

From Small Beginnings Come Great Things: Correlating Mineralogy from Thin-sections to Production History for the Panther River Tight Gas Field

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The Panther River field was discovered in 1958 in the foothills of Central Alberta and holds approximately 35 BCM (1 TCF) of dry, sour-gas in dolostones of the Mississippian Turner Valley Formation (Nelson et al. 1998). Panther has a complex geological history, affected by folding and thrusting and Thermochemical Sulphate Reduction (TSR) yielding a fractured and impaired reservoir. From 1960 to 1998, 6 vertical producing wells were drilled to test the productivity across the field. Drilling resumed in 2000 with the improved cost effectiveness of horizontal wells and since then, 20 long-lateral wells (1000 - 2000m) have been drilled with open-hole completions, providing abundant data for reservoir characterization from drill cuttings, petrophysical logs, and FMI. In contrast to many tight gas fields, Panther wells are not hydraulically fractured and yield relatively well-constrained pressure build-up data (key to our new understanding) from well-tests despite having a system perm (0.02-0.8 mD) that is several orders of magnitude higher than those typically encountered in tight gas fields. For many years attempts to correlate geological parameters with well deliverability have been largely unsuccessful. Of particular importance was how to assess the distribution of solid hydrocarbon residue and its impact on reservoir quality and well performance.

Here we present a novel approach to determining the modal abundance of minerals from digital images of thin-sections taken from drill cuttings. Drill cuttings were collected in 5m intervals while drilling the horizontal well-bore. From these samples, 13 of the 20 horizontal wells within the field were analyzed by selecting samples (50-100 samples along the horizontal well-length) covering the reservoir interval in each well. Thin-sections were made from the drill-cuttings samples and imaged using a petrographic microscope with a digital camera attachment. Thin-sections were photographed at 6.3x magnification to capture subtle details in the rock matrix and approximately 40 images were collected from each thin-section. In total, 939 thin-sections were prepared from rock cuttings and over 15,000 digital images were collected and categorized according to depth and reservoir member creating a large dataset that enables a better representation of the reservoir. For a rapid and standardized (non-biased) analysis, an in-house software algorithm was developed to extract the mineral abundance from each digital image using an automated rule-based approach (Figure 1). Firstly, all images were corrected for illumination effects due to differences in epoxy coloration and microscope lighting. Next the images were segmented to separate the drill-cuttings from the epoxy setting in preparation for identifying each drill-cutting and its component minerals in an image. Having separated the drill cuttings from the epoxy background, a marker-controlled watershed algorithm paired with an erosion-dilation algorithm was utilized to identify individual drill-cuttings and separate juxtaposed cuttings. The software then iterates through each drill-cutting to assess mineralogy based on pre-defined colour and geometry rules. Images were converted to Lab colour space to facilitate in the distinction between minerals that appear similar in the RGB colorspace. Each mineral present in the reservoir was identified and described by geologists defining a standard rule for each mineral (i.e. colour, shape, internal features, etc). Application of the rule-based algorithm permitted the segmentation and quantification of minerals present within each thin-section image. The mineral abundance calculations were normalized to the

area occupied by the drill-cuttings, thus providing an area percent for each mineral phase in a digital image. Output data was provided in excel spreadsheet format and reference segmented images to be used as a mode of comparison to the corresponding original thin-section image. A high confidence (>80%) of agreement was obtained through comparison of the automated image analysis output data and manually interpreted data.

From here, the mineral data was imported into Petrel for mapping and petrophysical calculations (Figure 2). In addition, the mineral data was compared with petrophysical well-logs to verify and improve estimations of reservoir porosity. Using Petrel, mineral maps could be generated to determine the spatial distribution and variance across the field, which could then be compared with production data, and petrophysical evaluations. Interestingly, it was observed in two reservoir members (MT1 and MT3C) that the distribution of solid hydrocarbon was most severe in the crestal parts of the Panther River structure and decreased towards the flank (inverse relationship with depth), while the third member (MT3A) showed a nearly isotropic distribution. Furthermore, the inverse depth relationship observed for solid hydrocarbon impairment correlates very well with well performance and has been used to plan additional wells in the field.

Automated Image Analyses Software Workflow

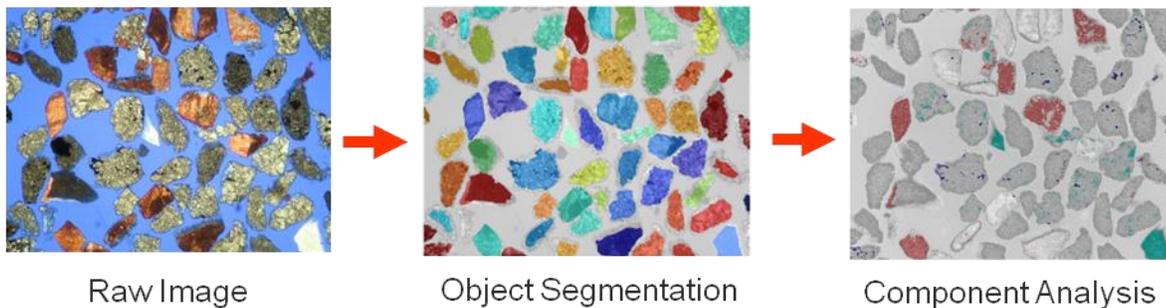


Figure 1: Thin-section image analysis workflow from raw petrographic thin-section to mineral identification.

