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Key Factors to Successful Drilling and Completion of EGS Well in Cooper Basin

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ABSTRACT

Operations have been very challenging for the drilling and completion of Enhanced Geothermal Systems (EGS) wells in the Cooper Basin, South Australia. High temperature, greater than 4 km depths, and high reservoir pressure have combined to make this field one of the most difficult geothermal projects in the world. When a production well failed catastrophically the project was delayed for a number of years. A thorough review of the potential causes of this failure led to significant changes in the well design. To reduce the risk of caustic cracking, the most likely cause of the well failure, changes were made to the well design and cementing operations were altered significantly from standard practice.

In addition to the well design and construction, there was the challenge of drilling through the main productive fault zone in the granite reservoir rock. Previous attempts to do so have led to large losses of weighted drilling fluid causing significant damage to the permeability of the fault zone. In one well, problems that occurred while drilling the main fault zone led to multiple operational problems and eventually the total loss of the well.

This paper will provide a review of the key factors that led to the successful drilling and completion of a replacement well for the well that failed. An analysis of the unique casing failure mechanism will be explained along with changes that were made in the replacement well design. A description of why reverse circulation cementing was chosen as part of the strategy to ensure long term well integrity will be given along with how the job was executed and the ultimate results. Details will be provided of how the challenges of drilling the main fault zone were overcome. Finally, information on how the successful drilling operation was actually executed will be explained.

1. INTRODUCTION

The Cooper Basin was chosen as a potential development site for EGS power production based on high temperatures in basement granitic rock found at about 4 km depth (See Figure 1). Geodynamics drilled its first well, Habanero 1 in 2003 where the “Main Fracture” was intersected with significantly higher pressures than expected (See Figure 2).

