A RE-EVALUATION OF GEOPRESSURED-GEOTHERMAL AQUIFERS AS AN ENERGY RESOURCE

A Thesis

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Abstract

The search for more efficient and economical forms of energy generation is a continual process. Natural gas production and electricity generation from geopressured-geothermal aquifers is an unconventional hydrocarbon source that has long been unproductive due to its marginal economics and lack of technological certainty. This thesis demonstrates that, based on modern technological competencies and economic constraints, geopressured-geothermal energy now maintains a viable future as an alternative domestic energy source.

1. Background

During the energy crisis of the 1970's, the United States began to explore for potentially significant amounts of hydrocarbons stored in unconventional resources. Oil shales, oil sands, methane hydrates, coalbed-methane and geothermal-geopressured aquifers were given research priority due to large quantities of potentially recoverable energy. Industry and governmental financial support were given to projects that evaluated the economic viability and level of technological competency required to develop these unconventional sources of oil and natural gas. Due to government deregulation of the natural gas market and the ensuing price collapse, the economic incentive to commercially develop most unconventional sources of natural gas was not present. The commercial development of geothermal-geopressured aquifers was considered marginally economic in only special circumstances and considered a long-term alternative hydrocarbon source.

Once again, the United States is poised to enter an energy crisis. The oil and natural gas price crash of the 1980's, and the lack of energy value price parity between oil and natural gas, has motivated many power generation, industrial, residential and municipal users to transition to natural gas as a primary energy and heating source during the past 15 years. The International Energy Administration (IEA) forecasts that this trend will continue and that world natural gas demand will increase by over 100% or 30 Tcfy by the year 2030 [2]. This transition and the forecasted increase in demand places a greater burden on the ability of energy companies to meet the world market demand of natural gas. As supply tightens, natural gas imports to the U.S. have risen, and plans to reactivate or build liquefied natural gas (LNG) trains at several U.S. ports have been announced.

To meet the forecasted increase in domestic U.S. and world energy demand, the IEA stated that global spending on hydrocarbon exploration and production must exceed $5.3 trillion dollars by 2030. Resources are again being dedicated to develop alternative domestic energy sources. Research currently focuses on economic methods to produce oil sands and oil shales, and the U.S. Department of Energy (DOE) has announced plans to fund a ten-year clean coal technology (coal gasification) pilot program [1]. Methane hydrates are also being considered as an unconventional energy source [72].

Attention may return to geopressured-geothermal aquifers as an unconventional hydrocarbon resource. But, continued research should be justified by demonstrating that there is potential for sustainable, economic production of geopressured brines. The geopressured-geothermal resource base for the northern Gulf of Mexico could exceed 1,000 TCF of recoverable natural gas [15]. This resource base is not insignificant; in 1995 the United State Geological Survey estimated that U.S. technically recoverable volumes of conventional and unconventional gas, excluding geopressured brines and clathrate structure-gas hydrates, was 1,073 Tcf [73]. New technologies allow more efficient extraction of methane and thermal energy from the geopressured brine. This thesis will demonstrate the current economic and technical viability of the geopressured-geothermal resource and highlight additional synergies that may come from the production of geopressured aquifers.

1.1 Estimating the Geopressured-Geothermal Resource

Jones described the depositional and geophysical processes which formed geopressured reservoirs in the Gulf of Mexico. He stated that geopressure was defined by Dickinson to include "any pressure which exceeds the hydrostatic pressure of a column of water [extending from the stratum tapped by the well to the land surface] containing 80,000mg/l total solids." A pressure gradient of 0.465psi/ft can be used to estimate the water column. To describe the formation of geopressured reservoirs, Jones listed ten dominating factors:

1. Deltaic sediments and their prodelta and neritic equivalents were rapidly deposited and deeply buried.
2. The montmorillonite content of these deposits ranged from about 50 to 80 percent or more.
3. Contemporaneous faults compartmentalized sand-bed aquifers prior to escape of their interstitial saline water.
4. Fluid pressure in compartmentalized reservoirs increased with deepening burial.
5. Salinity of aquifer water increased where hyper-filtration through semi-permeable clay beds concentrated dissolved solids in zones of water loss.
6. Heating of the deposits accompanied deepening burial.
7. Thermal dehydration of montmorillonite in a depth-related temperature zone with an average temperature of 221°F released some intracrystalline water as free pore water.

8. Diagenesis of dehydrated montmorillonite (alteration to illite or chlorite) released remaining intracrystalline water.
9. Dehydration and diagenesis of montmorillonite produced interstitial fresh water, while markedly reducing the bulk density, load-bearing strength, and thermal conductivity of clay beds.
10. Water flow upward from geopressured zones through clay beds in which dehydration and diagenesis of montmorillonite had occurred was accompanied by interstitial precipitation of cementing solids in the upper part of the clay bed, while the lower part of the same bed remained undercompacted and soft to the drill.

Geopressured-geothermal aquifers are a subset of geopressured reservoirs. As a potential resource, energy contained in the geopressured-geothermal aquifer takes three forms: mechanical energy as excess pressure at the wellhead, thermal energy, and methane dissolved in the aquifer pore water. Geopressured aquifers are commonly defined to have a pore pressure in excess of 0.675psi/ft (13.0ppg) and a geothermal gradient of 1.8°F/100ft or higher. Total aquifer bulk volumes can be in excess of 3 cubic miles, but individual reservoirs may be smaller [4]. Fig. 1 presents the geographic range of the geopressured zone in the northern Gulf of Mexico [5]. Fig. 2 shows the major depocenters during the Upper Cretaceous and Tertiary along the northern Gulf of Mexico. Fig. 3 presents the geologic time range of the geopressured zone in the northern Gulf of Mexico [5].

Estimates of the amount of geopressured-geothermal energy available in the northern Gulf of Mexico vary widely. Papadopulos et al (1975) estimated the resource

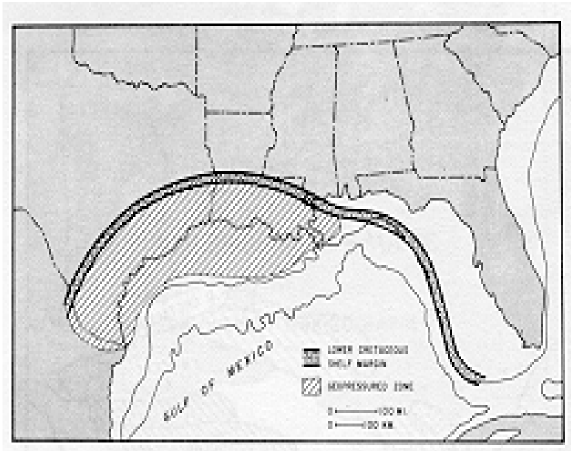

Fig. 1. Geographic range of geopressured zones in the Northern Gulf of Mexico.

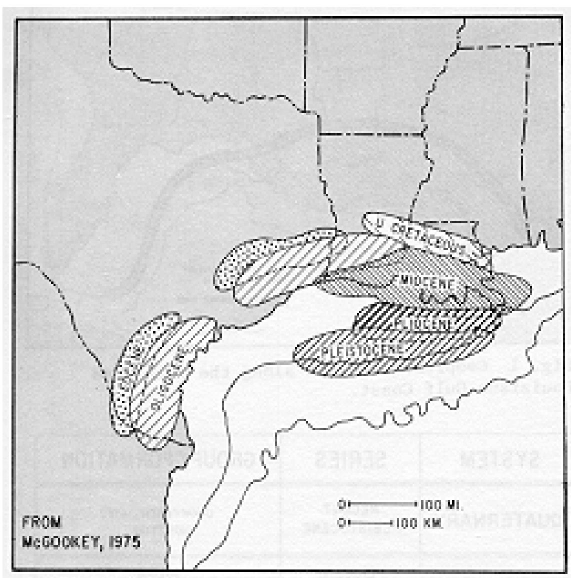

Fig. 2. Major Northern Gulf of Mexico depocenters.

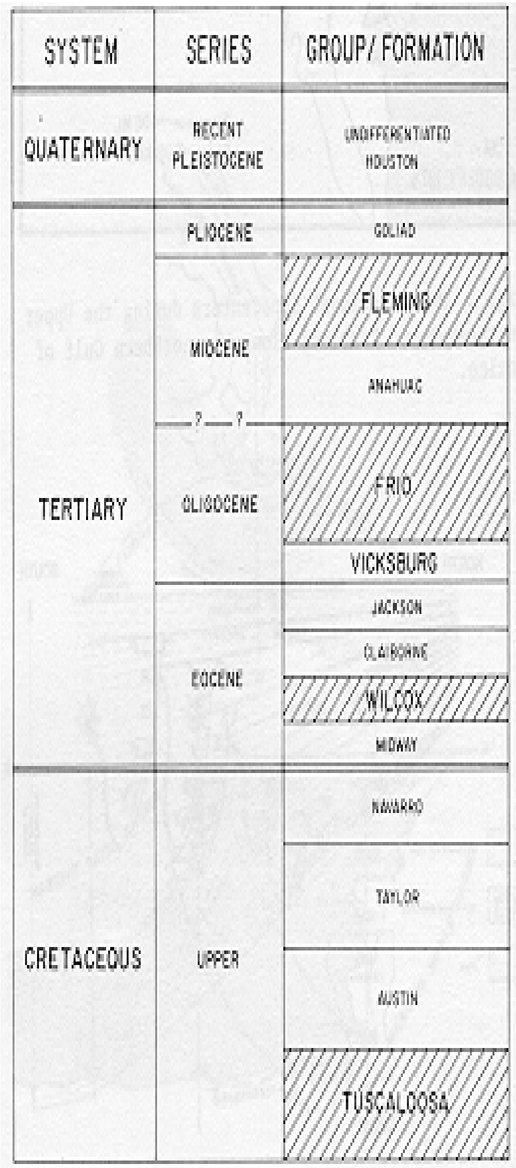

Fig. 3. Geologic time range of the geopressured zone.

total for onshore Texas and Louisiana to be 46,000EJ [1 EJ ≅ 1.04 Tcf] of thermal energy, 25,000EJ of methane, and 2,300EJ of mechanical energy. Based on the occurrence of geopressured aquifers in the studied area, offshore and other onshore sediments not included in the study were estimated to be 1.5 to 2.5 times the amount estimated in the study. Papadopulos also estimated absolute recovery efficiencies to be between 0.5% and 3.5% of the resource in place [6], [7]. Jones estimated the total methane content to be 49,000Tcf, of which 17,000Tcf was offshore. He estimated that between 246 to 1,145Tcf of methane could be recovered [8]. Brown went on to state that recovery efficiency "probably lies in the range of 4 to 50% of the methane within reservoirs which are eventually developed [9]." Hise estimated the total in place methane to be only 3000Tcf; and that perhaps 28Tcf of natural gas could be recovered [10]. Dorfman, Swanson and Osoba, and Doscher all performed studies that estimated the recoverable methane quantity to be about 7-8Tcf [11], [12], [13].

These estimates of the size and recoverable amount of the geopressured-geothermal resource were revised downward with time. Samuels and Wrighton reviewed the previously mentioned studies and other evaluations of the geopressured-geothermal resource and reported that varied assumptions of aquifer properties and differing methods of economic analysis made detailed comparisons practically impossible, but that the outlook for the commercial development of geopressured aquifers was low [14], [15]. Quitzau and Bassiouni used Monte Carlo simulation to account for uncertainties that affect the net present value (NPV) of commercial geopressured aquifer production and determined that exploration related directly to the development of geopressured aquifers was not economic viable [16].

Bassiouni published a report that ranked the sixty-three most promising geopressured-geothermal prospects in the state of Louisiana according to estimates of the total recoverable energy available in each prospect. The report detailed reservoir properties of the six highest ranking prospects and the Tuscaloosa trend; recommending three of these prospects, Grand Lake, Lake Theriot and Bayou Hebert, as suitable test sites. The Table 1 presents a summary of aquifer properties for the six highest-ranking prospects [4].

Table 1. Louisiana geopressured aquifers.

Prospect	Physio-graphy	Top of Geo-pressure (ft.)	Bulk Rock Volume (ft^3 x 10^9)	k (md)	ϕ (%)	In-Place Water (bbl x 10^9)	Avg. Pressure (psia)	Avg. Temp. (°F)	Avg. Water Salinity (ppm)	Gas Solub. (scf/bbl)	In-Place Dissolved Gas (Tcf)
Grand Lake	Marsh	13,600	657	21	18	21	12,600	240	100,000	28	0.6
Lake Theriot	Marsh	12,600	1,738	103	28	87	11,620	232	46,000	32	2.8
Bayou Hebert	Dry Land/ Marsh	13,000	543	45	16	15	11,600	230	87,000	26	0.4
Kaplan	Dry Land	12,000	312	273	23	13	12,770	259	57,000	37	0.5
South White Lake	Marsh	14,900	211	68	12	4	16,200	281	150,000	23	0.1
Solitude Point	Dry Land	19,000	1,914	5	9	30	15,000	328	60,000	58	1.7

1.2 Industry Experience with Geopressured Aquifers

In 1963, C.E. Hottman, of the Shell Oil Co., filed for a patent with the United States Patent and Trade Office (USPTO). Patent 3,258,069, titled "[A] Method for Producing a Source of Energy from an Overpressured Formation," described the mechanism for the formation of geopressured aquifers and a process by which to extract energy from the reservoirs [17]. Hottman was awarded an additional patent, 3,330,356, for the description of the apparatus to produce and separate the liquids produced from an overpressured reservoir [18]. In 1972 the National Science Foundation sponsored the Geothermal Resources Research Conference, which brought together scientists, engineers and environmentalists to discuss emerging geothermal technologies. In 1973, the conference report was published and geopressured water was recognized "as a significant and special type of geothermal energy, having in addition to thermal energy, natural gas and geohydraulic energy [19], [20]."

Parmigiano described an analytical model to predict the flowing wellhead pressure of a single well in the center of a closed boundary, circular aquifer under pseudo steady state conditions [21]. McMullan and Bassiouni, recognizing that maximizing flowrate maximized NPV, presented an equation to predict brine flowrate given a constant tubing head pressure. Additionally, the results of the study showed that the location of the well in respect to the aquifer was relatively unimportant compared to the effect of tubing size, skin, and initial aquifer properties (which would be expected based on Dietz inflow relations [74]). Fig. 4 and 5 show the effect of well location and tubing size on flowrate, respectively [22].

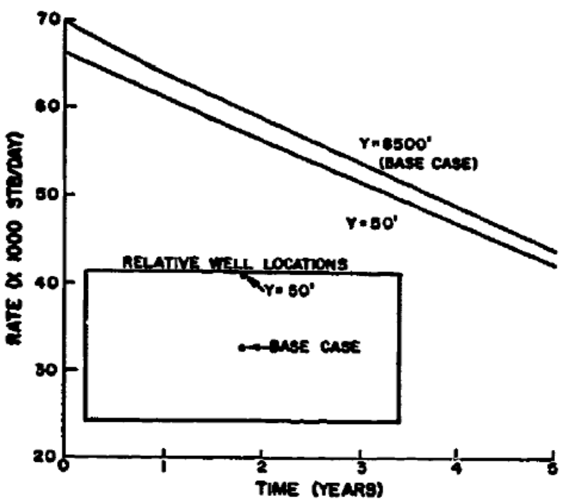

Fig. 4. The effect of well location on flowrate.

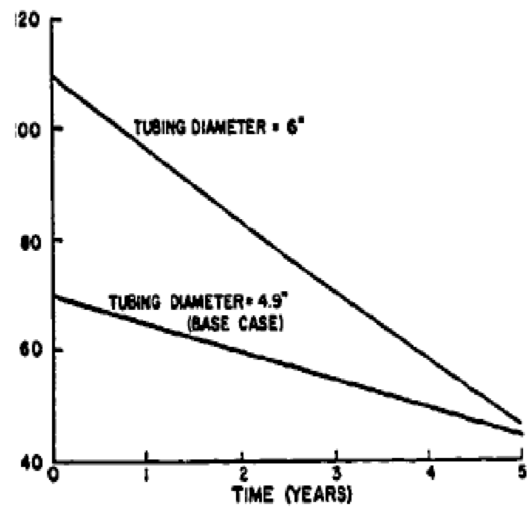

Fig. 5. The effect of tubing size on flowrate.

Several studies have numerically simulated the flow of water in a geopressured-geothermal aquifer. Isokari described a two-phase, two-dimensional reservoir simulation program for the modeling of a geopressured-geothermal aquifer [23]. Knapp et al.

included the effect of shale de-watering in the numerical simulation of geopressured aquifers. The results of the simulation's sensitivity analysis found that water influx from underlying and inter-bedded shales would play a more important role in aquifer pressure maintenance than water influx from laterally adjacent shales. They also found the depletion of geothermal geopressured aquifers can be approximated as an isothermal process [24]. Doscher, et al. found critical gas saturation to be an important parameter controlling ultimate recovery from a geopressured aquifer [25].

Economic studies of geopressured aquifers focused on determining the sensitivity of wellhead gas price to differing reservoir and completion parameters. Randolph varied the tubing diameter, porosity, permeability, rock compressibility, flowrate and aerial extent and found that the "reservoir criteria for natural gas production are much less stringent than for electricity generation from Gulf Coast geopressured aquifers [26]." Zinn used 1978 cost estimates to show that under optimistic reservoir criteria, some geopressured geothermal developments would be economic [27]. Doscher et al. determined that "the economic potential of methane production from geopressured aquifers leads to the conclusion that profitable exploitation of such reservoirs is not likely to occur in the near future, mainly because of the great reservoir size (1.5 cubic miles) required to sustain economic production rates and the cost of disposing of spent brines." Doscher's results showed that a methane cost of 4 to $15/Mscf would be necessary for a 15% rate of return prior to income taxes and amortized development costs [28].

Lamb and Rhode simulated a wellbore flow model for the Brazoria Fairway Austin Bayou Prospect and found that, due do heat generation from wellbore friction, effective flowing wellhead temperature would be within 7.5% of the static reservoir temperature (°F) at flowrates of 10,00BWPD and that, at flowrates of 60,000BWPD, the flowing wellhead temperature would at least equal to the static reservoir temperature [29].

Kharaka et al. predicted corrosion and scale formation rates from geopressured brines. Despite the potential for high salinities in geopressured brines, it was determined that the corrosive potential would be low due to the near absence of O_2 and sulfate-reducing bacteria. However, scaling tendencies led to the prediction of the likely formation of calcium carbonate, barium sulfate and other precipitates [30].

1.3 "Wells of Opportunity" and "Design Well" Programs

In 1975, the United States Energy Research and Development Administration (now DOE) began funding studies of the geopressured-geothermal resource that performed geologic assessments of the Gulf Coast geopressured-geothermal potential. The scope of the program was later expanded to include projects that sought 1) to physically verify the reservoir fluid and near wellbore petrophysical properties of geopressured aquifers, and 2) test the long-term producibility of geopressured aquifers. Completion of the goals was chartered under the Wells of Opportunity (WOO) and the Design Well (DW) programs, respectively. The purpose of the programs were "to determine whether or not the resource has potential… as an economic, reliable and environmentally acceptable energy source [31]."

1.3.1 The "Wells of Opportunity" Program

The Wells of Opportunity program provided short-term information on the productivity, range of occurrence, and methane content of a large number of geopressured aquifers. The wellbores utilized in the WOO program were conventional dry-holes that were then reentered and completed in potentially productive geopressured-geothermal aquifers. Wells proposed to the DOE in connection to the WOO program were evaluated and selected on the following criteria:

1. Bottom hole temperature greater than 275F (flexible).
2. Pressure gradient of 0.8psi/ft (flexible).
3. Salinity less than 75,000 ppm TDS.
4. Minimum of 100 essentially continuous feet of 100% water saturated porous sand of good permeability, as determined by available wells logs and core data.
5. Readily available land site near optimum reservoir areas.
6. Reasonably continuous drainage area.
7. Adequate casing and completion to mechanically permit the desired test.
8. Some geographical dispersion of the test sites.
9. Adequate and available well logs and geological data.
10. Suitable financial arrangements.
11. Indication of adequate gas in solution [31].

The WOO program was designed to provide large amounts of quickly available information from a diverse geographic and geologic area without great expense to the DOE. Short-term tests allowed for the data collection on aquifer fluid characteristics, near-wellbore petrophysical properties, fluid behavior under flow and well deliverabilities, the evaluation of completion techniques, and scale and corrosion potential.

Table 2. Reservoir characteristics of Wells-of-Opportunity.

