TIE-BACK CEMENTING OPERATION SUMMARY: EXPERIENCE FROM INDONESIA

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ABSTRACT

The cementing of production casing in geothermal well constructions is a critical activity that determines well integrity. Given that production steam flows in contact with the production casing, it is imperative that the casing and cement exhibit sufficient strength to maintain a reliable seal throughout the well's useful lifetime. Wells constructed in the 90s and early 2000s utilized the long-string cementing method. However, contemporary wells employ the tie-back cementing method, allowing the separation of running casing and cementing into two stages.

The primary concept behind the tie-back method is to reduce the hydrostatic pressure of the cement slurry in the first stage, thereby minimizing destructive effects on weak zones. The success of tie-back cementing is gauged by three key parameters obtained in the first stage: shear pin pressure, bump plug pressure, and the occurrence of a 'u-tube' when releasing the liner running tool. The absence of any of these three parameters can adversely affect the quality of cement in the shoe and annulus, potentially compromising cement integrity.

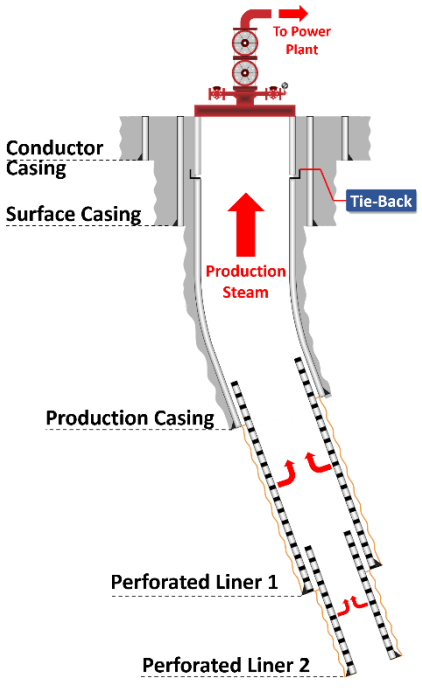
This paper provides a summary of the operational aspects of tie-back cementing in Indonesia's D and P Fields, covering 21 wells during the drilling campaign. Seventeen of these wells achieved successful tie-back cementing operations, as evidenced by the attainment of shear pressure and bump plug. The remaining four wells failed to achieve bump plug and/or shear pressure, necessitating further remedial cementing. Various approaches were employed in the D and P Fields to ensure successful tie-back cementing operations, which are detailed in this paper for the purpose of sharing lessons learned.

An observed best practice for achieving optimal cement results involves an extensive wiper trip with polish operation, particularly within intervals where dog leg is high, before running the liner. This ensures that the well is slick and approaches the ideal shear pressure.

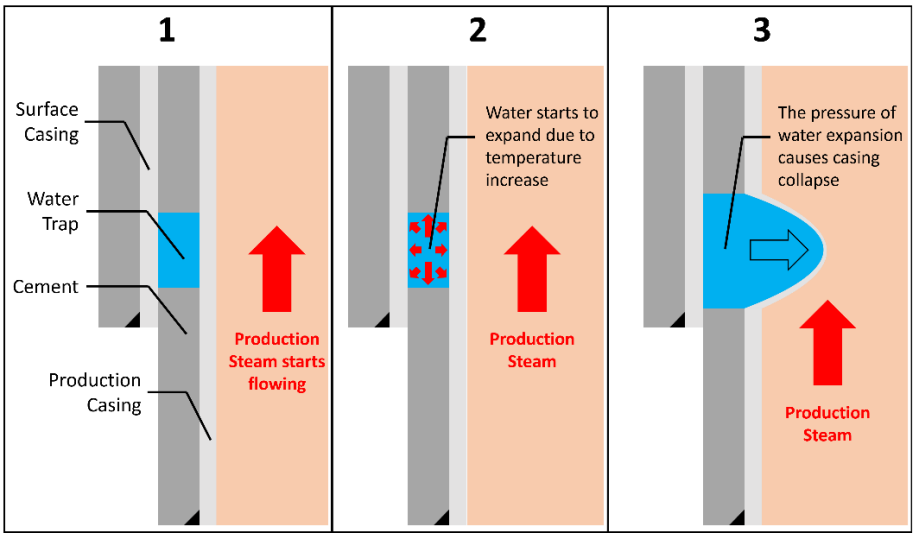
1. INTRODUCTION

Cementing is a crucial activity during drilling a geothermal well to determine well integrity. The cement will determine the age of the well and how much will workover operation has to be performed. All companies will desire a long-life well and no workover operation to gain as much as benefits. Moreover, surrounding environment security also being dictates by good cement behind production casing to prevent production steam leakage to surface. Thus, apart from a good cement slurry recipe, the cementing operation should be performed well to have a long term well.

Cement behind production casing is important to accommodate geothermal well completion. Geothermal well completion allows the production steam to flow inside the production casing instead of directing the flow through a tubing string such in Oil and Gas well. The worst case of this well completion scenario is when there is a fluid trap within cement column. A fluid trap inside cement within annulus casing to casing will remain as a fluid until the production steam starts to flow, the fluid trap will be evaporated and pressurized production casing. This situation will result in a casing collapse which will reduce the casing ID area and respectively the steam production volume. Thus, the company requires to perform expensive well workovers to redress collapsed casing or the worse scheme to install smaller ID casing (re-lining job) to have a better well integrity. Thus, a fluid trap inside cement shall be eliminated during cementing operation.