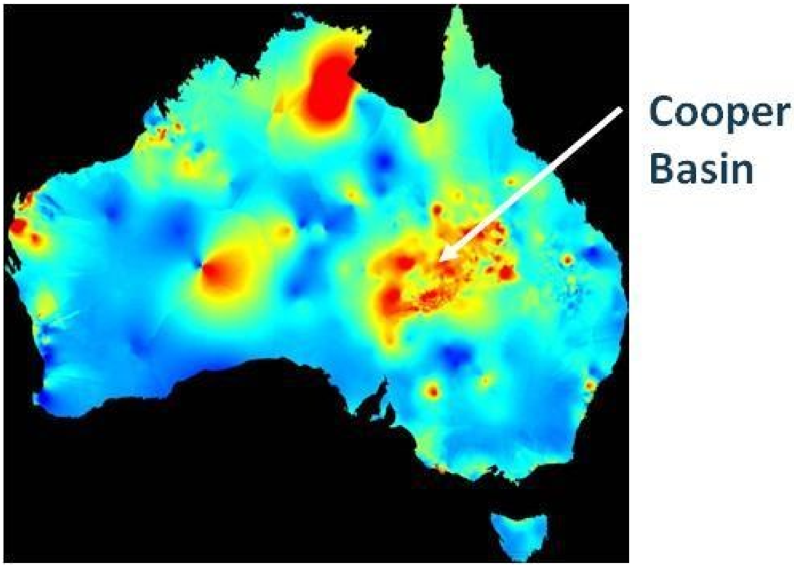

Figure 1: Heat Map of Australia at 5 km depth; Location of Cooper Basin

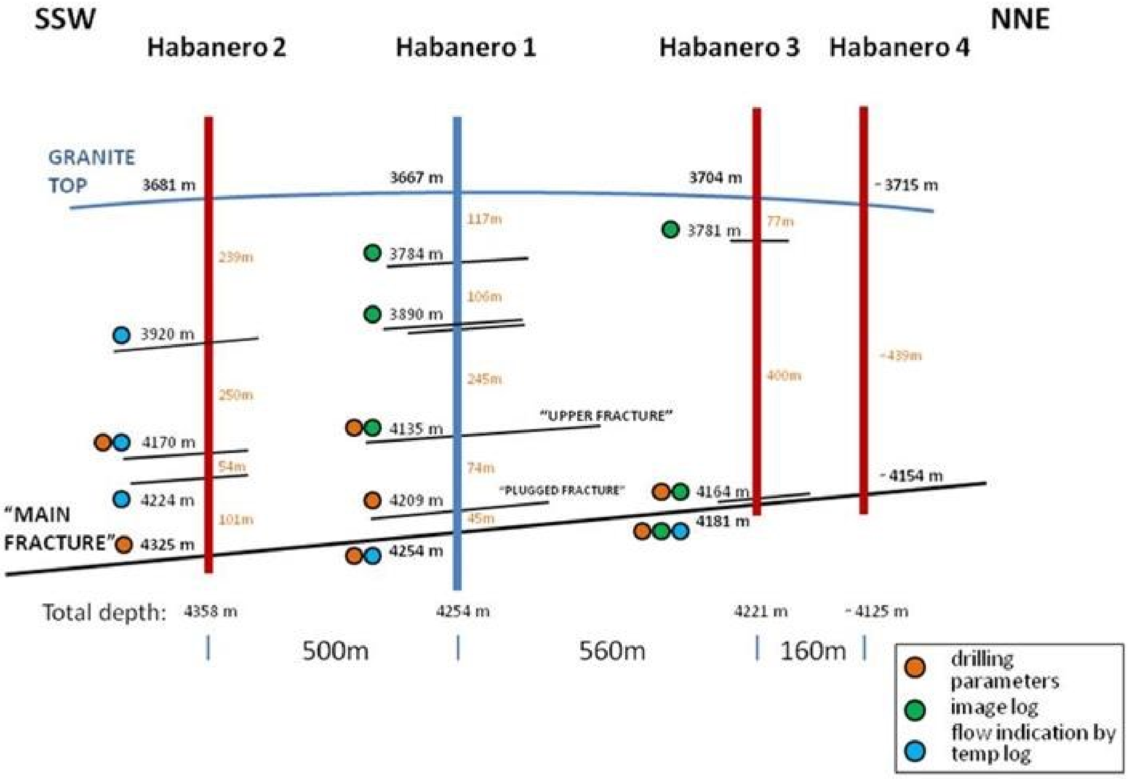

Figure 2: Conceptual Reservoir Diagram Prior to Drilling Habanero 4 - Fracture Depth Indications in Habanero Wells

2. DETERMINATION OF FAILURE MECHANISM

Habanero 3 was drilled in 2007 and failed in 2009 after being used with Habanero 1 to successfully demonstrate a closed loop EGS system. Failure occurred near surface in 244.5 mm (9-5/8 inch) casing followed several days later with failures in the next two outer casing strings and release of production brine at surface. This failure occurred just weeks before the scheduled tie into the 1 MW demonstration power plant. Extensive analysis and evaluation of the Habanero 3 casing failures were done and the suspected root cause of the 244.5 mm (9-5/8 inch) casing failure is caustic cracking on the OD of the casing. The caustic cracking was due to high pH alkaline fluid in the 244.5 mm (9-5/8 inch) x 339.7 mm (13-3/8 inch) casing annulus and high temperature. Contributing factors include slip marks on the OD of the casing where cracks initiated and high cyclic loads from reservoir pressure and temperature fluctuations. Rupture of the 244.5 mm (9-5/8 inch) casing caused damage to the 339.7 mm (13-3/8 inch) casing. OD cracks on the 339.7 mm (13-5/8 inch) casing grew and after several days the 339.7 mm (13-5/8 inch) casing failed causing a pressure shock overload on the 473.1 mm (18-5/8 inch) casing causing it to rupture and pressure containment of the wellbore was lost.

Environmentally assisted cracking or stress corrosion cracking is driven by a combination of three distinct factors: the environment (pH, H_2S, CO_2, electrochemical potential, temperature, etc.), stress or loading (sustained, and/or cyclic) and material properties (strength, microstructure, toughness, etc.) as shown in Figure 3. All three factors must be present for cracking and failure to occur. There must be sufficient stress to cause a crack to propagate in a material that lacks the mechanical properties that resist crack growth. In addition, the environment must be such that contaminates, corrosive fluids and environmental conditions enhance the growth of cracks. Removing or improving any of these 3 factors will prevent stress corrosion cracking.

