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Salton Sea Scientific Drilling Plan
and Well Designs

Submitted to
Bechtel National Inc.

by
Berkeley Group Inc.

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Preface

The following report has been submitted as a draft in partially completed form to Bechtel National Inc. at their request.

The initial BGI contract with Bechtel specifies that BGI would provide

"draft input to each of the activities. Bechtel will prepare final specifications."

The preparation of this report is outside the scope of our original contract under which there were no reporting requirements.

Due to schedule demands we have provided only the sections that the Bechtel technical manager has requested. The remainder of the report is being prepared and complete reports will be delivered at a later date.

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1. Introduction and Summary

Project Scope The purposes and goals of the Scientific Deep Drilling Program have been outlined in previous documents. The purpose of this report is to provide supporting documentation for the engineering recommendations and detailed specifications associated with the drilling program.

The drilling plan developed for Bechtel and described below has been revised several times due to changes in the project scope and project guidelines. Some of these changes were made due to the unforeseen cost implications associated with certain drilling operations and specifications. Some of the revisions were in response to DOE requests to Bechtel. The revisions have required the rewriting of some of the draft input for resubmission to Bechtel.

The current drilling project scope includes the following guidelines.

- Drill to a depth at which the temperature is approximately 572F (300C).
- Drill approximately 6000 feet deeper than the 572F depth (estimated 10,000 feet).
- Complete the well to allow production for up to 30 days.
- Make the well available, after drilling, for scientific experimentation.
- Attempt to retrieve cores from about 15% of the total depth.
- Attempt to retrieve four of those cores from depth

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between 500 and 3000 feet.

- Attempt geophysical borehole logs prior to setting intermediate and production casing strings.
- Provide casing termination at the surface that will allow a hang-down liner (do not include the hang-down liner in the draft specifications).
- No flow tests will be scheduled prior to reaching total depth.
- No rig standby time is to be specified in the drilling plan or draft input to specifications.
- The well should be designed to last up to one year without failure due to corrosion or borehole instability.
- An injection well will be drilled to about 4000 feet.
- The injection well must have at least a one year lifetime.
- The injection well must be capable of accepting the maximum potential flow from the production well.
- Geophysical wellbore logs will be attempted in the injection well prior to setting casing.
- No attempts at retrieving core will be made while drilling the injection well.
- Well testing and brine handling specifications and plans are outside the scope of this report.

The guidelines listed above have evolved during the numerous design iterations that have already been made and evaluated. Many of the guidelines have been defined for cost-related reasons. For example, the scientific experiments and the well testing is assumed to take place after the rig has been released

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because of the additional cost of up to 30 days of standby charges. Another example of a cost-related guideline is the we have planned for "attempts at core retrieval". In order to keep the number of drilling days at a minimum we assume that only one attempt to retrieve core will be made each 120 feet from 3000 feet to bottomhole depth. The drilling plan specifies the use of a 30 foot corebarrel, and when this corebarrel is run every 120 feet it has the potential to retrieve about 1500 feet of the total drilled depth of 10,000 feet if each attempt is 100% successful. Therefore, since core retrieval in the fractured portions of the well will almost certainly be much less than 100%, the total "retrieved" core from the well may be much less than 15% of the total drilled depth.

Some of the design iterations included coring at bit change, continuous coring, and wireline coring. These possibilities (and others) were all rejected as being either technically infeasible or too costly. If coring is done on bit change there is not sufficient "potential core footage" to meet the 15% guideline.

Flow tests with the rig on the hole were rejected as too costly and mechanically difficult except for a one to two day pit test after completion to clean out the well. The requirement of 30 days of rig standby time after drilling is not included. Coring the injection well was considered unnecessary

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and too costly. All of these guidelines play a part in the well design and drilling plan and were requested or authorized by Bechtel.

Locations of the Wells Figure 1.1 shows the approximate locations of the production well 14-2 and the injection well 13-1. The production well location has been defined by Bechtel to be 400 feet west and 400 feet north of a permanent marker at the intersection of Davis and McDonald Roads. The outline of the Salton Sea shown on the map is no longer correct, and should not be used for reference.

The locations of the nearby wells should be noted as they are referred to in the section below covering the resource properties.

Resource Properties The general guidelines for the project, as outlined above, together with the resource properties result in numerous restrictions and requirements on the well design. For this reason we will review the resource properties before summarizing the design criteria.

The Imperial Valley is a sediment-filled trough formed by relative tectonic movement of the Pacific and continental plates. The high temperature of the resource is related to thermal convection of hot fluids from the deepest parts of the

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reservoirs to the shallower depths. The temperature in the nearby Elmore #1 well has been used as the guideline for the highest probable resource temperature profile and is discussed below in Section 2. When the Elmore #1 temperature profile is extrapolated to about 10,000 feet the temperature is predicted to be in excess of 700F (370C).

The resource brine is composed primarily of a chloride solution. There are also metals, sulfur, gases, and silica dissolved in the brine. The brine is highly corrosive at all temperatures. Experience in the Imperial Valley shows that well-life can be as short as 3 months and as long as a few years, depending on the resource location, brine characteristics and completion design.

Well Design As indicated above, the combination of project guidelines and resource properties results in some necessary well design parameters. These design parameters have been reviewed by the DOE Industry Advisory Panel. With the exception of some minor recommendations our initial well design was endorsed. Some of the design parameters for the production well are:

- Intermediate casing to about 3000 feet.
- Production casing to about 6000 feet.
- Optional production liner.

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- Wellhead to meet ANSI 1500 lb service rating.
 - Production casing with maximum yield for strength.
 - Production casing with minimum yield to prevent hydrogen sulfide, CO2 and chloride induced failure.

Similar injection well parameters are:

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- Intermediate casing to about 2000 feet.
 - Injection/production casing to about 3000 feet.
 - Injection liner 2800-4000 feet.
 - Wellhead to meet ANSI 900 lb service rating.

