Groundwater salinity and the effects of produced water disposal in the Lost Hills–Belridge oil fields, Kern County, California

Janice M. Gillespie, Tracy A. Davis, Michael J. Stephens, Lyndsay B. Ball, and Matthew K. Landon

ABSTRACT

Increased oil and gas production in many areas has led to concerns over the effects these activities may be having on nearby groundwater quality. In this study, we determine the lateral and vertical extent of groundwater with less than 10,000 mg/L total dissolved solids near the Lost Hills–Belridge oil fields in northwestern Kern County, California, and document evidence of impacts by produced water disposal within the Tulare aquifer and overlying alluvium, the primary protected aquifers in the area.

The depth at which groundwater salinity surpasses 10,000 mg/L ranges from 150 m (500 ft) in the northwestern part of the study area to 490–550 m (1600–1800 ft) in the south and east, respectively, as determined by geophysical log analysis and lab analysis of produced water samples. Comparison of logs from replacement wells with logs from their older counterparts shows relatively higher-resistivity intervals representing the vadose zone or fresher groundwater being replaced by intervals with much lower resistivity because of infiltration of brines from surface disposal ponds and injection of brines into disposal wells. The effect of the surface ponds is confined to the alluvial aquifer—the underlying Tulare aquifer is largely protected by a regional clay layer at the base of the alluvium. Sand layers affected by injection of produced waters in nearby disposal wells commonly exhibit log resistivity profiles that change from high resistivity in their upper parts to low resistivity near the base because of stratification by gravity segregation of the denser brines within each affected sand. The effects of produced water injection are mainly evident within the Tulare Formation and can be noted as far as 550 m (1800 ft) from the main group of disposal wells located along the east flank of South Belridge.

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INTRODUCTION

Increased oil and gas production in many areas has led to concerns over the effects these activities may be having on groundwater quality. Historically, both the California State Water Resources Control Board (State Water Board) and the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) have defined groundwater resources needing specific protection from oil and gas activities as those containing less than 3000 mg/L total dissolved solids (TDS). Several recent developments have led the state to reconsider the 3000 mg/L TDS target. First, there has been an increased use of brackish groundwater resources having TDS of 1000 to 10,000 mg/L because these resources can be treated for domestic and industrial use for a lower cost than desalination of seawater (Leitz and Boegli, 2011; Mickley, 2012; Eastern Municipal Water District, 2019; McCann et al., 2018). Second, an audit by the US Environmental Protection Agency (EPA) of California oil and gas underground injection practices noted that the state has not consistently used federal standards to delineate protected groundwater resources (US Environmental Protection Agency, 2012). Third, public concerns about hydraulic fracturing and waste disposal practices of the oil and gas industry in general led to new legislation.

California Senate Bill 4 (SB 4 statutes of 2013) authorized the State Water Board to implement a program to monitor water quality in areas of oil and gas production beginning in 2015. The new program, the regional monitoring program of groundwater quality in areas of oil and gas development conducted in cooperation with the US Geological Survey, includes assessing potential impacts to groundwater associated with well stimulation (hydraulic fracturing), enhanced oil recovery (EOR) (water and steam flooding), and disposal of produced water by underground injection or surface sumps (California State Water Resources Control Board, 2018b).

The Lost Hills–Belridge study area lies in northwestern Kern County, California (Figure 1) and contains three large oil fields: North Belridge, South Belridge (collectively termed the Belridge oil fields) and Lost Hills. These oil fields are among the largest in California; South Belridge and Lost Hills were the third (22.6 million bbl/yr) and sixth (10.3 million bbl/yr) largest oil-producing fields, respectively, in 2016 (California Division of Oil Gas and Geothermal Resources, 2017). The area adjacent to the oil fields is also extensively farmed. Water quality in the aquifers is generally too poor to support large-scale farming without being blended with water from surface sources such as the California Aqueduct. However, some of the aquifers contain water with less than 10,000 mg/L TDS and are classified as underground sources of drinking water (USDW) under the Safe Drinking Water Act (1974). These aquifers must be protected from contamination when not exempted. Underground Injection Control regulations allow the EPA to exempt aquifers that do not currently or are not expected to serve as a source of drinking water, allowing these underground waters to be used

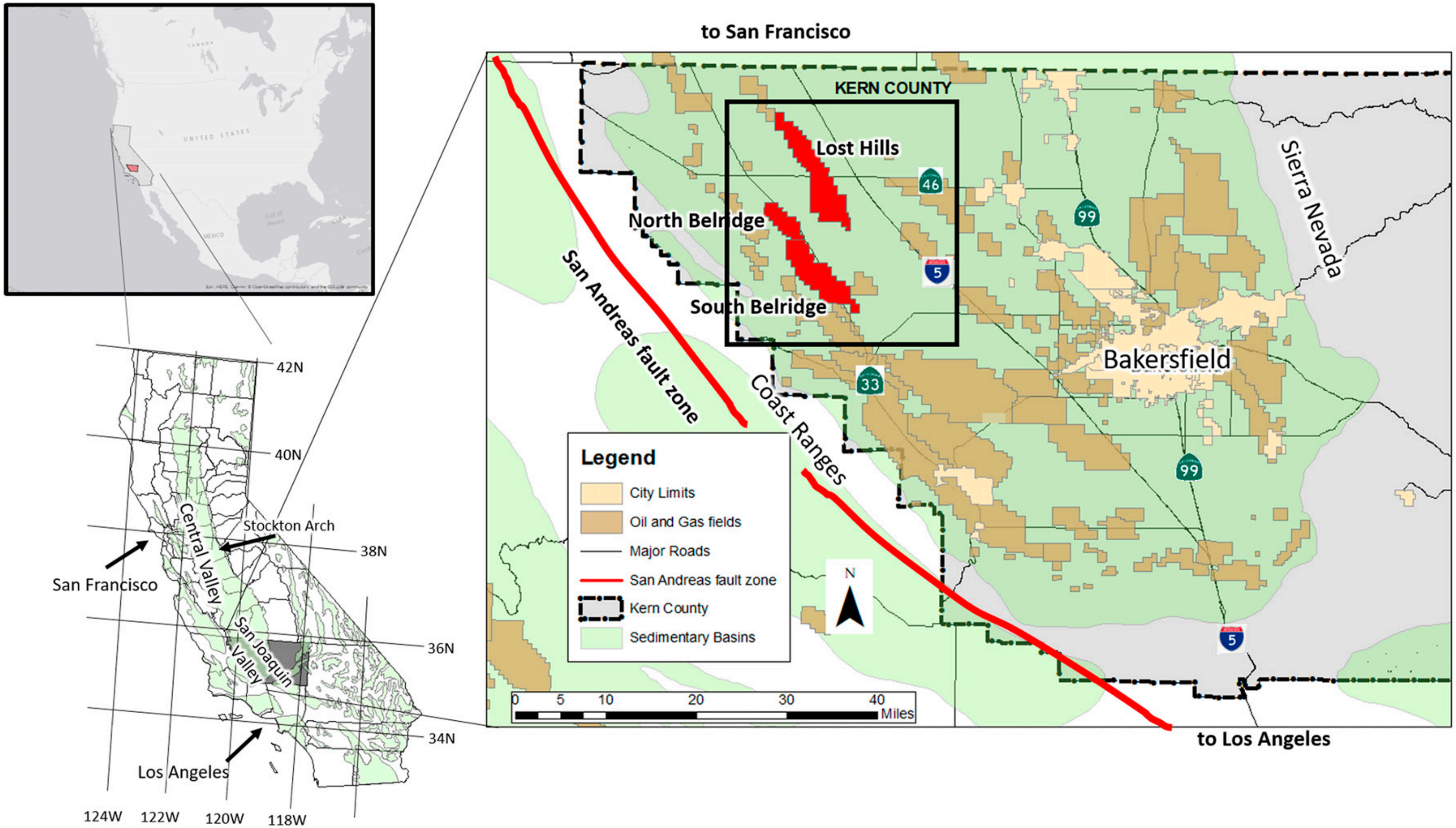

Figure 1. Location of the study area. Lost Hills and North and South Belridge oil fields shown in red. Study area outlined in black.

for oil or mineral extraction or disposal purposes (US Environmental Protection Agency, 2018).

A primary goal of this study is to determine the depth to the base of protected groundwater USDW, typically defined as waters containing less than 10,000 mg/L TDS that are not mineral, hydrocarbon, or geothermal energy producing (US Environmental Protection Agency, 2018). Because water analyses in deeper, brackish aquifers are sparse, this study also uses borehole geophysical log analysis to delineate protected aquifers in the area. Borehole geophysical logs from different time periods are used to map changes in subsurface salinity over time caused by produced water disposal in ponds and injection wells. These approaches can be used to improve the understanding of the occurrence of high salinity produced waters in proximity to oil fields at site-specific scales, movement of those fluids over time and to supplement more areally extensive, but commonly shallower and less spatially dense, monitoring well networks used to monitor shallow groundwater plumes from sites such as sump ponds.

GEOLOGIC SETTING

The Belridge and Lost Hills fields are located in the southwestern part of the San Joaquin Valley (SJV) which forms the southern part of the larger Central Valley of California (Figure 1). The SJV is bounded to the east and south by intrusive igneous and metamorphic rocks of the Sierra Nevada and to the south and west by igneous, metamorphic, and marine sedimentary rocks of the Coast Ranges. The northern geologic boundary is placed at the Stockton Arch, a broad low amplitude uplift which lies east of San Francisco.

The Central Valley initially formed as a forearc basin landward of a subduction zone in which the eastern Pacific plate was subducted beneath the North American continent. Circa 25 m.y.a, the East Pacific Rise encountered the trench offshore present-day southern California and the plate margin changed from convergent to transform, creating the San Andreas fault (Atwater, 1970). Movement along the San Andreas fault during the Miocene commonly cut off the southernmost SJV from open ocean circulation, forming a bottom layer of anoxic seawater in which organic-rich shales of the Monterey Formation (Figure 2) formed in a deep ocean setting (Graham, 1987). These shales ultimately became the source of much of the oil in the associated turbidite sands and overlying formations (Magoon et al., 2007).

Over time, the rate of sedimentation in the southern San Joaquin basin outpaced the rate of subsidence and shallow marine deposits of the Etchegoin and San Joaquin Formations were deposited above the deeper water deposits of the Monterey and Reef Ridge Formations (Lettis, 1982). Eventually, nonmarine conditions prevailed, resulting in deposition of the Pleistocene- age Tulare Formation and overlying alluvium across the area (Figure 2).

The southern part of the SJV is the most tectonically active area of the Central Valley. Transpressional forces along the San Andreas fault created an east-northeast vergent fold and thrust belt subparallel to the fault (Bartow, 1991) along the west side of the southern SJV. These folds and faults created numerous opportunities for the entrapment of vast pools of oil. The North and South Belridge oil fields and the Lost Hills oil field are located on south-plunging anticlines within the west side fold–thrust belt.