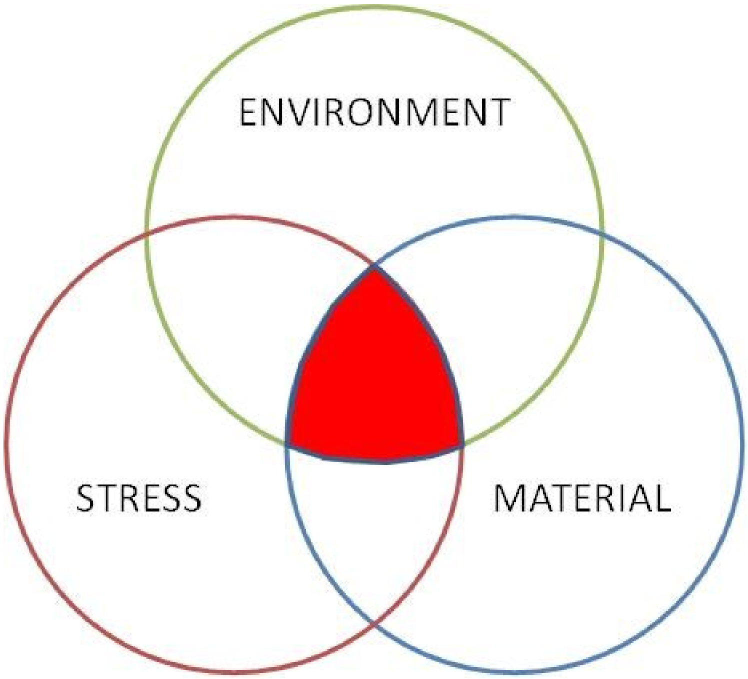

Figure 3: Three Factors Required to Cause Stress Corrosion Cracking (SCC)

3. DESIGN OF HABANERO 4

Habanero 4 was designed to replace the failed Habanero 3 well as the production well in a 1MW EGS demonstration pilot. It was required to address the two potential failure mechanisms identified during the failure analysis of Habanero 3 - caustic cracking and hydrogen embrittlement. Additional objectives were to manage production from a 280°C reservoir, 2 weeks of stimulation with room temperature water and to minimize damage to the main fracture that provided the majority of the reservoir permeability.

3.1 Casing and Tubing Design Considerations for the Habanero 4 Replacement Well

The well design objective for the Habanero 4 well was to select and verify casing, tubing and connections that have the mechanical strength to withstand the high stresses caused by the high changes in temperature and pressure associated with enhanced geothermal wells. Material selection is also an important part of the well design to ensure the production casing and tubing are suitable for the expected loads, stresses and environmental conditions. The severe environment consists of the thermal conditions and the fluids that are exposed to the casing and tubing.

3.2 Casing Mechanical Design

Working Stress Design (WSD) is the design methodology used to analyze the expected loads and strength of the selected casing and tubing. WSD is commonly used in the design and analysis of oil and gas wells throughout the world. This design methodology assumes minimum strength and maximum load assumptions with a safety factor (SF) to ensure a safe design. Minimum strength is based on minimum yield strength and minimum wall thickness. Maximum expected loads are assumed and compared to the strength to calculate the safety factor (SF). The design check is to have the SF ≥ DF (Design Factor). Due to the high temperatures of geothermal wells, the minimum yield strength is de-rated for elevated temperatures as part of the design check.

There were some stimulation loads where the tri-axial safety factor was slightly less than the design factors. These load cases were evaluated using reliability based design (RBD). The RBD evaluation show the probability of the tri-axial stress exceeding the minimum yield stress was less than 1 in 100 million, indicating a high reliability design. The casing manufacturer provided production QAQC data that was tighter than normal API standards to facilitate accurate RBD evaluation.

The wellbore schematic of the Habanero 4 well is shown in below (See Figure 4).