Contingencies Some of the project guidelines are fundamental in scope. The absolute necessity of some guidelines could result in increased cost if our assumptions about the resource are not correct. For example, if the temperature is not 575F or greater at 4000 feet, must we drill deeper than 10,000 feet? Since the time needed for drilling and coring below 10,000 feet is large, additional footage below 10,000 feet will be very costly.

Conversely, if the temperature is extremely high at depths shallower than 10,000 feet, must we continue to drill? If so the danger of exceeding the wellhead rating during flow tests is an eminent danger.

There are other contingencies that can have severe impact on cost. The most likely one is the possibility of getting stuck

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during coring or drilling. Even without coring there is a relatively high incidence of stuck drill pipe in the Imperial Valley. This phenomenon is especially prevalent during loss of circulation. This problem sometimes requires fishing or sidetracking to drill around the stuck equipment. The fishing operation to remove stuck drilling assemblies or sidetracking can be time consuming, costly problems.

Another contingency to be considered during drilling of the potential production zone is loss of circulation. To drill the production zone for maximum flow requires minimizing the use of lost circulation material to prevent wellbore damage (permanent reservoir flow impairment). But to drill with a minimum risk of getting stuck requires continuous circulation and placement of LOC material. These incompatible requirements can lead to either a non-productive well, or costly drilling problems.

The most difficult contingency to anticipate may be associated with coring. Under even the best conditions there is no guarantee of recovering complete cores. In the deeper parts of this well, below 4000 feet, we expect the rock to be brittle and fractured. This makes the likelihood of recovering large core percentages very small. The core recovery could be as small as 20%, or less, of the core barrel length (less than 6 feet per attempt). This is highly likely and has not been addressed in this drilling program. Since the total drilling

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and coring time is currently about twice as long as the straight drilling time, additional attempts at core retrieval (especially from the deeper depths) would increase the cost of drilling significantly.

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2. Formation Characteristics

There is a large amount of data available covering the formation properties at the Salton Sea. The majority of the data has been made available through the DOE Salton Sea Projects. The latter were primarily under the direction of the Lawrence Livermore Laboratory and the field developers. The data obtained and published by LLL included temperature profiles, analyses of cuttings, and well test results. Most of the data is available from depths less than 5000 feet. However, well Elmore #1 was drilled to 7000 feet and the River Ranch #1 well reached 8000 feet.

Most of the available well data is for shallow wells, but when the static temperature for the closest wells to 14-2 and 13-1 are plotted, along with the Elmore #1 data, they all extrapolate to about 700 to 715F at 10,000 feet. Figure 2.1 shows the comparison.

2.1 Rock Types

The sediments in the Salton Trough consist of recent sands, silts, and clays at shallow depths, and the deeper rocks are composed of similar, older sediments that have been metamorphosed due to high temperature and pressure at depth. The metamorphic mineral assemblages include common calcitic and silicic phases that are found in other geothermal resources

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Figure 2.1 Static Temperature Profiles

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around the world. The metamorphosed rocks are found in inhomogeneous assemblages common to deltaic sediments. The metamorphosed sediments are relatively impermeable, brittle, and have low porosity. The active seismicity in the Salton Trough results in almost continuous epochs of fracturing, cementation and refracturing. The pores and fractures are saturated with a saline brine.

2.2 Static Conditions

The assumed geothermal profile and hydrostatic profile used in the design are shown in Figure 2.2. The temperature profile is based on measurements made in Elmore #1 (Palmer 1975) which is located approximately 2 miles southwest of the proposed site for the Salton Sea Deep Well (SSDW). The Elmore #1 profile was chosen as the design basis because it exhibits high shallow temperatures and as such represents a "worst case" condition for the well design.

The maximum temperature measured in Elmore #1 was 680F at 6900 feet. The design bottomhole temperature for the SSDW was estimated by extrapolating the temperature gradient in the bottom 2000 feet of the Elmore #1 to the anticipated 10,000 foot completion depth. The bottom-hole temperature on this basis is 715F.

Inspection of chemistry data from the existing wells in the

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Figure 2.2

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area suggests the salinity of the reservoir fluid is approximately 270,000 ppm (Palmer 1975). The measured pressures in the existing wells indicate the formation is approximately hydrostatic from the surface.

The salinity and temperature profile along with brine density data presented by Dittman were used to calculate the hydrostatic profile. The resulting hydrostatic pressure at 10,000 feet is 4230 psia.

Fluid properties were determined using data reported by Haas (1971) for steam-brine mixtures. The saturation pressure for 27 percent salinity brine at 715F is 2619 psia. No reliable data could be found in the literature on noncondensable gas content. The effect of gas was assumed to be negligible in estimating the wellbore flowing conditions. However, gas was considered in calculating the design wellhead conditions.

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3.0 Completion Design

3.1 Casing Program

The casing program is shown in Figure 3.1. The industry advisory panel recommended that the 30 inch conductor casing should be set to 60 feet to ensure the unconsolidated surface sands are adequately stabilized. The 20 inch surface casing will be set to a maximum 700 feet; however, a shallower setting is advisable if a sudden increase in mud return temperature is noted before the 700 foot depth is reached.

It is important to ensure an acceptable surface casing is in place while the 17 1/2 inch diameter hole is drilled to 3000 feet. Formation temperatures could exceed 550F in the lower part of this interval and productive zones may be encountered anywhere below 2000 feet. There is also the possibility that a shallow CO₂ zone may be encountered in the near surface. The 20 inch casing should be as deep as possible to ensure well kicks can be safely controlled.

In view of the high temperatures that are anticipated and the largely unknown formation and fluid conditions at depth we have opted for a final completion that includes an intermediate string of 13 3/8 inch casing from the surface to 3000 feet and a 9 5/8 inch production string from the surface to 6000 feet. This program ensures the length of uncased hole is kept to a minimum at any particular point in the program which greatly

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reduces the risks of hole instability problems developing.

