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## A new Approach to determine T2 cutoff value with integration of NMR, MDT pressure data in TS-V sand of Charali field.

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### Summary

*Charali is a satellite field in north Assam shelf of Assam & Assam Arakan basin of India and is producing significant amount of oil & gas. 46 wells are drilled till date out of which about 14 wells are producing oil and gas from Barail and Tipam sands. Significant part of hydrocarbon is being produced from Tipam formation in the southern part of the Charali Main Block.*

*The lithology of TS- V sand in Charali field is sandstone in nature. Resistivity in TS - V sand in the oil bearing zones is low with low resistivity contrast. NMR logging is widely used in formation evaluation for determining Petrophysical properties of rocks. Standard T2 cutoff value used for clastic reservoir is 33ms to estimate bound fluid (BFV) & free fluid volume (FFV), but it varies in different formation and in different field due to surface relaxivity of rock surface. Surface relaxivity depends on mineralogy of the formation like presence of amount of paramagnetic/ferromagnetic minerals & adsorbed water in the formation. Petrophysical properties of formation rock like irreducible water saturation & permeability are dependent on bulk volume irreducible (BVI) & free fluid volume (FFV). It is observed that the Neutron & density porosity in wells of Charali Field is good about 20-24% in TS-V sand. Permeability measured on cores of TS-V sand in Charali wells is also very good. In spite of good porosity & permeability the free fluid volume estimated with CMR log after applying 33ms cutoff is quite low about 5-6%, indicating that T2 cutoff value of 33ms is not appropriate for computing bound and free fluid porosity in TS-V sand of this field. Bound fluid volume (BFV) & free fluid volume (FFV) are computed by applying T2 cutoff on T2 distribution curve. In our case it was observed that permeability determined with MDT pressure test in TS-V sand is not matching with NMR derived permeability from Timur Coat's model which uses bound & free fluid porosity of the formation. It was felt that the appropriate determination of T2 cutoff value is very important for appropriate estimation of bound fluid & free fluid porosity of the formation for realistic estimation of Petrophysical properties like permeability & irreducible water saturation. Generally T2 cut off value is determined on core plugs but in absence of such facility with us, an attempt has been made to determine T2 cut off value by integrating MDT pressure data with CMR log and a new methodology is presented in the paper.*

**Keywords:** *Log Interpretation, Assam Arakan Basin*

### Introduction

Charali is a satellite field in north Assam shelf of Assam & Assam Arakan basin of India and is producing significant amount of oil & gas. The Charali Field is a fault-bounded anticlinal structure located about 3.2 kilometers south-east of the giant Rudrasagar Field (Fig:1). E & P activities started in mid-seventies. 46 wells are drilled till date out of which about 14 wells are producing oil and gas from Barail and Tipam sands. Significant part of hydrocarbon is being produced from Tipam formation in the southern part of the Charali Main Block. therefore geometry of FS 2011-12 is being used to evaluate strati-structural prospect in Renji, Bhuban and shallower plays.

TS-V sand of Tipam formations of Miocene age in Assam is an example of low resistivity and low contrast. The lithology of TS- V sand in Charali field is sandstone in nature. Resistivity in TS-V sand in the oil bearing zones is low with low resistivity contrast. NMR logging is widely used in formation evaluation for determining Petrophysical properties of rocks. Standard T2 cutoff value used for clastic reservoir is 33ms to partition bound fluid (BFV) & free fluid volume (FFV), but it varies in different formation and in different field due to surface relaxivity of rock surface. Surface relaxivity depends on mineralogy of the formation like presence of amount of paramagnetic/ferromagnetic minerals & adsorbed water on grain surfaces in the formation. Petrophysical properties of formation rock like irreducible water saturation &

