HIBERNIA FIELD PETROPHYSICAL ANALYSIS 2009

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1.0 INTRODUCTION

Current petrophysical processes have been used for several years after refinement from the initial process on development wells. The processes have proven robust and adequately describe the reservoir for population in geologic and reservoir simulation models.

2.0 PETROPHYSICAL ANALYSIS PROCEDURES

2.1 POROSITY

Openhole density logs are used to calculate total porosity using standard Hibernia end points for matrix density (2645 kg/m^3) and fluid (820 kg/m^3). These standard values have been established using Hibernia B Pool cores from B-16 2, B-16 4, B-16 5, B-16 9, B-16_12 and B-16 17.

2.2 SHALE VOLUME

Shale volume is determined using from a linear Gamma Ray (GR) process using end points coincident with the minimum statistically coherent GR value representative of sandstone in the reservoir interval and the maximum statistically coherent GR value representative of shale within the reservoir interval. That is,

$$V_{sh} = \frac{GR - GR_{\min}}{GR_{\max} - GR_{\min}}$$

Values are generally picked within the clean sands of Layer 3 at 10 API units and within the Medial Shale at 120 API units.

If the Gamma Ray log is missing or determined to be incorrect, the Neutron and Density log crossover is used to determine shale volume using the following equation:

$$V_{sh} = \frac{\phi_N - \phi_D}{\phi_{Nshale} - \phi_{Dshale}}$$

where ϕ_N is neutron porosity in sandstone units and ϕ_D is density porosity calculated as described in Section 2.1. This crossover method has not been necessitated in the Hibernia formation.

2.3 WATER SATURATION

Given the quartz-rich nature of the Hibernia reservoir, the Archie saturation equation is appropriate and is used for development wells. The form of the Archie equation used to determine water saturation, is:

$$S_w = \left[\frac{aR_w}{R_t \phi_t^{\,m}} \right]^{1/n}$$

where:

- S_w = total water saturation (fraction)
- a = tortuosity factor
- R_w = resistivity of formation water (in Ω-m)
- R_t = true formation resistivity (in Ω-m)
- ϕ_t = total porosity (fraction)
- m = cementation exponent
- n = saturation exponent

Standard Hibernia values for Archie parameters a (1.0), m (1.84), and n (1.7) have been determined using core analyses corrected to reservoir stress. These standard values have been established using special core analysis of Hibernia B Pool core obtained in well B-16 17. Where oil-water contacts have been encountered to date, saturation changes have been abrupt and distinct due to the large grain size and lack of clay material to bind water. This has allowed the use of saturation equation process rather than a more involved saturation height function.

2.4 PERMEABILITY

Recognition that a wide range of permeability is associated with any given porosity value has driven the development of a grain size based permeability calculation process. Permeability is calculated using multiple regressions from effective porosity based on core data from the B-16 2, B-16 4, B-16 5, B-16 9 and B-16 17 wells. Grain size information is used to differentiate coarse, medium, fine grained and agrillaceous rock. Core within each facies type was net overburden and Klinkenberg corrected, and the resultant permeability values for each rock/grain size type were cross-plotted with core porosity values to establish 4 poro/perm relationships. Resistivity from well logs is used to assign a rock category and thereby a grain size to well log data. A permeability transform appropriate to the rock type is applied to each porosity to generate a permeability. This process has been very effective in B pool wells based on results from well tests. Further detail of the process is available for discussion if desired.

2.5 NET SAND AND NET-TO-GROSS

Net sandstone is determined using a summation of well log intervals. The standalone minimum thickness included in these summations is 0.1524 meters, as determined by the well log sample interval. In the Hibernia B Pool, net sandstone is defined using a porosity cutoff of ≥0.12. Hibernia A Pool net sandstone is determined using a shale volume cutoff of ≤0.4 and variable porosity cutoffs. These porosity cutoffs range from ≥0.10 to ≥0.12, vary from well to well, and are designed to maintain a balance between including all potentially prospective zones and exclude poor quality intervals that have been proven not to flow.

Net-to-gross ratios are determined to three decimal places for each reservoir zone in each well by dividing the true stratigraphic net sand thickness by the calculated true stratigraphic gross zone thickness using the following equation:

$$N:G = \frac{\sum H_t}{\sum G_t}$$

where H_t is net sand thickness and G_t is gross interval thickness.

2.6 AVERAGE VALUES

Average net sandstone porosity across the thickness of a reservoir zone is calculated to three decimal places using the following equation:

$$\phi_{avg} = \frac{\sum (\phi_i \times H_t)}{\sum H_t}$$

Where ϕ_i is porosity of the *i*th interval and H_t is net sandstone thickness. Similarly, the average hydrocarbon saturation in a reservoir zone above a hydrocarbon-water contact is calculated to three decimal places using the following equation:

$$S_{HCavg} = \frac{1 - \sum (S_{wi} \times H_t)}{\sum H_t}$$

where S_{wi} is water saturation of the *i*th net sand depth increment above the hydrocarbon-water contact.

2.7 FORMATION AND FORMATION WATER RESISTIVITY

In hydrocarbon-bearing zones when water-based muds are used, a resistivity device of electrode type is used for formation resistivity determination. Such device is either the dual laterolog – Rw (microresistivity) logs, corrected for invasion and borehole effects, or an array-type device where the formation resistivity is derived by processing of individual sensor readings.

When non-conductive muds are used (as in most Hibernia wells), when electrode devices are not applicable, or when conditions are unfavorable for electrode devices, a deep-reading induction type device is used for formation resistivity determination.

Salinity measurements on water samples acquired downhole and on the surface indicate variability within the Hibernia reservoir, generally increasing to the west and north and decreasing to the east. This is likely due to proximity to the salt intrusion along the Murre fault. Salinities used in the analysis of the B pool range from a low of 62500 ppm NaCl eq at B-16_18 to a high of 130000 ppm NaCl eq at B-16_11.

3.0 CORED INTERVALS

Since approval of the 2006 Hibernia DPA, only two cores have been obtained in Hibernia Field, each of which has cored Hibernia B Pool: B-16 55 and B-16_57w. Core analysis data for each of these cores has been provided to the C-NLOPB in the *Annual Data Acquisition Report*.

4.0 RESERVOIR PARAMETERS BY WELL

A summation of reservoir parameters derived for each reservoir in each well, including gross and net pay, average porosity, permeability, and water saturation is attached as Excel spreadsheet Geoscience.xls, in the tab named 20_Hibernia_Petrophysics.