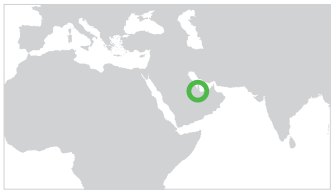
TGT

**Case study** Reservoir Pressure

# Formation pressure established for individual layers under flowing conditions, without shutting in the well



**Location:** UAE
**Well type:** Dual-string oil producer
**Reference:** SPE-182856

**Case benefits**
- Determined the sublayer formation pressure behind casing under flowing conditions
- Enabled the operator to evaluate well performance
- Confirmed the non-communication status for productive zones within the well

## Challenge

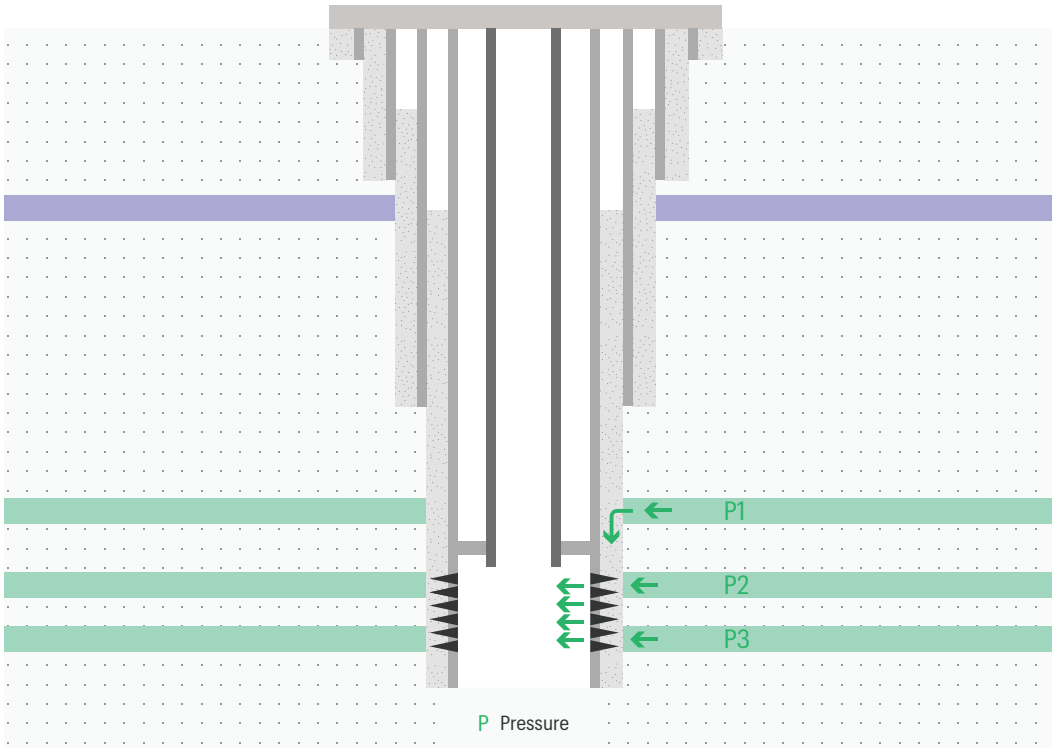
Multilayer carbonate reservoirs are often characterised by hydrodynamically isolated units that develop different formation pressures during production. These differences can result in wellbore and behind-casing crossflows. Conventional sublayer formation pressure measurements involve using wireline formation testing tool before production begins. Once a well is completed and onstream, it is difficult to determine the sublayer formation pressure.

An infill well recompleted as a deviated dual-string oil producer was producing from two strings, Unit A into the short string and Unit C into the long string, the well had an initial formation pressure of 4,200 psi. The aim of the diagnostics survey was to determine the current formation pressure in Unit C and to compare the results with wireline formation testing data which indicated that the formation pressure in Unit C was 800 psi below the initial reservoir pressure value.

## Solution

The operator selected TGT's Reservoir Pressure product to determine the formation pressure profile. Vital information about the reservoir parameters behind the casing was delivered by the True Flow diagnostic system with Chorus technology.

The Chorus platform used a triple flow rate programme and method. The amplitude of the acoustic signal associated with the flow of formation fluids in the reservoir depends on the pressure drawdown, so contains information about formation pressure.




Reservoir Pressure evaluates and quantifies formation pressure

Reservoir Pressure provides the clarity and insight needed to manage well system performance more effectively.

Recording acoustic signals at three different flow rates and then filtering out non-formation acoustic signals made it possible to estimate the formation pressure in each layer using Cascade's (digital workspace) numerical simulations.

The intervention was conducted a year after the well had been recompleted as a dual-string producer. Pressure buildup data was used to determine the stabilisation times before each logging run. This showed that infinite-acting radial flow developed in approx. 8 hrs and that the boundary was not reached during the diagnostic programme period.

