CARBONATE RESERVOIR ROCKS AT GIANT OIL AND GAS FIELDS IN SW IRAN AND THE ADJACENT OFFSHORE: A REVIEW OF STRATIGRAPHIC OCCURRENCE AND PORO-PERM CHARACTERISTICS

B. Esrafili-Dizaji** and H. Rahimpour-Bonab*

SW Iran and the adjacent offshore are prolific petroleum-producing areas with very large proven oil and gas reserves and the potential for significant new discoveries. Most of the oil and gas so far discovered is present in carbonate reservoir rocks in the Dehram, Khami and Bangestan Groups and the Asmari Formation, with smaller volumes in the Dashtak, Neyriz, Najmeh, Gurpi, Pabdeh, Jahrum, Shahbazan, Razak and Mishan (Guri Member) Formations. The Permo-Triassic Dehram Group carbonates produce non-associated gas and condensate in Fars Province and the nearby offshore. The Jurassic – Lower Cretaceous Khami Group carbonates are an important producing reservoir at a number of fields offshore and in the southern Dezful Embayment, and are prospective for future exploration. Much of Iran’s crude oil is produced from the Oligo-Miocene Asmari Formation and the mid-Cretaceous Sarvak Formation of the Bangestan Group in the Dezful Embayment.

This review paper is based on data from 115 reservoir units at 60 oil- and gasfields in SW Iran and the adjacent offshore. It demonstrates that the main carbonate reservoir units vary from one-another significantly, depending on the particular sedimentary and diagenetic history. Ooidal-grainstones and rudist- and Lithocodium-bearing carbonate facies form the most important reservoir facies, and producing units are commonly dolomitised, karstified and fractured. In general, reservoir rocks in the study area can be classified into six major types: grainstones; reefal carbonates; karstified, dolomitised and fractured carbonates; and sandstones. The stratigraphic distribution of these reservoir rocks was principally controlled by the palaeoclimatic conditions existing at the time of deposition. A comparative reservoir analysis based on core data shows that dolomitised and/or fractured, grain-dominated carbonates in the Dehram Group, Lower Khami Group and Asmari Formation typically have better reservoir qualities than the Cretaceous limestones in the Upper Khami and Bangestan Groups.

INTRODUCTION

More than 6000 exploration and appraisal wells have been drilled in SW Iran since the discovery of Masjid-i Soleimian in May 1908, resulting in the discovery of 124 oilfields and 57 gasfields. Most of these fields have multiple pay zones, and a total of 255 oil reservoirs and 128 natural gas reservoirs are known. Exploration has so far proved hydrocarbon reserves of about 157 billion barrels of oil and 1191 trillion cubic feet of gas (Oil & Gas Journal, 2017). Most of the oil and gas fields

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Key words: SW Iran, Zagros foldbelt, Persian Gulf, hydrocarbons, carbonate reservoirs, oil field, gas field, Dehram Group, Khami Group, Bangestan Group, Asmari Formation, grainstone, rudist facies.
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are located in the Zagros foldbelt and adjacent Persian Gulf (Fig. 1), and together contain up to 97% of Iran’s hydrocarbon reserves. Onshore fields hold more than 90% of the initial oil in-place whereas more than 70% of the initial gas in-place has been discovered offshore.

Oil and gas are produced from carbonate and sandstone reservoir rocks of Permian to Miocene ages (Fig. 2). Most productive reservoirs are carbonates but sandstone reservoirs include the Faraghan Formation, the Kushk (Zubair-equivalent), Azadegan (Burgan-equivalent) and Ahwaz (Ghar-equivalent) Members, and the Razak Formation. However, the bulk of the hydrocarbons are reservoired in four carbonate units: the Dehram, Khami and Bangestan Groups, and the Asmari Formation (Fig. 2) (Al-Husseini, 2007; Alsharhan, 2014; Beydoun et al., 1992). Other reservoir units of lesser importance are the Dashtak, Neyriz, Gurpi, Pabdeh, Jahrum, Shahbazan and Mishan (Guri Member) Formations which together contain less than 3% of Iran’s total oil and gas reserves.

The Permo-Triassic Dehram Group carbonates produce non-associated gas and condensate in the eastern Zagros area and the adjacent offshore, and host more than 90% of Iranian gas reserves. Supergiant gas fields producing from Dehram Group reservoirs include the offshore South Pars, Kish, North Pars and Golshan fields (Fig. 3) (Bordenave, 2008; Esрафili-Dizaji and Rahimpour-Bonab, 2013).

Most of Iran’s oil production comes from carbonate reservoirs in the Oligo-Miocene Asmari Formation and the Albian – Campanian Bangestan Group. The Asmari Formation reservoirs contain nearly 45% of the country’s proven oil in-place, while those in the Bangestan Group account for approximately 37%.

Fig. 1. Regional map showing structural elements in SW Iran and the adjacent offshore (after Sharland et al., 2001). Onshore structural trends are dominated by NW-SE trending Zagros folds and faults, while north-south trending pre-Zagros structures are dominant offshore.
Fig. 2. Generalized lithostratigraphic chart for SW Iran, illustrating stratigraphic units between the Cambrian and the Recent. Compiled from data in Ghavidel-Syooki (1997); James and Wynd (1965); Motiei (1995); Setudehnia (1975); and Szabo and Kheradpir (1978).
Supergiant oilfields producing from the Asmari Formation (see Fig. 10) include Gachsaran, Marun, Ahwaz and Agha Jari which are located in the Dezful Embayment (Al-Husseini, 2007; Bordenave and Hegre, 2005).

The Jurassic – Lower Cretaceous Khami Group carbonates serve as reservoirs at giant oil fields such as Ferdowsi, Doroud and Darquain (Fig. 5). These carbonates hold nearly 15% of Iran’s oil reserves and 4% of gas reserves, and have significant gas exploration potential.

This paper reviews the occurrence of oil- and gas-producing carbonate reservoirs in SW Iran and the adjacent offshore. Major reservoir rock facies and regional diagenetic trends are discussed to investigate controls on porosity distribution. A comparative reservoir analysis is presented which provides new insights into the geologic controls on reservoir characteristics. The results of this study are intended to help with the development of predictive reservoir models and the definition of future exploration and production strategies.

Geologic setting
More than a century of hydrocarbon exploration activity in the Zagros region of SW Iran has resulted in a detailed understanding of the structural and stratigraphic history of the area. The regional geology and petroleum habitat have been reviewed by Alsharhan (2014), Alsharhan and Nairn (1997), Beydoun et al. (1992), Bordenave (2014), Koop and Stoneley (1982), Murris (1980) and Sharland et al. (2001), and is not repeated here in detail. The prolific Zagros foldbelt extends from the northern coastline of the Persian Gulf to northern Iraq (Alavi, 2004). NW-SE trending faults and folds were developed during the Cenozoic Zagros orogeny and overprinted the pre-existing north-south trending Precambrian Pan-African structural grain (Beydoun et al., 1992) (Fig. 1).

