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Temperature Recovery after Long-term Injection: Case History from Soda Lake, Nevada

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ABSTRACT

Well 25A-33 at the Soda Lake Geothermal Project illustrates the use of long-term, low-pressure injection as a means to enhance productivity in a well with potentially commercial temperatures but low initial permeability. This paper documents the recovery in temperature when the well was put on pumped production after an injection period of more than two years and a shut-in period of one year. The well's production temperature has risen from 304°F to 352°F (151°C to 178°C) over a period of 16 months. The technique of enhancing productivity by long-term injection is especially suitable for wells drilled in geothermal fields with ongoing operations, because the power plant can provide a ready source of injection water. The approach is particularly applicable for projects with pumped production wells, because the pumps give the operator the ability to set the flow rate at whatever level the formation can yield after stimulation by injection.

1. Introduction

New geothermal wells sometimes encounter promising temperatures but insufficient permeability for commercial production. Geothermal operators have several options with such wells, including re-drilling, hydraulic fracturing, and acidizing. Each or these approaches may be appropriate in specific circumstances, but they are all fairly costly, and none of them is assured of success.

If a long-term source of injection water is available (particularly if production and injection operations are already underway at a nearby plant), a less expensive alternative may be to use the new well for injection over an extended period, with the possibility of conversion to production at a later time. Injection of cooler water (even at low rates and pressures) can induce fractures through thermal stimulation (McLean et al., 2016).

One limitation of this approach is uncertainty about how quickly production temperatures will recover after extended injection. Forecasting by numerical modeling is difficult, because formation properties are changed by the stimulation process, and the parameters that control the recovery of injected water are typically not well known. In the face of such uncertainty, case histories can provide useful insight.

The Soda Lake Geothermal Project has successfully stimulated an initially unproductive well (25A-33) by over two years of injection followed by a year-long shut-in period for heat-up. As of May 2017, 25A-33 has been on pumped production for 16 months, and its production temperature is still rising. The purpose of this paper is to document the well's improvement and the conditions that have allowed the stimulation by long-term injection to be successful.

2. Project Description

The Soda Lake Geothermal Project is located in Churchill County, Nevada, about 7 miles northwest of the City of Fallon and about 70 miles east of Reno. Geothermal exploration at Soda Lake began in the 1970s (McNitt, 1990), and drilling in the field has encompassed 23 wells and 6 re-drills (Ohren et al., 2011). The field has two binary power plants (Soda Lake 1 and 2) which have been on line since December 1987 and February 1991, respectively. These plants have a combined nameplate capacity of 23 MW gross, but they have never operated at that level due to a combination of insufficient flow and below-design temperatures. In recent years, the combined output of the two plants has averaged about 8 MW net. Cyrq Energy has operated the project since 2015 (Alterra Power, 2015) and has announced plans to replace Soda Lake 1 and 2 with a new plant to be called Soda Lake 3 (Ormat, 2016). The new plant is projected to come on line in early 2019.

As of May 2017, the project has 6 wells equipped for pumped brine production (4 in active use), one steam production well (drawing on an induced steam cap in the reservoir), and 4 wells equipped for injection (3 in active use). The flow-weighted average temperature of the brine production wells is 325°F (163°C), with individual wells ranging from 294°F to 368°F (146°C to 187°C). Production from the steam well is used in a steam re-heat (SRH) facility to re-heat a portion of the discharge brine for recirculation through Soda Lake 2. The sum of the plant-inlet flows at both plants (including recirculation from the SRH) is about 5,800 gallons per minute (gpm) (about 370 liters/second [L/sec]).

Figure 1 shows the current configuration of production and injection wells, as well as the location of the two existing plants. Well 25A-33 is located at the southwest margin of the wellfield. The nearest active well to 25A-33 is producer 32-33, about 0.3 miles (about 0.5 kilometers) away.

