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COURSE BROCHURE

# Advanced Carbonate Reservoir Formation Evaluation Training Course

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Rome

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Registered in the United Kingdom and Saudi Arabia

# Advanced Carbonate Reservoir Formation Evaluation Training Course

**Ref:** 1219_45841 **Date:** 22 February – 5 March 2027 **Location:** Rome **Fees:** 10500 GBP

Carbonate Reservoir Formation Evaluation is a 2-week advanced training course for petrophysicists, geologists and reservoir engineers that ends with a Carbonate Rock-Type Interpretation Report for a field well set. Carbonates hold a large share of the world's oil and gas, yet their mixed pore systems make standard log models unreliable, so volumetrics and completion choices depend on getting the petrophysics right. Jupiter Prime Training treats carbonate reservoir formation evaluation as integrated geology, petrophysics and reservoir work.

## Why Carbonate Reservoir Formation Evaluation Matters Now

Three forces shape carbonate interpretation today: maturing fields where bypassed pay hides in tight or vuggy intervals, wider use of nuclear magnetic resonance and image logs, and reservoir teams who need saturation-height functions they can trust in dynamic models. An operator that ties core, logs and pressure data to geological rock types can place infill wells and water injectors with confidence. One that applies a single cementation exponent across a heterogeneous section can misstate oil in place and misjudge water breakthrough. The course rests on Archie-based saturation methods, capillary pressure theory and the Petroleum Resources Management System PRMS for volumes reporting.

## Who Gains Most from Carbonate Reservoir Formation Evaluation

- Specialists who interpret open-hole logs and select saturation equations
- Geologists who describe facies, diagenesis and pore types from core and thin sections
- Laboratory liaisons who plan special core analysis and capillary pressure tests
- Reservoir engineers who build saturation-height and permeability inputs for simulation
- Data leads responsible for petrophysical databases and interpretation standards

Subsurface asset groups that send geologists, petrophysicists and reservoir engineers together gain most, because each rock type then carries the same meaning across disciplines.

## Carbonate Reservoir Formation Evaluation Capabilities

Participants move from raw curves and plugs to rock-typed porosity, saturation and permeability that a reservoir model can use.

- Classify carbonate pore systems from thin sections, core and image logs — rock-type definition
- Calculate porosity in mixed lithology with dolomite, anhydrite and clay corrections — net pay cut-offs
- Apply variable cementation and saturation exponents by pore type — hydrocarbon volume estimates
- Build NMR-based pore-size and permeability models — completion interval selection
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Design saturation-height functions from capillary pressure data — simulation initialisation
- Test log interpretations against formation pressure and test results — fluid contact and compartment decisions

## Key Carbonate Reservoir Formation Evaluation Terms

- Cementation exponent m — The Archie parameter linking porosity to formation factor, which rises with vuggy porosity and falls with fractures.
- Vuggy porosity — Pore space in cavities larger than grains, often poorly connected, that adds storage without matching flow capacity.
- Rock typing — Grouping rock into units with similar pore geometry, capillary behaviour and permeability for consistent reservoir properties.
- NMR T2 distribution — The relaxation time spectrum from nuclear magnetic resonance logs that reflects pore-size distribution and bound fluid.
- Saturation-height function — An equation giving water saturation as a function of height above free water level for each rock type.
- Dual-porosity system — A reservoir where fractures carry flow and the matrix provides most storage, each with its own properties.

## Carbonate Reservoir Formation Evaluation Day by Day

## Day 1: Carbonate Depositional and Diagenetic Context

- Platform, Ramp and Reef Depositional Models — Facies Distribution Expectations
- Dolomitisation, Dissolution and Cementation — Porosity Creation and Destruction
- Choquette-Pray and Lucia Pore Classifications — Pore Type Labelling
- Sequence Stratigraphy in Carbonates — Flow Unit Correlation
- Data Inventory Across Logs, Core and Tests — Interpretation Scope Setting

## Day 2: Core Description and Laboratory Data

- Core Description and Thin Section Petrography — Facies and Pore Logging
- Routine Core Analysis Quality Control — Plug Selection Bias
- Overburden Corrections to Porosity and Permeability — Reservoir Condition Values
- Core-to-Log Depth Matching — Calibration Integrity
- Special Core Analysis Programme Design — Laboratory Spend Priorities

## Day 3: Porosity and Lithology from Logs

- Density, Neutron and Sonic Responses in Carbonates — Tool Selection
- Mixed Mineral Solutions with Dolomite and Anhydrite — Matrix Parameter Choice
- Secondary Porosity Index from Sonic — Vug and Fracture Indication
- Shale and Clay Effects in Argillaceous Carbonates — Effective Porosity
- Borehole Environment Corrections — Log Quality Flags