In general, the geological history of the Zagros region can be divided into two periods based on tectonic history, palaeogeography and palaeoclimate. During the Precambrian and most of the Palaeozoic, the region was a part of the Gondwana supercontinent after the Infracambrian Amar orogeny (640–620 Ma), which was followed by NW-SE trending Najd rifting (620–570 Ma). The phase was terminated by Late Ordovician and Late Carboniferous, which coincided with the development of regional unconformities (Beydoun et al., 1992; Konert et al., 2001; Vennin et al., 2015). The Late Ordovician glaciation was followed by deposition in the Zagros area of the post-glacial and organic-rich sediments of the Sarchahan Formation (Fig. 2) which are important source rocks (Bordenave, 2014; van Buchem et al., 2014).

From the Permian to the Neogene, the SW Iran region formed the NE margin of the Afro-Arabian plate. The tectono-sedimentary history and hydrocarbon occurrence of the region during this time interval are largely linked to the opening (Permian) and closure (Late Cretaceous – Neogene) of the southern Neo-Tethys (Bordenave, 2014). From the Permian onwards, the area was located in a tropical climatic belt (from 30°S to 30°N latitude) and the stratigraphy is dominated by marine carbonates with minor shales and evaporites (Fig. 2) (Alsharhan, 2014; Ziegler, 2001).

The NW-SE trending Zagros fold-and-thrust belt was created by the collision of the Arabian plate with the Eurasian margin during the Late Cretaceous to Miocene (Alavi, 2004). NW-SE trending asymmetric Zagros folds constitute structural traps for oil and gas, and mostly formed during the Miocene.

On the basis of structural trends, stratigraphy and petroleum systems, the Zagros area is divided into eastern, central and western zones (Fig. 1). The Eastern Zagros is bordered by the Zendan or Dibba Fault to the east and the Kazerun Fault to the west. This zone, comprising Fars Province and the Bandar Abbas hinterland, is characterised by the presence of diapiric Infracambrian Hormuz Salt. Fars Province is mainly gas-prone and Permo-Triassic carbonate reservoirs occur in the Coastal and Sub-coastal zones. A few oil/gas accumulations have been discovered in the Bandar Abbas hinterland (Bordenave, 2008).

The Central Zagros is bounded by the Kazerun and Balarud faults to east and west respectively (Fig. 1), and is separated by the Mountain Front fault and the Zagros Deformation Front into the Izeh Zone, Dezful Embayment and Abadan Plain. Most of the giant oil fields occur in the latter two areas (Abdollahie Fard et al., 2006; Al-Husseini, 2007; Bordenave and Hegre, 2005) but a number of fields are situated in the Izeh Zone such as Kuh-e Rig, Shurom, Doudrou and Mokhtar (Al-Husseini, 2007).

The Western Zagros or Lurestan Province is located between the High Zagros and Balarud faults (Fig. 1). A few small oil and gas fields have been found in this province such as Sarkan, Maleh Kuh and Huleylan (Al-Husseini, 2007).
The Persian Gulf Basin formed as a foreland basin in the NE of the Arabian Plate (Fig. 1). Structural elements and deformation style in the Persian Gulf are different from those in the adjacent onshore which is dominated by NW-SE Zagros-type folding. In the Persian Gulf Basin, the major structural trends are controlled by north-south trending Pan-African tectonics inherited from the Infracambrian Amar orogeny (Al-Husseini, 2000; Edgell, 1996; Konert et al., 2001). Two north-trending highs, the Safaniya-Hendijan Arch and the Qatar Arch, have controlled the formation of major oil and gas fields such as Safaniya and North Dome – South Pars. Salt diapirs are common in the Persian Gulf and form structural traps, particularly in the eastern side (Edgell, 1996). The diapirs are sourced from thick Hormuz Series evaporites which were deposited during Infracambrian – Cambrian Najd rifting (Al-Husseini, 2000; Edgell, 1996).

Since the Cambrian, the Persian Gulf has structurally been divided by the Qatar Arch into western and eastern sub-basins (van Buchem et al., 2014). Jurassic to Cretaceous carbonate reservoirs are widespread in the eastern Persian Gulf and are mostly associated with salt domes. Gas-prone Permo-Triassic carbonates are the most significant reservoir rocks in the Qatar Arch area. In the western Persian Gulf, the Azadegan (Burgan-equivalent) sandstone reservoirs are productive and have been developed along the NNE-SSW Safaniya-Hendijan trend (Alsharhan and Nairn, 1997).

**MATERIALS AND METHODS**

This study of carbonate reservoir rocks in SW Iran and the adjacent offshore is based on data from 115 reservoir units at 60 oil- and gasfields (Table 1; field locations in Figs 3, 5, 8 and 10). The data was collected by the authors during industrial projects and studies, and extensive investigations into the stratigraphy, tectonics and petroleum systems in the study area have provided a large database from which to review the hydrocarbon occurrence and habitat. Therefore, the first part of the paper briefly reviews major (and minor) hydrocarbon reservoirs in SW Iran and the northern Persian Gulf and is based on Al-Husseini (2007); Alsharhan and Nairn (1997); Beydoun et al. (1992); Bordenave (2014); Ghazban (2007); Motiei (1995); and Alsharhan (2014). In the second part, reservoir facies and regional diagenetic trends are discussed, based mainly on data from the authors’ previous studies (especially Esrafili-Dizaji and Rahimpour-Bonab, 2013; Esrafili-Dizaji et al., 2015; Mehrabi et al., 2015a; Mehrabi et al., 2015b; Mehrabi et al., 2018; Rahimpour-Bonab et al., 2013). Reservoir rocks are classified into six principal classes considering the major factors controlling porosity generation and distribution at a regional scale. Despite reservoir complexity and heterogeneity, this comparative reservoir analysis may provide new insights into the geologic processes controlling reservoir characteristics (Ehrenberg et al., 2007a; Markello et al., 2008).

