Revisiting the Slave Point: A Junior's Experience in a challenging oil resource play using real time subsurface imaging through the integration of 3D seismic and Logging-While-Drilling Boundary Detection

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Summary

With the advancements in horizontal drilling and well stimulation techniques, interest is returning to the tight Slave Point reef margin trending from the Nipisi/Utikima Lake to the Red Earth/Otter Fields. This predominantly limestone reef margin produces light sweet oil from an array of reef facies, ranging from high permeability coral boundstone to distal forereef grainstones / wackestones. Reservoir quality limestone is disseminated within 3 Transgressive/Regressive cycles. In the Nipisi field, each reservoir cycle is separated with non-reservoir forereef wackestones to offshore mudstones. This limits the vertical pay encountered with conventional vertical wells, and lends itself to horizontal drilling as an effective development strategy.

This case study examines the development history of an underperforming oil accumulation in the Nipisi Slave Point "D" Pool. A previous attempt at drilling a horizontal well in the pool was cut short at 442m horizontal length, with only 10% of the well drilled in the target zone. This history suggested the geological uncertainty was high, and the 2-4m thick target reservoir could not be predicted with conventional geosteering methods (cuttings and Gamma Ray). We will highlight how a Junior E&P justified the cost of implementing advanced geosteering technology, and how this application improved real time drilling decisions and ultimate success in the appraisal and future field development strategy.

Recognizing the difficulty of keeping a horizontal wellbore in zone, and with limited capital resources available, the company mandated a detailed evaluation of risk-mitigation options. Sufficient reservoir exposure was critical to meeting production expectations for the well, in addition to providing a template for successful pool development in the future. Furthermore, wellbore stability concerns required this well to avoid any contact with the fissile shales of the Waterways Formation above the reservoir, as subsequent stimulation operations required stable openhole conditions.

The well was drilled using depth converted 3D seismic mapping and Logging-While-Drilling Boundary Detection in real-time in order to increase reservoir exposure and improve the calibration of the 3D structural interpretation as the horizontal was drilled. During the operation many adjustments to the well trajectory were made based on faulting and lateral reservoir variation that were either not predicted or beyond the resolution of the 3D seismic data. This resulted in a significantly modified wellplan and a real time improvement to the pre-drill structural model. It was clear upon completion of the operation that the integration of the LWD measurements with the 3D seismic interpretation made it possible to better predict structural and stratigraphic changes ahead of the bit, including the ability to respond to abrupt structural changes in the Waterway / Slave Point contact that were not evident on the 3D seismic data.

Total horizontal length drilled was 995m, with over 95% of the wellbore in productive reservoir, and no contact with the Waterways Shale in the open-hole section. Subsequent stimulation of this well resulted in a stabilized production rate an order of magnitude higher than existing vertical producers, and an almost 800% improvement in production from the previous horizontal well. This result, coupled with the increased drilling efficiency and geosteering capability, more than justified the investment made in the Real-time deep reading Logging-While-Drilling assembly, and proved the feasibility of this pool as an economic oil resource.