilling is one method of coping with influxes of water of up to 25 m^3/hr if these are to be expected, particularly in the deeper hole sections. Mist drilling involves the injection of a small amount of liquid phase – water plus surfactant – into the compressed air flow before it enters the drillstring. This method of drilling is no more efficient than air drilling at hole cleaning, and requires between 30 and 40% higher air injection rates /6/. For example, in the 1016 mm hole section, approximately 215 m^3 of water will be required per day to create a good mist. This is usually not recycled due to the expense of centrifuging, so adding a worst case water influx of 320 m^3/day, approximately 535 m^3 of water contaminated by drill cuttings and surfactants will have to be disposed of every day. This feature, along with the expense of additional compressors and boosters, make mist drilling an unattractive alternative.

3.3.3 Aerated liquids

Both drilling mud and water can be aerated prior to pumping down the drillstring, thus passing on some of the benefits of reduced bottom-hole pressure to increase the penetration rate. In a normally pressured well bore, reductions of up to 46% can be achieved in the bottom hole pressure exerted by the fluid column. Field experience shows that annular velocities of 30–60 m/min are required to adequately clean the hole with water. It is unfeasible to achieve this in a large diameter hole without a several expensive high discharge-volume pumps. A viscosified fluid will require lower annular velocities (15–20 m/min).

The main problem with this method of drilling is the management of the large surface volumes of fluid. At TD of the 838.2 mm hole section, assuming a 40% gas phase in the liquid, full-gauge hole and the hole geometry given in Table 3-3, this gives a hole volume of 1324 m^3 simply for the active system. If water is to be used (representing a disposable item) this amount will either have to be recycled or disposed of daily. Recycling water for use during percussion drilling will have to be done carefully as water hammers are very prone to plugging, and require a water cleanliness of <10 •m.

A typical setup for drilling with aerated mud is shown in the following figure:.

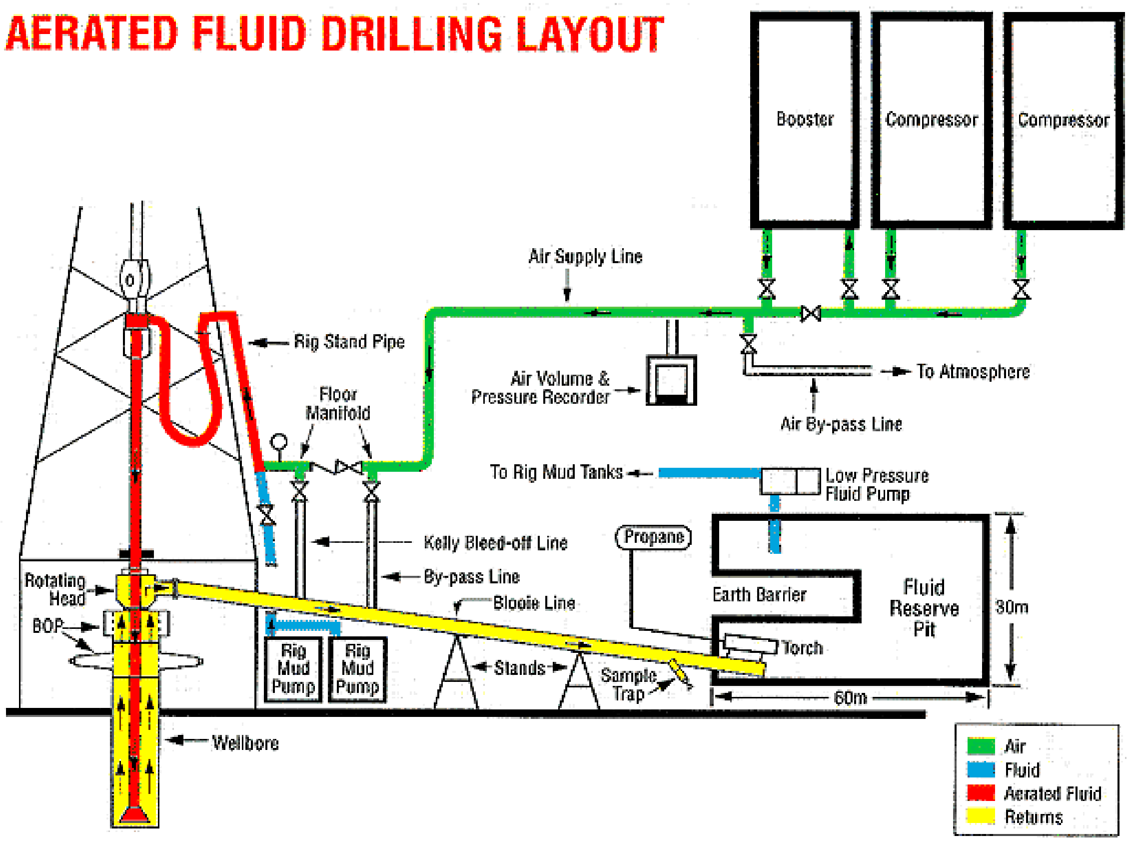

Figure 3-3. Typical aerated fluid drilling layout.

3.3.4 Unaerated fluids

The simplest and cheapest unaerated fluid to use is water. The carrying capacity is limited by its Newtonian rheology, but this can be modified by adding viscosifiers. The main disadvantages with using water are recycling / disposal and rate of penetration (ROP). As discussed above, the large volumes mean that both disposal or recycling are expensive options. Recycling is expensive because of the centrifuges and filtration equipment which are required to bring any water particles down to less than 10 •m so that clear water hammer drilling can proceed. The additional hydrostatic pressure produced by a full column of water will also reduce the cutting efficiency of the drill bit because of the balance with the assumed normal pressure gradient in the granite.

Similar arguments can be used against conventional mud as a drilling medium. In addition, although percussion drilling has been demonstrated to be the most energy-efficient drilling process, the development of mud hammers is still in its infancy with only two commercial runs to date (by Smith Tools, in Oman). These two runs have been made in small hole sizes (6”) and the engineering solutions required to size-up these hammers to drill extremely large hole sizes will not be available in two years time.

3.3.5 Foam

Foam is commonly used as a drilling medium. Since it is a also continuous liquid phase, its viscosity is high and consequently its carrying capacity for both cuttings and water influx is also very good. Rates of penetration with foam drilling are a bit lower than using air or mist drilling because of the increased hydrostatic head, but they are still typically 50–60% higher than comparative rotary drilling.

All foams are classified according to their bubble shape, quality and texture.

Bubble shape: The best foams have a bubble shape which approaches perfect packing, either polyhedral or spherical.

Quality: This is defined as the percentage of gas phase in the foam, thus 90 quality foam has 90% gas phase and 10% liquid phase. Most foams have a breakdown point to mist at about 95–98% gas phase.

Texture: This term describes the size and distribution of the bubbles. Fine sphere foams are lower quality than coarse polyhedral foams.

High quality polyhedral foam has non-Newtonian rheology /6/ and consequently their ability to clean the hole efficiently at much lower annular velocities than air, mist or fluid media is obvious /4/. The addition of a viscosifying agent creates a stiff foam, and means that cuttings can be suspended without setting when the circulation has stopped. There is field documentation of granite cuttings up to 6 cm diameter having been removed from the hole, despite the very low bulk density of the foam. Annular velocities as low as 30 m/min are sufficient in large diameter holes to adequately remove cuttings, and water influx volumes of up to 80 m^3/hour can be handled.

Because of the lower annular velocities required, fewer compressors are needed. For the well geometry suggested for this project, two compressors with combined 42 m^3 output at 206 bar discharge pressure will be sufficient for foam drilling. This should be compared with the requirements for air or mist drilling. This cost reduction is offset somewhat by the additional cost of chemicals, but this can be optimised by the use of a foam recycling system. At the moment, only one company, Weatherford ADS, is offering a recyclable foam system, marketed under the name Transfoam-C. This system also has the advantage that all its components are environmentally acceptable, so making cuttings and waste fluid disposal easier and cheaper than had previously been experienced.

A typical layout of a typical foam drilling setup for the oil industry is shown in Figure 3-4.