In order to compare different reservoir rocks, this study follows a simple approach which uses mean

<table>
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<tr>
<th>Reservoir</th>
<th>Field</th>
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<tr>
<td>Asmari reservoirs</td>
<td>Qaleh Nar, Cheshmeh Khosh, Soroosh, Abuzar, Gavarzin, Marun, Ahwaz, Gachsaran, Haft Kel, Mansuri, Aban, Kupal, Hendijan, Ramshir, Karanj, Kabud, Parsi, Danan, Bahregansar, Siah Bisheh.</td>
</tr>
<tr>
<td>Bangestan reservoirs</td>
<td>Ahwaz, Marun, Gachsaran, Reg-e Sefid, Ab-Teymour, Sirri (A), Azadegan, Hendijan, Darquain, Binak, Band-e Karkheh, Maleh Kuh, Dehluran, Aban, West Paydar, Sarvestan, Saadat Abad.</td>
</tr>
<tr>
<td>Khami reservoirs</td>
<td>Salman, Reshadat, Soroosh, Hengam, Balal, Darquain, Resalat, Ferdowsi, Doroud, SPOL(South Pars Oil Layer).</td>
</tr>
<tr>
<td>Dehram reservoirs</td>
<td>South Pars, North Pars, Lavan, Salman, Nar, Kangan, Golshan, Tabnak, Shanul, Varavi, Aghar.</td>
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poro-perm data for comparison (c.f. Ehrenberg et al., 2007a). In this method, arithmetic average values of porosity and permeability data were calculated for each reservoir, and mean values for the various reservoirs are plotted and compared to investigate general trends and characteristics. Although average poro-perm data may not be representative for a large and heterogeneous rock volume, the method simplifies complex geological processes since mean poro-perm values are a function of a reservoir unit’s sedimentary and diagenetic history. The data reported here should be regarded as representative for the producing reservoir zones which have been cored and evaluated, rather than the gross volume of the reservoir. Producing zones may have better reservoir properties than gross reservoir successions. In addition, it should be noted that the permeability values used in this study do not reflect the presence of, or contributions from, fracture networks.

HYDROCARBON HABITAT

In this section, the stratigraphic distribution and characteristics of the reservoir units at the major oil and gas fields in the SW Iran and the adjacent offshore are summarised.

Reservoirs in the Permo-Triassic Dehram Group

The Permo-Triassic Dehram Group consists of the Faraghan, Dalan and Kangan Formations in ascending order (Fig. 2) (Szabo and Kheradpir, 1978). The group is equivalent to the Unayzah and Khuff Formations in the Arabian Peninsula to the south. More than 33 gas and gas-condensate fields have so far been discovered which produce from Dehram Group reservoirs, which are mostly located in the upper Dalan and Kangan Formations (Esrafili-Dizaji and Rahimpour-Bonab, 2013). The majority of the accumulations are located in Fars Province and the adjacent offshore (Fig. 3), and a few occur in the Western Zagros (such as Kabirkuh and Samand in Lurestan). No information is available about the occurrence of gas accumulations in the Izeh Zone because no wells have yet penetrated the Triassic or deeper-lying intervals in this area. The Dehram Group carbonates in the Dezful Embayment are too deep (> 6000 m) to be reached by the drill, and hydrocarbons are not expected to occur here in these carbonates (Bordenave, 2014).

Very large volumes of gas and condensate (nearly half of the total initial gas in-place, IGIP) have been discovered in Dehram Group reservoirs in four supergiant fields offshore: South Pars (360 TCF), Kish (66 TCF), North Pars (47 TCF) and Golshan (42 to 56 TCF). Gas has also been proven in sandstones of the Faraghan Formation in the Golshan and Salman fields (Fig. 3). Gas in Dehram Group reservoirs is sourced from the Silurian Sarchahan shales, and the reservoirs are capped by the shales and anhydrite of the overlying Dashak Formation (Bordenave, 2014; Esrafili-Dizaji and Rahimpour-Bonab, 2013). In most offshore fields (with the exception of South Pars), trap structures are related to Hormuz salt diapirs. By contrast, traps in most onshore fields in Fars Province and Lurestan consist of anticlines oriented parallel to the Zagros trend, although the traps at the onshore Gardan and Namak Kangan fields are related to salt domes.

Most of the gas is contained in the upper Dalan and Kangan carbonates (Upper Khuff equivalents) whereas the lower Dalan and Nar Members form less common reservoir units. Offshore, at the supergiant gasfields, the thickness of this productive interval is c. 420-480 m. The upper Dalan and Kangan Formations in the Persian Gulf are divided into four regionally-identifiable reservoir units, designated in order of increasing age as K1, K2, K3 and K4. This four-fold subdivision can be correlated regionally using a sequence stratigraphic framework (Insalaco et al., 2006). In general the carbonates are characterised by a dominance of porous ooidal grainstones (Fig. 4) which vary in quality as a result of their diagenetic history (Ehrenberg et al., 2007a; Esrafili-Dizaji and Rahimpour-Bonab, 2014). Oomouldic porosity is the most important pore type recorded in the Dehram Group reservoirs (Fig. 4), which have an average porosity of 9% (range: 5-15%) and average permeability of 30 mD (range: 6-100 mD). As a general trend, reservoir quality declines from the offshore towards the onshore fields due to the increasing clay content (Esrafili-Dizaji and Rahimpour-Bonab, 2013; Insalaco et al., 2006).

Reservoirs in the Jurassic – Cretaceous Khami Group

The Khami Group was divided by James and Wynd (1965) into four formations, in ascending order the Surmeh, Fahliyani, Gadvan and Dariyan Formations, ranging in age from Middle Jurassic to Aptian (Fig. 2). More than 56 oil and gas fields have been discovered in the Khami Group carbonates (Fig. 5) and are in general located on pre-Zagros highs (e.g. the Kharg-Mish, Safaniya-Hendijan and Azadegan highs) and salt-related structures in the eastern Persian Gulf and Bandar Abbas hinterland (Ghazban, 2007; Motiei, 1995). Gas fields producing from Khami Group reservoirs are located in the Bandar Abbas area (e.g. Suru, Salakh and South Gashu fields) and Izeh Zone (Mokhtar field). The discovery of gas in Khami Group reservoirs (especially in the Marun, Bibi Hakimeh, Rag-e Sefid and Pazanan fields) suggests that these carbonates may have substantial gas exploration potential (Al-Husseini, 2007; Motiei, 1995). The wide geographical distribution of these reservoirs is evidence of discrete petroleum systems with slightly different charge histories (Bordenave, 2014).
Fig. 3. Gas fields in onshore SW Iran and the Persian Gulf producing from Permo-Triassic Dahram Group reservoirs. Most of the fields are located in the eastern Zagros and adjacent offshore.
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The Khami Group carbonates are characterised by mud-dominated facies with generally poor reservoir properties. Reservoir quality increases where the carbonates have undergone extensive dissolution or karstification (principally associated with subaerial unconformities), and is improved locally by dolomitisation and fracturing.