	Girouard No.1	Koelemay No.1	Saldana No.2	Prairie Canal No.1	Crown Zellerbach No.1	Fairfax Sutter No.2
Parish (County)	Lafayette, LA	Jefferson, TX	Zapata, TX	Calcasieu, LA	Livingston, LA	St.Mary, LA
Shut-in Surface Pressure (psia)	6695	4373	2443	6420	2736	-
Max Flow Rate (BWPD)	15,000	3,200	1,950	7,100	2,832	7,700
Max Gas Rate (Mcfd)	600	1,017	105	390	93	-
Surface Flow Temp (F)	255	206	220	230	198	240
Produced Gas-Water Ratio (scf/bbl)	40	30-318*	47-54	43-55	33	22.5-30
Lab Gas-Water Ratio (scf/bbl)	44.5	35	41	43	-	22.8
Water Salinity-TDS (ppm)	23,500	15,000	12,800	42,600	32,000	190,000
Carbon Dioxide (Mole %)	6	7.2-2.7	26.4-16.4	9.6	22.6	7.8
Total Water Produced (bbls)	41,930	30,030	9,328	41,079	10,338	-
Formation	Frio - Marg. Tex No.1	Yegua - "Leger"	Upper Wilcox	Hackberry, Upper Frio	Tuscaloosa	-
Perforations (ft)	14,774-14,819	11,639-11,780	9,745-9,820	14,782-14,820	16,720-16,750	15,781-15,878
Gross Interval (ft)	107	139	90	25	36	-
Net Interval (ft)	91	77	79	14	35	58
Original Reservoir Pressure (psia)	13,203	9,450	6,627	12,942	10,075	12,203
Original Reservoire Temperature (F)	274	260	300	294	327	270
Porosity – Log (%)	26	20	16	28	17	19.3
Porositry – Core (%)	-	26	20	25	-	-
Permeability - Core (md)	-	85	20	-	-	-
Permeability - Test (md)	200-240	100-200	16.7	95	16.6	14.5
Radial Distance Explored (ft)	1,658	1,972	2,768	3,897	1,758	-

There were limitations to the success of the WOO program. Wells selected for completion were not located in structurally favorable locations. Even though permeability barriers were encountered in all of the test wells, the short-term pressure transient tests did not provide information on complete reservoir limits. Due to the nature of the WOO program, not all wells tested were in good condition: 11 wells were accepted to the WOO program, 8 wells were successfully re-completed in geopressured aquifers, and seven wells provided flow data [37]. Table 2 provides reservoir information for six of the WOO program wells [33], [36].

In two wells, brines salinities were higher than expected and resulted in reduced methane solubilities. Carbon dioxide content of some wells was much higher than expected, resulting in reduced methane solubility in the brine. The Tuscaloosa sand test in Livingston Parish showed brine under-saturated with methane. The Lake Charles, LA and Laredo, TX wells produced gas at rates in excess of the methane solubility in brine. All other test wells showed methane content at or near saturation in the brine. Scaling and corrosion tendency depended on brine salinity and reservoir temperature. Bottom-hole temperatures were between 7% and 16% higher than log derived data [33].

1.3.2 The "Design Well" Program

The Design Well program focused on long duration tests to extensively study reservoir fluid composition, reservoir characteristics, and drive mechanisms. These wells were located at optimum reservoir locations and designed to produce geopressured brines at high rates for periods to 2 years. Parameters that were to be determined during the tests include:

1. Reservoir permeability, porosity, thickness, rock properties, depth, temperature, and pressure.
2. Reservoir fluid content, salinity, viscosity, inert gases and hydrocarbons in solution.
3. Reservoir fluid production rates, pressure, temperature, and possible sand production.
4. Equipment design for energy extraction and effluent disposal.
5. Environmental factors, such as brine disposal, reservoir compaction, surface subsidence, and fault activation [32], [31].

The location of design wells were chosen to allow testing of the most favorable fairways and to provide testing of sand complexes that had yet to be produced. Selection guidelines for design well sites were similar to the WOO and included these additional constraints:

1. Reservoir volume – at least one cubic mile, with good thickness.
2. Fluid temperature – greater than 275F.
3. Minimum permeability – 20md
4. Water salinity – less than 50,000mg/L.
5. Initial bottom hole pressure – greater than 0.7 psi per foot.
6. Production rate – capable of 40,000 barrels per day [31].

The Pleasant Bayou No.2 test well was the first well drilled and completed in the DOE Design Well program. Testing of the well lasted from 1979 until late August 1990 and approximately 15.4MMbbls water and 330MMscf natural gas was produced. Initial testing of the aquifer was conducted from 1979 through 1983, when wellbore failure occurred. In 1988 the well was re-completed and testing of an experimental Hybrid Power System (HPS) occurred until 1990. The Pleasant Bayou No.2 was the only Design Well to utilize the HPS for the generation of electricity. Microseismic monitoring and subsidence measurements recorded no increase in activity due to the production of geopressured brines [40].

The L.R. Sweezy No.1 test well produced geopressured brines from an aquifer with limited aerial extent (approximately 940 acres) in order to determine the effect of shale water influx and rock compaction on pressure behavior over time and the effect of geopressured aquifer production on surface subsidence. Eleven pressure transient tests were performed between April 1982 and January 1983 and S-Cubed determined that pressure response from the short- and intermediate-term tests were likely from stress-induced hysteresis and compressibility; the long-term pressure response possibly included additional, undetermined, reservoir drive mechanisms [40]. Ultimate recovery from the aquifer was predicted to be 11MMbbls water and 183.5MMscf of methane, but completion failure caused the well to be abandoned in February 1983. Prior to production, surface subsidence was experimentally determined to be 0.004ft for a pressure depletion of 3000psi and site monitoring showed no subsidence events related to the well activities [34], [35], [37], [38]. Table 3 presents reservoir characteristics of the four Design Wells [40], [37], [39].

The Amoco Fee No.1, Sweet Lake prospect, was originally identified by the Gulf Geothermal Corporation in 1974. A joint venture with Magma Power Company was later formed and the site of the Amoco Fee No.1 well became the 1st geothermal lease in Louisiana. The well was spudded in August 1980 and completed in February 1981 [41].

Flow tests of the well indicated that a permeability barrier existed closer to the well than seismic or structural mapping had predicted and restricted flow to +/15,000BWPD [42].

Table 3. Reservoir characteristics of Design Wells.

	Pleasant Bayou No.2	Gladys-McCall No.1		Amoco Fee No.1		L.R. Sweezy No.1
Parish (County)	Brazoria, TX	Cameron, LA		Cameron, LA		Vermillion, LA
Formation	Lower Miocene Oligoncene	Frio Oligocene		Miogypsinoides Sand Upper Oligocene		Upper Frio Oligoncene
Tested Zone	-	Zone 3	Zone 5	Zone 8	Zone 9	-
Max Flow Rate (BWPD)	28,900	6,604	36,500	36,500	4,400	10,700
Sustained Flow Rate (BWPD)	18,900	-	15,700	33,300	-	8,500
Produced Gas-Water Ratio (scf/bbl)	23	20.2-24.1	23	27-29.8	32	20.2
Total Water Produced (bbls)	15.4E6	27E6		1.1E6		2E6
Water-in-Place (bbls)	5E9	7.8E9		1.8E9		106E6
Water Salinity-TDS (ppm)	131,320	168,650	165,000	97,800	96,500	99,700 +/-240
Carbon Dioxide (mol %)	11.28	-	-	9.92		-
Perforations (ft)	14,644-14,704	15,245-15,255 15,260-15,280	15,390-15,470	15,160-15,470	15,511-15,627	13,349-13,388 13,395-13,406
Gross Interval (ft)	60	34	32	338	128	73
Net Interval (ft)	53	24	27	333	114	57
Original Reservoir Pressure (psia)	11,168	11,887	12,082	12,799	12,911	11,410
Original Reservoire Temperature (F)	305	293	298	291	294	237
Porosity	18	20	22	16	16	27
Permeability	192	42-140	12-162	160	67	126

Rock mechanic studies of the Sweet Lake test well showed that matrix compressibility would be a significant component of the drive mechanism and that pore volume compaction would be more pronounced during early stages of production [40]. Surface subsidence in the Sweet Lake area during the test period was attributed solely to natural processes.

The Gladys-McCall No.1, drilled and completed in 1981, provided a successful field test of a moderately sized geopressured aquifer. The well produced over 27MMbbls of water and 675MMscf between its initial production date in 1983 and shut-in in 1987. Scale production was controlled through the use of continuous inhibitor injection into the production stream and through the periodic injection of an inhibitor pill into the formation [46]. This enabled the well to produce brine at rates in excess of 30,000 BWPD.

Short- and long-term pressure transient tests estimated the primary aquifer volume at between 270 and 408MMbls. Long-term transient test estimated that an additional 7.5 billion barrels of water was partially connected to the primary volume. Numerical flow simulations of the aquifer were not performed; but, the additional volume was hypothesized to come from either shale water influx, additional volume connected through a partially-sealing fault, or a combination of both [43], [44]. Core analysis from the Gladys-McCall No.1 showed that both reservoir compaction and formation creep could greatly contribute to the reservoir drive mechanism [45]. Surface subsidence measurements of the Gladys-McCall site showed that elevation changes were higher than the regional rate of subsidence, but could not be directly related to the production of geopressured geothermal brines. Microseismic monitoring of the test site did not show an increase in fault activity due to geopressured-geothermal production [40].

1.4 Commercial Production of Brines in Japan

The Japanese have commercially produced methane saturated brines for over 65 years, though under a less hostile production environment than present in the Louisiana Gulf coast. Originally developed for the purpose of extracting iodine from aquifer brines, Godo Shigen Sangyo Co., Ltd. has produced methane-saturated brines from aquifers since 1935 [47]. As the cost and usefulness of the methane increased, it was used to aid in the iodine extraction process and later successfully employed to residential use. Godo Shigen has used the methane extracted from aquifer brines for commercial purposes since 1957 and for residential use since 1967.

The geologic setting is markedly different from the northern Gulf of Mexico. The production interval in Japan is from depths no greater than 7,000ft and is normally pressured. The reservoir drive mechanism is a combination of reservoir compaction and meteoric water influx. Subsidence is a common problem and strict regulations have been placed on the re-injection of produced brines. Many wells are placed on artificial lift to ensure adequate flow [48]. The methane aquifers in Japan are not representative of the U.S. Gulf Coast geopressured-geothermal resource and cannot be used as an analogous system.

2. Approach and Goals

Studies to determine the commercial potential of geopressured-geothermal aquifers typically focused either on reservoir performance or financial viability of field development [16], [24]. Unfortunately, no comprehensive studies to determine the commerciality of geopressured aquifers have been performed for almost twenty years. This study combines reservoir performance, facility efficiency and financial constraints to determine a range of potential outcomes for viable commercial development of geopressured-geothermal aquifers.

The reservoir performance model utilizes a commercial reservoir simulation program to predict the production rates from aquifers under constrained surface pressure. Sensitivities consider single- well and multi-well developments. Reservoir model components are varied to determine a wide range of aquifer productivities. Varied parameters include bulk volume, depth, reservoir dip angle, porosity/permeability, initial pressure and temperature gradient, salinity, formation compressibility, maximum allowable flowrate, wellbore radius, formation dip angle, and initial gas saturation. Two distances from the wellhead to the flow header are used in the single well groups and one distance is used in the multi-well group.

The facility model uses reservoir temperature and flowrate from the reservoir performance model to estimate the net electric output of the thermal recovery system. The financial model computes the discounted cash flow of geopressured aquifer developments. Input parameters for the financial model are flowrate from the reservoir model, discount rate, natural gas price, net electric output, electricity price, capital and operational costs, severance taxes and net revenue interest. Output parameters include discounted cash flow, payout time, profitability index and the internal rate of return.

By combining the results of the reservoir, facility, and financial models, a range of input parameters that yield a positive life-cycle cash flow are delineated. The ranges can be applied to evaluate geopressured-geothermal resources and identify areas where additional research is warranted.

3. Methods

The economic viability of geopressured aquifers is controlled by three components: reservoir performance, facility process design, and financial constraints. Each of these components is, in turn, defined by different variables. Some of these variables are inter-related (e.g., flowrate affects reservoir performance, facility process design, and financial constraints). The chapter describes a methodology to determine potential commerciality of geopressured aquifers. In this chapter variables expected to affect the commerciality of geopressured aquifers are defined, given ranges of likely values, and compared to results obtained during previous studies. Assumptions and uncertainties about these variables are voiced and explained.

3.1 Reservoir Performance Model

Results of the WOO and DW programs show that the properties of geopressured geothermal aquifers vary over a wide range. This section details the methodology for determining the range and level of input parameters for the numerical reservoir simulation program. Once all input parameters are defined the method for determining input parameters of sensitivity runs are described.

3.1.1 Reservoir Description

Early estimates of the minimum bulk volume required to commercially produce geopressured aquifers were between 1 and 7 cubic miles. Large bulk volumes enable wells to sustain flowrates of 80,000 BWPD for a period of 20 years [20]. Test wells later showed that the size of individual aquifers would be smaller and more compartmentalized than previously predicted. Of the completed tests from the Wells of Opportunity and Design Well programs, a majority of wells encountered minimum pore volumes of o 0.015 cubic miles (100MMBW) or less [37]. The largest aquifer encountered a connected volume of almost 3 cubic miles [40]. Additionally, a majority of wells tested aquifers found at depths between 14,500 ft and 16,000 ft, with formation dips ranging between 0 °/100 ft and greater than 2 °/100 ft and net intervals between 75 ft and 300 ft.

To represent the physical description of aquifers that have been tested, three levels of bulk volumes are available for input to the reservoir model: 0.05, 0.25 and 1.25 cubic miles. The grid has 100 grid blocks in both the 'X' and 'Y' directions, with the 'X' and 'Y' length of each grid block equal (with block sizes adjusted for overall aerial extent). Four vertical layers are used, of either 100 ft or 200 ft interval height. The aquifer structure has a constant dip of 0, 1 or 2 °/100 ft. The top of the reservoir is at a depth of either 13,500 ft or 15,000 ft. Table 4 shows the grid block height and length for each bulk volume.

Table 4. Grid block dimensions for numerical simulation.

Bulk Volume (cubic mile)	Grid Block Length (ft)		Aerial Extent (sq. mi)	Grid Block Height (ft)
	X'	Y'		Z'
0.05	60.66	60.66	1.32	50
	85.79	85.79	2.64	25
0.25	135.7	135.65	6.6	50
	191.8	191.83	13.2	25
1.25	303.3	303.32	33	50
	429	428.95	66	25

3.1.2 Porosity and Permeability

Core analysis from the Pleasant Bayou No.1 and No.2 wells shows that producing geopressured aquifers are composed of sandstone from a wide range of environments. As stated by Loucks et al., "reservoir quality depends on a complex relationship among the sandstone depositional environment, mineralogical composition, and consolidation history [50]." Depositional matrix and cements may reduce permeability [50]. Sandstone porosities at the Pleasant Bayou No.2 ranged between 1 and 24% with corresponding permeabilities ranging from below 0.01 md to greater than 1 Darcy.

Total porosity is the sum of macro- and micro-porosity, with macro-porosity composed of three groups: primary inter-granular porosity, secondary dissolution inter-granular, and secondary intra-granular porosity. In geopressured aquifers total porosity is typically dominated by micro-porosity and secondary dissolution porosities. Quartz, calcite, kaolonite and other cements reduce primary and secondary porosity during diagenesis and can restrict permeability [50]. Jones hypothesized that areas of high cementation would typically be at the top of geopressured aquifers, but later core analysis showed that this was not always the case [3], [40]. Figs. 6a and 6b show scanning electron microscope slide from the Pleasant Bayou No.1 well [50]. Fig. 7 shows secondary porosity plotted against depth for the Pleasant Bayou cores [50]. Fig. 8 and Fig. 9a and 9b are thin section slides from the Pleasant Bayou cores [50].

Well log and core analysis from wells in the WOO and DW programs showed that average porosities for geopressured aquifers could be expected to lie between 12% and 27%, with associated permeabilities between 16 md and greater than 200 md [Tables 2 and 3]. Table 5 describes the porosity values chosen for the reservoir performance

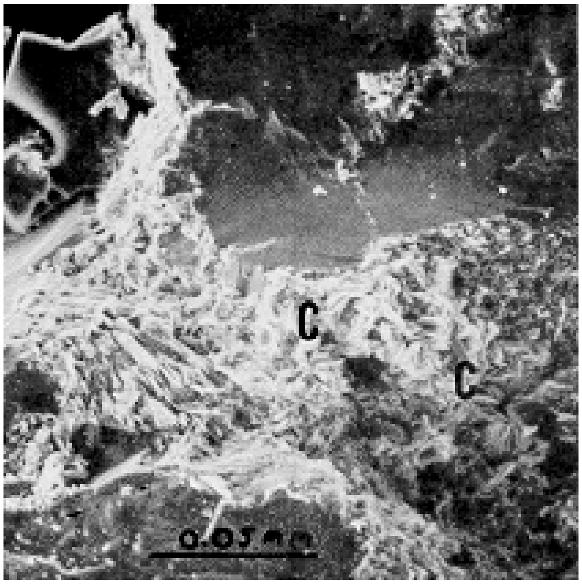

Fig. 6a. High porosity/ low permeability sample (ϕ=11.6%, k=0.8 md). Micro-porosity between flakes of authigenic pore-filling clay (C) is the main porosity type.

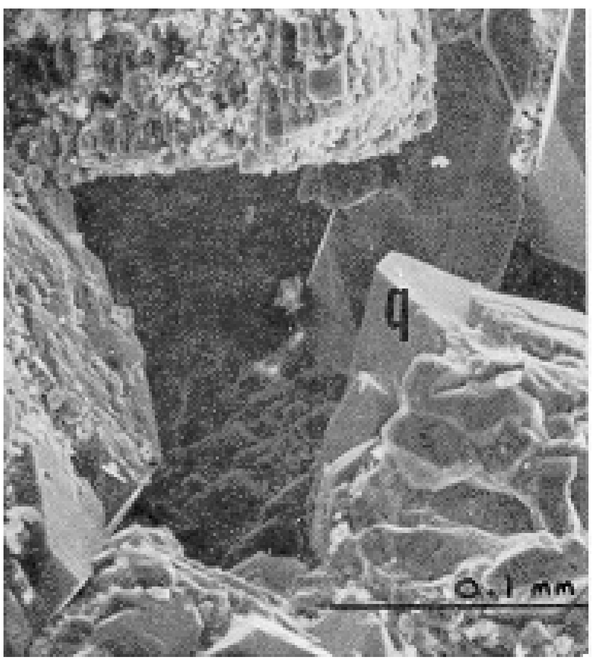

Fig 6b. High porosity/ high permeability sample (ϕ=21.6%, k=1041 md). Quartz overgrowths (q) are the main cement. Porosity is macro-porosity.

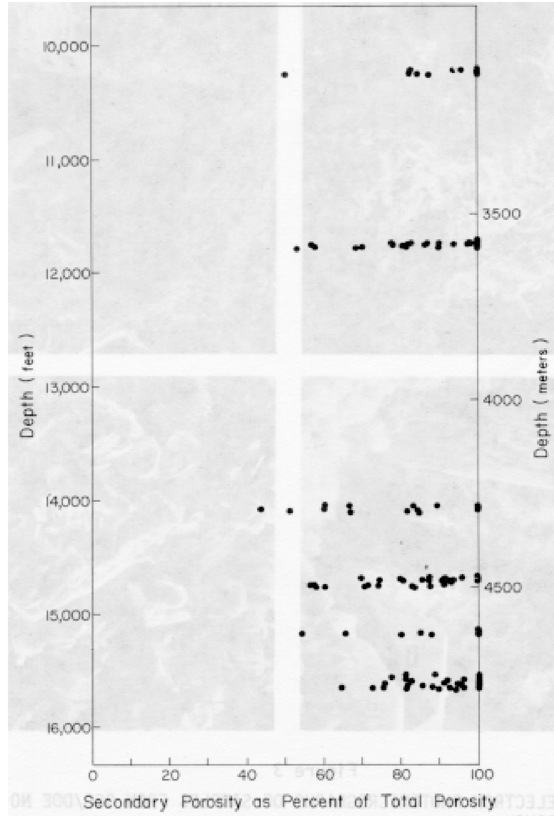

Fig. 7. Secondary porosity versus depth for Pleasant Bayou cores.

