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FINAL PROJECT REPORT

POTENTIAL IMPACTS OF FUTURE GEOLOGICAL STORAGE OF CO_2 ON THE GROUNDWATER RESOURCES IN CALIFORNIA'S CENTRAL VALLEY

Southern San Joaquin Basin Oil and Gas Production Analog for Geologic Carbon Storage

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PREPARED BY:

Primary Author(s):
Preston Jordan
Janice Gillespie

Lawrence Berkeley National Laboratory
1 Cyclotron Road
Berkeley, CA 94720

Contract Number: 500-09-034

Prepared for:

California Energy Commission

Joe O'Hagan
Contract Manager

Linda Spiegel
Office Manager
Energy Generation Research Office

Laurie ten Hope
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Robert P. Oglesby
Executive Director

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PREFACE

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ABSTRACT

This study assessed the history of oil production and pressure changes in the southern portion of the San Joaquin Basin in California's Central Valley as a reverse analog for understanding the pressure response to potential geologic carbon sequestration. Sequestration involves injecting carbon dioxide into permeable strata such as those that trap oil. This results in pressure increases in the existing fluid in the subsurface that can provide a motive force for brines at those depths to migrate into groundwater, affecting its quality. The pressure can also cause differential ground surface uplift that can affect surface water flow, particularly in engineered water conveyances such as canals. The strata underlying the Central Valley have been assessed as having considerable capacity to store carbon dioxide, but the area also contains urban areas and extensive agriculture that rely on engineered surface water delivery systems and groundwater supplies. The Stevens Sand, Temblor Formation and Vedder Formation were identified as having the largest cumulative net production from typical geologic carbon sequestration depths. Two oil pools were identified in each of these stratigraphic units for more detailed analysis, which included converting fluid level data to pressure at the pool scale. Data were collected that allowed an assessment of the hydraulic connectivity of each unit. The results indicated that the Vedder was hydraulically connected at the near basin scale, the Stevens was hydraulically connected at the pool scale and was disconnected between pools and the Temblor was disconnected within pools. Researchers used these results to analyze possible brine leakage driven by geologic carbon sequestration. They also reviewed over 200 articles on historic groundwater contamination. They concluded that no instance of contamination due to upward leakage of brine in the Central Valley was reported.

Keywords: carbon sequestration, saline aquifers, subsurface fluids, CO_2 injection

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EXECUTIVE SUMMARY

Introduction

A prospective means to mitigate climate change resulting from the emission of carbon dioxide (CO_2) is to capture it from large stationary sources such as fossil-fueled power stations and inject it into deep permeable strata overlain by low permeability strata, often termed saline aquifers because they contain saline water or brine. This approach is termed geologic carbon sequestration. Injection of CO_2 for storage without other measures will increase the pressure of the saline water occupying the receiving strata. This creates a driving force that can cause saline water in the strata to move into locations it otherwise would not. It can also cause differential ground surface uplift that could change the configuration of surface water conveyances, particularly if they are engineered.

The strata underlying California's Central Valley have been assessed as having considerable capacity to store CO_2. The Central Valley also contains urban areas and extensive agriculture, both of which rely on engineered surface water delivery systems and groundwater supplies. Consequently the Central Valley has features of concern relative to potential changes due to pressurization of subsurface fluids by the geologic carbon sequestration.

Project Purpose

This study analyzed historic pressures in the southern San Joaquin Basin in the southernmost portion of the Central Valley during the more than century of prolific oil production as a reverse analog to pressure changes that might result from injecting CO_2. A companion study simulated the pressure changes and ground deformation in response to hypothetical CO_2 injections utilizing a model incorporating surface water usage, groundwater usage and the deep basin.

Project Results

As proposed this study was to identify particular oil pools of interest, such as those near faults that could be potential leakage pathways, develop the production history for those pools and collect and analyze pressure data from the records for exploratory wells outside the fields. Unfortunately iIt was determined during the project that the records were largely unavailable, having been inadvertently destroyed years ago. Fortunately the project was able to adjust by developing a production database for each of the over 700 pools in the basin. The database was configured to calculate the production volumes at reservoir conditions, in contrast to the production volumes as reported at standard (surface) conditions. This allowed utilization of the history of pool discovery (initial) pressures and an idle well fluid level dataset as alternative sources of pressure information.

Pool initial pressures are available over the course of about a century. Consequently later pressures recorded conditions after earlier production had occurred. Normalizing the pressures against depth allowed pressures from different pools in different positions to be compared. Analysis of the depth-normalized pressures and the hydraulic head they implied indicated no discernible downward trend in pressures with time in the basin. During this period net fluid production taken at reservoir conditions was over 100 million meters cubed (m^3) per year. The pressures did have a relatively constant variance with time however, indicating natural variations in pressure were considerably larger than any trend due to production.

The Stevens Sand, Temblor Formation and Vedder Formation were identified as having the largest cumulative net production from typical geologic carbon sequestration depths. A volume of fluid more than 100 million m^3 or more at reservoir conditions was produced from each. No downward trend in the initial pool pressure time series for these units was identified. The head in the Stevens and Temblor was found to increase toward the basin axis, which is near the western margin of the basin due to its asymmetry. The head in the Temblor was also found to be high in the pools along the southern margin of the basin. The head in the Vedder was found to be relatively consistent, with the exception of high heads in the pools along the southern margin of the basin. The western and southern margins are the most tectonically active in the basin, which suggests the heads are high along these margins due to tectonically-driven compression.

In additional to these results covering the extent of the three stratigraphic units, in some field areas one or more oil pools were discovered in a particular unit. Multiple oil pools in the same unit in a field area typically occur in different individual strata or across fault boundaries, so comparing the initial pressure in pools discovered after production commences in other pools provides some perspective on the permeability of those features. The initial pressures in later discovered pools were not found to be consistently lower, indicating little pressure change due to production even within a single stratigraphic unit and field area.

Two pools were identified in each of the three stratigraphic units for more detailed analysis. Fluid level data from idle wells open to each pool were converted to pressure at the pool and depth normalized. This data variously extended back to the late 1980s to early 1990s. Pressure data from the earlier period was gathered from well records to provide a more complete understanding of the pressure history. These data existed in sufficient quantity to allow an assessment of the pressure in the pools through comparing values.

Analysis of the production histories for these pools as well as the pressure records provided information on the drive mechanisms in each pool (for instance gas cap expansion versus water), pressure response to production, pressure variation, and geographic pressure distribution. This information combined with the results for the three stratigraphic units as a whole allowed for conclusions regarding the hydraulic connectivity in each unit. The results indicate the Vedder is hydraulically connected at the near basin scale, the Stevens is hydraulically connected at the pool scale and disconnected between pools and the Temblor is disconnected within pools.

An unanticipated finding from the pool production database was the existence of numerous pools that are the shallowest in their respective field areas and received large volume, high pressure injections of water produced with oil from deeper pools that requires disposal. Many of these pools are positioned at intermediate depths between where geologic storage would occur and the base of current groundwater supply wells. One group of these pools receiving over 50 million m^3 of injected saline water are penetrated by over a thousand oil and gas related wells and overlain by hundreds of groundwater wells.

These pools provide a direct analog for possible brine leakage driven by geologic carbon sequestration. A past study of well blowouts found articles in the main newspaper in the area covered more than half of the high public consequence events. On this basis over 200 articles from the newspaper regarding groundwater contamination were gathered and assessed. The articles covered tens of contamination sites and sources and the closure of around 100 groundwater wells due to contamination, such as leaks from underground fuel storage tanks. No instance of contamination due to upward leakage of brine was reported.

Project Benefits

This study assessed the history of oil production and pressure in the southern portion of the San Joaquin Basin as a reverse analog for understanding the pressure response to potential geologic carbon sequestration. Carbon sequestration is a method for potentially storing captured CO_2 so that it is not released into the atmosphere. The study found no indication that geologic carbon sequestration would increase brine levels that could affect water quality. Successful carbon sequestration could help reduce the amount of greenhouse gases that contribute to climate change.

CHAPTER 1
Introduction

1.1 Background and Objective

A promising measure for mitigating climate change is to store large volumes of CO_2 captured from large point-source carbon emitters in deep saline aquifers. In California, the thick marine sediments of the Central Valley have been identified as prime targets for future CO_2 storage. Both the Sacramento and San Joaquin River basins have thick sedimentary sections at sufficient depth, multiple saline aquifers and oil and gas reservoirs, widespread shale seals, and significant geological data from oil and gas operations (e.g., PIER Collaborative Report, 2006).

California's Central Valley is currently the home to over six million people, and generates over $20 billion in agricultural crops each year. The agricultural and urban development in the area depends on an intricate surface water distribution system that routes water from surrounding watersheds to the Central Valley, and on the presence of extensive aquifers that provide substantial amounts of freshwater and are increasingly being used as a buffer for fluctuations in surface water supplies. Managing the Central Valley's water resources is already a challenging task in light of limited water availability (a result of drought and climate change), increasing demands, environmental concerns about wetlands, endangered species, and water quality, as well as land subsidence caused by groundwater pumping. In such a vulnerable and valuable system, any water resources impacts of large-scale CO_2 storage need to be evaluated and assessed before industrial-size storage projects get underway.

What are the hydrological concerns about CO_2 sequestration in the Central Valley? One primary concern results from the extremely large amounts of CO_2 that must be injected and sequestered underground if this technology is to contribute significantly to climate change mitigation (on the order of millions of tons per year per storage site). Storing these additional fluids in deep saline aquifers causes pressure changes and displacement of native brines, affecting subsurface volumes that can be significantly larger than the CO_2 plume itself (Figure 1). Environmental impacts on groundwater resources may result if the deep parts of the basin communicate effectively with shallower units. One possible communication path is that the large-scale pressure perturbation within a storage formation may extend updip to a freshwater aquifer used for domestic or commercial water supply. Via this direct hydraulic communication, CO_2 storage at depth could impact the shallower portions of the aquifer, which could experience pressure increase and water-table rise, changes in discharge and recharge zones, and changes in water quality.

Even if separated from deep storage formations by sequences of low-permeability seals, freshwater resources may be hydraulically communicating with deeper layers, and the pressure buildup at depth would then provide a driving force for upward brine migration. This can be, for example, via local high-permeability flow paths such as faults and abandoned boreholes. Alternately, seals may pinch out or have higher permeabilities locally, allowing for interlayer migration vertically.

Finally, land-surface deformation or uplift can be expected in response to CO_2 injection. Pressurization of in-situ formation fluids by injection of CO_2 also causes an expansion of the pore volume in the reservoir due to the elasticity of the solid phase network comprising the rock. This expansion results in an increase in ground surface elevation. Because the pressure increase in the reservoir will not be uniform, the surface elevation increase will not be uniform. The resulting differential elevation change can alter the flow of water at the surface even without a direct impact from pressure propagation and brine displacement. This is particularly the case in engineered conveyances which typically have low, constant slopes to maintain uniform flow.

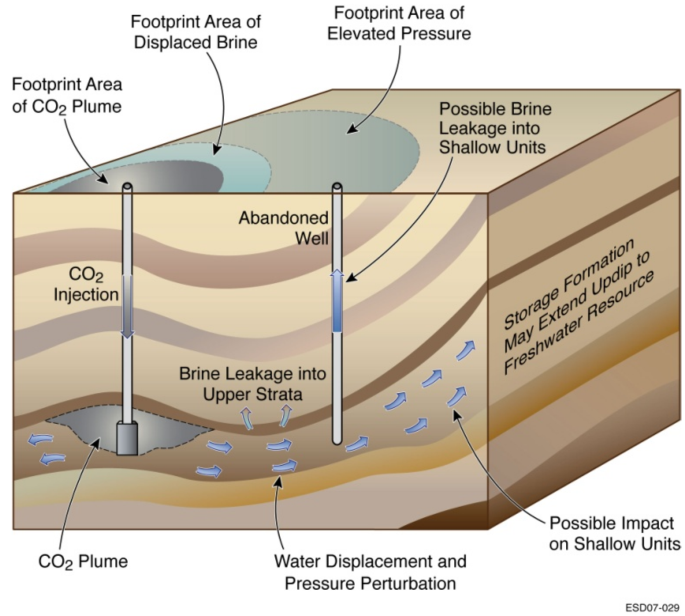

Figure 1: Schematic Showing Different Regions of Influence Related to CO_2 Storage (from Birkholzer et al., 2009).

Over the last decade or so, numerous research studies have been conducted in the United States and worldwide evaluating under which hydrogeological conditions the injected volumes of CO_2 can be safely stored over hundreds or even thousands of years. For example, many of these studies address issues such as the long-term efficiency of various CO_2 trapping mechanisms (e.g., structural trapping of CO_2 under sealing layers, dissolution of CO_2 into formation water, and mineral trapping as CO_2 reacts with the rock), and detection, mitigation and impact of potential CO_2 and brine leakage through localized pathways. Initially, less emphasis was placed on the understanding of large-scale pressure changes and the fate of the native brines or brackish waters that are being displaced by the injected volumes of CO_2. As discussed above, industrial-scale injection of CO_2 affects subsurface volumes much larger than the CO_2 plume. Thus, even if the injected CO_2 itself is safely trapped in suitable geological structures, large-scale pressure buildup and related brine displacement may affect valuable groundwater resources.

The topic of reservoir pressurization due to large-scale CO_2 storage has recently received increasing attention. In addition to concerns about potential brine migration and related impact on shallower groundwater resources, researchers are also addressing questions about pressure-driven caprock fracturing and/or fault reactivation (e.g., Rutqvist et al., 2007, 2008). Large-scale pressurization can also be an issue for activities involving exploitation of subsurface resources in the area, such as oil and gas or geothermal energy, or may affect neighboring CO_2 storage sites that reside in the same formation. Regarding the latter, the potential for pressure interference between GCS operations was illustrated in a regional-scale simulation for the Illinois Basin in the USA (Birkholzer and Zhou, 2009; Zhou and Birkholzer 2011). Such interference not only leads to cumulative effects of pressurization, but also has regulatory implications, since permitting needs to be conducted based on a multi-site evaluation (Birkholzer and Zhou, 2009). Pressure management via extraction of native brines has been proposed to mitigate pressure concerns (e.g., Court et al., 2011; Bergmo et al., 2011; Birkholzer et al., 2012), but the cost for pumping, treatment, and disposal of these brines can be prohibitive.

In 2010, the California Energy Commission, via its PIER program, commissioned a study to evaluate the potential impact of large-scale CO_2 sequestration in California with specific focus on the water resources in the Southern San Joaquin River Valley. The study work comprised two distinct, but related projects: The first project utilized production and pressure data from oil reservoirs in the San Joaquin Valley as a reverse analog to the potential pressure impact of CO_2 injection. The current report presents analysis of data from this analog. The second project investigated via simulation studies whether the basin-scale pressure changes and brine displacement caused by future CO_2 storage in the deep sediments could have an impact on the groundwater-surface water systems in the area. Results from this project are summarized in a companion report. The objective of the first project was to address the following questions:

- What is the extent and magnitude of pressure changes due to historic production, both along and across stratigraphy and associated with specific features, like wells and faults?
- What is the implication of these changes for geologic carbon storage?

This study does not look into the impact of leakage of CO_2. A companion study launched in 2012 conducts research to assess the potential groundwater quality impacts of localized leakage from deep storage aquifers into shallow potable aquifers, with focus on selected aquifer materials from field sites in California's San Joaquin Valley (funded by California Energy Commission under Project Title: Assessment of Potentially Deleterious Effect of CCS Operations on Groundwater Quality).

1.2 Methodology and Project Tasks

As originally envisioned, this study was to develop specific pressure propagation scenarios, such as along strata and via faults, for investigation and prioritize those scenarios for investigation. Areas of the southern San Joaquin Valley containing oil fields with production and pressure data that would best provide insight into the highest priority scenarios were to be analyzed as case histories. This approach was predicated on minimizing collection and analysis of production data to the case study fields, and maximizing collection of pressure data.

Acquisition of pressure data between oil fields was critical in this approach. The expectation was records for exploratory wells between fields could contain such data, most typically from drill stem tests. Preliminary searches found little of this data however, particularly with sufficient information to assess the quality of the data. For instance pressure recordings from drill stem tests were almost completely unavailable, as indicated by a list of just 52 wells for which drill stem test are available from the data and analysis vendor American Institute of Formation Evaluation. Further, almost all of these tests were performed in wells within fields. The paucity of drill stem test recordings in California is apparently due in part to the unintentional destruction of a large portion of them.[1] Pressures in drill stem tests start below the pressure in the rock formation and subsequently increase toward that pressure. The recordings show these pressure buildups during the test. These recordings are necessary to assess whether the pressures at the end of the buildups represent the pressure in the formation, and if not to possibly estimate the pressure in the formation.

In contrast to the scarcity of pressure data between fields, almost complete production data for each pool in each field was found to be available (a pool is the hydrocarbon resource in a particular strata within the field, and so a field may have multiple pools). Consequently, an alternate approach that could bear on the project objectives was pursued. The reported production history for every pool in the study area was assembled. Reported production volumes are at pressures and temperatures indicative of surface conditions. The volumes at the subsurface conditions in each reservoir were estimated. This allowed assessment of the total production in the basin and from specific strata and depths at reservoir conditions, which allows comparison to carbon storage volumes.

The resulting production histories were compared against the history of discovery (initial) pressures in each pool, which occurred over the course of a century. Consequently later measurements provide data outside of fields with earlier production. From this the trends and variability of pressure over time in response to the volumes produced from the reservoir can be assessed.

The reservoir production histories also provide for determining the stratigraphic units with the most production from geologic carbon storage depths. Pools within those strata were identified for focused study of pressure changes in response to production. In contrast to the paucity of pressure data between fields, pressure data within fields sufficient for drawing conclusions was available from two sources. While well records within fields also did not contain drill stem test recordings, with rare exceptions, they did contain a number of results that provided an understanding of the likely static pressure within the field at using these data various times. Fluid levels from idle wells in the field were also available, from which pressure could be calculated. These pressure data were analyzed for selected pools to develop an understanding of pressure changes closer to production and injection. These in turn bear on the magnitude of the pressure perturbation that could propagate from a storage operation.

[1] Email with subject "Re: more targeted DST data?" from Steve Misner with American Institute of Formation Evaluation to Janice Gillespie at 9:49 am PST on 18 June 2012

CHAPTER 2:
Southern San Joaquin Valley

2.1 Population Distribution

As mentioned, the population of the Central Valley numbers in the millions. The study area consists the oil production area in California's Oil and Gas District 4, shown on Figure 2. Almost all of the fields in this District are located in the Kern County portion of the San Joaquin Basin. This is the western portion of Kern County.

Figure 2: Location of California Oil and Gas District 4 (Jordan and Benson 2008).

The population of Kern County according to the 2010 United States Census was about 840,000. The majority of the population in the County resides in the eastern portion of the San Joaquin Basin. For instance, the largest city in the County is Bakersfield, which had a population in 2010 of about 350,000. Figure 3 shows the population density in the western portion of Kern County in 2000.

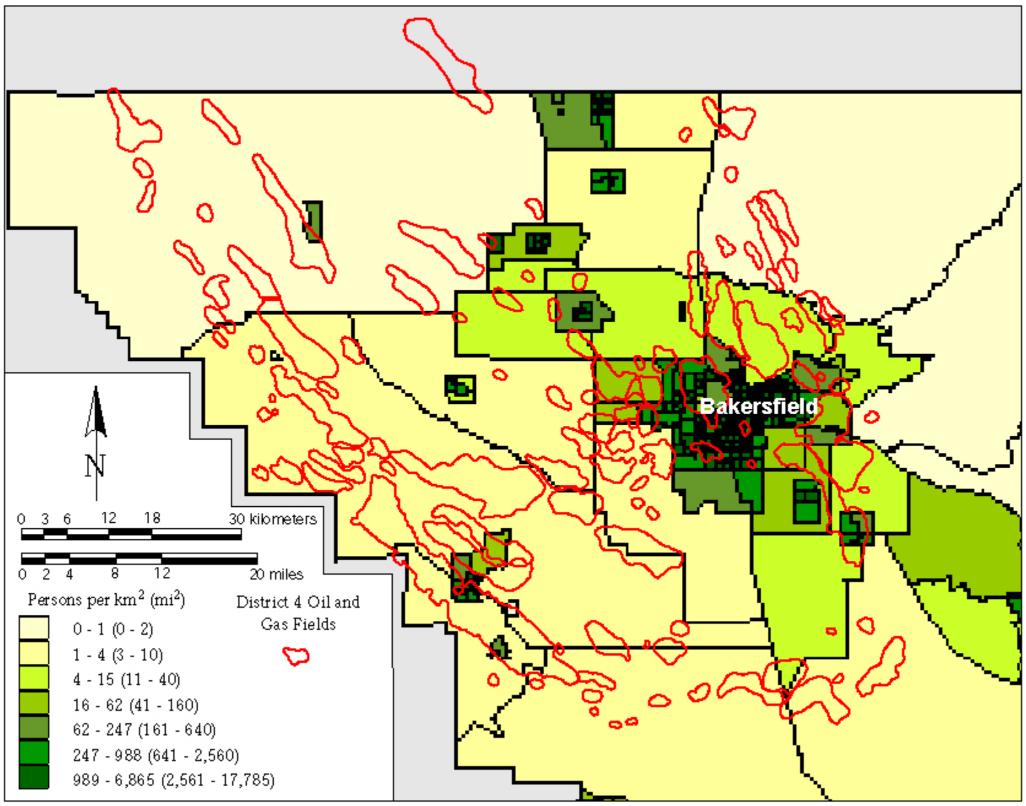

Figure 3: Population Density in 2000 in Western Kern County with Oil and Gas Field Locations Overlain (Modified from Jordan and Benson 2008).

Land use in the Kern County portion of the San Joaquin Basin is primarily agricultural as shown on Figure 4. Open land dominates along the western margin of the Basin in the County. The urban land uses shown within some fields in this area are actually classed industrial because the predominant use is the infrastructure for the oil field itself. This is not the case for the oil fields shown within the Bakersfield urbanized area. Infrastructure for those fields is not the dominant use in these areas, but rather residential, commercial and other industrial uses predominate.

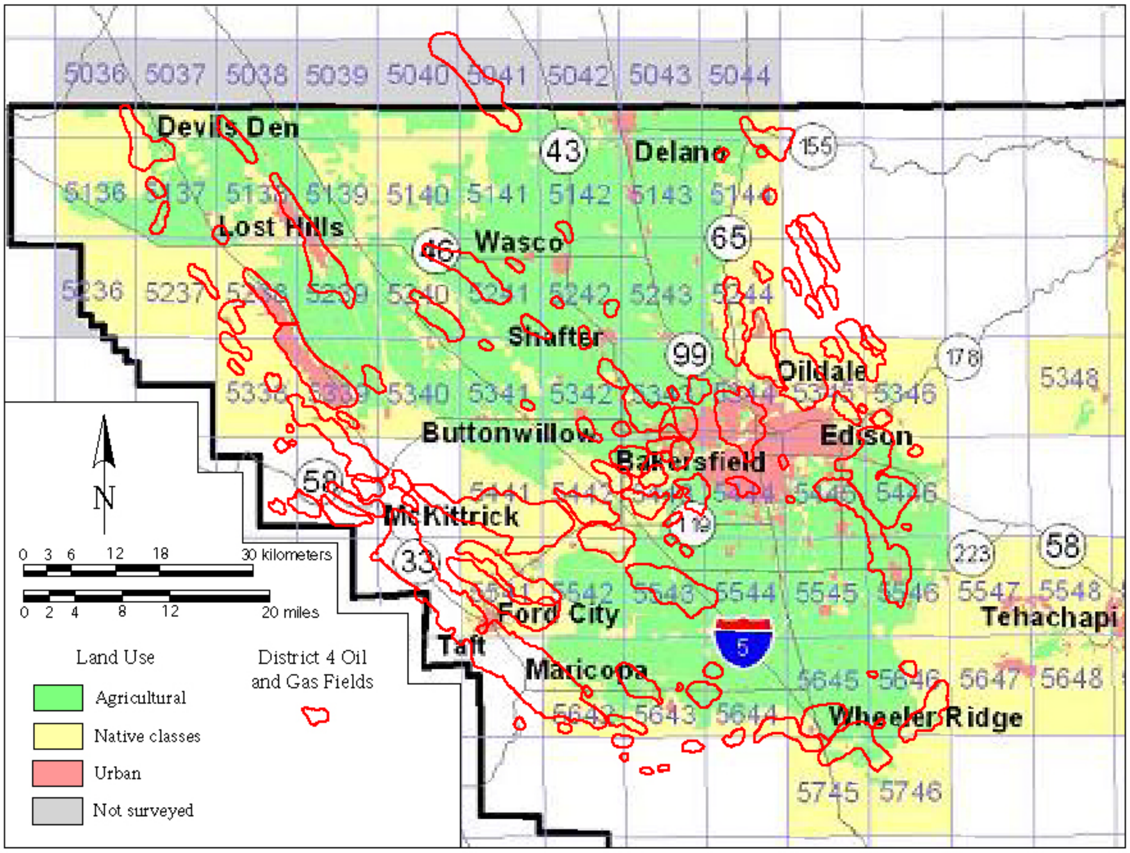

Figure 4: Land Use in Western Kern County in 1998 with Oil and Gas Field Locations Overlain (Modified from Jordan and Benson 2008).

As mentioned, groundwater is an important resource in the Central Valley. This is true in the study area as well. Figure 5 shows the number of groundwater wells in each section for which the State of California has a well completion report. Water with a total dissolved solids content (TDS) of approximately 2,000 mg/L occurs at or near the water table on the west side of the basin (Page, 1973). This is well above the secondary drinking water standard for TDS of 500 mg/L and above the salinity at which crop yields start to decline, which is generally a TDS of 1,000 mg/L or less (Table 5 of Technical Appendix 3 of Bookman-Edmonston Engineers Inc., 1999). The high TDS in shallow groundwater is likely why there are few to no groundwater wells in areas of low topographic relief on the west side of the basin and one reason much of the land is not used for agriculture. In contrast, the depth to groundwater with a TDS of 2,000 ranges up to 600 m on the east side of the basin (Page, 1973). This is one factor contributing to the high density of groundwater wells, predominant agricultural land use, and higher population densities in this area.

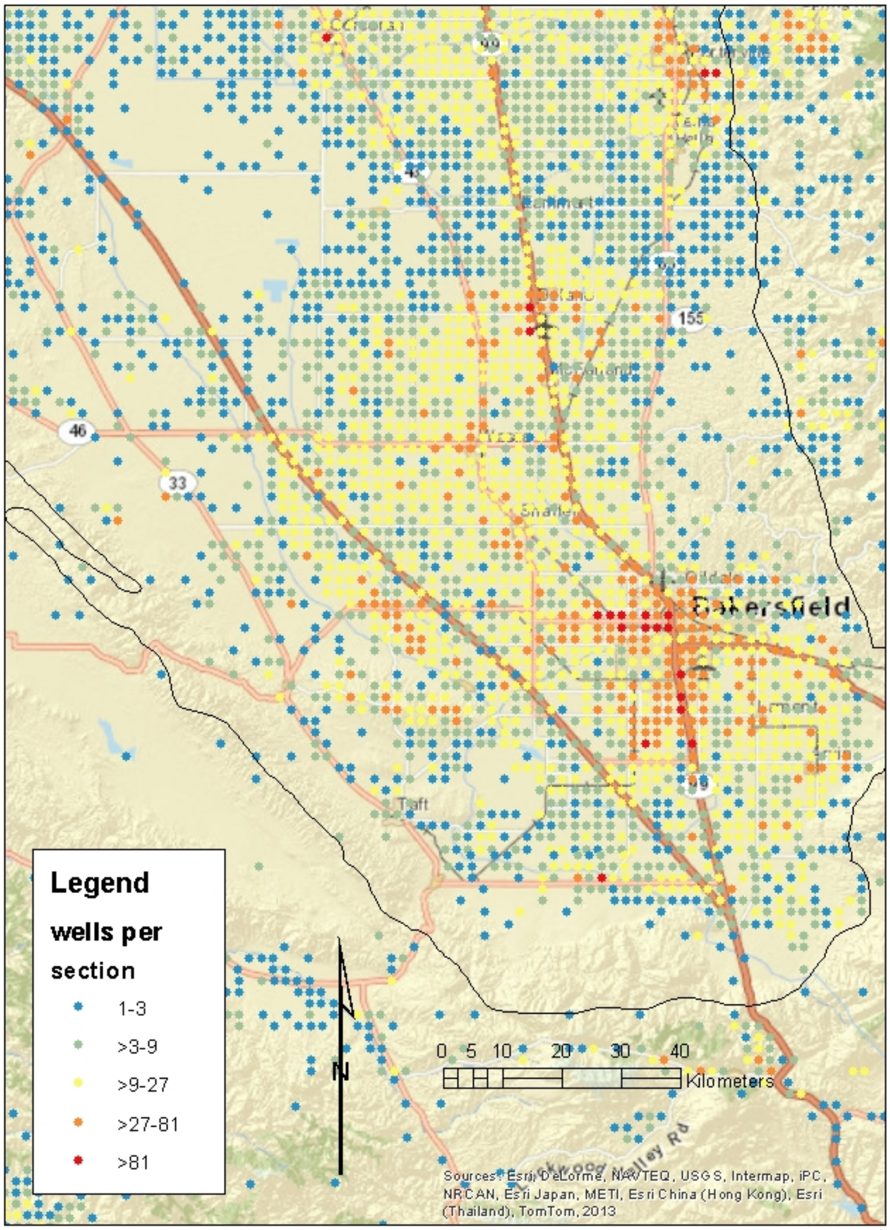

Figure 5: The Number of Water Wells for Which the State of California Has Well Completion Reports[2] with the Margin of the San Joaquin Basin Overlain[3].

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[2] Well density provided by Eric Senter of the California Department of Water Resources on 23 April 2013

2.2 Stationary Source CO_2 Emissions

The amount of CO_2 produced by large stationary sources in and near the southern San Joaquin Basin provides a useful metric for judging the net fluid volumes extracted historically during oil production in the area. CCUS, as conventionally conceived, targets the CO_2 from these sources.

The total amount of CO_2 emitted by large sources in the area was assessed using version 1303 of the National Carbon Sequestration Database and Geographic Information System's (NATCARB's) geodatabase, which was released on 1 July 2013.[4] According to the stationary sources metadata document, this geodatabase has updated locations for some types of sources included the West Coast Regional Carbon Sequestration Partnership's (WESTCARB's) files.[5]

The WESTCARB stationary source GIS layer was most recently updated on 5 September 2012 at the time of this writing.[6] The CO_2 emissions for a stationary source in the vicinity of the model were the same or higher in the WESTCARB GIS layer compared to the NATCARB geodatabase. While the metadata regarding the latter do not make note of this, a spot check of the values in the NATCARB geodatabase against the EPA facility level GHG emissions data[7] on 28 September 2013 indicates a match. For these reasons the NATCARB geodatabase was used for stationary source data.

The geodatabase lists the CO_2 emissions for 2010 for most stationary sources and 2007 for a few. The sources within the model area as well as three nearby sources to the south and southeast were extracted for a total of 62 sources. The three additional sources are cement manufacturing facilities within 40 kilometers of the edge of the San Joaquin basin boundary in the NATCARB geodatabase with no closer identified storage basins according to WESTCARB.[8]

These stationary sources produced 24 million tons (tons) of CO_2 in aggregate. Of these, the sources that produced more than 200,000 tons CO_2 per year were extracted for a total of 32 sources. The location of each source and amount emitted is shown on Figure 6. The type of each source is shown on Figure 7. In aggregate, these sources produced 20.5 million tons of CO_2 during the inventory year.

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[3] San Joaquin Basin margin from version 1303 of the NATCARB geodatabase, discussed below

[4] http://www.netl.doe.gov/technologies/carbon_seq/natcarb/download.html#top

[5] http://www.netl.doe.gov/technologies/carbon_seq/natcarb/metadata-v1303/NATCARB_Sources_v1303.pdf

[6] http://gif.berkeley.edu/westcarb/gis-data/WESTCARB_Sources.zip

[7] http://ghgdata.epa.gov/ghgp/main.do

[8] http://gif.berkeley.edu/westcarb/images/maps/saline_formations.pdf

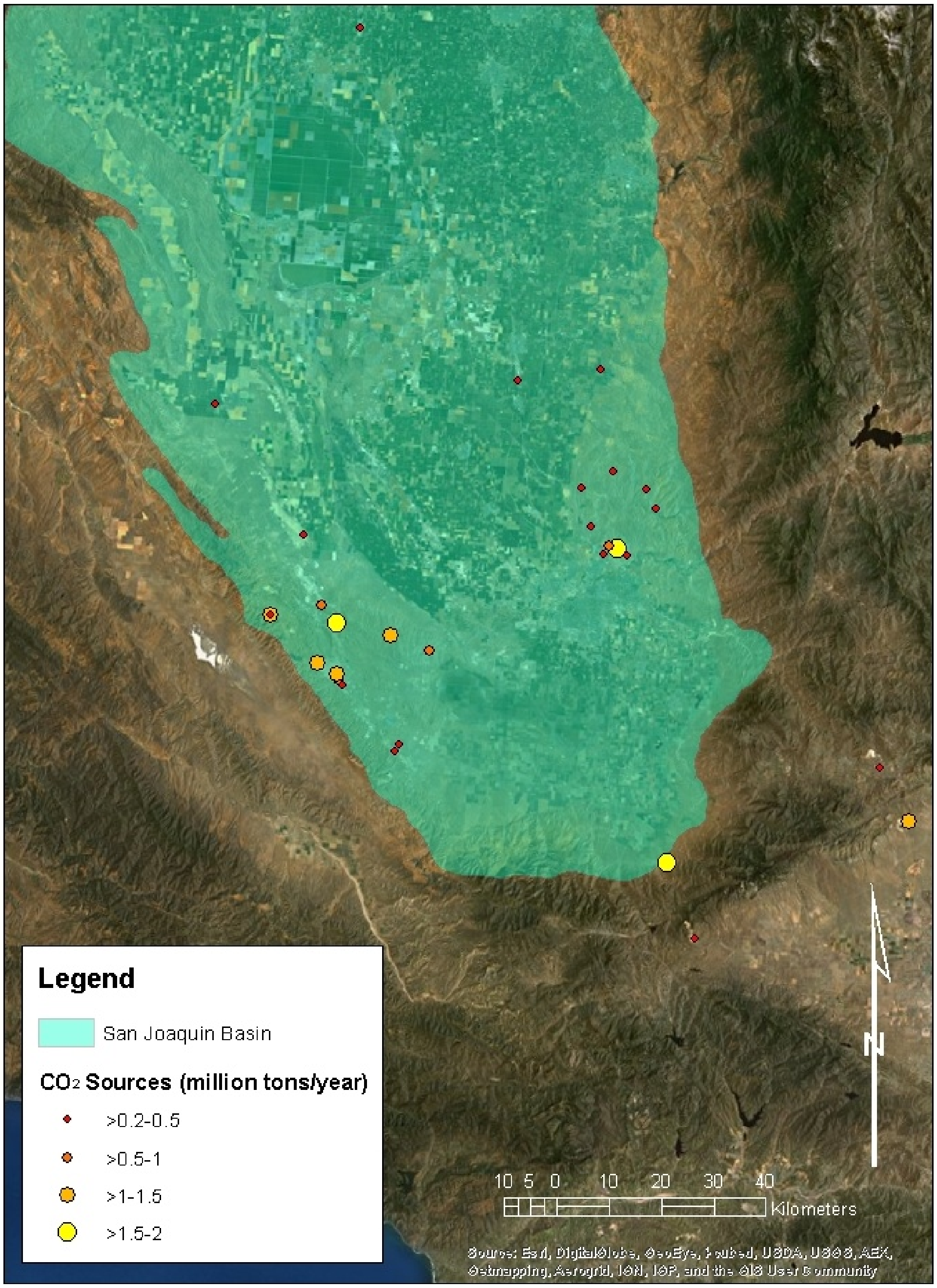

Figure 6: Amount of CO_2 Emissions from Large Stationary Sources in and Near the Southern San Joaquin Basin for the Most Recent Inventory Year Available (2007 or 2010).

