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Well Intervention and Enhancement in San Jacinto Geothermal Field, Nicaragua

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ABSTRACT

The San Jacinto-Tizate Geothermal Field was developed in 2003 by Polaris Energy Nicaragua S.A. (PENSA) under the guidance from Jacobs (formerly Sinclair Knight Merz, SKM). The first 10 MWe back pressure power plant unit was then installed at San Jacinto in 2005. Ram Power Corporation acquired PENSA in 2009 and embarked on the expansion and development of a 72 MWe condensing plant at San Jacinto to replace the 10 MWe back pressure unit. The commissioning of the first 36 MWe plant at San Jacinto-Tizate Geothermal Field in January 2012 resulted in some anticipated reservoir pressure drawdown which stabilized after about six months of production. The San Jacinto geothermal reservoir again showed increased pressure drawdown after commissioning of the second 36 MWe plant in December 2012. The decline produced some degradation of steam resource.

Jacobs was tasked by Ram Power to develop and implement a production enhancement plan in July 2013 to source out additional steam for San Jacinto. A number of options were identified for this program following a cost-benefit analysis undertaken by Jacobs, including: casing perforation, workovers and forking and deepening of existing wells.

This paper discusses the design and operational aspects of the well workover program and well testing, as well as the challenges encountered and solutions implemented for the successful completion of the work activities. Analysis of the downhole measurements after well intervention indicated a notable improvement in wellbore parameters which increased confidence in successfully meeting the targeted output requirements of the two plant units. Horizontal discharge testing of SJ6-1 and SJ6-2 in October 2013 showed modest improvement in their total production output of around 2.5 MWe. Production wells SJ9-3 and SJ12-3 on the other hand showed marked increase in their total production outputs of around 7.5 MWe during horizontal discharge testing.

1. INTRODUCTION

The San Jacinto-Tizate geothermal field is located in northwestern Nicaragua, approximately 20 km northeast of the city of Leon that is centrally situated among a series of active volcanoes (Figure 1). Initial exploration of the resource started in 1993 with a Russian company Intergeotherm S.A. The initial phase of exploration drilling concluded after two years with the completion of six wells and a top hole that confirmed a liquid-dominated reservoir with temperatures of 260°C – 300°C in the central upflow area and benign chemistry.

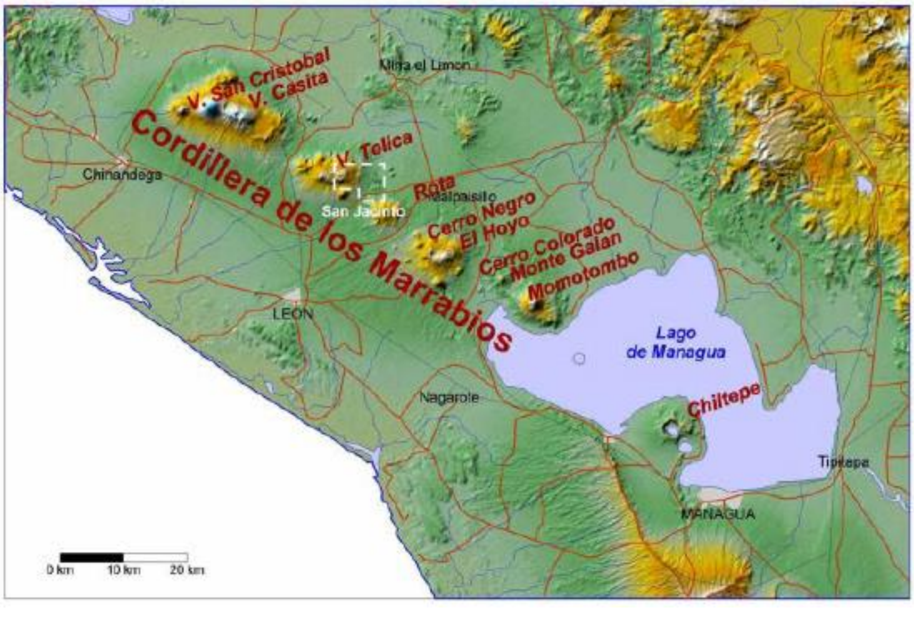


Figure 1: San Jacinto geothermal project location.

The project was acquired by Polaris Energy Nicaragua S.A. (PENSA) in 2003, who engaged Jacobs (formerly Sinclair Knight Merz, SKM) to evaluate the resource potential and develop and implement a strategy for the commercial development of the resource. A 10 MWe (2x5 MWe) back pressure unit was commissioned in 2005 using the existing wells. Ram Power Corporation then acquired PENSA in 2009 and embarked on the expansion and development of a 72 MWe (2x36 MWe) condensing plant at San Jacinto to replace the 10 MWe back pressure unit. The first 36 MWe unit (Phase 1) was successfully commissioned in January 2012. The increased production resulted in reservoir pressure drawdown which stabilized after six months of production. The second unit (Phase 2) was commissioned in December 2012 and was followed by further pressure drawdown and degradation of the steam resource.

Jacobs was tasked by Ram Power to develop and implement a production enhancement program in early 2013 to produce additional steam for San Jacinto. Following a cost-benefit analysis undertaken by Jacobs (SKM, 2013a) a number of options, were identified, for a limited budget and time frame, for the enhancement plan. This analysis indicated that casing perforation, workovers and forking and deepening of existing wells to be the preferred approach to obtaining additional steam from SJ6-1, SJ6-2, SJ9-3 and SJ12-3 production wells identified for the well intervention campaign (SKM, 2013b).

This paper discusses the design and operational aspects of the well workover program, the well testing and the challenges encountered and solutions implemented for the successful completion of the work activities.

2. SJ6-1 WELL ENHANCEMENT

2.1 Well History

Production well SJ6-1 is a vertical well drilled by Intergeoterm S.A. in December 1994 having a total depth of 1,881 m. The well was completed with a combination string of 9-5/8" OD (upper 75 m) and 8-5/8" OD casing to the casing shoe at 989 m. The well originally flowed with a total mass flow of ~130 tph and steam flow of ~23 tph at a wellhead pressure (WHP) of 5.25 barg.

SJ6-1 has been used intermittently as an injection well for brine, condensate and drilling fluids, from 2005-2012. In 2008 a workover and perforation job was undertaken to remove accumulated fill deposits from the bottom of the well (main permeable zone) and to attempt to improve production of the well by perforating parts of the blank liner. The injectivity was improved from 10 tph/bar to 22 tph/bar. This suggested a likely increase in production potential, estimated at 20-30 tph of additional steam flow (2.5-3.8 MWe gross). However, very limited discharge testing was undertaken to confirm the output due to the immediate requirement for the well to be used for injection during discharge testing of newly drilled production wells.

Injection into SJ6-1 stopped in July 2012 and the well's thermal recovery was monitored. The well was also subjected to 10 clearing discharge attempts in October 2012 to accelerate its thermal recovery. A number of wellbore issues were discovered during its period of recovery:

- The heat up was slower than expected, which was likely due to significant cooling of the surrounding reservoir following a prolonged period of injection.
- There was an obstruction near the bottom main permeable zone located approximately 105 m above the base of the liner. This blockage could have been the result of accumulation of particulate matter (e.g. cuttings, bentonite mud) from the injected fluid coming from various well pad sumps.
- There is a relatively cool inflow within the cased section of the well (at approximately 715-720 m) indicating some casing damage. It is noted that the temperature at this level prior to long term injection was originally over 250˚C (Figure 2).

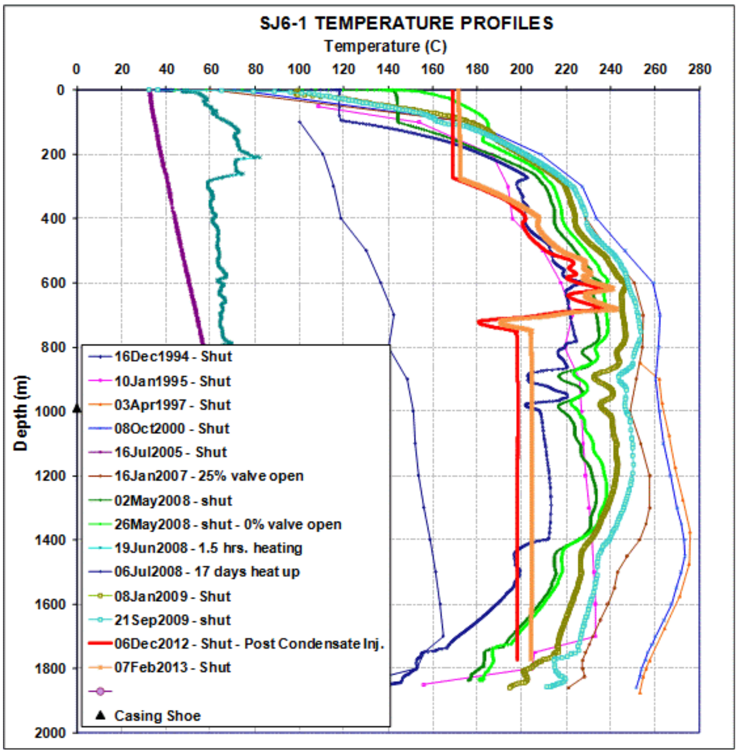


Figure 2: SJ6-1 temperature profiles.

The results of the discharge testing in October 2012 indicated that the well was capable of producing 8 tph of steam at a wellhead pressure (WHP) of 2.6–3.0 barg. Production was interpreted to be largely from the deep feed zone with a minor contribution from the shallow zone at the casing break. This indicates that there is some flow through the well bore obstruction described above.

There are some uncertainties regarding the wellbore condition of SJ6-1 due to the age of the well and its operational history. A caliper survey using Multi Finger Caliper Tool (MFCT) was conducted in March 2013 to assess the well condition and identify relative risks associated with the well enhancement program (SKM, 2013c). The caliper survey detected casing anomalies at 653 m, 788 m and 906 m.

2.2 Well Enhancement Program

The primary objective of the well enhancement program for SJ6-1 was to clear obstructions at the wellhead and at the bottom of production liner where major permeable zone exists. The well will also be deepened to further improve its overall permeability. Perforation of the 8-5/8" production casing above the top of the 6-5/8" liner was also programmed to access a hot shallow zone indicated by temperature surveys.

Deepening of the 7-3/4" hole by another 100 m to open up known permeability at the bottom of the well would involve pulling out of the 6-5/8" production liner. This carried an elevated risk of:

- Tools becoming stuck and blocking the well.
- The top of the liner failing to free (due to annular mineral deposits).
- These same mineral deposits resulting in the job taking longer due to having to cut and pull smaller sections.

