In Australia’s Surat basin, gas is contained in hundreds of coal seams which have highly variable properties. For example, permeabilities can range from Darcys to micro-Darcys in a single well, and the production from individual seams will not be uniform. The coal seams are grouped into four distinct reservoir zones of similar qualities and coal productivity is measured with dual packer drill stem tests (DSTs). Selected coal seams are isolated with the DST dual packers and tested providing the measurement of permeability to a four-layer dynamic reservoir model. These tests are performed when the well is drilled, are short duration and are generally single phase water production. The permeability values thus derived are used in the reservoir model throughout well life and they cannot be validated without additional zonal allocation datasets.

The allocation of total well production to separate reservoir units is vitally important. However, development planning economics will generally favour the low-cost route of completing wells to flow from multiple reservoir units, commingled. A single well rate, measured at surface, will comprise production from a number of very different reservoir zones. 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. For example, if zonal contribution is known, infill drilling can be targeted at the zones that have the most production potential and gas reserves left.

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.

**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 would need to be pulled out and the liquid 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 is used as it allows for visualisation of a 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 means that both visualisation and modelling can be done in the same package.

Figure 2 illustrates the DTS data collected for one well, with additional available production data, including well gas rate, water rate, down hole pressure, casing head pressure, pump speed and annular water level below ground. Each green bar represents the time during which DTS temperature data has been collected. It includes periods of time before the well is on production, during single phase dewatering and as gas production starts and increases. The fibre does not affect the down hole pump operation and it records during standard well operations.

Temperature model to provide zonal allocation
Changes in temperature profile in production wells are usually dominated by two major factors: the flow comingling and heat transfer effects. Assuming no chemical interaction between the fluids, the final temperature after comingling 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 through it to surface.

In order to reduce the complexity, modelling was only carried out on traces logged during the dewatering period with single-phase flow\(^2\). 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 3 where 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), d 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), whereas, the modelled flow rate contributions 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.

Geothermal gradient
The fidelity of the geothermal gradient used as input into the wellbore temperature modelling is essential. Temperature (and thermal energy) is allocated to the flow from a horizon by where it lies on the geothermal temperature profile. Even with long periods of shut-in, an accurate geothermal gradient may not be attainable due to a variety of reasons, particularly in wells where cross flow occurs, even before production is initiated. In Figure 4, one month of data is presented during shut-in pre-production.
The cross-flow events make picking a geothermal line challenging. The two postulated geothermal gradients, green lines, would give different zonal allocation results.

Analysis of the DTS data needs a high confidence in the geothermal line. On the right of Figure 4, the recorded temperatures from DST tests in this area are presented. This DST data shows a greater scatter than that of the two postulated geothermal gradients from DTS. Zonal allocation requires a more precise geothermal gradient than is measured by other means.

![Figure 4: Comparison of DST temperature measurements to the geothermal gradients from DTS data](image)

**Liquid level in the well**

Before production, the well has 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 records temperature data above and below this liquid level. The depth of the liquid level during normal operations is generally positioned as deep as possible, by pumping off the water, thereby creating the largest pressure drawdown on the formation. 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 analysis of the temperature data from DTS. The most accurate DTS interpretations are from periods when the liquid column is 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 discrete PLT campaign can be observed. All wells show 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 5, 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 5: Comparison of post-production shut-ins for two wells](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 phase of production from different horizons to be tracked and shut-in behaviour to be analysed. This information can form an understanding of crossflow behaviour and provide insight into 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. The method employed only provides contribution in the dewatering phase or early well life as this is the period dominated by single phase water production. In late well life, there is however the potential for the well to switch to single phase gas production. During this period the modelling complexity of bi-directional flow in the dewatering phase no longer exists as produced gas flows through the annulus to surface. This allows for further analysis to be carried out during this period using more widely available temperature models.

It is also recognised that supplementary data from fibre can improve the understanding of zonal allocation, and combining DTS with Distributed Acoustic Sensing (DAS) may provide a solution to the flow allocation challenge.

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**Reference**


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