Figure 2 shows the history of production temperatures since the start of plant operations. From 1994 to 2010, production temperatures declined by about 17°F (9°C). Several operational changes in 2010-2011 brought the temperature decline under control. Average production temperatures remained stable at about 329°F (165°C) from 2011 to 2015. In 2015, one of the hotter wells (41B-33) went offline because of a pump failure, and the coolest well (41A-33) increased its production rate after a pump repair. As a result, the average production temperature dropped to about 323°F (162°C) by the end of 2015. The rise in average production temperature since February 2016 has resulted from the 25A-33 heat-up.

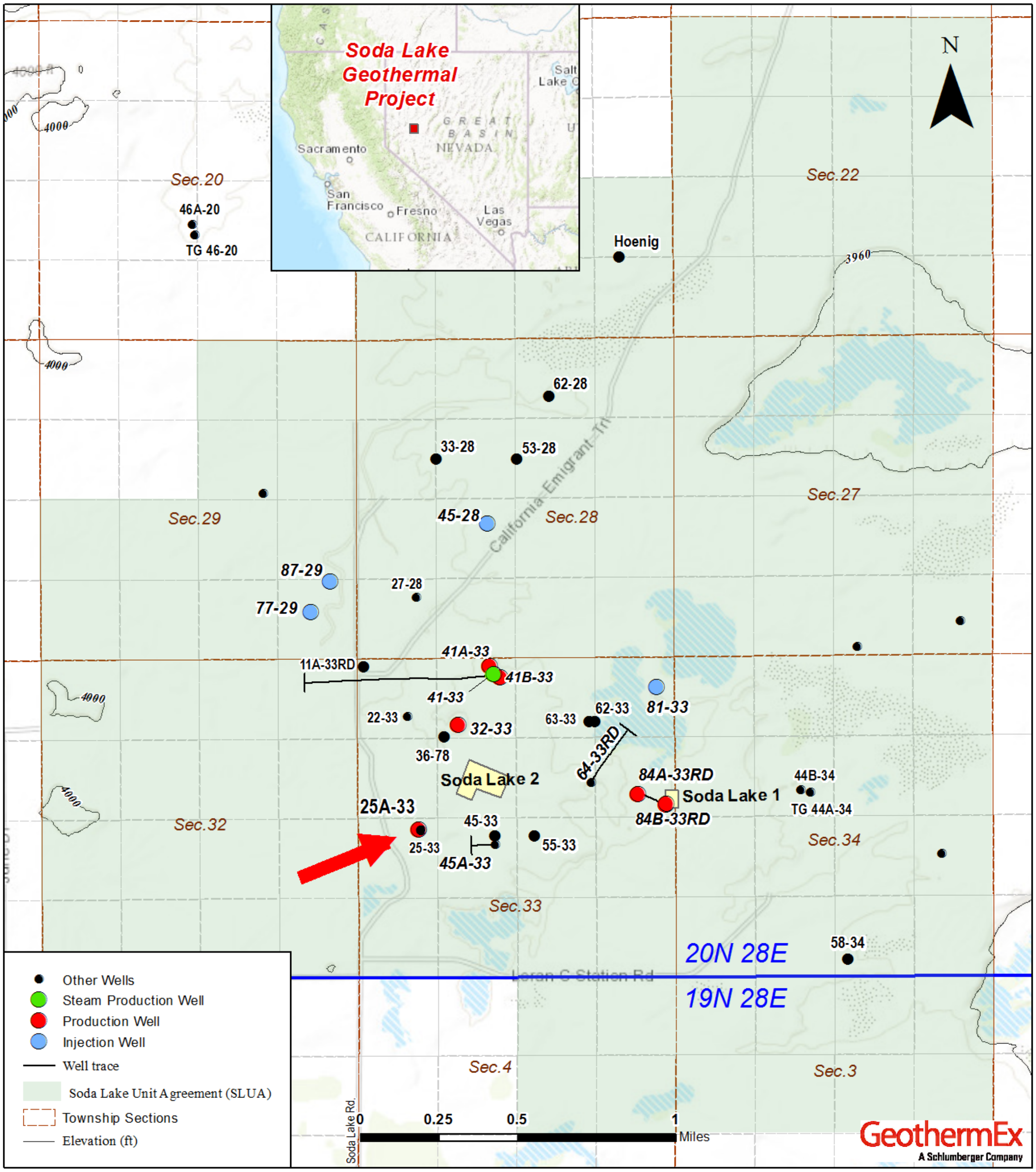

Figure 1: Well location map, Soda Lake Geothermal Project. Red arrow points to subject well (25A-33). Source: Adapted from GeothermEx (2016)