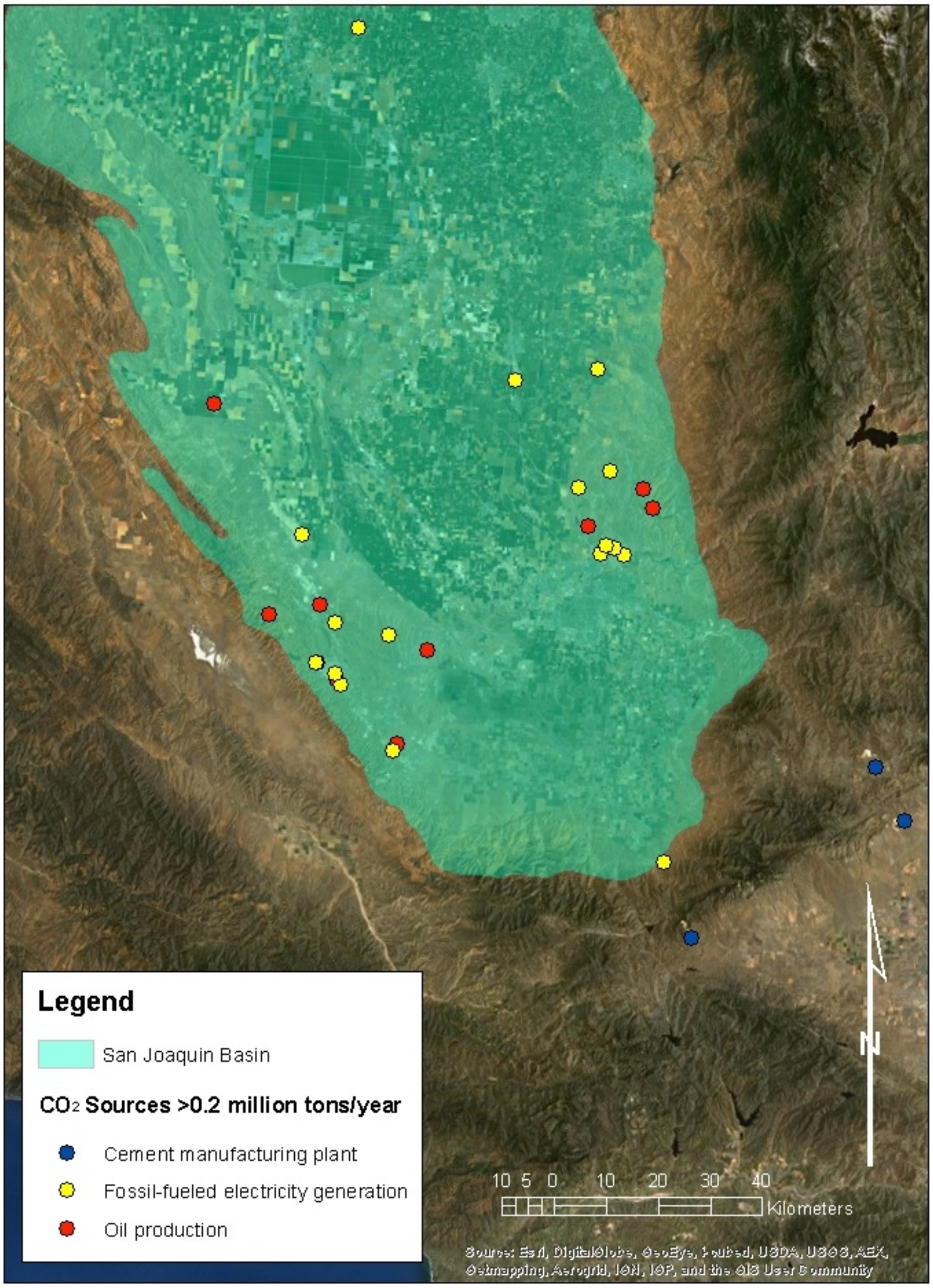

Figure 7: Types of Large Stationary CO_2 Emission Sources in and Near the Southern San Joaquin Basin.

2.5 Geology

The San Joaquin Valley is the southern extension of the Great Valley, an elongate basin located between the Sierra Nevada and the California Coast Ranges as shown on Figure 8. The southern part of the San Joaquin basin is filled by more than 7,000 m of Tertiary marine and nonmarine sediments, which bury the downwarped western margin of the Sierra Nevada metamorphic-plutonic terrane. The stratigraphic section is generally thin and predominately continental on the east side of the basin but thickens into largely deepwater marine facies to the west. The structure on the eastern basin margin is basically a monocline dipping toward the west, characterized by block faulting and broad, open folds. A major feature of the basin is the Bakersfield Arch, a westward-plunging structural bowing on the east side of the basin. This structure plunges south-southwest into the basin for approximately 25 km, separating the basin into 2 subbasins. The Bakersfield Arch is the site of several major oil fields (Wagoner, 2009). The western basin margin is occupied by a complexly deformed fold and thrust belt resulting from the tectonics at the boundary of the Pacific and North American plates, which also affects the structure near the southern margin of the basin. Several major oil fields are located in the fold and thrust belt along the western margin and several minor fields are located along the southern margin.

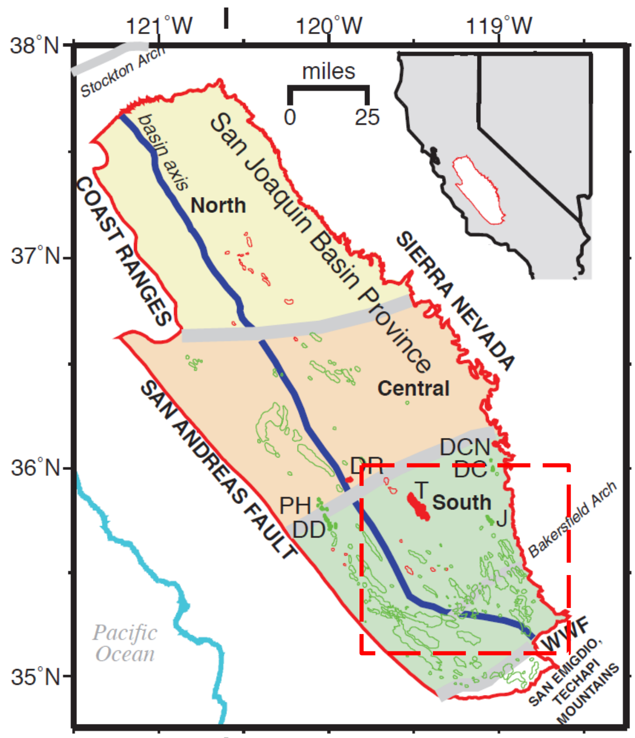

Figure 8: Planview of San Joaquin Basin.

A typical schematic cross-section through the San Joaquin Valley is shown in Figure 9. The deep sediments overlying the crystalline bedrock are the main target of future CO_2 storage in the area. Formed during inundations by the Pacific Ocean, they contain thick sequences of porous and permeable, mostly saline aquifers as well as laterally persistent marine shales. The overlying continental deposits, derived by erosion of the rocks from the surrounding mountains, have an average thickness of about 750 m in the Central Valley. Comprised primarily of sand and gravel interbedded with silt and clay, they form an extensive freshwater aquifer system with immense importance as groundwater resource for California. Groundwater management models in use by water agencies and consultants typically focus on the aquifer system in the thick continental sediments, while excluding the underlying marine and non-marine deposits (where CO_2 might be stored).

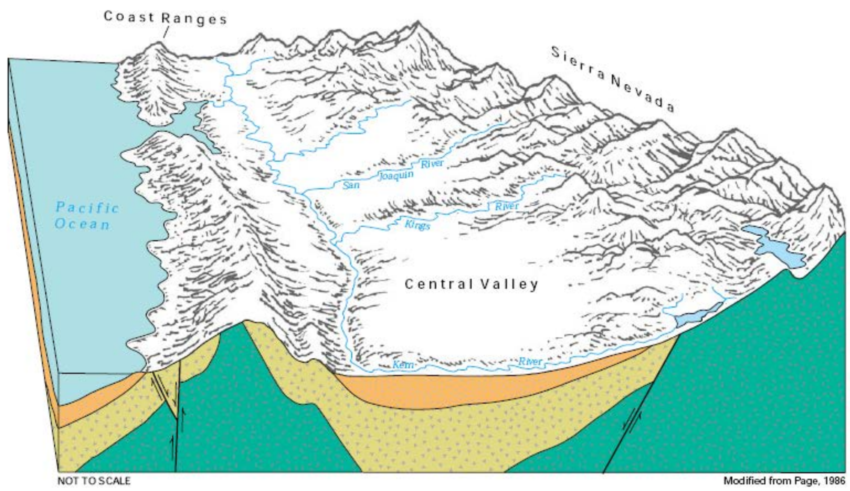

Figure 9: Geologic Cross–Section through the San Joaquin Valley.

The structural trough formed by uplift of crystalline rock (green) has been partially filled by thick marine (yellow) and continental sediments (light-brown) (USGS, 1995).

The stratigraphic relationships of the major formations in the Southern San Joaquin Valley are shown in Figure 10. The geologic framework model developed for this project included the following formations (from shallow to deep):

- **Tulare Formation** (Pleistocene)
  Nonmarine sediments. These are the youngest oil-producing sediments in the basin. This unit extends close to the surface and consists of interbedded claystone, shale, sandstone, and conglomerate.
- **San Joaquin Formation** (Pliocene)
  Nonmarine and marine sediments. Consists of interbedded claystone, shale, sandstone, and conglomerate.
- **Etchegoin Formation** (Pliocene)
  Unconformably overlies the Chanac Formation in the model area. Mostly fine- to coarse-grained marine sandstone and micaceous shale.
- **Macoma Clay** (Pliocene)
  Mostly marine claystone and siltstone. This is a member of the Etchegoin Formation. Basal Etchegoin sandstone occurs stratigraphically below this fine-grained unit in some areas. This unit is mapped because it is and easy-to-correlate time-stratigraphic marker.
- **Chanac Formation** (Pliocene)
  Mostly fine- to coarse-grained nonmarine sandstone, with interbedded siltstone and claystone. This deposit grades basinward into siliceous marine shale. Confined to a narrow zone in the subsurface of the southeastern part of the basin. The Chanac is the nonmarine equivalent to the Santa Margarita Formation.

- **Santa Margarita Formation** (upper Miocene)
  Rests unconformably on the Fruitvale Formation. Mostly coarse-grained sandstone, with sandy shale increasing toward the base of the unit. This unit rests on progressively older sediments toward the eastern edge of the basin. This unit is time equivalent to the Stevens Sand in the central part of the basin. The formation contains both marine and nonmarine facies.
- **Monterey Formation, including the McClure Shale and excluding the Stevens Sand** (upper Miocene)
  Fractured marine shale, typically siliceous, with some sandstone interbeds
- **Stevens Sand** (upper Miocene)
  Fine- to coarse-grained turbidite sandstone, with interbedded hard siltstone. The sandstone is highly variable in thickness and lateral extent. In the central part of the basin, thick siliceous shales overlie the Stevens.
- **Fruitvale Shale** (upper Miocene)
  Mainly marine deep water shale. Rests unconformably on top of the Round Mountain Formation. Massive marine siltstone and shale, with streaks of sandtone. Thickens toward the center of the basin. Dominant shale member of the Monterey Formation in the southeastern part of the basin.
- **Round Mountain Formation** (middle Miocene)
  The unit is mostly hard marine siltstone and shale.
- **Olcese Formation** (lower Miocene)
  Medium- to coarse-grained sandstone. Gradational contact with the underlying Freeman Jewett Formation. The upper and lower parts of this unit are marine, while the middle portion of the Olcese is nonmarine in origin.
- **Freeman-Jewett Formation** (lower Miocene)
  Rests conformably on the Vedder Formation. Mostly hard marine shale and siltstone with thin streaks of sandstone. Grades vertically into the overlying Olcese Formation and represents the beginning of a regressive phase of the Miocene marine deposition.
- **Vedder Formation** (lower Miocene)
  Fine- to coarse-grained massive marine sandstone, with subordinate siltstone and shale. The younger Rio Bravo and Pyramid Hill sands (basal member of the overlying Freeman-Jewett Formation) have been included in this unit. This is the oldest of the significant oil-producing deposits on the eastern side of the basin. The sands included in the Vedder range from a few feet to several hundred feet thick.
- **Walker Formation** (lower Miocene)
  The Walker Formation rests on basement rocks on the east side of the basin, is continental in origin, and consists mainly of sandstone and claystone. Toward the center of the basin, the Walker interfingers with the time-equivalent Vedder Formation.
- **Temblor Formation** (lower to middle Miocene)
  This formation has a widespread distribution in the subsurface of the southern and western San Joaquin basin. The formation has several different members with different lithologies, such as the Carneros and Phacoides. It represents the basinward equivalent of the Vedder, Freeman-Jewett, and Olcese Formations.

- **Undifferentiated deposits** (Eocene)
  There are a number of Eocene formations in this part of the San Joaquin basin, but the Kreyenhagen Formation is the most widespread. The Kreyenhagen is predominantly thick marine shale, but it also includes the Point of Rocks
  Sandstone in the west and the Famoso sand in the east. The younger Tumey Formation is also relatively widespread, and it occurs directly below the Vedder in the model area. The Tumey is also predominantly marine shale, but it includes the Oceanic sand in the west.
- **Basement** (pre-Tertiary)
  The basement in this part of the basin is mainly quartz diorite intrusive rocks.

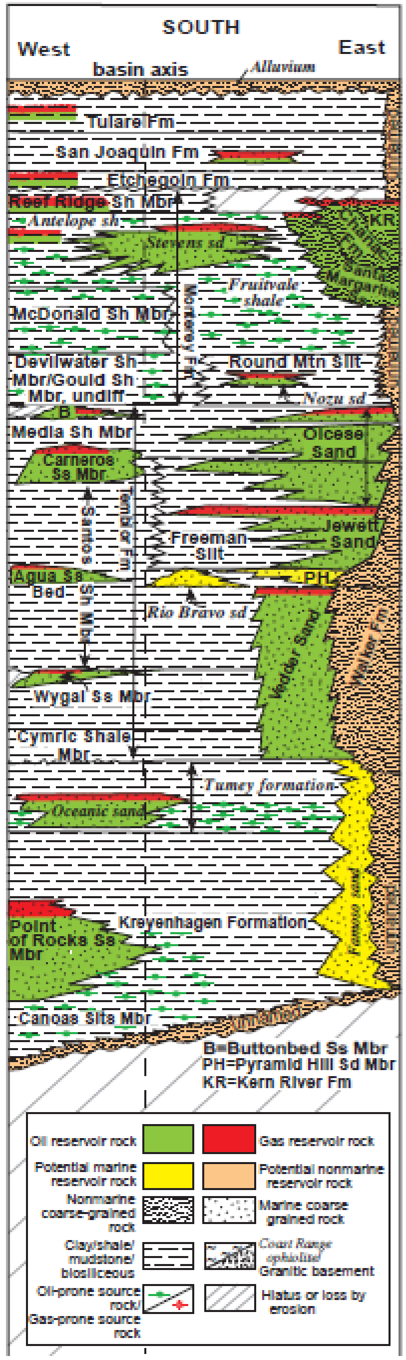

Figure 10: Generalized Stratigraphic Section for the Southern San Joaquin Basin (Hosford Scheirer, 2007).

With one exception these are the stratigraphic units used in the geologic model of Wagner (2009), whose extent is indicated in Figure 8. The shallowest unit in Wagoner (2009) is the Kern River Formation. This occupies the stratigraphic position of the Tulare and San Joaquin Formations throughout most of the basin, as shown on Figure 10. Pools are associated with these formations in the records assessed in this project, and so they were used instead of the Kern River Formation.

Note there is some difference between the stratigraphic units used in this project and those in the companion project. The geologic model of Wagoner (2009) was extended to cover the entire southern portion of the San Joaquin Basin. This extension necessitated some adjustment of the stratigraphic units.

CHAPTER 3:
Annual Fluid Volume Database

A database of annual production and injection volumes for each pool in District 4 was assembled from various sources as described below. Each pool is associated with a field, area, pool (FAP) code, which provides the primary relate field in the database. A list of these codes is provided by the California Division of Oil, Gas and Geothermal Resources (DOGGR).[9] Some new codes were also created for reasons described below.

3.1 Data Sources and Assembly

Production data was assembled for 719 individual pools. The number of records for each fluid type in the database is given in Table 1. Discussion of the data sources and data quality checks follows.

Table 1: Number of Records in the Database for Each Type of Fluid Production and Injection

Fluid type	# of records
Oil production	16,567
Water produced with oil	16,480
Gas produced in association with oil	16,233
Gas produced not in association with oil	556
Water produced in association with gas not associated with oil	372
Gas injected	13,051
Water flood	634
Water disposal	763
Steam flood	93
Cyclic steam	290
Water injection	8,642

3.1.1 DOGGR Production and Injection Database

The DOGGR production and injection database[10] provides access to monthly fluid production and injection volumes at standard conditions for each well. Production volumes for oil, water and gas are available as well as injection volumes of water/steam and gas/air.

The available database queries provide sums for each year. A database query is also available to sum all the volumes for a pool. Export of the results as comma-delimited text is provided. The

[9] ftp://ftp.consrv.ca.gov/pub/oil/FAPFILE.doc

[10] http://opi.consrv.ca.gov/opi/opi.dll

production and injection sums for each pool were queried and exported in the summer of 2011. Files of just the annual sums through 2010 were subsequently created, with separate files for oil and produced water, produced gas, injected water/steam and injected gas/air. The FAPyear and FAP were added to the beginning of each record in these files and the results imported into the respective files in the annual fluid volume database.

The time series start at various months in 1977 depending on the well. Consequently only annual volumes after 1977 were imported into the annual fluid volume database.

Volumes exported from the DOGGR database for the Any field, Any area, Diatomite pool were merged into the production for the South Belridge Field, Any area, Diatomite pool prior to import into the annual fluid volume database. The DOGGR database contained oil, water and gas production for the Any field, Any area, Diatomite pool in 2009 and 2010. The sums for this pool were from three wells located within the southern extent of the South Belridge Field (API# 0307934, 0307936 and 00307934). Records for only one of these wells (API# 0307936) were available through DOGGR's well records database.[11] This record assigned the well to the South Belridge Field. DOGGR also makes available a GIS layer of all the wells in District 4.[12] The attribute table assigns all three wells to the South Beldridge Field.

3.1.2 Annual Reports of the State Oil and Gas Supervisor

Fluid volumes prior to 1978 were taken from the annual reports of the State Oil and Gas Supervisor, which cover back to the second half of 1915. Scans of the reports are available.[13] These were downloaded and the text recognition tool in Adobe Acrobat X applied to render the fluid volumes as numbers. These numbers were copied into Excel spreadsheets for import into the database.

The reports for later years report oil, oil-associated water and gas, and non-oil-associated gas and water production, and gas, water disposal and flood, cyclic steam, and steam flood injection. The reporting of each of these starts in different years, apparently due to a different commencement time for each. The totals for each in the first year it is reported suggest the activity started previous to that year.

Production volumes for many fields that later were divided into areas were initially reported for the entire field as a whole. Many such fields were the subject of technical articles in the later annual reports. These articles often contained tables that retrospectively broke out production by area. Where such information was available, it was substituted for the earlier volumes reported for the field as a whole. Similar information was available for the Lost Hills Field in Land (1984). This information was likewise incorporated into the database.

Steam injection volumes for 1977 are not available in the annual report for that year. The volumes were back calculated by subtracting the cumulative volumes in the 1976 report and the

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[11] http://owr.conservation.ca.gov/WellSearch/WellSearch.aspx

[12] ftp://ftp.consrv.ca.gov/pub/oil/GIS/Shapefiles/D4Wells.zip - the 101712 version was used

[13] Available from http://conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx

1978 injection volumes from the cumulative volumes in the 1978 report. The resulting values were entered into the database. Due to a change in significant figures from the 1976 to 1978 reports, the 1977 steam volumes in the database have fewer significant figures than for earlier years.

The names of fields, areas and pools with reported volumes did not obviously match a field, area or pool in DOGGR's current listings. For many of these, a note in the annual report for the year after the name transitioned to a new name provided the correlation, allowing assignment of the same FAP code. When correlation was not possible, new codes were created. New codes were created for 92 of the 719 pools with production and/or injection. Of these, 18 required new codes up to the field level and 23 up to the area level. The remaining 51 required new codes only at the pool level. All these new codes included a letter instead of a number in the final place, in contrast to the codes used by DOGGR. The pool codes are listed in Appendix A.

3.1.3 Data Quality Checks and Cumulative Production

The time series for each type of fluid production and disposal was plotted for numerous pools. Obvious data gaps or value spikes were investigated and resolved. Many of these were due to illegible scans in the annual reports available from DOGGR. These were resolved by entering data from new scans of those pages provided by DOGGR or by the Baker document delivery service of the University of California Berkeley library system.

The cumulative production or injection of various fluids was checked against those in the 2009 annual report, which is the latest available annual report. Table 2 lists these results.

Table 2. Comparison of Cumulative Volumes from the Annual Fluid Volume Database and the California Oil and Gas Supervisor's 2009 Annual Report.

Fluid type	Data base	Annual report	Database/ annual report (%)
Oil (MMbbl)	12,100	12,300	98.4%
Oil-associated gas (MMMcf)	13,900		
Non-oil-associated gas (MMMcf)	438		
Gas injected for pressure maintenance (MMMcf)		4,320	
Injected gas listed on storage tables (MMMcf)[1]		378[1]	
Injected gas (MMMcf)	4,730	4,700	100.6%
Net oil-associated gas (MMMcf)		9,360	
Net non-oil-associated gas (MMMcf)		702	
Net gas (MMMcf)	9,610	9,680	99.3%
Water produced with oil (MMbbl)	59,000		
Water produced with non-oil-associated gas (MMbbl)	5		

Disposed water (MMbbl)	1,370	12,700	
Water flood (MMbbl)	874	6,380	
Cyclic steam (liquid water input in MMbbl)	940	4,220	
Steam flood (liquid water input in MMbbl)	1,000	13,100	
Injected water (MMbbl)	31,900		
Total injected water (MMbbl)	36,100	36,400	99.2%

[1]Cumulative not available. Summed from annual volumes on gas storage tables.

Cumulative oil production and gas injection are the only fluid types with the same reporting frame throughout the production history. Cumulative oil production matched to within 2 percent.

The 1999 annual report lists cumulative gas injection for pressure maintenance. Cumulative gas injection for storage is not available in this report or any earlier report. The reports from 1962 to 1977 have separate gas storage tables. The volumes from these tables for District 4 were summed to provide the cumulative shown on Table 1. This was summed with the cumulative gas injected for pressure maintenance to provide the total gas injection according to the annual reports. This total was within 1 percent of the injected gas total from the database.

For the database results, subtracting the cumulative injected gas from the oil associated and non-associated gas production provides the cumulative net gas. For the annual reports, summing the net oil associated and non-associated gas production and subtracting the injected gas listed on the storage tables, which does not appear to be accounted for in the net cumulative, provides the cumulative net gas. These figures agree to within 1 percent.

Cumulative water injection is reported by four injection purposes in the annual reports: disposal, flood, cyclic steam and steam flood. Cyclic steam and steam flood volumes are reported as the liquid volume from which the steam was produced. The sum of the volumes reported for these four types of injection provides the cumulative water injected. Because these four types of injections were occurring prior to 1978, the database also contains such data. Water injection in the database after 1977 is in the single category provided by the online injection data source. Summing these five cumulatives provides the database cumulative water injected. The database and annual report cumulative agree to within 1 percent.

Cumulative produced water is not available in the annual reports. Consequently the volume from the database shown in Table 2 makes this figure available for the first time. The cumulative is 59 billion barrels, or 9.4 billion m^3. Subtracting the cumulative injected provides a net cumulative of 23 billion barrels (3.7 billion m^3).

3.2 Net Production Volume at Reservoir Conditions

All fluid volumes are reported at standard conditions in the data sources. In order to understand pressure changes in the subsurface in response to fluid production, an estimate of the volume produced at the pressure and temperature condition in each pool is required.

For water produced, disposed and injected for floods, the difference in volume between standard and reservoir conditions is small and so ignored. For oil, gas typically effervesces at standard conditions resulting in a loss of oil volume relative to reservoir conditions. This change is significant and so addressed. For gas, some of the reported volume is effervesces from oil and must be discounted when calculating the volume produced at reservoir conditions. For the remaining gas, there is obviously a substantial change in volume from standard to reservoir conditions.

Many of these adjustments are captured in the following budget equation,

$$V = B_o * P_o + P_{wo} + B_g * P_g + P_{wnag} - B_g * I_g - I_w \qquad (1)$$

where V is the volume produced, B_o is the ratio of oil volume at reservoir to surface conditions (oil formation volume factor), P_o is the volume of oil produced at surface conditions, P_{wo} is the water produced with oil, B_g is the ratio of gas volume at reservoir to surface conditions (gas formation volume factor), P_g is the estimated volume of gas produced from gas-phase in the reservoir at surface conditions, P_{wnag} is the volume of water produced with gas from pools with no oil (non-associated gas), I_g is the volume of gas injected at surface conditions, and I_w is the volume of water injected.

Equation 1 assumes that all injected gas remains a separate phase rather than dissolving into oil in the reservoir. In reality, some of the injected gas certainly must come into contact with and so dissolve into oil, this assumption is operationally reasonable. However operators seek to minimize injecting gas into oil because this would reduce the relative permeability to oil. This would counteract the goal of gas injection, which is to maintain or increase reservoir pressure to enhance oil production.

Companies will also avoid such dissolution because it can reduce the efficiency of oil production. Bubbles will form in oil with considerable dissolved gas as the pressure in the reservoir declines. The bubbles will reduce the relative permeability to oil.

P_g is calculated according to

$$P_g = (P_{ag} - P_{ago}) + P_{nag} \qquad \text{for } (P_{ag} - P_{ago}) + P_{nag} > 0$$

$$P_g = 0 \qquad \text{for } (P_{ag} - P_{ago}) + P_{nag} < 0 \qquad (2)$$

where P_{ag} is the volume of gas produced in association with oil, P_{ago} is the estimated volume of gas produced from solution in produced oil, and P_{nag} is the volume of gas produced not in association with oil. The second term is calculated according to

$$P_{ago} = P_o * GOR \qquad (3)$$

where GOR is the ratio of the volume of gas from solution in oil to the volume of oil at surface conditions.

The initial values of B_o and B_g are reported in the California Oil and Gas Fields Volume 1 (DOGGR 1998) for some, but not all, pools. Where available, these values were used. This ignores the change in these values through time due to changes in reservoir conditions, which is perhaps reasonable given the prevalence of pressure maintenance.

For the pools where B_o, *GOR,* and/or B_g are required to calculate the production at reservoir conditions but are not available from DOGGR 1998, an assignment was made based on hierarchy of strategies discussed below. As many of the strategies are based upon pool depth, assigning a depth in the database to each pool with production and injection was the starting point.

3.2.1 Depth

Depth assignments for pools with production or injection were made according to a prioritized list of strategies, as follows:

1) Assign from DOGGR (1998)
2) Assign from a pool in the same field and area that has a depth and a similar name
3) Assign the average from pools in the same field and area that have similar names
4) Assign the average from pools in same field and stratigraphic unit
5) Assign the average from same field and stratigraphic unit
6) Assign from a pool in the same stratigraphic unit in a nearby field
7) Assign the average from pools in the closest strata in the same field and area

Depth was available in DOGGR (1998) for 269 of the 719 pools with production or injection. An additional 199 depths were available for pools without production or injection.

3.2.2 Formation Volume Factor for Oil

Of the 719 pools with production or injection, 462 had oil production. Assignments of B_o were made according to a prioritized list of strategies similar to that for depth, with three additional strategies, as follows:

1) Assign from DOGGR (1998)
2) Assign from a pool in the same field and area that has a depth and a similar name
3) Assign the average from pools in the same field and area that have similar names
4) Calculate based on *GOR* from DOGGR (1998)
5) Assign the average from pools in same field and stratigraphic unit
6) Assign the average from same field and stratigraphic unit
7) Assign from a pool in the same stratigraphic unit in a nearby field
8) Calculate based on depth
9) Assign from pool in the same stratigraphic unit at a similar depth
10) Assign the average from pools in the closest strata in the same field and area

B_o is available in DOGGR (1998) for 160 of the 462 pools with oil production. The third strategy uses the correlation between B_o and GOR for pools with both reported, as shown on Figures 11 and 12. The seventh strategy uses the correlation between B_o and depth shown on Figure 13.

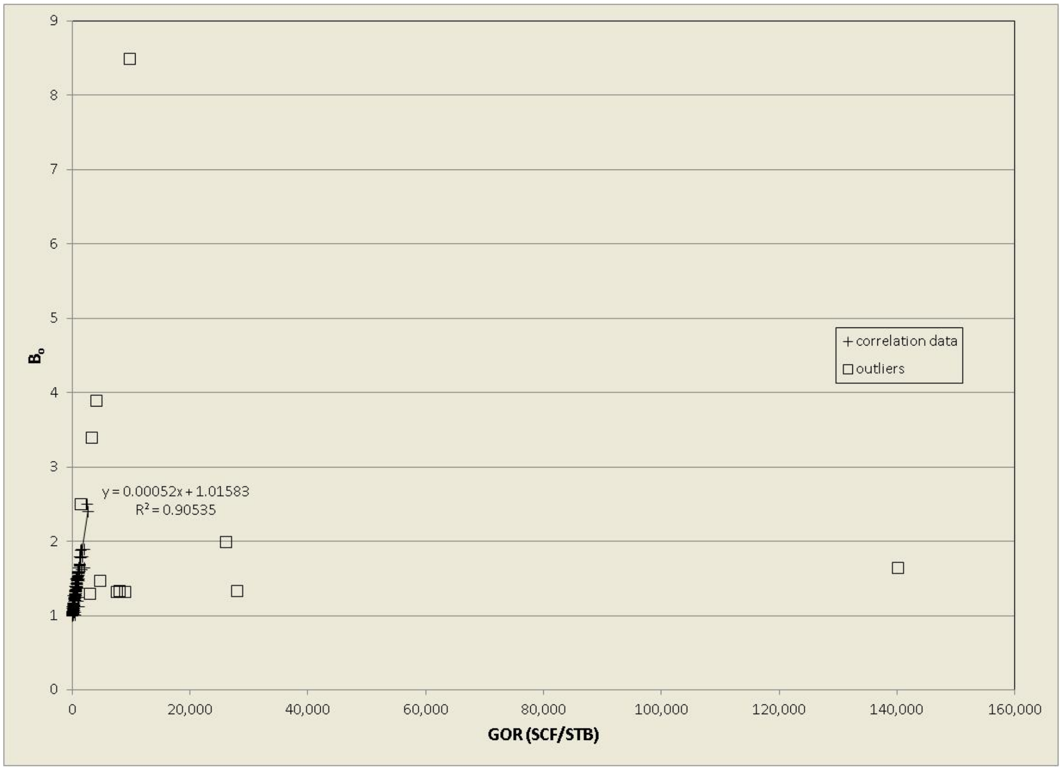

Figure 11: *B_o* versus *GOR.*

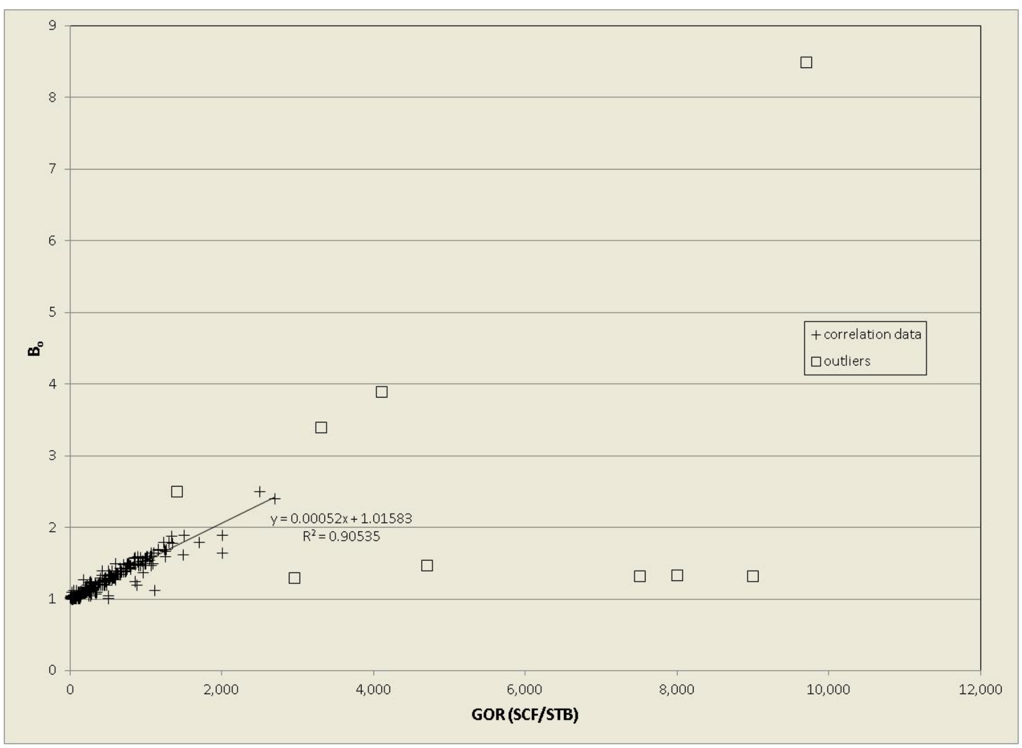

Figure 12: Detail of B_o versus *GOR.*

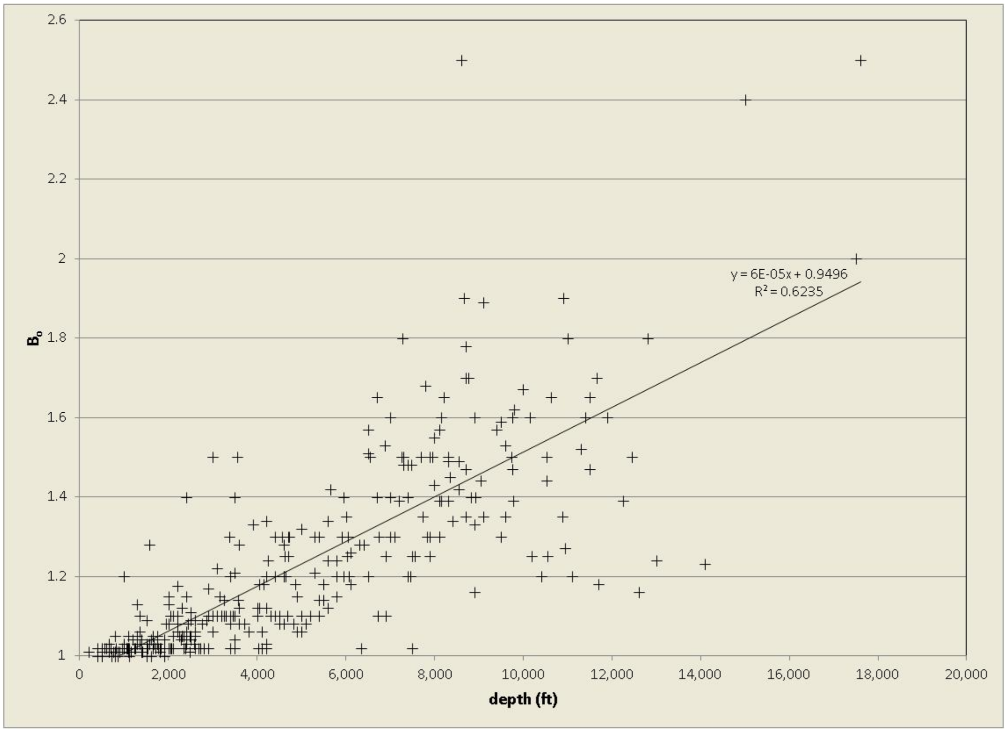

Figure 13: B_o versus Depth.