permeability are dependent on bulk volume irreducible (BVI) & free fluid volume (FFV). It was observed that the Neutron & density porosity in wells of Charali Field is good about 24% in TS-V sand (Fig:2). Permeability measured on cores of this sand in other wells is also very good. In spite of good porosity & permeability the free fluid volume estimated with CMR log after applying 33ms cutoff is quite low about 5-6%, indicating that T2 cutoff value of 33ms is not appropriate for computing bound and free fluid porosity in TS-V sand of this field. It was felt that the appropriate determination of T2 cutoff value is very important for appropriate estimation of bound fluid & free fluid porosity of the formation for realistic estimation of Petrophysical properties like permeability & irreducible water saturation. Generally T2 cut off value is determined on core plugs but in absence of such facility to measure NMR T2 cutoff value on core samples, an attempt has been made to determine T2 cut off value by integrating MDT pressure data with CMR log

$$\frac{1}{T_2} = \frac{1}{T_{2-Bulk}} + \rho \frac{S}{V} + (\gamma G T_E)^2 \frac{D_o}{12}$$

If surface to volume ratio of pore volume increases the relaxation time tends to decrease. TS- V sands of Tipam formation in Charali field reported from core study are fine to medium grained (Fig:3) thereby increasing the surface to volume ratio of pore space that may be one of the cause for reduction in T2 cutoff value. Porosity & permeability determined on cores of TS-V sand in wells of Charali field is good. Permeability measured on cores is of the order of 300-400md and at places it is reaching to 900-1000md shows low capillary bound water. It indicates that it has less effect on reduction of T2 relaxation time.

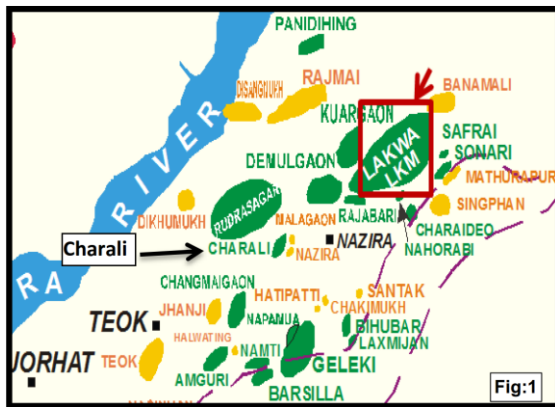


Fig:1

### Causes for variation in T2 cutoff value

T2 cutoff value for sandstone reservoir is normally taken as 33ms for computation of bound and free fluid volume but it varies significantly in different formation & different field. T2 cutoff value of 33ms is applicable only for water wet sandstone having only macro porosity and if there is no internal gradient present due to the presence of paramagnetic minerals in the formation. The possible causes for reduction of T2 cutoff value are:

- Relaxation time T2 of protons depends on the surface to volume ratio of the pore space, diffusion due to magnetic field gradient as given in the equation below.

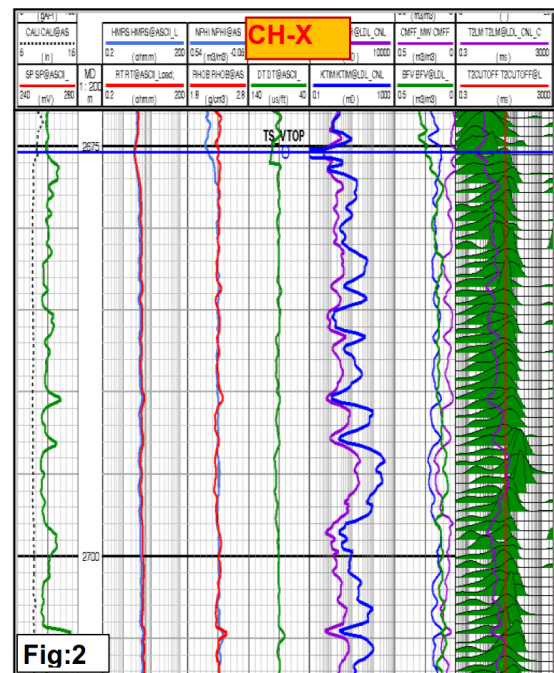


Fig:2

- Tipam sandstone in Charali field is shaly in nature having macro & micro porosity. Presence of authigenic clay minerals, pore filled Kaolinite & grain coating smectite are reported in core studies (Fig:3). These clay minerals, as they are dispersed in nature due to diagenesis resulted in pore filling & coating of grain surfaces and leads to generation of micro porosity in the formation. Rock fragments are also reported in good proportion in Tipam sands also adding some micro porosity in the