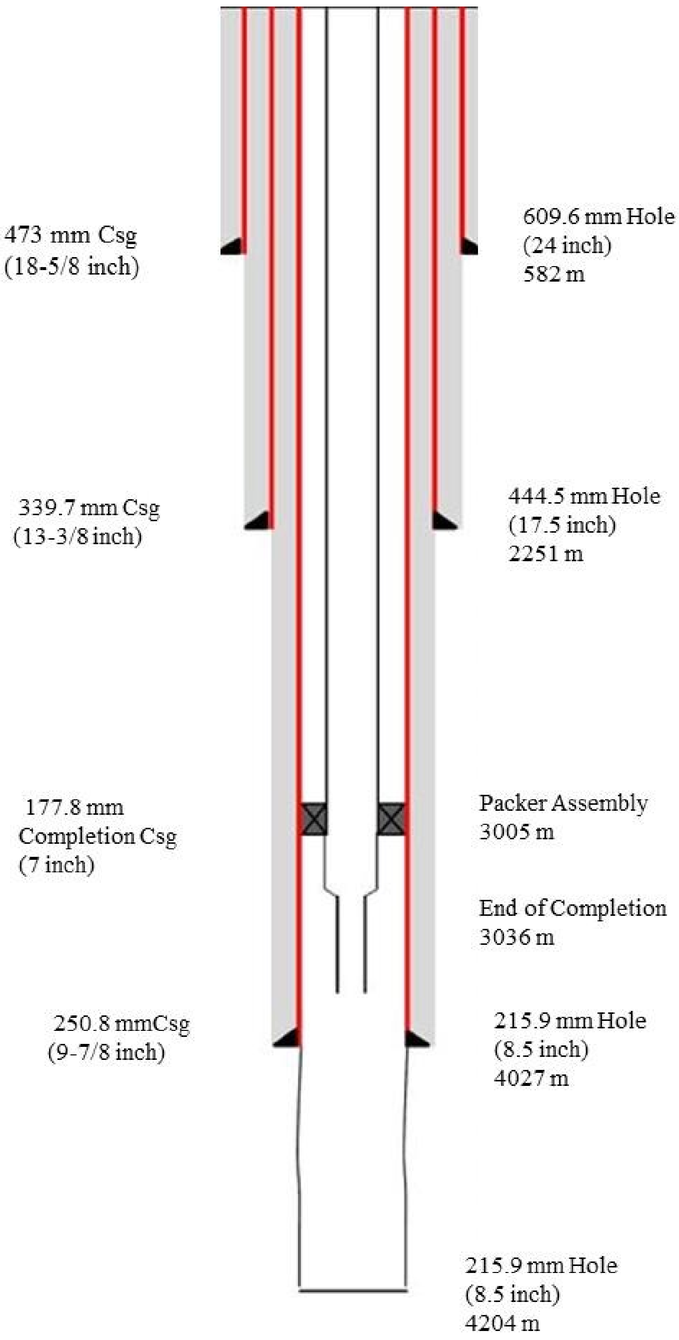

Figure 4: Habanero Wellbore Schematic

Thermal modeling using a commercial wellbore thermal simulator is used to estimate the producing temperature profile based on the reservoir temperature, the produced fluids and the production rate. The producing temperature profile and the undisturbed geothermal profile are used to estimate the change in temperature from the initial condition to the final conditions. Habanero 4 was designed for an extended stimulation so a stimulation temperature profile is also estimated. The change in temperature causes un-cemented casing and tubing to either expand or contract in length. When casing is cemented in place, the change in length is not allowed and the disallowed length change is converted into thermal stress. The casing thermal stresses are in addition to the stresses caused by pressure and tension loads.

In the case of tubing where the seals are allowed to move, the length change takes place and the change in length is used to determine the length of the polished bore receptacle (PBR) to accommodate the tubing seal assembly. It should be noted that the tubing can buckle due to internal pressure and the bending stresses must be considered as part of the total stresses. If the tubing seal assembly is latched or anchored, the changes in length due to temperature change result in additional stresses. Producing conditions cause the average temperature of the tubing to increase and elongate. If the seals are not allowed to move the disallowed change is length is converted to additional stresses caused by compressive loads and bending stresses caused by buckling.

Figure 5 shows an example of the various temperature profiles of interest for a geothermal well casing and tubing design. The profiles include the undisturbed geothermal profile, cool down while drilling, cementing, stimulation at different surface fluid temperatures and producing. The large change in temperature at surface between undisturbed and producing is illustrated in the figure. Also the stimulation temperature profile compared to the undisturbed profile shows the magnitude of cooling while stimulating the well.