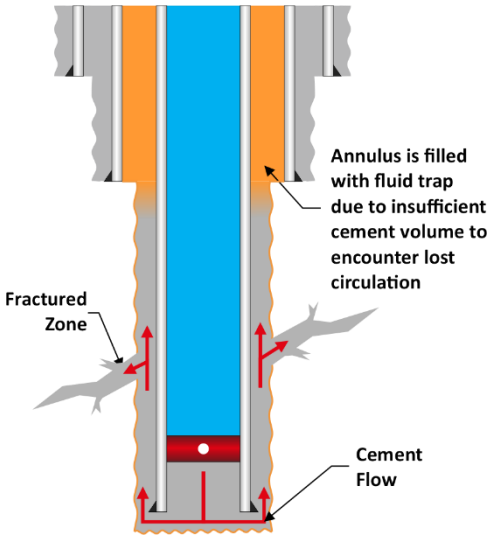


Typical Geothermal Well Completion



The process of casing collapse by fluid trap inside casing to casing annulus

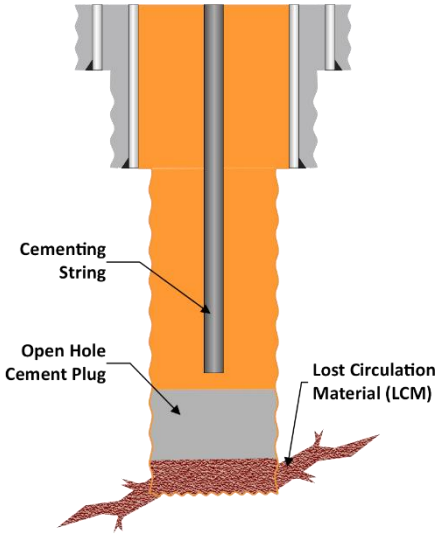
The other hard challenge in cementing a geothermal well is lost circulation. Lost circulation in geothermal well comes from fractured zone in an igneous formation. The thief fractured zone varies based on its size which affects the rate of lost circulation. A bigger fracture will cause Total Lost Circulation (TLC) which indicated by no fluid return at surface (shale shaker possum belly). While a smaller fracture will cause Partial Lost Circulation (PLC) which can be seen by small fluid return at surface. Lost circulation will be aggravated by high density cement (15.8 ppg default density). High density cement will induce a fracture for a weak zone due to its hydrostatic pressure. This inducement will increase the lost rate. The existing of thief zone will require more cement volume excess to fill the whole annulus volume with cement, increasing well cost respectively. Furthermore, excessive lost circulation will cause no return at surface during cementing operation, left water or mud in front of cement slurry trapped inside the annulus. Fluid trap in the casing to casing annulus is dangerous for production casing as mentioned before.



Lost Circulation causes fluid trap during cementing operation

Companies attempt to assess the best way to cement the production casing and result several cementing methods for a better well integrity with their pros and cons. Those cementing method options will be summarized below.

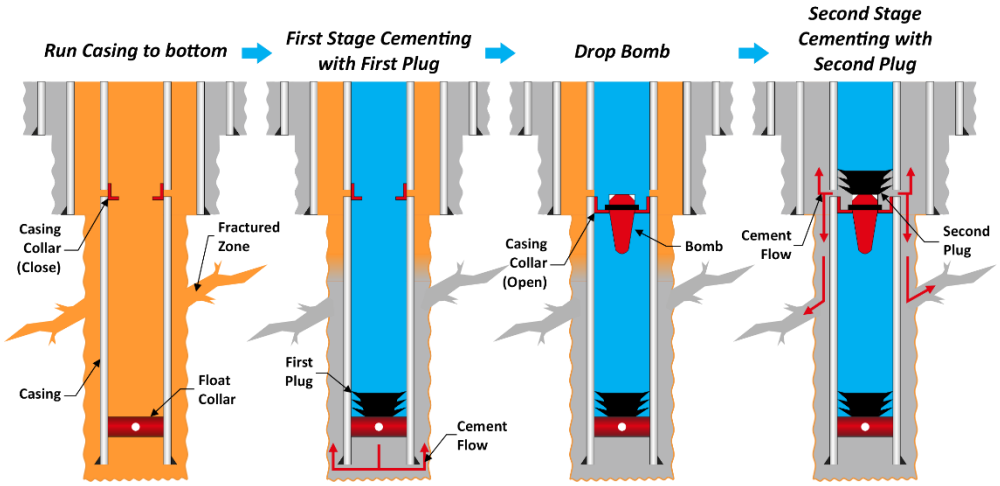
a. Open Hole Plug with Lost Circulation Material (LCM) and Cement
   LCM is commonly used in drilling phase to cover the lost zone that will decrease its permeability. Thus, limiting the number of drilling fluid entering the zone. LCM is provided in various grain size by mud company to allow LCM size combination. The most fit LCM combination is gained by trial and error or based on offset well. Similar with LCM, Open Hole Plug is a cementing method to decrease the lost zone permeability. The cement slurry hopefully entering the lost zone and set inside it. The cement covering borehole wall will not sustain since it will be re-drilled. Unfortunately, the cement volume for plugging is unknown due to subsurface uncertainty. Eventually, the company should pump hundred barrels of cement to cover the lost zone and sometimes getting failed. LCM is then combined with the cement slurry to reduce cement volume and cost. LCM is circulated first to the well until a certain lost rate is observed and then prepare and pump cement slurry to the open hole. Wait on cement and redress it with drill bit to regain the hole diameter. After desired lost rate is observed by combining LCM and Open Hole Plug Cementing, perform casing primary cementing.