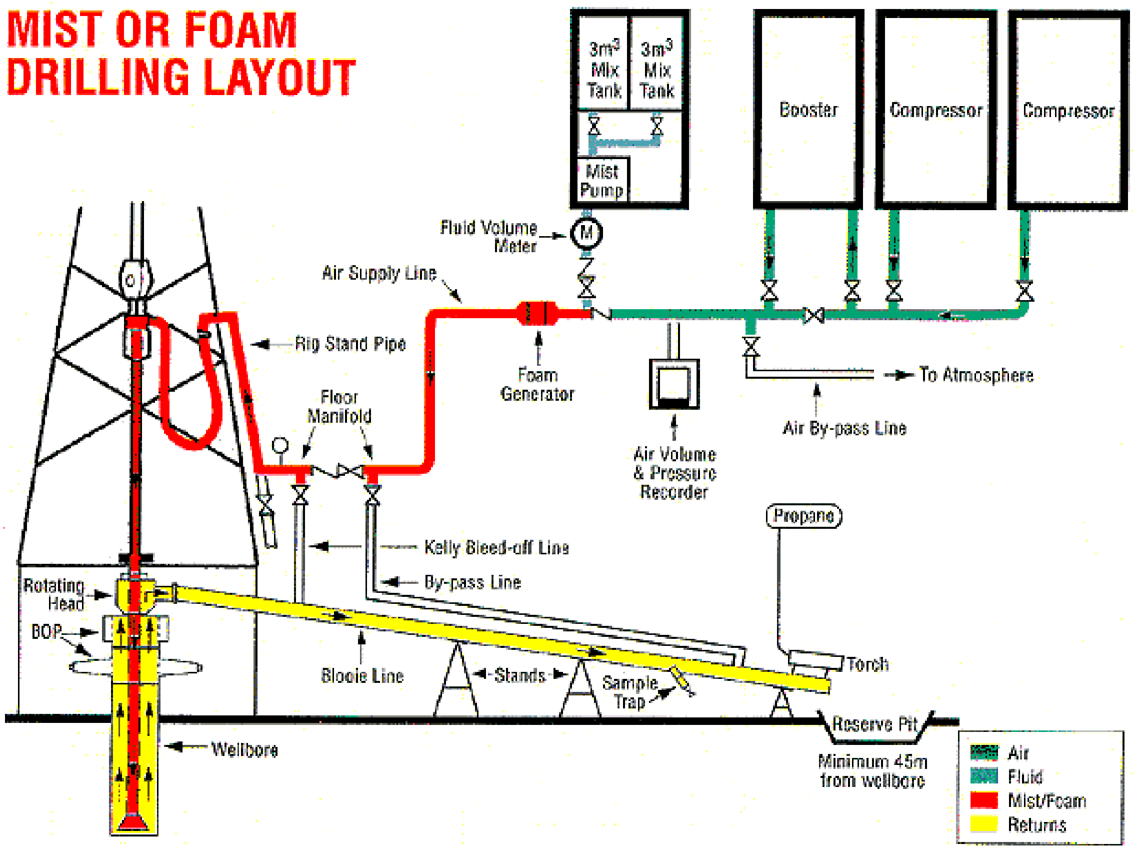

Figure 3-4. Typical foam or mist drilling layout.

As mentioned above, stiff foam is created by the addition of a viscosifier to stable foam. Stiff foams were developed for drilling 64" holes for the US Atomic Energy Authority /8/ and their benefits over stable foams are obvious. Since the viscosities are higher, the carrying capacity is increased, and annular velocities as low as 4–6 m/min have been reported as sufficient to clean 17½" hole, even with low quality foam /5/. In addition, the liquid phase is low so the hydrostatic pressure exerted on the bottom of the hole is less than with aerated or non-aerated fluids resulting in ROP enhancements, particularly during percussion drilling /7/.

3.3.6 Recommendation for the drilling fluid

The various methods discussed above can be ranked in the following manner:

1 for least amount of equipment, lowest cost, most efficient method of hole cleaning/making.

5 for most amount of equipment, highest cost, most inefficient system.

Drilling efficiency here is loosely defined as effect on bit hydraulics, ability to clean the hole, and the restrictions on the methods available for drilling in granite.

On the basis of Tables 3-4 and 3-5, foam is the best method of cleaning the hole and requires the fewest compressors. It is not necessarily the cheapest method, requiring at least some compressors and a recycling system in addition to the chemical requirements.

Table 3-4. Ranking of the various drilling methods available.

Fluid type	Amount of Equipment	Cost	Drilling Efficiency	Ranking
Air	5	5	1	11
Mist	5	5	1	11
Foam	3	3	2	8
Aerated water	3	2	2	7
Aerated mud	3	3	4	10
Water	1	1	4	4
Mud	3	2	5 (rotary only)	10

Table 3-5. Advantages and disadvantages of various drilling fluid media.

Ranked as fluid type	Advantages	Disadvantages
Mud	Cheap Maintain borehole stability	Restricts drilling to rotary Low efficiency Large volumes to maintain Large volume for disposal
Water	Cheap May maintain borehole stability	Low efficiency Large volumes to maintain Large volume for disposal
Aerated mud	Increases drilling efficiency at bit Good hole cleaning	Additional compressors Restricts drilling to rotary Large maintenance volumes
Aerated water	Increases drilling efficiency at bit Cheap Easy to maintain volume	Poor hole cleaning unless viscosified
Foam	Best hole cleaning Able to deal with large water influx Recyclable Fewest compressors	More expensive than fluid
Mist	Very good ROPs	Most expensive method (equipment) Unable to deal with large water influx
Air	Very good ROPs	Expensive equipment Unable to deal with moderate or large water influx

3.3.7 Wellbore stability

The issue of wellbore stability should be briefly discussed here. In the context of the choice of foam as the drilling fluid, the well will be drilled with bottom-hole pressures below hydrostatic pressure. This will significantly aid the rates of penetration, but the borehole wall will now be inherently unstable. From the point of view of elastic stress analysis (distribution) of a circular hole (i.e. prior to wellbore failure), there is no difference between hole sizes. In other words, the stress distribution around the holes of different sizes will be the same for a given in-situ stress regime. However, if there are local fractures, distinct planes of weakness, rubbles etc. in the formation, then a larger hole could potentially intersect the features (or more of them) and result in a less stable hole (failure along fractures, planes of weakness, rubbles etc.). This latter feature is an inherent risk of large diameter wellbores. Until the stress situation at the waste disposal site is better understood, it has been assumed for the purposes of this document that the granite is normally stressed, so there will be no more problems with drilling a large diameter borehole than there would be in drilling a smaller borehole.

3.3.8 Casing connections, casing running

Large casing strings such as those proposed above are generally run with large OD connections, and consequently require a large wellbore in which to be run. For example, an ABB-Vetco ALT-2 connection on 42” (1066.8 mm) casing has an OD of 45” (1143 mm). Add to this OD an additional 50 mm wall clearance, and the minimum hole size becomes 46” (1183 mm). This hole is more expensive to drill, and connections such as these cannot be justified on technical grounds. A set of connectors would cost approximately $US 8,250 per set, representing a cost of $338,250 per well (based on the well designs shown above) simply for this casing string. Welding the connections would be approximately 40% cheaper. The same logic can be applied to all the other casing sizes as well. Not only will welded connections give an essentially internally and externally flush connection, the strength of the weld will be the same as the pipe body itself, existing technology could be used, and the well design be slimmer and cheaper than using conventional casing connections. It is the “slimmer” well design that has been adopted for this study.

Operationally, running casing strings of these sizes is a slow process due to the weight and the dimensions of each casing joint. The rig will have to be capable of suspending the load of the longest string (762 mm, approximately 750,800 kg air weight) whilst having sufficient overpull capacity to pull back the string in case of any problem. This is discussed further in section 3.5.

3.3.9 Cementing, or annulus and wellbore isolation

Due to the volumes required, cementing the well will be difficult. In addition, cement displays shrinkage over time. This is because after the exothermic reactions in the cement during setting, which results in cement temperatures above the ambient temperature in the surrounding granite, a certain amount of cooling will occur. This may result in the formation of a micro-annulus if significant stresses are applied to the well, and may present a leak path up which contaminants may leak. In addition, the cementing of such large strings and large annular volumes is itself fraught with operational difficulties. On this basis, it is not recommended that the 36” casing is cemented. However, for the reasons of structural stability and isolation of the groundwater, the 42” casing should be cemented in place. In order to ensure good cement penetration into any fractures in the annulus, back-pressure should be applied to the annulus during cementing and a hesitation squeeze performed. Because the granite has a high fracture gradient, there should be no concerns about breaking down the formation.

A much better alternative for the 36” casing string is to displace a bentonite-fresh water slurry into the annulus after setting casing, instead of cement. This has the advantage that the bentonite swells instead of shrinking during hydration. As a financial consideration, bentonite is substantially cheaper than cement (approximately 70% cheaper). The only cement required in this case is a small amount of cement across the shoe (maybe the bottom 100m only). This small amount of cement across the casing shoe will enable it to withstand any loads exerted while drilling the next hole section; otherwise, there is a risk of the shoe joints backing off which could be disastrous given the dimensions of the casing.

The placement of the bentonite and cement slurries will be by the stab-in method (i.e. displaced down the drillpipe). This method has the advantage that the volumes of slurry required are much smaller than would otherwise have been for a conventional cementation. Additionally, the displacement of a smaller volume of cement around the shoe is easier to control in such large casing. There is no need to centralise the 42” and 36” casings except below the wellhead, but centralisation of the 30” casing will be needed on the shoe track and just inside the shoe of the previous casing. This will ensure good stand-off from the wellbore.

The only significant volumes of cement which are required are in the final string of 30” casing, from approximately 200 m below mudline to the wellhead. This can be placed conventionally through drillpipe. In addition, given the number of barriers below the final cement plug, there is no requirement for expensive high-quality oilfield cement, as well-prepared cement equivalent to API Class A will be sufficient, and will also be more readily available locally.

Isolation of the wellbore after the canisters have been deployed is to be made by means of high-density Wyoming bentonite barriers. Prior to displacement, the bentonite will require a maximum of approximately 4 hours hydration in fresh water. A bentonite grain-size of approximately 1 mm will be sufficient to allow rapid displacement before hydration makes it impossible to pump the slurry. The bentonite pills should be placed as balanced plugs within the well, on top of a viscosified mud.

The use of mechanical barriers (bridge plug, RTTS packer, etc) in the casing as a means of isolating the wellbore has also been considered. However, these all contain elastomers as part of their sealing element, which will degrade over time. Additionally, if there is a problem with the running or retrieving of the plug it may be required to be milled out. This presents unacceptable risks to the future retrieval of the waste canisters and is not considered a feasible option.

3.4 Drilling tools

In this section, there will be discussion of various downhole tools which are available, some techniques, and finally recommendations for the state-of-the-art tools. The choice of foam as the fluid medium for drilling, in addition to the results of the bit efficiency calculations, immediately leaves percussion drilling as the only technique capable of drilling these wells.

3.4.1 Downhole hammers

There are many companies who market downhole hammers. These hammers may be suitable for drilling with air, mist, water, or foam. Currently, mud hammers are being commercially developed (in particular by Smith Tool) but, because the tools are still experimental and given the choice of drilling fluid medium it is not necessary to consider mud hammers any further.