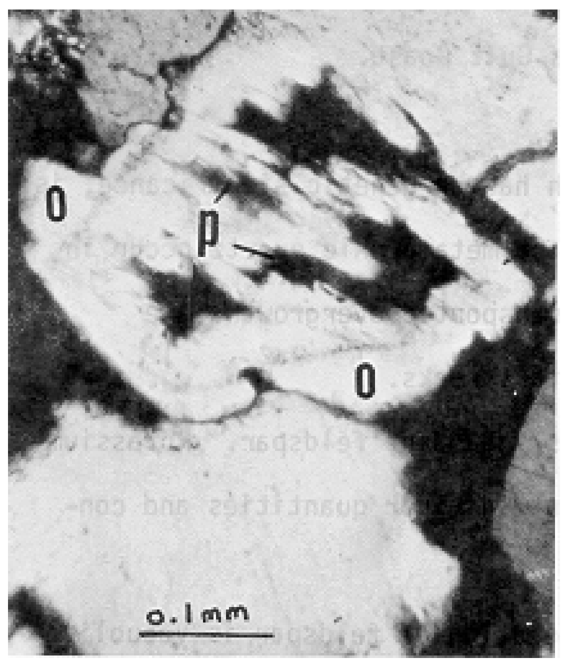

Fig. 8. Secondary porosity (p) in leached plagioclase. Plagioclase overgrowths (o) partially surrounds the grain (crossed polars).

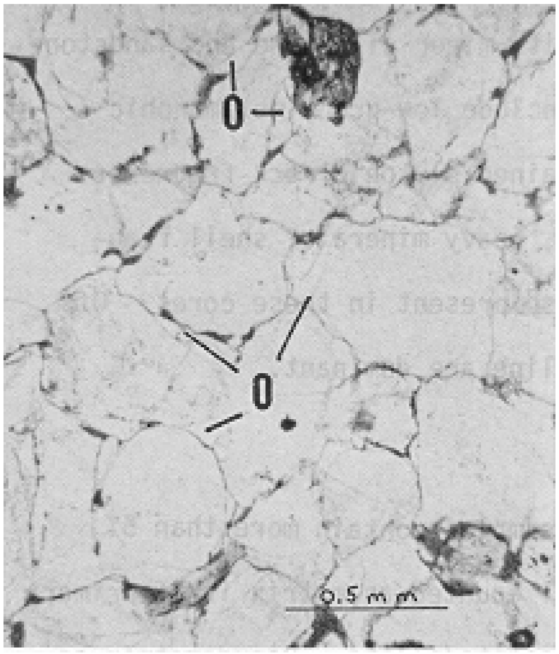

Fig 9a. Quartz cemented sandstone. Quartz overgrowths (o) are indicted (plane-polarized light).

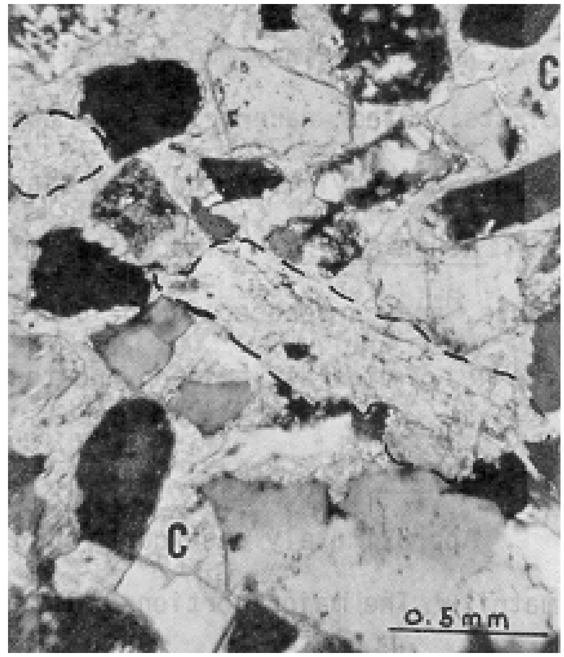

Fig 9b. Calcite cemented sandstone. The cement (c) is in the form of large poikiloptic crystals and has completely replaced some grains (outlined) (crossed polars.

model. The values lie within the observed range of the WOO and DW test wells but are not specific of particular test sites. The numerical reservoir simulator assumes that stipulated values of porosity are of primary macro-porosity only.

Table 5. Porosity and permeability values for numerical simulation.

	ϕ (%)	k (md)
Option 1	15	50
Option 2	20	100
Option 3	25	200

A single, synthetic relative permeability curve is used for all reservoir simulation runs and is presented in Table 6 [Tables 2 & 3]. Critical gas saturation, S_{gc}, will be held at 2% for all simulation runs. Suzanne showed that for the low values of initial gas saturation expected in geopressured aquifers, critical gas saturation would be less than 2% and residual gas saturation would be close, if not equal to critical gas saturation [52]. The relative permeability model used assumes that the aquifer is “clean” sandstone and that a dual (or bound) water model is not applicable.

Table 6. Relative permeability model for numerical simulation.

S_g	K_{rg}	K_{rwg}
0.000	0.000	1.000
0.200	0.001	0.851
0.075	0.012	0.752
0.120	0.020	0.594
0.190	0.026	0.484
0.240	0.050	0.387
0.290	0.084	0.352
0.340	0.128	0.302
0.390	0.183	0.229
0.440	0.248	0.167
0.470	0.293	0.116
0.500	0.343	0.075
0.600	0.539	0.044
0.700	0.786	0.022
0.750	0.900	0.008
1.000	1.000	0.000

3.1.3 Pressure and Temperature Gradient

The onset of “hard” geopressure is defined as hydrostatic gradients in excess of 0.7 psi/ft, and occurs at depths ranging between 8,500 ft and 15,000 ft in the northern Gulf of Mexico region. Fig. 10 shows the depth of occurrence for geopressure in Neocene deposits in the northern Gulf of Mexico and demonstrates the breadth of the deposits [51]. Wells tested under the WOO and DW program encountered pressure gradients between 0.68 psi/ft and 0.90 psi/ft. Reservoir temperature gradients for wells tested under the two programs were between 1.6 °F/100ft and 3.1 °F/100ft.

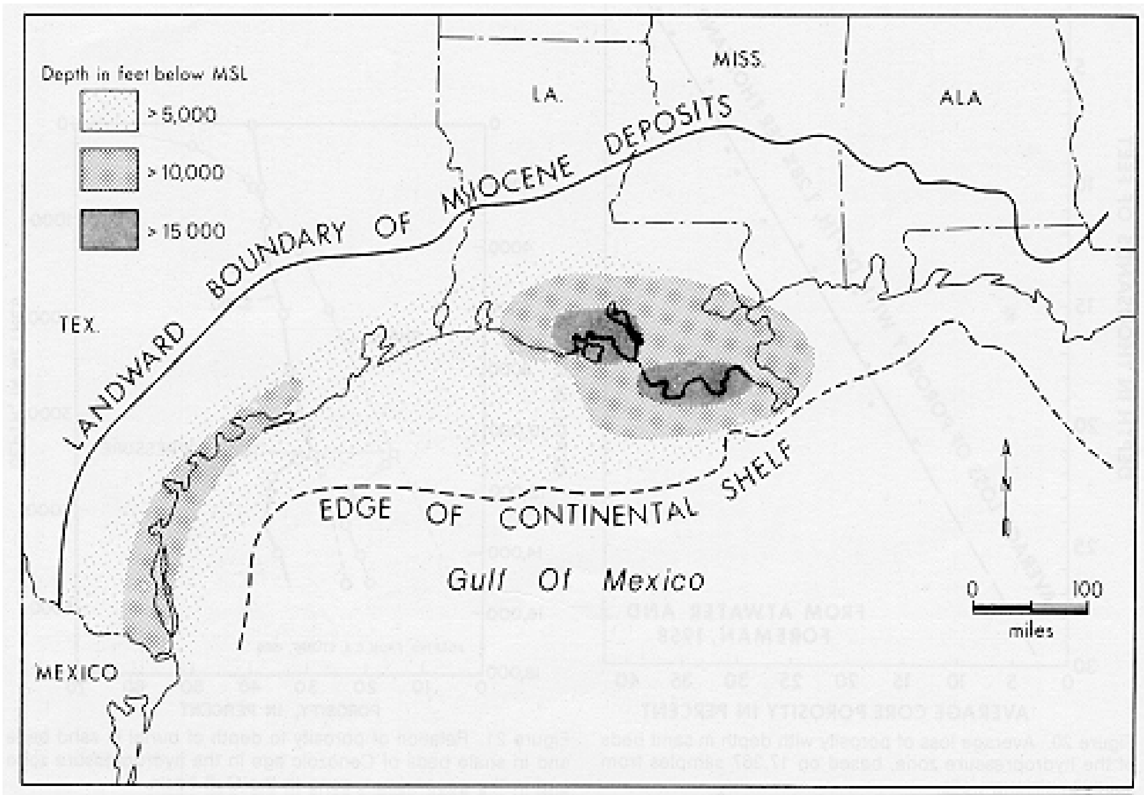

Fig. 10. Depth of occurrence of geopressure in Neocene deposits.

Three levels of pressure gradient and three levels of temperature gradient are used of numerical modeling of the reservoir. The pressure gradient is 0.7 psi/ft, 0.8 psi/ft, and 0.9 psi/ft; reservoir temperature gradients are 1.8 °F/100ft, 1.95 °F/100ft and 2.1 °F/100ft and are independent of pressure gradient. Initial pressure and reservoir temperature are calculated for top of structure. For the purpose of calculating fluid properties, temperature will be isothermal throughout the aquifer.

3.1.4 Salinity, Formation Volume Factor, and Water Viscosity

Subsurface water salinity varies greatly and with little correlation to the temperature, pressure and depth of the reservoir. Initial publications on the development of geopressured reservoirs estimated that brine salinity below the onset of geopressure would be 35,000 mg/L or lower [3]. Brine salinities from the WOO and DW program test wells varied between 12,800 mg/L and 190,000 mg/L. Fig. 11 presents calculated and produced brine salinity versus depth for the Red Fish field, Galveston County, Texas [61].

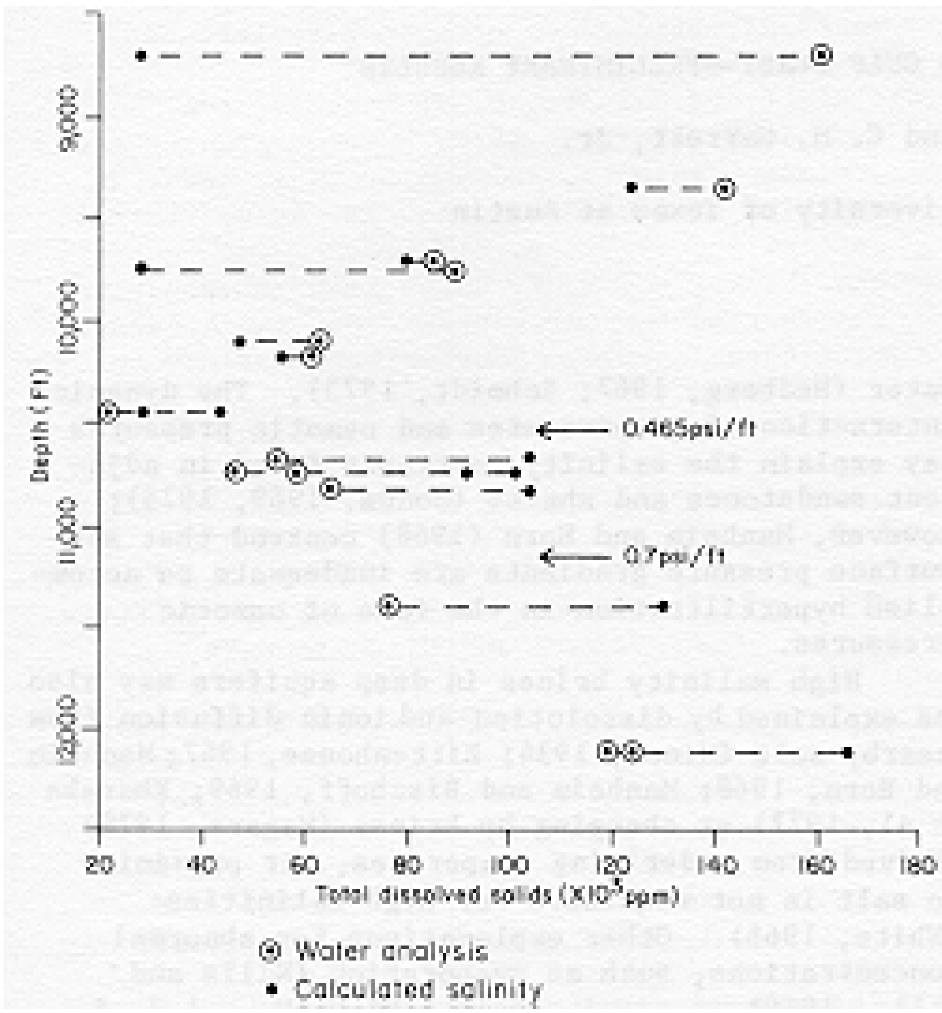

Fig. 11. Calculated and produced brine salinity versus depth for Red Fish Field.

Brine salinities calculated from the spontaneous potential (SP) log commonly yielded estimates that were higher than that of the produced brine [61]. In a few instances, well log calculated salinities were much lower than salinities from produced brines. Silva and Bassiouni associated this to the non-ideal membrane behavior of shales and proposed a correction to the calculation of salinity from the SP log [53].

Three levels of salinity are used in this study: 25,000 mg/L, 50,000 mg/L, and 100,000 mg/L. This salinity range presents a significant portion of the likely range.

Eqn. 1 defines the formation volume factor of water, B_w, as a function of the change of water volume from standard conditions for a given temperature and pressure. Eqn. 2a and 2b define ΔV_{wp} and ΔV_{wT}, respectively [60]. For the reservoir performance model, a table for B_w is generated that corresponds to the formation depth, temperature and pressure gradient of the case sensitivity. B_w will not be corrected for salinity.

$$B_w = (1 + \Delta V_{wp})(1 + \Delta V_{wT})$$

Eqn. 1

$$\Delta V_{wp} = -1.95301(10^{-9})pT - 1.72834(10^{-13})p^2T - 3.58922(10^{-7})p - 2.25341(10^{-10})p^2,$$

Eqn. 2a

where T is in °F.

$$\Delta V_{wT} = -1.0001(10^{-2}) + 1.33391(10^{-4})T + 5.50654(10^{-7})T^2,$$

Eqn. 2b

where T is in °F and p is in psia.

Water viscosity at a given temperature and atmospheric pressure is calculated using Eqn. 3a and corrected to reservoir pressure using Eqn 3b [60]. The equation is valid to within 7% for the temperature, pressure and salinity range that will be used.

$$\mu_{w1} = AT^B$$

Eqn. 3a

where T is in °F,

$$A = A_0 + A_1 S + A_2 S^2 + A_3 S^3,$$

where $A_0 = 109.574$, $A_1 = -8.40564$, $A_2 = 0.313314$, $A_3 = 8.72213x10^{-3}$, and

$$B = B_0 + B_1 S + B_2 S^2 + B_3 S^3 + B_4 S^4,$$

where $B_0 = -1.12166$, $B_1 = 2.63951x10^{-2}$, $B_2 = -6.79461x10^{-4}$, $B_3 = -5.47119x10^{-5}$, $B_2 = 1.55586x10^{-6}$, and S is salinity in weight percent solids.

$$\mu_w = \left[0.9994 + 4.0295(10^{-5})p + 3.1062(10^{-9})p^2\right]\mu_{w1}$$

Eqn. 3b

3.1.5 R_{sw}, B_g, and μ_g

Many experimental studies have determined the solubility of methane in distilled water, R_{sw}. Culberson and McKetta published the first empirical correlation of methane solubility at varying temperatures and pressure for distilled water [54], [60]. Eqn. 4 and Fig. 12 describe the Culberson and McKetta correlation. Sultanov et al. expanded the correlatable range of methane solubility in pure water by taking measurements from 302 °F to 680 °F and 711 psi to 15,645 psi [55]. Price extended the range to include methane solubilities between 309 °F to 662 °F and 100 to 28,600 psi [56].

$$R_{sw} = A + Bp + Cp^2$$

Eqn. 4

where

$$A = A_o + A_1 T + A_2 T^2 + A_3 T^3,$$

where $A_0 = 8.15839$, $A_1 = -6.12265x10^{-2}$, $A_2 = 1.91663x10^{-4}$, $A_3 = -2.1654x10^{-7}$,

$$B = B_o + B_1 T + B_2 T^2 + B_3 T^3,$$

where $B_0 = 1.01021x10^{-2}$, $B_1 = -7.44241x10^{-5}$, $B_2 = 3.05553x10^{-7}$,

$B_3 = -2.94883x10^{-10}$,

$$C = (C_0 + C_1T + C_2T^2 + C_3T^3 + C_4T^4)(10^{-7}),$$

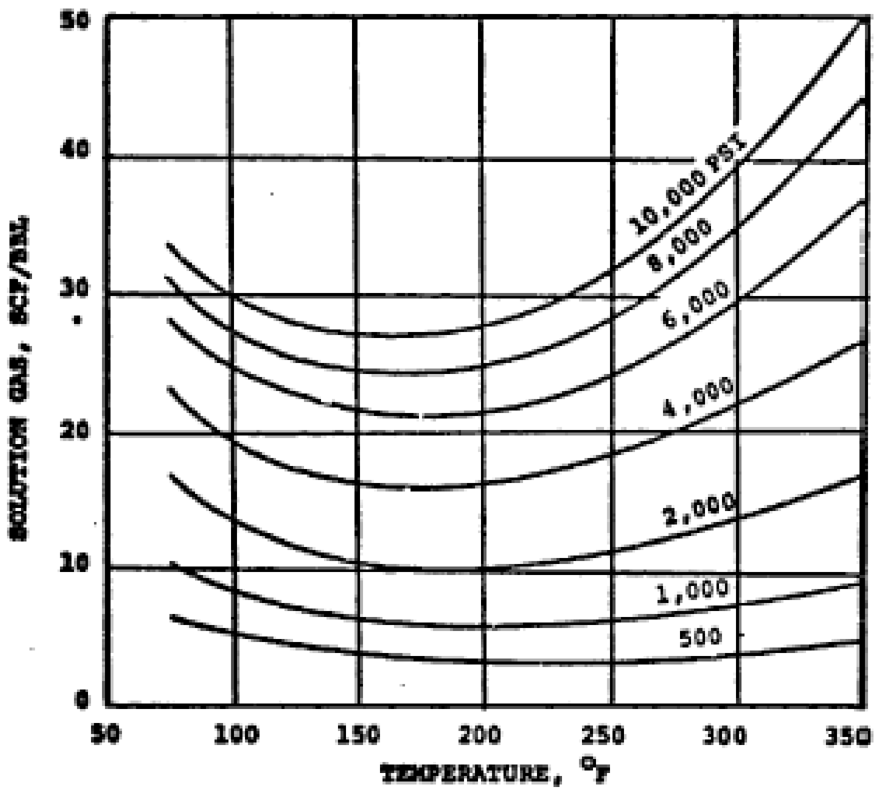

Fig. 12. Culberson and McKetta correlation for methane solubility in pure water.

where $C_0 = -9.02505$, $C_1 = 0.130237$, $C_2 = -8.53425x10^{-4}$, $C_3 = 2.34122x10^{-6}$,

$C_4 = -2.347049x10^{-7}$.

$$\log\left(\frac{R_{sw}\ brine}{R_{sw}\ \ pure\ water}\right) = -0.0840655S * T^{-0.285854}$$

Eqn. 5

where T is in °F, p is in psia, and S is weight percent solids.

Fewer studies have been conducted to determine the solubility of methane in brines. Eqn. 5 shows McKetta and Wehe's equation to adjust Culberson and McKetta for salinity [59], [60]. Haas gathered data to derive an empirical equation to cover methane solubility in NaCl solutions below 600 °F and 20,000 psi [57]. Blount et al. presented an empirical equation for methane solubility in brines of all salinities and valid between temperatures of 158 °F to 464 °F and pressures above 3,500 psi. A second empirical equation was developed for methane solubilities for temperatures between 464 °F and 601 °F and for pressures above 5000 psia [58]. Blount's equations are based on experimentally determined aqueous methane solubility data from 212 °F to 464 °F, and from 2,000 psi to 22,500 psi in NaCl solutions of 0 to 25 percent weight; the resulting correlations are presented as Eqns. 6a (158 °F to 464 °F) and 6b (212 °F to 464 °F) below, respectively.

$$\ln(CH_4) = -1.4053 - 0.002332T + 6.30x10^{-6}T^2 - 0.004038S - 7.579x10^{-6}p + 0.5013\ln(p) + 3.235x10^{-4}T\ln(p)$$

Eqn. 6a

$$\ln(CH_4) = -3.3544 - 0.002277T + 6.278x10^{-6}T^2 - 0.004042S + 0.9904\ln(p) - 0.0311\ln(p)^2 + 3.204x10^{-4}T\ln(p)$$

Eqn. 6b

Blount et al. noted that the salt composition had no measurable effect on methane solubility but that the carbon dioxide content of the brine "…has large and unexpected effects on the methane solubility" [58] Fig. 13. The effect of heavier hydrocarbon gases on methane solubility in brines has not been quantified.