The Elmore #1 temperature profile exhibits a gradual change from a conductive to convective gradient in the vicinity of 2000 feet to 4000 feet. This may represent the transition from the near surface formation and aquifers, to the geothermal reservoir. The casing depth of 3000 feet was chosen to ensure the near surface aquifers are adequately protected from contamination by geothermal fluids. Moreover, the Elmore #1 profile closely approaches the boiling point with depth curve in the region 3000 feet to 5000 feet as shown on Figure 2.2. Spontaneous boiling and discharge could occur if wellbore temperatures are allowed to approach the formation temperature. Cementing the 13 3/8 inch casing to 3000 feet will allow any well control problems that may occur to be safely dealt with.

Two major factors influenced the selection of 6000 feet for the 9 5/8 inch casing depth.

1) The extensive coring operations planned for this well will require many round trips of the drilling assemblies. The associated interruptions in mud circulation and the regular running of pipe in and out of the hole may cause deterioration of the wall and promote severe sloughing, collapse or swelling problems. Minimizing the interval of open hole subject to these conditions at any one time will

lessen the risk of severe hole problems occurring.

2) The projected bottom-hole temperature is 715F and the corresponding saturation temperature is 2619 psia. If the well produces from bottom-hole with no drawdown then the wellbore fluid will begin to flash when the pressure drops to 2619 psia. Above this point the fluid in the wellbore will be at a higher pressure than the formation fluid and wellbore fluids could escape into the surrounding formation. This condition will occur above 6000 feet for the conditions projected for the SSDW. Casing to 6000 feet provides assurance that wellbore fluids will be contained within the well up to the surface. The 9 5/8 inch casing will be run and cemented to the surface to provide double string protection in the near surface portion of the well.

A 7 inch slotted liner is shown on the Figure. It is recommended that the liner be available on-site but run only if problems are encountered in maintaining the hole open during drilling and its stability over time is of concern.

3.2. Wellhead Design

Two criteria were employed in determining the design wellhead condition.

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- 1) A steam column in the wellbore at the reservoir temperature (i.e. 715F).
- 2) A gas (50:50, H₂S:CO₂) column in the wellbore to the bottom of the cemented casing (6000 feet) at an assumed average temperature of 500F.

The first criterion results in a maximum design wellhead pressure of 2200 psi and the second criterion results in a design wellhead pressure of 2250 psia. Based on these design conditions we recommend the critical wellhead components meet ANSI 1500 lb service ratings. This would include as a minimum, the casing head flange, expansion spool, 3 inch wing valves (double valving), and double 10 inch master valves.

3.3 Casing Design

The three main conditions that the casing will be subjected to are: 1) emplacement operations, 2) well discharging and 3) injecting (or circulating) cold fluids. The relevant loading and stress conditions include:

- 1) Collapse - (Due to external pressure) The design case is normally assumed to occur when casing is being run empty into a mud filled hole. The worst case service condition occurs when the wellbore is hot and empty such as might occur when stimulating the well by pumping nitrogen through continuous tubing.
- 2) Tension - Tension stresses occur due to string weight,

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internal pressure and cooling of the wellbore below the neutral (zero thermal stress) temperature.

- 3) Compression - Compression stresses occur when the wellbore is heated above the neutral temperature.
- 4) Burst - Stresses due to internal pressure.

In most cases the casing will experience a combined stress condition. For this reason a biaxial stress analysis was used in determining casing stresses and the maximum energy distortion theory was employed as the failure criterion.

Temperature changes in the well may be as high as 500F. For example, the temperature increase in the near surface between shut-in and flowing or the temperature decrease at 6000 feet between shut-in and injecting or circulating cold fluids could both approach 500F. In this case, large thermal stresses will be produced by these large temperature changes and are the determining factor in the casing design. It is of interest to note that the thermal stress is a function of temperature, elastic modulus and the expansion coefficient only. Therefore, failure depends on material strength alone rather than a combination of strength and casing dimensions (e.g. wall thickness).

The thermal stress developed at a given well condition is a function of the cement bonding temperature since this will be

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the zero stress reference temperature of the casing. The cement bonding temperature is difficult, if not impossible to predict. For the purposes of this design we assumed the cement bonding temperature in the near surface would be 200F and could be as low as 300F or as high as 500F at 6000 feet.

Another important factor that is particularly relevant to geothermal wells is creep. At high temperatures steel under stress will undergo significant creep. Creep will relax the stresses in the casing with time. It is virtually impossible to predict what the stress condition may be at a particular time and more importantly, what it is likely to be when the well condition is abruptly changed, such as when the well is discharged.

There is evidence that corrosion may be severe in this environment; however, the actual severity of the problem in terms of casing serviceability is unknown. For this reason the thickest wall casings that would permit the use of standard 12 1/4 inch and 8 1/2 inch bits without special preparation were arbitrarily selected for the 13 3/8 inch and 9 5/8 inch strings. This approach provides a combination of maximum strength and maximum corrosion protection.

The casing material was selected on the basis of the stress calculations under the service conditions outlined in Table 3.1. Only API grade carbon steel casing materials were considered.

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Table 3.1
Summary of Design of 9 5/8"
C95, 47#, Buttress Casing String

Depth (ft)	Assumed Cement Bonding Temp.	Operation or Service Condition	Loading or Stress	Design Factor
6000	-	Running empty into 9.5 lb/gal mud	collapse	1.52
6000	300F	Flowing at 700F	compression	0.96
6000	300F	Injecting at 1500 psi WHP, 100F fluid	biaxial ¹	1.85
6000	500F	Injecting at 1500 psi WHP, 100F fluid	biaxial ¹	1.06
6000	500F	Wellbore hot but empty	collapse	1.54
6000	500F	Flowing at 700F	compression	1.96
surface	200F	Running	weight	4
surface	200F	Injecting at 1500 psi WHP, 100F fluid	biaxial ¹	3.5
surface	200F	Flowing with 650F WHT	biaxial ²	1.16
6000	-	Injection after creep relaxation	biaxial ¹	0.87
surface	-	Flowing after creep relaxation	biaxial ²	0.66

¹) Internal pressure with axial tension

²) Internal pressure with axial compression

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Of these the highest strength considered was C95 (95,000 psi minimum yield) since there is evidence that very high strength steels are subject to stress cracking in high chloride and hydrogen sulfide environments (Greenip 1978).

