EVALUATION OF THE DEEPEST PRODUCTION WELL IN SALAK GEOTHERMAL FIELD, INDONESIA

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ABSTRACT

Well AWI 9-9 was recently drilled at the Salak (also known as Awibengkok) Geothermal Field, West Java, Indonesia, as a make-up steam supply well to support full load power generation at the 377 MWe power facilities. The well was also drilled to provide information on the temperatures in and the permeability of the undrilled portion of the southwest area of the Awibengkok field. AWI 9-9 was completed in 21 days to a total depth (TD) of 10,402 ft (3,170 m) making it the deepest production well drilled in the Awibengkok reservoir.

The well completion test indicated that AWI 9-9 has inter-zonal flow with the upflowing hot (610 °F or 321 °C) reservoir fluid from the bottom feed zone exiting the feed zone at ~6,532' (1,991 m) MD. The presence of an inter-zonal flow at AWI 9-9 creates difficulties in assessing the actual reservoir parameters encountered by the well. Adjustment of the conventional geothermal well characterization method thus needed to be made in order to fully characterize the well. The well's unique sub-surface condition also increased the risk of well control issues so these risks needed to be fully understand and mitigated.

The bottom entry in this well, the deepest permeable entry identified to date (10,032' or 3,058 m MD), confirms the interpretation of deep permeability at the Awibengkok reservoir. The presence of the deep feed zone in the MVS indicated that this formation is still permeable to sustain commercial production. The depth of recorded micro-seismicity events suggests that permeability could extend as deep as 13,000' (~4,000 m) BSL. At this depth, it is possible that supercritical fluid exists and that it can be harnessed to generate power outputs in order of magnitude greater than from conventional high-temperature fluid.

Keywords: Salak, completion test, deep well, supercritical fluid, interzonal flow, well control

INTRODUCTION

The Salak geothermal field is located about 60 kms southwest of Jakarta, West Java, Indonesia on the southwestern flank of the Gunung Salak volcano (2,211 m ASL). Commercial production started in 1994 with an initial 110 MW (Units 1 and 2) and was expanded to 330 MW by 1998 when Units 3, 4, 5 and 6 were installed. In 2002, following the Asian Economic Crisis of 1997-1998, turbine output was increased to 377 MWe (Ibrahim et al., 2005). Salak is presently the largest producer of geothermal power in Indonesia.

Salak is a fracture-controlled, liquid-dominated geothermal system with commercial reservoir temperatures ranging from 464 - 600 °F (240 – 316 °C), benign fluid chemistry and low to moderate non-condensable gas (NCG) content (~0.5-3%w/w) (Stimac et al., 2008). The reservoir is contained within a sequence of volcanic units of predominantly andesitic to rhyodacitic composition, with a basement of Miocene marine sedimentary rock cut by igneous intrusions. With a current installed capacity of 377 MWe and a proven reservoir area of about 18 km^2 (Figure 2), the field has a power density of about 20 MWe/km^2.

At the start of commercial operations in 1994, brine was injected infield in the hottest portion i.e the upflow zone of the reservoir at AWI 9 and in the southern edge of the field at AWI 10. The general belief then was that the "limited" brine produced from generating 110 MWe would not significantly harm the high-temperature reservoir. In 1998, the increase in generation capacity increased the produced brine to an average injection rate of 12,000 kilo-lb/hr (130,600 ton/day). Chemical breakthrough and thermal breakthrough were observed at the main production area and, as a result, infield injection has been minimized by transferring both condensate and brine injection to the edge and outside of the field's production area.

To maintain full generation of 377 MWe, the field has been developed through the periodic drilling of make-up wells. The most recent make-up well drilling campaign was in 2012-2013. During this period three new wells were drilled in the western-most production pad AWI 9, namely, AWI 9-7 in 2009, AWI 9-8 in 2012 and AWI 9-9 in 2013. These wells provide key reservoir information as they were drilled in a previously undrilled area at the southwestern edge of the field. At 620 °F (327 °C) AWI 9-7 has shown the highest temperature yet measured at Salak while AWI 9-8 confirms the lateral extension of the reservoir margin to the southwest.

The bottom of a geothermal reservoir is normally defined when the permeability of the rock is not sufficient to sustain commercial production. Data from the relatively deep make-up wells shows the potential for an extension of the depth of permeability. In addition, the depth of recorded micro-seismicity events suggests that permeability could extend as deep as 13,000 ft (~4,000 m) BSL especially in the southwestern part of the field (Libert et al, 2014). AWI 9-9 was designed to test temperature and permeability at depth in the area of the inferred upflow region of the Salak reservoir.

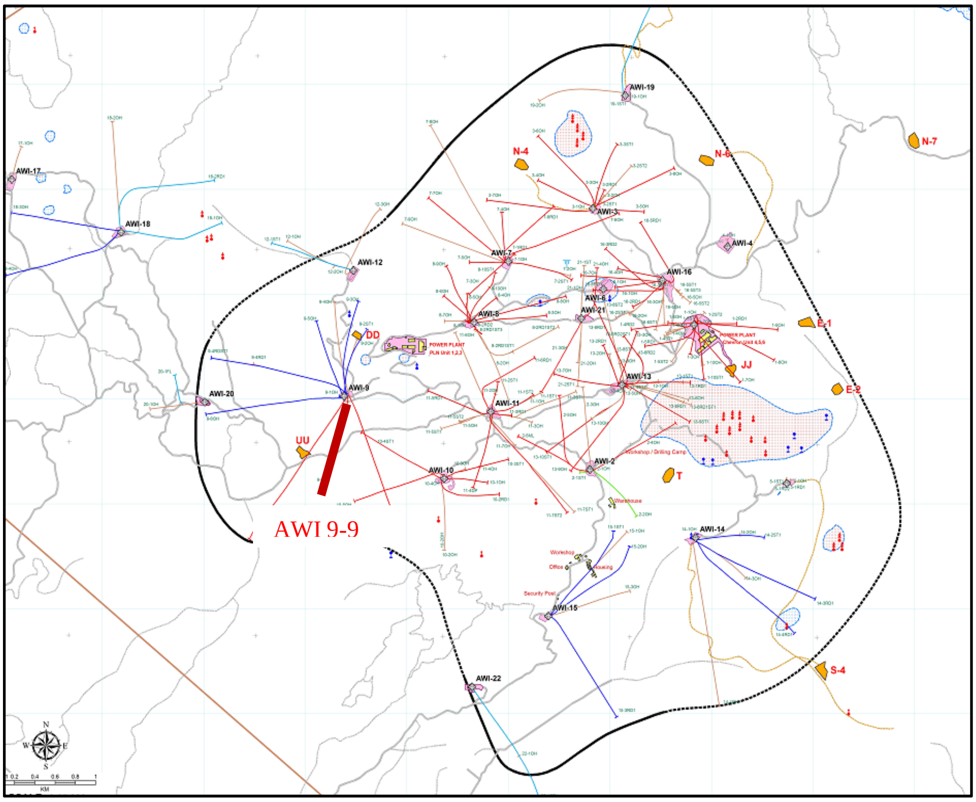

Figure 2: Map of the Salak geothermal field showing the commercial reservoir boundary (black solid/dashed line), production (red) and injection wells (blue). Also shown is AWI 9-9, the deepest production well drilled in Salak (bold red line).