McKetta and Wehe's correction for Eqn. 4 is used to generate profiles for methane solubility in water versus pressure for pressures below 3,500 psia. Blount's correlation is used to calculate the solubility of methane in brine for pressures above 3,500 psia. The effects of carbon dioxide and heavier hydrocarbon gases on R_{sw} will not be considered in this study.

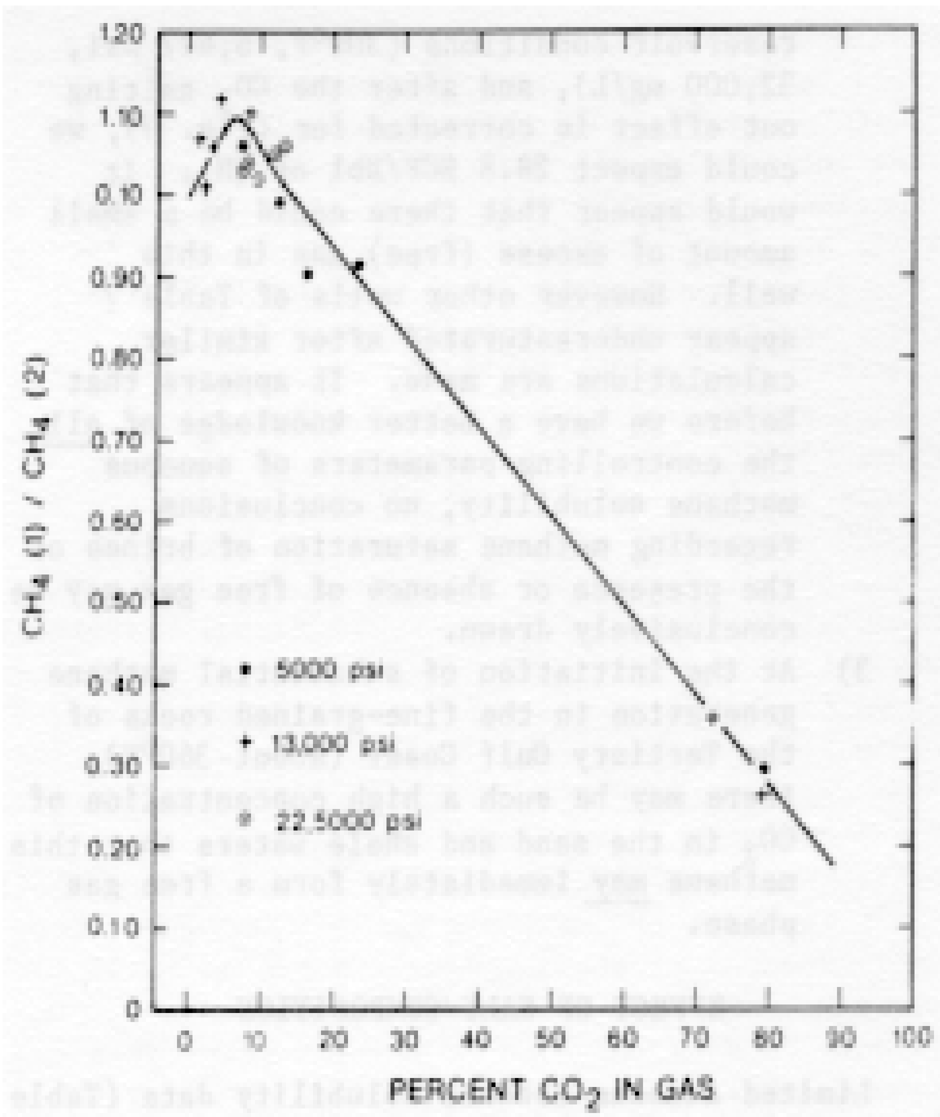

Fig. 13. Change in methane solubility with increasing CO_2 concentration in brine. Temperature and NaCl concentration are constant (300 °F, 5.0% weight); pressure is variable. "CH_4 (1)/CH_4 (2)" refers to the methane solubility in the brine with a certain amount of CO_2 present divided by the methane solubility of the brine without CO_2 present.

Eqn. 7 is used to calculate the gas formation volume factor, $B_{g,}$ of methane. Eqn. 8 is used to calculate the viscosity, $\mu_{g,}$ of methane in the model and is generated using McMullan's Excel add-in [60], [75], [76]. Both B_g and μ_g assume only methane is present in the reservoir model.

$$B_g = 0.00502 \frac{zT}{p}$$

Eqn. 7

where B_g is rb/scf, T is absolute temperature, °R, p is in psia, and z is calculated using McMullan.

$$\mu_g = K \exp\left[X\rho^Y\right]$$

Eqn. 8

where

$$K = \frac{(7.77 + 0.0063M)T^{1.5}}{209 + 19M + T},$$

$$X = 3.5 + \frac{986}{T} + 0.01M\ ,$$

$$Y = 2.4 - 0.2X\ ,$$

where M is molecular weight, T is absolute temperature, °R, and ρ is density, gm/cc.

An initial free gas saturation in geopressured aquifers has been discussed by several authors. Some wells in the WOO and DW programs produced methane in excess of solubility in brine. In one of the wells the excess gas production was later attributed to the presence of up-dip hydrocarbons [36]. In other wells the source of excess gas production was not determined, but free gas production was not excluded [40]. In the reservoir model three options of initial free gas saturation are available: 0, 1, and 2% initial gas saturation.

3.1.6 Drive Mechanisms

Multiple drive mechanisms affect the pressure-production behavior of geopressured aquifers. Early research focused on water and gas expansion and rock compressibility as drive mechanisms for geopressured aquifers [23]. Later modeling efforts included the effects of shale water influx and critical gas saturation on reservoir recovery [24], [25]. Core analysis from some Design Wells showed that formation compaction and creep deformation could add significantly to formation recoveries [45].

The effects of shale water influx and formation compaction as reservoir drive mechanisms have been studied extensively. Numerical simulation studies by Knapp and Isokari modeled the effect of water influx from both over- and under-lying shales and from laterally adjacent shales; these studies showed that shale water influx could contribute substantially to pressure maintenance [24]. Long-term pressure transient analysis from the Gladys-McCall test well showed the influx of water into the primary aquifer that could potentially be from shale [43]. Multiple 2- and 3-D seismic surveys (time-lapse seismic) from the Parcperdue test site (L.R. sweezy No.1), along with detailed pressure and production information were intended to determine the effect of shale influx on aquifer pressure maintenance, but wellbore failure during production precluded the continuation of the project.

Core analysis from the Pleasant Bayou, Sweet Lake (Amoco Fee No.1), and Parcperdue (L.R. Sweezy No.1) test wells showed varying levels of pore volume compaction [40], [45], [70], [78]. Studies have shown that formation creep could provide a significant increase to the reservoir drive mechanism [45], [83]. Table 7a and 7b shows pore volume and permeability change for effective overburden stress for the L.R. Sweezy and Pleasant Bayou wells, respectively.

Table 7a. Rock compaction table for L.R. Sweezy No. 1 well.

	L.R. sweezy No.1		
	$\sigma_{ob\text{-}eff}$	Pore Volume Multiplier	Permeability Multiplier
Load	0	1	1
	1000	1	1
	2000	0.99	1
	3000	0.98	1
	4000	0.97	0.98
	5000	0.97	0.9
	6000	0.96	0.86
	7000	0.95	0.81
	8000	0.94	0.83
Unload	7000	0.95	0.86
	6000	0.96	0.93
	5000	0.97	1
	4000	0.97	1.07
	3000	0.98	1.14
	2000	0.99	1.21
	1000	1	1.21
	0	1	1.21

Table 7b. Rock Compaction table for Pleasant Bayou No. 1 well.

	Pleasant Bayou No.1		
	$\sigma_{ob\text{-}eff}$	Pore Volume Multiplier	Permeability Multiplier
Load	0	1.00	1.00
	2000	0.98	1.00
	4000	0.96	1.00
	6000	0.95	1.00
	8000	0.94	0.87
	10000	0.94	0.78
	12000	0.93	0.70
	14000	0.92	0.67
Unload	14000	0.92	0.68
	12000	0.93	0.75
	10000	0.94	0.80
	8000	0.94	0.90
	6000	0.95	0.96
	4000	0.96	0.96
	2000	0.98	0.96
	0	1.00	0.96

To maintain a generalized approach to modeling the productive capacity of geopressured aquifers, water and gas expansion and rock compressibility are used as drive mechanisms in the numerical simulation runs. While research has shown that the effects of shale water influx, rock compaction, and creep deformation could potentially compromise a significant portion of total drive mechanism, these effects relate more to site specific aquifer modeling than to the general productive capacity of geopressured aquifers. The effect of creep deformation will not be considered in the model; the effects of shale water influx and formation compaction are only considered in conditional runs. Three levels of rock compressibility will be used: 10E-6/psi, 15E-6/psi, and 20E-6/psi.

3.1.7 Wellbore Modeling and Well Locations

Several strategies can be utilized in the development of geopressured-geothermal aquifers. Quitzau identified three situations for the development of geopressured aquifers:

1. The geopressured well case. A well is drilled specifically for the production of geopressured aquifers.
2. The dry hole case. A well intended for the production of deep, conventional is dry and completed in a geopressured aquifer.
3. The marginal hole/ geopressured aquifer re-completion case. A is drilled for conventional hydrocarbons but finds reserves of questionable certainty. The well may or may not produce these hydrocarbons, and is later re-completed to the geopressured aquifer [16].

Each development situation has both positive and negative technical and economic implications. A well drilled purposefully for the development of geopressured aquifers offers the ability for wellbore design and location to be maximized for the production of geopressured aquifers, (i.e. away from permeability barriers and faults) but results in higher capital costs. A dry hole converted to the production of geopressured brines allows for the recuperation of some capital costs, but wellbore diameter and location on structure may be unfavorable. A well re-completed to a geopressured aquifer offers the potential for significant cost savings, but wellbore integrity may be questionable.

The reservoir model uses three wellbore diameters in the simulation sensitivity runs. All wells are assumed to be drilled vertically and well drilling and completion cost are adjusted for the development situation (Table 8).

Table 8. Capital costs and operating expense for simulation wells.

Development Situation	Lease Operating Expense ($M/yr)	Depth (ft)	13500	15000
		D_w (in)	Drill and Completion Cost ($MM)	
1	50	7	8	9
2	50	5.5	4.5	6
3	50	4.5	1.5	1.5

All wells are completed without tubing and a ¼" to ½" chemical injection string runs to a point above the perforations allow continuous injection of corrosion and scale inhibitors. A commercial nodal analysis software package models vertical flow performance (VFP. VFP profiles consider flowline distances from the wellhead to the flow header of 100 ft and 2,500 ft. To stay within the constraints of Lamb and Rhode, flowing wellhead temperature, T_{wf}, is calculated at 94% of the static aquifer temperature [28]. Temperature loss along the flowline is estimated at 1 °/100 ft. Well production is constrained by maximum flowrate and minimum header pressure. Six levels of flowrate are considered: 10,000, 25,000, 35,000, 50,000, 60,000, 70,000 BWPD. Lease operating expenses will be escalated by $1 /year/BWPD design rate to account for corrosion and inhibitor treatment. Header pressure is not allowed to drop below 500 psig.

Reservoir simulations consider single- and multi- well. In single-well aquifer developments, the well is placed at the center of the reservoir model. In multi-well reservoir simulations the aquifer is developed using 2, 3, or 4 wells. All wells in a multi-well development have uniform wellbore diameter and flowrate restriction. Four options for well pattern are used for each multi-well development scenario.

3.1.8 Run Selection

If variations of reservoir input parameters are considered using full factorial design, over 470,000 simulation runs would be needed to provide the results of all combinations. Orthogonal arrays (OA) define the reservoir input parameters for the sensitivity runs with a much smaller number of simulation runs. OA's allow analysis of effects of individual variables on the outcome and variable interaction [79]. An OA is used to generate sensitivity run input parameters for both groups of distance of flowline length and for the multi-well group (Tables 9a and 9b).

By combining the input parameters that have been described in the previous sections, a mixed array (MA) of 36 runs can be generated for both the single well groups and the multi-well group [80], [81].

Table 9a. List and range of parameters for single-well numerical simulation.

Property	Units	Levels	Values					
V_b	cubic miles	6	0.05 (h=200 ft)	0.05 (h=100 ft)	0.25 (h=200 ft)	0.25 (h=100 ft)	1.25 (h=200 ft)	1.25 (h=100 ft)
q	BWPD	6	10,000	25,000	35,000	50,000	60,000	75,000
ϕ (k)	% (md)	3	25 (200)	20 (100)	15 (50)			
g_{pp}	psi/ft	3	0.7	0.8	0.9			
g_T	°F/100ft	3	1.8	1.95	2.1			
D_w	in	3	7	5.5	4.5			
S	ppm	3	25,000	50,000	100,000			
S_{gi}	%	3	0	1	2			
Dip angle	°/100ft	3	0	1	2			
C_f	psi^{-1}	3	10E-6	15E-6	20E-6			
D	ft	2	13,500	15,000				

Table 9b. List and range of parameters for multi-well numerical simulation.

Property	Units	Levels	Values					
Number wells (pattern)		6	2 (vertical)	2 (horizontal)	3 (triangle)	3 (inverted triangle)	4 (star)	4 (square)
Well spacing		6	Centered - ¼ offset	¼ high – ¼ - 1/8 offset	Centered - 1500 ft	Centered - 3000 ft	¼ high – 1500 ft	Centered – ¼ offset
V_b	cubic miles	2	0.25	1.25				
dip angle	°/100ft	3	0	1	2			
Cf	psi^{-1}	3	10E-6	15E-6	20E-6			
S_{gi}	%	3	0	1	2			
g_{pp}	psi/ft	2	0.7	0.9				
q	BWPD	3	25,000	50,000	75,000			
Dw	in	3	7	5.5				
D	ft	1	15,000					
S	ppm	1	50,000					
g_T	°F/100ft	1	2					
ϕ (k)	% (md)	1	20 (100)					

3.1.9 Simulation Output

Results from the reservoir simulation runs include average monthly gas and brine production rates, cumulative gas and brine production totals, flowing header pressure, well bottom-hole pressure, and field pressure. These results are used in the facility process model and the financial model.

3.2 Facility Process Model

Multiple components of production systems could be considered for installation during the commercial development of geopressured-geothermal aquifers. Facility components include equipment for the recovery of hydraulic energy, methane extraction, thermal recovery, secondary products and brine disposal. This study examines the use of single- well facilities. The use of central collection and brine processing facilities for multi-well developments are not considered. Fig. 14 is a simplified flow process diagram for a geopressured development.

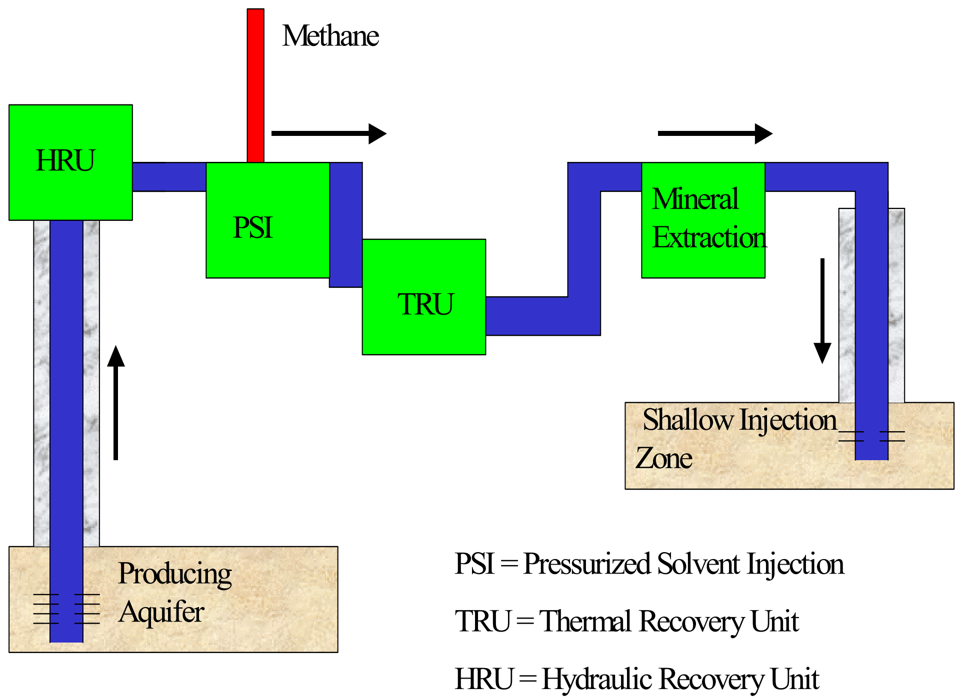

Fig. 14. Simplified flow process diagram for a geopressured development.

3.2.1 Hydraulic Recovery Unit

The installation of pressure reduction turbines to recover hydraulic energy from geopressured aquifers has been studied for geopressured geothermal energy development. A hydraulic recovery turbine was proposed for installation as part of the Pleasant Bayou No.2 Hybrid Power System (HPS). A Pelton turbine was partially installed but not operated during the testing of the HPS because off-the-shelf equipment to complete the installation could not be obtained. It was estimated that the hydraulic turbine would have added 7 to 8% to the net energy of the plant [40]. For this study a pressure recovery turbine will not be considered for the facility because the hydraulic energy is to be preserved to facilitate re-injection at lower costs.

3.2.2 Methane Extraction

The extraction of methane from geopressured brine by de-pressurization is an inefficient process. WOO and DW production typically used a two-stage separation process to recover methane [68]. This process utilized standard separation equipment, resulted in methane recoveries between 75 and 85%, and often required charge pumps downstream of the separators disposal injection [40], [68]. Quong et al. proposed the injection of a paraffin solvent into the production stream to recover methane. Experiments to measure the effectiveness of hexadecane as a solvent showed that an additional 5 to 15% of the original methane in solution could be extracted, and could reduce total development costs [68]. Table 10 shows the installed and operational cost for the methane extraction system that will be used in the facility model ($M equals $1000).

Table 10. [82]. Capital cost and operating expense for methane extraction system.

Design Flowrate (BWPD)	Installed Cost ($M)	Operational Cost ($M/yr)
10,000	100	10
25,000	250	25
35,000	350	35
50,000	500	50
60,000	600	60
75,000	750	75

3.2.3 Binary-cycle Power Plant

Brine in geopressured geothermal aquifers does not occur at reservoir temperatures that allow for use of flash steam power generation. Table 11 from the World Bank shows typical applications of geothermal energy for given temperature ranges [65]. The generation of electricity from intermediate and low temperature geopressured brines must use a binary-cycle power plant, in which the primary fluid (geopressured brine) heats a secondary fluid (typically iso-butane) which powers the turbine (this system is also known as an Organic Rankine Cycle (ORC) system). Binary-cycle power plants operate between 7-12% efficiencies and can accept brines at temperatures as low as 212 °F [65]. Fig. 15 presents a schematic of a typical binary-cycle power plant [63].

Table 11. [65]. Application and technology used for low- to medium- temperature brine.