Hydrogeology and Aquifer Stratigraphy

The west side of the southern SJV lies in the rain shadow of the Coast Ranges to the west. The average rainfall is only 12–23 cm (5–9 in.) in the study area (Wood and Davis, 1959). What rain occurs falls mainly in winter. Temperatures commonly exceed 100°F during the summer resulting in high rates of evaporation. Consequently, streams draining the east side of the Coast Ranges are generally ephemeral and flow mainly in winter and spring. The water quality of these streams near the Belridge oil fields ranges from 1900 to 3200 mg/L TDS (Wood and Davis, 1959). This is partially the result of high evaporation rates but may also be attributed to the relatively soluble rock types found in the metamorphic and marine sedimentary rocks in the Coast Ranges (Laudon and Belitz, 1991). These streams are the main source of natural recharge to the groundwater system in the study area. In the last century, recharge from anthropogenic land use includes return flow from agricultural activity and leakage from unlined canals (Wood and Davis, 1959).

The Pleistocene Tulare Formation and overlying alluvium form the main aquifer in this area (Figure 2). Maps of the surface geology show that the Tulare Formation crops out in the northern Lost Hills and North Belridge fields, where most of the formation has been removed by uplift and erosion along the anticlines (Wood and Davis, 1959). The maximum thickness of

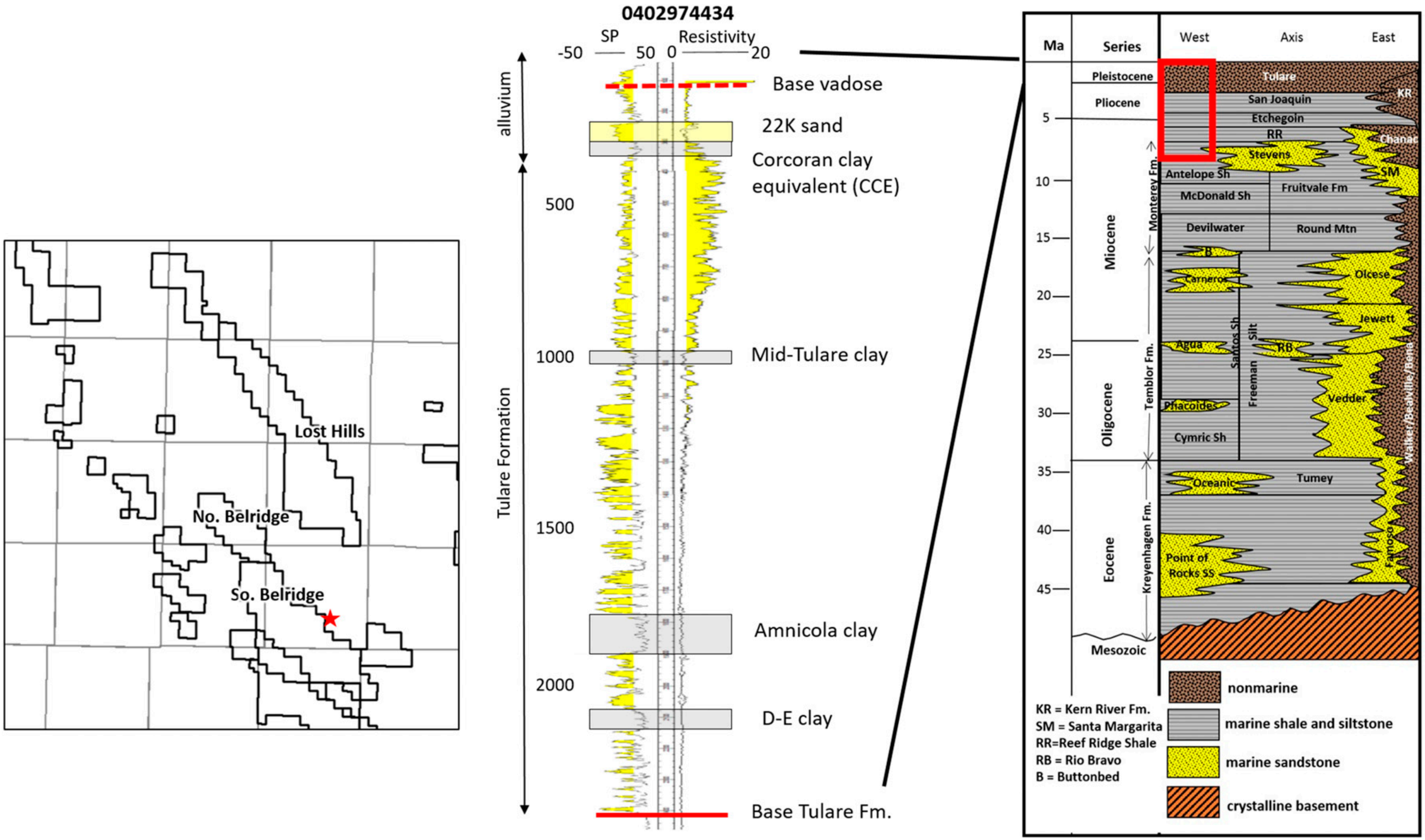

Figure 2. Type log (API 0402974434 shown by red star on inset map) of the alluvium and Tulare Formation in the study area. Yellow shading on spontaneous potential (SP) curve indicates sand bodies in the aquifer. Yellow shading on resistivity curve indicates resistivity greater than 3 ohm m. Major confining clays are shown in gray. Depth values in feet. Stratigraphic column of the southern San Joaquin Valley is shown on the right, with formations addressed in this study highlighted in red. Modified from Scheirer and Magoon (2007). Fm. = Formation; Mtn. = Mountain; No. = North; Sh. = Shale; So. = South.

the Tulare Formation on the western basin margin is 1147 m (3500 ft) (Woodring et al., 1940; Loomis, 1990).

Where it does not crop out, the Tulare Formation is overlain by alluvial deposits. Both the Tulare Formation and the overlying alluvium are derived primarily from the Coast Ranges and interfinger with Sierran-derived sediments from the east (Laudon and Belitz, 1991). The Tulare Formation and overlying alluvium have similar lithologic compositions and were deposited in fluvial and lacustrine environments; therefore, they are not readily distinguishable, especially in the subsurface. Maps of the water-level contours in the Tulare and alluvial aquifer by Wood and Davis (1959) indicate eastward gradients in the aquifer.

At Belridge and Lost Hills, the basal Tulare Formation contact is an angular unconformity, below which the San Joaquin Formation has been removed over most of the area. As a result, the Tulare Formation commonly lies directly upon marine deposits of the late Miocene to Pliocene Etchegoin Formation along the crests of the anticlines.

In the study area, the lower Tulare Formation consists of lacustrine and deltaic sands and the upper Tulare contains alluvial fan, meandering channels, and floodplain facies (Kiser et al., 1988; Miller et al., 1990). The Tulare Formation and overlying alluvium also include lacustrine clays, which form confining beds. Several distinct regional clay units within the Tulare Formation are present in the study area. Some of these clays are not present throughout the study area but, when present, act as local confining layers. The three main clays mapped using borehole geophysical logs in this study are the Amnicola, the Middle Tulare, and the Corcoran Clay Equivalent (CCE) (Figure 2). The D-E Clay is only present in the southeastern part of the area and was not mapped in this study.

The Amnicola is the oldest of the three mapped clay layers. It is described as an olive gray, partly calcareous/dolomitic, claystone that contains the gastropod *Amnicola* (Woodring et al., 1932; Berryman, 1973; Maher et al., 1975). In the southeast part of the study area where it is best developed, the Amnicola Clay lies atop a large coarsening upward sand. The Amnicola Clay is absent across the anticlinal crests and in the northern part of the syncline between Lost Hills and North Belridge. Fossil evidence from recent drilling in the area indicates that the Amnicola Clay is likely present along the east flank of northern Lost Hills.

Overlying the Amnicola Clay is a coarsening upward zone of sands, silts and clay that ranges from approximately 120–200 m (~400–700 ft) thick. The zone thickens to the south and thins to the north and along the crest of the anticlines. A clay layer with a pronounced high gamma-ray signature on geophysical logs lies above this zone and is termed the Middle Tulare Clay in this report. The Middle Tulare Clay marks a change in log character from vertically stacked, funnel shaped spontaneous potential (SP) and resistivity patterns with relatively high gamma-ray response (80–100 API in the lower Tulare Formation to a blocky SP and resistivity log pattern with lower gamma-ray response (40–80 API) in the upper Tulare Formation. This change in log pattern may represent a change from a series of prograding lacustrine delta environments in the lower Tulare Formation to a fluvial meander belt setting in the upper Tulare Formation as noted by Miller et al. (1990).

The Corcoran Clay described by Frink and Kues (1954), also known as the E clay (Croft, 1972) or blue clay by water well drillers, is the youngest of the three mapped clay layers and is an important marker bed within the SJV aquifer system. It divides the groundwater system of the western SJV into an upper semiconfined zone and a lower confined zone (Williamson et al., 1989; Belitz and Heimes, 1990). Several studies have mapped the upper clays of the Tulare Formation, beginning with Croft (1972), who mapped numerous clay layers in the southern SJV, including the study area. More recent studies have focused specifically on the Corcoran Clay and have used both surface and subsurface data to map the extent and thickness of the clay (Page, 1986; Burow et al., 2004; Faunt, 2009).

Petroleum companies operating in the area refer to a basal alluvial clay at the contact between the Tulare Formation and overlying alluvium as the CCE, although its relationship to the Corcoran Clay as defined by Frink and Kues (1954) is not clear because Frink and Kues (1954) place the Corcoran Clay within the Tulare Formation and Kiser et al. (1988) place it within the alluvium. In the northeastern part of the study area, the CCE correlates to the E clay of Croft (1972). South of the study area in the SJV, the identification of the Corcoran Clay becomes more problematic, and Page (1986) refers to the Corcoran Clay in this area as the modified E clay. Because the exact relationship between the CCE and the Corcoran Clay is not known, the clay will be termed the CCE in this paper.

The CCE is up to 60 m (200 ft) thick within the study area. It is absent in the northwestern part of the study area and above the Lost Hills and Belridge anticlines. Drillers in the area observe a color change in cuttings from orange-brown above the CCE to gray below it. A thick (18–21 m [60–70 ft]) sand, the 22K sand, lies above the CCE near South Belridge (Figure 2). Where the 22K sand is present above the CCE, it forms a separate aquifer from the underlying Tulare Formation.

OIL FIELD ACTIVITY

The Lost Hills and Belridge fields were discovered during 1910–1912. Initial production was from heavy oil sands in the Tulare and Etchegoin Formations and from fractured shales of the Monterey Formation. In 1930, light oil was discovered in the deeper Temblor Formation at North Belridge, but it is the shallower heavy oil, along with fractured diatomaceous deposits and shales in the Etchegoin, Reef Ridge, and Monterey Formations, that have been the mainstay of the fields to the present day because of the development of EOR techniques such as steamflooding, waterflooding, and hydraulic fracturing (Bailey, 1939; Ritzius, 1950; Land, 1984; California Division of Oil Gas and Geothermal Resources, 1998).

The waterflood technique was first initiated in the late 1940s in the Monterey shales in Lost Hills and the mid-1950s in the Temblor Formation sandstones in North Belridge (Figure 3). In the 1980s, waterfloods commenced in the Tulare Formation and the diatomite zones of the Monterey, Reef Ridge, and Etchegoin Formations. In the 1950s and 1960s, thermal EOR techniques (mainly steam cycling and flooding and, to a lesser extent, firefloods) were initiated to maximize production of heavy oil in the Tulare and Etchegoin Formations and Monterey diatomite.