The leading suppliers of downhole hammers are Ingersoll-Rand, Smith Tool, Sandvik (Drilltech Mission) and Numa. Downhole hammers have essentially similar configurations and specifications, but the robustness of the hammer and the size of the piston (therefore the force of the impact) are the main criteria for selection. In these categories, Numa hammers are far ahead of their competitors.

There is very little new technology development at the moment in hammers, other than for drilling with mud. All hammers are capable of drilling with the other fluid media discussed above.

3.4.2 Drill bits

The main focus of research at the moment in downhole hammering technology is in the application of new drill bit technology. In particular, the gauge protection on the bit and the composition of the inserts are the main areas for development.

There are two approaches being taken about improving the composition of the carbide inserts. Most companies are changing the composition of the their tungsten carbide inserts to incorporate more boron and cobalt, in order to improve the hardness and therefore the wear resistance of the inserts. Two companies (Drillmaster International and Smith Tool) are incorporating polycrystalline diamond composite (PDC) technology into the cutter design and manufacture. This cutter technology developed in the oil industry over the last 15 years, and revolutionised the rates of penetration achieved and bit durability, justifying the additional expense of the bits. For example, a 12¼" tricone rock bit may cost US$ 17,000 whilst a 12¼" PDC bit may cost $US 47,500. Both Smith and Drill Master claim increases in bit durability of between 4 and 12 times compared with offset wells. Diamond enhance hammer bits have been available since 1988, but their problems of reliability (premature cutter failure) and their high cost compared with normal carbide insert bits has not given them a significant share of the market.

Drillmaster International's cutters are a sintered mixture of diamond and tungsten carbide on top of a tungsten carbide core. The outer coating is sintered diamond. This design has a basic flaw, however, because the impact force of the hammer in hard rock drilling is often high enough to spall off layers of the diamond coating, resulting in premature cutter wear and reduced ROPs. Smith, however, have developed this design further to include a transition layer between the tungsten carbide core and the outer diamond layer. The chemical bond between each layer helps to reduce the impact damage on the cutter and minimises the risk of the coatings spalling off.

Perhaps the most interesting development in hammer bit design is the introduction of diamond-enhanced gauge protection on the bit. Smith are currently the only company marketing this design of bit, which they trade as the Impax™ PD series. It is impossible to ream an undergauge hole with a hammer bit, as this will remove the outer cutters extremely quickly. In addition to this, if the gauge wears unevenly, then there may be a tendency for the bit direction to become unstable and for the hole to start deviating. Therefore, it is important to keep the hole in gauge and assess when the bit should be pulled before it goes out of gauge. Traditionally, in hammer drilling if a hole has gone undergauge then the next largest hole size down is drilled.

The PD enhanced insert feature on Smith's bits are set at 90° to the longitudinal axis of the bit and project out to just less than the gauge diameter of the bit. In the larger hole sizes, the PD gauge protection is 3/32" less than the gauge diameter. See Figure 3-5.

Figure 3-5. *Smith Impax™ 10.75” bit with PD Gauge feature.*

3.4.3 Downhole hammers

Rotary drilling, as has been shown above, is very inefficient in hard rock and large boreholes when compared with percussion (hammer) drilling. The hole sizes proposed for the waste disposal project are standard in the mining and construction industry, although the depths are much greater. It is difficult to select new developments in hammers because they all have the same basic design, and flaws in this design have been remedied in the same way by the different hammer manufacturers. The main hammer manufacturers are Numa, Ingersoll-Rand, Smith Tool, Sandvik (Drilltech Mission) and Drillmaster International. All these manufacturers have hammers capable of drilling the hole sizes required.

Of the main hammer manufacturers, it is generally accepted in the drilling industry that Numa hammers are the most reliable, the most robust and, because they have a heavier piston than any of the other comparably-sized hammers, have the highest impact force per unit of air or liquid pumped.

It is recommended that the BHA during drilling be kept as simple as possible. A full-gauge stabilised locked assembly should be run in order to maintain vertical hole angle. In addition, approximately 82 m of 10” (or larger) drill collars should be run immediately above the hammer. When drilling, the hammer will only require approximately 22 kN weight on bit even in the 838.2 mm hole section, and the string will, therefore, be run in tension. This has the advantages of keeping the assembly as stiff as possible and minimising any unwanted deviation from the vertical. The BHA should be run either on 6-5/8” drillpipe or heavy-walled 7” / 9-5/8” casing. These have the advantages of additional stiffness and strength, combined with larger ODs and IDs than conventional 5” drillpipe. However, further study will be required to determine whether drilling with casing is feasible due to the modifications required to surface equipment (e.g. BOPs) and the fatigue life of premium threads in repeated stress cycles imposed by drilling. Here, the API drillpipe has a major advantage.

Conventional rotary drilling and continuous wireline coring strings drilling in a homogeneous formation will, in general, give the straightest hole if the weigh in bit is kept as low as possible and the drillstring RPM is high (100–120 RPM for conventional drilling, 250–300 RPM for continuous wireline coring). However, hammer drilling in large diameter wellbores only requires a small RPM (say, 10–15). Any higher will usually lead to premature gauge wear and undergauge hole. The calculated torque for the drillstring mentioned in the previous paragraph is approximately 10.5 kNm.

When drilling the main disposal wells, it has been assumed that a pilot hole will not be needed. There will be no requirement for logging and well testing (the geology of the disposal area will be well-enough studied by that time), and the large diameter hammers are easily capable of drilling without a pilot hole. It can be argued that deviation control will be better in the large diameter holes because the BHA will be a larger OD, higher weight and therefore will impart more weight to keep the drillstring in tension.

However, in the appraisal wells a pilot hole is recommended for logging purposes. The “ideal” hole size for logging tools is between 152.4 mm (6”) and 215.9 mm (8.5”) diameter due to the effect of the stand-off from the borehole wall with centralised tools. The availability of standard equipment for these hole sizes is guaranteed. Unfortunately, the developments in wireline logging technology are towards developing tools for smaller hole sizes so any pilot hole will have to be drilled in a significantly smaller hole size than the main hole. For logging and testing purposes, the largest hole size to be drilled should be 311.1 mm (12.25”).

Two problems will be encountered while drilling the pilot hole: maintaining deviation, and opening up the main hole from the pilot hole.

Maintaining deviation. Two approaches can be taken: either maintain a mechanically stiff drillstring (as discussed above) or use a vertical drilling tool. A prototype of this tool was developed on the KTB project. However, further developments of the tool have moved the design away from a Vertical Drilling System into a more generic steerable system far removed in concept and design from the requirements for a Vertical Drilling System. The additional time and cost of re-developing the tool back into a vertical drilling system are not warranted given the project duration. Alternatively, field experience from hammer drilling has shown, even with large borehole diameters (e.g. the MHP well discussed in Section 3.1.1 a stiff drillstring can be easily achieved and maintained.

Hole opening: After logging and testing, the hole can be opened to full size. Given the high ratio between the pilot hole size and the final hole size, rates of penetration may not be significantly improved. The main technological obstacle to opening such a large hole is the reliability of a hammer underreamer. Such tools are available currently, but are eccentric in design and designed for drill-in casing systems. The development of a full-gauge underreamer suitable for pilot hole opening will be a priority for this project.

3.5 Drilling rig technology

The exceptional hole sizes proposed for this project will require a different approach to drilling rig design. The basic design for a rig is that of a mast which acts as a hoist for lowering / raising items from the wellbore. Most drilling rigs have some capacity for setting back stands of drillpipe. This adds to the loading on the rig.

The maximum loading on the rig will be during the running of the slotted 762 mm (30”) casing. As shown above, this casing has an air weight of 750,800 kg. To this must be added a safety factor to cover difficulties running the casing string. The shock loading is a worst case of additional load, for example when the string is stopped suddenly during normal running. For the string designed above, and additional load of approximately 110,000 kg must be added to the design calculations, giving a total possible loading on the rig while running the last casing joint of approximately 860,800 kg.

This load calculation does not take into account any drillpipe which is racked back. The air weight of the drillstring can be calculated as follows:

TD = 4000 m

3908 m of 6-5/8” OD drillpipe (48.21 kg/m)	188,400 kg
82 m of 10” OD x 2.75” ID drill collars (364.56 kg / m)	29,900 kg
30” hammer/bit	1,000 kg
Total air weight	**219,300 kg**

With all the drillpipe racked back in the derrick, and while running casing a total load of approximately 1,080,100 kg could be experienced by the derrick. A typical 2000 HP land rig and a typical offshore jackup rig in the North Sea typically have a derrick rating of approximately 567,000 kg; even a large semisubmersible drilling rig will have a derrick rating of 907,200 kg. It is clear that drill pipe cannot be racked back during casing running operations. It is also clear that considerable caution must be taken when running the casing so as not to exceed the design limitations of the equipment. Finally, it is clear that a normal drilling derrick on a land rig cannot be used to run the casing.

Casing running is done using the blocks, and is always a limiting factor in derrick design. It is recommended for the SKB operations that a jacking system be considered for running the casing. This puts all the loading on the wellhead through the sub-structure of the rig. The jacks are hydraulically activated and, if designed like the readily available hydraulic workover units, have bi-directional slips which hold the pipe under positive and negative axial loads. The failsafe mechanism is closed on these systems, so that if the hydraulics should fail, the slips will lock into position and will not be released from the casing. Therefore, the rating of the drilling rig mast should be based on the rating of the drillstring weight alone, which allows most normal 2000 HP land rigs to be considered. Running the 42” casing will, however, require modifications to the rotary table opening, since most land rigs have a rotary table opening of 37.5”. A top drive is generally recommended for the top-hole sections when hammer drilling, in order to get some weight to the bit. However, the weight of the 10” collars may be sufficient on their own. The drilling torque requirements at TD of 4000 m are 10.5 kNm, which is well within the capability of any 2000 HP land rig.