2.3 Well Workover Results

The ThermaSource Rig 104 was set up and commenced the workover of well SJ6-1 on 17 July 2013 and was released after a total of 29.5 days of workover operations (SKM, 2013c). The obstruction found at the wellhead, across the wing valve of expansion spool, was successfully milled using a 7-3/4" taper mill bottom-hole assembly (BHA). The BHA was replaced with 8" taper mill and was again tripped in and out without rotation and noted absence of drag and obstruction.

The well was cleared using 7-3/4" and 5-1/2" bits to 1870 m prior to the recovery of the 6-5/8" liner. The 7-3/4" bit tagged the top of 6-5/8" liner at 934 m. The casing anomalies, recorded by MFCT caliper log, at 653m, 788m and 906m, were not detected by the 7-3/4" bit. The 5-1/2" bit successfully washed and cleared the fill inside 6-5/8" liner from 1,772 m until 1,870 m without any circulation returns to surface.

The cut and pull operation prior to deepening of the well took more time than programmed. A total of 19 days was incurred in attempting to recover the 942 m length of old 6-5/8" liner. However, only 367 m of liner was recovered leaving 575 m of liner downhole. The top of the remaining 6-5/8" liner at 1,297 m was apparently centered and suspected to be split at the top and the body oval to ~1318 m. Three (3) recovery attempts using a casing spear failed to recover the liner. The cut and pull operation was terminated because the liner was stuck, even when cut at 1,340 m and at 1,350 m.

The remaining old liner was cleared using a 5-1/2" flat bottom mill to 1834 m (46 m off-bottom). Further clearing of the 6-5/8" liner was terminated so as not to compact the fill and metal debris at the bottom of the liner. If compacted, these could have blocked communication with the bottom permeable zone. The new 6-5/8" liner, with perforation throughout its length, was run and squatted on top of the old liner. The new 9-5/8" Top of Liner (TOL) is at 791 m.

The cut and pull operation in this intervention program may have been easier if better well completion data had been available during program preparation and execution. The program was prepared based on limited well information from the Russian drilling contractor. The cut and pull operation revealed that composite 6-5/8" casings were used, with the topmost 316m section thicker (24 pounds/ft, ppf) and in relatively good condition while the lower 50 m recovered section was thinner (20 ppf) and in relatively poor condition. This was not known during the preparation phase. The basis for 24 ppf specification was based on casing caliper run prior to the first workover.

The over-gauged hole at cut depth of 1,250 m was not expected. The over-gauge hole caused the clearing BHA to miss entry into the 6-5/8" liner. The 7-3/4" hole was supposedly vertical and covered with 6-5/8" liner with a 7.39" OD coupling- barely 0.18" of annular clearance with 7-3/4" hole. The stuck 6-5/8" liner initially suggested a tight annular clearance.

The 8-5/8" production casing was successfully perforated in the intervals 610–650 m, 666-687 m and 779-785 m.

2.3.1 Post Workover/Perforation Completion Test Results

A post workover/perforation completion test using a Kuster K10 Pressure-Temperature-Spinner (PTS) tool was conducted to establish wellbore characteristics and determine initial indicators of well improvement. The maximum logged depth was set at 1250 m due to a suspected liner break at 1,297 m. A water loss survey conducted at 506 gpm pump rate revealed that most of the fluid exited past the depth of 700-800 m as shown in Figure 3. An isothermal profile is observed past the new TOL with wellbore temperatures at around 200°C. There were no stationary spinner responses at the maximum logged depth suggesting no fluid movement there. The immediate shut temperature survey (4 hours) showed temperature kicks at the perforated sections.

A step-rate injectivity test was conducted with three pump rates (506, 700 and 906 gpm) and PTS tool set at 1,250 m. Downhole pressures approached stabilization within the prescribed pumping duration of 1 hour**.** The stable downhole pressures for each pump rate were correlated and a post workover injectivity index of around 12 tph/bar was calculated**.** This is less than the post workover injectivity of ~22 tph/bar measured after the June 2008 workover. This indicated that the bottom zone was not contributing to the wells overall permeability.

A short Pressure Fall-Off (PFO) test was conducted in the well, after the injectivity test. The PFO data was analyzed and modelled using the Saphir (2010) well test interpretation program and employed the standard homogenous well/reservoir model with an infinite acting boundary. The log-log and semilog analysis of PFO data showed downhole pressures approaching stabilization during the short monitoring period. The corresponding pressure derivative data showed some initial scatter at early time and noise prior to the pressure stabilization.

The modelled data produced a permeability-thickness (kh) of 3.3 darcy-meters (d-m) with negative skin (s=-4.0) suggesting absence of skin damage (Figure 4). Interestingly, the present permeability thickness is very much less than the permeability thickness of 9.2 d-m measured after the first workover and liner perforation activities in June 2008. It would appear that the present kh value mainly reflects the permeability characteristics of the upper zone near TOL. The above results would probably indicate the bottom zone is not being fully accessed under the present well condition.

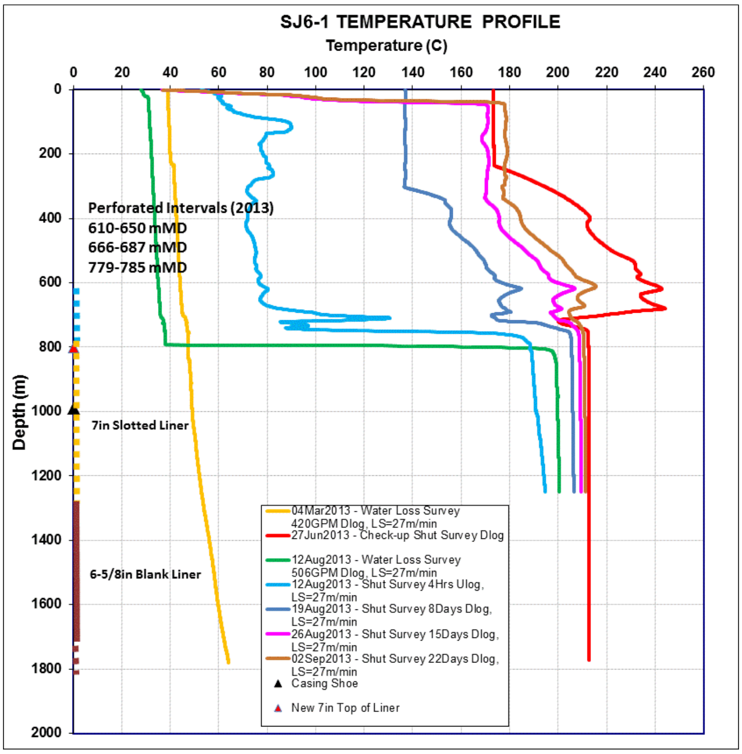


Figure 3: SJ6-1 temperature profiles during post workover/perforation completion test.

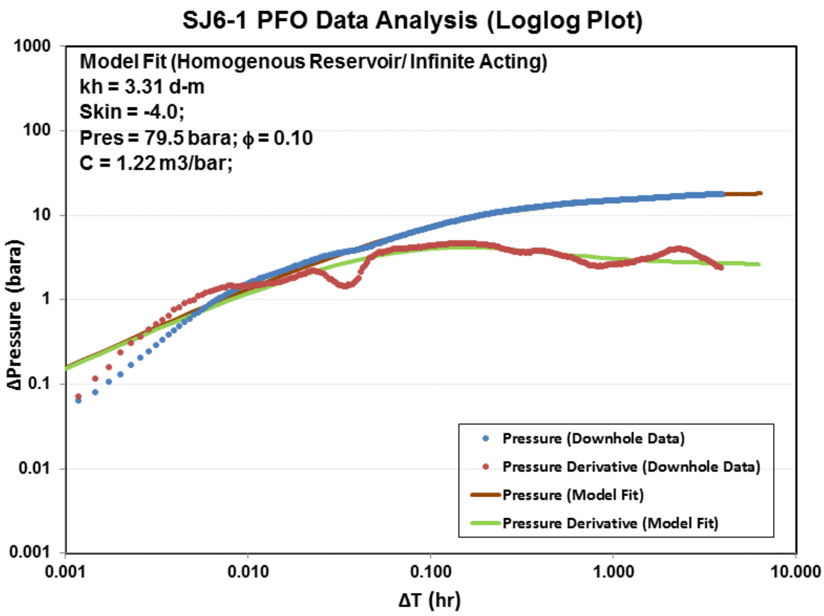


Figure 4: SJ6-1 pressure falloff test model results (log-log analysis).

2.4 Horizontal Discharge Test Results

SJ6-1 was tested through the silencer at 100% valve opening on 04 September 2013 after the well showed continued temperature recovery and a positive wellhead pressure (WHP) of 9 barg. Upon opening the well, the WHP gradually declined to about 4 barg with total mass flow estimated at around 100 tph (Figure 5). The well was throttled to 25% well opening and attained the targeted WHP of more than 5.1 barg with corresponding total mass flow of ~72 tph. The discharge enthalpy of the well at throttled conditions was estimated at around 970 kJ/kg. Steam flow is estimated at around 10.4 tph at a separation pressure of 6.1 bara, which is equivalent to approximately 1.3 MWe.

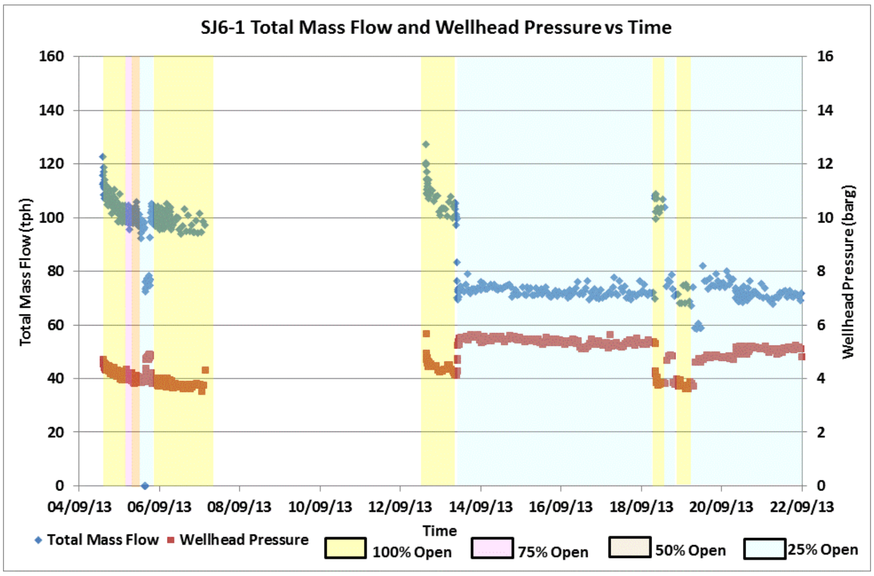


Figure 5: SJ6-1 total mass flow and wellhead pressure with time.