Reservoir Temperature	Reservoir Fluid	Common Use	Technology commonly chosen
High Temperature >220°C (>430°F).	Water or Steam	Power Generation Direct Use	• Flash Steam • Combined (Flash and Binary) Cycle • Direct Fluid Use • Heat Exchangers • Heat Pumps
Intermediate Temperature 100-220°C (212 - 390°F).	Water	Power Generation Direct Use	• Binary Cycle • Direct Fluid Use • Heat Exchangers • Heat Pumps
Low Temperature 50-150°C (120-300°F).	Water	Direct Use	• Direct Fluid Use • Heat Exchangers • Heat Pumps

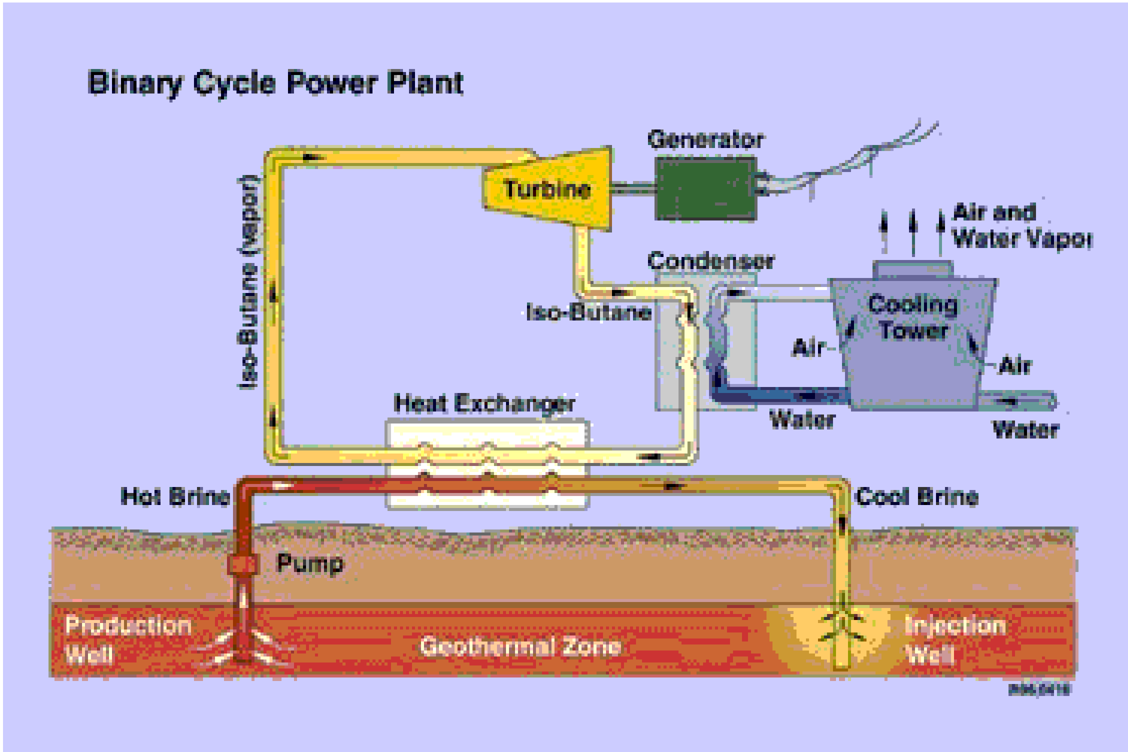

Fig. 15. [63]. Process-flow schematic for typical binary-cycle power plant.

The Pleasant Bayou No.2 test site was the only installation of a binary-cycle power plant for use in a geopressured-geothermal facility. The Pleasant Bayou No.2 test site used a Hybrid Power System (HPS) installed on September 3, 1989. The HPS used both a binary-cycle power plant and a gas turbine to generate electricity. This 1 MW facility was not optimized for electricity generation, but to provide data over a large range of operating conditions. Despite this, over the period from late November 1989 until May 1990, the facility generated 3,445 MWh as well as cycled 1.4 MMstb of brine and 39.2 MMscf of natural gas through the facility [40].

Today there are multiple installations of binary-cycle power plants in the United States, mostly in California. The California Energy Commission (CEC) reports that installed cost of geothermal power will be 2,275 $/kW in 2005 with well exploration and development costs exceeding 60% of the total [66]. This gives an installed facility cost of 1 $MM /MW. Yearly operational expenses of 10% of the installed costs could be expected [66]. Fig. 16 shows the expected electric output of a binary-cycle power plant given inlet temperature and flowrate [65]. Table 12 approximates Fig. 16 for field units and includes the installed and operational cost of the power plant.

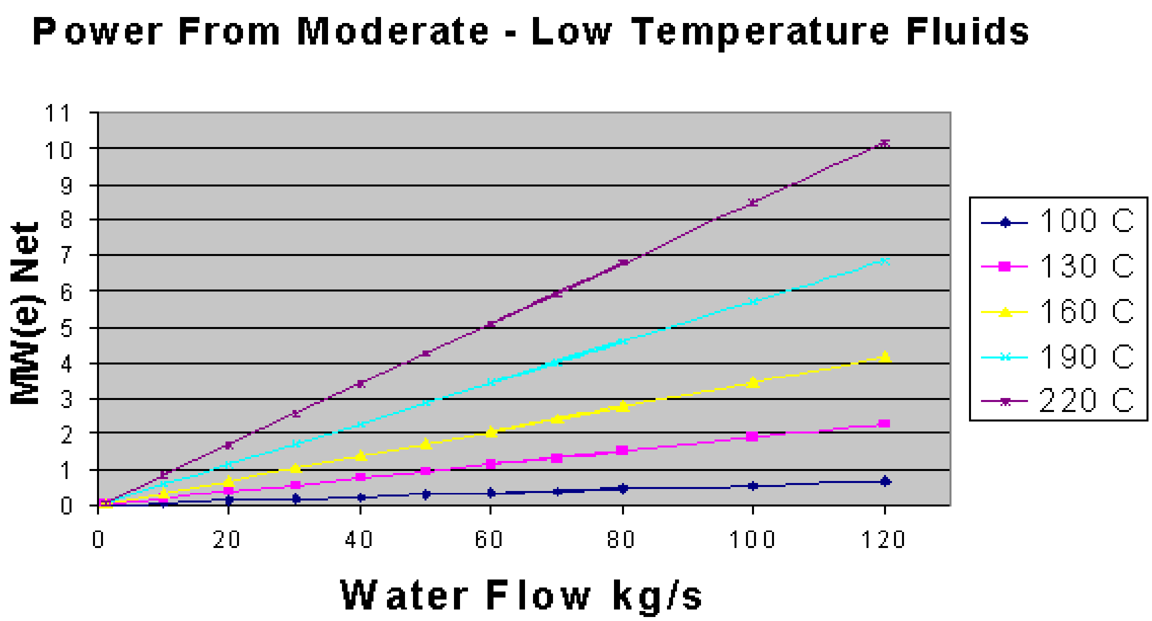

Fig. 16. Expected power output from binary-cycle power plants.

Table 12. Approximation of Fig. 16 in Field Units.

Design Flowrate (BWPD)	Brine Inlet Temperature					
	212 F (100 C)			266 F (130 C)		
	Net MW (design)	Installed Cost ($M)	Operating Cost ($M)	Net MW (design)	Installed Cost ($M)	Operating Cost ($M)
10,000	0.15	150	15	0.40	400	40
25,000	0.30	300	30	0.90	900	90
35,000	0.40	400	40	1.20	1,200	120
50,000	0.58	580	58	1.75	1,750	175
60,000	0.70	700	70	2.25	2,250	225
75,000	0.80	800	80	2.50	2,500	250

A Kalina cycle binary-cycle power plant could be installed. Kalina cycle systems use an ammonia-water mixture as the secondary fluid. Installation and operating costs for a binary-cycle power plant operating on the Kalina cycle are estimated to be 15 % lower than ORC systems with operating efficiencies up to 20% higher [69], [70], [71]. However, the Kalina cycle is relatively unproven and will not be considered in this study.

Development scenarios with and without the installation of a binary-cycle power plant are considered in this study. For this study, Table 12 is used to determine the output and installed cost of the thermal recovery system for development of geopressured geothermal aquifers. An HPS will not be utilized for the study. Wells will be placed in one of two categories: inlet temperatures greater than 212 °F and temperatures greater than 266 °F. Electric output for wells flowing below the designed flowrate is calculated using Eqn. 9.

$$MW(e)\ Net_{Effective} = MW(e)\ Net_{Design} * \frac{Current\ Flowrate}{Designed\ Flowrate}$$

Eqn. 9.

3.2.4 Secondary Product Recovery

Brine has been produced from wells for the commercial extraction of salt since as early as 1800. In western Oklahoma, brine produced in association with hydrocarbons is collected and commercially processed to remove iodine. Lithium, bromine and iodine are also extracted from brines throughout the United States [64]. In Japan, iodine is the primary product generated from the production of aquifer brine, methane dissolved in solution is the secondary product [48]. The production of geopressured brine could offer a large source for the future production of lithium, iodine, and bromine. Unfortunately, chemical analysis of brine produced during the WOO and DW tests did not indicate whether testing for these three minerals occurred [40]. A chemical analysis from the

Pleasant Bayou No.2 well did indicate concentrations of 82 ppm for bromine, 30 ppm for iodine, and 39 ppm for lithium [67]. While these concentrations are close to the minimum required for extraction, the installation of secondary product development facilities will not be included in the facility design.

3.2.5 Brine Disposal

In the WOO and DW programs, produced brine was injected into shallow disposal wells. Injection disposal of brines was chosen over surface discharge to limit the environmental impact of geopressured brine production [40]. Table 13 shows initial cost and operating expenses versus flowrate for injection of brine into shallow disposal wells and is used to assign costs for brine disposal in this study.

Table 13. Capital Cost and Operating Expense for Brine Disposal Wells.

Design Flowrate (BWPD)	Driling and Comletion Costs ($M)	Operating Expenses ($M/yr)
10,000	1,000	10
25,000	1,000	25
35,000	1,000	35
50,000	2,000	50
60,000	2,000	60
75,000	3,000	75

3.3 Financial Model

The potential commerciality of geopressured aquifers has always been susceptible to marginal economic conditions. Previous studies estimated that realized natural gas prices would need to exceed $4 /Mscf to $15 /Mscf to allow for the commercial production of geopressured aquifers and often relied on varied and optimistic estimates of reservoir and facility properties [15]. Some studies neglected the amoritization of capital expenses and many studies did not consider the production of electricity from thermal recovery in the financial analysis [40]. Wrighton also commented on the lack of standardization in the financial analysis methods. Some analysis was based on Rate of Return (ROR), some on before tax earnings, and some on after tax earnings [15]. Most economic evaluations did not include dry hole risk. Several evaluations included Monte Carlo simulation [16]. The variation in economic evaluation techniques resulted in a lack of consistency between results. A minimum economic solution of $5.50 /Mscf in one model was not comparable to a minimum economic solution of $9.00 /Mscf result in another model. This led to confusion in the industry about the commercial potential of geopressured aquifers.

Mian presented a standard layout for spreadsheets that can be used to predict the financial performance of an oil or gas property and allows for the calculation of before-federal income tax (BFIT) or after-federal income tax (AFIT) discount cash flow, the rate of return (ROR), profitability index (PI), and payout time of a project [83]. The spreadsheet was modified for use in this study to predict the financial performance of geopressured-geothermal developments. Input parameters are broken into two groups: those that remain static throughout the life of the project and those that can change during the life of the project. Static properties for this project include severance tax rates, net revenue interest, discount rate, and operating expenses. Dynamic properties are average water and gas production totals per year. Natural gas and electricity price are considered static parameters for the project.

Predicting the financial performance of geopressured aquifers requires an understanding of the unique funding and tax mechanisms that are currently available from the U.S. government [84]. The U.S. tax code allows for special tax credits and allowances to be claimed during the production of geopressured brines. A 10% investment tax credit can be claimed for investments in geothermal energy. A tax credit of $6.40 /BOE is allowed for the first 200 Mscf of gas produced from a geopressured aquifer. Wells that produce geopressured brine must use percent depletion rate of 10% instead of cost depletion to account for production. These credits and allowances are only available for wells drilled between 1978 and 1984 and, except for percent depletion, are not be considered in the general modeling of financial performance. However, a separate spreadsheet has been created to show the effect of the capital investment and production tax credit on geopressured aquifer financial performance.

In this study, financial feasibility is based upon the valuation of BFIT AFIT discounted cash flow and ROR using a modified form of Mian's spreadsheet. Four sets of commodity price sensitivity are used. Table 14 is a price sensitivity list for methane and electric sales. Base case prices are $0.03 /kW-hr for electricity and $4.50 /Mscf for natural gas. The cost of electricity is within the long-term wholesale price on the New York Mercantile Exchange [85]. The natural gas price is comparable to that currently used by an independent oil and gas company [82]. Price set 1 allows for the variation of natural gas price, set 2 varies electricity price, set 3 allows for parity between natural gas market price and electricity price. Set 4 is used to determine the value of a geopressured aquifer development *sans* a binary-cycle power plant.

Severance tax is \$0.07 /Mscf for natural gas in all cases; there is no severance tax on water production [83]. A 7.5 % royalty is paid to the lease owner for brine and methane production. The discount rate is 10% in all cases. There is no exploration risk (i.e. dry-hole, seismic evaluation) and no well replacement cost in with this project. A well production rate cut-off of 1,000 BWPD is used.

Table 14. List of Natural Gas and Electricity Price Values.

Set 1		Set 2		Set 3		Set 4	
\$/Mscf	\$/kW-h	\$/Mscf	\$/kW-h	\$/Mscf	\$/kW-h	\$/Mscf	\$/kW-h
2.5	0.03	4.5	0.02	2.5	0.02	2.5	-
3.5	0.03	4.5	0.025	3.5	0.025	3.5	-
4.5	0.03	4.5	0.03	4.5	0.03	4.5	-
5.5	0.03	4.5	0.05	5.5	0.05	5.5	-
6.5	0.03	4.5	0.07	6.5	0.07	6.5	-
7.5	0.03	4.5	0.09	7.5	0.09	7.5	-

4. Results

Economic viability can be broken into three performance groups: positive under all constraints, positive under a specific range of constraints (marginal), and never positive. For this study, negative performance is defined as having a negative ROR, marginal performance has a ROR below 30% and a positive NPV, and positive performance has a ROR above 30% and a positive NPV. Realized natural gas price, electricity price, capital cost, and operating expenses are the underlying constraints for this study. The method of selecting the range of input parameters for sensitivity runs is described in Chapter 3. The following sections discuss the performance of the sensitivities runs under the imposed financial constraints.

4.1 Single-Well Developments

The commercial potential of single-well developments in geopressured aquifers is affected most by the bulk volume of the aquifer, capital development costs and operating expenses, designed flowrate, initial gas saturation, wellbore diameter, porosity and permeability, and factors controlling methane solubility (Fig. 17). The effects of reservoir height, formation dip angle, depth, and rock compressibility on financial performance were negligible compared to the effects bulk volume and wellbore radius. Unless noted, results presented in this section are for sensitivity runs with flowline length of 100 ft. The effect of flowline length on the commerciality of geopressured aquifers is negligible due to the value of brine compared to the value of methane.

Table 15 ranks each component on the range of effect it has on a project being either "marginal or economic" or "economic." Important to note is the change of rank for certain factors. The change of rank for D_w can be related to the details of well cost and assumptions of development plan: each D_w assumes a specific development approach. The large change in ranks of S_{gi} and pressure gradient are associated with threshold values. The range of S_{gi} plays a large role in a project reaching "marginal or economic" status, but does not matter as much to progress to "economic" status. The opposite is true of pressure gradient. The range of pressure gradient for a geopressured aquifer to reach "marginal or economic" status does not rank very high, but to reach "economic" status pressure gradient matters more.

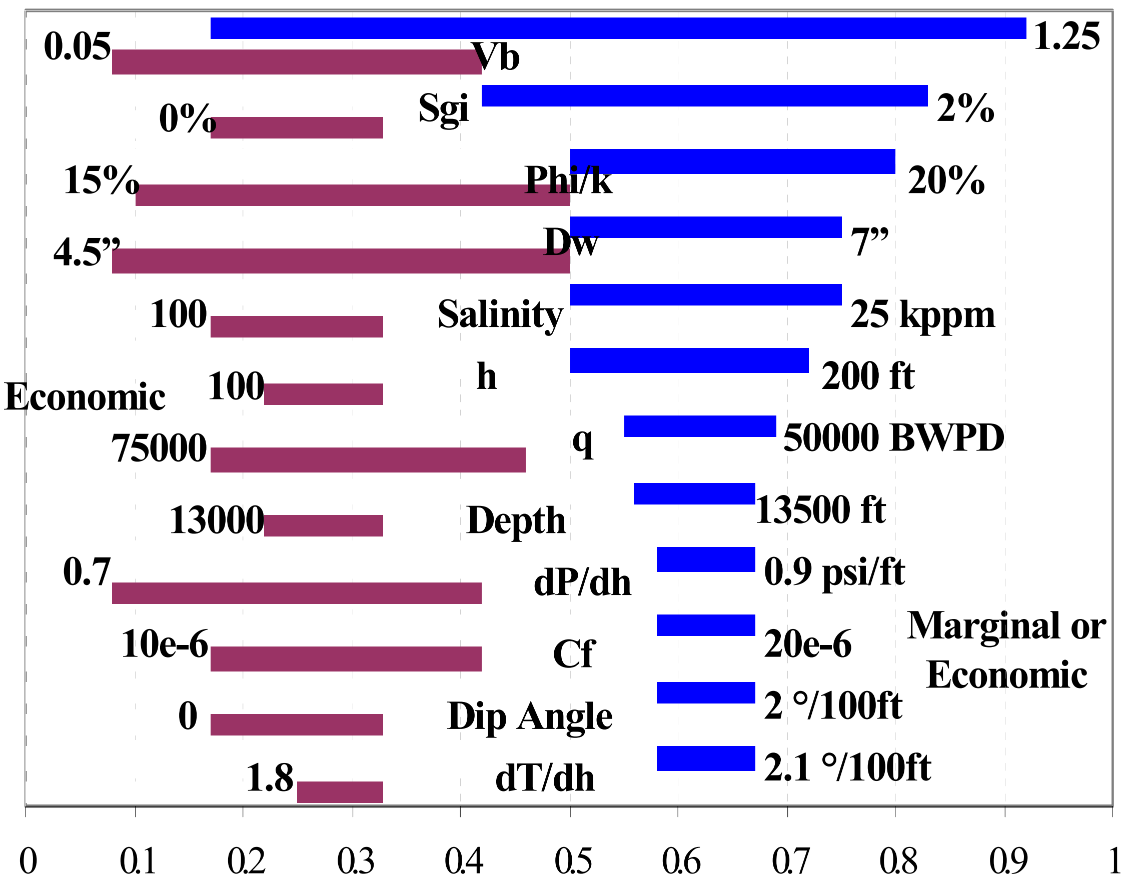

Fig. 17. Tornado diagram of results of sensitivity analysis for single-well developments with flowline length of 100 ft. Note that the x-axis represents the fraction of runs that exceed the requirement, not the probability that the requirement will be met.

Table 15. Rank of factors.

Rank	
"Marginal or Economic"	"Economic"
V_b	D_w
S_{gi}	Phi/ k
Phi/ k	V_b
D_w	dP/dh
Salinity	Flowrate (q)
Aquifer height (h)	C_f
Flowrate (q)	Salinity
Depth	Sgi
dP/ dh	Dip Angle
C_f	Aquifer height (h)
Dip Angle	Depth
dT/ dh	dT/dh

Table 16 shows the input parameters for each case along with the resulting BFIT ROR. Analysis of the interaction of input parameters and the effect on ROR can be important in determining the economic viability of a project and is visualized through contour mapping. Fig. 18a and 18b display the interaction of depth versus V_b and dip angle versus V_b on economic viability, respectively (regions valued below –0.50 are always un-economic, regions between –0.50 and 0.50 are marginally economic, and regions greater the 0.50 are always economic). In the figures, near vertical contours perpendicular to the bulk volume axis show that bulk volume dominates the economic viability of geopressured aquifers. Similar results were seen for rock compressibility, porosity/permeability, and aquifer height.

Table 16. Results for geopressured aquifers with 100 ft flowline. *L*, *M*, and *H* (low, medium, high, respectively) describe the value of the input parameter, except for *Class* where the values represent never economic (L), marginally economic (M), and always economic (H). *S* and *D* correspond to shallow or deep. See Table 9a for numerical values of input parameters.

Design Case	V_b	h	q (BWPD)		ϕ/ k	g_{pp}	Salinity	R_w	S_{gi}	Dip angle	g_T	C_f	D	ROR (%)	Class
1	L	L	10000	L	H	L	L	H	M	M	H	H	S	-	L
2	L	L	25000	L	H	L	L	H	H	H	M	M	D	-	L
3	L	H	25000	L	M	M	M	M	M	M	H	H	S	-	L
4	L	H	10000	L	M	M	M	M	H	H	M	M	D	8	M
5	M	L	60000	H	H	M	M	H	H	L	H	L	S	55	H
6	M	L	75000	H	H	M	M	H	L	H	L	H	D	19	M
7	M	H	75000	H	M	L	L	M	H	L	H	L	S	8	M
8	M	H	60000	H	M	L	L	M	L	H	L	H	D	-	L
9	H	L	35000	M	H	M	L	M	L	M	M	L	S	31	H
10	H	L	50000	M	H	M	L	M	M	L	L	M	D	32	H
11	H	H	50000	M	M	L	M	H	L	M	M	L	S	5	M
12	H	H	35000	M	M	L	M	H	M	L	L	M	D	8	M
13	L	L	35000	M	M	M	H	L	H	H	L	L	S	107	H
14	L	L	50000	M	M	M	H	L	L	L	H	H	D	-	L
15	L	H	50000	M	L	H	L	H	H	H	L	L	S	-	L
16	L	H	25000	L	L	H	L	H	L	L	H	H	D	-	L
17	M	L	10000	L	M	H	L	L	L	M	L	M	S	16	M
18	M	L	25000	L	M	H	L	L	M	L	M	L	D	55	H
19	M	H	25000	L	L	M	H	H	L	M	L	M	S	-	L
20	M	H	10000	L	L	M	H	H	M	L	M	L	D	-	L
21	H	L	60000	H	M	H	H	H	M	H	H	M	S	27	M
22	H	L	75000	H	M	H	H	H	H	M	M	H	D	56	H
23	H	H	75000	H	L	M	L	L	M	H	H	M	S	11	M
24	H	H	60000	H	L	M	L	L	H	M	M	H	D	38	H
25	L	L	60000	H	L	H	M	M	L	L	M	M	S	-	L
26	L	L	75000	H	L	H	M	M	M	M	L	L	D	-	L
27	L	H	75000	H	H	L	H	L	L	L	M	M	S	-	L
28	L	H	60000	H	H	L	H	L	M	M	L	L	D	-	L
29	M	L	35000	M	L	L	H	M	M	H	M	H	S	10	M
30	M	L	50000	M	L	L	H	M	H	M	H	M	D	20	M
31	M	H	50000	M	H	H	M	L	M	H	M	H	S	49	H
32	M	H	25000	L	H	H	M	L	H	M	H	M	D	77	H
33	H	L	10000	L	L	L	M	L	H	L	L	H	S	27	M
34	H	L	25000	L	L	L	M	L	L	H	H	L	D	59	H
35	H	H	25000	L	H	H	H	M	H	L	L	H	S	35	H
36	H	H	10000	L	H	H	H	M	L	H	H	L	D	-	L

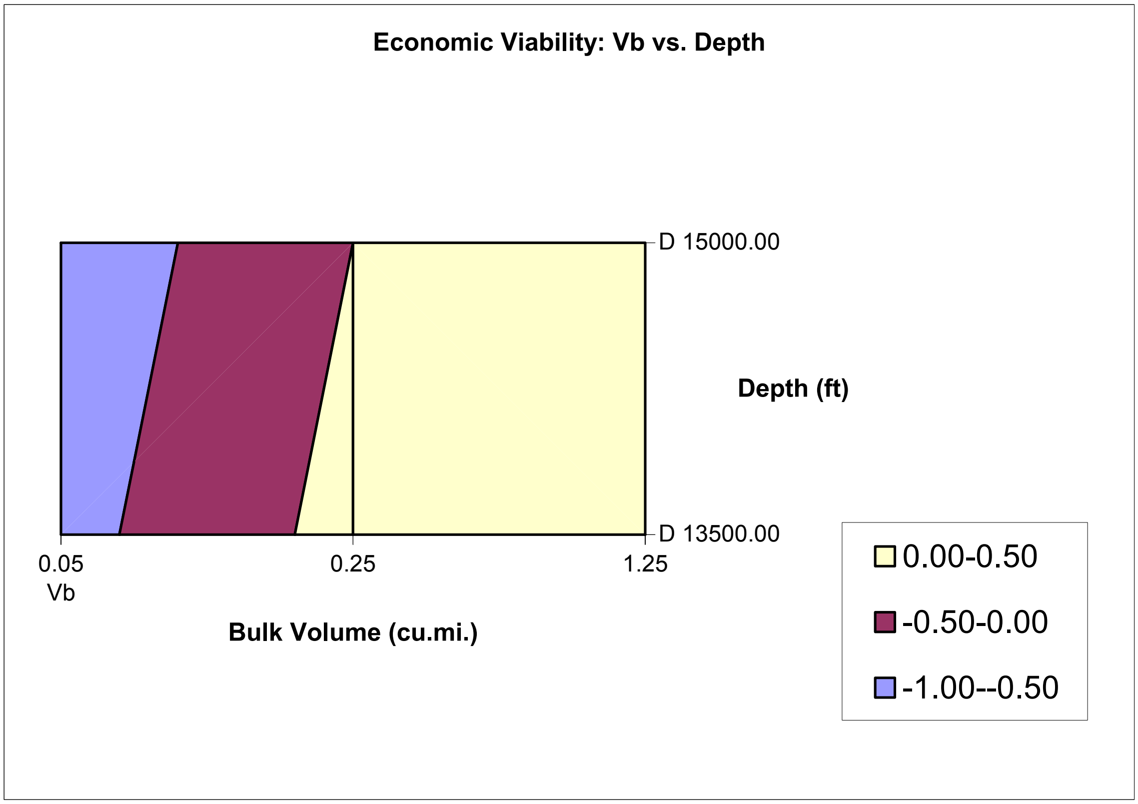

Fig. 18a. Economic viability: V_b vs. depth.

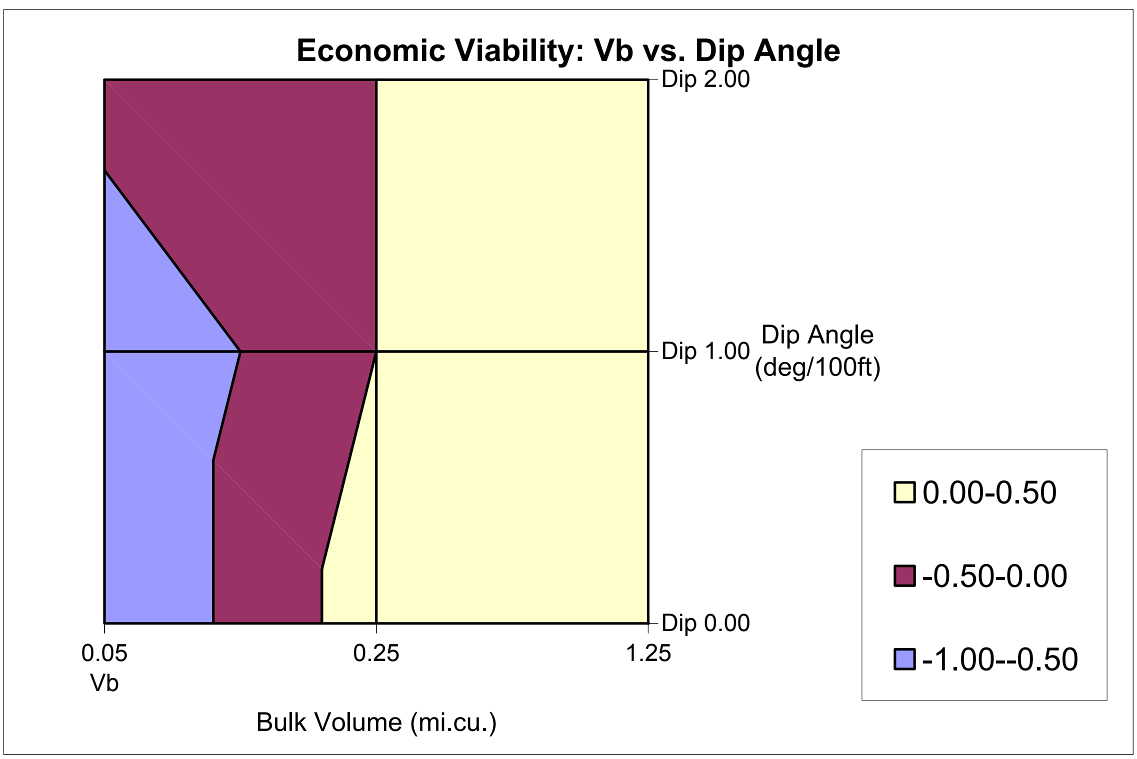

Fig. 18b. Economic viability: V_b vs. dip angle.

Fig. 19a, 19b, and 19c map the economic viability for comparisons of *Vb* versus salinity, pressure gradient, flowrate, and wellbore diameter, respectively. Each of these maps present a relationship where bulk volume shares dominance with the other parameter over the economic viability of the development. Other input parameters that contribute similarly to the economic viability of geopressured include temperature gradient and initial gas saturation. Given increased descretization

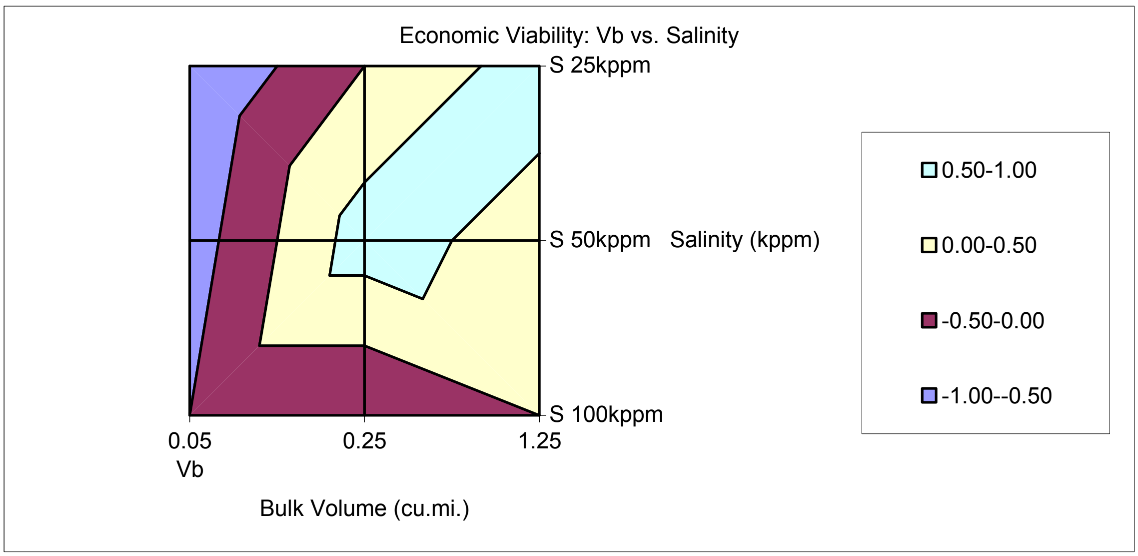

Fig. 19a. Economic viability: V_b vs. salinity.

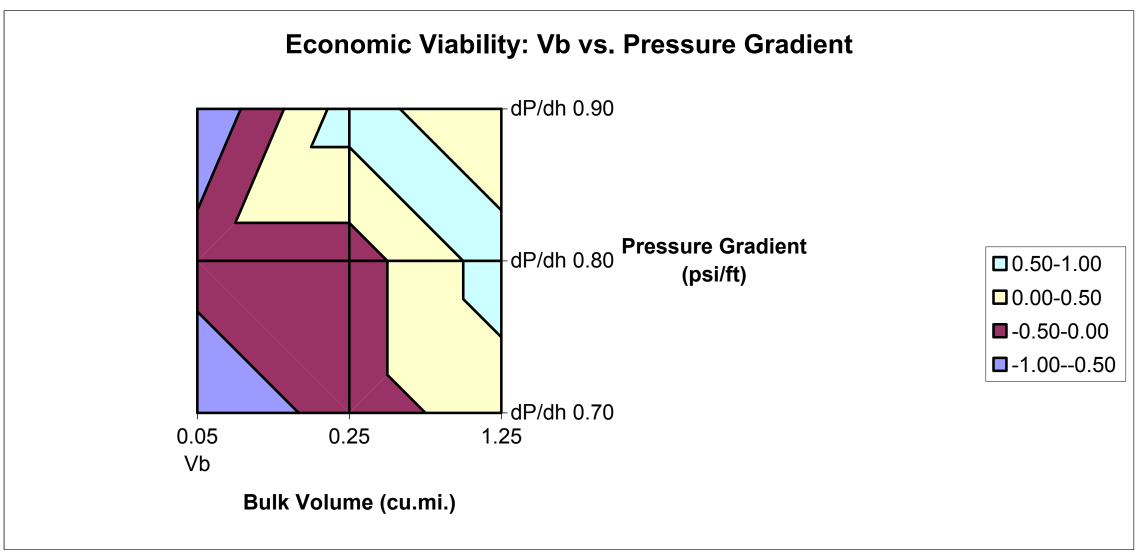

Fig. 19b. Economic viability: V_b vs. pressure gradient.

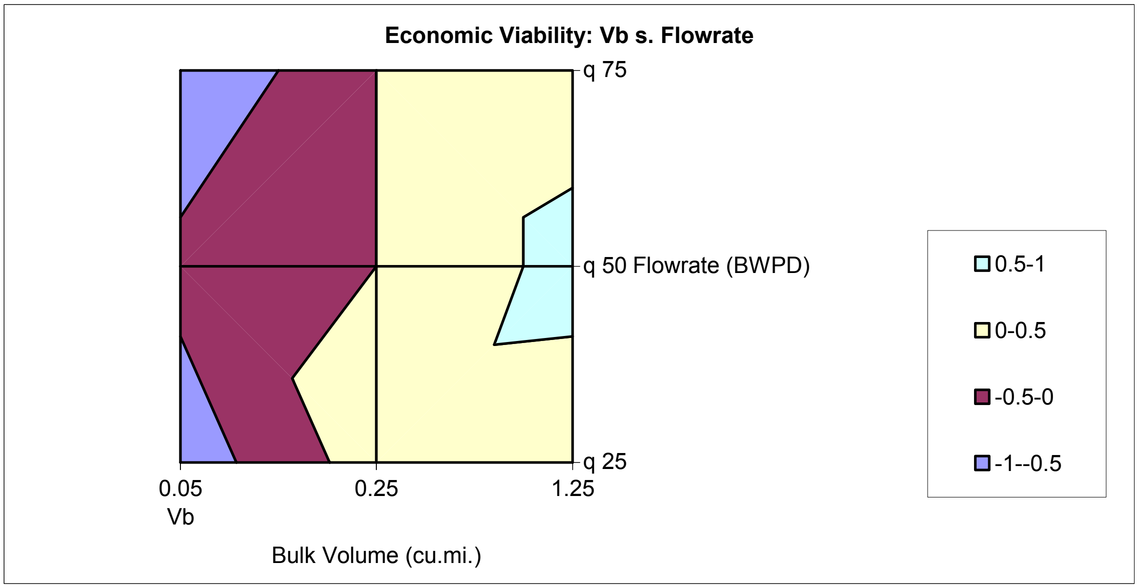

Fig. 19c. Economic viability: V_b vs. flowrate (flowrate is divided as follows: ≤25,000 BWPD, ≤50,000 BWPD, and ≤75,000 BWPD).

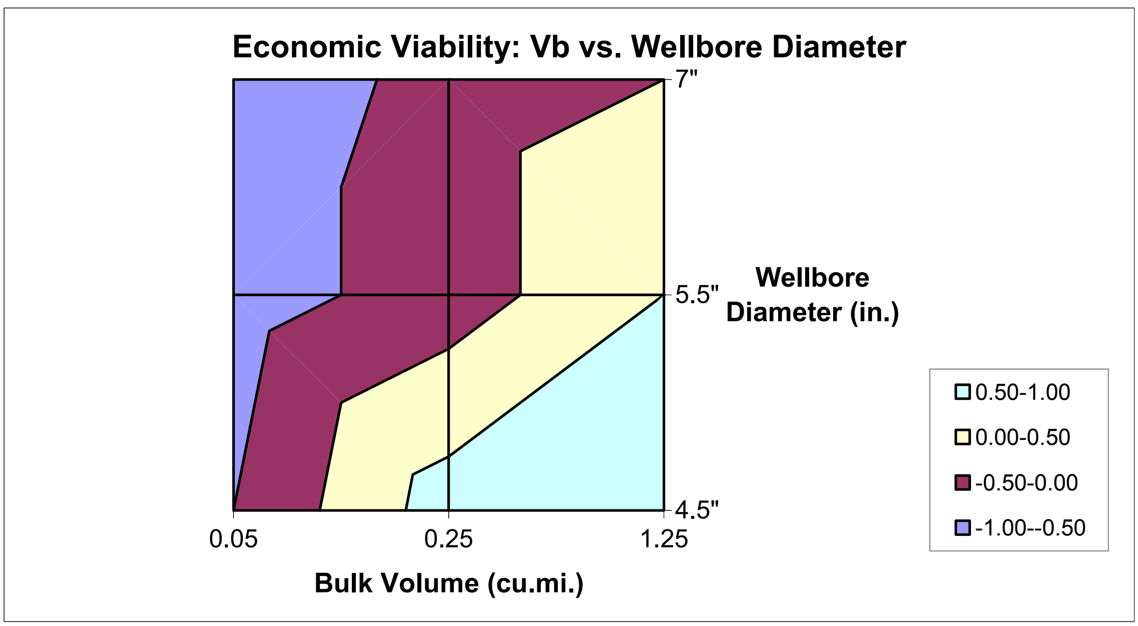

Fig. 19d. Economic viability: V_b vs. wellbore diameter.

This method of financial analysis allows for the comparison of any two input parameters (Fig. 20). Given further descretization, this analysis method could aid in determining the appropriate design flowrate and wellbore diameter of a geopressured aquifer development.

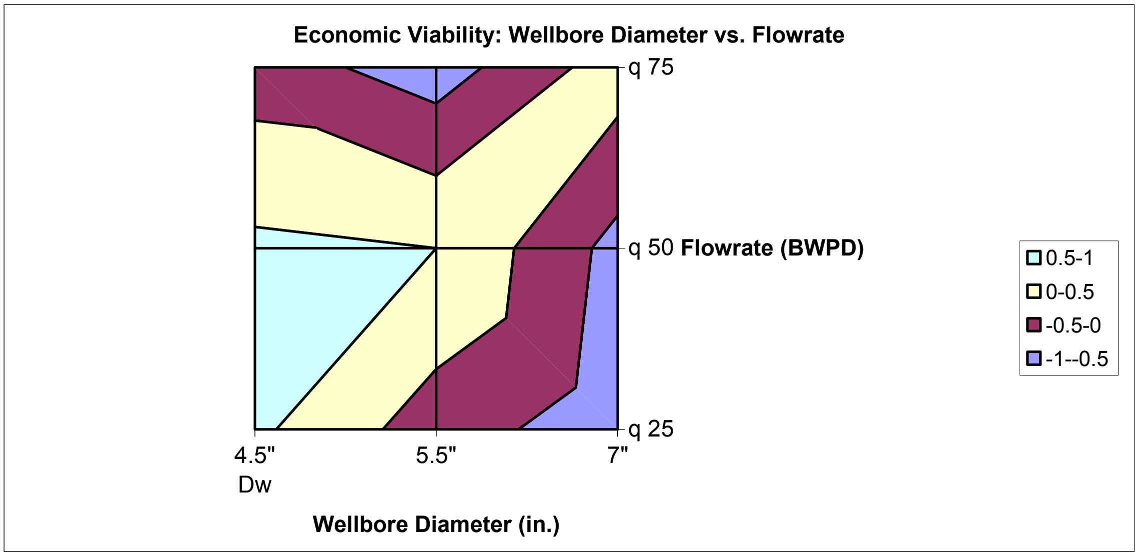

Fig.20. Economic viability: wellbore diameter vs. flowrate.

Analysis of the commerciality of oil and natural gas developments are often first reviewed on the basis of "in-place" volumes. As Fig. 17 showed, geopressured-geothermal aquifers are most dependent on the volume of resource initially in-place. The following sections will discuss the performance of sensitivity runs by grouping cases on the basis of bulk volume.

4.1.1 Bulk Volumes of 0.05 Cubic Miles

Sensitivity runs with bulk volumes of 0.05 cubic miles were never economic at base case financial conditions, except for Case 13 and Case 4. Fig. 21 shows the BFIT NPV of all sensitivity runs with bulk volumes of 0.05 cubic miles and a flowline distance of 100 ft (base case prices).

Case 13 presents a best-case scenario for the development of a small geopressured aquifer. In this development scenario an existing wellbore has been re-completed to a geopressured aquifer. The design flowrate of 35,000 BWPD is near the upper limit of approximately 25,000 BWPD for 4 ½" O.D. casing and the aquifer has an initial gas saturation at the critical gas saturation. Case 4 is a dry-hole well that was completed in a geopressured aquifer. Case 16 is similar in design to the Amoco Fee No. 1 test of Zone 9; an aquifer with limited connected volume [40].