3.2.3 Gas-R

The inverse of the B_o to *GOR* regression on Figures 1 and 2 is quite close to a rule of thumb to calculate the *GOR* for solution gas from B_o. The inverse of the regression is

$$GOR = 1923(B_g - 1.016) \qquad (4)$$

A rule of thumb is

$$GOR = 2000(B_g - 1.05) \qquad (5)$$

according to Arps (1981). This indicates the GOR reported in DOGGR (1998) is for solution gas only, rather than for all gas production, including free gas from a gas cap.

While *GOR* was reported in the California Oil and Gas Fields Volume 1 for some pools, values calculated from B_o using the regression equation on Figures 11 and 12 were used for two reasons. First, this eliminated the *GOR* outliers. Second it provided consistency between the value of B_o and *GOR*, which should exist given their physical relationship.

3.2.4 Formation Volume Factor for Gas

B_g values were developed using Equation 2.46 from Gou and Ghalambor (2005) as follows:

$$B_g = 0.00504 \frac{zT}{p} \qquad (4)$$

where z is the compressibility factor, *T* is temperature and *p* is pressure. This equation provides a value for converting gas volume in cubic feet at standard pressure and temperature conditions to barrels at the reservoir pressure and temperature. Gou and Ghalambor (2005) provide an approach for calculating *z* using gas gravity, pressure and temperature. Gas gravity is the natural gas density divided by the density of air.

B_g is most sensitive to pressure. Of the 463 pools with gas production or injection, 205 have initial pressure reported in DOGGR (1998). All but two of these also have reported initial temperature. For the purposes of calculating B_g, temperatures for these pools were calculated from their reported depth and the average geothermal gradient calculated from all the reported initial temperature, depth pairs for pools in District 4 in DOGGR (1998).

Gas gravity was not reported for 48 of the pools with reported initial pressures. Reported gas gravities were found to correlate weakly with depth according to a power law with a coefficient of 0.3237 and an exponent of 0.0976. This correlation was used to assign gas gravities using the reported depths for calculating B_g for pools with reported initial pressures and gas production or injection.

For the remaining pools, B_g was calculated from the following depth correlation. The correlation was developed by optimizing the fit of B_g calculated from depth to the B_g calculated from initial pressure, temperature and gas gravity discussed above.

$$B_g = \frac{9.356}{d} + 1.55 * 10^{-7} * d - 0.0013 \qquad (5)$$

The first term can be understood as representing the predominance of pressure on the value of B_g, and the second and third terms as representing the non-ideal nature of real gas compression. Correlation without the second and third terms creates a depth bias were the B_g estimated from depth alone is too large relative to the calculated B_g at shallow depths and too small at great depths.

Figures 14 and 15 show the correlation between B_g estimated from equation 5 versus calculated from the initial pressure, temperature and depth for those pools with all three values reported. As shown on Figure 14, construction of the correlation excluded the three largest calculated values of B_g as those would have pulled the correlation upward away from the bulk of the values. These three largest calculated values are from the three shallowest pools, which were all less than 1,000 feet deep and so not germane to the carbon storage analog.

There are 147 data points shown on Figure 14. Figure 15 shows six of the estimates are more than twice the calculated values and one is less than half the calculated value. Consequently the estimated value has a greater than 95 percent chance of being within a factor of two of the calculated value. The lower uncertainty on produced oil volume and little uncertainty on produced water volume, leads to an aggregate volume transferred uncertainty for most pools that will be considerably less than a factor of two.

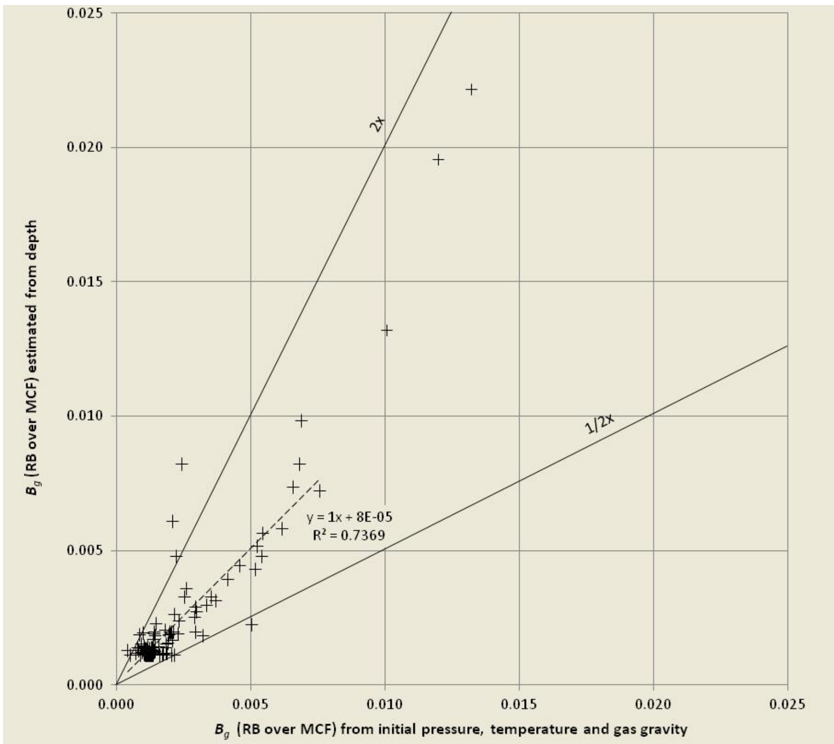

Figure 14: Relationship of Estimated to Calculated B_g.

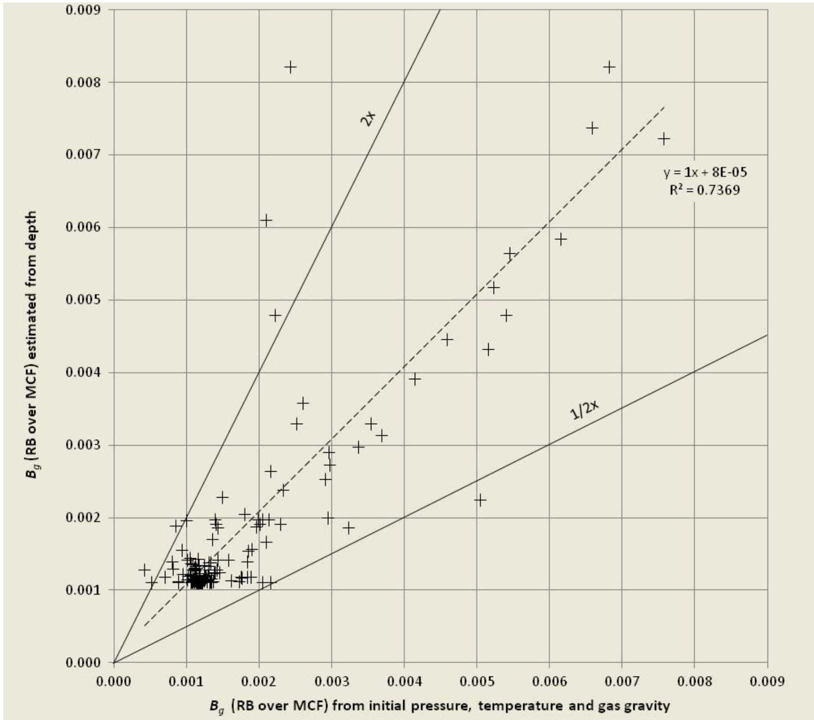

Figure 15: Detail of Relationship of Estimated to Calculated B_g.

3.2.5 Stratigraphic Unit Assignment

Each pool was assigned to a stratigraphic unit in the geologic model in order to allow mapping and analysis by position in the stratigraphic section. Pools were assigned based on host geologic unit reported in DOGGR where available. Where not available, assignments were based on pools with similar names. Where no similarly named pools were available, assignments were based upon expert knowledge of the strata from which production occurred in different fields.

An exception to the above was volumes reported by field and area but not pool. These were assigned to a "no pool" pool for each field and area where they occurred. These typically occurred early in a field's history before pools had been defined. These "no pool" pools were generally assigned to the stratigraphic unit from which the most production occurred at the time pool-specific production was first reported. This certainly results in some portion of the early production not being assigned to the stratigraphic unit from which it derived. However pools were usually defined at the time production from a field became larger and so the early production volumes are typically a small portion of the cumulative production for a field. This limits the magnitude of the error resulting from assignment of "no pool" pool production to a stratigraphic unit.

3.3 Net Production Volume Distribution

Net cumulative production in District 4 as of 2010 was 8.4 billion m^3 (53 billion reservoir barrels) summing the result of equation 1 applied to the production from each pool. This result has little relevance to geologic carbon storage however due to the nonlinear increase of CO_2

density with pressure as discussed below. Consequently understanding the spatial distribution of production is necessary to gain insight into the implications for geologic carbon storage of the production history in District 4.

3.3.1 Field Area GIS Layer

A GIS layer of the field areas is required to map the net fluid volumes produced. A field outline GIS layer is available from WESTCARB[14], and a GIS layer of the field administrative boundaries is available from DOGGR.[15] These are shown on Figure 16. The WESTCARB field outlines typically lay within the DOGGR administrative boundaries. However for some fields the two are not coincident and in others the outline is considerably smaller than the boundary. These GIS layers also do not discriminate areas within fields.

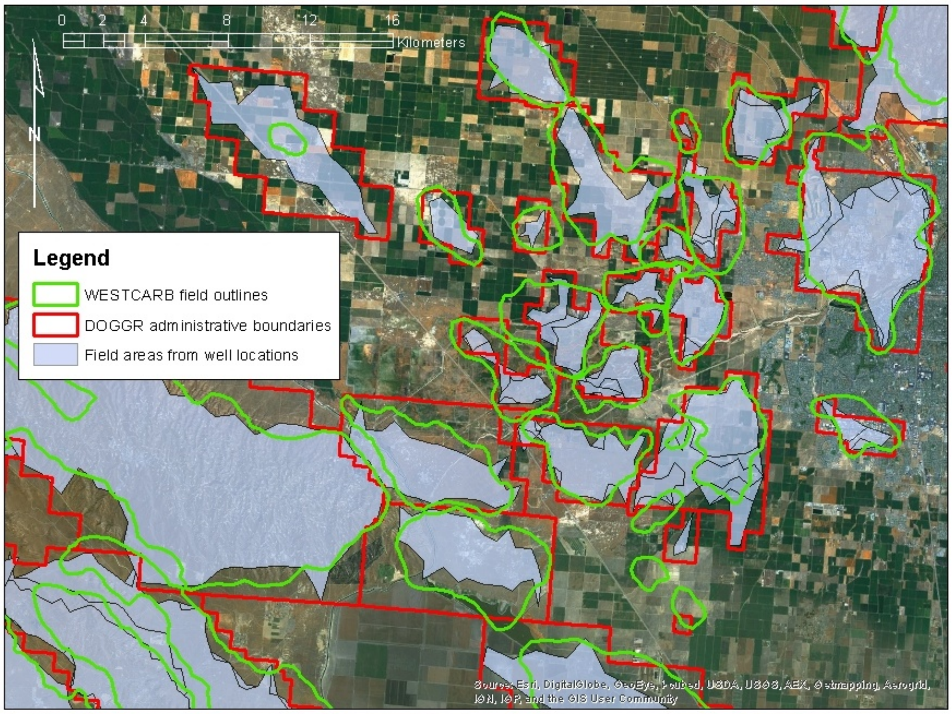

Figure 16: Overlay of Different Field Representations.

The outlines and boundaries were checked against the wells assigned to each field in the District 4 well GIS layer. These generally occupied a portion of the administrative area, but variously coincided with, were smaller or larger than, or were shifted from the outlines. Consequently, in order to provide an accurate representation of the extent of each well field area, polygons were aggregated from the well locations assigned to each field area in the District 4 well GIS layer that also had net production. The aggregation distance was set to the minimum that would result in a single polygon. This was done discounting outlier wells at a

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[14] http://gif.berkeley.edu/westcarb/gis-data/CA_Oil_and_Gas_Fields.zip

[15] ftp://ftp.consrv.ca.gov/pub/oil/GIS/Shapefiles/CA_AdminBdry.zip

default location for wells that had not been located, wells located in other field areas, and other apparent outliers.

Polygons for an additional field area was developed from well locations in the GIS layer in order to have polygons for each field area that had net production in the database and DOGGR codes rather than custom assigned codes. While thousands of wells in the GIS layer are assigned to any field, any area, DOGGR's production and injection database had records for only a few tens of these wells in three different pools. The wells in one of the pools were actually associated with the South Belridge field, Any area, Diatomite pool as mentioned above, and so not included in the Any field, Any area polygon construction. The other two pools were in the Tulare and received water injection, likely disposal. The wells in these pools were located in three groupings. They were aggregated into three polygons, creating the only field area represented by more than one polygon.

The three other field areas for which polygons were developed from well locations were the areas in the North Tejon Field. Wells in this field were only assigned to any area in the DOGGR GIS layer. These wells were subset into three areas based upon an estimate suggested by the area names, and polygons created based on these groupings.

This work resulting in polygons for 183 of the 218 field areas with net production. The field areas with polygons had more than 98 percent of the total net production for all field areas with net production, and 96 percent of the total net injection for all field areas with net injection. An FA field for the field area code for each polygon was added to the attribute table for each polygon, and all the polygons assembled into one GIS layer. The FA codes in this GIS layer allow it to be joined to various query results from the database, such as is shown in figures below.

3.3.2 At CO_2 Storage Depths

The District 4 net fluid production totals presented above incorporates all fluid production and injection without regard to depth. To ensure efficient and lower risk storage only reservoirs with an initial fluid pressure and temperature sufficient to maintain CO_2 in a relatively dense state are typically considered. This allows more $CO_2$to be stored per pore volume and reduces the buoyancy force promoting its leakage. The minimum desirable pressure and temperature is often taken as the critical point (7.39 MPa and 31.1 °C), but subcritical conditions with respect to pressure also provide for dense CO_2.

In the northeastern portion of District 4, the mean pressure gradient and zero pressure depth indicates the CO_2 critical pressure occurs at a depth of 840 meters based upon Jordan and Doughty (2009). The mean temperature at this depth is above the critical temperature; however the CO_2 density at the mean temperature and pressure is still rather low at about 200 kg/m^3 as shown on Figure 17.

In addition, because pressures and temperatures vary at a given depth, there is also some uncertainty regarding the pressure and temperature at this depth at a specific location. This is also represented on Figure 17. As shown on the figure, a density as low as 100 kg/m^3 occur within the 95 percent pressure-temperature confidence interval. The 95 percent confidence interval also includes a region near the critical point where the density changes by 300 kg/m^3 with a change in pressure of 1 MPa. This is more than 60 percent of the average density in that portion of the confidence interval. This makes accurate prediction, monitoring and accounting of the CO_2 plume resulting from injection difficult.

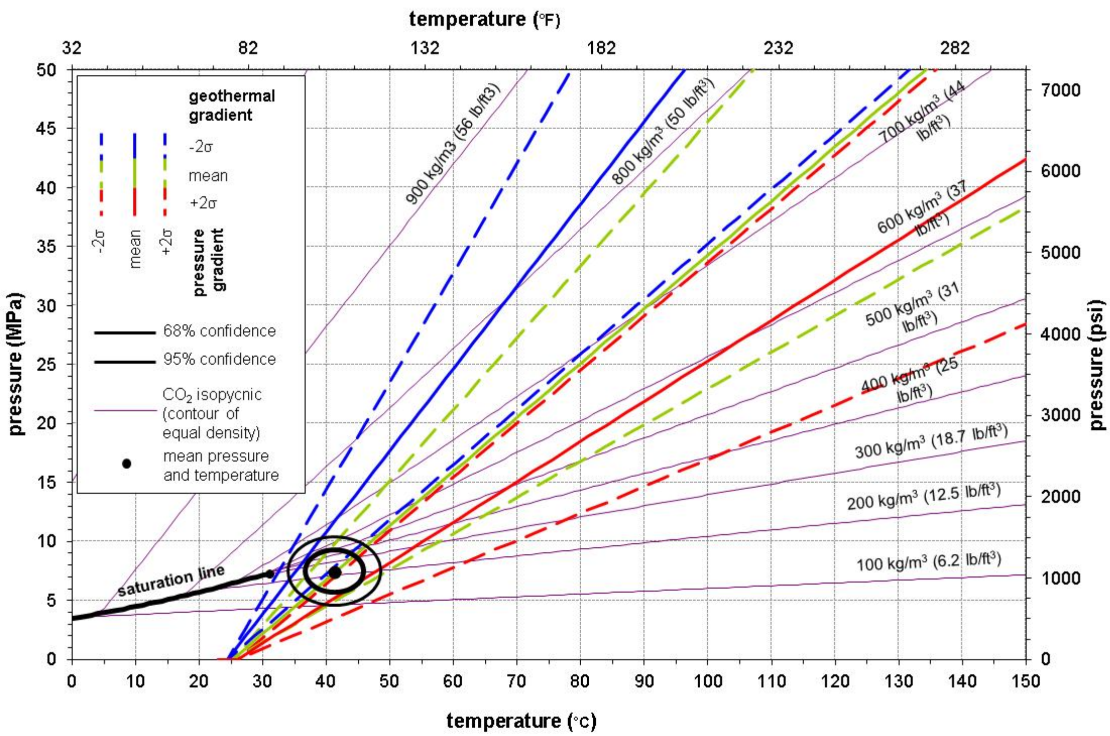


Figure 17: CO_2 Density Probability Distribution at 840 m in the Northwest of District 4 (Modified from Jordan and Doughty 2009).

At a depth of 1500 m all CO_2 densities within the 95 percent confidence interval are greater than 200 kg/m^3, as shown on Figure 18 and the density at the mean temperature and pressure is over 600 kg/m^3. This provides for storage of three times as much CO_2 per pore volume than at a depth of 840 m given at the mean temperature and pressure and twice as much CO_2 per pore volume at the minimum density in the 95 percent confidence interval.

The maximum change in CO_2 density with a change in pressure is also only 100 kg/m^3 for a change of one MPa within the confidence interval at a depth of 1500 m. This change is a third of the rate of change as the maximum in the confidence interval at 840 m. It is less than 20 percent of the average density in that area of the confidence interval.

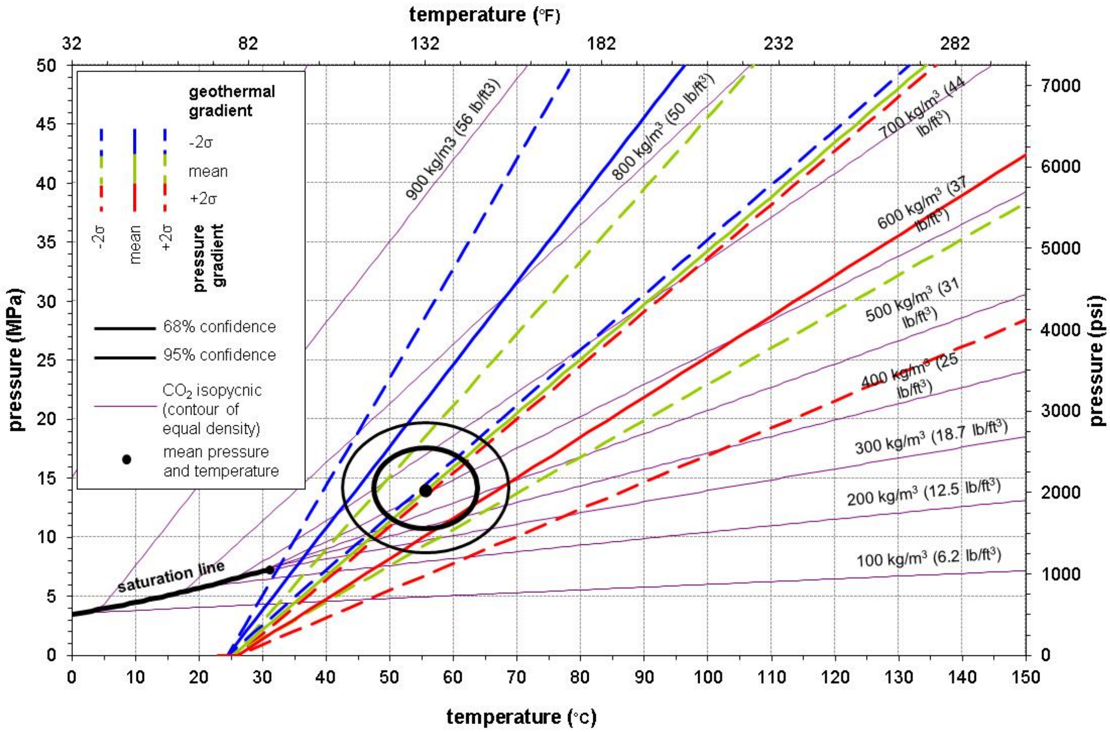


Figure 18: CO_2 Density Probability Distribution at 1500 m in the Northwest of District 4 (Modified from Jordan and Doughty 2009).

Given a minimum storage depth of 1500 m, Table 3 shows the net volume of fluid produced from each stratigraphic unit during oil and gas recovery. Approximately 100 million m^3 at reservoir conditions (Rm^3; 600 million reservoir barrels) or more were produced from the Stevens, Temblor and Vedder each, indicating they have the most demonstrated storage capacity. Their combined net production is approximately 1 billion m^3 (7 billion RB). This is equivalent to 600 million tons of CO_2 taking the average storage density as 600 kg/ m^3. This is over 30 years of emissions at the 18.5 million tons/year large local stationary source rate discussed above.

Table 3: Net Production through 2010 for Each Stratigraphic Unit during Oil and Gas Recovery at Reservoir Conditions.

Stratigraphic Unit	Net Production	
	(million Rm^3)	(million RB)
unassigned	0	0
Tulare	50	300
San Joaquin	80	500
Etchegoin	10	90
Chanac	50	300

Santa Margarita	8	50
Monterey (inc. McClure)	30	200
Fruitvale	1	5
Stevens	800	5,000
Round Mountain	1	8
Olcese	8	50
Freeman_Jewett	8	50
Temblor	100	800
Vedder	100	700
Eocene	80	500
basement	0	0
total	1,400	9,000

Figures 19 through 21 show the net fluid production from the Stevens, Temblor and Vedder field areas below 1500 m, respectively. The figures identify the two field areas from each stratigraphic unit selected for pressure data collection and analysis discussed below. All of these had among the highest production per unit area for that unit, except North Coles Levee. That field area was selected in order to allow utilization of a well-by-well fluid production database assembled at California State University Bakersfield (CSUB) in this study.

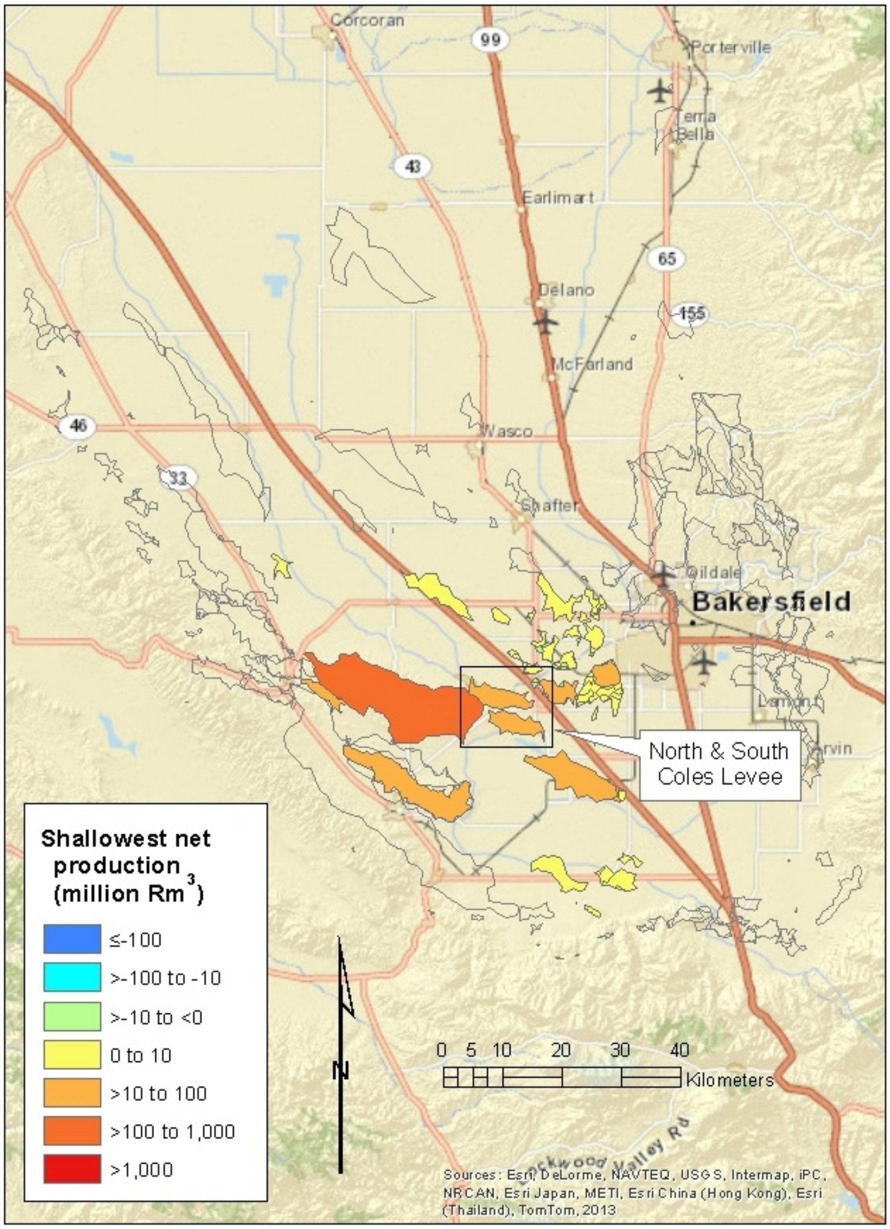


Figure 19: Net Production from the Stevens by Field Area below 1500 m Depth (Negative Values Are Net Injection).

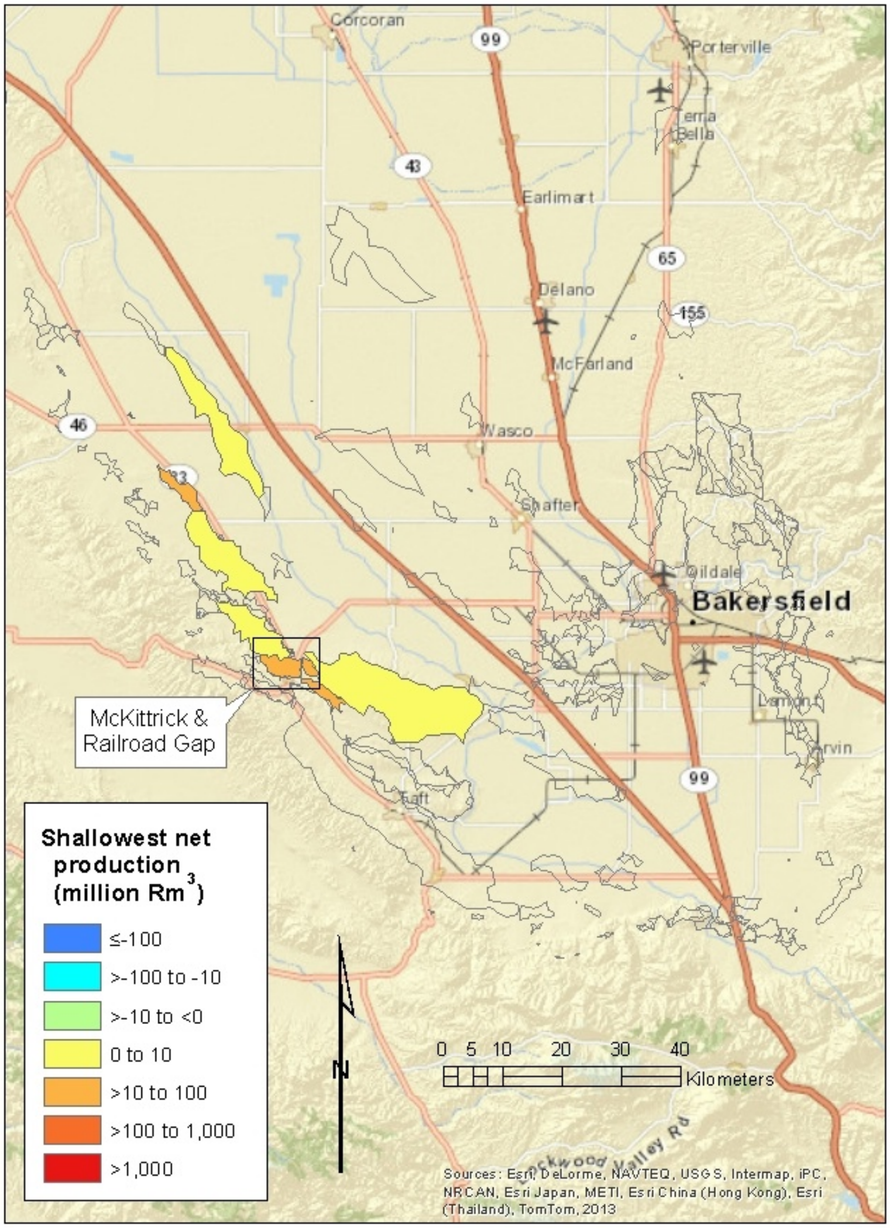


Figure 20: Net Production from the Temblor by Field Area below 1500 m Depth (Negative Values Are Net Injection).

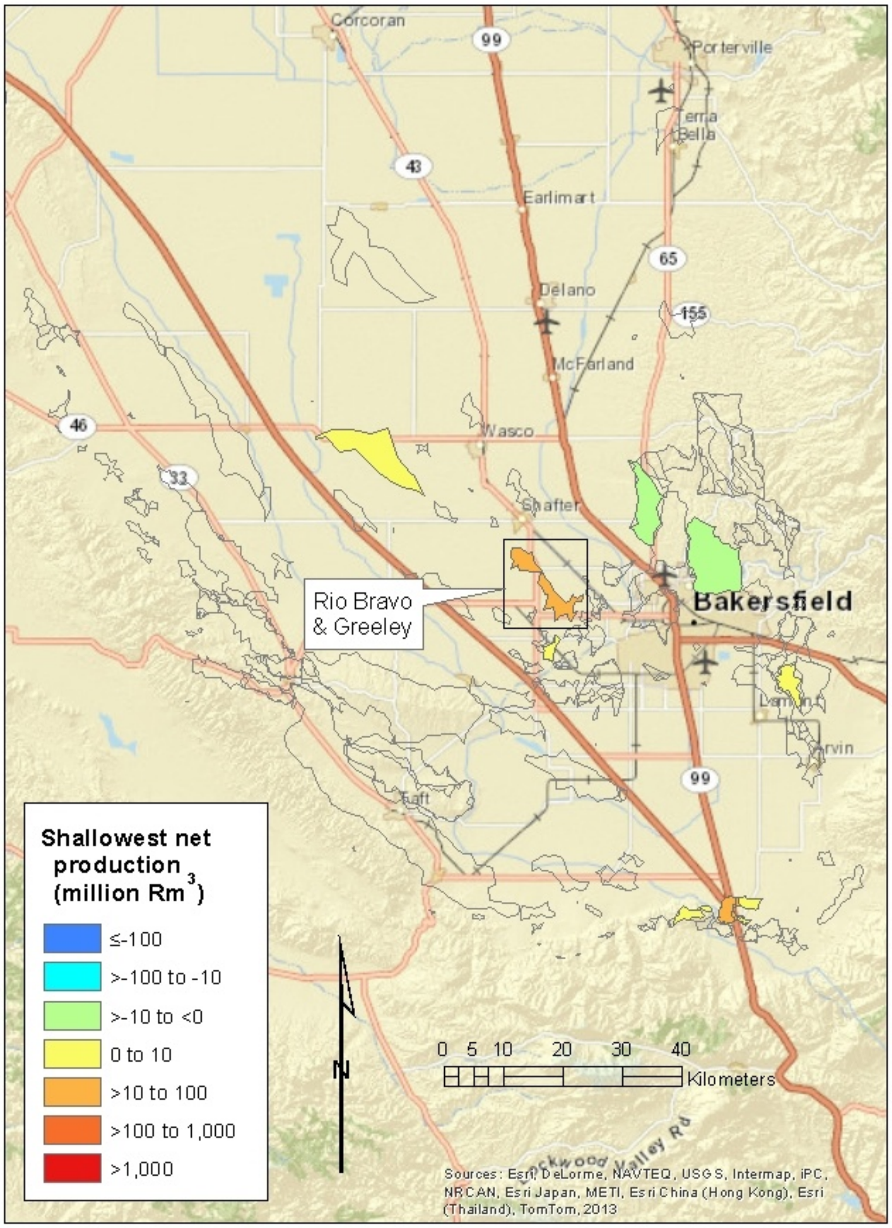


Figure 21: Net Production from the Vedder by Field Area below 1500 m Depth (Negative Values Are Net Injection).

3.3.3 Shallowest Injection Pools

Besides net production at CO_2 storage depths, analysis of the annual fluid volume database indicated considerable net injection occurred in some field areas above those depths. These injections are typically for disposing of water produced along with oil from greater depths. Many of these net injections were the shallowest activity in the field area, having no overlying production and consequently no overlying pressure sink to attenuate upward pressure propagation or brine leakage from the injection interval.

These shallowest net injections provide a direct analog for brine leakage to depths intermediate between a storage interval and groundwater ("thief zones") that might occur due to pressurization resulting from CO_2 storage. Consequently they allow a direct assessment of whether brine pressurization at these intermediate depths causes changes in the quality of groundwater produced from wells at shallower depths for residential, agricultural and commercial use, as discussed below.

Figure 22 shows the net production from the shallowest stratigraphic unit with activity in each field area. Note that for some fields the field area is a different color than the polygon representing the field as a whole. This is because for some fields, production may be assigned to the entire field (Any area) as well as specific areas, or early production was assigned to the field as a whole prior to the definition of areas.

The Fruitvale Field, which had a large volume net injection in its shallowest interval, is indicated on Figure 22. This location was chosen for analysis of groundwater quality presented below.