Buttress thread joints were selected for the 9 5/8 inch and 13 3/8 inch strings. Buttress thread joints offer strengths similar to the pipe body itself and are widely used in geothermal applications.

The inner casing strings could reach temperatures of the order of 700F when the well is flowing. Published data on the properties of casing at elevated temperatures was reviewed and indicated that yield strength at 700F is approximately 80 percent of the cold yield for a wide range of casing steels (see Snyder 1980, Nicholson 1984).

Based on the above described approach the two selected inner strings are as follows:

9 5/8 inch casing

Specification: API grade C95, 47#/ft, Buttress

Wall Thickness = 0.472"

Joint Area (minimum) = 10.47 sq. in.

Cold yield = 95,000 psi

Hot yield = 76,000 psi

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13 3/8 inch casing

Specification: API grade C95, 68#/ft, Buttress

Wall thickness = 0.48"

Joint Area (minimum) = 14.46 sq. in.

Cold yield = 95,000 psi

Hot yield = 76,000 psi

The results of the casing design for the above described 9 5/8 inch string to 6000 feet is shown in Table 3.1. The 13 3/8 inch design (not tabulated) produced similar results since, as explained above, the thermal stresses were similar for both strings and dominated the design. It is important to note that no corrosion allowance was included in the design calculations.

The complete casing design is given below:

30" conductor: 0-60', 118#/ft plain end

20" conductor: 0-700', 94#/ft, k-55, LT&C

13 3/8" intermediate: 0-3000', 68#/ft, C95, buttress

9 5/8" production: 0-6000', 47#/ft, C95, Buttress

7" slotter liner: 5800-10,000', 29#/ft, N80, LT&C

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4.0 Drilling Program

The production and injection wells that are needed for this project have been designed to meet the various requirements and problems that can develop in the drilling, testing and workover operations that will occur during their expected lifetimes. The well and casing diameters have been chosen to meet the expected drilling and completion activities. The minimum bit diameters used in successful geothermal operations is 8 1/2 inches. This size has been chosen from experience associated with drilling high temperature, fractured reservoirs normally encountered in geothermal environments.

Smaller bit sizes can be used in workover operations for cleanout. However, these sizes (6 inch diameter and smaller) do not last long in drilling operations. The bit life is important in drilling operations from the view that much of the time associated with drilling is used in running the drill pipe in and out of the wellbore. Moreover, these smaller bit diameters are run with smaller diameter drilling strings and bottomhole assemblies that withstand lower torque and tensional forces than those necessary to drill a usable hole in the deep geothermal environments. Deviation of the wellbore off vertical is also a problem with the small diameter drilling assemblies. Deviation should not be allowed to be greater than 1 degree per 100 feet or greater than 5 degrees at any depth. If deviation is greater

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than this the drilling operation should be adjusted to straighten the hole back to vertical (slowly), maintaining the 1 degree per hundred foot criteria.

The deep hole production well is shown in Figure 4.1. The 60 feet of 30 inch casing is necessary to remove cuttings and to assist in cementing of the 20 inch casing through shallow loss of circulation zones. The actual depth of this string will depend on how deep the auger bit drilling rig can bore a 36 inch hole. The advisory panel suggested that the normal practice in the area is to set the 20 inch casing to at least 700 feet. This casing string is needed for blow-out prevention when drilling the 17 1/2 inch hole for the 13 3/8 inch casing. The 13 3/8 casing depth has been chosen for several reasons. The reservoir caprock is assumed to be at approximately 3000 feet from the temperature survey in well Elmore #1 (see discussion in Section 3). This 3000 foot depth is at the beginning of the point where the temperature versus depth begins to become isothermal. This casing depth will also seal off the shallow aquifers above the caprock that could be damaged if a blowout occurs when drilling the 12 1/4 inch hole for the 9 5/8 production string. Another reason for the 3000 foot setting depth is to minimize the amount of open hole in the wellbore at any one time.

It has also been alluded to that several gas pockets have

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Figure 4.1

Well Drilling and Casing Program

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been found above 3000 feet. It will be advantageous to case through this zone before drilling the higher temperature zones at greater depths.

The 9 5/8 inch casing string should be set to at least 6000 feet. Maintaining the minimum amount of open hole is one reason. Other reasons have been discussed previously.

The lower uncased portion of the well is to be completed with an 8 1/2 inch open hole. The minimum bit size discussed above has some impact on the choice of this diameter. Also, the well may be drilled deeper than the current target depth of 10,000 feet. This will require that 7 inch casing be set to as yet an undetermined depth. Wellhead design conditions may change if a deeper completion results in higher temperature. Furthermore, if hole conditions get to the point where sloughing zones are causing drill pipe sticking or there are loss of circulation zones that can not be sealed off, then 7 inch casing will have to be set. Drilling would then have to proceed with 6 inch drill bits and the required bottom hole assemblies. This will hopefully not occur. However, we are drilling into unknown conditions at this site and should plan to meet these problems.

The corrosive characteristics of the brine in the Salton Sea area have been well documented. One solution to corrosion of the casing has been to run a production liner from surface to several hundred feet above the bottom casing point. The annulus

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between the liner and the outside production string is filled with an inert compound (gas or liquid). The advisory panel has suggested that nitrogen be used as the annular fluid. This will require a 7 inch string hung in a packer assembly from the surface to about 5800 feet. Corrosion of this 7 inch liner will still occur; however, the 9 5/8 production string will be protected by the nitrogen gas from the inside and by cement on the outside. If the 7 inch string corrodes, it can be removed and replaced.

