Large Volume Geothermal Injection in Nevada

Dick Benoit

Sustainable Solutions

Keywords

Injection, field layout, Nevada, Beowawe, Blue Mountain, Bradys, Desert Peak, Dixie Valley, Don Campbell, Jersey Valley, McGinness Hills, Patua, Salt Wells, Soda Lake, Steamboat, Stillwater, Tuscarora, Wild Rose

ABSTRACT

Large volume injection of cooled geothermal fluid in Nevada began in December 1985 with the Beowawe and Desert Peak power plants injecting 3200 gpm and 1665 gpm. By late 2015 12 additional fields had been placed in production so that in 2016 a total of +210,000 gpm of cooled brine was being injected into 76 individual injectors ranging in total depth from 323' to 11,047'. Sustained injection rates of over 40,000 gpm have been achieved in three fields. The geology, injection/production strategies, and layouts of these 14 fields vary widely. Injection into the geothermal systems has been universally successful in supporting the reservoir pressures but four of the fields encountered serious cooling problems. At Beowawe cooling was greatly reduced by shifting injection into the geothermal system. At Stillwater the cooling was reversed by moving injection to a greater distance from the producers. At Blue Mountain and Bradys both short and long-term cooling has severely limited the field outputs. In most fields there is documented ongoing long-term resource cooling but it is at rates that will allow the projects to operate for periods of at least a few decades. It is not presently possible to predict which injection strategy is most likely to be the most or least successful prior to the onset of production.

1. Introduction

Northern and Western Nevada host 16 operating geothermal fields. Fifteen of these return cooled brine to the reservoir from which it was produced. Only the small Wabuska field has never had an injection program. The Nevada Division of Minerals (NDOM) requires geothermal plant operators to submit monthly reports of the amounts of fluid and their temperatures for every active production and injection well, as well as the amount of megawatts sold. This database, extending back into the 1980s, is the key factor in allowing this paper to be written. A second NDOM well permitting database provides the total depths of wells completed more than five years ago. Published papers for most of the fields supply valuable information on the geology of the resources but few discuss the specific injection strategy or tactics. This paper utilizes well locations and depths to infer an injection strategy when none has been published.

In 2016 the 15 injecting fields had 76 active injection wells with most fields having 3 to 7 active injectors. Extreme values are 2 and 11 active injectors. Injection rates into individual wells range from about 100 gallons per minute (gpm) to 15,000 gpm. Total injection rates of individual fields ranged from about 3200 gpm at both Desert Peak and Jersey Valley to 48,000 gpm at Wild Rose. The total injection rate in 2016 for all Nevada fields was about 210,000 gpm or 0.64 acre-feet per minute or 336,000 acre-feet per year. This amounts to about 45% of the estimated 2010 public supply water use for all 2.7 million residents of Nevada.

Injection of spent geothermal brine in Nevada commenced during the last week of 1985 at rates of 2000 to 4000 gpm. By late 2015 the geothermal industry was injecting over 40,000 gpm in three different fields. Between 1985 and 2015 many injection challenges were encountered that required rearranging the field layouts and even the overall injection strategy. Two of the fields had truly serious injection problems that either bankrupted the original developer or led to a distressed sale of the field. Individual fields are discussed in the chronological order in which they first commenced operations.

2. Wabuska (1984)

The small and low temperature (200 ^{o}F) Wabuska binary project, was the first geothermal power generation project in Nevada. All of its brine has been disposed on the surface so it will not be further discussed.

3. Beowawe (1985)

Chevron's 16.6 MW dual-flash Beowawe power plant commenced operations the last week of 1985 with two closely-spaced 410 ^{o}F production wells completed at depths of 7000' and 9563' and one shallow injection well located over a mile distant from the producers. The producers at Beowawe have more separation between them than indicated by the wellhead locations as one is directional and they are completed at much different depths. The first injection well, the Batz well, was selected because it was believed to be outside of the reservoir was capable of accepting 3200 gpm of injectate (Epperson, 1982, Hoang, et al., 1987). Later tracer testing showed a weak connection (Benoit and Stock, 1993) and this was supported by numerical modeling (Butler, et al., 2001).

The initial injection strategy at Beowawe was simple subsurface disposal of fluid, with no consideration of reservoir pressure support. The Batz well was the only injector at Beowawe during its first eight years of operation. After two years of production a 7 ^{o}F/year cooling trend developed leading to the loss of between 45 and 60 ^{o}F in the production wells as cold groundwater flooded into the reservoir (Benoit and Stock, 1993, Benoit, 1997). This decline was temporarily addressed by drilling a third production well in 1991. Fortunately, a potential replacement injection well, 85-18, existed that was known to be completed within the resource at a depth of 1900'. It was reworked and placed in service in early 1994 and accepted all the injectate. One of the first successful tracer tests in a Nevada geothermal field was performed in 1994 at Beowawe with peak return times of 17 to 35 days (Rose et al., 1995). By 1996 this change in injection strategy reduced the cooling rate to about 1 ^{o}F/year, allowing Beowawe to continue operating beyond its first 30 year power sales agreement (Benoit, 2013, 2014). As the amount of fluid needing injection has gradually increased due to cooling of the produced fluid, the Batz well was partially returned to service in 2009.

