IMPROVED METHODS FOR ESTIMATING THE VISCOSITY OF HEAVY OILS FROM MAGNETIC RESONANCE DATA

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ABSTRACT

Borehole magnetic resonance (MR) is routinely used to estimate the viscosity of light oil, even when it is mixed with water in the pore space of reservoir rock. However, light oil methods are inadequate when oil viscosity is above several thousand mPa-s. There have been a number of publications relating magnetic resonance measurements to heavy oil viscosity, but the correlations proposed have not been found to be universally applicable. MR measurements of heavy oil depend not only on the properties of the oil, but also on tool characteristics and the details of data acquisition and processing. Thus MR-viscosity correlations must be customized accordingly. Moreover, when water and oil MR signals overlap, new methods are required to prevent the presence of water from corrupting the MR estimation of oil viscosity. Using laboratory measurements on a large number of Canadian and international heavy oil samples, we have developed new correlations, the coefficients of which depend on tool hardware, acquisition modes, and processing algorithms. These are demonstrated to be useful from 10 mPa-s to 1,000,000 mPa-s or more. We also introduce the partitioned hydrogen index method, which uses a porosity model and a new correlation technique to estimate oil viscosity. This is applicable to formations with significant quantities of water. Using MR and rheological measurements over the range 10°C to 100°C, we find the only effects of temperature are through the routine Curie law correction and the effect of temperature on viscosity itself. Magnetic resonance-viscosity correlations do not require explicit temperature dependence.

INTRODUCTION

Vast quantities of heavy oil exist in many parts of the world. Production economics depends on several factors, one of the most important of which is oil viscosity. Heavy oil reservoirs may contain several grades of oil. For example, a reservoir might be composed of stacked porous beds separated by impermeable layers. Each bed can contain oil with properties different from the oils in adjacent beds. Moreover, viscosity can vary vertically within a single bed.

Borehole logging tools are the most accurate and cost-effective means of determining properties of fluids found in subsurface geological formations. Borehole magnetic resonance (MR) is routinely used to estimate the viscosity of light oil, even when it is mixed with water in the pore space of reservoir rock. However, commonly employed MR methods are inadequate when applied to heavy oil.

The results of MR measurements of heavy oil depend not only on the properties of the oil, but also on tool characteristics and the details of data acquisition and processing. Thus MR-viscosity correlations must be customized for each borehole logging tool and each mode of employment of any given logging tool.

Although the relaxation time distribution is a ubiquitous and useful feature of MR log interpretation, its details can be influenced by processing parameters such as the regularization parameter or the lower and upper bounds of the distribution, \( T_{2\text{min}} \) and \( T_{2\text{max}} \). Use of time domain data avoids these issues. A new correlation uses the initial decay rate of an MR echo train to estimate oil viscosity.
Oil is commingled with water in hydrocarbon bearing rocks, and the measured MR signal is the sum of signals from these fluids. It is necessary to isolate the oil signal to estimate oil viscosity. A porosity model and a new correlation technique, the partitioned hydrogen index method, are required to accurately estimate oil viscosity free from the interfering effects of water.

Temperature affects the overall signal level through the Curie law, and has an important effect on the viscosity of crude oils. However, we have verified that the equations and their coefficients presented here have no temperature dependence, once the Curie correction has been performed, as is standard in all MR borehole logging tools.

The MR techniques described in this paper allow estimation of in situ viscosity over the range from 10 mPa-s to more than 1,000,000 mPa-s (1 mPa-s = 1 centipoise). The laboratory measurements on which this work is based were performed on crude oils with no dissolved gas. Therefore the applicability of these results to live crude oils is untested.

PREVIOUS WORK

LaTorraca et al. [1999] studied the relationship between viscosity and MR properties of twelve San Joaquin Valley heavy oil samples ranging from approximately 1,000 mPa-s to 100,000 mPa-s at a temperature of 28°C. They found that empirical correlations between viscosity and MR properties depend on the echo spacing used in the MR measurements

$$\eta = \frac{2200 + 470 \cdot TE^2}{T_{2LM} - (TE + 0.5)} \frac{T + 273}{298}$$

where $T$ is temperature in °C, $\eta$ is viscosity in mPa-s, $T_{2LM}$ is the logarithmic mean relaxation time in ms, and $TE$ is the echo spacing in ms. A number of limitations were pointed out, including the problem of overlapping water and oil signals and the need to take into account the effects of signal to noise ratio.