formation. If micro and macro pores have connectivity in the pore system, protons of the macro pores have access to the micro pores and relax faster due to surface relaxation processes. This may be one of the causes for reduction of T2 relaxation and thereby T2 cutoff value in TS-V sand of the Charali field to be reduced.

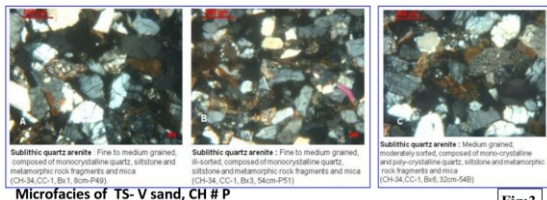
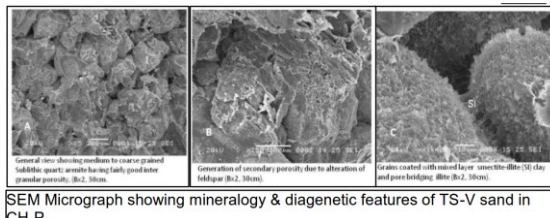


Fig:3



SEM Micrograph showing mineralogy & diagenetic features of TS-V sand in CH-P

- If there are paramagnetic minerals present in the formation then it creates magnetic field gradients. Protons diffuse in the variable field gradient & precess with different Larmor frequency and experiences fast relaxation. Study for magnetic minerals on cores of Charali field carried out at KDMIPE, reveals that the magnetic percentage varies from 10.54% in well CH-Z to 19% in well CH-V. Core study on magnetic mineral is provided in Table-1. So the presences of paramagnetic minerals are also responsible to have low T2 cutoff value.

Table 1

Sr No	Well No	Total weight	Total-Magnetic	% Magnetic	Magnetic % corrected
1	Charali-W	190.0	41.3	21.74	16.30
2	Charali-W	186.9	39.4	21.08	15.81
3	Charali-V	202.5	53.3	26.32	19.74
4	Charali-V	185.4	36.9	19.90	14.93
5	Charali-Z	173.7	24.4	14.05	10.54
7	Charali-Y	151.0	28.9	19.14	14.35
8	Charali-P	180.7	32.9	18.21	13.66

### Methodology adopted

The lithology of TS-V sand in this field is sandstone in nature. In NMR logging T2 cutoff value is very important to partition the free fluid and bound fluid volume present in the formation.

Our aim wa to determine realistic T2 cutoff value. Available cors of TS-V formation of Tipam sandstone from three wells of Charali field were collected for NMR study to determine T2 cut off value but it could not be carried out on core samples. An approach was used to determine T2 cutoff value from the available log data by integrating CMR & MDT pressure test.

### Determine of T2 cut off from available log data

#### Methodology adopted

1) Well CH-H was chosen as the key well for determining T2cutoff value because it has CMR log & MDT pressure point apart from conventional logs.

[a] MDT pressure points at various depths were taken in water bearing TS-5 sand of well CH-H. These pressure points are used to compute the oil & water gradient from Depth (TVD) V/s Formation Pressure Plot (Fig-4). TVD was computed after applying the deviation and azimuth in the hole.