The current injection strategy at Beowawe is injection into a shallow lateral outflow far above a deeper producing reservoir (Benoit and Stock, 1993). There is as much or more vertical separation than lateral separation between the 85-18 injector and the producers.

4. Desert Peak (1985)

In contrast to the initial Beowawe injection strategy, injection at Desert Peak was undertaken (with significant trepidation) by Phillips Petroleum at the end of 1985 to return fluid directly to the reservoir. The 9.4 MW net dual-flash plant commenced operations with two production wells producing from depths of 2500 to 4100', temperatures of 401 – 408 ^{o}F and one injection well located about ¾ mile distant completed at a depth of 2900' with a temperature near 400 ^{o}F. The design injection rate was 1665 gpm (Faulder and Johnson, 1987). The extent of possible cooling was completely uncertain but injection was viewed as risk that had to be taken. There were no other long-term Basin and Range analogues at the time for comparison purposes but injection at Phillips' other project at Roosevelt in Utah was proceeding without obvious cooling during its first year of operations.

From 1985 until Feb. 2004 well 21-2 was by far the most important injector in the field and no new wells needed to be drilled (Benoit, 2013). After 2004, the original plant was replaced with a larger binary plant and many changes were made to the field layout, including greatly expanding the production area footprint and placing the original 21-2 injector in service as a producer in January 2016, after 30 years of injection service.

This was a more successful initial injection program than was initially implemented at Beowawe. However, there was no specific strategy other than to use a slightly cooler permeable well as the first injector. The initial strategy is now most simply described as injection into a fault zone at about the same depth and temperature as the production area and located about ¾ mile distant. Desert Peak now has two active injectors, making it, along with Beowawe, the fields with the fewest number of active injectors in Nevada.

5. Steamboat (1986)

Injection began at Steamboat with the Geothermal Development Associates 5.5 MW (net) Steamboat 1 binary power plant at a production rate of 2500 gpm of 320 ^{o}F fluid (Kaplan et al., 1987). The Steamboat 1 project is confined to a 33 acre site of an electrical substation so the initial injection strategy was constrained within a very restricted area. The first injection well drilled was impermeable so the completed wellfield accessed only 20 to 25 of the 33 acres.

Three production wells and two injectors supported the project with the closest producer and injector being only a few hundred feet apart. The production wells were completed between depths of 517’ and 627’ in granitic rocks. The two successful injectors were drilled to depths of 525’ and 4700’ with the great majority of the injection into the 525’ deep well (Goranson et al., 1991). This project was increased to 7 MW in 1989, renamed as Steamboat 1/1A and the injection rate reached 3700 gpm (Goranson et al., 1990). Steamboat 1 was the first project in Nevada with both injectors and producers located only hundreds of feet apart and completed at similar depths. This strategy was viewed as being successful due to the injectate flowing down beneath the injectors rather than laterally directly toward the nearby producers (Goranson et al., 1990).

In 1988 the 12 MW Yankee-Caithness flash plant commenced operations in the southern part of the Steamboat field as a completely independent project where temperature were 420 to 460 ^{o}F. This project had a more conventional injection program with a lateral distance of 4500’ between the three producers and the single injector (Goranson et al., 1990) which accepted 3200 gpm. The three producers had depths between 2681’ and 3050’, while the injector was 3471’ deep but there was no significant difference between the elevations of the production and injection zones (Goranson et al., 1990). This was a successful injection strategy for the Yankee-Caithness project.

In 1992 Far West Capital completed the Steamboat 2 and 3 binary plants near the Steamboat 1/1A plant and increased the amount of fluid injected by 20,000 gpm, making it by far the largest volume geothermal injection program in Nevada. Production was from 9 producers into a cluster of three new injectors located only several hundred feet away from the nearest producers. The typical production well produced from depths of 600 to 1000’ and the injectors were completed to depths of 1080 to 2500’ (Rose et al., 1999). The overall production/injection strategy employed by Far West Capital was the same as at Steamboat 1/1A; to inject at similar or modestly greater depths than the production zone depths. This strategy has proven successful in that it has not undergone any major changes in 25 years.

Since 2004, Ormat consolidated ownership of the Steamboat resource, built three additional binary plants between 2005 and 2008, and increased the output to 85 MW and injection rates to 40,000 gpm in 2010 (Walsh et al., 2010) and a reported 42,600 gpm in 2016. In 2016, 23 production wells supplied 10 injectors, reconfirming the exceptionally high permeability of the Steamboat geothermal system. This permeability is most recently interpreted as resulting from orthogonal high angle fracturing (Walsh et al., 2010).

Injection at the Steamboat geothermal field resulted in ongoing temperature declines of 1.2 to 1.7 ^{o}F/year (Hansen, et al., 2014) which is at the lower end of cooling rates documented in Nevada geothermal fields. The injection and cooling history played a key role the development of a cutting edge numerical model of the Steamboat field which coordinates the rather unique geology, with multiple steeply-dipping fault zones, with the long-term performance of the field (Bjornsson et al., 2014). The Steamboat numerical modeling proposes an evolving fluid flow management strategy to extend the productive life of the field. This long and successful injection history allowed Steamboat to serve as a testing laboratory for injecting very large volumes of fluid into relatively restricted areas and provided the confidence to utilize similar injection programs in more recently developed areas.

