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Reservoir Pressure Mapping from Well-Test Data: An Eagle Ford Example

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ABSTRACT

Reservoir-pressure data are needed as input for a variety of exploration, drilling, and completion activities. Unfortunately, pressure data are not public domain in many areas and so inefficiencies caused by suboptimal completion design, acreage acquisition, or production strategies can weaken financial returns. This problem is perhaps most acute in unconventional plays where ultra-low permeabilities prevent common pressure detection methods (e.g., mud weights) from providing reliable information. In this paper we present a method to rapidly mine publicly available well-test data and create pressure maps for reservoirs of interest. We illustrate the methods and results for an area of the South Texas Eagle Ford play. Input for our mapping comes from data (initial shut-in pressure, fluid density, vertical depth to the formation, and temperature) submitted to the state of Texas as part of the mandatory reporting requirements for gas wells (G–1 Forms) and oil wells (W–2 Forms) retrieved from the State of Texas Railroad Commission (RRC) website. The G–1 data can be converted to a bottom-hole pressure using an adaptation of the standard ρgh formula. Pressure estimation from W–2 data is less straightforward but pressures predicted from both data sources form a continuous trend that increases with depth. Despite the nature of the approximations and potential errors in our method, we demonstrate that, in agreement with published data, it shows the distribution of overpressures reasonably well for the Eagle Ford in our study area. We interpret the results to indicate that overpressures in that formation are primarily due to the thermal cracking of oil to gas. For many purposes, the ability to make quickly and inexpensively map pressures from public-domain data will more than compensate for any lack of precision in the pressure predictions at a specific well location.

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INTRODUCTION

Reservoir pressures provide a basis for several aspects of the exploration-extraction process. Pressures are needed as input for both safe drilling practices as well as for the design of the most effective completion methods. Pressures in conventional reservoirs can be acquired through the use of wireline formation test tools, and provide information ranging from reservoir pressure, temperature, and estimates of permeability. The extremely low permeability of unconventional reservoirs, such as the Eagle Ford in South Texas or the Haynesville of Louisiana/East Texas, makes standard tools for defining subsurface pressures ineffective in these plays.

Methods for obtaining pressures in unconventional plays, such as diagnostic fracture injection testing (DFIT) tests, exist but they are costly and the accuracy of the results depends on the quality of the test data and the interpretation of that data, unlike the direct pressure measurement of a wireline formation test tool. In Texas and many other jurisdictions, none of these pressure measurements are freely available.

This study presents a novel use of public-domain data to define subsurface/reservoir pressures. We document the workflow used to convert well-test data submitted to the Texas Railroad Commission (RRC) into subsurface pressures and then use those results to map subsurface pressures at the Eagle Ford level in Karnes County of South Texas (Fig. 1). The pressure estimates can also be displayed as a function of depth. Together, the map and depth formats are used to determine the depth and spatial relationships of pressure distributions and can be used to help interpret the distribution of other attributes such as production, gas-oil ratio (GOR), American Petroleum Institute (API) gravity, and other reservoir parameters.