(i) Lower Khami reservoirs
Within the lower Khami Group, the upper parts of the Surmeh Formation constitute the main hydrocarbon reservoir unit in a number of oil fields in the Persian Gulf including Salman, Ferdowsi, Golshan, Reshadat, Doroud, Balal, Foroozan, Resalat and Sirri A (Fig. 5). In addition, the formation forms a reservoir unit at

Fig. 4. Sedimentological log based on cores from the upper member of the Dalan Formation (K3 and K4 reservoir units) in the South Pars field, together with petrophysical logs (GR and RHOB), poro-perm values and depositional sequences. The thick oolitic intervals in the K4 unit form good reservoir intervals. The photomicrographs (right) illustrate various oolitic rock types. Dolomitisation in general occurred as a result of diagenesis in hypersaline conditions (see text for details).
Fig. 5. Location map showing the distribution of fields producing oil and gas from Jurassic – Cretaceous Khami Group reservoirs.
fields on the Kharg-Mish structural high (Garangan, Chillingar and Sulabdar fields; Bordenave, 2014; Motiei, 1995). The upper Surmeh reservoir, 90-150 m thick, is equivalent to the Arab Formation (Fig. 6) in countries to the south, and includes four regressive cycles or members (A, B, C and D), each of which consists of a carbonate reservoir with an anhydrite cap rock (Daraei et al., 2014; Ghazban, 2007). The best reservoirs consist of dolomitised microbiotas and ooidal grainstones with average porosity of about 15% and permeability up to 100 mD.

The Surmeh Formation reservoirs were sourced with hydrocarbons from the Sargelu and Hanifa – Tuwaïq Mountain Formations (Bordenave, 2014). Anhydrites of the Hith Formation, deposited in a sabkha environment, serve as a regional seal.

(ii) Upper Khami reservoirs

Upper Khami reservoir units include limestones in the Fahliyan, Gadvan and Dariyan Formations (Fig. 2) which are relatively poorly documented in the literature.

The Neocomian Fahliyan Formation forms a reservoir at fields in the Abadan Plain (e.g. Azadegan, Yadavaran, Susangerd, Juffair, Ab-Teymour and Darquain fields; Fig. 5), in the offshore Persian Gulf (Bahrengansar, Foroozan, Doroud, Nowruz, Ferdowsi, Esfandiyar, Golshan and Salman fields), and in the southern Dezful Embayment (Marun, Bibi Hakimeh, Rag-e Sefid, Gachsaran, Garangan, Gulkhari and Sulabdar fields) (Al-Husseini, 2007; Motiei, 1995). The Neocomian reservoirs are provided by intraformational shallow-marine sandstones (see Enayati-Bidgoli and Saemi, 2019). The formation's thickness varies from 40 m in the offshore Ferdowsi field to 366 m onshore at Azadegan field. The best reservoir quality intervals are found in Lithocodium floatstones and peloid-foram grain-packstones in the Khalij Member and Kushk sandstone (see Enayati-Bidgoli and Saemi, 2019). The oil was probably sourced from organic-rich shales of the Sargelu, Hanifa – Tuwaïq Mountain and Gadvan Formations (Bordenave, 2014). Seals for the Gadvan reservoirs are provided by intraformational shallow-marine mudstones in the upper Gadvan.

The Aptian Dariyan Formation consists mostly of Orbitolina-dominated facies deposited in a carbonate ramp setting, and the unit is tentatively correlated with the Shu’aiba Formation of Qatar, UAE and Oman (Alsharhan and Naim, 1997). In the shallower parts of the ramp, high-energy shoals and Lithocodium-algal communities were developed, whereas Orbitolina-rich and bioclastic facies were deposited in the middle to outer parts (Mehrabi et al., 2015b). Argillaceous limestones and shale facies with a dominant pelagic fauna were deposited in calm and deep-water conditions in the intrashelf Kazhdumii and Bab basins (e.g. Mehrabi et al., 2018).

The Dariyan Formation forms a significant reservoir at a number of oil fields which are in general located at the margins of the Aptian intrashelf basins. Fields include South Pars Oil Layer (SPOL), Reshadat, Resalat and Salman where the formation is in general 110 to 220 m thick. The matrix porosity and permeability of the Dariyan reservoirs are variable but are relatively high in grain-dominated facies and Lithocodium floatstones. Intense dissolution and karstification has resulted in the development of high quality reservoir intervals (Mehrabi et al., 2015b; Mehrabi et al., 2018). The formation’s porosity is moderate to good (17% on average) at a number of oilfields but permeability is low, ranging from 1 to 15 mD. The porosity is commonly reduced by compaction and cementation, and fractures can be essential for well productivity.

The Middle Jurassic Sargelu and Cretaceous Garau shales are thought to be the source rock for the oil in the Khalij Group reservoirs. The overlying shale-dominated Kazhdumii Formation (Albian) acts as a seal for Dariyan Formation reservoirs (Bordenave, 2014).
Fig. 6. Sedimentological log of the upper Surmeh carbonates in the Resalat field together with representative core photographs (right), well logs, poro-perm data and depositional sequences. The reservoir succession consists of cycles of highly dolomitised grain-dominated (shoal) carbonates followed by muddy facies and capped by thick anhydrites.
Fig. 7. Sedimentological log through the Lower Cretaceous Fahliyan Formation carbonates from a producing field in the Persian Gulf. The reservoir section consists of three depositional sequences which were deposited in the shallow part of a carbonate platform. Porous and permeable intervals were developed in highstand systems tract (HST) deposits below karstified exposure surfaces (SBs) and comprise thick, Lithocodium-rich floatstones.
**Reservoirs in the Bangestan Group**

The Bangestan Group is composed of three formations – Kazhdumi, Sarvak and Ilam – which were deposited during the Albian to Campanian (Fig. 2). The Sarvak and Ilam Formations form prolific reservoir rocks at fields in the Dezful Embayment and eastern Persian Gulf, and more than 72 fields have been discovered which produce from Bangestan reservoirs in SW Iran. A few fields producing from these reservoirs also occur in Lurestan, Izeh, Fars and the western Persian Gulf, the Qatar Arch and the Bandar Abbas area (Fig. 8). More than one-third of Sarvak reservoirs are yet to be developed (e.g. the Azadegan field). The largest oil accumulations in Bangestan Group reservoirs (>10 billion barrels) occur at the Azadegan, Mansuri, Yadavaran, Gachsaran, Rag-e Sefid and Ab-Teymour supergiant fields. Despite the large volumes of initial oil in-place, recovery factors for the reservoirs are relatively low, ranging from 20 to 30%.

The **Sarvak Formation** shows major thickness variations in the Dezful Embayment ranging from 635 m at the Azadegan field to more than 1066 m at Masjidi Soleiman. Previous studies (e.g. Esrafili-Dizaji et al., 2015; Rahimpour-Bonab et al., 2013) have emphasised the importance of diagenetic processes in the development of the reservoirs in the Sarvak Formation. In most Bangestan Group fields, the Sarvak carbonates have been extensively altered immediately beneath the regional-scale end-Turonian unconformity at the top of the formation. Dissolution porosity is believed to have been developed during a phase of mid-Cretaceous uplift as the result of which the top of the Sarvak Formation became subaerially exposed, leached and fractured (Esrafili-Dizaji et al., 2015; Rahimpour-Bonab et al., 2013). High porosity reservoir rock intervals were formed by karstification and fracturing of the carbonates below both the regional unconformity and also below local unconformities in the Sarvak succession. The Sarvak carbonates are characterised by thick, rudist-dominated intervals which have good potential for reservoir development (Fig. 9). Based on an analysis of cores from a number of fields, the mean porosity of the Sarvak carbonate reservoirs is about 13% (range 5-25%), but permeability is low (14 mD on average).

