Lessons Learned and Performance Improvement: Drilling Case Study from Sarulla Geothermal Operation, North Sumatra

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ABSTRACT

A lessons-learned and continuous improvement approach used to improve drilling performance significantly during a five-well drilling campaign on one drilling pad at the Sarulla geothermal development field in North Sumatra, Indonesia. Drilling times were reduced by 73%, and costs decreased by 64% from the first to the fifth well. Drilling challenges on this pad included severe lost circulation, high vibration when drilling the surface hole sections, soft and swelling clays in shallow sections, along with sloughing Paleosol formations in the deeper section, and a corrosive drilling fluid environment, which resulted in drill pipe (DP) washouts and twist offs.

Optimized intermediate casing setting depths were developed to manage the sloughing formation issues. The use of nested liners was employed to stabilize the difficult hole sections already drilled but allowing drilling to commence safely with smaller hole sizes deeper. To help prevent intercepting previous wells and kickoff issues in the soft clay formation, the 26-in. surface hole section was "nudged" using directional drilling techniques. Formation clay samples were tested using the linear swelling method (LSM) and X-ray diffraction (XRD) to optimize drilling fluids formulations specific for each section, and a set of best practices for drilling these formations was developed.

Other performance improvements that were applied include the following:

- Using a shock sub in the surface section
- Replacing drilling stabilizers with roller reamers to reduce the torque while drilling in the reservoir
- Using casing running tools (CRTs) to increase efficiency and safety of casing operations
- Using a custom-designed and built polycrystalline diamond compact (PDC) drill bit to help enhance the rate of penetration (ROP)
- Modifying tubular inspection procedures to detect internal DP flaws

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1. INTRODUCTION

Well Pad Y is a drilling pad in the Sarulla geothermal field that is located on the Namora I Langit field in the Tapanuli Utara district, North Sumatra, Indonesia. The operator and service company, project management team collaborated to drill wells to supply steam and brine for the 3 × 110 MWe plants located in the Namora I Langit and Silangkitang field areas within the Sarulla region. The service company was hired to run the drilling project using integrated project management (IPM) approach.

Well, Pad Y is located in the Namora I Langit field. Five injection wells were drilled on well Pad Y. Figure 5 shows a typical well schematic, which indicates that these wells are drilled directionally with an inclination from 30 to 40°.

2. DRILLING CHALLENGES

2.1 Surface Loss Circulation

Total lost circulation (TLC) is a primary challenge during geothermal well drilling. The permeable nature of the formation is not limited to the geothermal reservoir structure alone but often occurs in much of the shallower and overlying formations as well[2].

Shallow TLC was observed during drilling of an 8 ½" pilot hole in Well 1. Three cement plugs with the conventional cementing design were performed to cure the loss before drilling continued to the target depth (TD) section. Partial lost circulation (PLC) to full return was observed while enlarging the 8 1/2-in. pilot hole to 26 in. in the first well. The cement plugs from the first well apparently spread out through the fracture and cured the zone because no losses were observed during surface hole drilling on the next four wells on the pad.

2.2 High Vibration During Surface Hole Drilling

High vibration was observed during drilling on well Pad Y, particularly at the surface section. The vibration occurred in the axial direction and was caused by the hard Dacite formation. The bottom hole assembly (BHA) was lightweight because of the shallow depth that contributed to the bouncing and propagated vibrations.

High vibrations were observed while drilling the surface 26-in. hole in Well 1 with a rotary BHA (without mud motor). A total of 21 hours of nonproductive time (NPT) occurred because of top drive failure and mud logging RPM sensor issues, both caused by high vibrations while drilling.

Because of severe vibrations and low ROP while drilling with the 26-in. BHA, the drilling team, decided to enlarge the 8 ½" pilot hole to 17 ½" with a rotary BHA to TD section.

A 26-in. directional BHA was used to enlarge the 17 ½" hole to 26-in. to the section TD. The mud motor helped increase the penetration rate and lowered the vibration.