LCM and OH Plug Cement illustration

b. Dual-Stage Cementing (DSC)

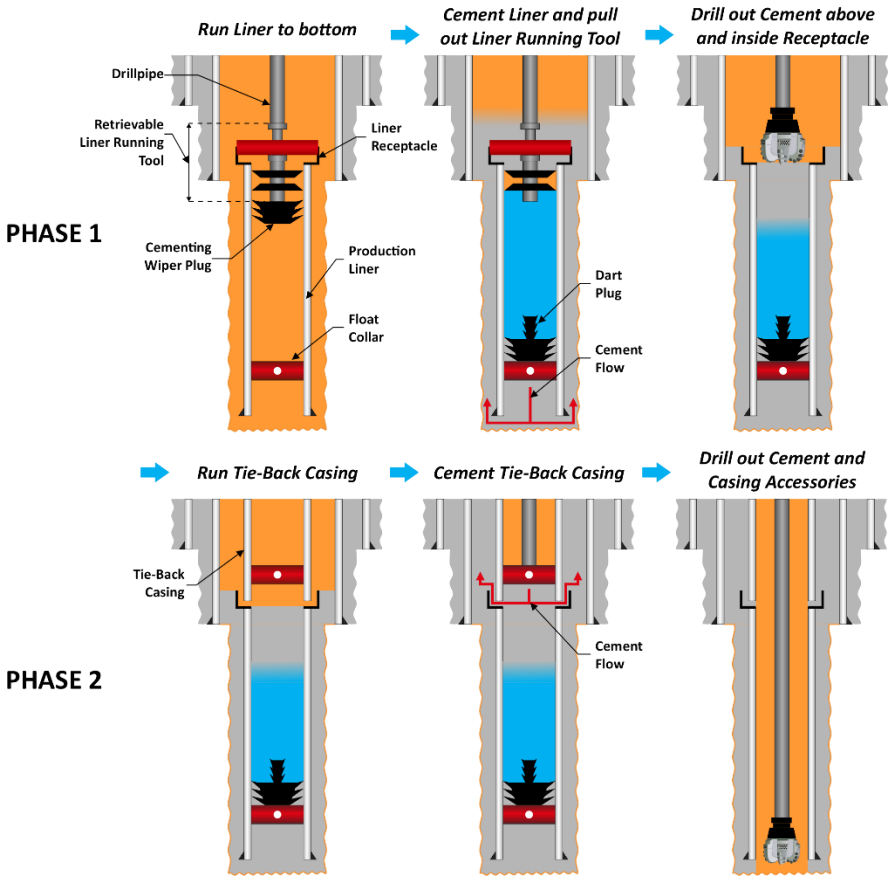
DSC cementing divides the cementing into 2 phases after running longstring casing to bottomhole. The idea of dividing the cementing phase is to reduce the hydrostatic pressure of the cement slurry, resulting less destructive effect for weak zone. The main actor to divide the cementing phase is Dual Stage Cementing Collar (DSCC) equipment installed in the casing (usually overlapping 30-50 m from previous casing shoe). The first phase of DSC will fill annulus from bottom hole to DSCC and the second phase will fill the annulus from DSCC to surface with cement. The crucial phase of DSC operation is when it has to pump second phase cement slurry before the first phase cement is set. The other concern using DSC method is to ensure that sufficient cement volume is reaching DSCC level, by this no trapped fluid will be left in annulus. Furthermore, DSCC equipment stress rating should be similar or more than the installed casing since it will be a permanent component in the well.



DSC method flow

c. Tie-Back Cementing

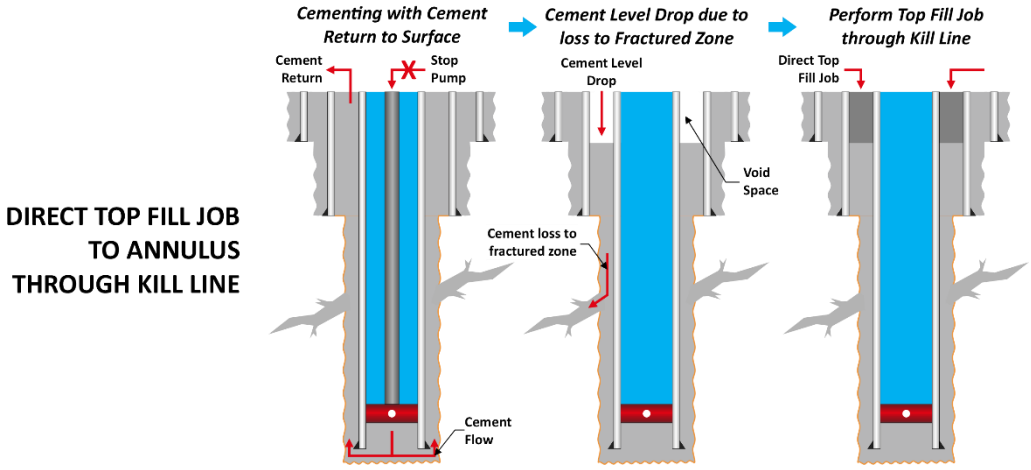
Different with DSC method, Tie-Back Cementing divides the running and cementing operation each in 2 phases. The idea is similar with DSC method, to reduce cement slurry hydrostatic pressure, with eliminating the risk of trapped fluid in the annulus casing to casing. Liner string is run to bottom hole with a liner running tool and then cemented. The top of liner is placed 30-50 m above previous casing shoe. A tie-back casing then run to top of liner (inside liner receptacle) and cemented. The tie-back casing should enter the liner receptacle to ensure no gap within the whole casing string. A gap between liner and tie-back casing will potentially cause gas leakage to surface through weak annulus channel. The crucial part of the operation is to ensure that the overlap liner and previous casing area are well filled with homogen cement. Trapped fluid within this area will cause casing collapse.