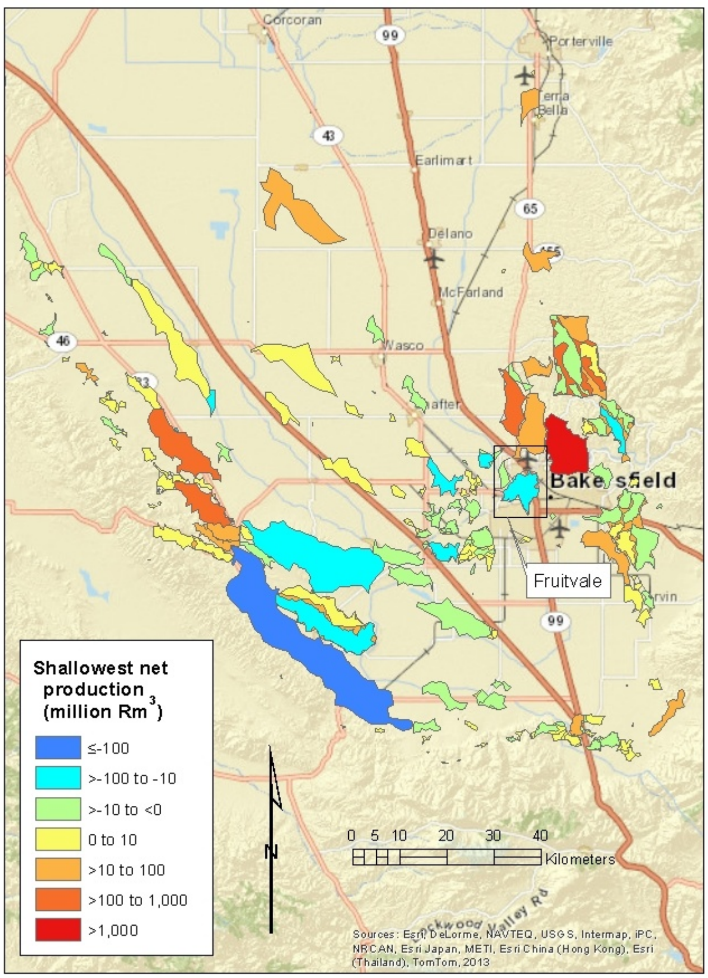


Figure 22: Net Production from the Shallowest Pool in Each Field Area (Negative Values are Net Injection).

3.4 Summary

A database of annual production volumes for each pool was assembled from the DOGGR production and injection database and annual reports of the State Oil and Gas Supervisor. The cumulative production and injection of various fluids reported in the 2009 annual report were within 2 percent of the cumulative values from the database, indicating the quality of the data entry.

The database was populated with parameter values for each pool allowing estimation of the volume of production at reservoir conditions from the reported volume at standard conditions. This provided the result that cumulative production in District 4 as of 2010 was 8.4 billion Rm^3 (53 billion RB). This alone has little implication for geologic carbon storage however, because such storage requires pressures that only occur at depth. Consequently it was necessary to segment production by depth in order to understand its implications.

Due to the variation in temperature and pressure at a particular depth, creating uncertainty regarding storage conditions, storage below 1500 m depth was found to be the most likely scenario to assure CO_2 is stored at higher density and so more efficiently and securely. Cumulative net production below this depth was 1400 million Rm^3 (9000 million RB). The three stratigraphic units with the largest production were the Stevens, Temblor and Vedder, with 800 million Rm^3 (5 billion RB), 100 million Rm^3 (800 million RB), and 100 million Rm^3, (700 million RB), respectively, accounting for more than 70 percent of the total production from the selected storage depth range.

In order to map the location of production in each of these stratigraphic units, a new GIS layer (roughly, map) was needed of the field areas in District 4. This was produced from the well locations assigned to each field area. Using this GIS layer, the net production from each field area in each stratigraphic unit was mapped. This assisted with selection of two field areas from each unit for pressure data collection and analysis.

The GIS layer and production database also allowed mapping the cumulative net production in the shallowest stratigraphic unit in each field area. A large fraction of these consisted of net injection. These provide a direct analog for brine leakage from storage depths to intermediate depths, and whether such leakage impacts groundwater quality at wells at shallower depths.

CHAPTER 4: Pressure Response

4.1 Data Sources

Data regarding pressure in the reservoirs was collected from three sources, described as follows.

4.1.1 Pool Initial Pressures, Depths and Discovery Years

As mentioned above, DOGGR (1998) lists initial fluid pressures for 437 pools. Typically the pressures reported are a single value, but for 39 pools a range is reported.

Initial pressures for pools in District 4 were entered into the annual fluid volume database so they could be used in the calculation of gas formation volume factor described above. Of the 437 pools with an initial pressure or pressure range reported, 256 matched pools already defined in the database because they had production or injection. Of the 182 remaining pools, all but 7 did not obviously correlate to pools with codes available from DOGGR and so required a new code. The fields and areas for all of these had codes available from DOGGR, so only new pool codes were required.

In order to understand the initial pressures within the context of fluid production in the basin, the date of the initial pressure value is required. This was assumed to be the year of pool discovery reported in DOGGR (1998). Such years were reported for 447 pools. These years were also entered into the database.

4.1.2 Idle Well Fluid Levels

Wells that have not been plugged and abandoned and through which fluids are not being produced or injected on a regular basis are termed idle. DOGGR requires periodic testing of idle wells to assure they continue to prevent unintended migration of fluids along the well. One of these tests is measuring the fluid level in an idle well. Changes in fluid level can indicate a change in the integrity of the well, such as development of a hole in the casing due to corrosion.

DOGGR periodically requires owners to measure the fluid levels in their idle wells and submit the results. District 4 aggregates these measurements. Mark Gamache with District 4 provided the aggregated data as an Excel spreadsheet on 1 December 2008. It included 46,519 measurements.

The 24 oldest measurements were dated 1 January 1901. This is more measurements on a single day than occur in the dataset over the next almost 90 years, which suggests the date of these measurements is incorrect. It may be a default date assigned to measurements for which a date was not provided with the data submittal.

The next four oldest measurements in the data set are each listed from a single date ranging from 1904 to 1953. The next oldest are five measurements dated 1 September 1985. Every year through 2008 subsequently has measurements and there is typically more than one measurement listed for a given date. This suggests the data prior to 1985 have erroneous dates listed.

There were two measurements with dates after the 1 December 2008 data delivery. The dates of both of these are after 2008. An additional five measurements had values other than a date in the date field.

Based on the above, valid measurement dates occur in the range from 1985 to 2008. A total of 46,484 measurements occur in this range. It is likely that some of the dates provided for these measurements are also erroneous, however the dates of these measurements are presumed accurate barring analysis of geographic area subsets of the data.

The depth of the shallowest well casing perforation was provided for over 90 percent of the measurements in the valid date range. The American Petroleum Institute well number (API#) was provided for all the measurements. This allows their well records to be accessed as described below. These records can be used to provide additional information regarding a fluid level measurement, such as the perforation depth range at the time of the measurement and the geologic unit at those depths.

4.1.3 Well Records

DOGGR provides online access to scanned well records.[16] As of early 2012 all of the records for District 4 were available, barring scanning and other errors. Lists of wells for records access can be generated in response to a variety of queries. A single API# can be entered. This was used for accessing the records for a well with idle fluid level measurements available. The list of wells for a particular field area can be generated. This was used to download records for wells in pools of interest in order to search for additional pressure data. Such well lists can be generated using the DOGGR production and injection database.

The well records are available in PDF, however they contain unsearchable scans. In order to make them searchable, the text recognition tool in Adobe Acrobat X was applied, typically to a group of records in batch mode. The records of pools of interest were subsequently searched in batch mode for pressure data. Various search terms were applied related to drill stem tests and pressure bomb measurements. A list of terms is provided in Table 4.

Table 4: Search Terms Used to Identify Pressure Data in DOGGR Well Records.

Term	Explanation
bottom hole	At the bottom of the boring or well
BHP	Bottom hole pressure
cushion	Fluid preloaded into drilling rod to improve drill stem test performance
D.S.T.	Drill stem test
DST	Drill stem test

[16] http://owr.conservation.ca.gov/WellSearch/WellSearch.aspx

drill stem test	A test involving sealing off an interval of a boring and allowing formation fluid from that interval to flow into and up the drill rod while the downhole pressure is measured
downhole	A measurement made or tool operated within the boring or well, as opposed to made or operated at the well head
formation tester	A small volume device for measuring pressure in a formation at the boring wall
FSI	Final shut in (one of the phases in a drill stem test)
FSIP	Final shut in pressure (measured during this phase of a drill stem test)
ISI	Initial shut in (one of the phases in a drill stem test)
ISIP	Initial shut in pressure (measured during this phase of a drill stem test)
J.F.T	Johnston Formation Tester (a specific drill stem test tool and approach)
JFT	Johnston Formation Tester (a specific drill stem test tool and approach)
pressure bomb	A limited volume device for measuring pressure downhole
psi	Pounds per square inch (a unit of pressure)
static	Not flowing
static fluid level	Level of fluid in a well that is not flowing

4.2 Initial Pressures

Because pools are discovered at different times, some considerably after the start of production, the initial pool pressures provide one means of assessing pressure changes in the basin due to production. This data is analyzed below through both gradient and head perspectives.

4.2.1 Pressure Gradient Factor

Fluid pressure in the geologic section typically increases with depth due to the weight of the overlying fluid column. Comparing pressures from different depths requires normalizing by dividing by observation depth. This results in an equivalent pressure gradient that would result in the observed pressure at the same depth.

Water is the most predominant fluid in the subsurface. For this reason pressures that match the hydrostatic gradient times the depth are termed “normal.” Alternately, the pressure gradient equivalent to a particular pressure-depth combination is expressed as a percentage of the hydrostatic gradient. Such an expression of pressure occurs in a mathematically asymmetric space. Gradients may be infinitely larger than 100 percent of hydrostatic, but are limited to 0 percent of hydrostatic below 100 percent.

This asymmetry results in values whose distribution is more difficult to discern graphically and to which standard parametric statistical methods cannot be applied. An alternate approach presented in Jordan (2009) avoids these disadvantages. The following equation converts pressures into depth normalized values in a space that is symmetrical around the hydrostatic gradient.

$$
\begin{aligned}
w &= \frac{g}{h} - 1 && \text{for } g > h \\
w &= 0 && \text{for } g = h \\
w &= -\left(\frac{h}{g} - 1\right) && \text{for } g < h
\end{aligned}
\tag{6}
$$

where w is the pressure gradient factor, g is the pressure gradient (pressure divided by the depth at which it was measured) and h is the hydrostatic gradient. "Normal" pressures have a pressure gradient factor of 0. A pressure that is half of hydrostatic, termed "under pressured," equates to a pressure gradient factor of -1. A pressure that is twice hydrostatic, termed "overpressured," equates to a pressure gradient factor of 1.

4.2.2 Initial Pressure Gradient Factor

Figure 23 shows the initial pressure gradient factor through time, as well as the multiple of the hydrostatic gradient for ease of understanding. The y-axis labels also have the equivalent multiple of the hydrostatic in parentheses. Figure 24 shows the central distribution of the factor with annual net production overlain and the eleven-year moving average shown. The moving average was calculated by averaging the yearly averages to avoid dominance of one year over another due to variation in the number of measurements in a given year. This provides for a more accurate portrayal of the timing of shifts in the factor than averaging the measurements directly. The standard deviation shown on the figure is from all the measurements within the eleven-year window.

No downward trend in the moving average through time is apparent as might be expected based on the net fluid volume production. The moving average declines at the end of the series, but the increase in standard deviation suggests this decline is not significant. The lack of downward trend through the 1950's to 1970's suggests no basin-wide pressure decline even with net production of about 100 million m^3/year on average, or at least a decline smaller than the natural variation in pressure.

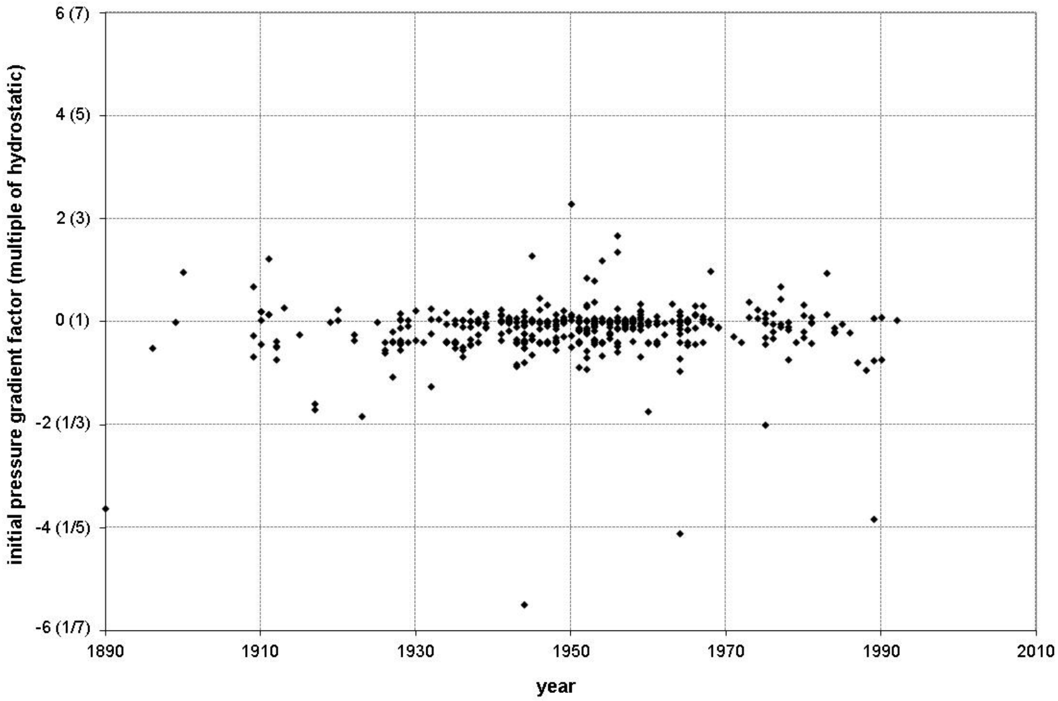


Figure 23: Initial Pressure Gradient Factor through Time.

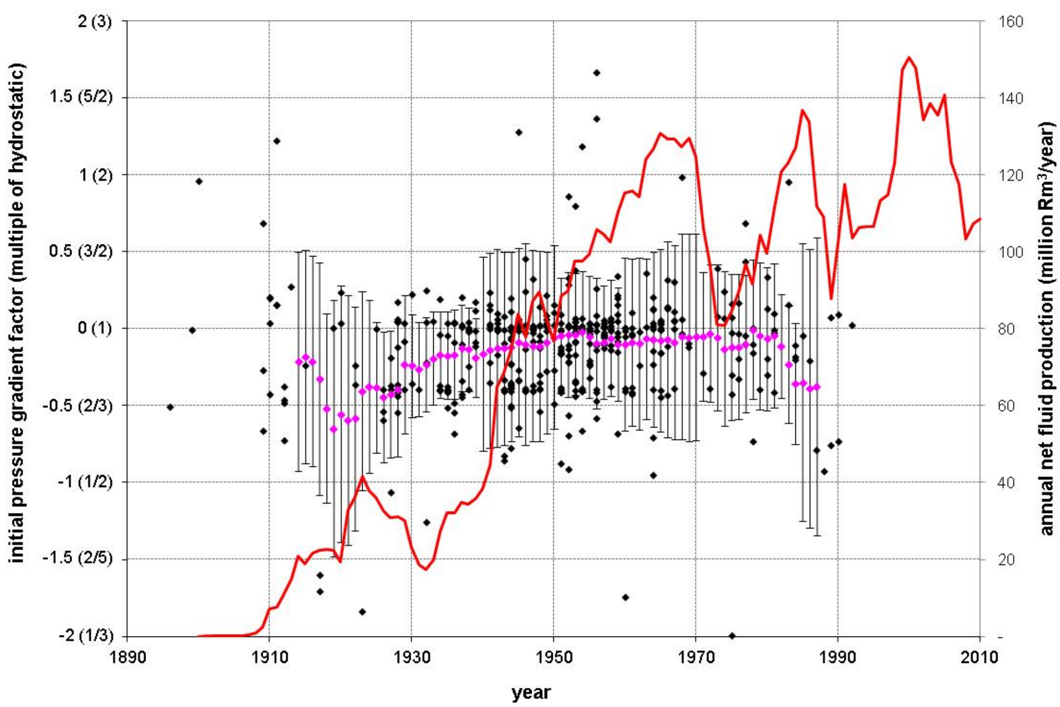


Figure 24: Central Distribution of Initial Pressure Gradient Factor through Time with the Eleven-Year Moving Average and Standard Deviation Shown and Annual Net Fluid Production at Reservoir Conditions Overlain.

The standard deviation from the 1920's through the 1970's varied by about a factor of 2 without any evident time trend. This suggests the pressure measurement accuracy remained relatively constant. There is a concentration of factor values around -0.4 from the 1920's through 1960's. This seems more likely to be some sort of measurement artifact rather than real. For instance this could be due to some standard lower threshold for measuring pressure versus depth. If so, the actual pressures may be lower and the moving averages would be lower. However, even if this measurement bias does exist, the moving averages through this period are increasing rather than decreasing as they would if pressures below the hypothesized measurement threshold became more common with time.

Figures 25 through 27 show the factor and annual net production for each of the three geologic units identified as having the largest net production from storage depths: the Stevens, Temblor and Vedder. Downward trends in the initial pool pressures are not evident for any of these, although there is no initial pressure data across peak production from the Stevens. The factor range is similar in the Stevens and Temblor and smaller in the Vedder.

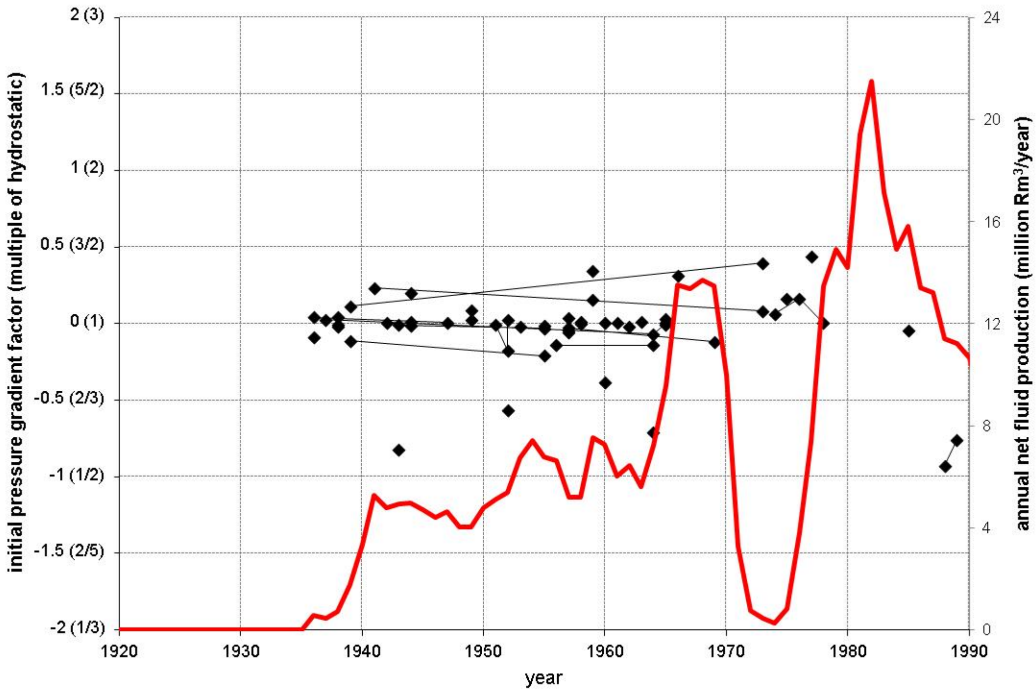


Figure 25: Initial Pressure Gradient Factor and Net Fluid Production from Stevens Pools through Time.

Lines segments connect results from pools in the same field area.

Against expectation there is an apparent upward overall trend in pressure in the Vedder, which is discussed further below. However initial pressures in different pools in the same field area, which are connected by the line segments on Figures 25 through 27, do not show a consistent downward or upward trend as would occur with declining pressure. The initial pressure from pool to pool in the Vedder is particularly uniform with time, suggesting an open system. The most variation occurs in the Temblor, but the direction of the changes and timing suggests naturally occurring variation among compartments rather than variation due to production.

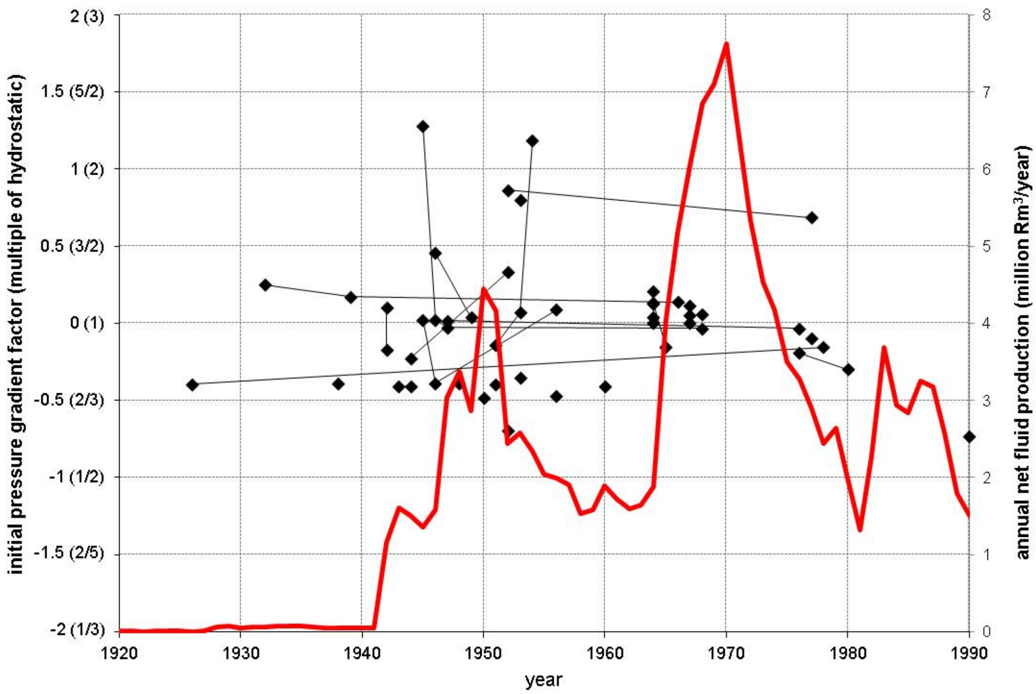


Figure 26: Initial Pressure Gradient Factor and Net Fluid Production from Temblor Pools through Time.

Lines segments connect results from pools in the same field area.

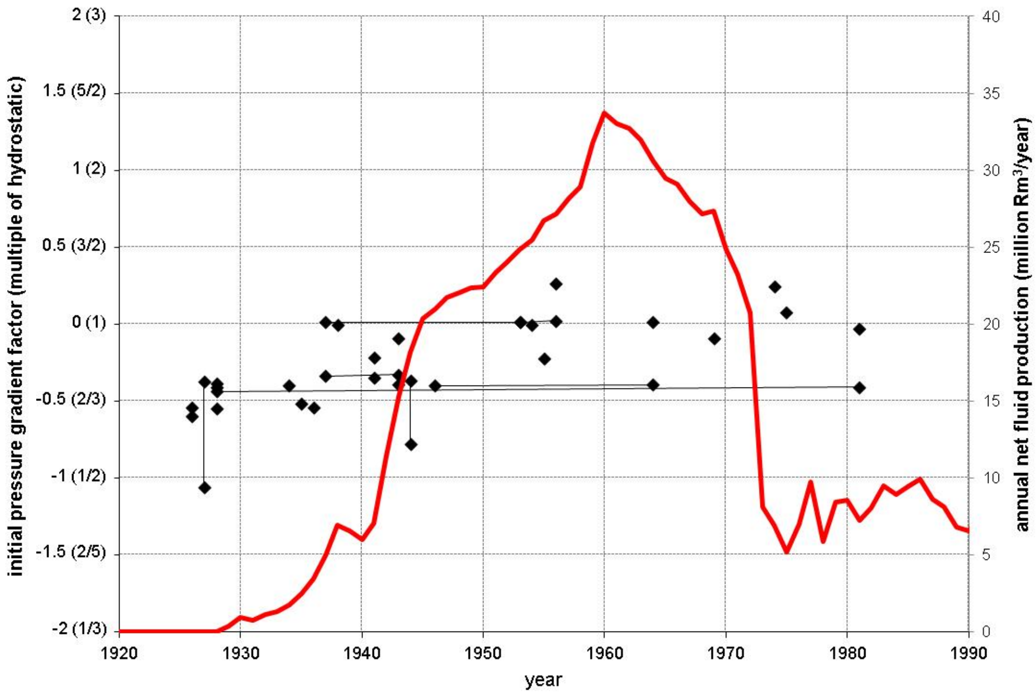


Figure 27: Initial Pressure Gradient Factor and Net Fluid Production from Vedder Pools through Time.

Lines segments connect results from pools in the same field area.

The geographic distribution of the pressure gradient factor in each of the three units is shown on Figure 28 through 30. For field areas with an initial pressure from more than one pool, the factor from the earliest pool is shown. The figures show the factor generally increases from the basin margin to the axis in all three units. The pressure gradient factor calculation does not take into account water table depth. This results in the calculated factor underestimating the actual factor by more for shallower than deep pools. As pools deepen toward the basin axis, this may contribute to the geographic distribution of the calculated factor as shown. This is assessed further below.

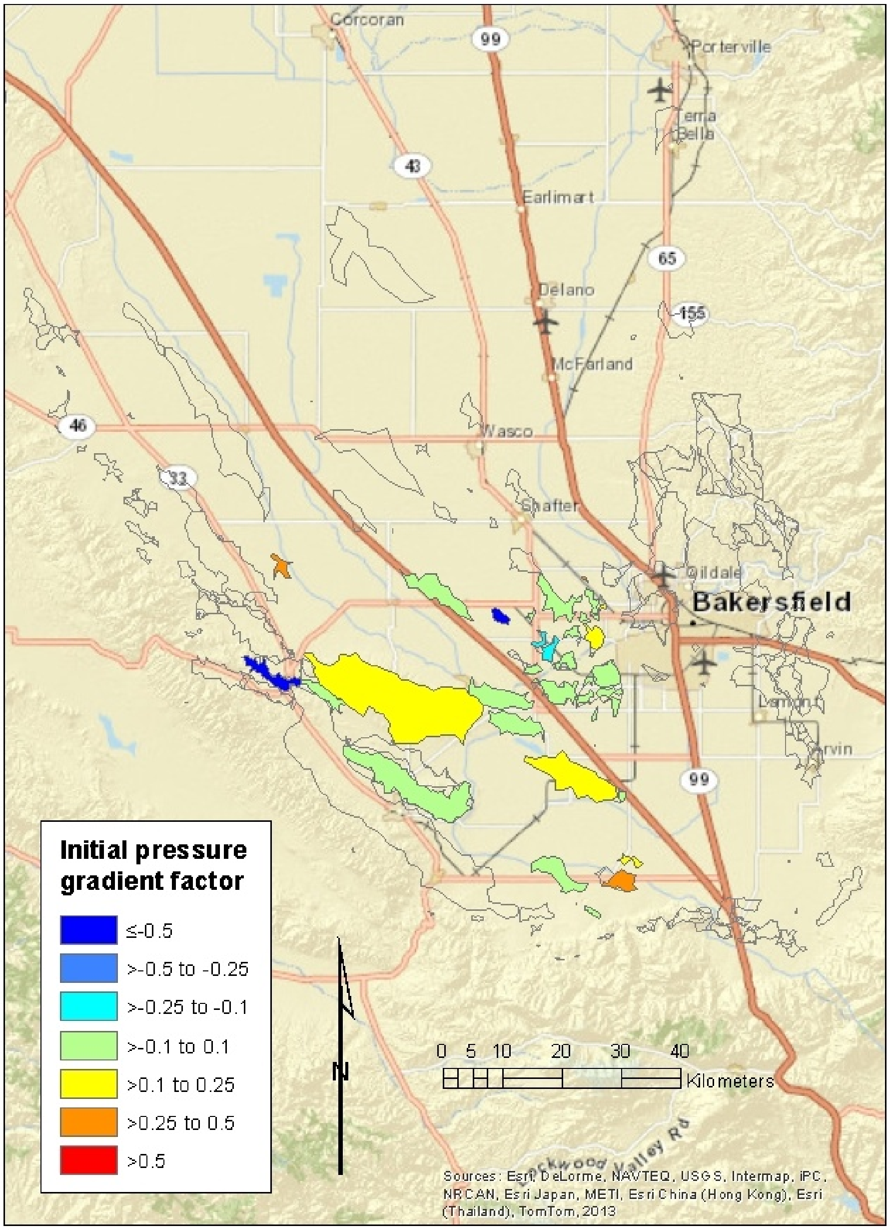


Figure 28: Earliest Pressure Gradient Factor for Each Field Area in the Stevens.

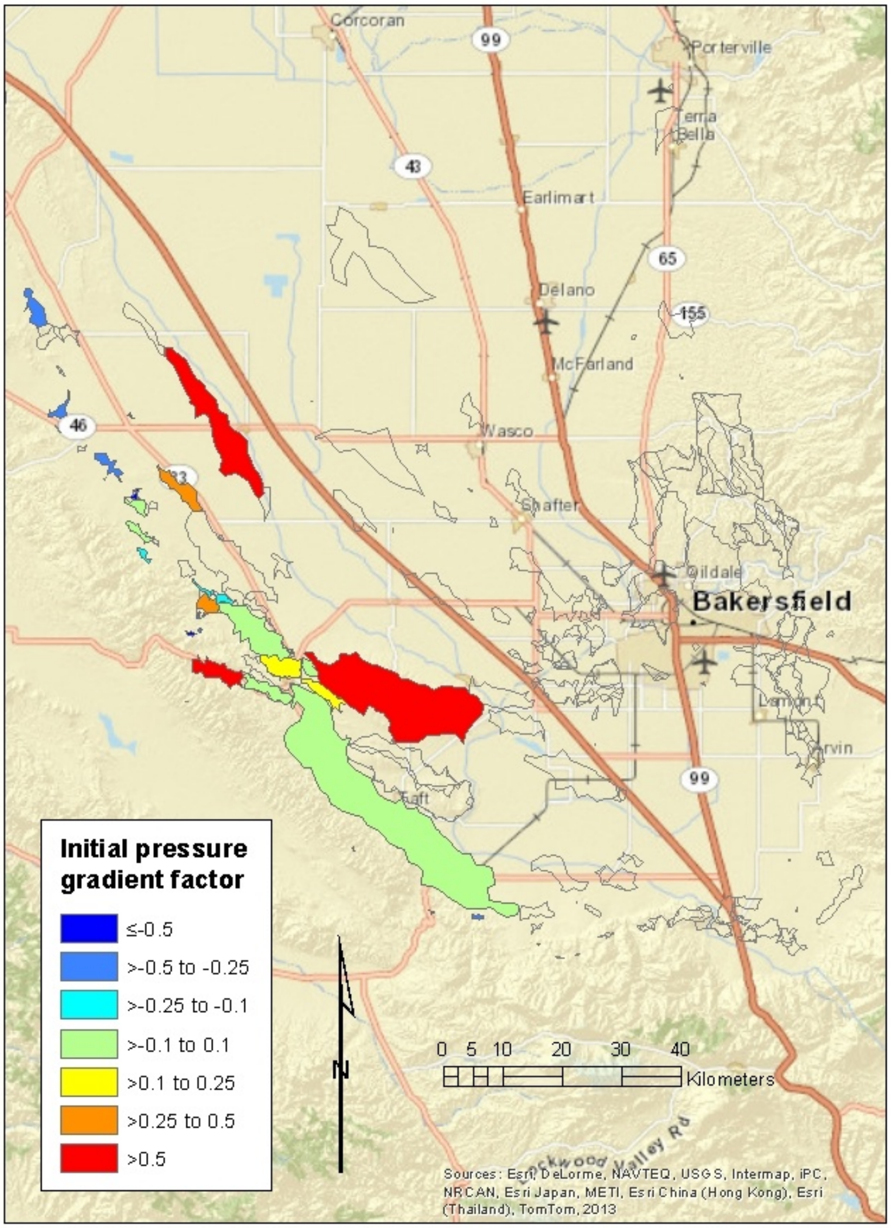


Figure 29; Earliest Pressure Gradient Factor for Each Field Area in the Temblor.

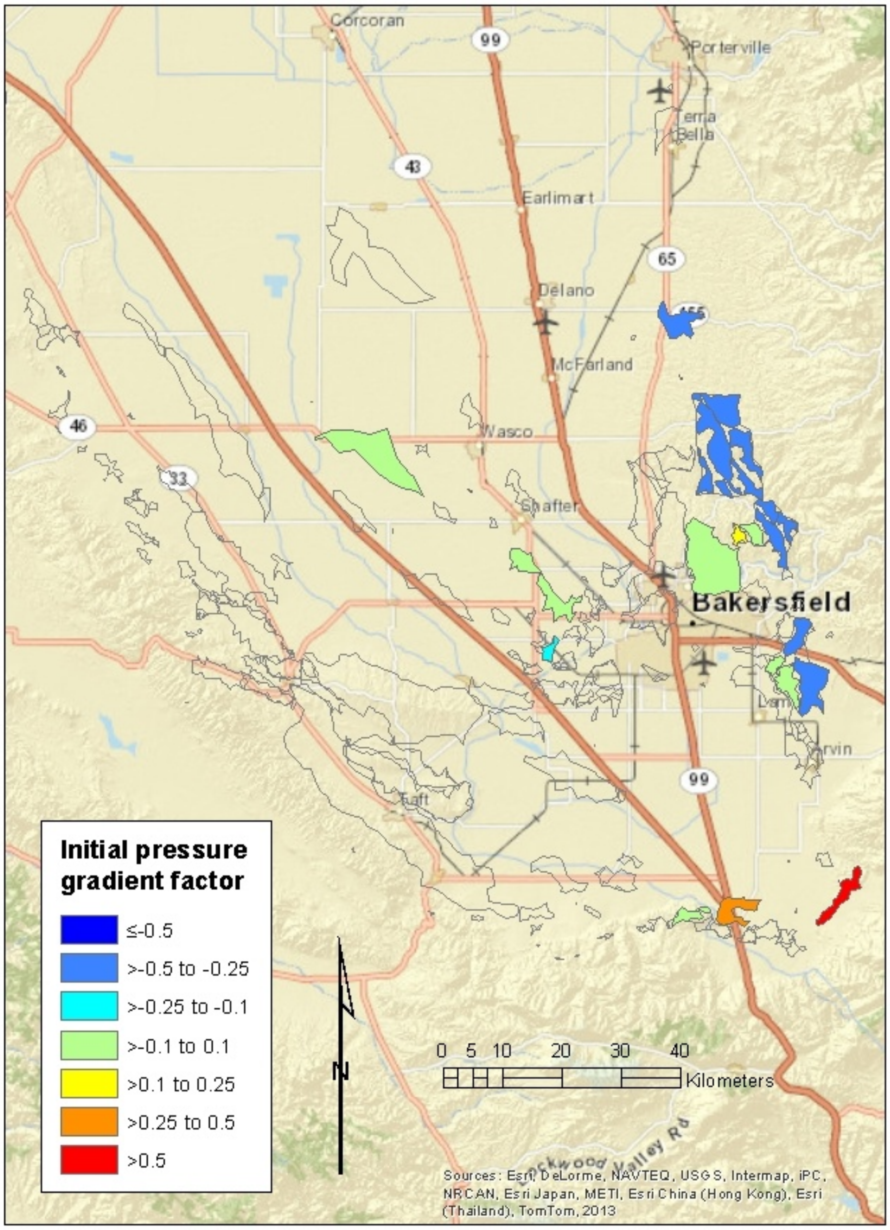


Figure 30: Earliest Pressure Gradient Factor for Each Field Area in the Vedder.