To overcome the high vibration and low ROP issue during drilling of the 26" surface section, a 26" directional BHA was used to drill the next four wells. As a result, the average ROP on the next four wells was higher compared to the first well.

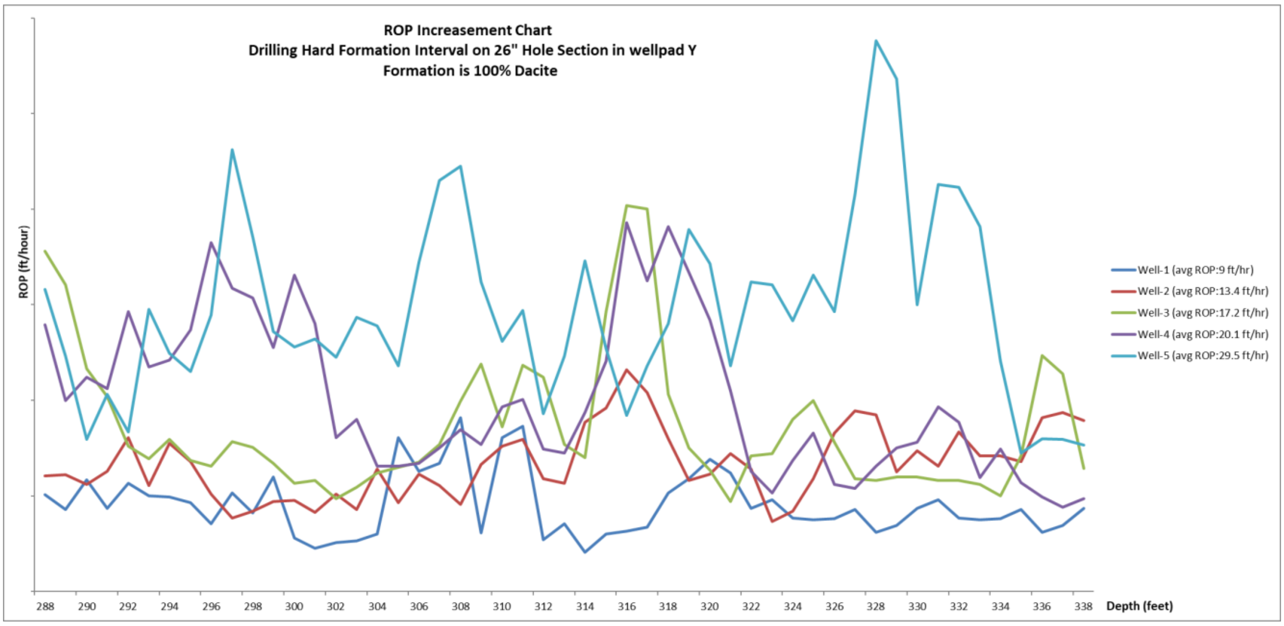

Figure 1: ROP record from five wells in a specific interval.

2.3 Corrosive Drilling

Corrosive subsurface fluid is another issue during the drilling of geothermal wells. Corrosion test ring placement in the drill string is a common technique used to evaluate the corrosiveness of drilling fluid. Corrosion inhibitors are used to minimize the corrosion effect on the drill string. Corrosion inhibitor is injected through the string and/or annulus based on the previous well corrosion rate reading and recommendation from drilling fluid and air drilling providers.

The corrosion rate readings were different on every section of each well, high to severe corrosion rates (above 6 lb/ft^2/year) were observed on the intermediate and production section on well no 2,3,4 and 5. Two corrosion rings were installed on each section drilled. One was installed on the first joint of the HWDP, and another was installed on the top drive saver sub. This provided a comparison of the reading results. A normal exposure time is 100 hours, with a minimum of 40 hours exposure time necessary for a correct corrosion rate reading.

Maintaining the pH with caustic soda of the drilling fluid that is pumped into the annulus during significant or total loss conditions is another important practice besides injecting corrosion inhibitors.

2.4 DP Washout and Twist Off

Several washouts, crack and twist off events occurred on this well pad and were a direct result of drilling in the corrosive environment.