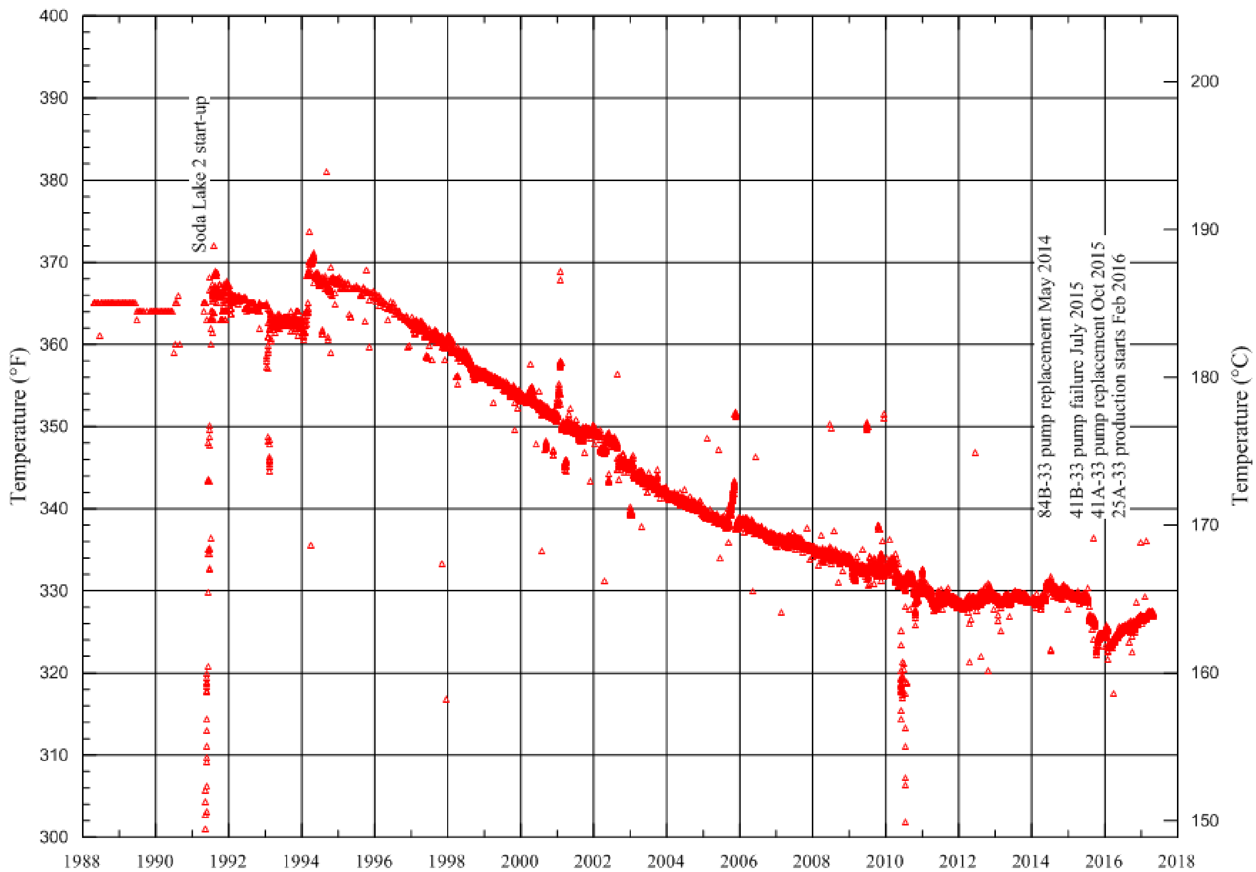

Figure 2: Flow-weighted average temperature of production wells at Soda Lake Geothermal Project