In the diatomite zones, large-scale waterflooding, primarily to enhance oil recovery after hydraulic fracturing, began in the late 1960s and 1970s but became increasingly common after 1980. Although the waterfloods increased production, they also served to mitigate land subsidence and wellbore casing collapse caused by fluid removal from the high-porosity diatomite zones (Dale et al., 1996).

As oil is removed, water commonly comes in to fill the void, and it is common for water–oil ratios (WORs) to increase over the life of an oil field. In the Belridge oil fields, the WOR increased from 0.09 in 1931 to approximately 14 in 2016, and in Lost Hills, the WOR increased from 1.5 in 1931 to approximately 12 in 2016. Some of the produced water is reused for EOR practices such as waterflooding, but the remainder is disposed of by a variety of means. Initially, water disposal was accomplished by spreading the produced water on the ground, commonly in surface ponds or dry stream beds, and the water was allowed to evaporate or percolate into the underlying alluvium (Mitchell, 1989).

A series of legislative bills passed at both the state and federal level starting in 1969 with the Porter Cologne Water Quality Act, the 1972 Clean Water Act, and the Safe Drinking Water Act (1974) provided authority to establish regulations regarding surface water and groundwater degradation. As a result of these regulations, produced water disposal began to move from surface ponds to injection into nonoil-producing zones via water disposal wells. The federal Underground Injection Control program established nationwide requirements for the protection of all aquifers containing water with less than 10,000 mg/L TDS.

At Lost Hills oil field, water disposal by injection has increased from approximately 160,000 m^3/yr (~1 million bbl/yr) in 1973 to 4.8 million m^3/yr (30 million bbl/yr) in 2009. Disposal initially occurred into both the Tulare and Etchegoin Formations, but, by 1990, disposal was almost exclusively into the Etchegoin Formation. At North and South Belridge fields, disposal began at 636,000 m^3/yr (4 million bbls/yr) in 1970 and increased to more than 12 million m^3/yr (>78 million bbl/yr) in 2009 (Figure 3). Belridge disposal is almost entirely into the Tulare Formation.

METHODS

The main data used in this study are borehole geophysical logs and water quality laboratory analyses. These data were used to pick marker horizons for geologic mapping and to determine water salinity and aquifer pressures. Data compiled and analyzed for this study are available from Gillespie et al. (2019).

Mapping

Approximately 900 borehole geophysical logs from wells within the study area were used to determine the lateral continuity and stratigraphic relationships

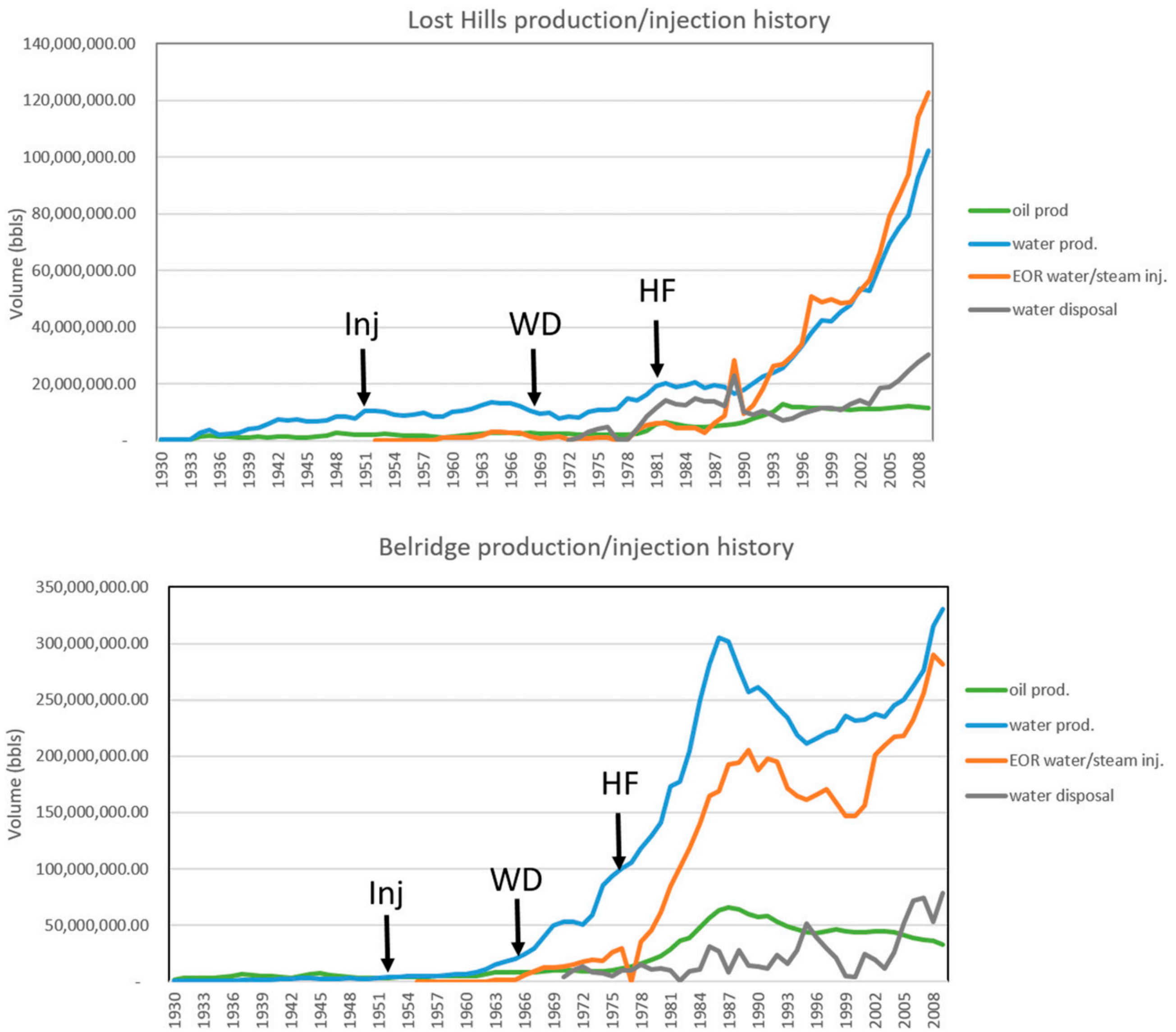

Figure 3. Production (prod.) and injection (inj.) curves for the Lost Hills and North and South Belridge fields (combined). EOR = enhanced oil recovery; HF = initiation of hydrofracking; Inj = initiation of water injection for enhanced oil recovery; WD = initiation of disposal of produced water in injection wells. Data prior to 1973 are from California Division of Oil Gas and Geothermal Resources (2015); post-1973 data are from California Division of Oil Gas and Geothermal Resources (2019).

between the late Miocene to Holocene formations. Electric logs (resistivity, SP) and gamma-ray logs were used to identify correlatable layers (Figure 2). Well data (geophysical logs, mud logs, core data, and well histories) were obtained primarily from oil and gas well records available from the DOGGR (California Division of Oil Gas and Geothermal Resources, 2018) and from water well records obtained from well owners and the California Department of Water Resources.

Because the Tulare Formation and overlying alluvium form the major nonexempt aquifers in the area, these layers were mapped in more detail, particularly with regard to clay layers. Many of the clay markers lose their coherence when mapped over large distances and between distantly spaced wells outside the oil field boundaries because of the rapidly changing character of the Tulare fluvial–lacustrine delta system. In many places, it was not possible to correlate the clay layers throughout the region. The correlations were used to construct thickness (isochore) maps of the combined alluvium and Tulare Formation (Figure 4) and CCE and Amnicola clays (Figure 5). The correlated logs were

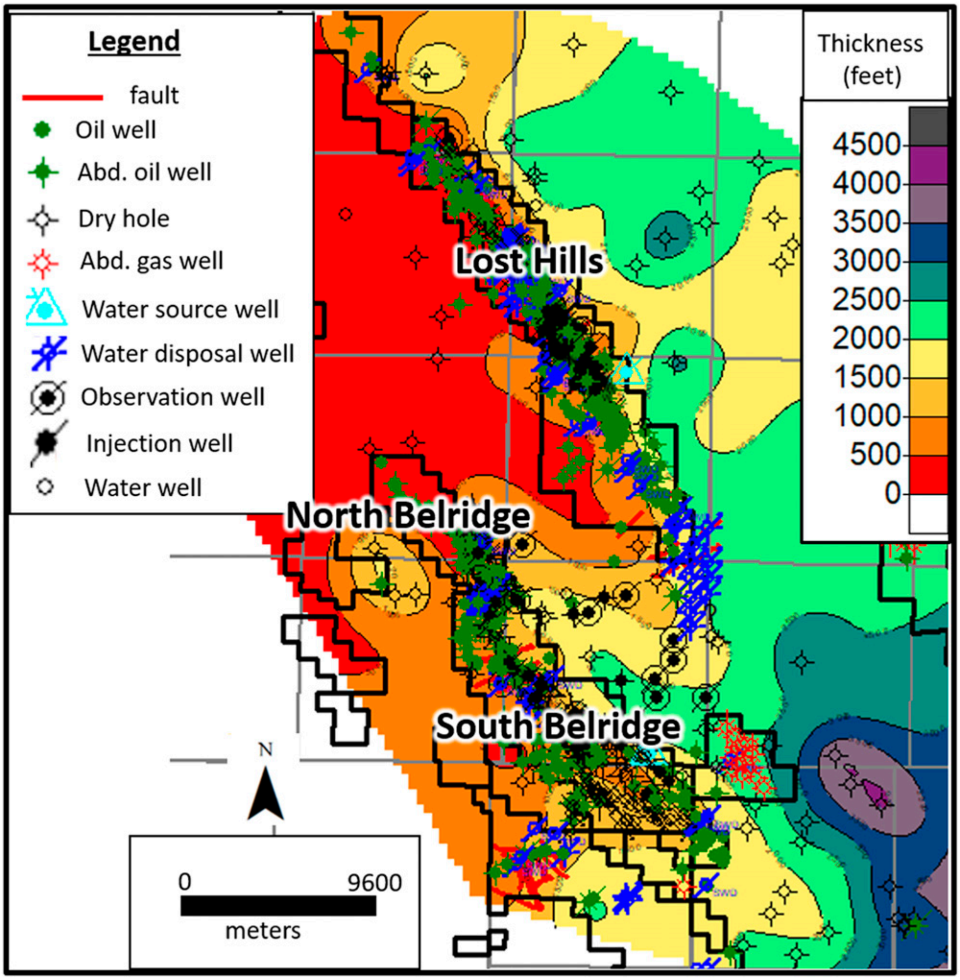

Figure 4. Map showing depth to base of Tulare Formation. The values are equivalent to the thickness of the Tulare Formation and overlying alluvium. Wells shown are those used to determine thickness. Black lines are oil field administrative boundaries. Gray lines are township boundaries. Red lines are faults (Young, 1968; California Division of Oil Gas and Geothermal Resources, 1998). Abd. = abandoned.

compared to salinity data to determine the extent to which salinity is controlled by aquifer stratigraphy.