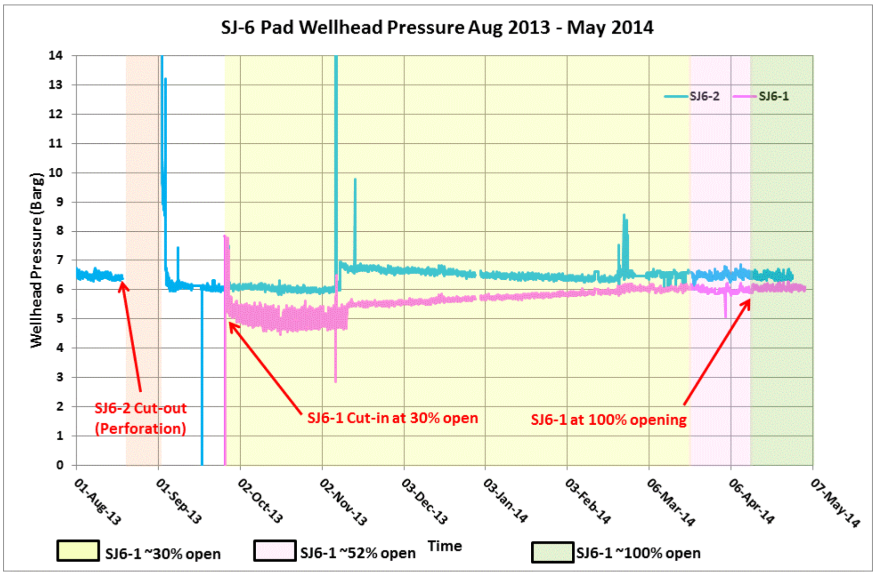


Figure 6: SJ6-1 and SJ6-2 wellhead pressure with time.

The well was connected to the San Jacinto steam field system after one month of testing at 30% valve opening. The wellhead pressure initially stabilized at around 5.1 barg and steadily increased over the next 6 months (Figure 6). The well was fully opened on 14 April 2014 to optimize production and wellhead pressure was maintained at around 6.2 barg. Tracer flow test (TFT) measurement conducted in the well when its WHP was about 5 barg, confirmed a steam flow contribution of at least 9 tph.

3. SJ6-2 WELL ENHANCEMENT

3.1 Well History

Production well SJ6-2 was completed in June 2008 with a large diameter, two liner design. The 9-5/8" liner was set at 1461 m and 7" liner set at 1,953 m. Loss circulation in the 12-1/4" production hole started at 997 m followed by total losses from 1,015 m to bottom hole at 1,463 m. A composite liner was initially run with blank liner from 574 m to 843 m and perforated liner from 844 m to 1461 m due to limited availability of 9-5/8" perforated liner. An 8-1/2" hole was further drilled to 1,990.6 m with a total loss of circulation (SKM, 2013d).

The post drilling completion test showed a major permeable zone at 860–940 m with minor zones at 1,460-1,540 m, 1,620-1,660 m and 1,900 m. A high positive skin (s=+20) was obtained during the completion test indicating the presence of formation damage, probably mostly in the deep zone.

Initial testing of the well in 2008 showed an output of 203 tph steam flow (~26 MWe) but a short flow test in 2011 indicated a decline to 151 tph steam flow (~20 MWe). The decline could be due to a number of factors:

- localized pressure drawdown
- mineral deposition caused by wellbore inter zonal flows between deep and shallow feed zones
- feed zone collapse.

A TFT survey in June 2013, after commissioning power plant Units 3 and 4, showed further decline to around 60 tph steam flow (~7.8MWe).

3.2 Well Enhancement Program

SJ6-2 was programmed for casing perforation to access additional permeability behind the 9-5/8" blank liner. Perforation was also programmed for the perforated sections of the original main feed zones to recover production that may have been affected by mineral deposition. The casing perforation represents a cost effective opportunity because it does not require a rig and there is minimal production down time.

3.3 Casing Perforation Results

The perforation job was conducted using a Schlumberger wireline unit on 23 August 2013. A fabricated 12" Class 600 x 7-1/16" x 3000 riser spool was installed on top of the existing master valve and adapted to Schlumberger's 7-1/16" x 3000 psi recovery spool (SKM, 2013d). A crane was used in raising and lowering of the perforating gun. The wireline was a 0.46" diameter cable which was rated at 176°C and the charges used were High Melting Explosive (HMX) charges rated at 204 °C. The perforating gun was a 4-1/2" High Shot Density (HSD) gun loaded with Powerjet 4505, with HMX explosives on a 6 meter gun carrier.

The perforating gun assembly consisted of a Casing Collar Locator (CCL) tool, an electric head and a detonating head. The perforating guns were loaded with five shots per foot charges arranged in a 72-degree phasing. The average perforation hole diameter was 0.47". Prior to the perforation job, a dummy gun carrier with CCL checked the condition of the hole and determined the casing collar locations. Casing collars were avoided during the perforation. The perforations done are tabulated in Table 1 below.

3.3.1 Post Perforation Completion Test Results

A post perforation completion test was conducted on 24 August 2013 to establish wellbore characteristics with the maximum logged depth set at 1940 m due to suspected liner break at 1,297 m. A water loss survey conducted at 700 gpm pump rate showed the majority of the fluid exited past the depth of ~1,750 m to 1,800 m as shown in Figure 7. The well built up pressure at less than 700 gpm pumping rate. The immediate shut temperature survey (8 hours) showed temperature kicks at the perforated sections and fast temperature recovery at ~1,750 m. An injectivity test was conducted with the tool set at 1,200 m while pumping at 800 gpm for one hour. Pumping was shut for an hour and pressure fall off was monitored for 8 hours. A post perforation injectivity index of around ~23 tph/bar was calculated which is less than the post drilling injectivity value of 46 tph/bar measured in July 2008.

Table 1 Perforated intervals 9-5/8" casing

Run No	Perforated Interval (mCHF)	Interval Length (m)
1	873.5 – 879.5 m	6
2	860.5 – 866.5 m	6
3	847.5 – 853.5 m	6
4	839.5 – 845.5 m	6
5	835.5 – 841.5 m	6
6	827.5 – 833.47 m	6
7	824.5 – 830.5 m	6
8	813.5 – 819.5 m	6
9	803.5 – 809.5 m	6
10	794.5 – 800.5 m	6

3.3.2 Horizontal Discharge Test Results

SJ6-2 was briefly tested through the silencer at 100% valve opening on 02 September 2013. The WHP stabilized at about 8.0 barg with total mass flow estimated at around 230 tph (Figure 8). The total mass flow is much higher than the 178 tph estimated by TFT on June 2013. The discharge enthalpy of the well was estimated at 1,250 kJ/kg which is less than the baseline enthalpy of ~1,370 kJ/kg. Steam flow was estimated at around ~71 tph at separation pressure of 6.1 bara which is equivalent to approximately 9.0 MWe.

The well was connected to the San Jacinto steam field system on 03 September. The wellhead pressure of the well was initially about 6.1 barg and increased to around ~6.6 barg after 6 months of utilization (Figure 6). TFT measurement conducted in the well on November 2013 confirmed the improved steam flow at around 70 tph.

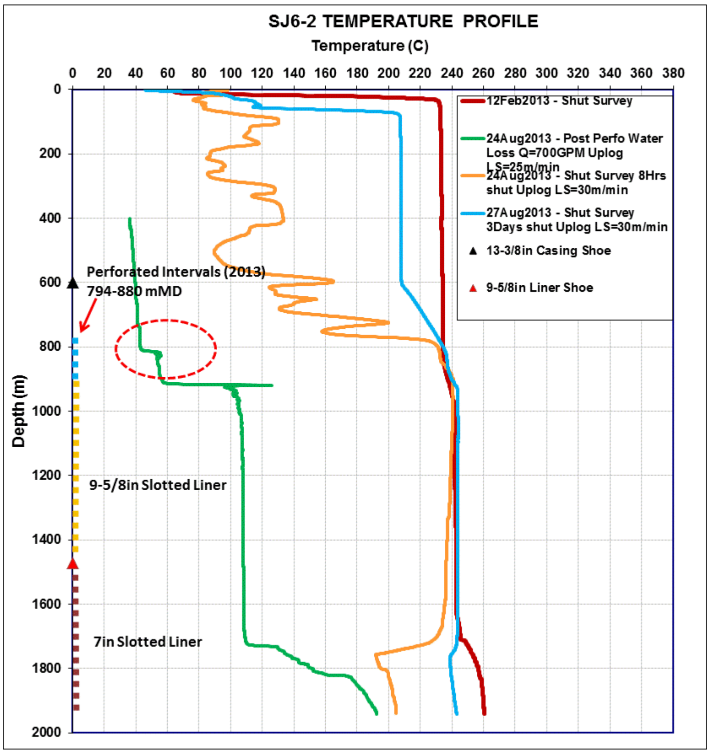


Figure 7: SJ6-2 downhole temperature profiles.

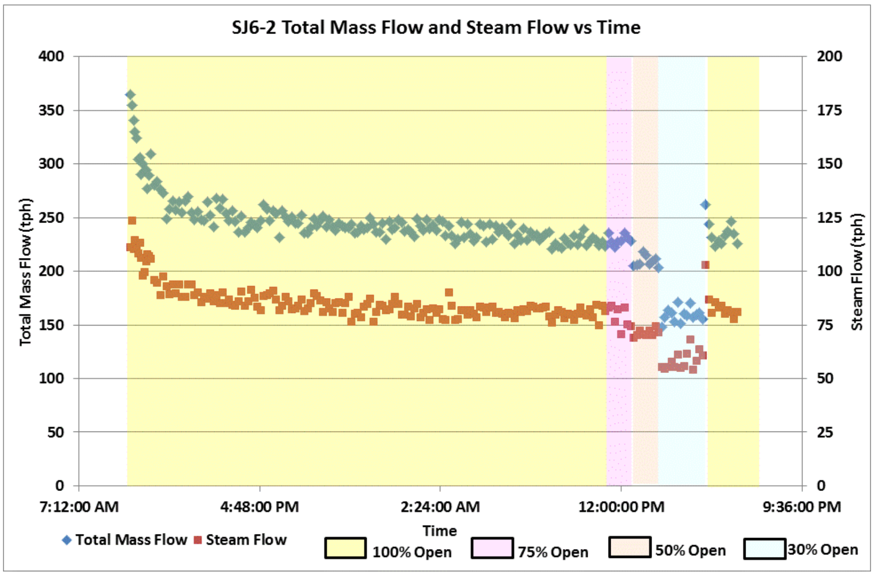


Figure 8: SJ6-2 total mass flow and wellhead pressure with time.