## Day 4: Resistivity and Saturation Models

- Archie Equation Assumptions in Carbonates — Where They Break Down
- Variable m From Pore Type Partitioning — Saturation Accuracy
- Saturation Exponent and Wettability — Oil-Wet Rock Corrections
- Formation Water Resistivity Determination — Salinity Uncertainty
- Invasion Profiles and Deep Resistivity Choice — True Resistivity Estimation

## Day 5: NMR and Advanced Logging

- NMR T2 Cut-Offs for Carbonates — Bound and Free Fluid Split
- Timur-Coates and SDR Permeability Models — Flow Capacity Prediction
- Diffusion and Relaxation Fluid Typing — Light Oil and Gas Identification
- Dielectric and Spectroscopy Logs — Low-Resistivity Pay Detection
- Borehole Image Facies and Vug Mapping — Heterogeneity Quantification

## Day 6: Fractures and Dual-Porosity Evaluation

- Image Log Fracture Classification — Open Versus Healed Fractures
- Fracture Porosity and Aperture Estimates — Storage Versus Flow Contribution
- Dual-Porosity Saturation Approaches — Matrix and Fracture Volumes
- Mud Loss and Production Log Evidence — Conductive Fracture Confirmation
- Fracture Intensity Upscaling — Simulation Grid Properties

## Day 7: Rock Typing and Permeability Prediction

- Lucia Rock-Fabric Method — Petrophysical Class Assignment
- Flow Zone Indicator and Hydraulic Units — Permeability Transforms
- Winland Pore Throat Radius — Reservoir Quality Ranking
- Cluster Analysis and Electrofacies — Uncored Well Prediction
- Permeability Upscaling to Grid Blocks — Model Property Consistency

## Day 8: Capillary Pressure and Saturation-Height

- Mercury Injection and Porous Plate Data — Pore Throat Distributions
- Leverett J-Function Normalisation — Rock-Type Curves
- Free Water Level and Transition Zones — Contact Definition
- Saturation-Height Function Fitting — Simulation Initialisation
- Imbibition Versus Drainage Effects — Waterflood Saturation Forecasts

## Day 9: Integration with Pressure and Production Data

- Formation Pressure Gradients — Fluid Contacts and Compartments
- Mini Drill-Stem and Interval Pressure Tests — Permeability Validation
- Production Logging Inflow Profiles — Contributing Interval Checks
- Net Pay Cut-Off Sensitivity — Volumetric Uncertainty Ranges
- PRMS-Consistent Volume Reporting — Reserves Booking Inputs

## Day 10: Practising the Carbonate Rock-Type Interpretation Report

- Multi-Well Log and Core Interpretation — Applying Porosity and Lithology Methods
- Pore-Type Saturation Model Selection — Applying Variable Exponents
- Rock Type and Permeability Assignment — Applying Classification Schemes
- Saturation-Height and Pressure Reconciliation — Checking Contacts Against Tests
- Carbonate Rock-Type Interpretation Report — Model-Ready Properties and Uncertainties

## Applying Carbonate Reservoir Formation Evaluation After the Course

- Re-run saturation for three key wells using pore-type based cementation exponents and compare hydrocarbon volumes with the current model.
- Fit saturation-height functions by rock type from existing capillary pressure data and pass them to the reservoir simulation lead.

## Carbonate Reservoir Formation Evaluation Questions FAQ

### What is carbonate reservoir formation evaluation, and why does it matter now?

It is the integrated interpretation of logs, core, NMR and pressure data to quantify porosity, saturation and permeability in carbonates. It matters now because mature carbonate fields hide bypassed pay, and simple log models misstate volumes in mixed pore systems.

### Which roles gain most from carbonate reservoir formation evaluation skills?

Petrophysicists, geologists and reservoir engineers gain most. Laboratory liaisons and data leads also benefit, because rock types, core programmes and saturation-height functions must be defined once and used consistently by every discipline.

### How does a carbonate reservoir formation evaluation course differ from a general log interpretation course?

It focuses on the pore complexity specific to carbonates. You work with vugs, fractures, variable cementation exponents, NMR permeability and rock typing, while a general course centres on clastic rocks and standard shaly-sand models.

### What do you bring back from carbonate reservoir formation evaluation training?

You bring back an interpretation report for a field well set. It contains rock types, porosity, saturation, permeability and saturation-height functions with stated uncertainties, ready for the reservoir model.

## Carbonate Reservoir Formation Evaluation: The Way Forward

The Carbonate Rock-Type Interpretation Report gives subsurface teams one set of model-ready properties. Its first use is often a decision on oil in place or the next infill target, read by reservoir engineers and asset planners. After that first use, revisit the rock-type scheme as new core and NMR data arrive, because carbonate heterogeneity rarely reveals itself in early wells alone.