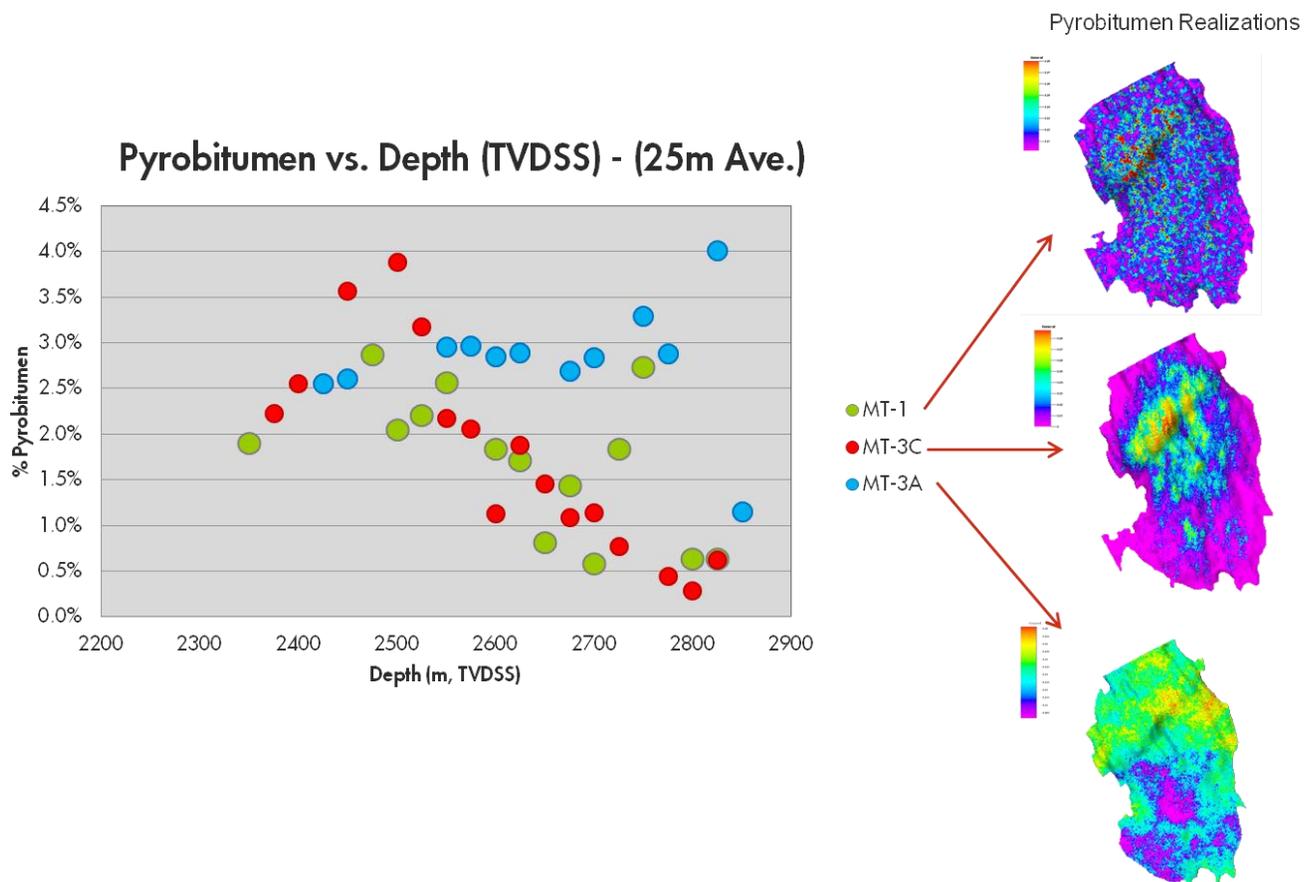


Figure 2: Solid hydrocarbon reservoir impairment with depth as determined from thin-section image analysis (left) and corresponding petrel models for the three reservoir intervals in Panther River highlighting the distribution of solid hydrocarbon impairment (right).

References

Nelson, R.L., Dyck, W.C., Jamieson, F. M., and Jenkins, R.A., 1998, Multiple pad acid fracs in a deep horizontal well: SPE Rocky Mountain Regional/Low-Permeability Reservoirs Symposium, April 5-8, Denver, Colorado, 363-374.