4. SJ12-3 WELL ENHANCEMENT

4.1 Well History

SJ12-3 is a large diameter hole directionally drilled to the eastern part of the San Jacinto reservoir on August 2011 with 13-3/8” production casing and 9-5/8” production liner. It was terminated at a depth of 2,381 m (relative to casing head flange, CHF) with partial losses, due to increasing and unacceptably high pump pressures averaging about 2,900 psi over the final 100 m of drilled hole (SKM, 2013e). Although the well was hot and there were indications of increasing permeability with depth, it was thought that any attempts to go deeper would increase the risk of the drill pipe becoming stuck. This concern was mitigated in the well enhancement program by changing the pump liners to allow higher pump pressures. Prior to the workover campaign, the well had been on long-term production and had an output of approximately 5 MWe.

4.2 Well Enhancement Program

The primary objectives of the well enhancement program for SJ12-3 are (SKM, 2013e):

- Deepen the well to find additional production capacity.
- Drill a second leg (fork leg) to increase production capacity.

The original 12-1/4” hole was deepened with an 8-1/2” hole by drilling an additional 220 m hole. After deepening, a 12-1/4” forked leg was drilled by milling the 13-3/8” casing window at 910 m and drilling a new 12-1/4” hole to a nominal total depth of 2,600 m. The fork leg is programmed to be drilled with an inclination of 45° and an azimuth of 120° to the east/southeast across the main north-south oriented structural trend in the field. This would be toward the interpreted upflow and hotter part of reservoir and would represent a good option to target additional capacity in a less exploited step out location. Magnetic surveys have also indicated that a deep diorite body may exist at depth in this region. It is anticipated that any deep contact with the diorite would likely have some permeability around its margin.

4.3 Well Workover Results

The workover of well SJ12-3 was completed after 70 days on 1 January 2014. This was much longer than planned due to a series of drilling difficulties encountered.

4.3.1 Well Deepening Results

The workover program for deepening SJ12-3 targeted a nominal completion depth of 2,600 m. The well was quenched for a total of 16 hours until the well was in vacuum. The 8-1/2” BHA was run into the hole and drilled to a total depth of 2,488 m without circulation returns. Close monitoring of key drilling parameters showed clear evidence of a substantial drilling break at 2,424 m, suggestive of a new permeable zone having been encountered. Soon after, the drill string became stuck at 2,488 m.

The stuck pipe was worked continuously for a total of 12 days. Five (5) string shot runs were made but were all unsuccessful in backing off the drill string. The drill string only became free when working the pipe after the 5th string shot with a maximum pull of 350,000 lbs. The well was completed by running 7” perforated liner to 2,478 m which was resting on 10 m of fill with the 7” TOL sitting at 2,352 m (SKM, 2013e).

A water loss survey was conducted in the deepened well using a K10 PTS tool at 300 and 1,000 gpm pump rates. The maximum logged depth was ~2,430 m. Figure 9 shows the corresponding temperature and pressure profiles obtained during the water loss survey. The temperature profile at 300 gpm pump rate shows major permeability at ~2,200-2,300 m. Positive stationary spinner responses were also recorded at 2,430 m during the survey suggesting fluid movement past this depth. This indicates permeability below the logged depth of 2430 m. An immediate shut temperature survey confirmed permeability at ~2,250 m. The pressure profile at a 300 gpm pumping rate showed the water level to be at around 300 m. This is somewhat lower than the pressure profile at 200 gpm pump rate (~250 m) during the post drilling completion test in 2011. This suggests an improvement in permeability (increase in storage capacity) of the well after deepening. It is possible that the reservoir drawdown may also have an effect on the water level but probably to a smaller extent.

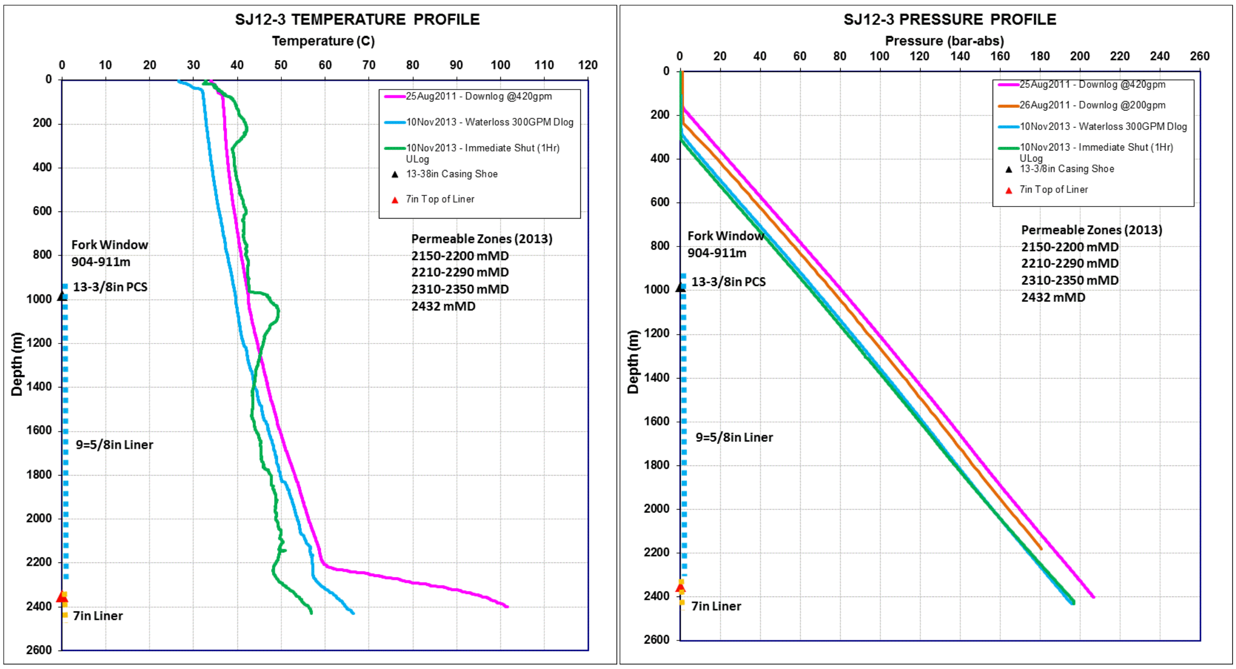


Figure 9: Temperature and pressure profiles from water loss survey conducted in deepened SJ12-3.

A short injectivity test was also conducted using 300 and 1,000 gpm pump rates with the PTS tool set at 2,430 m. Downhole pressures obtained at higher rates have not shown complete stabilization. Average pump rates were employed due to variability during the injectivity test. The post deepening injectivity index was estimated from the downhole pressures with a probable range of 15 to 23 tph/bar. This index is moderately higher than the post drilling injectivity index obtained at around 16 tph/bar in 2011, suggesting a probable increase in well production potential.

4.3.2 Well Forking Results

The directional kick-off of the 12-1/4” forked leg commenced at 912 m by milling a window through the bottom part of the 13-3/8” production casing using a Pathmaker whipstock system. The fork was drilled to a total depth of 2,459 m with a final inclination of

65.6° and an azimuth of 134°. The average rate of penetration for the forked leg ranged from 7-10 m/hr with a water flow rate of 1,100 gpm. Partial losses of 30-90 gpm were experienced from 1,768 m to total depth. A decision was made to terminate the forked leg at 2459 m due to rig pump pressure constraints and no obvious signs of permeability associated with intrusive rocks found near the bottom of the well.

The angle of the well at total depth was significantly higher than the programmed 45° (SKM, 2013f). Previous measurements at 1,789 m showed the inclination to be 32° but the conduct of succeeding check-up surveys were kept to a minimum below 1,800 m to reduce the risk of becoming stuck. The survey at 2406 m showed a high inclination of 67.1°. The higher than anticipated well inclination built up over a depth of ~ 600 m was considered to be due to the new BHA and formation abrasiveness. The BHA was designed to build angle (i.e. more flexible) and address the elevated torque and pressure during drilling. It was noted on the last trip that the stabilizer blades and heavyweight drill pipes (HWDP) were worn out and that could have been a factor in the excessive build.

There were numerous drilling breaks but only a very few resulted in loss of drilling fluid. Most of the drilling breaks were attributed to contact between lavas and tuffs, increased veining or intercalations of red tuffaceous sediments (SKM, 2013f). Epidote, which is indicative of temperatures of >250°C, occurred throughout the entire forked leg but it was at trace levels and sporadic, unlike the original leg where it was in abundance from ~2,000 m depth.

Post forking completion tests were conducted in the well and consisted of water loss and injectivity tests. The maximum logged depth was 2270m. Figure 10 shows the corresponding temperature and spinner profiles obtained during the water loss survey. The survey at a pump rate of 500 gpm revealed permeability at ~1,100m, ~1,750 m and ~1,900 m. Spinner responses confirm the major permeability to be located at 1,750 m. Positive spinner responses recorded during a stationary spinner run at 2,270 m suggested fluid movement below this depth indicating some additional permeability below the maximum logged depth.

