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3-D Geologic Model of a Fractured Carbonate Reservoir, Norman Wells Field, NWT, Canada

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Norman Wells is a Devonian-age carbonate bank complex located in the Northwest Territories, 60 km south of the Arctic Circle. The bank complex reaches a maximum thickness of 130 m across the bank interior and thins basin-ward due to a combination of bank-margin backsteps and depositional pinch-out. Norman Wells is an oil reservoir with approximately 108 km^3 (680 million barrels) of oil in place. The limestone reservoir has very low matrix permeability (avg. 2 to 4 millidarcies) and is naturally fractured. The permeability due to fracturing is critical to achieving economic oil production from Norman Wells.

Previous 3-D modeling efforts at Norman Wells did not attempt to quantify the effects of fracture permeability, resulting in discrepancies between reservoir simulation models and historical field performance data. In the present study, a 3-D geologic model was constructed utilizing static (outcrop, core, well logs and seismic) and dynamic (injection and production logs) data to quantify the combined affects of matrix and fracture properties on total, full-field permeability. Matrix and fracture properties were modeled separately and then combined into a total permeability model. Matrix properties were modeled using core and log data combined with facies and stratigraphic information. Fracture properties were modeled using outcrop, core and image log data, with flow properties calibrated to injectivity-derived kh data. Structural, stratigraphic and facies information were used to guide the distribution of fracture permeability. Using this new total permeability model as the basis for building a reservoir simulator, a history match of production performance was achieved. Benefits of incorporating the effects of fracture permeability directly into the 3-D geologic model include: 1) reduced need for adjusting permeabilities in the flow simulator, and 2) geologic data can guide the distribution of the fracture permeability rather than ad-hoc adjustments in the flow simulator. The new reservoir simulator is currently being used for reserves determination, production forecasts, opportunity identification, and field management.