In addition to the modifications discussed above, safety will be of great concern during the casing running operations because of the extreme sizes involved. Specialist training may be required for rig crews and other services handling the casing.

3.6 Foreseen future improvements

Fluids: The further development of recycling of foam is being undertaken at the moment. This will certainly lead to cheaper and better foam recycling systems as competition takes place between companies.

Hammers: Unless a large diameter mud hammer can become commercially available in the next two years, then no new developments are anticipated for mud hammers. Since there is no commercial demand for these tools, it is not likely they will ever be developed.

Bits: The biggest technology development can come with in the field of hammer bits. Smith have already demonstrated that they can improve by a factor of ten the lifetime of a bit by introducing better cutter technology. Further developments can be anticipated in the regions of gauge protection, insert wear resistance, and the more development of the more aggressive bullet-shaped carbide inserts for use with PDC technology.

One of the most obvious gaps in technology is the availability of a full-gauge underreamer suitable for drilling with a hammer. No company seems to be developing this technology at the moment, relying instead on eccentric underreamers and pipe rotation to open the hole.

Rigs: Should the project get clearance to proceed, the development of a casing running system based on hydraulic jacks is essential.

4 Deposition technology

4.1 State-of-the-art

4.1.1 Canister design and deployment

Approaches were made to several companies: Smith Red Baron (SRB), Weatherford and Baker Oil Tools. These companies have the best oilfield experience in building specialist running and retrieving tools for a wide variety of applications. The basis of design was as follows:

The canisters must be deposited by a single-trip system which has a positive-acting fail-safe latching device. If the primary latching mechanism fails during running (which will go unseen during the running operations), the secondary device will allow the canister to be run to its deposition point. If the canister does not release from its primary running device, the weight of the running string will not change (as monitored by the driller), and it will then become necessary to use the secondary method of releasing the canister. Each of the methods must be simple. The basic waste canister was assumed to be a steel cylinder 4.2 m in height and approximately 500 mm in diameter, deposited inside a minimum wellbore ID of 750 mm. A fishing neck had to be designed for each canister to ensure retrieval, but the canister itself must not be engaged by any running / retrieving tool.

The best design (in terms of simplicity, effectiveness and the use of field-proven methods) was presented by Smith Red Baron (SRB). Schematic drawings showing the running procedure are shown in Attachment 3.

SRB have modified a jetted double J-slot latching method for the top of the canisters, with a collet catch to provide 100% redundancy. This would be used to run and release the canister once at the bottom of the well. There will be a shear pin incorporated into the collet mechanism which ensures that the canister cannot be inadvertently released. There will be 8 shear pins each with a shear value of approximately 2270 kg. Once the canister has been placed on bottom, approximately 18150 kg set-down weight will be applied to break the shear pins before the collet will open. The pipe is then turned and the J-slot running tool pulled out of the canister fishing neck.

When running the canisters SRB will use a running tool as well as a high flow bypass valve above the jetted J-slot tool. The running tool will contain a grease reservoir below a floating piston. The type of the grease will be determined once more information is available with regard to downhole conditions. The high flow bypass valve allows the running string to be filled up with wellbore fluid whilst running the canister to bottom. Upon releasing the canister, and as the J-slot tool is pulled out of the canister, circulation is increased until the high flow bypass valve closes. At this point the pressure increases forcing the grease into the canister’s J-slot. This grease will ensure that no barite or solids settle inside the fishing neck of the waste canister. The grease can be easily jetted out with the jetting function of the tool when the canisters are required to be retrieved. Above the top-most canister, a “junk basket” will be deployed in order to catch any debris which may settle in the well during its lifetime and prevent it from collecting between the waste containers and the casing wall.

To enable easy running and retrieval, the canisters must be centralised. The centralisers should be solid bodied, attached to the canister as longitudinal fins. The outer diameter of the centralisers should be approximately 15 mm less then the internal diameter of the casing. Each centraliser should be approximately 1 m in length and 15 mm in width, positioned at mid-point down the canister. They should be made of material sufficiently durable that they will not be destroyed during deployment or retrieval and that they will not corrode during the life of the project. Materials such as Kevlar or HDPE are ideal in these circumstances, although bonding them to the canister may be a problem. This can be overcome by encapsulating the entire canister in a thin plastic coating which then serves as a sheath on which to bond the centraliser. Metallic materials are not recommended because, in the event that a portion of the stabiliser becomes dislodged during either running or retrieving, operations will not be compromised as the stabilisers can also be deformed if significant load is applied.

The location of each canister in the hole after placement will always be accurately known, although the amount of settlement of each canister in the underlying bentonite barrier needs to be understood. Each length of drillpipe has a unique serial number, and its length is measured as standard practice during drilling operations. A tally is kept by the driller of these lengths. Therefore, at any given time the position of the end of the drillpipe can be given to within 10 centimetres over 4000 m. The positioning can be refined by accounting for both the stretch of the drillpipe under its own weight and the buoyancy of the drillstring in the mud. Pipe stretch is measured using the following formula:

$$\Delta L = F \times L \times SC \qquad \text{Equation 4-1}$$

where:

F is force acting on the drillpipe at the point of reference

L is the length of the pipe

SC is a stretch constant for the material and pipe body OD, supplied by the drillpipe manufacturer.

4.1.2 Displacement to the deployment mud

Once TD has been reached, prior to running the casing the hole will be displaced from foam to the bentonite deployment mud. This will be achieved by tripping out the hammer drilling assembly and running in with open-ended drillpipe in order to achieve maximum displacement velocity.

After running each canister, once the running tool has been disengaged and the grease pumped into the fishing neck, the bentonite slurry can be displaced conventionally through the drillstring. It is recommended that after coming out of the hole, apart from the necessary redressing and re-filling of the grease chamber, the running tool is checked thoroughly for cleanliness and is function tested prior to engaging the next canister.

4.2 Foreseen future improvements

There are really no new developments to be made for the running / retrieval because the technology has been available for the last 60 years. However, since the hole sizes are well beyond the conventional oilfield sizes, all equipment would have to be tailor-made for the job.

5 Retrievability

5.1 State-of-the-art

As discussed above, the same tool design is used for retrieving the canisters as it is for running them. Prior to retrieving the canisters it is most likely that the barite and other solids in the mud system will have settled and will have achieved cement like properties. Therefore the following steps will be required to ensure successful recovery of the canisters.

After drilling out the abandonment plugs of concrete, bentonite and asphalt wash down with a 711.2 mm (28”) bit to within 0.5 metre or so of the debris catcher. Once at the debris catcher, the wellbore should be fully displaced to low-viscosity normally weighted mud. Once the hole has been displaced to fresh mud, the debris catcher can be retrieved.

The next run in hole will be made with a centralised 711.2 mm OD x 682.6 mm (28” OD x 26 7/8” ID) integral washover shoe to wash over the fishing neck of the top canister. This will ensure the overshot can engage the canister and will clear any debris from the annulus. It is important that the swallow of the washover shoe does not engage the centralisers as this may result in damage to the centralisers, and possibly their dislodgement.

The J-slot / collet retrieving tool will be run to recover the canister. When setting down the running tool on the canister, drillstring weight will be carefully monitored by the driller. The tool will require approximately 2250 kg set-down weight to engage on the canister fishing neck. The safety feature in the tool when it is in the retrieving mode is shear pins. Eight pins will be placed in the running tool, with a shear value of 4500 kg per pin, thus an overpull of 36,000 kg would have to be seen before the collet would release.

After retrieving the first canister, the next run will be with a 711.2 mm (28”) bit. This will remove the bentonite barrier above the next canister, but it is essential that the bit does not come closer than 0.5 metres of the second canister. After pulling out of hole with the bit, a run with the washover shoe has to be made in order to clear settled bentonite from the annulus above the centraliser. The retrieving tool can then be run in to recover the second canister. Grease in the canister’s fishing neck will have protected it from significant debris ingress.

The above procedure will then be repeated for all subsequent canister runs. Schematic drawings showing the retrieval process are shown in Attachment 4**.**

5.2 Foreseen future improvements

As discussed in section 4.2, there are no improvements to be made in tool design, because the existing design makes use of field proven, simple and robust technology. However, one aspect needs to be studied in more detail: the settlement of the canisters over time. This has a critical bearing on their retrieval since this affects their position in the hole. If this position is not known accurately, it may result in problems during retrieval.

6 Discussion

It is possible to make an approximate cost estimate, even though there has never (to the knowledge of the author) been a similar well drilled anywhere in the world. Assuming a net on-bottom rate of penetration (ROP) of 1.5 m per hour and a casing running speed of 1 joint per hour, it will take approximately 137 days to drill the well from spud to true depth (TD), excluding any logging, testing, pilot hole drilling or time taken to run the canisters. Assuming a daily rig cost of 20,500 Euro (including all services), and a plain-end solid-body casing price of 500 Euro per tonne (resulting in a casing cost of approximately 762,500 Euro), an estimated wellhead cost of 100,000 Euro, a cost for other consumables of 480,000 Euro for diamond-enhanced hammer bits, 50 Euro/metre for foam, and 300,000 Euro for the canister running / retrieving tool system, an estimate for the well cost is approximately 4.65 Meuro to drill the well.