6. Empire (San Emidio) (1987)

The original 3.6 MW (net) Empire binary plant utilized a 285 oF resource along a short segment of the Lake Range normal fault (Rhodes et al., 2010). Literature documenting of the development and early years of this project is sparse and incomplete, leaving no record of any specific injection strategy and little information on the early injection history (Bloomquist, 2004). Spray cooling ponds were temporarily utilized and a geothermal wetland supplied by surface discharge was proposed as a way to deal with cooling problems from the initial injection program but the wetland was never built. Experiences from Empire had no impact on later injection developments in Nevada.

Since the early 1990’s a more defined injection program has evolved that now includes 3 – 4 active production wells with completion depths of 1700’ to 1800’ and three very closely-spaced active injection wells with total depths of 323’ to 800’ supporting a 12.8 MW repowered plant and accepting 4200 gpm. These are the shallowest active injection wells in Nevada by a small margin. The maximum horizontal separation between injectors and producers is about ¾ mile. The Empire resource cooled at an average rate of 3.3 oF/year between 1987 and 1996 when wellfield problems impacted the project. Between 1997 and 2009 the cooling rate averaged 1.5 oF/year as the field management improved (Hansen et al., 2014). As the Empire project has now operated for over 30 years and is now producing at its highest megawatt outputs the overall production/injection strategy has somehow been reasonably successful.

7. Soda Lake (1987)

The 3.6 MW (net) Soda Lake I binary plant developed by Ormat and Chevron (Ram and Kreiger, 1989) commenced operations with one production well and one injection well located 1.35 miles apart in what are now known to be two separated portions of the field. The initial field strategy was simply to use the hotter, 360 oF, and deeper of two existing wells for production and the modestly cooler and shallower well for injection.

When the 16 MW (net) Soda Lake II binary plant came on line in 1990 numerous additional production and injection wells were drilled, tested, placed in service, and sometimes removed from service (Benoit, 2016). The injection program at Soda Lake evolved considerably as the production focus changed from just maximizing the amount of fluid produced to maintaining liquid levels in individual production wells while trying to minimize resource cooling. Tracer testing and water chemistry has shown that this field is segmented into largely separate zones and the pressures in each of the zones need to be balanced by injection to maintain an adequate fluid level above the production pumps. This makes the field fairly unique in Nevada from a production management perspective. Soda Lake is also unique in Nevada in that only wells completed within a few feet of each other produce from the same stratigraphic unit. Permeability in nearly all wells is in different formations and no single structure is controlling the field. Each

Soda Lake well has unique geological and production characteristics. Soda Lake has the widest dispersion of both production and injection wells of all the smaller Nevada geothermal fields.

Cooling due to injection at Soda Lake was a serious problem between 1995 and 2009 with the plant fluid-inlet temperature declining by 38 oF (Hanson, et al., 2014). However, since 2009 production well temperatures have been remarkably stable (Benoit, 2016) and the injection program has not undergone any long-term changes. The current injection rate is about 5100 gpm.

The major contribution from injection in the Soda Lake field has been the recognition of how sustained injection can improve the permeability in moderately consolidated Tertiary basin filling rocks (Ohren et al., 2011, Benoit, 2016).

8. Dixie Valley (1988)

The 62 MW (gross) Dixie Valley project commenced operations as the largest dual-flash power plant in the world and in the United States it had the largest volume geothermal injection program at 9,000 gpm. Until 2013, Dixie Valley had claim to all of the deepest active production and injection wells in Nevada, with the sole exception of one Beowawe production well. It is also the hottest Nevada geothermal field with an initial production temperature of 480 oF. The injection history at Dixie Valley has been extensively documented, especially the early years when numerous changes and additions were made to the wellfield (Benoit, 1991). At plant startup there were six production wells and four injection wells. By 2013 the number of active injectors had increased to 11, the largest number of active injectors in Nevada, supplied by eight active production wells (Benoit, 2015). Cooler exploration wells, incapable of a wellhead pressure to flow into the gathering system, are utilized as injectors. Injection rates has been as high as 11,000 gpm, including up to 2000 gpm of augmented cold shallow groundwater (Benoit et al., 2000). The Dixie Valley augmentation program appears to be the only ongoing long-term injection augmentation program in the world into a liquid-dominated field and has now continuously operated for 20 years.

The injection strategy at Dixie Valley can be described as dispersing injectate along a single narrow fault zone in two dimensions. The production wells are confined to two small and widely separated clusters with depths from 8000’ to 10,000’. The injectors are spread out along the fault zone with injection depths ranging from 1000’ to 10,000’. The total length of the utilized part of the fault is 3 3/8 miles. The quality of the injection program was tested and confirmed by the first use of seven polyaromatic sulfonate tracers in high temperature environments in the late 1990s (Rose et al., 2001). These tracers have since been successfully utilized throughout the world. Initial tracer return times ranged from 30 to 150 days and peak arrival times as long as a year were recorded. These tracer results at Dixie Valley provided confidence that the injection augmentation program would not create any serious short-term cooling problems. Injection at Dixie Valley has cooled the reservoir as the amount of fluid required to generate a megawatt has been slowly increasing since 1997 (Benoit, 2014). However, the actual amount of cooling is uncertain as no downhole temperature logs or data have been published in the past 2 decades.