3. Stimulation of 25A-33

When well 25A-33 was drilled in 2010, it had one of the highest temperatures ever measured at Soda Lake: 391°F (199°C) at a depth of 4,983 feet (1,519 meters) (Ohren et al., 2011). It was also one of the least permeable wells in the field, based on tests within the first few months of completion (Benoit, 2014). Table 1 summarizes the history of the attempts to improve the well's permeability and establish commercial production. These included injection tests at a range of pressures, detonation of explosive charges (deflagration), and repeated air lifts through 2-7/8-inch tubing. At injection pressures up to 400 psig (28 barg), the well took only about 150 gpm (25 L/sec). At the pressure of the plant's injection system ("system pressure," equal to about 140 psig [about 10 barg]), the well took little or no water (Ohren and Benoit, 2012). After a workover to remove bridges and install a 7-inch slotted liner, the well took just 7 gpm (0.4 L/sec) at system pressure. The deflagration on 1 February 2011 induced little improvement on its own: immediately after deflagration, the well took just 30 to 40 gpm (1.9 to 2.5 L/sec) at system pressure. However, during injection over 5 days after deflagration, the well's injection rate rose to about 600 gpm (38 L/sec) at system pressure. Benoit (2014) estimated the well's Injectivity Index to be about 1.9 gpm/psi (1.7 L/sec per bar) at that point, based on a pressure fall-off test. Three air-lifts over the following four months induced production of 300-400 gpm (19-25 L/sec), but flow from the well was never self-sustaining. The operator at the time

Table 1: Chronology of Soda Lake 25A-33

Date	Activity	Comment
27 Jun - 17 Aug 2010	Drilling	Drilled to total depth of 5,989 ft. Well was side-tracked at 3,905 ft to get around "drillable" packer that proved to be non-drillable.
14 Aug 2010	Static TP log	Logged during completion, just hours after last circulation. Low injectivity noted (24 bbl/hr = 17 gpm).
26 Aug - 24 Sep 2010	Static TP logs	3 suveys during heat-up, conducted inside 2-7/8" tubing hung at 5,720 ft. Survey on 24 Sep 2010 showed 390.8°F at 4,943 ft, with reversal below.
28 Sep 2010	Injection test	Could not get water down 2-7/8" tubing (later found to be plugged). Well took 150 gpm down annulus (outside 2-7/8" tubing) at 400 psig.
4-5 Oct 2010	Tubing removed	Removal of 2-7/8" tubing (bottom plugged w/ mud and pipe dope). Injection attempted, but well took little or no water at pressure of plant's injection system (about 140 psig).
1-8 Dec 2010	Install 7" liner	Cleaned out bridges to 5,957 ft. 4-hour injection test after clean-out: 81-132 gpm at 350-750 psig. 7" liner installed with slots in 4 intervals between 4,120 ft and 4,979 ft. After liner installation, well took just 7 gpm at injection-system pressure of 140 psig.
1 Feb 2011	Deflagration	Charges detonated at 3 depths between 4,150 ft and 4,910 ft. Injection capacity immediately after deflagration was 30-40 gpm at injection-system pressure.
2-22 Feb 2011	Injection test	In first 5 days of test, injection rose to over 600 gpm at injection-system pressure. Maximum injection after 2 weeks was about 750 gpm at 120 psig. TP log during injection on 8 Feb 2011 showed virtually all water leaving well at about 5,000 ft. 2-hour fall-off test on 8 Feb 2011 showed Injectivity Index of 1.9 gpm/psi (Benoit, 2014).
3 Mar 2011	Install tubing	2-7/8" tubing set at 2,021 ft for air-lifting.
16 Mar - 27 Jun 2011	Three air-lifts	Flow 300-400 gpm while lifting. Flow was never self-sustaining. Static TP surveys 4 Apr and 25 May show residual cooling from Feb 2011 injection, with minimum temperature between about 4,980 ft and 5,000 ft. Productivity Index estimated at 0.5 gpm/psi from air lift on 4 Apr 2011 (Benoit, 2014).
11 Feb 2012	Tubing removed	Preparation for long-term injection.
2 Jul 2012	Start long-term injection	Injection started at around 300 gpm and rose to around 750 gpm at injection-system pressure over 2 months. From July 2012 to Feb 2015, injection was generally 200-300 gpm, with occasional higher spikes at times of plant operational needs.
27 Feb 2014	Static TPS log & injectivity test	Log shows minimum temperature of 206°F in main permeable zone around 5,000 ft after 18 months of injection (Jul 2012 - Dec 2013). Well had been shut in for 2 months prior to this survey. Injectivity Index estimated at 8.6 gpm/psi (Benoit, 2014).
13 Aug 2014	Injection peak	The "Aha" moment (per Dale Smith at Soda Lake): 25A-33 took 1,800 gpm over 4 hours at a WHP of 21 psig.
9 Feb 2015	End of injection	
1-3 Apr 2015	Air lift	Static survey on 1 Apr (before airlift) shows 212°F in main permeable zone around 5,000 ft. Flowing survey on same day after start of air lifting shows zone at 5,000 ft heated to 232°F. Air lifted 2.5 days through 2-7/8" tubing hung at 1,974 ft. Productivity Index estimated at < 9.3 gpm/psi (Benoit, 2015).
3-11 Jun 2015	Air lift	Static survey on 3 June (before airlift) shows 252°F in main permeable zone around 5,000 ft. Productivity Index estimated at about 6 gpm/psi from 4-day build-up (Benoit, 2015).
4 Feb 2016	Start pumped production	Initial production temperature 304°F. Temperature rose by 10°F in first day, then about 1°F/week for first 2 months. One year after start-up, temperature was rising about 1°F/month, reaching 352°F by May 2017. Production has been kept constant at about 1,000 gpm.