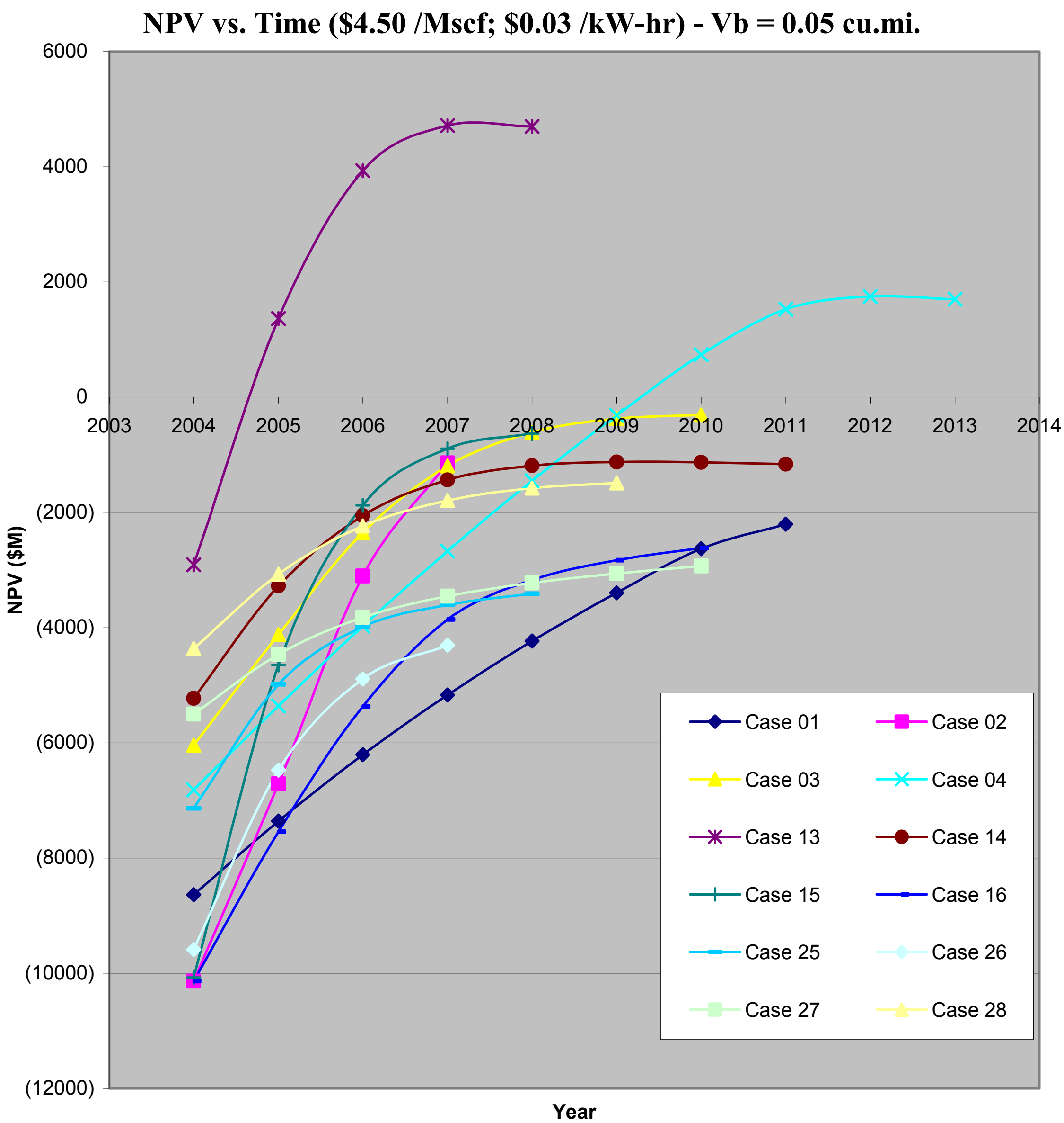

Fig. 21. NPV vs. Time ($4.50 /Mscf/ $0.03 /kW-hr) – V_b = 0.05 cu. mi.

Removing the binary-cycle power plant from the aquifer development increased the BFIT NPV of all sensitivity runs, Fig. 22. The ROR for Case 13 increased from 107 % to 127 %. The BFIT NPV of Case 14 increased by over $1 MM.

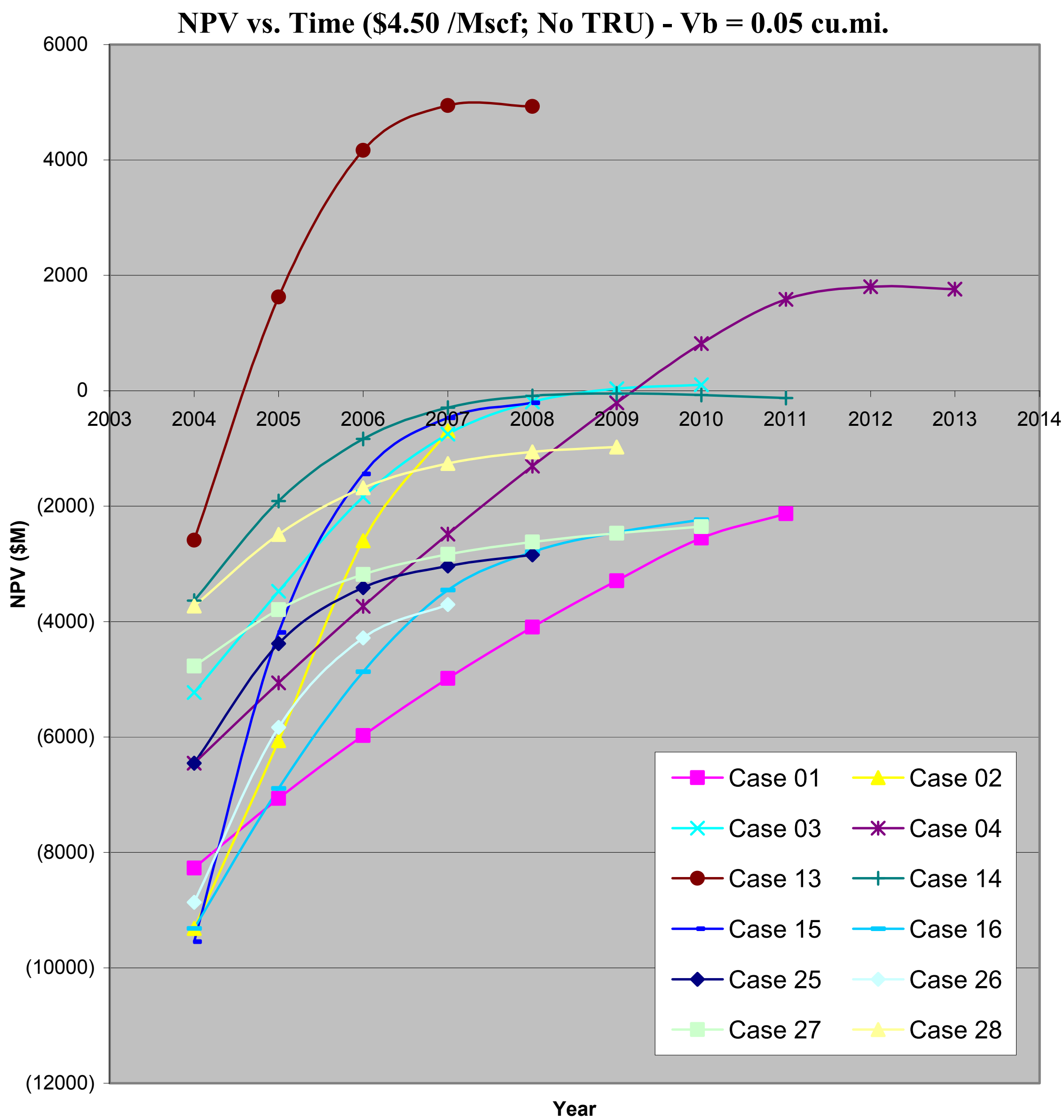

Fig. 22. NPV vs Time ($4.50 /Mscf; No TRU) - V_b = 0.05 cu. mi.

4.1.2 Bulk Volumes of 0.25 Cubic Miles

Sensitivity runs of aquifers with bulk volumes of 0.25 cubic miles produced generally positive economic results. Fig. 23 shows BFIT NPV versus time for base case natural gas and electricity cost. Fig. 24 shows BFIT NPV versus time for $4.50 /Mscf natural gas and no installed binary-cycle power plant.

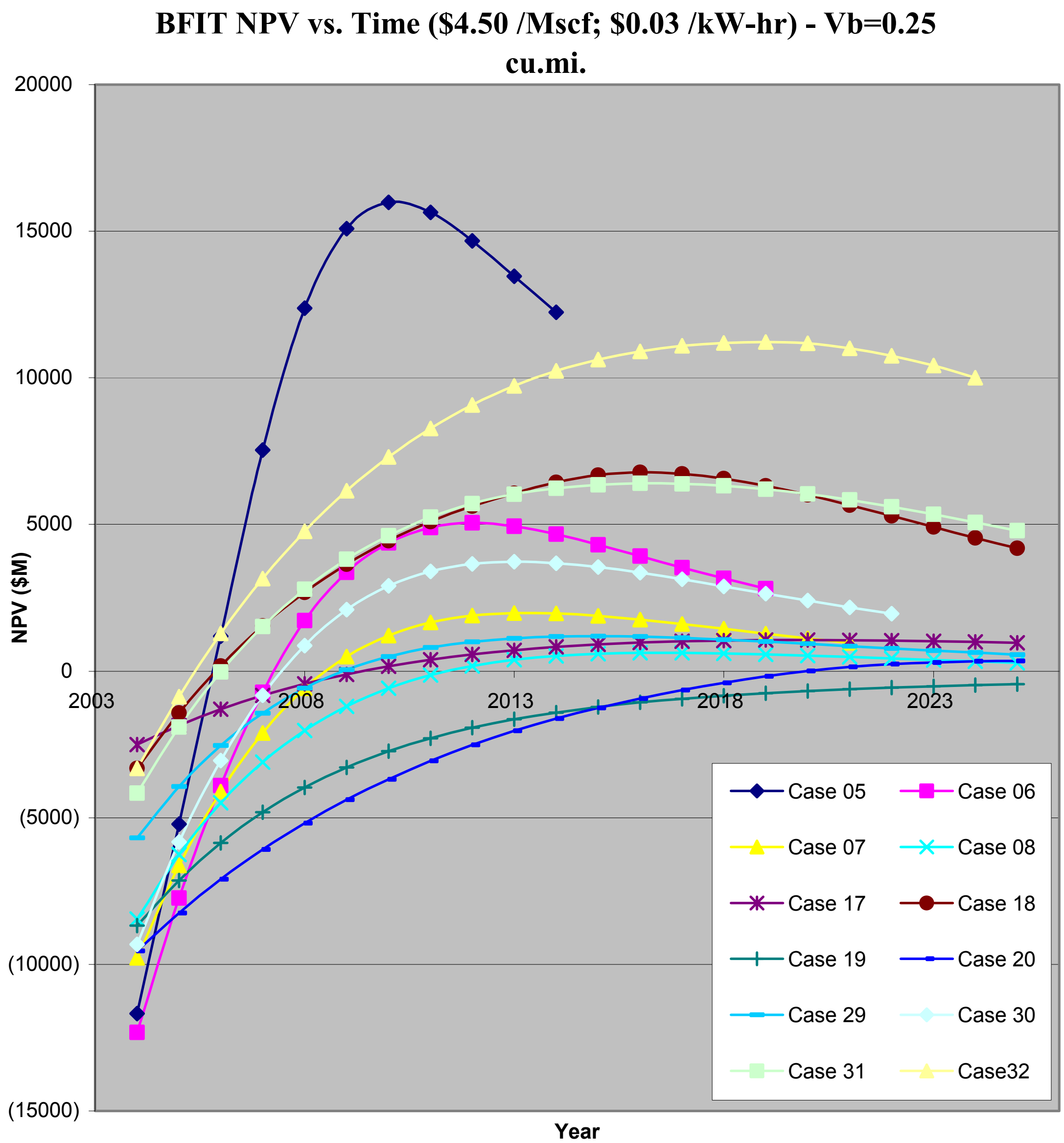

Fig.23. NPV vs. Time ($4.50 /Mscf; $0.03 /kW-hr) - V_b = 0.25 cu. mi.

Case 19 represented the only well that did not yield a positive NPV but has a low design flowrate and no initial gas saturation. Case 20, which was marginally economic, had a lower design flowrate than Case 19 but did have an initial gas saturation. Case 5 and Case 32 are the best-case scenarios for aquifers with bulk volumes of 0.25 cubic miles. Case 5 was drilled for the production of geopressured aquifers and benefits from a high design flowrate and an initial gas saturation.

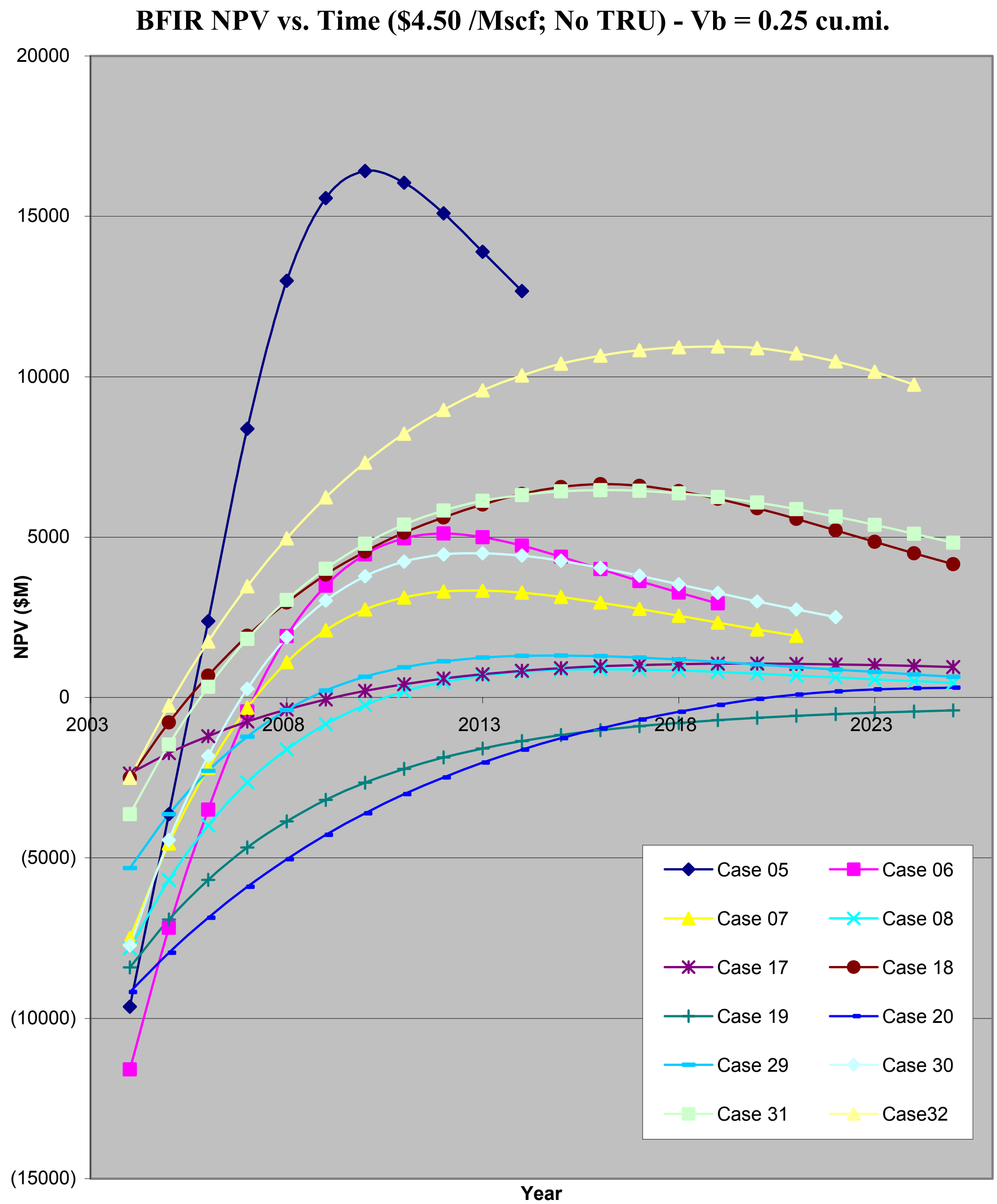

Fig. 24. NPV vs. Time ($4.50 /Mscf; No TRU) - V_b = 0.25 cu. mi.

Removing the binary-cycle power plant from the financial analysis had little effect on the BFIT NPV of the sensitivity runs but did caused an increase in the ROR

(Table 17). The increase in ROR between the two financial constraints is more pronounced in sensitivity runs where design flowrate is much higher than initial flowrate.

Table 17. Comparison of sensitivity runs with V_b = 0.25 cu.mi.

Sensitivity Run	ROR (%)		Flowrate	
	$4.50 /Mscf $0.03 /kW-hr	$4.50 /Mscf No TRU	Design (BWPD)	Initial (BWPD)
Case 5	55	64	60000	60000
Case 6	19	20	75000	75000
Case 7	8	22	75000	29467
Case 8	-	3	60000	32646
Case 17	16	17	10000	10000
Case 18	55	68	25000	25000
Case 19	-	-	25000	24815
Case 20	-	-	10000	10000
Case 29	10	12	35000	28582
Case 30	20	27	50000	30466
Case 31	49	55	50000	39563
Case 32	77	95	25000	25000

4.1.3 Bulk Volumes of 1.25 Cubic Miles

Wells that produced from bulk volumes of 1.25 cubic miles all had positive BFIT NPV. Not installing a binary-cycle power plant had mixed effect on BFIT NPV but increased the ROR. Table 18 shows the effect of binary-cycle power plant installation on ROR.

Fig. 25 shows BFIT NPV versus time for all sensitivity runs with bulk volume of 1.25 cubic miles. Case 22 had the highest NPV is a well drilled for the production of geopressured brines with a design flowrate of 75,000 BWPD and an initial gas saturation of 2 %. Case 36 is a dry-hole converted to use in geopressured brine production and has a design flowrate of 10,000 BWPD.

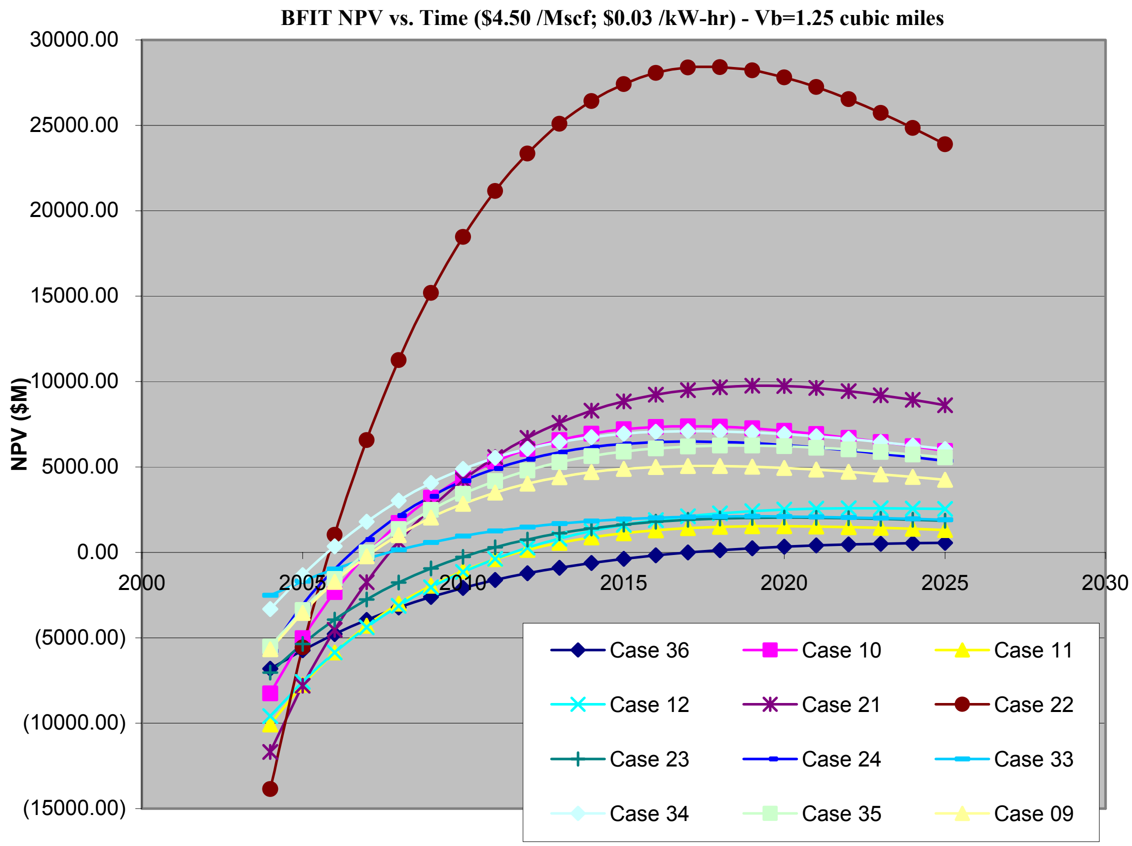

Fig. 25. NPV vs. Time ($4.50 /Mscf; $0.03 /kW-hr) - V_b = 1.25 cu. mi.

Table 18. Comparison of Sensitivity Runs with Vb = 1.25.

