Geological and Petrophysical Evaluation of Sandstone Cores in the Great Burgan Field in Kuwait*

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Abstract

In Kuwait, the Southeast Great Burgan Field possesses the world’s largest sandstone oil reservoirs both in terms of reserves and production (Kirby et al., 1998; Sorkhabi, 2012). It comprises three giant sectors: Burgan, Ahmadi, and Magwa which are characterized by their domal structure (Carman, 1996; Kaufman et al., 2002). The 28-36° API mature oil is produced predominately from two Mid-Cretaceous (Late Albian to Early Cenomanian) sandstone reservoirs, the Wara and Burgan formations (Kaufman et al., 2002; Strohmenger et al., 2006). Both formations were deposited in a fluvial deltaic environment on the continental shelf margin of the ancient Tethys Ocean (Kirby et al., 1998; Sorkhabi, 2012).

The Burgan sandstone (BF) succession consists of two units, the third and fourth sands. The third sand succession is divided into three members, the lower, middle and upper (Kaufman et al., 2002; Datta et al., 2012; Sorkhabi, 2012). On the other hand, Wara sandstone (WF) succession is divided into first and second units (Sorkhabi, 2012). Both formations are separated by a carbonate succession of the Mauddud Formation which was deposited in a shallow marine environment (Kirby et al. 1998; Strohmenger et al., 2006). In this research, whole cores extracted from the Upper Burgan (UBF) and WF in the Burgan and Ahmadi fields were evaluated using an integrative workflow combining Digital Core Analysis (DRA) methods with conventional techniques. This integrative workflow provided improved understanding of the geological and petrophysical properties of these oil prolific reservoirs.
References Cited


GEOLOGICAL AND PETROPHYSICAL EVALUATION OF SANDSTONE CORES IN THE GREAT BURGAN FIELD IN KUWAIT

Osama Al-Jallad¹, Moustafa Dernaika¹, Safouh Koronfol¹, Mona Rashaid² and Laila Hayat²

[¹] Ingrain Inc., [²] Kuwait Oil Company
Introduction:
- Geological Settings.
- Study Objectives.

Methodology.

Results and Data interpretation:
- DE and Micro Scanning.
- Petrography.
- DE Scanning.
- Mercury Injection.
- Poroperm.
- XRD Analysis.
- XCT Imaging
- Numerical Computation.

Summary and Conclusion.
The South East Great Burgan Field possesses the world’s largest sandstone oil reservoirs both in terms of reserves and production (Kirby et al. 1998).
The 28-36° API mature oil is produced predominately from two Mid-Cretaceous (late Albian to early Cenomanian) sandstone reservoirs; Wara and Burgan formations (Kaufman et al., 2002).

Both formations were deposited in a fluvial deltaic environment on the continental shelf margin of the ancient Tethys Ocean (Kirby et al. 1998).

Both formations are separated by carbonate succession of Mauddud Formation which deposited in a shallow marine environment.
Introduction: Study Objectives

Better reservoir performance.

Understanding the geological and petrophysical (RCA and SCA) properties in both formations.

Analyzing whole cores derived from Upper Burgan (UBF) and Wara Formation (WF) using an integrative workflow.
Methodology and Workflow

- Dual Energy CT Scanning
- Selecting Plugging Location and Sample Extractions
- Properties Upscaling
- Plug Dual Energy Scanning
- Core Plugs Segmentation
- Integration between conventional data and CT Images
- Conventional Analysis
- High Resolution Imaging
- 40 µm/voxel XCT Imaging and Wafers Selections and Cutting

Digital Rock Analysis (DRA)

Conventional Rock Analysis
Results and Data interpretation: Whole Core DE Scanning
**Results and Data interpretation: Core Characterization**