(Alterra Power) decided to undertake long-term injection at system pressure, in hopes the well's permeability would improve over time.

A series of temperature surveys conducted in 25A-33 provides useful insight into the well's evolution (Figure 3). An early survey conducted through drill pipe just hours after circulation (14 August 2010) shows the well cooled by drilling, with the hint of cross-flow behind pipe based on isothermal temperatures over an interval from about 3,900 to about 4,300 feet Measured Depth (ft MD). By 26 August 2010, the temperature profile began to show a zone just above 5,000 ft MD as a significant inflection point, and a month later (24 September 2010), this was the zone that recorded the hottest temperature in the well (391°F [199°C]). The temperature reversal below this point suggests that this zone was the locus of a deep thermal plume that controlled the overall temperature profile of the well. A survey after a week of injection post-deflagration (8 February 2011) showed virtually all the injection water leaving the well just below 5,000 ft MD. Two surveys during the heat-up after this short-term injection test (11 April and 25 May 2011) showed the most residual cooling in the zone at around 5,000 ft MD (reflecting the fact that it had taken most of the injection), with an isothermal section extending back up the well to about 3,900 ft MD (the inflection point in the survey of 14 August 2010). Thus, there appeared to be two or more zones with some permeability in the interval between 3,900 and 5,000 ft MD (with the deeper zone clearly dominant), even though early testing indicated that the permeability of these zones was quite low.

Alterra Power started long-term injection into 25A-33 on 2 July 2012. At system pressure, the well initially took little or no water. Using high-pressure Griffin pumps, a flow rate of about 175 gpm (11 L/sec) was established. The injection rate increased over several days at decreasing wellhead pressures. The Griffin pumps were removed on 10 July 2012, and the well took about 300 gpm (19 L/sec) at system pressure. Over the next two months, injection at system pressure rose to about 750 gpm (47 L/sec). Between July 2012 and February 2015, injection was generally in the range of 200 to 300 gpm (13-19 L/sec), with occasional higher spikes at times of plant operational needs.