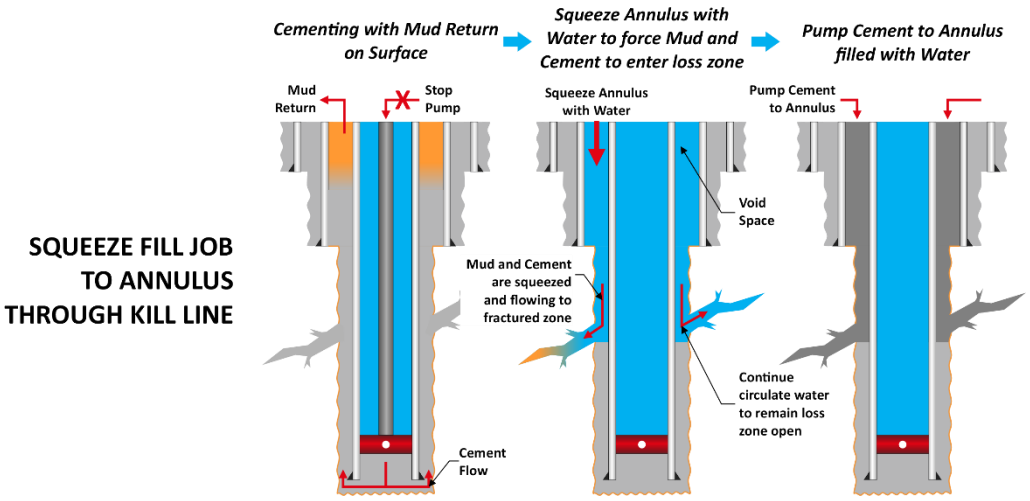
Tie-Back Cementing flow

d. Low Density Cement
The other option for geothermal well cementing is Low Density Cement. Low density cement will cause less destructive effect to the weak zone and the lost circulation can be minimized. In the other hand, low density cement is vice versa with drilling mud. Cement with low density is much more expensive than the higher density one. Further assessment regarding low density cement cost compared to previously mentioned method should be done to select the most suitable method for the company.

e. Longstring Method
The last method is the most simple and common method for the operation. A longstring casing is run to bottom hole and cemented once with regular cement slurry. Lost circulation will obviously happen and remedial cementing from surface should be performed. If there is a cement return to surface and then the cement level in annulus is drop, perform top fill through annulus valve with cement. But if there is no return at surface, prepare for squeeze job. Fill annulus with water (should be ensure that only water is pumped down) and squeeze annulus until lost circulation is observed. After getting lost circulation, continuously fill annulus with water until minimum 1.5x annulus volume to ensure that the whole annulus casing to casing is homogen with water. Pump regular cement afterward until annulus casing to casing is filled with cement. Perform top fill job if any cement level drop is observed.



Top Fill Job Flow



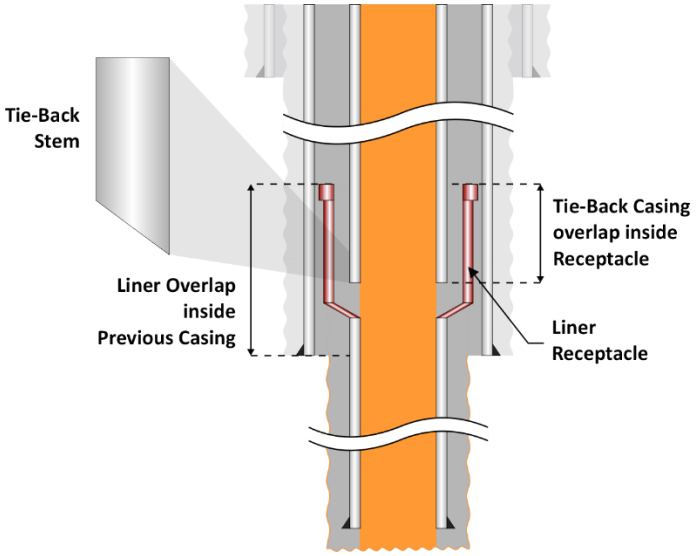
Squeeze Fill Job Flow

2. TIE-BACK CEMENTING OPERATION

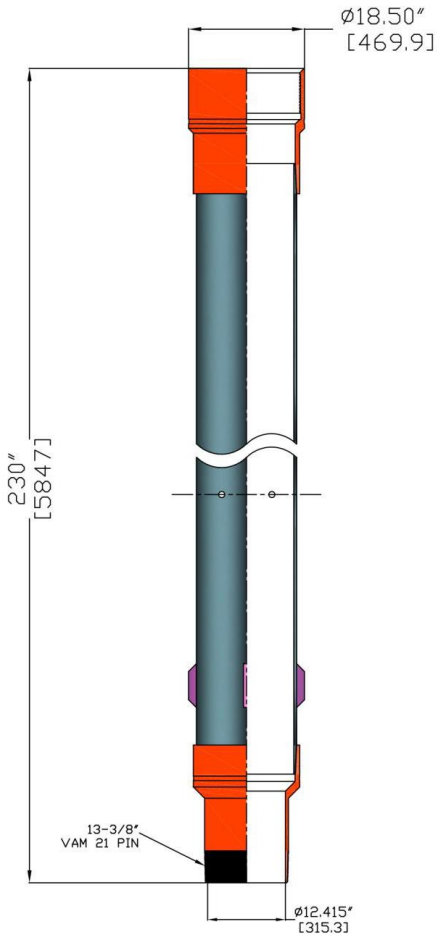
Tie-back cementing is a cementing method to divide the phase of running casing and cementing into 2 phases. The main idea is to reduce cement slurry hydrostatic pressure for the first phase, resulting less destructive effect to the weak zone. Moreover, this method will eliminate the existing of trapped fluid in annulus casing to casing which very dangerous for the well integrity. Fluid trap in annulus casing to casing will cause casing collapse and reduce well production rate. The detailed equipment and steps to perform Tie-Back Cementing will be described below.

2.1. EQUIPMENT

The first activity of tie-back cementing is running liner to bottom hole with liner running tool. The length of the liner has to cover open hole plus 30-50 m addition for overlapping previous casing. A liner receptacle is installed at the top of liner string where the lower section of tie-back casing (tie-back stem) will be placed. Tie-back stem is cut production casing at the thread to adjust how long is the overlap of Tie-Back Casing inside Liner Receptacle. The tip of tie-back stem is taper designed to ease the casing entering Liner Receptacle. A space between bottom of tie-back casing and bottom of receptacle is designed for the path of cement flow and to anticipate casing tally failure.