The well design presented above has been made on the basis of the final diameter of the waste canister, 500 mm. However, does the diameter have to be so large? If the diameter of the canister could be reduced, then the cost of the well will also be reduced, since rates of penetration will improve with decreasing hole size. For example, if the canister diameter was reduced by 100 mm, the well would take 131 days to drill and cost approximately 4.47 Meuro. Not only are there reduced costs (an estimated saving of at least 180,000 Euro but the handling of all the tubulars becomes easier with each reduction in size, operations become safer, and the environmental impact is reduced because there is a smaller amount of drilling waste (fluids and cuttings) to be disposed of.

It is the author’s conclusion that, even with current technology, the hole could be drilled today although it represents one of the most challenging projects ever to be presented to the drilling industry.

7 References

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Attachment 1

Casing selection criteria and tensile design for installation

CASING SELECTION GUIDE AND DESIGN CRITERIA. 30" CASING

Mud weight during installation (ppg)	8.7
Percent of casing removed by slotting	20.00%
Dogleg severity (°/100 ft)	1.5
Section TD (ft)	13123

										INSTALLATION LOAD (TENSILE)						
Grade	OD (INS)	WT (INS)	D/T	YP (PSI)	Burst (PSI)	Collapse (PSI)	Tensile (LBS)	Plain end weight (LB/FT)	Slotted pipe weight (LB/FT)	String air weight (LBS)	Buoyed WT (LBS)	Tension (LBS)	Shock (LBS)	Net load (LBS)	Design factor	Can the casing be used?
X52	30	0.5	68.000	52000	1338	1507	2736334	157.93	126.34	1658012	-220426	358185	229376	2025147	1.35	Safe to use
X52	30	0.469	72.495	52000	1255	1415	2569056	147.92	118.34	1552923	-206455	335483	215380	1897331	1.35	Safe to use
X52	30	0.438	77.626	52000	1172	1323	2401465	138.29	110.63	1451824	-193014	313642	201355	1773806	1.35	Safe to use
X52	30	0.406	83.744	52000	1087	1227	2228137	128.32	102.66	1347155	-179099	291030	186846	1645932	1.35	Safe to use
X52	30	0.375	90.667	52000	1004	1134	2059908	118.65	94.92	1245635	-165602	269098	172761	1521891	1.35	Safe to use
X52	30	0.344	98.837	52000	921	1042	1891364	108.95	87.16	1143801	-152064	247099	158645	1397480	1.35	Safe to use
X52	30	0.312	108.974	52000	835	946	1717054	98.93	79.14	1038607	-138079	224373	144042	1268944	1.35	Safe to use
X52	30	0.281	120.996	52000	752	852	1547873	89.19	71.35	936352	-124484	202283	129866	1144017	1.35	Safe to use
X52	30	0.25	136.000	52000	669	759	1378377	79.43	63.54	833888	-110862	180147	115660	1018833	1.35	Safe to use
X56	30	0.5	68.000	56000	1441	1623	2946821	157.93	126.34	1658012	-220426	358185	229376	2025147	1.46	Safe to use
X56	30	0.469	72.495	56000	1352	1524	2766676	147.92	118.34	1552923	-206455	335483	215380	1897331	1.46	Safe to use
X56	30	0.438	77.626	56000	1262	1424	2586193	138.29	110.63	1451824	-193014	313642	201355	1773806	1.46	Safe to use
X56	30	0.406	83.744	56000	1170	1321	2399533	128.32	102.66	1347155	-179099	291030	186846	1645932	1.46	Safe to use
X56	30	0.375	90.667	56000	1081	1222	2218362	118.65	94.92	1245635	-165602	269098	172761	1521891	1.46	Safe to use
X56	30	0.344	98.837	56000	992	1122	2036854	108.95	87.16	1143801	-152064	247099	158645	1397480	1.46	Safe to use
X56	30	0.312	108.974	56000	899	1018	1849136	98.93	79.14	1038607	-138079	224373	144042	1268944	1.46	Safe to use
X56	30	0.281	120.996	56000	810	918	1666940	89.19	71.35	936352	-124484	202283	129866	1144017	1.46	Safe to use
X56	30	0.25	136.000	56000	721	817	1484406	79.43	63.54	833888	-110862	180147	115660	1018833	1.46	Safe to use
X60	30	0.5	68.000	60000	1544	1739	3157308	157.93	126.34	1658012	-220426	358185	229376	2025147	1.56	Safe to use
X60	30	0.469	72.495	60000	1448	1632	2964295	147.92	118.34	1552923	-206455	335483	215380	1897331	1.56	Safe to use
X60	30	0.438	77.626	60000	1353	1526	2770921	138.29	110.63	1451824	-193014	313642	201355	1773806	1.56	Safe to use
X60	30	0.406	83.744	60000	1254	1416	2570928	128.32	102.66	1347155	-179099	291030	186846	1645932	1.56	Safe to use
X60	30	0.375	90.667	60000	1158	1309	2376817	118.65	94.92	1245635	-165602	269098	172761	1521891	1.56	Safe to use
X60	30	0.344	98.837	60000	1062	1202	2182343	108.95	87.16	1143801	-152064	247099	158645	1397480	1.56	Safe to use
X60	30	0.312	108.974	60000	964	1091	1981217	98.93	79.14	1038607	-138079	224373	144042	1268944	1.56	Safe to use
X60	30	0.281	120.996	60000	868	984	1786007	89.19	71.35	936352	-124484	202283	129866	1144017	1.56	Safe to use

(contd.)

										INSTALLATION LOAD (TENSILE)						
Grade	OD (INS)	WT (INS)	D/T	YP (PSI)	Burst (PSI)	Collapse (PSI)	Tensile (LBS)	Plain end weight (LB/FT)	Slotted pipe weight (LB/FT)	String air weight (LBS)	Buoyed WT (LBS)	Tension (LBS)	Shock (LBS)	Net load (LBS)	Design factor	Can the casing be used?
X60	30	0.25	136.000	60000	772	876	1590435	79.43	63.54	833888	-110862	180147	115660	1018833	1.56	Safe to use
X65	30	0.5	68.000	65000	1673	1884	3420417	157.93	126.34	1658012	-220426	358185	229376	2025147	1.69	Safe to use
X65	30	0.469	72.495	65000	1569	1768	3211320	147.92	118.34	1552923	-206455	335483	215380	1897331	1.69	Safe to use
X65	30	0.438	77.626	65000	1465	1653	3001831	138.29	110.63	1451824	-193014	313642	201355	1773806	1.69	Safe to use
X65	30	0.406	83.744	65000	1358	1534	2785172	128.32	102.66	1347155	-179099	291030	186846	1645932	1.69	Safe to use
X65	30	0.375	90.667	65000	1255	1418	2574885	118.65	94.92	1245635	-165602	269098	172761	1521891	1.69	Safe to use
X65	30	0.344	98.837	65000	1151	1302	2364205	108.95	87.16	1143801	-152064	247099	158645	1397480	1.69	Safe to use
X65	30	0.312	108.974	65000	1044	1182	2146318	98.93	79.14	1038607	-138079	224373	144042	1268944	1.69	Safe to use
X65	30	0.281	120.996	65000	940	1066	1934841	89.19	71.35	936352	-124484	202283	129866	1144017	1.69	Safe to use
X65	30	0.25	136.000	65000	836	949	1722971	79.43	63.54	833888	-110862	180147	115660	1018833	1.69	Safe to use
X70	30	0.5	68.000	70000	1801	2029	3683526	157.93	126.34	1658012	-220426	358185	229376	2025147	1.82	Safe to use
X70	30	0.469	72.495	70000	1690	1905	3458345	147.92	118.34	1552923	-206455	335483	215380	1897331	1.82	Safe to use
X70	30	0.438	77.626	70000	1578	1780	3232741	138.29	110.63	1451824	-193014	313642	201355	1773806	1.82	Safe to use
X70	30	0.406	83.744	70000	1463	1652	2999416	128.32	102.66	1347155	-179099	291030	186846	1645932	1.82	Safe to use
X70	30	0.375	90.667	70000	1351	1527	2772953	118.65	94.92	1245635	-165602	269098	172761	1521891	1.82	Safe to use
X70	30	0.344	98.837	70000	1239	1402	2546067	108.95	87.16	1143801	-152064	247099	158645	1397480	1.82	Safe to use
X70	30	0.312	108.974	70000	1124	1273	2311419	98.93	79.14	1038607	-138079	224373	144042	1268944	1.82	Safe to use
X70	30	0.281	120.996	70000	1012	1147	2083675	89.19	71.35	936352	-124484	202283	129866	1144017	1.82	Safe to use
X70	30	0.25	136.000	70000	901	1022	1855508	79.43	63.54	833888	-110862	180147	115660	1018833	1.82	Safe to use
X80	30	0.5	68.000	80000	2059	2318	4209744	157.93	126.34	1658012	-220426	358185	229376	2025147	2.08	Safe to use
X80	30	0.469	72.495	80000	1931	2177	3952394	147.92	118.34	1552923	-206455	335483	215380	1897331	2.08	Safe to use
X80	30	0.438	77.626	80000	1804	2035	3694561	138.29	110.63	1451824	-193014	313642	201355	1773806	2.08	Safe to use
X80	30	0.406	83.744	80000	1672	1888	3427904	128.32	102.66	1347155	-179099	291030	186846	1645932	2.08	Safe to use
X80	30	0.375	90.667	80000	1544	1745	3169089	118.65	94.92	1245635	-165602	269098	172761	1521891	2.08	Safe to use
X80	30	0.344	98.837	80000	1416	1602	2909791	108.95	87.16	1143801	-152064	247099	158645	1397480	2.08	Safe to use
X80	30	0.312	108.974	80000	1285	1455	2641622	98.93	79.14	1038607	-138079	224373	144042	1268944	2.08	Safe to use
X80	30	0.281	120.996	80000	1157	1311	2381343	89.19	71.35	936352	-124484	202283	129866	1144017	2.08	Safe to use
X80	30	0.25	136.000	80000	1029	1168	2120580	79.43	63.54	833888	-110862	180147	115660	1018833	2.08	Safe to use