Eighteen months into the stimulation, Alterra Power stopped injection into 25A-33 for two months to assess the well's improvement. A static survey after the two-month heat-up (27 February 2014) showed a temperature of 206°F (97°C) in the zone at 5,000 ft MD. An injectivity test showed the Injectivity Index had risen to about 8.6 gpm/psi (7.9 L/sec per bar) – over four-fold improvement since the injectivity test of February 2011 (Benoit, 2014). This was encouraging, and injection continued at the same low rates and pressures as before the 2-month heat-up. The "Aha moment" of insight into the well's improvement came on 13 August 2014, when the well took 1,800 gpm (114 L/sec) over four hours at a wellhead pressure of just 21 psig (1.4 barg) (Dale Smith, personal communication).

Cyrq Energy stopped injection into 25A-33 on 9 February 2015. A static temperature survey on 1 April 2015 showed a temperature of 212°F (100°C) in the zone at 5,000 ft MD, and a flowing survey during air-lifting on the same day showed this zone's temperature rising to 232°F (111°C). A static survey 2 months later (3 June 2015) showed the zone had heated to 252°F (122°C). A 1-week airlift in June 2015 yielded flow at about 650 gpm (41 L/sec), and a 4-day build-up following the air-lift indicated a Productivity Index of 6.2 gpm/psi (5.7 L/sec per bar) (Benoit, 2015).