LaTorraca et al. also derived a relationship using the MR-apparent hydrogen index, $HI$, which can be written

$$HI = \frac{\phi_{MR} - \phi_w}{\phi_T - \phi_w}$$

where $\phi_{MR}$ is the MR-derived apparent porosity, $\phi_T$ is the neutron/density-derived total porosity of the formation, and $\phi_w = \phi_T \cdot S_w$ is the total water volume. Then a correlation can be devised that is independent of the relaxation time distribution

$$\ln(\eta) = \left(11 + \frac{1.1}{TE}\right) - \left(5.4 + \frac{0.66}{TE}\right) \cdot HI$$

This approach is most sensitive when $HI$ is significantly less than unity, i.e., for viscosities greater than about 5000 mPa-s.

University of Calgary researchers investigated a group of Canadian very heavy oils and bitumens at temperatures ranging from 25°C to 80°C [Bryan et al., 2005]. The viscosities ranged from less than 1 mPa-s to more than 3,000,000 mPa-s. An MR-viscosity correlation was devised that uses both $T_{2LM}$ and relative hydrogen index (RHI; defined below)

$$\eta = \frac{1.15}{T_{2LM} \cdot RHI^{0.55}}$$

where $T_{2LM}$ is measured in seconds. The use of both relaxation time and amplitude information maximizes the sensitivity of the correlation at both low and high viscosities.

Nicot et al. [2007] published a viscosity correlation based on $T_{2LM}$

$$\eta = \frac{K}{T_{2LM}^{0.9} \left(1 + C\right)} \left(1 + \frac{C}{T_{2LM}^{0.9}}\right)$$

The constants in this equation depend on $TE$ when the viscosity is high. Like all viscosity correlations that depend only on relaxation time, its sensitivity to variations in viscosity decreases as viscosity increases.

Sun et al. [2007] used a time-shift algorithm to define a new MR-apparent hydrogen index, $HI_{ts}$. Then viscosity was estimated from

$$\log \eta = a - b \cdot HI_{ts}$$

where $a$ and $b$ are derived from experiment and depend on $TE$. $HI_{ts}$ loses sensitivity below about 1,000 mPa-s, so this correlation is less useful in that range.

Previous papers have been instructive and useful, but none have incorporated all important factors in a comprehensive, unified analysis. These factors include
hydrogen index in a single equation, (2) development of correlations with stable tuning parameters, (3) verification that the correlations are accurate over a wide range of temperatures, (4) realization that the correlations depend on the acquisition and processing modes of logging tools, and (5) development of a systematic method for dealing with overlapping water and oil signals. Our work incorporates all these factors. However, the effect of dissolved gas has not been investigated.

**DATABASES**

Two databases were used in the present investigation. The first is derived from thirty-four oil samples, from six wells in Alberta, which were measured in laboratory MR apparatus with echo spacing of 0.3 ms and sample temperature of 17°C. These were the same data used in earlier MR-viscosity correlation studies, in which the unmodified laboratory data were processed using software supplied with the laboratory instrument [Bryan, et. al., 2007]. For the present investigation, the raw echo decays were preprocessed to simulate the electrical properties, measurement modes, and pulse sequence parameters of several commercial magnetic resonance borehole logging tools. These modified echo data were then processed using the algorithms designed for those specific logging tools. The same rheologically measured viscosities were used in both the earlier and the present work.

To create the second set of data, the viscosity and MR properties of fourteen international heavy oils were measured. Each sample was measured at no less than four temperatures ranging 10°C to 115°C to investigate how viscosity and MR properties depend on temperature. Viscosity measurements ranged from 10 mPa-s to 600,000 mPa-s. Additional viscosities were estimated by theory-based extrapolation. MR measurement modes and pulse sequences were those used by commercial magnetic resonance borehole logging tools. Tool-specific noise was added to the raw data before processing using the algorithms designed for those specific logging tools.

Crude oils are characterized by broad distributions of relaxation times. To obtain a single-parameter measure of the $T_2$ distribution, the logarithmic mean relaxation time, $T_{2,M}$, of the distribution is computed

\[
T_{2,M} = \exp \left\{ \frac{\sum_{i=1}^{n} m_i \ln(T_{2i})}{\sum_{i=1}^{n} m_i} \right\}
\]

where $m_i = m(T_{2i})$ are the amplitudes of the $T_2$ components in the $T_2$ distribution, and $n$ is the number of components. The lower limit of $T_{2,M}$ is controlled by the dead time of the measurement.