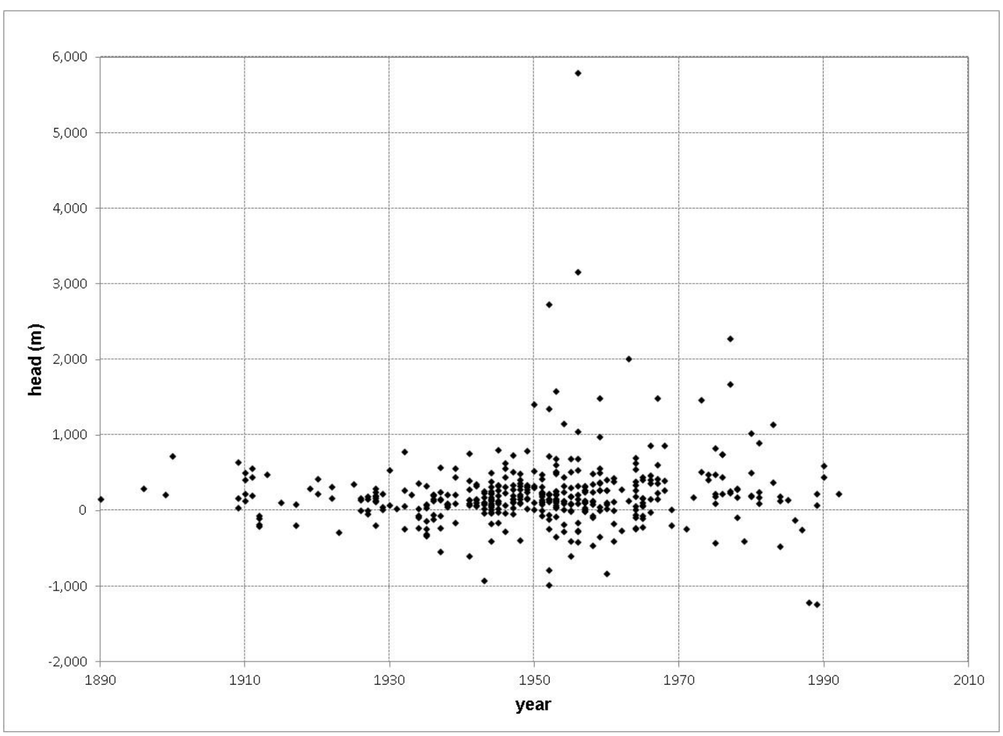
4.2.3 Initial Head

Pressure gradients and over versus normal versus underpressured are useful concepts in drilling and reservoir engineering. For instance they provide information for specifying drilling mud weights and understanding the potential energy in a reservoir available for primary production. Pressure alone does not control flow between reservoirs however. Rather the hydrologic concept of fluid potential is required to understand flow over the longer distances that are the focus of this project.

Fluid potential involves both pressure and the elevation of the pressure measurement. While DOGGR (1998) provides pool depths, it does not provide elevation. Elevation rasters are available from the USGS through the National Map viewer.[17] Rasters covering 1 degree of latitude by 1 degree of longitude with elevations every 1 arc second were downloaded and mosaicked for the study area. The average elevation in each field area polygon was computed by the zonal statistics tool in ArcMap, and subsequently imported into the annual fluid volume database to perform a fluid potential calculation query.

Fluid potential for each pool was calculated as a head. The elevation head was calculated by subtracting the pool depth from the field area average elevation. The pressure head was calculated by dividing the pressure by the density of fresh water at a standard temperature. The actual density of the water in a pool may be higher due to salinity or lower due to thermal expansion. Review of the pool water salinities available in DOGGR (1998) indicates salinities are typically low, for instance less than sea water. Salinities also tend to increase with depth. The salinities are sufficiently low that the small thermal expansion of water due to increasing temperature with depth tends to offset the small density shift due to salinity. So assuming a fresh water density does not introduce a large error.

Figure 31 shows the initial heads through time for the entire study area and Figure 32 shows the central distribution of initial heads with annual net production overlain. Figure 32 shows the moving average head generally increased rather than decreased. The increase is significant. For instance the heads measured in the 70's are significantly higher than in the 30's at the 95 percent level according to a two-tailed, unequal variance Student's t-Test.



[17] http://nationalmap.gov/viewer.html

Figure 31; Initial Head through Time.

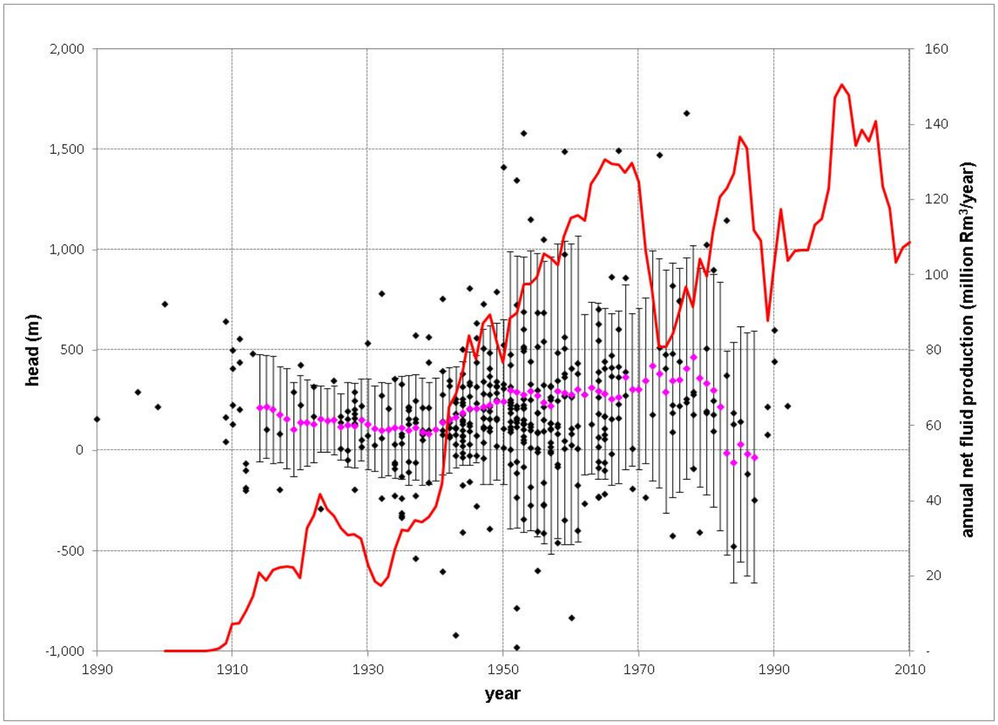


Figure 32: Central Distribution of Initial Head through Time with the Eleven-Year Moving Average and Standard Deviation Shown and Annual Net Fluid Production at Reservoir Conditions Overlain.

Figures 33 through 35 show the head and annual net production for each of the three geologic units identified as having the largest net production from storage depths. There is no apparent trend in any of the units. This includes for the Vedder, in contrast to the upward trend in the initial pressure gradient factor evident on Figure 27.

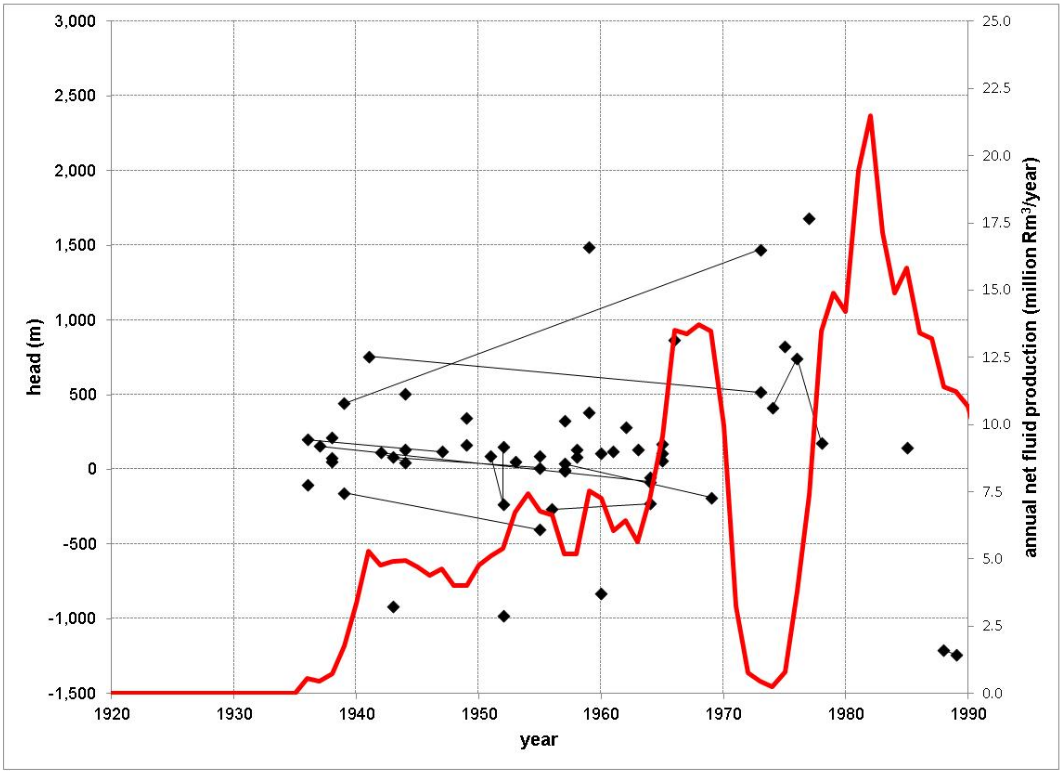


Figure 33: Initial Head and Net Fluid Production from Stevens Pools through Time.

Lines segments connect results from pools in the same field area.

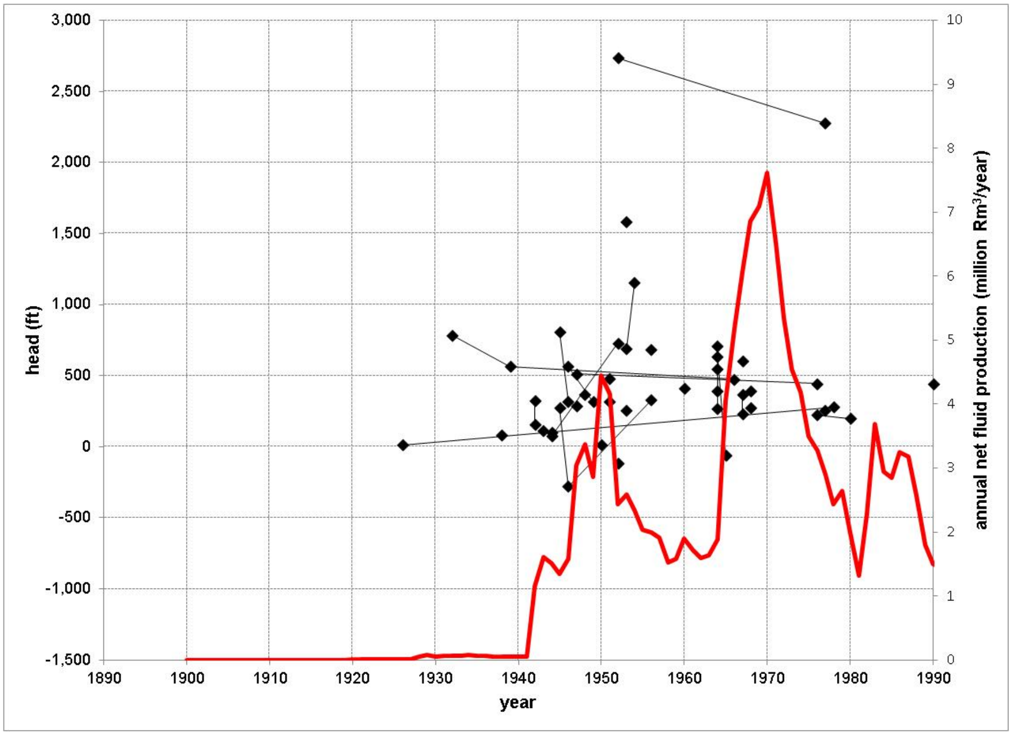


Figure 34: Initial Head and Net Fluid Production from Temblor Pools through Time.

Lines segments connect results from pools in the same field area.

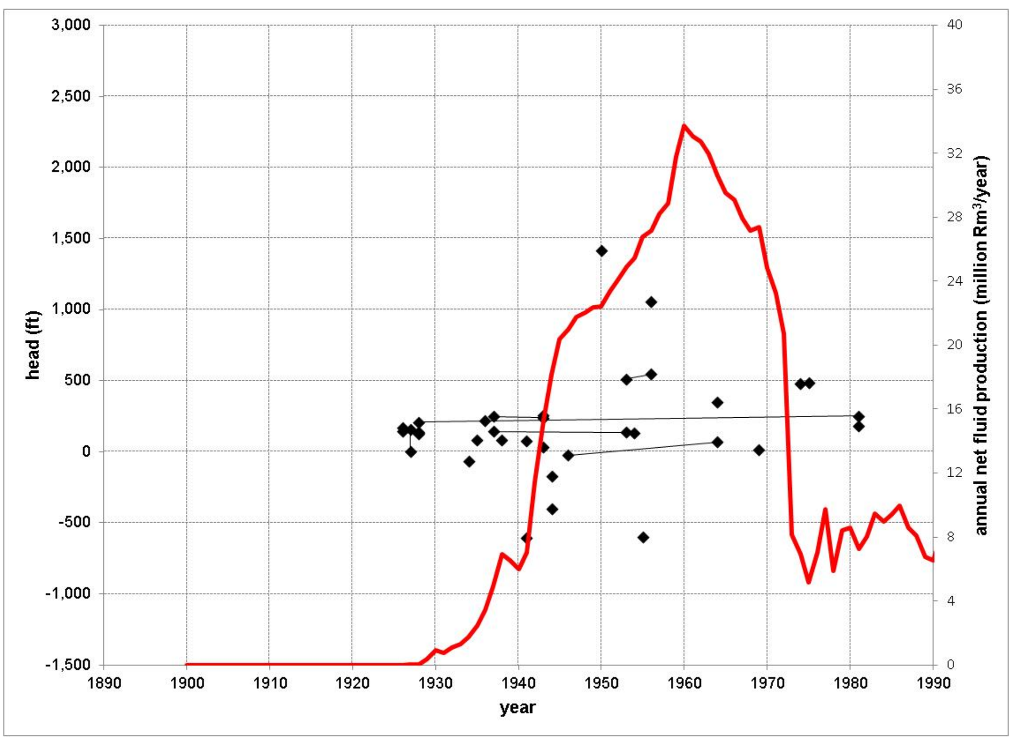


Figure 35: Initial Head and Net Fluid Production from Vedder Pools through Time.

Lines segments connect results from pools in the same field area.

The range in head is largest in the Stevens and smallest in the Vedder. The standard deviation is about the same in the Stevens and Temblor and smaller in the Vedder. There is no consistent trend evident in the pool-to-pool heads within a field area, similar to the initial pressure gradient factor results. Similar to the initial pressures, the heads from different pools within a field area are remarkably consistent in the Vedder suggesting it is open with regard to pressure communication. The heads from different pools in a field area vary from each other, and vary similarly, in the Stevens and Temblor, suggesting these units are relatively more compartmentalized.

Table 5 compares the average heads and ground surface elevations in each unit. The elevations are averaged from the average elevation of the field area for each pool. The average head in the Temblor is greater than the average ground surface elevation and equal to the 90th percentile elevation. This could be due to compression in the actively deforming fold and thrust belt along the western basin margin. The average head in the Stevens is about the same as its average ground surface elevation and the average head in the Vedder is less than the average elevation.

Table 5: Average Ground Surface Elevation and Head for Pools in the Stevens, Temblor and Vedder.

	Stevens		Temblor		Vedder	
	elevation	head	elevation	head	elevation	head
mean (m)	130	120	330	470	260	170
median (m)	100	110	290	350	270	140
90th percentile (m)	200		490		360	

Figures 36 through 4.16 show the geographic distribution of the earliest initial head in each field area in the each of the three units. Figure 36 and 37 show higher head in the Stevens and Temblor toward the basin axis, similar to the initial pressure gradient factor distribution. Figure 37 shows relatively constant head in the Vedder from the east toward the basin axis. This is in contrast to the increase in the initial pressure gradient factor toward the axis, suggesting again the Vedder is relatively open with regard to pressure communication. The high heads in the Stevens and Temblor along the basin axis and in the Temblor and the Vedder along the southern margin of the basin coincide with the tectonically active portions of the basin, suggesting these heads are due to tectonic strain.

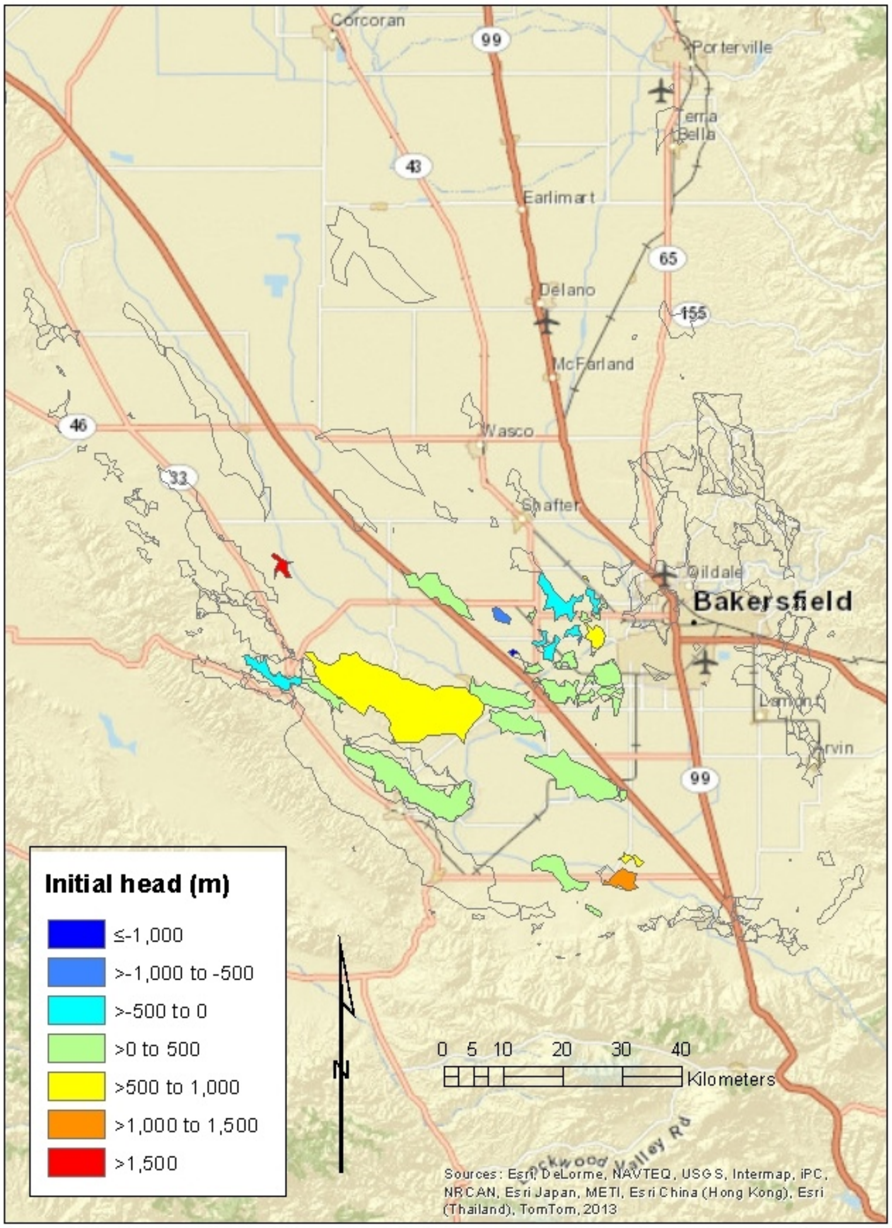


Figure 36: Earliest Head for Each Field Area in the Stevens.

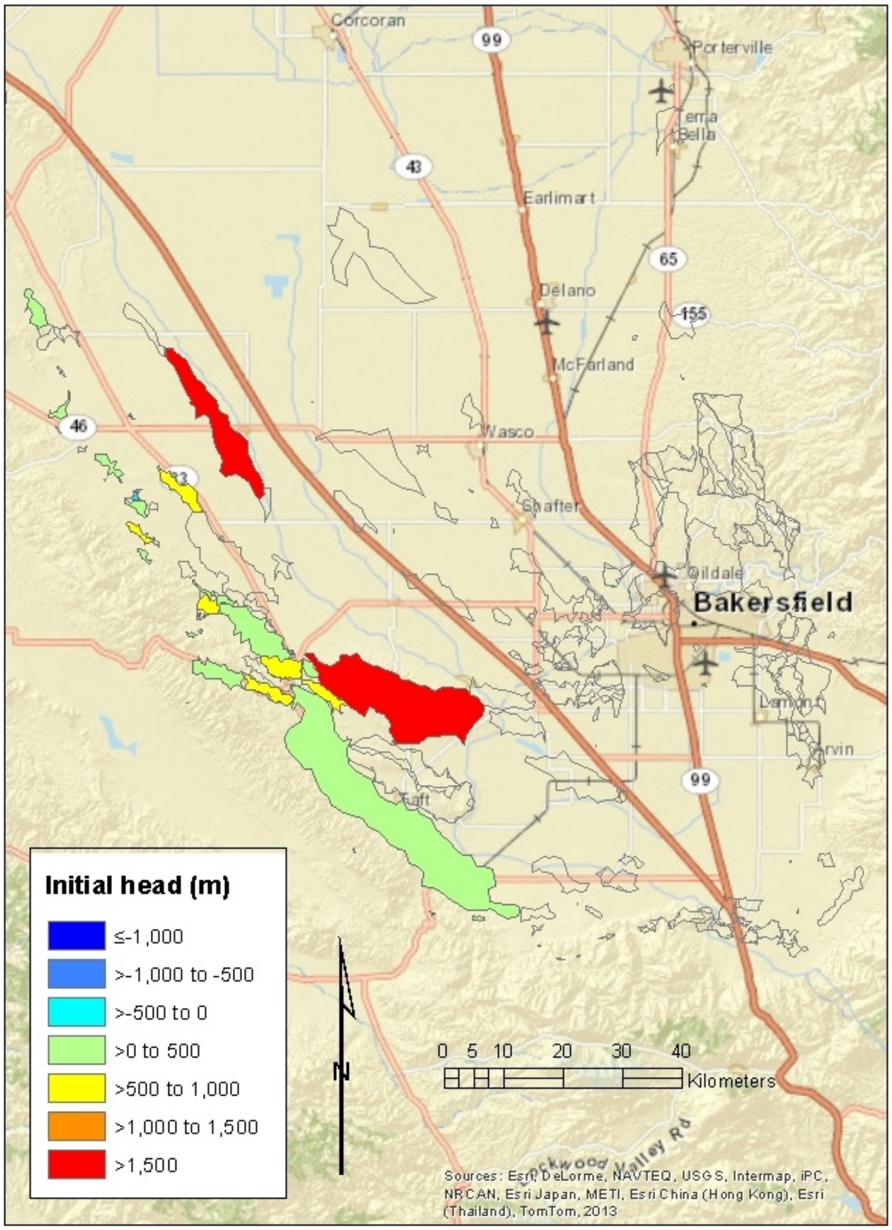


Figure 37: Earliest Head for Each Field Area in the Temblor.

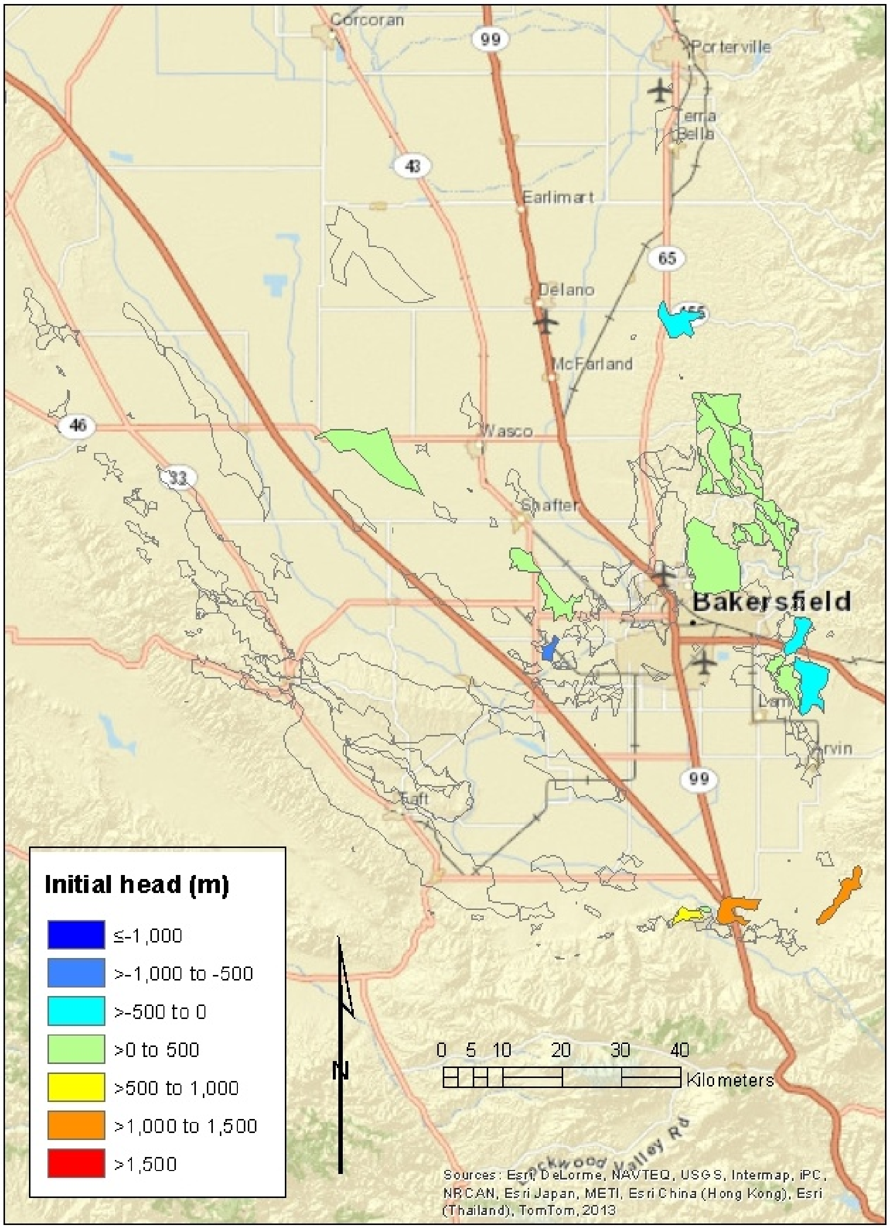


Figure 38: Earliest Head for Each Field Area in the Vedder.

4.3 Well Records and Idle Well Fluid Levels

As mentioned, the well records for select pools in the three units with the most production from potential storage depths were searched for pressure data. This resulted in identification of pressure data collected in various manners, as suggested by the search terms described. For instance, pressures were available from drill stem tests, Johnson Formation Tester tests, pressure bomb reading, and listed on various well permit application forms. The depth to the top perforation at the time of the pressure reading was also captured from the well records.

For idle well fluid levels, the pressure was calculated from the fluid column height. This was taken as the difference between the fluid level and top perforation depths. This column height was multiplied by the hydrostatic gradient to compute pressure.

The pressures were converted to percent of hydrostatic pressure. The hydrostatic pressure was calculated by multiplying the depth to the top well perforation by the hydrostatic gradient.

In the figures that follow, the initial pressure in each pool is plotted as are the pressures from the well records. When there are more than five pressure readings available in a year, the median is shown with bars indicating 16th and 84th percentile pressures. These percentiles were picked because they are about the percentiles at which one standard deviation occurs in a normal distribution. The standard deviation was not computed and plotted however because the distribution of each pressure set was not determined, and is likely not normal in any event. For instance, the distributions are likely to be left skewed due to the nonlinear nature of pressure buildup with time. Consequently pressure measurements are more likely to underestimate than overestimate pressure in the formation. For this reason, the upper pressures from these measurements are considered more representative of pressure in a pool.

This is the not the case with idle well fluid levels because they are able to equilibrate over a long time. Consequently median pressures from these fluid levels are considered more representative of pressure in a pool. Because of this and because idle well fluid level readings are typically numerous in any year with at least one reading, the median pressure for a given year is plotted in every instance for that data set. For years with ten or more reading, bars indicating the 16th and 84th percentile pressures are also plotted. The minimum fluid level depth is 0. Consequently, barring variation in fluid density, 100 percent of hydrostatic is the maximum possible pressure. This may cause upper truncation of the pressure distribution, which provides another reason for assessing the distribution with percentiles rather than standard deviation.

One goal of analyzing the following pools is to understand the pressure response to production at a field scale. Because of the low side bias of most pressure measurement techniques, pressures in the upper portion of the distribution will be considered more representative of the response at this scale.

4.3.1 Stevens Pools in North and South Coles Levee Fields

Figures 39 and 40 show production from and pressures in the Stevens pools in the North and South Coles Levee Fields. Free gas production and injection occur at high ratios relative to oil production. Free gas production is slightly less than gas injection initially. However total gas production in the South Coles Levee pool, accounting for dissolved gas, is the same as or slightly more than injection. Total gas production in the North Coles Levee pool is less than injection for the first almost two decades of injection, with the excess sourced from shallower gas zones in the field. Later in each pool’s history significant net free gas production occurs due to blow down of the gas cap. There is negligible water production in each field until water injection starts later in their history. Even then, water production is a fraction of water injection. These observations indicate gas cap expansion is the main drive mechanism, and the pools are largely isolated relative to sources of water.

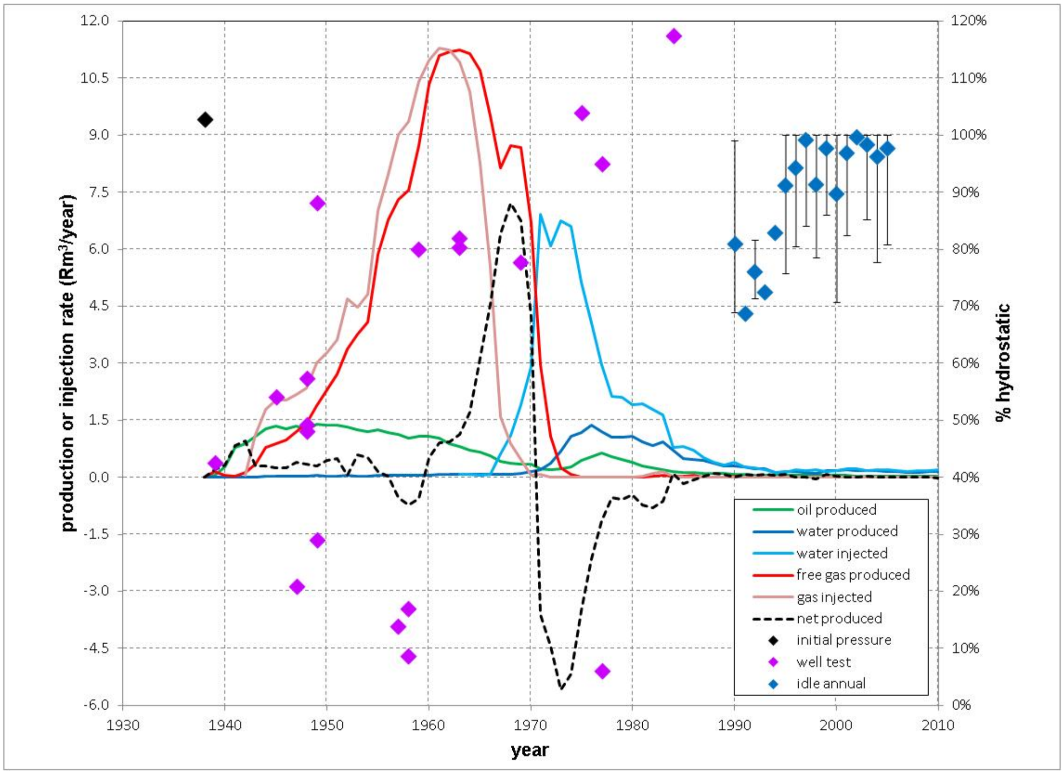


Figure 39: Production from and Pressure in the Stevens in North Coles Levee Field.

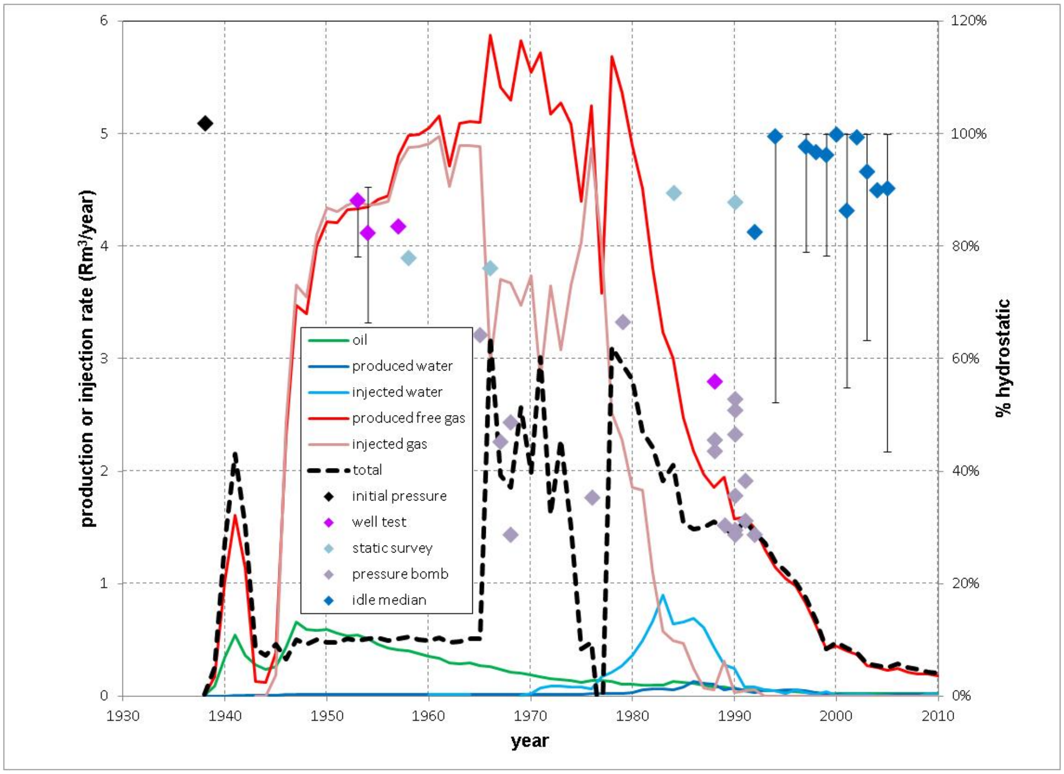


Figure 40: Production from and Pressure in the Stevens in South Coles Levee Field.

Net production from the Stevens pool in the North Coles Levee Field averaged 400,000 Rm^3/yr through the mid 1950's. The upper pressures appear to stabilize at about 80 percent of hydrostatic at the end of and just after this period. Net production from the Stevens pool in the South Coles Levee Field averaged 500,000 Rm^3/yr from the mid-1940's, shortly after the start of production, to the mid-1960's. The upper pressures appear to stabilize at 75 percent to 80 percent of hydrostatic in at the end of and just after this period.