Wireline formation testers measure pressure build up within a small interval of the sands (Schlumberger, 2006). Within a single homogeneous aquifer, the pressure values should increase with depth along a straight line representing the hydrostatic gradient. Shifts from the hydrostatic pressure gradient line indicate the presence of pressures in individual aquifer layers that imply restricted hydraulic connections with other aquifer layers caused by confining clay layers (Coburn and Gillespie, 2002). Wireline formation tests in the Tulare Formation have been conducted in some test holes drilled in the study area by oil companies prior to well installation (Gillespie et al., 2019). These records, compiled for 59 wells, were analyzed to help determine which clays are significant confining layers.

Salinity Determination

For this study, two different methods were used to determine water salinity within the aquifers in and around the Belridge–Lost Hills oil fields. The first is indirect estimation of salinity using geophysical logs collected prior to installation of oil wells. The second is direct measurement by lab analysis of produced water samples from oil wells in the area, which were compared to the indirect estimates.

Log Analysis

Although direct sampling and chemical analyses are commonly considered the best method for determining TDS in any aquifer, in many cases (particularly in deep aquifers containing brackish water) these analyses are uncommon. In addition, water samples provide only

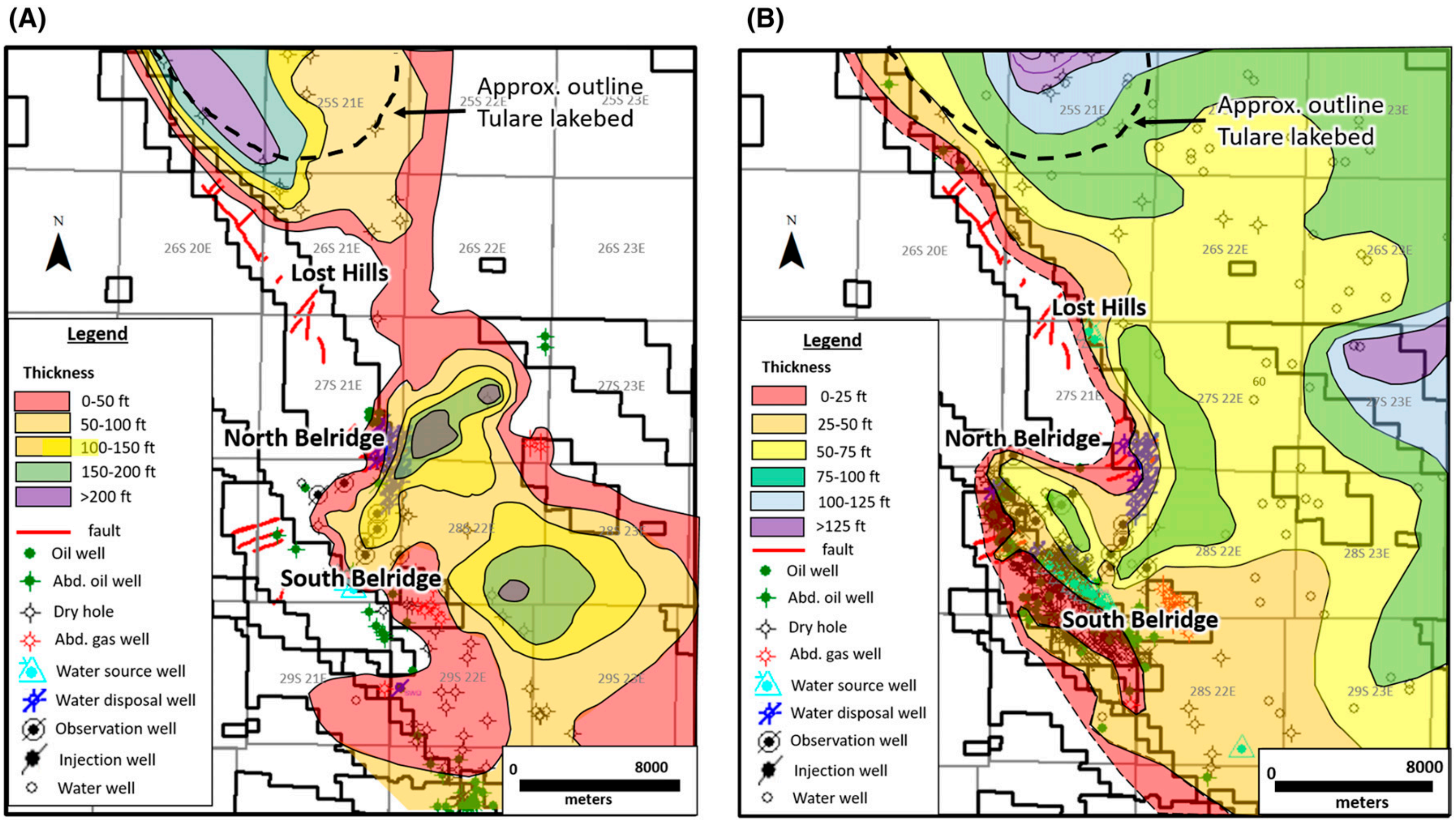

Figure 5. Isochore maps of the (A) Amnicola Clay and (B) Corcoran Clay Equivalent layers in the study area. Wells shown are those used to determine thickness. Gray lines are township boundaries. Red lines are faults (Young, 1968; California Division of Oil Gas and Geothermal Resources, 1998). Abd. = abandoned; Approx. = Approximate.

point-source data from a single depth interval and do not tell us at what depth the salinity changes. However, in active petroleum-producing basins such as the SJV, open-hole geophysical logs are abundant. Geophysical logs provide continuous vertical records of the properties of the formation matrix, fluids adjacent to the borehole, and fluids within the borehole. Using log analysis, it is possible to calculate the depths at which salinity changes occur. These depths may be verified by chemical analyses where available. Of particular interest for determining salinity are the electrical logs (SP and resistivity) because the ability of water to conduct an electrical current is strongly influenced by both the temperature and salinity of the formation water.

Use of electrical logs to determine water salinity is most common in the petroleum literature. In oil-bearing reservoirs, it is important to know the resistivity of the water which occurs with the oil to determine the oil saturation using the Archie (1942) equation or one of its many variants.

Fewer studies have evaluated the use of electrical logs to determine salinity in fresh to brackish aquifers. Howells (1990) and Howells et al. (1987) used well-log interpretation to determine the location of the base of moderately saline (<10,000 mg/L TDS) water in Utah. Lindner-Lunsford and Bruce (1995) used the Archie Equation to determine salinity in aquifers with TDS less than 1000 mg/L in southwest Wyoming. Schnoebelen et al. (1995) used geophysical logs to map the depth to 10,000 mg/L TDS water in carbonate aquifers in Indiana using the SP log, mud filtrate resistivity, and the resistivity porosity method of Archie. They compared the results to sampled water analyses and found the resistivity porosity method to be most accurate. More recently, Hamlin and de la Rocha (2015) used the Archie Equation to map fresh (<1000 mg/L TDS), slightly saline (1000–3000 mg/L TDS), moderately saline (3000–10,000 mg/L TDS), and very saline (>10,000 mg/L TDS) water in the Carrizo–Wilcox aquifer of south Texas. Gillespie et al. (2017) used log analysis to determine depth to 10,000 mg/L TDS on a regional basis throughout much of the southern San Joaquin Basin, but the western margin fields were not considered in their study because the presence of shallow oil reservoirs require more extensive mapping to locate wet sands for log analysis.

In this study, a variation of the Archie Equation was used to estimate salinity (as NaCl equivalent) from the geophysical logs. Archie (1942) related the in situ electrical resistivity of a fully water saturated sedimentary rock (R_o) to its porosity (ϕ), nondimensional factors related to matrix properties (the cementation factor [m],and the tortuosity factor [a]), and the resistivity of the formation water (R_w) as shown in equation 1.

$$R_w = R_{o^*}(\phi^m/a) \quad (1)$$

R_o is the resistivity of a clean (minimal clay content), oil-free, wet sand and can be obtained from the deep resistivity curve. Sands were chosen based on an evaluation of nearby core, mud log, and drillers log data indicating that the sands analyzed did not contain oil or gas. The porosity value is obtained from porosity logs, such as density, neutron, sonic, or nuclear magnetic resonance logs, and core analysis. For this study, sonic porosities were not used; the poorly consolidated nature of the aquifer sediments causes additional slowing of the sonic wave from compression of the material, resulting in artificially high porosity values.

Because of the poorly sorted nature of the sediments and the presence of large amounts of clay and silt in some zones, the average porosity used for salinity calculations weighted density measurements twice as much as neutron values. Neutron values for porosity are based upon the abundance of hydrogen atoms in a formation. Because clays contain hydroxide groups within their crystal lattice, the neutron curve tends to overestimate porosity when clays are present. The largest separation between the density and neutron curves on each log was considered to be a zone with 100% clay. The separation of the density–neutron curves for each evaluated interval was compared to the 100% clay separation value to estimate clay content. The R_w values were not calculated for intervals containing more than 25% clay.

The exponent m (unitless) is related to the degree of cementation in clastic rocks. It typically ranges from 1.3 to 2.6 (Wylie and Rose, 1950). The value a (unitless) is called the tortuosity factor and is related to the length the current must travel through the formation. The value for a typically ranges from 0.5 to 1.5. For this study, special core analyses from five intervals in the Tulare Formation were available in the California DOGGR online files from a water disposal well south of the Lost Hills field (American Petroleum Institute [API] well number [no.] 0402974433). The value for a was kept constant at a value of 1 and m was allowed to vary. The measured values for m ranged from 1.5 to 1.8 with a mean value of 1.7 (standard deviation of 0.15) and a median value of 1.8. For this study, salinity calculations used $a = 1$ and $m = 1.7$ based on the special core analysis results.

Upon obtaining a value for R_w and calculating the temperature of the zone of interest from a linear interpolation between bottom borehole temperature and air temperature of 75°F, the formation water salinity can be estimated from empirical charts such as those provided by Schlumberger (1997) or from equations such as those in Bateman and Konen (1977) relating fluid resistivity to NaCl equivalent TDS concentration.

Geochemical Analyses

The California Division of Oil Gas and Geothermal Resources (2016) maintains a website containing scanned copies of chemical analyses of oil field waters. These data are useful in determining the salinity of the deeper aquifers not normally used for drinking water or irrigation. Data taken from these reports included dates of testing, source of water for test (when available), major ion concentrations, and TDS concentrations. The compiled data are available from Gillespie et al. (2019). Chemical analysis of groundwater samples compiled from various sources were also available (Metzger et al., 2018). However, these samples were generally available from relatively shallow depths and had TDS ranging from approximately 1000 to 3000 mg/L and therefore did not directly contribute to efforts to map the depth to USDW.

Scanned copies of well completion reports are also available for the wells with chemical analysis from the California Division of Oil Gas and Geothermal Resources (2018) Well Finder online search engine. The completion reports for the wells provide information including perforated intervals, date perforated, geological formation sampled (in some cases), scanned copies of borehole geophysical logs, pressure tests, and bottom-hole temperatures. These records were used to determine the depth interval and formation represented by the produced water chemical analysis data (Gillespie et al., 2019).

Produced water chemical analyses from approximately 150 oil production, injection, and observation wells in the study area were available from DOGGR's online chemical analysis database (California Division of Oil Gas and Geothermal Resources, 2016). Additionally, 12 samples from the Tulare Formation and alluvium were available from groundwater monitoring wells in the Lost Hills oil field on the Geotracker website (California State Water Resources Control Board, 2018a). The vintage of samples in the database ranges from 1932 to 2017.