The **Santonian Ilam Formation**, whose thickness is highly variable, consists largely of mud-dominated deposits with occasional grain-dominated intervals (Fig. 9). Studies at giant oil fields such as Gachsaran, Marun, Ahwaz, Rag-e Sefid and Ab-Teymour show that the formation was in general deposited in the deeper parts of a carbonate ramp under warm and humid climatic conditions (Mehrabi et al., 2013). Data from the Ahwaz, Azadegan, Darquain, Hendijan and Band-e Karkheh oilfields show that the average porosity of the formation is >10% whereas mean permeability is <10 mD. Fields producing from Ilam reservoirs occur in the Abadan Plain, Lurestan and eastern Persian Gulf. Ilam reservoirs occur in fields around the Azadegan High including Azadegan, Yadavaran, Ab-Teymour, Dehluwan, Darquain and Susangerd. In Lurestan, the Ilam Formation occurs as the main reservoir in the Maleh Kuh, Sarkan and Veyzenhar oilfields and in the Halush gasfield. Fracturing has enhanced the productivity of the Ilam Formation in the Sarvestan and Saadat Abad oil fields in Interior Fars (Fig. 8). A regional-scale seal for these reservoirs is provided by the Upper Cretaceous Gurpi Formation.

The **Albian Kazhdumi Formation** is considered to be the principal source of the hydrocarbons in the Sarvak and Ilam reservoirs (Bordenave and Hegre, 2010). To the SW, in the Abadan Plain and the NW Persian Gulf, the Kazhdumi shales pass into the Burgan-equivalent Azadegan Sandstones which are composed of poorly cemented to unconsolidated siliciclastics (Mehrabi et al., 2019). These sandstones form a reservoir for oil at fields such as Soroosh, Abuzar, Foroozan, Esfandiyar and Binalud.

**Reservoirs in the Asmari Formation**

More than 80% of Iran’s crude oil is produced from the Oligo-Miocene Asmari Formation. The formation consists mostly of carbonates with two significant sandstone and anhydrite members, known as the Ahwaz and Kalhur Members, respectively (Ehrenberg et al., 2007b; James and Wynd, 1965; van Buchem et al., 2010) (Fig. 2). The thickness of the formation ranges from 150 to 480 m at oilfields in the study area.

The Asmari limestone is a reservoir rock in at least 57 oil and gas fields, nearly all of which are located in the Dezful Embayment and the adjacent offshore (Fig. 10). Asmari limestones are massive and dense with poor primary reservoir properties, but productivity is enhanced by fracturing and dolomitisation (Aqrawi et al., 2006; McQuillan, 1985). Fracture porosity is developed along the crests of tight folds and in shear zones at fault bends. Fractured Asmari carbonate reservoirs occur in the Gachsaran, Ahwaz, Marun, Agha Jari, Bibi Hakimeh, Pazanan, Haft Kel, Karanj, Rag-e Sefid, Kabud, Qaleh Nar and Parsi oil fields (Motiei, 1995) (Fig. 10).

Although fractured carbonates provide the most important reservoir units in the Asmari Formation, production also comes from the Ahwaz Sandstones. These poorly-consolidated sandstones form the main pay zones at the giant Ahwaz, Marun, Mansuri, Cheshmeh Khosh, Ramshir, Shadegan, Ab-Teymour, Ramin, Susangerd, Band-e Karkheh, Doroud, Bahregansar and Hendijan oil fields (Ehrenberg et al., 2006; Motiei, 1995). Based on core data, the average porosity of the sandstone pay zone is 12% whereas average permeability is 100 mD.
Fig. 8. Map showing the distribution of fields producing from Bangestan Group reservoirs. These fields mainly occur in the Dezful Embayment and Abadan plain, and offshore in the eastern Persian Gulf.
Fig. 9. Sedimentological log through the Sarvak and overlying Ilam (Bangestan) carbonates in the Ahwaz field, together with petrophysical logs (GR and sonic), poro-perm values, and core photographs. The log shows that the upper part of the Sarvak Formation is characterised by thick, porous, rudist grainstones with extensive karst-related dissolution. The Ilam Formation is composed of mud-dominated facies.
Fig. 10. Map showing the distribution of oil fields producing from the Asmari Formation reservoirs, most of which are located in the Dezful Embayment. Gas fields producing from the Asmari are located in the Bandar Abbas hinterland.
Fig. 11. Sedimentological log through the Asmari carbonates in the Qaleh Nar oil field, together with thin-section photomicrographs, poro-perm values and depositional sequences. The Asmari Formation in this field is composed of numerous depositional cycles, which were deposited in the inner part of a carbonate ramp. Porous intervals correspond to grain-dominated facies (oolidal, foram and peloidal grainstones).
Carbonate reservoir rocks in SW Iran: a review

The Asmari limestones are characterised by grain-dominated facies (Fig. 11) which were deposited on a carbonate ramp (Aqrawi et al., 2006). Carbonate reservoir intervals have local matrix porosity and permeability, and include ooid grainstones and dolomitised facies in the Upper Asmari (Honarmand and Amini, 2012). Typical matrix porosity in the carbonate pay zones ranges from 5% to 15% (10% on average).

Minor reservoirs

Minor reservoirs at oil and gasfields in SW Iran and the adjacent offshore occur in various stratigraphic intervals. Units with principally source rock or seal potential, such as the Dashtak, Pabdeh and Jahrum Formations, may locally also form subordinate reservoirs. The Dashtak Formation produces gas from dolomitised and fractured ooidal grainstones in the Aghar, Tabnak, Nar, Dalan and Zireh fields (Esrafili-Dizaji and Dalvand, 2018). The Jurassic Alan, Mus and Sargelu Formations form minor reservoir intervals at the Darquain, Masjid-i Soleiman and Kuh-e Asmari fields. The Pabdeh Formation is oil-bearing in the Zagheh, Kerenj and Masjid-i Soleiman fields, and contains gas in the Qaleh Nar and South Gashu fields. Fields which produce oil from the Jahrum Formation include Abuzar, Nargesi, Gulkhari and Kuh-e Mond (Motiei, 1995).

In the Balarud field, the Shahbazan Formation is an oil reservoir together with the Asmari Formation. At the Sarkhun field, the Jahrum and Razak Formations together with the Guri Member of the Mishan Formation produce natural gas (Kashfi, 1982).

Table 2. Average porosity and permeability data for the major carbonate reservoirs in SW Iran and the adjacent offshore.