The design of the injection well incorporates a similar design methodology as discussed above. However, the completion is also based on the expected injection rates. The maximum injection rate is estimated to be 1000 gpm. A production liner has been recommended to lengthen the expected life of the well. The friction loss along the length of the wellbore needs to be included in the design of the well. The pressure loss for 7 inch casing and 5 inch casing is on the order of 2.5 psi/100 and 12 psi/100 for their respective casing diameters.

If 3500 feet of 5 inch casing were placed in the well, a pressure drop on the order of 420 psi would develop from friction losses associated with injection rates of 1000 gpm. This pressure drop plus the pressure increase from flow into the reservoir will have to be developed at the surface. For a 7 inch liner the friction losses for 1000 gpm will be on the order

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of 90 psi. From surface design considerations, this 90 psi pressure loss will be much easier to include into the surface injection facilities.

Workover operations to alleviate injection well damage are also included in the design considerations. The workover operations include: producing the injection well, acidizing, scale removal, redrilling and cleanout operations. If redrilling were necessary to obtain reservoir injectivity, the larger diameter casing in the well will allow for the most efficient strategy in recompletion.

The injection well also must be designed as a production well. The well should be produced immediately after completion. Testing of the well should be performed to determine reservoir and wellbore characteristics. An estimate of injectivity should be determined and monitored during injection testing and injection operations.

4.1 Drilling Rates and Coring Operations

The design of the drilling program includes several assumptions for drilling rates and estimates for the time necessary to case the well, run electrical logs, cement the casing to the borehole and flow test the well at the total depth. Approximately 15% of the well will be cored at various

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depths.

The drilling rates, core rates, bit life, etc, used in the design are shown in Table 4.1.

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TABLE 4.1

Design Assumptions for Salton Sea Deep Well

Depth	bit life (hours)	drilling rate (ft/hr)	# of cores	core rate (ft/hr)	# of bits	# of core bits
0 - 700	45	15	0	0	1	0
700 - 3000	80	12½	4	5	2	2
3000 - 6000	48	10	18	5	5	3
6000 - 10000	45	8	27	5	9	6

The rate at which the drill string is pulled out of the hole or run into the hole is 18 feet/minute (5 minutes per 90 feet). The time it takes to circulate the mud in the hole is assumed to be 40 minutes per 1000 feet when running into the hole or circulating before pulling out of the hole for coring operations. The coring operation itself requires several other

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operations as outlined below.

- 1) Circulate
- 2) Pull drill pipe out of hole
- 3) Stand back bottom hole assembly
(collars, stabilizers, reamers, shock sub, bit)
- 4) Pick up core barrel and collars
- 5) Run drill pipe into hole
- 6) Circulate
- 7) Core interval
- 8) Pull drill pipe out of hole
- 9) Lay down core barrel, stand back collars
- 10) Pick up bottom hole assembly
- 11) Run drill pipe into hole
- 12) Circulate
- 13) Begin drilling

The total time to perform a given coring operation is 6 hours/1000 feet plus 8 hours (for pickup/laydown and 30 feet of core at a 5 ft/hr core rate). Thirty foot cores are assumed due to the difficulties associated with coring operations; mainly core barrel jamming, low volume circulation rates, fractured formations, high temperatures, etc.

Figure 4.2 illustrates the various times associated with the coring operation. As can be seen in the figure the time it takes to obtain 30 feet of core at 10,000 feet (assuming the

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Figure 4.2 Well Depth versus Coring Time

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FOR 30' CORES AT CORE RATE 5' / HR
 TOTAL CORING TIME (HOURS)
 $= 0.006 (\text{Depth}) + 8$

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SALTON SEA DEEP WELL
 WELL DEPTH (feet)

VERSUS
 TIME (HOURS)
 FOR VARIOUS
 OPERATIONS

[]

operation begins during drilling and ends with drilling operations resuming) is 68 hours (2 days and 20 hours). This is a time consuming operation at great depths. Choosing to obtain approximately 1500 feet of core yields the following drilling scenario:

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- 1) 0-700 feet - no cores
 - 2) 700-3000 feet - drill 500 feet, core 30 feet - which yields 4 cores (120 feet)
 - 3) 3000-6000 feet - drill 120 feet, core 30 feet which yields 18 cores (540 feet)
 - 4) 6000-10,000 feet - drill 120 feet, core 30 feet which yields 27 cores (810 feet)

The total program obtains core every 50 feet between 700 and 3000 feet and 30 feet of core every 100 feet of drilling from 3000 to 10,000 feet for a total of 49 cores. Additional coring times can be obtained from figure 4. for any specified depth.

The circulation rates discussed above (40 minutes/1000 feet) have been assumed for operations relevant to drilling and coring. We have not modeled the expected circulating temperature (T_{in} , T_{out}) and circulating temperatures as a function of depth. The input required for these calculations has not been obtained by BGI to date. This input should include the times when the wellbore will be left quiescent for some duration of time. The circulation rates we have used are

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estimated for "breaking down" the mud in the well after it has set for a period of time and for the circulation time to remove cuttings from the wellbore before coring operations begin. Circulation times for cementing operations have also been assumed to allow for circulation of the annulus and for conditioning the mud.

Detailed circulation rates should be calculated before the well drilling is begun and should be updated during the drilling operation. Temperature changes along the length of the wellbore after it has been warmed should be minimized to reduce any large temperature changes that may damage the casing. We have not calculated what the allowable temperature change for a given time period should be at this time. Further investigation should be performed in this area and the resulting guidelines maintained during the drilling operation. This will require that temperature versus depth surveys be taken periodically during the drilling activities.