<table>
<thead>
<tr>
<th>Field</th>
<th>WC-Tray</th>
<th>Depth Interval (ft)</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ahmadi</td>
<td>C1-T06</td>
<td>xx98 -xx99</td>
<td>WU</td>
</tr>
<tr>
<td></td>
<td>C1-T09</td>
<td>xx08-xx09</td>
<td>WM1</td>
</tr>
<tr>
<td></td>
<td>C2-T11</td>
<td>xx64-xx65</td>
<td>WM1</td>
</tr>
<tr>
<td></td>
<td>C3-T06</td>
<td>xx88-xx89</td>
<td>WL1</td>
</tr>
<tr>
<td></td>
<td>C3-T14</td>
<td>xx20-xx21</td>
<td>WL1</td>
</tr>
<tr>
<td></td>
<td>C5-T15</td>
<td>xx21-xx22</td>
<td>BU2</td>
</tr>
<tr>
<td></td>
<td>C6-T04</td>
<td>xx57-xx58</td>
<td>BU2</td>
</tr>
<tr>
<td></td>
<td>C6-T11</td>
<td>xx88-xx89</td>
<td>BU2</td>
</tr>
<tr>
<td></td>
<td>C7-T03</td>
<td>xx99-xx00</td>
<td>BU3</td>
</tr>
<tr>
<td>Burgan</td>
<td>C3-T10</td>
<td>xx38-xx39</td>
<td>BU2</td>
</tr>
<tr>
<td></td>
<td>C4-T02</td>
<td>xx67-xx68</td>
<td>BU3</td>
</tr>
<tr>
<td></td>
<td>C4-T04</td>
<td>xx72-xx73</td>
<td>BU3</td>
</tr>
<tr>
<td></td>
<td>C4-T04</td>
<td>xx75-xx76</td>
<td>BU3</td>
</tr>
<tr>
<td></td>
<td>C4-T07</td>
<td>xx87-xx88</td>
<td>BU3</td>
</tr>
<tr>
<td></td>
<td>C4-T08</td>
<td>xx88-xx89</td>
<td>BU3</td>
</tr>
</tbody>
</table>

**Burgan**

- C3-T10: xx38-xx39 ft
- C4-T02: xx67-xx68 ft
- C4-T04: xx72-xx73 ft
- C4-T04: xx75-xx76 ft
- C4-T07: xx87-xx88 ft
- C4-T08: xx88-xx89 ft

**Ahmadi**

- C1-T06: xx98-xx99 ft
- C1-T09: xx08-xx09 ft
- C2-T11: xx64-xx65 ft
- C3-T06: xx88-xx89 ft
- C3-T14: xx20-xx21 ft
- C5-T15: xx21-xx22 ft
- C6-T04: xx57-xx58 ft
- C6-T11: xx88-xx89 ft
- C7-T03: xx99-xx00 ft

**Top and Bottom**

- Top: xx87-xx88 ft
- Bottom: xx99-xx00 ft

**Core Characterization**

- WC-Tray C6-T04: xx57-xx58 ft
- WC-Tray C7-T03: xx99-xx00 ft
- WC-Tray C3-T14: xx20-xx21 ft
- WC-Tray C1-T06: xx98-xx99 ft

**Field**

- Ahmadi: C1-T06, C1-T09, C2-T11, C3-T06, C3-T14, C5-T15, C6-T04, C6-T11, C7-T03
- Burgan: C3-T10, C4-T02, C4-T04, C4-T04, C4-T07, C4-T08
Results and Data interpretation: Core Characterization

The cores are highly heterogeneous with alternating layers of massive and laminated sandstone. Also, scattered patches of high dense minerals and vuggy pores were observed as well.
Results and Data interpretation: Core Characterization

The generated Zeff logs show average Zeff response equal to 11.8.

The generated Rhob logs reflect the variability of porosity distributions along the length of these cores.
Results and Data interpretation: Plug Extraction and DE Scanning

Bulk density profile indicates homogenous porosity distribution. Average bulk density is 2.14 g/cc. Thus, the estimated porosity from plug DE is 14.43% considering the grain density is 2.50 g/cc.

Uniform Zeff profile along the sample; Zeff averages at 11.79, which indicates quartz response (Zeff for pure quartz is 11.8). The dominance of quartz was confirmed by thin-section and XRD.
Results and Data interpretation: Core Plugging and DE Scanning

Wara Formation Cores

Upper Burgan Formation Cores

DE XCT Scanning (500 µm/voxel)
Results and Data interpretation: Core Plugging and DE Scanning

Plug DE XCT Scanning (500 µm/voxel)
Results and Data interpretation: Plugs Characterization

- Normalized vs Pore Throat Size
- Distribution Functions
- Porosity, % vs K (mD)
- Pore Throat Radius (Microns)

Note: Cutting blade is 1.60mm thick.
Results and Data interpretation: Micro CT Scanning (40 µm/voxel)

AH Field (Wara Formation)  AH&BG Field (Upper Burgan Formation)

Micro XCT Scanning (40 µm/voxel)
Results and Data interpretation: 40 µm/voxel Wafers Selections
Results and Data interpretation:
Petrographical Analysis

AH Field (Wara Formation)

BG Field (Upper Burgan Formation)

BG Field (Upper Burgan Formation)
Results and Data interpretation: Petrographical analysis

AH Field (Wara Formation)

BG Field (Upper Burgan Formation)

BG Field (Upper Burgan Formation)
The majority of the Wara and Upper Burgan samples are composed mainly of Quartz with minor concentrations of pyrite.

