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Drilling Performance Improvements of Salak Geothermal Field, Indonesia 2006 - 2008

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ABSTRACT

Chevron Geothermal of Indonesia launched the 2006-2008 Drilling Campaign to respond to maintain steam and injection capacity in the Gunung Salak Geothermal field. The drilling team has been successful in reducing the depth vs. days curves from an average of 55 days in 1993 to an average of less than 20 days in 2008. The best performance at the time of writing this paper is a 5350 ft well drilled in 9.6 days from spud to Total Depth. The evolution of this continued improvement process has resulted in "world class" drilling performance.

The critical success factors of this campaign include standardized well design, equipment improvements, and performance improvement processes that was made possible by a synchronized multi-disciplinary Well Decision Teams, Multi-disciplinary Decision Review Boards, Performance Monitoring, Ingenuity Projects (technology application), Interactive Communication (Integrated Pre-Spud Meetings and Daily Morning Meetings), Flat Spot Performance and Goal Setting (Perfect Well Targeting, and ultimately, the Single Digit Well Target). Additionally, we put a strong emphasis on improving our two way communication through the Stuck Pipe Prevention Workshops. The outcome of this successful approach has boosted productivity, reduced well costs and cycle time, and ultimately, improved the economics of the drilling campaign by over $4,000,000 per year (or one additional well per year).

1. INTRODUCTION

Chevron Geothermal Salak (CGS) is known for spearheading extensive drilling activities for decades. A total of 93 new wells were drilled from 1983 to 2008; 28 among which were re-drilling, sidetracking or clean out.

Aside of the well known challenges of drilling geothermal well such as hard formation, total lost circulation and high temperatures environment, the challenge to achieve optimum drilling time becomes the lead economic factor. An optimum drilling time directly improves cost efficiency.

This paper explores the drivers and challenges, the steps of reducing the non-productive time, the synchronized multidisciplinary organizational approach in drilling, and the appropriate application of available technology to execute this relatively new aspect of geothermal drilling campaign. Results of 2006-2008 drilling campaign will be reviewed as the case study, followed by conclusions.

2. DRIVERS AND CHALLENGES

Records of early drilling time of geothermal wells in Gunung Salak showed an average 55 days to reach depth between 7,000' to 9,500' measured depth. However, the documented lessons learned and the logs of daily drilling activities have shown opportunities for possible optimum drilling time. CGS recapped this lead information as the corporate operational strategy, which was subsequently pursued throughout.

3. PERFORMANCE IMPROVEMENTS PROCESS

This section describes the establishment of performance improvement process, the ingenuity projects (the selection and application of technology), and the standardized well design. Those three parts will be presented in the order presented.

3.1 Principles of Performance Improvement Process

At CGS, the steps to develop a performance improvement process are to: (a) define performance objectives; (b) establish performance indicators in the system; (c) develop and execute a performance monitoring plan; and (d) to continually analyze the results of monitoring to determine which processes require tuning, and set up one adjustment at a time. Based on CGS' experience, technical expertise and leadership or project management are two key areas that must be improved simultaneously for material gain in drilling operations. Accordingly, the following sub-sections describe five main performance improvement drivers, namely, the processes in the well decision team, the management of risk, the process in managing changes, the perfect well targeting, and the consolidation workshop of all stakeholders.

3.1.1 Well Decision Team Process

Phase 1 start with the Well Decision Team (WDT), which is a multidisciplinary team composed of Reservoir Engineers, Geologists and Drilling Engineers and supported by Steam Supply Team. This team works together to review the well portfolio and to identify all drilling alternatives. After a systematic and established assessment process, WDT will determine whether or not a well will be drilled.

In **Phase 2** the WDT will identify all alternatives for the respective well. After collected all applicable data from the offset well, WDT could suggest the best direction to hit the optimum target point. All of the developed plans are then proposed to the Decision Review Board (DRB) meeting for review and suggestions.

The detailed action plans such as the directional drilling target and plan; days vs. depth curve which include the authorization for expenditure days and perfect well days; or drilling procedures, should be finalized and routed to all DRB members for approval in **Phase 3**. Drilling procedures shall include a sign off page identifying the author, reviews and approvals. The procedures is prepared by the assigned Project Engineer, reviewed by the Drill Site Manager and approved by the Drilling Superintendent, Drilling Engineer Manager, and Geothermal Drilling Manager.

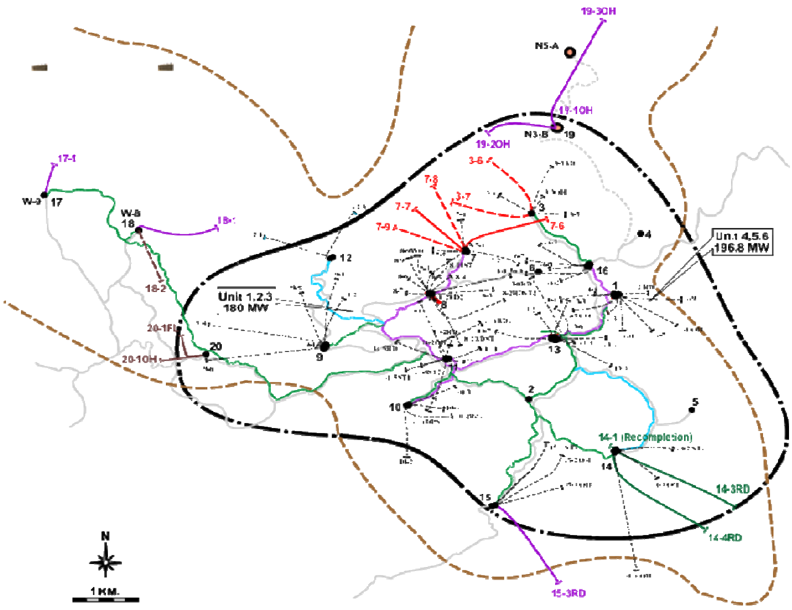

Figure 1: Chevron Geothermal Salak Asset.