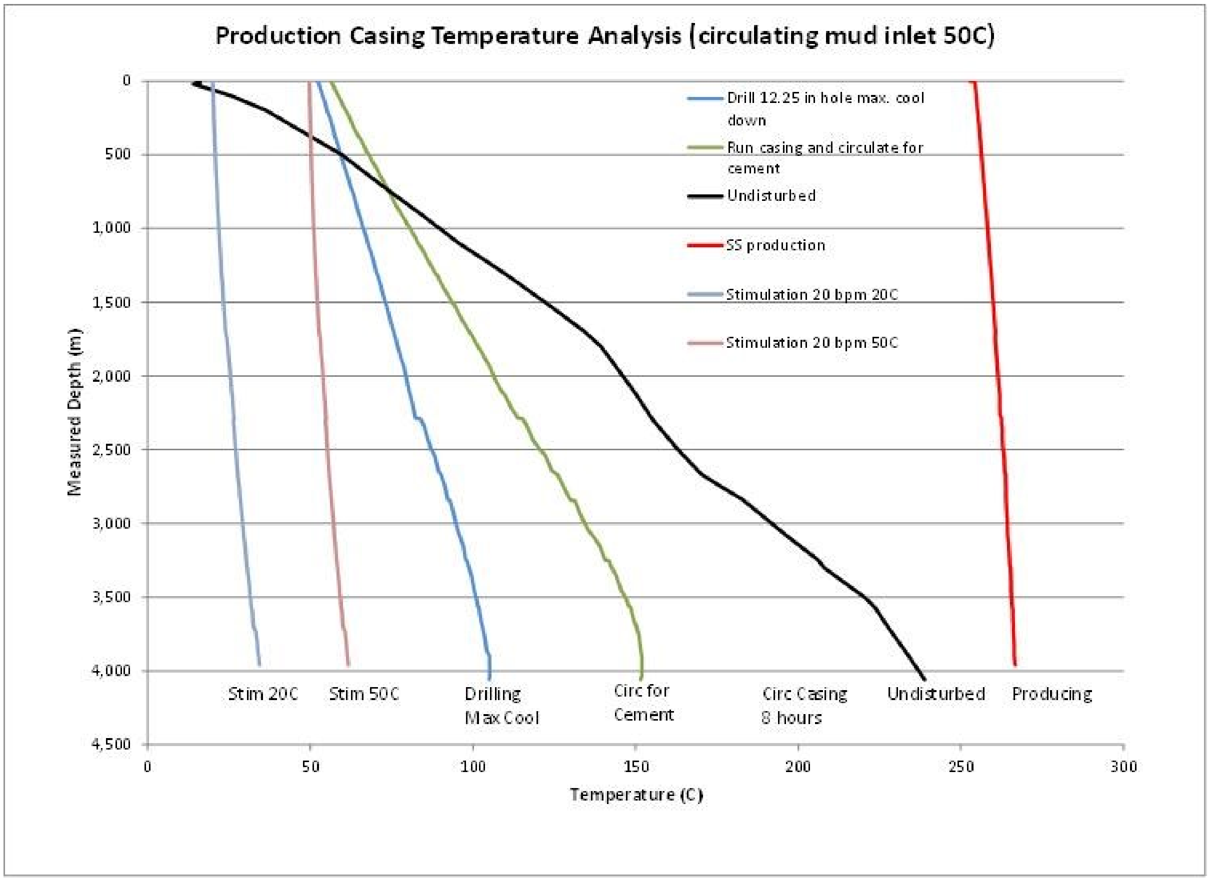

Figure 5: Thermal Modelling Results for Production Casing and Tubing for Habanero 4

Temperature strength derating is required in geothermal wells since the producing conditions temperature is significantly above room temperature where minimum casing and tubing yield strengths are measured and checked. A typical average derating factor for temperature is 5.4%/100°C above 21°C room temperature. For example, if the casing or tubing is 244°C under producing conditions, the minimum yield strength would be de-rated by 12%. The de-rated yield strength is based on the local temperature at depth.

Selection of the casing and tubing connections is an important consideration in the design of the production casing and tubing. The connections must withstand the same loads as the pipe body. Connections are highly stressed due to the makeup process and the makeup stresses are in addition to the well loads and thermal stresses. Connections tested and qualified to the expected well conditions should be used for geothermal wells. A connection testing program based on industry accepted testing protocols (ISO 13679:2002) is recommended.

Managing casing wear is important for casing that will be exposed to drilling and rotating drill pipe after the casing is run and cemented. In the Habanero 4 well, the 250.8 mm (9-7/8 inch) casing was run and cemented prior to drilling the 251.6 mm (8-1/2 inch) hole for production casing. Based on the load and stress analysis, it was determined that additional wall thickness was desirable to provide a wear allowance. The casing was ordered with tighter than normal wall thickness tolerances to provide the wear allowance. The minimum wall tolerance was -10% (90% remaining wall or 10% below nominal wall) and part of the casing was required to have 95% remaining body wall (RBW). The 95% RBW casing was strategically placed at depths where the stresses were the highest to end up with suitable safety factors in case there was some wear due to drilling.

Most geothermal wells are planned with cement to surface for the production casing to prevent buckling and buckling stresses and to prevent high pH fluids in the annulus as discussed previously. However, contingency plans need to be in place to deal with the top of cement (TOC) below surface in case cement is not fully placed to surface.