Other few samples are made mainly quartz with considerable concentrations of clay minerals such as kaolinite, illite, and chlorite as well as other authigenic minerals.
Results and Data interpretation: Poroperm and MICP

Enhancing the Reservoir Quality
Results and Data interpretation: Rock Typing

WF-RRT I

UBF- RRT I

Normalised Data vs Pore Throat Size

Distribution Functions

Pore Throat Radius (Microns)

Normalised Data vs Pore Throat Size

Distribution Functions

Pore Throat Radius (Microns)
Results and Data interpretation: Rock Typing

WF-RRT II

UBF- RRT II
Results and Data interpretation: DRA (High Resolution Scanning)

Upper Burgan Formation - RRT I (4-2)

Upper Burgan Formation - RRT I (1-1)

Upper Burgan Formation - RRT I (2-3)

Upper Burgan Formation - RRT I (4-5)
Based on MICP; 2 µm/voxel resolution is needed to resolve the pore system of RRT I samples in both formations.
Based on MICP; 1 and 0.015 µm/voxel resolutions were needed to resolve the pore system of RRT II samples in both formations.
Results and Data interpretation: DRA (Images Segmentation)

Wara and Upper Burgan RRTI
Results and Data interpretation: DRA (Images Segmentation)

Upper Burgan RRTII
Results and Data interpretation: DRA (Numerical Computation)

Numerical Computation at Subsamples Scale

- Porosity
- Absolute Permeability
- PcRI
- Relative Permeability
- FRF

- Segmentation
- Lattice Boltzmann Method
- Finite Element Method
Results and Data interpretation: DRA (Computation and Upscaling)

- Before any advanced computation attempt; simulation of pore throat size distribution is done and results are compared with the physical lab MICP data.
- This is to insure that the pore system has been completely and properly captured and acquired 3D digital samples are real representation of the actual rock.

The simulated PTSD from these two sample form the same rock category showed excellent match with the lab MICP data.
These samples were deemed unrepresentative and thus excluded from DRA computations.
Results and Data interpretation: DRA (Plug Segmentation)

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Phases</th>
<th>Phases Percentage (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UBF RRT II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pore</td>
<td>1.13</td>
<td></td>
</tr>
<tr>
<td>Low Dense</td>
<td>57.66</td>
<td></td>
</tr>
<tr>
<td>Medium Dense</td>
<td>36.42</td>
<td></td>
</tr>
<tr>
<td>High Dense</td>
<td>4.66</td>
<td></td>
</tr>
<tr>
<td>Solid</td>
<td>0.13</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Phases</th>
<th>Phases Percentage (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UBF RRT I</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pore</td>
<td>0.78</td>
<td></td>
</tr>
<tr>
<td>Low Dense</td>
<td>78.62</td>
<td></td>
</tr>
<tr>
<td>Medium Dense</td>
<td>8.35</td>
<td></td>
</tr>
<tr>
<td>Solid</td>
<td>12.25</td>
<td></td>
</tr>
</tbody>
</table>
Results and Data interpretation: DRA (Upscaling Computed Data)

Upscaling the Computed Properties at Subsample Scale up to the corresponding Flow Unit with plug

Porosity, Permeability, FRF, PcRI and Kr at Subsample Scale
Results and Data interpretation: DRA (Upscaled RCA Properties)

- **DRA Perm, mD**
  - WF-RRT I
  - UBF-RRT I
  - UBF-RRT II

- **DRA Porosity, frac**
  - WF-RRT I
  - UBF-RRT I
  - UBF-RRT II

- **DRA FRF**
  - $FRF = \frac{1}{\Phi^m}$

- **Lab Porosity, Frac**
  - WF-RRT I
  - UBF-RRT I
  - UBF-RRT II

- **Lab Perm, mD**
  - UBF-RRT I
  - WF-RRT I
  - UBF-RRT II
Fluid Properties were used by the simulator to compute SCA properties at subsample level.