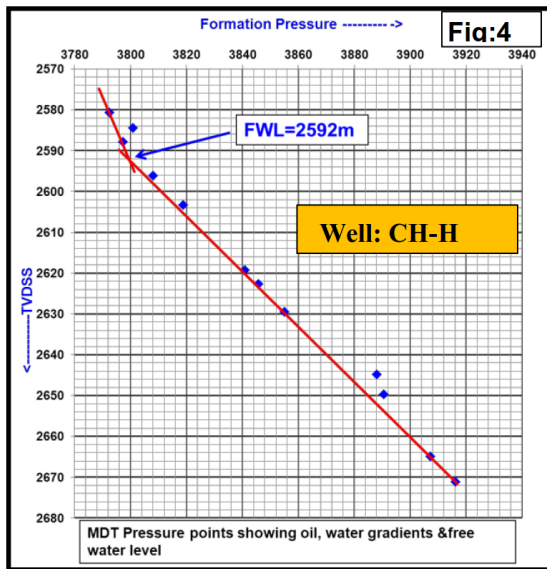
[b] Computed the density of formation water at reservoir condition from the water gradient.

[c] Calculated mobility from the pretest of the MDT tool.

[d] Converted mobility to permeability after multiplying viscosity to mobility which was estimated from the pretest.

2) CMR log data was processed with three new T2 cut off values (10ms, 15ms & 20ms & 33ms) to estimate bound fluid & free fluid volume. In this process we had four set of bound fluid volume (BFV) & free fluid volume (FFV) of four different cutoff values.

3) Flow zone indicator (FZI) was computed for each set using MDT permeability & porosity obtained from processed output of CMR log with different T2 cutoff value. For computation of FZI first RQI was computed with  $0.0314\sqrt{(K/\Phi_z)}$  equation. Where K is the permeability taken from MDT pressure points  $\Phi$  is the porosity from CMR with new T2 cutoff values. Then  $\Phi_z$  value was computed by  $(\Phi/(1-\Phi))$  equation. Where  $\Phi$  is the porosity computed from CMR by applying new T2 cutoff values.  $FZI_{MDT}$  was computed with  $RQI/\Phi_z$  equation.



4) Flow zone indicator (FZI) was also computed for each set of NMR processed data with new estimated BFV, FFV & porosity with equation given below.

$$FZI_{NMR} = [(b(1-NMR_{SWR})) / (1+a(NMR_{SWR}-1))]^c$$

(Reference-3&4)

a, b & c are constants which are normally determined on cores, but in absence of core study, values of a, b & c are taken as 1 (default) for all set of T2 cutoff for computation of FZI.

The above relationship was given by Amaeful et al. They derived nonlinear relationship between FZI & irreducible water saturation ( $S_{wir}$ ) based on core studies as  $S_{wir} = 1 - 1/(a + bFZI^c)$  (Reference-1).

If appropriate T2 cut off is used in NMR measurement then  $S_{wir}$  equivalent to irreducible water saturation can be estimated by NMR ( $NMR_{SWR}$ ).

6) Xplots between  $FZI_{MDT}$  &  $FZI_{NMR}$  (Fig-5 to 7) were generated and found that  $FZI_{MDT}$  &  $FZI_{NMR}$  with 15ms cutoff is best matched which was considered realistic T2 cutoff value.