The relative hydrogen index (RHI) is the MR signal amplitude of oil per unit mass, $A_o/M_o$, divided by the MR signal amplitude of water per unit mass, $A_w/M_w$ [Bryan et al., 2005], temperature corrected by the Curie law [Fukushima and Roeder, 1981]

\[
RHI = \frac{A_o M_w}{A_w M_o}
\]

where the signal amplitude from an oil sample is found from

\[
A_o = \sum m_i
\]

and the signal amplitude from a water reference is found from an analogous computation.

Whereas the relative hydrogen index is a ratio of signals normalized by sample masses, the hydrogen index (HI) is a ratio of signals normalized by sample volumes. HI is a ratio of the number density of hydrogen atoms in an oil to the number density of hydrogen atoms in water. RHI is easier to measure in the laboratory because it is simpler to measure sample mass than volume, but HI is more applicable to well log measurements, which sense a defined volume of earth formation. RHI is converted to HI using

\[
HI = \frac{\rho_o}{\rho_w} \cdot RHI
\]

where $\rho_o$ is the oil density and $\rho_w$ is the water density.

The intrinsic density of hydrogen atoms in a crude oil depends on its chemical composition, e.g., paraffinic vs. naphthenic, and generally decreases with increasing viscosity. The viscosity dependence of the intrinsic hydrogen index was chemically determined for a small set of crude oils by LaTorraca et al. [1999]. Moreover, as viscosity increases, an increasing fraction of hydrogen MR signal is lost in the measurement dead time. For these two reasons, MR-measured hydrogen index decreases with increasing viscosity.
TOOL-DEPENDENT CORRELATIONS

The sensitivity of MR measurements to the details of data acquisition and processing suggest that no single MR-viscosity correlation is optimal for all well logs. To investigate this, the first database was reprocessed to simulate measurements of the five different MR tools and acquisition modes: CMR-Plus, MR Scanner shells 1, 4, and 8, and proVISION (Marks of Schlumberger). These simulated data sets were then fit to [Bryan et al., 2005]

\[ \eta = \frac{\alpha}{T_{2LM}^\beta} \]  \hspace{1cm} (11)

The constants \( \alpha \) and \( \beta \) in equation (11) are retuned for each borehole logging tool and operating mode. Figure 1 shows, for a single crude oil, measured viscosity, estimated viscosity with coefficients held constant, and estimated viscosity with coefficients tuned for the individual magnetic resonance tools and measurement modes. The rheologically measured oil viscosity was 289,000 mPa-s. Clearly, accurate viscosity estimates are only possible when tool-specific correlations are used. Higher oil viscosity increases the sensitivity to tool-specific effects. For lighter oils (e.g. below 1000 mPa-s), which were the primary focus of earlier work [Kleinberg and Vinegar, 1996], tool-independent correlations can be satisfactory.

NEW HI-T2 VISCOSITY CORRELATION

We propose the HI-T2 viscosity correlation

\[ \ln(T_{2LM} \cdot \eta) = \alpha - \beta \cdot HI. \]  \hspace{1cm} (12)

This formulation has several advantages over previously published equations. Most importantly, it utilizes both relaxation time and amplitude information.

At low viscosity, logarithmic mean \( T_2 \) depends strongly on viscosity, whereas the hydrogen index is insensitive to changes. At high viscosity the reverse is true.

It has long been known that viscosity is inversely proportional to relaxation time in the limit of low viscosity, and this behavior is captured in equation (12). Furthermore, we follow Sun et al. [2007] in adopting an exponential dependence of viscosity on MR-apparent hydrogen index, which works well for high viscosity oils. Note, however, that we use the hydrogen index derived from measurements made by specific MR logging tools and their processing and interpretation suites. The Sun et al. [2007] definition of hydrogen index is not incorporated into these suites at the present time.