Figure 2: Twisted-off, Wash-out and Crack on the Drill Pipe Observed during Drilling

To help minimize the possibility of DP washout and twist off events, ultrasonic thickness (UT) inspection of the slip area was added to the regular DS1 Cat-4 inspection for DP. The tubular inspection service provider was also replaced to help ensure a more reliable inspection result. This subject is discussed in the Performance Improvement section.

3. IMPLEMENTING LESSON LEARNED

3.1 Intermediate Casing Setting Depth

During drilling of Well 1, instability of a Paleosol clay zone in the 17 ½" hole section prevented the 13 3/8-in. liner from being set on bottom (60 ft off-bottom). Three Paleosol cement stabilization plugs were performed to cover the Paleosol zone below the 13 3/8" casing to the bottom of Paleosol before drilling of the 12 ¼" production hole continued. These Paleosol cement stabilization plugs caused 110 hours of UPT during the cementing operations, wait on cement (WOC), drill out cement, and necessary trips.

3.2 Nudging on the 26-in. Hole Section

All five wells on Pad Y were drilled as J-style directional type wells with 35 to 40° final inclinations. Kickoff points were usually at 100 ft below the previous casing (20-ft casing setting depth). Soft dacitic tuff and mudstone formations with clay inclusions were observed 200 ft above and below the kick off point.

To achieve a 3° planned dogleg in the soft formation, the directional drilling service company and operator agreed to perform a nudge routine on the 26-in. hole section. Inclination was targeted 3 to 5° at the TD of the 26" hole section. This method improved the possibility of achieving the planned dogleg (3°/100 ft) during buildup inclination in the soft formation interval and following the planned trajectory.

Nudging was also necessary to help prevent well collision issues in the nearby surface sections of the other pad wells because the distance between the centers of the conductors was only 6.5 m

3.3 Drilling Fluid Formulation.

Clay was suspected in all three intervals of the Pad Y wells. The drilling fluid formulation was optimized using the cuttings laboratory testing of the wet drill cutting samples that contained clay. The three laboratory test methods are as follows:

- A methylene blue index (MEBi) test determines the ability of clay to absorb cations from a solution and thereby predict the clay reaction upon exposure to the various drilling fluids. A MEBi test is usually performed by a mud logging company at the rig site. The drill cuttings are tested immediately after they are collected from the shale shaker.
- XRD testing is used to identify the molecular composition of the clay minerals, which helps determine the clay type. XRD testing is crucial to proper mud system selection. This test was conducted by a third-party laboratory.
- A LSM test measures the swelling tendency of clay in differing drilling fluid solutions. This test was performed in-house in the drilling fluid division laboratory.

Following are the three different clay zones observed on well Pad Y:

- Swelling type clay interval
  High MEBi number was generally observed in the swelling type clay (±650 to 1,100 ft MD) in all Pad Y wells. The MBEi reading ranges on the interval were usually from 14 to 64. XRD testing indicated a high Smectite percentage (22%) from this interval. Smectite is a reactive/swelling clay, and the LSM test results indicated the clay in this interval swelled 21.6% in the 6% KCl polymer mud., the shallow swelling clay interval was covered and cemented by 20-in. casing to help prevent drilling issues during the next longer hole section.
- Shallow Paleosol

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The shallow Paleosol interval is located at the intermediate casing points on the Pad Y wells, except for Well 4. Shallow Paleosol is sloughing and swelling clay type. XRD test results showed a high percentage of illite-Smectite.

- Deep Paleosol
  The deep Paleosol interval is located at the production section in all Pad Y wells, except Wells 4 and 5. Deep Paleosol is sloughing clay type[3]. LSM result of deep paleosol cutting is showing 12% swelling at 6% KCL Polymer mud system.