3.3 Completion Design

An 177.8 mm (7 inch) completion tubing string was run to 3000 m depth. The 177.8 mm (7 inch) tubing enables application of a maximum of 68.9 MPa (10,000 psi) surface pressure during the stimulation treatment of the main fracture. A specially designed high temperature packer and polished bore receptacle (PBR) were deployed that could withstand the expected temperatures, pressures and environment. The setting depth was 3000 m inside the 250.8 mm (9-7/8 inch) casing string which was cemented in place to 4023 m. Although tubing and packer completions are not standard in the geothermal industry, they were included in Habanero 4 to comply with regulations for a double barrier as the well was drilled under the South Australian Petroleum regulations. The completion also removed the pressure cycling from the 244.5 mm (9-5/8 inch) production casing which was a key contributor to the failure of Habanero 3 and created a replaceable barrier if corrosion was found to be higher than expected.

3.4 Casing and Tubing Materials Selection

Casing material (grade) selection is the first step in materials selection. The production casing grade selected for this well is TN110SS, a sour service 110 ksi grade. In addition to specifying the grade, other material specifications included maximum allowable hardness, NACE Method A testing at a threshold of 85% or higher and DCB testing to ensure suitable K_{ISSC} values for the material. Stringent material requirements are required to protect against cracking caused by hydrogen embrittlement and caustic cracking from high pH fluid. In line with ISO 15156-2, 2003, the TN110SS material was qualified for the Habanero project through Method A and D tests in a simulated reservoir fluid. Operationally, care must be taken to minimize tong and slip die damage to the OD of the casing to avoid crack initiation sites.

4. REVERSE CIRCULATION CEMENT JOB

Reverse circulation cementing was chosen to address the issue of the caustic environment behind the production casing. When conventional circulation cementing was used on the Habanero 3 well the cement that was retarded to safely circulate at the bottom of the well during placement was found to not set up when exposed to the cooler temperatures in the well near the surface. When reverse circulation cementing method is employed the cement is retarded in stages. There is a higher concentration of retarder in the cement that is circulated to the bottom of the well and less retarder for stages of cement that are closer to the surface. Because of the lower retarder concentration that can be used to safely place the cement the entire cement column is able to set up at the geostatic temperatures in which it is placed. Set cement, if it has effectively displaced the drilling fluid, will eliminate the high caustic environment that led to the failure in Habanero 3.

4.1 Challenges to Reverse Circulation Cementing

4.1.1 Circulation Reverse Direction and Requirement for Pressure Control

Several challenges existed when implementing the reverse circulation technique. One is to be able to run the casing in the well with the ability to prevent flow at the casing shoe, as is required when drilling in hydrocarbon bearing formations. This is typically accomplished by using a float shoe or float collar at the bottom of the casing string. The float contains a valve that allows for circulation down the casing but prevents flow into the casing. This provides a pressure barrier in case well experiences a pressure kick while running casing. The BOP (blow out preventer) can be closed to control flow on the outside of the casing and the float will prevent flow up the exposed inside of the casing, allowing the drilling operator to retain control of the well and prevent and un-controlled blow-out of the well. The problem is to circulate in the reverse direction a typical float will prevent this. To overcome this problem one of two potential solutions is typically used; a stab-in float or a pump-out float. The advantage of the Stab-In Float is that drill pipe can be run to depth and the float valve opened for reverse circulation by stabbing in a small diameter pipe, stinger, attached to the bottom of the drill pipe (DP). When the job is done the stinger is pulled out of the float valve and any excess cement inside the casing (inside the DP) can be reverse circulated out of the well leaving essentially no cement above the float that would have to be drilled up after the job. The advantage of the Pump-Out Float (POF) is that no DP is needed to open the valve to reverse circulation. Instead a ball is circulated to the POF. Once it engages on the valve piece flow is restricted and the valve mechanism is pushed out with pressure, shearing pins that hold it in place. The disadvantage of the POF is that any cement remaining inside the casing after the job must be drilled out. On Habanero 4 a pump-out float was used.

4.1.2Surface Iron and Back-Pressure Control

Another challenge faced by doing a reverse circulation cement job was the arrangement of the surface iron needed to control the flow direction of fluids before and during the job. Additional manifolding was used so that it was possible to hold back-pressure during circulation of the cement in place and to be able to circulate out the well in either direction. There was concern that when the heavier cement slurry was pumped into the annulus that an overbalance pressure would result in free fall of the cement an uncontrolled flow out of the well.

4.2 Cement Design

The cement used for this application required that it be able to meet a number of challenges. The cement had to withstand the expected high temperatures during the operation and flowing of the well. Because the temperatures was excessively high compared to normal high temperature oil and gas wells the amount of silica included in the blend was raised to 65 percent by weight from the normal 35-40%.

