Final Report

Texas Geothermal Assessment for the I35 Corridor East

FOR

Texas State Energy Conservation Office Contract CM709

Dr. David Blackwell, Maria Richards, and Patrick Stepp

Southern Methodist University
Roy M. Huffington Department of Earth Sciences
SMU Geothermal Laboratory
PO Box 750395
Dallas, Texas 75275-0395

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LIST OF ABBREVIATIONS

API - American Petroleum Institute

bbl - barrel

bbls - barrels

bbls/day - barrels per day

BCF - billion cubic feet

BHT - bottom-hole temperature

cm^3/sec - cubic centimeters per second

DOE - Department of Energy

EGS - enhanced geothermal system

EJ - exajoule (10^{18} joules)

FT - Feet (3.28 ft = 1 m)

gal/sec - gallons per second

GPM - gallon per minute

kg/s - kilogram per second

kW - kilowatt

m - meters

MA - million years ago

MMBBL/Day - million barrels per day

MW - megawatt (1000 kW)

PSI - pounds per square inch

RRC - Railroad Commission

TSC - time since circulation

EXECUTIVE SUMMARY

The impressive extent of the thermal energy available to Texans lying beneath the ground became evident through the 2004 publication of the Geothermal Map of North America. The high volumes of saltwater produced during hydrocarbon production, combined with the high temperatures found in Texas at depth, provide an ideal mix of resources from which to produce electricity from geothermal energy. Although previous investigations into the geothermal resource potential along the Gulf Coast led to a successful demonstration project in 1989-90, the business environment was not yet supportive of renewable energy (John et al. 1998) and the geothermal energy potential remained untapped. In 2010, we have a convergence of ideal economic forces, political climate, and technological advancements for using existing hydrocarbon production infrastructure as a means of generating baseload, renewable electricity for Texans.

Geothermal energy is a baseload renewable resource located in close proximity to where the majority of Texas citizens live. The development of this resource requires an understanding of both the business model and geologic structures involved. The existing infrastructure and expertise of the oil and gas industry in this area affords us the opportunity to leverage that investment and combine geothermal energy production with hydrocarbon and waste heat production. The interest from the business community is evidenced by the successful SMU Geothermal Conferences, which drew hundreds of participants, as well as by the number of companies installing systems throughout the Gulf Coast.

We achieved our stated project goal of defining geothermal resources through improved understanding of subsurface temperatures. The focus of study was the area of Texas generally east of Interstate 35 because of the overlap between high heat flow levels, the location of major Texas population centers, and the availability of numerous oil and gas field data. Both new and existing temperature data from oil and gas wells were collected, collated, and analyzed. Corrections to non-equilibrium BHT temperatures were compared with in situ well measurements to improve the accuracy of temperature readings.

Within the area of study, different temperature characteristics were observed by region. South Texas has the highest measured temperatures (in excess of 300˚F) at depths of 10,000 to 12,000 feet. The Gulf Coast geopressured areas have the most accessible energy potential, because of the large fluid volumes, entrained gas, and artesian flow. East Texas, while dominated by shallower drilling (typically less than 10,000 feet) and waterflood fields, possesses a crust with high natural radioactivity in the granites (such as is associated with the Sabine Uplift). This is indicates the elevated temperatures needed for geothermal energy can be expected at depth. The drilling in North Central Texas is currently predominantly in the Barnett shale formation, averaging 7,000 to 8,000 feet. Beneath the Barnett shale formation, lays the Ellenberger limestone, which has temperatures in the 200 to 250˚F range and can produce water volumes in the 20,000 to 50,000 barrels per day range, based on injection well capacity. In short, all of the areas studied, while yielding different results, showed remarkable promise for geothermal energy potential.

In addition to the report detailing the extensive work done collecting, collating, and analyzing temperature data from oil and gas wells, we have included information from four conferences hosted by SMU on 'Geothermal Energy Utilization Associated with Oil and Gas Development'. As mentioned, a successful development of this resource requires an appreciation for the business potential as well as the geologic potential, which these conferences sought to combine. The full archive of the conference presentations and related papers are posted on the SMU Geothermal Laboratory website. Additionally, the website contains information developed to assist companies starting a geothermal project and a list of resources to contact for assistance.

The outcome of the temperature assessment work and the outreach projects, such as the conferences and web resources, has led to several projects in our general area reaching development stage. Among them:

- ♦ Universal GeoPower LLC and the U.S. Department of Energy (DOE) have a geothermal demonstration project in Liberty county, near Houston, designed to generate 250 KW of power using a watered-out and abandoned oil well from a Pratt & Whitney binary generation system.
- ♦ Louisiana Geothermal LLC and the DOE have a second demonstration project in Cameron Parish.
- ♦ Gulf Coast Green Energy, with a grant from the Renewable Partnership to Secure Energy for America (RPSEA), is deploying an ElectraTherm Green Machine in Jones County, MS on a Denbury Resources Inc. owned well that is expected to generate 30-50 KW.
- ♦ Hilcorp Energy Company and Cleco Power LLC are in development on a project in western Louisiana, also using the ElectraTherm Green Machine.
- ♦ The GeoPower Texas Company has acquired Texas General Land Office geothermal leases for development of off-shore wells near Galveston, Brazoria, and Matagorda Counties.

Conclusion: The next five years will be crucial to gain enough momentum to establish a geothermal industry in Texas. There are currently over 200,000 active wells in Texas. That is 200,000 potential sources of cost-competitive, renewable, baseload, clean energy to Texans. We have a window of opportunity to leverage our state's investment in the oil and gas industry while the economic forces, political pressures, and available technology are aligned towards a common goal of renewable energy. Additional resources of time and dollars would be well spent on exploiting the geothermal energy potential of Texas.

INTRODUCTION

For a century, Texas has been a leading energy producing state. Its abundance of oil and gas has sparked an energy industry unlike that of any other state. Sherk (1982) stated "To say that the State of Texas is rich in energy resources is roughly akin to saying that the sky is blue or the ocean is wet." Time has indeed demonstrated Texas is incredibly rich in both conventional and alternative energy resources. Geothermal resources in Texas are becoming increasingly viable. Since 1982 when Sherk made this statement, there have been advances in the geothermal and oil and gas industries which increase the compatibility of these industries. In fact, from the number of wells drilled since 1980, Texas now has 200,000 more reasons to develop geothermal energy[1].

Today the population of Texas is growing at a rate of 16%, creating a need for new sources of power[2]. This need has been reinforced by the rolling blackouts of 2007 and the request by TXU to build 13 new coal power plants in 2006[3]. With the development of geothermal energy power plants, the additional baseload renewable energy can help meet these ever increasing energy demands. In addition, increasing concern over air quality in Texas cities has resulted in a greater focus on alternative energy resources. Texas has shown leadership in renewable energy with its Renewable Portfolio Standard (RPS). The 2005 RPS increase from 2,000 MW to 5,880 MW stimulated a historic explosion of wind energy development, and Texas is now the largest developer of wind energy in the United States[4]. The goal for more renewable energy motivated this resource evaluation of geothermal energy as a source of electrical production.

Geothermal energy is a baseload renewable resource with a consistent capacity to compete with nuclear, natural gas, and coal power plants. Existing technology allows it to be scalable and configured either as distributed or centralized energy sources, making it local and capable of being installed inside or close to population centers. It utilizes the current knowledge base of the oil and gas industry, creating a new green industry for Texas while simultaneously keeping the

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[1] http://www.rrc.state.tx.us/

[2] http://quickfacts.census.gov

[3] Dallas Morning News, September 01, 2006

[4] http://www.seco.cpa.state.tx.us/re_wind.htm

existing hydrocarbon service industry productive long after the wells cease to produce hydrocarbons. Geothermal development can also enhance Texas' ability to produce hydrocarbons at lower costs, for longer periods of time, and to extract gas in locations where it is presently uneconomic. Areas in Texas with the greatest geothermal potential directly correlate with the active hydrocarbon production areas of the eastern and southern portions of the state. They are located near the large urban areas of Dallas-Fort Worth, Houston, San Antonio, and Corpus Christi. The majority of oil and gas fields in these regions are connected to the power grid, with existing major transmission lines often directly overhead allowing for convenient grid connections for the geothermal power development to use the existing power line system.

This geothermal assessment focuses on temperature mapping of wells with depths of over 7000 feet, capable of electrical generation in the eastern half of Texas (located between interstate I-35 and the eastern border of Texas). This area covers North, East, and South Texas, as well as the Texas Gulf Coast. This regional focus was chosen because of the collocation of existing oil and gas fields with higher heat flow areas (Figure 1) as shown on the Geothermal Map of North America, (Blackwell and Richards, 2004a) and described in general resource analyses by Blackwell et al. (2006) and Negraru et al. (2008). The assessment of existing and new temperature data, along with the changes in geothermal technology, illuminates the compelling reasons Texas has for developing its geothermal potential.

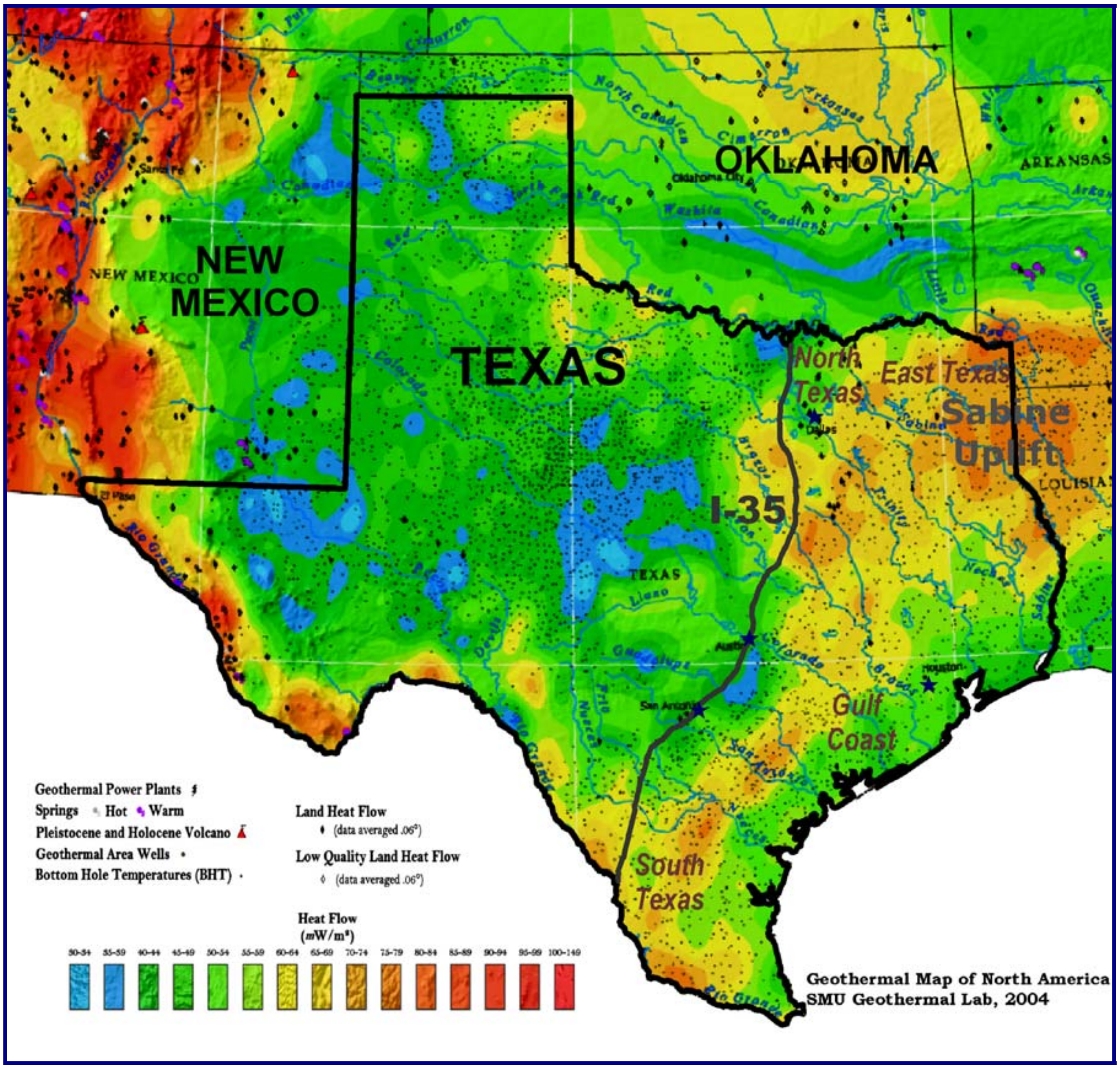

Figure 1. South-central portion of the Geothermal Map of North America (Blackwell and Richards, 2004a) with the Texas State boundary highlighted and the areas discussed in report.

OVERVIEW OF PREVIOUS REPORTS

Geothermal power production could be at the leading edge of Texas energy development for this century. Texas has been building its geothermal resource knowledge base since the early 1900s, as shown by temperature data collected by Plummer and Sargent (1931) and Spicer (1964) from early oil wells typically between 2500 and 5000 feet deep.

Starting in the mid 1970s, the oil embargo resulted in concentrated studies of geopressured - geothermal resources in Texas. Grants of approximately $200 million were awarded by the U.S. Department of Energy (DOE). The primary goals of these studies were to: define the extent of the geopressured reservoirs; determine the technical feasibility of reservoir development, including downhole, surface and disposal technologies; establish the economics of production; identify and mitigate adverse environmental impacts; identify and resolve legal and institutional barriers, and determine the viability of commercial exploitation of this resource (John et al., 1998). This previous research revealed massive geothermal and geopressured resources in Texas. It concluded with the successful demonstration of geopressure electrical generation conducted by the DOE at Pleasant Bayou, Brazoria County in 1989-90 (Shook, 1992; John et al., 1998). Technical feasibility was demonstrated, but momentum was lost during the period of low energy prices between 1985 and 2003.

As part of the geothermal studies C.M. Woodruff investigated geothermal energy in central Texas throughout the 1970s to the early 1990s. His research focused primarily on the mid-depth ranges of geothermal resources (5000 feet to the surface), and aquifers associated with low to moderate temperatures (70 to 150°F), useful for direct use applications and not electrical power generation. Woodruff wrote the first Geothermal Resource Assessment for the State of Texas in 1980 and produced the Geothermal Map of Texas in 1982. Much of his research focused on to the Balcones, Luling, Mexia, and Talco fault zones with an evaluation of hydrologic properties of Cretaceous aquifers located in North and Central Texas and low-temperature development for direct use applications (Woodruff and McBride, 1979), such as heating hot water in the community hospital in Marlin, Texas (Woodruff et al., 1982).

More recent studies/research focus on regional heat flow off-shore in the Gulf of Mexico (Nagihara and Jones, 2005; Nagihara and Smith, 2008) and as part of the Geothermal Map of

North America (Blackwell and Richards, 2004a); a review of the geothermal resources in the South Central portion of the United States (Negraru et al., 2008); and the use of Enhanced Geothermal Systems (EGS) in the United States with each individual state's resources categorized (Tester et al., 2006; Blackwell et al., 2006). Additionally, a resource study of oil and gas well data examines the geothermal resource potential in West Texas (Erdlac, 2006).

These studies prove conclusively that geothermal resources exist. Geopressure continues to be viewed as an integral part of the Texas geothermal resource. A search for "geopressure and Texas" on the Office of Science and Technology Information website, results in over 300 publications[5]. As a single option, the geopressured resource holds the largest potential for electrical development in Texas. Geothermal understanding of this geopressured resource has changed little since the completion of studies in the 1990s, but technology and energy economics have continued to evolve. Therefore, past geologic research is of the utmost importance as a knowledge base for this and any future geothermal assessment or development project. A review of the multiple geopressure related publications and references is provided in Appendix A.

GENERALIZED REGIONAL GEOLOGY

Throughout geologic time Texas has experienced multiple periods of uplift and regional seas covering the surface creating the numerous layers of sediments. The depth to basement determines the maximum thickness of sedimentary layers, and therefore the maximum depth of drilling for oil and gas wells. The eastern half of the state was part of the collision between the North American tectonic plate and the Europe-African-South American plate that formed the supercontinent Pangaea. This event folded and faulted the sediments now exposed in the Appalachian Mountains, the Ouachita Mountains in southwestern Arkansas and southeastern Oklahoma, and the Marathon region near Big Bend National Park in West Texas. Originally a mountain chain extended through the zone of deformation between the Ouachitas and Big Bend around the Llano uplift, the region is now covered by younger sediments and the exact nature of these rocks is not known. Today these buried "mountains" form the basement rocks under much of Central Texas as part of the Ouachita Overthrust Belt (Figure 4).

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[5] http://www.osti.gov

As North America rifted away from Europe/South America during the break up of Pangaea, fault zones formed which still impact Texas. The Balcones fault zone was created along the Texas Craton and slightly further south-east the Luling - Mexia fault zones were created. Today these are zones of weakness that allow warm fluids to rise quickly along them and create elevated temperatures in the deeper fresh water aquifers, such as the Trinity, Hosston, and Edwards (Woodruff et al., 1982). The newly formed East Texas and Gulf Coast basins were buried by thick deposits of Middle Jurassic marine salt and sediments. Igneous oceanic crust formed in the Gulf Coast Basin during the Late Jurassic. The boundary between oceanic and continental crust lies beneath the present-day Texas continental margin, but its exact location is unknown. Jurassic and Cretaceous deposits formed broad carbonate shelves that were periodically buried in places by deltaic sandstones and shales at the edge of the widening Gulf of Mexico. Mobilization of the salt from evaporates formed salt domes in East Texas and the Gulf Coast. The deposition along the Texas Gulf Coast continental shelf continued to build new land mass towards the Gulf of Mexico, as it continues to do today. Area of deposition shifted over time across the Gulf Coast. The sediment flow was dominated from the western side of the Gulf Coast (now South Texas and Central Gulf Coast) during the Eocene and Oligocene (~55 - 23 MA). It gradually shifted eastward, where it is today with sediment primarily from the North and East (Mississippi Delta) (Salvador, 1991, Figure 2).

Sea level has fluctuated continuously throughout the geologic past. During the most recent glacial advances, the sea levels were 300 to 450 feet lower than today (an interglacial period), because so much sea water was contained in the ice sheets. The climate was both more humid and cooler than that of today, and the largest Texas rivers carried more water and sediment to the Gulf of Mexico. These deposits underlie the initial fifty miles or more of the Gulf Coastal plain inland from the current shoreline. Approximately 3,000 years ago sea level reached its modern position, and the coastal features that are present today, such as the deltas, lagoons, beaches, and barrier islands, have formed since that time (Sellards, et al., 1933).

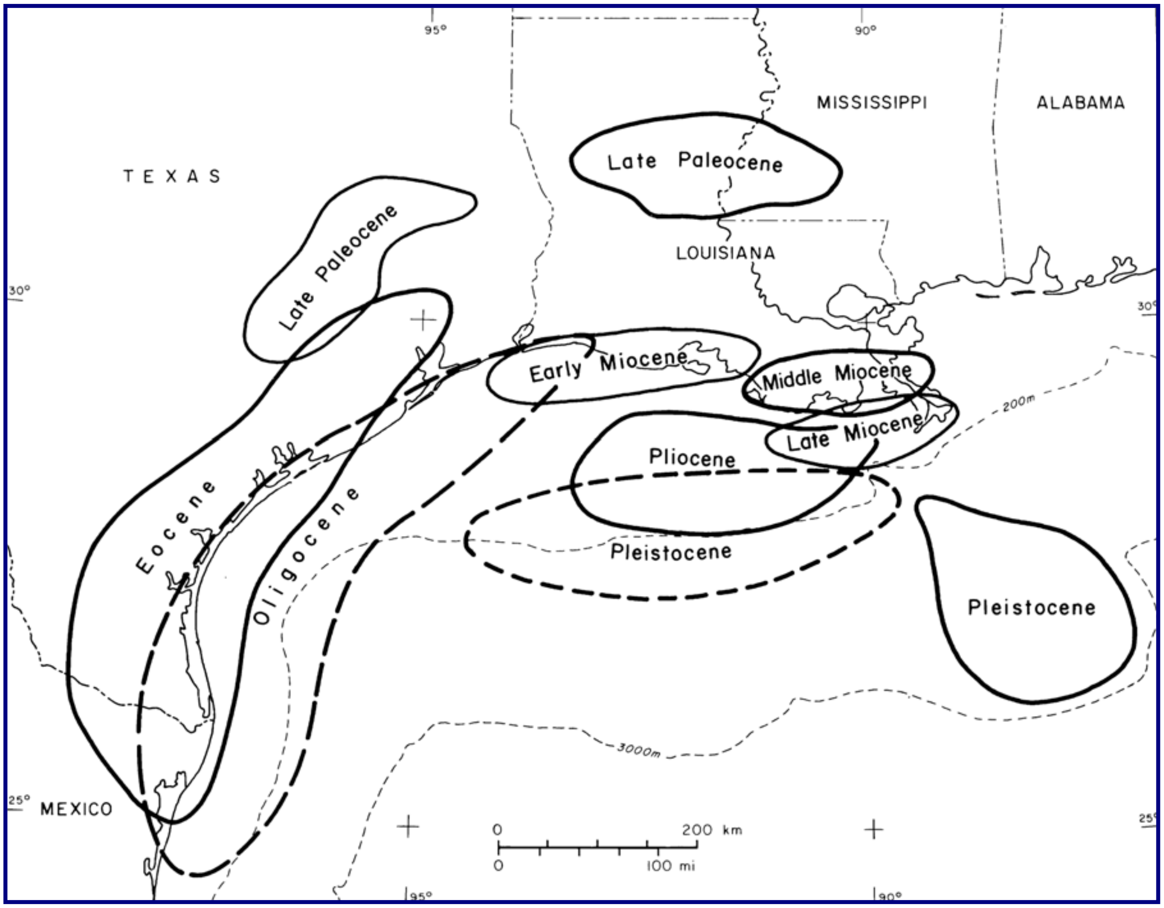


Figure 2. Location of Cenozoic depocenters, northwestern Gulf of Mexico from oldest to youngest: Late Paleocene, Eocene, Oligocene, Early to Late Miocene, Pliocene, Pleistocene, (Salvador, 1991).

Gulf Coast Geology

The Gulf Coast is known for its geopressured - geothermal resources located along the coastal regions of both Texas and Louisiana. The region is approximately 100 miles (160 km) wide and 750 miles (1,200 km) long onshore and encompasses roughly an equivalent area offshore (Wallace et al., 1979; Davis et al., 1981). The pattern of geopressured formations in Texas consists of roughly concentric bands of sediment, trending parallel to the Gulf of Mexico coastline. The regional dip is Gulfward, with formations becoming progressively younger and thicker in the downdip direction towards the Gulf Coast.

The formation of geopressured strata along the Gulf Coast resulted from the rapid sediment deposition over the last 65 million years at each successive position of the continental margin into the rapidly subsiding Gulf of Mexico basin. Sequences of prograding deltas deposited sand on top of unconsolidated shales (water-laden clays and silt) and salt deposits. The weight of the overlying sands caused large scale slumping along growth faults and the sands became hydrologically isolated by the surrounding, less permeable shales. With progressive burial, the pressure of the saline fluids trapped within the sandstones increased, becoming greater than hydrostatic, (0.465 psi/ft) and eventually approaching lithostatic pressure (~1.0 psi/ft, Davis et al, 1981). As a result of the high pressure, the sands are very porous and permeable for their depth. These geopressured sands contain entrained methane. Wells drilled into this geopressured sand flow artesian (naturally) to the surface. Water temperature can range from 190°F (88°C) to over 400°F (205°C). This water is an important resource because it contains three forms of energy: 1) *thermal* from the high temperatures; 2) *hydraulic* from the high fluid flow pressure; and 3) *chemical* from the dissolved methane in the fluids.

A number of distinct clastic wedges within the Gulf Coast have been identified for their resource potential in the onshore portion of the geopressured zone. Foremost among these are the Upper Claiborne Group, Wilcox Group, Vicksburg and Frio Formations (Figures 3 and 4).