Another advantage of equation (12) is that its tuning parameters are more stable than those of other correlations. To understand this, we write equation (12) as

\[ \eta = \frac{\exp(\alpha)}{T_{2LM} \exp(\beta \cdot HI)} \]  \hspace{1cm} (13)

Comparing equation (11), for example, to equation (13), one sees that as \( HI \to 0 \), \( HI \beta \) increases much faster than \( \exp(-\beta \cdot HI) \). Because of the power law dependence on \( \beta \) in equation (11), a small change of \( \beta \) can result in a large change in the MR viscosity estimate. Our new HI-T2 viscosity correlation does not exhibit as much sensitivity to tuning parameters.

The laboratory data is refit for each tool and mode individually using equation (12). The accuracy of a few of the many correlations are shown in Figure 2. Generally, the correlations work well over the entire range of viscosity. However, a few combinations of tools and oils do not work well, e.g., proVISION in bitumen with viscosity greater than 1,000,000 mPa-s.

TIME DOMAIN METHOD

Because heavy oil relaxation rates are typically near the sensitivity limit of downhole tools, the \( T_2 \) distribution obtained by regularization can be sensitive to the regularization parameter and to \( T_{2min} \). By performing \( T_2 \) analysis in the time domain, one eliminates these uncertainties. A single exponential is fit to the first 4 ms of the CPMG echo decay

\[ \text{Amplitude} = A_0 \exp\left(-\frac{n \cdot TE}{T_{2I}}\right) \]  \hspace{1cm} (14)

where \( A_0 \) is the oil signal extrapolated to zero time, \( n \) is the echo number, and \( T_{2I} \) is the initial decay time. Using \( A_0 \), HI can be found using equations (8) and (10). Finding \( A_0 \) and \( T_{2I} \) requires some care in the presence of water, particularly if the water signal decays rapidly.

The MR-viscosity correlation for time domain data is the same as the correlation using MR parameters found from \( T_2 \) distributions

\[ \ln(\eta \cdot T_{2I}) = a - b \cdot HI. \]  \hspace{1cm} (15)
The tuning parameters are different and are renamed to avoid confusion. This method was tested on the databases, and its accuracy was found to be comparable to the method embodied in equation (12).

OVERLAPPING OIL AND WATER SIGNALS: PARTITIONED HYDROGEN INDEX VISCOSITY CORRELATION

In heavy oil reservoir well logs, the MR signal usually has both oil and water components. These components sometimes overlap in the CPMG decay and the T₂ distribution, and it is important to separate them before employing a viscosity correlation. We use the porosity model in Figure 3.

The water saturation can be estimated from the Archie equation. Water saturation can also be estimated from dielectric logging, which is relatively insensitive to water resistivity. Total water volume is composed of movable (free) water and bound (irreducible) water

\[ \phi_s = \phi_{sw} + \phi_{swirr} \]  

(16)

In cases where invasion of mud filtrate is deeper than the depth of investigation of the magnetic resonance tool, \( S_w \) is the invaded zone saturation.

The bound water volume \( \phi_{swirr} \) is found from any of a number of borehole measurements. The gamma ray (GR) log can be employed, using a calibration in which bound water volume equals total water volume at irreducible water saturation in shales. Other measurements are useful if it is known that the formation is at irreducible water saturation. These include the dielectric, shallow resistivity, or capture sigma logs. The free, or movable, water volume is total water in excess of bound water

\[ \phi_{swf} = \phi_s - \phi_{swirr} \]  

(17)

The total oil volume is found from the total water volume

\[ \phi_o = \phi_s - \phi_w \]  

(18)

The invisible heavy oil is the difference between true porosity and MR porosity

\[ \phi_{soi} = \phi - \phi_{MR} \]  

(19)

This assumes there is no MR-invisible water. In clean formations (those with little or no clay or shale content), most MR tools detect all formation water. However, not all MR borehole logging tools are capable of measuring the total water signal in shales and shaly sands. Tools having that capability include the Schlumberger combinable magnetic resonance tool (CMR) [Freedman et al., 1997].