9. Stillwater (1989)

The original 12.5 MW (net) Stillwater binary plant commenced operating with 4 producers and 3 injectors with a total flow rate of about 5500 gpm. The initial field layout had obvious similarities to the Steamboat 1 project with the producers and injectors all located within about 1/8 mi2. Production and injection was primarily from unconsolidated Quaternary alluvium above a depth of 1500' (Forest et al., 1995).

Almost immediately upon plant startup severe cooling of the production wells commenced and by the end of 1991 the plant inlet-temperature had declined from 332 to 268 oF. Stillwater was the first geothermal project in Nevada to suffer rapid cooling immediately after startup. The cooling led to the drilling of two new injection wells, one 3/4 mile north of the existing wellfield and another 1 ¼ miles south of the original wellfield. Two of the original injectors were reworked and one was converted into a producer. Further dispersing the injectate gradually increased the plant inlet temperature to 320 oF between May 1992 and April 1994. This represents the only case in Nevada where a major injection-caused temperature decline has been mostly recovered by moving injection to more remote locations. Following the field modifications and temperature recovery Hanson et al. (2014) report an average temperature decline of 1.0 oF/year until 2009.

The original Stillwater power plant was replaced with a larger binary plant in 2009. In 2016 there were seven production wells and six injection wells in service accepting about 9700 gpm. The actual amount of megawatts produced by the new geothermal plant is uncertain as the project now includes passive solar and concentrating solar plants but only the total megawatts from the project are reported.

10. Bradys (1992)

Bradys Power Partners developed the Bradys 21.1 MW pumped dual-flash plant. It started up with eight closely-spaced +2000' deep producers and four closely-spaced 500' injectors centered about 0.85 mile distant, along the strike of the Bradys fault, from the producers (Benoit, 2013, 2014). The design injection rate was 11,350 gpm. A measurable temperature decline began within a week of the start of injection and decline rates as high as 25 oF/year impacted all eight production wells. Initial tracer returns reached the production wells in as little as 2 days. Over several years numerous changes were made to the production and injection sides of the field to try to stabilize the plant output but these provided only temporary relief and the original developer sold the project. A 5 MW binary power plant was also added to the project by the new owner, Ormat, to make more efficient use of the now cooler fluid (Kreiger and Sponsler, 2002). The most significant and costly of the field changes was the building of a 4 mile-long pipeline to inject fluid into a small unnamed geothermal system located between the Bradys and Desert Peak fields where 4 new shallow injectors were drilled. This, along with a small amount of injection into the Beowawe Batz well, represent the only ongoing programs of injection outside of a producing reservoir in Nevada. No details have been published on the results of this strategy. Bradys, along with Desert Peak, are the only fields in Nevada to date to drill new production wells some distance from the original production wells to try to maintain production, even if the new Bradys wells were initially intended to be injectors.

In 2016 the Bradys project was utilizing only 3 of 9 permitted injection wells at a rate of about 8000 gpm. Five production wells were in service producing fluid with temperatures between 255 and 287 oF, down from a field startup temperature of 355 oF. The 2016 plant output varied between 4 and 8 MW net. No recent changes have been made to the field layout. Bradys has had the most discouraging injection experience to date of all the Nevada geothermal projects and operates at the lowest capacity factors. On the positive side the plant has operated for 25 years.

11. Salt Wells (2009)

ENEL's 18.1 MW Salt Wells binary plant, commenced operating in with 4 production wells between 485' and 700' in depth and 4 injection wells with depths between 691' and 1640'. Tertiary basalt flows are present at these depths. No papers have been published on the Salt Wells field operations. The Salt Wells injection strategy appears to be injecting at modestly greater depths than the production zone. The original producers were located within about a ½ mi2 area. The injectors define a northerly trending line about 1 1/4 miles long. The total area covered by the producers and injectors at plant startup was about ¾ mi2. Since the start of production, ENEL has found it necessary to replace two production wells with two more widely separated wells and the shallowest original injector has been deepened by 960'. Presumably these changes were driven by resource cooling issues. The two new production wells modestly increased the overall field area to about 1 mi2. The injection rate in 2016 was about 9300 gpm. The power plant output has shown relatively little year to year variation so it appears that the revised field layout has successfully maintained the plant output for the first 7 years of its life.

12. Blue Mountain (2009)

Nevada Geothermal Partners' 49.5 MW (net) Blue Mountain binary plant began operating with five closely-spaced production wells and four closely-spaced injection wells. Both clusters were located within a ½ mi2 area and the design plant flow rate was 15,000 gpm. The initial field operating strategy was simply to inject at least ½ mile from the production wells (GeothermEx, 2008). The chosen injection strategy and field layout at Blue Mountain had two twists not previously seen in Nevada. The first consisted of pumping 375 oF fluid from Triassic sedimentary rocks in a fault zone between depths of 2370' to 4413' and injecting zone between depths of 5706' and 7707' where temperatures as high as 416 oF have been measured (Casteel et al., 2010, Benoit, 2013). The second new twist was that the injection is almost directly down dip into the same fault zone.