## Result

The diagnostic programme was performed at three different operating regimes, with only the flow rate changing in the long string. Chorus diagnostics showed two major flowing zones: one within the upper perforations of Unit A and the other in Unit C (Figure 1). The acoustic signal in Unit A was constant because the flow rate varied only in the long string. That proved that there is no communication between units A and C.

Cascade's numerical modelling was able to match the recorded wellbore pressure and acoustic signal amplitude (or power) for three flow rates. These were found to match at each rate. The current formation pressure ($P_e$) for Unit C was determined to be approximately 40 psi lower than the wireline formation testing data depicted by points A and B (Figure 1). Pressure drops over time, so for a fair comparison between current formation pressures and the original wireline formation data (points A and B), adjustment calculations were needed for verification. Both values proved to be in agreement.

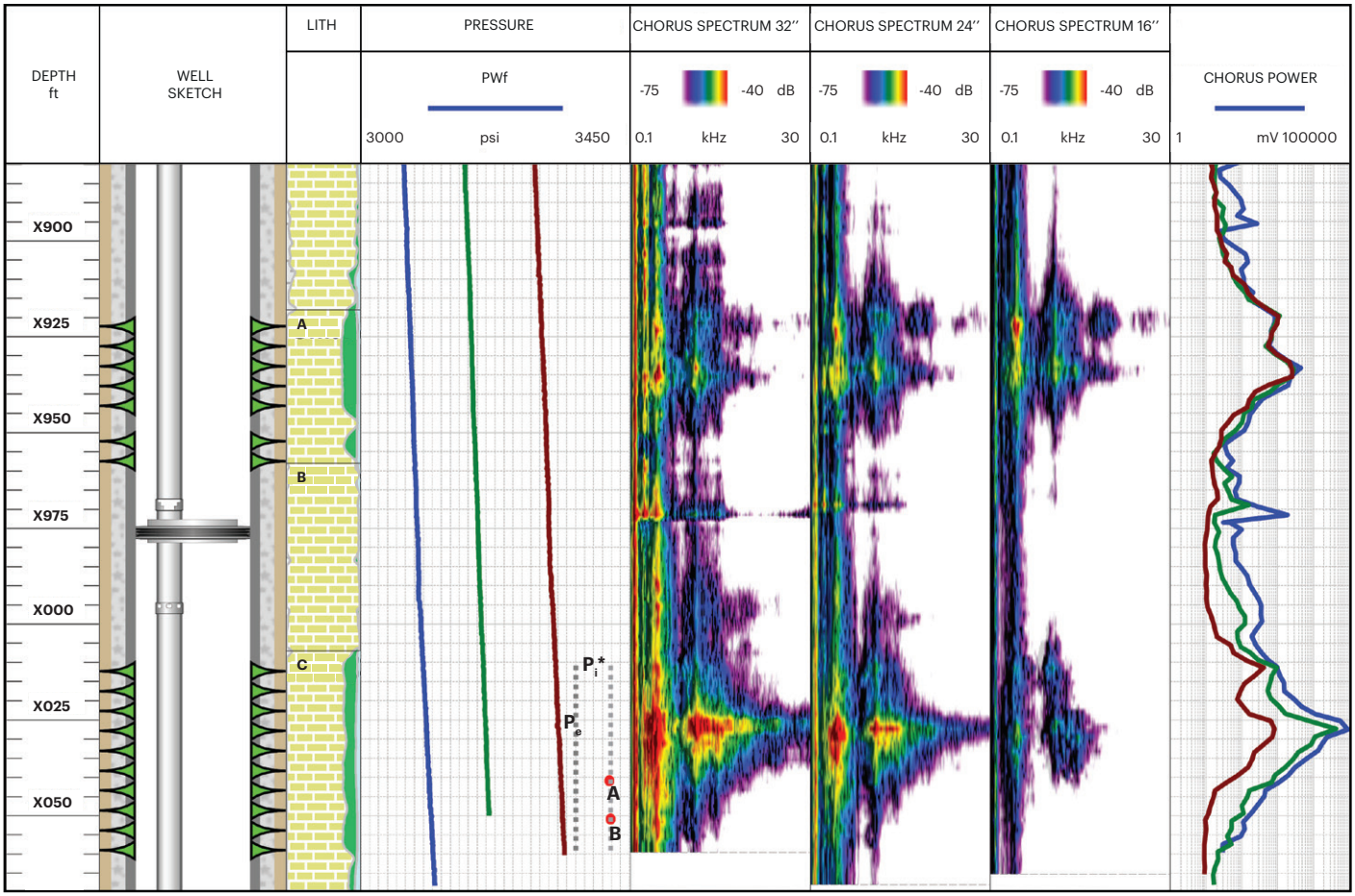



Figure 1. The acoustic spectra in Unit A and B are recorded at three different rates varied only in the long string. Current formation pressure value ($P_e$) in Unit C was defined within the Reservoir Pressure product; the pressure value calculated backward to seven months, to the time when wireline formation testing data (points A and B) were acquired, is depicted by $P_i$*.