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Facies</th>
<th>Arithmetic mean</th>
<th>Geometric mean</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Porosity (%)</td>
<td>Permeability (mD)</td>
<td>Porosity (%)</td>
</tr>
<tr>
<td>Dalan-Kangan</td>
<td>13.05</td>
<td>39.27</td>
<td>8.15</td>
</tr>
<tr>
<td>Surmeh</td>
<td>19.78</td>
<td>310.60</td>
<td>17.67</td>
</tr>
<tr>
<td>Asmari</td>
<td>16.82</td>
<td>58.53</td>
<td>13.40</td>
</tr>
<tr>
<td>Sarvak</td>
<td>11.73</td>
<td>21.77</td>
<td>8.93</td>
</tr>
<tr>
<td>Fahliyan and Dariyan</td>
<td>20.63</td>
<td>19.55</td>
<td>17.56</td>
</tr>
<tr>
<td>Dariyan</td>
<td>14.10</td>
<td>0.76</td>
<td>12.07</td>
</tr>
<tr>
<td>Asmari</td>
<td>8.70</td>
<td>3.77</td>
<td>7.41</td>
</tr>
</tbody>
</table>

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RESERVOIR ROCK CHARACTERISTICS

Major reservoir facies

Carbonate reservoir rocks in SW Iran consist of various facies types deposited in a range of shallow-water environments from the Permian to the Miocene. Reservoir properties may vary locally, although some facies are of more regional extent with relatively uniform petrophysical properties. Based on data from 60 oil- and gas fields in the study area, three major carbonate reservoir facies are recognised: ooidal grainstones, rudist grainstones, and Lithocodium bound-floatstones.

Ooidal grainstones form the main producing intervals in reservoirs in the Dehram Group and Surmeh Formation and locally in the Asmari Formation (see Figs 4, 6 and 11) (Darai et al., 2014; Ehrenberg et al., 2007a; Esrafili-Dizaji and Rahimpour-Bonab, 2014; Honarmand and Amini, 2012). In this facies, primary porosity and permeability are highly variable due to the unstable mineralogy, and reservoir characteristics are enhanced by dolomitisation and dissolution. Porosity ranges up to 35 % while permeability may reach 1000 mD (Fig. 12, Table 2). In general, in shallow Surmeh and Asmari Formation reservoirs (<2 km deep in the Reshadat, Balal, Ferdowsi, Gavarzin and Abuzar
fields), reservoir properties are better than in more deeply buried units (>3 km, e.g. the Dehram Group reservoirs).

**Rudist rudstones-grainstones** are common in the mid-Cretaceous Bangestan Group carbonates (Fig. 9) and form important reservoir units below unconformity surfaces in the Sarvak Formation (Esrafi-Dizaji et al., 2015). Rudist-rich facies show wide variations in both porosity and permeability (Fig. 13A). Porosity varies up to 30% and permeability ranges from < 1 to > 1000 mD; the average porosity is about 12% (Table 2). Dominant pore types are interparticle, dissolution-enlarged and intraparticle. A cross-plot of poro-perm data (Fig. 13A) shows that there is a linear relationship between porosity and log permeability with a moderate correlation coefficient \( R^2 = 0.60 \). For 1 mD as a critical flow parameter, the porosity cut-off is 12.5%.

**Lithocodium boundstone/floatstones** in the Lower Cretaceous Khami Group reservoirs (particularly in the Fahliyan and Dariyan Formations; Fig. 7) show relatively good reservoir properties (Lasemi and Nourafkan, 2008; Mehrabi et al., 2015b). In fields in the Persian Gulf (e.g. Soroosh, Salman, Ferdowsi, Resalat and SPOL), this facies shows high porosity and relatively low permeability due to the nature of the pore system (Fig. 13B, Table 2). Pores are dominantly micropore and intraparticle but vuggy types also occur. Porosity ranges up to 36% (20% on average) and permeability up to 500 mD (20 mD on average). There is a fairly close, linear relationship between porosity and log permeability (Fig. 13B); at 1 mD, the porosity cut-off is 17.5%.

A range of other facies types occur in producing carbonate reservoirs in SW Iran, but in terms of flow capacity they are only locally important. The contribution by these facies to production depends on the development of fracture systems, for example in **Orbitolina facies** in the Lower Cretaceous Dariyan and Gadvan Formations, and reeval boundstones in the Oligocene – Miocene Asmari Formation.

**Orbitolina pack-grainstones** in the Dariyan Formation locally have moderate to high porosity but generally poor permeability (Mehrabi et al., 2015b; Mehrabi et al., 2018). Oil staining in cores of this formation with intra-skeletal porosity is recorded in the Soroosh, Reshadat and Salman fields. Poro-perm data (Fig. 14A, Table 2) show that porosity is commonly >5% (up to 30%) but that permeability is generally

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**Fig. 12.** Cross-plots of porosity versus permeability for the ooidal grainstones of the Asmari (A), Surmeh (B) and Dalan-Kangan (C) reservoirs. D: Cross-plot of porosity versus permeability for all ooidal facies, showing the relatively higher reservoir quality in the Surmeh Formation than in the Asmari Formation and the wide variations in poro-perm values in the Dalan-Kangan Formation.
less than 10 mD. In addition, the relationship between porosity and permeability is not linear and pore connectivity is poor. The facies has reservoir potential only where it has been fractured.

**Coral boundstone-rudstones** are common in the Asmari Formation in some locations and have variable reservoir properties (Fig. 11). In the Gavarzin gas field, the facies constitutes two-thirds of the formation and has fair to moderate reservoir potential (Fig. 14B, Table 2), with average porosity of about 8% and permeability <10 mD.

The relationship between porosity and permeability in reservoir facies may provide insights into the pore system and original mineralogy. Cross-plots of porosity versus log permeability for the ooidal grainstones (Fig. 12D) show a wide scattering of data points. In comparison, there is a linear relationship between porosity and log permeability for the rudist and *Lithocodium*-bearing facies (Fig. 13A, B), although the correlation coefficients are not high.

The variable correlation between porosity and permeability data in the ooidal grainstones in the Dalan-Kangan, Surmeh and Asmari Formations (Fig. 12D) may indicate multiple and complex pore systems, reflecting the unstable aragonitic mineralogy and high diagenetic potential. In rudist and *Lithocodium* carbonates, in general there is a more uniform relationship between porosity and permeability due to the more stable original mineralogy. *Orbitolina* and coral facies carbonates in general have variable porosity but low permeability (<10 mD, Fig. 14) and there is poor connectivity between the dominantly interskeletal pores.

**DIAGENESIS AND PATTERNS OF POROSITY DISTRIBUTION**

The carbonate reservoir rocks in the study area were deposited in tropical climatic conditions from the Permian to the Miocene, and two depositional – diagenetic models can be recognized which have controlled the distribution of porosity and reservoir properties (Fig. 15) (Esrafi-Dizaji and Rahimpour-Bonab, 2014; Mehrabi et al., 2015a; Rahimpour-Bonab et al., 2013; Sun and Esteban, 1994).