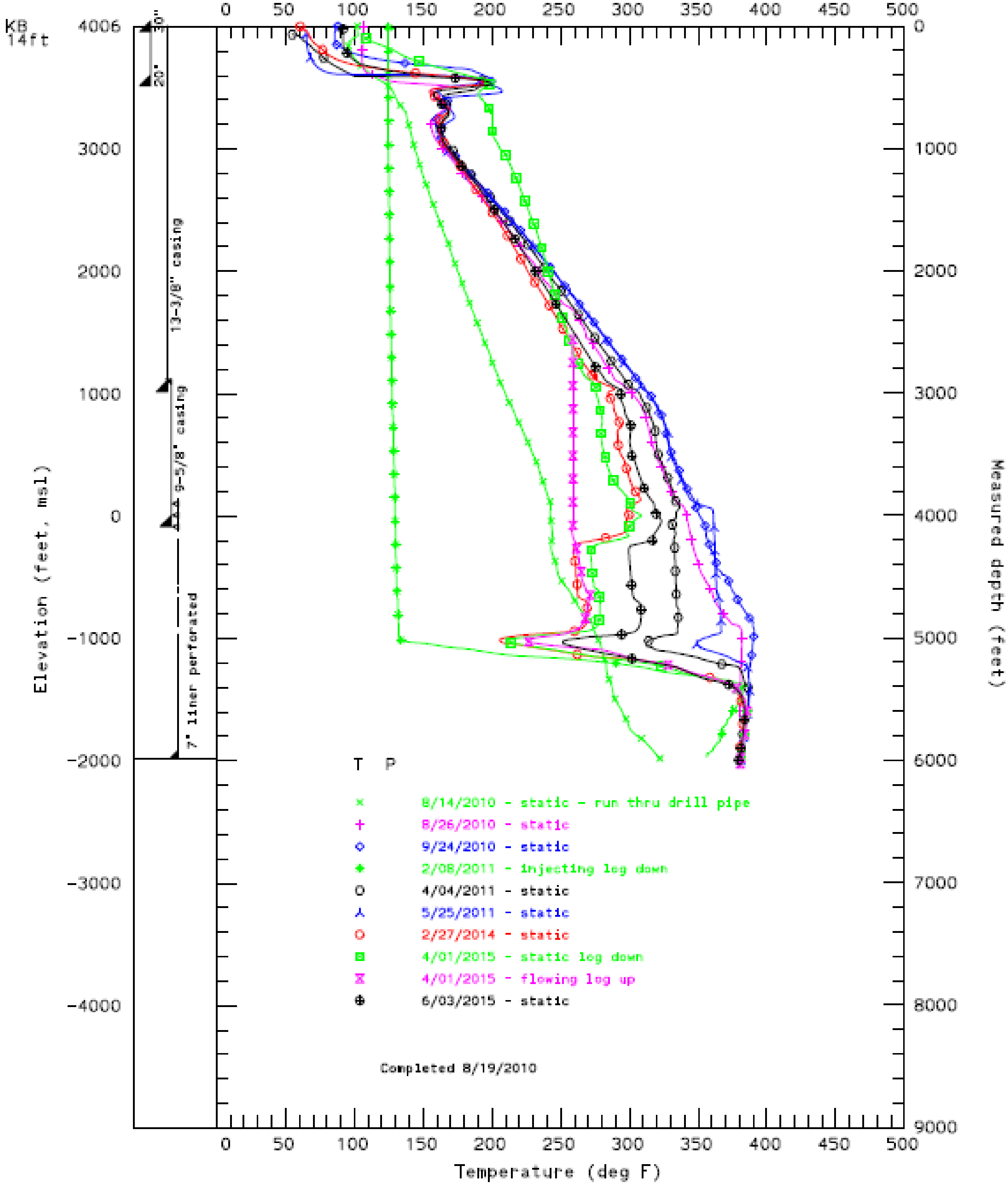

Figure 3: Selected temperature profiles, Soda Lake 25A-33

4. Temperature Recovery of 25A-33

Well 25A-33 started pumped production on 4 February 2016. On the first day, the production temperature rose from 304°F (151°C) to 314°F (157°C). Figure 4 shows the shape of the temperature recovery curve through April 2017. In early May 2017, a recalibration of the temperature gauge for 25A-33 showed a production temperature of 351°F (177°C), slightly higher than before the calibration. The rate of drift out of calibration is unknown, so Figure 4 presents the data through April 2017 as originally reported (the shape of the curve should be essentially unchanged). As of 18 May 2017, the production temperature of 25A-33 had reached 352°F (178°C). Cyrq Energy has limited the production rate of 25A-33 to about 1,000 gpm (63 L/sec) in order to minimize interference with adjacent production well 32-33, which produces at a higher temperature (368°F [187°C]). When 25A-33 eventually stabilizes in temperature, the optimal balance of flow rates between these two wells will be re-assessed.