The drilling rig size, capacity, and auxiliary equipment that will be needed to drill this well has been outlined in previous draft input to the drilling program plan. It will suffice here to state that the rig should be capable of drilling with 4 1/2 inch drill pipe and have the ability to set a 9 5/8 inch casing string to 10,000 feet. The rig should be capable of drilling to 16,000 feet. The circulating system should have

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approximately 1000 barrels of surface volume and a dual pumping system (2 mud pumps) capable of 1750-2000 Horsepower. Maximum circulation rates of up to 1000 gallons per minute should be obtainable when operating the mud pumps in parallel to the drill pipe. A 27 1/2 inch rotary table with a 20 foot high substructure (for blow out prevention equipment) should be included.

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5.0 Drilling Procedure with Daily Drilling Activities

Table 5.1 is a condensed summary of the drilling activities associated with the Salton Sea Deep Well - SSDW drilling and coring project. The total drilling time includes the time associated with drilling, casing, cementing, logging and coring. A 36 hour flow test has been included at 10,000 feet (Total Depth). The various scientific activities that will take place during the drilling and testing operations have not been included in our time estimates.

The total drilling time is estimated to be 152 days from the beginning of drilling the 26 inch hole to completing the well at 10,000 feet (open hole from 6000 to 10,000 feet). The assumptions for drilling rates, circulating times, etc, have been discussed in Section 4.0. The total drilling time includes only time spent drilling (i.e. rotating time). The coring time given in the summary is indicative of rotating hours to obtain core. Total time Running and Pulling out of hole and the total time circulating are the total time used in the various operations. The time used in the complete coring operation is on the order of 90 days. The total casing, cement, WOC, logging, testing, etc time does not include the time needed to set a 7 inch production liner from 5800 to 10,000 feet or for a 7 inch hang-down liner from surface to 5600 feet.

The total number of drilling bits and core bits that are

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Table 5.1
Drilling Program Summary

Total Time	3657 hours	152 days
Total Drilling Time	830 hours	35 days
# of Bits	17	
26"	1	
17½"	2	
12¼"	5	
8½"	9	
Total Coring Time	294 hours	12 days
# of Core Bits	11	
9 7/8"	5	
8½"	6	
Total Time Running in and Pulling out of hole	1412 hours	59 days
Total Time Circulating	691 hours	29 days
Total Time casing, cement, etc	391 hours	16 days

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shown in Table 5.1 are estimated from the previous criteria. It is normal drilling practice to dispose of bits that show the slightest amount of wear. The bits will be pulled out of the hole to obtain cores after about one-third of their estimated useful life. This may require that the number of bits used to be increased by a factor of 2 to 3 times the values shown in the table. The same will apply to core bits and other portions of the bottom hole assembly.

Figure 5.1 is a graph of well depth versus time for the drilling operation to a total depth of 10,000 feet. The tables in Appendix A are a detailed listing of the estimated time for various drilling and coring operations on an hourly basis. These tables were used to develop Figure 5.1. It should be noted on the Figure that the depth versus time decreases at increasing depth. A comparison between Figures 4.1 and 5.1 is instructive to this point.

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Figure 5.1 Well Depth versus Drilling Time

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SALTON SEA DEEP WELL

APPENDIX A

Daily Drilling Operations Versus Time and Depth

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DEPTH (ft)	TIME (hrs)	OPERATION	TOTAL TIME hrs/day	TOTAL DRILLING TIME (hrs)	TIME ON BIT (hrs)	BIT #/size	TIME ON COREBIT (hrs)	TOTAL CORING TIME (hrs)	COREBIT #/size	POOH RIH TOTAL TIMES (hrs)	TOTAL CIRCULATING TIME (hrs)	Casing NippleUp WOC	# of Core	CIRC TIME	POOH RIH LAYDOWN
700	48	Drill 26" hole	48/2	45	48	1/26				1	2				
	4	Run 20" casing	52									4			
	2	Stabin	54							2					
	2	Circulate	56								4				
	2	Cement	58									6			
		Pull up chk float													
		Dump cement													
	1	POOH - Lay down 26"	59							3					
	12	WOC - Nipple up	71									18			
		20" flange													
		20" spool													
		18" D G BOP													
		20" ABOP, RH													
	6	Pitcher Nipple	77									24			
	3	RIH w 17½ BHA	80			2/17½				6					
	1	Drillout 26" show	81	46	1										
	40	Drill to 1200'	121/5	86	41										
	1	Circulate	122								5				
	1	POOH	123							7					
	1	PU core barrel	124						1/9 7/8	8					
	1	RIH	125							9					
	1	Circulate	126								6				
1230	6	Core 30'	132					6					1		
	1	Circulate	133								7				
	1	POOH	134							10					
	1	Lay down core B	135							11					
	1	Pick up BHA	136							12					
	1	RIH	137							13					
	1	Circulate	138								25				

DEPTH (ft)	TIME (hrs)	OPERATION	TOTAL TIME (hrs/day)	TOTAL DRILLING TIME (hrs)	TIME ON BIT (hrs)	BIT #/size	TIME ON COREBIT (hrs)	TOTAL CORING TIME (hrs)	COREBIT #/size	POOH RIH TOTAL TIMES (hrs)	TOTAL CIRCULATING TIME (hrs)	Casing NippleUp WOC	# of Core	CIRC TIME	POOH RIH LAYDOWN
1730	40	Drill to 1730'	178	126	81										
1760	18	Core 30'	196			3/17 1/2	12	12	1/9 7/8	22	28		2	3	9
2260	40	Drill to 2260'	236	166	40										
2290	22	Core 30'	258				18	18	1/9 7/8	33	33		3	5	1
2790	40	Drill to 500'	298	206	80										
2820	25	Core 30'	323				24	24		46	38		4	6	13
3020	16	Drill to set casing	339	222	-	RR									
	3	Circulate for logs	342								41				
	3	POOH	345							49					
	12	Run Logs	357									36			
	3	RIH	360							52					
	3	Circulate	363								44				
	3	POOH	366							55					
	12	Run Logs	378									48			
	3	RIH	381							58					
	3	Circ for casing	384								47				
	10	Run casing 17 1/2"	394									58			
	2	Rig up cementers	396									60			
	3	Circ annulus	399/16								50				
	3	Cement	402									63			
	-	Rig down	-												
	24	WOC	426									87			
	-	Land Casing	-												
	-	Cut off casing	-												
		Nipple Up													
	12	Weld on casing head	438									99			
		5000# x 5000# Drilling spool													
		13 5/8 DG BOP, ABOP													