Pressures vary considerable in each pool. This could be due to compartmentalization, gas injection for pressure management followed by water flooding, or both. Figures 41 through 44 suggest injection activities are largely responsible. Figure 41 indicates gas injection occurred exclusively at the crest of the structure, likely in the gas cap, formed by the Stevens in the North Coles Levee Field. Figure 42 shows water injection also occurred primarily at the crest of the structure. Figure 43 shows that even though injection substantially ceased by 1990, the higher pressures at the crest of the structure still reflect this history. Figure 44 shows that even though water injection substantially ceased by the early 1990's in the South Coles Levee pool, the idle fluid levels are still elevated near the highest density of water injection wells. DOGGR (1998) does not show any faults in this pool and a relatively continuous reservoir across the field, suggesting the idle well fluid level variation across the field was due to the injection pattern rather than compartmentalization.

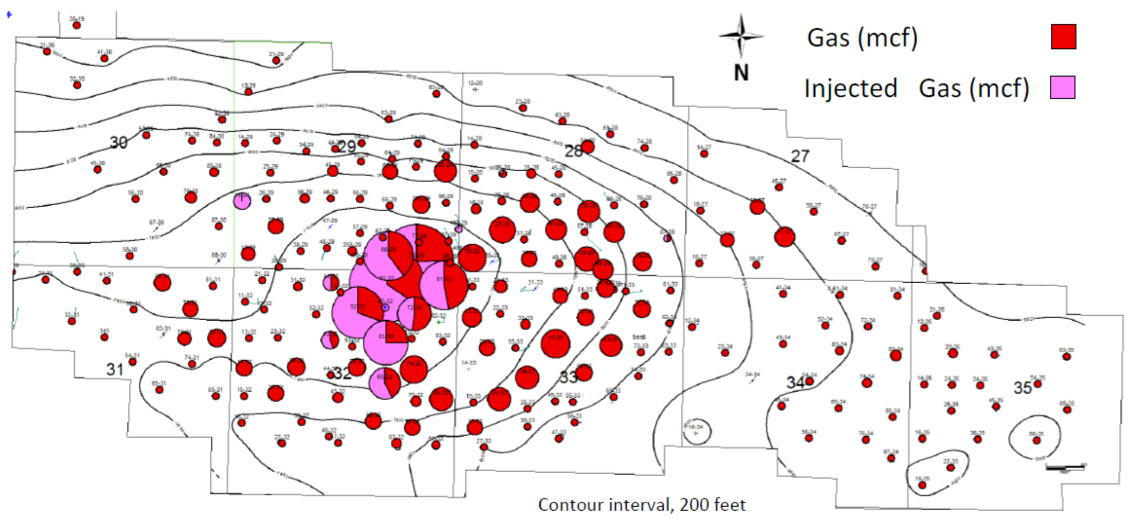


Figure 41: Gas Production and Injection for Each Well Shown on Structure Contours of the Top of the Stevens in the North Coles Levee Field.

Symbol size indicates production plus injection volume. (Goodell, 2013)

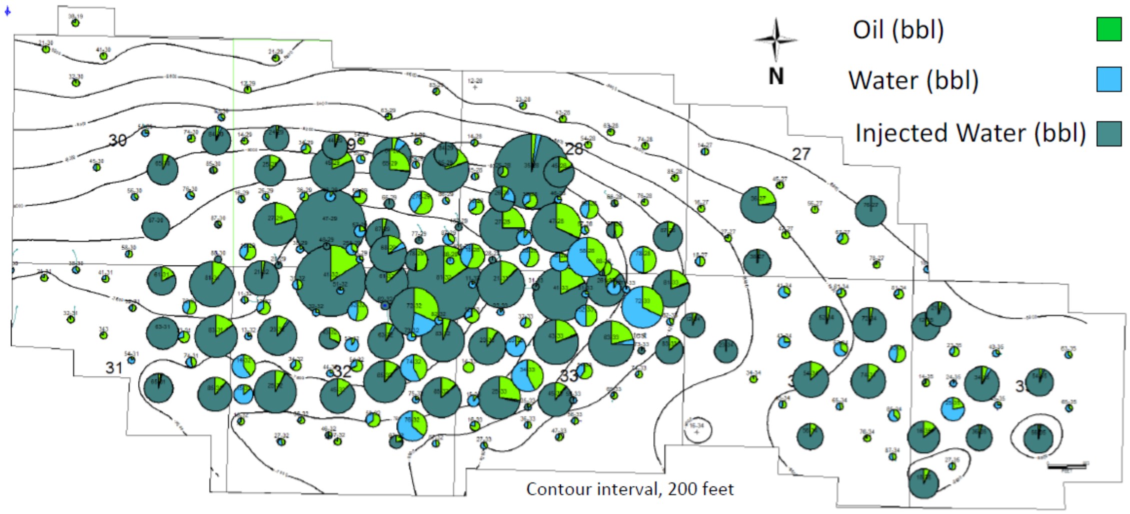


Figure 42: Oil and Water Production and Water Injection for Each Well Shown on Structure Contours of the Top of the Stevens in the North Coles Levee Field.

Symbol size indicates production plus injection volume. (Goodell, 2013)

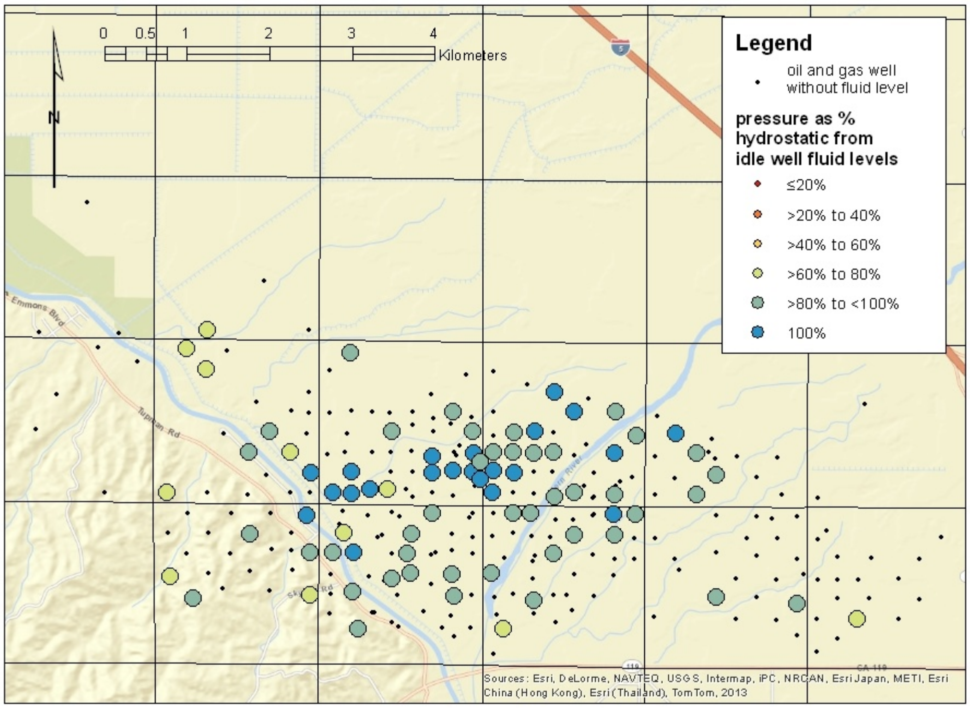


Figure 43: Mid-2000's Idle Well Fluid Levels in the Stevens in the North Coles Levee Field Expressed as Percent Hydrostatic.

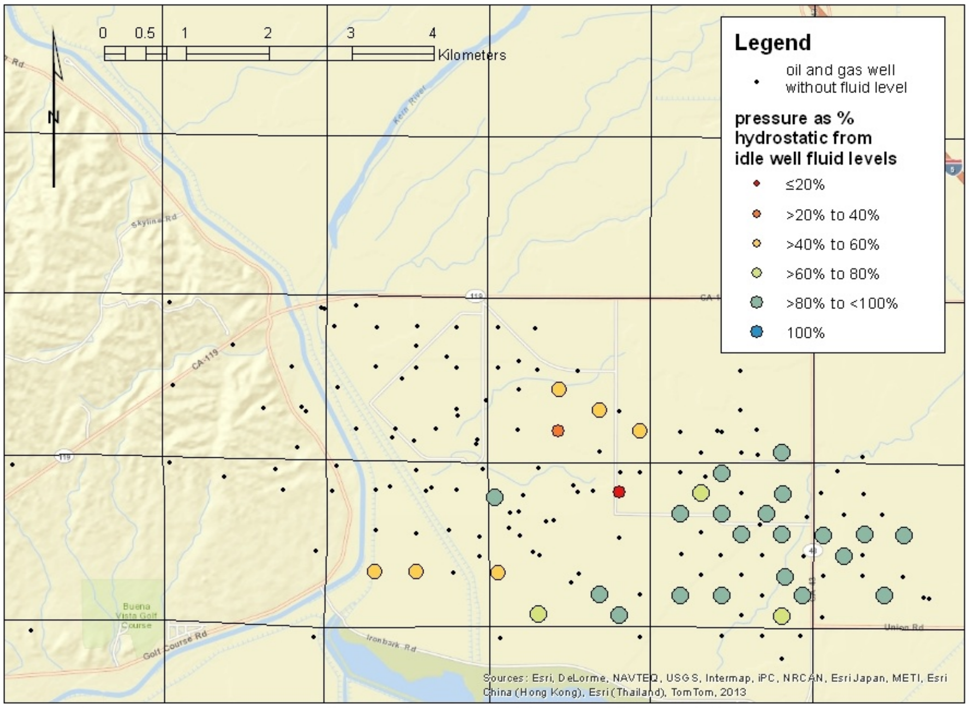


Figure 44: Mid 2000's Idle Well Fluid Levels in the Stevens in the South Coles Levee Field Expressed as Percent Hydrostatic.

Injection mapping for the Stevens pool in the South Coles Levee Field was not performed and not found to be available. However DOGGR (1998) does not show any faults in the field and a relatively continuous reservoir across the field, so the idle well fluid level mapping in Figure 44 suggests injection was focused in the eastern portion of the field.

4.3.2 Temblor Pools in McKittrick and Railroad Gap Fields

Figures 45 and 46 show the production from and pressure in Temblor pools in the McKittrick Field, Northeast Area, and Railroad Gap Field. There is nominal injection in the McKittrick pool and no injection in the Railroad Gap pool. Free gas production is one to a few times oil production, and there is some water production. These suggest a mix of weak gas cap and water drive. DOGGR (1998) shows a gas cap in both these pools.

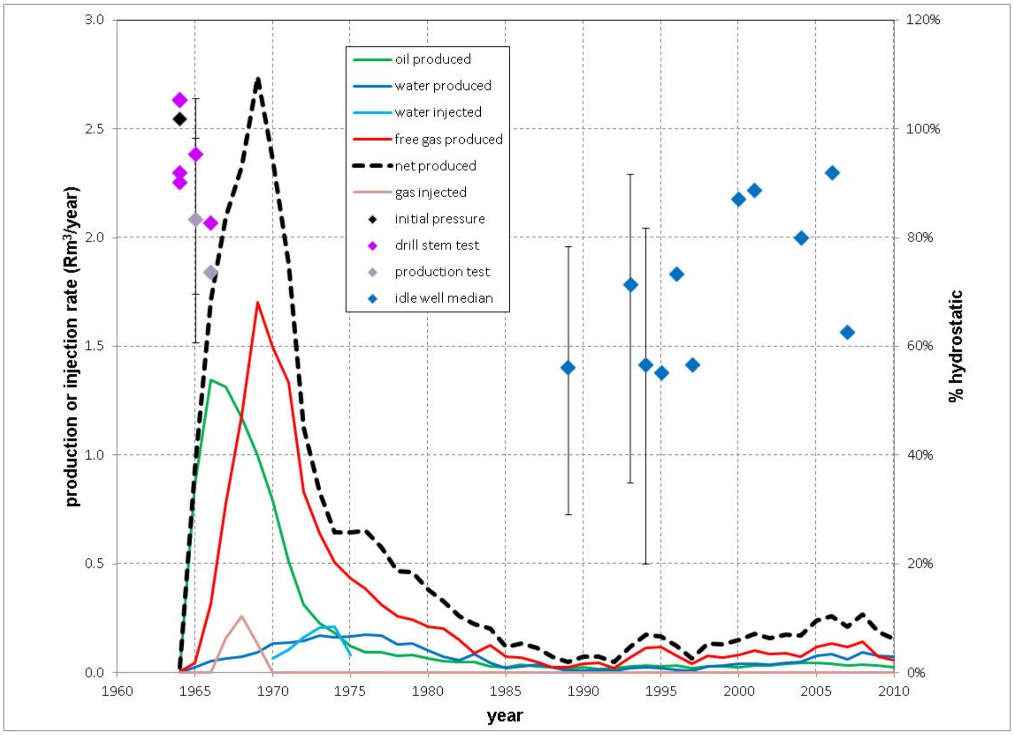


Figure 45: Production from and Pressure in the Phacoides Pool of the Temblor in the Northeast Area of McKittrick Field.

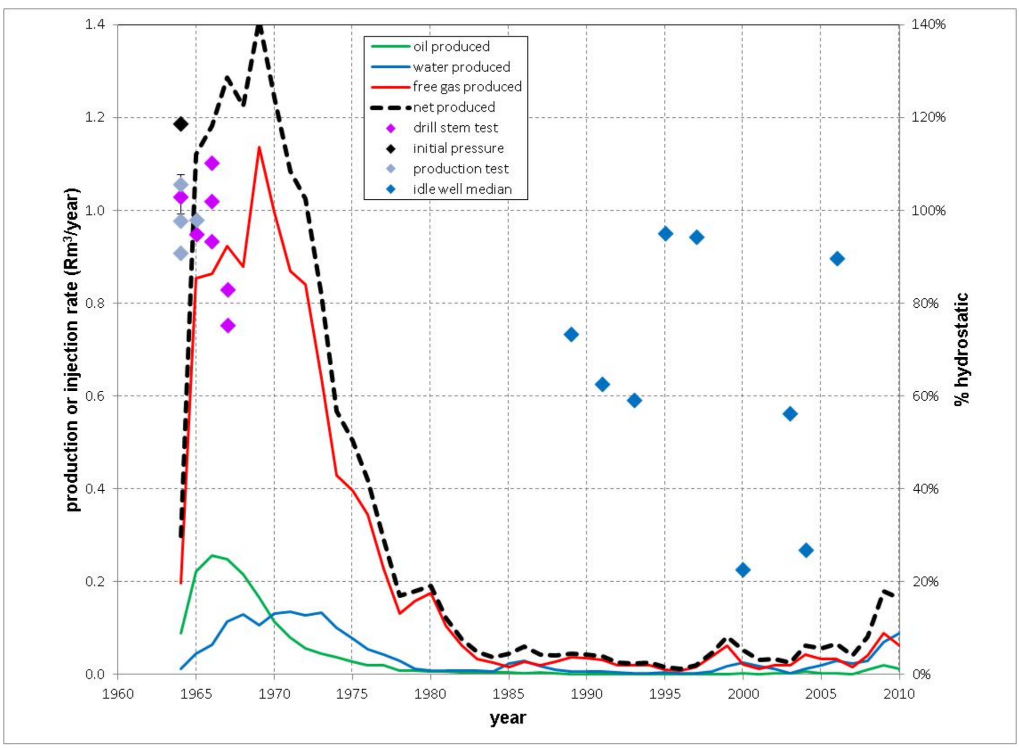


Figure 46: Production from and Pressure in the Carneros Pool of the Temblor in the Railroad Gap Field.

Net production from the Phacoides pool in McKittrick Field, Northeast Area, averaged 100,000 Rm^3/yr from the mid 1980's to mid-2000's. The median pressures from idle well fluid levels during this time are about 70 percent of hydrostatic. Net production from the Carneros pool in the Railroad Gap Field averaged 40,000 Rm^3/yr from the mid 1980's to mid 2000's. The median pressures from idle fluid levels during this time are about 60 percent of hydrostatic.

Pressures vary more than in the Stevens pools discussed above. Figure 47 maps idle well fluid levels in the Phacoides pool of the McKittrick Field, Northeast Area, relative to the fault intersections with the top of the Carneros shown in DOGGR (1998). The fluid level and fault pattern suggests compartmentalization by the faults. DOGGR (1998) also shows a fault intersecting the Carneros in the Railroad Gap Field. The fault terminates below the surface contoured on the associated structure map.

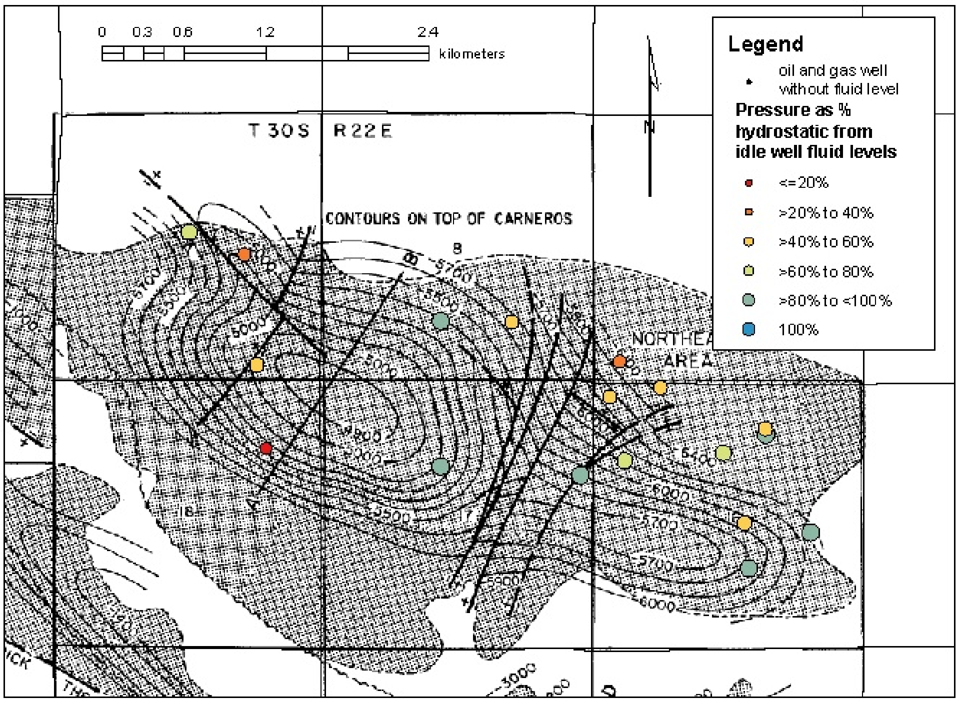


Figure 47: Mid 2000's Idle Well Fluid Levels in the Phacoides Pool of the Temblor in the McKittrick Field, Northeast Area, Expressed as Percent Hydrostatic Superimposed on the Structure Map for this Field from DOGGR (1998).

4.3.3 Vedder Pools in Greeley and Rio Bravo Fields

Figures 48 and 49 show the production from and pressure in Vedder pools in the Greeley and Rio Bravo Fields. Nominal gas injection starts in both shortly after production commences, with the addition of water flooding as oil production tapers off. Gas injection leads free gas production, suggesting recycling of dissolved gas produced from oil. The excess of gas injected over free gas produced is produced back as oil production tapers off.

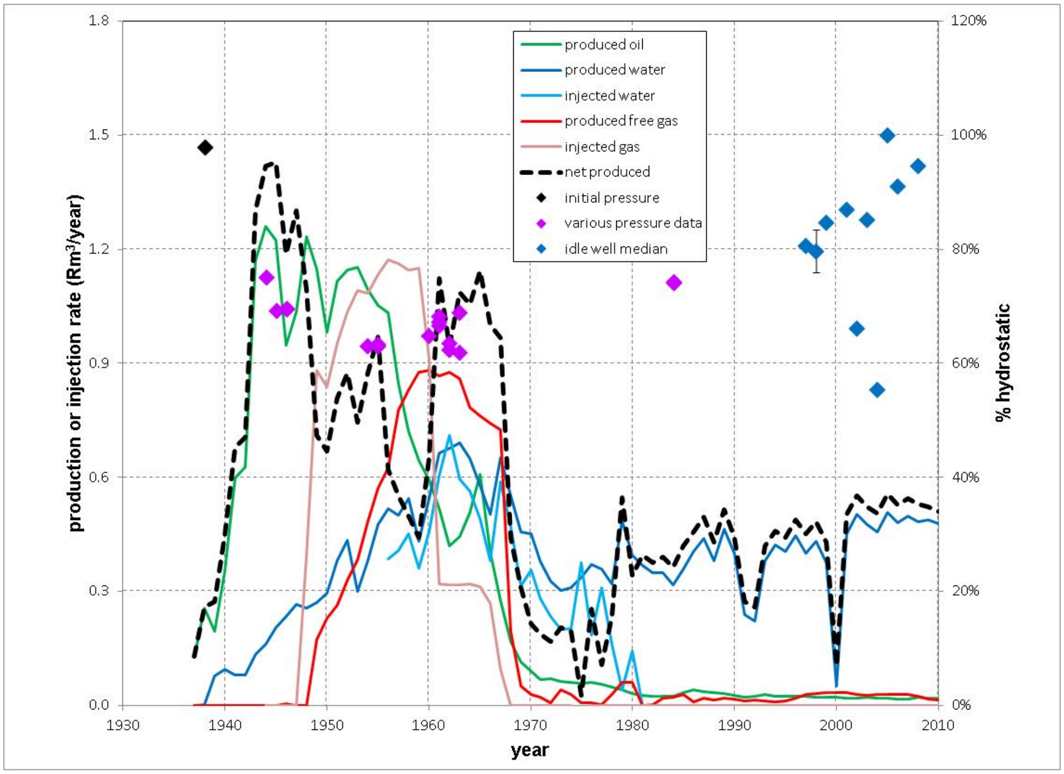


Figure 48: Production from and Pressure in the Vedder in the Greeley Field.

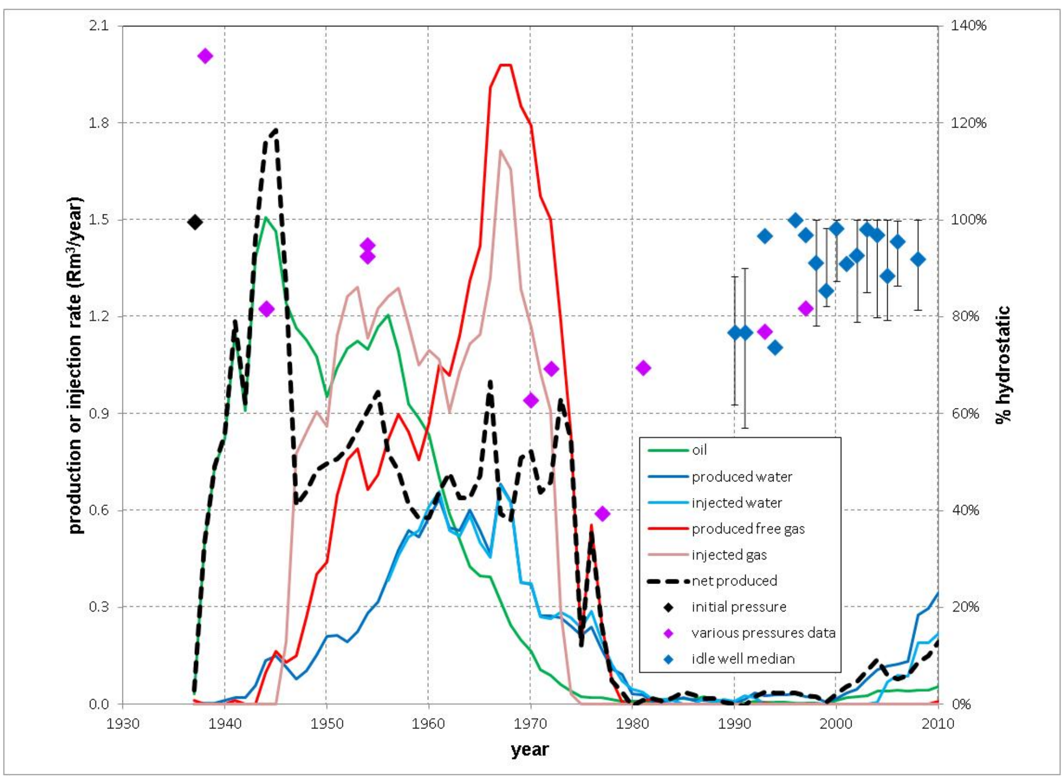


Figure 49: Production from and Pressure in the Vedder in the Rio Bravo Field.

Water injection closely tracks water production in both fields, suggesting almost complete water recycling. However in the Greeley Field water production declines only by a fraction after flooding ceases, and then slowly increases. In the Rio Bravo Field water production decreases to zero following flooding, but then picks up again in 2000 and increases afterward. A lesser volume of flooding subsequently commences, probably as partial recycling of the produced water. These observations suggest weak to strong water drive.

Net production from the Vedder pool in Greeley Field averages 450,000 Rm^3/yr from 1980 to 2010. The median pressures from idle well fluid levels during this time are about 85 percent of hydrostatic. Net production from the Vedder pool in the Rio Bravo Field averages 700,000 Rm^3/yr from the mid 1950's to mid-1970's. The upper pressures appear to stabilize at about 70 percent of hydrostatic toward the end of and just after this period.

Figures 50 and 51 show the fluid level distribution in each of the Vedder pools. The figures show the levels are relatively uniformly distributed.

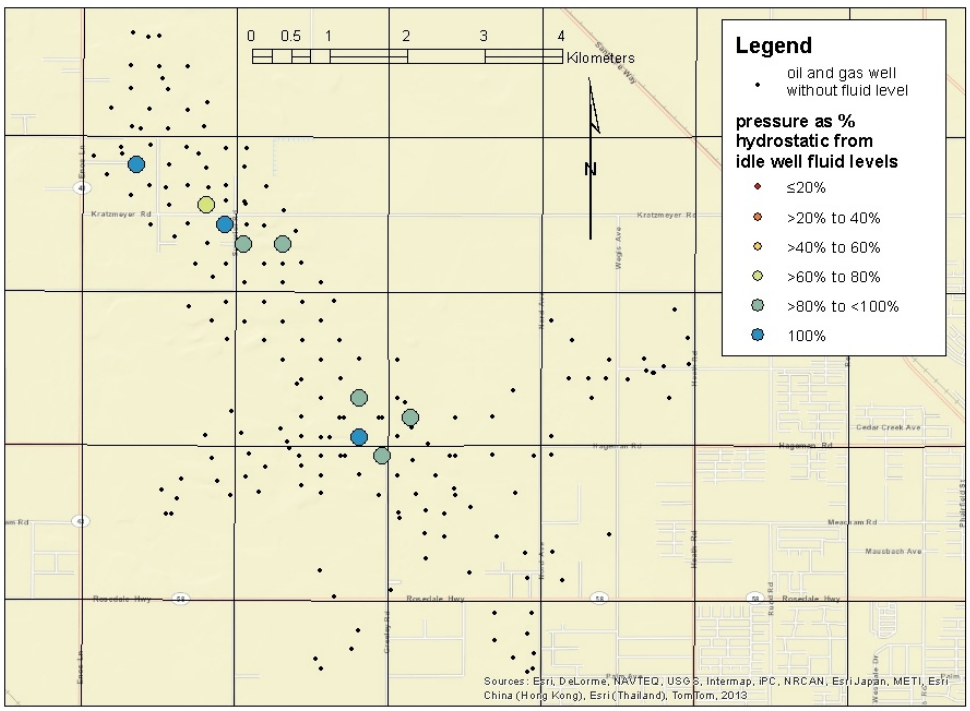


Figure 50: 2005 Idle Well Fluid Levels in the Vedder in the Greeley Field Expressed as Percent Hydrostatic.

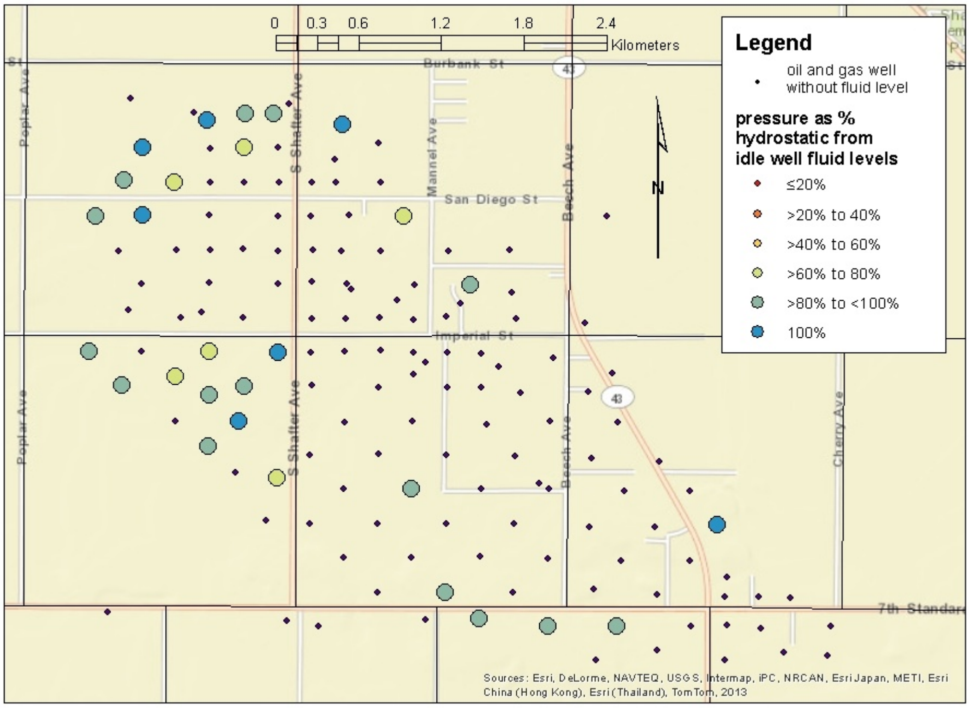


Figure 51: 2005 Idle Well Fluid Levels in the Vedder in the Rio Bravo Field Expressed as Percent Hydrostatic.

4.3.4 Pressure Response Comparison

Table 6 contains the median and 16th percentile pressures from all the idle fluid levels in each pool as well as the difference between the two. Because of the upper truncation previously discussed, statistics regarding the distribution above the median are not considered.

Table 6: Select Percent Hydrostatic Statistics for Each Pool from Idle Well Fluid Levels.

	Stevens		Temblor		Vedder	
	North Coles Levee	South Coles Levee	McKittrick, Northeast, Phacoides	Railroad Gap, Carneros	Greeley	Rio Bravo
Years	1990-2005	1992-2005	1989-2007	1989-2006	1997-2008	1990-2008
Median	96%	94%	59%	57%	85%	90%
16th percentile	78%	58%	29%	29%	77%	77%
Difference	18%	36%	30%	28%	7%	13%

For each of the pools considered except the Stevens in South Coles Levee, the idle well fluid levels are from a period of relatively constant production long after peak production. The median pressures for the two pools in each unit are much closer to each other than the difference between the units. The Stevens pools are nearly hydrostatic, suggesting the effectiveness of the water flooding with little water production in restoring reservoir pressure before the start of the idle well fluid levels. The Vedder pools have the next highest median pressures, which are slightly underpressured relative to hydrostatic. This suggests natural pressure maintenance given water production equal to or larger than water injection. The Temblor pools have the lowest median pressures, approaching half of hydrostatic. This suggests limited pressure recovery from primary production, and so reservoirs not in communication with the aquifer beyond the pools.

The difference between the median and 16th percentile pressures also follows a consistent pattern from unit to unit. The Vedder pools have the lowest variability, indicating relatively less reservoir heterogeneity. The North Coles Levee Stevens pool has the next lowest variability and the South Coles Levee Stevens pool has the highest variability. Both pools were produced under pressure maintenance and later water flooding. Additionally, unlike all the other pools considered, net production in the South Coles Levee was changing (declining) during the period covered by the idle well fluid level data set. These suggest the Stevens pools are likely relatively hydraulically connected internally and the observed variation is due to production activities. The Temblor pools have the highest average difference between the median and 16th percentile pressures. As these pools did not have secondary production, this suggests compartmentalization within the pools.

Table 7 presents the initial pressure in each pool along with the pressure and production during the stable production period identified above. This allows calculation of the productivity index (PI) shown on the table by dividing the net production by the pressure decline.

Table 7: Initial Pressure, Pressure and Production during a Stable Production Period, and Productivity Index (PI) for Each Pool.

	Stevens		Temblor		Vedder	
	North Coles Levee	South Coles Levee	McKittrick, Northeast, Phacoides	Railroad Gap, Carneros	Greeley	Rio Bravo
Initial pressure (Mpa)	27.5	29.0	24.5	25.2	33.6	34.5
Initial pressure depth (m)	2,690	2,970	2,410	2,130	3,450	3,480
Selected constant production period	production start (~1940) to mid-1950's	mid 1940's to mid-1960's	mid 1980's to mid-2000's	mid 1980's to mid-2000's	1980 to 2010	mid 1950's to mid-1970's
Pool pressure (% hydrostatic)	80%	75%	70%	60%	85%	70%
Pool pressure (MPa)	22	22	17	13	29	24
Pressure decline (Mpa)	5.5	7.0	7.5	12.2	4.6	10.5
Net production (Rm^3/yr)	400,000	500,000	100,000	40,000	450,000	700,000

PI (Rm^3/Mpa/yr)	72,500	71,782	13,364	3,277	98,120	66,776

The average PI for the Vedder pools is the highest. The Stevens pools' PIs are slightly lower. The PI for the Temblor pools is considerably lower.

4.4 Summary

Because many pools are discovered after production starts in other pools, the initial pressure and head in those pools provide a measure of pressure propagation through the basin. Analysis of the century of pool discoveries, from the late 1800's to late 1900's, shows no trend, either up or down, in basin-wide pressure. This suggests changes in pressure at the sub basin scale are considerably less than the natural variability in pressure. Net production during this time peaked at over 100 million Rm^3/year.

Geographically, the initial heads are consistent in the Vedder, except for higher due to overpressure along the southern basin margin. Heads in the Temblor are higher toward the basin axis, which is near the western basin margin due to the asymmetric structure of the basin, and along the southern margin due to overpressures. Heads in the Stevens are likewise higher toward the basin axis due to higher overpressure. The overpressures are located near the tectonically active margins of the basin, suggesting the overpressures are due to tectonically-driven compaction, and that this effect is much larger across the basin than pressure changes due to production.

The pressures in pools discovered in these units after production from a different pool in the same unit and field area are also not consistently less than the pressure in the previously discovered and developed pool. This suggests pressure propagation across stratigraphic or other barriers within these field areas is limited.

Various analyses of pressure and productivity data for the three units provide consistent results with regard to the structure of each unit along the spectrum from hydraulically homogenous ("open") to heterogeneous ("compartmentalized"). Table 5 summarizes the results from the various analyses.

Table 8: Summary of Analysis Results for the Stevens, Temblor and Vedder.

	Stevens	Temblor	Vedder
Initial pressure variation	intermediate	largest	smallest
Initial head variation	largest	intermediate	smallest
consistency of pool pressures in the same field area	intermediate	lowest	high
geographic pressure and head distribution	head higher and overpressured toward basin axis	heads higher and overpressured toward basin axis and along southern margin	consistent heads except overpressure along southern margin
water drive	none	weak	weak to strong
gas cap expansion drive	strong	weak	none
pressure variation from idle well fluid levels	intermediate	highest	lowest
PI	high	lowest	highest

These results suggest the Vedder is hydraulically connected over areas much greater than that occupied by a single pool, the Stevens is hydraulically connected over areas about the size of a pool, and the Temblor is hydraulically connected over areas smaller than a pool. The Vedder forms a hydraulically "open" system at the near basin scale. The Stevens is an open system at the pool scale but compartmentalized at the basin scale. The Temblor is compartmentalized at the sub-pool scale.