Very shortly after project start up the fluid-entry temperatures in the production wells began to decline at high rates forcing the drilling of three new injectors during the first half of 2010. Two unsuccessful step-out exploratory wells were also drilled. A three well drilling program planned for 2012 was never implemented. The production rate was voluntarily reduced as a method of preserving the resource temperature, and the original project developer was bankrupted.

As of 2016, the original production wells remain in service but a significant fraction of the injection has been shifted to the newer injectors north of the original field. In 2016 the power plant was generating between 25 and 30 MW net and operating at reduced fluid production rates. Blue Mountain was originally proposed as a 31 MW (net) power plant. Had that size of plant been built the project today would be viewed as being much more successful.

13. Jersey Valley (2010)

Ormat started up the 15 MW binary Jersey Valley power plant with two closely-spaced production wells completed at depths of 3263' and 3400' producing 333 oF fluid (Drakos et al., 2011). Injection was into 4 wells spread along a one mile length of normal fault with total depths of 3291' to 5816'. The producers were selected on the basis of having higher permeability. The overall injection strategy is to spread out the injection along a range-front fault at greater depths than the production wells. In 2016 the injection rate was about 3200 gpm.

During the first 3-4 years of production the annual average production rate gradually increased from 2000 to about 3500 gallons per minute and the megawatt output also rose. NDOM production figures show the net plant output varying between 4 and 12 MW during the year. Inconsistent monthly production temperatures have declined by about 17 oF. Pre-production numerical modeling predicted temperature declines of 0.9 to 5.4 oF/year (Drakos et al., 2011).

The production/injection program at Jersey Valley has been relatively successful to date in that the original two producers and four injectors remain in service and no new wells have been added to the gathering system. This is offset by the fact the plant has always been operating significantly below its nameplate capacity.

14. Tuscarora (2011)

Ormat's 18 MW Tuscarora binary plant began operating with three very closely-spaced +342 oF production wells producing from between depths of 4500' and 5000' (Chabora et al., 2015). There are five active injectors with the bulk of the fluid being injected at depths between 2000 and 3000'. The 5100 gpm of spent brine is injected in four more widely distributed injectors to the north of the producers, with one well to the south of the plant accepting about 200 gpm of cooling tower blowdown. All of the wells, except for the small volume injector south of the plant, are located within about 1/3 mi2. Dering and Faulds (2012) suggest the Tuscarora field is "restricted to the complex intersection of steeply dipping faults along the hinge zone of the accommodation zone".

An initial pressure decline associated with the start of production required the replacement of an original producer which had its production casing set at a relatively shallow depth. One new injection well was placed in service in 2014, to replace one of the original injectors closest to the production wells that had initial tracer returns within several hours of the tracer injection (Chabora et al., 2015). Cooling of the Tuscarora field due to injection has been moderate. An initial cooling rate of 3.5 oF/year was reduced to 1.7 oF/year with the replacement of one injector. Since the beginning of 2013 the project has consistently operated between 13.2 and 17.5 MW (net).

15. McGinness Hills (2012)

Ormat started up the first McGinness Hills plant as a 30 MW net binary power plant (Nordquist and Delwiche, 2013). The plant actually produced 36 net MW (Lovekin, et al., 2016) and was supplied by 4 closely-spaced producers with depths of 2100' – 3900' and temperatures of 328 – 338 oF. The spent fluid is injected into a cluster of 3 injection wells located about 2 ¼ miles distant from the producers between depths of 1730 and 2480' with natural state temperatures of 308 to 317 oF. This strategy was so successful in supporting the reservoir pressure without any cooling that a second 36 MW power plant was placed in service in February 2015, less than 3 years after the startup of the first unit. The producers for the second plant were located in the same locations as the initial producers, all within 1/8 mi2. Two of the new injectors are significantly closer to the producers, being separated by about 1 ¼ miles. In 2016 there were a total of 10 active producers and 6 active injectors. The total amount of fluid injected at McGinness Hills was reported by Lovekin et al. (2016) to be 30,000 gpm but monthly data from the NDOM in 2016 indicate a more current production rate of 40,000 gpm.

Repeated tracer testing between the injectors and producers produced very similar return curves, with initial return times of 30 to 40 days (Lovekin et al., 2016), showing only very minor differences in tracer returns between the individual production and the individual injection wells. As of 2016 there had been no measurable cooling of the resource.

Production and injection permeability is due to fracturing in bedrock associated with normal faulting that has created two closely-spaced grabens. Conceptually, injection is into a graben bounding fault zone where this fluid flows down to greater depths and then rises along another oppositely dipping graben bounding fault zone to the production wells (Lovekin, et al. 2016). This is conceptually similar to the injection pattern seen at Steamboat. The confidence to produce and such large volumes of fluid at McGinness Hills was based on the prior collective Nevada injection experience and putting considerable thought and planning into developing an injection program early in the exploration process, rather than simply utilizing cooler or less productive exploration wells (Patrick Walsh personal correspondence).

16. Don A. Campbell (Wild Rose) (2013)

The first Dan A. Campbell, sometimes referred to as Wild Rose, 16 MW (net) power plant reached firm operation with 5 closely-spaced production wells and 3 closely-spaced injectors. The second 16 MW unit started up in September 2015, as the most recent power plant in Nevada, with an additional closely-spaced 4 producers and 2 injectors adjacent to the original wells. The production and injection well clusters are located about 1 ½ miles apart, with one mostly inactive injector located in between them. Orenstein and Delwiche (2014) describe both the production and injection zones as being in silicified and fractured alluvial sand and gravel with temperatures near 266 oF but did not present any overall conceptual understanding of the resource. This was the coolest geothermal field in Nevada with an injection program when it commenced operations.