The sample analyses may not always represent natural aquifer conditions. For example, water samples are commonly collected when a well has production problems or during the initial development of a well (Blondes et al., 2016). Production problems may include holes in well casings or annular cement that may have caused water from a different zone to enter the perforations. In most cases, few data exist regarding the sampling procedures and analysis techniques, particularly for the older samples. However, older samples were considered to be important for this study because they predate the use of many EOR techniques such as water flooding, waste disposal, and steam injection, the large-scale use of which commenced in the early to mid-1960s. These EOR processes may significantly alter the salinity of the samples and cause the more recent samples to be an inaccurate reflection of the original aquifer conditions. Samples taken at different time intervals are helpful in determining temporal changes in salinity that may have occurred because of oil field activities.

One quality control method used in this study was to perform a charge balance on the analyses. Because water is electrically neutral, the negative (anions) and positive (cations) charged ions should sum to zero. The difference between the total milliequivalents of the cations and anions is divided by the sum to give a charge balance error. We used a cutoff of ±5% to determine which samples to discard in this analysis.

For wells used for injection purposes, the initiation of water injection relative to the date of sampling may be important to consider. Samples taken after the start of injection in the sampled well may not accurately represent the true formation water composition. In most cases, it was not feasible to catalog the time of initiation of injection in nearby wells because of the large number of injection wells that could potentially affect a sampled well. Consequently, the effect of subsurface injection on sample TDS data remains a source of uncertainty in the analysis.

RESULTS

The methods and data discussed in the previous section were used to construct geologic maps showing the thickness and continuity of aquifers and confining units as well as to determine aquifer salinity and temporal changes in salinity. These results are discussed below.

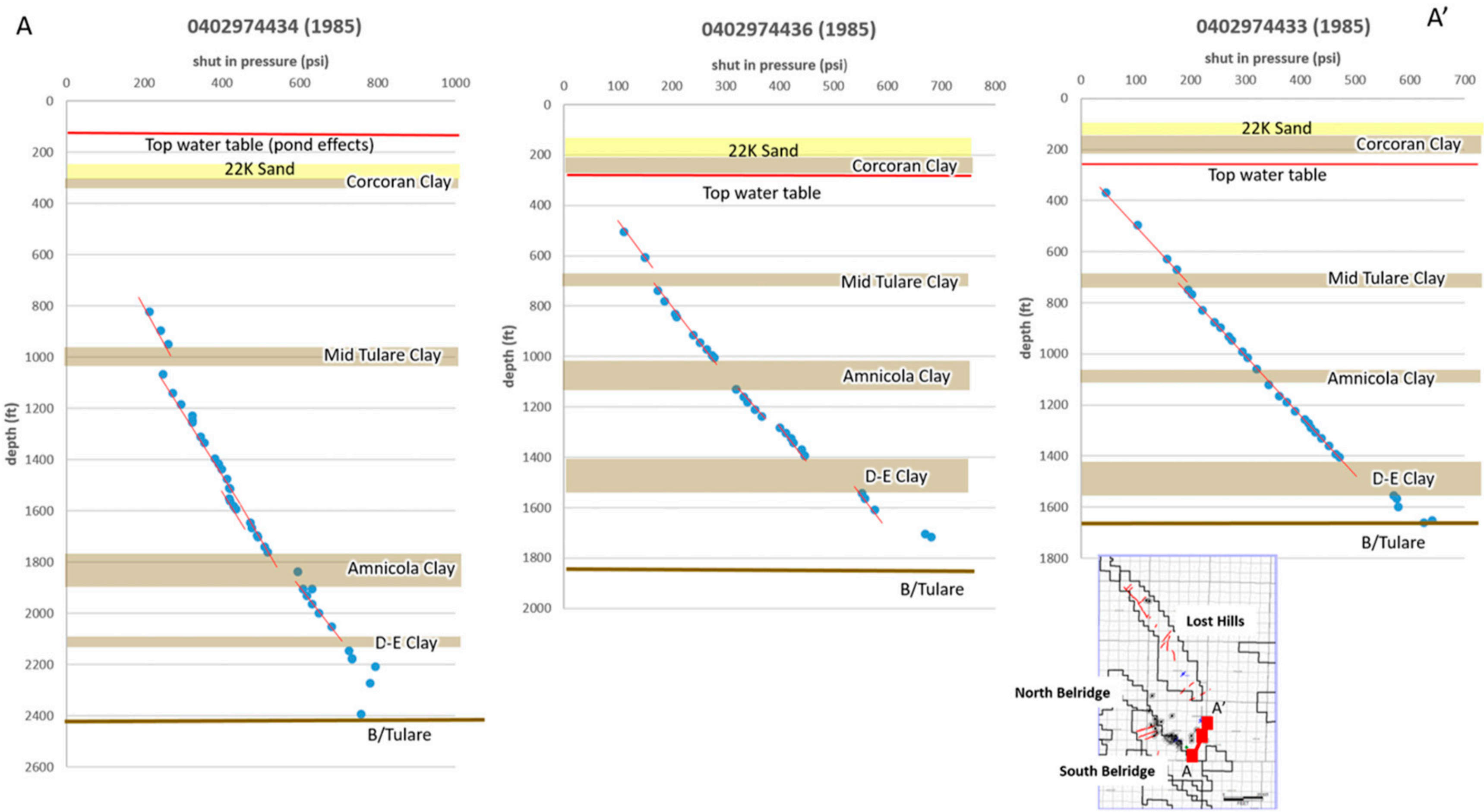

Figure 6. Graphs of shut-in pressure (from open-hole sequential formation testers) versus depth for three wells across the study area. Red lines are used to emphasize the pressure gradient. Tan areas show major clay layers, the 22K sand is shown in yellow. Base of Tulare and top of the water table are also noted. Wells are identified by their API number and the year drilled and logged at the top of each graph.

Geologic Mapping

The thickness of the Tulare Formation and overlying alluvium in the study area (Figure 4) ranges from 1200 m (4000 ft) in the southeast part of the study area to 75 m (~250 ft) along the anticline crests in the northern parts of Lost Hills and North Belridge oil fields. Because chemical analyses indicate that the protected aquifers occur largely within the Tulare Formation and overlying alluvium throughout the study area, the map of the depth to the base of the Tulare Formation defines the extent of potential protected aquifers outside the oil field limits.

The Amnicola Clay is thickest (67 m [~220 ft]) along the northeastern and southeastern flank of the Lost Hills anticline and east of the South Belridge anticline (Figure 5A). It thins to zero in the northwest part of the study area. The clay is replaced by sandier sediments east of the central part of the Lost Hills anticline. The CCE thickens to 61 m (~200 ft) in the northcentral part of the study area in the Tulare lakebed but is commonly less than 30 m (<~100 ft) thick (Figure 5B). It is absent over the Lost Hills anticline crest and in the northwestern part of the study area. These clay maps (Figure 5A, B) are used to determine the presence of possible confining beds that, in some cases, may control the distribution of protected water resources and restrict the migration of potential contaminants.

Graphs of pressure versus depth collected in 1985 from three wells along a northeast-trending transect from South Belridge to south of Lost Hills are shown in Figure 6. Marked changes in the hydrostatic pressure gradient in well API no. 02974434 occur across the Middle Tulare Clay and Amnicola Clay layers. An additional, deeper clay, here termed the D-E Clay, forms a local confining layer isolating a relatively low permeability section at the base of the Tulare Formation from the rest of the aquifer. These characteristic deviations in hydrostatic gradients indicates that the clays hydraulically separate individual aquifer layers in the area of this well.

Farther northeast, in wells API no. 02974436 and API no. 02974433, these deviations from hydrostatic gradient are much less noticeable, especially across the Amnicola Clay. This suggests that either (1) the clay layers are less confining south of Lost Hills, or (2) the hydrologic regime near South Belridge has been altered by production and injection into the Tulare Formation and the pressure responses in aquifer layers near the field in 1985 had not had sufficient time for their pressures to reach equilibrium. Recent drilling and multiple well monitoring site data (April 2018) off the eastern flank of the northern Lost Hills oil field indicates a 4.5 m (~15 ft) head difference across the Amnicola Clay with an upward gradient of 0.038 (measured May 31, 2018), suggesting that it is a confining layer in the northeastern part of the study area (US Geological Survey, 2018a, b).

Salinity Analysis

Log analysis from 30 wells in areas outside the oil field boundaries or within the oil fields but below the oil–water contact were used to create a map of the depth to the base of USDW. The depth map to the base of USDW shows two trends (Figure 7). In the area between Lost Hills and the Belridge oil fields, depth to USDW increases toward the south from 150 m (~500 ft) between North Belridge and Lost Hills to 490 m (~1600 ft) southeast of South Belridge. In the

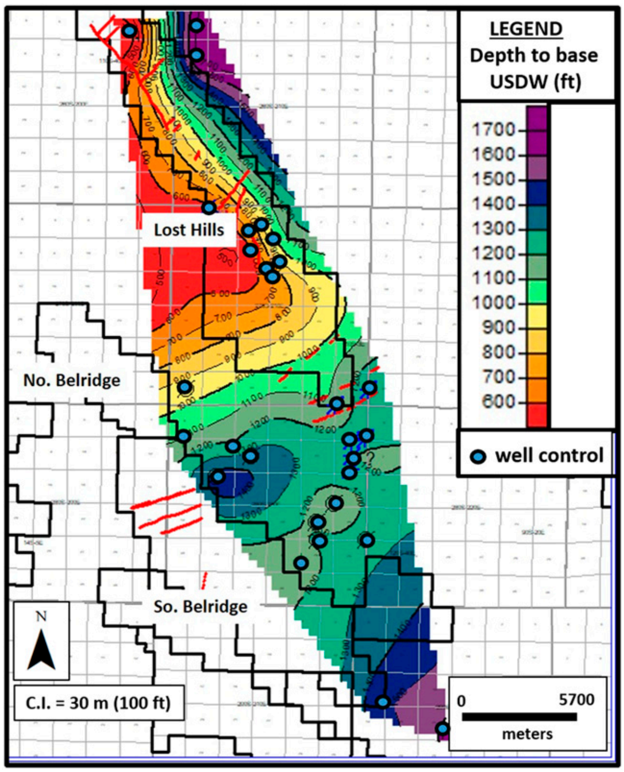

Figure 7. Map showing depth to base of underground sources of drinking water (USDW) (total dissolved solids = 10,000 mg/L) based on log analysis. Red lines indicate faults (Young, 1968; California Division of Oil Gas and Geothermal Resources, 1998). Black lines are oil field administrative boundaries. Wells shown as blue dots are those used to determine the base of USDW. Depth values in feet. C.I. = contour interval; No. = North; So. = South.

eastern part of the study area, depth to base of USDW increases sharply eastward from approximately 215 m (~700 ft) on the west flank of the Lost Hills anticline to as great as 550 m (~1800 ft) within 3 km (~2 mi).

Salinity–depth profiles based on chemical analyses of produced water samples were compared to the depth to base USDW map estimated from borehole geophysical log analysis. However, this comparison was limited because most of the lab analyses come from oil-producing wells within the field boundaries rather than in areas outside the fields. The presence of oil in the sampled intervals within the fields precludes the use of log analysis to calculate the salinity in these same wells. Plots of TDS versus depth of the samples in each field are shown in Figures 8 and 9 along with log-calculated TDS.