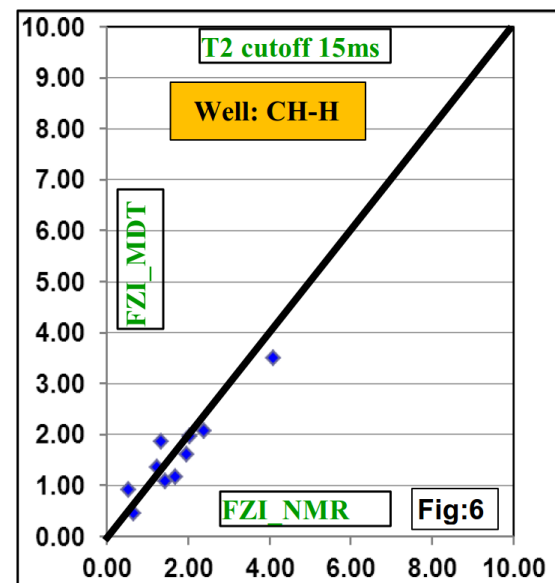
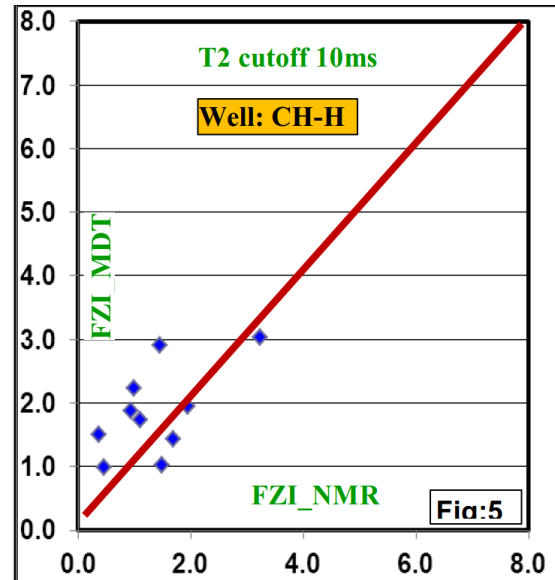
7) Calculated CMR permeability with the help of flow zone indicator ( $FZI_{NMR}$ ) estimated with each cut off value by the equation given below.

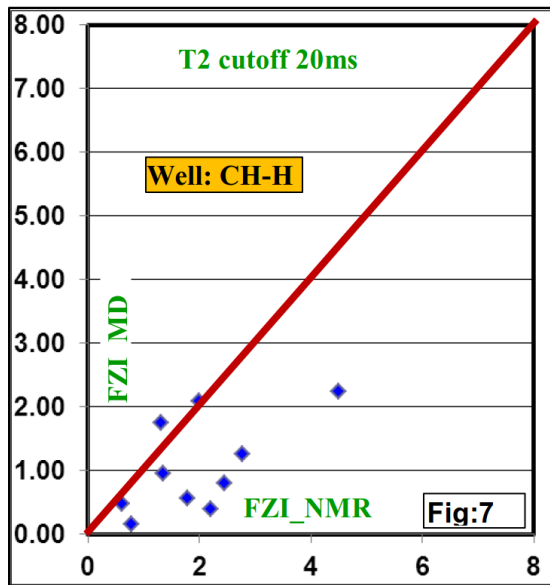
$$K_{NMR} = 1014 * FZI_{NMR}^2 * ((\Phi_{NMR}^3) / (1 - \Phi_{NMR})^2)$$

(Reference-3&4)

8) Matched the permeability computed from the  $FZI_{NMR}$  method (CMR) and MDT permeability & found

permeability estimated with 15ms cutoff has best match (Fig:8).