The deep Paleosol caused sloughing issues during drilling of the 12 ¼" hole section on the first well, particularly after TLC occurred below the deep Paleosol zone. The well design was modified for the remaining wells on the pad to help prevent drilling issues caused by the sloughing Paleosol. The 10 ¾"perforated liner was set after entering the TLC zone to cover the deep Paleosol zone with the 10 3/4-in. perforated casing. Drilling then continued using a smaller bit size and running smaller perforated casing. This is further discussed in the Nested Liner section.

Based on the three laboratory tests described previously, an inhibitor was necessary to drill through the three clay zones. LSM test results indicate that KCl is the best inhibitive drilling fluid formulation for this application[3]. The KCl percentage began at 4% in the first section and increased based on cuttings data in the next section to the maximum 8% KCl.

Laboratory testing of the clay samples to help select the most effective inhibitor significantly decreased drilling issues and resulting UPT caused by swelling and sloughing clays. Wells 1 and 2 experienced multiple stuck pipe events. Subsequently, there were no stuck pipe issues during drilling operations in Wells 3, 4, and 5 after using the inhibited mud system.

The KCl percentage was usually maintained while drilling in full-to-minor lost circulation conditions. Once TLC occurred, the KCl percentage could not be maintained because of high chemical costs and mixing speeds that could not keep up with the rate of losses.

3.4 Nested Liner

To help overcome the hole issues while drilling the 12 ¼" hole section with TLC in the unstable deep Paleosol zone, a 10 ¾" perforated liner was run across the zone immediately after TLC occurred. The sloughing deep Paleosol zone caused a stuck pipe event when drilling Well 1 on the pad. The stuck pipe event occurred because the 12 ¼" hole section was planned from the 13 3/8" casing shoe to the well TD at 7,500 ft MD, which equated to ±4,000 ft of open hole.

Based on the lessons learned from Well 1 drilling operations in this hole section, a 10 ¾" liner was planned to be run in the subsequent wells and set at ±5,800 ft MD or after the TLC was encountered. Drilling then continued using a smaller size (9 ½") to the planned TD at 7,500 ft MD, and the wells were completed by setting a 7" perforated liner. As a result, no stuck pipe events caused by hole issues occurred during drilling of the 12 ¼" hole sections of Wells 2, 3, 4, and 5.

4 PERFORMANCE IMPROVEMENT

4.1 Shock Sub

As discussed in the Drilling Challenges section, to reduce the axial vibration created by the drill bit while drilling through the hard Dacite formations in the surface section, a shock sub was used with a mud motor. The use of a shock sub in the 26-in. hole section helped minimize inefficient drilling and eliminated unplanned trips and pilot hole drilling. There were no downhole tool issues or excessive bit wear recorded, unlike Well 1. The drill bits were reusable based on the dull grading of all five drilled wells.

While there were no vibration measurement records available for the BHA run without a shock sub, the data showed good penetration and low bit wear results from the BHA runs with a shock sub, particularly for the 26-in. bit grading and axial and lateral vibration readings – figure-3.

No significant vibrations were recorded by the electromagnetic (EM) measure while drilling (MWD) tool for the Pad Y wells, in which a shock sub was used in the BHA string. The axial vibration was considered low with a 4 G maximum reading and usually coming in at 0.5 to 1 G. Figure-3 shows the vibration readings.

Well No.	HS (in.)	Axial Vibration (Z)		Lateral Vibration (X)	
		Range (G)	Average (G)	Range (G)	Average (G)
1	26	No reading			
	17 1/2	0 to 1.5	1	0 to 2.2	2
2	26	0 to 3	0.5	0 to 3	1
	17 1/2	1. to 2	1	0 to 4	2
3	26	0 to 1	0	0 to 2	0.5
	17 1/2	0 to 1	0.5	0 to 1	1
4	26	0 to 2	1	0 to 3	2
	17 1/2	0 to 4	1	0 to 4	2
5	26	0 to 2	0.5	0 to 3	2
	17 1/2	0 to 2	1	0 to 2	1
	12 1/4	0	0	0 to 1	1

Figure 3: Table of axial and lateral vibration record

4.2 Roller Reamer

High drillstring torque was encountered in the first two wells in the 12 ¼” hole section. A preventive method to include a roller reamer as part of the BHA configuration significantly reduced the torque issues while drilling[4]. The roller reamer provided a low torque point stabilization system in which the cutters roll around the wall of the formation. Furthermore, it helped smooth the trajectory of the well by removing ledges and reducing tortuosity from the doglegs. A special geothermal cutter was used to extend the cutter life.