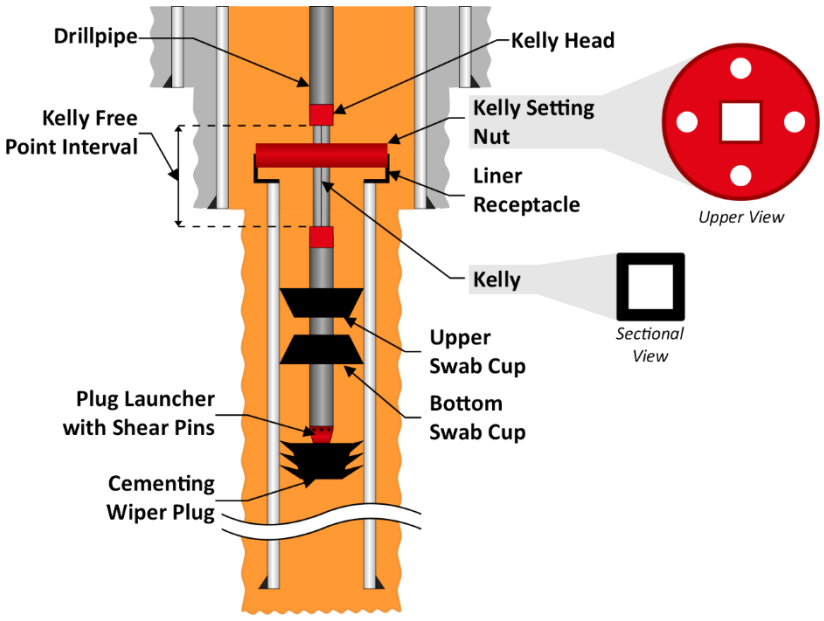


Casing Configuration in Tie-Back Cementing



Liner Receptacle Drawing for 13-3/8" Production Liner

The liner running tool consists of equipment for cementing support and drillpipe to deliver the liner to desired depth.



Liner Running Tool Illustration

The function of each equipment is unique and will be described as follows.

- Drill pipeis used to deliver the liner to the bottom hole.
- Kelly acts as the free point interval of the running tool. The liner running assembly tension should be freed (no tension nor compression) during running tool release from the liner. The approach is aimed to eliminate stress in the connection thread of kelly setting nut and liner receptacle before the disassemble. Kelly is square designed and placed in the center of kelly setting nut to possibly releasing the liner running tool from liner with rotation.

- Kelly setting nut is the tool to connect the liner to the liner running tool. Kelly setting nut and liner receptacle are connected in the rig floor. Before being picked up to the floor, the number of rotation to connect the tool should be conducted in ground to ensure the number of rotation when releasing the liner. Four circle holes in the tool acts as vacuum pressure prevention inside receptacle, thus the fluid above liner will able to fill the space below the kelly setting nut.
- Liner receptacle is the place for tie-back casing landed. By installing the receptacle, the tie-back scheme is possible to be conducted and leave no open space nor gap between liner and tie-back casing. The length of the receptacle is approximately 5 meters, while the tie-back casing will penetrate as long as 4.5 m inside receptacle, leave 0.5 m gap for cement pathway and casing tally error.
- Bottom swab cup is installed for sealing the liner during cementing, thus the cement is possible to be displaced down the liner assembly by pushing the wiper plug with displacement fluid. The upper swab cup acts as the backup of the bottom swab cup.
- Plug launcher is functioned to connect the Wiper Plug with the entire liner running tool assembly above it. Plug launcher is permanently connected to the wiper plug but it is detachable from the liner running tool. The plug launcher is temporarily connected to the liner running tool with the shear pin. Thus, the wiper plug will go down to sweep the cement slurry once the shear pins are broken by pressure build up from DP dart, displacement fluid and pump pressure. Shear pin commonly has pressure rating up to 275 each, while usually 8 shear pins are installed in the string to result total shear pin pressure rating to 2,200 psi. The shear pin is installed on the rig floor by hand.



Actual Liner Running Tool Picture

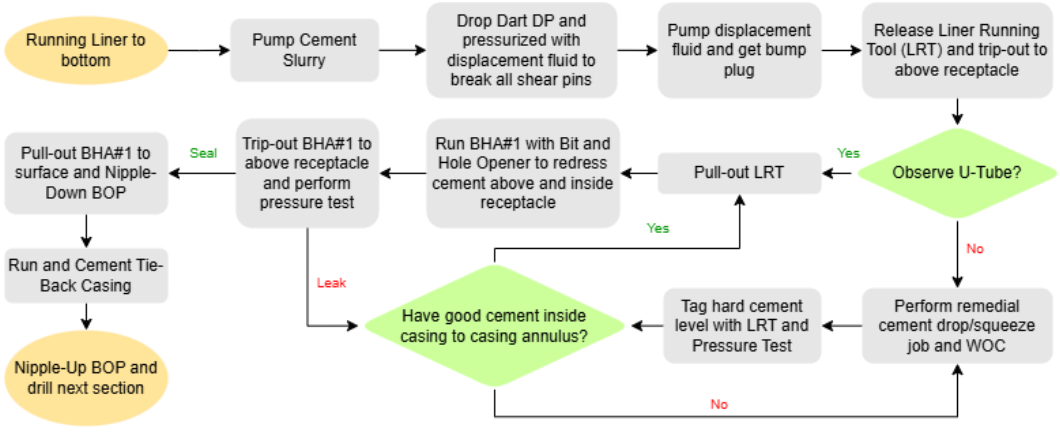


Shear Pins are being hand-tightened on the Rig Floor

- Once the plug launcher is detached from the liner running tool, the wiper plug is pushed down by the displacement fluid to sweep the cement slurry inside liner string down to shoe track and annulus.