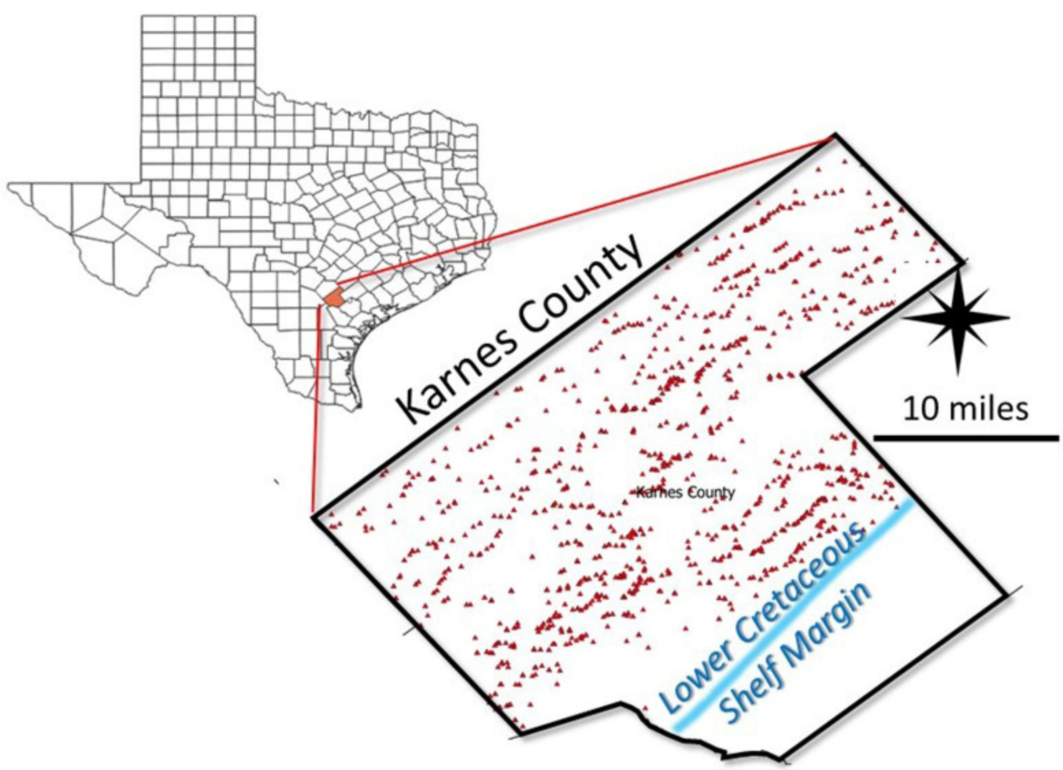

Figure 1. Location of the Karnes County study area in South Texas. Red dots show wellhead locations for Eagle Ford wells used in this study. Drilling is confined to areas up dip (i.e., to the northwest) of the Lower Cretaceous shelf margin that underlies the Eagle Ford.

METHODS

Our primary dataset consists of oil and gas well records submitted by operators to the RRC. We derive our data from either a G–1 form (gas wells) or a W–2 form (oil wells), both of which record the initial potential of the well. These forms contain a substantial amount of other data that can be used for analyses from GOR and temperature to structure and pressure. We present a method to acquire the necessary data from these forms and use some simplified calculations to estimate the pressure at the "reservoir" level. Details of the work flow for building a data base from the RRC website are available from the lead author upon request.

The G–1 and W–2 forms provide location data, depth data, formation tops, and test information required to calculate the bottom-hole pressure (BHP). The BHP for a well is derived from the G–1 forms using the reported:

- true vertical depth (TVD) of the producing zone in ft,
- dry gravity (DG), converted to a gradient in psi/ft, and
- shut-in wellhead pressure (SIWHP) in psi.

The bottom-hole pressure was then calculated using the simplified formula below

$$BHP = SIWHP + TVD * DG. \tag{1}$$

The calculations for BHP using the well test data from the W–2 forms is a bit more complicated as the pressure provided is a flowing pressure. For this calculation we have utilized a modified Bernoulli pipe flow calculation for the BHP calculation, which uses the following variables:

- oil produced during 24 hour test,
- water produced during 24 hour test,
- tubing size,
- choke size,
- formation TVD, and
- oil gravity.

The BHP is then calculated as the sum of the ΔP_{elev} (elevation change) + ΔP_{vel} (velocity change from tubing to choke) + ΔP_{HL} (head loss) using the following equation:

$$BHP = (\rho / 144) * [(Z_2 - Z_1) + (V_2^2 - V_1^2) / 2g + H_L], \tag{2}$$

where:

$$\Delta P_{elev} = (\rho / 144) * (Z_2 - Z_1), \tag{3}$$

$$\Delta P_{vel} = (\rho / 144) * (V_2^2 - V_1^2) / 2g, \text{ and} \tag{4}$$

$$\Delta P_{HL} = 2.161 * 10^{-4} * [(fL\rho Q^2) / d^5), \tag{5}$$

where ρ is fluid density (lb/ft^3), Z is elevation of the fluid measured from a reference plane (ft), H_L is head loss (ft), f is Darcy friction factor (dimensionless), L is pipe length (ft), D is pipe inside diameter (ft), v is fluid velocity (ft/sec), g is gravitational acceleration (32.2 ft/sec^2), Q is flow rate (gpm), and d = pipe diameter (in). Further information about these equations can be found at: http://kb.eng-software.com/eskb/ask-an-engineer/theory-equations-and-calculated-results-questions/relationship-between-pressure-drop-and-flow-rate-in-a-pipeline.

