Basin-Wide Delineation of Gas Shale "Sweet Spots" using Density and Neutron Logs; Implications for Qualitative and Quantitative Assessment of Gas Shale Resources

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The critical issue confronting exploration in Gas Shale Plays is the identification of "sweet spots"; areas where well performance will be most economic. This problem is often addressed by creating an OGIP map which involves calibrating core and log data, usually with special core evaluation, specialty logs and geochemistry, to predict where the most gas resides in the reservoir. Assuming a reasonably consistent recovery factor, an OGIP map should predict where the EURs of wells will be highest. Creation of an OGIP map presents several challenges. In the exploration and early delineation phase of a Gas Shale Play, core and geochemistry data are often hard to obtain. Further, basic reservoir parameters such as porosity and water saturation are suspect in Gas Shale making quantitative resource assessment difficult. In addition, industry research is increasingly focused on a greater detailed understanding, either through advanced geochemistry or SEM analyses. These data are very difficult to upscale, or use, to create a basin-scale map that identifies the highest quality reservoir. This paper will present two approaches to identifying "sweet spots"; 1) "Apparent Shale Porosity" *Thickness Mapping and; 2) Neutron "Gas-Effect" and discuss the implications on qualitative and quantitative assessment of Gas Shale Resource evaluation.

"Apparent Shale Porosity" *Thickness Maps are a simple and straightforward approach to assess basin-wide Gas Shale reservoir potential. Once the basic Gas Shale potential of a shale is established, i.e. sufficient TOC and maturity, the density and neutron logs are used to map the "sweet spots". "Apparent Shale Porosity" *Thickness (PHIas*H) maps are created using the density log, without correction for TOC. Simply, the cumulative porosity over a cutoff, usually 5- 6%, is summed over the thickness of the shale and subsequently mapped as PHIas*H and PHIas (average). Comparison of these maps with well EURs, 30-day peak rate or reported Initial Potentials, show a remarkable correlation and, therefore, utility in mapping "sweet spots" as illustrated by examples from the Eagleford, Haynesville and Marcellus Gas Shale Plays.

We refer to these maps as "Apparent Shale Porosity" Maps because we infer that the response of a density log in Gas Shale is a composite response from porosity, organic matter and matrix density and does not represent the true porosity of the shale. However, its utility in identifying "sweet spots" suggests that the principal driver in the Gas Shale density log response is TOC and porosity allowing "Apparent Shale Porosity" to be used as a proxy for reservoir quality in Gas Shale. The pioneering SEM work using ion-milled samples at the Bureau of Economic Geology at the University of Texas, has clearly shown that the majority of the porosity network in Gas Shale appears associated with the TOC (Loucks et. al, 2009). This work provides a conceptual reason for the why the density log is so useful in identifying "sweet spots".

Further, we couple this with a "Neutron Gas-Effect" observed between the neutron and density log. The "Gas-Effect" is noted as a convergence of the neutron and density log, to the point in some shale of cross-over; a response quite opposite of neutron- density response in lean, non-organic shale. Graphically, the two curves can be shifted to overlie in a lean shale; producing a "Neutron Gas Effect" display to accentuate the effect in an organic-rich shale. The "Neutron Gas-Effect" can be shown to occur in all commercial Gas Shale and does not occur in shale that is currently non-economic. We believe this to be a direct detection technique for identifying a commercial Gas Shale.

Due to the competitive nature of Gas Shale plays, few regional maps showing reservoir "sweet spots" have been published. Most published maps use thickness or resistivity to map Gas Shale, though we suspect that many companies already used some form of porosity mapping in their Gas

Shale assessment. Early assessments of the Barnett-Fort Worth by the USGS emphasized source rock maturity, top and bottom seals as principal controls in their Resource Assessment of the Barnett. However, comparison or 30-day peak gas rates (used as proxy for EUR) with a gross thickness map appears a better predictor of well performance than seals or maturity. Seals, maturity and mineralogy are no doubt important, but appear to be secondary controls on Gas Shale reservoir “sweet spots”.

It should be noted that basin-scale trends have limitations. EURs from decline analysis from the Barnett- Fort Worth, in northeastern Johnson County, Texas, show that well performance varies significantly between adjacent wells suggesting statistical variance in well performance within “sweet spots”, though the average well within a “sweet spot” will be higher than a well outside a “sweet spot”. Assuming best practices by operators, this variation could reflect geological variation on a small scale, or more likely, a statistical variation due to the fracture stimulation effectiveness. The statistical variation of adjacent wells does suggest that caution should be used when comparing well performance with any specific geological parameter such as TOC, maturity, silica content, without first putting that well in a basin-scale perspective.

The qualitative basin-scale techniques discussed in this paper are useful exploration tools and utilize conventional open-hole logs widely available with little or no calibration with rock data. Perhaps, more importantly, the techniques provide insights into the challenges of quantifying Gas Shale resources and OGIP maps. First, the similarity of “Apparent Shale Porosity” *Thickness maps to OGIP and its utility as a predictor of well EUR is not coincidental. Clearly, the gross, uncorrected density log response provides the “framework” for all OGIP mapping, as porosity and thickness are key parameters in any in-place assessment. The utility of “correcting” log porosity for TOC using the density log or gamma ray, may be not be any more quantitative than using the raw data. Second, though the density log response in Gas Shale is a composite effect of TOC, porosity and matrix density, it appears that the low density of Gas Shale is primarily driven by TOC and its associated porosity. As stated above, the association of nanno-pore reservoir network with TOC in Gas Shale has been established in SEM work and provides a conceptual reason for the why the density log is so useful in identifying “sweet spots” but it also poses a problem of scale and our ability to quantify OGIP. Current logging tools, with sample rates of 0.5 feet (1.524×10^{-1}m) are unlikely to resolve the nanno-scale (1×10^{-9}m) porosity network of Gas Shale in a quantitative manner that we are accustomed to in conventional reservoirs. We are, at best, using average porosities and saturations from core grafted onto our “Phi*H” maps, in very heterogeneous Gas Shale reservoirs, and hoping for a quantitative answer. This suggests that the current approach to creating OGIP maps is deeply flawed and new logging tools and methodologies are needed to quantify Gas Shale reservoirs. Third, the neutron log has been somewhat neglected as a tool in Gas Shale analysis. If our observations are correct, the neutron log may provide a method to estimate gas-filled and effective porosity in Gas Shale, though it will still be an averaged value, due to scale issues.

In conclusion, “Apparent Shale Porosity” *Thickness maps and the “Gas-Effect” on Neutron logs provides a sound methodology for mapping “sweet spots“ on a basin-wide scale but remains a qualitative technique and has limitations due to the statistical nature of Gas Shale well EURs. The utility of these qualitative tools most likely relates to the fact that TOC and its associated porosity is the primary driver of Gas Shale reservoir quality. The nanno-scale porosity network of Gas Shale can be mapped in a qualitative manner, but poses serious challenges to quantifying OGIP calculations using current logging tools and methodologies.