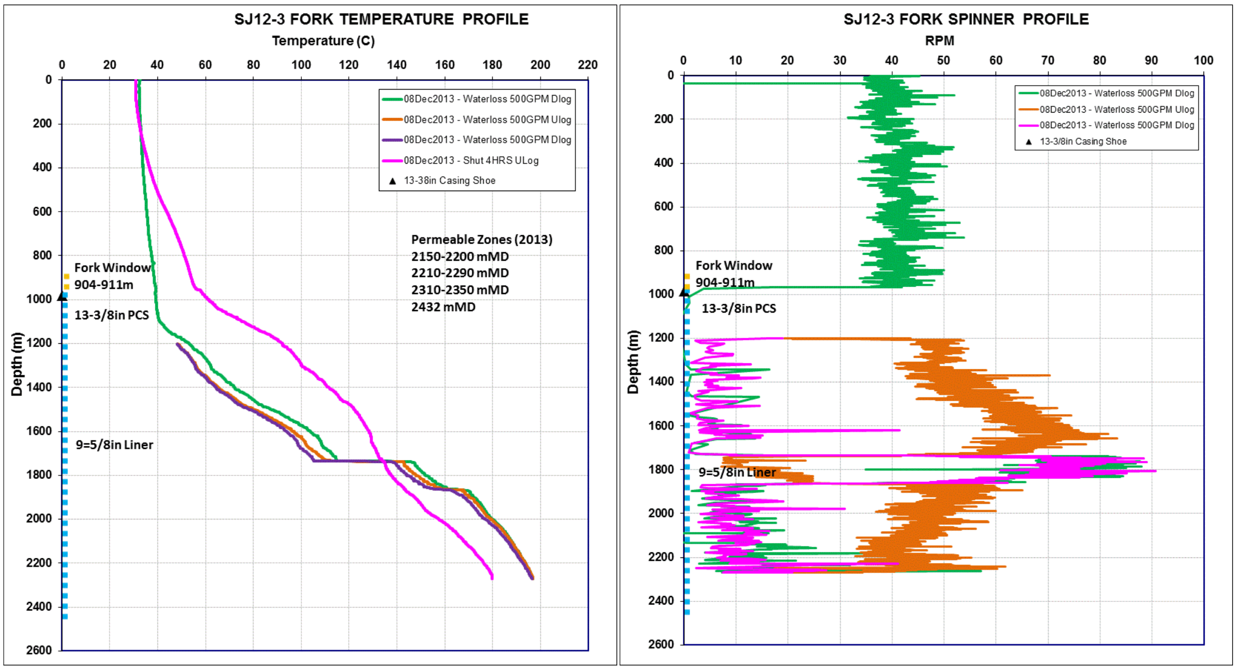


Figure 10: Temperature and spinner profiles from water loss survey conducted in SJ12-3 fork leg.

Injectivity testing at 500 and 1,100 gpm pump rates showed a moderate injectivity index of 8 t/hr/bar. A positive WHP was observed during injectivity testing further corroborating only moderate injectivity.

4.3.3 Whipstock Assembly Retrieval Operation

Prior to the recovery of the whipstock assembly, the 9-5/8” internal casing cutter cut the protruding 9-5/8” liner above the casing window. The casing spear recovered the 7 m of 9-5/8” perforated liner including the liner adapter. The top of the liner was reported at 924 m which was designed to provide 5 m open hole below the casing window to provide room for thermal expansion.

Retrieval of the whipstock took several attempts before it was finally pulled from the hole. A total of nine (9) retrieval hooks and four (4) box taps were run to recover the whipstock. Initially, it appeared that the casing was damaged immediately above the whipstock and this caused lateral movement of the casing, thereby preventing the box tap from latching and the hook from engaging.

A series of Downhole Video (DHV) camera runs were made to assess the whipstock ramp condition. The camera runs confirmed a depth discrepancy between the Pason measurements and camera depth measurements. The drill pipe stands were strapped-out and the 900 m (32 stands) of drill pipe were shown to be longer by 9.6m than previous records indicated. It took a total of approximately 16.6 days to eventually pull the whipstock out of the hole. The discrepancy in the drill pipe tally at the setting and retrieval of the whipstock was the primary cause for the delay in the retrieval.

4.3.4 Combined Legs Injectivity Test

A stepped rate injection test was conducted on the combined legs of the well after successfully retrieving the whipstock and packer assembly. Prior to the test, the 1-3/4" sinker bar dummy run hung up at 911 m. A 7-3/4" OD go-devil was run and was also held up at 911 m. The obstruction was milled by a 12-1/8" convex mill from 911 m to 915 m and a 1-3/4" sinker bar was run in hole and held up at 913 m. It was decided not to send any instruments below 911 m.

The Kuster K-10 PTS tool was run for injectivty test using 800 gpm and 1,100 gpm pump rates with tool set at 900 m. The calculated injectivity index for the combined legs is ~14.8 tph/bar which is slightly less than the injectivity of the original leg. Spinner data revealed the majority of the injected water at 1,100 gpm entering the fork leg that could have affected the combined leg injectivity and reflected the improved capacity of the fork leg.

A DHV camera was later run and showed a parted connection of 13-3/8" casing at 912 m. The casing separated on the low side with no major distortion. There was no damage above and below ~911 m.

4.3.5 Horizontal Discharge Test Results

SJ12-3 was discharged on 29 January 2014 through the atmospheric silencer using two-phase fluid injection from nearby production well SJ12-2. The well was tested using a 10" James tube for 25 days and discharge parameters were monitored for stabilization. Wellhead pressure steadily increased to around 5 barg at 100% well opening and discharge enthalpy gradually increased to around 1,300 kJ/kg (Figure 11). The baseline discharge enthalpy of the well prior to the workover was ~1,500 kJ/kg. The well showed regular surging of discharge fluids during the clearing discharge which is anticipated to stabilize with time.

The total mass flow at 100% opening is conservatively estimated at around ~210 tph with corresponding steam flow of ~80 tph and a discharge enthalpy of ~1250 kJ/kg (Figure 12). Total mass flow prior to workover is ~90 tph.

The well was subjected to a short deliverability test to determine well behavior at different well openings prior to connection to the power plant. The well showed an initial increase in discharge enthalpy (>1,300 kJ/kg) at 60% well opening and WHP stabilizing to 6.0 barg. Total mass flow was estimated at ~210 tph. The estimated output at this condition is >10 MWe for a discharge enthalpy of 1,400 kJ/kg.

The well was successfully cut-in to the San Jacinto production system on 23 February 2014 at 50% well opening with a WHP of 9-10 barg. A corresponding increase in total steam flow of around ~57 tph was measured. This steam flow translates to around 7.4 MWe of initial output contribution. The well registered a higher system WHP compared to previous discharge test parameters at a similar well opening and suggests additional flow is likely at lower operating WHPs.

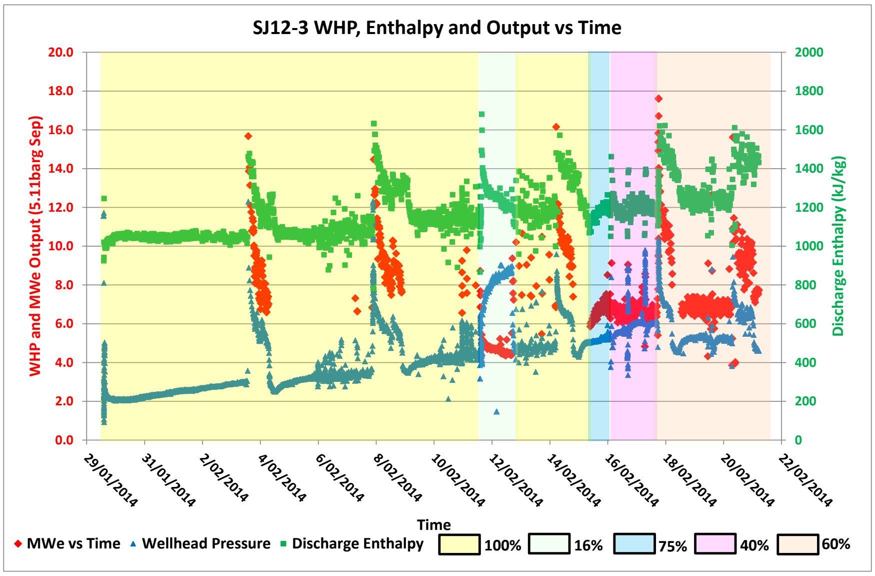


Figure 11: SJ12-3 wellhead pressure, enthalpy and output with time.

5. SJ9-3 WELL ENHANCEMENT

5.1 Well History

SJ9-3 is a deviated production well completed in August 2010 with a 13-3/8" production casing and 9-5/8" liner (blank/slotted combination). The well has a steam output of 36 tph. There is a drillable shoe at the bottom of the well which is favorable for any deepening and well forking options to improve production.

A review of well drilling and testing results undertaken by Jacobs in February 2011 indicated that the well has formation damage caused by mud during drilling. An acid treatment program to remove the formation damage was successfully implemented on 31 July 2011. Subsequent re-testing of the well confirmed that the acid stimulation has improved steam production, with a steam flow rate of 57 tph after 8 days of testing. Perhaps most importantly, the well stimulation work resulted in the well having an increased flowing wellhead pressure against the marginally commercial baseline wellhead pressure. The well has however shown some rundown due to its still relatively modest permeability. A Kuster PT tool and about 1,676 m of slick line was also left in the well, presumably with the tool near bottom and the wireline curled in the liner section of the well.

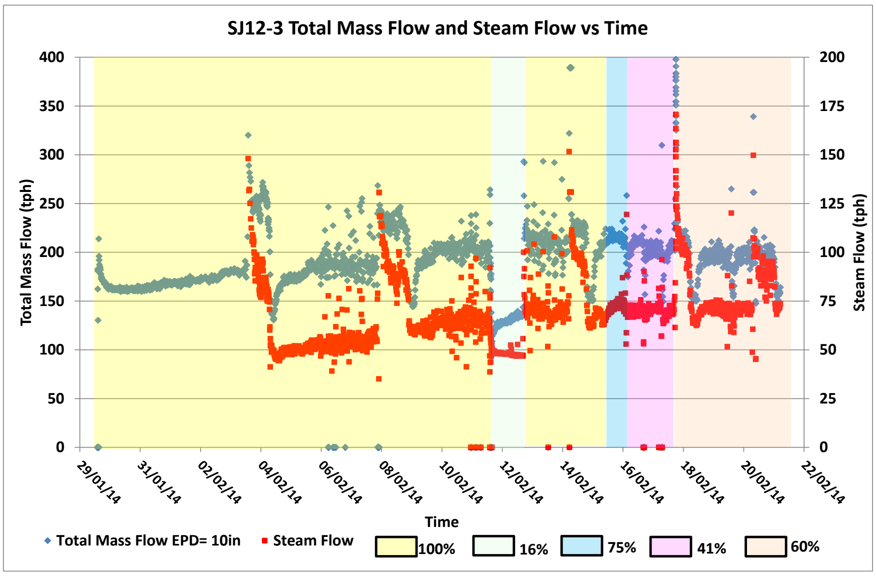


Figure 12: SJ12-3 total mass flow and steam flow with time.