EAGLE FORD EXAMPLE

We apply our methodology to the Eagle Ford play of South Texas. Like other unconventional plays, this low-permeability source-rock reservoir is developed using horizontal wells. In our study area, the first Eagle Ford completion forms were filed in 2010 with the most forms filed in 2014 and 2016 (Fig. 2). Figure 1 shows the locations of the well heads having G–1 and W–2 data (Eagle Ford completions only). The underlying Lower Cretaceous shelf margin defines the limit of the play to the southeast in Karnes County.

Figure 3 plots pressure as a function of depth. The data are divided into pressures derived from the W–2 forms (red squares) and pressures derived from the G–1 forms (blue dots). Depth is presented as depth below ground level (TVD). Kelly bushing (KB) elevations are not readily available for the wells (they are not reported on the G–1 or W–2 forms), but differences in elevation between the KB and ground level (commonly 30–40 ft) are considered a negligible source of error for our purposes. Eagle Ford completion depths range from ~8000 ft to 13,000 ft in our study area.

Reservoir pressures for the Eagle Ford display a relatively normal trend down to around 10,000 ft (red data points) and then rapidly increase to almost vertical stress levels at around 13,000 ft (red and blue data points). We attribute this rapid rise in pressure to the thermal cracking of oil to gas.

Note the continuity of the pressure trend from the BHP values calculated from W–2 data to those derived from G–1 data. This continuity is interpreted to show that: (a) our two different methods provide consistent results, and (b) a continuous pressure buildup is present from the shallower to deeper levels.

In addition to our calculated BHP pressures for the Eagle Ford in Karnes County, Figure 3 shows BHP data from Bebout (1982) for Wilcox reservoirs in adjacent Dewitt County and BHPs from Clemons et al. (2016) for Eagle Ford shales in South Texas (county not specified). Although the calculated BHP data exhibit a wide scatter, the overall trend of the calculated pressures are similar to published data.

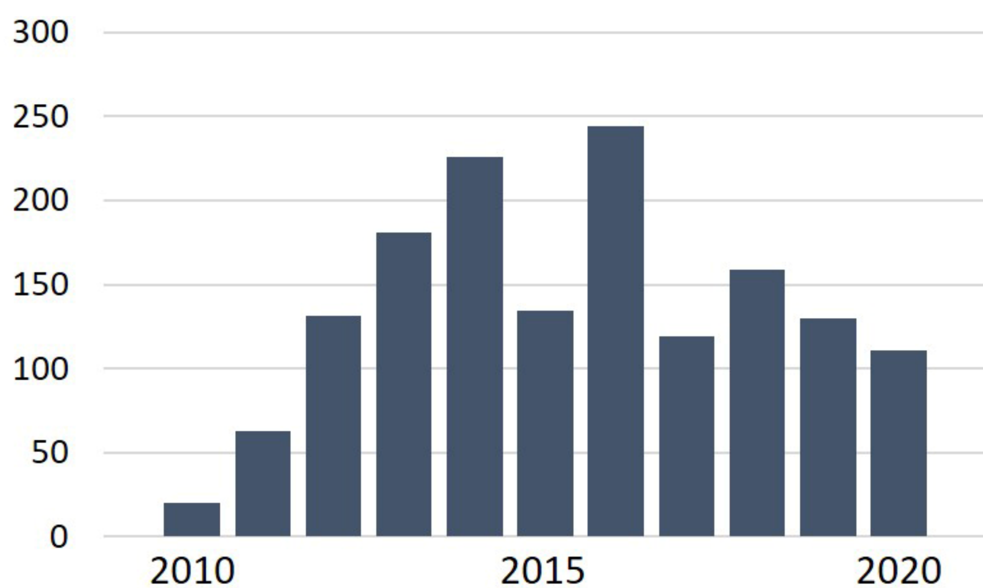

Figure 2. Histogram showing the number of completion forms filed for the Eagle Ford in Karnes County. Data from the Texas RRC website (https://www.rrc.texas.gov).