MR porosity is divided into MR free fluid (FF) and MR bound fluid volume (BFV)

\[ \phi_{MR} = BFV + FF \]  

(20)

by using a cutoff value, e.g., 33 ms in sands and sandstones. The visible heavy oil volume is the excess of MR bound fluid over the irreducible water volume

\[ \phi_{sovh} = BFV - \phi_{swirr} \]  

(21)

The visible light oil volume is the excess of MR free fluid over free water

\[ \phi_{sovl} = FF - \phi_{swf} \]  

(22)

The total MR-apparent hydrogen index of oil is

\[ H_I = \frac{\phi_{MR} - \phi_w}{\phi - \phi_w} = \frac{S_{sovh} + S_{sovl}}{S_o} \]  

(23)

We introduce hydrogen index values for the light and heavy oil fractions, which are defined by

\[ H_{l\text{ovl}} = \frac{S_{sovl}}{S_o} \]  

(24a)

\[ H_{o\text{voh}} = \frac{S_{sovh}}{S_o} \]  

(24b)

Figure 4a shows that HI is sensitive to viscosity changes at high viscosity, but is relatively insensitive to viscosity changes at low viscosity. Figure 4b shows that the reverse is true for HI\(_{ovl}\). This contrast can be exploited to estimate viscosity with maximum precision over the entire range of viscosity.

A correlation independent of T\(_{2\text{LM}}\) or T\(_{2I}\) but retaining information about the T\(_2\) distribution of the oil is

\[ \ln(\eta) = A - B \cdot H_I_{\text{diff}} \]  

(25)

where
\[ \text{HI}_{\text{diff}} = \text{HI}_{\text{ovh}} - \text{HI}_{\text{ovl}} \]  

(26)

For low viscosity oils, the preponderance of signal is in the visible light oil fraction, and \( \text{HI}_{\text{diff}} \) is negative. As viscosity increases, \( \text{HI}_{\text{ovl}} \) decreases and \( \text{HI}_{\text{ovh}} \) increases, so \( \text{HI}_{\text{diff}} \) increases and eventually becomes positive. At still higher viscosity, \( \text{HI}_{\text{ovl}} \) goes to zero, and the visible heavy oil fraction diminishes as the invisible heavy oil fraction becomes larger; this causes \( \text{HI}_{\text{diff}} \) to decrease again. Thus \( \text{HI}_{\text{diff}} \) is nonmonotonic with increasing viscosity, as shown in Figure 5.

To distinguish between the two branches we define a parameter \( \zeta \) which depends on logging tool, acquisition mode, and processing algorithm. In Figure 5, the solid blue circles represent those points at which \( \text{HI}_{\text{ovl}} \) is less than \( \zeta \), and the black squares represent those points at which \( \text{HI}_{\text{ovl}} \) is greater than \( \zeta \).

The constants \( A \) and \( B \) of equation (25) depend on whether \( \text{HI}_{\text{ovl}} \) is less than or greater than \( \zeta \):

\[ \ln(\eta) = \begin{cases} 
A_1 - B_1 \cdot \text{HI}_{\text{diff}} & \text{if } \text{HI}_{\text{ovl}} \leq \zeta \\
A_2 - B_2 \cdot \text{HI}_{\text{diff}} & \text{if } \text{HI}_{\text{ovl}} > \zeta 
\end{cases} \]  

(27)

The effectiveness of equations (27) is shown in Figure 6. As was true of the equation (12) correlation, some tools have difficulty with bitumens with viscosity in the range of millions of mPa-s.

**TEMPERATURE EFFECT**

All MR measurements have a temperature dependence based on the Curie law [Fukushima and Roeder, 1981]. The appropriate correction is automatically applied to data from borehole logging tools, and has been applied to all data discussed in this report. One might surmise that a further temperature correction to viscosity correlation equations might be necessary. However, heavy oil MR data collected from 10°C to 100°C do not exhibit temperature dependence independent of changes in viscosity. Figure 7 shows these data correlated with viscosity using equation (12).

**CONCLUSION**

New MR-viscosity correlations are introduced. They have the following characteristics, which, when taken together, differentiate them from previous correlations: (1) They use both relaxation time information and MR-apparent hydrogen index measurements, which combine to obtain correlations valid for viscosities spanning more than four orders of magnitude. (2) Their tuning parameters are stable. (3) They are accurate over a wide range of temperatures. (4) They are customized for various well logging tools, acquisition parameters, and processing modes. (5) They include a systematic method for dealing with overlapping water and oil signals.

The fit parameters of the new correlations are found to depend on logging tool, measurement mode, and processing details. Indiscriminate application of a single correlation to MR logs can lead to very large errors in viscosity estimation, which grow as viscosity increases beyond 1000 mPa-s.