Sensitivity Run	ROR (%)		Flowrate		ΔNPV (Base Case - No TRU) ($M)
	$4.50 /Mscf $0.03 /kW-hr	$4.50 /Mscf No TRU	Design (BWPD)	Initial (BWPD)	
Case 09	31	32	35000	35000	59
Case 10	32	33	50000	49648	74
Case 11	5	6	50000	37117	(44)
Case 12	8	8	25000	25000	63
Case 21	27	31	60000	60000	376
Case 22	56	64	75000	75000	555
Case 23	11	23	75000	22998	(533)
Case 24	38	61	60000	24634	(388)
Case 33	27	29	10000	10000	14
Case 34	59	73	25000	25000	187
Case 35	35	36	25000	25000	63
Case 36	-	-	10000	10000	96

4.1.4 Additional Sensitivities

In addition to the sensitivity runs generated by the orthogonal array, simulations were conducted to gauge the effect of shale water influx and reservoir compaction on geopressured aquifers. Core analysis from the L.R. Sweezy test well was used to model compaction. Table 19 shows the properties of shale used in the sensitivity runs. Each of the three case was incorporated into single-well Case 14.

Table 19. Parameters for rock compaction and shale-water sensitivity.

	Bulk Volume (cubic miles)			
	Sand	Shale	k_{shale}	k_v/k_h
Laterally Adacent Shale	0.05	0.15	0.001	0.1
Over-/under-lying (no Rock Compaction)	0.05	0.05	0.001	0.1
Over-/under-lying (with Rock Compaction)	0.05	0.05	0.001	0.1

Laterally adjacent shale contributed little to the BFIT NPV of Case 14. Over-/under-lying shales showed significant contribution to the commerciality of the aquifer. The rock compaction model from the L.R. Sweezy provided less pressure support than the 20 microsip rock compressibility that was used in Case 14 and resulted in a lower NPV. Fig. 26 shows the effect of shale water influx and formation compaction on Case 14's BFIT NPV.

4.2 Multi-Well Developments

Sensitivity runs on multi-well developments of geopressured aquifers were performed. Multi-well development scenarios typically did not see and increase in ROR compared to single well developments. Fig. 27 shows the NPV for a 2-well development of a 0.25 cubic mile aquifer. NPV is controlled most by flowrate and initial gas saturation than the spacing or position of wells.

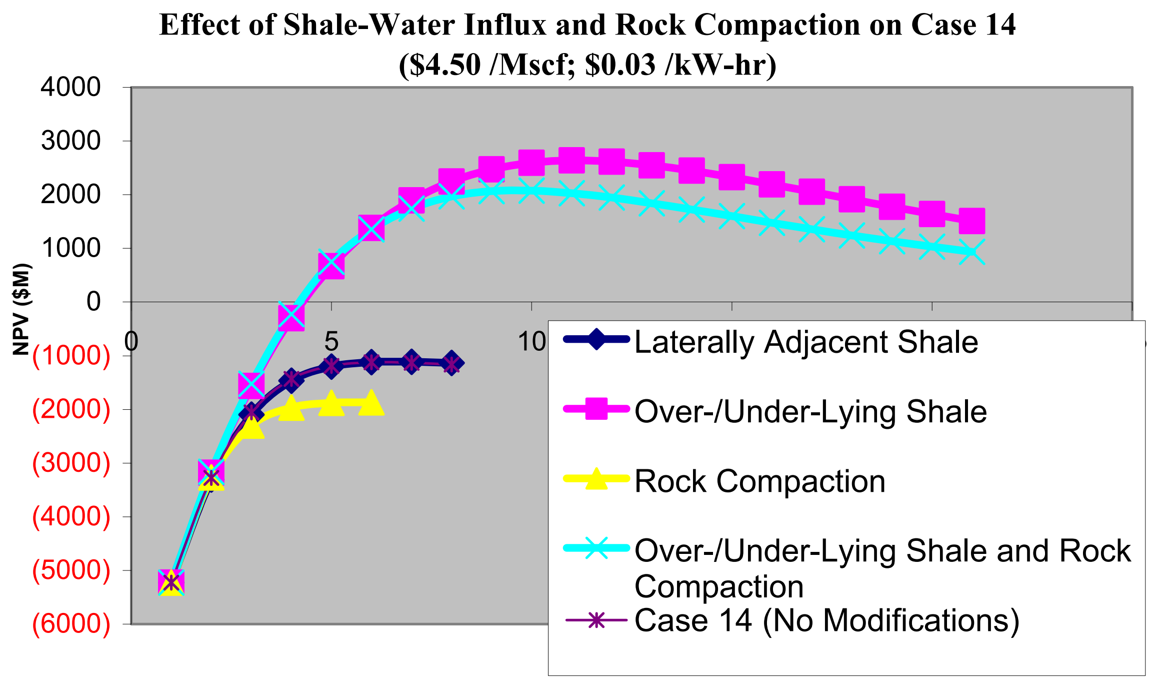

Fig. 26. Effect of Shale-water Influx and Rock Compaction on Case 14.

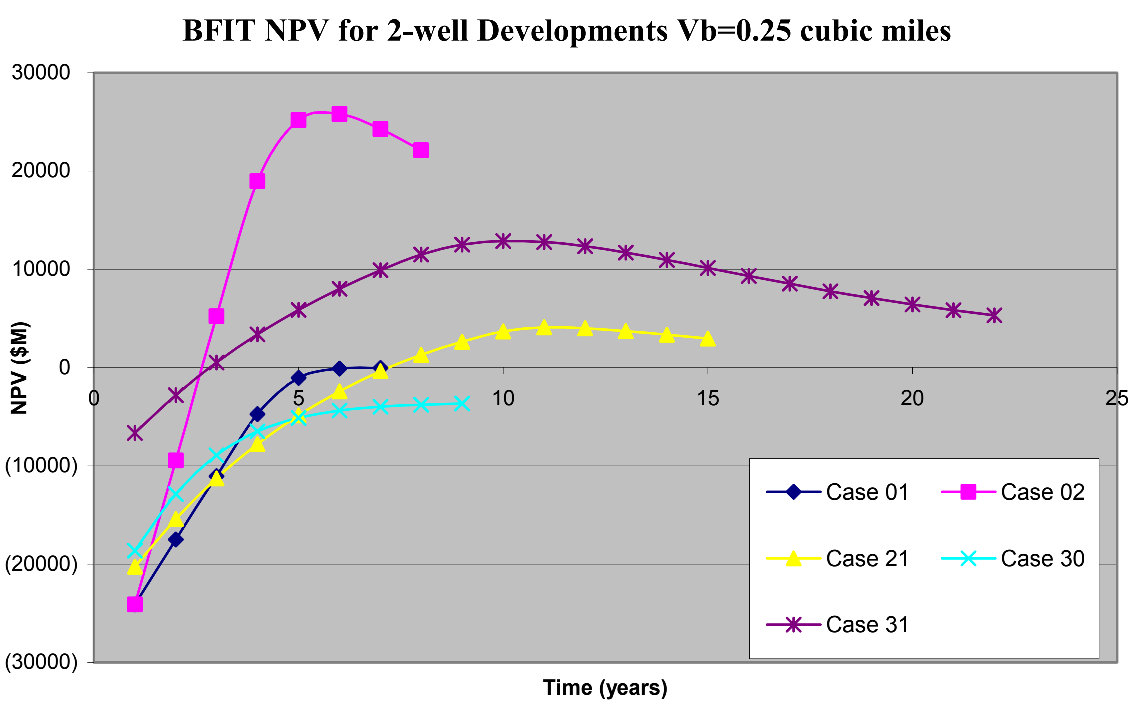

Fig. 27. BFIT NPV for 2-well Developments.

5. Conclusions

This study shows that the 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 is depends on the scarceness of conventional hydrocarbons.

5.1 Aquifer Description

Geopressured-geothermal aquifers with bulk volumes as low as 0.05 cubic miles can be commercially viable under base case price constraints when optimistic initial conditions and capital cost controls are in-place. The mixed array used to determine input parameters for the sensitivity runs allowed for a representative range of results to be observed. Sensitivity runs were most affected by the aquifer bulk volume, capital development costs and operating expense, designed maximum flowrate, and initial gas saturation. The effect of Multi-well developments have little economic benefit. Initial gas saturation increases the NPV of the development scenario. Previous estimates of aquifer bulk volume required to ensure commercial development were between 1 to 3 cubic miles. In this study, bulk volumes of 0.25 cubic miles often economic; bulk volumes of 1.25 cubic miles are always economic.

There are several uncertainties that were not included in this study. The effect of aquifer heterogeneity was not studied in the model. Water influx from both laterally adjacent and over- and under-lying shales was considered only in a conditional run. The effects of formation compaction were not included in all sensitivity runs. The relative permeability model represented clean sandstone and dual-water effects were not considered. The effects of rock compaction and shale-water influx can be significant on the commerciality of geopressured aquifers and should be investigated further.

5.2 Binary-Cycle Power Plants

There is no economic incentive to install a binary-cycle power plant under the temperature gradient and depth ranges used in this study. However, the values for temperature gradient and depth used in this study represent a limited range of those expected in northern Gulf of Mexico environments. Aquifers tested in the WOO and DW programs varied in depth from 9,500 ft to 15,500 ft and with geothermal gradients between 1.5 °F/100ft and 2.5 °F/100ft.

This study also placed sensitivity runs into one of two categories for inlet temperature to the binary-cycle power plant: temperatures greater than 212 F and temperatures greater than 266 °F. The binary-cycle power plant was not optimized for inlet temperature or flowrate, potentially reducing efficiency. Table 20 shows the equivalent dollar values for geopressured brine at various flowing wellhead temperatures and electricity prices. The value of methane in solution is not included. At flowing wellhead temperatures of 320 °F and higher, the value of geopressured brine for use in a binary-cycle power plant increases substantially compared to the values used in this study. The development of geopressured aquifers for use in electricity generation could then become more viable.

Table 20. Water Value vs. Temperature.

$/kW-hr	Binary-Cycle Inlet Temperature		
	212	266	320
	Water Value ($/Mstb)		
0.02	5.43	16.2	29.18
0.025	6.79	20.28	36.48
0.03	8.15	24.31	43.77
0.05	13.58	40.51	72.95
0.07	19	56.72	102.13
0.09	24.44	72.93	131.31

Electricity generated from the binary-cycle power plant may benefit from higher than wholesale electricity price. Many small power plants could produce geopressured aquifers to provide a "micro-scale" power grid: this would imply a shorter distance from the power source to the user, increased efficiency, and reduced threat of regional blackouts.

The "direct-use" application of geopressured aquifers would also enable a higher realized natural gas price. Fig. 28 displays single-well Case 14, an aquifer with 0.05 cubic miles of bulk volume. While un-economic under base case prices, Case 14 would be economic at natural gas and electricity prices that are closer to the prices that residential customers pay.

Effect of Escalating Prices on Case 14

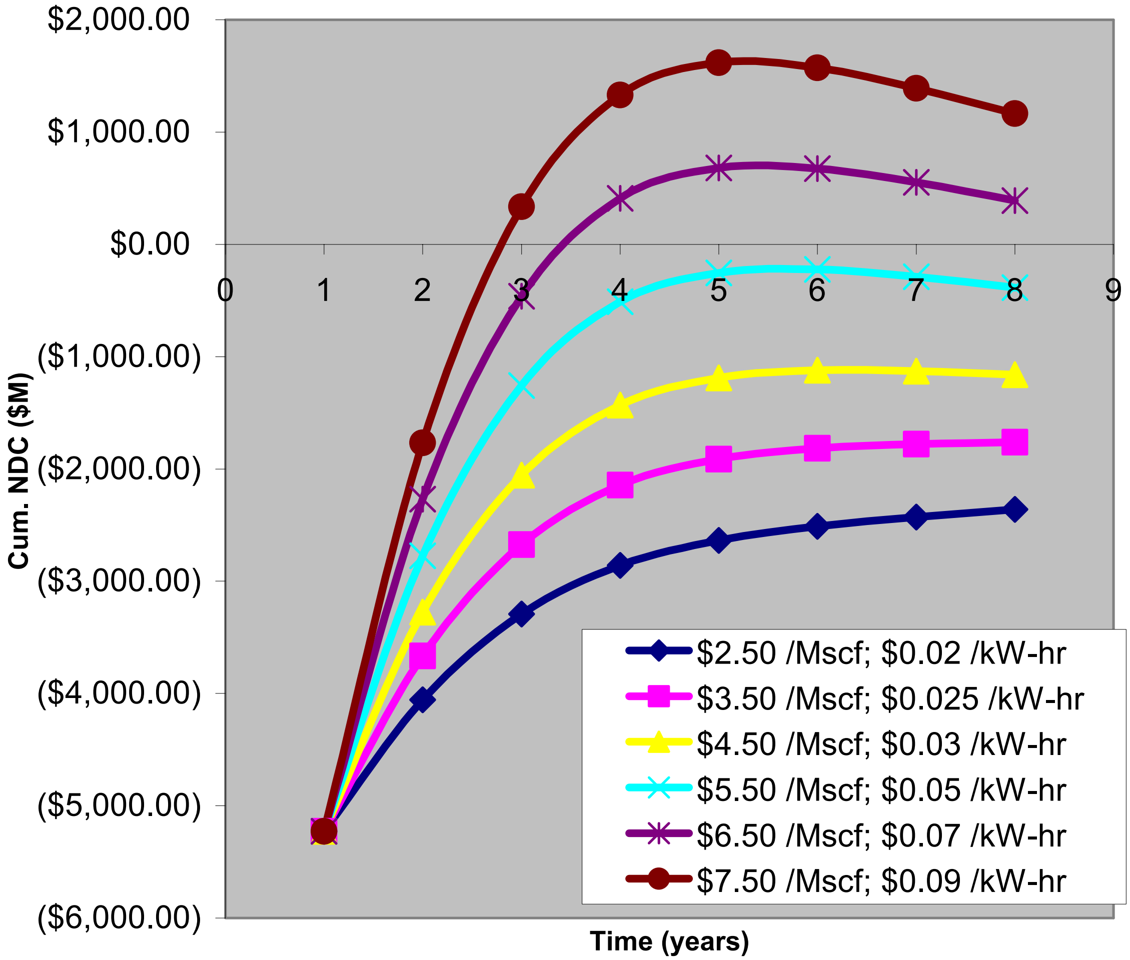

Fig. 28. Effect of Electricity Price on Case 14.

Kalina-cycle thermal recovery units could increase efficiency in low and moderate temperature projects enough to justify thermal recovery systems in geopressured aquifer developments.

5.3 Application of Tax Credits

Fig. 29 shows the effect of available tax credits on the AFIT NPV of a geopressured aquifer development. Single-well Case 29 is a dry-hole converted to the production of geopressured brines. Aquifer bulk volume is 0.25 cubic miles and a 400 kW binary-cycle power plant is installed in the development. Available tax credits production and capital expenditure are applied and have the same result as a $1.00 /Mscf increase in the realized natural gas price. The capital investment tax credit can provide a significant incentive to invest in geopressured aquifers. However, the production tax credit is valid only for wells drilled before 1985 and would require renewal to encourage investment in geopressured aquifers.

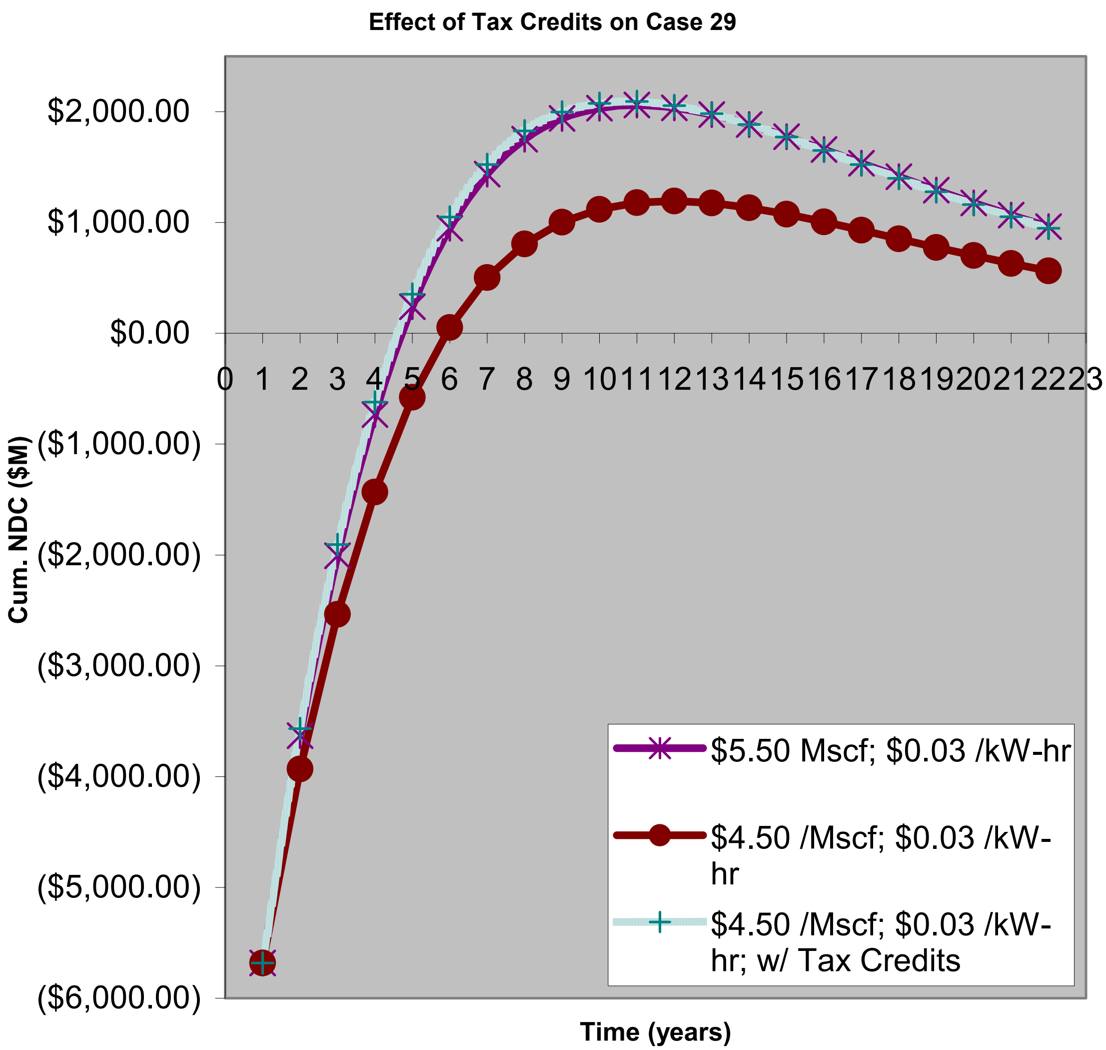

Fig. 29. AFIT NPV Effect of Tax Credits.

5.4 The Future of Geothermal-Geopressured Brine Energy

The economic and technical constraints posed in this study delineate a potential range of conditions where the development of geopressured aquifers may have commercial application. However, these factors also indicate that challenges remain before field development of geopressured aquifers can begin. Five groups emerge that warrant further investigation and could greatly enhance the value of the geopressured-geothermal resource:

1. Reservoir characterization and resource estimation. By refining estimates of rock compaction, shale-water influx, and diagenic history a more detailed analysis of aquifer drive mechanisms could be determined. The re-activiation of the Wells of Opportunity program could refine estimates expected aquifer volumes and aid in quantitatively determining the effects of carbon dioxide and heavier hydrocarbons on methane solubility in brine.
2. Facility optimization and systems analysis. Detailed system analysis and facility optimization could decrease capital cost and operating expense while providing for more efficient extraction of methane. Accurate temperature, flowrate, and facility coupling could provide "fit-for-purpose" equipment and significantly reduce expense.
3. High efficiency binary-cycle power plants. Further investigation of Kalina-cycle power plants could provide for a cheap, yet highly efficient, means of extracting thermal energy from geopressured brine. Detailed

evaluation on the implementation of a Hybrid Power System could further enable geopressured aquifers to provide a "micro-scale" power grid.

4. Detailed economic analysis. Accurate estimation of facility and power plant expense, along with more detailed estimates of drilling cost may provide a more economic opportunity. Commercial potential of geopressured aquifers could increase with the inclusion of dry-hole risk, well replacement cost, and the likely-hood of different development.

5. Legal and political difficulties. The aerial extent of potentially commercial geopressured aquifers is likely to be in excess of 10 sq. mi. and small acreage landowners could derail the development of this energy source. Mineral law case history is vague concerning the ownership of sub-surface brine [86]. The renewal of federal tax credits and the implementation of severance tax relief and federal loan guarantees could provide significant economic incentive to develop geopressured aquifers.

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