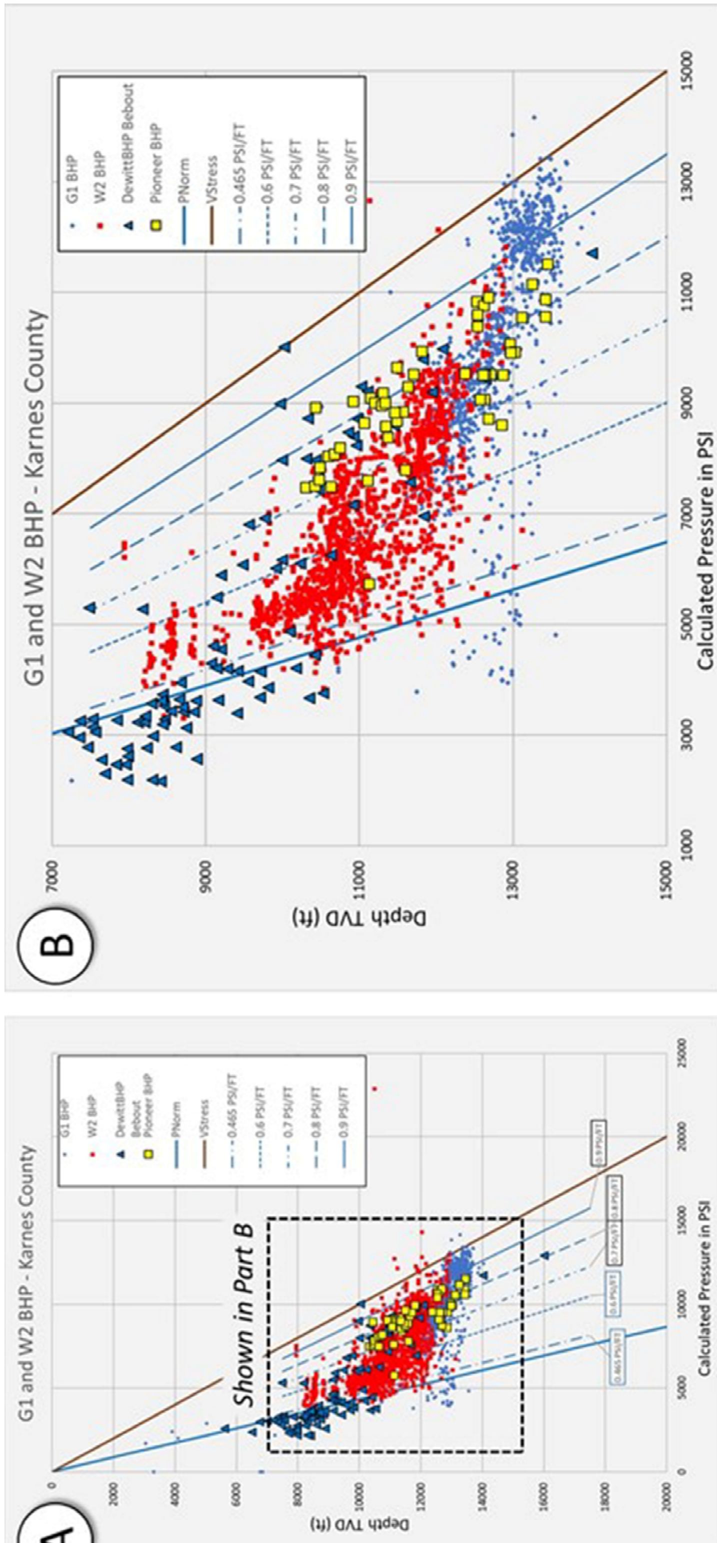

Figure 3. Pressure vs. depth plots for Eagle Ford wells in Karnes County. Blue data points are based on G-1 forms, and red data points are based on W-2 forms. Yellow squares are Eagle Ford pressures from Clemons et al. (2016) who did not specify which counties the data were from. Blue triangles are pressure measurements from the overlying Wilcox Group (Eocene) in neighboring Dewitt County (Bebout et al., 1982). (A) All data. (B) Expanded view of area highlighted in Part A. See text for discussion.

The scatter in the W–2 data is not surprising considering the available input data. A search of the available literature finds very few methods to calculate the BHP from a flowing well. The methodologies for BHP from flowing pressure assume that the flow into the wellbore at the formation level is not impeded by any completion problems. Completion problems that limit the flow into the wellbore will alter the flow rate coming out of the choke, and thus the flow velocity. Another critical factor in the calculation of the velocity-change component of the equation is the need to know the choke length to properly calculate flow velocity. An assumption of a 6" choke has been used for the choke velocity calculations. Changing the assumed choke size has a significant impact on the velocity calculation, and thus the ΔP associated with that calculation. A significant factor to the scatter for the BHP calculation may be caused by the assumed choke size.

When the data are displayed in map view the trend of increased pressure with depth is more apparent. A map of BHP is presented in Figure 4A. The contour lines represent the depth interpretation (TVD) of the top of the Eagle Ford shale based on formation top data acquired from the G–1 and W–2 forms. Although there is scatter in the data, the overall trend displays an increasing pressure with depth. Localized anomalies ("bullseyes") most likely represent erroneous input data on the forms, pressure anomalies associated with faults, or depleted reservoir pressures encountered by infill wells over the 10-year span of drilling represented in our dataset (Fig. 2).

Figure 4B shows the GOR data from the G–1 and W–2 forms, also with the structural contours as an overlay. Note how the high GOR crosses the depth contours in the southwestern portion of the map, indicating that the GOR may be controlled by a different, or additional mechanisms other than just depth. Other studies (e.g., Bozdiak, et al., 2014; Bebout et al., 1982), indicate that this area coincides with an area of enhanced faulting inboard of the Lower Cretaceous shelf margin.

We note that other approaches to predict pressure have been developed and used for the Eagle Ford in Karnes County. For example, Kalinec et al. (2019) demonstrate the use of drilling data to derive pore pressures in our study area, and Zhu et al. (2019) predict pore pressures from forward modeling of diagenetic processes (e.g., compaction). Both of these methods are labor intensive, and neither is suitable for quick mapping purposes.

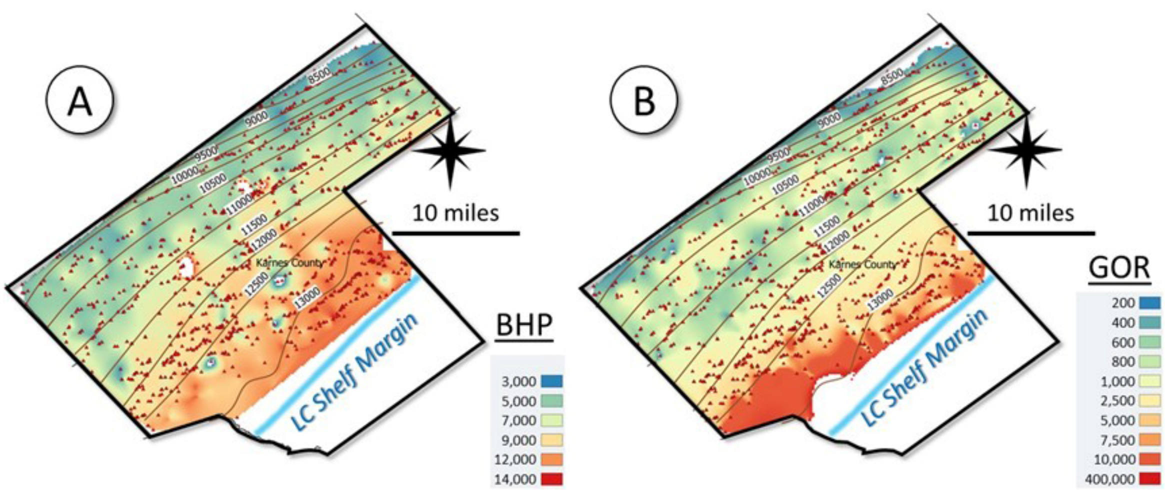

Figure 4. (A) Map of bottom-hole pressure (BHP, in psi) calculated from G–1 and W–2 forms. (B) Map of gas-oil-ratio (GOR) calculated from the same forms. LC, Lower Cretaceous. See text for discussion.

SUMMARY AND CONCLUSIONS

We have presented a novel method to estimate bottom-hole pressures from public-domain data readily available from the State of Texas RRC. The values that we have calculated for the Eagle Ford shale display an increase in depth below ground surface similar to other published reports. Similar analyses can be undertaken for any productive formation, in any area, in Texas or other areas where similar data sets are publicly available.

Given potential sources of error and uncertainties discussed herein, we consider our pressure calculations to be most useful for regional evaluation purposes.

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