Geothermics 83 (2020) 101715

Contents lists available at ScienceDirect

Geothermics

journal homepage: www.elsevier.com/locate/geothermics

The Salak Field, Indonesia: On to the next 20 years of production

Glenn U. Golla*, Tri Julinawati, Risa P. Putri, Gregg A. Nordquist, Frederick T. Libert, Aquardi R. Suminar

Star Energy Geothermal, Sentral Senayan II Office Tower, 25th Floor, Jl. Asia Afrika No. 8, Jakarta 10270, Indonesia

ARTICLE INFO

Keywords:
Salak
Injection breakthrough
Non-Condensable gases
Marginal recharge
Effective fractures
Wellbore scale

ABSTRACT

The Salak Geothermal Field is the largest producing geothermal field in Indonesia with an installed power generation capacity of 377 MWe. After more than 23 years of commercial operations and through vigilant resource management, the Salak Field is still performing well. Since 1994, when commercial production started, the net capacity factor has averaged about 91% annually. After the last turbine uprating in 2005, the net capacity factor has improved to an annual average of 95%. By 2019, a substantial injection realignment will be implemented which will move all condensate injection outside the field production boundary and shift most brine injection outside and to the southeast margin. This project will mitigate brine injection impact to the AWI 7 and 8 wells and hasten development of the steam cap in the western portion of the field. With this injection realignment, reservoir simulation forecasts show the Salak geothermal resource will likely be able to continue steam production at its current level in the foreseeable future.

Similar to other long-producing geothermal fields, Salak has encountered resource management challenges, such as, injection breakthrough, influx of marginal recharge, wellbore scaling, and production of significant amounts of non-condensable gas ("NCG"), in response to commercial production. To address these challenges, an extensive reservoir monitoring program and integration of new make-up drilling results enabled updates and fine-tuning of the conceptual model of the field. Key updates include increased understanding of the distribution of the producing effective fractures and their permeability in the reservoir, identification of injection capacity outside the commercial field boundary in the Cianten Caldera, and improved understanding of NCG interference in the steam cap and injection and natural recharge impacts on the field. These insights and the updated conceptual understanding of the Salak geothermal system coupled with reservoir simulation have provided a credible forecast of the Salak reservoir's future performance for decision-makers to have the necessary confidence to fund the injection realignment project. Additionally, the refined conceptual model provides the reservoir management team with a means to plan and target development make-up wells and effectively focus future data gathering and reservoir monitoring activities.

1. Introduction

The Salak Geothermal Field (also known as Awibengkok), located about 70 km south of Jakarta in West Java (Fig. 1), is the largest operating geothermal field in Indonesia with an installed capacity of 377 MWe. Commercial production commenced at Salak in March 1994 with the commissioning of the 55 MWe Unit 1. Another 55 MWe power plant, Unit 2, followed in June 1994, while Units 3, 4, 5 & 6 (4 × 55 MWe) came online in 1997. In 2002, Units 4, 5 & 6 were uprated to 65.6 MWe each by increasing the turbine inlet pressure and cooling water rate to the main condenser and other heat exchangers to improve plant efficiency. Units 1, 2 & 3 were similarly uprated in 2004 and are now capable of generating 60 MWe each. These turbine upratings increased Salak Field's installed capacity to the current 377 MWe. Under the JOC with PERTAMINA (now PT Pertamina Geothermal Energy (or "PGE"), Star Energy Geothermal Salak Ltd. ("SEGS") supplies steam to Units 1, 2 & 3 (owned and operated by the Government of Indonesia's Perusahaan Listrik Negara or "PLN" and operated by its subsidiary PT Indonesia Power). SEGS supplies the steam to, operates, and produces electricity from Units 4, 5 & 6.

An early solution for brine disposal was to inject the produced brine infield to economically develop Units 1 and 2. However, maintaining a proper balance between pressure support and thermal breakthrough (from injection and natural recharge) was recognized to be critical to the successful long-term management of the Salak Feld (Acuña et al., 2008). This led to a plan to relocate brine injection to deeper or more distal locations along the field margins and, if possible, outside of the field production boundary. Realignment of the injection areas focused

* Corresponding author.
E-mail address: glenn.golla@starenergy.co.id (G.U. Golla).

https://doi.org/10.1016/j.geothermics.2019.101715
Received 31 December 2018; Received in revised form 6 August 2019; Accepted 7 August 2019

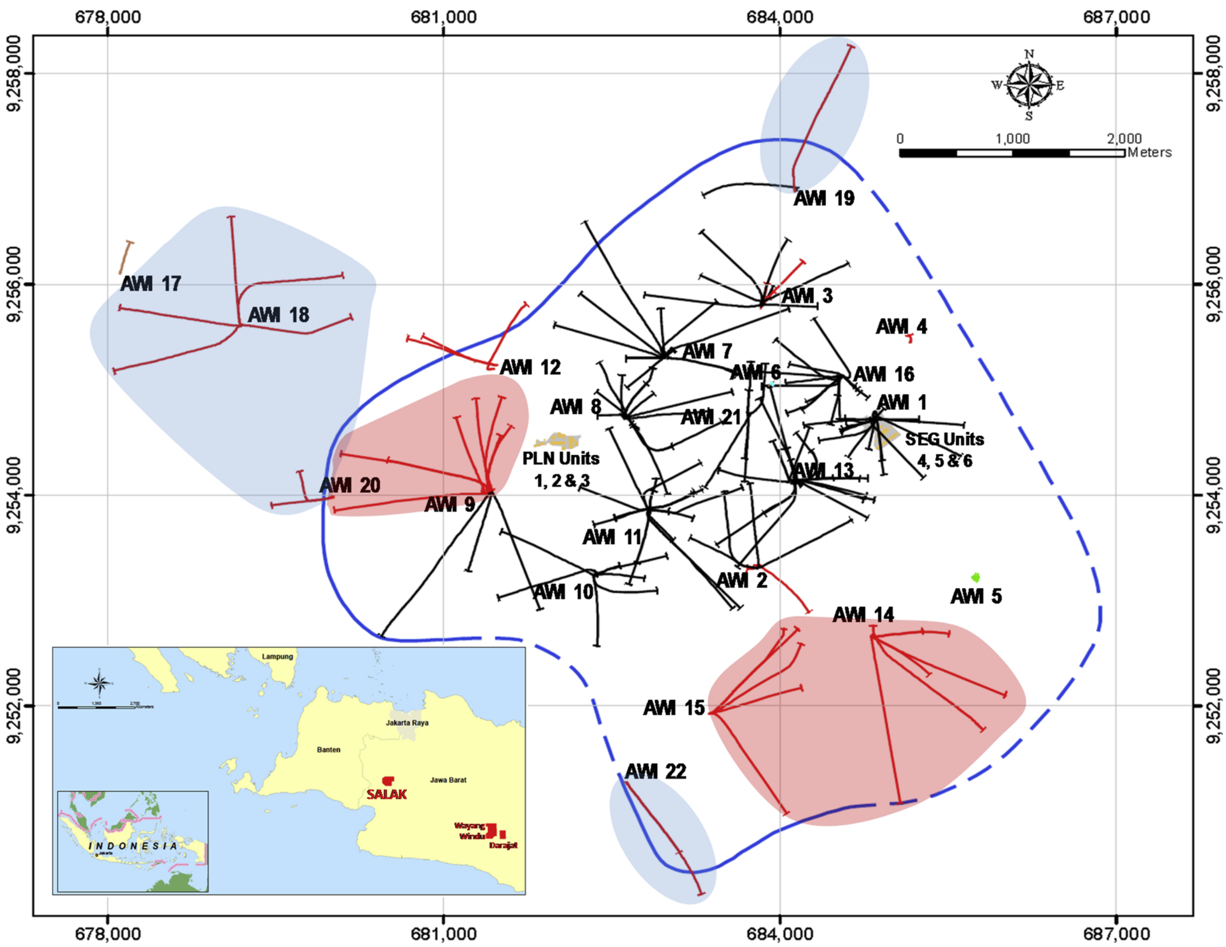

Fig. 1. Map of the Salak Geothermal Field with its drilled wells (black for producers and red for injectors), production boundary (blue solid line; dashed where poorly constrained by drilling), and current injection areas (blue for condensate and red for brine). In the inset map are the three geothermal fields that Star Energy Geothermal ("SEG") operates, namely, Salak (377 MWe), Wayang Windu (227 MWe), and Darajat (271 MWe) in West Java, Indonesia.

on mitigation of injection impacts and expansion of the area available for production leading to the expansion of the steam cap and mitigation of production decline rates (Ganefianto et al., 2010). Data gathering and reservoir monitoring efforts, including step-out drilling in the Cianten Caldera in the west (Stimac et al., 2008), were designed and focused to provide the data and insights necessary to support and assess the implications of this strategy.

Key resource implications considered after the removal of infield brine injection included increased natural recharge of potentially cooler fluids as the pressure support from injection was removed, increased NCG related to steam cap expansion, and potential increased scaling due to boiling and/or shallow meteoric fluids. The data gathering and interpretation, reservoir monitoring, and forecasting practices implemented to measure, assess, and mitigate these potential resource impacts leveraged lessons learned from nearly 97 years[1] combined experience of SEG developing and commercially producing Salak, Darajat, and Wayang Windu geothermal fields.

2. Production and generation history

The drilling of 11 wells[2] during 1983–1986 marked the exploration and appraisal drilling stage of the development of the Salak Field (Fig. 2). During 1989–1993, eight (8) development wells for Units 1 & 2 were drilled while 39 wells for Units 3, 4, 5 & 6 were drilled during 1994-1997. The first make-up well drilling campaign was in 2003–2005 and consisted of nine producers and an injector. Another make-up well campaign in 2006–2009, where 25 producers and seven injectors were drilled, included step-out drilling in the northwest, north, and southeast portions of the field to expand the production area and identify outfield injection areas (Ganefianto et al., 2010). The most recent make-up well drilling campaign took place during 2012–2013 when nine producers and two injectors were drilled (Fig. 2). Table 1 shows the current well count at Salak Field.

At the end of 2017, the Salak Field had produced 483,165 MM kg of steam (plus 1,257,164 MM kg of brine), which was used to generate 59,307 GW h (net) of electricity (Fig. 3). A comparison of the actual vs. theoretical net generation indicates that the Salak Field has averaged about 91% net capacity factor annually since commercial production began (Fig. 3). Following the last turbine uprating in 2005, the annual net capacity factor improved to about 95%.

Timely production make-up well drilling, remedial well works, and surface facility optimization projects have been able to maintain steam production at Salak Field at or above the rated power plant capacity. Past remedial well works conducted at Salak Field have included conventional bullhead-conveyed acid stimulation, slow and coiled tubing-conveyed acidizing, and long-term hydraulic fracturing with geomechanical analyses to optimize the injection pressure and length of injection during the hydraulic stimulation of a well (Pasikki and Gilmore, 2006; Pasikki and Pasaribu, 2014; Pasikki et al., 2010;

[1] Cumulative time since the execution of the JOCs for Darajat, Salak, and Wayang Windu Geothermal Fields.

[2] Including the three (3) exploration wells drilled in the Ratu Prospect located northeast of the Salak Geothermal Field.

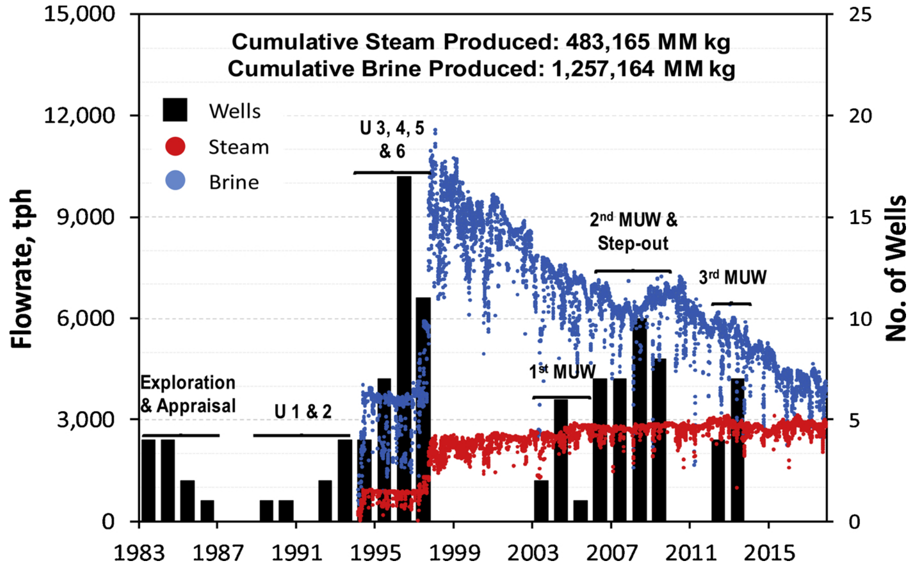

Fig. 2. Drilling activity and historical steam and brine production at Salak Field. Commercial production started in 1994 with Units 1 and 2 while Units 3, 4, 5 and 6 came online in 1997.

Table 1
Current Well Status at Salak Field.

Well Type	Number of Wells
Producers	77
Brine Injectors	12
Condensate Injectors	10
Observation	5
Plugged & Abandoned (P&A)	6
Total	**110**

Yoshioka et al., 2009; this issue); the obtained results have been mixed. Recently, hydraulic fracturing of specific depth intervals or zonal stimulation (Golla et al., 2013; Yoshioka et al., 2015), scale clean-out using the coiled tubing-conveyed rotary jetting (Putra et al., 2018) and wireline-conveyed broaching tools (Hidayaturrobi et al., 2017) have been successfully applied in some wells.

Some of the surface facility projects that improved steam supply included debottlenecking of AWI 7 and AWI 8 to facilitate uprating of Units 1–3 and debottlenecking of AWI 16 to provide more steam to Units 4–6. Also, the capacity of the gas removal system at Units 4–6 was increased to handle steam with higher NCG content. Lastly, the conversion of some injection wells (e.g., AWI 2-2, 3-2, 3-3, and 9-1) to production wells (Pasikki et al., 2011) required some surface facilities adjustments.

3. Conceptual model of the salak geothermal system

The Salak geothermal system is a high-temperature water-dominated reservoir with benign chemistry and low-to-moderate NCG content (Acuña et al., 1997). Mapped surface and subsurface structures and lineaments exhibit a northeast trend and control fluid flow direction (Stimac et al., 2010). Maximum reservoir temperature was measured in excess of 325 °C with the main system's upflow located in the western portion of the production area (Fig. 4). The conceptual model of the field shows that geothermal fluids generally flow towards the northeast and east-southeast and outflow in the surface thermal manifestations, which are mostly located near the eastern and northern margins of the drilled reservoir.

Reservoir temperature, fluid chemistry, tracer tests, and pressure

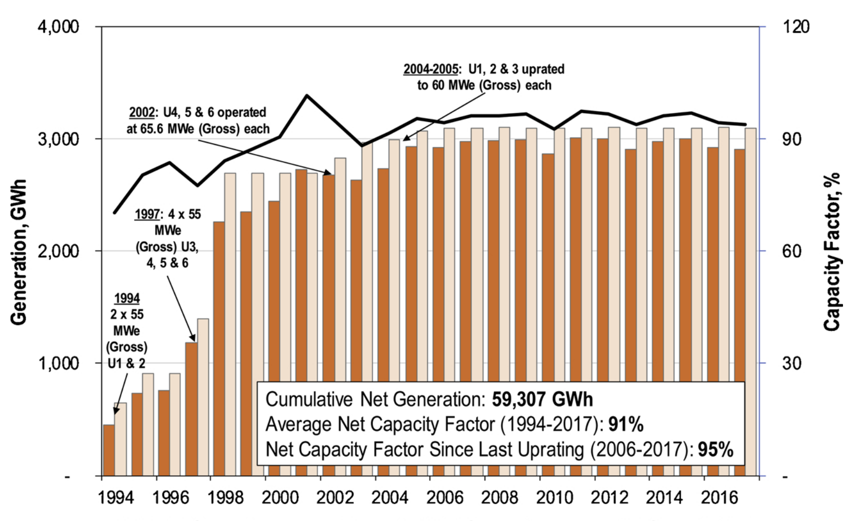

Fig. 3. Annual actual and theoretical net generation and net capacity factor of the Salak Geothermal Field. The significantly high net capacity factor (> 100%) in 2001 is related to a period when the power plants operated past their 55-MW rating for capability testing purposes.

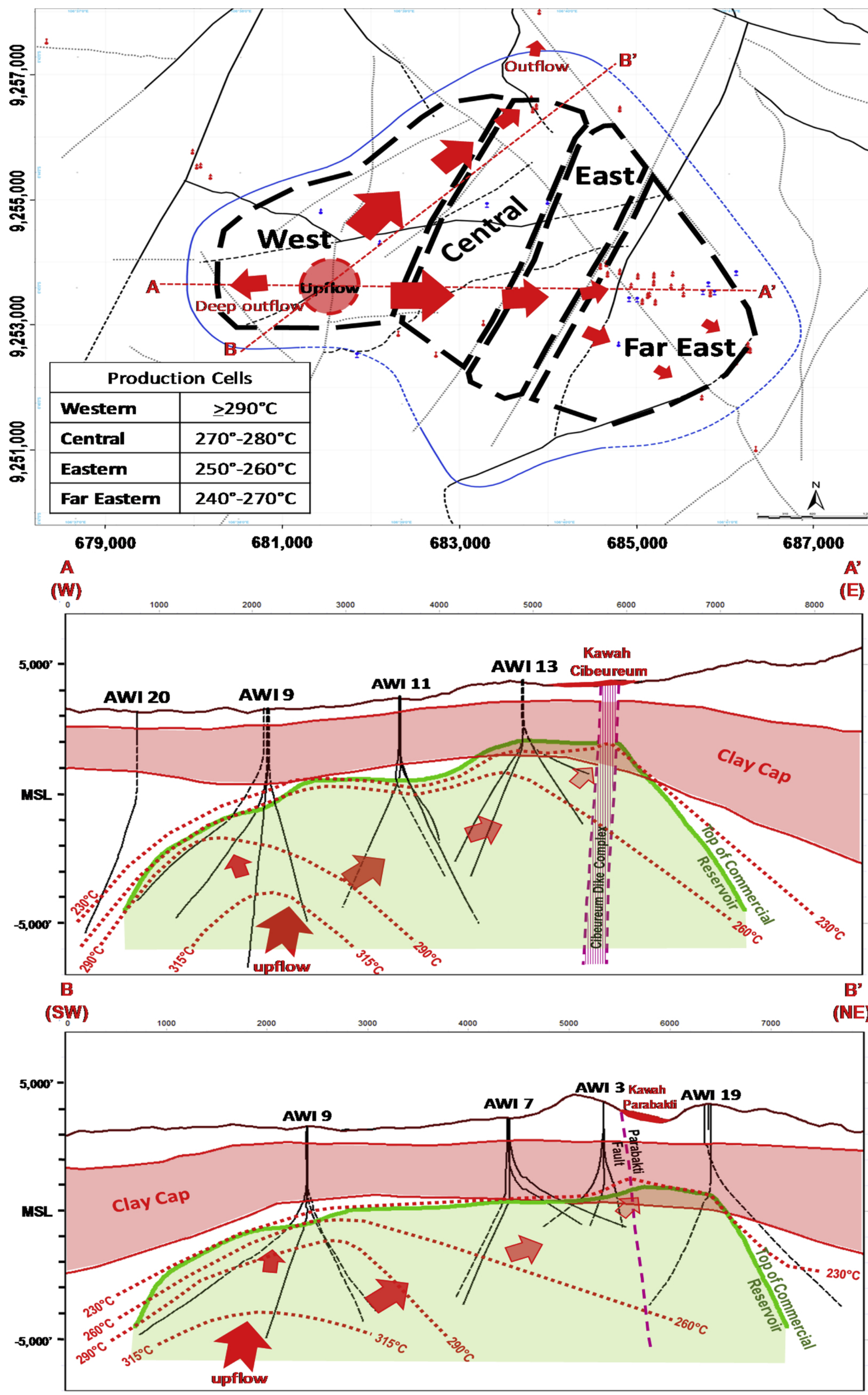

Fig. 4. Map and cross-sections showing the general flow (arrows) of geothermal fluids at the Salak geothermal system before commercial operations. The sharp drop in temperature between AWI 9 and 20 indicates the commercial production boundary in the west. The northernmost well (cross-section B-B') encountered temperatures > 230 °C but its initial pressure suggests that it is outside the commercial reservoir.

trends suggest that the Salak Field can be subdivided into four production cells, namely, the West, Central, East, and Far East (Rohrs et al., 2005) (Fig. 4). The West production cell comprises West Salak in this paper while East Salak, where a steam cap quickly developed after commercial production, encompasses the East and Far East production cells. The Central production cell, where most wells are producing two-phase fluids, is the transition between West and East Salak. Building on unpublished studies (Acuña et al., 1997; Rohrs et al., 2005), Stimac et al. (2008) published an excellent description of the conceptual model of the Salak geothermal system. The following sub-sections highlight key subsurface findings since 2008.

3.1. AWI 9-9 deep lithology and permeability

AWI 9-9, the last well of the 2012–2013 Drilling Campaign, is currently the deepest well drilled at Salak Field at 3171 m MD[3] (Fig. 5). In general, the rocks intersected by AWI 9-9 are similar to those encountered in offset wells. However, at depth, borehole image logs indicate that AWI 9-9 intersected predominantly pyroclastics (volcanics) with interbedded lavas and sedimentary rocks below 3048 m MD (Abdurachman et al., 2015). These lava flows and pyroclastics are deeper than the previously interpreted continuous sedimentary rocks (Stimac et al., 2008). Prior to drilling AWI 9-9, sedimentary rocks (called Continuous Sediments) were believed to underlie the Mixed Volcanics-Sediments ("MVS") to form the basement of the Salak reservoir. However, this deep sequence of pyroclastics and sedimentary rocks at AWI 9-9 suggests that the MVS continues deeper in the Salak reservoir (Abdurachman et al., 2015).

Pressure-Temperature-Spinner ("PTS") and heat-up data indicate that AWI 9-9 encountered three permeable zones at 1884 m MD, 1991–2,143 m MD, and 3058 m MD (Libert, 2017) (Fig. 6). The deepest feed zone is characterized by high temperature (~325 °C), high pressure (~175 barg), and high discharge enthalpy (~1465 kJ/kg), is now the deepest fluid entry identified to-date at Salak, and confirmed the presence of deep permeability that is likely related to the geothermal system's upflow in this part of the field (Abdurachman et al., 2015). Wellbore simulation indicates that AWI 9-9 can produce about 295 tph (or tons per hour) of steam. AWI 9-7 and AWI 9-8, drilled on the same pad as AWI 9-9 and toward the south and southwest (Fig. 5), respectively, also encountered temperatures in excess of ~315 °C; thus, supporting the interpreted location of the main upflow of the system in this area.

3.2. Characterization of the reservoir's fracture system

This section describes the recent re-evaluation of the fracture system at Salak Field. The first step in this re-evaluation was the assessment of the distribution of feed zones identified in PTS surveys. The next step was to examine the orientation of open fractures identified in borehole image logs. Open fractures appear as sinusoids in the borehole image logs and contain electrically conductive material (assumed to be aqueous fluid). These open fractures were then correlated with the feed zones identified from PTS data. Other than in past analyses, where stereo nets were used to show the orientation of all open fractures encountered by the borehole image tool, the recent analysis focused on the so-called "effective fractures," i.e., those that are actually producing geothermal fluids.

3.2.1. Distribution of feed zones

Based on the results of the 110 wells drilled so far, fluid entries are distributed throughout the whole volume of the Salak geothermal reservoir. Fig. 7 shows the distribution of these feed zones across the Salak Field in relation to mapped surface structures and lineaments. Analysis indicates that the feed zones are not concentrated along or controlled by any of the mapped surface structures (Gunderson, 2016), similar with the finding at Darajat Field (Intani et al., 2017). Although the surface structures and lineaments do not appear to control the distribution of feed zones at Salak Field, their general strike is similar to the dominant orientation of the effective fractures and assumed responsible for the production of geothermal fluids (as described in Section 3.2.2).

The West-East cross-section shows that the feed zones with the highest productivity index or PI' values are clearly concentrated at shallower depths, near the top of the reservoir ("ToR") (Fig. 7). Note that the eastern portion of Salak Field consists of a steam cap where the ToR is shallower compared to the western sector of the field (Fig. 4). The South-North cross-section shows that there are more of the larger PI' feed zones in the northern portion of the field compared to the southern sector, but this may be an artifact of the denser drilling in the north.

Fieldwide, the PI vs. Elevation plot for Salak shows a wide range of PI values at all elevations (Fig. 8). While it appears from this plot that PI decreases with depth on average, the predominant characteristic is the wide range of PI values (i.e., about two orders of magnitude) at any given depth in the reservoir. The S-curves for distinct elevation ranges show that these fracture populations slightly shift to higher PI values at shallower elevations. The shallowest feed zones, normally those in the East Salak steam cap, have the highest permeability, about half an order of magnitude greater than the rest of the feed zones.

3.2.2. Orientation of effective fractures

There are 18 wells at Salak with borehole image logs, 12 of which are inside the commercial production area, with about 9612 m (cumulative) of reservoir logged with the borehole image tool (Fig. 9). Analysis of these image logs revealed about 4900 open fractures.

The stereo net of all open fractures interpreted from the borehole image logs indicates two main populations of these open fractures at Salak can be identified: one with a preferred west-northwest (continuing through vertical to east-southeast) dip direction, and one that is more random and distributed in all directions (left stereo net in Fig. 10). The strike orientation of these open fractures is NE-SW, perpendicular to the dip direction, and parallel to the horizontal maximum stress (S_{Hmax}) direction of N22 °E (Sugiaman, 2003). Both populations are steeply dipping with the majority of dips > 60°. There is also a subset of open fractures that are sub-horizontal and dip < 30° from horizontal as shown by the concentration of data points at the center of the stereo net (Fig. 10). Previous studies of open and partially open fractures from Salak borehole image logs have identified the same NE-SW strike orientation (Stimac et al., 2008, 2010).

The stereo net on the right in Fig. 10 shows the orientation of the effective fractures, i.e., fractures or geologic features identified in borehole image logs that correlate with the feed zones interpreted from PTS data, and considered contributing to the production of geothermal fluids (Golla et al., 2017). From the 4900 open fractures identified in image logs, about 100 effective fractures (~2%) correlated with about 33 identified feed zones. The effective fractures appear to have a similar distribution as the open fractures (perhaps with greater variability in dips): there is a population dipping northwest and southeast (or with strike orientation of NE-SW) with generally steep (> 60°) dip, and another population with random dip direction and magnitude (Gunderson, 2016).

The alignment of the effective fractures with the S_{Hmax} and mapped surface structures and lineaments at Salak suggests a strong structural grain to the interconnected network of producing fractures. Local stress changes, mineral precipitation, and effects of production may change the location of the permeable pathways but the overall direction of fluid flow is predominantly NE-SW. The NE-SW trending and steeply dipping effective fractures and the analyses of the distribution of feed zones suggest that future make-up wells at Salak should have northwest and

[3] MD refers to Measured Depth.

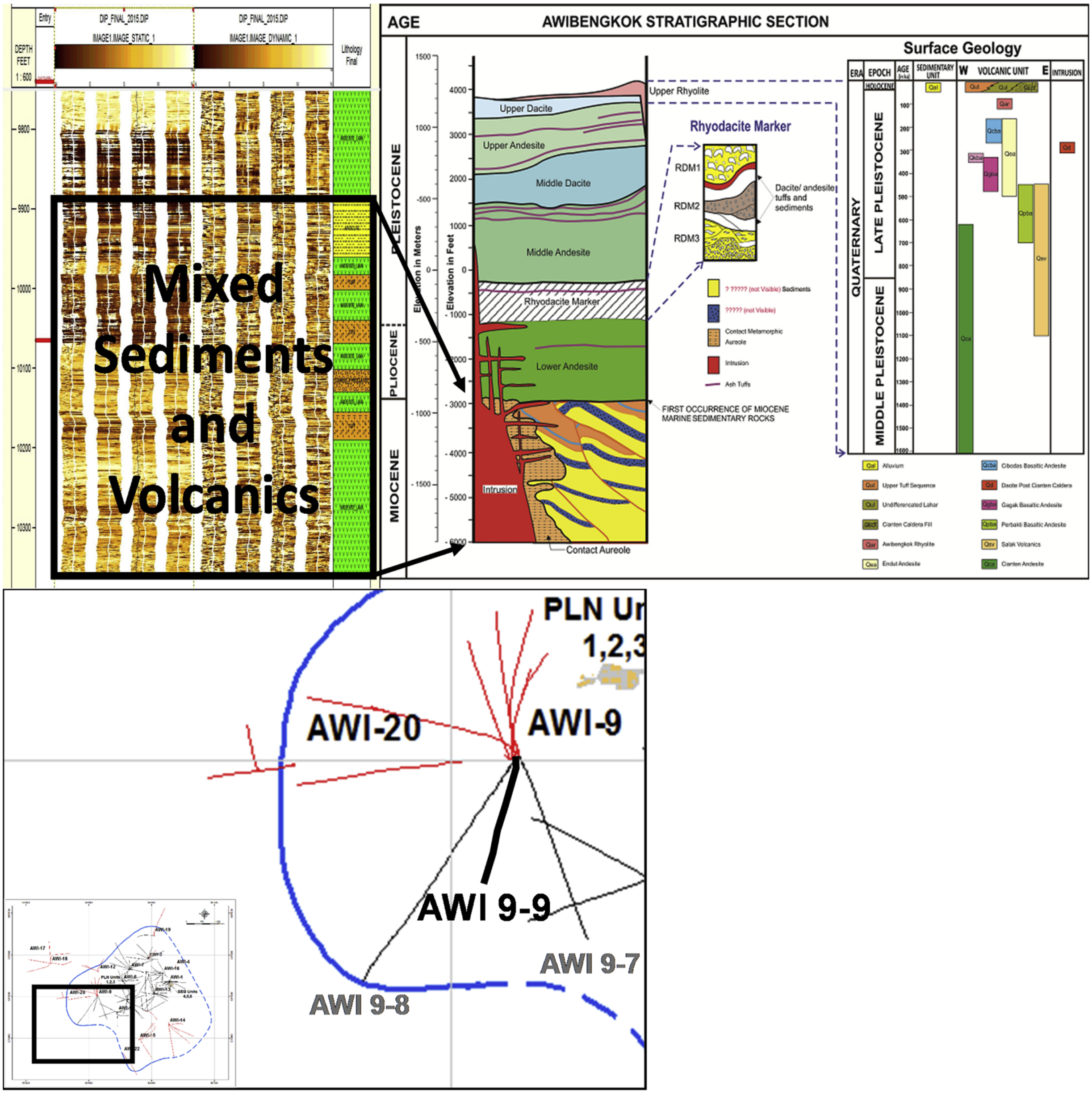

Fig. 5. Snapshot of the borehole image data from AWI 9-9 showing the mixed sediments and volcanics encountered at depth (top left). Stratigraphic column of the Salak Field showing the correlation between surface and subsurface rocks (top right; modified from Stimac et al., 2008).

east-southeast trajectories to increase their chances of encountering feed zones. Additionally, high permeability feed zones are normally found at shallow depths and dominantly in the eastern and northern portions of the field.

4. Resource performance during 1994-2017

At the commencement of commercial production in 1994, the majority of the production wells were drilled in West Salak (Figs. 4 and 11). Drilling and significant mass extraction began at East Salak only in 1997, when Units 3, 4, 5 & 6 started commercial operations.

At West Salak, steam production has been fairly stable averaging about 730 tph until 1996 and increased to about 1000 tph in 1997 when the rest of the power plant units came online (Fig. 11). Brine production was relatively stable at about 3600 tph at the start of commercial operations of Units 1 & 2 in 1994 and increased to about 5500 tph in 1997 when Units 3, 4, 5 & 6 started power generation. Brine production increased slightly in 2008–2010 due to drilling of step-out and make-up wells in West Salak, reaching a peak of about 2865 tph, and then began to decline due to the general expansion of the steam cap in the east.

East Salak exhibits a different behavior in that brine production immediately dropped while steam production exhibited a gradual increasing trend. From a high of about 6000 tph of produced brine at East Salak, brine production declined rapidly (Fig. 11). Currently, East Salak produces a minimal amount of brine, as almost all wells in this area are now single-phase steam producers. This sudden drop in brine production is due to the development and expansion of the steam cap, believed to be already present in East Salak prior to commercial production (Murray et al., 1995). The expanding steam cap in East Salak increased deliverability of several wells in that area and, for a time, most make-up wells were drilled preferentially in East Salak where they could achieve higher initial production rates and produce almost no brine.

Now, both West and East Salak exhibit relatively stable steam production (Fig. 11). As of the end of 2017, the Salak Field was producing about 2880 tph of steam and 3670 tph of brine (Fig. 2), with 60% of

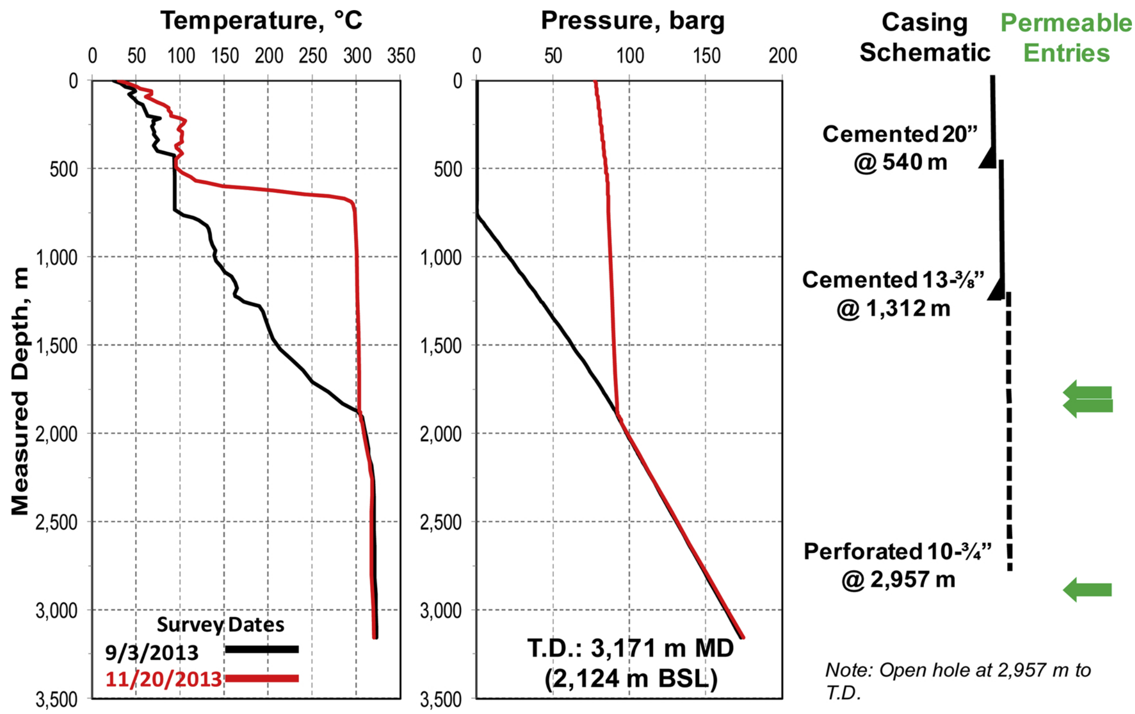

Fig. 6. Temperature and pressure profiles of AWI 9-9 a few days (black) and about 2.5 months after well completion (red). On the right is a schematic diagram showing the casing setting depths and the three identified feed zones. The well has an open-hole section from 2957 m MD to T.D.

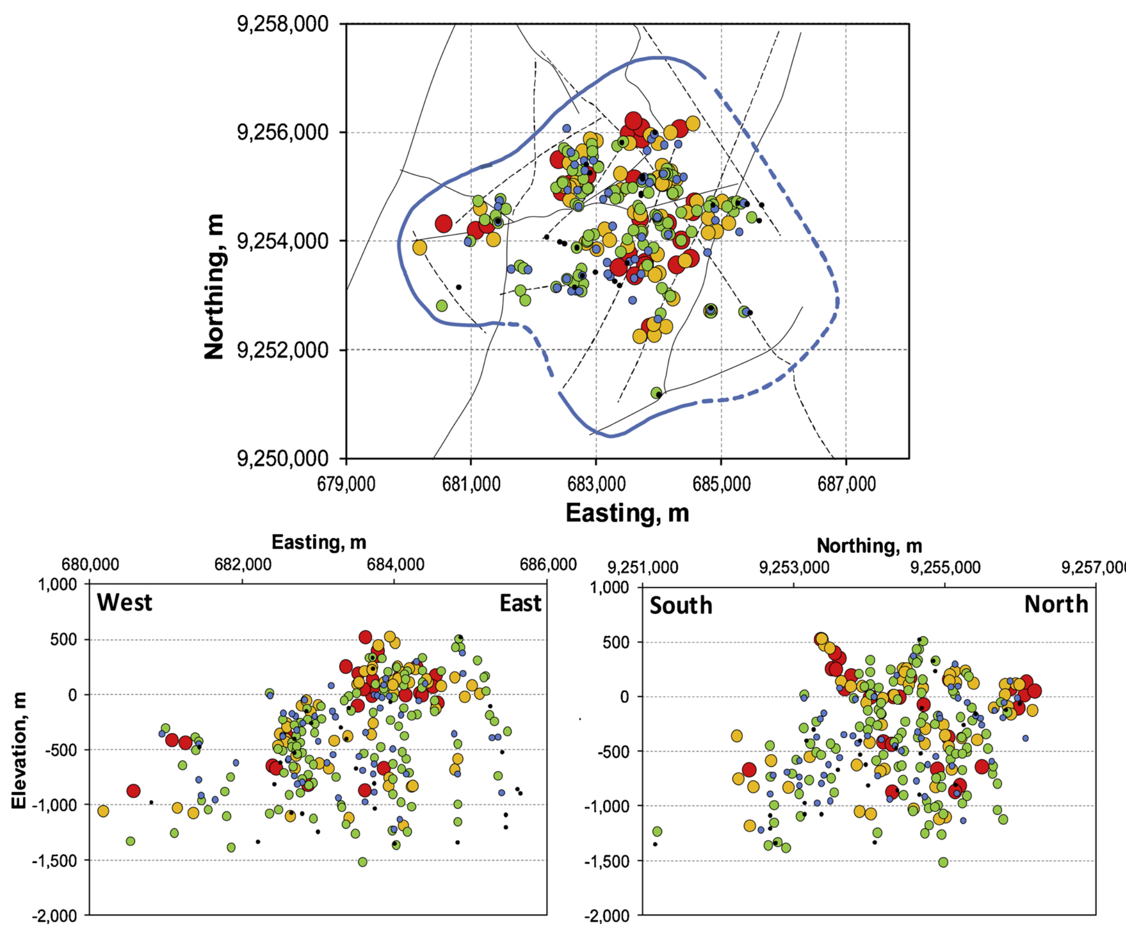

Fig. 7. Distribution of all feed zones, represented by circles, encountered by wells drilled at Salak Field. The color and size of the circles denote the magnitude of permeability (represented as Productivity Index, PI'[5]) of each entry, i.e., red: top 10% PI, orange: next 20% PI, green: middle 40% PI, blue: next 20% PI and black: lowest 10% PI. The black lines represent mapped surface structures and lineaments (dashed when inferred) while the blue line is the commercial production area (dashed where poorly constrained by drilling). Cross-sections (below) show the vertical distribution of feed zones.

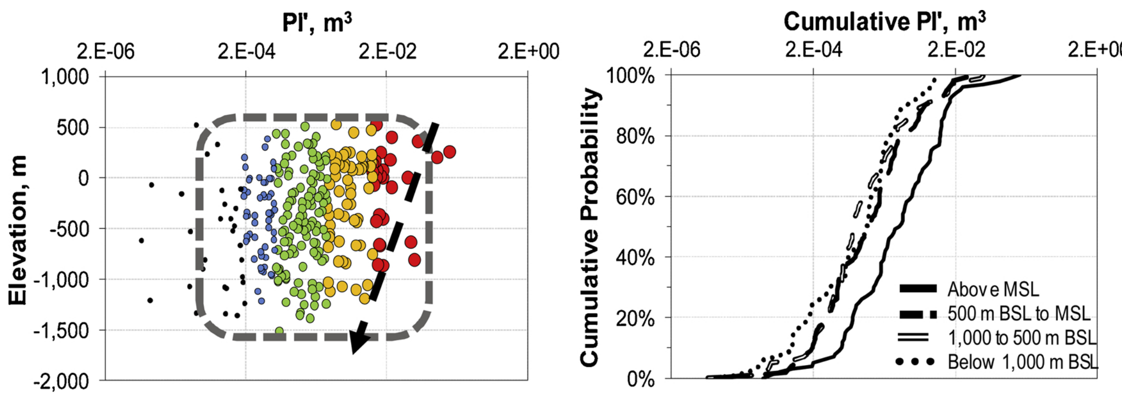

Fig. 8. Variation of individual PI' with elevation (left) and s-curves of PI' distribution (right) of all feed zones at Salak. The color and size of the circles denote the magnitude of permeability of each entry similar to those at Fig. 7.

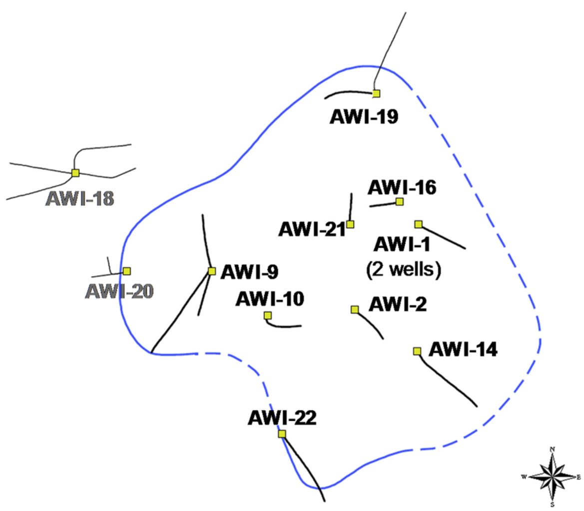

Fig. 9. Map showing wells with borehole image logs at Salak Field. Only wells drilled inside the commercial production area (solid and dashed polygon) were included in this analysis.

steam production coming from East Salak. Almost all of the brine production comes from West Salak with < 1% of brine produced in the eastern portion of the field. Current reservoir flash is about 45%, up from 20% at the commencement of commercial production in 1994 (Fig. 11).

The three main reservoir processes occurring at Salak are: (1) boiling, (2) mixing of reservoir fluids with either condensate or brine injectate, and (3) mixing of reservoir fluids with relatively cool, natural marginal recharge ("MR") (Syaffitri and Molling, 2013). Significant mass extraction has resulted in a general pressure drawdown and lowering of liquid level, consequently, inducing reservoir boiling and steam cap expansion. East Salak manifests this subsurface process clearly: the rapid decline in brine production correlates with significant reservoir boiling and an increasing trend in production enthalpy as the steam cap developed (Fig. 11).

Injection of both condensate and brine into the reservoir provides pressure support to sustain production. However, the injected condensate and brine can negatively affect the production wells if this fluid does not heat-up sufficiently prior to reaching the producers. Reservoir monitoring at Salak has documented cases where the injected fluid has negatively affected nearby production wells, e.g., infield brine injection at AWI 9 and edgefield condensate injection at AWI 12 cooling feed zones in several AWI 7 wells (Figs. 1 and 12). Tracer tests confirm the connectivity between the AWI 9 and 12 injectors with surrounding production wells (Gunderson, 2004). The main reservoir process in the AWI 7 area during 2004–2007 was cooling due to condensate injection in AWI 12 as shown by the decline in produced chloride and both steam and brine production (Fig. 12). During 2008–2012, chloride concentration was relatively stable and believed to be due to the interplay of both condensate and injection breakthrough. When condensate injection at AWI 12 was terminated in early 2013, there was an immediate increase in chloride concentration of AWI 7 wells because the main reservoir process at that time was mixing of brine and reservoir fluids due to brine injection breakthrough (Fig. 12).

Aside from injection, naturally occurring MR is another process providing positive pressure support in a geothermal reservoir. It is currently assumed that continued mass extraction may lead to more influx of relatively cooler MR as reservoir pressure decreases due to continued production. In AWI 16, the influx of MR resulted in the dilution of chloride in the produced fluids and cooling of the brine-producing entries in certain wells, thus lowering steam production (Fig. 13). The long-term impact of MR in sustaining production at Salak, as described in the following section is the subject of ongoing studies.

5. Resource management challenges and initiatives

Evaluations of the Salak resource and its expected performance indicate that production is sustainable at current levels for the foreseeable future. This long-term production is dependent on resolving or mitigating reservoir cooling due to condensate and brine injection breakthrough, influx of relatively colder MR fluids, production of high-NCG steam, continuing to mitigate scaling, and optimizing surface facilities.

With the aim of optimizing long-term reservoir performance, the 2006–2009 drilling campaign was started in correspondence with the Salak Injection Realignment Project (SIRP) with the following objectives:

- Expand the commercial production area through the recovery of the injection area around AWI 9,
- Move all condensate injection outfield to AWI 18 and AWI 20, and
- Transfer a significant amount of the brine currently injected at AWI 9 outfield in AWI 18 and to the southeastern edge of the field.

The expected impact of the strategy to remove brine at AWI 9 is to increase the net voidage, cause an expansion of the steam cap, and expose more feed zones to dry steam conditions. The success of this strategy relies on the optimization of the competing effects (i.e., steam cap expansion and deep pressure support). With this perspective, an important component of the planned strategy is represented by the flexibility to inject brine either outfield or in the southeastern part of the field so that the optimum distribution can be obtained. Condensate injection into AWI 18 and 20 commenced in 2012 while the completion of the brine injection facilities outfield and in southeastern Salak is in 2019. It is anticipated that full implementation of the SIRP will

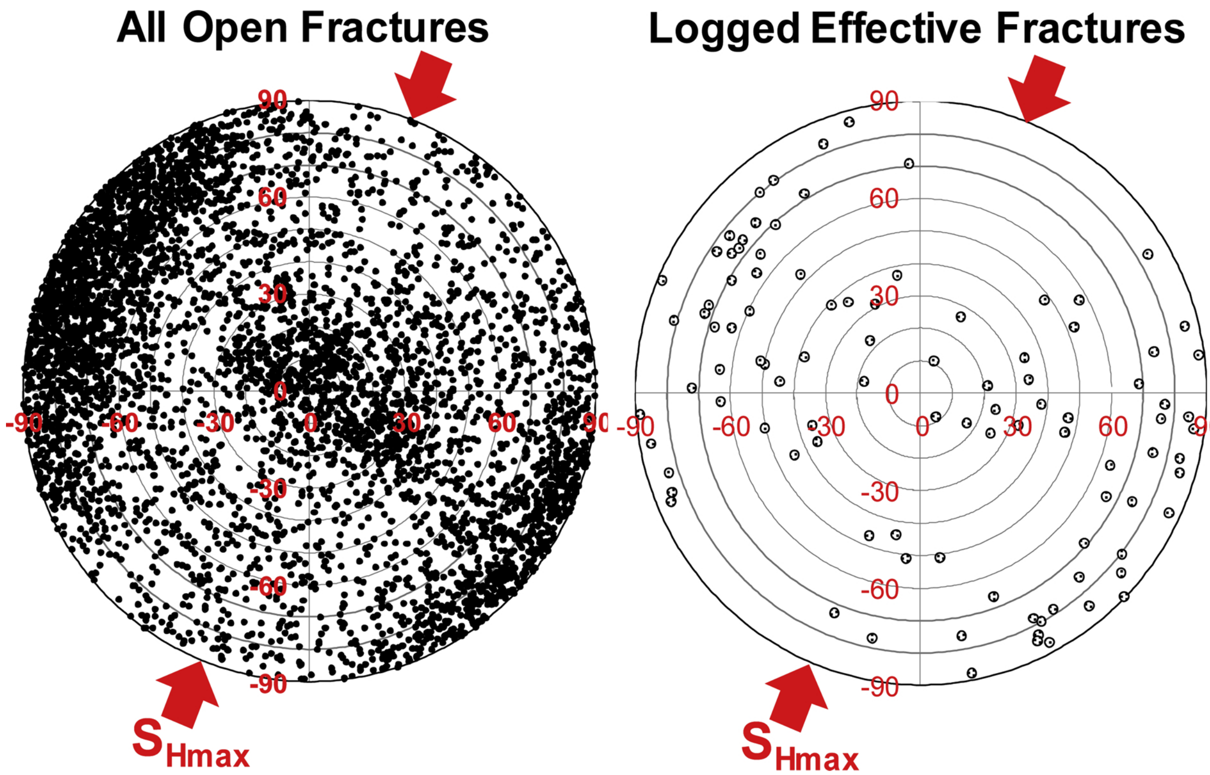

Fig. 10. Stereo nets showing the direction and magnitude of the dip of All Open Fractures (left) and Effective Fractures (right) identified in borehole image logs of wells inside the Salak production area. Sugiaman (2003) estimated the SHmax orientation at Salak at N22 °E.

significantly mitigate reservoir cooling due to infield brine injection, hasten the development of the steam cap in West Salak, and generally reduce the steam production decline rate (Acuña et al., 2008; Ganefianto et al., 2010; Golla et al., 2013; Pasikki et al., 2011).

5.1. Brine and condensate injection breakthrough

Thermal breakthrough from both brine and condensate injection is currently experienced at Salak Field. To date, about 10% of steam production, particularly from wells on the AWI 7 and 8 pads, has been lost due to this phenomenon. However, it is expected that some of this production can be regained with the successful implementation of the SIRP.

Brine Injection Breakthrough. At the start of commercial operations in 1994, the produced brine was injected infield into the hottest portion of the reservoir near the south-southwestern edge of the field at AWI 9 and AWI 10 (Fig. 1). At that time, it was viewed that the “limited” brine produced from generating 110 MWe would not significantly harm the high-temperature reservoir, especially if infield injection is adopted for a short period only. Note that infield injection was the only available option at that time to develop Units 1 & 2 economically.

The commissioning of Units 3–6 increased generation capacity at

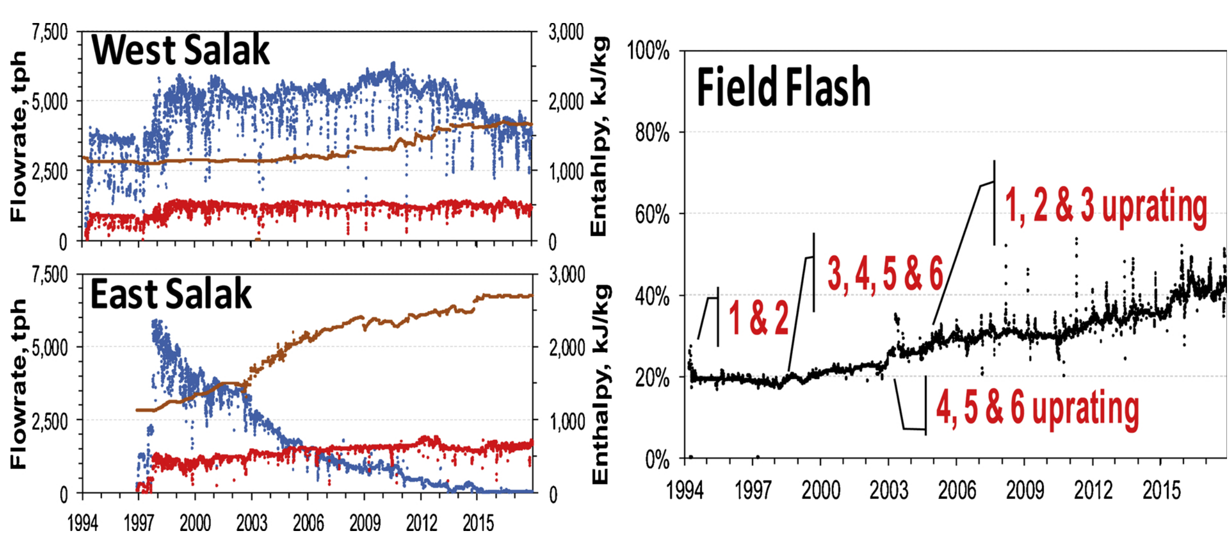

Fig. 11. (Left) Historical steam (red dots) and brine (blue dots) production and discharge enthalpy (orange dots) at West and East Salak. Note that commercial production started at West Salak where Units 1, 2 and 3 are located. (Right) Historical field wide steam fraction or flash showing its steady increase.

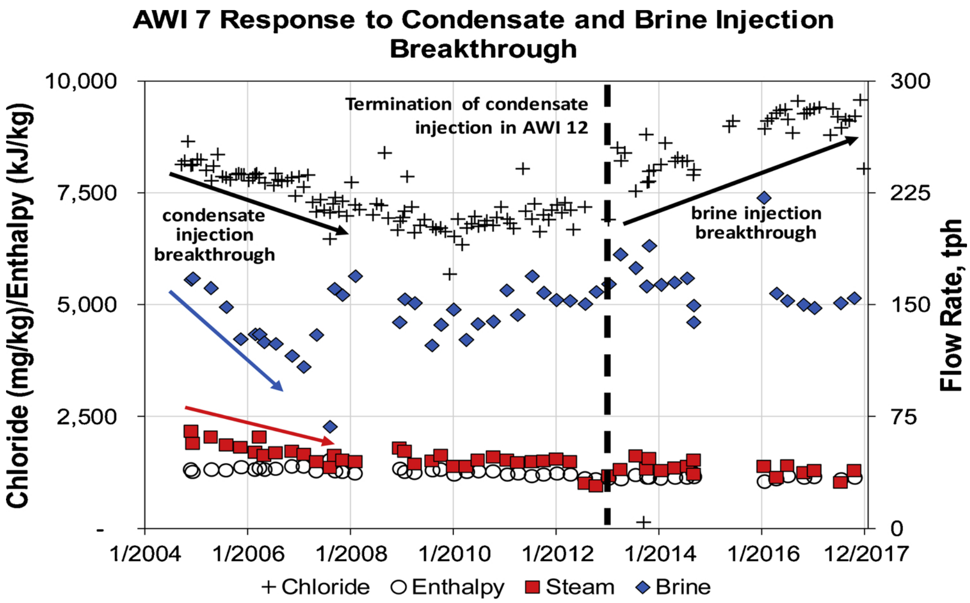

Fig. 12. Typical response of AWI 7 wells to condensate and brine injection breakthrough based on the chloride concentration and decline in steam and brine production. This data is from a single AWI 7 well, located in the Central production cell, impacted by both condensate and brine injection breakthrough.

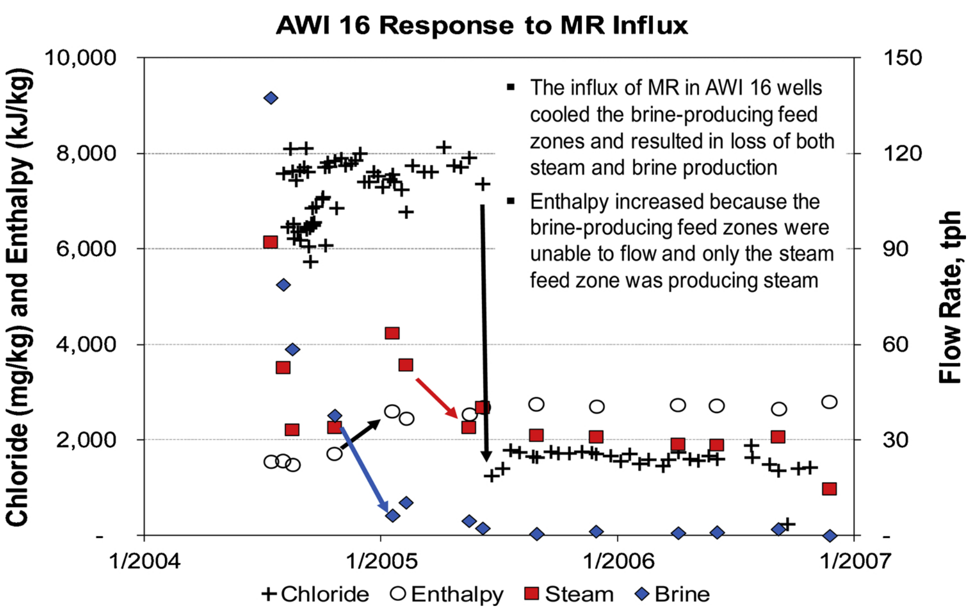

Fig. 13. Typical response of an AWI 16 well to the influx of MR. Note the significant decreases in chloride concentration and steam and brine production when cold fluid mixes with geothermal fluids. For this particular well (AWI 16-5), its enthalpy increased in late 2004 because only the steam feed zones were producing and the brine feed zones have cooled.

Salak to 330 MWe in 1997; thus, increasing significantly the volume of produced brine that was injected infield. The Unit 3–6 development plan included converting the AWI 10 pad to production while the AWI 12 pad was supposed to be a new brine injection location. However, AWI 12-3[4] did not have sufficient permeability to accept much injectate, thus, it was eventually used as an additional condensate injector for Units 1–3. AWI 10-1 and 10-2, initially used as brine injectors in 1994, commenced production about 1–2 years after stopping injection in 1996. Although stopping infield brine injection was recommended shortly after the start-up of Units 3–6, the Asian economic crisis hit in 1997 and capital spending (including drilling brine injectors outside the production area) was put on hold until the Energy Sales Contract ("ESC") was renegotiated and amended in 2002.

Monitoring indicated chemical breakthrough in AWI 11 wells within four (4) months after injection started at AWI 10; brine injection at AWI 10 ceased shortly after (Abdurachman et al., 2015). Infield injection at AWI 9 resulted in chemical breakthrough at AWI 7 and 8 wells within nine (9) months after injection started (Fig. 14). Thermal breakthrough eventually occurred in 1997, but at low enough rates that some of these production wells have continued to produce steam (Fig. 12). Currently, the produced brine is injected both infield (at AWI 9) in the west and edgefield (at AWI 14 and 15) in the southeast (Fig. 1).

Condensate Injection Breakthrough. Condensate from Units 1 & 2 was initially disposed at AWI 2-1 in the central part of the field (Fig. 1). With the addition of Unit 3 in 1997, AWI 12-3 was also used as a condensate injector. Units 4, 5 & 6 condensate was initially disposed in both AWI 2 and 4 for a short period and, later, into AWI 19, 20, and 22

[4] AWI 12-2 encountered problems while drilling at about 1,207' and was abandoned on September 23, 1995.

[5] Productivity Index (PI) is a measure of feed zone permeability with unit of mass flow/ΔP obtained from the analysis of PTS data. PI' is the modified PI that is "independent" of fluid mobility properties, such as, density, viscosity, and relative permeability (Pasikki et al., 2017).

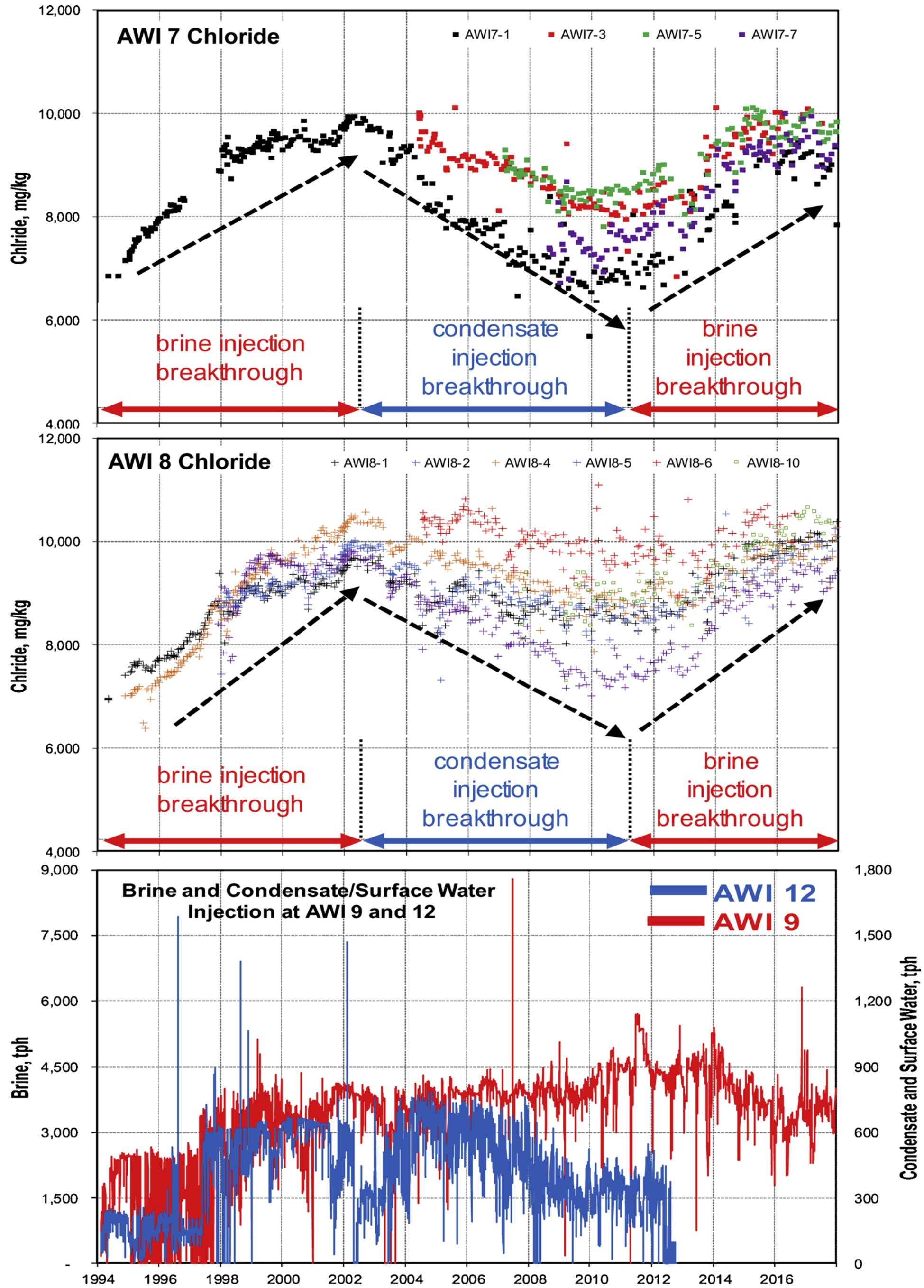

Fig. 14. (Top and middle) Historical chloride concentration showing the impact of brine and condensate and surface water injection as observed in AWI 7 and AWI 8 production wells (each color represents a specific production well). (Bottom) Total brine injected in AWI 9 and condensate and surface water injected in AWI 12. Condensate injection into the two AWI 12 wells ended in 2013.

(Fig. 1). Tracer tests in 2002 showed no connection of AWI 12 injectors to nearby production wells (Rohrs et al., 2005); however, some AWI 7 and AWI 8 wells exhibited chloride dilution and production decline when condensate injection started at AWI 12 in 2004 (Fig. 14). In 2013, condensate injection at AWI 12 ceased as part of the Condensate-Out Project. Recent data indicate that the chloride concentration in AWI 7 and 8 wells rebounded after condensate injection ended at AWI 12 (Fig. 14). Nonetheless, the exact impact of terminating condensate injection at AWI 12 is not clear because infield brine injection in AWI 9 affects the AWI 7 and AWI 8 producers also.

AWI 18 and AWI 20 in the northwest, AWI 19 in the north, and AWI 22 in the south are the current condensate injectors (Fig. 1). Reservoir surveillance indicate that all of these locations are either poorly connected or not connected to the Salak production area.

5.2. Influx of marginal recharge (“MR”)

Molling and Rohrs (1996) delineated chemically distinct natural MR in at least three different locations, namely, east-northeast, northwest, and south (Fig. 15). Aside from having dilute Cl and high Mg concentrations, the northwestern MR is rich in HCO_3 and SO_4 while the east-northeastern MR has high boron, HCO_3 and NH_4. The MR in the south and east is typical with high Mg and dilute Cl. So far, these colder natural recharge fluids have not significantly affected production but they appear to be causing some wellbore scaling, especially at East Salak. There is a strong correlation between the distribution of wells

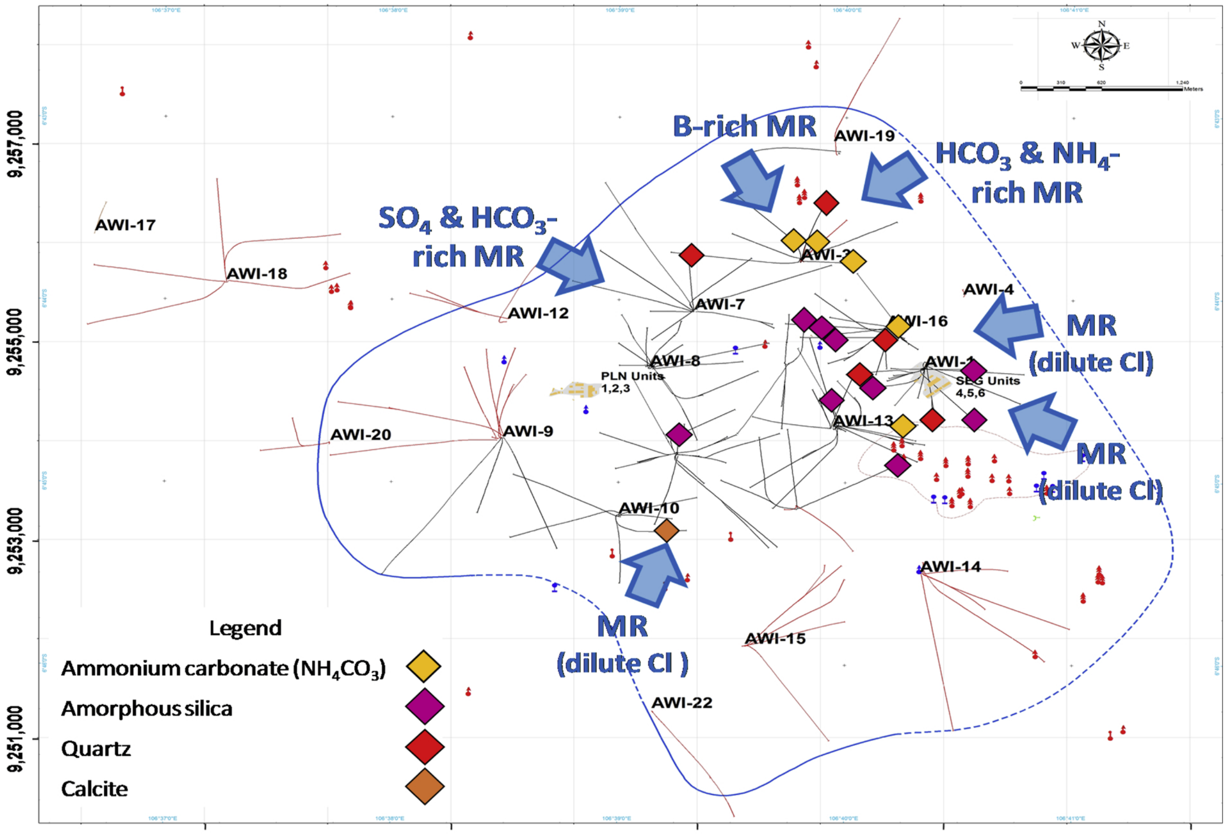

Fig. 15. Identified MR sources at Salak Field. The MR in the east and southwest is typical with dilute chloride while chemically distinct MR fluids are found in the north and northwest. Also shown are the wells that have experienced wellbore scaling. Long shut-in of wells, and not necessarily the presence of MR, produces ammonium carbonate scale near the wellhead.

with scale and the locations where MR has been identified (Fig. 15).

The most common types of scales found at Salak Field are amorphous silica and ammonium bicarbonate. Both scales are common in high enthalpy wells although silica is common in wells located in areas known to have MR while ammonium bicarbonate is typical in wells that have been shut-in for an extended period. When there is influx and boiling of MR in the steam cap, both silica (SiO_2) and calcium (Ca) are concentrated in the remaining reservoir brine, and eventually amorphous silica, quartz, and calcium carbonate can precipitate as scale. On the other hand, during long shut-in periods of wells, condensation occurs and ammonia (NH_3) gets concentrated in the steam condensate as the up-welling steam boils it. The boiling of steam condensate and ammonium-rich MR, especially in northeast Salak (Fig. 15), precipitates ammonium bicarbonate scale near the wellhead. Pumping hot condensate into the wellbore easily removes the ammonium bicarbonate scale.

As the reservoir pressure continues to decrease, more MR is likely to invade the reservoir. The unabated entry of colder natural recharge may eventually cool-off the deep brine feed zones possibly leading to some loss in production. At the same time, further development of the steam cap may create superheating and the boiling of MR that will potentially deposit scale. Ongoing studies will lead to a better understanding of these reservoir phenomena to enable development of mitigation plans and address their detrimental impact on Salak. Recent remedial works have been quite successful in regaining lost production by conducting scale clean-outs using wireline-conveyed mechanical broaching tools (Hidayaturrobi et al., 2017) and coiled-tubing conveyed rotary jetting tools (Putra et al., 2018). These well interventions are more cost-efficient compared with traditional acidizing and well workovers using a drilling rig.

5.3. Production of High-NCG steam

The steam cap in East Salak started to develop almost immediately after commercial production (Fig. 11), resulting in the accumulation of NCG at the top of the reservoir (Fig. 16). Gas concentrations in the steam cap tend to be greater than the gas produced from flashing of the reservoir brine. Rohrs (2007) reported that the NCG composition of produced steam is subject to processes that control the gas content of the reservoir brine and steam phases. Continued boiling of the brine accumulates NCG in the steam cap leading to significantly high concentrations at or near the top of reservoir (Julinawati et al., 2017). Additionally, condensation at or near the contact between the relatively cold clay cap and the steam cap results in elevated NCG at the ToR.

In East Salak, shallow feed zones in AWI 1, 13, and 16 wells typically contain the highest NCG content (Figs. 4 and 16). Rohrs (2007) suggested that a contributing factor may be cooling and condensation within the steam cap caused by shallow MR. Putri and Julinawati (2018) concluded in their study that the high-NCG regions at Salak are associated with areas where MR appears to be entering the reservoir. With the expected expansion of the steam cap towards West Salak after completion of the SIRP and continued production from the mature steam cap at East Salak, NCG concentrations in produced steam is anticipated to increase in the future.

To manage the production of high-NCG steam, some of the steps taken at Salak have included the following:

- Optimization of production from steam cap wells that are connected to nearby high NCG wells (interference) by adjusting wellhead pressures (shutting-in or throttling) to obtain the optimum steam with low NCG concentration,

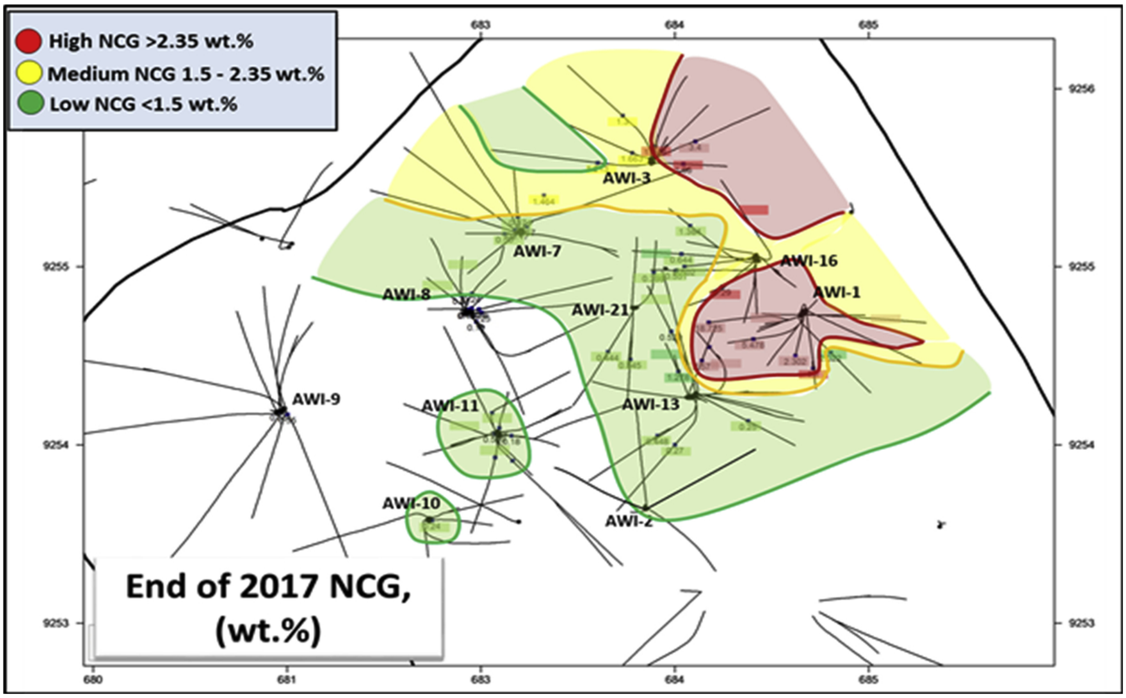

Fig. 16. Contours of produced NCG in steam at the end of 2017 (from Julinawati et al., 2017). High-NCG steam production occurs at East Salak where a steam cap has developed and the top of reservoir is shallowest. The black dots along well trajectories are the midpoint of production in each well; white portions in the map indicate the absence of steam cap. For two-phase producers, the wellbore hydraulic model estimates NCG production from each steam cap feed zone.

- Installation of additional inter-condensers to increase the capacity of the gas removal system at Units 4–6,
- Drilling of make-up wells designed to avoid high-NCG areas of the reservoir, and
- Flowing of high-NCG wells to the diffuser sump to reduce the NCG content in particular areas of the reservoir.

In 2016, an NCG Interference Test was conducted to determine the operating setting of wells at East Salak that will produce steam within the plant's NCG limit, create guidelines for operating high-NCG wells to ensure sufficient steam supply specifically to Unit 4, and fully understand the connectivity between wells (Julinawati et al., 2017; Putri and Julinawati, 2018). The Interference Test identified AWI 1 production wells, which typically have the highest NCG content, as having the strongest connection to other production wells. Flowing the AWI 1 wells helps maintain lower NCG production in the other East Salak wells (Fig. 17). Recently, Putri and Julinawati (2018) reported the following factors that influence production of NCG in East Salak:

- relative elevation of feed zones (feed zones encountered by AWI 1 wells are between MSL to ˜300 m, thus, leading to production interference),
- 3D distance and relative elevation between major feed zones (wells with major feed zones < 360 m of separation have strong connectivity), and
- the operating setting of wells (throttled vs. fully opened).

Still stranded is about 200 tph of high-NCG steam in East Salak, which is unused because of the limited gas handling capacity of the power plants. Other initiatives currently evaluated to maximize use of the stranded high-NCG steam include converting electric pumps to steam-driven pumps and installing an additional power plant specifically designed to handle high-NCG steam.

6. Discussion

Similar to other geothermal fields, the Salak Geothermal Field has experienced resource challenges resulting from long-term commercial production. However, by drawing on lessons learned from reservoir management and best practices developed during almost a century of combined exploration, development, and operations in Salak, Darajat and Wayang Windu, a resource management strategy has been implemented that can sustain long-term production levels.

Key in sustaining Salak's peak commercial production long-term is the successful implementation of the SIRP, as it aims to reduce reservoir cooling due to infield brine and condensate injection, hasten development of the steam cap at West Salak, and reduce the field's production decline rate. The updated conceptual understanding of the Salak system coupled with reservoir simulation forecasting have provided decision-makers with the necessary confidence to fund the project.

Maintenance of the steam cap at East Salak, from where about 60% of current steam production is derived, and development of the steam cap in West Salak are critical to the success of SIRP. Evaluation of analog fields to anticipate how the steam cap might develop and issues that could positively or adversely influence their production efficiency includes the two-phase and steam zones in the mature Mak-Ban and Tiwi geothermal fields in the Philippines, both of which have been operating for almost 40 years. These two fields each encountered positive and negative impacts in the steam zone as they matured. At Mak-Ban Field, where the majority of the production wells produce from shallow steam cap/two-phase and deep brine reservoirs, intra-zonal flow occurs inside wells that are shut-in (Sunio et al., 2010). The intra-zonal flows have been seen as recharging the shallow reservoir and overall production has been stable. As the shallow steam cap pressure continued to deplete, a relative increase in cooler fluid inflow from the shallow reservoir has led to both flow instability and cold water downflow in wells under flowing condition. This resulted into stepwise-drops of individual well production (Sunio et al., 2010). At Tiwi, influx of natural recharge and injection fluids into the Matalibong area raised the steam-water interface and reduced the volume of the steam zone by

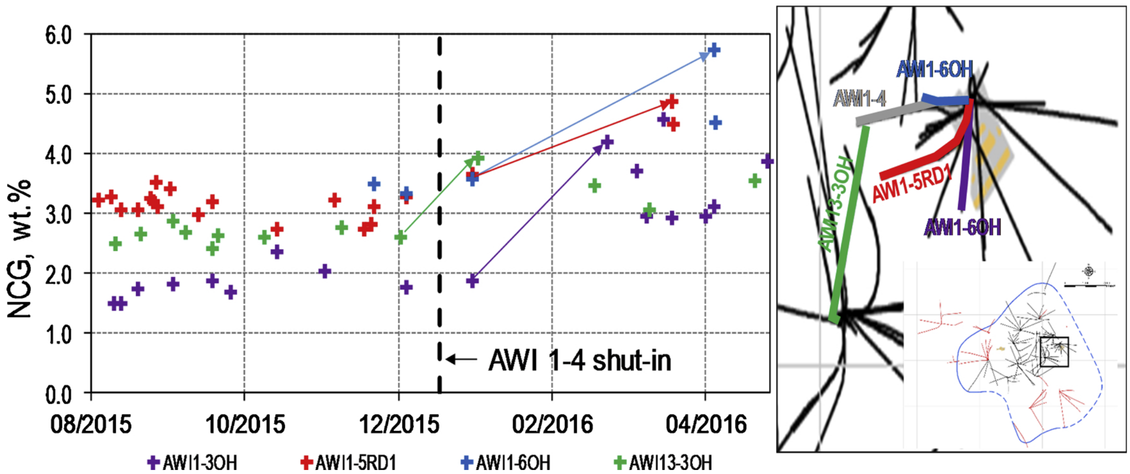

Fig. 17. The shut-in of AWI 1–4 after its unsuccessful workover resulted to NCG increase at AWI 1–3, 1–5, 1–6, and 13-3. Therefore, when AWI 1–4 is shut-in, the surrounding wells shows NCG increase. Putra et al. (2018) reported that the successful scale drill-out of AWI 1–4 and its subsequent flowing into the diffuser sump and venting of the NCG resulted to an increase in production from surrounding wells by about 48 tph (˜6.5 MW).

flooding some of the deeper production zones (Menzies et al., 2010).

A key for future make-up well targeting has come from the detailed study of the nature and distribution of the effective fractures (the fractures producing geothermal fluids). These results have provided critical insights now used to locate and prioritize new well pad locations and for targeting future production make-up wells. Highly permeable feed zones are concentrated at shallow depths in the northern and eastern portions of the field. The general alignment of the effective fractures along the S_{Hmax} direction and the NE-SW trend of surface structures and lineaments indicates that future make-up wells should have either northwest or east-southeast trajectories to increase their chances of encountering feed zones.

In the eastern steam cap and in the west, as a steam cap develops, wellbore scaling and increased NCG in the produced steam are expected. For scale clean-out, experience has shown that both traditional and cost-efficient innovative (i.e., wireline- and coiled tubing-conveyed scale clean-out) well workovers are effective to regain lost steam production. In the case of NCG, a detailed review of well connectivity in the East Salak steam cap has shown that venting from a key well can significantly lower NCG concentration in nearby wells. Venting AWI 1–4 into the diffuser sump has successfully allowed production from otherwise high-NCG production wells to be fed into the system, adding an estimated 6.5 MW.

Finally, focusing on optimization of the surface facilities has resulted in improved steam supply. These projects have included increasing the power plants' gas removal system to allow for higher NCGs, debottlenecking of pipelines, and conversion of previous injection wells to production. These high-value projects have added steam to the system without drilling any make-up wells. Altogether, properly designed surface facilities projects can extend the time between make-up well drilling campaigns and decrease the overall number of make-up wells needed to maintain generation.

7. Summary and conclusion

After nearly 25 years of commercial operation, the Salak Geothermal Field continues to generate electricity at its current installed capacity of 377 MWe. Data from the recent wells and monitoring programs, together with refinements of the conceptual model and optimization of the surface facilities, contributed to an effective management of the Salak reservoir and maintenance of the field's high capacity factor (95% net since 2006). The resulting estimate of future performance, derived from a careful analysis of the historical performance coupled with numerical simulation, supports and provides a credible case for moving most injection outfield and to the field's southeast margin.

Although injection management has been a critical issue at Salak through time, it has not significantly affected the field's performance, despite the large volume of infield injection in the early years. The influx of cooler natural recharge is relatively low, as it appears to enter the reservoir on specific pathways with limited mass flow rates.

By undertaking fit-for-purpose surveillance programs and continuing to leverage lessons learned to improve processes along with a proactive approach to field management issues as they arise production can be maintained at high levels. These efforts include application and implementation of new ideas and potential breakthrough technology.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgement

The authors would like to thank the management of SEGS and PGE for allowing publication of this paper. Massive thanks to SEGS colleagues who contributed to the development of the charts and figures in this paper, and the hours spent reviewing and improving its contents. Reviews by Mauro Parini and David Sussman were helpful in improving the original manuscript.

References

Abdurachman, F., Aprilina, N.V., Hernawan, A., Kusumah, Y.I., Libert, F., Nelson, C., Paramitasari, H., Pasaribu, H., Putra, F.J., Ryder, A., Satya, D.Y., Simatupang, C., Tanuwidjaja, R., Wicaksono, S., Golla, G., Rejeki, S., 2015. 2014 Salak State of the Reservoir. Unpublished Star Energy Geothermal report, October 15, 2015. pp. 126.

Acuña, J., Astra, D., Molling, P., Prabowo, H., Stimac, J., Sugiaman, F., Cumming, W., Nordquist, G., Shemeta, J., 1997. Awibengkok 1997 Conceptual Model Summary. Unpublished Star Energy Geothermal report, September 1, 1997. pp. 423.

Acuña, J.A., Stimac, J., Sirad-Azwar, L., Pasikki, R.G., 2008. Reservoir management at Awibengkok geothermal field, west java, Indonesia. Geothermics 37 (2008), 332–346.

Ganefianto, N., Stimac, J., Azwar, L.S., Pasikki, R., Parini, M., Shidartha, E., Joeristanto, A., Nordquist, G., Riedel, K., 2010. Optimizing production at salak geothermal Field, Indonesia, through injection management. Proceedings, World Geothermal Congress 2010, Paper No. 2415 25–29 April 2010.

Golla, G., Pasikki, R., Jermia, J., Peter, P., Choiri, M., Gunawan, A., Yamin, W., Dumrongthai, P., Ward, D., Fadilla, G., Nugroho, W., 2013. Salak Brine Outfield Injection Project: End of Phase 2 Decision Support Package. Unpublished Star Energy Geothermal report, January 8, 2013, 104 slides. .

Golla, G.U., Putra, F.J., Satya, D.Y., Intani, R.G., Pamurty, N.P., Gunderson, R.P., 2017.

Characterization of Permeable Entries and Fractures at the Salak, Darajat, and Mak-Ban Geothermal Reservoirs. Unpublished Star Energy Geothermal report, March 30, 2017. pp. 77.
Gunderson, R., 2004. Awibengkok Tracer Test Result: 1992 – 2002. Unpublished Star Energy Geothermal report, September 16. pp. 2004.
Gunderson, R.P., 2016. Distribution and Orientation of Fractures at Awibengkok and Darajat Fields, Indonesia and Mak-Ban and Tiwi Fields, Philippines: Relation to Drilling Results. Unpublished Star Energy Geothermal report, May 11, 2016. pp. 35.
Hidayaturrobi, A.D., Putra, R.B., Souvanir, T., Purba, E., Panggabean, P., Munir, N., Yudhistira, A.D., Mubarok, Z., Putri, R.P., Sihombing, A., 2017. Salak Workover 2017: Phase 5 Static Lookback Meeting. Unpublished Star Energy Geothermal presentation, December 14, 2017, 59 slides. .
Intani, R.G., Satya, D.Y., Golla, G., Nordquist, G., 2017. Permeable entry characterization at darajat Field, West java. Proceedings, 5th Indonesia International Geothermal Convention & Exhibition 2017 2017 August 2-4.
Julinawati, T., Paramitasari, H., Putri, R.P., Hidayaturrobi, A.D., 2017. NCG interference evaluation to enhance steam production of High NCG Wells at salak geothermal Field. Proceedings, 5th Indonesia International Geothermal Convention & Exhibition 2017 2017 August 2-4.
Libert, F.T., 2017. Evaluation of the deepest production Well in salak geothermal Field, Indonesia. Proceedings, 5th Indonesia International Geothermal Convention & Exhibition 2017 2017 August 2-4.
Menzies, A., Villaseñor, L., Sunio, E., Lim, W., 2010. Characteristics of the matalibong steam zone, tiwi geothermal Field, Philippines. Proceedings, World Geothermal Congress 2010 25-29 April 2010.
Molling, P., Rohrs, D., 1996. Awibengkok Reservoir Baseline Chemistry. Unpublished Star Energy Geothermal report, June 25, 1996. pp. 27.
Murray, L.E., Rohrs, D.T., Rossknecht, T.G., Aryawijaya, R., Puyastuti, K., 1995. “Resource Evaluation and Development Strategy, Awibengkok Field,” 1995 World Geothermal Congress, SECTION 6 - Resource Evaluation and Modeling.
Pasikki, R.G., Gilmore, T.G., 2006. Coiled tubing acid stimulation: the case of AWI 8-7 production Well in salak geothermal Field, Indonesia. *PROCEEDINGS*, Thirty-First Workshop on Geothermal Reservoir Engineering, Stanford University January 30-February 1, 2006.
Pasikki, R.G., Libert, F., Yoshioka, K., Leonard, R., 2010. Well stimulation techniques applied at the salak geothermal Field. Proceedings, World Geothermal Congress 2010, Paper No. 2274 25–29 April 2010.
Pasikki, R.G., Maarif, J., Joeristanto, A., Libert, F., Kay, N., 2011. Studies and implementation of injector Well conversion during salak Field operation. PROCEEDINGS, Thirty-Sixth Workshop on Geothermal Reservoir Engineering, Stanford University January 31 - February 2, 2011.
Pasikki, R.G., Pasaribu, H., 2014. Application of hydraulic stimulation to improve Well injectivity. Proceedings, Indonesia International Geothermal Convention Exhibition 2014 4-6 June 2014.
Pasikki, R.G., Peter, Libert, F., 2017. Impact of enthalpy and pressure change to geothermal inflow performance relationship. Proceedings, The 5th Indonesia International Geothermal Convention & Exhibition (IIGCE), 2-4 August 2017.
Putra, R.B., Souvanir, T., Panggabean, P., Purba, E., Arstianti, Cahyono, A., 2018. First time in Indonesia, coiled tubing unit (CTU) clean-out totally plugged scale: risks, mitigations, and lessons learned. GRC Transactions 42, 2018.
Putri, R.P., Julinawati, T., 2018. Connectivity of Wells in the East salak steam cap: results of NCG interference testing. Proceedings, 40th New Zealand Geothermal Workshop 14–16 November 2018.
Rohrs, D.T., 2007. Salak 2007 NCG Production History and Forecasts. Unpublished Star Energy Geothermal report, October 1, 2007. pp. 51.
Rohrs, D., Gunderson, R., Melosh, G., Suminar, A., Nordquist, G., Molling, P., Sirad-Azwar, L., Acuña, J., 2005. Salak 2005 Conceptual Model Update. Unpublished Star Energy Geothermal report, October 1, 2005. pp. 272.
Stimac, J., Nordquist, G., Suminar, A., Sirad-Azwar, L., 2008. An overview of the Awibengkok geothermal system, Indonesia. Geothermics 37 (2008), 300–331.
Stimac, J., Baroek, M., Suminar, A., Sagala, B., 2010. Integration of surface and Well data to determine structural controls on permeability at salak (awibengkok), Indonesia. Proceedings, World Geothermal Congress 2010 25-29 April 2010.
Sugiaman, F., 2003. State-of-Stress and Wellbore Stability in Awibengkok Field. Unpublished Star Energy Geothermal report, July 31, 2003. pp. 20.
Sunio, E.G., Menzies, A.J., Alvarez, R.R., Lim, W.Q., Peter, Stark, M.A., 2010. Downflows in Wells at the mak-Ban geothermal Field, Philippines. Proceedings, World Geothermal Congress 2015 19-25 April 2015.
Syaffitri, Y., Molling, P., 2013. Evaluation of Reservoir processes using liquid geothermometry at awibengkok geothermal Field, Indonesia. 35Th New Zealand Geothermal Workshop: 2013 Proceedings 17–20 November 2013.
Yoshioka, K., Izgec, B., Pasikki, R., 2009. Optimization of geothermal Well stimulation design using a geomechanical Reservoir simulator. PROCEEDINGS, Thirty-Third Workshop on Geothermal Reservoir Engineering, Stanford University January 28-30, 2008.
Yoshioka, K., Jermia, J., Pasikki, R., Ashadi, 2015. Zonal hydraulic stimulation in the salak geothermal Field. Proceedings, World Geothermal Congress 2015 19-25 April 2015.
Yoshioka, K., Pasikki, R., Stimac, J., et al., 2019. A long term hydraulic stimulation study conducted at the Salak geothermal field. Geothermics 82, 168–181 In this issue.