2.2. CEMENTING STEPS

The diagram below shows the typical cementing steps that were being applied in the geothermal tie-back cementing.



Tie-Back Cementing Flowchart

The U-tube occurrence is a crucial parameter after cementing the liner. This parameter indicates the existence of cement slurry above the liner. By that, the annulus casing to casing is assumed to be filled with cement slurry. If U-Tube is not observed, the remedial cementing then has to be done which aimed to once again fill the annulus casing to casing with cement slurry. The remedial cementing typically can be performed by drop or squeeze cementing job depending on the lost circulation observation while waiting on cement after observing U-Tube. The drop job cementing is suitable when the lost circulation is massive. This remedial method is aimed to place pumped remedial cement slurry above receptacle and the lost circulation will naturally move the cement column into casing to casing annulus downward. While the squeeze cement will force the remedial cement slurry to enter casing to casing annulus due to the absence of lost circulation.

The pressure test after cleaning out cement above and inside receptacle is performed mainly to ensure there is a competent base to conduct tie-back cementing which typically will have higher cement density than the liner. If the pressure test leakage is indicated by the poor cement quality on casing shoe, which is less likely to occur, the remedial cementing will be done after drilling 1-3m new formation for the next section.

3. TIE-BACK CEMENTING OPERATION IN INDONESIA

The tie-back cementing system was used for all production casings in D & P Drilling Campaign. Out of 21 wells, 17 wells achieved successful tie-back cementing operations, as indicated by the attainment of shear pressure and bump plug. However, three wells failed to obtain bump plug, and one well failed to obtain both shear pressure and bump plug. These four wells required remedial cementing operations to ensure well integrity. The paper also evaluates the 17 successful wells based on various criteria, such as cementing duration, shear pressure value, U-tube occurrence, remedial cementing job necessity, squeeze cementing necessity, liner lap pressure test result, and cement volume requirement for tie-back cementing.

3.1. SUMMARY OF OPERATION

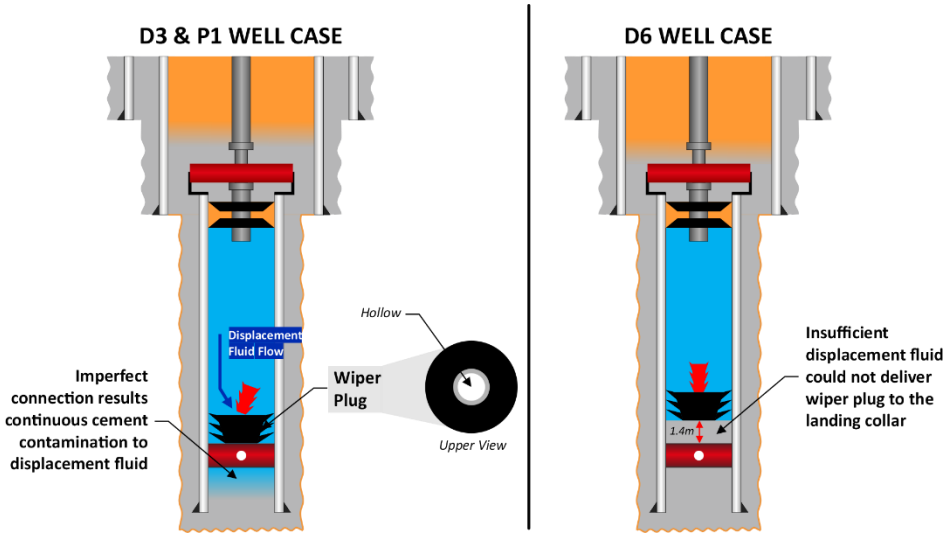
The general tie-back cementing operation in D & P Field involves running liner to bottom, cementing the liner, redress cement inside liner receptacle, running tie-back casing to liner receptacle, and cement tie-back casing. Absolutely, a special case in the operation requires additional steps to successful the cementing operation. For the first well both in D & P Field, additional cement drop job for liner cementing was not performed in an efficient way. The cementing string was pulled out of hole first, after liner primary cementing, while waiting on cement. A BHA Assembly with 14-3/4” Bit and 17-1/2” hole opener then run to top of cement to redress the cement to top of liner. Unfortunately, no cement was observed on top of liner in both first wells due to lost to thief formation. The cement drilling assembly then pulled out of hole and the cementing string was rerun to conduct remedial drop job cementing to ensure the casing to casing annulus is filled with cement. Since the primary cementing has been set, a squeeze cementing operation was required to force the remedial cement to fill the liner lap. The consumptive remedial cementing for liner then was being improved by conducting the drop job immediately right after the primary cementing was completed. The new procedure was applicated to all next wells. The cementing string was not pulled of out hole, but tripped out to 1 meter above top of liner to conduct cement drop job to ensure that there is a cement column above liner. The slurry of drop job cement is hopefully filling casing to casing annulus even though there is a fluid lost during waiting on cement. The cement volume for drop job varies based on lost circulation condition during cementing.

After waiting on cement, BHA assembly with 17-1/2” and 14-3/4” bit was run to redress cement to top of liner and bottom of receptacle respectively. The actual profile of liner is important to determine tie-back casing setting depth and to ensure the tie-back casing is entering liner receptacle. In the first well in both D & P Field, 14-3/4” bit and 17-1/2” hole opener was combined in an assembly to reduce the number of tripping. But the assembly left an uncertainty whether the tag is on the bit or hole opener. The assembly then being separated for the next well to ensure more certain liner profile. The other procedures of liner and tie-back cementing conducted in D & P Field were general as mentioned in CEMENTING STEPS.