CASING SELECTION GUIDE AND DESIGN CRITERIA. 36" CASING

Mud weight during installation (ppg)	8.7
Percent of casing removed by slotting	0.00%
Dogleg severity (°/100 ft)	1.5
Section TD (ft)	6562

										INSTALLATION LOAD (TENSILE)						
Grade	**OD (INS)**	**WT (INS)**	**D/T**	**YP (PSI)**	**Burst (PSI)**	**Collapse (PSI)**	**Tensile (LBS)**	**Plain end weight (LB/FT)**	**Slotted pipe weight (LB/FT)**	**String air weight (LBS)**	**Buoyed WT (LBS)**	**Tension (LBS)**	**Shock (LBS)**	**Net load (LBS)**	**Design factor**	**Can the casing be used?**
X52	36	0.5	68.000	52000	1338	1507	2736334	189.57	189.57	1243958	-165380	644917	276028	1999524	1.37	Safe to use
X52	36	0.469	72.495	52000	1255	1415	2569056	177.97	177.97	1167839	-155260	605454	259141	1877174	1.37	Safe to use
X52	36	0.438	77.626	52000	1172	1323	2401465	166.35	166.35	1091589	-145123	565923	242223	1754612	1.37	Safe to use
X52	36	0.406	83.744	52000	1087	1227	2228137	154.34	154.34	1012779	-134645	525065	224728	1627927	1.37	Safe to use
X52	36	0.375	90.667	52000	1004	1134	2059908	142.68	142.68	936266	-124473	485397	207750	1504941	1.37	Safe to use
X52	36	0.344	98.837	52000	921	1042	1891364	131.00	131.00	859622	-114283	445662	190742	1381742	1.37	Safe to use
X52	36	0.312	108.974	52000	835	946	1717054	118.92	118.92	780353	-103745	404566	173154	1254328	1.37	Safe to use
X52	36	0.281	120.996	52000	752	852	1547873	107.20	107.20	703446	-93521	364694	156085	1130705	1.37	Safe to use
X52	36	0.25	136.000	52000	669	759	1378377	95.45	95.45	626343	-83270	324721	138986	1006780	1.37	Safe to use
X56	36	0.5	68.000	56000	1441	1623	2946821	178.89	178.89	1173876	-156062	608584	276028	1902426	1.55	Safe to use
X56	36	0.469	72.495	56000	1352	1524	2766676	167.95	167.95	1102088	-146518	571366	259141	1786076	1.55	Safe to use
X56	36	0.438	77.626	56000	1262	1424	2586193	157.00	157.00	1030234	-136966	534114	242223	1669605	1.55	Safe to use
X56	36	0.406	83.744	56000	1170	1321	2399533	145.67	145.67	955887	-127081	495569	224728	1549103	1.55	Safe to use
X56	36	0.375	90.667	56000	1081	1222	2218362	134.67	134.67	883705	-117485	458147	207750	1432117	1.55	Safe to use
X56	36	0.344	98.837	56000	992	1122	2036854	123.65	123.65	811391	-107871	420657	190742	1314919	1.55	Safe to use
X56	36	0.312	108.974	56000	899	1018	1849136	112.25	112.25	736585	-97926	381875	173154	1193687	1.55	Safe to use
X56	36	0.281	120.996	56000	810	918	1666940	101.19	101.19	664009	-88277	344248	156085	1076065	1.55	Safe to use
X56	36	0.25	136.000	56000	721	817	1484406	90.11	90.11	591302	-78611	306554	138986	958231	1.55	Safe to use
X60	36	0.5	68.000	60000	1544	1739	3157308	178.89	178.89	1173876	-156062	608584	276028	1902426	1.66	Safe to use
X60	36	0.469	72.495	60000	1448	1632	2964295	167.95	167.95	1102088	-146518	571366	259141	1786076	1.66	Safe to use
X60	36	0.438	77.626	60000	1353	1526	2770921	157.00	157.00	1030234	-136966	534114	242223	1669605	1.66	Safe to use
X60	36	0.406	83.744	60000	1254	1416	2570928	145.67	145.67	955887	-127081	495569	224728	1549103	1.66	Safe to use
X60	36	0.375	90.667	60000	1158	1309	2376817	134.67	134.67	883705	-117485	458147	207750	1432117	1.66	Safe to use
X60	36	0.344	98.837	60000	1062	1202	2182343	123.65	123.65	811391	-107871	420657	190742	1314919	1.66	Safe to use
X60	36	0.312	108.974	60000	964	1091	1981217	112.25	112.25	736585	-97926	381875	173154	1193687	1.66	Safe to use

(contd.)

										INSTALLATION LOAD (TENSILE)						
Grade	**OD (INS)**	**WT (INS)**	**D/T**	**YP (PSI)**	**Burst (PSI)**	**Collapse (PSI)**	**Tensile (LBS)**	**Plain end weight (LB/FT)**	**Slotted pipe weight (LB/FT)**	**String air weight (LBS)**	**Buoyed WT (LBS)**	**Tension (LBS)**	**Shock (LBS)**	**Net load (LBS)**	**Design factor**	**Can the casing be used?**
X60	36	0.281	120.996	60000	868	984	1786007	101.19	101.19	664009	-88277	344248	156085	1076065	1.66	Safe to use
X60	36	0.25	136.000	60000	772	876	1590435	90.11	90.11	591302	-78611	306554	138986	958231	1.66	Safe to use
X65	36	0.5	68.000	65000	1673	1884	3420417	178.89	178.89	1173876	-156062	608584	276028	1902426	1.80	Safe to use
X65	36	0.469	72.495	65000	1569	1768	3211320	167.95	167.95	1102088	-146518	571366	259141	1786076	1.80	Safe to use
X65	36	0.438	77.626	65000	1465	1653	3001831	157.00	157.00	1030234	-136966	534114	242223	1669605	1.80	Safe to use
X65	36	0.406	83.744	65000	1358	1534	2785172	145.67	145.67	955887	-127081	495569	224728	1549103	1.80	Safe to use
X65	36	0.375	90.667	65000	1255	1418	2574885	134.67	134.67	883705	-117485	458147	207750	1432117	1.80	Safe to use
X65	36	0.344	98.837	65000	1151	1302	2364205	123.65	123.65	811391	-107871	420657	190742	1314919	1.80	Safe to use
X65	36	0.312	108.974	65000	1044	1182	2146318	112.25	112.25	736585	-97926	381875	173154	1193687	1.80	Safe to use
X65	36	0.281	120.996	65000	940	1066	1934841	101.19	101.19	664009	-88277	344248	156085	1076065	1.80	Safe to use
X65	36	0.25	136.000	65000	836	949	1722971	90.11	90.11	591302	-78611	306554	138986	958231	1.80	Safe to use
X70	36	0.5	68.000	70000	1801	2029	3683526	178.89	178.89	1173876	-156062	608584	276028	1902426	1.94	Safe to use
X70	36	0.469	72.495	70000	1690	1905	3458345	167.95	167.95	1102088	-146518	571366	259141	1786076	1.94	Safe to use
X70	36	0.438	77.626	70000	1578	1780	3232741	157.00	157.00	1030234	-136966	534114	242223	1669605	1.94	Safe to use
X70	36	0.406	83.744	70000	1463	1652	2999416	145.67	145.67	955887	-127081	495569	224728	1549103	1.94	Safe to use
X70	36	0.375	90.667	70000	1351	1527	2772953	134.67	134.67	883705	-117485	458147	207750	1432117	1.94	Safe to use
X70	36	0.344	98.837	70000	1239	1402	2546067	123.65	123.65	811391	-107871	420657	190742	1314919	1.94	Safe to use
X70	36	0.312	108.974	70000	1124	1273	2311419	112.25	112.25	736585	-97926	381875	173154	1193687	1.94	Safe to use
X70	36	0.281	120.996	70000	1012	1147	2083675	101.19	101.19	664009	-88277	344248	156085	1076065	1.94	Safe to use
X70	36	0.25	136.000	70000	901	1022	1855508	90.11	90.11	591302	-78611	306554	138986	958231	1.94	Safe to use
X80	36	0.5	68.000	80000	2059	2318	4209744	178.89	178.89	1173876	-156062	608584	276028	1902426	2.21	Safe to use
X80	36	0.469	72.495	80000	1931	2177	3952394	167.95	167.95	1102088	-146518	571366	259141	1786076	2.21	Safe to use
X80	36	0.438	77.626	80000	1804	2035	3694561	157.00	157.00	1030234	-136966	534114	242223	1669605	2.21	Safe to use
X80	36	0.406	83.744	80000	1672	1888	3427904	145.67	145.67	955887	-127081	495569	224728	1549103	2.21	Safe to use
X80	36	0.375	90.667	80000	1544	1745	3169089	134.67	134.67	883705	-117485	458147	207750	1432117	2.21	Safe to use
X80	36	0.344	98.837	80000	1416	1602	2909791	123.65	123.65	811391	-107871	420657	190742	1314919	2.21	Safe to use
X80	36	0.312	108.974	80000	1285	1455	2641622	112.25	112.25	736585	-97926	381875	173154	1193687	2.21	Safe to use
X80	36	0.281	120.996	80000	1157	1311	2381343	101.19	101.19	664009	-88277	344248	156085	1076065	2.21	Safe to use
X80	36	0.25	136.000	80000	1029	1168	2120580	90.11	90.11	591302	-78611	306554	138986	958231	2.21	Safe to use