In model A (hypersaline diagenetic model), reservoir rocks typically consist of repeated shallowing-up cycles which begin with oolitic-peloidal grainstones, followed by dolomitic lagoonal and intertidal facies, and capped by supratidal anhydritic facies (Fig. 15A). During warm and arid climatic periods associated with low sea levels, high energy ooid shoals developed on platform margins. The periodic emergence of these shoals into the meteoric realm resulted in extensive dissolution and the creation of oomouldic reservoir rocks (Esrafi-Dizaji and Rahimpour-Bonab, 2014). Hypersaline lagoons were established behind the shoals due to the limited seawater circulation, and dolomitisation and anhydrite precipitation occurred (Rahimpour-Bonab et al., 2010). In this model therefore, reservoir units consist of oolitic grainstones and dolomitised facies. Cycles were terminated by tight anhydrite facies which form cap rocks or intraformational flow barriers. In general, reservoir properties decrease upwards from cycle bottoms to tops and are accompanied by an enrichment in δ¹⁸O and a depletion in δ¹³C isotope values. This diagenetic model and porosity distribution pattern applies to carbonate reservoirs in the Dehram Group, Surmeh Formation and Asmari Formation (Daraei et al., 2014; Esrafi-Dizaji and Rahimpour-Bonab, 2014; Sun and Esteban, 1994).

In model B (Fig. 15B), the subaerial meteoric diagenetic model, reservoir intervals in general shallow and coarsen upward. Cycles begin with basinal or deep-marine facies and are terminated by karstified facies bounded above by regional unconformities or subaerial palaeo-exposure surfaces of more regional extent. As a result of sea level fall under humid climatic conditions,
Fig. 14. Cross-plots of porosity versus permeability for the Orbitolina facies of the Dariyan Formation (A) and the coral boundstones of the Asmari Formation (B). The facies show wide variations in porosity and permeability values.

Fig. 15. Hypersaline and subaerial models of diagenesis for carbonate reservoir rocks in SW Iran. Model A (hypersaline diagenetic model) shows the development of sabkha-type cycles under an arid palaeoclimate with dominant hypersaline diagenesis which resulted in the development of ooidal shoals and dolomitised reservoirs with evaporite cap rocks. Model B (subaerial meteoric diagenetic model) has shallowing-up cycles formed under a humid palaeoclimate with intense karstification and the creation of vuggy pore systems.
shallow-water carbonates were progressively exposed and subjected to meteoric diagenesis resulting in extensive dissolution and karstification. With long-term exposure, karst-related features such as fissures, caverns, breccias and paleosols are developed and can exert major controls on reservoir properties (Esrafilidizaji et al., 2015; Rahimpour-Bonab et al., 2013). In contrast to the previous model, higher porosity and permeability values occur in karstified facies with a dominant vuggy pore system in the upper parts of the cycles (Fig. 15B). In addition, significant depletion in both $\delta^{18}O$ and $\delta^{13}C$ values occur towards the tops of the cycles. This diagenetic model is applicable to reservoir units in the upper Khami and Bangestan Groups (Mehrabi et al., 2018; Mehrabi et al., 2015a, 2015b).

**COMPARATIVE RESERVOIR ANALYSIS**

In order to compare the reservoir quality of the various carbonate facies, the arithmetic means of porosity and permeability values were calculated based on core data from 115 reservoirs at 60 oil and gas fields (Table 3). Although this comparison is only based on matrix poro-perm values (not in situ porosity and permeability), the results show the general trend of reservoir potential for the different reservoir units. Average matrix porosity for the studied reservoirs ranges from 8 to 21 % (Table 3). The Bangestan and Khami Group reservoirs have higher mean porosity than the Dehram Group and Asmari Formation reservoirs, but permeability is variable. The best reservoir rocks occur in the Surmeh Formation (Arab-equivalent), where mean matrix porosity is 16% and permeability is 170 mD.

A frequency histogram of the average porosity in the reservoirs is presented in Fig. 16A. This plot shows that the highest frequency occurs at 9-11 % average porosity (with 16% of the frequency), and 81 % of the data-points are in the range of 5-17 % porosity. The ranges of mean porosity values for various reservoir rocks in Fig. 16B show that the Cretaceous limestone reservoirs have greater porosity variation than dolomitised pre- and post-Cretaceous reservoir rocks in the Dehram Group, Surmeh Formation and Asmari Formations.

A cross-plot of average matrix porosity versus permeability for the carbonate reservoir units

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**Table 3. Mean porosity and permeability data for Permian – Miocene carbonate reservoir rocks in SW Iran and the adjacent offshore.**

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Arithmetic mean</th>
<th>Geometric Mean</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Porosity (%)</td>
<td>Permeability (mD)</td>
</tr>
<tr>
<td>Dalan</td>
<td>9.16</td>
<td>22.72</td>
</tr>
<tr>
<td>Kangan</td>
<td>8.48</td>
<td>36.11</td>
</tr>
<tr>
<td>Surmeh</td>
<td>15.99</td>
<td>170.45</td>
</tr>
<tr>
<td>Fahliyan</td>
<td>14.83</td>
<td>61.88</td>
</tr>
<tr>
<td>Gadvan</td>
<td>20.78</td>
<td>8.29</td>
</tr>
<tr>
<td>Dariyan</td>
<td>15.77</td>
<td>3.05</td>
</tr>
<tr>
<td>Sarvak</td>
<td>12.84</td>
<td>11.89</td>
</tr>
<tr>
<td>Ilam</td>
<td>14.22</td>
<td>2.05</td>
</tr>
<tr>
<td>Asmari</td>
<td>10.76</td>
<td>46.39</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
(Fig. 17A) shows general trends which reflect the carbonates’ depositional and diagenetic histories. The plot suggests that the carbonate reservoir rocks can in general be classified into three groups (Fig. 17B):

**Group 1:** This group includes the Dalan, Kangan, Surmeh and Asmari Formations and has relatively good reservoir properties (Fig. 17B). Reservoir rocks are characterized by stacked, grain-dominated cycles and sealed by anhydrites and sabkha deposits. Mean porosity is 4 to 18% and mean permeability is >100 mD. Reservoir rocks are mostly grainstones and dolomitised facies, and fracturing is common, especially in the Asmari Formation.

**Group 2:** This group (Sarvak and Fahliyan Formations) consists of mixed grainy and muddy carbonates which have intermediate reservoir properties (Fig. 17B). Carbonates in this group have higher porosity (5-25%) but lower permeability (up to 60 mD) than those in Group 1. Karstified and reeval carbonate reservoirs are included in this group and dissolution is the main porosity-enhancing process.

Carbonates in **Group 3** show high porosity and relatively low permeability, and include reservoir units in the Gadvan, Dariyan and Ilam Formations which are characterised by mud-dominated facies with occasional grain-dominated intervals. Although porosity can reach 25%, mean permeability is generally <10 mD (Fig. 17B).

