In Australia's Surat basin, gas is contained in hundreds of coal seams which have highly variable properties and are grouped into four distinct reservoir zones of similar qualities. Economically, producing these wells from multiple reservoir units is generally favoured and as a result, understanding the relative contribution to production by different zones at different times in the well's life, and whether production is dominated by a single zone, adds value to planning future wells.

The well designs are quite simple. An 8.5" inch wellbore is drilled from surface casing through the target coal seams. A 7" production casing and pre-perforated liner with external casing packer and cement stage tool is run to total depth. The external casing packer is deployed at the top of the reservoir, and the 7" casing is cemented in place through the stage tool above the packer. No external packers are installed between groups of coal seams (zones) to segregate production from each zone through the pre-perforated liner.

Production tubing is then installed in the well; typically running to the base of the pre-perforated liner, and a progressive cavity pump (PCP) is installed in the tubing to lift water production associated with the coal seam gas (de-watering). Gas production comes from the coal seams and flows around and through the pre-perforated liner, then up the annular space between the production liner/casing and the production tubing, to surface, while water flows to the bottom of the completion where it is lifted up the production tubing by the PCP, as shown in figure 1.

**Figure 1:** Schematic of a coal seam gas well showing flow paths of the different fluids

Understanding zonal allocation – challenges and solutions

Normally, production logging tools (PLTs) are run to understand zonal allocation in commingled wells. However, running PLTs in coal seam gas wells can be expensive as the PCP pump needs to be pulled out and the well lifted with gas. The switch to gas lift at a shallower depth also doesn’t represent normal operating condition and may affect the result. An additional issue with these wells is the unsegregated, open-hole completion. With no external packers, neither the PLT tools nor distributed temperature sensor (DTS) fibres inside the liner can measure flow in the space between the liner and the sand face.

DTS from a fibre optic cable is a potential solution to the challenges associated with PLTs. For DTS, a light pulse is transmitted down the fibre optic cable in the well. The light is reflected by imperfections in the fibre and a permanent interrogator on the surface can calculate the relative temperature from as low as 0.5 to 1m intervals down the fibre. This dataset of temperature with depth is then collected over time. In addition to fibre installations run on the outside of the tubing, it can also be installed on the outside of the pre-perforated liner, as close to the formation as possible.

The set-up adopted has the fibre connected on the surface to a permanent interrogation unit. Typically, recordings are made every six hours and transmitted to a cloud-based database for immediate visualisation and analysis. The commercially available software FloQuest was used as it allowed for visualisation of large amount of DTS data in
combination with gauge and log data for easy comparison, event mining or identification. The built-in modelling tool also meant that both visualisation and modelling can be done in the same package.

Many of these wells have had more than a year of DTS data collected, which covers shut-in, pre-production, the initial dewatering with single-phase water and initial gas production and ramp-up periods.

**Temperature model to provide zonal allocation**

Changes in temperature profile in production wells are usually dominated by two major factors: the flow commingling and heat transfer effects. Assuming no chemical interaction between the fluids, the final temperature after commingling is calculated by following the principles of energy conservation. The heat loss to the formation is however, more complex to evaluate as there is the possibility of annular bi-directional flow with water flowing down while gas bubbles up through it to surface.

In order to reduce the complexity, modelling was only carried out on traces logged during the dewatering period having single-phase flow. Inflow temperature is taken to be the same as that of the geothermal and as such, it is important to obtain a good initial geothermal temperature profile.

The set of inflow rates that delivers a match to observed temperature profiles describes the inflow profile of the well. The calculated rates are then used to achieve the corresponding permeabilities of the zones. To assess the validity of a DTS interpretation, the results can be compared to permeability measurements made from sensors in nearby wells. An example of this is shown for a single point in time in Figure 2 which shows the DTS logged temperature in a well with single-phase water production.

Gas rate was also verified from gauge data. As shown in figure 2, a very good match between modelled and observed temperature can be achieved. As is the case for any history matching activity, a non-unique solution is delivered that is subject to some uncertainty. For instance, a different geothermal gradient assumption would necessitate different inflow rates to achieve a match.

Measured data (light green curve), has been matched by the modelled temperature (black curve), by varying the water produced from different horizons. It can be seen that the modelled well bore temperature matches the measured temperature closely. The four producing formations are: upper Juandah (UJ), lower Juandah (LJ), Tangalooma (TG), and Taroom (TR).

DTS data for two additional dates from the same well were matched with FloQuest models. This DTS result was then compared to the reservoir model behaviour for this well. In this case, the reservoir model populated by static drill stem testing measurement behaved in a similar way to the dynamic DTS data. The flow rate contributions interpreted from DTS showed around 40-60% (UJ, LJ), 0-15% (TG) and 0-5% (TR). The modelled flow rate contributions from the reservoir model averaged over the producing period were 58% (UJ), 38% (LJ), 2% (TG), and 1% (TR). This example for one well shows the insight possible with DTS measurements.

**Liquid level in the well**

Before production, the well had a full water column to ground level, then as the pump removes water from the well this column falls and drawdown is placed on the formation. The DTS recorded temperature data above and below this liquid level. The depth of the liquid level during normal operations is generally sought to be as deep as possible, by pumping off the water, to create the largest drawdowns on the formation. This means it is common for the reservoir section to be partially covered by a water column and have gas to surface in the casing (liner)/tubing annulus. This complicates the temperature data from DTS.

The most confident DTS interpretations are from periods when the liquid column was kept above the reservoir section, although this is not representative of standard well operations.

**Depletion trends**

Since DTS records temperature throughout the life of the well, events that may not be investigated by a PLT campaign can be observed. All wells showed cross flow events when shut-in and with confidence in the geothermal gradient the direction of cross flow can be inferred. Assessing trends across areas can provide an indication as to which horizons deplete the fastest. In figure 3, post production shut-ins from two wells are compared, with both showing the same behaviour of shallower coals flowing to deeper intervals. It can be postulated that the deeper coals intervals have been depleted more by production than the upper coals.

![Figure 2: Interpretation of DTS data to give zonal allocation](image)
Conclusion

Accurate zonal allocation from DTS data has been demonstrated during single-phase water production periods. DTS temperature data can be collected continuously during well life, allowing the tracking of the phasing of production from different horizons and shut-in behaviour to be analysed. This can provide an understanding of crossflow behaviour and subsequently interpretation of zonal contribution and depletion.

Challenges have been encountered when trying to accurately quantify zonal allocation. Having only one dataset (temperature with depth), flow behind pre-perforated liner, uncertain geothermal gradient and fluid level below the top perforation all add complexity to the DTS interpretation process.

With multi-phase gas and water production, temperature modelling becomes more complicated and quantitative zonal allocation based on DTS temperature data alone is not currently possible. There is potential that as wells move to single-phase gas conditions a new thermal model can provide zonal allocation. It is also recognised that supplementary data from fibre could improve the understanding of zonal allocation. Combining DTS with Distributed Acoustic Sensing (DAS) may provide a solution to the flow allocation challenge.

Reference