CASING SELECTION GUIDE AND DESIGN CRITERIA. 42" CASING

Mud weight during installation (ppg)	8.7
Percent of casing removed by slotting	0.00%
Dogleg severity (°/100 ft)	1.5
Section TD (ft)	1640

										INSTALLATION LOAD (TENSILE)						
Grade	OD (INS)	WT (INS)	D/T	YP (PSI)	Burst (PSI)	Collapse (PSI)	Tensile (LBS)	Plain end weight (LB/FT)	Slotted pipe weight (LB/FT)	String air weight (LBS)	Buoyed WT (LBS)	Tension (LBS)	Shock (LBS)	Net load (LBS)	Design factor	Can the casing be used?
X52	42	0.5	84.000	52000	1083	1223	3389786	221.61	222	363440	-48318	879570	461241	1655934	2.05	Safe to use
X52	42	0.469	89.552	52000	1016	1148	3181995	208.03	208	341169	-45357	825671	432977	1554460	2.05	Safe to use
X52	42	0.438	95.890	52000	949	1073	2973889	194.92	195	319669	-42499	773637	405691	1456498	2.04	Safe to use
X52	42	0.406	103.448	52000	880	996	2758741	180.35	180	295774	-39322	715809	375366	1347627	2.05	Safe to use
X52	42	0.375	112.000	52000	813	920	2549997	166.71	167	273404	-36348	661672	346977	1245705	2.05	Safe to use
X52	42	0.344	122.093	52000	745	845	2340940	153.04	153	250986	-33368	607416	318525	1143559	2.05	Safe to use
X56	42	0.5	84.000	56000	1167	1317	3650539	221.61	222	363440	-48318	879570	461241	1655934	2.20	Safe to use
X56	42	0.469	89.552	56000	1094	1237	3426764	208.03	208	341169	-45357	825671	432977	1554460	2.20	Safe to use
X56	42	0.438	95.890	56000	1022	1156	3202650	194.92	195	319669	-42499	773637	405691	1456498	2.20	Safe to use
X56	42	0.406	103.448	56000	947	1072	2970952	180.35	180	295774	-39322	715809	375366	1347627	2.20	Safe to use
X56	42	0.375	112.000	56000	875	991	2746151	166.71	167	273404	-36348	661672	346977	1245705	2.20	Safe to use
X56	42	0.344	122.093	56000	803	910	2521012	153.04	153	250986	-33368	607416	318525	1143559	2.20	Safe to use
X60	42	0.5	84.000	60000	1250	1412	3911292	221.61	222	363440	-48318	879570	461241	1655934	2.36	Safe to use
X60	42	0.469	89.552	60000	1173	1325	3671532	208.03	208	341169	-45357	825671	432977	1554460	2.36	Safe to use
X60	42	0.438	95.890	60000	1095	1238	3431411	194.92	195	319669	-42499	773637	405691	1456498	2.36	Safe to use
X60	42	0.406	103.448	60000	1015	1149	3183163	180.35	180	295774	-39322	715809	375366	1347627	2.36	Safe to use
X60	42	0.375	112.000	60000	938	1062	2942305	166.71	167	273404	-36348	661672	346977	1245705	2.36	Safe to use
X60	42	0.344	122.093	60000	860	975	2701084	153.04	153	250986	-33368	607416	318525	1143559	2.36	Safe to use
X65	42	0.5	84.000	65000	1354	1529	4237233	221.61	222	363440	-48318	879570	461241	1655934	2.56	Safe to use
X65	42	0.469	89.552	65000	1270	1435	3977493	208.03	208	341169	-45357	825671	432977	1554460	2.56	Safe to use
X65	42	0.438	95.890	65000	1186	1342	3717361	194.92	195	319669	-42499	773637	405691	1456498	2.55	Safe to use
X65	42	0.406	103.448	65000	1100	1245	3448426	180.35	180	295774	-39322	715809	375366	1347627	2.56	Safe to use
X65	42	0.375	112.000	65000	1016	1150	3187497	166.71	167	273404	-36348	661672	346977	1245705	2.56	Safe to use
X65	42	0.344	122.093	65000	932	1056	2926175	153.04	153	250986	-33368	607416	318525	1143559	2.56	Safe to use
X70	42	0.5	84.000	70000	1458	1647	4563174	221.61	222	363440	-48318	879570	461241	1655934	2.76	Safe to use
X70	42	0.469	89.552	70000	1368	1546	4283455	208.03	208	341169	-45357	825671	432977	1554460	2.76	Safe to use
X70	42	0.438	95.890	70000	1278	1445	4003312	194.92	195	319669	-42499	773637	405691	1456498	2.75	Safe to use

(contd.)

										INSTALLATION LOAD (TENSILE)						
Grade	**OD (INS)**	**WT (INS)**	**D/T**	**YP (PSI)**	**Burst (PSI)**	**Collapse (PSI)**	**Tensile (LBS)**	**Plain end weight (LB/FT)**	**Slotted pipe weight (LB/FT)**	**String air weight (LBS)**	**Buoyed WT (LBS)**	**Tension (LBS)**	**Shock (LBS)**	**Net load (LBS)**	**Design factor**	**Can the casing be used?**
X70	42	0.406	103.448	70000	1184	1340	3713690	180.35	180	295774	-39322	715809	375366	1347627	2.76	Safe to use
X70	42	0.375	112.000	70000	1094	1239	3432689	166.71	167	273404	-36348	661672	346977	1245705	2.76	Safe to use
X70	42	0.344	122.093	70000	1003	1137	3151265	153.04	153	250986	-33368	607416	318525	1143559	2.76	Safe to use
X80	42	0.5	84.000	80000	1667	1882	5215056	221.61	222	363440	-48318	879570	461241	1655934	3.15	Safe to use
X80	42	0.469	89.552	80000	1563	1767	4895377	208.03	208	341169	-45357	825671	432977	1554460	3.15	Safe to use
X80	42	0.438	95.890	80000	1460	1651	4575214	194.92	195	319669	-42499	773637	405691	1456498	3.14	Safe to use
X80	42	0.406	103.448	80000	1353	1532	4244217	180.35	180	295774	-39322	715809	375366	1347627	3.15	Safe to use
X80	42	0.375	112.000	80000	1250	1416	3923073	166.71	167	273404	-36348	661672	346977	1245705	3.15	Safe to use
X80	42	0.344	122.093	80000	1147	1300	3601446	153.04	153	250986	-33368	607416	318525	1143559	3.15	Safe to use

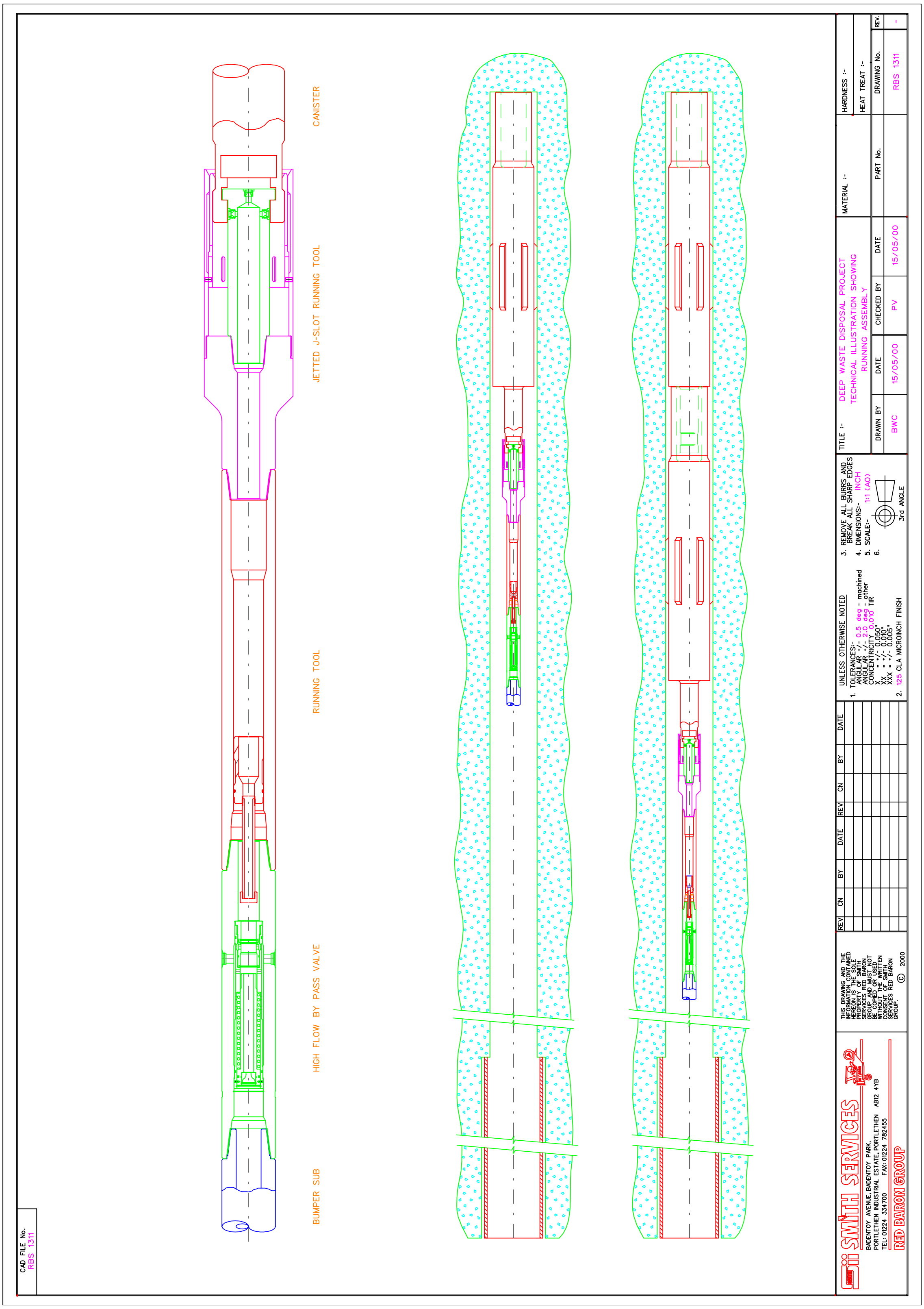
Attachment 2

Determination of biaxial casing buckling stresses

Casing Outside Diameter (in)	**30**	Casing Weight in air	1653760
Casing Inside Diameter (in)	**29**	Buoyancy	-279726
Casing wt in air (lb/ft)	**126,02**	Casing Weight in Mud	1374035
Shoe Depth (ft)	**13123**	Stability Force	
Seabed Depth (ft)	**0**	at TOC (on landing and cementing)	0
Mud wt initial (psi/ft)	**0,46**	at shoe (in mud)	-279726
Mud wt final (psi/ft)	**0,46**	at shoe (in cement)	-279726
Cement density - Lead (psi/ft)	**0,46**	at shoe (after drilling out)	-279726
Cement density - Tail (psi/ft)	**0,46**	at TOC (after drilling ahead)	0
TOC – Lead (ft)	**0**		
TOC – Tail (ft)	**0**	Hanger load after cementing	1374035
Applied Casing Pressure (psi)	**0,00**	Axial load reduction from temp rise	2289234
Average Temp change (deg F)	**247,00**	Hanger load after drilling ahead	-915199
Average Hole Dia (in)	**33**		
		Axial force at shoe	
Youngs Modulus (psi)	**30000000**	On landing	-279726
Coefft expansion steel (/deg F)	**6,667E-06**	On cementing	-279726
Outside casing area (in^2)	706,86	After drilling ahead	-2568960
Inside casing area (in^2)	660,52	Axial force at TOC	
Area of steel (in^2)	46,34	After cementing	1374035
2nd Moment of Area I (in^4)	5042,20	After drilling ahead	-915199
		(Reverse) Ballooning (lb)	0
Axial load at Hanger (lb)	-915199	Neutral Point (ft bdf)	-8741
Axial Force at TOC (lb)	-915199	Buckled Shortening (in)	0,18
Buckling Force at TOC (lb)	-915199	Buckled Shortening Axial Load (lb)	2366
Axial Stress at TOC (psi)	-19750	Radial Clearance (in)	1,50
Buckling Bending Stress (psi)	-2042	Buckled Shortening (Alternate)	0,18
Buckled Dogleg (deg/100ft)	0,31	Reduced Wt/ft	104,70
Helix Pitch (ft)	301		

Attachment 3

Smith Red Baron schematic drawing for running the waste canisters


CANISTER
JETTED J-SLOT RUNNING TOOL
RUNNING TOOL
HIGH FLOW BY PASS VALVE
BUMPER SUB
CAD FILE No.
RBS 1311
HARDNESS :-
HEAT TREAT :-
MATERIAL :-
PART No.
DRAWING No.
RBS 1311
REV.
-
TITLE :-
DEEP WASTE DISPOSAL PROJECT
TECHNICAL ILLUSTRATION SHOWING
RUNNING ASSEMBLY
DRAWN BY
BWC
DATE
15/05/00
CHECKED BY
PV
DATE
15/05/00
3. REMOVE ALL BURRS AND BREAK ALL SHARP EDGES
4. DIMENSIONS:- INCH
5. SCALE:- 1:1 (AO)
6.
3rd ANGLE
UNLESS OTHERWISE NOTED
1. TOLERANCES:-
ANGULAR +/- 0.5 deg - machined
ANGULAR +/- 2.0 deg - other
CONCENTRICITY 0.010 TIR
X = +/- 0.050"
XX = +/- 0.010"
XXX = +/- 0.005"
2. 125 CLA MICROINCH FINISH
REV
CN
BY
DATE
REV
CN
BY
DATE
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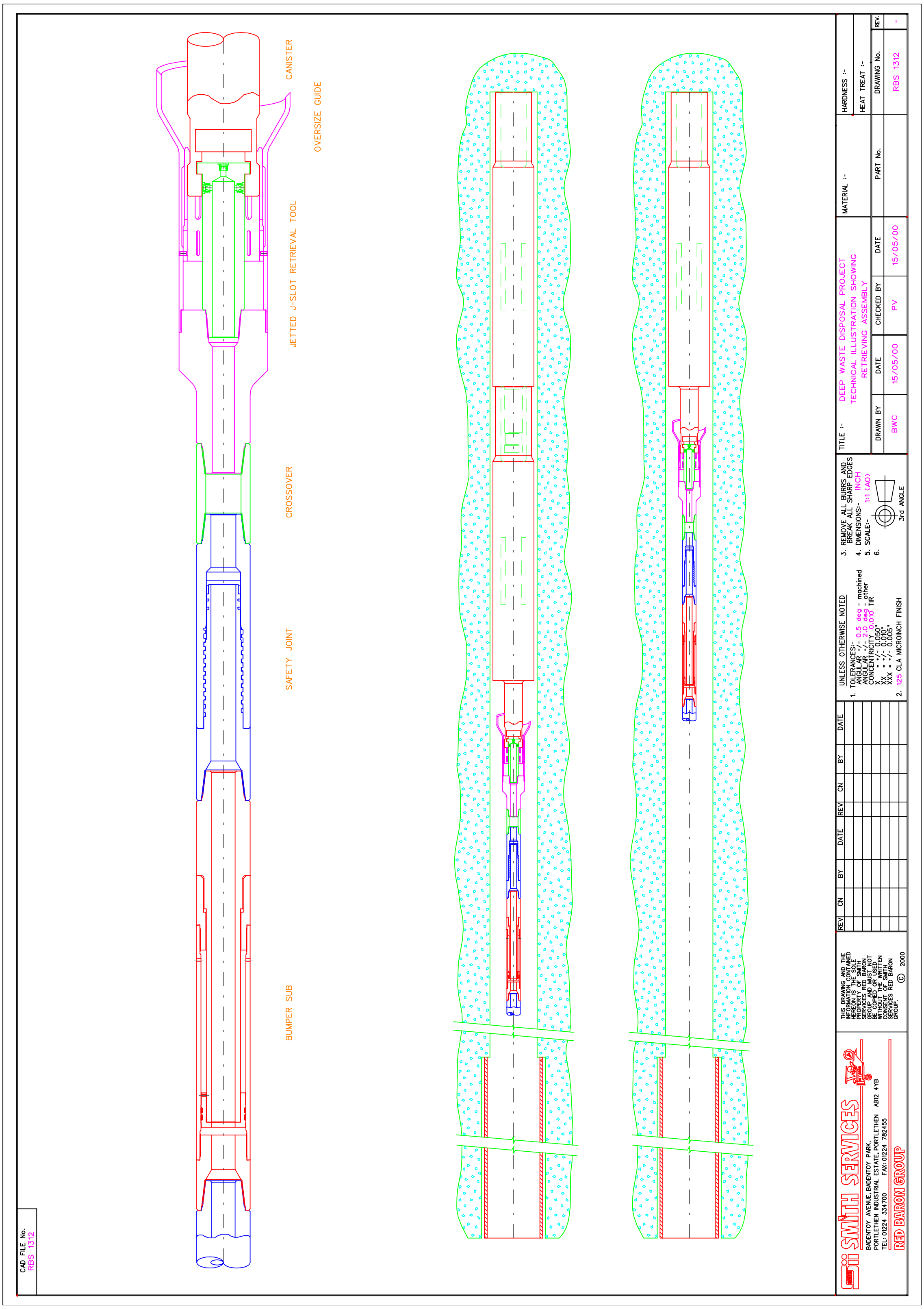
SMITH SERVICES
BADENTOY AVENUE, BADENTOY PARK,
PORTLETHEN INDUSTRIAL ESTATE, PORTLETHEN AB12 4YB
TEL: 01224 334700 FAX: 01224 782455
RED BARON GROUP

Attachment 4

Smith Red Baron schematic drawing for retrieving the waste canisters


CANISTER
OVERSIZE GUIDE
JETTED J-SLOT RETRIEVAL TOOL
CROSSOVER
SAFETY JOINT
BUMPER SUB
CAD FILE No.
RBS 1312
SMITH SERVICES
BADENTOY AVENUE, BADENTOY PARK,
PORTLETHEN INDUSTRIAL ESTATE, PORTLETHEN AB12 4YB
TEL: 01224 334700 FAX: 01224 782455
RED BARON GROUP
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© 2000
REV CN BY DATE REV CN BY DATE
UNLESS OTHERWISE NOTED
1. TOLERANCES:-
ANGULAR +/- 0.5 deg - machined
ANGULAR +/- 2.0 deg - other
CONCENTRICITY 0.010 TIR
X = +/- 0.050"
XX = +/- 0.010"
XXX = +/- 0.005"
2. 125 CLA MICROINCH FINISH
3. REMOVE ALL BURRS AND BREAK ALL SHARP EDGES
4. DIMENSIONS:- INCH
5. SCALE:- 1:1 (A0)
6.
3rd ANGLE
TITLE :- DEEP WASTE DISPOSAL PROJECT TECHNICAL ILLUSTRATION SHOWING RETRIEVING ASSEMBLY
MATERIAL :-
HARDNESS :-
HEAT TREAT :-
DRAWN BY BWC
DATE 15/05/00
CHECKED BY PV
DATE 15/05/00
PART No.
DRAWING No. RBS 1312
REV. -