CHAPTER 5: Groundwater Quality Response

The existence of numerous pools with net injection in the shallowest portions of the fields in which they are located provides a direct analog for brine leakage from storage depths to intermediate depths that can in turn be investigated for whether leakage from these intermediate depths impacts groundwater quality at the overlying groundwater wells. Figure 52 shows the field areas overlain on the groundwater well density.

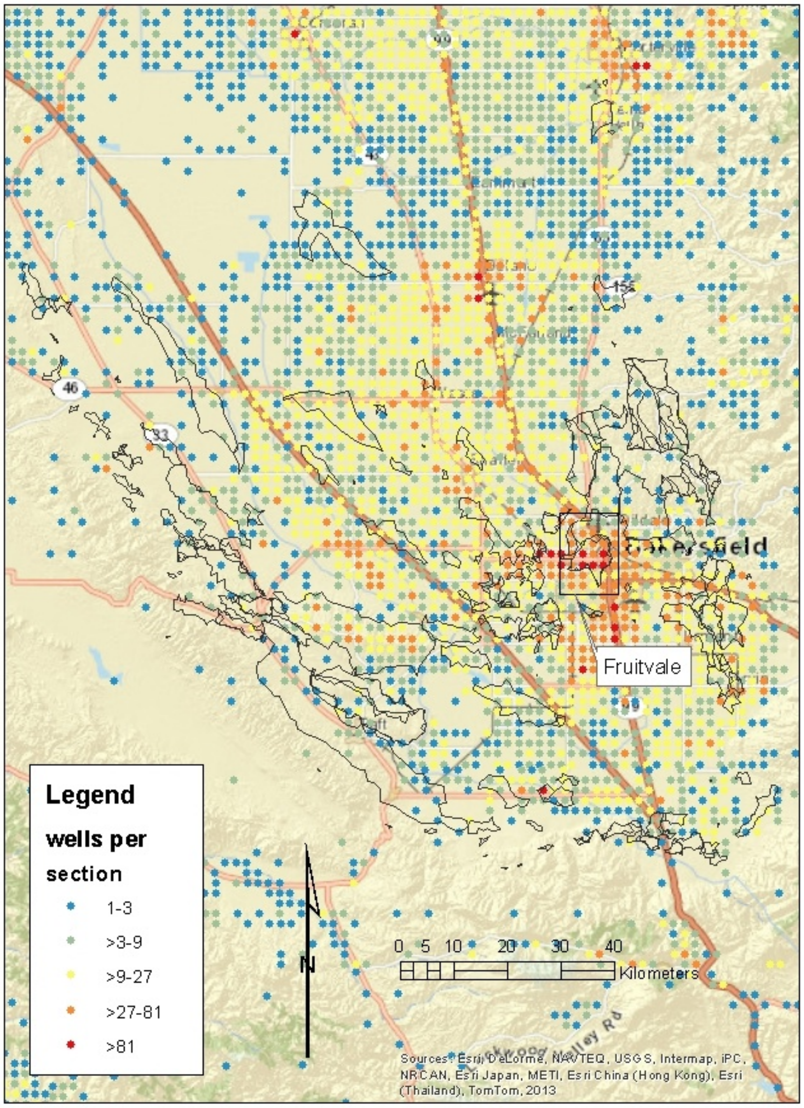


Figure 52: Number of Groundwater Wells in Each Section with Field Areas Overlain.

Field areas toward the center of the basin tend to have a large number of groundwater wells overlying them while field areas along the western and southern margins and central portion of the eastern margin tend to have few to no wells. The co-location of shallow net injection resulting from produced water disposal and numerous groundwater production wells provides an opportunity to assess the potential impacts of brine leakage from the net injection pools into the overlying fresh water aquifer as an analog for brine leakage from geologic carbon storage projects.

5.1 Data Sources

5.1.1 DOGGR Injection and Well Records Databases

The DOGGR injection database[18] provides monthly injection volumes and well head pressures for each injection well. These were downloaded for selected pools, as described below. The total number of wells in select field areas was taken from the DOGGR well records database[19], also as discussed below.

5.1.2 The Bakersfield Californian

A previous study found that the *Bakersfield Californian* covered as many high public consequence well blowouts as did records from DOGGR. These were the subset of all blowouts that required public evacuation. DOGGR's records covered one such event. The *Bakersfield Californian* covered this event as well as one other (Jordan and Benson 2008). This suggests the *Bakersfield Californian* provides the most thorough record of events with a high public consequence.

The Bakersfield Californian site was searched using a variety of engines and search terms to identify articles regarding groundwater quality changes (searches were constrained to the site using the term "site:bakersfieldcalifornian.com"). Preliminary searches identified the terms "groundwater contamination" and "groundwater pollution" as yielding apparently complete results regarding the topic of interest while minimizing irrelevant results. Searches performed by Google were found to yield a superset of the results from all other search engines using the same terms. This includes results using the search engine on the *Bakersfield Californian* site itself.

The final search terms selected were "groundwater contamin" and "groundwater pollut." While Google uses automatic stemming, which returns sites with words with nearly the same form (for instance sites with "bicycle" returned for a search on "bike"), it was found that the terms "groundwater contamin" returned more results than did "groundwater contamination."

The final searches were performed on 30 June 2013 for the first term and 1 July 2013 for the second term. The union of the relevant results consisted of 111 articles. The date of the earliest article in this set was 9 February 2006 and the latest article was 29 June 2013. However there were six articles dated 9 February 2006, some of which clearly indicated in their text that they were from an earlier date. This suggested the *Bakersfield Californian* system was returning a default date of 9 February 2006 for these earlier articles.

The *Bakersfield Californian* was subsequently contacted regarding the possibility of searching for earlier articles. Estella Aguilar did so, resulting in an additional 118 articles dated from 21 July

[18] http://opi.consrv.ca.gov/opi/opi.dll

[19] http://owr.conservation.ca.gov/WellSearch/WellSearch.aspx

2000 to 18 January 2006. She also provided correct dates for the articles with the apparent default date of 9 February 2006 identified using from the Google searches. It turned out this date was correct for one of the six articles.

So, in sum, the searches identified 229 articles regarding groundwater contamination published over 13 and a half years from 2000 to 2013.

5.2 Statistics Regarding Select Shallowest Net Injection Pools

As suggested above, a number of net injection pools provide direct analogs for brine leakage in response to geologic carbon storage. The best analogs would (1) have no overlying pressure sink due to production, (2) be overlain by numerous potential receptors that are (3) actively monitored, (4) receive large injection volumes at (5) high pressures into (6) saline water, and (7) have numerous potential leakage pathways. The pools with cumulative net injection in the fluid production database were investigated relative to these criteria.

The first criterion, as mentioned, was cumulative net injection pools and no overlying activity in their fields. These were identified from the mapping in Chapter 3 above.

The second criterion is met in part by numerous overlying groundwater wells. This ruled out fields along the western and southern edges and the central portion of the eastern edge of the basin.

The third criterion requires the groundwater wells to be used for public or domestic water supply or irrigation. TDS increases in such wells are likely to be detected. Public water supplies are generally tested for TDS on a voluntary basis and so TDS increases would be detected. TDS increases in domestic supply wells, which are typically not tested for TDS, will be acutely detected as a change in taste. TDS increases in wells supplying irrigation water will be qualitatively detected through acute adverse effects on crops. These detection thresholds obviously vary, but are all lower than the difference between the groundwater TDS and the TDS of the water in the cumulative net injection pools if it is saline.

The pools with the largest cumulative net injection volumes (criterion four) that meet the previous three criteria are shown on Table 9. Injection in these pools started in the mid-1960s. In aggregate they have received an average annual net injection volume at reservoir conditions equivalent to about 5 percent of the total CO_2 emitted by stationary sources creating more than 200,000 tons/year CO_2 each in and near this portion of the San Joaquin Valley in recent years. This would be substantial leakage to intermediate depths, even if all the CO_2 available from local stationary sources were injected.

Table 9: Statistics Regarding Select Cumulative Net Injection Pools.

Field	Area	Depth		Cumulative Volume[2]			Average wellhead pressure[4]		Average TDS (ppm)	Wells in area[9]
		(ft)	(m)	(MMRB)	(million m^3)	(mega tons CO_2)[3]	(psi)	(Mpa)		
Fruitvale	Main	3,000	920	231	37	22	920	6.3	2,300[5]	905

Rosedale Ranch	Main & Any[1]	3,500	1,100	153	24	15	890	6.1	12,100[6]	177[10]
Greeley	Any	3,500	1,100	91	14	9	790	5.4		199
Ten Section	Main	4,725	1,400	89	14	8	540	3.7	29,300[7]	225
Canfield Ranch	East Gosford	3,000	920	43	7	4	1,150	7.9	33,000[8]	187
total						58				1,693

[1]the only Etchegoin pools are in the Any and Main areas; Any area Etchegoin injection ends in 1977 and Main Etchegoin injection starts in 1978; these suggest the two pools are the same

[2]as of 2010

[3]assuming a density of 600 kg/m^3

[4]1978 through 2010

[5]DOGGR 1998; 2,200 mg/L is average of results in ftp://ftp.consrv.ca.gov/../../pub/oil/D4 Chemical Analysis/Fruitvale/Fruitvale - Etchegoin Zone.pdf

[6]DOGGR 1998; 24,000 mg/L is average of results in ftp://ftp.consrv.ca.gov/../../pub/oil/D4 Chemical Analysis/Rosedale Ranch/Rosedale Ranch - Etchgoin.pdf

[7]DOGGR 1998

[8]average of results in ftp://ftp.consrv.ca.gov/../../pub/oil/D Chemical Analysis/Canfield Ranch/Canfield Ranch - Etchegoin Zone.pdf

[9]as of 14 October 2013

[10]wells in Main area

The location of these pools is shown on Figure 53. They are all located in the Etchegoin Formation on the Bakersfield Arch.

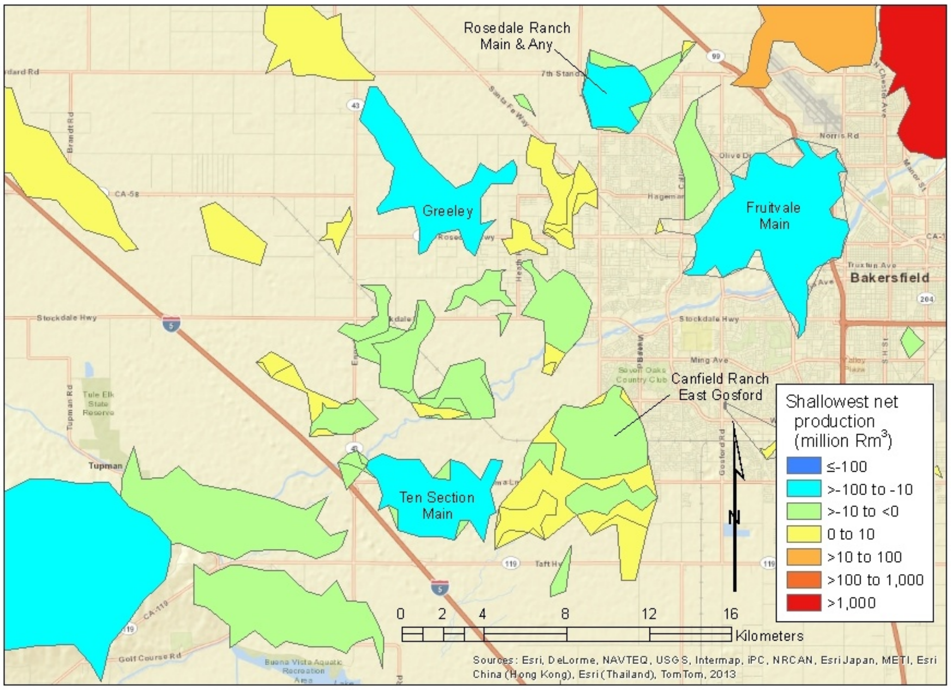


Figure 53: Cumulative Net Production from the Shallowest Pool in Each Field Area in the Vicinity of the Bakersfield Arch (Negative Values Are Net Injection).

Information relative to the fifth criterion (high injection pressure) is provided on Table 9. Wellhead injection pressures for all the injection wells in each pool on Table 9 were downloaded and averaged. The average pressures range from 26 percent (Rosedale Ranch, Main) to 87 percent (Canfield Ranch, East Gosford) of the hydrostatic pressure at the depth of the pool. The average wellhead pressure for four of the five pools is over 50 percent of hydrostatic. The wellhead pressure in the pool with the largest net cumulative injection volume, Fruitvale Main, is 69 percent of hydrostatic. Consequently the average wellhead pressure added to the hydrostatic pressure is close to typical fracturing pressures for most of the pools. This is typically the maximum allowable injection pressure under Safe Drinking Water Act regulations. So the pools on Table 9 meet the sixth criteria, high injection pressure, albeit to varying degrees.

Information on the sixth criterion (saline formation water in the injection pool) is also provided on Table 9. For the four pools for which TDS is available, the values indicate the formation water is well above the secondary drinking water standard for TDS of 500 mg/L. It is also well above the salinity at which crop yields start to decline, which is generally a TDS of 1,000 mg/L or less as mentioned above (Table 5 of Technical Appendix 3 of Bookman-Edmonston Engineers Inc., 1999). In addition, the water disposed in these pools likely has higher TDS because it is produced from deeper pools.

Information regarding the seventh criterion (numerous potential leakage pathways) is also provided on Table 9. Because the pools listed are the shallowest in each field area, every oil production-related well in the field areas containing those pools are located extends to or through each pool. Table 9 lists the well total for each field area according to the DOGGR well records database. There are approximately 1700 oil-production related wells in these field areas, and so these pools meet the seventh criterion. In addition to numerous potential well leakage pathways, the Fruitvale and Ten Section Main areas have faults in the Etchegoin that extend into the next shallower geologic unit according to DOGGR (1998). So the pools in each of these two areas further meeting the seventh criterion due to the presence of these potential leakage pathways.

The selected pools meet all the criteria to consist of direct analogs for brine leakage to intermediate depths driven by geologic carbon storage.

5.3 Survey of the Bakersfield Californian

Having identified a set of pools that are analogs for brine leakage to intermediate depths, the Bakersfield Californian articles concerning groundwater contamination were analyzed to determine if they reported groundwater contamination that could be due to brine. Of the 229 articles identified, 183 were news, which is four fifths. The remaining articles were opinion pieces, including editorials, columns, guest columns and letters to the editor.

Of the 183 news articles, 145 were written by 38 staff writers for the paper. This is an indication of the resources the paper dedicated to the topic. The other 38 news articles were variously authored by the paper's government editor, sourced from other news organizations, authored anonymously, and authored by someone not designated as other than a staff writer.

The annual number of articles regarding groundwater contamination fluctuated, as shown on Figure 54, from a high of 36 to a low of two. Each article regards one or more groundwater contamination items. Each item was categorized by whether it regarded a groundwater contamination occurrence or a concern for groundwater contamination that might have or could occur. Figure 54 shows the count of articles that reported on contamination occurrences.

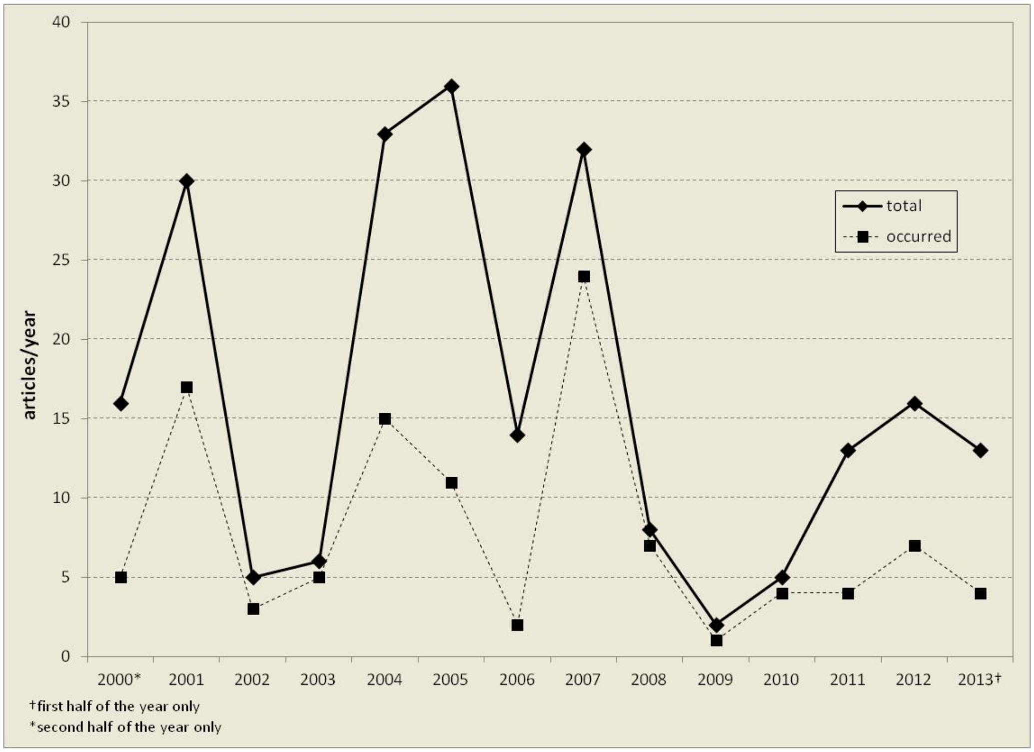


Figure 54: Annual Number of Articles Concerning Groundwater Contamination in the Bakersfield Californian.

"Occurred" regards articles that reported on observed contamination as opposed to only concern that contamination might have or will occur.

Some articles cover more than one groundwater contamination item. So the total number of items is greater than the number of articles, as shown on Figure 55. On average, more than two groundwater contamination items were covered per month in the paper, again suggested the attention to this topic both in the community and by the paper. This accords with indications in various articles that groundwater provides a significant portion of the domestic water supply in the area.

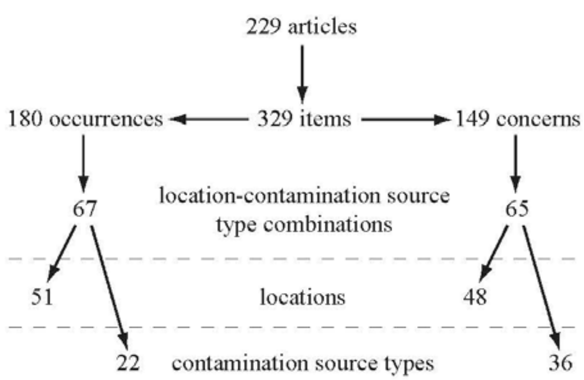


Figure 55: A Breakdown of Articles in the Bakersfield Californian Regarding Groundwater Contamination from Mid-2000 to Mid-2013.

Each groundwater contamination item regards either an occurrence or concern. The number of each is shown on Figure 55. The number and fraction of articles expressing concern indicates a high level of interest in the community for assuring groundwater quality. About a fourth of the concerns were expressed in editorials and opinion pieces, while these types of articles expressed only about a fifteenth of the items regarding actual occurrences. Many of the concerns expressed covered large geographic areas, such as the entirety of Kern County or California.

Table 10 provides the number of items reported per contamination source. There are 45 different sources. The source is a specific release pathway and/or type of facility as available in the reporting. If that information is not available then the source material or specific contaminant is listed. "All" is also listed because a few articles reported on the contamination of groundwater wells by all sources.

Table 10: Number of Groundwater Contamination Items by Contamination Source Reported in the Bakersfield Californian from Mid-2000 to Mid-2013.

Actual and/or potential contamination source	Number of items		
	Occurred	Concern	Total
Agriculture	9	7	16
All	1	3	4
Natural arsenic contamination	22		22
Dairies	3	26	29
Drilling fluid disposal - unlined ponds		1	1
Drum cleaning and reconditioning	2	2	4
Dry cleaners	1	1	2
Ethanol plant		2	2
Farm equipment storage yard		1	1
Fire training facility		2	2
Gas station spill	11	1	12
Gold mine		1	1
Hydraulic fracturing		10	10
Hydraulic fracturing fluid flowback disposal - unlined pond storage		1	1
Industrial waste disposal		1	1
Iron and manganese contamination	1		1
Landfill		5	5
Light industry		2	2

Manure composting		2	2
MTBE released via various pathways	5	1	6
Natural gas compressor station	2		2
Nitrate released by various activities	4		4
Oil field waste disposal		1	1
Oil production	1		1
Oil wells		1	1
PCE from unknown release	2		2
Pesticide and/or fumigant plant	11		11
Petroleum coke stock pile		1	1
Petroleum refinery	42		42
Power plant	16	1	17
Produced water surface disposal	12	3	15
Rocket research		1	1
Septic systems		4	4
Septic tanks, agriculture, dairies, sewage sludge land application	1		1
Sewage	1	1	2
Sewage sludge		3	3
Sewage sludge composting		3	3
Sewage sludge land application		47	47
Solar facility		1	1
Solvent from unknown release	1	1	2
Steam injection		1	1
Steam injection of imported MTBE-contaminated water		2	2
Underground storage tank leak	23	3	26
Waste disposal	9	2	11
Waste oil, oily soil and/or contaminated soil recycling operation		4	4
Total	180	149	329

Collectively the items report on the closure of around a hundred wells due to contamination. The exact number could not be calculated because of ambiguity regarding overlap between some reports in some cases. Reports on the well closures suggest a reporting threshold regarding well closures of one to a few public supply wells and a few too many domestic supply wells.

Many items report on groundwater contamination that happened years to decades prior the article containing the item was published. This indicates the paper has an institutional memory regarding groundwater contamination.

The information above suggests historic articles in the *Bakersfield Californian* cover groundwater contamination relatively thoroughly. This, along with the results of the well blowout study mentioned, suggest a moderate probability (~0.5 for instance) the paper would have reported a contamination event that closed wells in numbers indicated by the surmised reporting threshold. No well closures or groundwater contamination due to disposal injection of produced water were reported. This suggests zero to perhaps one such event occurred during the 12-year reporting period and some number of years previous due to the institutional memory demonstrated in many of the articles. It appears unlikely that two or more such events would have occurred without being reported.

CHAPTER 6: Conclusions and Outlook

This study assessed the history of oil production and pressure in the southern portion of the San Joaquin Basin as a reverse analog for understanding the pressure response to potential geologic carbon sequestration. Sequestration involves injecting CO_2 into permeable strata such as those that trap oil. This will result in pressure increases in the existing fluid in the subsurface that can provide a motive force for brines at those depths to migrate into groundwater, affecting its quality. The pressure can also cause differential ground surface uplift that can affect surface water flow, particularly in engineered water conveyances such as canals.

Analysis of the history of initial (discovery) pressures across the basin did not reveal downward trends at the basin-scale in response to net fluid production, which was greater than 100 million m^3/year at reservoir conditions (Rm^3) during more than a decade of this history. If basin-wide trends exist, they are considerably smaller than the non-temporal variation in discovery pressures that appears to be a natural feature of the basin.

The Stevens Sand, Temblor Formation and Vedder Formation each had net cumulative production from geologic storage depths equal to or greater than 100 million Rm^3. Consistent downward trends in discovery pressure through time were not observed in any of the three units, indicating any unit-wide pressure decline is again masked by the natural variation in pressure. The same holds for pools discovered at different times within the same stratigraphic unit and field area. This suggests pressure propagation across stratigraphic or other barriers within a field area is limited.

Initial (discovery) heads in the Stevens and Temblor increase toward the basin axis, which is toward the western margin of the basin due to its asymmetry. Heads are also relatively high in the Temblor along the southern margin. In contrast the initial heads in the Vedder are relatively consistent over most of this unit's extent. The only area where initial heads in these pools vary considerably from the average is along the southern margin of the basin where the heads are relatively higher due to higher pressures. The pattern of higher heads in the vicinity of the western and southern margins coincides with the tectonically most active areas of the basin. This suggests tectonically-driven compression is responsible for the high pressures observed in the vicinity of these margins.

Analysis of production and injection histories for two pools each at geologic carbon storage depths selected in the Stevens, Temblor and Vedder indicates different drive mechanisms involved in the production of each. The Stevens pools produced under gas cap expansion with virtually no water cut during primary production. The Temblor pools produced under weak gas cap expansion and water drive. The Vedder pools produced under weak to strong water drive. The Vedder pools had the highest average productivity index (PI; 80,000 Rm^3/Mpa/yr) and the least pressure decline. The PI is a measure of the amount of fluid that can be produced per pressure change from a particular stratigraphic interval. The Stevens had the next highest average PI (70,000 Rm^3/Mpa/yr) and next least pressure decline. The Temblor had a far lower average PI (under 10,000 Rm^3/Mpa/yr) and a far larger pressure decline.

The above findings along with other differences in the pressure distribution in each pool and each stratigraphic unit indicate the Vedder is hydraulically connected at the near basin scale, the Stevens is connected at the pool scale and disconnected between pools and the Temblor is disconnected within pools. This finding bears on the storage capacity of these units. The results could be processed to develop hydraulic parameters measured at a scale more relevant to carbon storage than typical core and single well test measurements. Development of results for additional pools in each of the three stratigraphic units would allow a more statistically robust understanding of these parameters. The parameters would in turn allow exploration of how storage projects in these units would need to be configured, leading to a better understanding of the capacity for and technical and economic feasibility of storage in the basin.

An unanticipated finding from the production and injection database was the existence of pools at depths intermediate between geologic carbon sequestration and groundwater into which large volumes of produced water were at high pressure for disposal. These pools were also the shallowest in their fields so that no pressure sink due to production of an overlying pool was present. Consequently these pools provide a direct analog for possible brine leakage from carbon storage reservoirs. An analysis of hundreds of articles in the main newspaper in the area found coverage of tens of contamination sites and closure of around a hundred wells due to contamination from other sources, such as leaks from underground fuel tanks, but no reports of contamination due to subsurface brine leakage.

The produced water disposal analogs for brine leakage from carbon storage invite further investigation into whether impacts to groundwater have occurred. Thousands and thousands of analyses for numerous constituents in groundwater samples from hundreds to thousands of wells in the area are available from the Groundwater Ambient Monitoring and Assessment Program (GAMA) operated by the California Water Resources Control Board. The GAMA geotracker site provides access to water quality data for select groundwater wells aggregated from a number of sources.[20] These data could be statistically analyzed to bound groundwater quality changes over the disposal analogs due to subsurface brine leakage. This analysis could bind the probability of subsurface brine leakage via various pathways, including wells associated with oil and gas production and faults.

[20] http://geotracker.waterboards.ca.gov/gama/

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APPENDIX A:
Codes for Pools with Production

Field		Area		Pool	
Code	Name	Code	Name	Code	Name
000	Kern County	00	Any	00	No Pool Breakdown
000	Kern County	00	Any	06	Tulare (Dewatering)
000	Kern County	00	Any	10	Tulare
00k	Kern County	7a	Antelope Hills (2)	00	No Pool Breakdown
018	Ant Hill	00	Any	00	No Pool Breakdown
018	Ant Hill	00	Any	05	Olcese
018	Ant Hill	00	Any	10	Jewett
01k	Kern County	7b	Bates	00	No Pool Breakdown
020	Antelope Hills	00	Any	00	No Pool Breakdown
020	Antelope Hills	03	Hopkins	05	Phacoides
020	Antelope Hills	03	Hopkins	10	Eocene
020	Antelope Hills	06	Williams	03	Gas Zone
020	Antelope Hills	06	Williams	05	Upper
020	Antelope Hills	06	Williams	10	East Block-Button Bed
020	Antelope Hills	06	Williams	15	East Block-Agua
020	Antelope Hills	06	Williams	20	West Block-Button Bed & Agua
020	Antelope Hills	06	Williams	25	Button Bed
020	Antelope Hills	06	Williams	30	Point of Rocks
020	Antelope Hills	09	Nepple Gas	00	No Pool Breakdown
022	Antelope Hills, North	00	Any	00	No Pool Breakdown
022	Antelope Hills, North	00	Any	05	Miocene-Eocene
022	Antelope Hills, North	00	Any	0a	Miocene
022	Antelope Hills, North	00	Any	10	Point of Rocks
024	Antelope Plains	00	Any	00	No Pool Breakdown
032	Asphalto	00	Any	03	Tulare
032	Asphalto	00	Any	05	Etchegoin
032	Asphalto	00	Any	10	Olig
032	Asphalto	00	Any	15	Antelope Shale

032	Asphalto	00	Any	20	Stevens
032	Asphalto	00	Any	25	1st Carneros
032	Asphalto	00	Any	30	Carneros
032	Asphalto	00	Any	9g	1st and 2nd Carneros
032	Asphalto	00	Any	9h	3rd Carneros
040	Beer Nose	00	Any	05	Bloemer
042	Belgian Anticline	00	Any	00	No Pool Breakdown
042	Belgian Anticline	03	Main	00	No Pool Breakdown
042	Belgian Anticline	03	Main	05	Oceanic
042	Belgian Anticline	03	Main	10	Point of Rocks
042	Belgian Anticline	06	Northwest	00	No Pool Breakdown
042	Belgian Anticline	06	Northwest	05	Miocene
042	Belgian Anticline	06	Northwest	10	Eocene
044	Bellevue	00	Any	00	No Pool Breakdown
044	Bellevue	03	Main	00	No Pool Breakdown
044	Bellevue	03	Main	10	Etchegoin
044	Bellevue	03	Main	15	Stevens
044	Bellevue	06	North	00	No Pool Breakdown
044	Bellevue	09	South	05	Stevens
046	Bellevue, West	00	Any	00	No Pool Breakdown
046	Bellevue, West	00	Any	0u	Etchegoin
046	Bellevue, West	00	Any	10	Tulare-Etchegoin
046	Bellevue, West	00	Any	15	Stevens
050	Belridge, North	00	Any	00	No Pool Breakdown
050	Belridge, North	00	Any	05	Tulare
050	Belridge, North	00	Any	07	Diatomite
050	Belridge, North	00	Any	0b	Shallow
050	Belridge, North	00	Any	10	Temblor
050	Belridge, North	00	Any	15	R Sand
050	Belridge, North	00	Any	20	64 Zone
050	Belridge, North	00	Any	25	Y Sand
050	Belridge, North	00	Any	5z	Wagonwheel Zone
052	Belridge, South	00	Any	00	No Pool Breakdown

052	Belridge, South	00	Any	05	Tulare
052	Belridge, South	00	Any	06	Tulare (Dewatering)
052	Belridge, South	00	Any	10	Tulare-Etchegoin
052	Belridge, South	00	Any	15	Tulare-Diatomite
052	Belridge, South	00	Any	20	Diatomite
052	Belridge, South	00	Any	23	Diatomite-Antelope Shale
052	Belridge, South	00	Any	25	Antelope Shale
052	Belridge, South	00	Any	30	McDonald
052	Belridge, South	00	Any	40	Belridge 64
052	Belridge, South	00	Any	88	Class I Disposal
060	Blackwells Corner	00	Any	00	No Pool Breakdown
060	Blackwells Corner	00	Any	03	Devilwater
060	Blackwells Corner	00	Any	05	Agua
060	Blackwells Corner	00	Any	10	Tumey
060	Blackwells Corner	00	Any	1l	Aqua-Tumey
066	Bowerbank	00	Any	04	Gas Zone
066	Bowerbank	00	Any	05	Stevens
06c	Paloma Gas	00	Any	00	No Pool Breakdown
06g	Coles Levee Gas	00	Any	00	No Pool Breakdown
06h	McKittrick-Temblor	00	Any	00	No Pool Breakdown
06p	Belridge	00	Any	00	No Pool Breakdown
06q	Belridge-Devils Den-Lost Hills	00	Any	00	No Pool Breakdown
06r	Belridge-Lost Hills	00	Any	00	No Pool Breakdown
080	Buena Vista	00	Any	6h	Gas Zone
080	Buena Vista	03	Buena Vista Front	00	No Pool Breakdown
080	Buena Vista	03	Buena Vista Front	05	Tulare
080	Buena Vista	03	Buena Vista Front	10	Sub-Scalez & Mulinia
080	Buena Vista	06	Buena Vista Hills	00	No Pool Breakdown
080	Buena Vista	06	Buena Vista Hills	05	Tulare
080	Buena Vista	06	Buena Vista Hills	08	Gas Zone
080	Buena Vista	06	Buena Vista Hills	09	Gas Zone-Upper
080	Buena Vista	06	Buena Vista Hills	0c	Upper
080	Buena Vista	06	Buena Vista Hills	0d	27B

080	Buena Vista	06	Buena Vista Hills	0v	Gusher
080	Buena Vista	06	Buena Vista Hills	10	Upper (Undifferentiated)
080	Buena Vista	06	Buena Vista Hills	11	Sub-Scalez & Mulinia
080	Buena Vista	06	Buena Vista Hills	15	Sub-Scalez
080	Buena Vista	06	Buena Vista Hills	20	Upper (Sub-Scalez 11-D Unit)
080	Buena Vista	06	Buena Vista Hills	25	Upper (To-Etchegoin 8d)
080	Buena Vista	06	Buena Vista Hills	30	Upper (To-Sub Calitroleum 27b)
080	Buena Vista	06	Buena Vista Hills	35	Upper (Wilhelm Calitroleum 1c)
080	Buena Vista	06	Buena Vista Hills	38	Upper (Wilhelm Gusher)
080	Buena Vista	06	Buena Vista Hills	40	Upper (Gusher)
080	Buena Vista	06	Buena Vista Hills	45	Upper (99-9D)
080	Buena Vista	06	Buena Vista Hills	55	27B (Undifferentiated)
080	Buena Vista	06	Buena Vista Hills	57	27B (E-1)
080	Buena Vista	06	Buena Vista Hills	59	Reef Ridge
080	Buena Vista	06	Buena Vista Hills	60	Antelope Shale-East Dome
080	Buena Vista	06	Buena Vista Hills	65	Antelope Shale-West Dome
080	Buena Vista	06	Buena Vista Hills	70	555 Stevens
092	Buttonwillow Gas	00	Any	00	No Pool Breakdown
095	Cal Canal	00	Any	00	No Pool Breakdown
095	Cal Canal	00	Any	03	Tulare-San Joaquin
095	Cal Canal	00	Any	04	Etchegoin
095	Cal Canal	00	Any	05	Stevens
096	Calders Corner	00	Any	00	No Pool Breakdown
096	Calders Corner	00	Any	05	Stevens
104	Canal	00	Any	00	No Pool Breakdown
104	Canal	00	Any	02	Etchegoin
104	Canal	00	Any	03	Gas Zone
104	Canal	00	Any	05	Upper Stevens
104	Canal	00	Any	0f	Lower Stevens
104	Canal	00	Any	2c	Stevens
104	Canal	03	Main	02	Etchegoin
104	Canal	03	Main	03	Gas Zone
104	Canal	03	Main	05	Upper Stevens