5.2 Well Enhancement Program

The objectives of the workover for SJ9-3 were four-fold (SKM 2013g). These are:

- Recover the wireline and Kuster survey tool,
- Deepen the well to find additional permeability,
- Perforate sections of the blank 9-5/8" liner and 13-3/8" production casing which indicated permeable zones or 'hotspots' and
- Fork the well to find additional production capacity.

Deepening of SJ9-3 was conducted by drilling an 8-1/2" diameter hole through the bottom of the 9-5/8" liner by an additional 500 m. The objective was to intercept additional permeability within the eastern reservoir area that is known to be hot. The deepening was proposed at an increased angle of deviation in order to maximize the horizontal offset of the well to favor interception of any fault structures, which were generally steeply dipping.

During the drilling of SJ9-3, circulation losses were recorded at intervals which were subsequently excluded by the installation of blank liner. The well has blank liner from 1,043-1,172 m and from 1,582-1,667 m. Temperature surveys performed following acid stimulation of the well indicated shallow deflection at 620 m and near the bottom at 1,562-1,582 m (Figure 13). The drilling losses showed the following which confirms permeability behind the blank liner:

- Circulation losses at 1,582.9 m. Injected ~3,200bbls of mud/water around this depth during injectivity test. Lost 407bbls during trip.
- Circulation losses at 1,603.7 m, 1,621.9 m, total loss at 1,616.5 m.

The target intervals for perforation were 1,163-1,172 m and 1,590-1,640 m for the 9-5/8" blank liner and 619-640 m for the 13-3/8" production casing.

The well was forked at 630 m and a 12-1/4" hole was drilled to a nominal total depth of 1,800 m. A maximum inclination of 45° toward the east was proposed with the aim of intercepting the SJ9 Fault shallower than the original leg. The proposed well profile gave a horizontal offset of approximately 650 m from the point of forking. This allowed some widening of production to the east and south east parts of the reservoir and, like the deepening activity, was expected to help test whether diorite intrusive rocks occur in this part of the field.

5.3 Well Workover #2 Results

The ThermaSource Rig 104 was set up and commenced the second workover of well SJ9-3 on 23 August 2013. The Rig was released after a total of 52 days of workover operation.

5.3.1 Recovery of Wireline and Kuster Survey Tool

A total of six wireline spears were run and recovered 1,337 m of slickline. The remaining 339 m of slickline and 4.5 m of survey tool were milled to the bottom of 9-5/8" liner at 1,666 m (SKM 2013g).

5.3.2 Well Deepening Results

The original hole was deepened with 8-1/2" hole from 1,666 m to 1,972 m using water at 870 gpm flow rate without returns to surface. Deepening was terminated at 1,972 m considering the risk of stuck pipe while drilling below recommended flow rate of 1,100 gpm. The stand pipe pressure was near the pressure relief setting of the pumps (margin of 100 psi.). There were also evidence of remaining junk in the hole and the probability of additional permeability at depth was small. The 7" perforated liner was run to total depth with the top of liner (TOL) sitting at around 1,653 m (SKM 2013g).

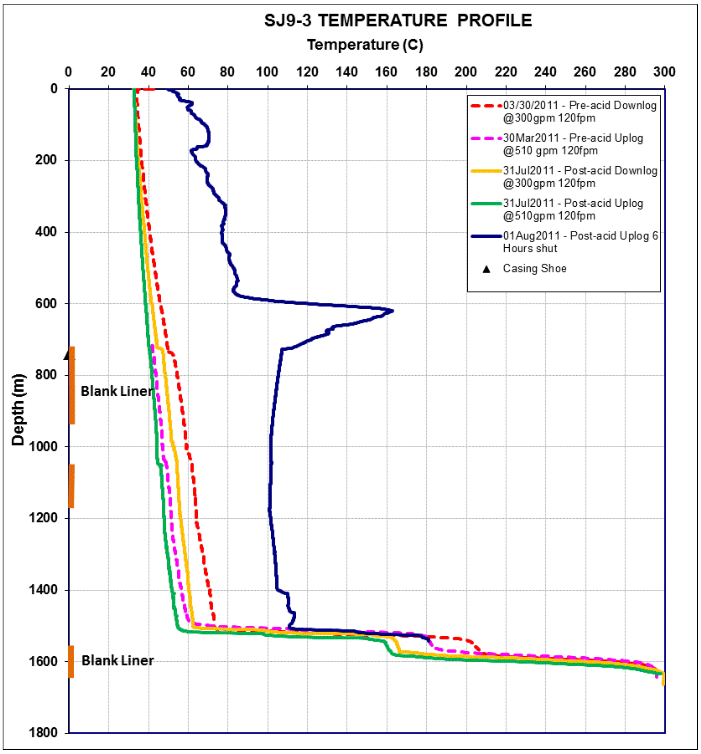


Figure 13: SJ9-3 temperature profile during acid stimulation job.

A water loss survey was conducted in the deepened well *prior* to perforating the original well leg using K10 PTS tool at 500 and 1,000 gpm pump rates. Maximum logged depth was ~1950 m. Temperature profiles obtained during water loss survey revealed temperature deflections just below the 9-5/8" liner that gradually increased along the 7" liner section (Figure 14).

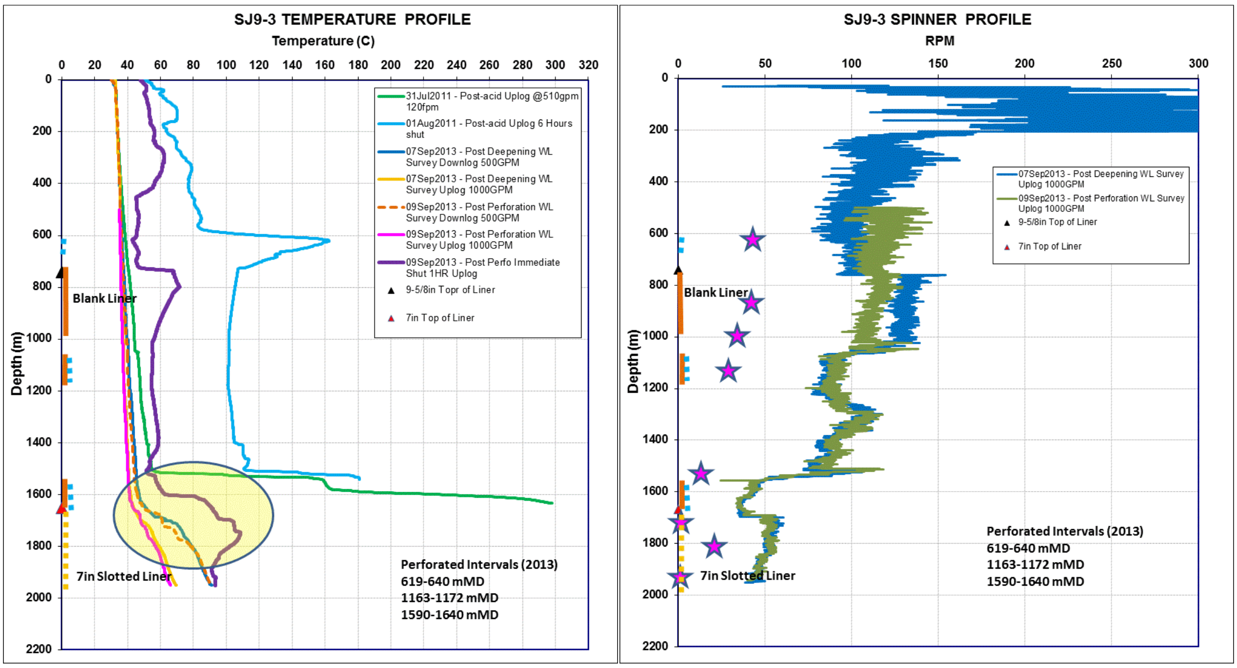


Figure 14: Temperature and spinner profiles of deepened SJ9-3 well during water loss survey.

The water loss test recorded permeability in the original leg at the following depths: 1,180–1,200 m; 1,475–1,575 m; 1,590–1,640 m and 1,800–1,850 m.

A lower temperature profile was recorded at higher pump rate (1,000 gpm) along the deepened section suggesting an increased water loss. Corresponding up-log spinner responses at 1,000 gpm pump rate confirm the aggregate permeability encountered along the section. Stationary spinner responses (pink stars) also supported the permeable horizon along the depth from 1,800-1,850 m. There were no stationary spinner response readings at maximum logged depth (1,950 m) suggesting no fluid movement past the depth (Figure 14).

A post-deepening injectivity test was conducted with the PTS tool at 1,950 m using pump rates of 300, 500 and 1,000 gpm. An injectivity index of about 9.0 tph/bar is estimated from the downhole pressures obtained and is slightly higher than the post-acid injectivity of around 7.4 tph/bar taken at 1,550 m.

5.3.3 Casing Perforation of SJ9-3 Original Section

Three sections of the well were perforated at the following depths:

- 1,590–1,640 m blank section of 9 5/8” liner
- 1,163-1,172 m blank section of 9 5/8” liner
- 619–640 m section of 13 3/8” production casing.

The deepest two sections were completed prior to forking of the well and the shallowest section after forking of the well. Perforation was also conducted using Schlumberger wireline equipment and services. The wireline used was 0.46” diameter cable which was rated at 176 °C and the charges used were HMX charges rated at 204 °C. The perforating gun used was a 4-1/2” High Shot Density (HSD) gun loaded with Powerjet 4505, HMX explosives on a 6 m gun carrier (SKM, 2013g).

A water loss and pressure fall off test (PFO) was conducted *after* perforation of the original well to a maximum log depth of 1,950 m while pumping at 500 gpm and 1,000 gpm. Similar temperature profiles were obtained to those measured prior to perforation indicating similar permeability location (Figure 14). An immediate shut-in survey (1 hr) also showed fast temperature recovery along the perforated targets and deepened section.

An injectivity test was also carried out after the perforations in the two deeper sections. Similar injectivity of about 8.9 tph/bar was estimated after perforation. The PFO survey after perforation showed good permeability-thickness kh of around 1.54 d-m with negative skin (s=-4.3) suggesting an absence of formation damage.

5.3.4 Well Forking Results

A 13-3/8” casing window was milled using the Pathmaker whipstock system and the 12-1/4” fork hole was drilled from 692 m to 1,967 m. Partial losses were encountered immediately after milling through window of the forked leg which were attributed to cement anomalies in the 13-3/8” casing. Almost full returns were sustained from approximately 830–1,077 m with a 75% return of fluids and an average loss rate of 350 bbls/hr (SKM, 2013h). Total loss circulation was encountered at 1,201 m with partial returns at 1,211 m where loss rate was 1,050-1,200 bbls/hr. Partial returns (20-30%) continued from 1,211 m to total depth.