Wood and Davis (1959) reported the groundwater chemistry in this area as being an $NaSO_4$ type; however, only one Tulare Formation monitoring well, Mackessey no. 1 (API no. 02987363) was an $NaSO_4$ type; the rest are NaCl type. Because the calculated salinity from Archie log analysis assumes NaCl water types, the log-calculated and lab sample TDS values should be comparable. The two monitoring wells completed in the alluvium have higher SO_4 concentrations relative to the Tulare Formation wells; however, Cl is the dominant anion.

Only four Tulare Formation lab samples (blue dots) in Lost Hills are in the California DOGGR database. Data from 14 monitoring wells in the central part of the Lost Hills field were used to enlarge the data set (Figure 8). With the exception of one sample, TDS concentrations in the Tulare Formation and alluvium are less than 10,000 mg/L indicating protected (USDW) aquifers. These wells have top perforations ranging from 40 to 290 m (133–950 ft). The well with a lab analysis indicating a salinity of 12,295 mg/L TDS in the Tulare Formation had a top perforation at 300 m (984 ft). This suggests that the base of USDW lies somewhere between 290 and 300 m (950 and 985 ft) within the field. Log analysis suggests that the base may occur as deep as 580 m (~1900 ft), but many of the wells used for log analysis come from areas east of the field boundary where the Tulare Formation is much thicker (200 ft within the field vs. 2000 ft east of the field [Figure 4]). Within the field, interpolated contour lines from log data show the depth to base USDW at 213 m (~700 ft) along the western field boundary and 365 m (~1200 ft) along the eastern field boundary, a trend that is consistent with the more limited water sample data.

Typical TDS concentrations in the underlying Etchegoin Formation (red dots) range from 20,000 to 35,000 mg/L, probably because of the presence of trapped connate seawater within these marine deposits. In northern Lost Hills (Figure 8), two samples from Etchegoin sands have TDS concentrations below 10,000 mg/L. However, in this area, an active steamflood is ongoing within the Tulare and Etchegoin Formations. Here, the Etchegoin Formation sands lie at shallow depths (<150 m [~500 ft]) immediately below producing intervals in the Tulare Formation. The Etchegoin Formation samples in this area are much more dilute (5600–8,000 mg/L) than in other areas. This may be because the sands are in hydraulic communication with the fresher water sands of the overlying Tulare Formation or because the Etchegoin sands in this area are steamflooded and the more saline formation water is diluted by the injected steam. Since the two Etchegoin USDW samples are post-steamflood initiation, the latter explanation is likely.

Only one chemical analysis sample from the Tulare Formation is available in the North Belridge field (Figure 9). The TDS concentration of the sample is 6055 mg/L from a depth interval of 157–211 m (515–692 ft). It confirms that waters above approximately 211 m (~700 ft) are USDW, consistent with the log-derived depth to USDW map, which shows depth to USDW near the well at 275 m (900 ft).

Many lab analyses are available for the Tulare Formation at South Belridge (Figure 9), but they do not show salinity values that are correlated with depth. The log-generated depth to USDW map shows that salinity trends along the northern part of the oil field are variable but the southern part of the field shows depth to USDW increasing toward the southeast. Therefore, samples from northern and southern South Belridge were considered separately. The boundary between the two subareas is shown by the dashed line in Figure 9. Because of the variability in sample TDS values with depth, comparisons of sample data to calculated salinities from well-log analyses can only be made in a general fashion.

In the northern part of the South Belridge field, no samples below 365 m (1200 ft) are USDW, suggesting that the base of USDW lies above this depth. The log-derived map shows depth to base of USDW at 335 m (1100 ft) in the north. To the south, the base of USDW increases to 427 m (~1400 ft). Near the dividing line between the north and south parts of the field, the depth to base USDW decreases to 365 m (1200 ft).

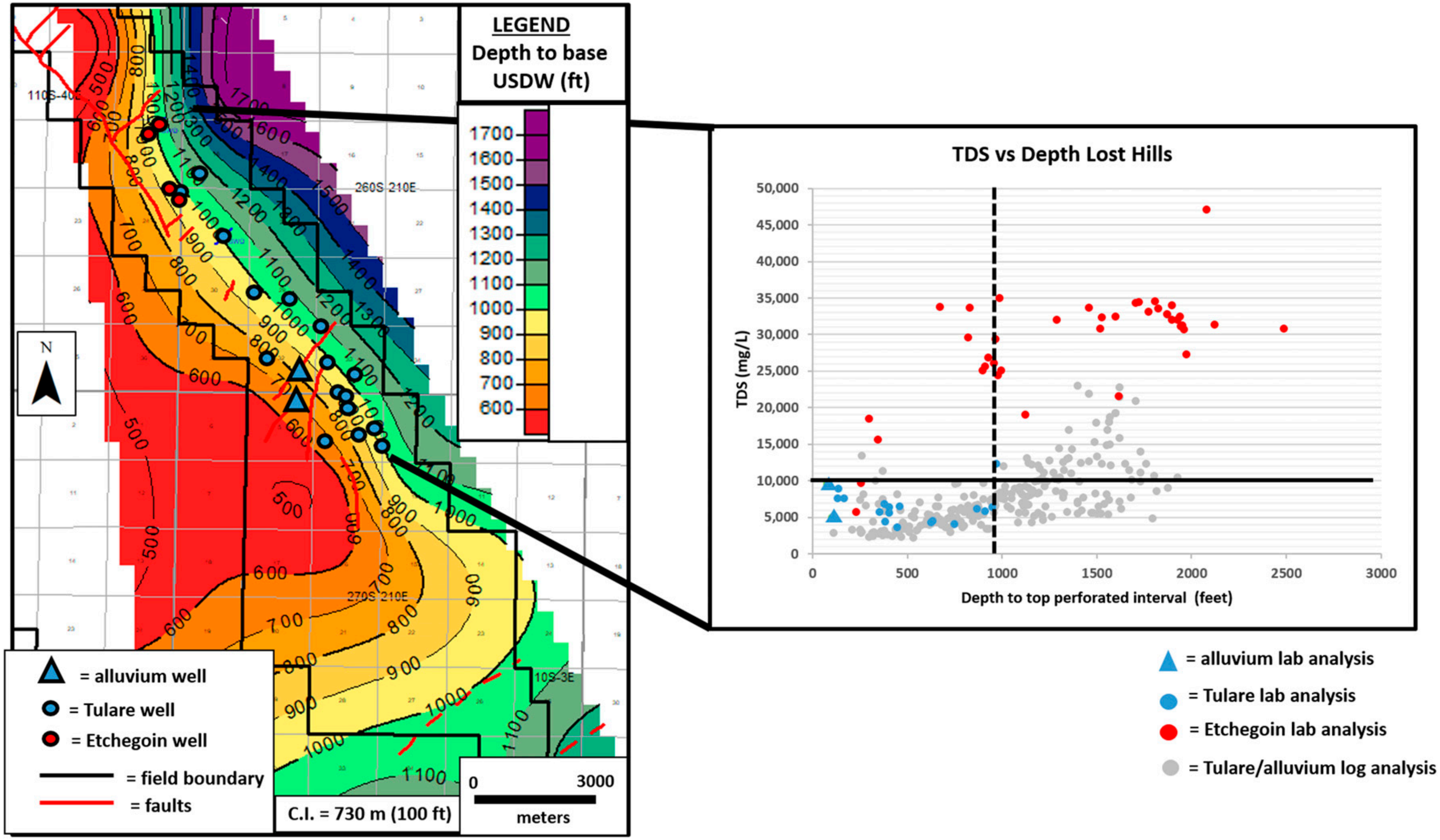

Figure 8. Graph of total dissolved solids (TDS) versus depth of geochemical samples from the Tulare and alluvium (blue) and Etchegoin (red) formations in and near the Lost Hills oil field. Gray dots represent TDS calculated from geophysical logs in the field. The horizontal red line marks 10,000 mg/L and the vertical dashed red line marks the approximate depth of the deepest underground sources of drinking water (USDW) sample. The adjacent map shows the location of the Tulare and alluvium wells sampled as blue dots and shallow (<150 m [500 ft] deep) Etchegoin samples as red dots (deeper Etchegoin sample sites are not shown on map) and the contours to base USDW from log analysis. Lost Hills is the only area that contains brackish water in the Etchegoin Formation. However, the brackish waters in the Etchegoin occur in an oil-producing zone that is steam flooded so it is considered to be an exempt aquifer and is not protected. C.I. = contour interval.

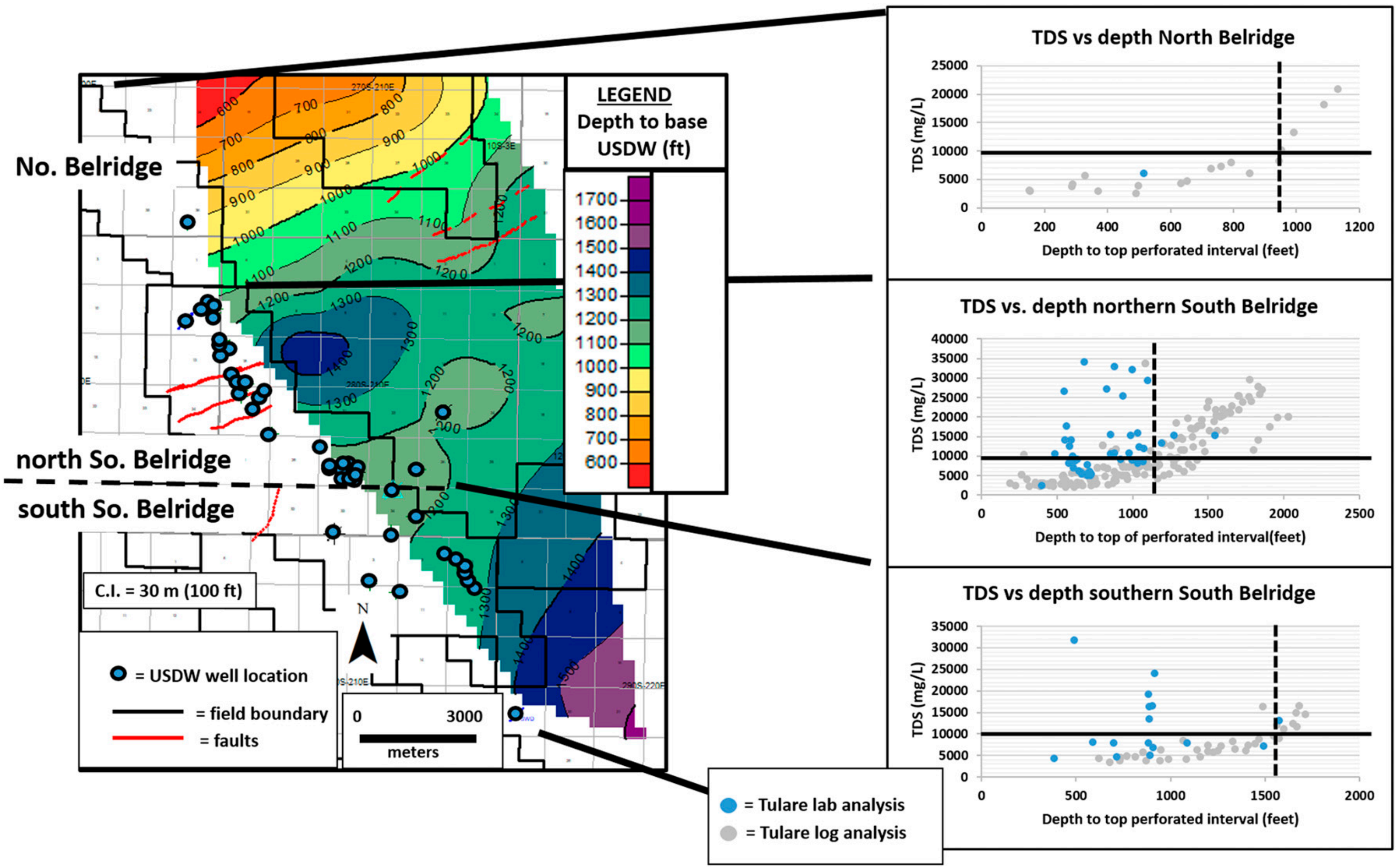

Figure 9. Graph of total dissolved solids (TDS) versus depth of geochemical samples from the Tulare Formation in and near the North and South Belridge oil fields. The northern and southern parts of the South Belridge field (marked by the red line on the map) are shown in separate graphs. Blue dots show Tulare Formation (Fm.). Measurements of TDS from lab analyses. Gray dots show Tulare Fm. The TDS calculated from log analysis. Horizontal red lines on the graphs mark 10,000 mg/L and the dashed vertical red lines mark the approximate depth of USDW from lab samples. The adjacent map shows the location of the wells sampled (blue dots) and the contours to base underground sources of drinking water (USDW) (in feet) from log analysis. Black lines are oil field administrative boundaries, and red lines are faults. C.I. = contour interval; No. = North; So. = South.

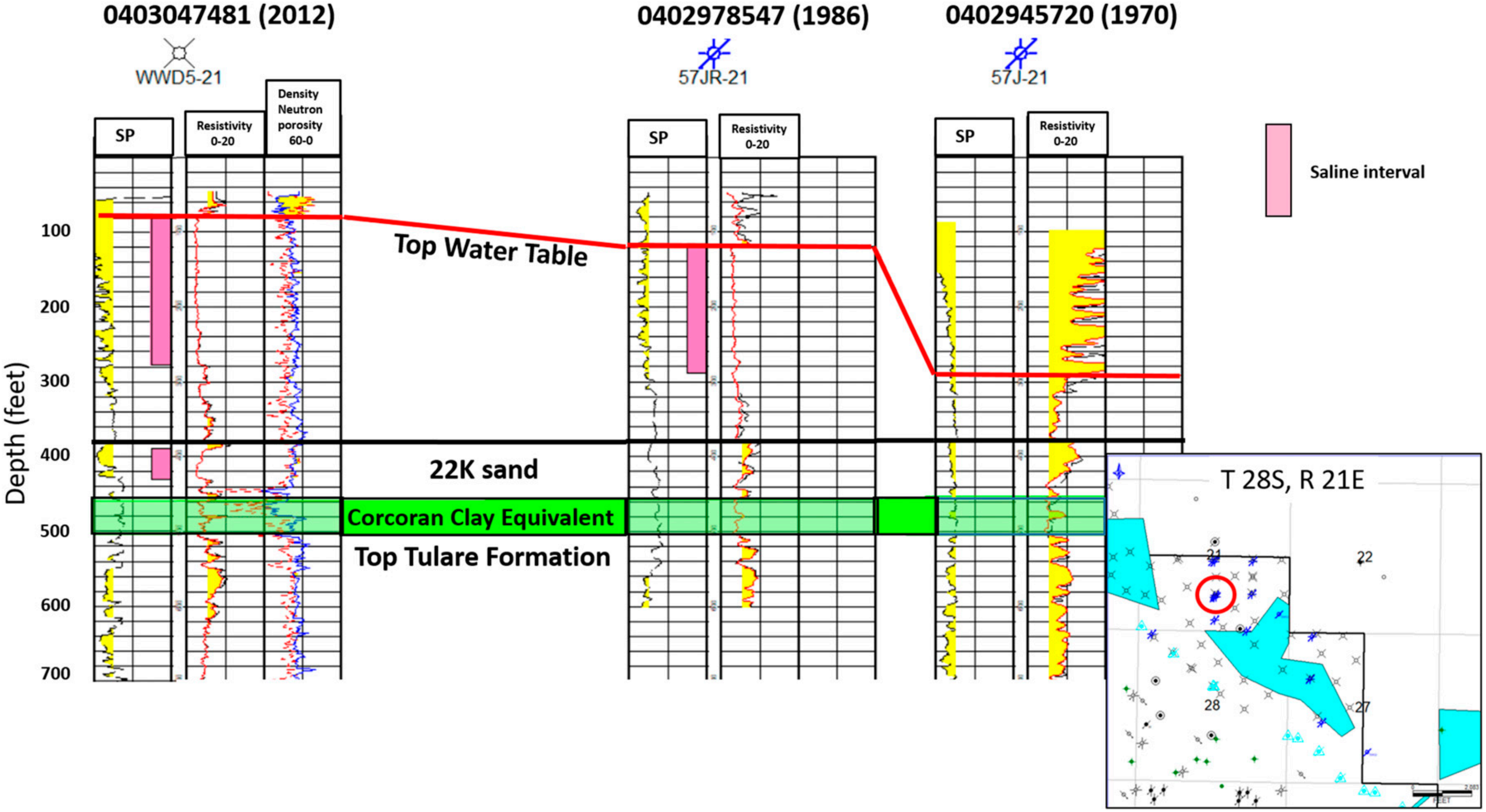

Figure 10. Cross section showing three wells drilled and logged in different years near a produced water disposal pond (light blue polygon on inset map). Yellow shading on spontaneous potential (SP) curve (left track) indicate sand layers. Yellow shading on resistivity curve (right track at scale of 0–20 ohm m) indicate resistivity of more than 3 ohm m. Pink bars indicate low resistivity sands affected by infiltration of saline produced water from the pond. The API numbers at the top of the logs are used for well identification. Year drilled and logged in parentheses. Depth scale in feet.

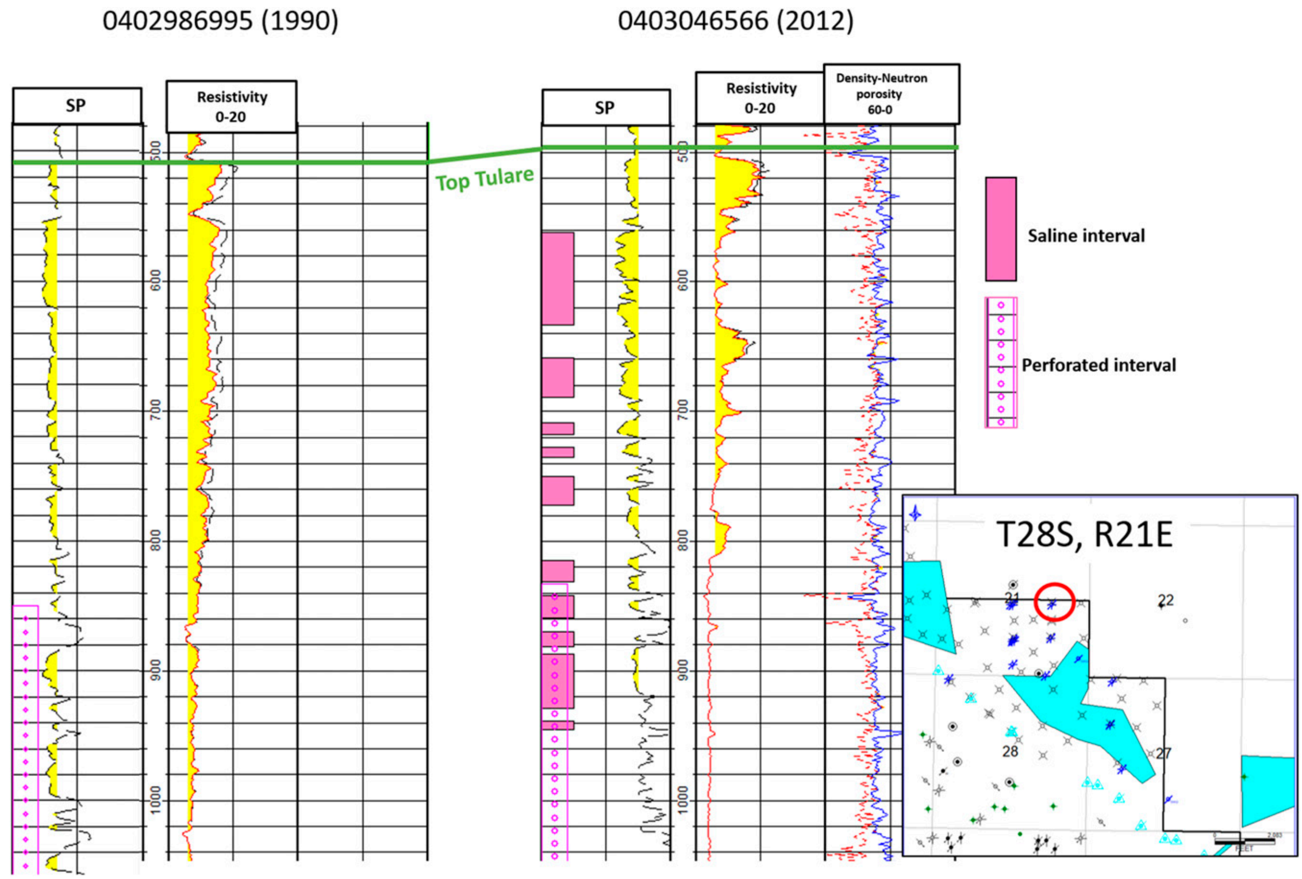

Figure 11. Two adjacent wells drilled and logged in different years (1990 and 2012) in an area containing numerous disposal wells on the east flank of South Belridge. Yellow shading on spontaneous potential (SP) curve (left track) indicate sand layers. Yellow shading on resistivity curve indicates resistivity greater than 3 ohm m. Pink bars indicate low resistivity sands in the 2012 well (0403046566) affected by injected saline produced water. The API numbers at the top of the logs are used for well identification. Year drilled and logged in parentheses.

This may be caused by the presence of an active water disposal field in the Tulare Formation near this area. Overall, the log-derived map shows base of USDW approximately 61 m (~200 ft) deeper than lab analyses would suggest. As at Lost Hills, this may be caused by the geographic distribution of the two data sets: the lab samples coming mainly from within the oil field boundaries, whereas the log data are confined to the area outside the oil field.

In the southern part of South Belridge field, a well near the southern tip of the field was sampled at multiple intervals. Samples as deep as 455 m (~1495 ft) are USDW and the deepest sample, from 480 m (1575 ft), has a TDS value of 13,074 mg/L, suggesting that the base of USDW in the southern part of South Belridge lies between 457 and 480 m (1495–1575 ft) (Figure 9). The depth to USDW map from log analysis in the southern part of South Belridge shows that the base of USDW ranges from 365 m (1200 ft) in the north to approximately 487 m (~1600 ft) in the south.