Use of the \( T_2 \) distribution may not always be the best way to obtain a measure of relaxation time, as the \( T_2 \) distribution is sensitive to changes in regularization and computational limits. An alternative method uses time domain data to find a value for the initial relaxation time \( T_{2I} \). A new MR-viscosity correlation is presented that estimates the viscosity using \( T_{2I} \) and \( \text{HI} \). This method is applicable when there is no rapidly-decaying water signal.

In field logs, oil and water signals often overlap in both echo decay and \( T_2 \) distribution. Petrophysical evaluation is used to determine oil and water saturations above and below a \( T_2 \) cutoff. The partitioned hydrogen index method is then used to estimate viscosity, thereby incorporating information from the \( T_2 \) distribution without the need to compute \( T_{2LM} \).

Temperature only affects the MR-viscosity correlations presented here through the routine Curie correction, and the effect of temperature on viscosity itself. No explicit temperature correction is required. However, the effect of dissolved gas has not been assessed.

The accuracy of the correlations introduced here has been verified from 10 mPa-s to at least 1,000,000 mPa-s. The upper limit of validity depends on tool type, acquisition mode, and processing algorithm.

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**NOMENCLATURE**

A1 – Fit parameter for partitioned HI correlation  
A2 – Fit parameter for partitioned HI correlation  
Ao – Oil sample MR signal  
Aw/Mw – Water MR signal per unit mass  
B1 – Fit parameter for partitioned HI correlation  
B2 – Fit parameter for partitioned HI correlation  
BFV – Bound fluid volume  
FF – Free fluid volume  
HI – Hydrogen index  
HIdiff – Hydrogen index difference  
HIovh – Hydrogen index of visible heavy oil  
HIovl – Hydrogen index of visible light oil  
Mo – Oil sample mass  
RHI – Relative hydrogen index  
So – Total oil saturation  
Soi – Saturation of MR-invisible heavy oil  
Sovh – Saturation of MR-visible heavy oil  
Sovl – Saturation of MR-visible light oil  
Sw – Total water saturation  
Swf – Free water saturation  
Swirr – Irreducible water saturation  
T2I – Initial decay time [s]  
T2LM – Logarithmic mean T2 relaxation time [s]  
T2min – Lower bound of T2 relaxation time distribution  
T2max – Upper bound of T2 relaxation time distribution  
TE – Echo spacing [ms]  
a – Fit parameter used in the time domain correlation  
b – Fit parameter used in the time domain correlation  
m0 – Amplitude of a component of the T2 distribution  
n – Echo number  
α – Fit parameter for the HI-T2 viscosity correlation  
β – Fit parameter for the HI-T2 viscosity correlation  
η – Viscosity [mPa-s]  
ρo – Oil density  
ρw – Water density  
φ – Porosity

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Figure 1. Rheologically measured viscosity of a crude oil (horizontal dashed line) compared to an MR-viscosity correlation [equation (11)] with fixed coefficients (blue bars) and with coefficients tuned for specific tool measurement modes and processing algorithms (red bars).
Figure 2: Accuracy of HI-T$_2$ viscosity correlation (equation 12) for five different tools and measurement modes. For some modes, viscosities greater than millions of mPa-s are underestimated. (1 cP = 1 mPa-s)
Figure 3: Porosity model defining invisible heavy oil, visible heavy oil, and visible light oil fractions of a crude oil mixed with water in an earth formation.

Figure 4 (a) Total hydrogen index (HI) vs. viscosity. Sensitivity of total HI decreases with decreasing oil viscosity. (b) Visible light oil hydrogen index (HI_{ovl}) vs. viscosity. HI_{ovl} sensitivity increases with decreasing oil viscosity. (1 cP = 1 mPa-s)
Figure 5. The partitioned hydrogen index viscosity correlation (equations 27) fit to heavy oil data. The coefficients $A_1$ and $B_1$ are found by fitting a straight line to data for which $HI_{ovl} \leq \zeta$ (solid blue circles), and $A_2$ and $B_2$ are found by fitting a straight line to data for which $HI_{ovl} > \zeta$ (black squares).
Figure 6. Accuracy of partitioned hydrogen index viscosity correlation (equations 27) for five different tools and measurement modes.  Viscosities of millions of mPa-s are underestimated for some tools and measurement modes.  (1 cP = 1 mPa-s)
Figure 7. Data collected over the range 10°C to 100°C, fit using equation (12) with CMR-Plus parameters. No explicit temperature correction is needed. (1 cP = 1 mPa-s)