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## LIST OF ABBREVIATIONS AND SYMBOLS

m	Meter
m/s*g/cc	Meter per second * gram per cc (P-Impedance Unit)
Hz	Hertz
$\phi$	Porosity
$\phi_{eff}$	Effective Porosity
m/s	Meter per Second
ms	Millisecond
mD	millidarcy
km	Kilometer
s Se	Second
bbl	Barrel (unit)
bopd	Barrels of oil per day
bwpd	Barrels of water per day
Vp	Compressional Velocity
Vs	Shear Velocity
AI	Acoustic Impedance
AVA	Amplitude variations with Angle
BS	Bit Size
CALI	Caliper Log
CMP	Common Midpoint
GB	Gigabytes DIS TESETVE O
GR	Gamma Ray Log
DENS	Density Log
DSMF	Dip-Steered Median Filter
DTC	Compressional Sonic Log
DTS	Shear Sonic Log
FFT	Fast Fourier Transform

NEUT	Neutron Porosity Log
NMO	Normal Move-out
PEF	Photoelectric Log
RESS	Resistivity at shallow
RESM	Resistivity at medium
RESD	Resistivity at deep
SP	Spontaneous Potential Log
TEMP	Temperature Log
TENS	Cable Tension
PDF	Probability Density Function
RMS	Root Mean Square
API	American Petroleum Institute (Gamma Ray Unit)
RC	Reflection Coefficient
VSP	Vertical Seismic Profiling
QC	Quality Control
НС	Hydrocarbon
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