The hole became tight between depths 1,824–1,843 m that required additional reaming. However this activity appeared successful and drilling continued to 1,975 m where high torque was encountered which increased the risk to continue; hence, drilling of the fork was terminated. However the drill pipe became stuck during pull-out at 1968 m that was later attributed to the tight zone at 1,824-1,843 m where a red, collapsing mudstone was thought to occur. Several days were spent working on stuck pipe but finally the drill pipe was cut at 1,847 m. A total of 119 m of fish was left in hole with the top of fish at 1,839 m.

The new 9-5/8” perforated liner was run in the fork hole and squatted on top of the fill at 1,809 m. The new top of 9-5/8” liner of the fork leg was set at 704 m. The whipstock assembly and the inflatable packer were recovered thereby opening access to the original deepened hole.

A water loss survey was conducted after the 9-5/8” liner was run into the hole with the maximum logged depth at ~1,800 m and pump rate of 500 gpm. The temperature profile obtained during the survey revealed high permeability at 1,220 m, 1,600 m, and 1,700 m (Figure 15). A shut-in PT survey 6 hours after pressure fall-off test (PFO) test also showed temperature deflections at 1,220 m, 1,600 m and 1,700 m with maximum temperature at the bottom at 194°C.

Corresponding spinner profiles obtained confirmed permeability at 1,220 m, and 1,500-1600 m as shown in Figure 15. Stationary spinner responses (pink stars) at selected depths confirmed the permeable zones detected during the moving logs. There was no stationary spinner response at maximum logged depth (1,800 m) suggesting no fluid movement past the depth. If there had been some permeability below 1,839 m (top of fish) it may have effectively been ‘blocked off’ by the fish in the hole.

Analysis of PFO test showed permeability-thickness kh of around 1.30 d-m with negative skin (s=-4.9). This kh value is similar to the permeability value obtained at the deepened leg of SJ9-3. The stepped injection test conducted on the fork leg resulted in an injectivity index of 9 tph/bar.

Good permeability is obtained in both the deepened and perforated section of the original leg and the fork leg which is supported by modest high temperatures. Each of the legs showed injectivity index of around 9.0 tph/bar compared to original well at 7.4 tph/bar. This suggested that effective permeability could have been more than doubled by the workovers. The two legs showed negative skin indicating no damage was created during workover and deepening.

5.3.5 Well Workover #3 Results

Initial discharge attempts using air compression and associated downhole surveys after the Thermasource Rig 104 completed the second workover in October 2013, indicated a fixed blockage at 1,524 m within the original leg of the well. Three sinker bar and a 6” lead impression block (LIB) surveys were run in the original leg but all recorded a blockage at 1,524 m.

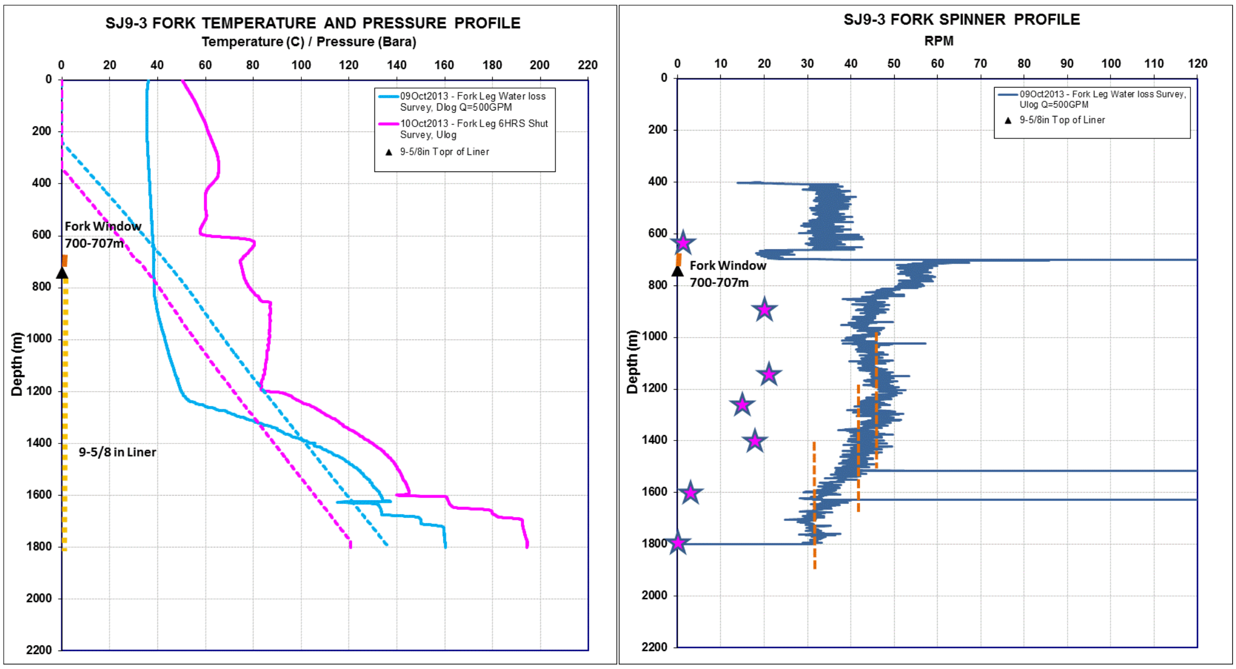


Figure 15: Temperature, pressure and spinner profiles of SJ9-3 fork leg during water loss survey.

This initial blockage was interpreted to be accumulated debris generated during milling of the window and drilling out of the isolation plug. The initial discharge attempts were also suspected to have fed the original leg with drilled cuttings coming from the forked leg. The discharge tests also carried a lot of sediments which led to the replacement of an eroded hole in the pipeline elbow and removal of accumulated sediment in the master valve and atmospheric separator. Dynamic PTS surveys indicated that production was primarily coming from the shallow perforated zone and the forked leg, with negligible contribution from the original deepened leg.

Further blockages were subsequently identified much shallower in the hole at 1,101 m and 1,030 m. These were identified by DHV surveys which were considered to be due to bridging of some platy scale material (Figure 16). The exact mechanism for scale deposition is uncertain, but was possibly associated with mixing of fluids of different temperatures, and possibly chemistry, during numerous attempts to discharge the well.

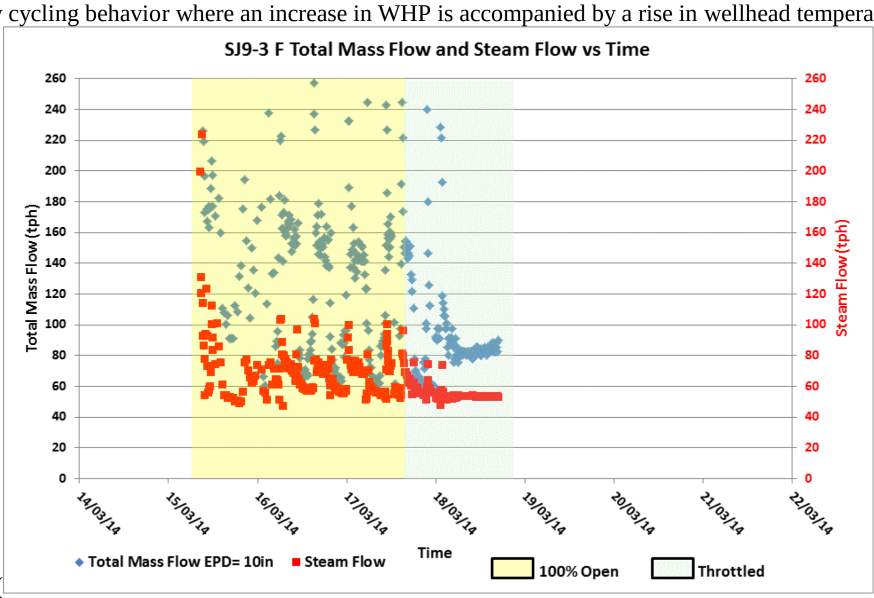
Figure 16: Downhole video (DHV) survey showing top of fill at 1030 m at original leg of SJ9-3.

Themasource Rig conducted the third workover on 09 January 2014 to clear the well bore obstructions in the original leg of the well. The deepened original leg was cleared to total depth of the hole at 1,980 m. Obstructions were also tagged at depths of 1,030 m, 1,483 m and 1,523 m in the 9-5/8" liner and at 1,745 m inside the 7" liner (SKM, 2013i). All obstructions were reamed and washed with a high flow rate and with minimum string rotation. After clearing and cleaning all obstructions inside the 9-5/8" and 7" liners, a sinker bar run was conducted to tag the measured cleared depth at 1980 m and verify that the well bore was clear to total depth.

5.3.6 Horizontal Discharge Test Results

The well was successfully discharged through the silencer using 10" James end pipe diameter on 06 February 2014. Clearing discharge of the well showed highly variable WHP and lip pressure readings. This erratic behavior could be due to interplay of two phases feed from perforated section, fork leg and possibly deepened leg of the well.

The well continued to show cycling behavior where an increase in WHP is accompanied by a rise in wellhead temperature (WHT)



and mass flow (Figure 17Figure 17). It would appear that the original leg (with two-phase contribution) mainly contributes to the upsurge of wellhead parameters while the fork leg dominates the flow at low wellhead pressures. Clearing discharge continued at 100% well opening and consistently displayed cycling behavior with WHP ranging from ~3.7 barg (Low WHP mode) to ~6.1 barg (High WHP mode).

Total mass flow measured at LWHP mode was roughly 90 tph with equivalent steam flow of ~55 tph at atmospheric separation (Figure 17). Discharge enthalpy was calculated at around 1750 kJ/kg. Brine flow consistently showed clear discharge at this low WHP condition. Total mass flow measured at HWHP mode was ~160 tph with equivalent steam flow of ~78 tph at atmospheric separation. A lower discharge enthalpy was however calculated at around ~1450 kJ/kg. Brownish effluent of brine was observed during upsurge in WHP.

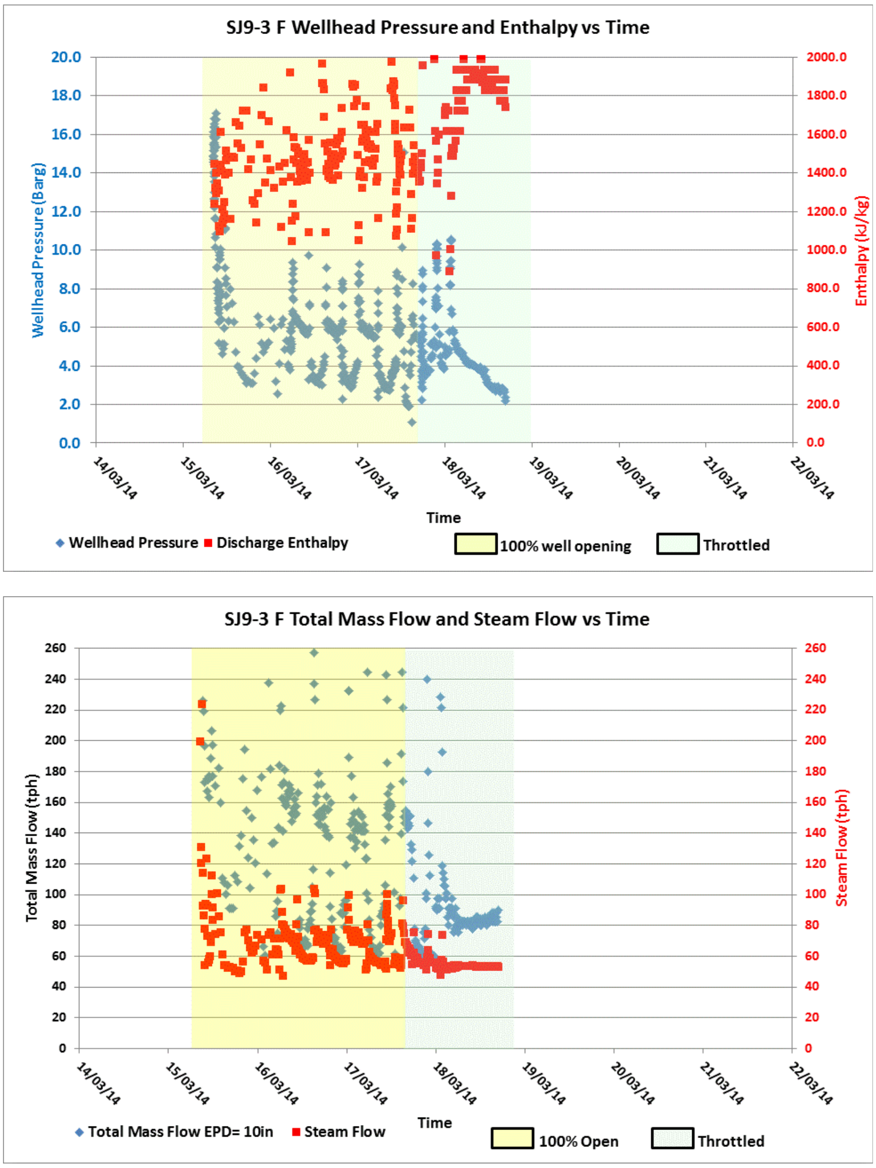


Figure 17: SJ9-3 wellhead monitoring parameters during horizontal discharge.

Flowing PTS survey were then conducted to establish the wellbore dynamics and confirm the flow contributions at these two discharge episodes (Figure 18). Flowing temperature profile during down-log (LWHP mode) described several permeable zones in the original leg (~1,000 m, ~1,220 m, ~1,540 m, ~1,600 m and ~1,800 m) and perforated zone and fork leg. Flowing pressure profile during down-log showed flashing of up-flowing fluid at around ~800m. This suggested that all feed zones in original leg were in liquid phase.

Flowing temperature profile during up-log (HWHP mode) showed further heating of reservoir fluid below 800 m to 1,000 m producing higher WHT of ~160C. Flowing pressure during up-log showed downhole pressures progressively declining (transient) with much deeper flashpoint at around ~1,600 m. This confirmed the previous liquid feed zones at 1,000 m, ~1,220 m and ~1,540 m became two phase due to pressure drawdown. Discharge at HWHP mode revealed hot fluids in original leg masking the fluid contribution from fork leg and perforations.

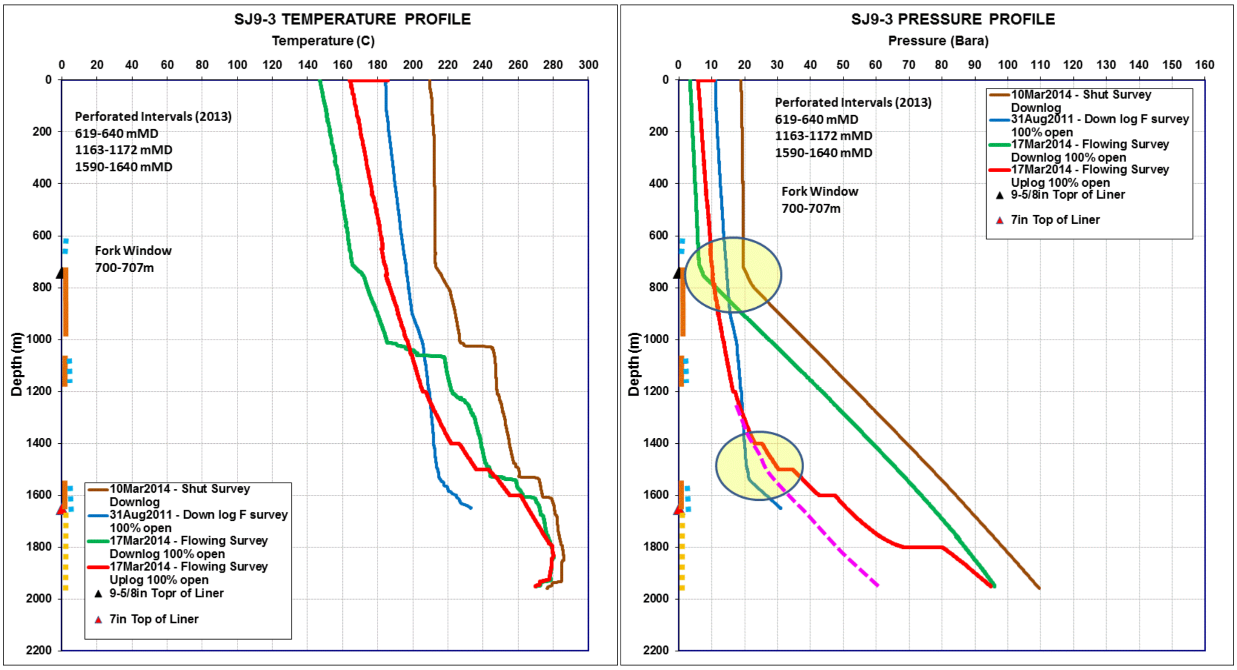


Figure 18: SJ9-3 downhole temperature and pressure profiles.

SJ9-3 was cut-in to the production system at 25% opening on 05April 2014 without SJ9-1 supplying steam to Separator#2. The well also displayed unstable WHP that declined to <5 barg after 6hrs of monitoring (Figure 19). SJ9-3 was tested again at ~30% well opening with SJ9-1 connected to the system but still showed variation in WHP with some level of stability for a period of ~12hrs. Flow was regularly diverted to the silencer for a few minutes when the WHP approached 5 barg. Collectively, the well still continued to demonstrate small variation in wellhead pressure at higher well opening (~55%) during the Lenders production testing in May 2014. It is however expected that stable discharge with WHP at sustained level above 5 barg will be achieved once the well chemistry has fully stabilized. The anticipated positive output contribution of the well (>36 tph steam flow) will also be confirmed by the TFT measurements to be conducted in the next few months.

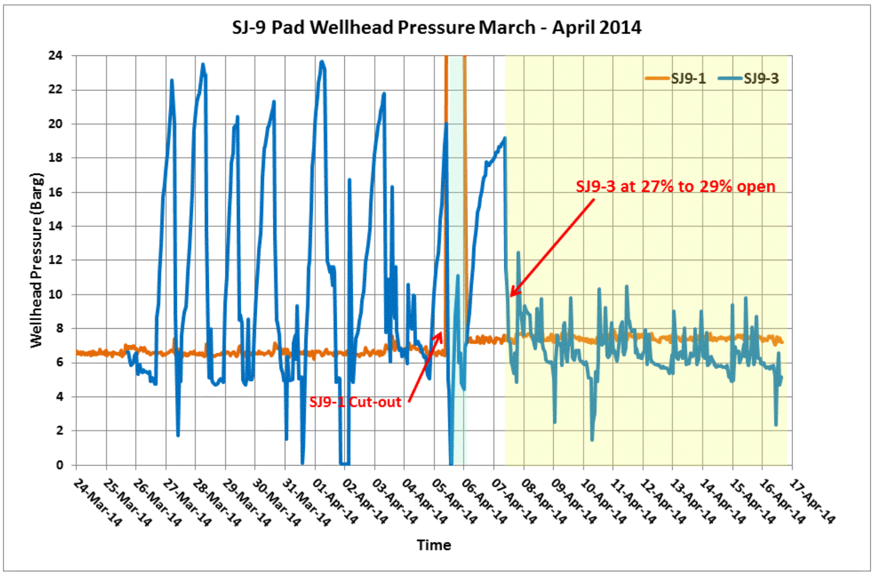


Figure 19: SJ9-3 wellhead pressure during production testing.

6. CONCLUSIONS

Jacobs and PENSA have successfully developed and implemented a production enhancement program in July 2013 to produce additional steam for the San Jacinto power plant. A number of options for a limited amount of budget and time frame were identified for the enhancement plan following a cost-benefit analysis undertaken by Jacobs. This analysis indicated the following preferred well intervention approaches for the candidate production wells in obtaining additional steam:

- SJ6-1 casing perforation and deepening,
- SJ6-2 casing perforation,

- SJ12-3 deepening and forking and
- SJ9-3 casing perforation, deepening and forking.

The above well enhancement techniques applied have been considered effective and consistent with the requirements of sustaining long term operation of San Jacinto geothermal field. Experiences obtained from these intervention procedures showed that the chance of success is generally increased with a correct and appropriate engineering approach to any well problem. Analysis of the downhole measurements after well intervention indicated a notable improvement in wellbore parameters that increased confidence in successfully meeting the targeted output requirements of the San Jacinto plant units. Horizontal discharge testing of SJ6-1 and SJ6-2 showed modest improvement in their total production output of around 2.5 MWe. Production wells SJ9-3 and SJ12-3 on the other hand showed marked increase in production outputs of around 7.5 MWe during their horizontal discharge testing.

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