104	Canal	03	Main	07	Middle Stevens
104	Canal	03	Main	10	Lower Stevens
104	Canal	06	Pioneer Canal	05	Upper Stevens
104	Canal	06	Pioneer Canal	10	Lower Stevens
106	Canfield Ranch	00	Any	00	No Pool Breakdown
106	Canfield Ranch	03	Gosford, East	00	No Pool Breakdown
106	Canfield Ranch	03	Gosford, East	05	Etchegoin
106	Canfield Ranch	03	Gosford, East	10	Stevens
106	Canfield Ranch	03	Gosford, East	2e	Upper and Lower Stevens
106	Canfield Ranch	03	Gosford, East	2r	Upper Stevens
106	Canfield Ranch	03	Gosford, East	2s	Lower Stevens
106	Canfield Ranch	06	Gosford, South	05	Etchegoin
106	Canfield Ranch	06	Gosford, South	10	Stevens
106	Canfield Ranch	06	Gosford, South	2f	Lower Stevens
106	Canfield Ranch	09	Gosford, West	00	No Pool Breakdown
106	Canfield Ranch	09	Gosford, West	03	Etchegoin
106	Canfield Ranch	09	Gosford, West	05	Stevens
106	Canfield Ranch	12	Old	00	No Pool Breakdown
106	Canfield Ranch	12	Old	03	Etchegoin
106	Canfield Ranch	12	Old	05	Stevens
106	Canfield Ranch	12	Old	2g	Upper Stevens
106	Canfield Ranch	12	Old	2h	Lower Stevens
106	Canfield Ranch	15	Old River	00	No Pool Breakdown
106	Canfield Ranch	15	Old River	05	Stevens
115	Capitola Park	00	Any	00	No Pool Breakdown
117	Carneros Creek	00	Any	03	Button Bed
117	Carneros Creek	00	Any	04	Carneros
117	Carneros Creek	00	Any	05	Phacoides
117	Carneros Creek	00	Any	10	Point of Rocks
140	Chico-Martinez	00	Any	00	No Pool Breakdown
140	Chico-Martinez	00	Any	1m	Etchegoin
146	Cienaga Canyon	00	Any	05	Temblor
156	Coles Levee, North	00	Any	00	No Pool Breakdown

156	Coles Levee, North	00	Any	05	Tulare
156	Coles Levee, North	00	Any	0g	Stevens
156	Coles Levee, North	00	Any	10	San Joaquin - Etchegoin
156	Coles Levee, North	00	Any	23	Gas Zone
156	Coles Levee, North	00	Any	25	Stevens (Undifferentiated)
156	Coles Levee, North	00	Any	30	Stevens (21-1 & Upper Western)
156	Coles Levee, North	00	Any	35	Stevens (Main Western)
156	Coles Levee, North	2n	Richfield Western	2o	21-1
158	Coles Levee, South	00	Any	00	No Pool Breakdown
158	Coles Levee, South	00	Any	05	Tulare
158	Coles Levee, South	00	Any	06	Tulare - San Joaquin
158	Coles Levee, South	00	Any	07	San Joaquin - Etchegoin
158	Coles Levee, South	00	Any	08	Gas Zone
158	Coles Levee, South	00	Any	10	Stevens
158	Coles Levee, South	00	Any	15	F1
158	Coles Levee, South	00	Any	20	F2
158	Coles Levee, South	00	Any	25	Nozu
160	Comanche Point	00	Any	00	No Pool Breakdown
160	Comanche Point	00	Any	05	Santa Margarita
190	Cymric	03	Cymric Flank	05	Carneros
190	Cymric	03	Cymric Flank	10	Phacoides
190	Cymric	0h	McKittrick Front	0i	Tulare
190	Cymric	0h	McKittrick Front	0j	Reef Ridge
190	Cymric	0h	McKittrick Front	0k	Carneros
190	Cymric	0h	McKittrick Front	0l	Phacoides
190	Cymric	0h	McKittrick Front	0m	Oceanic
190	Cymric	0h	McKittrick Front	1u	Amnicola
190	Cymric	0n	1-Y	1q	Tulare-Upper Miocene
190	Cymric	0n	1-Y	4a	Reef Ridge
190	Cymric	12	Salt Creek Main	05	Etchegoin
190	Cymric	12	Salt Creek Main	10	Carneros West
190	Cymric	12	Salt Creek Main	15	Carneros Unit
190	Cymric	12	Salt Creek Main	20	Phacoides

190	Cymric	15	Salt Creek West	05	Phacoides
190	Cymric	18	Sheep Springs	03	Tulare
190	Cymric	18	Sheep Springs	05	Etchegoin
190	Cymric	18	Sheep Springs	07	Monterey
190	Cymric	18	Sheep Springs	10	Carneros
190	Cymric	18	Sheep Springs	15	Phacoides
190	Cymric	18	Sheep Springs	20	Oceanic
190	Cymric	24	Welport	03	Tulare-Antelope
190	Cymric	24	Welport	05	Tulare
190	Cymric	24	Welport	10	Etchegoin
190	Cymric	24	Welport	15	San Joaquin
190	Cymric	24	Welport	17	Olig (Reef Ridge)
190	Cymric	24	Welport	20	Reef Ridge-Antelope
190	Cymric	24	Welport	25	McDonald-Devilwater
190	Cymric	24	Welport	30	Carneros
190	Cymric	24	Welport	35	Agua
190	Cymric	24	Welport	40	Phacoides
190	Cymric	24	Welport	43	Carneros-Phacoides-Oceanic
190	Cymric	24	Welport	45	Oceanic
190	Cymric	24	Welport	50	Point of Rocks
194	Deer Creek	00	Any	00	No Pool Breakdown
194	Deer Creek	00	Any	05	Santa Margarita
196	Deer Creek, North	00	Any	00	No Pool Breakdown
204	Devils Den	00	Any	00	No Pool Breakdown
204	Devils Den	03	Alferitz	00	No Pool Breakdown
204	Devils Den	03	Alferitz	10	Escudo-Carneros
204	Devils Den	03	Alferitz	15	Eocene Gas Zone
204	Devils Den	03	Alferitz	17	Point of Rocks
204	Devils Den	03	Alferitz	1k	Escudo
204	Devils Den	06	Bates	00	No Pool Breakdown
204	Devils Den	09	Old	00	No Pool Breakdown
204	Devils Den	09	Old	03	Alluvium-Temblor
204	Devils Den	09	Old	05	Point of Rocks

21k	Kern County	7t	Shafter	00	No Pool Breakdown
220	Dyer Creek	00	Any	00	No Pool Breakdown
221	Eagle Rest	00	Any	03	Pleito
221	Eagle Rest	00	Any	05	Eocene Sands
222	Edison	00	Any	00	No Pool Breakdown
222	Edison	03	Edison Groves	00	No Pools Breakdown
222	Edison	03	Edison Groves	03	Kern River
222	Edison	03	Edison Groves	05	Kern River-Chanac
222	Edison	03	Edison Groves	10	Olcese
222	Edison	03	Edison Groves	1e	Chanac
222	Edison	06	Jeppi	00	No Pool Breakdown
222	Edison	09	Main	00	No Pool Breakdown
222	Edison	09	Main	03	Chanac
222	Edison	09	Main	05	Santa Margarita
222	Edison	09	Main	10	Freeman-Jewett
222	Edison	09	Main	15	Kern River-Schist
222	Edison	09	Main	20	Schist
222	Edison	12	Portals-Fairfax	00	No Pool Breakdown
222	Edison	12	Portals-Fairfax	05	Santa Margarita
222	Edison	12	Portals-Fairfax	10	Main Wicker
222	Edison	15	Race Track Hill	00	No Pool Breakdown
222	Edison	15	Race Track Hill	05	Kern River-Transition
222	Edison	15	Race Track Hill	06	Chanac
222	Edison	15	Race Track Hill	07	Santa Margarita
222	Edison	15	Race Track Hill	10	Olcese
222	Edison	15	Race Track Hill	15	Pyramid Hill
222	Edison	18	West	00	No Pool Breakdown
222	Edison	18	West	05	Chanac
222	Edison	18	West	10	Chanac-Santa Margarita
222	Edison	18	West	13	Santa Margarita
222	Edison	18	West	15	Chanac-Jewett
222	Edison	18	West	25	Pyramid Hill-Vedder
224	Edison, Northeast	00	Any	00	No Pool Breakdown

224	Edison, Northeast	00	Any	05	Chanac
228	Elk Hills	00	Any	00	No Pool Breakdown
228	Elk Hills	00	Any	05	Tulare
228	Elk Hills	00	Any	0p	Upper
228	Elk Hills	00	Any	13	Gas Zone
228	Elk Hills	00	Any	14	4th Mya
228	Elk Hills	00	Any	15	Upper (Undifferentiated)
228	Elk Hills	00	Any	17	Upper (Sub-Scalez)
228	Elk Hills	00	Any	18	Reef Ridge
228	Elk Hills	00	Any	20	Stevens
228	Elk Hills	00	Any	21	Stevens (Main Body B Sand)
228	Elk Hills	00	Any	22	Stevens (29R)
228	Elk Hills	00	Any	23	Stevens (Northwest)
228	Elk Hills	00	Any	24	Stevens (31S)
228	Elk Hills	00	Any	25	Carneros
228	Elk Hills	00	Any	30	Agua
228	Elk Hills	2v	Main	2w	Upper (Sub-Scalez)
238	English Colony	00	Any	05	Stevens
256	Fruitvale	03	Calloway	00	No Pool Breakdown
256	Fruitvale	03	Calloway	05	Etchegoin
256	Fruitvale	03	Calloway	10	Etchegoin-Chanac
256	Fruitvale	06	Greenacres	05	Billington
256	Fruitvale	09	Main	00	No Pool Breakdown
256	Fruitvale	09	Main	05	Etchegoin
256	Fruitvale	09	Main	07	Etchegoin-Chanac
256	Fruitvale	09	Main	10	Chanac
256	Fruitvale	09	Main	15	Martin & Kernco
256	Fruitvale	09	Main	20	Kernco
256	Fruitvale	09	Main	22	Chanac-Santa Margarita
256	Fruitvale	09	Main	25	Santa Margarita
260	Garrison City Gas	00	Any	00	No Pool Breakdown
272	Gonyer Anticline	00	Any	00	No Pool Breakdown
274	Goosloo	00	Any	00	No Pool Breakdown

274	Goosloo	00	Any	05	Stevens
280	Greeley	00	Any	00	No Pool Breakdown
280	Greeley	00	Any	05	Etchegoin
280	Greeley	00	Any	0q	Stevens
280	Greeley	00	Any	10	Stevens (Undifferentiated)
280	Greeley	00	Any	15	Olcese 12-21
280	Greeley	00	Any	20	Rio Bravo-Vedder
280	Greeley	00	Any	2i	12-21 Jewett
280	Greeley	00	Any	2x	Vedder
328	Jasmin	00	Any	00	No Pool Breakdown
328	Jasmin	00	Any	05	Pyramid Hill
328	Jasmin	00	Any	07	Vedder
328	Jasmin	00	Any	10	Cantleberry
330	Jasmin, West	00	Any	00	No Pool Breakdown
330	Jasmin, West	00	Any	05	Famoso
332	Jerry Slough	00	Any	00	No Pool Breakdown
336	Kern Bluff	00	Any	00	No Pool Breakdown
336	Kern Bluff	00	Any	03	Kern River
336	Kern Bluff	00	Any	05	Miocene
336	Kern Bluff	00	Any	10	Transition-Santa Margarita
336	Kern Bluff	00	Any	15	Vedder
336	Kern Bluff	00	Any	1y	Santa Margarita
338	Kern Front	00	Any	00	No Pool Breakdown
338	Kern Front	00	Any	05	Etchegoin
338	Kern Front	00	Any	06	Etchegoin-Chanac
338	Kern Front	00	Any	07	Chanac
338	Kern Front	00	Any	10	Santa Margarita
338	Kern Front	00	Any	1f	Kern River-Chanac
340	Kern River	00	Any	00	No Pool Breakdown
340	Kern River	00	Any	05	Kern River
340	Kern River	00	Any	07	Chanac
340	Kern River	00	Any	08	Chanac-Santa Margarita
340	Kern River	00	Any	10	Santa Margarita

340	Kern River	00	Any	11	Olcese
340	Kern River	00	Any	12	Jewett
340	Kern River	00	Any	15	Vedder
340	Kern River	00	Any	1o	Pliocene
340	Kern River	00	Any	20	Vedder-Famosa
342	Kernsumner	00	Any	00	No Pool Breakdown
35k	Kern County	8i	Rosedale Ranch	00	No Pool Breakdown
372	Lakeside	00	Any	00	No Pool Breakdown
372	Lakeside	00	Any	05	San Joaquin
372	Lakeside	00	Any	10	Stevens
374	Lakeside, South	00	Any	00	No Pool Breakdown
375	Landslide	03	Boulder Creek	10	Stevens
375	Landslide	06	Main	10	Stevens
40k	Kern County	8n	Ant Hill, South	00	No Pool Breakdown
428	Los Lobos	00	Any	00	No Pool Breakdown
428	Los Lobos	00	Any	03	Tulare
428	Los Lobos	00	Any	05	Etchegoin
428	Los Lobos	00	Any	10	Reef Ridge
428	Los Lobos	00	Any	15	Monterey
432	Lost Hills	00	Any	00	No Pool Breakdown
432	Lost Hills	00	Any	05	Tulare
432	Lost Hills	00	Any	10	Tulare-Etchegoin
432	Lost Hills	00	Any	25	W-3
432	Lost Hills	00	Any	27	Etchegoin
432	Lost Hills	00	Any	29	Etchegoin-Cahn
432	Lost Hills	00	Any	30	Cahn
432	Lost Hills	00	Any	32	Devilwater
432	Lost Hills	00	Any	35	Carneros
432	Lost Hills	00	Any	50	Antelope/McDonald
434	Lost Hills, Northwest	00	Any	05	Etchegoin
434	Lost Hills, Northwest	00	Any	10	Antelope Shale
446	McClung	00	Any	00	No Pool Breakdown
446	McClung	00	Any	05	Etchegoin

446	McClung	00	Any	10	Stevens
44k	Kern County	8r	Grapevine (2)	00	No Pool Breakdown
450	McDonald Anticline	00	Any	00	No Pool Breakdown
450	McDonald Anticline	00	Any	1r	Tulare
450	McDonald Anticline	01	Bacon Hills	00	No Pool Breakdown
450	McDonald Anticline	01	Bacon Hills	05	Antelope
450	McDonald Anticline	01	Bacon Hills	10	Oceanic
450	McDonald Anticline	03	Layman	00	No Pool Breakdown
450	McDonald Anticline	03	Layman	1j	Point of Rocks
450	McDonald Anticline	03	Layman	25	Tolco
450	McDonald Anticline	03	Layman	45	2A
450	McDonald Anticline	03	Layman	50	Upper Agua
450	McDonald Anticline	03	Layman	55	Lower Agua
450	McDonald Anticline	03	Layman	60	Phaocoides
450	McDonald Anticline	03	Layman	65	First Point of Rocks
450	McDonald Anticline	03	Layman	70	Main Point of Rocks
450	McDonald Anticline	8h	McDonald Anticline	00	No Pool Breakdown
454	McKittrick	00	Any	00	No Pool Breakdown
454	McKittrick	00	Any	4q	Gas Zone
454	McKittrick	03	Main	00	No Pool Breakdown
454	McKittrick	03	Main	03	Tulare
454	McKittrick	03	Main	05	Upper
454	McKittrick	03	Main	10	Olig
454	McKittrick	03	Main	12	Antelope Shale
454	McKittrick	03	Main	15	Stevens
454	McKittrick	06	Northeast	00	No Pool Breakdown
454	McKittrick	06	Northeast	05	Upper
454	McKittrick	06	Northeast	07	Tulare
454	McKittrick	06	Northeast	0t	Gas Zone
454	McKittrick	06	Northeast	10	Antelope Shale
454	McKittrick	06	Northeast	15	Carneros
454	McKittrick	06	Northeast	20	Phacoides
454	McKittrick	06	Northeast	23	Phacoides/Oceanic

454	McKittrick	06	Northeast	25	Oceanic
454	McKittrick	06	Northeast	27	Point of Rocks
464	Midway-Sunset	00	Any	00	No Pool Breakdown
464	Midway-Sunset	00	Any	05	Alluvium
464	Midway-Sunset	00	Any	0z	Upper
464	Midway-Sunset	00	Any	12	Tulare
464	Midway-Sunset	00	Any	15	Tulare 13A
464	Midway-Sunset	00	Any	1a	Upper (Calitroleum 20D)
464	Midway-Sunset	00	Any	20	Tulare-PMO
464	Midway-Sunset	00	Any	22	Tulare/Monarch
464	Midway-Sunset	00	Any	23	Tulare-San Joaquin
464	Midway-Sunset	00	Any	25	Top Oil & Kinsey 5K
464	Midway-Sunset	00	Any	2b	Upper (Monarch 22C)
464	Midway-Sunset	00	Any	30	Top Oil-Calitroleum 20D
464	Midway-Sunset	00	Any	35	Etchegoin 9C
464	Midway-Sunset	00	Any	37	Etchegoin-Antelope Sands
464	Midway-Sunset	00	Any	40	Wilhelm
464	Midway-Sunset	00	Any	49	Sub-Lakeview
464	Midway-Sunset	00	Any	50	Potter
464	Midway-Sunset	00	Any	55	Monarch
464	Midway-Sunset	00	Any	56	Antelope Sands
464	Midway-Sunset	00	Any	60	Metson
464	Midway-Sunset	00	Any	65	Leutholtz
464	Midway-Sunset	2y	Midway East	3r	Shallow (Calitroleum)
464	Midway-Sunset	3s	Midway West	3t	Upper (Monarch)
464	Midway-Sunset	3v	East	00	No Pool Breakdown
479	Monument Junction	03	Main	05	San Joaquin
479	Monument Junction	03	Main	10	Reef Ridge
479	Monument Junction	03	Main	15	Antelope
479	Monument Junction	06	Mongoose	15	Antelope
488	Mount Poso	00	Any	00	No Pool Breakdown
488	Mount Poso	03	Baker-Grover	00	No Pool Breakdown
488	Mount Poso	03	Baker-Grover	03	Olcese

488	Mount Poso	03	Baker-Grover	05	Vedder
488	Mount Poso	06	Dominion	00	No Pool Breakdown
488	Mount Poso	06	Dominion	04	Pyramid Hill
488	Mount Poso	06	Dominion	05	Vedder
488	Mount Poso	09	Dorsey	00	No Pool Breakdown
488	Mount Poso	09	Dorsey	03	Pyramid Hill
488	Mount Poso	09	Dorsey	05	Vedder
488	Mount Poso	12	Granite Canyon	00	No Pool Breakdown
488	Mount Poso	12	Granite Canyon	05	Vedder
488	Mount Poso	15	Main	00	No Pool Breakdown
488	Mount Poso	15	Main	05	Olcese
488	Mount Poso	15	Main	10	Pyramid Hill
488	Mount Poso	15	Main	15	Pyramid Hill-Vedder
488	Mount Poso	15	Main	20	Vedder
488	Mount Poso	15	Main	30	Vedder-Walker
488	Mount Poso	18	West	00	No Pool Breakdown
488	Mount Poso	18	West	05	Olcese
488	Mount Poso	18	West	10	Vedder
490	Mountain View	03	Arvin	00	No Pool Breakdown
490	Mountain View	03	Arvin	01	Santa Margarita-Stenderup
490	Mountain View	03	Arvin	05	Kern River
490	Mountain View	03	Arvin	10	Chanac-George
490	Mountain View	03	Arvin	15	Santa Margarita
490	Mountain View	03	Arvin	3p	Cattani
490	Mountain View	06	Arvin, West	00	No Pool Breakdown
490	Mountain View	06	Arvin, West	10	Richards
490	Mountain View	06	Arvin, West	15	Chanac-Cattani
490	Mountain View	06	Arvin, West	20	Cattani
490	Mountain View	06	Arvin, West	25	Houchin, Main
490	Mountain View	06	Arvin, West	30	Houchin, Northwest & Brite
490	Mountain View	06	Arvin, West	33	Chanac-Santa Marg.-Stender
490	Mountain View	06	Arvin, West	35	Stenderup
490	Mountain View	06	Arvin, West	40	Frick

490	Mountain View	06	Arvin, West	4c	Brite
490	Mountain View	06	Arvin, West	4d	Houchin Northwest
490	Mountain View	09	Digiorgio	10	Schist
490	Mountain View	12	Main	00	No Pool Breakdown
490	Mountain View	12	Main	05	Kern River-Chanac
490	Mountain View	12	Main	07	Chanac
490	Mountain View	12	Main	10	Nichols
490	Mountain View	12	Main	15	Transition-Santa Margarita
490	Mountain View	15	Vaccaro	05	Chanac
490	Mountain View	15	Vaccaro	10	Upper Miocene
490	Mountain View	15	Vaccaro	4e	Cattani
490	Mountain View	15	Vaccaro	4f	Derby
490	Mountain View	15	Vaccaro	4g	Stockton
490	Mountain View	15	Vaccaro	4h	Tipton
532	Paloma	00	Any	00	No Pool Breakdown
532	Paloma	00	Any	3x	Gas Zone
532	Paloma	03	Main	00	No Pool Breakdown
532	Paloma	03	Main	05	Tulare
532	Paloma	03	Main	07	Tulare-San Joaquin
532	Paloma	03	Main	08	Gas Zone
532	Paloma	03	Main	09	Etchegoin
532	Paloma	03	Main	10	Paloma
532	Paloma	03	Main	13	Antelope
532	Paloma	03	Main	15	Lower Stevens
532	Paloma	06	Symons	00	No Pool Breakdown
532	Paloma	06	Symons	05	Symons
532	Paloma	06	Symons	10	Paloma
532	Paloma	2t	South	00	No Pool Breakdown
544	Pioneer	00	Any	00	No Pool Breakdown
544	Pioneer	00	Any	05	Miocene
560	Pleito	00	Any	00	No Pool Breakdown
560	Pleito	03	Creek	00	No Pool Breakdown
560	Pleito	03	Creek	03	Kern River-Chanac

560	Pleito	03	Creek	05	Santa Margarita
560	Pleito	06	Ranch	00	No Pool Breakdown
560	Pleito	06	Ranch	05	Kern River-Chanac
566	Poso Creek	03	Enas	00	No Pool Breakdown
566	Poso Creek	03	Enas	03	Etchegoin & Chanac
566	Poso Creek	03	Enas	05	Chanac
566	Poso Creek	06	McVan	00	No Pool Breakdown
566	Poso Creek	06	McVan	03	Etchegoin-Chanac
566	Poso Creek	06	McVan	05	Etchegoin
566	Poso Creek	06	McVan	10	Vedder-Walker
566	Poso Creek	09	Premier	00	No Pool Breakdown
566	Poso Creek	09	Premier	05	Etchegoin
566	Poso Creek	09	Premier	10	Basal Etchegoin
566	Poso Creek	09	Premier	15	Etchegoin-Chanac
566	Poso Creek	09	Premier	20	Chanac
566	Poso Creek	09	Premier	25	Chanac R
566	Poso Creek	09	Premier	30	Chanac-Santa Margarita
566	Poso Creek	09	Premier	31	Santa Margarita
566	Poso Creek	09	Premier	35	Vedder
582	Railroad Gap	00	Any	00	No Pool Breakdown
582	Railroad Gap	00	Any	03	Gas Zone
582	Railroad Gap	00	Any	05	Amnicola
582	Railroad Gap	00	Any	10	Olig
582	Railroad Gap	00	Any	15	Antelope Shale
582	Railroad Gap	00	Any	17	Antelope Shale/Carneros
582	Railroad Gap	00	Any	20	Valv
582	Railroad Gap	00	Any	25	Carneros
582	Railroad Gap	00	Any	30	Phacoides
582	Railroad Gap	00	Any	4k	Upper Santos
58k	Kern County	9c	Quinn Ranch	00	No Pool Breakdown
602	Rio Bravo	00	Any	00	No Pool Breakdown
602	Rio Bravo	00	Any	03	Gas Zone
602	Rio Bravo	00	Any	04	Round Mountain

602	Rio Bravo	00	Any	05	Olcese
602	Rio Bravo	00	Any	08	Rio Bravo
602	Rio Bravo	00	Any	10	Rio Bravo-Main Vedder-Osborn
602	Rio Bravo	00	Any	15	Main Vedder
602	Rio Bravo	00	Any	20	Osborn
602	Rio Bravo	00	Any	22	Osborn-Helbling
602	Rio Bravo	00	Any	25	Helbling
608	Rio Viejo	00	Any	03	San Joaquin
608	Rio Viejo	00	Any	05	Stevens
60k	Tulare County	00	Any	00	No Pool Breakdown
617	Rose	00	Any	02	San Joaquin/Etchegoin
617	Rose	00	Any	05	McClure
624	Rosedale	00	Any	00	No Pool Breakdown
624	Rosedale	03	East	00	No Pool Breakdown
624	Rosedale	03	East	05	Stevens
624	Rosedale	06	Main	00	No Pool Breakdown
624	Rosedale	06	Main	05	Etchegoin
624	Rosedale	06	Main	10	Stevens
624	Rosedale	09	North	00	No Pool Breakdown
624	Rosedale	09	North	05	Stevens
624	Rosedale	12	South	00	No Pool Breakdown
624	Rosedale	12	South	05	Stevens
624	Rosedale	7r	Rosedale, East	00	No Pool Breakdown
624	Rosedale	8u	Rosedale	00	No Pool Breakdown
626	Rosedale Ranch	00	Any	00	No Pool Breakdown
626	Rosedale Ranch	00	Any	10	Lerdo
626	Rosedale Ranch	00	Any	1b	Etchegoin
626	Rosedale Ranch	00	Any	1c	Lerdo-Chanac
626	Rosedale Ranch	00	Any	1d	Chanac
626	Rosedale Ranch	03	Main	00	No Pool Breakdown
626	Rosedale Ranch	03	Main	05	Etchegoin
626	Rosedale Ranch	03	Main	08	Lerdo-Chanac
626	Rosedale Ranch	03	Main	20	Chanac

626	Rosedale Ranch	06	Northeast	08	Lerdo-Chanac
626	Rosedale Ranch	06	Northeast	20	Chanac
628	Round Mountain	00	Any	00	No Pool Breakdown
628	Round Mountain	03	Alma	00	No Pool Breakdown
628	Round Mountain	03	Alma	05	Vedder
628	Round Mountain	06	Coffee Canyon	00	No Pool Breakdown
628	Round Mountain	06	Coffee Canyon	03	Freeman-Jewett-Ph
628	Round Mountain	06	Coffee Canyon	05	Pyramid Hill
628	Round Mountain	06	Coffee Canyon	10	Pyramid Hill-Vedder
628	Round Mountain	06	Coffee Canyon	15	Vedder
628	Round Mountain	06	Coffee Canyon	20	Walker
628	Round Mountain	09	Main	00	No Pool Breakdown
628	Round Mountain	09	Main	01	Olcese-Walker
628	Round Mountain	09	Main	02	Freeman-Jewett-Pyramid Hill
628	Round Mountain	09	Main	03	Jewett
628	Round Mountain	09	Main	05	Jewett-Vedder
628	Round Mountain	09	Main	07	Vedder
628	Round Mountain	09	Main	10	Pyramid Hill
628	Round Mountain	09	Main	12	Pyramid Hill-Vedder
628	Round Mountain	09	Main	15	Vedder-Walker
628	Round Mountain	09	Main	20	Walker
628	Round Mountain	12	Pyramid	00	No Pool Breakdown
628	Round Mountain	12	Pyramid	05	Jewett and Pyramid Hill
628	Round Mountain	12	Pyramid	10	Vedder
628	Round Mountain	12	Pyramid	13	Olcese
628	Round Mountain	15	Sharktooth	00	No Pool Breakdown
628	Round Mountain	15	Sharktooth	05	Olcese
628	Round Mountain	15	Sharktooth	10	Vedder
62k	Kern County	9e	East Side	00	No Pool Breakdown
63k	Kern County	9f	West Side	00	No Pool Breakdown
648	San Emidio Nose	00	Any	00	No Pool Breakdown
648	San Emidio Nose	00	Any	05	Tulare-San Joaquin
648	San Emidio Nose	00	Any	10	Reef Ridge

648	San Emidio Nose	00	Any	15	Stevens
648	San Emidio Nose	03	Main	05	Tulare-San Joaquin
648	San Emidio Nose	03	Main	08	Etchegoin-Reef Ridge
648	San Emidio Nose	03	Main	10	Reef Ridge
648	San Emidio Nose	03	Main	15	Stevens
648	San Emidio Nose	06	Northwest	15	Stevens
650	San Emigdio	00	Any	00	No Pool Breakdown
652	San Emigdio Creek	00	Any	05	Eocene
690	Semitropic	00	Any	00	No Pool Breakdown
690	Semitropic	00	Any	03	Gas Zone
690	Semitropic	00	Any	05	Randolph
690	Semitropic	00	Any	10	Vedder
692	Semitropic, NW Gas	00	Any	00	No Pool Breakdown
696	Seventh Standard	00	Any	05	Etchegoin
696	Seventh Standard	00	Any	10	Lower Stevens
698	Shafter, SE Gas	00	Any	00	No Pool Breakdown
699	Shafter, North	00	Any	02	San Joaquin/Etchegoin
699	Shafter, North	00	Any	03	Etchegoin
699	Shafter, North	00	Any	05	McClure
700	Shale Flats Gas	00	Any	00	No Pool Breakdown
702	Shale Point Gas	00	Any	00	No Pool Breakdown
70k	Kern County	00	Strand East	00	No Pool Breakdown
716	Stockdale	06	Panama Lane	05	Nozu
720	Strand	00	Any	00	No Pool Breakdown
720	Strand	03	East	00	No Pool Breakdown
720	Strand	03	East	05	Etchegoin
720	Strand	03	East	10	Upper Stevens
720	Strand	03	East	15	Stevens
720	Strand	06	Main	00	No Pool Breakdown
720	Strand	06	Main	05	San Joaquin
720	Strand	06	Main	10	Etchegoin
720	Strand	06	Main	13	Gas Zone
720	Strand	06	Main	15	Upper Stevens

720	Strand	06	Main	20	Lower Stevens
720	Strand	06	Main	23	4th Stevens Sand
720	Strand	06	Main	25	Vedder
720	Strand	09	Northwest	00	No Pool Breakdown
720	Strand	09	Northwest	02	San Joaquin
720	Strand	09	Northwest	03	Gas Zone
720	Strand	09	Northwest	05	Stevens
720	Strand	12	South	00	No Pool Breakdown
720	Strand	12	South	05	Stevens
752	Tejon	00	Any	00	No Pool Breakdown
752	Tejon	03	Central	00	No Pool Breakdown
752	Tejon	03	Central	03	Chanac-Santa Margarita
752	Tejon	03	Central	05	Olcese
752	Tejon	06	Eastern	00	No Pool Breakdown
752	Tejon	06	Eastern	05	Transition-Santa Margarita
752	Tejon	09	Southeast	00	No Pool Breakdown
752	Tejon	09	Southeast	05	Reserve Sand
752	Tejon	12	Western	00	No Pool Breakdown
752	Tejon	12	Western	02	Chanac
752	Tejon	12	Western	03	Transition
752	Tejon	12	Western	05	Transition-Santa Margarita
752	Tejon	12	Western	10	Upper Fruitvale Sand
752	Tejon	12	Western	12	S Margarita-Fruitvale-Rd Mtn
752	Tejon	12	Western	15	Fruitvale-Round Mountain
752	Tejon	8r	Grapevine (1)	00	No Pool Breakdown
752	Tejon	9b	Tejon	00	No Pool Breakdown
754	Tejon Flats	00	Any	00	No Pool Breakdown
756	Tejon Hills	00	Any	00	No Pool Breakdown
756	Tejon Hills	00	Any	05	Santa Margarita
756	Tejon Hills	00	Any	10	S
756	Tejon Hills	00	Any	2d	S & Valv
756	Tejon Hills	00	Any	4s	Gas Zone
758	Tejon, North	00	Any	00	No Pool Breakdown

758	Tejon, North	00	Any	03	Fruitvale
758	Tejon, North	00	Any	05	Santa Margarita
758	Tejon, North	00	Any	10	Olcese
758	Tejon, North	00	Any	12	Olcese-Eocene
758	Tejon, North	00	Any	15	JV-Basalt
758	Tejon, North	00	Any	20	Vedder-Eocene
758	Tejon, North	2j	Highway	00	No Pool Breakdown
758	Tejon, North	2k	Main	00	No Pool Breakdown
758	Tejon, North	2l	South	00	No Pool Breakdown
759	Temblor East	00	Any	00	No Pool Breakdown
760	Temblor Hills	00	Any	05	Agua & Point of Rocks
762	Temblor Ranch	00	Any	00	No Pool Breakdown
762	Temblor Ranch	00	Any	05	Miocene
766	Ten Section	00	Any	00	No Pool Breakdown
766	Ten Section	03	Main	00	No Pool Breakdown
766	Ten Section	03	Main	05	San Joaquin-Etchegoin
766	Ten Section	03	Main	08	Gas Zone
766	Ten Section	03	Main	10	Upper Stevens
766	Ten Section	03	Main	15	Lower Stevens
766	Ten Section	06	Northwest	00	No Pool Breakdown
766	Ten Section	06	Northwest	03	San Joaquin
766	Ten Section	06	Northwest	05	Stevens
768	Terra Bella	00	Any	00	No Pool Breakdown
790	Trico Gas	00	Any	00	No Pool Breakdown
798	Union Avenue	00	Any	00	No Pool Breakdown
798	Union Avenue	00	Any	05	Chanac
798	Union Avenue	00	Any	07	Chanac-Santa Margarita
798	Union Avenue	00	Any	10	Santa Margarita
79a	Trico Gas, Northwest	00		00	No Pool Breakdown
808	Valpredo	00	Any	00	No Pool Breakdown
808	Valpredo	00	Any	05	Miocene
822	Wasco	00	Any	00	No Pool Breakdown
826	Welcome Valley	00	Any	00	No Pool Breakdown

832	Wheeler Ridge	00	Any	00	No Pool Breakdown
832	Wheeler Ridge	03	Central	00	No Pool Breakdown
832	Wheeler Ridge	03	Central	05	Coal Oil Canyon
832	Wheeler Ridge	03	Central	07	Coal Oil Canyon-Main
832	Wheeler Ridge	03	Central	08	Miocene-Oligocene
832	Wheeler Ridge	03	Central	10	Main
832	Wheeler Ridge	03	Central	15	Valv
832	Wheeler Ridge	03	Central	20	2-38
832	Wheeler Ridge	03	Central	25	Olcese
832	Wheeler Ridge	03	Central	27	Oligocene-Eocene
832	Wheeler Ridge	03	Central	30	ZA-5
832	Wheeler Ridge	03	Central	33	ZB-3
832	Wheeler Ridge	03	Central	35	ZB-5
832	Wheeler Ridge	03	Central	45	Massive Eocene
832	Wheeler Ridge	03	Central	50	Refugian Eocene
832	Wheeler Ridge	06	Northeast	10	FA-2
832	Wheeler Ridge	06	Northeast	15	Hagood
832	Wheeler Ridge	06	Northeast	1x	Santa Margarita
832	Wheeler Ridge	06	Northeast	20	ZB-1
832	Wheeler Ridge	06	Northeast	22	Vedder
832	Wheeler Ridge	09	Southeast	05	Olcese
832	Wheeler Ridge	12	Telegraph Canyon	00	No Pool Breakdown
832	Wheeler Ridge	12	Telegraph Canyon	05	Eocene
832	Wheeler Ridge	15	Windgap	00	No Pool Breakdown
832	Wheeler Ridge	15	Windgap	05	Reserve
832	Wheeler Ridge	15	Windgap	10	Olcese
834	White Wolf	00	Any	00	No Pool Breakdown
858	Yowlumne	00	Any	03	San Joaquin
858	Yowlumne	00	Any	05	Etchegoin
858	Yowlumne	00	Any	10	Stevens
858	Yowlumne	00	Any	12	South Yowlumne