3.2. RESULT

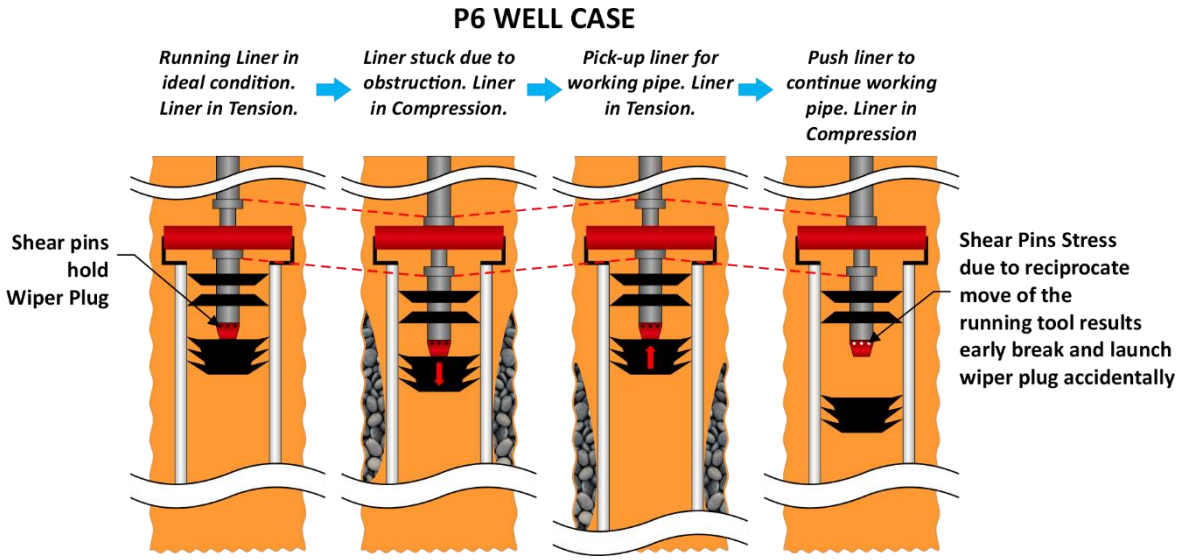
The tie-back cementing operations involved 13 wells that were completed within the planned days. The duration included primary cementing of liner, releasing liner running tool, performing cement drop job, waiting on cement, drilling out cement above and inside liner receptacle, pressure test, remedial and squeeze cementing (if any), and performing primary cementing for tie-back casing, and excluded BOP handling and running liner or casing. Eight wells exceeded the planned days due to longer cement drilling caused by longer cement interval, additional squeeze cementing, longer WOC, and cementing unit or drilling equipment failure. The average deviation of those eight wells from the plan was 1.68 days. The average tie-back cementing duration per well was 2.16 days/well without counting equipment failure and 2.48 days/well by including equipment failure handling.

The tie-back cementing was successfully performed in 17 wells out of 21 wells. All those 17 wells were achieving shear pressure and bump plug during liner primary cementing, ensuring the cement is placed successfully in the annulus and good cement slurry (less contaminant with water) is existed in production casing shoe. While the other 3 wells, namely D3, D6 and P1 well, failed to get bump plug and 1 remaining well, namely P6 well, failed to get shear pressure and bump plug. D3 and P1 wells were not achieving bump plug due to Wiper Plug and DP Dart connection failure which let the displacement fluid to continuously flow through the equipment even though the volume of displacement was exaggerated. This occurrence results in cement-water contaminant in the last cement slurry pumped. The other evidence is that the wiper plug cutting was found at similar depth with the tally depth of landing collar position, means wiper plug is successfully placed at the landing collar but bump plug was not achievable. While D6 well was not achieving bump plug due to insufficient displacement fluid pumped that failed the wiper plug to reach landing collar. The wiper plug cutting also separated 1.4 m from landing collar position based on actual liner tally.



D3, D6 and P1 Cases Illustration

P6 well failed to get shear pressure and bump plug, making the cement slurry to have a long contact, that may result a large amount of contamination, with water during pumping 230 bbls displacement fluid (water). Shear pressure was not achievable due to premature shearing of 8 shear pin installed. The premature shearing in this case was caused by long wash operation (along 273 m interval) with 300 gpm fluid and high obstruction tagging (30-50 klbs tag in 3 times) during liner running with liner running tool. The other well in the fields also performing wash operation but within 1, 3, 61, and 134 m interval only, but still achieving shear pressure with similar pump rate. In the other hand, the parameter of obstruction tagging in the successful wells were 10-20 klbs only although were having until 4 times tag during running liner. Wash liner activity may reduce the shear pin rating due to abrasive action of solid particle in the drilling fluid, while tagging action will allow the liner running tool inside the liner to have tension and compression condition continuously that will make the shear pin holding the wiper plug stressed out. Furthermore, the stress effect is escalating since the wiper plug is not designed to move upward. Premature shear pressure made the wiper plug launched earlier before the dart plug is on the spot, making them hard to be connected and make the bump plug was not achievable.



Tension and Compression Condition During Running Liner Illustration

From those 17 successful wells, no well achieving ideal shear pressure from the number of shear pin installed. The actual shear pressure was always below the installed shear pin rating. The causes of this occurrence are working pipe, wash down and tag activity during running liner. Moreover, shear pin rating decreases also was caused by the hydrostatic pressure of displacement fluid above dart plug. Working pipe parameter during running liner in D1 well was 6 times obstruction tag in 7-8 klbs before reciprocating pipe in 927 mMD. In D2 well, liner slack off and pick-up weight were recorded, allowing working pipe activity. Furthermore, the casing was pushed with 20 klbs, washed with 300 gpm and reciprocated while circulating hole clean. While in P4 well, the liner assembly was given a 50 klbs overpull after tagging obstruction in 20 klbs. The cycle of tension to compression will cause stresses to shear pin holding the wiper plug. The wash down activity was done in 7 wells with flowrate 250-300 gpm within maximum 134 m interval. Premature shear in the remaining 7 wells was caused by 7-20 klbs tag and the existing if hydrostatic pressure from displacement fluid.