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DEPTH (ft)	TIME (hrs)	OPERATION	TOTAL TIME (hrs/day)	TOTAL DRILLING TIME (hrs)	TIME ON BIT (hrs)	BIT #/size	TIME ON COREBIT (hrs)	TOTAL CORING TIME (hrs)	COREBIT #/size	POOH RIH TOTAL TIMES (hrs)	TOTAL CIRCULATING TIME (hrs)	Casing NippleUp WOC	# of Core	CIRC TIME	POOH RIH LAYDOWN
3020		Spool Pitcher Nipple													
	8	Rotating head	446									107			
	3	Pick 12 1/2 BHA	449			4/12 1/2									
	6	RIH & Circ	455							61	53			3	3
	3	Drill out cement	458	225	3										
3050	1	Drill 30'	459	226	4										
3080	26	Core 30'	485				30	30	1/9 7/8	75	59		5	6	14
3200	12	Drill 120'	497	238	16										
3230	27	Core 30'	524				6	36	2/9 7/8	90	65		6	6	15
3350	12	Drill 120'	536/22	250	28										
3470	29	Core 30'	565				12	42		106	72		7	7	16
3590	12	Drill 120'	577	262	40										
3620	30	Core 30'	607				18	48		123	79		8	7	17
3740	12	Drill 120'	619	274	12	5/12 1/2									
3770	30	Core 30'	649				24	54		140	86		9	7	17
3890	12	Drill 120'	661	286	24										
4020	31	Core 30'	692				30	60		158	94		10	8	18
4140	12	Drill 120'	704	298	36										
4170	33	Core 30'	737				6	66	3/9 7/8	177	102		11	8	19
4290	12	Drill 120'	749	310	48										
4320	34	Core 30'	783				12	72		196	111		12	9	19
4540	12	Drill 120'	795	322	12	6/12 1/2									
4570	35	Core 30'	830				18	78		216	120		13	9	20
4690	12	Drill 120'	842	334	24										
4720	36	Core 30'	878				24	84		237	129		14	9	21
4840	12	Drill 120'	890	346	36										
4870	37	Core 30'	927				30	90	3/9 7/8	258	139		15	10	21

Depth (ft)	TIME (hrs)	OPERATION "	TOTAL TIME (hrs/day)	TOTAL DRILLING TIME (hrs)	TIME ON BIT (hrs)	BIT #/size	TIME ON COREBIT (hrs)	TOTAL CORING TIME (hrs)	COREBIT #/size	POOH RIH TOTAL TIMES (hrs)	TOTAL CIRCULATING TIME (hrs)	Casing NG Cement NippleUp WOC	# of Core	CIRC TIME	POOH RIH LAYDOWN
4990	12	Drill 120'	939/39	358	48	6/12 $\frac{1}{4}$									
5020	38	Core 30'	977				6	96	4/9 7/8	280	149		16	10	22
5140	12	Drill 120'	989	370	12	7/12 $\frac{1}{4}$									
5170	39	Core 30'	1028/42				12	102		303	159		17	10	23
5290	12	Drill 120'	1040	382	24										
5320	40	Core 30'	1080				18	108		326	170		18	11	23
5440	12	Drill 120'	1092	394	36										
5470	40	Core 30'	1132				24	114		350	181		19	11	24
5590	12	Drill 120'	1144	406	48										
5620	41	Core 30'	1185				30	120	4/9 7/8	374	192		20	11	24
5740	12	Drill 120'	1197/50	418	12	8/12 $\frac{1}{4}$									
5770	42	Core 30'	1239				6	126	5/9 7/8	399	204		21	12	25
5890	12	Drill 120'	1251	430	24										
5920	43	Core 30'	1294				12	132		425	216		22	12	26
6040	12	Drill 120'	1306	432	36										
	6	Circ for Logs	1312								222				
	6	POOH	1318							431					
	12	Run Logs	1330									119			
	6	RIH	1336							437					
	6	Circulate	1342								228				
	6	POOH	1348							443					
	12	Run Logs	1360									131			
	6	RIH	1366							449					
	6	Circ for Casing	1372								234				
	6	POOH/Lay down 12'	1378							455					
	24	Run Casing	1402									155			
	2	Rig up cementers	1404									157			
	6	Circ annulus	1410								240				