The set cement slurry also would be exposed to significant stress loading due to expansion and contraction of the casing from pressure and temperature cycles. Pressure cycles were expected when the well was first flowed and put on production, unloading the weighted drilling fluid that was left in the hole at the end of drilling operations. Additional pressure loading would occur on the casing during the high pressure stimulation work that was planned to stimulate the existing fault zone in the reservoir rock. Design work was done with a finite elemental analysis (FEA) program to help insure that the cement would not fail from the additional stresses that occurred in the cement during these operations.

It was also imperative that the slurry had not significant settling leading to the formation of pockets of mix water or thin slurry. This was especially challenging as five stages of cement slurry with different retarder loading were planned to fill the 4000 m long annulus. Because changes in the retarder loading can affect slurry stability two different base slurry designs were used; a 1.85 s.g. (15.4 lb/gal) slurry for the first 3 stages and a 1.8 s.g. (15.0 lb/gal) slurry for the last 2 stages.

5. DRILLING AND COMPLETION OF THE MAIN FRACTURE

When the first well, Habanero 1, was drilled for this EGS project it was assumed that a normal pressure gradient would be present in the granitic basement rock. Therefore, after the production casing was set into the reservoir rock the open hole was drilled with normal density water based mud. When the “main fracture” was encountered at 4254 m (See Figure 2) it was discovered that the fracture contained geothermal brine at an overbalance pressure of about 34.5 MPa (5000 psi). This caused significant drilling operational problems in both the Habanero 1 well and Habanero 2. The end result was that over 160 m^3 (1000 bbls) of weighted drilling fluid was lost into the main fracture in Habanero 1 which resulted in significant impedance to flow. Habanero 2 was eventually abandoned after several sidetrack attempts through the main fracture were unsuccessful. Some success was achieved in Habanero 3 with similar drilling parameters, indicating that the fracture resistance is not equal across the field.

To drill Habanero 4 it was known that there would be a significant challenge of drilling through the main fracture without experiencing influx of formation fluid and/or loss of drilling fluid. Influx of formation fluid could cause gelation of the water based drilling fluid leading to significant delays and problems drilling the open hole. Loss of drilling fluid to the fracture could result in significant damage to the productivity and/or injectivity into the main productive fracture reducing the economic value of the well. This challenge is further increased as a higher weight mud needs to be in place before tripping to surface to allow for expansion of the drill fluid as the well bore heats up after circulation has ceased. A plan was developed to prevent either one of these problems from happening while drilling the main fracture. This plan consisted of the following:

- Measuring the rheological properties of the water based drilling fluid at downhole temperature and downhole pressure
- Measuring the density of the weighted water based drilling fluid as a function of temperature and pressure up to and including bottom hole conditions
- Using an integrated simulation model (ISM) program to predict downhole pressure as a function of temperature. This would model changes in both rheological properties and density as functions of both temperature and pressure.
- Conducting a dynamic leak-off test while drilling through main fracture using the ISM (integrated simulation model). Increase circulation rate until losses are noted in the mud pit. Slow the rate gradually until a small influx of fluid from the fracture is detected at surface.
- Modelling to determine acceptable displacement rates for the higher weighted mud used for tripping and surge/swab rates that keep ECD below the dynamic leak-off test results.

Samples of the drilling fluid from location were taken and shipped to the vendor lab in Perth where the rheological properties of the drilling fluid were measured using a HP-HT Rheometer (See Table 1). This information was used along with density measurements of a base drilling fluid sample taken at an assortment of pressures and temperatures to calculate the expected down-hole temperature during the dynamic leak-off test. A temperature simulation program was used as well to predict temperature as a function of depth. So, down-hole pressure was estimated based on information on the density, temperature, and rheological properties of the drilling fluid as a function of depth.