DRILLING SUMMARY

AWI 9-9 was designed as a low inclination (17°) standard 2D directional well that targets production from the deep brine reservoir in the southwestern part of the field. Although relatively shallower than the original target, AWI 9-9 was drilled to 6,665 ft (2,032 m) BSL, still the deepest production well drilled in Awibengkok. Typical for a production well in the field, AWI 9-9 was completed as a big hole with a 13-⅜" production liner. The reservoir hole section was drilled in two hole sections, namely, 12-¼" and 9-⅞" diameter. Perforated 10-¾" production liner was installed in the 12-¼" hole section. (Figure 3).

SUBSURFACE GEOLOGY

AWI 9-9 penetrated a series of hydrothermally altered volcanic rocks to a depth of 6,504 ft (1,982 m) MD where mud circulation was lost. The rocks encountered by this well were similar to those of other wells drilled in the Field and can be divided into six formations (Table 1). The transition from argillic to propylitic alteration occurs in the Middle Andesite Formation and the Rhyodacite Marker (RDM). Phyllic alteration was also observed in the RDM at 3,660 - 3,920 ft (1,115 -1,195 m) MD and in the Lower Andesite Formation at 4,160 – 4,340 ft (1,268 -1,322 m) MD. RDM occurencess also supported by a significant spike ingamma ray value (Figure 4) suggests that the number of radioactive elements increase with increasing silica. Overall, the general lithology encountered at AWI 9-9 is similar to those encountered at AWI 9-7 and AWI 9-8.

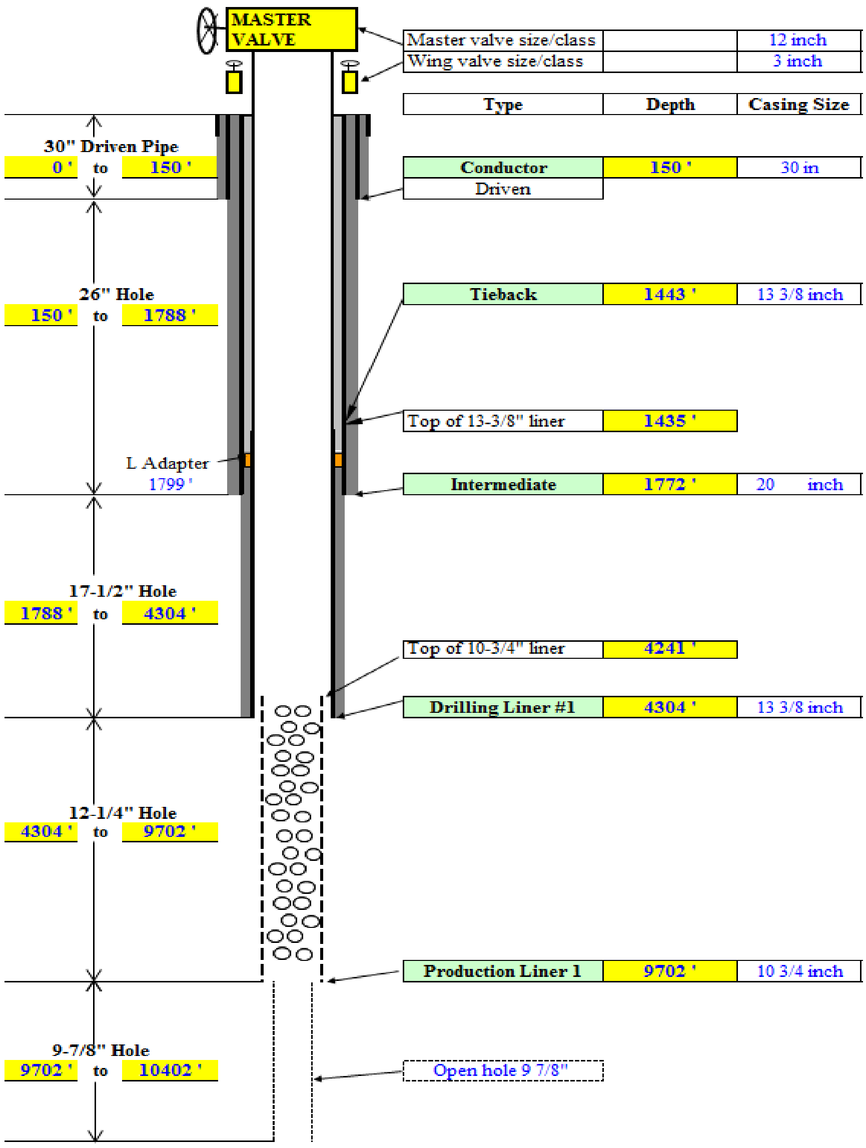

Figure 3: Well completion schematic of AWI 9-9

Table 1: Lithology and alteration of AWI 9-9 based on interpretation of rock cuttings

Depth	Lithology	Alteration
184 – 540 ft (56 – 165 m)	Upper Dacite	Unaltered to weakly argillic
540 – 840 ft (165 – 256 m)	Upper Andesite	Moderate to strongly argillic
840 – 1,280 ft (256 – 390 m)	Middle Dacite	Argillic
1,280 – 3,660 ft (390 – 1,115 m)	Middle Andesite	Weak to moderately argillic transitioning to propylitic
3,660 – 4,340 ft (1,115 – 1,322 m)	Rhyodacite Marker	Argillic; propylitic
4,340 – 6,504 ft (1,322 – 1,982 m)	Lower Andesite	Propylitic

WELL CHARACTERIZATION

Completion test

Upon completion of the drilling operations and the releasing of the rig, a completion test consisting of an injection Pressure-Temperature-Spinner (PTS) survey and a multi-rate injection test was performed. This was followed by heat up surveys or series of shut-in pressure and temperature (PT) surveys. The completion test and heat up survey analysis suggest that AWI 9-9 encountered three permeable entries. Analysis of the PTS data also revealed two directions of fluid movement during the injection test i.e. downflowing injected condensate and upflowing hot (610°F or 321°C) reservoir fluids from the bottom feed zone at ~10,032 ft (3,058 m) MD. Both fluid streams exit at the feed zone located at ~6,532’ (1,991 m) MD (Figure 4).

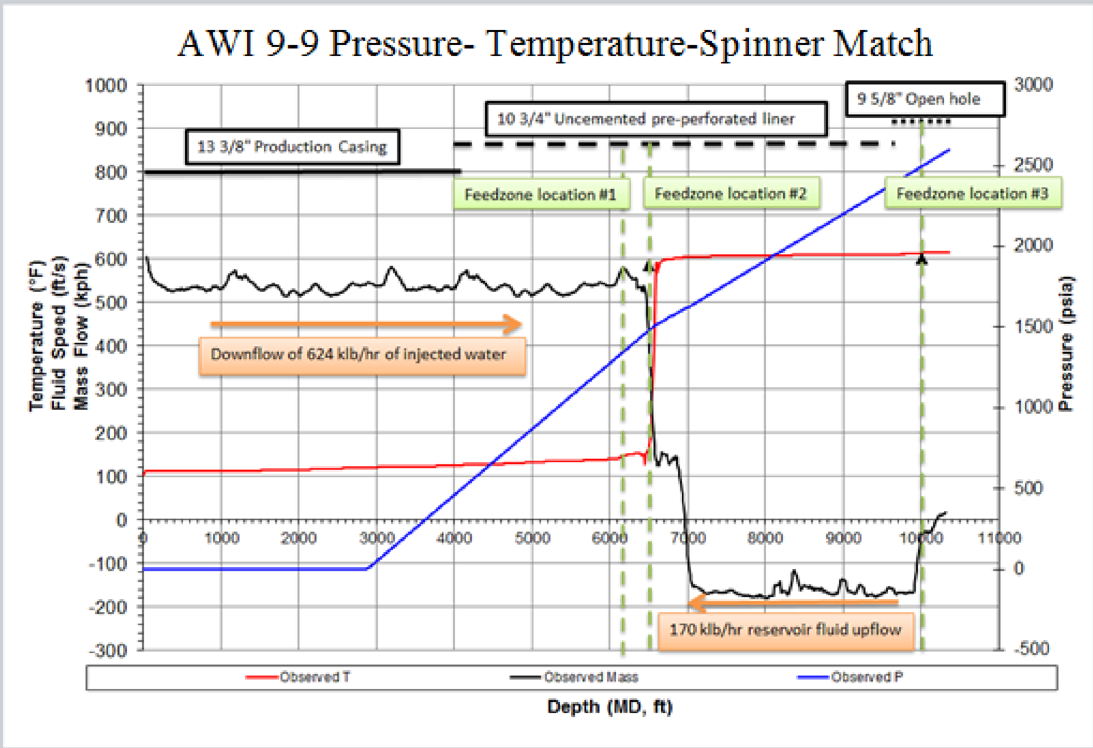

Figure 4: AWI 9-9 injection PTS analysis showing the three permeable zones encountered by the well. Black line is the mass flow calculated from spinner data, blue line and red line are measured injection pressure and temperature respectively.

Interpretation of the aforementioned phenomenon was based on at least three evidences observed in the PTS data. First is change in the direction of spinner rotation below ~6,532' MD. Second is temperature profile of the well above ~6,532' MD which is imprinting condensate temperature that is slightly heated up by the hot formation. Below ~6,532' MD the temperature jumps to 610°F (321°C) followed by isothermal profile down to the well TD. And lastly, injection pressure profile showed 2 different pressure gradient at above and below ~6,532' resulted from significant temperature differences and pressure drop from gravity and friction suffered by the upflowing zone.

The shallowest permeable entry is located at 6,182' (1,884 m) MD. Based on rock cuttings, the host rock is andesite lithic tuff of the Lower Andesite Formation. There was no indication of permeability at this depth during drilling, (e.g., no drilling breaks, fluid losses and drops in stand pipe pressure) and also this feedzone does not clearly appear during injection PTS survey. This uppermost feedzone was detected from the heat up survey data. The deep upflow creates a convective isothermal zone that was undisturbed during the completion test as seen in Figure 5. The upflow also provides convective heat transfer to the cold condensate column above the upflow exit point thus increasing the well heating up period (10 days to fully heat up). This dynamic condition triggers deep boiling in the wellbore where the steam-liquid interface (or top of the boiling zone) is controlled by AWI 9-9's shallowest feedzone. Without the existence of this uppermost feedzone at 6,182' the top of the boiling zone would be expected to be at a greater depth around the upflow exit point (~6,532' MD)

The second permeable entry is an extended interval of about 500 ft from 6,532 to 7032' MD (1991 to 2,143 m) MD. This feedzone is consistent with a drilling break at 6,499' (1,980 m) MD and Total Loss of Circulation (TLC) at 6,504' (1,982 m) MD.

The third feed zone is at 10,032' (3,058 m) MD, within the interval of blind drilling, Completion test data indicate that this entry is a high-temperature (610°F or 321°C) inflow which results in an interzonal flow that exits the well at 6,532' (1,991 m) MD. In addition, even though FMI analysis indicates no direct correlation between feed zone location and structure data, the interval range of the feed zone based on PTS to permeability indication (fracture/ fault cluster and significantly drop in pressure while drilling) is 67 feet (20 m), suggesting the range of feed zone with high-temperature feed zone near TD may still corresponds with a large fracture that identified at depth 9960 to 9965' (3,035-3037 m) MD (Figure 6).

The injectivity index (II) measured by an injectivity test was 20 kph/psi (or 36.5 kg/s/bar) (Figure 7). However, this measured value underestimates AWI 9-9's actual injectivity as it only calculates the change in downhole pressure as a function of changes in the condensate injection rate. The calculated II does not quantify the deepest feedzone permeability as it does not accept the injected fluid during the test (inflowing); moreover, the second feedzone at ~6,532' (1,991 m) MD has a higher injectivity to that calculated as this feedzone accepts both injected condensate and upflowing reservoir fluid from the deepest feedzone.

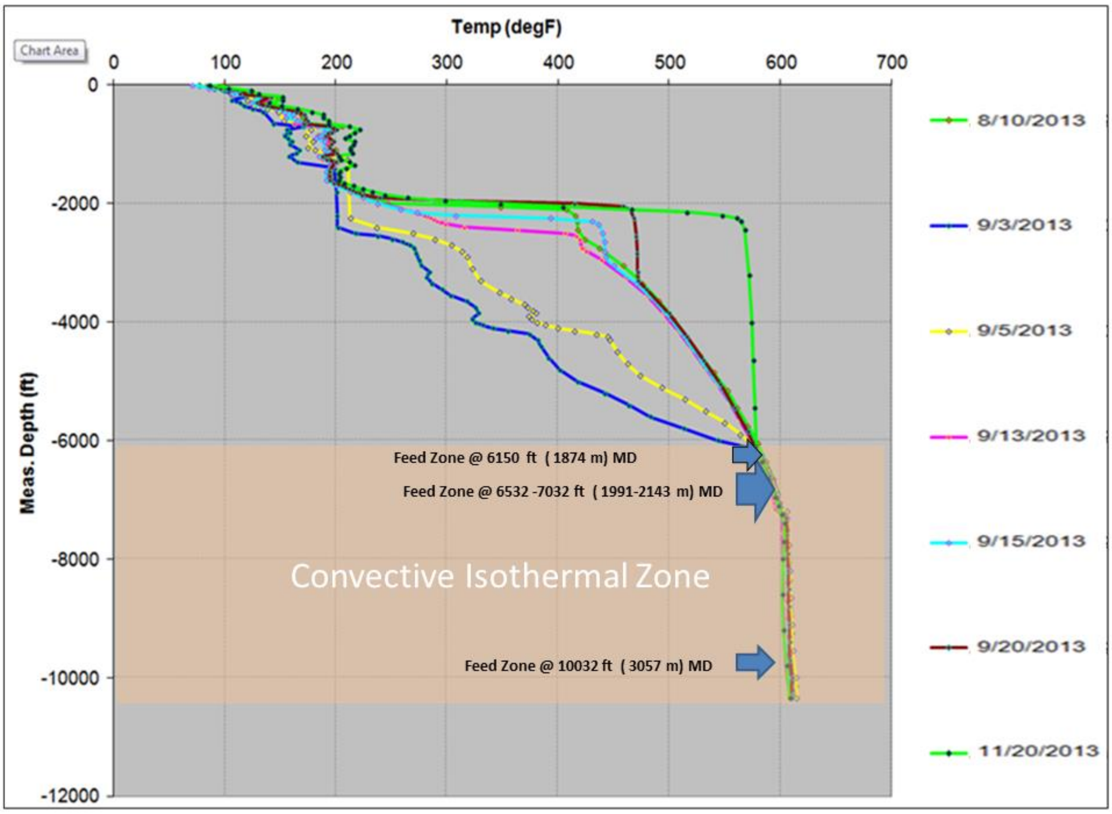

Figure 5: Chart showing the AWI 9-9 heat-up profile and the existence of a feed zone at ~6150' MD. This feedzone acts as a pressure reliever preventing the top of the boiling zone from going deeper. Also shown is a suggested presence of fluid movement from ~6500 ft-MD to the well TD as indicated by the isothermal temperature profile.

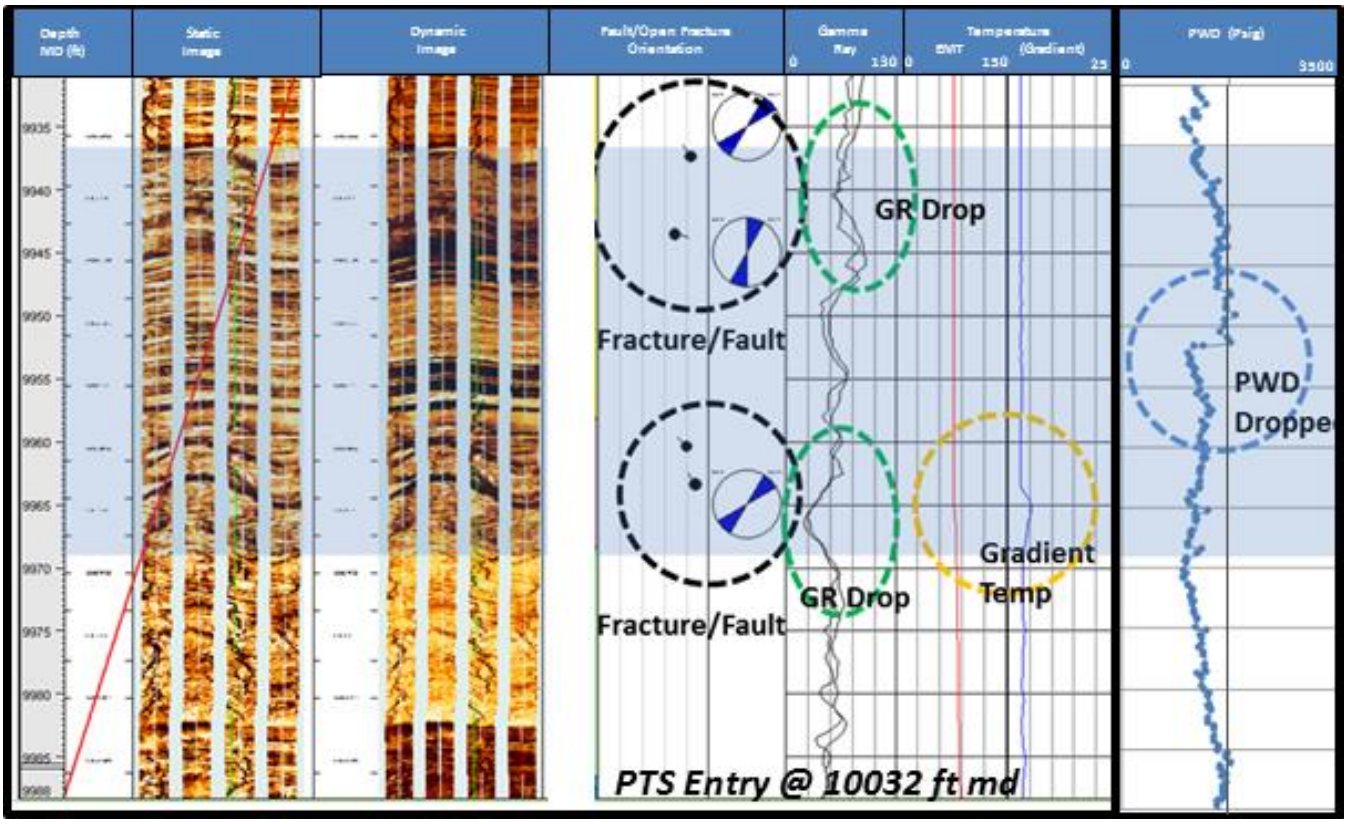

Figure 6: Screenshot showing FMI interpretation and GR, temperature gradient and PWD profiles of AWI 9-9. Although the injecting PTS data identified the bottom permeable entry at 10,032' (3,058 m) MD, it is believed that this feed zone is correlated with a NE-SW trending fracture/fault zone at 9,960'-9,965' (3,035-3037 m) MD.

The well injectivity was therefore estimated by calculating the injectivity of each feedzone based on injection PTS data (Table 3). Injection PTS analysis provides information of the mass flow rate of each feedzone, II is then calculated by dividing the mass flow rate with the differential pressure in the wellbore (from injection PTS data) and at the reservoir (from SI PT data). The total injectivity of AWI 9-9 is at minimum 27 kph/psi (or 50 kg/s/bar). The injectivity of the shallowest feedzone was neglected as it was hardly detected by the spinner. Due to the dynamic conditions in the wellbore, the reservoir pressure of the deepest feedzone was based on an estimated value that will be discussed in the next section (4.2). Despite all of the uncertainties and difficulties surrounding AWI 9-9 injectivity test interpretation, having II above 20 kph/psi (or 36.5 kg/s/bar) suggests that the permeability of the well is considerably high than that of other producers in the field.

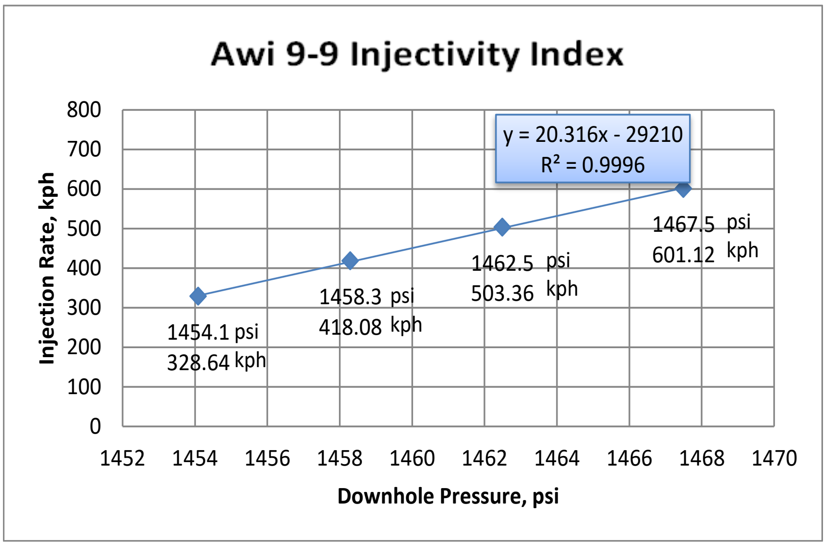

Figure 7: Injectivity index from a multi-rate injection test suggesting that AWI 9-9 has II of 20 kph/psi or 36.5 kg/s/bar which is an underestimation of the actual injectivity of the well

Table 3: Calculated Injectivity Index based on injection PTS data. AWI 9-9 has total II of 27.3 kph/psi or 50 kg/s/bar

Depth, ft-MD	6,532	10,032
Mass Flow, kph	748	170
Wellbore P, psia	1479	2494
Reservoir P, psia	1451	2682
II, kph/psi (kgs/bar)	26.2 (47.9)	1.1 (2)
Remarks	Mass flow rate is both injected condensate and upflowing reservoir fluid from the deepest feedzone	Reservoir pressure is estimated

Steam Deliverability Estimation

After the completion test, the well's deliverability was estimated using wellbore simulation with inputs from the completion test and heat up surveys. The required parameters to construct a Awi 9-9 wellbore model are feedzone' productivity index (PI), pressure, and enthalpy that can be computed from temperature. Feedzone PI can be obtained by converting the calculated II (APPENDIX A). However, the feedzone pressure and temperature cannot be obtained directly from SI PT data due to the presence of a hot upflow from the bottommost feedzone.

The interzonal flow in AWI 9-9 created difficulties in assessing the actual reservoir pressure and temperature encountered by the well. The upflow masks the actual formation temperature from 6,532' (1,991 m) MD to TD. The measured wellbore pressure also does not represent actual reservoir conditions. The measured pressure at the source of inter-zonal flow is lower than the actual reservoir pressure; consequently, the measured pressure at the exit point of the up-flow is higher than the actual reservoir pressure.

For this reason, the temperature and pressure of the feed zone at ~6,532' (1,991 m) MD were estimated based on offset wells data and analysis of the injectivity test respectively. During the injectivity test, the tool was hung at ~6,482' (1,976 m) MD, this meant the reservoir pressure at that depth could be estimated by calculating the intercept of the injectivity chart which is the bottomhole pressure at zero injection rate. The reservoir pressure of the feedzone at ~6,532' (1,991 m) MD could therefore be calculated by gravity correction of the reservoir pressure at ~6,482' (1,976 m) MD.

The temperature of the deepest feedzone is the upflowing fluid temperature. As for the reservoir pressure, it needed to be estimated by calculating the fluid mixture density from the measured pressure gradient (SI PT) and adjusting the measured reservoir pressure to get steam quality of zero, assuming that the fluid in the reservoir is in compressed liquid state. The steam quality can be computed with following formula :

$$Q = (V_{mix} - V_L)/(V_S - V_L) \quad (1)$$

Where Q is the steam quality, and Vmix, VL, and VS are the specific volume of mixture, liquid, and steam in cu-ft/lb respectively.

Input data for the wellbore model is summarized in Table 4. The wellbore simulation results indicate that AWI 9-9 can produce about 650 kph (82 kg/s) of steam at system pressure (Figure 8). However, considering all of the uncertainties pertaining to the special conditions at AWI

9-9, this initial estimate of the well's deliverability may change pending conduct of a flow test to fully characterize the well and the reservoir in the southwestern part of the field.

Well Control

AWI 9-9 was completed with API-6D class 600 wellhead equipment. The maximum working pressure of the equipment is 1500 psig (103.4 barg) at temperatures below 200°F (93°C) and de-rated to 1210 psig (83.4 barg) at 600°F (316°C). The material selection was based on the maximum anticipated surface pressure of the well which was determined based on boiling zone at Awi 9 area which is around -1000 ft asl. At this depth, pressure and temperature at the boiling zone correspond to a shut-in wellhead pressure (SI WHP) of 940 psig (64.8 barg) at 530°F (277°C). The SI WHP could go as high as 1058 psig (72.9 barg) when NCG accumulation is present in the upper casing section. This value is an assumed worst case scenario where the accumulated NCG is 100 percent carbon dioxide (CO_2) that being heated up by underlying steam to reach critical condition. However, it is known that the accumulated NCG is a mixture of CO2 and other gases with lower partial pressure which will result in a lower SI WHP.

Approximately one week after the completion test, AWI 9-9 SI WHP started to build up and stabilized at ~1120 psig (Figure 9a), which was above the maximum anticipated SI WHP of the well. The casing head flange and the wellhead temperature record (Figure 9b) suggesting no casing growth was observed as the SI WHP building up. The low wellhead temperature (90°F or 32°C) indicating presence of NCG accumulation at shallow casing section which is contradictory to the fact that the critical pressure of the NCG is 1058 psig (72.9 barg).

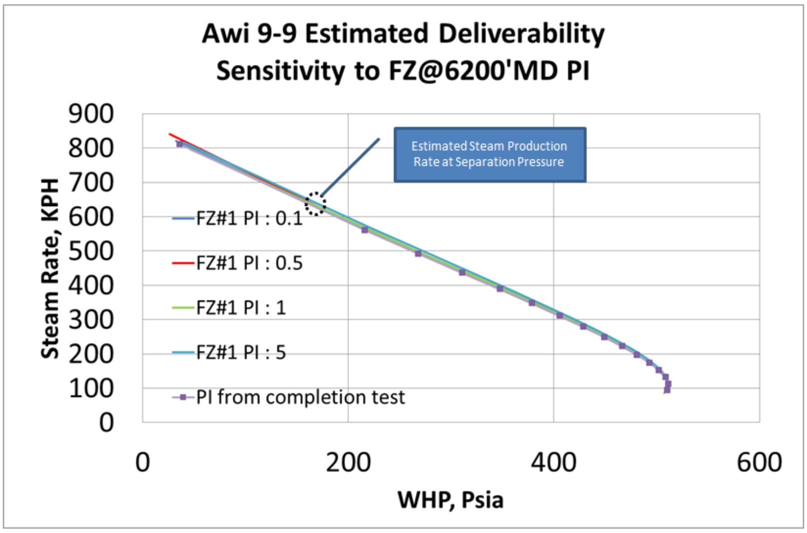

Figure 8: Chart showing synthetic deliverability curve of AWI 9-9; at current system pressure, the well can produce about 650 kph (82kg/s) of steam. The multiple curves represent sensitivity analysis of the shallow feed zone #1 which shows that it does not significantly affect well performance as the well's hydraulic condition is controlled by the 2nd and 3rd feedzone.

Table 4: Input data for wellbore simulation

Depth, ft-MD	II, kph/psi	PI, kph/psi	Reservoir Pressure, psia	Reservoir Temperature, °F	Enthalpy, btu/lb	Remarks
6,182	N/A	0.1 – 5	1328	550	550	Multiple runs of wellbore simulation with various PI since the feedzone is detected from the heat up survey
6,532	26.2	21	1451	570	575	Reservoir pressure estimated based on intercept of following equation from figure 11. Y = 20.316 X + 29210 Where X is bottomhole pressure at ~6,482' (1,976 m) MD
10,032	1.1	0.9	2682	610	630	Measured upflow temperature

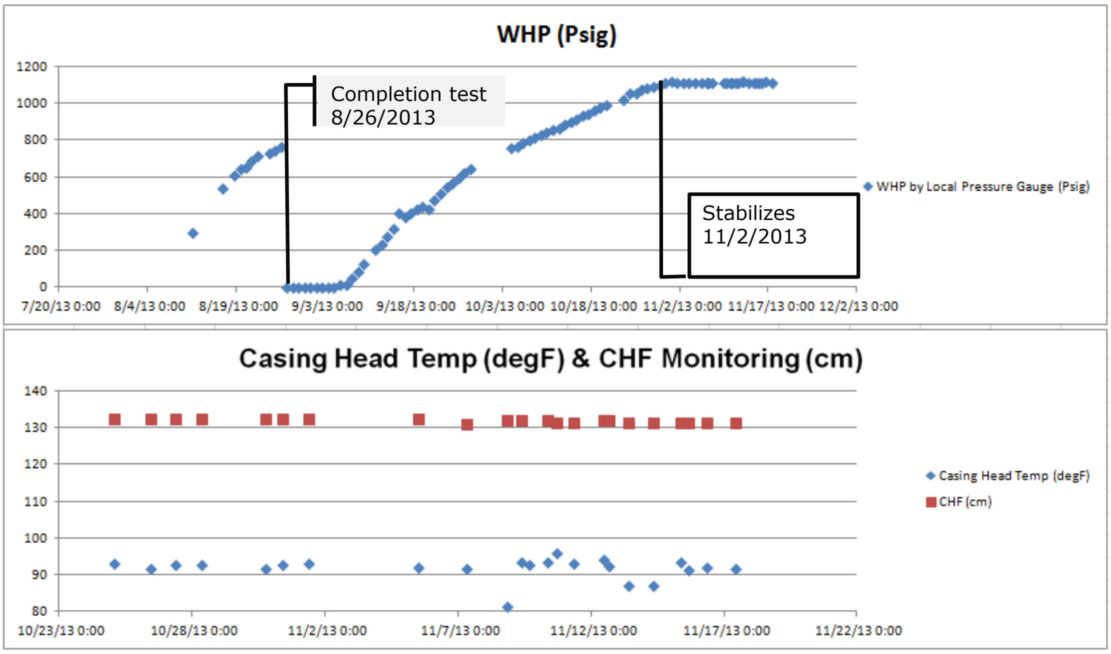

Figure 9: AWI 9-9 WHP monitoring (a) and record of casing head temperature and height (b)

Consequently, a shut-in PT survey was then performed to investigate the cause of the elevated SI WHP and to determine whether or not it was safe to vent/bleed the well to release the pressure. The survey revealed that the NCG (mainly CO_2) accumulated at the shallow part of the casing had reached supercritical condition as a result of pressurization of the steam from the boiling zone at 6182'.

CO_2 usually behaves as a gas in air at standard temperature and pressure (STP), or as a solid called dry ice when frozen. If the temperature and pressure are both increased from STP to be at or above the critical point for CO_2, it can adopt properties midway between a gas and a liquid. More specifically, expanding to fill its container like a gas but with a density like that of a liquid. This condition protects the wellhead from exposure to higher pressure and temperature. In the absence of NCG accumulation, Awi 9-9 SI WHP could be expected to reach 1205 psig (83 barg) at 569°F (298°C) (Figure 10).

Information from a static PT survey indicates that venting the well via a 3" bleed line would increase its WHP rather than reducing it. Under bleed conditions, the situation could be worse if dynamic conditions are created in the wellbore that allow higher pressures to be transmitted from the bottom of the well. This is a function of the temperature, pressure and the permeability of the zones.

For Awi 9-9, however, the sub-surface conditions are such that they should act to minimize the possibility of an increase in pressure; the deep temperature is "only" 610°F (321°C) and the pressure is over 2,500 psig (172 barg), which is well above the saturation pressure of 1,645 psig (113 barg). This means that under bleed conditions, flashing will occur higher up in the wellbore and the fluid will still have a relatively high density due to the relatively low enthalpy of 540 BTU/lb (1256 kj/kg), which will further decrease the pressure. The zone at 6,532' (1,991 m) MD also appears to have very high permeability. Thus it is expected that the wellhead pressure will still be controlled by the zone at 6,182' (1,884 m) MD even under bleed conditions. So the wellhead pressure may not change much from the shut-in condition as there is already an upflow occurring.

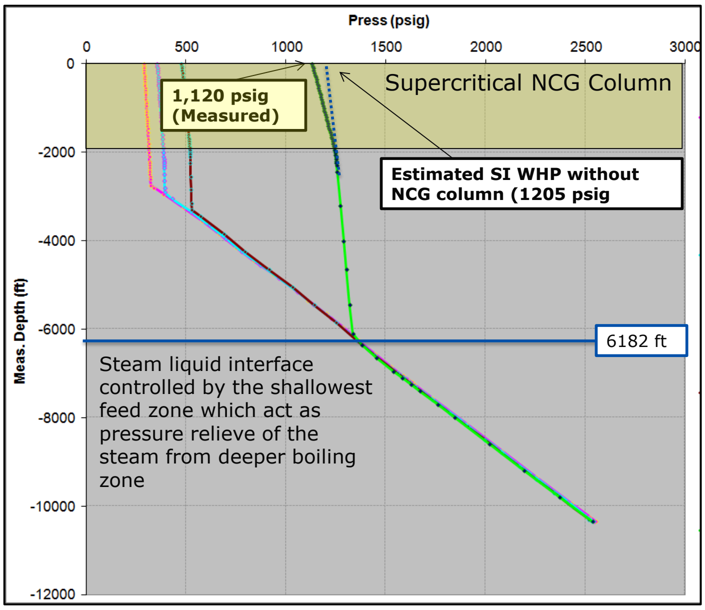

Figure 10: Shut-in PT survey of Awi 9-9. Presence of supercritical NCG column protecting the wellhead from exposure to higher pressure and temperature.

A different situation applied at Bul-108 (Mak-Ban geothermal field, Phillippines). The data from Bul-108 provides an example of what happens when conditions are more favorable for building up wellhead pressure. In this well, the bottomhole temperature was ~610°F (338°C), and a saturation pressure of 2,042 psig (140 barg). So flashing started much deeper in the wellbore. The well also has high permeability in the lower zone and low permeability in the shallow zone, which is also favorable for transmitting high pressures (Figure 11).

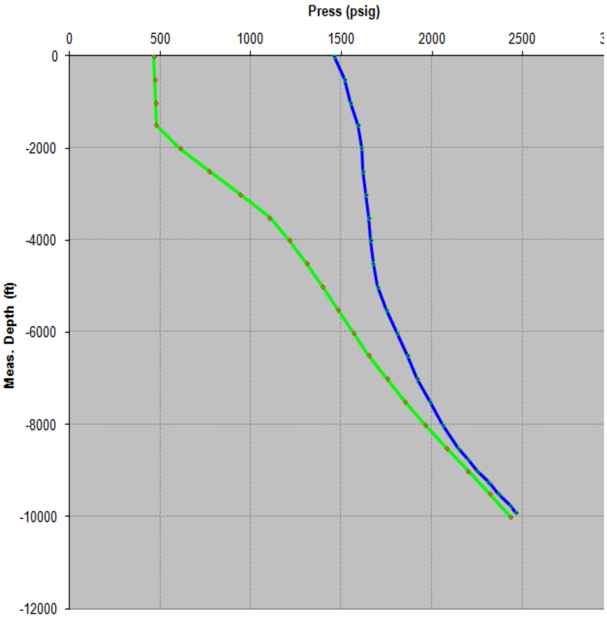

Figure 11 :The plots of shut-in and bleeding pressure of Bul-108. Green line shows the well's shut-in pressure profile, whereas the blue line shows that the dynamic condition in the wellbore (bleeding) causes the wellhead pressure to built up to near 1,460 psig (100 barg). Note that this well was completed with a ANSI900 series wellhead.