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DEPTH (ft)	TIME (hrs)	OPERATION "	TOTAL TIME (hrs/day)	TOTAL DRILLING TIME (hrs)	TIME ON BIT (hrs)	BIT #/size	TIME ON COREBIT (hrs)	TOTAL CORING TIME (hrs)	COREBIT #/size	POOH RIH TOTAL TIMES (hrs)	TOTAL CIRCULATING TIME (hrs)	Casing NippleUp WOC	# of Core	CIRC TIME	POOH RIH LAYDOWN
6040	10	Cement	1420									167			
	2	Rig down	1422									169			
	24	WOC	1446									193			
		Land Casing													
		Cut off casing													
		Nipple up													
		Expansion spool													
		1500# Valve													
		Spool													
		13 5/8 DG BOP													
		Spool													
		Pitcher Nipple													
	24	Rotating Head	1470									217			
	8	Pickup 8 1/2 BHA w/6" collars	1478			9/8 1/2				463					
	6	RIH	1484							469					
	6	Circulate	1490/62								246				
6080	8	Drill out cement	1498	440	8										
6170	45	Core 30'	1543				6	138	6/8 1/2	495	258		23	12	26
6230	15	Drill 120'	1558	455	23										
6260	46	Core 30'	1604				12	144		522	271		24	13	27
6380	15	Drill 120'	1619/67	470	38										
6410	46	Core 30'	1665				18	150		550	284		25	13	28
6530	15	Drill 120'	1680	485	15	10/8 1/2									
6560	47	Core 30'	1727				24	156		578	297		26	13	28
6680	15	Drill 120'	1742	500	30										
6710	48	Core 30'	1800				30	162	6/8 1/2	607	310		27	13	29
6830	15	Drill 120'	1815	515	45										
6860	49	Core 30'	1864				6	168	7/8 1/2	636	324		28	14	29

DEPTH (ft)	TIME (hrs)	OPERATION	TOTAL TIME (hrs/day)	TOTAL DRILLING TIME (hrs)	TIME ON BIT (hrs)	BIT #/size	TIME ON COREBIT (hrs)	TOTAL CORING TIME (hrs)	COREBIT #/size	POOH RIH TOTAL TIMES (hrs)	TOTAL CIRCULATING TIME (hrs)	Casing NippleUp WOC	# of Core	CIRC TIME	POOH RIH LAYDOWN
6980	15	Drill 120'	1879	530	15	11/8 $\frac{1}{2}$									
7010	50	Core 30'	1929				12	174	7/8 $\frac{1}{2}$	666	338		29	14	30
7130	15	Drill 120'	1944	545	30										
7160	51	Core 30'	1995				18	180		697	352		30	14	31
7280	15	Drill 120'	2010/83	560	45										
7310	52	Core 30'	2062				24	186		728	367		31	15	31
7430	15	Drill 120'	2077	575	15	12/8 $\frac{1}{2}$									
7460	53	Core 30'	2130				30	192	7/8 $\frac{1}{2}$	760	382		32	15	32
7580	15	Drill 120'	2145	590	30										
7610	54	Core 30'	2199				6	198	8/8 $\frac{1}{2}$	792	397		33	15	32
7730	15	Drill 120'	2214	605	45	12/8 $\frac{1}{2}$									
7760	54	Core 30'	2268				12	204		825	413		34	16	33
7880	15	Drill 120'	2283	620	15	13/8 $\frac{1}{2}$									
7910	55	Core 30'	2338				18	210		859	429		35	16	34
8030	15	Drill 120'	2353	635	30										
8060	56	Core 30'	2409				24	216		893	445		36	16	34
8180	15	Drill 120'	2424	650	45										
8210	57	Core 30'	2481				30	222	8/8 $\frac{1}{2}$	928	461		37	16	35
8330	15	Drill 120'	2496	665	15	14/8 $\frac{1}{2}$									
8360	58	Core 30'	2554				6	228	9/8 $\frac{1}{2}$	963	478		38	17	35
8480	15	Drill 120'	2569	680	30										
8510	59	Core 30'	2628				12	234		999	495		39	17	36
8630	15	Drill 120'	2643	695	45	14/8 $\frac{1}{2}$									
8660	60	Core 30'	2703				18	240		1036	512		40	17	37
8780	15	Drill 120'	2718	710	15	15/8 $\frac{1}{2}$									
8810	61	Core 30'	2779				24	246		1073	530		41	18	37
8930	15	Drill 120'	2794	725	30										
8960	62	Core 30'	2856				30	252	9/8 $\frac{1}{2}$	1111	548		42	18	38

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DEPTH (ft)	TIME (hrs)	OPERATION "	TOTAL TIME (hrs/day)	TOTAL DRILLING TIME (hrs)	TIME ON BIT (hrs)	BIT #/size	TIME ON COREBIT (hrs)	TOTAL CORING TIME (hrs)	COREBIT #/size	POOH RIH TOTAL TIMES (hrs)	TOTAL CIRCULATING TIME (hrs)	Casing NippleUp WOC	# of Core	CIRC TIME	POOH RIH LAYDOWN
9080	15	Drill 120'	2871	740	45	15/8 $\frac{1}{2}$									
9 10	63	Core 30'	2934				6	258	10/8 $\frac{1}{2}$	1149	565		43	18	38
9230	15	Drill 120'	2949	755	15	16/8 $\frac{1}{2}$									
9250	63	Core 30'	3012				12	264		1188	584		44	19	39
9370	15	Drill 120'	3027	770	30										
9400	64	Core 30'	3091				18	270		1228	603		45	19	40
9520	15	Drill 120'	3106	785	45	16/8 $\frac{1}{2}$									
9550	65	Core 30'	3171				24	276		1268	622		46	19	40
9670	15	Drill 120'	3186	800	15	17/8 $\frac{1}{2}$									
9700	66	Core 30'	3252				30	282	10/8 $\frac{1}{2}$	1309	641		47	19	41
9820	15	Drill 120'	3267	815	30										
9850	67	Core 30'	3334				6	288	11/8 $\frac{1}{2}$	1350	661		48	20	41
9970	15	Drill 120'	3349	830	45	17/8 $\frac{1}{2}$									
10000	68	Core 30'	3417				12	294		1392	681		49	20	42
	10	Circulate mud out	3427								691			10	
	10	POOH	3437							1402					10
	12	Nipple down BOP	3449									229			
	18	Nipple up flowline	3467									247			
	36	Heat up well	3503									271			
	24	Flow well	3527									283			
	12	Test well	3539									355			
	72	Cool well	3611												
	10	RIH to Laydown	3621							1412					10
	24	Laydown pipe	3645									379			
	12	Clean bits/Nipple down	3657									391			
		Release Rig													

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