### Results and Data interpretation: DRA (SCA: Upscaled PcRI)

<table>
<thead>
<tr>
<th>Field</th>
<th>Brine (141°F and 1952 psi)</th>
<th>Oil (141°F and 1952 psi)</th>
<th>IFT (N/M)</th>
<th>Contact Angle</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Density (gm/cc)</td>
<td>Viscosity cp</td>
<td>Density (gm/cc)</td>
<td>Viscosity (cp)</td>
</tr>
<tr>
<td>AH</td>
<td>NA</td>
<td>NA</td>
<td>0.771</td>
<td>1.433</td>
</tr>
<tr>
<td>BG</td>
<td>NA</td>
<td>0.64</td>
<td>NA</td>
<td>1.13</td>
</tr>
</tbody>
</table>

The computed PD in all samples matched very well with the corresponding MICP drainage data.

**Upscaling to Plug Level**

**UBF-RRT I**

**UBF-RRT II**

<table>
<thead>
<tr>
<th>n, 1st Drainage</th>
<th>n, Imbibition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sw</td>
<td>RI</td>
</tr>
<tr>
<td>1.0000</td>
<td>1.0000</td>
</tr>
<tr>
<td>0.8916</td>
<td>1.1311</td>
</tr>
<tr>
<td>0.8491</td>
<td>1.3488</td>
</tr>
<tr>
<td>0.7463</td>
<td>2.8601</td>
</tr>
<tr>
<td>0.4160</td>
<td>11.3262</td>
</tr>
<tr>
<td>0.21</td>
<td>39.22</td>
</tr>
</tbody>
</table>
Fluid Properties were used by the simulator to compute SCA properties at subsample level.

Kr end point saturations came inline with corresponding saturations from Pc which indicates data consistency.

**Results and Data interpretation: DRA (SCA: Upscaled Relative Permeability)**

<table>
<thead>
<tr>
<th>Field</th>
<th>Brine (141°F and 1952 psi)</th>
<th>Oil (141°F and 1952 psi)</th>
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<td></td>
<td>Density (gm/cc)</td>
<td>Viscosity (cp)</td>
<td>Density (gm/cc)</td>
<td>Viscosity (cp)</td>
</tr>
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<td>NA</td>
<td>NA</td>
<td>0.771</td>
<td>1.433</td>
</tr>
<tr>
<td>BG</td>
<td>NA</td>
<td>0.64</td>
<td>NA</td>
<td>1.13</td>
</tr>
</tbody>
</table>

**Upscaling to Plug Level**

- **UBF-RRT I**
- **UBF-RRT II**

Fluid Properties were used by the simulator to compute SCA properties at subsample level.
Summary and Conclusion

• In this study, total of 15 ft whole cores from Greater Burgan Field (The world largest siliciclastic Reservoir).

• The cores represents the Mid-Cretaceous siliciclastic successions of Wara and Upper Burgan Formation that deposited in a fluvial deltaic environment on the continental shelf margin of the ancient Tethys Ocean.

• These core were characterized using an integrative workflow taking in considerations the conventional and digital core analysis methods.
Summary and Conclusion

• The convectional core analysis methods including petrography, XRD, MICP and proper as well as the digital methods including high resolution and DE scanning affirms on two main rock types:

  • RRT I which characterized by very high porosity and permeability with narrow PTSD at 10 µm. It composed mainly of framework monocrystalline quartz grains in addition to common detrital K-Feldspar, plagioclase, opaque grains and traces of heavy minerals and clays. Clean primary inter-granular pore with very good connectivity are dominant.

  • RRT II which characterized by low porosity and permeability with bimodal PTSD 4.5 and 0.018 microns, respectively. It composed mainly made of both detrital clays and framework detrital monocrystalline quartz. The most dominate pore system in this rock type is the micro-pores hosted by clay minerals and while the primary interparticle pores are rare and isolated.
Summary and Conclusion

- Up-scaled poroperm cross plots show a perfect linear relation.

- Upscaled primary drainage and imbibition Kr’s showed similar end points to the corresponding Pc cycles.

- Residual oil saturation ($S_{or}$) defined by the imbibition Pc curves of WF and UBF is in the range of approximately 6%.

- Pores within clay minerals in sample AH-5 remained water filled and this explains the high $S_{wi}$ in this sample.

- The Up-scaled Krw curves and end points in WF/UBF RRT I indicate oil wet behavior (Krw end points in the range of 0.836 to 0.901); this is in line with the observed forced imbibition from Pc computations.
Acknowledgment

The authors would like to thank KOC for their contributions and support through the course of this study. The keen interest shown by Laila Hayat and Mona Rashied is gratefully acknowledged.