To mitigate potential exposure of the wellhead equipment to conditions above its design limit, the well was quenched and maintained under vacuum by 2 BPM (5 kg/s) of condensate injection. Continuous injection minimizes the thermal cycle and the injected condensate will mix with the hot upflow prior to entering the reservoir from feedzone at ~6,532' (1,991 m) MD. Based on simple heat and mass balance, the resulting mixture will have a temperature of ~500°F (260°C) which is considerably high and will not negatively impact the production area in the short run.

Well Operability, Monitoring, and Maintenance

There are several uncertainties that remain to be mitigated in order to safely operate AWI 9-9. The first is scaling potential. Under normal condition, the well's maximum expected surface pressure is 1205 psig (83 barg) at 569°F (298 °C) which is still lower (albeit by a thin margin) than the installed surface equipment maximum working pressure i.e. 1210 psig (83.4 barg) at 600°F (316°C). However, this condition is controlled by the uppermost feedzone at 6,182' (1,884 m) MD which may potentially be plugged if scaling occurred during the well's production life. Scaling could occur if the uppermost feedzone which is currently in a liquid state evolves into two-phase and/or dry steam which results ins a boiling and evaporation process that creates an ideal environment for scale precipitation. In addition, low enthalpy fluid (marginal recharge, brine injectate) inflow into the uppermost feedzone which induce cooling favorable for scale precipitation may occur in the future as the reservoir pressure declines.

Other uncertainties are related to the fluid characteristic and how the deep upflow will affect the wellbore hydraulic condition. These uncertainties apply because AWI 9-9 has not yet been flow tested. Several attempt to take liquid sample of the upflowing fluid have failed due to the high temperatures in the well. Recommendations for a specific well surveillance and monitoring program to address and mitigate these aforementioned uncertainties are shown in Table 5.

Table 5: Recommended surveillance and monitoring program for AWI 9-9

Type	Frequency	Remarks
Discharge test	1x prior to put online	Take discharged fluid sample, take down-hole fluid sample, run flowing PTS, and conduct flow performance test (FPT).
Downhole fluid sampling	Every 1-3 years	Obtain information on the deep upflow (pristine sample without mixing with shallower feedzone).
Surface gas and liquid sampling	Every 3-6 months	Monitor gas and liquid chemistry.
Casing condition monitoring (caliper, HTCC)	Every 1-5 years depends on fluid characteristic	Even though the Awibengkok reservoir fluid is known to be benign (Stimac et al., 2008), it is possible that the upflow from the bottommost feedzone has more magmatic influence which will increase the corrosion potential. Running caliper will enable to monitor corrosion, casing deformation, and scaling deposition.
Flowing PTS	At the beginning of production and when there is indication changes in well hydraulic condition	Understand well hydraulic condition under flowing condition with presence of the deep upflow.
Static PT	Annualy	Monitor reservoir pressure, temperature, and boiling zone evolution.
Maximum Clear Depth (MCD) Monitoring	In every downhole survey	Run dummy tool to tag MCD prior to any downhole surveys to evaluate wellbore clearance (fill from unconsolidated formation, corrosion product, scaling etc.)

Even though AWI 9-9 is the first well that intersected a high temperature upflow zone in the Awibengkok field and all other Chevron operated geothermal fields (i.e Darajat, Mak-Ban, and Tiwi) there are existing wells elsewhere with high SI WHP that intersect high pressure and a high temperature reservoir.

One example is Bul-108 (discussed above), the well had experienced surface pressure of 1,460 psig (100 barg) under bleeding condition, however, there was no well control issue as the well was completed with ANSI 900 series wellhead equipment. Up to the present there has been no wellhead or casing condition reliability issues (Libert, 2012) and the well behaves in a similar way to the other two-phase producers in the Mak-Ban field (Menzies, *pers.comm*, 2014).

Another analog example are wells drilled in the Rotokawa geothermal field. The field is located in the Taupo Volcanic Zone (TVZ) of New Zealand. As in the case of Awibengkok, the Rotokawa reservoir has heterogeneous permeability with semi-sealing compartments with pressure differences ranging of 550 psi (38 bar) across the field. The wells drilled in Rotokawa encountered temperatures of 625°F (330°C) at 8,500' (2,500 m) depth (Hernandez et al., 2015). Corresponding to that reservoir condition, the wells in Rotokawa have very high SI WHP as well as flowing well head pressure (FWHP). These wells supply the Nga Awa Purua (NAP) power station which was commissioned in 2010. This power station operates the largest triple flash geothermal single unit in the world with a high pressure inlet of 340 psig (23.5 barg) (Horie, 2009). Consequently, the wells operate at high FWHP; some of them operate as high as ~580 psig (~40 barg) of FWHP (Libert, 2015). These wells as well as the entire surface facility were completed with class 900 series material (Zarrouk, *pers.comm*, 2015) to control the high pressure and high temperature system. After five years of operation, the NAP steam field has been safely and successfully operated with aforementioned design, in addition, the wells also behave in a similar fashion to common two-phase geothermal wells (Quinao, *pers.comm*, 2015)

Therefore, upgrading the existing wellhead equipment of AWI 9-9 from API 6D class 600 series to class 900 series is recommended. The class 900 series have higher maximum allowable working pressure (1815 psig (125 barg) at 600°F (316°C)) which will be sufficient to cope with the anticipated risk of higher pressure and temperature at the surface. In the worst case scenario where the uppermost feedzone at 6,182' (1,884 m) MD plugs up, the boiling zone in the wellbore will be controlled by the second feedzone at ~6,532' (1,991 m) MD where the subsurface condition at that depth will correspond to the surface condition of 1400 psig (97 barg) at 590°F (310°C). This worst case scenario is still below the class 900 maximum working pressure.

POTENTIAL UPSIDE

The AWI 9-9 well characterization reveals that deep permeability exists at the South-Western (SW) portion of Awibengkok reservoir. The well confirms the presence of permeable zone at 10,032' (3,058 m) MD which corresponds to a reservoir pressure and temperature of 2,682 psig (185 barg) and 610°F (321°C) respectively. This part of the reservoir has been identified as the upflow zone of the Awibengkok geothermal system (Acuna et al, 1997) and has been exploited mainly as an area for brine disposal since 1994. Approximately 4,000 kilo-lb/hr (43,500 ton/day) of brine has been injected in the AWI 9 area since 1994 and the number tripled in 1998 to 12,000 kilo-lb/hr (130,600 ton/day) when electricity generation expanded from 110 MW to 330 MW.