Fig. 17B shows that dolomitised carbonate reservoir rocks in Group 1 tend to have lower porosity and higher permeability than the Cretaceous limestones in the Bangestan and upper Khami Groups (Groups 2 and 3). The low matrix porosity (about 5%), especially in some dolomitized reservoirs in Group 1, suggests the importance of fracture systems in production (c.f. Schmoker *et al.*, 1985).

**DISCUSSION: CLASSIFICATION OF RESERVOIR ROCKS**
Table 4. Summary of the six genetic reservoir types recognized in SW Iran and the adjacent offshore.

<table>
<thead>
<tr>
<th>Reservoir Type</th>
<th>Name</th>
<th>Reservoir Facies</th>
<th>Porosity Type</th>
<th>Examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>Grainstone reservoir</td>
<td>ooid grainstone</td>
<td>interparticle, mouldic and intraparticle</td>
<td>Dalan, Kangan, Surmeh, Asmari</td>
</tr>
<tr>
<td>II</td>
<td>Reefal and algal mound reservoir</td>
<td>lithocodium mounds, rudistid and coral-algal patch reefs</td>
<td>growth-framework, mouldic, microporosity</td>
<td>Fahiyan, Dariyan, Sarvak</td>
</tr>
<tr>
<td>III</td>
<td>Dolomititic reservoir</td>
<td>dolomitized peritidal and lagoonal facies</td>
<td>Intercrystalline and microporosity</td>
<td>Dalan, Kangan, Surmeh, Asmari</td>
</tr>
<tr>
<td>IV</td>
<td>Karstified reservoir</td>
<td>dissolved facies associated with unconformities</td>
<td>solution vugs, mouldic and microporosity</td>
<td>Fahiyan, Gadvan, Dariyan, Sarvak</td>
</tr>
<tr>
<td>V</td>
<td>Fractured reservoir</td>
<td>fractured carbonates</td>
<td>fractures (all other types)</td>
<td>Sarvak and Asmari</td>
</tr>
<tr>
<td>VI</td>
<td>Sandstone reservoir</td>
<td>sandstone (conglomerate and siltstone)</td>
<td>intergrain (mouldic)</td>
<td>Faraghan Formation and Kushk, Azadegan and Ahwaz Members</td>
</tr>
</tbody>
</table>

Following Wilson (1980) and Ahr (2008), reservoir rocks in SW Iran and the adjacent offshore can be classified into six genetic types (I-VI, Table 4). Each type is defined on the basis of depositional facies and/or post-depositional modifications which control porosity generation and distribution. To show the temporal relationship of the reservoirs studied with eustasy, climate and tectonic history, in Fig. 18 the stratigraphic distribution of the reservoirs was plotted together with variations in global sea chemistry (Sandberg, 1983), a eustatic sea-level curve (Haq et al., 1987), phases of Zagros structural evolution (Sepehr and Cosgrove, 2004; Alavi, 2004) and palaeolatitude (Beydoun, 1998), as well as a range of palaeoclimatic indicators.

The plot shows that development of these reservoir rocks was strongly controlled by palaeoclimatic conditions. From the Permian onwards, the Zagros area migrated from latitude 30°S to 30°N; the region was located in the southern hemisphere during the Late Palaeozoic, moving from equatorial waters (in the Triassic and Cretaceous) and then drifted northwards to its present-day location. Due to the tropical climatic conditions, the associated stratigraphic succession consists predominantly of marine carbonates with subordinate intervals of fine clastics (marls, shales, argillaceous carbonates) and periodic evaporites (Alsharhan, 2014; Beydoun, 1998).

Based on palaeoclimatic indicators and palaeolatitudinal positions (Fig. 18), the stratigraphic succession in the Zagros area is interpreted to have been deposited in a range of climatic conditions. Lithostratigraphic data indicate that the pre-Cretaceous succession (Permian to Jurassic) in general includes thick evaporites, such as the Lower-Middle Triassic Dashtak and Upper Jurassic Hith Formations, together with dolomite-dominated lithologies. These units were deposited in carbonate-evaporite platforms during low eustatic sea levels under arid to semi-arid conditions, and carbonates were subsequently dolomitised. The Dehram Group and Surmeh Formation (Lower Khami Group) reservoirs were deposited during this period and are in general composed of ooid grainstones and dolomitised facies (Esrafili-Dizaji and Rahimpour-Bonab, 2014; Daraei et al., 2014) with dominant oomoldic and intracrystalline pore types (reservoir types I and III: Table 4). They are capped by thick evaporites.

During the Cretaceous, the study area was located close to the equator. This period coincides with high eustatic sea levels, calcite seas and a humid palaeo climate. Cretaceous carbonates are characterised by build-ups dominated by Lithocodium mounds and rudist communities, with regional karstification and laterite formation associated with periodic subaerial exposure. Evaporites and ooid grainstones were in general not deposited during this period. However, siliciclastics derived from the Arabian Shield were eroded and transported through deltas into inner platform areas during the Early to mid-Cretaceous, interfingerling to the east with marine carbonates. Reefal and karst-related carbonates reservoirs in the upper Khami and Bangestan Groups (reservoir types II and IV, Table 4) formed in this period, together with the Kushk and Azadegan sandstone reservoirs (Esrafili-Dizaji et al., 2015; Mehrabi et al., 2018; Rahimpour-Bonab et al., 2013; Enayati-Bidgoli and Saemi, 2019; Mehrabi et al., 2019). Subaerial exposure and meteoric dissolution were critical for the development and preservation of porosity in the carbonates, and vuggy and dissolution pores and fractures are common. Cap rocks are composed of shales and argillaceous limestones (Gadvan, Kazhdumi and Gurpi Formations).

During the Cenozoic, the Zagros area moved to northern latitudes with a semi-arid to arid climate. The
Fig. 18. Reconstruction of palaeoclimatic changes in SW Iran based on data from the stratigraphic record and palaeogeographic location. Palaeoclimate in this area has changed significantly over time due to the northward drift of the Arabian Plate, resulting in major facies and lithological variations in the related sedimentary deposits. Palaeoclimatic indicators include general lithology (e.g. evaporites indicating aridity), allochem types present, and diagenetic imprint. (Based on data from Alavi, 2004; Alsharhan, 2014; Darawi et al., 2014; Esrafil-Dizaji and Dalvand, 2018; Esrafil-Dizaji and Rahimpour-Bonab, 2013; James and Wynd, 1965; Mehrabi et al., 2018; Murris, 1980; Rahimpour-Bonab et al., 2013; Wynd, 1965; Ziegler, 2001).
prolific Asmari carbonate reservoir were deposited in this period; importantly, the carbonates were significantly fractured during regional shortening associated with the Zagros orogeny. