

Geothermal Exploration in Mature Reservoirs: Data bias and co-produced gas

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Summary

Hot, subsurface brines hosted in sedimentary reservoirs have the potential to provide baseload geothermal power, district heating and thermal storage opportunities for communities across the world (Banks and Harris, 2018; Palmer-Wilson et al., 2018; Dalla Longa et al., 2020). Sedimentary-hosted geothermal plays benefit from a wealth of subsurface data due to decades of hydrocarbon exploration. However, it is important to note that the oil and gas data available to geothermal developers can exhibit pronounced biases within data critical to geothermal applications (Allen Gray et al., 2012). Oil and gas production wells are selected based on the reservoirs ability to produce hydrocarbons, and not formation water. Due to this, water-charged geothermal fairways are often overlooked, and the available data is biased toward hydrocarbon-bearing fairways. This bias can exacerbate geologic uncertainty in the subsurface and lead to false conclusions about geothermal reservoirs. The subjective uncertainty in reservoir volume is of critical importance in the exploration stage of geothermal development (Witter et al., 2019), and is discussed here in the context of biased oil and gas data and reservoir compartmentalization.

Compartmentalization poses a risk to the continuity of geothermal reservoirs, consequently affecting hydrothermal recharge and total reservoir productivity (Poro et al., 2012; Daniilidis et al., 2016; Erlström et al., 2018; Weibel et al., 2020). This risk has been identified within Alberta, where Spirit River and Cardium formation reservoirs have been subject to compression resulting in reservoirs being displaced and compartmentalized by faults (Epoch Energy Development Inc., 2018). Here RESPEC investigates geothermal potential of compartmentalized, overpressured sandstone reservoirs using data from wells targeting gas horizons trapped within faulted, roll-over anticlines.

Power generation from the co-production of brine and natural gas has been successfully implemented in Swan Hills Formation carbonates and future projects intend to expand to other carbonate formations in Alberta (Mueller, 2023). The volume of gas within a mature reservoir poses an uncertainty to geothermal reservoirs when reservoir complexity impedes accurate calculations of remaining gas volumes. Produced gas-to-brine ratios are sensitive to initial gas saturations, which affect peak gas production and gas production overtime (Daniilidis et al., 2016). Here we show how lateral gas extent impacts the longevity of a geothermal operation within a heterogeneous carbonate reservoir.

Methodology

RESPEC has worked on a pre-feasibility study of an overpressured sandstone fairway and presents their findings from data collected within the Enverus PRISM database. Production data was reviewed to identify wells with relatively large water production volumes. High water producing wells completed within the sandstone reservoirs were used as an analogue to predict the potential PI index available to a geothermal production well.

Another key learning from RESPEC's work in mature reservoirs is the significance of gas that is co-produced with brine, even in depleted fields. This was investigated using a 3D scoping model representing a vertical cross-section of a carbonate reservoir replicated over 50 km of model domain in an E-W direction in which the horizontal producers and injectors are simulated. Modelling scenarios using different lateral and vertical distributions of gas are used since the volume of remaining gas is unknown.

Observations

The investigated sandstones are composed of laterally extensive shoreface and proximal delta facies that show appreciable porosity and permeability. Growth faulting and associated roll-over anticlines are the primary structural elements that form the trapping mechanism for reservoir fluids. Sediments in the hanging wall of growth faults have been downthrown to appreciable depths where reservoir temperatures reach 500°F.

At first glance these wells showed significant water production (~6008 m³/day) with a low gas-water-ratio, however, after the first test, water production drops sharply and the gas-water-ratio increases (Table 1). The likely reason for this is that the reservoir has a small volume and/or it is highly compartmentalized. The large volume of water was effectively produced by gas lift and water production wanes significantly as reservoir pressure drops, suggesting that long-term high water production rates initially observed at this well are not sustainable long term.

Geothermal injection and production wells targeting highly compartmentalized sandstones also risk early thermal breakthrough. Available potential tests show low to medium productivities, with most investigated wells having a PI index of less than 0.2 L/s/bar. This data is useful, but it does not necessarily represent the PI index of a geothermal well that is carefully selected based on our understanding of the subsurface structure. Geothermal wells should target less-compartmentalized sandstones off-topographic highs within the water-leg to minimize gas production and maximize water production.

Co-produced gas is unsurprisingly common in mature reservoirs, and it must be physically dealt with by geothermal operators. Several opportunities exist depending on the needs of the operator, these include on-site power generation, sale of the gas, reinjection, flaring, etc (Daniilidis et al., 2016; Wieland et al., 2020). Regardless of the gas end use, gas within a reservoir plays an important role in developing a geothermal field.

Predicting gas rates over the lifetime of a geothermal well is difficult in highly heterogenous reservoirs where the remaining gas cannot be accurately quantified. The uncertainty in gas rates is large in terms of peak rates, decline rates and geographic variability. RESPEC modelled scenarios varying the amount and spatial distribution of gas. An important finding was a significant difference in the peak simulated pressure drop at the production well. The simulated pressure drop peaks at 5 MPa after one month assuming a base-case for gas extent (br09b in Figure 1), whereas the pressure drop peaks at 2.2 MPa after one year assuming a reduced gas lateral extent (br09h in Figure 1). The drastic difference in magnitude of the simulated pressure drop implies that geothermal production wells are highly sensitive to gas distribution. Properly quantifying the remaining gas in terms of saturation and extent is critical in terms of reservoir pressure management over the lifespan of a geothermal well. If accurate quantification of gas is not possible, a geostatistical approach using multiple realizations of possible gas extent can be employed to help quantify the uncertainty (Witter et al., 2019).

Test Date	Hours Tested	Flowing Tubing Pressure (psi)	Initial Shut In Pressure (psi)	Gas Volume (Mcf)	GWR	Water Volume (bbl)	Water Rate (m ³ /d)	Top Depth (ft)	Bottom Depth (ft)
1/5/1986	24	3100	5100	2561	1.9	37785	6008	8813	9250
6/1/1986	24	1000	4900	659	622	30	5	8813	9250
12/1/1986	24	800	4900	435	351.9	35	6	8813	9250
7/6/1987	24	580	1900	628	44.5	400	64	8813	9250
4/7/1988	24	580	900	578	1169.1	14	2	8813	9250
10/28/1988	24	460	1200	316			0	8813	9250
12/17/1988	24	440	1200	368	231.6	45	7	8813	9250
12/26/1988	24	530	500	428			0	8813	9250
6/17/1989	24	470	540	276	300.6	26	4	8813	9250
12/8/1989	24	500	800	118			0	8813	9250
5/24/1990	24	580	800	194			0	8813	9250
11/18/1991	24	480	590	185	1746.2	3	0	8813	9250
6/23/1992	24	420	650	83			0	8813	9250
6/16/1993	24	240	600	67			0	8813	9250
1/8/1994	24	220	600	51	206.3	7	1	8813	9250
7/16/1994	24	210	420	93			0	8813	9250

Table 1: Production tests for a high productivity well

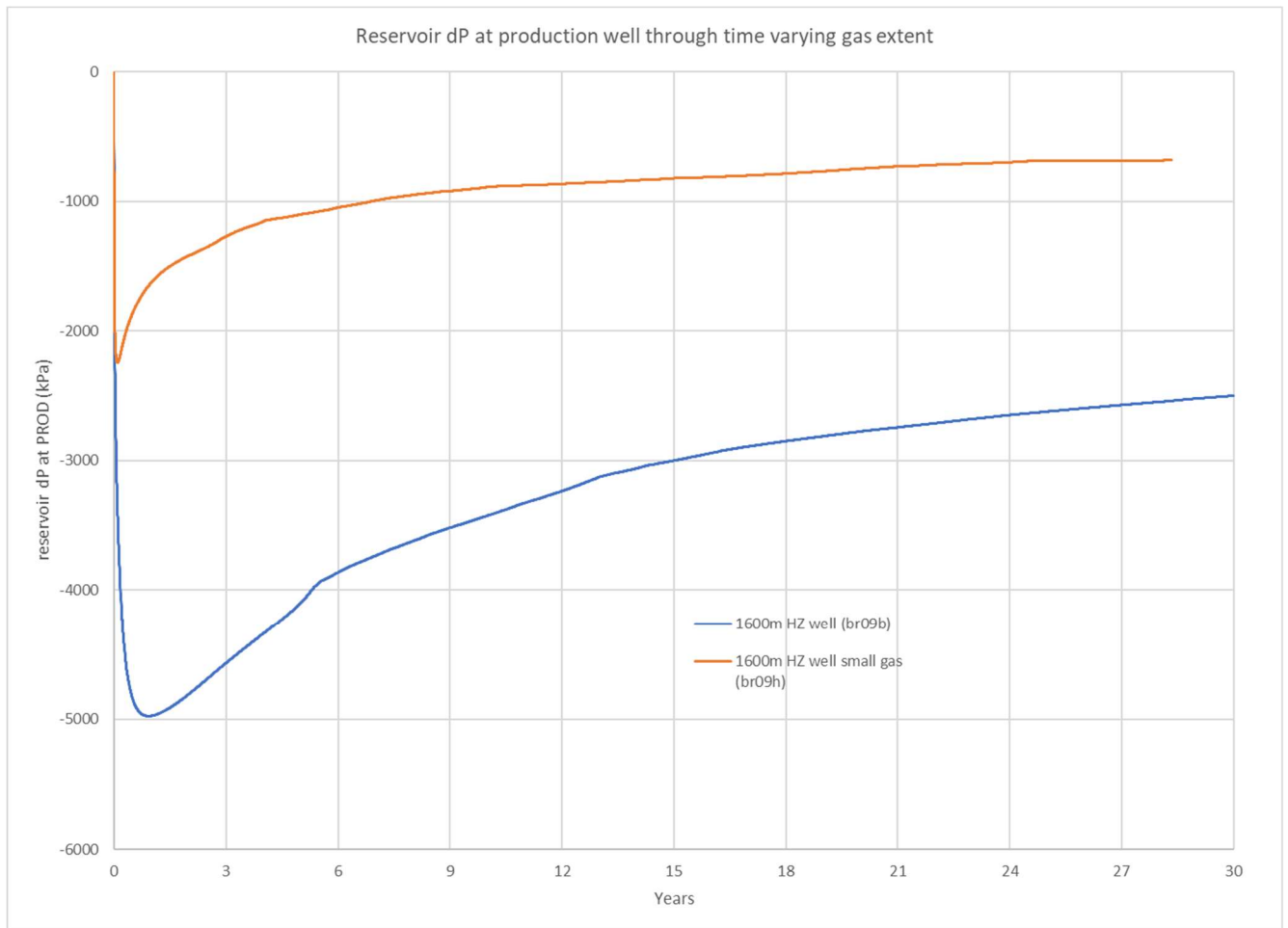


Figure 1: Change in simulated pressure at the production well when varying gas lateral extent

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