The other aspect to be discussed is U-Tube existence after pumping cement for primary liner cementing. U-tube effect will confirm that there is a column of cement above liner receptacle, which is expected. In the D & P Field, five wells have

successfully achieved the U-Tube effect, one well did not succeed, and for the remaining eleven wells, it is not recorded in the report whether the U-Tube effect was achieved after liner cementing. The only one well did not get U-Tube effect was caused by lost circulation during the cementing which let the large volume of cement to flow into thief zone, making the cement slurry could not reach top of liner even though the cement volume excess was 176%. In the other hand, 5 wells with U-Tube effect have only 104% cement excess in average.

The absence of U-Tube effect will require additional cementing job to fill the top of liner and liner lap with cement. This additional cementing job usually called Cement Drop Job. In D & P Field, all wells were performing drop job even a U-Tube effect was observed. Drop job was aimed to encounter the volume of cement lost to formation during waiting on cement period. By giving enough volume of cement above receptacle, the liner lap will be kept full of cement until the thickening time even though there is a lost circulation. Unfortunately, Cement Drop job was not performed once, four wells in the fields required twice drop job and one well required until three times of drop job with squeeze cementing. Those four wells required twice cement drop job due to there was no competent cement above top of liner from the first drop job and there is a leak during pressure test after the first cement drop job. Three out of those four second cement drop job required squeeze cementing since there is already set cement inside liner lap. The only one well with three times cement drop job experienced leak during pressure test from first and second drop job. The second and third cement drop job required squeeze cementing to force the new slurry entering liner lap.

Pressure test was conducted to ensure the cement integrity result from primary cementing and/or cement drop job. Moreover, the pressure test EMW (Equivalent Mud Weight) value was usually similar with the cement slurry for tie-back casing cementing i.e 16.2 ppg. This EMW value would ensure the liner structure will competent enough to hold the hydrostatic pressure during tie-back casing cementing. 20 Wells in the fields was performed pressure test with EMW around 16.2 ppg, while the remaining 1 well did not conduct pressure test and only performed static fluid test after the second drop job with squeeze cementing.

After ensuring the competency of liner structure, the tie-back casing then run to bottom and cemented in place with stinger cementing system. There is only one major problem during tie-back cementing in D & P Field when the cementing unit failed during pumping 160 bbls cement. The cementing line the being disconnected and 160 bbls cement was circulated out of the well. The cementing operation was continued after almost 4 days of waiting on cementing unit repair. The cement slurry used for cementing tie-back casing was 16.2 ppg for 20 wells and 15.8 ppg for 1 well. There are two cases of cement level drop after cementing in D3 and P11 well. The cement level dropped 77 cm in D3 well and 15 cm in P11 well. Remedial top job was performed to fill in the dropped level cement in the annulus.

The total volume of cement slurry to perform tie-back cementing in D & P field was 22,582 bbls for all 21 wells or 1,075 bbls for one well in average. The volume equals to 2 times of total actual cement requirement for the well. The requirement includes the volume for liner shoe track, liner rat hole, liner-hole annulus, liner-casing annulus, tie-back casing shoe track, tie-back casing rat hole and tie-back casing to 20” casing annulus. In detail, the liner cementing required 750 bbls of cement slurry per well or equals to 2.5 times of actual cement requirement while the tie-back casing cementing required 325 bbls slurry per well or 1.4 times of actual cement requirement.

4. CONCLUSIONS

The success of Tie-Back Cementing Operation is determined by the success of the liner cementing, since the tie-back casing cementing having a low uncertainty due to not related directly to open hole formation. The liner cementing should achieve shear pressure and bump plug to ensure that there is enough cement in annulus and good cement slurry (less contaminant) is placed under the production casing shoe. The absence of shear pressure will let the cement to have a long contact with water which may reduce the cement quality, while the absence of bump plug will place a portion of water in shoe track or even below the casing shoe in a worst case. In D & P Field, three wells were not achieving bump plug and one well was not experiencing both shear pressure and bump plug. Those three wells did not achieve bump plug due to Wiper and Dart Plug connection failure and insufficient displacement volume. Wiper and dart plug connection failure is difficult to detect since the test cannot be done because they are not detachable once they latched. A good communication for improvement with the service provider will help both sides to have a better result. For the insufficient displacement volume issue, all the team involved should be well informed regarding the cementing program.

The cause of one well did not achieve shear pressure and bump plug was due to premature pin shearing that was caused by long wash operation (along 273 m interval) with 300 gpm fluid and high obstruction tagging (30-50 klbs tag in 3 times) during running liner. Wash liner down activity may reduce the shear pin rating due to abrasive action of solid particle in the drilling fluid, while tagging action will allow the liner running tool inside the liner to have tension and compression condition continuously that will make the shear pin holding the wiper plug stressed out. The data from the other 19 wells shows that wash liner down with 300 gpm in 134 m interval is still safe and tagging obstruction in 10-20 klbs is still acceptable even though performed in 4 times.

No well within 17 successful wells achieved ideal shear pressure. The shear pin rating degrades by working pipe and wash liner down operation. To have an optimum cementing result, wiper trip operation before running the liner should be optimum to ensure the well is slick. Hole interval with high dog leg should be polished to ease the running of liner. Longer period of polish hole is an investment of a good cementing result. A U-Tube effect is hopefully observed after cementing the liner. Unfortunately, the data shows that more cement volume excess will not ensure the existence of U-Tube. Thus, 100% excess cement is enough for primary liner cementing, then a cement drop job can be performed afterward. By this

composition, the volume of cement can be minimized. The volume of cement for tie-back cementing also can be minimized since the downhole uncertainty is low and predictable.

5. REFERENCES

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