During of the 12 ¼” hole section in Wells 1 and 2, high torque values were experienced. Inconsistent torque values were even observed while the BHA was still inside the casing, and the values behaved abnormally throughout drilling in this section. As a result, additional time was necessary to clean and ream the holes smooth[4]. The drilling superintendent proposed using roller reamers to help improve the drilling performance, reduce the possibility of string failure, and reduce unplanned trips. With operator approval, roller reamer use began in Well 3. As a result, the torque values were significantly reduced. Torque never exceeded its simulated value and remained on its predicted line. This scenario improved drilling operations and reduced the overall time[4] of the well completion. A roller reamer usually replaced the second stabilizer at ±85 ft above the bit on the rotary BHA during drilling of the 12 ¼” and 9 ½”hole sections.

4.3 CRTi

A CRTi was used to run the 13 3/8” intermediate casing. This was a performance improvement that was initiated by the drilling team after the Well 1 13 3/8”casing was set ±60 ft off-bottom because of the sloughing Paleosol formation.

The CRTi has an internal gripper that is attached directly to the top drive. No hydraulic power unit (HPU) is necessary because the CRTi works mechanically and uses the power and torque produced from the rig’s top drive. The CRTi was selected to replace conventional casing running equipment because of the following:

- Pump down, push down, and ream down feature
- Rotating feature
- Faster rig up and rig down process
- Enhanced safety

The 13 3/8” casing was set on bottom in Well 3 without issues. After the successful 13 3/8” casing operation using the CRTi, it was run again on the 10 ¾” blank and perforated liner.

4.4 PDC Bit

Geothermal wells are traditionally drilled using roller cone bits IADC 4XX and above because of the effective crushing action in hard formations. However, roller cone bits have limitations related to sealing and bearing life, and several bit trips are usually necessary as a result. The service company drill bit division collaborated with the operator using a customer interface process to develop the MM75RH fixed-cutter drill bits. The MM75RH is a seven-bladed, 16-mm cutter PDC bit with a new backup cutter feature.

This custom-designed PDC bit (MM75RH) is the third generation of the service company's PDC bit that is specifically designed to drill geothermal wells5. In the new design, the unique cutter is attached as a backup cutter (Figure 4). The backup cutter is designed to help improve the bit durability in abrasive and high-impact environments. These active auxiliary cutters help reduce reactive force and limit the depth of the cutter of cut. This is helpful during mud motor BHA applications.

Figure 4: Third generation PDC cutter bit design

The PDC cutter bit was used to drill Well 5, in which the formation consisted of Andesite (breccia), Dacite tuff, and rhyolite tuff before reaching the TLC zone. The following positive results were achieved:

- Reduced number of runs
  The PDC cutter bit was the first bit able to finish the section in a single run. In previous wells, two to three TCI bits were necessary to drill the 12 ¼" section on Pad Y.
- Reduced number of trips
  Because drilling was completed in a single run using the 12 ¼" PDC cutter bit, the number of trips in Well 5 was reduced to two. A minimum of three-bit trips was necessary during drilling in the previous wells.
- Longer run interval
  The 12 ¼" PDC cutter bit drilled 2,119 ft in Well 5, which is the longest run in Pad Y. The longest TCI bit run was 1,260 ft. The bit grading was 1-1-CT-S-X-IN-WT-TD and still can be re-run.
- ROP
  Table 1 shows the average ROP recorded for the three different bit types.