The first well in the injection area encountered lost circulation at 1245' and the second at 683'. The first well in the production area encountered lost circulation at 1256'. Depths of more recent wells were not publicly available at the time this paper was written. The total reported injection flow rate in 2016 was 48,200 gpm, making it the largest geothermal injection project in Nevada as well as hosting the largest volume individual injector in the state at 15,000 gpm. Somewhat irregular reported production temperatures between early 2014 and late 2016 show little or no cooling occurring during the first three years of production. No tracer testing results have been published.

17. Patua (2013)

The 48 MW gross or 30 MW net Patua plant commenced operations with six production wells and seven injectors. It is the most recent geothermal field to commence operations in Nevada. The most recent publicly available technical paper on Patua (Peterson, et al., 2013) was written before all the wells were drilled and the plant had started up so it contains no information on the injection system or its performance. The Patua field appears to have the longest set of production and injection pipelines of any geothermal field in Nevada. Production and injection wells are widely dispersed but there is one cluster of 3 production wells and one cluster of 3 injection wells. Due to the dispersal of the production wells, the initial production temperatures were variable, ranging from 286 to 318 oF.

NDOM permitting records show the active Patua production wells have total depths of 8441’ and 9677’ (for wells drilled more than 5 years ago) and the active injection wells have total depths of 8528’ to 11,047’, potentially making some of these the deepest active individual injectors in Nevada. These total depths are all within the granitic basement (Peterson et al., 2013). In 2016 the injection rate at Patua was 7500 gallons per minute. This injection has resulted in an apparently highly variable cooling of the production wells between 0 and 9 oF between early 2013 and late 2016. Given the wide spacing of the various wells it is reasonable to expect that the individual wells will show variable changes over time.

18. Field Layouts

All of the Nevada fields have some common characteristics in the layout of production and injection wells that are inherited from the exploration process. The fields have either most or all of production well spacing measured in several tens of feet to perhaps 1200’ (40 acre spacing). This is due to an understandable tendency to reduce dry hole risk during exploration drilling by utilizing small stepout distances. It is also helpful that clustering of producers in Nevada has proven to be a successful development strategy, with the added benefit of reducing gathering system costs. Dixie Valley has two clusters of production wells. Steamboat, Soda Lake, Patua, and Desert Peak (since 2004) stand out as having individual production wells or small clusters of production wells that are more widely spaced or dispersed.

It is in the injection side of the field layout that more variability and dispersal is expressed, even if it was not the original developer’s intent. Again, this most often follows from earlier exploration where, with the most obvious exception of Blue Mountain, cooler (if only by a small amount) and perhaps less permeable wells, often originally drilled as intended producers, are later placed in service as injectors. In most cases this strategy is working to the point of getting the fields to produce for 30 years or longer at reasonable capacity factors. Tight clustering of injection wells seems to have been the primary serious injection problem in Nevada. At Stillwater, Bradys and Blue Mountain the initial remediation efforts in dealing with cooling focused of shifting injectate to more dispersed locations. It is far less costly to shift injectors than to place new and more dispersed pumped production wells in service. Only at Stillwater were the temperatures largely recovered by dispersing the injection well locations. At Steamboat (now with a 30 year production history), close spacing of producers and injectors has been successful. Nowhere has a remediation strategy been to concentrate injection into a smaller area or volume of the resource.

A relatively new problem facing the Nevada geothermal industry is the slow, long-term cooling of the resources. Can any injection modifications or strategy stop or reverse this trend? Any cures will involve working primarily on the injection side of the problem as that is the only aspect of geothermal resource management fully in control of the operators.

19. Discussion and Conclusions

Geothermal injection at 14 different Nevada fields has produced a wide range of outcomes varying from discouragingly negative to almost unbelievably positive i.e. McGinnis Hills. Every possible spatial relationship between producers and injectors along a fault zone has been utilized, with the obviously questionable exception of locating injection directly updip from producers. The collective experience has shown the benefits of injection of cooled brine back into the reservoir in maintaining reservoir pressures. Only at Wabuska, which in 2016 was operating near the 1 MW net output level, has injection not been implemented. At Beowawe a major cold groundwater intrusion managed to maintain reservoir pressures, in spite of injection being outside of the reservoir, but at the price of a 7 oF/year cooling trend. The benefits or penalties of partial injection outside of the Bradys reservoir have not been publicly quantified.

Individual injection wells have capacities ranging from 100 to 15,000 gpm. Total individual field injection amounts range from 3200 gpm to 48,000 gpm. Ratios of active injection wells to production wells in 2016 range from 2 injectors and 6 producers at Desert Peak to 4 injectors and 2 producers at Jersey Valley. Total depths of injectors range from 323’ at Empire to 11, 047’ in one injector at Patua. Lithologies of injection zones range from Quaternary alluvium to Tertiary sedimentary and volcanic rocks, to Mesozoic sedimentary and metavolcanic rocks to granitic rocks. Some fields return water directly to fractured rocks in fault zones and some inject into sub horizontal stratigraphic formations, and some are a combination of both.