Despite the amount of brine injected, a high temperature zone still exists in the area. Moreover, AWI 9-7 which was drilled in 2012 found the highest temperature yet measured in the reservoir (620 °F or 327 °C). Data from recently drilled deep wells show the potential for an extension of permeability at depth. In addition, the depth of recorded micro-seismicity events suggests that permeability could extend to as deep as 13,000' (~4,000 m) BSL in this area (Figure 12)

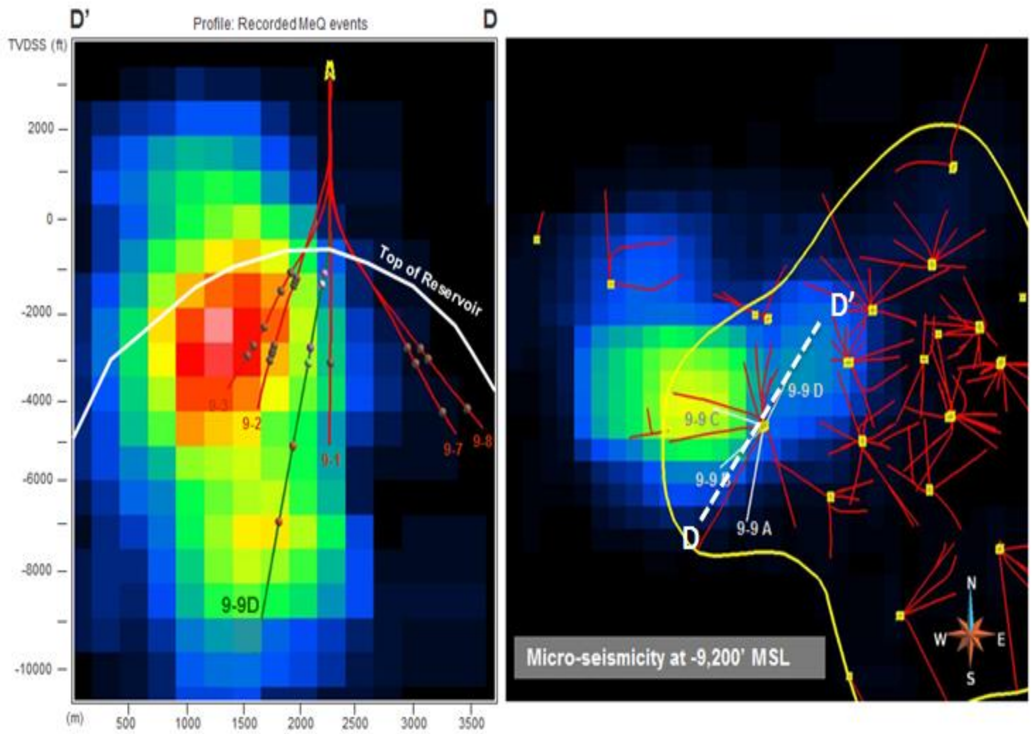

Figure 12 : Recorded MeQ event at pad AWI 9 due to injected fluid movement in the deep reservoir. The map shows cumulative MeQ events from 1998 until 2014.

At 13,000' (~4,000 m) the expected reservoir pressure is approximately 3,725 psig (257 barg) which is higher than the critical pressure of pure water. If the reservoir temperature at that depth is at or exceeds 705 °F (374 °C), supercritical fluid exists in the deep SW portion of the Awibengkok reservoir. Even though current highest maximum temperature recorded in this area is "only" 620 °F (327 °C), this peak does not means higher temperature do not exist at greater depth. This is especially the case because the area where the highest temperature was found has been affected by cooling from ~20 years of injection.

CONCLUSION AND RECOMMENDATION

The recently drilled AWI 9-9 in the southwestern portion of the Awibengkok field has revealed the presence of deep permeability below the current drilled depths of the reservoir. This deep permeability is located in Tertiary rocks in the Mixed Volcanics-Sediments (MVS) Formation which extends deeper than previously thought.

The well completion test indicated that AWI 9-9 has inter-zonal flow with the upflowing hot (610 °F or 321 °C) reservoir fluid from the bottom feed zone exiting the feed zone at ~6,532' (1,991 m) MD. This favorable result at AWI 9-9 confirms previous interpretations that the upflow of the geothermal system is beneath the Awi-9 pad. The bottom entry to this well, now the deepest permeable entry identified to date, confirms the interpretation of deep permeability in the Awibengkok reservoir. The presence of the deep feed zone in the MVS indicates that this formation is sufficiently permeable to sustain commercial production.

Upgrading the existing wellhead equipment from API 6D class 600 series to class 900 series is recommended in order to anticipate the risk of higher pressure and temperature at the surface due to scale deposition at the uppermost feedzone at 6,182' (1,884 m) MD and to also to anticipate potential anomalies in the well hydraulic condition because of the deep upflow.

Finally, supercritical fluid that has the potential to generate power outputs in order of magnitude greater than conventional high-temperature geothermal fluid may exist at greater depth in the SW portion of Awibengkok reservoir. Drilling an 'ultra' deep well or deepening existing deep wells to harness this source of energy may well be worth evaluating.

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APPENDIX

RL is the part of the productivity index (PI) that does not depends on fluid properties. Injectivity index (II) obtained from a pressure-temperature-spinner survey can be corrected by mobility to obtain PI.

Constant PI (in kph/psi) can be defined as:

$$\frac{W}{PI} = (P^* - P_{wf}) \tag{A1}$$

where W is mass flow rate in kph; P^* is the formation pressure in psi, and P_{wf} is wellbore pressure in psi.

In a steady-state radial flow **W/PI** can be expressed from Darcy's law (Paccaloni, 1979) as:

$$\frac{141.2WB\mu}{kh}\left(\ln\frac{r_e}{r_w}+s\right)=P^{*}-P_{wf} \qquad \text{(A2)}$$

where r_e is the drainage radius in ft, r_w is the wellbore radius in ft, s is skin factor, B is the formation volume factor in bbl, kh is permeability thickness in md.ft, and μ is fluid viscosity in cP

Combining eq A1 and A2, RL can be defined as:

$$\frac{1}{RL}=\frac{141.2B\mu}{kh}\left(\ln\frac{r_e}{r_w}+s\right) \qquad \text{(A3)}$$

Combining eq A1 and A3, RL (in (kph-cuft-cp)/(lb-psi)) is obtained by multiplying PI with VT (kinematic viscosity of mixture, in Cuft-cp/lb)

$$PI = RL\frac{1}{\nu_T} \qquad \text{(A4)}$$

VT (kinematic viscosity of mixture, in Cuft-cp/lb) is calculated as:

Assuming $k_{rs} + k_{rw} = 1$

$$\frac{1}{\nu_T}=k_{rs}\frac{\rho_s}{\mu_s}+k_{rw}\frac{\rho_L}{\mu_L} \qquad \text{(A5)}$$

In the wellbore simulator used for this project it is further assumed that k_{rw}~S_w to obtain:

$$\nu_T = X\frac{\mu_S}{\rho_S}+(1-X)\frac{\mu_L}{\rho_L} \qquad \text{(A6)}$$

Where X is steam quality, k_{rs} is relative permeability of steam, k_{rw} is relative permeability of liquid, S_w is water saturation, ρ_s, ρ_L, μ_s, μ_L are steam density in lb/cuft, liquid density in lb/cuft, steam dynamic viscosity in cp, and liquid dynamic viscosity in cp respectively.

Therefore, PI can be calculated by first obtaining RL from II by multiplying it with kinematic viscosity of the injected fluid.