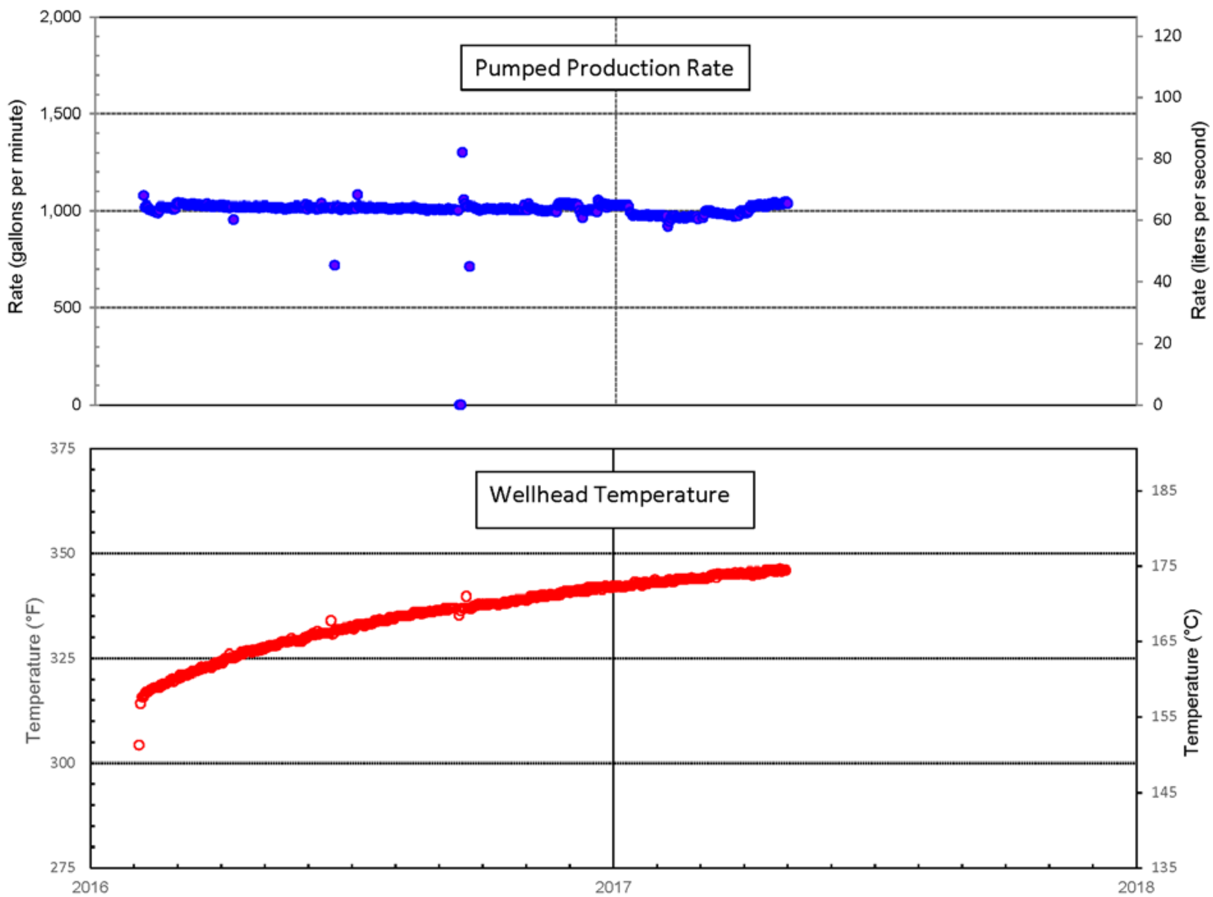

Figure 4: Temperature recovery of Soda Lake 25A-33 under pumped production after extended injection

5. Discussion

The shape of the temperature profiles in Figure 3 suggests that the rise in production temperatures at 25A-33 is driven primarily by temperature recovery in the main permeable zone at about 5,000 ft MD. This zone appears to have been a pre-existing conduit for a deep thermal plume that emplaced heat in this portion of the reservoir, even though no significant loss of circulation was noticed at this depth during drilling. It is unclear whether deflagration made much of a contribution to the improvement in the well's permeability, though it is possible that the shock of deflagration helped open a path for injected water to reconnect to permeability that existed before damage by drilling. Most of the improvement in permeability appears to have come from the injection itself: the first big rise in injection rates occurred over 5 days of injection after deflagration. Considering that the improvement in permeability seems to have been focused on the hottest part of the well, it seems likely that the mechanism of this improvement is thermal stimulation; that is, fracturing induced by the temperature contrast between cool injection water and high formation temperatures. As injection is prolonged, the thermal stimulation would affect a larger and larger volume of the formation around the well. Other mechanisms of permeability enhancement may also be at play, such as the flushing of drilling mud and cuttings away from the well, or the shearing of fractures that are favorably oriented within the stress field. In any case, it is worthwhile to note that the stimulation of 25A-33 was accomplished with relatively low injection pressures (that is, system pressures of about 140 psig [about 10 barg]), without the need for elaborate intervention procedures.

The time required for the stimulation of 25A-33 (over two years of injection followed by a year of shut-in, plus over a year for temperature recovery) is in a sense a hidden cost, since potential revenue was being foregone. On the other hand, 25A-33 provided value as an injector during the stimulation period, and the stimulation by injection avoided the cost of additional drilling, with its attendant risks. It is also possible that, with a clearer idea of the potential for a favorable outcome, the time allotted for the stimulation and heat-up could be shortened in application to other wells.

6. Conclusion

The temperature recovery at Soda Lake 25A-33 is useful as an example of the time required for temperature recovery after stimulation by extended injection at low rates and pressures. The continuing rise in production temperatures over a period of more than a year shows that the full benefit of this stimulation technique does not come quickly – but the potential benefit is real. This stimulation technique is especially suitable for wells drilled in geothermal fields with ongoing operations, because the power plant can provide a ready source of injection water. The approach is particularly applicable for projects with pumped production wells, because the pumps give the operator the ability to set the flow rate at whatever level the formation can yield after stimulation by injection.

7. Acknowledgement

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