All of the fields with injection programs that began operating prior to 2012 have long-term cooling of the production wells. Cooling has not been reported or confirmed in the McGinness Hills or Wild Rose fields which commenced operations within the past five years. Cooling rates have ranged from a low of near 1 oF/year at a minimum to a maximum of a few degrees per month. It has taken anywhere between a week or two to several years for cooling trends to become established and measurable. The earliest arriving cooling trends have been the greatest in magnitude and done the greatest financial damage to the projects. Only at Stillwater has major cooling of the resource been reversed by modifying the injection program. This reversal was done by spreading out from a very tightly clustered production/injection area to a more "normal-sized" area with significant separation between producers and injectors. At Bradys and Blue Mountain, which had significant separation between production and injection well clusters attempts at further dispersion have not yet recovered any temperatures. At other fields cooling trends have been reduced, even to the point of being difficult to measure, by modifying the field layout but actual temperature recovery has been occurred only once.

Benoit (2013) reviewed injection into six fault-hosted geothermal fields in the Basin and Range province and concluded that programs injecting 2000 to 3500 gpm/mile of fault could operate for a few decades without excessive cooling. However, given the more recent encouraging results at McGinness Hills and Don A. Campbell, that earlier conclusion might now be viewed as being conservative, provided that a method or technique is developed that can reliably predict deep or downward subsurface flows of injectate in advance of commencement of power generation.

Specific injection strategies developed in a haphazard manner range from initial injection outside of the reservoir to large horizontal separation between injectors and producers to a large vertical separation between injection and production zones to very close spacing between producers and injectors with injection at the same depth as production. Perhaps what has been most surprising but not widely appreciated is how successful very large volume injection can be when the injectate moves primarily downward into a reservoir i.e. Steamboat and McGinness Hills, rather than primarily horizontally toward nearby production wells completed at similar depths. The recent numerical modeling at Steamboat (Bjornsson et al., 2014), represents the first time advanced techniques have been to develop a potential strategy and tactics for dealing with long-term cooling of Nevada's geothermal reservoirs.

The flip side of the Steamboat injection success is how little is known about predicting responses to injection behavior and begs the question as to why injection at Bradys, for example, didn'tor couldn't also take a deeper and longer flow path to return to the production wells. Could this behavior have been predicted?

Acknowledgements:

Patrick Walsh reviewed and improved a draft of this paper.

References

Benoit, D. "A Case History of Injection through 1991 at Dixie Valley, Nevada." *Geothermal Resources Council Transactions*, Vol. 16, (1992) 611 – 620.

Benoit, D., and Stock, D. "A Case History of Injection at the Beowawe, Nevada Geothermal Reservoir." *Geothermal Resources Council Transactions*, Vol. 17, (1993) 473 – 480.

Benoit, D. "Injection-Driven Restoration of the Beowawe Geothermal Field." *Geothermal Resources Council Transactions*, Vol. 21, (1997) 569 – 575.

Benoit, D., Johnson, S., and Kumataka, M. “Development of an Injection Augmentation Program at the Dixie Valley, Nevada Geothermal field.” *Proceedings World Geothermal Congress* (2000) 819 – 824.

Benoit, D. “An Empirical Injection Limitation in Fault-Hosted Basin and Range Geothermal Systems.” *Geothermal Resources Council Transactions*, Vol. 37, (2013) 887 – 894.

Benoit, D. “The Long-Term Performance of Nevada Geothermal Projects Utilizing Flash Plant Technology.” *Geothermal Resources Council Transactions*, Vol. 38, (2014) 977 – 984.

Benoit, D. “A Case History of the Dixie Valley Geothermal Field.” *Geothermal Resources Council Transactions*, Vol. 39. (2015) 3 – 11.

Benoit, D. “Soda Lake Geothermal Field Case History 1972 to 2016.” *Geothermal Resources Council Transactions*, Vol. 40, (2016) 523 – 534.

Butler, S. J., Sanyal, S. K., Robertson-Tait, A., Lovekin, J. W., and Benoit, D. “A Case History of Numerical Modeling of a Fault-Controlled Geothermal System at Beowawe, Nevada.” *Proceedings, 26th Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford CA (2001) 6 p.

Bjornsson, G., Arnaldsson, A., and Akerley, J.”A 3D Numerical Model for Steamboat, Nevada.” *Geothermal Resources Council Transactions*, Vol. 38, (2014) 917 – 925.

Bloomquist, R. G. “Empire Energy, LLC – A Case Study.” *Oregon Geoheat Center Bulletin, June 2004,* 11 – 13.

Casteel, J., Trazona, R., Melosh, G., Niggemann, K., and Fairbank, B. “A Preliminary Conceptual Model for the Blue Mountain Geothermal System, Humboldt County, Nevada.” *Proceedings World Geothermal Congress 2010 Bali Indonesia*, (2010) 6 p.

Chabora, E., Lovekin, J., Spielman, P., and Krieger, Z. “Resource Performance at Ormat’s Tuscarora Geothermal Project, Nevada USA.” *Proceedings World Geothermal Congress 2015 Melbourne, Australia*, (2015) 8 p.