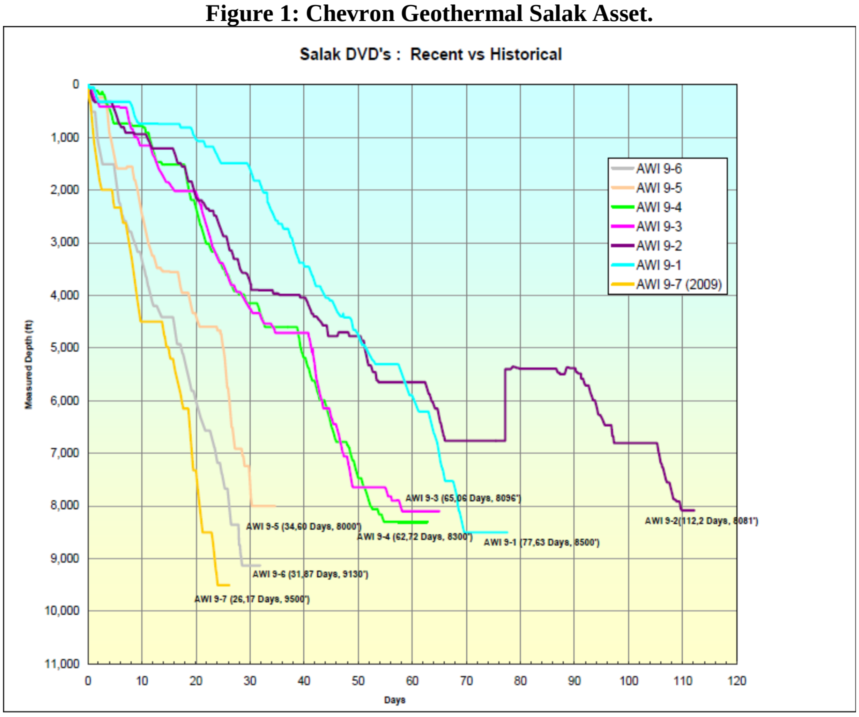

Figure 2: Example of Depth vs. Days Graph of Awi 9.

To capture the complete spectrum of the potential risks, the WDT will conduct the risk assessment meeting at this stage. This meeting identifies all the potential and real risk based on history from the offset wells as well as all experiences thus far recorded.

Prior to drilling the well in **Phase 4,** the Pre-Spud Meeting is a standard. The objective of the meeting to inform involved parties in the implementation of the project, the well objectives, the risks, areas of latest change, and to obtain adherence to their roles and responsibilities for the execution of the drilling procedure.

Chevron has established a proprietary standard operating procedure for WDT work process implementation known as Single Well Chevron Project Development and Execution Process (SWCPDEP), which appears in the form of checklist. We believe that SWCPDEP provides the best the road map, especially for complex routine operations in which time is a constraint.

The final stage **(Phase 5)** of the project is to capture all new situations encountered and to record process improvement in our post project review and reports. Here we review the technical limit, update the performance metrics, and identify lost time by measuring it against the newest benchmark of non-productive time.

3.1.2 Risk and Uncertainty Management Standard

The Risk and Uncertainty Management Standard is a Chevron Geothermal process designed to ensure that technical, operational, health safety and environment, and financial risks and uncertainties are identified, managed, and mitigated. This process is to be used as part of the Single Well CPDEP process and is consistent with other Chevron's risk and uncertainty management tools.

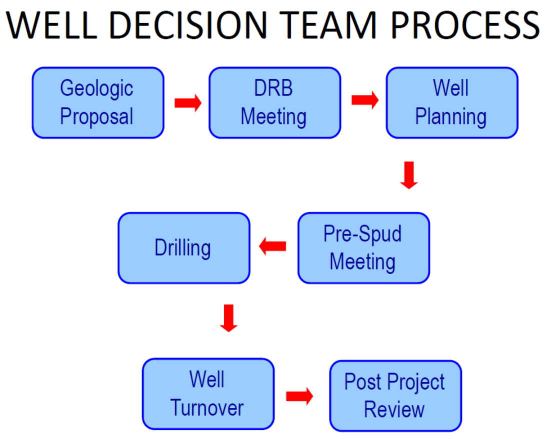

Figure 3: Chevron Geothermal Salak Well Decision Team Work Flow Chart.

Our risk assessment process is not designed to eliminate all risks, but rather, to minimize it to the extent possible. We apply a scalable and appropriate risk assessment in all projects or wells. The multidisciplinary team, which consists of WDT, and CGS' business partners, should verify that risk assessment recommendations are followed thoroughly. Records of causes of non-productive time are used to highlight risks and to determine its probability and magnitude. This information will be used in Phase 3 to select the well design.

However, if any unexpected change and new procedures were developed during drilling operations, this change should be described in the Management of Change (MOC) process. Again, the risk assessment completed in Phase 3 will be used as the basis to assess impacts of this change. The detailed description of the MOC is presented in the next sub-section.

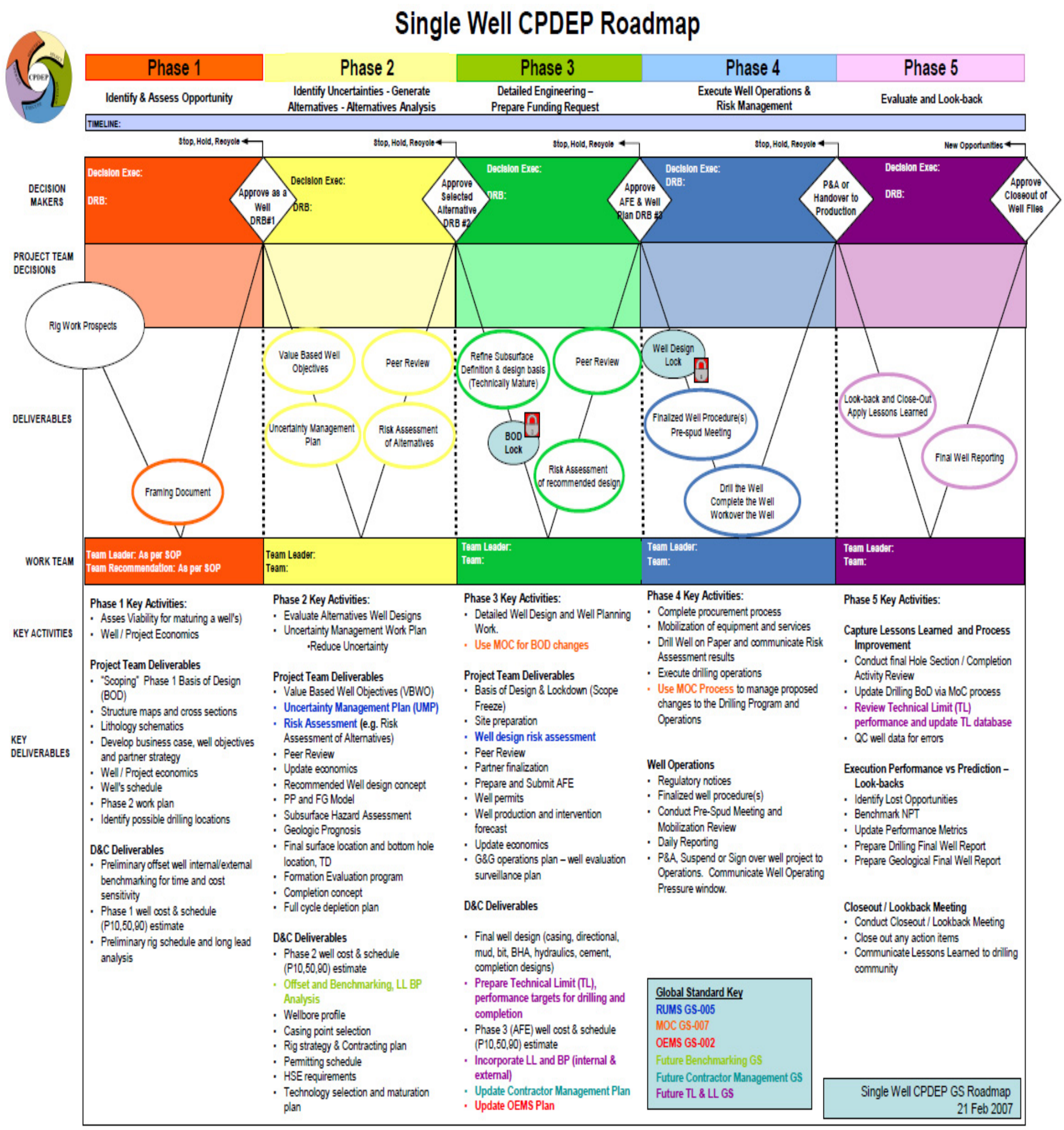

Figure 4: Single Well Chevron Project Development and Execution Process (CPDEP) Roadmap for Well Planning.

Chevron Reliability and Efficiency Risk Prioritization Matrix

For the Assessment of Well and Subsurface Asset Risks from Event or Activity

Legend (May be adjusted by each SBU / Asset)	Management should determine whether R&E risks are "Accept", "Mitigate", or "Avoid": For each risk, identify the response as follows: (Use numbers as guidelines only, and not absolutes in terms of A,M,V selection).
1, 2, 3, 4	Avoid – This response indicates that changes to the project plan and safeguards will be developed to eliminate the risk or to protect the project / well.
5	Mitigate - This response indicates that additional safeguards are needed and will be implemented to reduce the likelihood or consequence of the risk event to an acceptable level. The risk is not eliminated, but alleviated.
6	Accept or Mitigate – This response indicates that safeguards in place may be adequate. Risk reduction is at management / team discretion.
7, 8, 9, 10	Accept - No further risk reduction is required. Risk reduction is at management / team discretion.

Likelihood Description & Index (with confirmed safeguards)								
Likelihood Percentages (May be adjusted by each SBU / Asset)	Likelihood Indices							
>40%	1	Likely	6	5	4	3	2	1
20 - 40%	2	Occasional	7	6	5	4	3	2
10-20%	3	Seldom	8	7	6	5	4	3
5-10%	4	Unlikely	9	8	7	6	5	4
<5%	5	Remote	10	9	8	7	6	5
<1%	6	Rare	10	10	9	8	7	6
Consequence Descriptions & Index (without safeguards)	Consequence Indices: Examples (To be adjusted by each SBU/Asset)		6	5	4	3	2	1
			Incidental	Minor	Moderate	Major	Severe	Catastrophic
	Consequence Description	Wells and subsurface (rig / equipment damage / downtime, mechanical damage / downtime)	1/2 Day lost Costs <$150,000.	Day Lost: Costs 150 M$ - 300 M$	Loss of Hole Section: Costs 300 M$ - 1.5 MM$	Lose more than one Hole Section: Costs 1.5 MM$ - 4.5 MM$	Loss of Well: Costs 4.5 MM$ - 7.5 MM$	Loss of rig Costs >7.5 MM$

Decreasing Likelihood

Decreasing Consequence/Impact

This matrix is endorsed for use across the Company D&C Community.

Figure 5: Matrix of Chevron Risk and Uncertainty Management Standard.

3.1.3 Management of Change (MOC)

The purpose of the Management of Change (MOC) process at CGS is to minimize the possibility of incidents by systematically managing permanent and temporary changes to facilities, operations, and products. This process is not intended to prioritize the change, or estimate the cost as a result of the change but to protect the integrity of the established drilling plan and Standard Operating Procedures (SOP).

The Chevron Geothermal Salak ground rule is that a change should not enter the Management of Change (MOC) Process until the Well Decision Team (WDT) has convinced the Decision Review Board (DRB) to consider the change. The MOC Process assists the WDT in managing the change, including in determining the change's potential impact on health, environment and safety, as well as impacts on technical, operations, maintenance, and design aspects.

In the event of a new, real-time operational consideration while drilling necessitates a change from the agreed drilling plan, the MOC is required to issue a temporary notification which should be approved by all stakeholders. An example of this case is the MOC practiced in AWI 2-3 well. In order to avoid drilling problems in the production section, the Well Decision Team designed two perforated liners instead of only one. However, after a careful risk review, the team decided to drill the productive interval in a single pass, which was proven successful. Additionally, in determining the best the option to drill AWI 2-3, the WDT used the Chevron Project Development and Execution Process (CPDEP), and Capital Stewardship and Organizational Capabilities (CSOC) tools.

3.1.4 Perfect Well Targeting

The "Perfect Well Targeting" described in this paper is the minimum drilling time that could possibly be achieved to reach the target depth and is calculated based on the best observed time, best of the best time, and the best offset time including the recorded technical limitations. The perfect well concept is to establish a performance level and move forward to improve it. A properly conducted technical limit process helps to identify improvement opportunities.

To establish the technical limit we analyze the statistics of the operations, and then we determine which can do faster compared to others. Drilling procedures were then broken down into specific steps based on the achievement of the technical limit. For example, in 2008, a drilling of a 26" hole section in Gunung Salak achieved a rate of 55 feet per hour (fph). Since 55 fph is the best drilling rate ever in Gunung Salak field, we establish it as the base of perfect well targeting for 26" hole section until the team could break the record with a new technique. Same techniques were also applied for Flat Spot optimization, which is the fastest time to run the casing and set the cement, which is set as the base for a perfect well calculation. The spreadsheet calculations are also used for probabilistic time and cost, or authorization for expenditure estimation.

3.1.5 Stuck Pipe Prevention Workshop

At CGI, stuck pipe incidents accounted for 30% of the total non-productive time of the total recorded loss time in 2007. This workshop was aimed at reducing the frequency of the incidents and serves to mitigate similar incidents in the future.

Probability	Days (+Rig Move)	Days (Operational)	Cost	
10	21.4	13.8	$ 3,477,165	PERFECT
50	34.1	25.3	$ 4,276,890	TARGET
60	41.6	32.1	$ 4,776,176	AFE

Instructions:
1. Go to "Schematic" tab and input DEPTHS
2. Go to "Time Database" and choose offset wells to include in the calculations
3. Under "Design Well" choose activities to include by typing "y" if operations included and "n" if NOT included.
4. Input probabilities and click on COMPUTE to populate probability Table. Click on DVD CHARTS to create DVD graphs.

COMPUTE

DVD CHARTS

Input Cells

Probability: 60

TIME & COST ESTIMATE FOR Awi 7-8

Total well time and cost = 41.6 days and $4,776,176 at P60 estimate

Include in Estimate? (Y/N)	Input Cells	Probability Rate	Input Unit	Depth	Task	General Operations	Phase Hrs	Phase Days	Cummulative Days
y	1	226.5357	ea	0	1.01	Move Rig	226.54	9.44	9.44
y	83	0.0483	ft	83	1.03	P/U and M/U 26" mill assembly.RIH and mill thru 30" conductor shoe at 83'. POOH. P/U amd M/U 26" drilling assemb;y and RIH to 83'	12.01	0.50	9.94
y	1417	0.0536	ft	1500	2.00	**Drill 26" Hole Section to 1,500 ft**	75.99	3.17	13.11
y	1500	0.0045	ft	1500	2.03	POOH and lay down 26" BHA	6.74	0.28	13.39
y	1	2.9625	ea	1500	2.07	Remove flow line and cut-off 30" conductor pipe.	2.96	0.12	13.51
y	1	1.1750	ea	1500	2.08	Rig-up to run 20" casing and conduct pre-job safety meeting.	1.18	0.05	13.56
y	1500	0.0102	ft	1500	2.09	Run 20" casing with parasite aeration string (PAS).	15.34	0.64	14.20
y	1	5.9625	ea	1500	2.10	Cement 20" casing	5.96	0.25	14.45
y	1	4.8125	ea	1500	2.11	WOC. POOH stinger. Conduct top job on if necessary	4.81	0.20	14.65
y	1	8.4000	ea	1500	2.12	Nipple up and test 21-1/4" x 2M BOPE and flowlines.	8.40	0.35	15.00
y	1500	0.0035	ft	1500	2.13	Make-up 17-1/2" directional drilling BHA, shallow test MWD and RIH to TOC.	5.18	0.22	15.21
y	1	2.6750	ea	1500	3.00	Drillout cement and 20" shoe track.	2.68	0.11	15.32
y	2600	0.0460	ft	4100	3.00	**Drill 17-1/2" Hole Section to 4,100 ft**	119.52	4.98	20.30
y	4100	0.0020	ft	4100	3.03	POOH and lay down 17-1/2" BHA	8.26	0.34	20.65
y	1	0.7750	ea	4100	3.06	Rig-up to run 13-3/8" casing (liner) and conduct pre-job safety meeting	0.78	0.03	20.68
y	4100	0.0023	ft	4100	3.07	Run 13-3/8" liner.	9.28	0.39	21.07
y	1	4.3000	ea	4100	3.08	Cement 13-3/8" liner.	4.30	0.18	21.25
y	1	4.9625	ea	4100	3.09	WOC. POOH liner running tools.	4.96	0.21	21.45
y	1	18.2125	ea	4100	3.10	Squeeze liner lap and pressure test	18.21	0.76	22.21
y	1500	0.0046	ft	4100	3.11	Make-up 12-1/4" bit with 14-3/4" x 17-1/2" hole opener. RIH and redress tieback recepta	6.93	0.29	22.50
y	1	5.5375	ea	4100	3.12	Remove V-door and walk. Nipple down BOP. Final cut 20" casing.	5.54	0.23	22.73
y	1	0.6667	ea	4100	3.13	Rig-up to run 13-3/8" casing (tieback) and conduct pre-job safety meeting	0.67	0.03	22.76
y	1500	0.0056	ft	4100	3.14	Run 13-3/8" tieback casing.	8.46	0.35	23.11
y	1	4.3125	ea	4100	3.15	Cement 13-3/8" tieback casing.	4.31	0.18	23.29
y	1	7.5625	ea	4100	3.16	WOC. POOH and lay down stinger. Cut-off 30" stub and remove 30" x 20" landing plate.Install master valve. Nipple up and test 21-1/4"x2M BOPE and flowlines.	7.56	0.32	23.61
y	1417	0.0026	ft	4100	3.17	Make-up 12-1/4" BHA and RIH to TOC inside 13-3/8" tieback.	3.75	0.16	23.76
y	1	6.9125	ea	4100	3.18	Drillout cement and 13-3/8"tieback shoe track.	6.91	0.29	24.05
y	1	15.1875	ea	4100	3.19	RIH to TOC of 13-3/8" liner. Pressure test. Drillout 13-3/8" liner shoe track.	15.19	0.63	24.68
y	2600	0.0476	ft	6700	4.00	**Drill 12-1/4" Hole Section to 6,700 ft**	111.76	4.66	29.34
y	6700	0.0013	ft	6700	4.03	POOH and lay down 12-1/4" BHA.	8.75	0.36	29.71
y	1	0.6625	ea	6700	4.06	Rig-up to run 10-3/4" perforated liner and conduct pre-job safety meeting.	0.66	0.03	29.73
y	6700	0.0045	ft	6700	4.07	Run 10-3/4" perforated liner.	30.16	1.26	30.99
y	4100	0.0008	ft	6700	4.08	POOH 10-3/4" liner setting tools.	3.42	0.14	31.13
y	6700	0.0021	ft	6700	4.10	Make-up 9-7/8" BHA and RIH to bottom of 10-3/4" liner to 6,700 ft	13.88	0.58	31.71
y	2300	0.0865	ft	9000	5.00	**Drill 9-7/8" Hole Section to 9,000 ft**	199.01	8.29	40.00
y	9000	0.0010	ft	9000	5.03	POOH and lay down 9-7/8" BHA.	9.00	0.38	40.38
y	1	0.5000	ea	9000	5.06	Rig-up to run 8-5/8" perforated liner and conduct pre-job safety meeting.	0.50	0.02	40.40
y	9000	0.0016	ft	9000	5.07	Run 8-5/8" perforated liner.	14.00	0.58	40.98
y	9000	0.0012	ft	9000	5.08	POOH 8-5/8" liner setting tools.	10.74	0.45	41.43
y	1	3.6875	ea	9000	6.09	Nipple down BOP. Remove V-door and flowlines. Shut-in well and release rig.	3.69	0.15	41.58
						TOTAL OPERATING TIME	771	32.1	32.1
						TOTAL OPERATING TIME + RIG MOVE/RIG SKID	998	41.6	41.6

Figure 6: Time Estimator

No	Well Name (Salak)	Total Well Hour (Hrs)	NPT (Hrs)	Stuck Time (Hrs)	Well Cost ($)
1	AWI 11-6RD	600.00	76.00	1.00	2,211,412.21
2	AWI 11-4DP	119.50	0.50	0.00	577,500.05
3	AWI 13-8CO	276.00	74.00	66.00	975,904.00
4	AWI 13-8RD	351.00	107.00	0.00	1,673,206.06
5	AWI 8-7CO	328.00	2.00	0.00	1,012,538.37
6	AWI 3-4OH	695.00	69.00	0.00	3,445,610.45
7	AWI 3-5OH	545.00	22.00	0.00	2,819,925.91
8	AWI 1-10OH	806.00	162.00	141.00	3,593,031.56
9	AWI 1-5CO	177.00	0.00	0.00	499,620.49
10	AWI 8-9WO	350.00	16.50	1.50	1,173,883.90
11	AWI 8-10OH	677.50	203.50	160.00	3,559,546.97
12	AWI 15-3RD	979.00	234.50	0.00	3,402,200.96
13	AWI 19-1P&A	601.00	236.00	62.50	3,050,550.12
14	AWI 19-2OH	913.50	132.50	0.00	4,495,791.70
15	AWI 19-3OH	1004.50	101.50	8.00	5,216,958.03
	TOTAL	**8423.00**	**1437.00**	**440.00**	**37,707,680.78**
			17.06%	*30.62%*	

No	Well Name (Darajat)	Total Well Hour (Hrs)	NPT (Hrs)	Stuck Time (Hrs)	Well Cost ($)
1	DRJ 25	939.25	173.25	0	4,348,302.42
2	DRJ 26	1284.50	292.50	0	5,260,184.41
3	DRJ 27	763.50	161.50	0	3,868,860.79
4	DRJ 28	1149.00	101.75	61	4,887,440.43
5	DRJ 29	931.00	187.50	0.25	4,438,044.07
6	DRJ 30	1443.00	451.00	87.5	2,294,832.41
7	DRJ 30RD	1020.50	493.00	121.25	4,049,378.17
TOTAL		**7530.75**	**1860.50**	**270**	**29,147,042.70**
			24.71%	*14.51%*	

Salak	
Well Cost	37,707,680.78
NPT Cost	6,433,092.40
Stuck Cost	1,969,770.81

Darajat	
Well Cost	29,147,042.70
NPT Cost	7,200,886.09
Stuck Cost	1,045,009.00

TOTAL STUCK COST	**3,014,779.81**

Figure 7: 2007 Salak and Darajat Stuck Pipe Incidents (Note that the lost due to stuck-pipe is equal to drilling one well).

Through the years of observation, we established that deficiencies in four different areas are suspect: communication, prior and during drilling process; teamwork awareness to recognize the drilling hazards; interpretation of stuck pipe procedures by all involved; and adherences to the standard operating procedure during drilling operation. CGS successfully conducted two prevention workshops in March and April 2008. The setup of this process aimed at eliciting actual information from the workshop attendees, and easing them to contribute freely and to discuss the issues openly. Listed below is the process of the workshop in sequential order.

The goals of these workshops achieved the following milestones: [1] to build an operation recommendation between Geothermal Drilling and Completion Departments and their business partners; [2] common target that in 2009 the target is to reduce the SPI incidents from average two (2) occurrences every hole section to none; [3] to reduce non productive time from 30% to below of 15% per year; and [4] an increased awareness of the causes of stuck pipe incidents and their mitigation procedures.

3.2 Ingenuity Projects (Technology Applications)

Ingenuity is one of the core values of CGI, and living this value has resulted in the flourishing of ideas for improvement as presented in detail below. As all ideas are encouraged, brainstorming, high grading, team assignment and results reporting is a standard loop in the CGI's ingenuity projects.

NO.	PARTICULARS			LEAD	RANK
1	Liner top packer/ Long string / DV / ACP / reverse circulating for tieback			DGP/Heraco	hi
2	PDC bit			NNR/SA	hi
3	Drop multishot gyro	v		MJP/SA	hi
4	Do we need air in Darajat			NNR	hi
5	Multilateral	v	v	NNR/MJP	hi
6	EM-MWD			MJP/SA	hi
7	Well Intervention - "Process Ownership"			SA/IBS(RES)	hi
8	Hydro - fracturing			RMS/JA	hi
9	Break the Salak - Darajat Silos			RMS/TAJ	hi
10	On-site cuttings/residue disposal	v		NNR	hi
11	Aerated Drilling UBD			NNR	med
12	PWD sub				med
13	Hole Cleaning modelling				med
14	Formation damage				med
15	Welltesting expertise				med
16	Expandable tubular				med
17	Drilling with casing				med
18	Unihead				med
19	Cutting / waste disposal				med
20	Work over unit				med
21	Flowing drilling				med
22	Down hole chemical treatment				med
23	Hazardous waste disposal				med
24	Offline casing run				med
25	Casing Connection				low
26	Slim hole drilling				low
27	Rotary steerable				low

Figure 8: GPO D&C Ingenuity Projects Opportunity List.

To appreciate all ideas Geothermal Drilling and Completion team ranked proposals of ingenuity projects according to its potential applicability in a transparent way. To illustrate the process, the table below lists the recorded 27 proposals for new technology applications, ranked from low to high priority.

In the following sub-sections we will present three successful ingenuity projects, namely, multilateral well, drilling bit selection, and the application of electromagnetic wave survey tool.

3.2.1 Multilateral Well

The primary objectives to drill multilateral in Awibengkok field of Gunung Salak were to confirm the feasibility of multilateral completions for deep injection wells to determine the deep injection potential of the proximal south-west area of Salak, to delineate reservoir conditions, and to identify potential for future production alternatives. The candidate for this multilateral drilling project was Awi 20-1 well, which was drilled in order to define the deep injection potential of the south-west margin of the Salak reservoir. The well is drilled as a multilateral or forked well to maximize the economics of deep injection in this area.

Awi 20-1 was complete in 62.96 days from spud to rig release, which is 13.1 days ahead of plan. And this brought the well 6.6% under the budget. Some successes in drilling perspectives were noted from this well, such as: successful sidetracking and completion of forked section of Awi 20-1 using single trip whipstock; successful retrieval of the 10-3/4" whipstock and open up the original hole completion of the multilateral well; the 100% core recoveries in the 12-1/4" hole and in 9-7/8" hole of forked leg; and finally the use of the more durable bit instead the aggressive one.

At this point, CGS registered important improvement opportunities such as: stuck pipe while reaming down new bit; the difficulty in retrieving whipstock; float valve failure which caused cement to equalize back into the casing; and low rate of penetration when using polycrystalline diamond compact (PDC) bit inside the 12-1/4" hole section.

3.2.2 Drilling Bit Selection

Due to the harder, deeper and sometimes depleted environments, footage drilled per bottom hole assembly and the rate of penetration in geothermal wells are usually low. If these issues are left unattended, they will drive up drilling cost exorbitantly. Consequently, CGS determined to find solutions that will increase both the footage drilled and the penetration rate.

CGS' sustained drilling program from 2006 to 2008 has provided a vast data of rock bit behaviors in geothermal formations and results of our trial and error process of bit selection. Additionally, CGS' contract strategy for each vendors enabled us to widen our alternatives of bits for each hole section.

This, combined with other techniques has contributed to a significant improvement in the average bottom bit hours. For example, in drilling 11 wells at 26"-hole section, in 2004 CGS achieved 28.27 ft/hr of on bottom bit hours rate. In contrast, by 2008 CGS has significantly increased this rate to 40.38 ft/hr. By the end of 2008 we have increased the overall drilling rate by 30%.

3.2.3 Electro Magnetic Wave Survey Tool

Reliable survey tool is indispensable for drilling safety. However, we often lost of pulse once the drill passes the partial or the total loss circulation zones. Stuck pipe incidents are also a well-known risk when waiting for survey results after pipe connections. Records indicate that 63% stuck pipe incidents occurred during drilling through the partial or the total loss circulation zones, or during waiting period after pipe connections.

Electromagnetic measurement (EM) while drilling is the most appropriate tool available in the market to avoid stuck pipe and loosing survey data. With EM we could secure updated survey data while drill-string is working. For this reason CGS run the EM at AWI 7-8 well in 2008. The first trial, which tandems the EM to mud pulse measurement, gave a convincing reliability of survey results. It showed definite advantages, in that we could have all the accurate readings of data which we usually received from mud pulse measurement (azimuth, dip angle, tool face).

The EM proved to save three to five minutes in every connection time due to wait on survey results before continuing drilling. As shown in **Figure 13**, EM brought the 12-1/4" hole to drill within 3.66 days including non productive time, compared to 4.6 days of plan. In addition to bit improvement, the EM alone saved 145 minutes total wait on survey after connections. The well saved the cost to US$ 1.1 million, or 25% under the budget. As EM has significantly saving time and cost, the tools is now the standard survey tool for drilling geothermal wells in Gunung Salak field.

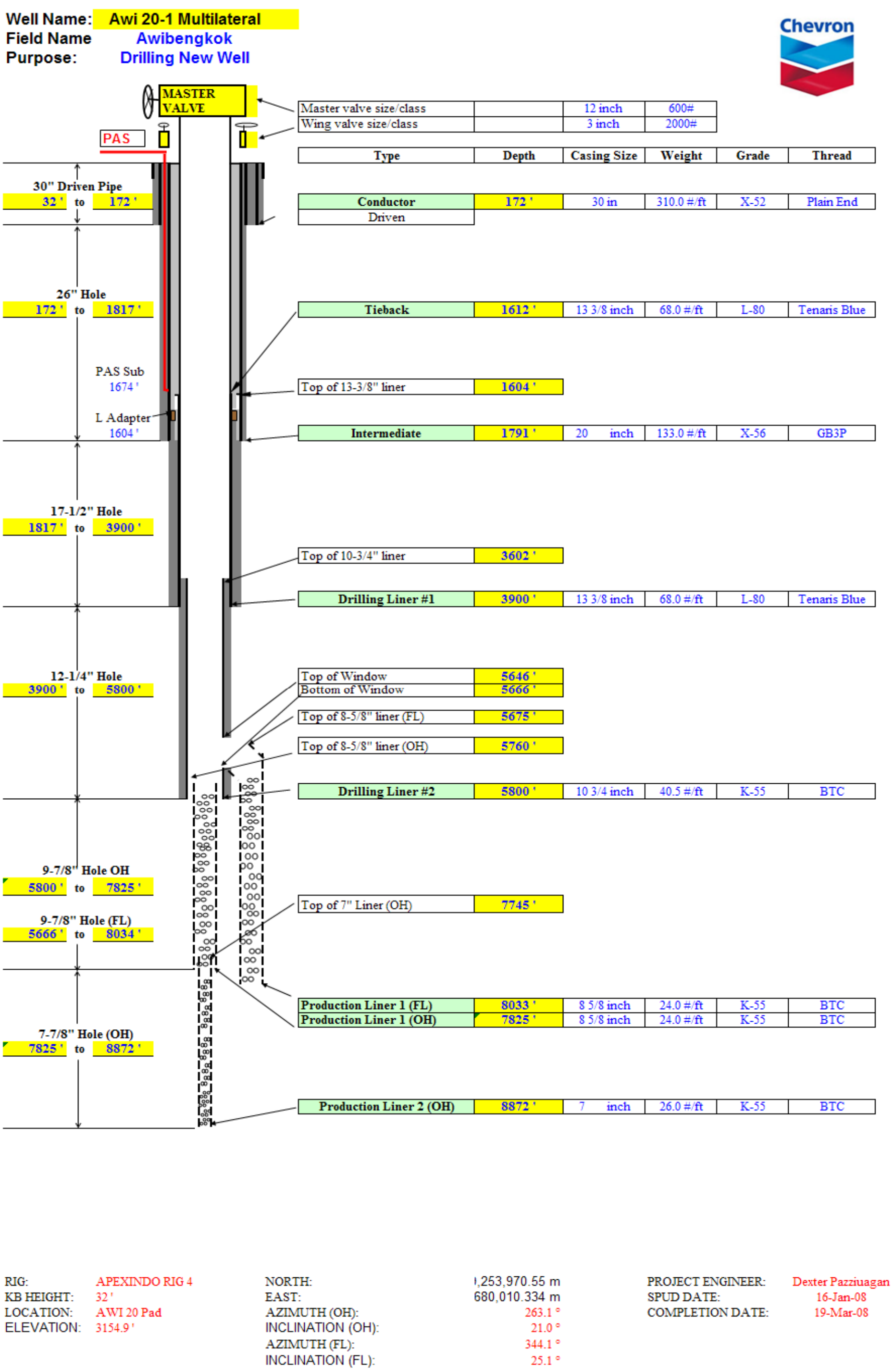

Figure 9: Awi 20-1 Well Diagram.

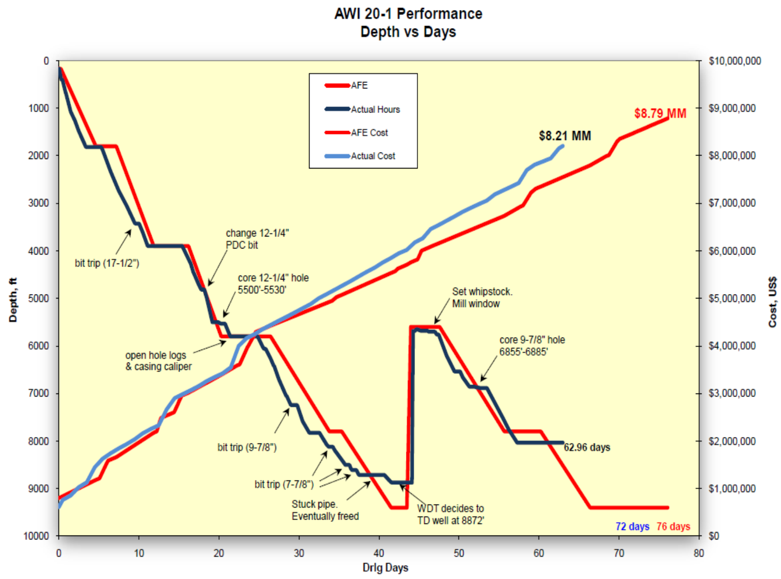

Figure 10: Awi 20-1 Multilateral DVD Graph.

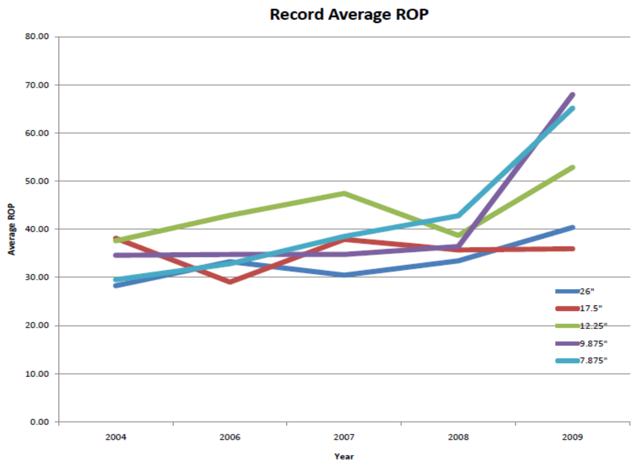

Figure 11: Awi Trend Record of Average Bottom Rate of Penetration 2004 to 2009.

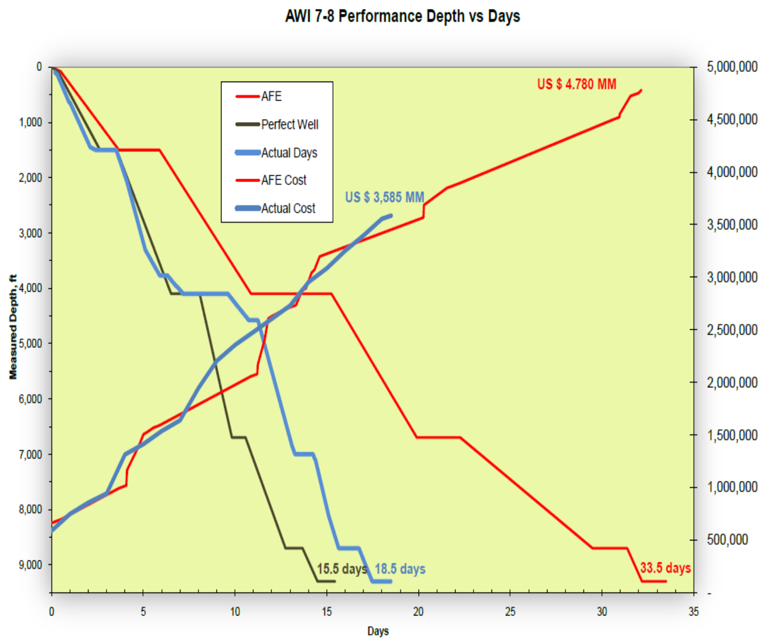

Figure 12: Awi 7-8 Performance Chart.

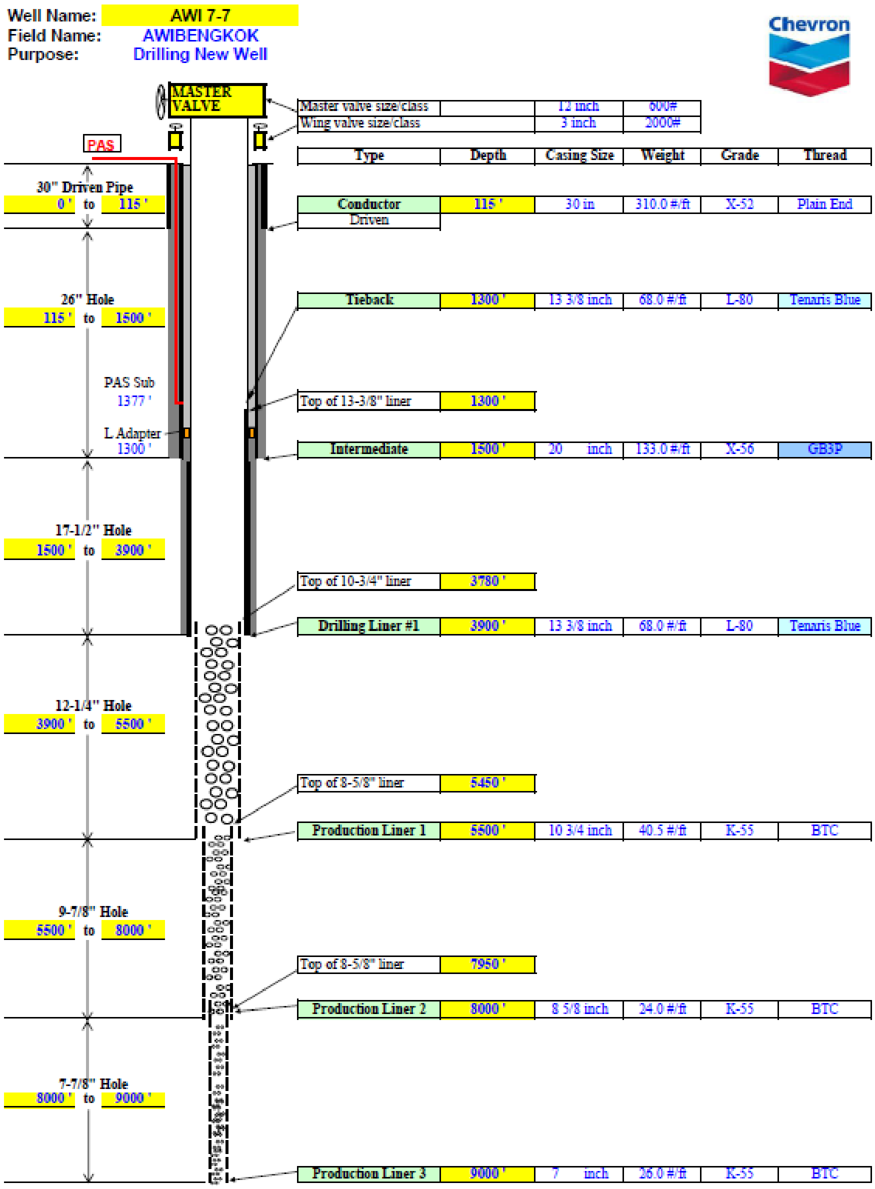

Figure 13: Standard Salak Well Design.

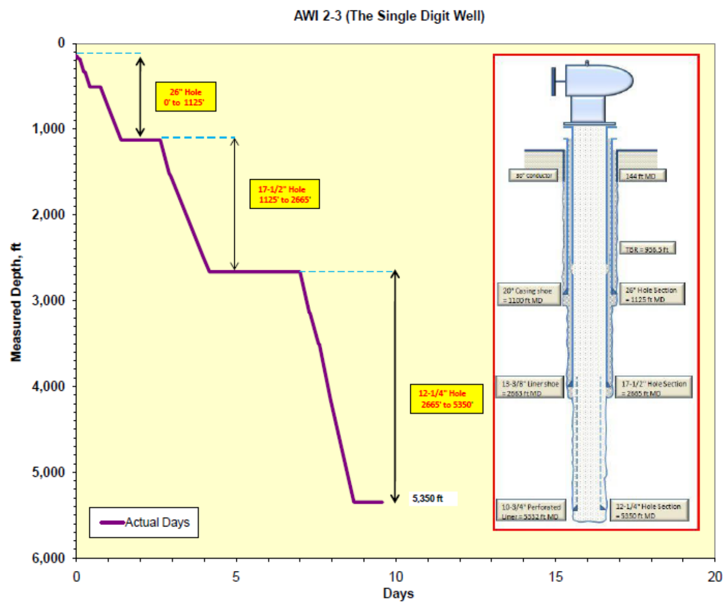

Figure 14: AWI 2-3 Schematic Graph, the Single Digit Well.

3.3 Standardized Well Design

There are four criteria of consideration to design the geothermal wells, captured in detail in CGS' well design guideline book. Well control considerations, casing design and casing coupling selection, and the requirements of wellhead equipment are the detail considerations. The CGS well design guidelines helps drilling engineers how to best utilize geologic and reservoir information; identify potential drilling hazards; set design criteria and evaluate casing design loads.

3.3.1 Considerations

Drilling to our target safely is our main goal. Three main causes are commonly known to causing abnormal pressures in geothermal wells namely, over pressure formations, water influx and over pressure shallow gas. The first two could be predicted using the existing data on saturation relationship between temperature and pressure of water. However, geothermal wells often contain significant concentrations of non-condensable gases or dissolved solids in the formation fluid, resulting in large deviation of the same saturation relationship, rendering the prediction based on pure water useless.

While all of the above are true, the geothermal well design must satisfy the pre-requisite that, in the event a kick occurred, it will be contained and circulated out of the wellbore without compromising the integrity of the casing shoe. Well Control considerations will also be affected by casing design, casing coupling selection, and wellhead equipment design requirements.

3.3.2. Casing Design and Casing Coupling

All casing strings must be designed to withstand the risk of burst and collapse, and must include the projected tensile load into considerations. In addition, the tieback casing is designed to bear up the thermally induced stresses. If drilling in an environment that is either undeveloped (rank wildcat) a risk assessment should be performed to identify potential hazards. If sufficient offset well information is available then some latitude can be allowed in the well design that may result in setting casing at shallower depths or even eliminating a string altogether.

3.3.3. Wellhead Equipment

Maximum operating conditions will define the pressure rating of the wellhead equipment required to meet the design criteria. The pressure rating of the wellhead equipment and valves must be de-rated for use at elevated temperatures.

4. RESULTS AND CONCLUSIONS

4.1 Results

The performance improvement process, equipment improvement, standardized well design, and ingenuity projects, are proven factors that improved drilling performance in Salak Geothermal field. All those factors may not be new innovations, but are evolving in its frequency and complexity and its natural progression in response to the industry's requirements.

CGS achieved its peak performance in April 2009, when the Drilling and Completion team accomplished the goal to drill AWI 2-3 well in less than 10 days. AWI 2-3 was completed on April 28, 2009 without incident and with less than 24 hours of the set non-productive time. The well, which is internally called as the "Single Digit Well," was drilled in 9.6 days from spud to rig release, reaching a target depth of 5,350 feet as planned and came in 27% below budget. The huge operative challenges of this well add to the important role of WDT in our success. The well has to be built up to 53 degree inclination with more than 3.5^0/100 ft of Dogleg severity, which increase the risks of stuck pipe as well as adding challenges in performing completion tests.

In the hindsight this success is a result of many different aspects, but all involved teamwork as pre-requisite. The thorough review of the risk assessment, the decision tree analysis and the regimented implementation of the management of change process have helped the WDT to come with timely and accurate decisions to achieve the goal of completing the nearly perfect well targeting as planned. The continuous improvement processes also contributed significantly in the achievement of this milestone.

All technical findings in this successful operation were recorded. The team has identified new benchmark of non-productive time and documented them as new lessons learned. All related safety activities were presented and reviewed at field pre-spud meeting, then recorded in daily report. Accordingly, the Geothermal Drilling and Completion team revised the Standard Operating Procedures to be followed and reviewed for the related activities (from rig mobilization until rig release). Although initially the WDT estimated to have 65% chance of drilling success, the team has completed the well successfully.

4.2 Conclusions

This paper shows that CGS has achieved its internal goal to achieve optimum drilling time. This achievement is marked by the completion of the "Single Digit Well" in April 2009. However, this "peak-to-date" may become obsolete once we achieved a newer benchmark.

While we recognized the tremendous progress in drilling technology; the experience at CGS has shown that the application of new technology is a necessary but not a sufficient method to answer the complexity of drilling operations. This paper showed that CGS' achievement was a result of concentrated and synchronized multidisciplinary efforts of all stakeholders, implemented through several different CGS management tools namely, the Well Decision Team, the Risk Uncertainty Management Standard, the Management of Change process, the Perfect Well Targeting, the stuck-pipe incident workshop, the Ingenuity Projects, and the Standardized Well Design. The successful development and implementation of the management tools cited above evolved around the management's commitment and the organizational readiness to nurture, and to put them into action.

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