Table 1: 12 1/4-in. Bit average ROP

12 1/4-in. Bit Type	Average ROP (ft/hr)
TCI	34.9
Hybrid	30
PDC R1	51.8

4.5 Tubular Inspection Procedure

Tubular inspection quality was an important issue during Well 1 drilling operations. Twist offs, cracks, and washout events occurred after inspection. The rig contractor, IPM team, and operator agreed to add UT inspection of the slip area in addition to DS-1 (Category 4) pipe inspection as the performance improvement initiative. UT inspection of the slip area was included because most of the DP failures occurred at that location, and external visual inspection did not detect the internal pitting and cracks that were the failure initiation points.

The drilling contractor also agreed to replace the DP that had a failure in the slip area based on UT inspection results. The inspection provider was also replaced to provide a more reliable inspection result. As a result of this performance improvement initiative, no DP failures were observed during drilling operations in Wells 4 and 5.

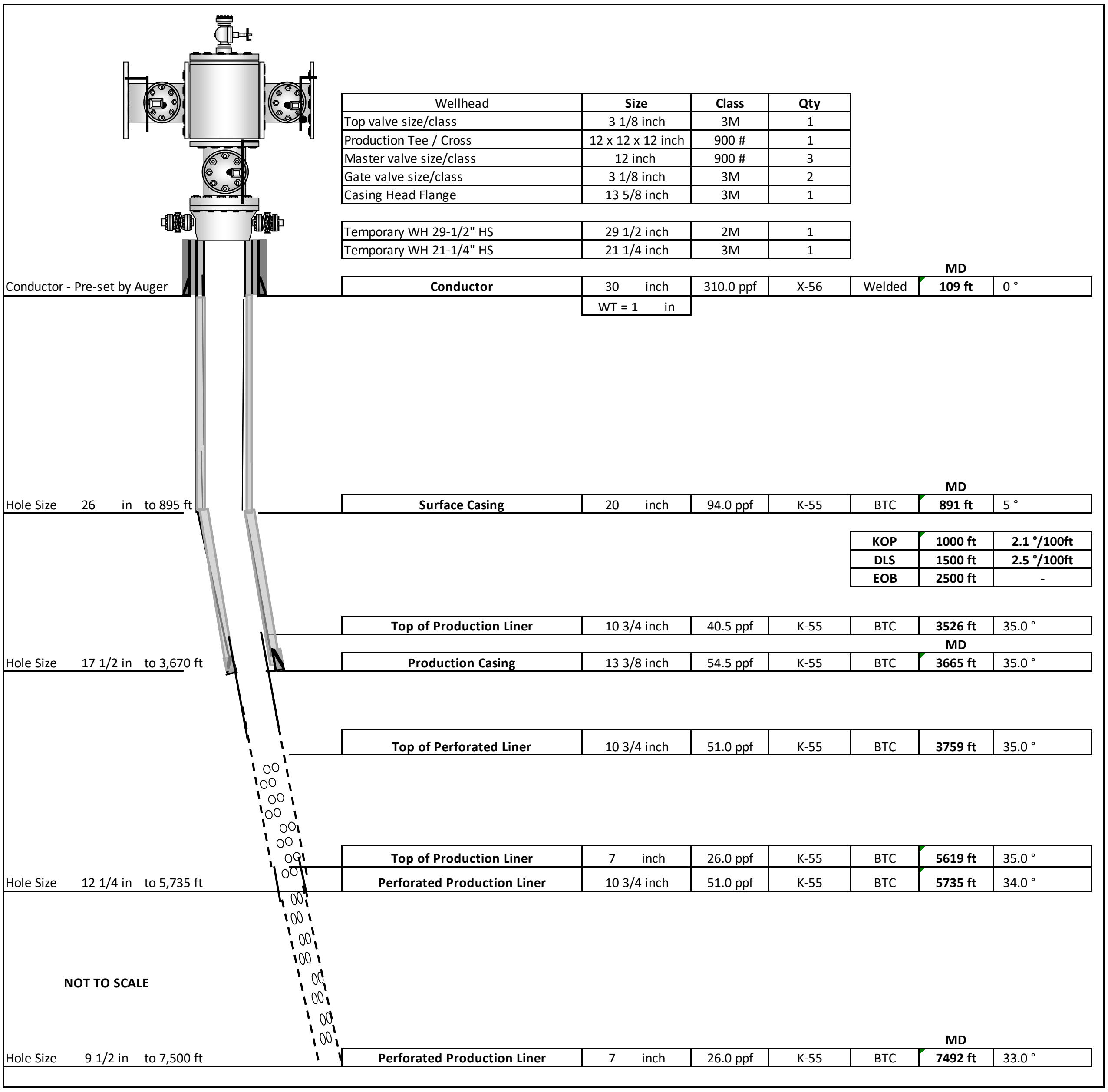

Figure 5: Typical schematic of Pad Y Wells

5. CONCLUSION

Using lessons learned and a continuous improvement approach helped significantly improve the drilling performance of the five injection wells drilled on well Pad Y. The reduced number of drilling days for each well was the result of the performance improvements and new technologies implemented. Well 5 was completed 6.42 days ahead of schedule and 15% below the planned costs (Figure 6).

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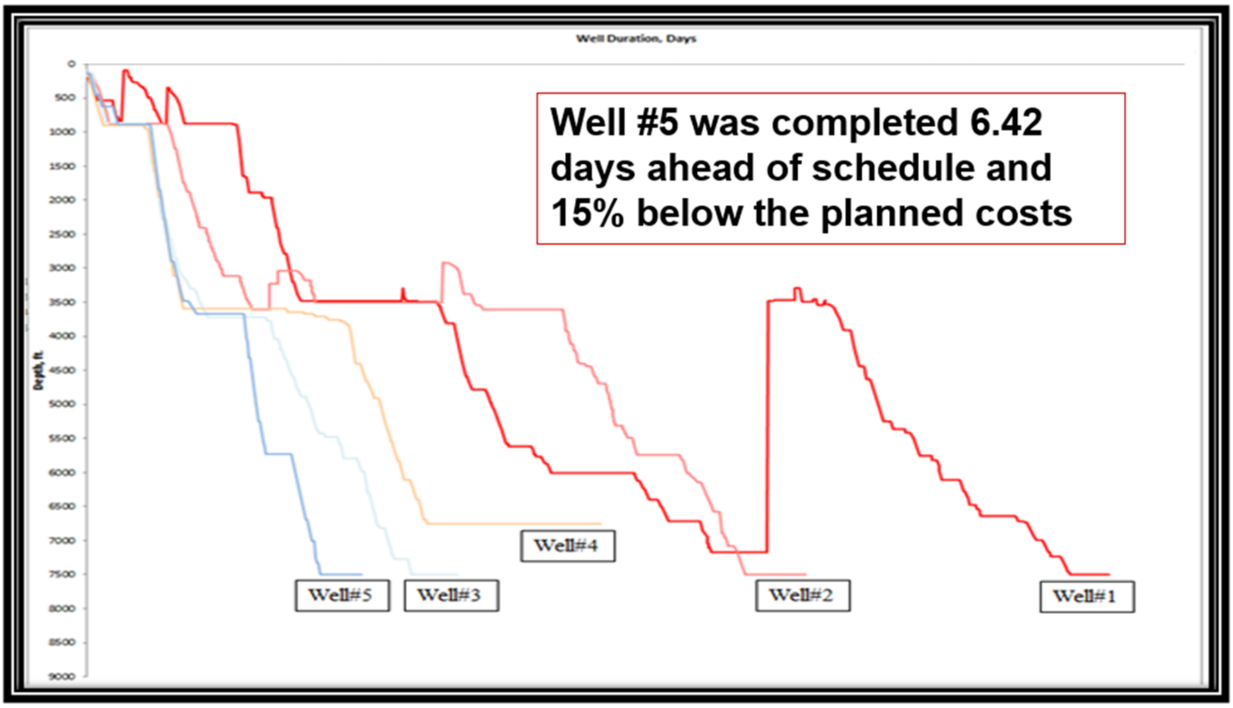

Figure 6: Drilling Days Record from five driller wells

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