Dering, G., and Faulds, J. “Structural Controls of the Tuscarora Geothermal Field, Elko County, Nevada.” *Geothermal Resources Council Transactions*, Vol. 36, (2012) 41 – 46.

Drakos, P., Spielman, P., and Bjornsson, G. “Jersey Valley Exploration and Development.” *Geothermal Resources Council Transactions*, Vol. 35, (2011) 751 – 759.

Epperson, I. J. “Beowawe, Nevada, Well Testing: History and Results.” *Geothermal Resources Council Transactions*, Vol. 6, (1982) 257 – 260.

Faulder, D. D., and Johnson, S. D. “Desert Peak Geothermal Field Performance.” *Geothermal Resources Council Transactions*, Vol. 11, (1987) 527 – 533.

Forest, R. T., Johnson, S. E., and Johnson, S. D. “An Injection Turnabout Success at Stillwater, Nevada.” *Geothermal Resources Council Transactions*, Vol. 19, (1995) 485 – 491.

GeothermEx. “Status of Resource Development at the Blue Mountain Geothermal Project, Humboldt County, Nevada.” *Report prepared for Nevada Geothermal Power Inc.*, 21 April 2008, 124 p.

Goranson, C., van de Kamp, P., and DeLong, T. “Geothermal Injection and Monitoring Program History at the Caithness Power Inc. Flash Steam Power Plant Steamboat Springs, Nevada.”

Proceedings of the Symposium on Subsurface Injection of Geothermal Fluids, Oct. 29 – 30, 1990, 101 - 123.

Goranson, C., van de Kamp, P., and Call, E. "Summary and Interpretation of Six Years of Groundwater Monitoring Data at the SB GEO Inc. Geothermal Power Plant Steamboat Springs, NV." *Proceedings of the Underground Injection Control Practices – Reno, NV 1991* 77 – 93.

Hanson, H., Mines, G., and Wood, R. "Summary of Historical Production for Nevada Binary Facilities." *Geothermal Resources Council Transactions*, Vol. 38, (2014) 1001 – 1005.

Hoang, V. T., James, E. D., and Epperson, I. J. "Development Drilling, Testing, and Initial Production of the Beowawe Geothermal Field." *Proceedings, 12 th Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, CA (1987) 159 – 162.

Kaplan, U., Krieger, Z., and Dillenberger, A. "Innovative Design, Construction and Operation of the Steamboat 5 MW Geothermal Power Plant at Steamboat Springs, Washoe County, Nevada." *Geothermal Resources Council Transactions*, Vol. 11, (1987) 429 – 436.

Krieger, Z., and Sponsler, E. "Improvement to the Brady Geothermal Project to Compensate for Decline in Resource Performance." *Geothermal Resources Council Transactions*, Vol. 26, (2002) 735 – 738.

Lovekin, J., Delwiche, B., and Spielman, P. "McGinness Hills-Case Study of a Successful Expansion." *Geothermal Resources Council Transactions*, Vol. 40, (2016) 67 – 71.

Nordquist, J., and Delwiche, B. "The McGinness Hills Geothermal Project." *Geothermal Resources Council Transactions*, Vol. 37, (2013) 57 – 63.

Orenstein, R., and Delwiche, B."The Don A. Campbell Geothermal Project." *Geothermal Resources Council Transactions*, Vol. 38, (2014) 91 – 97.

Peterson, N., Combs, J., Bjelm, L., Garg, S., Kohl, B., Goranson, C., Merrill, R., van de Kamp, P, Lamb, A. "Integrated 3D Modeling of Structural Controls and Permeability Distribution in the Patua Geothermal Field, Hazen, NV." *Proceedings: Thirty-Eighth Workshop on Geothermal Reservoir Engineering* Stanford University, Stanford, CA (2013) 11 p.

Ram, H., and Krieger, Z. "Innovative Geothermal Power Plants the Solution to Geothermal Resource Constraints-The Ormat Way." *Geothermal Resources Council Transactions*, Vol. 13, (1989) 639 – 644.

Rhodes, G. T., Faulds, J. E., and Teplow, W. "Structural Controls of the San Emidio Desert Geothermal Field, Northwestern Nevada." *Geothermal Resources Council Transactions*, Vol. 34, (2010) 819 – 822.

Rose, P. E., Adams, M. C., and Benoit, D. "A Tracer Test at the Beowawe Geothermal Field, Nevada, Using Fluorescein and Tinopal CBS." *Geothermal Resources Council Transactions*, Vol. 19, (1995) 217 – 221.

Rose, P., Goranson, C., Salls, D., and Kilbourn, P. "Tracer Testing at Steamboat Hills, Nevada, Using Fluorescein and 1,2-Naththalene Dislfonate." *Proceedings: 24th Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, CA (1999), 7 p.

Rose, P., Benoit, W. R., and Kilbourn, P. M., 2001, “The Application of the Polyaromatic Sulfonates as Tracers in Geothermal Reservoirs.” *Geothermics*, Vol. 30, (2001) 617 – 640.

Walsh, P., Martini, B. A., and Spielman, P. “High Angle Fracture Controlled Permeability at Upper Steamboat Hills Geothermal Field, Nevada.” *Geothermal Resources Council Transactions*, Vol. 34, (2010) 833 – 837.