Temperature (°C)	60	60	125	200	230
Pressure (MPa)	0	9.65	41.4	70.7	70.7
HP-HT Fann Readings					
600 rpm	69	77	57	38	36
300 rpm	48	51	41	27	22
200 rpm	40	43	36	25	18
100 rpm	29	30	29	21	13
6 rpm	16	17	21	18	7
3 rpm	16	17	21	19	8
Static Gel Strengths (KPa)					
10 Second			96	91	
10 Minute			153	134	
30 Minute			153	139	

Table 1: Rheological Properties and Progressive Gel Strengths of Field Sample of Drilling Fluid

A dynamic leak-off test was conducted by slowly increasing the circulation rate after drilling the main fracture and noting when losses occurred, and then calculating the downhole pressure as per above. The circulation rate was then slowly decreased until an influx of fluid was noted, and the corresponding downhole pressure was calculated. These upper and lower pressure limits were used to then design a procedure to balance a static column of drilling fluid on the fracture that would not exceed the upper limit while the hole was circulated and also not drop below the lower limit when circulation was stopped and the drilling fluid heated up. Once TD had been reached, 50 m below the main fracture, the drilling fluid density was increased stepwise while circulating at a slow rate. The hydrostatic pressure component of pressure on bottom was increased while the friction pressure component was decreased. At the end of this operation a column of drilling fluid was successfully balanced on top of the fracture. When the circulation was stopped the pressure decreased due to removal of friction pressure component. The pressure continued to drop further due to heating of the drilling fluid which caused a reduction in density.

As can be seen in the predictive model the pressure at the main fracture was maintained in the “window” of upper and lower boundaries obtain from the dynamic leak-off test. In actual field operations the mud was successfully placed and left static above the fracture. The drill string was then subsequently slowly pulled out of the hole without any indication of influx of fluids from the reservoir’s main fracture.

As this process still required sufficient fracture resistance to create the drilling window and this was known to vary across the field. It was less than 345 KPa (50psi) from Habanero 2 results. Several contingency operations were prepared in case the process was unsuccessful. As the fracture width was unknown, a Lost Circulation Material train was developed with ramping up particle size distributions. The first stage of this was premixed prior to drilling the fracture. A rotating control head was included in the well control equipment to maintain the ability to strip above the fracture and fill the wellbore with a fluid pill loaded with sized calcium carbonate. In this situation the completion would be run and the wellbore cleaned by Coil tubing later. Due to the diameters and mud weights involved this would be a slow but achievable process.

6. CONCLUSIONS

Determination of the failure mechanism of the Habanero 3 well and subsequently designing the Habanero 4 well was a major challenge. Key challenges were casing design and material selection, isolation of the 250.8 mm (9-5/8 inch) casing, and drilling the main fracture. Stringent casing manufacture QAQC, reliability based design and qualification of TN110SS casing material was required to achieve casing integrity. A reverse circulation cement job was designed and successfully implemented to provide needed integrity of the 250.8 mm (9-5/8 inch) casing string. Rigorous drilling fluid modelling with downhole parameters and temperature modelling were combined to enable the main fracture to be drilled with minimal losses and damage.

Habanero 4 was successfully drilled, completed, and stimulated. The well was then used in a 6 month demonstration phase of the EGS technology where fluid was produced from Habanero 4, used to generate power at a temporary power plant, and then produced fluid was re-injected back into Habanero 1 (Hogarth and Bour, 2015) (See Figure 6). Special precautions were made during the production phase in Habanero 4 to slowly heat the well up and reduce stress on the various casing strings due to thermal expansion.

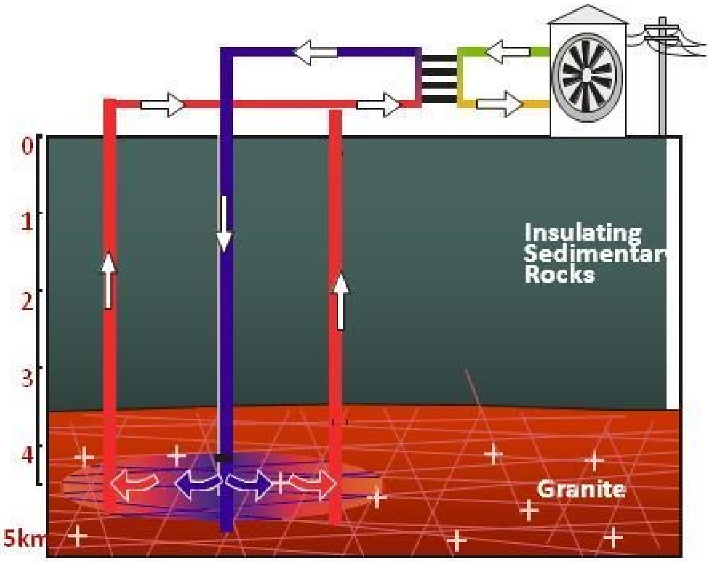

Figure 6: Conceptual Diagram of EGS System

6. REFERENCES

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