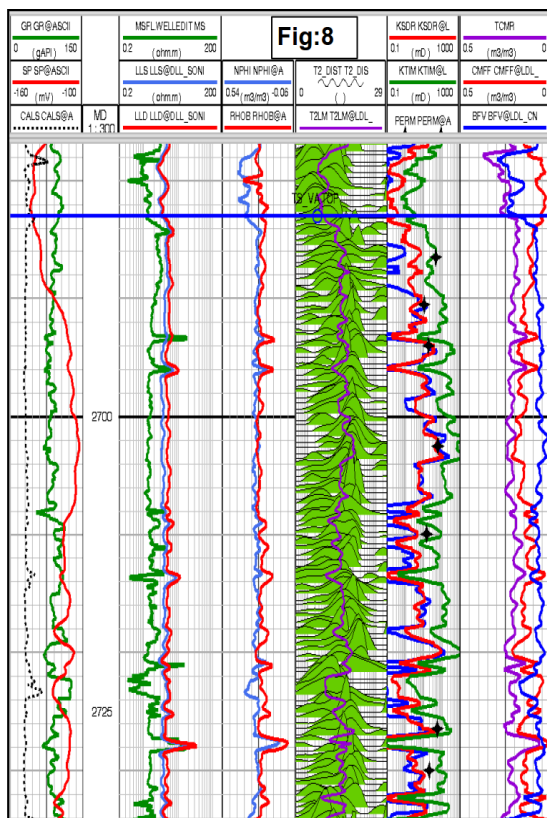


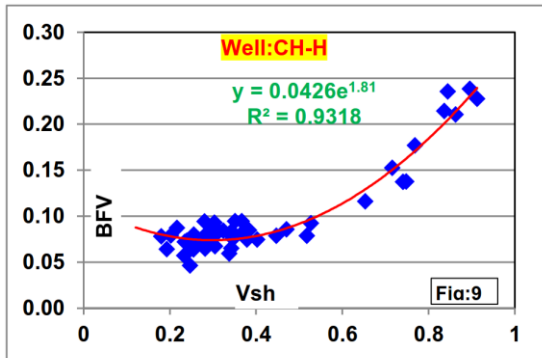


### Propagation of adopted Methodology and Validation in wells where CMR data is not available

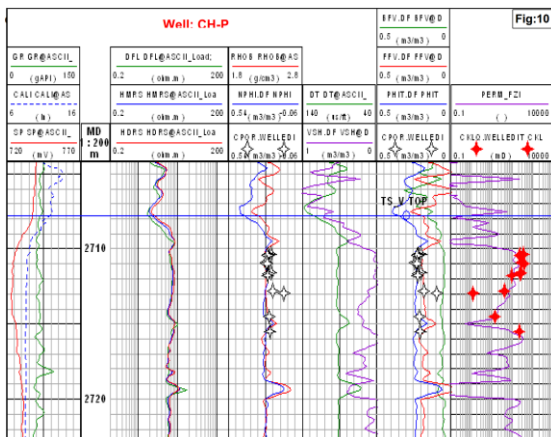
Methodology was propagated to compute permeability from flow zone indicator (FZI) method in other wells where NMR log is not available. Permeability computed from FZI method was also used for validation of methodology in wells where permeability was measured on cores.

- Shale volume was computed (Black & red curve in last track of Fig-7 & 8) from Neutron Density log using equation  $(PHIN - PHID) / (PHINsh - PHIDsh)$  in wells (CH-H & K) where CMR log data was available and matched with shale volume computed from ELAN processed result.
- Cross plot between shale volume & bound fluid volume (computed from 15ms T2 cutoff) was prepared in well CH-H where CMR data is available and a transform was generated to relate BFV with shale volume (Fig-9).
- Established a relation between Shale volume & BFV and an equation is firmed up for computing BFV from shale volume in other wells.
- Shale volume was computed through Neutron-Density log in other wells where CMR data is not available.
- Using regression which was generated in wells CH-H & CH-B, bound fluid volume was computed from shale volume in wells where CMR was not available.
- Total porosity was computed from PHIN-PHID curve and free fluid volume (FFV) was computed by subtracting bound fluid volume (BFV) from total porosity.
- Computed permeability using flow zone indicator (FZI) method.
- Total porosity estimated from PHIN-PHID curve and measured on cores (Fig:10) in well CH-P is matching very well. Permeability estimated with Flow Zone Indicator (FZI) and measured on cores (Fig:10) in same well is also has good match, validating the adopted technique





Cross plot between shale volume & bound fluid volume computed with CMR data after applying 15ms cutoff value in well Charali-H



## Conclusions

1. Standard T2 cutoff of 33ms for TS-V sand of Charali field is not appropriate for computing free fluid & bound fluid volume from CMR log.
2. T2 cutoff value can be determined from logs with integration of CMR and MDT pressure points.
3. T2 cutoff value of 15ms determined with integration of CMR and MDT pressure points appears to be realistic for free fluid & bound fluid volume computation for TS-V sand of Charali field.
4. Regression determined from shale volume and bound fluid volume computed from CMR with appropriate cutoff may be used in other wells to compute bound fluid volume where CMR is not available.
5. Log based permeability can be estimated with Flow Zone Indicator (FZI) method using bound fluid, free fluid & total porosity of the formation.

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