SYSTEM	SERIES	GROUP/FORMATION
Quaternary	Recent	Undifferentiated
	Pleistocene	Houston
Tertiary	Pliocene	Goliad
	Miocene	Fleming
	? ?	Anahuac
	Oligocene	Frio
		Vicksburg
	Eocene	Jackson
		Claiborne
		Wilcox
		Midway

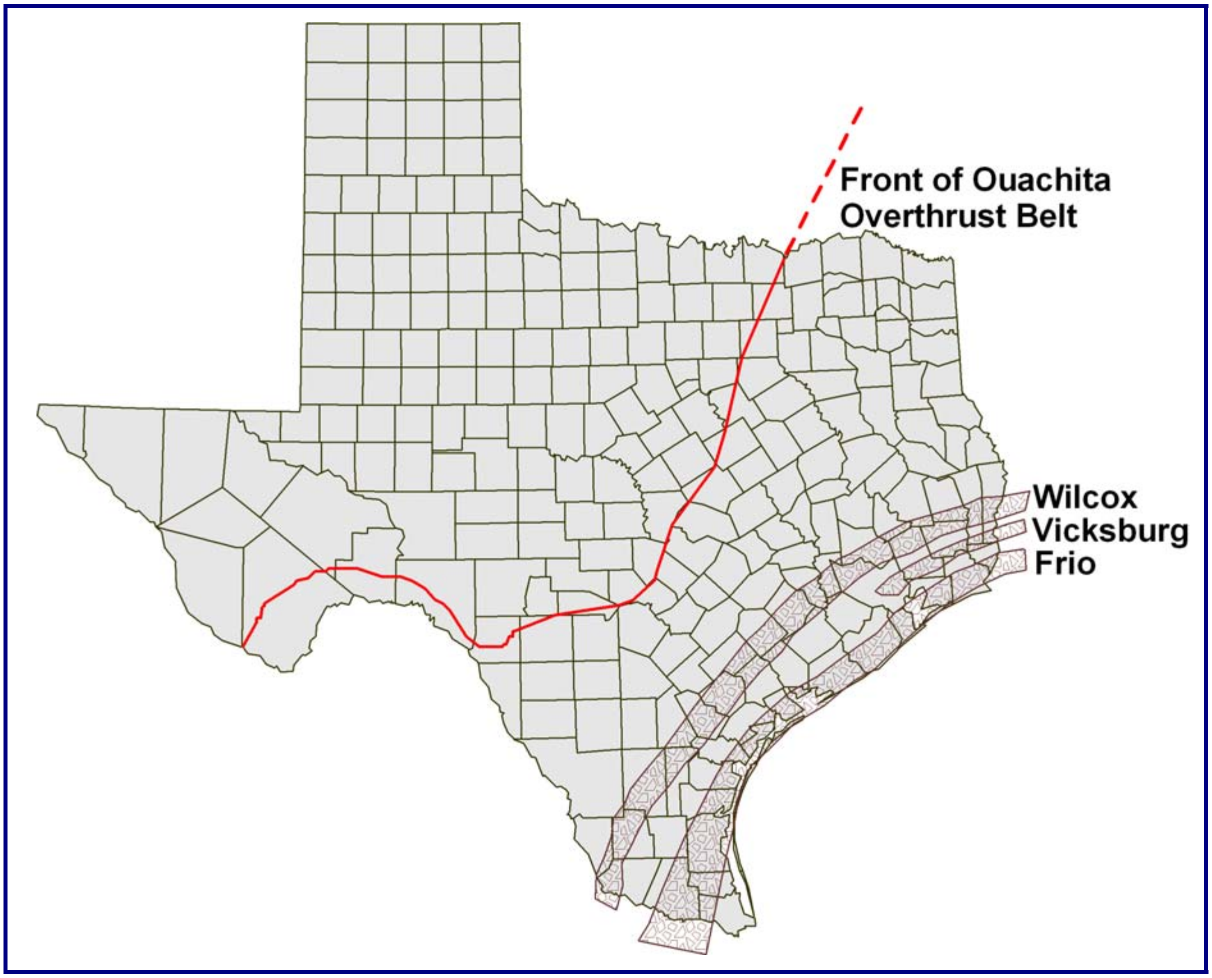


Figure 4. Geothermal corridors of primary geothermal favorability at depth shown in brown fill. (Bebout et al., 1983). Front of the Ouachita Overthrust Belt is drawn as a solid line in Texas and dashed in Oklahoma to represent it continues beyond the boarder and on into Arkansas.

East Texas Geology

The East Texas embayment (basin) and the Sabine uplift (Figures 1, 5, 6) are the dominating structures of East Texas and northwestern Louisiana. The sediments filling the East Texas embayment are the oldest of the Gulf Coast sequence with most being Cretaceous and Jurassic in age. The Paleozoic basement rock in this area appears to have higher levels of natural radioactivity than the basement rock in Texas north and east of the Ouachita belt (Negraru et al., 2008). As a result the heat released increases the geothermal gradient in the overlying sediments in the vicinity of the Sabine Uplift (Figures 1 and 5).

East Texas and the Gulf Coastal area are also known for various types of salt bodies (Seni and Jackson, 1983) (Figure 6). The layers of salt formed during the Middle Jurassic (~170 MA), when the area fluctuated from an inland sea to land. The salt formations were deeply buried by the accumulating sediments, but the less dense salt could migrate through the upper sedimentary layers forming prominent subsurface features such as: diapirs, horizontal tongues, and domes. As the salt moves, it forms significant traps for the maturing oil and gas in the sediments. Local thermal anomalies are formed around the salt bodies because the salt has a very high thermal conductivity compared to the surrounding sediments.

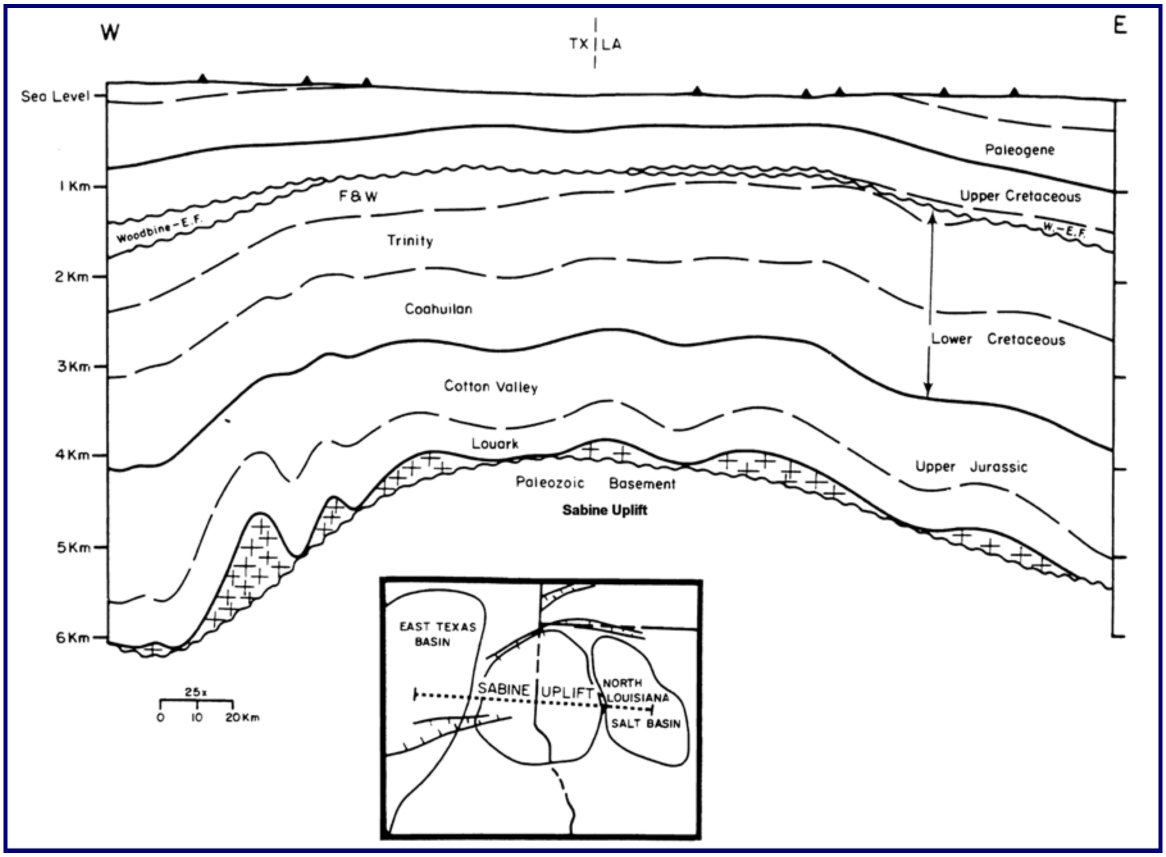


Figure 5. A geologic cross-section of East Texas through western Louisiana (Salvador, 1991). The Sabine Uplift is shown as the Paleozoic Basement rocks at the bottom of this cross-section. The location of the cross-section is also drawn on Figure 6 as a blue line.

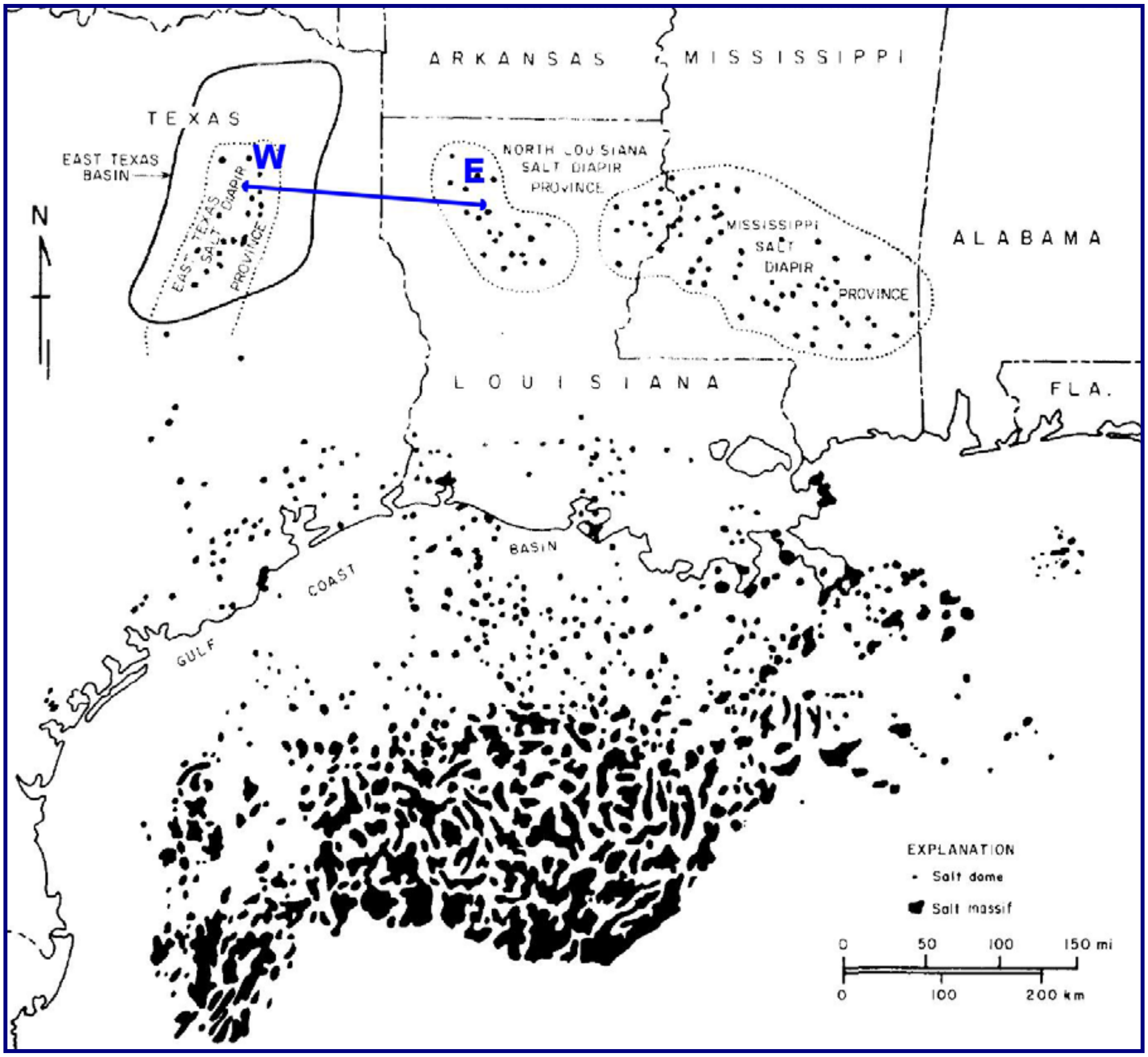


Figure 6. Map of East Texas basin, location of inland salt-diapir provinces, and salt domes, (Seni and Jackson, 1983). Cross-section in Figure 5 is shown as a blue line.

DATA COLLECTION METHODOLOGY

The temperature data used in this assessment consists of five data sets with locations shown in Figure 7 and the data overview in Table 1. Appendix B contains the raw data. The SMU Geothermal Laboratory Texas Railroad Commission Oil/Gas Temperature data (SMU-TX RRC) database is a new result of this assessment. The data were extracted from well log headers downloaded from the Railroad Commission (TX-RRC) website[6]. The assessment area is within

[6] http://www.rrc.state.tx.us/

the TX RRC Oil and Gas Districts 1 though 6. The SMU-TX RRC database contains the following information on 4,887 wells: 1) latitude and longitude (NAD 27); 2) county; 3) API and TX RRC surface and bottom well ID numbers; 4) type of well (oil/gas/both) and production status as of 2006; 5) bottom hole temperature (BHT); 6) depth of measurement; 7) elevation; 8) time since circulation; 9) field name and operator. SMU-TX RRC data are mostly from wells drilled during the 2000s, with some wells from the 1990s. As such, this database reflects a snapshot of current drilling activities in the eastern portion of Texas and is a random dataset based on availability of well logs on the TX RRC website.

The second largest dataset available is the Texas subset of the American Association of Petroleum Geologist (AAPG) Geothermal Survey of North America GSNA) Well Data (AAPG, 1994). This dataset was collected for the United States as part of the Geothermal Gradients Map of North America (DeFord and Kehle, 1976) from oil and gas wells drilled before 1972. This database includes 2,498 wells that are used in this assessment.

The key difference between the two oil and gas databases is the areal distribution of the data. The SMU-TX RRC data were collected using current online information based on what was submitted. As a result there are clusters of data in fields where many new wells were drilled and other areas with few points. The AAPG Geothermal Survey Well Data were collected on a more even distribution. Because of this difference in approach, it is possible to create maps both on a regional scale and, in some instances, at a local county-field scale.

Other data sets used include the Gulf Coast Geopressure data (Gregory et al., 1980), the Hunt Oil Company Fairway Field data in Anderson and Henderson Counties (Hunt Oil and Kweik, this report), the Freestone County well data (Burns, 2004) and the USGS GEOTHERM shallow database (Bliss, 1983).

The Gulf Coast Geopressure data (Gregory et al., 1980) include 654 well data points with the following available parameters: well number, total depth, bottom-hole temperature (BHT), formation, sand thickness, porosity, fluid pressure, water salinity, and methane solubility. The report data were converted to digital for this and future studies. These data are helpful in modeling 3-D aspects of the Gulf Coast because of the included geologic information.

The Fairway Field (located in Anderson and Henderson counties) data were collected for this assessment through collaboration with Hunt Oil Company. Well data were collected from the Hunt Oil Company files to characterize the thermal regime, review the history of the field and to investigate possible changes in temperature over time. The data collected include 216 wells with production data, 2,241 pressure tests, and 30 wells with injection data. These wells were drilled over a 40 year period from 1965 to 2005.

A previously detailed thermal study was completed on Freestone County as part of a SMU Masters Thesis (Burns, 2004) with the well data collected from oil and gas well log headers. There are 174 well locations with some wells having up to four interval temperature measurements.

The USGS GEOTHERM shallow database for Texas (Bliss, 1983) was sent to us for inclusion in this assessment by Janet Abbot of Spa Waters of Texas, who has some of the original data records. The data set contains primarily shallow wells (<5,000 ft) and spring chemistry data. Because these wells are shallow and therefore not suitable for electrical production, they were not used in the resource evaluation. This data set is included in Appendix B.

Table 1. Data set information used in this assessment.

Name of Data Set	**Author, year**	**Number of Wells**	**Area of Coverage**
SMU Geothermal Laboratory Texas RRC Oil/Gas Temperature Database	SMU, 2009	4,887	RRC Districts 1 - 6
AAPG Geothermal Survey Well Data	AAPG, 1994	2,498	North America
Gulf Coast Geopressure	Gregory et al., 1980	654	Texas Gulf Coast
Freestone County Well Logs	Burns, 2004	174	Freestone County
Hunt Oil Fairway Field	Kweik, 2009	216	Anderson and Henderson Counties
USGS GEOTHERM	Bliss, 1983	1,120	Texas

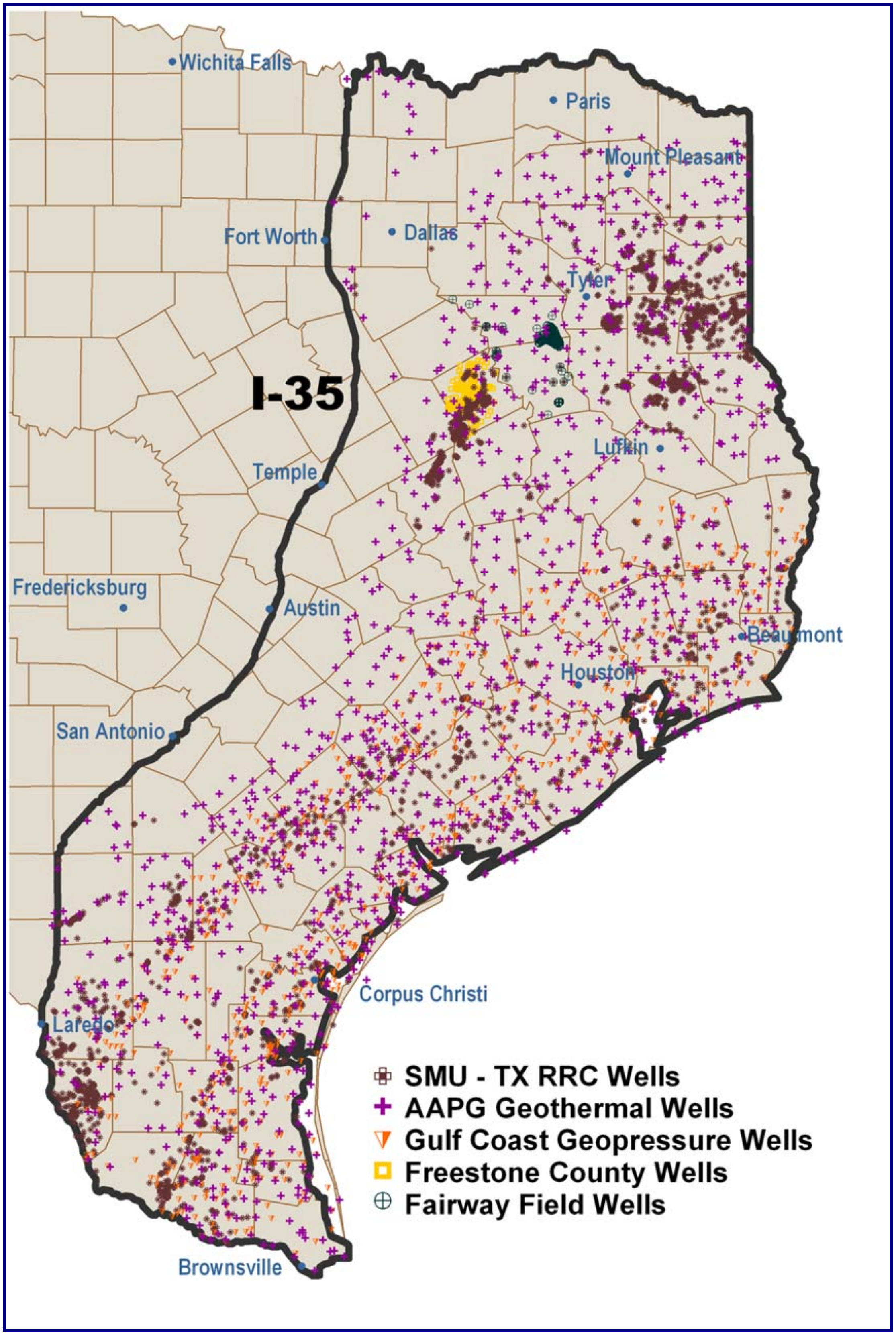


Figure 7. The locations of different data sets used in this assessment.

DATA CORRECTIONS

The temperature data in this assessment are from oil and gas wells. In order to give value to the data, multiple steps were taken to determine well data accuracy and correct for differences in raw data versus in-situ temperatures. In a best case scenario, the temperatures would be from measurements of wells at equilibrium with high precision, high resolution equipment (Wisian et al, 1998). This is rarely possible. To improve the value of the collected data, corrections were made to the data and comparisons of the corrected data were made with more accurate methods. This section describes the data and these corrections and comparisons.

While drilling a well, fluid is injected and circulated from the surface to the drill bit in order to cool the bit, stabilize the borehole walls, and clear the cuttings from the borehole. The mud and fluids impact the surrounding rock formations, thereby cooling the borehole at the deeper depths and potentially heating it in the shallow depths depending on the surface air temperature, drilling speed, type of drilling fluid, etc. Most wireline logging tools have maximum reading thermometers included with the other data recorders. Logging of the well usually occurs after initial drilling ceases and before the well section is cased. Therefore, an individual well can have more than one bottom-hole temperature (BHT) measurement, making these interval maximum temperature measurements in some cases.

For a well to return to the original, in-situ temperature, there is a period of equilibration. Many factors can affect the time needed for this process to occur. Some of these factors include the thermal conductivity of the rock formations, pore fluid movement, and drilling times and conditions. The process of re-equilibration generally takes several times the period of time the drill bit was at or below the point of measurement (Harrison and Luza, 1985). To adjust for these differences the well log header temperatures (BHT) are given a correction as discussed in the following section. The data included in this assessment are available in spreadsheet format in Appendix B.

Data Review

The Fairway Field data were acquired from the in-house files of Hunt Oil Company. This allowed for the collection of different types of available well log data not often readily available in the public domain (pressure, injection, production) from the up to 40 years of production.

Within this data set, if a well had multiple temperatures collected at the same depth, the temperature used was determined by repeatability of the value and the temperature of nearby wells.

The other existing datasets used [AAPG Geothermal Survey Well Data, Gulf Coast Geopressure, and Freestone County Wells] were already reviewed for errors by their respective authors. Next, the SMU-TX RRC data were combined with the other data sets and compared within a 1° by 1° area for similar temperatures and depths between the different data sets. Wells with temperatures greater than the local standard deviation (±27°F) were removed as outliers and noted in the database.

Temperature Correction

There are various types of temperature corrections that can be applied to the BHT value to calculate the approximate in-situ temperature. This is usually done based on the time since circulation recorded with the BHT reading, or derived from an empirical correction based on the depth of the measurement. The Gregory et al. (1980) report states the Harrison correction was applied to the temperature values to represent in-situ values. This same correction was used previously by Blackwell and Richards (2004a) on the Geothermal Map of North America, and Harrison et al. (1983) for oil and gas wells in Oklahoma. This correction is similar to the correction used by Kehle et al., (1970) for the Geothermal Gradient Map of North America (Equation 1). The correction used by SMU Geothermal Laboratory is based on the Harrison correction, which is a second order polynomial that correlates the BHT measurement to depth (Equation 2). It was applied to the SMU-TX RRC data, AAPG Geothermal Survey Well data, Freestone County Well data, and Fairway Field data using SMU-Harrison Equation 1. This correction value is then added to the well log header BHT measurement to calculate an approximate in-situ temperature.

Kehle Correction Equation 1. $\triangle\,°F = -8.819 \times 10^{-12} z^3 - 2.143 \times 10^{-8} z^2 + 4.375 \times 10^{-3} z - 1.018$

where z = depth in feet. (Gregory et al., 1980, p. 59).

SMU-Harrison Equation 2. $\triangle\,°C = -16.51213476 + 0.01826842109\,z - 0.000002344936959\,z^2$

where z = depth in meters.

A comparison of the SMU-Harrison equation and the Kehle equation shows the largest difference at shallow depths, i.e., 4.5 °F at 6,000 feet, with the SMU-Harrison correction the lesser of the two. At depths of 12,000 feet or greater, the corrections are the same. The SMU-Harrison equation is used to correct BHTs between the depths of 3,000 and 12,900 feet. Deeper than 12,900 feet the BHT data were given a linear increase starting with the maximum value of the SMU-Harrison correction (34.3°F) and increasing slightly by 0.05°F every 500 feet. The deeper wells are expected to have longer times between drilling circulation and BHT measurements. As a result, the correction is assumed to not increase at the same rate as the shallower depths.

In order to assess the validity of the calculated in-situ temperature, the values were checked against wells in Texas logged by the SMU Geothermal Laboratory. The well locations (Republic, Chapman, Garcia, and West Ranch) were chosen because of their equilibrium temperatures logs made with high-accuracy, high precision temperature logging equipment (Figures 8 and 9; Wisian et al., 1996 and 1998; Blackwell and Richards, 2004b; and Negraru et al., 2008). An additional temperature log from the Pleasant Bayou well (DOE #2) was used. That well was logged in 1988 by Panex (Randolph et al., 1992).

The difference between the well log header BHT values, the Harrison corrected temperature values, and the equilibrium well measured temperature - depth curves is shown in Figures 9 a - f. The BHT data were selected within ±0.5° of latitude and longitude (~30 mile radius) around the equilibrium well location. By limiting the distance from the equilibrium well, the data are assumed to be most comparable. The equilibrium temperature graphs show that the well log header BHTs are generally too cold in comparison to the in-situ temperature. After applying the SMU-Harrison correction, the data fall more tightly around the logged equilibrium temperature line.

The West Ranch well (Figure 9d) has the poorest correlation to the corrected data. This limited correlation could be due to the influence of shallow water sources for waterflooding of the West Ranch field to push the oil out of the deeper formations. The West Ranch well was measured by the SMU Geothermal Laboratory in 1983.

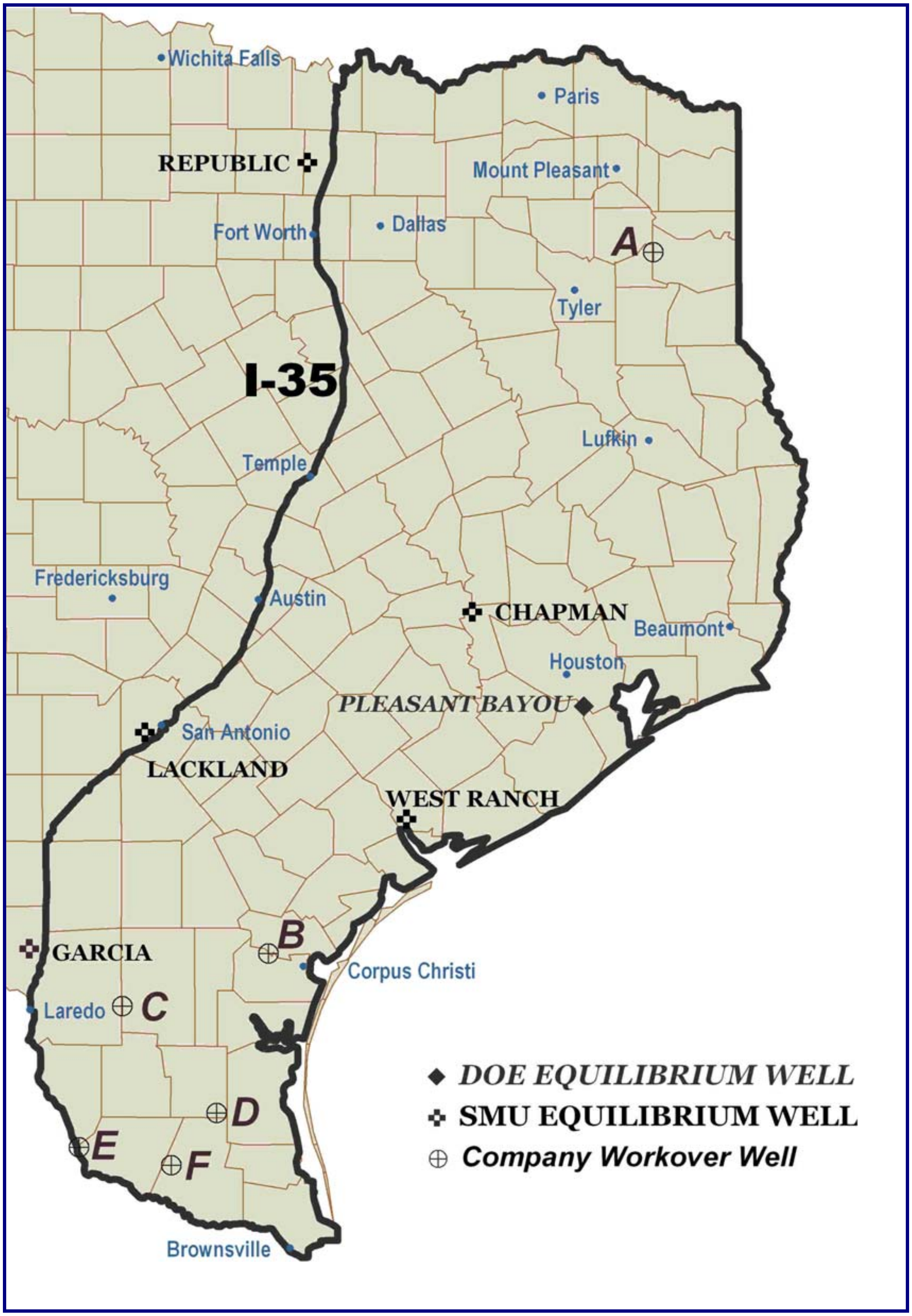


Figure 8. Locations of wells with equilibrium temperature logs used to compare temperature corrections applied to well log bottom-hole temperatures.

Figure 9 (a - e). Equilibrium temperature data are shown as a black line, the log header BHT values in the area shown as a square symbol, and the corrected BHT values are shown as a cross symbol.

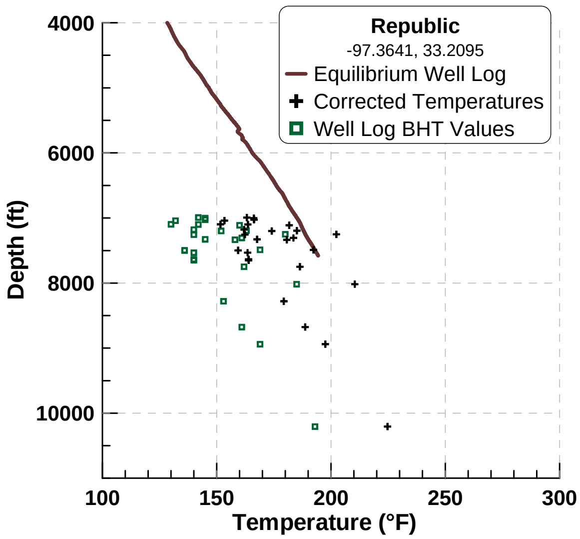


Figure 9a. Republic Well

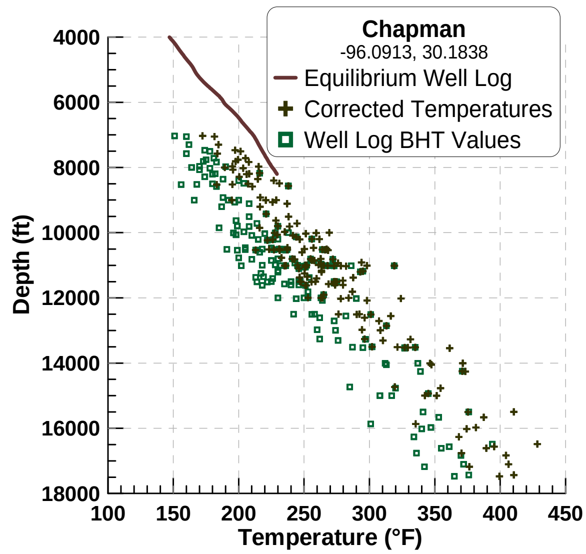


Figure 9b. Chapman Well

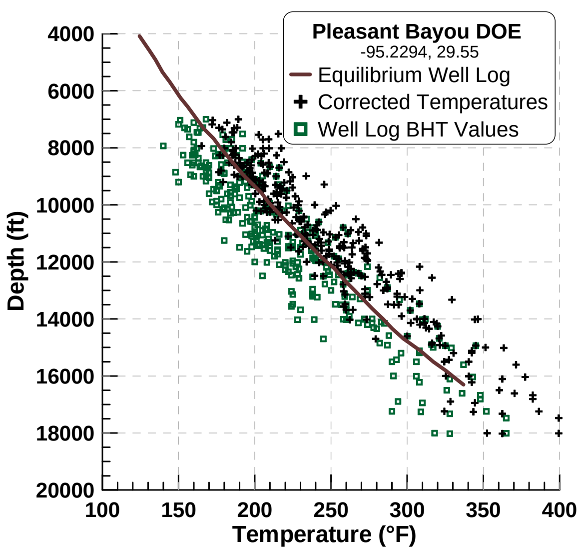


Figure 9c. Pleasant Bayou DOE Well

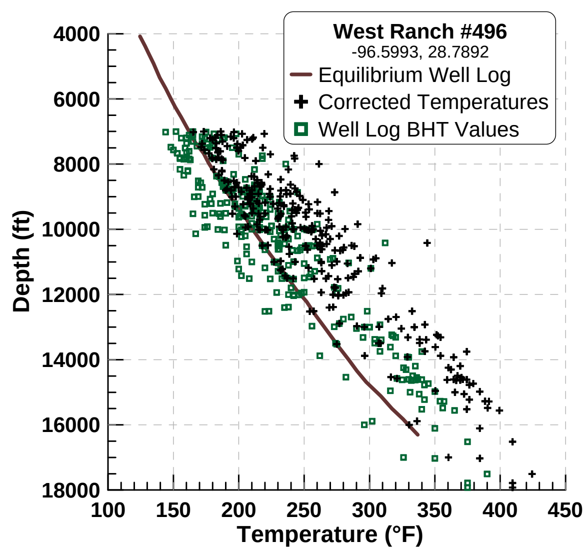


Figure 9d. West Ranch #496 Well

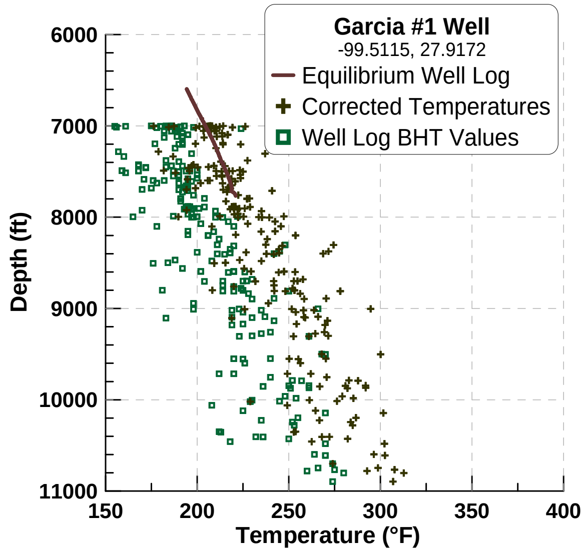
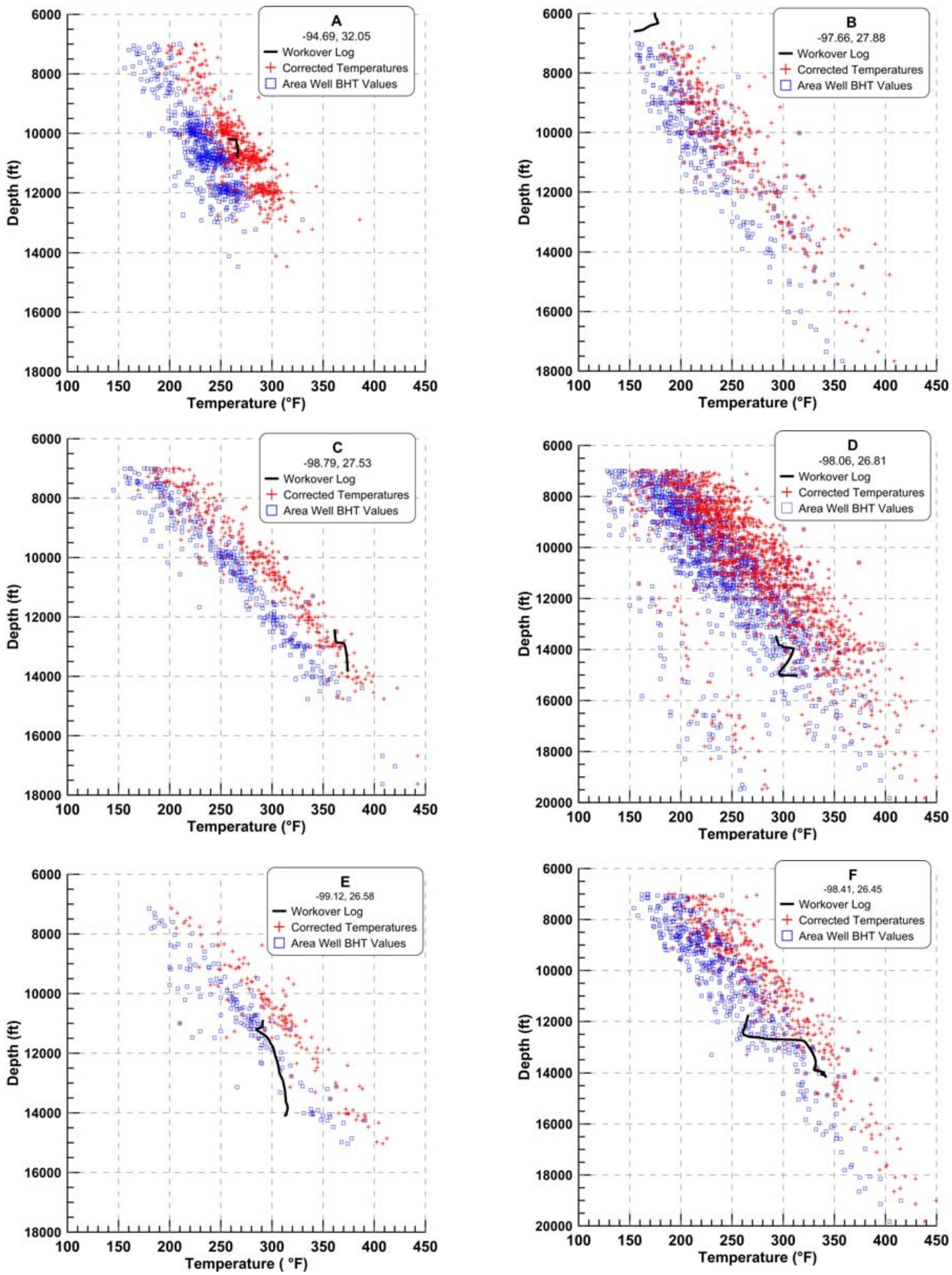


Figure 9e. Garcia #1 Well

Companies today use high accuracy temperature logs as production logs to help them understand wellbore flow conditions. New technology developments have made routine high resolution temperature measurements possible (Blackwell et al., 1998). However, this does not mean that the measurements are optimum (Blackwell et al., 1997). Measurements may be taken months to years after drilling, but not necessarily after the well has been out of production and is in thermal equilibrium. These very detailed temperature logs assist in determining where fluid (gas, oil or water) is entering the well or if fluid is flowing up/down within or behind the casing. When gas enters a well, the expansion of the gas will cause the temperature to drop rapidly as it expands because of the pressure change. If water is flowing behind the casing or laterally, then the temperature will remain fairly constant for the distance the fluid is flowing. The following examples in Figure 10 show how much temperature can change within a small depth range. The highest temperatures measured are considered closest to in-situ values (the SMU corrected temperatures) and the cooler temperatures disturbed (original BHT). Wells are not identified as the actual names are proprietary. All wells are from south Texas.

Figure 10 (a - f). The workover well temperature log is shown as a black line, uncorrected BHT values within an area of ±0.5 longitude and latitude are shown as a square, and the corrected well temperatures are shown as a cross. Locations are shown by letter on Figure 8.



The curves shown in Figure 10 are also helpful to understand the temperature profiles for the wells in the fields around each workover well. The graphs also show the variation in the temperature trends according to the geological structure as depicted by Figure 10 D where there are two geothermal trends in the area, one colder than the regional. Information about the reservoir thicknesses can be depicted by the depths plotted as shown by breaks in the data (Figure A). The temperature -depth graphs in Figure 10 show that most areas in South Texas are over 300°F, even uncorrected BHT measurements, by 14,000 ft.

Pressure Data

For the Fairway Field area, pressure data from the production well records were used as a second comparison of the application of the SMU-Harrison correction on the SMU-TX RRC data points in Anderson and Henderson counties (Figures 7 & 11). The SMU-Harrison corrected BHT data follow the general trend of the pressure data with values slightly warmer than the uncorrected (blue triangles). There is an outlier group of data at 10,000 feet that are related to a variety of disturbances and recording errors. Pressure data are an improved parameter to use for estimating in-situ values when available over well log BHTs. This is because pressure data are collected with a temperature measurement throughout the life of a well. These are not considered an exact in-situ temperature because the well is active and has usually been flowing. They do represent values not influenced by drilling fluids, so are considered close to undisturbed (Kehle et al., 1970; Erkan et al., 2007). The pressure data contain numerous values for a specific well which can then indicate a reasonable spread of temperatures at that depth. These temperatures usually vary 10 to 25°F for a similar depth measurement as shown by the sample set of wells in Figure 12.

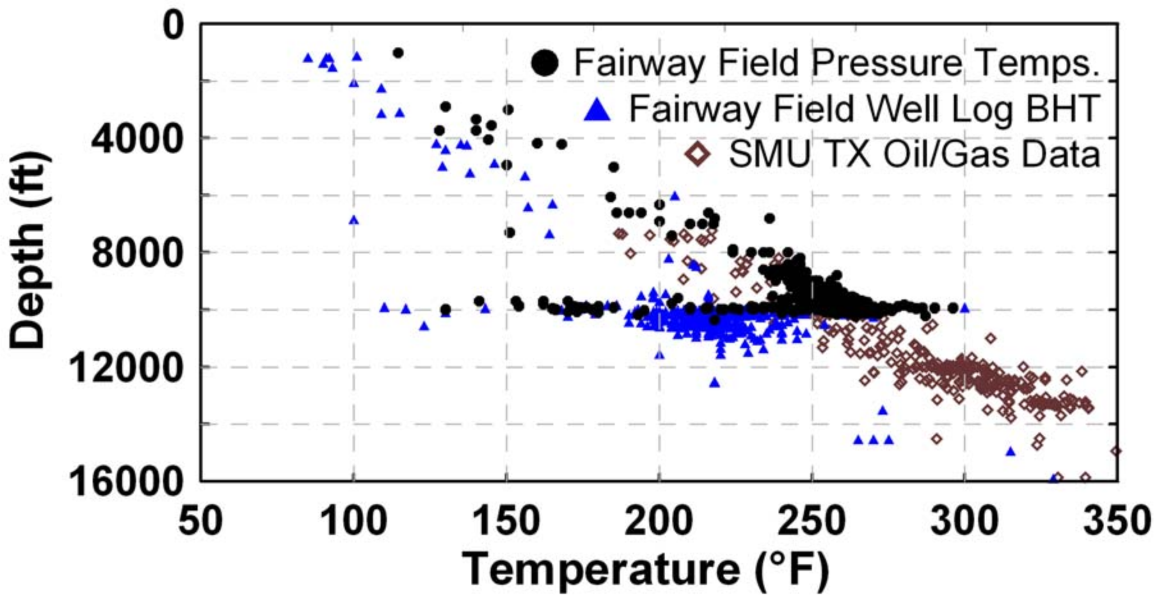


Figure11. The corrected SMU-TX RRC BHT data (diamonds) located within or near the Fairway Field, the averaged Fairway Field pressure/temperatures data (circles), and the uncorrected Fairway Field BHT data (triangles) are plotted. The trend of the pressure temperatures and corrected temperatures are similar except within the reservoir zone at approximately 10,000 feet.

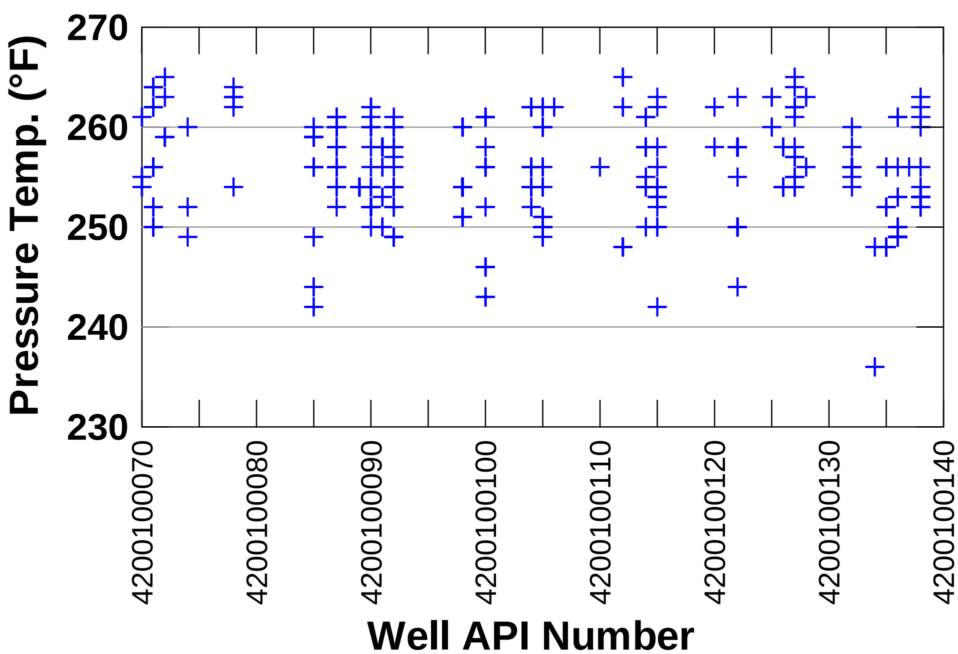


Figure 12. Hunt Oil Company Fairway Field temperatures from a subset of the pressure data. For the specific well site (API #), the amount of variation in temperature readings over time is shown. Each vertical line of data represents one well. The well API number is shown on the bottom axis with 42 = Texas and 001 = Anderson County, then the individual well numbers.

ANALYSIS OF THE DATA

The data from the SMU-TX RRC database, the AAPG Geothermal Well Survey (AAPG, 1994), Gulf Coast Geopressure database (Gregory et al., 1980), Freestone County (Burns, 2004), and Fairway Field (Hunt Oil Company and Kweik, this report) were used to generate a series of temperature maps of the area of the study at various depths and at different scales. The maps were produced using software which developed a 3-dimensional lattice and second program for 2-dimensional grids. The 3-dimensional lattice is able to take into consideration the gradients of data in all directions to create smooth contour maps of temperatures at specific depths. These maps represent the general trend of the data and regional temperatures. Depths are slices of the lattice for a specific interval (Figure 13 a to h) shown at 1,000 feet intervals between the depths of 7,000 to 14,000 feet. The highest values are in the South Texas Wilcox formation zone (Counties: Zapata, Jim Hoggs, Webb, Duval, Live Oak, McMullen, etc.). The coldest area in this assessment was in the North Central portion of the state with Cooke and Grayson Counties having the lowest temperatures. The reason for this area being colder than other parts of eastern Texas is related to the basement rocks associated with the Wichita Mountains and the rift zone associated with them (Muehlberger et al., 1967).

Next the data were used to generate a 2-dimensonal set of maps at 9,000 and 12,000 feet focused on the county level (Figure 14 a - b). Wells with depth values of ± 2,000 feet from the mapped depth were selected. The well gradient was used with the corrected temperature to interpolate to specific depths of 9,000 and/or 12,000 feet and then contoured to create temperature maps. The well locations are plotted showing where data were used for generating the maps to assist viewers in determining the accuracy of map values and data variability. At this level of detail, the individual counties can be viewed with the location of data points clearly shown. Although there are areas containing counties with little to no data, it is helpful to see where the county sits within the larger temperature trends for the region. Most of the wells are relatively densely located, with the average distance between wells approximately 3.6 miles. From this the map contours are based on a grid spacing of 13 square miles.

The depths of 9,000 and 12,000 feet were chosen for the 2-dimensional detailed maps because 9,000 feet is the initial depth where most of Eastern Texas is near 200°F. This is the initial temperature needed in Texas, with the current binary turbine technology requirements. Temperatures at 12,000 feet were chosen because in this area the majority of “deep” oil and gas wells are completed between 12,000 and 13,000 feet (Figure 15). Wells in this depth range are representative of what is currently available to use as an exploration tool for the development of geothermal power.

Figure 13 (a - h). Slices of a 3-dimensional lattice for depths of 7,000 to 14,000 feet showing generalized trends of the temperature at each depth from a low of 125°F to over 360°F.

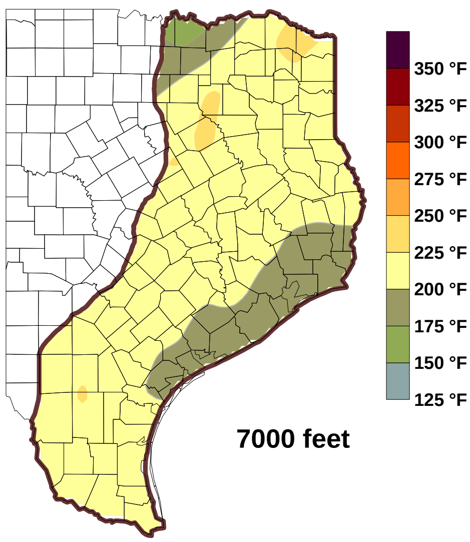


Figure 13 a. 7,000 feet depth temperatures

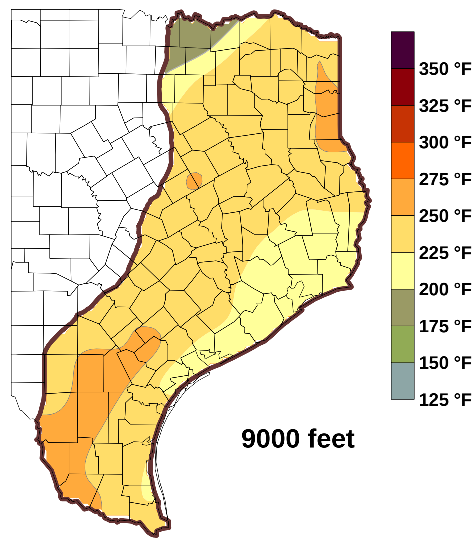


Figure 13 c. 9,000 feet depth temperatures

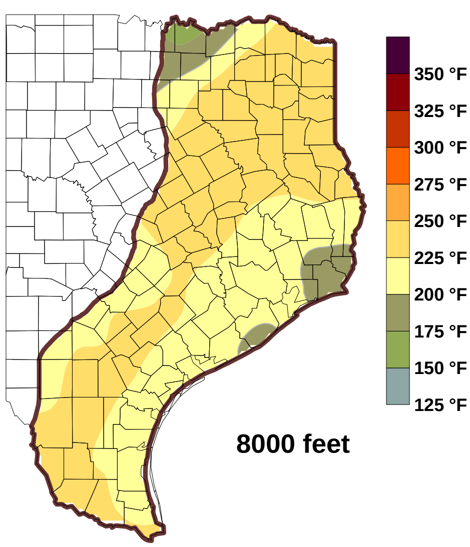


Figure 13 b. 8,000 feet depth temperatures

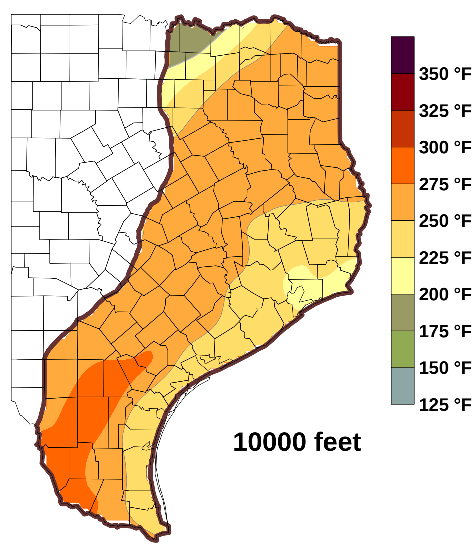


Figure 13 d. 10,000 feet depth temperatures

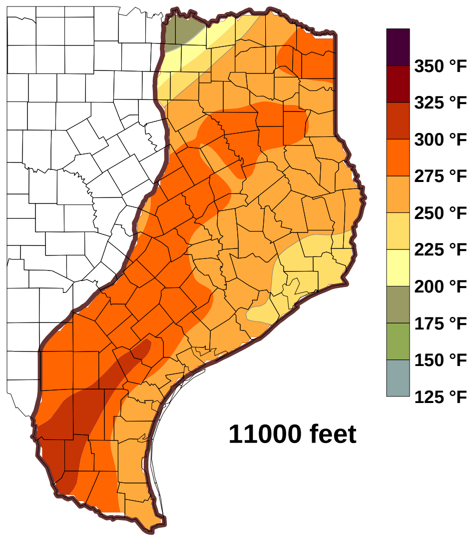


Figure 13 e. 11,000 feet depth temperatures

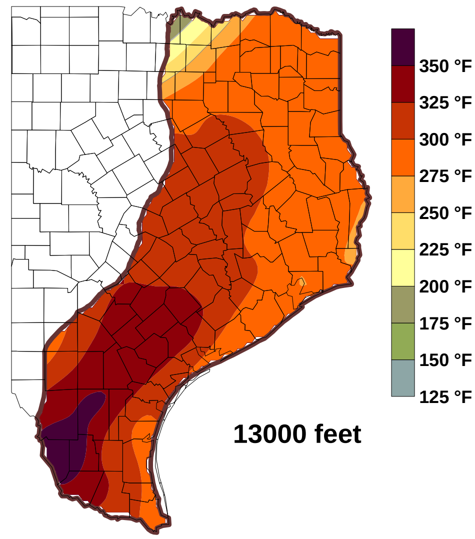


Figure 13 g. 13,000 feet depth temperatures

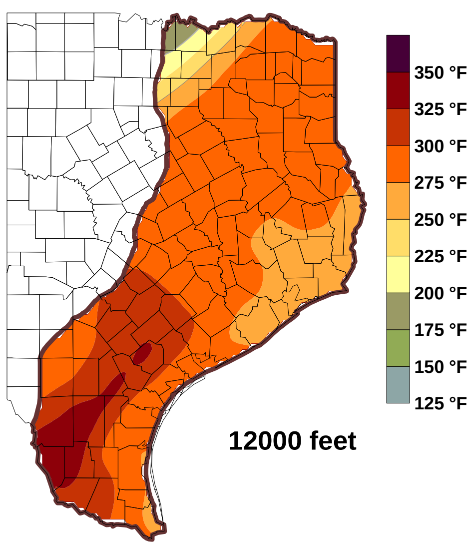


Figure 13 f. 12,000 feet depth temperatures

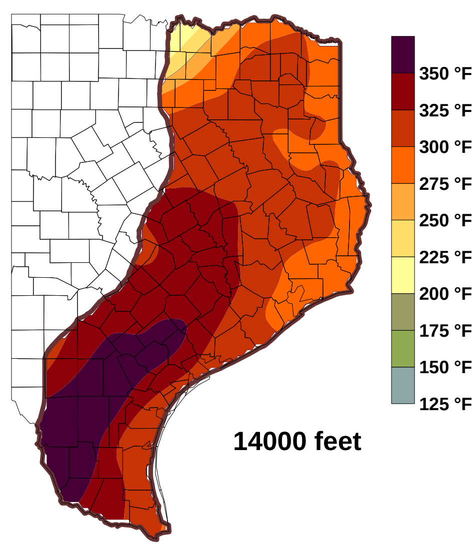


Figure 13 h. 14,000 feet depth temperatures

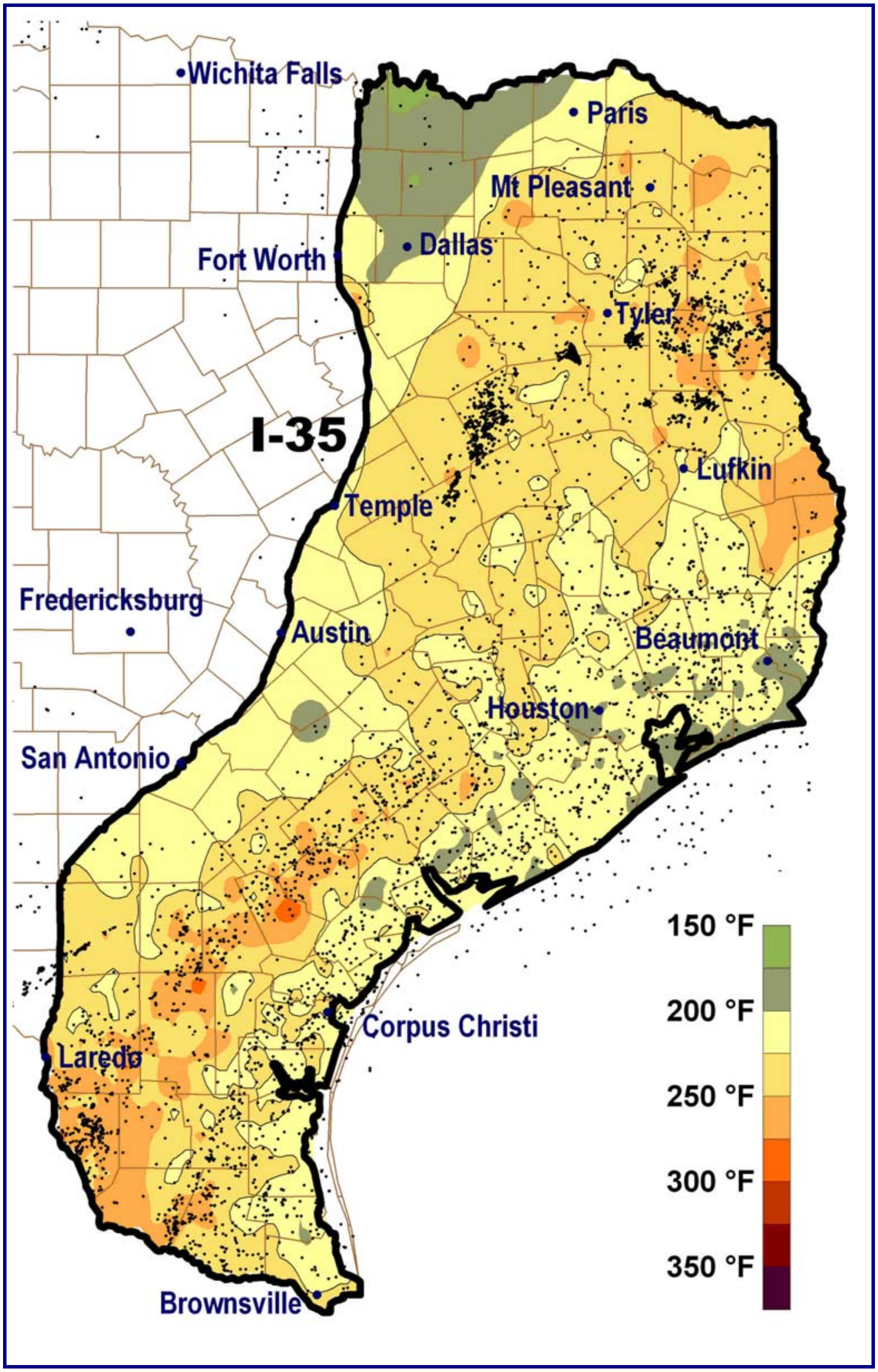


Figure 14a. Map of detailed corrected temperatures at 9,000 feet. Data are shown as small dots.

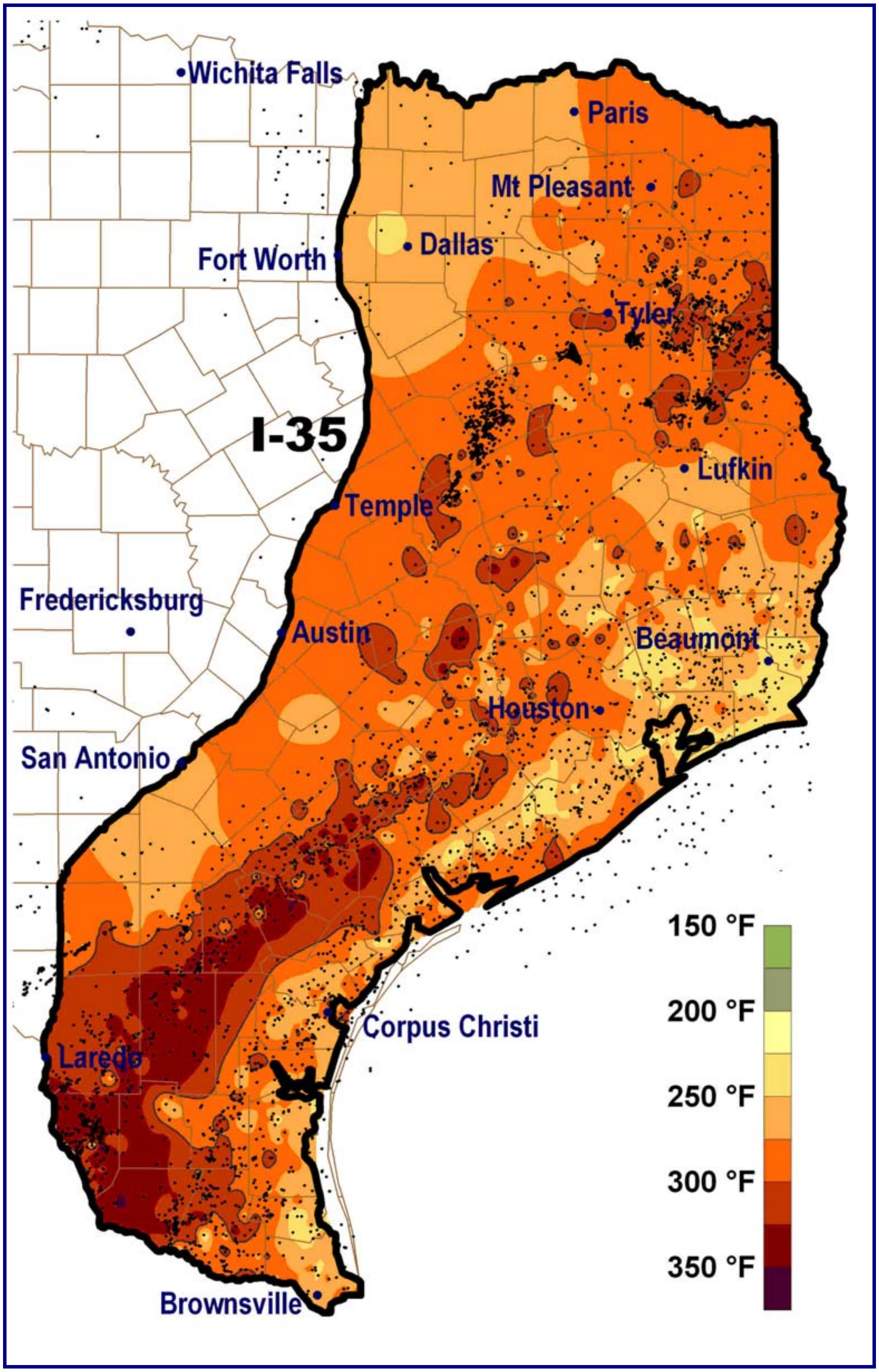


Figure 14b. Map of detailed corrected temperatures at 12,000 feet. Data are shown as small dots.

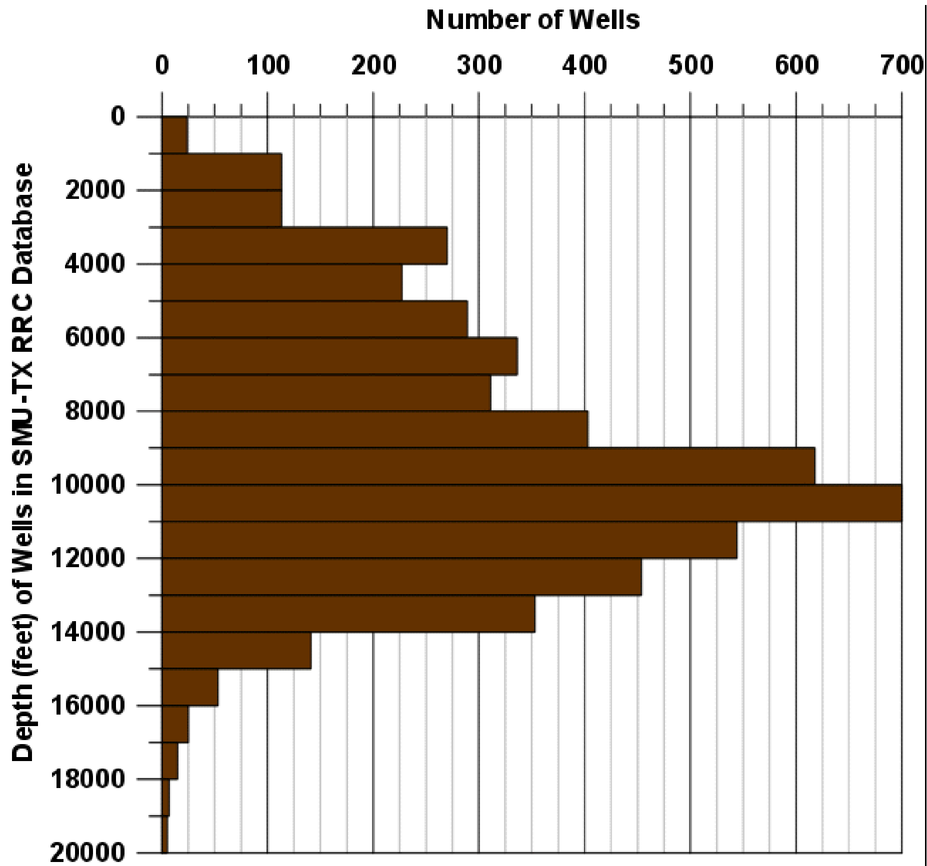


Figure 15. Histogram of drilling depth versus number of wells for the study area.

In reviewing the detailed temperature maps at smaller subsets such as field-size, the temperatures can vary by up to 25°F at a given depth as shown by the Fairway Field data. The reason for this difference is related to the specific conditions existing at the time the temperature was measured. There are numerous situations that cause temperature values to vary that cannot be captured with the limited well condition information available and the relatively simple applied corrections used here.

1. The oil and gas data BHTs are collected at the time of logging by using a maximum reading thermometer, yet the logging gear may be lowered deeper than the recorded depth generating too warm a temperature value.

2. Another logged well temperature value may have been recorded by the logging company, instead of the recorded measurement at the time of logging.

3. The surface temperature variation from summer to winter (and in some instances day to day) impacts the well temperature by changing the drilling fluid temperature. Temperatures are further altered by the duration of circulated drilling fluid and drilling conditions.

4. The length of time the well sits between the last circulation of the drilling fluid and the logging of the well impacts the temperature. The logging typically occurs within 6 to 10 hours, but for some wells it is months since drilling so the well starts to return to the undisturbed value.

5. Geologic structure will affect temperatures because of fluid movement along pathways and faults through a stratigraphic zone.

The corrected temperature data show that by 9,000 feet, the majority of Texas east of the Interstate I-35 corridor is at or above 200°F (Figure 14a). The two primary areas with a concentration of temperatures less than 200°F are the North Texas region where values are in the 150-175°F range, and the band along the Gulf Coast with temperatures of 175°F to over 200°F. The hottest areas at 9,000 feet are located in East and South Texas with temperatures reaching 250°F to over 275°F respectively.

The corrected temperature data for 12,000 feet have a pattern similar to the 9,000 feet depth level. At 12,000 feet, throughout the entire area, temperatures reach at least 200°F, but more often are at or above 250°F. The hottest areas continue to be East and South Texas with temperatures commonly over 300°F, some measuring as high as 350°F at 12,000 feet.

Temperature values continue to increase with depth such that at 13,500 feet the corrected temperatures are consistently over 300°F throughout the majority of the project area (Table 2; Figure 16). At 14,500 feet the average corrected temperature value is 340°F. Wells drilled to depths over 15,000 feet are restricted primarily to regions of the Gulf Coast and South Texas because of the sediments are thickest in these areas. Here the average corrected temperature continues to increase to 350°F at 17,500 ft. In the data for this assessment, the deepest well drilled since 2000 is in South Texas along the Gulf Coast is in Brooks County, reaching a depth of 19,829 feet with a corrected temperature of 438°F. The hottest wells are in Hidalgo County, South Texas (450°F at 19,006 feet) and in Lavaca County, west of Houston (452°F at 19,456 feet)

Table 2. Interval depth with average and maximum temperatures for that 1,000 feet interval.

Depth Range Feet	Number of Wells	Average Uncorrected Temperature °F	Average Corrected Temperature °F	Maximum Corrected Temperature °F
12,000 - 13,000	879	263	299	363
13,000 - 14,000	628	283	320	430
14,000 - 15,000	330	304	340	423
15,000 - 16,000	159	306	349	420
16,000 - 17,000	107	319	361	422
17,000 - 18,000	60	319	358	454
18,000 - 24,000	46	362	402	544

The deeper (>13,000 feet) temperatures in East Texas were calculated by Negraru et al, (2008) using heat flow values and rock thermal conductivity. These are determined to be hotter than the wells in South Texas and the Gulf Coastal areas. The wells in this assessment for East Texas are generally less than 13,000 feet, thus in Figure 14b, the East Texas temperatures are generally extrapolated rather than measured for the depths over 12,000 feet. Wells are not drilled deeper in this area due to the basement rock of the Sabine Uplift being relatively shallow (Figure 5). These basement rocks of the Sabine Uplift apparently have high contents of natural radioactive elements that cause the higher than normal heat flow in this area (Negraru et al., 2008). It is due to this additional heat generation that at 9,000 feet, East Texas temperatures are warmer than those in North Texas on the other side of the Ouachita Overthrust Belt.

The purpose of the detailed maps in Figure 14 is to direct initial exploration studies, and not for specific site selection. Formation temperature is one of the variables used when selecting wells to focus on for geothermal energy development. The corrected temperature is a starting point for the power production calculations (Appendix C). From this temperature the fluid will slightly cool as it flows to the surface and moves though the pipe at the well head to the turbine. The temperature decrease is a function of distance, fluid speed, and pipe insulation. If the fluid from the well is a combination of oil, gas, and brine, then depending upon the power plant design and technology, there may need to be separation of fluids before electrical generation. This process would further decrease the fluid temperature.

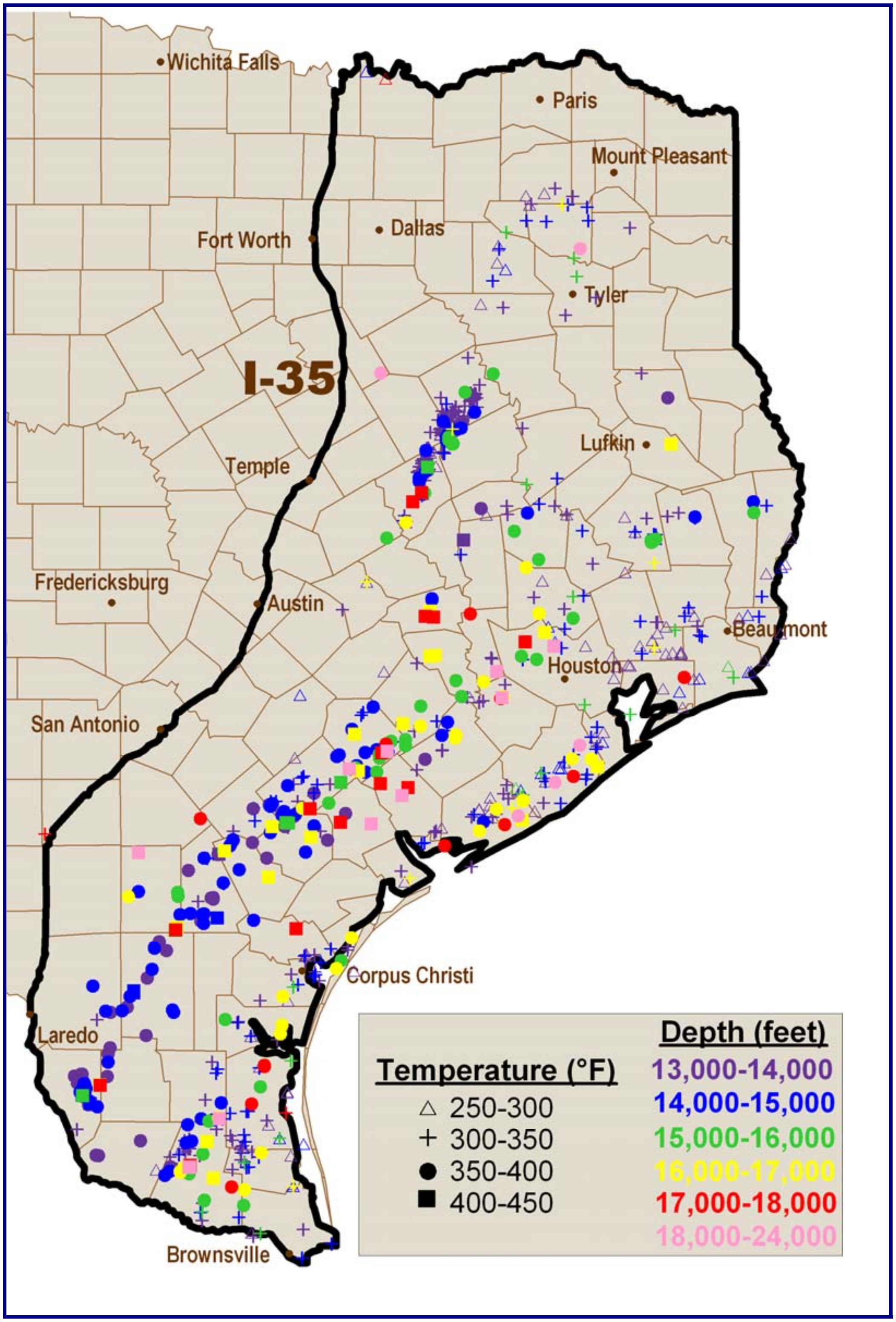


Figure 16. Well locations with depth between 13,000 to 24,000 feet. The color of the symbol represents the depth and the symbol shape represents the temperature range.

FAIRWAY FIELD

During the summer of 2008, the Hunt Oil Company provided well logs, production, and pressure data (measurements taken over the life of the wells) from the Fairway field for the SMU Geothermal Laboratory to use for a study of long term changes in pressure and temperature in an operating the oil and gas field (Hunt Oil and Kweik, this report). A total of 2733 well logs were reviewed. The information collected included: latitude/longitude, well depth, elevation, BHT, TSC, gradient, date of drilling, and type of log. The well head surface temperatures were measured during a site visit in August 2008 using a heat gun to compare the BHT measurement with current well head fluid temperatures.

Fairway Field (James Lime Unit) is an oil field located in Poynor, Texas covering approximately 23,000 acres in Anderson and Henderson Counties (Figure 17). The field is operated, but not wholly owned, by Hunt Oil Company. Discovered in 1960, it was estimated to have over 410 million barrels of oil. Since its first production in 1960, Fairway field is still producing. The field currently includes 147 wells: 83 oil producing wells, 37 gas producing wells, 8 brine disposal wells, and 19 shut-in wells. The total cumulative production as of December 2008 was 213 million barrels of oil, 1 BCF of gas, and 477 million barrels of water. Water and gas injection have been used to stimulate hydrocarbon recovery at different times and locations. Currently, the water cut is 94% of the total production, while approximately half of the original in place oil remains in the field.

Data results from the well injection and cement logs were available for this assessment, but not used. Injection well logs are not reliable, in that they will almost always measure colder than the actual formation and will vary depending on the amount and rate of fluid being pumped into them. Temperatures from cement logs have values hotter than normal, due to the chemical reaction taking place in the cement between the well and casing, releasing excess heat to the surroundings.

The field has undergone four major stages in its 50 years of production history. The first stage involved the primary recovery of oil at a high rate for two years. In its second stage, the recovery scheme was based on water-alternating-gas (WAG) miscible recovery flood in 1963. This involved the injection of a large volume of water and gas to facilitate migration of oil towards the well bores to improve production. In the third stage, the field was put through a tertiary recovery scheme, where a large volume of natural gas was injected into the field to help recover even more oil (Figure 18). However, this injection was halted in 2000, due to the rise in natural gas prices. The gas was then recovered. The production of the stored natural gas eliminated the need for water injection. In 2000, Fairway entered its current stage, which includes dehydrating the field under a pressure depletion drive to induce a gas blowdown phase with high water flow (David Luttner, personal communication).

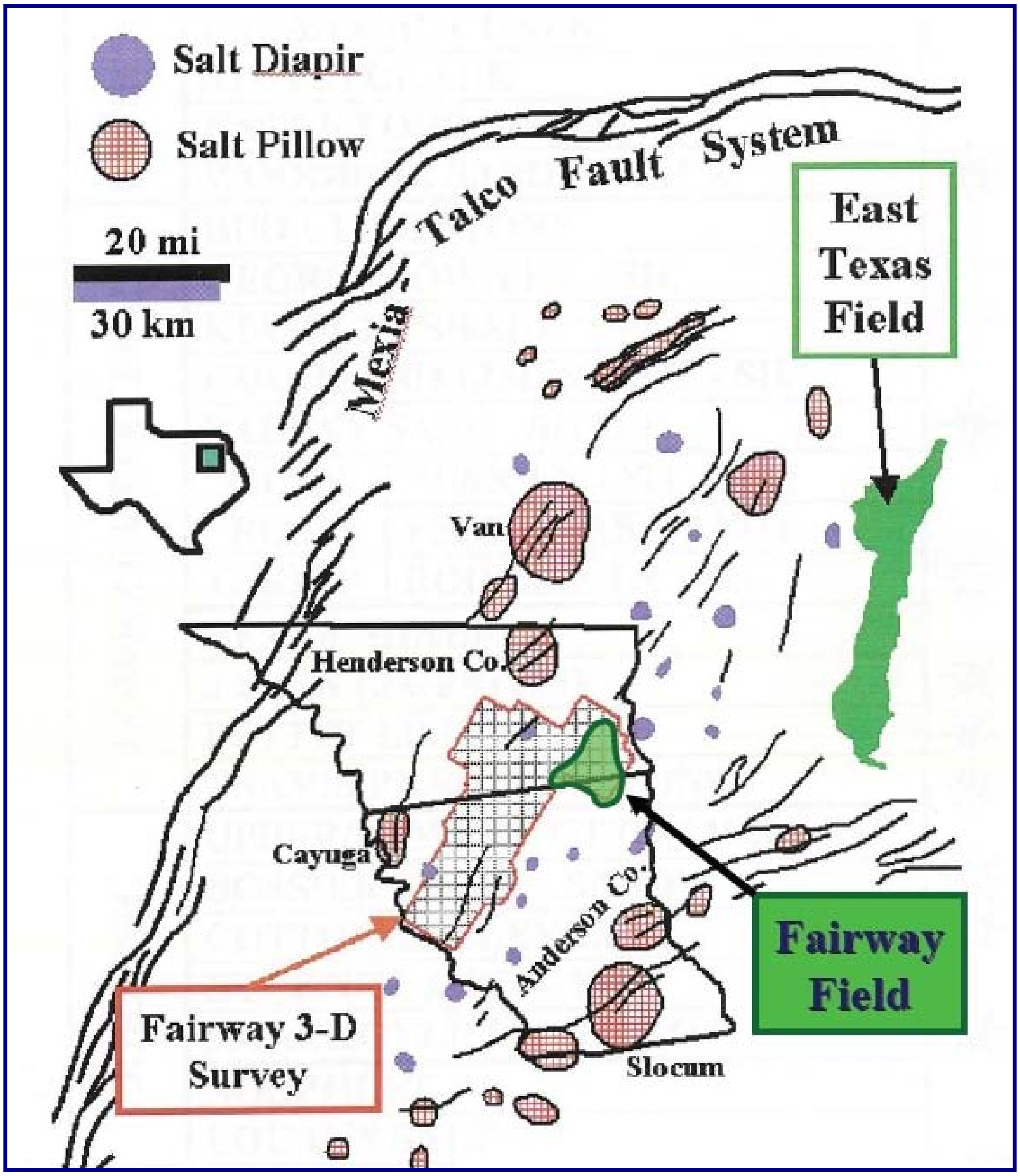


Figure 17. Overview map of the location of Fairway Field in East Texas, Henderson and Anderson Counties, the base is from Seni and Jackson (1983)

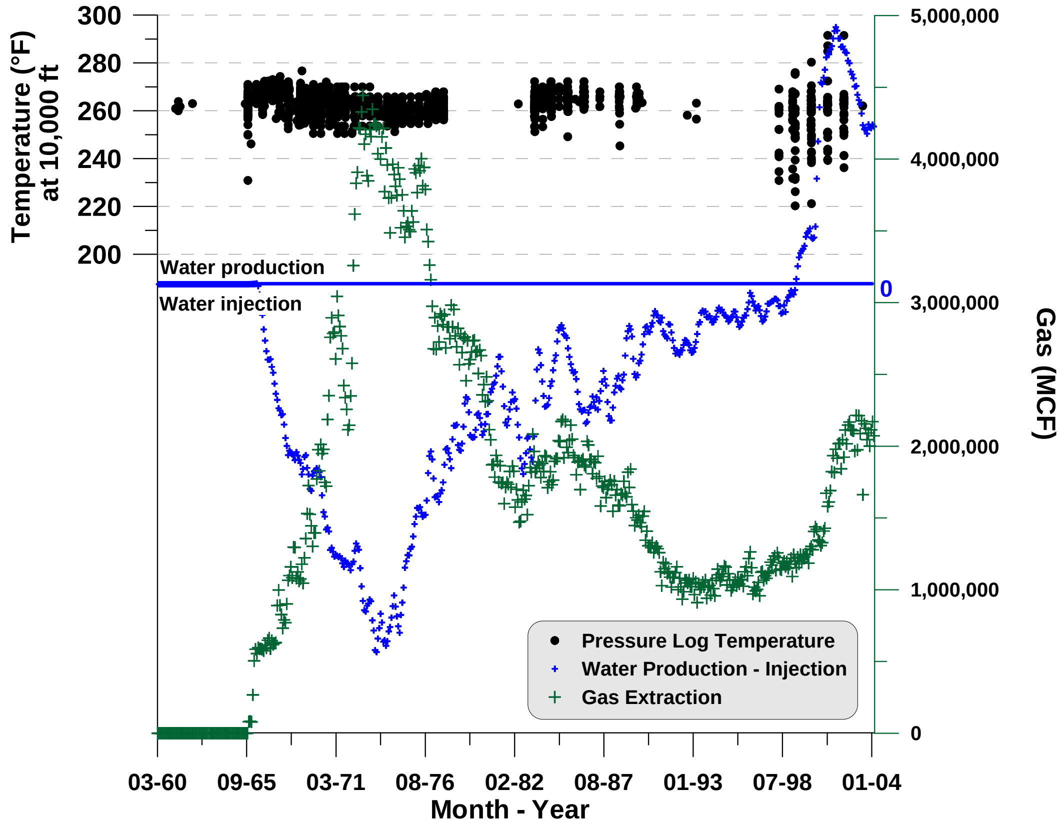


Figure 18. Fairway Field pressure log temperatures compared to the water injection and gas extraction from March, 1960 to January, 2004. There is no axis for water, rather distance below the blue line shows increasing injection and distance above the blue line shows increasing production.

The review of temperature changes over the field production history showed only slight fluctuations in temperature from the initial measured values in 1960 to 2005. The well log BHT temperature values were from a subset of logs between 9,000 and 11,000 feet and corrected to 10,000 feet using the average geothermal gradients based on a surface temperature of 70°F (Figure 18). There were 2070 pressure logs used to review the temperature changes. The average temperature value fluctuates slightly between 1960 and 2004, most directly related to the amount of water injected (waterflooding) and the gas extraction, yet it is difficult to determine if one activity has a greater impact on the reservoir temperature than the other with the two activities occurring at the same time. The average temperature decreased from 1965 to 1976. Then after the waterflooding and gas extraction were reduced, there is a slight increase in measured temperatures in the 1980s indicating the field did start to return to the warmer, natural background temperature. There is more scatter in the data in the 2000s that possibly is related to the water production, or the increase in the number of wells. The water amount shown in Figure 18 is the difference between the monthly injection and production values. Throughout the life of the field as noted above, there has been injection and extraction of both water and gas.

GEOTHERMAL RESOURCE UTILIZATION

This eastern Texas geothermal assessment focused on the moderate to high temperature geothermal resources accessible through depths typically associated with hydrocarbon wells. The advantages of using oil and gas wells/fields are: 1) the geothermal and oil and gas industries have overlapping knowledge bases that can build on each other's expertise to improve both industries; 2) existing oil field data are accessible for initial reservoir review and understanding, reducing exploration costs compared to conventional geothermal systems; 3) oil and gas fields have the existing infrastructure necessary for geothermal project development, i.e., roads, well pads, electrical connections to the grid, etc.; 4) the new binary turbine designs for distributed energy production makes them easier to plug and play with oil/gas wells; 5) oil and gas fields are normally in a state of flux with wells coming online and being abandoned creating new opportunities for geothermal production. There are different scenarios which can be used to develop the geothermal resources that exist in Texas from electrical production to direct use of the heat. These are explained in this next section.

Electrical Production

For geothermal resources to be commercially viable, heat must be removed from the produced fluid at a sustainable rate, and return a reasonable profit. These conditions depend on the quality of the resource - temperature, depth, fluid characteristics, and the ability to extract and then reinject the fluids. These factors are a function of geology, i.e., rock type, layer thickness, porosity, permeability, pressure, and thermal history. Determining the temperatures within a geothermal reservoir (field) is the first step in evaluating the resource since temperature can be used to determine the extent of stored energy (Appendix C). Using the temperature, estimates are made as to how much heat is available for producing electricity under different fluid production scenarios. Secondly, a recovery factor is calculated for the amount of heat available for extraction. The recovery factor depends on such variables as the type of fluid (water or gas) that causes flow from the formation into the well, rock and fluid compressibility, the water influx from shale, reservoir pressure decline, production rate, amount of heat extraction at the surface, and which formation is used for fluid injection. Many of these variables are difficult to evaluate and typically a well production and injection test are needed.

Since Texas has extensive and diverse geothermal resources for electrical production, it is helpful to divide them into three categories for discussion: 1) geothermal-geopressured resources; 2) coproduced fluids; and 3) enhanced geothermal systems.

Geothermal-Geopressured Resources

A geothermal-geopressured resource consists of highly pressurized hot brine, due to pore water being trapped during the rapid burial history. There are three dominate parallel zones of geopressured formations (Wilcox, Vicksburg, and Frio) consisting of thick sand deposits that parallel the Texas Gulf coastline. These bands are considered the most important resource of geopressure in the United States (Wallace et al., 1979) (Figures 4 and 20). The weight of the impervious rock layer above the entrapped sand lenses, coupled with decomposition of existing organic matter, results in highly pressurized zones containing dissolved methane. The heat in the fluid is from the sediment being heated from below by natural radioactive decay in the basement rock. Wells drilled into geopressured formations flow naturally to the surface. Water temperatures in these formations range from approximately 200°F to over 450°F. The total geopressure thickness is estimated at 50,000 feet; wells are drilled into geopressure at depths of 8,500 to 18,000 feet in eastern Texas (SMU-TX RRC data).

Although the entire Gulf Coast area is considered geothermal-geopressured at various depths, Bebout et al., (1982; 1983) described specific "geothermal fairways" having the most prospective reservoirs. These fairways are based on pressure, temperature, and sediment thickness. From northwest to southeast the fairways are in the *Wilcox formation*: Zapata, Duval, Live Oak, DeWitt, Colorado and Harris; and in the *Frio formation*: Hidalgo, Armstrong, Corpus Christi, Matagorda, and Brazoria (Figure 20). Examples of the geothermal fairway parameters for the Wilcox formation are shown in Table 3.

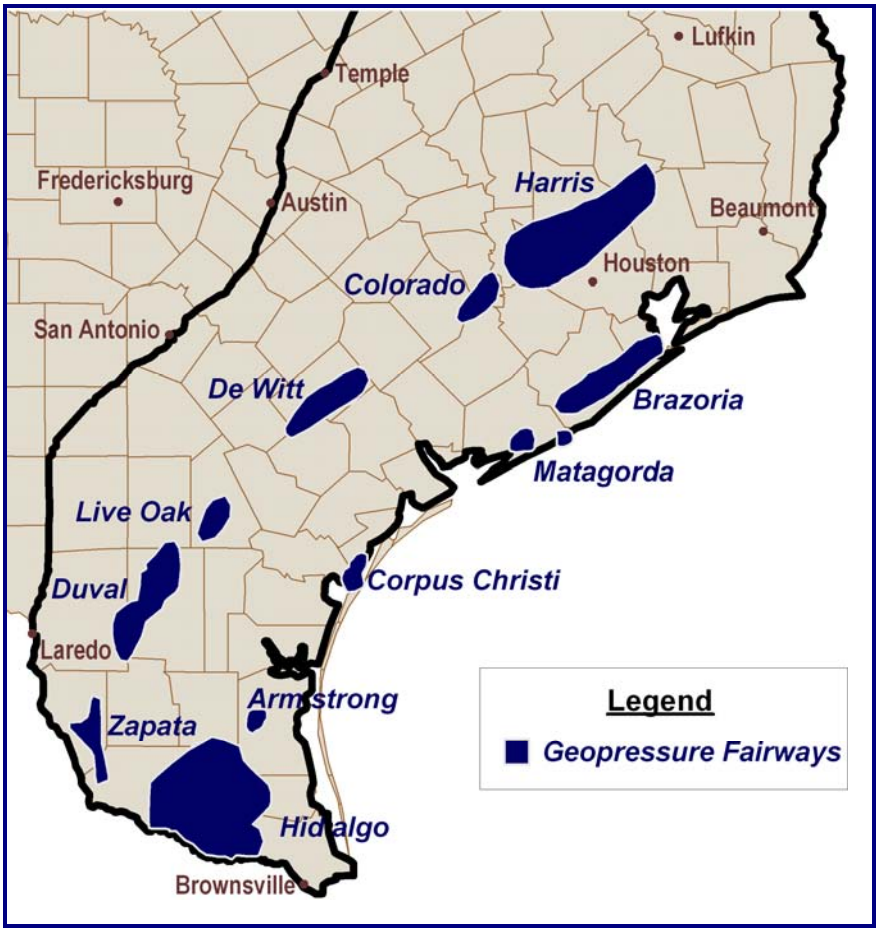


Figure 20. Geothermal - geopressured fairways as depicted by Bebout et al. (1982; 1983).

Table 3. Summary of the physical characteristics of the six Wilcox geopressured geothermal fairways (Table 4, Bebout et al., 1982). * SWC = Side wall core; ** DC = Diamond core

	ZAPATA	DUVAL	LIVE OAK	DE WITT	COLORADO	HARRIS
PART OF WILCOX	Upper	Upper	Upper	Lower	Lower	Lower
DEPTH TO TOP OF PROSPECTIVE SANDSTONE (ft)	9,600 to 10,500	11,000 to 12,000	9,200 to 11,000	10,490 to 10,660	10,960 to 11,400	12,500 to 13,300
THICKNESS OF PROSPECTIVE SANDSTONE (ft)	280 to 620	> 600	> 600	550	1,600	> 2,000
TOP OF GEOPRESSURE (0.7 psi/ft)	10,700 ft	10,000 ft	9,950 ft	10,000 ft	12,000 ft	11,550 ft
TEMPERATURE	300° F at 11,400 ft	300° F at 10,750 ft	300° F at 11,000 ft	300° F at 10,850 ft	300° F at 11,780 ft	300° F at 12,990 ft
POROSITY (%)	17 to 22	7 to 14	16 to 24	6 to 25	4 to 19	Average: 15
PERMEABILITY (in millidarcys)	0 to 19 *SWC	0.1 to 44 **DC	5 to 40 SWC + DC	0.01 to 242 DC	Most < 5; locally up to 545 DC	Most < 1 DC

Wallace et al., (1979) estimated that over 2,000 exajoules (EJ) of recoverable thermal energy and methane are contained within the Texas Gulf Coast geopressured deposits. Uncertainties about the reservoir mechanics, the connectedness of the geopressured zones, and their capability to produce brine for extended periods of time, are often brought up as a concern. In the final summary documentation of the extensive DOE studies, John et al. (1998) state the brine flow tests completed on the wells at Pleasant Bayou (Brazoria fairway), Gladys McCall (Cameron Parish, LA), and Hulin (Vermillion Parish, LA) proved the geopressured resource along the Gulf Coast to be viable for development (Figure 21). The longest tests were done on the Department of Energy (DOE) Pleasant Bayou well No. 2 in Brazoria County. During 1989-1990 electrical production demonstration the well (perforated from 14,644 to 14,700 feet) produced 10,000 bbls/day of brine at 290°F along with 22 scf/bbl of gas. The total cumulative flow for the well from 1978 to 1992 was 25 million bbls with the average flow rate during the last five years at 18,000 bbls/day at a pressure of 3,000 psi (John et al., 1998). From this demonstration, it was concluded that the well could produce at 20,000 bbls/day for 20 years (Shook, 1992). The research also found that if a substantial portion of the produced water is reinjected into the producing reservoir to maintain reservoir pressure and fluid flow rates, more than 90 % of the gas can be extracted from the formation (Gregory, 1977). This gas extraction is accomplished while electricity is being produced from the extracted geothermal heat.

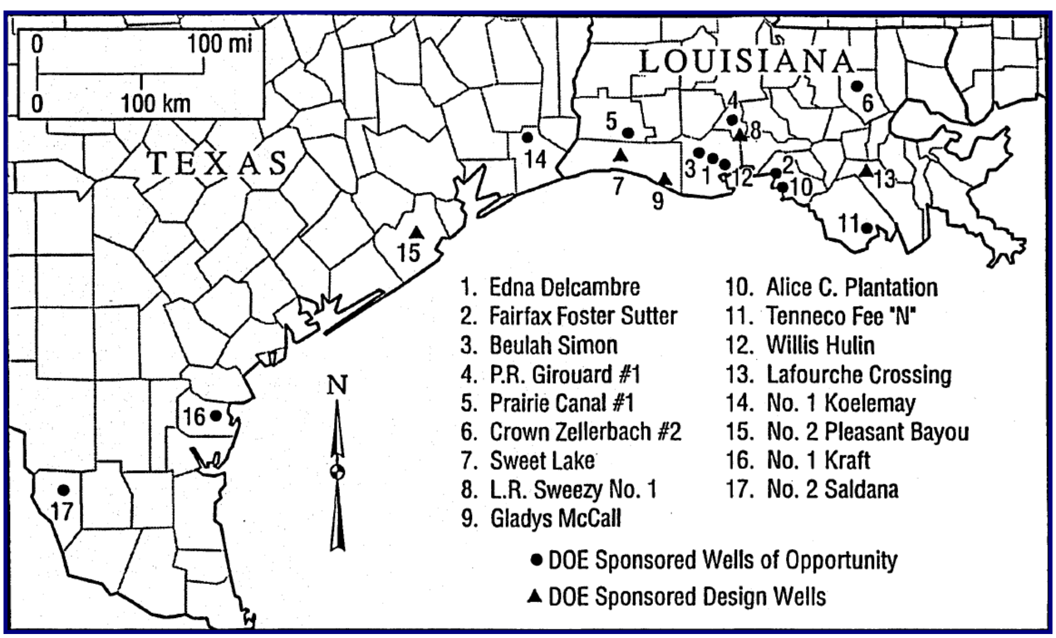


Figure 21. Location of wells investigated for the DOE geopressured - geothermal research program in the Gulf Coast (John et al., 1998).

Coproduced Resources

Coproduced geothermal resources are directly integrated into the production of oil and gas. Coproduction uses a well for the purpose of *both* the extraction of oil and/or gas and the heat from the fluids for electricity. The electricity can be used on-site or sold to the grid. Traditionally the fluid (brine) is trucked off or directly reinjected at an expense to the project. Locations where the fluids are directly injected on-site are the “low-hanging-fruit” for coproduction sites. The business plan incorporates the brine water as an economic commodity to allow for longer hydrocarbon production from a well. This type of development is the best case scenario for the utilization of the geothermal resource from an oil and gas field because of the minimal additional expense - primarily the installation of binary turbines. Fields which currently use waterflooding to increase hydrocarbon production from deep formations could be an initial focus point for geothermal development.

The second scenario for coproduction is the end of the life of oil and/or gas wells or “stripper’ wells. In these cases the well produces adequate hydrocarbon volumes to be economically viable until at some point of increasing production of brine water it is no longer economic. Rather than abandoning the well, to keep it economical the well could be converted to coproduction to recover the additional expense of the produced brine. This conversion allows a greater percentage of the hydrocarbons from the field to be extracted while producing a renewable energy to run field applications and/or to sell to the grid. For the transition from an oil/gas well to a coproduced well, additional treatment of the well may be necessary since the quantity of fluid needed for geothermal electrical production is often much greater than the capping/abandonment point for oil/gas wells.

The third scenario is to work with oil and gas companies drilling new wells. When a well is drilled that produces too much water to develop as an economic hydrocarbon well, the well would be immediately completed as a geothermal well to maximize water production and the electrical power capability.

Additionally, as oil and gas fields are developed, drilling is designed to avoid all formations with water and to perforate only the zones with hydrocarbons. Because of this pattern, the geothermal resources (brine water) are left behind, “stranded” (Erdlac, 2008). The extent of stranded water in Texas fields is not readily determined because companies do not focus on those zones and records of possible water production are not required by the Texas Railroad Commission. The current quantification of brine available is primarily a result of the research completed during the 1970s to 1990s geopressured - geothermal studies for the Gulf Coast Region. Areas such as East Texas where the technique of waterflooding is used to extract more oil and gas have current information on fluid injection volumes. Thus, it is certain that far more fluids presently exist stranded in oil and gas fields than the current records show.

Fluids Produced and Injected

Texas is the nation's number one oil and gas producer with more than 216,000 active oil and gas wells statewide. Along with these are the injection and disposal wells which return the produced water and frac fluids from these oil and gas wells. Texas has more than 50,000 permitted oil and gas injection and disposal wells[7]. Disposal wells inject fluid into an underground interval that is not producing oil and gas. Injection wells reinject fluids into the same or similar reservoir, from which the fluids originated, usually for secondary recovery of the oil. Operators use secondary recovery techniques when an oil field's recovery rate has decreased. One technique of secondary recovery, sometimes known as waterflooding, injects produced saltwater into a reservoir to reestablish sufficient pressure that will allow an operator to recover additional amounts of oil.

The quantity of water an individual oil and gas well produces is not recorded by the Railroad Commission. However, there is a section on the TX RRC W10 Form for "Daily Water" and some operators fill it in. Review of the records between 1994 and 2007 from this form includes over 12,000 wells for Districts 1 - 6 (Figure 22). Using the 12,000 wells as indicators of production depths with the most available water, there are two peaks, one between 5,000 to 7,000 feet and a second between 9,000 to 11,000 feet (Figure 23). Based on the total water produced, highest flow rates are produced at depths less than 7,000 feet and most likely have too low a temperature for electrical production (Figure 23). Of the 12,000 wells there are only three wells [API # 4223902390 (Jackson Co.), 4249900386 (Brazoria Co.), 4203931304 (Wood Co.); Figure 24] with recorded daily water production values of over 6,000 barrels per day (175 gpm) which is close to the minimum flow rate necessary for electrical production with current binary technology (~200 gpm @ 200°F for 50 kW). Combining the fluids from multiple wells is one method to achieve the desired flow rates.

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[7] Jan. 2010, http://www.rrc.state.tx.us/about/faqs/saltwaterwells.php

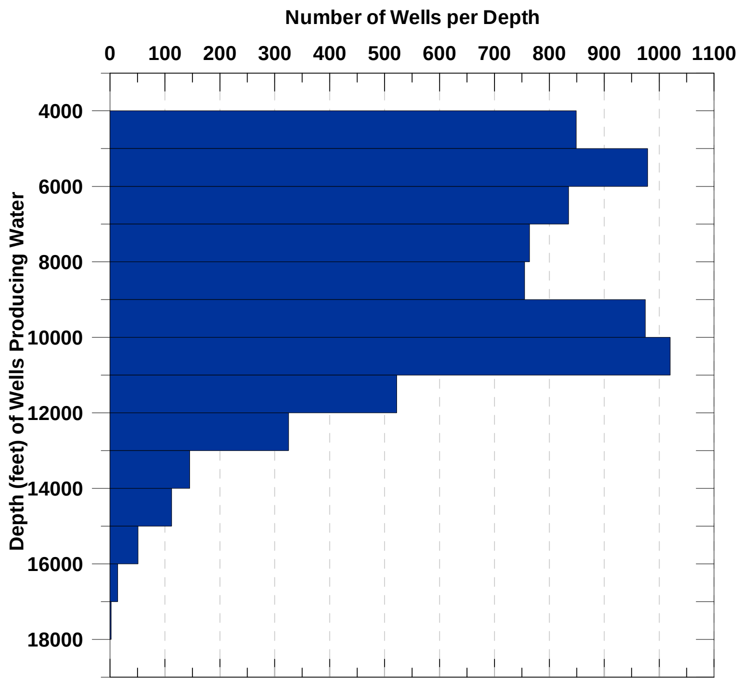

Figure 22. Histogram of recorded well daily water production (TX RCC form W10) for Districts 1 - 6.

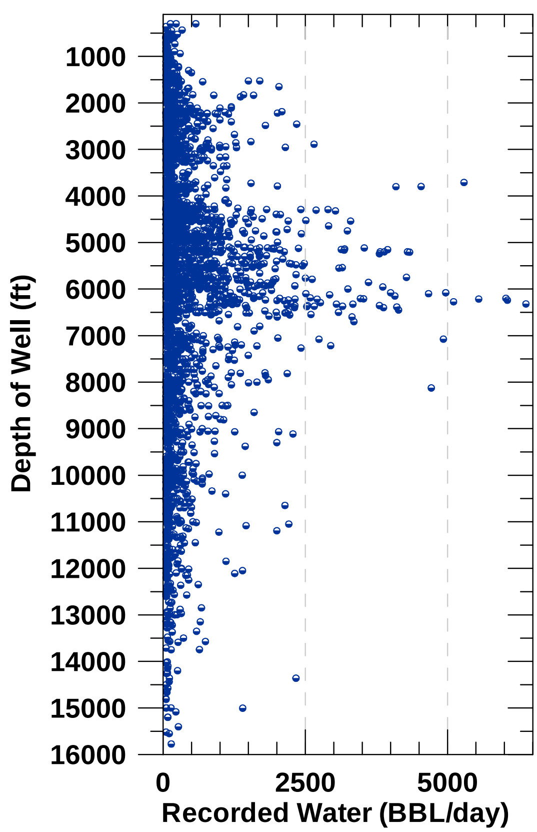

Figure 23. Daily water production versus depth of well.

The counties with the highest total volumes of combined injection and disposal are shown in Table 4. These are based on the records from the H10 form of the Texas RRC[8]. Figure 24 is a map of eastern Texas with the county water volumes. Guadalupe County near San Antonio has the largest volumes for 2007 and more than double the per well injection rate. In East Texas, Gregg and Upshur Counties are the two counties with the highest injection rates. Johnson County, in North-Central Texas, is unique in going from no disposal in wells in 2002 to having the 10th largest volume in 2007. The amount of fluid a formation has injected into it gives an indication as to how much is available for production. Therefore, deep (>10,000 ft) injection wells with high disposal rates are considered one initial indicator of where to explore for geothermal development.

Table 4. The total volume of well injection and disposal in barrels (BBLS) for each county during the years 2002 and 2007.

COUNTY	2002 BBLS	BBLS/day '02	2007 BBLS	BBLS/day '07	# of wells	BBLS/well '07
BRAZORIA	76,018,663	208,270	82,961,267	227,291	114	727,730
CALDWELL	85,350,824	233,838	126,802,271	347,403	82	1,546,369
FORT BEND	40,404,936	110,698	2,988,225	8,187	98	30,492
GREGG	162,441,485	445,045	171,657,048	470,293	68	2,524,368
GUADALUPE	137,000,401	375,344	316,642,226	867,513	54	5,863,745
HARRIS	41,152,107	112,745	37,261,790	102,087	149	250,079
JACKSON	55,276,969	151,444	44,467,697	121,829	133	334,344
JOHNSON	0	-	65,750,533	180,138	24	2,739,606
MONTGOMERY	39,537,722	108,323	49,856,560	136,593	54	923,270
RUSK	85,265,556	233,604	102,776,570	281,580	184	558,568
STEPHENS	179,602,280	492,061	208,317,611	570,733	683	305,004
UPSHUR	129,415,393	354,563	130,498,073	357,529	44	2,965,865
VAN ZANDT	36,564,117	100,176	29,701,971	81,375	45	660,044
WICHITA	71,703,725	196,449	72,771,002	199,373	1450	50,187
WOOD	78,710,794	215,646	68,851,192	188,633	140	491,794

[8] http://webapps.rrc.state.tx.us/H10/h10PublicMain.do

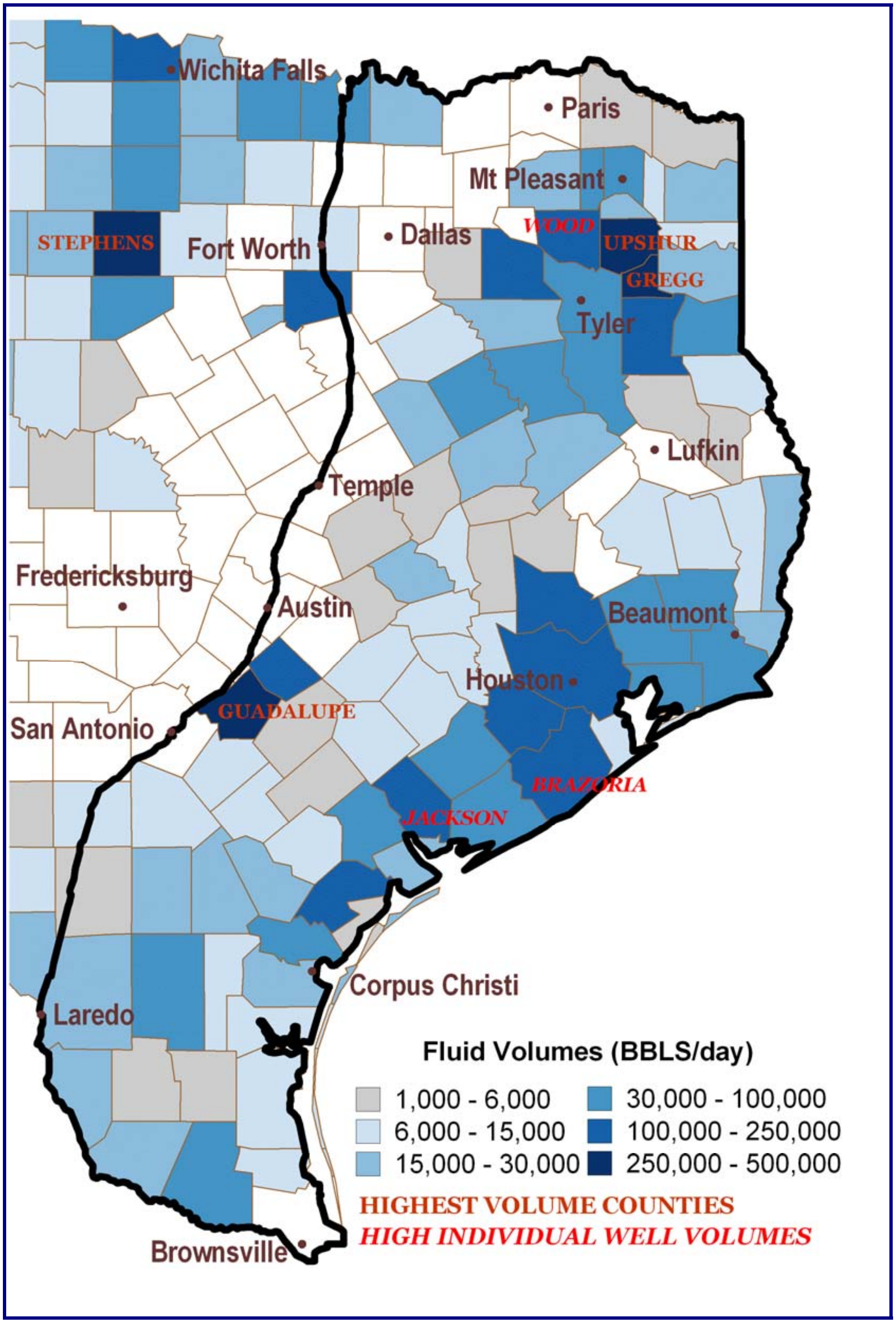

Figure 24. Map of eastern Texas with counties shaded according to their combined injection and disposal volumes.

Available Wells

There are various methods of exploration to determine which wells within a field are the "low-hanging-fruit" for geothermal exploration. The ability to extend the life of a field and use existing wells leads to the review of wells in line for plugging and abandonment. During the last three years, there have been 19,328 wells plugged in Texas (Table 5). For the I-35 study area which includes RRC Districts 1 - 6, there have been 2,684 wells abandoned in 2009 alone. By comparing data within the SMU-TX RRC Database, 47% were deeper than 10,000 feet and 54% were greater than 250°F. Therefore, it is estimated that 45 to 55% of the wells abandoned in 2009 were capable of geothermal energy production. If 50% of these wells (from Districts 1 - 6) were converted and had a minimal energy output of at least 250 kW, eastern Texas could continuously generate 335,500 kW (33.5 MW) of base load power. Using the current availability for geothermal power plants at 94%, then 2,762,641,200 kW/hours of electricity per year could be produced from the wells instead of them being plugged. That is enough for 8,400 homes or a whole county in some cases.

Table 5. Texas RRC Summary of Drilling, Completions, and Plugging Reports for 2009.

	Year Summary			TX RRC Districts for 2009					
	2009	2008	2007	1	2	3	4	5	6
Drilling Overview									
New Drill Dry/Completions	12,937	15,255	12,291	499	342	481	986	687	1,345
Re-Enter Dry/Completions	509	513	369	19	7	22	8	0	8
Re-Completions	1,852	1,615	1,638	100	187	178	195	82	103
Total Completions	15,279	17,337	14,247	618	536	680	1,188	768	1,456
Oil Completions	5,860	6,208	5,084	460	117	298	81	42	118
New Drill	4,618	5,202	4,051	365	49	212	60	37	95
Re-Enter	239	259	186	17	2	14	1	0	2
Re-Completion	1,003	747	847	78	66	72	20	5	21
Gas Completions	8,706	10,361	8,643	135	409	349	1,096	706	1,307
New Drill	7,933	9,501	7,853	114	291	245	918	630	1,225
Re-Enter	43	72	67	2	5	6	6	0	3
Re-Completion	730	788	723	19	113	98	172	76	79
Injection/Other Completions	713	768	520	23	10	33	11	20	31
Total Holes Plugged	6,390	6,046	6,892	498	350	562	690	226	358
Completed Holes	6,371	6,000	6,841	498	350	561	689	225	316
Oil	3,991	3,855	4,682	406	86	318	242	161	169
Gas	1,916	1,636	1,620	83	250	219	422	33	135
Other	464	509	539	9	14	24	25	31	12
Dry Holes Drilled.Plugged	19	46	51	0	0	1	1	1	0
New Drill	17	45	49	0	0	1	1	1	0
Re-Enter	2	1	2	0	0	0	0	0	0

http://www.rrc.state.tx.us/data/drilling/drillingsummary/2009/annual2009.pdf

Other wells considered "available" are those used in secondary recovery applications. The best case scenario is where produced water is directly connected to an injection well. This situation allows for a binary turbine to be installed between the two wells with minimal infrastructure changes necessary. As shown in Table 5, the quantity of the fluid being injected or disposed of is huge. For the combined volumes of Districts 1 - 6 the total amount was 2,172,701,192 barrels in 2007. The average barrels per well was 364,242. Over half of the fluid was used for secondary recovery. There are currently 2,237 secondary recovery injection wells in District 1 - 6 that could be reviewed for depth and interconnection within the hydrocarbon field to see if they are injecting into formations with temperatures over 200°F.

Enhanced Geothermal Systems Resource

Enhanced Geothermal Systems (EGS) are developed in geologic formations with limited quantities of water but at high temperatures (Tester et al., 2006). These formations become productive when fluid is injected into the rock to act as a carrier for the extraction of heat. This type of geothermal resource potential is huge in comparison to other geothermal categories in Texas because it utilizes deeper - hotter resources and therefore has higher conversion efficiency. EGS can essentially be developed anywhere at any well depth where temperatures of 300°F or higher exist. The horizontal drilling and multiple stage fracturing techniques in common use today are forming potential EGS geothermal reservoirs in many wells at many locations. Texas has the advantage of using the sedimentary basins, hydrocarbon knowledge, and existing well situations to increase the possibility of near-term development of EGS.

The EGS resources occur because of heat conducting from the Earth's interior and natural radioactivity within the rocks. The basement rock of the Sabine Uplift in East Texas is considered the area with the highest heat flow in Texas (Blackwell and Richards, 2004a) (Figure 1). Here the potential for EGS is the greatest, especially if combined with coproduction of oil and gas from the upper formations. The calculated subsurface temperatures in East Texas are 400°F at 20,000 ft (Negraru et al., 2008). A realistic EGS potential for Texas is 318,652 EJ (Negraru et al., 2008) with the majority of the thermal energy from the eastern half of the state because the Permian Basin is relatively low temperature at similar depths to east Texas. For a perspective as to how much 318,652 EJ of EGS resources can produce, using an average binary turbine conversion rate of 10% from thermal energy to electrical production, and a very conservative availability rate of 0.2%, there is enough to power the entire industrial sector for over 500 years at the 2008 Texas electrical consumption rate of 32,525 thousand megawatt-hour (MWh)[9]. Even modest utilization of this EGS resource is capable of supplying a large portion of the state's energy on a permanent baseload basis.

Direct Uses of Geothermal Resources

Many of the wells in Texas are drilled to depths where the temperatures are less than 200°F. In these situations, the water production can be reviewed for specific economic applications. Use of the warm to hot water for commercial applications or community space heating is referred to as "Direct Use". For instance, John et al., (1998) determined the following applications from the Gulf Coast geothermal - geopressured wells: the heating of houses, sulfur extraction, coal desulfurization, chemical processing, extraction of chemicals from brine, water desalination, fish rearing, greenhouse heating, cane sugar processing, lumber drying etc.

Absorption chillers use heat instead of mechanical energy to provide cooling. This is another application for using the produced warm to hot water. While most vapor compression chillers require electricity to operate the machine, absorption chillers use heat, typically in the form of steam or hot water. The absorption chiller is designed for large applications such as hospitals, industrial settings, high-rise offices, so this is a direct use for wells that are being drilled within city limits or near a specific end user site.

For existing oil and gas fields in rural areas, direct use applications can be added at the surface for increased productivity of all the resources. Direct use applications are common in the western United States. Agencies willing to assist in project development are the USDA, Rural Alliance for Renewable Energy (RARE), and National Renewable Energy Laboratory (NREL) - DOE EERE - Geothermal Program.

Heavy Oil Extraction

The Southwest Texas Heavy Oil Province is the largest heavy oil resource in the Gulf Coast region, primarily located in Zavala, Maverick, Uvalde and Kinney counties. It is found from depths of 0-3000 feet. Potentially it is the second-largest identified reservoir in the United States (Ewing, 2005). In 1994, Seni and Walter researched the use of geothermal energy to extract

[9] http//:www.eia.doe.gov

heavy oil in South Texas. To determine how much of the resource was left, they compared the overall sizes and extraction rates of different reservoirs. Thus "medium- and heavy oil reservoirs constitute 10% of the large oil reservoirs in Texas, their cumulative production represents only 8.4% of the production from the large oil reservoirs. The 1.6% difference is a result of the lower average productivity and is equivalent to a difference of 629 MMbbls (1.0 x 10^8 m^3) (or 1.6% x total cumulative production of large reservoirs in Texas)." This is one resource target still available for production in conjunction with geothermal energy development.

The heavy-oil reservoirs are concentrated in the Jackson Group, Cole sandstone, whereas medium-oil reservoirs are concentrated in the Government Wells, Lorna Novia, and Mirando sandstones within the same area. The medium oil resource is larger than the heavy oil resource. This allows for a multi-level resource development using medium oil, heavy oil and geothermal resources. The geothermal resources reach temperatures of over 350°F and are below the oil reservoirs.

The San Miguel 'D' sandstone (2,100 feet depth) was targeted for heavy oil research in the early 1980s, when Exxon and Conoco produced 417,673 barrels from pilot plants (Ewing, 2005). The viability of using the geothermal-geopressured resources was studied again in 1991 as part of a Department of Energy research project (Negus-de Wys et al., 1991). The conclusions at that time were that the break-even price for oil needed to be $14/barrel and gas $2 per thousand cubic feet. Using those figures, at the time there would be a payback in less than two years. The study included a pilot project using the Alworth Field in South Texas and the Wilcox Formation for a water source at fluid temperatures of 250°F to 500°F between 16,000 and 18,000 feet. Seni and Walter (1994) continued to study the heavy oil extraction, concluding that this was the best area to test the viability of using geopressured-geothermal fluids to improve oil recovery. They noted that the Upper Wilcox geopressured-geothermal reservoirs will produce approximately 1,000 to 2,000 barrels per day of fluids. These rates are adequate to test the geothermal technology and evaluate engineering data on South Texas geothermal and heavy oil reservoirs.

During the past few years oil prices (USO) fluctuated between $117 and $40 per barrel and the natural gas fund (UNG) between $63 and $8, showing how much variation there can be in the market. The current focus on renewable energy may contribute to renewed interest. With the need for energy continuing to increase, as Ewing (2005) stated, "this resource deserves another look."

DEVELOPMENT and COMMERCIALIZATION

Legal Aspects

According to the Texas Geothermal Resources Act of 1975, "Geothermal energy and associated resources" means: (1) all products of geothermal processes, embracing indigenous steam, hot water and hot brines, and geopressured waters; (2) steam and other gases, hot water and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations; (3) heat or other associated energy found in geothermal formations; and (4) any by-product derived from them. The term "by-product" means any element found in a geothermal formation which when brought to the surface is not used in geothermal heat or pressure inducing energy generation" (Oberbeck, 1977). The Railroad Commission of Texas, Oil and Gas Division, has defined geopressured aquifers under its documentation “Rules having Statewide General Application to Oil, Gas, and Geothermal Resource Operations within the State of Texas,” (March 1982) as “a geopressure aquifer as having a pressure of greater than 0.5 pounds per square foot of depth and a temperature gradient in excess of 1.6°F per 100 feet of depth. The Texas Geothermal Resources Act of 1975 was amended in Vernon’s Texas Codes Annotated, Natural Resources, Section 141.002(5) to clarify “*by-products*” as: “any other element found in a geothermal formation which is brought to the surface, **whether or not** it is used in geothermal heat or pressure inducing energy generation”. This indicated that methane entrained in geothermal fluids is considered part of the geothermal resource which includes by-products, (Sherk, 1982).

As geothermal energy is developed in Texas, there will be legal discussions. According to the SMU Geothermal Energy Utilization Conference presentations by Stepp (2009) and Gibson (2009) examples of potential legal issues include:

- Debate of ownership between the surface owner and mineral right owner.
- How does the rule of capture and trespass by fracturing impact geothermal projects?
- Is the brine fluid still categorized as drainage if other valuable minerals are extracted from the fluid but the remaining fluid or gas continues through the binary system?
- What if the valuable mineral is really defined as a waste in Texas but is now being used productively?
- If CO_2 is utilized as a heat transmitter, and not emitted when extracted from the hydrocarbons is it considered a “waste”?
- Mineral owner may be liable for waste if not capturing heat from produced water.

The most recent legislation is the Texas House Bill 4433, September 2009, which is an exemption from the severance taxes on oil and gas incidentally produced in association with the production of geothermal energy. The Texas Comptroller office is working on the determination of incidentally.

Business Development

Leasing and development of geothermal projects have been occurring for the last 40+ years in the United States. Yet the business plan for developing low-temperature (< 300°F) geothermal projects in areas outside of the Western United States is still considered "risky" (Dunn, 2010). According to the Department of Energy, geothermal energy has one of the lowest levelized costs (cost of power production over the life of a power plant) of any form of power, renewable or nonrenewable! The biggest risk for geothermal project development is the capital needed on the front-end. Potentially this can be as high as 95% of the capital budget (Dunn, 2010). In the last few years, there are now companies with a business plan to develop geothermal energy in relationship to oil and gas fields. Since there are many different scenarios for geothermal development, a series of questions were compiled to assist in new development, see Appendix D.

Technology Changes and Impacts

How much energy can be produced from one well? This is a common question. The simple answer is that it varies with temperature, fluid flow rates, and the type of technology used for the power plant. An initial set of calculations are shown in Appendix C for calculating the electrical production that will show how changing the different parameters (i.e., casing size, flow rates, thickness of lithology) impacts the electrical output.

The improvement in binary geothermal technologies to use lower temperature geothermal wells has resulted in renewed emphasis on developing the Texas geothermal resource. A paradigm shift for the geothermal industry was started in 2006 when the lowest temperatures currently in production dropped to 165°F at Chena Hot Springs, Alaska. The Pratt & Whitney Power System (PWPS) PureCycle® changed the focus on geothermal resources from sites using approximately 300°F+ producing 1 - 10s of MW of electricity to low temperature (165 - 300°F) sites producing as few as 50 kW with new technologies. In October 2008, the ORMAT Technologies Company installed a binary plant at the Rocky Mountain Oilfield Testing Center (RMOTC) operating on a

195°F fluid from a series of oil striper wells in the Tea Pot Dome field, Wyoming. This installation was the first commercial application of coproduction. In recent years, new products have entered the electrical power market with designs starting as low as 180 to 200°F in Texas with a required delta T of approximately 100 to 120°F between the hot and cold fluid sources (Appendix D).

Using different technologies, there are four new geothermal power demonstrations currently underway. In Texas, there is a DOE demonstration in Liberty County, just north of Houston that is designed to generate 250 kW. The developer is Universal GeoPower LLC, and they will be using the PWPS PureCycle®. There is a second DOE demonstration along the Gulf Coast of Louisiana in progress by Louisiana Geothermal LLC. Using the ElectraTherm Green Machine there are two projects in this region. One is a RPSEA project in central Mississippi deployed by Gulf Coast Green Energy using a Denbury Resources well. The second is a project Hilcorp Energy Company and Cleco Utility Company are developing in western Louisiana. Both projects are expected to be 50 kW or less. Other companies are actively proceeding to develop geothermal power in Texas, such as the GeoPower Texas Company has purchased the rights for geothermal leases from the Texas General Land Office for wells off-shore along Galveston, Brazoria, and Matagorda Counties.

The current technologies are based on either temperature or pressure or both for generating electricity. These power plants are small, easily transportable and efficient enough to produce small amounts of electricity; yet can be scaled-up to produce MWs. The purpose is to tap into small applications that have been previously overlooked by the large-scale power plant development companies. Texas has the capability to use the geothermal resources in large-scale (MWs) production: converting an entire oil field into a geothermal field, EGS projects, or geopressured-geothermal development. It is also prime for the start-up project for mini power plants (kWs) on low flow, low temperature sites.

CONCLUSIONS

Geothermal energy power production is a renewable baseload resource. Through reservoir engineering and proper management of the resource the necessary heat extraction can be maintained over decades. The use of sedimentary basins and geopressured formations are the initial entry points for companies in Texas to develop geothermal electrical production.

Developing existing hydrocarbon fields into geothermal electrical production has the quickest potential for tapping into the thermal energy resource stored under Texas.

The Future of Geothermal Report (Tester et al., 2006) suggests Enhanced Geothermal Systems (EGS) could be a sustainable source of energy. There will be initially high costs for development that will then decrease as technology, knowledge, and market growth improve. Texas has the resources to be one of the proving grounds for EGS through use of deep sedimentary basins, and in doing so, decrease the initial EGS drilling and reservoir engineering expenses. The geothermal - geopressured zones in South Texas are where the heat flow and temperatures are highest in Texas. This is the area of highest temperatures reaching over 350°F at 12,000 feet, over 450°F at 19,000 feet, and over 500°F at 23,500 feet. Unlike the Gulf Coast geopressured areas, the amount of fluid available for production in South Texas at these depths is not quantified, but shallower depths have lower permeability. These deeper formations are a candidate for EGS geothermal projects. With the EGS projects currently under development in Australia, Europe, and western United States, an EGS project development in Texas is definitely viable.

Along with the use of EGS resources in South Texas for electrical production, the geothermal resource can be used to increase the production of heavy oil. The areas for EGS are collocated with the heavy-oil reservoirs. The ability to cascade the use of the produced water with other industries increases the economic viability of a project. The power plants are not able to extract all the heat from the fluid stream, leaving heat for other applications. Geopressured-geothermal resources can also be used for applications such as absorption chillers, desalination, agriculture, and aquaculture projects. Geothermal energy can be teamed with other renewable energies that are surface land space intensive.

One advantage of the new less than 1 MW geothermal power plant technology is the scalability and development in configurations that are either distributed or centralized. Geothermal power plants have a very small footprint and therefore can be installed as part of a neighborhood, or a commercial building. This could directly reduce the usual 59% of the electricity normally lost to generation, transmission, and distribution[10].

[10] 2006, http://www.eia.doe.gov/.

Using information from existing oil and gas wells, tens of thousands of temperature data points can be used as an exploration tool for defining the most accessible resource locations. The temperatures from well log records can be corrected for in-situ temperatures, or pressure temperature data can be used as a proxy for equilibrium temperature. Although temperature at depth is only the initial starting point for reviewing potential resources, the extent of BHT data in Texas is huge with over 600,000 wells currently on record. This assessment shows that the general trend of temperatures in Texas is wide sweeping and that by 10,000 feet many areas are hot enough to generate electricity with current technology. There are wells within every district in this study that have elevated gradients and need further study of the geologic conditions to determine if some are more favorable than others for site specific development.

Geothermal development in Texas is on the cutting edge, yet it is a resource that has been examined multiple times in the past. Every time is has been deemed a worthwhile target. With multiple power projects underway currently in the Gulf Coast region and many companies looking into how to tap the resource economically, the time for Texas to become a leader in geothermal energy is starting to come to fruition. This is a new beginning for the geothermal energy industry in Texas.

General Considerations

- Many BHTs are needed to define a temperature profile for an area. BHTs can have differences of 25°F between neighboring wells because of the impact from drilling fluids.
- New regulations are needed for brine production data from an individual well. This is more useful than injection data from a series of wells for companies looking for locations to install binary turbines at the well head. The injection data is helpful to see how much fluid is produced from a field, representing the permeability of the producing formations.
- Corrections to the BHT data typically increase the measured temperatures by about 30°F at 9,000 feet to about 34°F at 12,000 feet. The corrected temperatures are better estimates the in-situ temperature value for the producing formation.
- Policy from both the Texas and Federal government agencies is still considered the main method to move an industry into a new direction. The 2009 Texas Severance Tax Exemption for geothermal (HB 4433) and the continued focus of the Texas Public Utility Commission to increase renewable energy development in Texas is a positive step. There is increased funding from the Department of Energy for geothermal projects in low-temperature environments which should also make a difference.
- Marketing of geothermal energy development is of the utmost importance to reach the public and create momentum in the power utility and oil and gas industries.

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Appendix A

Summary of Major Geopressured - Geothermal Reports

The following section is a brief description of the major geopressured - geothermal reports based on the research completed during the 1970s to 1990s. The reports are listed in alphabetical order by the last name of the first author.

Bebout et al., 1982: This report did regional studies of the lower Eocene Wilcox Group in Texas to assess the potential for producing heat energy and solution methane from geopressured fluids in the deep-subsurface growth-faulted zone. However, in addition to assembling the necessary data for the geopressured geothermal project, this study has provided regional information of significance to exploration for other resources such as lignite, uranium, oil, and gas. Because the focus of this study was on the geopressured section, emphasis was placed on correlating and mapping those sandstones and shales occurring deeper than about 10,000 ft. The Wilcox and Midway Groups comprise the oldest thick sandstone/shale sequence of the Tertiary of the Gulf Coast. The Wilcox crops out in a band 10 to 20 miles wide located 100 to 200 miles inland from the present-day coastline. The Wilcox sandstones and shales in the outcrop and updip shallow subsurface were deposited primarily in fluvial environments; versus the downdip environment in the deep subsurface, the Wilcox sediments there were deposited in large deltaic systems, some of which were reworked into barrier-bar and strandplain systems. Growth faults developed within the deltaic systems, where they prograded basinward beyond the older, stable Lower Cretaceous shelf margin onto the less stable basinal muds. Continued displacement along these faults during burial resulted in: (1) entrapment of pore fluids within isolated sandstone and shale sequences, and (2) buildup of pore pressure greater than hydrostatic pressure and development of geopressure.

Bebout et al., 1983: From this research detailed geological, geophysical, and engineering studies conducted on the Frio Formation have delineated a geothermal test well site in the Austin Bayou Prospect which extends over an area of 60 square miles. A total of 800 to 900 feet of sandstone occurs between the depths of 13,500 and 16,500 feet. At least 30 percent of the sand has core permeabilities of 20 to 60 millidarcys. Temperatures at the top of the sandstone section are 300°F.

Water, produced at a rate of 20,000 to 40,000 barrels per day, will probably have to be disposed of by injection into shallower sandstone reservoirs. More than 10 billion barrels of water are in place in these sandstone reservoirs of the Austin Bayou Prospect; there should be approximately 400 billion cubic feet of methane in solution in this water. Only 10 percent of the water and methane (1 billion barrels of water and 40 billion cubic feet of methane) will be produced without reinjection of the waste water into the producing formation. Reservoir simulation studies indicate that 90 percent of the methane can be produced with reinjection.

Dorfman et al., 1983: This research, conducted by the Bureau of Economic Geology and the Center for Energy Studies, includes the following areas of interest; geological studies depicting pressure gradients and thermal gradients, sand distribution and fault patterns, all of which are used in petroleum exploration; geophysical data for interpretation of seismic velocities based upon lithologic changes and subsurface discontinuities; sandstone consolidation data involving changes of permeabilities with depth and diagenetic histories of Cenozoic rocks in the Gulf Coast Basin--this work also covers fluid migration pathways and resulting rock-water interactions and has led to a better understanding of generation, maturation and accumulation of hydrocarbons; work on salinity of formation waters covering several areas of study, such as chemical analysis to anticipate scale and corrosion problems, and investigations of logging techniques to better ascertain salinity from well logs; reservoir continuity studies, together with computational modeling to assist in estimation of ultimate recoveries and formation drives; rock mechanics studies, which have recently led to the development of new models to account for creep and determine compressibilities of sandstones and shales in geopressured environments; co-production of gas and water in watered-out gas reservoirs.

Edwards, 1974: This report attempts to locate geothermal resources within the general framework of Texas property law and to determine whether these resources can be developed under the law as it now exists. The significant geothermal resource in Texas consists of enormous reservoirs of hot, geopressured water, which formed along the Gulf Coast when water-laden sediments were deposited between surrounding impermeable features, so that the water which would otherwise have been forced out of the sediments was unable to escape. One of the impediments to the development of this resource, given the very sizable commitments of capital entailed, is the uncertain legal status of geothermal resources.

Geothermal Program Review X, 1992: The theme of the review, "Geothermal Energy and the Utility Market -- The Opportunities and Challenges for Expanding Geothermal Energy in a Competitive Supply Market," focused on the needs of the electric utility sector. Geothermal energy, with its power capacity potential of 10 GWe by the year 2010, can provide reliable, environmentally clean electricity which can help offset the projected increase in demand. The six technical sessions included presentations by the relevant field researchers covering DOE-sponsored R&D in hydrothermal, hot dry rock, and geopressured energy. Individual projects are processed separately for the databases.

Gregory et al., 1980: The objective of this project was to appraise the total volume of in-place methane dissolved in formation waters of deep sandstone reservoirs of the onshore Texas Gulf Coast within the stratigraphic section extending from the base of significant hydrocarbon production (8000 ft) to the deepest significant sandstone occurrence. The area of investigation is about 50,000 mi^2. Factors that determine the total methane resource are reservoir bulk volume, porosity, and methane solubility; the latter is controlled by the temperature, pressure, and salinity of formation waters. Regional assessment of the volume and the distribution of potential sandstone reservoirs was made from a data base of 880 electrical well logs, from which a grid of 24 dip cross sections and 4 strike cross sections was constructed. Solution methane content in each of nine formations or divisions of formations was determined for each subdivision. The distribution of solution methane in the Gulf Coast was described on the basis of five reservoir models. Each model was characterized by depositional environment, reservoir continuity, porosity, permeability, and methane solubility.

Griggs, 2004: This study shows commercial production of geopressured-geothermal aquifers is feasible under reasonable assumptions of natural gas and electricity price. However, the near-term likelihood of large-scale developments of geopressured aquifers is low. Factors that reduce the chance of near-term development include the availability of better exploration prospects, an uncertainty in current technology, and the lack of any current geothermal geopressured aquifer research programs. The medium-term development of geopressured aquifers relies on the sustainability of high natural gas prices, the application and acceptance of new technologies, and diversification of conventional exploration and production companies and electric utility companies. The long-term development of geopressured aquifers depends on the scarceness of conventional hydrocarbons.

Jackson et al., 1993: This report outlines the types of data, data sources and measurement tools required for effective reservoir characterization, the data required for specific enhanced oil recovery (EOR) processes, and a discussion on the determination of the optimum data density for reservoir characterization and reservoir modeling. The two basic sources of data for reservoir characterization are data from the specific reservoir and data from analog reservoirs, outcrops, and modern environments. Reservoir data can be divided into three broad categories: (1) rock properties (the container) and (2) fluid properties (the contents) and (3) interaction between reservoir rock and fluid. Both static and dynamic measurements are required.

John et al., 1998, Volume 1: The significant accomplishments of this program included (1) identification of the geopressured-geothermal onshore fairways in Louisiana and Texas, (2) determination that high brine flow rates of 20,000--40,000 barrels a day can be obtained for long periods of time, (3) brine, after gas extraction can be successfully reinjected into shallow aquifers without affecting the surface waters or the fresh water aquifers, (4) no observable subsidence or microseismic activity was induced due to the subsurface injection of brine, and no detrimental environmental effects attributable to geopressured-geothermal well testing were noticed, (5) sanding can be controlled by reducing flow rates, (6) corrosion controlled with inhibitors, (7) scaling controlled by phosphonate scale inhibitors, (8) demonstrated that production of gas from saturated brine under pressure was viable and (9) a hybrid power system can be successfully used for conversion of the thermal and chemical energy contained in the geopressured-geothermal resource for generation of electricity.

John et al., 1998, Volume 2A: This volume describes the following studies: Geopressured-geothermal resource description; Resource origin and sediment type; Gulf Coast resource extent; Resource estimates; Project history; Authorizing legislation; Program objectives; Perceived constraints; Program activities and structure; Well testing; Program management; Program cost summary; Funding history; Resource characterization; Wells of opportunity; Edna Delcambre No. 1 well; Edna Delcambre well recompletion; Fairfax Foster Sutter No. 2 well; Beulah Simon No. 2 well; P.E. Girouard No. 1 well; Prairie Canal No. 1 well; Crown Zellerbach No. 2 well; Alice C. Plantation No. 2 well; Tenneco Fee N No. 1 well; Pauline Kraft No. 1 well; Saldana well No. 2; G.M. Koelemay well No. 1; Willis Hulin No. 1 well; Investigations of other wells of opportunity; Clovis A. Kennedy No. 1 well; Watkins-Miller No. 1 well; Lucien J. Richard et al No. 1 well; and the C and K-Frank A. Godchaux, III, well No. 1.

John et al., 1998, Volume 2B: This volume describes the following studies: Design well program; LaFourche Crossing; MG-T/DOE Amoco Fee No. 1 (Sweet Lake); Environmental monitoring at Sweet Lake; Air quality; Water quality; Microseismic monitoring; Subsidence; Dow/DOE L.R. Sweezy No. 1 well; Reservoir testing; Environmental monitoring at Parcperdue; Air monitoring; Water runoff; Groundwater; Microseismic events; Subsidence; Environmental consideration at site; Gladys McCall No. 1 well; Test results of Gladys McCall; Hydrocarbons in production gas and brine; Environmental monitoring at the Gladys McCall site; Pleasant Bayou No. 2 well; Pleasant Bayou hybrid power system; Environmental monitoring at Pleasant Bayou; and Plug abandonment and well site restoration of three geopressured-geothermal test sites.

John et al., 1998, Volume 3: This volume describes the following studies: Geopressured-geothermal hybrid cycle power plant: design, testing, and operation summary; Feasibility of hydraulic energy recovery from geopressured-geothermal resources: economic analysis of the Pelton turbine; Brine production as an exploration tool for water drive gas reservoirs; Study of supercritical Rankine cycles; Application of the geopressured-geothermal resource to pyrolytic conversion or decomposition/detoxification processes; Conclusions on wet air oxidation, pyrolytic conversion, decomposition/detoxification process; Co-location of medium to heavy oil reservoirs with geopressured-geothermal resources and the feasibility of oil recovery using geopressured-geothermal fluids; Economic analysis; Application of geopressured-geothermal resources to direct uses; Industrial consortium for the utilization of the geopressured-geothermal resource; Power generation; Industrial desalination, gas use and sales, pollutant removal, thermal EOR, sulfur Frasch process, oil and natural gas pipelining, coal desulfurization and preparation, lumber and concrete products kilning; Agriculture and aquaculture applications; Paper and cane sugar industries; Chemical processing; Environmental considerations for geopressured-geothermal development.

John et al., 1998, Volume 4: This bibliography contains US Department of Energy sponsored Geopressured-Geothermal reports published after 1984.

Loucks et al., 1979: This study analysis of reservoir quality of lower Tertiary sandstones along the Texas Gulf Coast delineates areas most favorable for geopressured geothermal exploration. Reservoir quality is determined by whole core, acoustic log, and petrographic analyses. The Wilcox Group has good reservoir potential for geopressured geothermal energy in the Middle Texas Gulf Coast and possibly in adjacent areas, but other Wilcox areas are marginal. The

Vicksburg Formation in the Lower Texas Gulf Coast is not prospective. Reservoir quality in the Frio Formation increases from very poor in lowermost Texas, to marginal into the Middle Texas Gulf Coast and to good through the Upper Texas Gulf Coast. The Frio Formation in the Upper Texas Gulf Coast has the best deep-reservoir quality of any unit along the Texas Gulf Coast.

Loucks et al., 1981: This study discusses variable intensity of diagenesis as the factor primarily responsible for contrasting regional reservoir quality of Tertiary sandstones from the upper and lower Texas coast. Detailed comparison of Frio sandstone from the Chocolate Bayou/Danbury Dome area, Brazoria County, and Vicksburg sandstones from the McAllen Ranch Field area, Hidalgo County, reveals that extent of diagenetic modification is most strongly influenced by (1) detrital mineralogy and (2) regional geothermal gradients. The regional reservoir quality of Frio sandstones from Brazoria County is far better than that of Vicksburg sandstones from Hidalgo County, especially at depths suitable for geopressured geothermal energy production. However, in predicting reservoir quality on a site-specific basis, locally variable factors such as relative proportions for porosity types, pore geometry as related to permeability, and local depositional environment must also be considered. Even in an area of regionally favorable reservoir quality, such local factors can significantly affect reservoir quality and, hence, the geothermal production potential of a specific sandstone unit.

Morton et al., 1983: This study focuses on structural styles that are conducive to the development of large geothermal reservoirs include blocks between widely spaced growth faults having dip reversal, salt-withdrawal basins, and shale-withdrawal basins. These styles are widespread on the Texas Gulf Coast. Detailed structural mapping at several horizons in selected study areas within the Frio growth-fault trend demonstrates a pronounced variability in structural style. At Sarita in South Texas, shale mobilization produced one or more shale ridges, one of which localized a low-angle growth fault trapping a wedge of deltaic sediments. At Corpus Christi, shale mobilization produced a series of large growth faults, shale-cored domed anticlines, and shale-withdrawal basins, which become progressively younger basinward. At Blessing, major growth faults trapped sands of the Greta/Carancahua barrier system with little progradation. At Pleasant Bayou, a major early growth-fault pattern was overprinted by later salt tectonics - the intrusion of Danbury Dome and the development of a salt-withdrawal basin. At Port Arthur, low-displacement, long-lived faults formed on a sand-poor shelf margin contemporaneously with broad salt uplifts and basins. Variability in styles is related to the nature and extent of Frio sedimentation and shelf-margin progradation and to the presence or absence of salt.

Nagihara and Jones, 2005: Eighty-two seafloor heat-flow measurements were recently obtained across the Mississippi Fan region in the deepwater northeastern Gulf of Mexico. These data display an abrupt transition in heat flow between an area near the center of Pleistocene deposition (20 mW/m^2) and the eastern margin of the fan (40 mW/m^2). Although deposition of fan sediments has very likely suppressed the shallow subsea floor thermal regime, causing lower seafloor heat-flow values near the center, the magnitude and abruptness of the heat-flow contrast cannot be fully accounted for by the mechanisms related to sedimentary deposition, which include radiogenic heat production in sediments, pore-fluid migration, and presence of salt structures. The most plausible explanation for the sharp heat-flow contrast is that the heat released from the igneous basement is significantly greater in the eastern margin of the fan. The zone of contrasting heat flow lies along a previously suggested boundary between the oceanic crust and the thin transitional crust in the northeastern Gulf of Mexico. The area of higher heat flow coincides with the suggested zone of transitional crust, which, because of its granitic origin, generates greater amounts of radiogenic heat than oceanic crust. This finding opens up the possibility that heat-flow data may be used in delineating crustal lithologic boundaries along continental margins.

Negus-de Wys, 1989: This report summarizes geopressured reservoirs. In the Gulf Coast area the normal gradient is 0.465 psi/ft. Pressures may approach lithostatic pressure and have been measured as high as 1.05 psi/ft in the Gulf Coast area. Geopressured basins exist worldwide and in a number of U.S. locations, east, west, north and south. The Gulf Coast area has been studied extensively and is the subject of the DOE geopressured-geothermal research at present. The assumed ranges in resource characteristics include: depth from -12,000 to > -20,000 feet, brine flow rate from 20,000 to 40,000 bpd, temperature from 300 to 400 F, bottom-hole pressure from 12,000 to 18,500 psi; salinity from 20,000 to 200,000 mg/L, gas-water ratio from 40 to 80 scf/bbl., and condensate from a trace to production. Energy in the geopressured resource includes gas, thermal, and hydraulic energy. It has been estimated that there are 6,000 quads of methane and 11,000 quads of thermal energy in the Gulf Coast area geopressured-geothermal reservoirs. Estimates run as high as 50,000 quads for the thermal energy (Wallace et al., 1978). Present industrial interest in the Pleasant Bayou and Hulin wells includes: desalination plants, an economic study by a power company for regional use, use of generated electricity by a coalition of towns, aquaculture (catfish farming) research program, and an unsolicited proposal for enhanced oil recovery of heavy oil. Direct uses of the hot brine cover dozens of industries and processes. An example of multiple uses in the USSR is shown. Outside agency interest includes the U.S.G.S., N.S.F., G.R.I., and possibly other areas within DOE. A research spin-off: a sensitive in-line benzene monitor has been designed by USL and will be tested in the near future. An in-line pH monitor is also under development for the harsh conditions of the geopressured-geothermal wells.

Negus-de Wys, 1990: This summary of the industry cost-shared proposals to the consortium, represented in the presentations included in these proceedings, attests to the interest developing in the industrial community in utilizing the geopressured-geothermal resource. Sixty-five participants attended these sessions, two-thirds of whom represented industry. The areas represented by cost-shared proposals include (1) thermal enhanced oil recovery, (2) direct process use of thermal energy, e.g., aquaculture and agriculture, (3) conversion of thermal energy to electricity, (4) environment related technologies, e.g., use of supercritical processes, and (5) operational proposals, e.g., a field manual for scale inhibitors. It is hoped that from this array of potential use projects, some will persist and be successful in proving the viability of using the geopressured-geothermal resource. Such industrial use of an alternative and relatively clean energy resource will benefit our nation and its people.

Shook, 1992: This research on modeling and prediction of geopressured-geothermal reservoirs is an excellent example of an engineering problem that can be solved through many different means. The problem may be approached from a purely numerical viewpoint, where a successful history match "demonstrates" the validity of the reservoir model, or from an analytical point of view. Each method has its own inherent limitations and weaknesses. Such limitations can be minimized by using some combination of both numerical and analytical methods, taking advantage of the strengths of each without the attendant weaknesses. This paper describes a combined numerical/analytical approach to reservoir engineering at the Pleasant Bayou geopressured-geothermal reservoir. A reservoir description had previously been developed, through which a successful history match was performed. Certain details of the reservoir can also be obtained through analysis of pressure and flow transients; these can then be used to constrain the numerical model. Methods for extracting such reservoir data are discussed, and the manner in which they can be used as constraints in the numerical models are presented.

Appendix B

Data used in this Assessment

1. SMU Geothermal Laboratory, TX Railroad Commission data collected for this project. Included in this appendix.
2. AAPG Geothermal Survey Well Data, 1994. This can be purchased through the AAPG Bookstore, Product Code 482. It includes: A. Exploratory Well File (CSDE), 1950-1989; B. Geothermal Survey of North America (GSNA), 1972; and C. Correlation of Stratigraphic Units of North America (COSUNA)
3. Gulf Coast Geopressure data, Gregory et al., 1980. Included in this appendix.
4. Freestone County Well data, Burns, 2004. Included in this appendix.
5. Fairway Field data, Hunt Oil Company and Kweik, 2008. Company data not included.
6. USGS GEOTHERM data for Texas, Bliss, 1983. This is only a portion of the entire dataset currently assessable.

Appendix C

Calculating the Potential Power from a Well

Calculating the potential power from the fluid temperatures and flow rates is the initial aspect to determining if a well/field should even be considered. The following materials from the Tester et al. (2006) Report, The Future of Geothermal Energy will assist in accomplishing this.

Using Figure 7.3 from Tester et al. (2006), the inlet and outlet temperatures can be used to determine the gross power output for a kilogram per second of fluid movement.

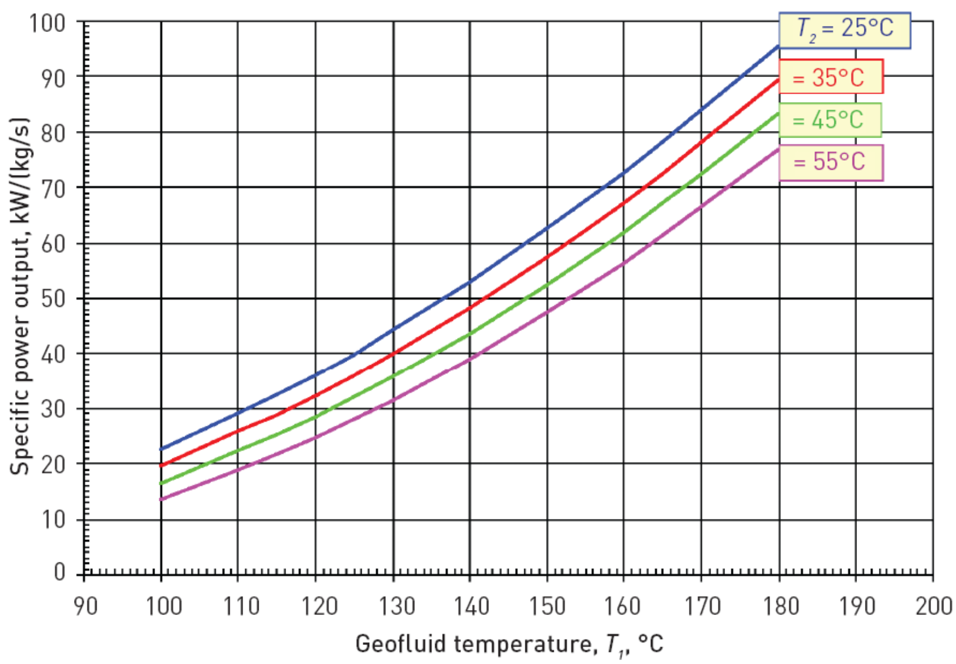


Figure 7.3 Specific power output (in kW/(kg/s)) for low- to moderate-temperature geofluids as a function of inlet (T_1) and outlet temperatures (T_2) shown in degrees Celsius (°C).

The 2006 Report used the example of 40°C (104°F) output (T_2) for its estimated power based on the yearly fluid for from the production of the oil and gas wells, as shown in Table 7.3. The output temperature will vary according to the initial (input) temperature, the cooling water temperature, the amount of total dissolved solids in the water, and the speed that the water is moved through the heat exchanger. Currently the output temperature varies between 49°C (120°F) in Chena Hot Springs, Alaska to approximately 67°C (152°F) at the Rocky Mountain

Oilfield Testing Center (RMOTC), Wyoming and is expected to be even hotter in Texas. In general the outlet temperature is generally about 10 to 40°C (18 to 72°F) cooler than the inlet temperature.

Within a State, well temperatures will vary greatly according to location and depth of resource. Table 7.3 from Tester et al., (2006) shows the MW capacity if all the flow is at each of the input temperature of 100°C, 140°C, or 180°C (212°F, 258°F, 355°F).

Table 7.3 Estimated power from California and Gulf states coproduced waters; outlet temperature assumed to be 40°C.

State	Flow rate, kg/s	MW @ 100°C	MW @ 140°C	MW @ 180°C
Alabama	927	16.6	42.3	79.9
Arkansas	1,204	21.6	54.9	103.7
California	2,120	37.9	96.7	182.5
Florida	753	13.4	34.3	64.8
Louisiana	9,786	175.2	446.3	842.6
Mississippi	2,758	49.4	125.8	237.5
Oklahoma	59,417	1,064	2,709	5,116
Texas	56,315	1,008	2,568	4,849
TOTALS	131,162	2,348	5,981	11,293

To change the watts (W) value, it is based on the change in outlet temperature (T_2) in comparison to the input temperature (T_1). Using the 2006 Report Figure 7.3 (above) and Equation 7.2 and Equation 7.3 below, new resource estimates can be compared.

Tester et al., (2006) Equation 7-2.

$$\frac{\Delta \dot{W}}{\Delta T_2} = 0.098701 - 0.0039645 T_1.$$

Tester et al., (2006) Equation 7-3.

$$\dot{W}_{actual} = \dot{W}_{T2=40C} + \frac{\Delta \dot{W}}{\Delta T_2} \times (T_2 - 40).$$

Thus given an example from a well in Texas, with an input temperature of 121°C (250°F) and an outlet temperature of 107°C (225°F) we can use the equations to determine the new kW value. Using Figure 7.3, T_1 = 121°C and the correlated kW per kg/s for 40°C outlet temperature (halfway between the 35 and 45°C curves) is 31 kW.

Now using the equations the new value is:
kW = 31 + (0.098701 - 0.0039645*121°C) * (107°C-40°C)

kW = 5.5 per kg/s flow rate

In a second related example, if the outlet temperature (T_2) is decreased to 82°C (180°F) then the kW value increases to 14.9 kW per kg/s flow rate. More energy is being extracted for the same amount of flow. From this equation it shows that for the same drop in temperature, the higher inlet temperature (T_1) there is an increased amount of power (W) which can be produced.

Since the well temperature of 1000s of wells can not be easily used in determining the potential power, the tables give multiple temperature values to use as a range. Depending on if the average temperature of a group of wells is known, or estimated from the geology and heat flow, it is helpful to have more than one temperature estimate to give the possible range for a project. Table 7.3 gives initial input temperatures (T_1) to start from in estimating the total flow. From there the total flow rate can be manipulated, i.e., if you want to consider 50% of the wells at 100°C and 50% of the wells at 180°C.

One way to convert from bbl to kg/s, divide the bbl by 365.24 days/year to get bbls/day. Next bbls/day *.0004861 = gal/sec. From gal/sec * 3785.411784 to get cm^3/s. 1 gram of water is equal to 1 cm^3. Lastly multiply by .001 to get kg/s.

Example conversion:
Using Texas 12,097,990,120 bbl/year = 3312339.64 bbls/day
3312339.64 bbls/day *0.0004861 = 16,101.28 gal/sec
16,101.28 gal/sec * 3785.411784 = 60,949,990 cm^3/sec
60,949,990.49 cm^3/sec = 60,949,990.49 g/sec
60,949,990.49 g/sec *.001 = 60,949.99 kg/sec

To convert from kg/s to gpm, depending on the method of conversion, the conversion rate is either 15.81 (using kg to pounds to gallons) or 15.85 (using kg to liters to gallons). Therefore in working with the different units the accuracy of the final number will vary according the number of digits and method of conversion.

Calculating Potential Flow

By using Darcy's Law, which expresses radial liquid flow into a borehole in units of barrels of liquid per day, the open-flow potential of a well can be determined (Harrison et al, 1982). This can be used to review the available wells in an oil and gas field to get initial numbers for how much production can be expected to flow from a formation according to the borehole sizes.

$$bbl / day = 7.07kh(P_e - P_w) / \mu \ln(r_e / r_w)$$

where bbls/day = barrels per day (42 gallons/barrel)

k = permeability in darcies

h = interval thickness in feet

P_e = 1 atmosphere in psi (14.7 psi)

P_w = formation pressure in psi

μ = viscosity (1.0)

r_e = distance from well bore fluid will flow into it (660 feet is standard if unknown)

r_w = radius of well bore in feet

Calculating Coproduced Energy Content of Fluid

For geothermal wells situated in hydrocarbon fields, the fluids are usually mixed with oil and gas. Each of these has its own energy content, i.e., the heat from the water, and the separated oil and gas from the fluid stream. The following equations can be used to determine the entire energy value (million BTU) of the produced fluid. These were constructed by Efstathios (Stathis) Michaelides, Ph.D., P.E., Professor and Chair, Mechanical Engineering, University of Texas at San Antonio One UTSA Circle San Antonio TX 78249

Telephone - 210-458-5580 or Email - stathis.michaelides@utsa.edu.

The table below shows the Excel spreadsheet with the equations for the calculation.

	B	C	D
	Average Daily Flow Rates	**Input**	**Energy Content, MBTU**
3	Average daily barrels of oil (US bbls)		=C3*42*0.14
4	Average daily gas (scf)		=C4*400/1000000
5	Average daily barrels of saltwater (US bbls)		=C5*159*(C6-75)*2.2/1000000
6	Average fluid temperature at the wellhead (°F)		
	Percent of energy in saltwater		=D5/(D3+D5+D4)*100
	Total energy possible from well		**=SUM(D3:D5)**

The next table shows numbers in the Excel spreadsheet with an example of the calculations.

	B	C	D
	Average Daily Flow Rates	**Input**	**Energy Content, MBTU**
3	Average daily barrels of oil (US bbls)	***50***	294
4	Average daily gas (scf)	***10000***	4
5	Average daily barrels of saltwater (US bbls)	***15000***	918
6	Average fluid temperature at the wellhead (°F)	***250***	
	Percent of energy in saltwater		75.5
	Total energy possible from well		**1216**

Appendix D

Business Report Questions

Organizations and Companies to Contact for Assistance

Companies with Low-Temperature Technology

Phone: (214) 768-2749
Fax: (214) 768-2701
P.O. Box 750395
Dallas, TX 75275-0395
smu.edu/geothermal

Questions to Consider
Before Starting a Geothermal Venture
Appendix D

Andrés Ruzo[1] Maria Richards[1] David Blackwell[1] Shannon McCall[2]

1. SMU Geothermal Laboratory
2. Telios Corporation

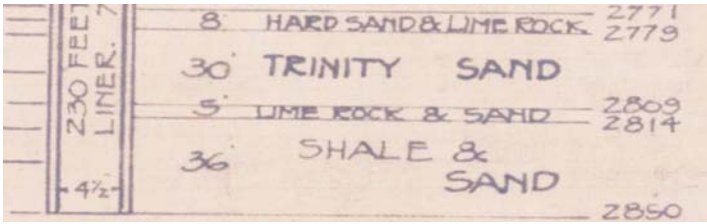
Executive Summary

The purpose of this document is to give those interested in developing geothermal resources and undertaking business ventures in the geothermal field an aid in the form of a basic checklist of things that should be considered when engaging in such a venture, in order to increase the probability of project success.

In any geothermal project there are four main areas that need to be considered in order to evaluate the potential success of the project. In the following pages we will expand on the specific questions that should be answered in the various analyses necessary for developing a geothermal project.

These areas include:

i.	Geologic	*Does the resource exist?*
ii.	Legal	*Can the resource be legally harnessed?*
iii.	Engineering	*Can the resource be efficiently harnessed?*
iv.	Financial	*Can the project be financed?*
		What are the Costs involved?



Geologic Investigation

"Does the resource exist?" This is the starting block for any geothermal venture, simply because you need to identify a geothermal resource and its characteristics before you can develop it.

What is the geology of the area?

- Geologic structure of the area
- Stratigraphic column and cross sections
- Are any local well logs available?
- Is seismic information available?
- Is a chemical analysis of the fluids available?

Does the geothermal resource exist?

- Where, at what depth, in what formation?
- What is the temperature, pressure, formation thickness, and flow rate of the resource?
- What is the estimated size and producing potential of the formation?
- Do you expect natural gas to be saturated in brine? If so what is the gas/brine ratio?
- Is it saturated, super saturated? What portion of the gas do you expect to extract?

Are there geological risks involved?

- Seismic, karsting, fault, or other geologic factors that may present a risk to wells and production.
- What is the produced water chemistry, i.e., amount of total dissolved solids, pH, mineral content?
- What is the likelihood of cooling the formation?
- Would field "rotation" help to mitigate cooling?

Is the resource sustainable long term?

- Does the resource replenish itself naturally, or is injection into the original formation necessary?
- Where should an injection well be located as to not thermally impact the reservoir?
- How long is the reservoir expected to sustain production rates, 10, 20, 30, 100 years?

Where will the produced fluids be dispensed?

- Into what ground formation?
- At what depth will the fluid be reinjected?
- What is the chemistry of the formation that is being injected into?
- What is the risk posed by production fluid chemistry?
- What's the size of the disposing formation?
- Are there geological risks related to disposing into this formation?
- Can the spent fluids be used for secondary recovery?

Will coproduction of hydrocarbons and geothermal fluids from the same well occur?

- Is there oil, gas, or both in the production formation?

Legal Investigation

"Can the resource be legally harnessed?" Legal issues often become some of the greatest obstacles in the development of many geothermal ventures. A thorough legal analysis will clearly identify potential issues with the site, amount of power produced, or other issues that could pose serious threats to the project. In the United States, the highest quality geothermal fields, such as in Yellowstone, are closed to all development.

What are the governing bodies of the area?

- Federal, State, Local
- Geologic (Ex. Texas Railroad Commission)
- Environmental (Ex. EPA)
- Utility companies?
- Lobbyists, etc.

Is the resource in an area approved for development?

- What state, county, city permits are needed?
- Can you drill/inject in this area?
- What zoning laws exist that threaten the project? Noise bans, visible emission bans, aesthetic rules and regulations?
- What protocols are required in order to legally produce and sell power in your area?
- What is the interconnectivity charge to load your power onto the grid?

How do you get the rights to the resource?

- It is important to note that in the state of Texas geothermal waters are considered a "mineral" and are subject to Texas mineral laws.
- Who owns the mineral rights?
- Who owns the surface land rights?
- How much will it cost to get the rights?

What environmental rules exist that could benefit/ threaten your project?

- Do any tax credits, stimulus packages, or other incentives exist that could benefit your project?
- What environmental protocols exist regarding drilling and fluid reinjection?
- What environmental protocols exist regarding emissions? (Note: Texas' geothermal resources are most efficiently harnessed by binary power plants, which give off no emissions.)

What hydrocarbon rules exist that could impact your project?

- Are there any tax benefits from producing both hydrocarbons and geothermal energy from the same well site? (Such as the Texas House Bill 4433, Severance Tax Exemption.)

Engineering Investigation

"Can the resource be efficiently harnessed?" Once the geologic resource is well understood, it becomes essential to find the most efficient way of harnessing its full potential in order to maximize plant output as well as financial gain.

What type of plant design is best suited for harnessing the resource?

- Dry steam, flash steam, or binary plant?
- Will the temperature, pressure, and fluid flow rate of my reservoir be able to support one of these plants?
- Can absorption chillers or other renewable energy types be incorporated?
- What diameter wells/ pipes do I need to produce my desired amount of energy?
- How many wells do I need to obtain my desired fluid flow rate to maximize power plant output?
- What insulation is needed in order to most efficiently transport the heat?
- What material should my casing/ pipes be made of to avoid corrosion, scaling, or other impurity related issues?

To what extent is reservoir engineering required in your resource?

- Do you need to fracture the formation in order to increase production?
- Does your reservoir require fluid injection such as an enhanced geothermal system (EGS)?

What working fluids will be involved in the plant operations?

- What refrigerants will be using in the binary systems?
- How much cooling fluid is neede and where will it come from?
- In the wells, pipes, and plant systems, what chemicals will be used to eliminate issues of scaling?

What will be required to run the plant?

- What electrical, computer, etc. systems are required in order to run the plant at its highest efficiency?
- What personnel will be needed to run the plant?
- What backup/ emergency systems will be installed in the case of a malfunction?
- What parameters will be collected on a regular basis?

How will the energy be transported from the plant to the desired market?

- What infrastructure is available to do this?
- Where is the closest utility transfer station?

Financial Investigation

"Can the project be financed?" Answering this question will be the true make or break of any business venture. If the numbers don't make sense, then the project won't make sense. Even in the case of green energy projects, there is no exception.

Opportunity Analysis

- Who will purchase the geothermal energy?
- What is the most profitable target market for your power generation— selling to the grid, distributed energy, coproduction, a combination of each?
- If gas is produced, will it be sold to a pipeline, used in a fuel cell, or in a turbine?
- How much energy is needed to satisfy the site demand?
- What are the resources already available?
- How can profits be maximizes from these resources?
- Can a Power Purchase Agreement be secured? At what price, for how many years?
- Who is the competition?
- What is the price to beat of the competitor?
- How will this project be financed (debt/equity)?
- What is the source of capital?
- What is the cost of capital?
- What financial risks are associated with the project?
- Was a Strengths, Weaknesses, Opportunities, and Threats (SWOT) Analysis completed?
- What is the anticipated performance of the plant?

Note, that for coproduced systems these questions need to be addressed for both the geothermal and hydrocarbon production.

Profit Analysis

- What is the estimated Cost of Capital ?
- Where will the project funding come from?
- What is the Net Present Value for the Project?
- What is the Future Value of the investment?
- What is the Required Rate of Return for the project?
- What discount rate is being used for risk?
- How many years does the project need to be in production to produce the required rate of return?
- How dependent are the estimates based on commodity prices??
- What is the effect of raising or lowering commodity prices?
- Are there government incentives or subsidies that may affect the outcome of these calculations?
- What is the potential for gains from "cap and trade"/ carbon-credit earnings for this project?
- If a coproduction site, what are the earnings from hydrocarbons?
- What are the expected gross and net profit from the project?
- What is the timeline for the project?
- What are the risks associated with not being on schedule? Expenses, legal ramifications, etc.
- Given the calculations, the expected budget, and the potential payback, does the project make financial sense?

Cost Analysis

What are the Exploration Cost?

- Seismic surveys, well logging and data, geologic analysis and flow tests, chemical analysis of geothermal fluids, etc.
- What are the drilling costs (drill rig, well fracturing, personnel, casing, etc.)?
- Is it possible to recomplete an existing well?
- What is the cost to recomplete a well?
- What is the estimated lifespan of a well?
- Production well (new): drilling costs, casing costs, emplacement of the wellhead, preparing the site for power plant installation.
- Production well (existing): work-over costs of well, perforation of casing, formation fracturing.
- Where will the injection well be located, designed and drilled to necessary depth, casing, injection pump, etc.?
- What are the development costs for infrastructure on and off site?

What are the Legal Costs?

- Legal costs associated with zoning, siting, drilling permits and mineral right procurement.
- Legal costs associated with rules and regulations of how to properly case and prepare a well for production use.
- What are the permitting costs and procedures? In Texas see Oil & Gas Permits from the Rail Road Commission http://www.rrc.state.tx.us/licenses/og/index.php

What are the Development Costs?

- Purchase (or design and manufacturing) of the power plant, shipping, and installment costs.
- Connection of pipes to other necessary infrastructure to the plant (separator, injection well, rock muffler, etc.).
- What are the installation costs related to equipment, transmission wires and cables, cost of machinery, and personnel to install and test run the plant.
- If connection to gas pipeline, will the gas need to be cleaned or pressurized to meet pipeline requirements.
- What are the production costs?
- Taxes and interconnection tariffs?
- What are the operation and maintenance costs associated with running the plant (cost of day-to-day plant operation, obtaining personnel etc.?
- Costs of routine yearly maintenance and monitoring, chemicals for injection to prevent scaling and corrosion?
- What is the total budget for fully developing the resource, completing project, and running it for a specific time frame?

Geothermal Agencies and Business Contacts for Texas

Organizations Assisting Renewable Energy Development

Geothermal Energy Association
Karl Gawell
209 Pennsylvania Ave., SE
Washington, D.C. 20003
karl@geo-energy.org
www.geo-energy.org
P: 202-454-5264

Geothermal Resources Council
Curt Robinson
P.O. Box 1350
Davis, CA 95617
grc@geothermal.org
www.geothermal.org
P: 530-758-2360

Research Partnership to Secure Energy for America (RPSEA)
Michael Ming
1650 Highway 6, Suite 300
Sugar Land, TX 77478
mming@rpsea.org
www.rpsea.org
P: 281-313-9555

Texas Renewables Energy Industries Association (TREIA)
Russell Smith
P.O. Box 16469
Austin, TX 78761
rsmith@treia.org
www.treia.org
P: 512-345-6469

Texas Renewable Energy Education Consortium (TREEC)
Sidney Bolfing
3801 Campus Drive
Waco, TX 76705
sidney.bolfing@tstc.edu
www.treec.org
P: 254-867-3206

Federal and State Agencies Assisting Renewable Development

Department of Energy Geothermal Technologies
Office of Energy Efficiency and Renewable Energy
Tim Reinhardt
timothy.reinhardt@ee.doe.gov
www1.eere.energy.gov/geothermal/
P: 202-287-1351

Texas State Energy Conservation Office (SECO)
Dub Taylor
LBJ State Office Building
111 East 17th St., Room 114
Austin, TX 78701
dubtaylor@cpa.state.tx.us
www.infinitepower.com
P: 512-463-1931

Texas Railroad Commission
1701 N. Congress
P.O. Box 12967
Austin, TX 78711
http://www.rrc.state.tx.us/about/divisions/index.php
http://www.rrc.state.tx.us/contact/RRCphonedirectory.pdf

Drilling Permits for Oil/Gas wells
Lorenzo Garzo
P: 512-463-6751
drillingpermits-info@rrc.state.tx.us

Injection Well Permits
Doug Johnson
P: 512-463-6792
ac@tceq.state.tx.us

TX General Land Office - Mineral Leasing
Peter Boone
1700 North Congress Avenue, Suite 600
Austin, TX 78701
peter.boone@glo.state.tx.us
www.glo.state.tx.us/
P: 512-475-1501

Rural Alliance of Renewable Energy (RARE)
Travis Brown
1700 N. Congress Ave. Suite 22
Austin, TX 78701
tbrown@orca.state.us
www.infinitepower.com/rare
P: 512-936-7878

Companies with Low Temperature Technology Geothermal Power Plants

Pratt & Whitney Power Systems
Michael Ronzello
400 Main Street
East Hartford, CT 06108
michael.ronzello@pw.utc.com
www.pw.utc.com
P: 860-727-2465

Gulf Coast Green Energy
Loy Sneary
2200 Avenue A, Suite 103
Bay City, TX 77414
loys@sbcglobal.net
www.gulfcoastgreenenergy.com
www.electratherm.com
P: 888-448-2112

ORMAT Technologies, Inc.
Josh Nordquist
6225 Neil Road
Reno, NV 89511
jnordquist@ormat.com
www.ormat.com
P: 775-356-9029

Turbine Air Systems
Halley Dickey
6110 Cullen Blvd.
Houston, TX 77021
HDickey@TAS.com
www.TAS.com
P: 713-877-8700

Cryostar USA
Tim Ryan
5909 West Loop South, Suite 220
Bellaire 77401, TX
Tim.Ryan@cryostar.com
www.cryostar.com
P: 713-661-6000

Deluge, Inc.
Brian Hageman
8765 E. Bell Road, Suite 210
Scottsdale, AZ 85260
bhageman@delugeinc.com
www.delugeinc.com
P: 602-431-0566

Linear Power Ltd.
Robert Hunt
6082 Espy Avenue
Long Beach, MS 39560
hunt0972@bellsouth.net
http://renewableone.com/linearpower
228-363-0736

Engineering Power Plants

Power Engineers
Kevin Wallace
3940 Glenbrook Drive
P.O. Box 1066
Hailey, ID 83333
www.powereng.com
P: 208-788-3456

CH2M Hill
Richard Campbell
9191 South Jamaica Street
Englewood, CO 80112
richard.campbell@ch2m.com
P: 888.242.6445
http://www.ch2m.com/

Telios Corporation
Shannon McCall
3535 Travis St., Suite 115
Dallas, TX 75204
smccall@teliospc.com
www.teliospc.com
P: 214-774-6199

Condenser- Cooling Towers

Tranter
Jody Stonecipher
P.O. Box 2289
Wichita Falls, TX 76307
jstonecipher@tranter.com
www.tranter.com
P: 940-264-1034

Dry Coolers Inc.
Bob Antaya
3232 Adventure Lane
Oxford, MI 48371
bob@drycoolers.com
www.drycoolers.com
P: 800-535-8173

Reservoir Engineering

GeothermEX Inc.
Subir Sanyal
3260 Blume Drive, Suite 220
Richmond, CA 94806
mw@geothermex.com
www.geothermex.com
P: 510-527-9876

Blade Energy Partners
Sriram Vasantharajan
2600 Network Blvd Suite 550
Frisco, TX 75034
sriramv@blade-energy.com
www.blade-energy.com
P. 972-712-8407

Consultants

Good Company Associates
Robert King
816 Congress Avenue, St 1400
Austin, TX 78701
rking@goodcompanyassociates.com
www.goodcompanyassociates.com
512-279-0751

Erdlac Energy Consulting
Richard Erdlac
4900 Thomason Drive
Midland, TX 79703
rcerdlac@cleansed.net
P: 432-69-5288

Geologic Data

UT Bureau of Economic Geology
Daniel Ortuna
Well Log Library
10100 Burnet Road
Austin, TX 78758
daniel.ortuno@beg.utexas.edu
P: 512-471-7139
http://www.beg.utexas.edu

IHS Energy
888-645-3282 or 713-840-8282
http://energy.ihs.com/index.htm

Drillinginfo, Inc.
Sales: 888-477-7667 ext. 1
sales@drilinginfo.com
http://www.info.drillinginfo.com

For more contacts and discussion of materials

Geothermal Energy Association
Membership list www.geo-energy.org

Geothermal Resources Council
www.geothermal.org/roster.html

SMU Geothermal Laboratory
David Blackwell & Maria Richards
Huffington Dept. of Earth Sciences
3225 Daniel Ave. Room 235
Dallas, TX 75275-0395
blackwel@smu.edu mrichard@smu.edu
www.smu.edu/geothermal
P: 214-768-2745 or 214-768-1975

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