Effects of Oil Field Activities on Water Salinity

The effects of water disposal in surface ponds on groundwater salinity is evident by comparing geophysical logs from old wells near the pond locations to logs from newer wells drilled nearby. Older geophysical logs (pre-1970s), indicate that the upper sands in the alluvium are desaturated (vadose zone) as indicated by areas of crossover on density–neutron logs and have high resistivity (> 20 ohm m; Figure 10). However, geophysical logs collected from wells drilled later in the area do not show density–neutron crossover characteristic of a vadose zone and have extremely low resistivity (<1 ohm m) in the upper alluvial sands because of the presence of high salinity produced water that has filled the vadose zone. Invasion of low resistivity water is especially apparent

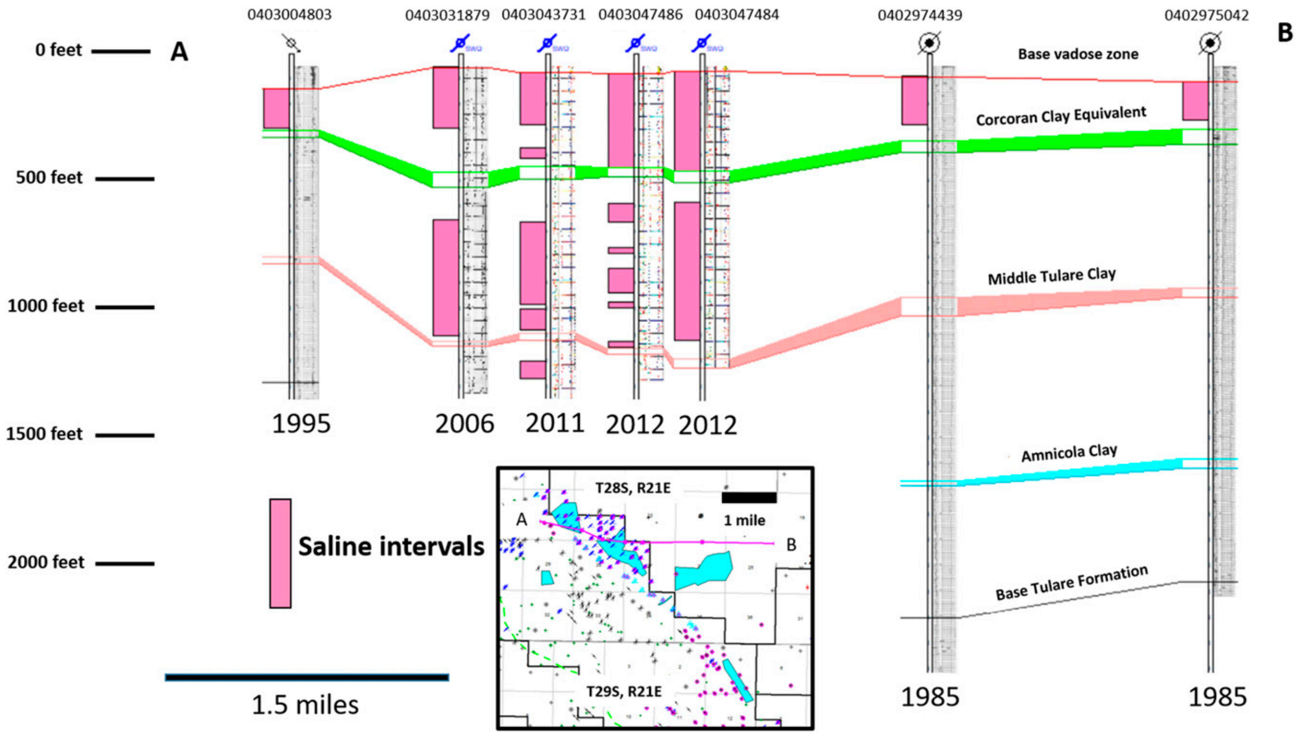

Figure 12. Cross section showing intervals affected by disposal of saline produced water (pink boxes) at South Belridge oil field. Wells identified by API number at top of each well. Year drilled and logged shown at bottom of each well. Inset map shows location of cross section. Produced water disposal wells are highlighted in pink and disposal ponds are shown in blue in the inset map.

where saline waters have infiltrated the 22K sand, which lies directly above the CCE (well 03047481 in Figure 10) in the lower part of the alluvium. The saline water lies atop the CCE, which appears to be protecting the underlying Tulare aquifer from contamination. Log-calculated and measured TDS concentrations can exceed 20,000 mg/L in affected parts of the alluvium.

The effects of surface disposal ponds are less evident in Lost Hills and North Belridge compared to the area adjacent to South Belridge. Lost Hills in particular tends to have highly saline water in the shallow parts of the aquifer even where disposal ponds are not present. Swain and Duell (1989) noted TDS concentrations as high as 21,700 mg/L from very shallow wells (6 m [~20 ft]) along the east flank of Lost Hills but did not note the cause of the high salinity in the area.

The effects of water disposal injection wells are more subtle than that of the ponds and are especially difficult to identify in sands closer to the base of USDW where resistivity is naturally fairly low. Geophysical logs in sands affected by saline injection tend to have a concave resistivity profile and resistivities are as small as half that in logs from older, unaffected wells (Figure 11). Injected saline water tends to follow individual sand layers leaving some layers relatively unaffected. In some cases, only the lower part of an individual sand contains saline water, whereas the waters in the upper part remain brackish. This suggests that the waters are stratified and mixing has not had time to occur. Log-calculated TDS concentrations show a relatively smooth increase with depth in wells logged prior to the start of large-scale disposal activities whereas recent logs in these areas show a much more variable TDS concentration profile with depth. Additionally, density–neutron curves in wells affected by disposal of produced waters show thin intervals (~1 m [~3 ft] thick) of crossover. This may be caused by bacterial metabolism of trace amounts of organic matter in the disposal water resulting in the generation of small amounts of biogenic methane (McMahon et al., 2018).

The cross section in Figure 12 shows wells affected by saline produced water disposal by injection (below the CCE) and percolation (above the CCE) along the east flank of the South Belridge oil field. Wells affected by disposal of produced waters in saline ponds ($n = 139$) and by disposal in injection wells ($n = 125$) are also shown in the map in Figure 13. The effects of disposal ponds are evident from changes in borehole resistivity

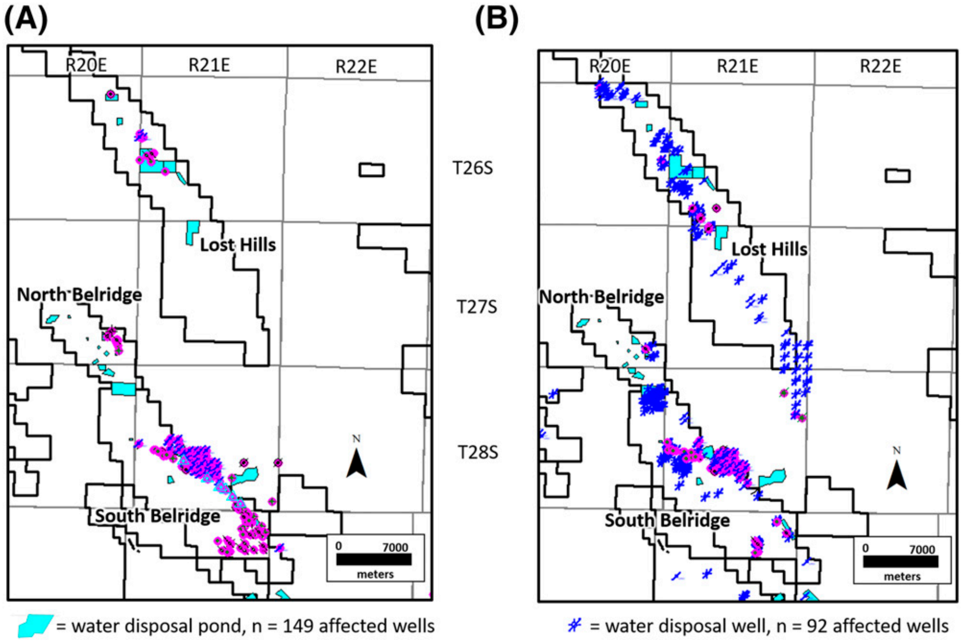

Figure 13. Wells highlighted in pink are wells affected by saline produced water from (A) disposal ponds and (B) water disposal wells in the study area. R20–R22E = Range 20–22 East; T26–28S = Township 26–28 South.

at least 1525 m (5000 ft) in a downgradient direction (east) from some of the ponds. These borehole geophysical log analyses help fill in a more detailed understanding of the areal and vertical extent of saline water movement near historical disposal ponds. Water sample data from monitoring wells downgradient of selected historical ponds support the log analysis and indicate saline water movement above the CCE of up to several kilometers to the east (California State Water Resources Control Board, 2018a). The effects of injection wells can be observed in geophysical logs from new wells (ca. 2013–2015) drilled within the oil field boundary at least 550 m (~1800 ft) west of the main Tulare water disposal wellfield along the central part of the east flank of South Belridge. No new wells are available east (downgradient) of the disposal field because that area is outside the oil field limits and new drilling has not occurred. Existing monitoring wells are not deep enough to determine the effects of injection disposal east of the field.

CONCLUSIONS

The Tulare Formation and overlying alluvium contain most of the groundwater classified as USDW in the study area. The thickness of these formations ranges from approximately 75 m (~250 ft) in North Belridge and northern Lost Hills to more than 1200 m (>~4000 ft) in the southeastern part of the study area. Log-generated maps of groundwater salinity and geochemical analyses indicate that depth to protected waters ranges from 150 m (~500 ft) in the northwestern part of the study area to 490 m (1600 ft) in the southeast and 550 m (~1800 ft) east of Lost Hills.

The Tulare Formation contains multiple clay layers, the largest and most extensive being the CCE, Middle Tulare, and Amnicola clays. Pressure gradients change across the confining layers, particularly near the South Belridge field. The larger shifts in pressure gradients across the clay layers near South Belridge may indicate greater confining ability of the clays near the field; however, the shift in gradient may also indicate that production and injection activities within the various aquifer layers near the field have not allowed sufficient time for the pressure to reach equilibrium throughout the formation.

Disposal of produced waters in both surface ponds and injection wells have affected water salinity over time near the oil fields. Disposal in surface ponds has mainly affected the alluvial aquifer above the Tulare Formation. Water with high salinity has filled the vadose zone above the water table at a distance of at least 1525 m (5000 ft) downgradient of the disposal ponds at South Belridge. The

CCE appears to protect the underlying Tulare Formation from the downward percolation of water from disposal ponds within the area analyzed. The effects of produced water injection are mainly evident within the Tulare Formation and can be noted as far as 550 m (1800 ft) from the main group of disposal wells located along the east flank of South Belridge; no recent geophysical logs farther downgradient were available for analysis.

Geophysical logs from newer wells with sands affected by produced water injection have resistivities approximately half that of geophysical logs from wells drilled prior to or early in the course of produced water injection. This saline water tends to occur within the lower parts of affected sands because of gravity segregation and is associated with thin areas of density–neutron crossover, perhaps indicative of methane produced in situ by microbial degradation of organic matter in the produced water. This analysis demonstrates the utility of borehole geophysical data in understanding groundwater salinities at different spatial and temporal scales and an approach for constructing regional patterns based on site-specific information.

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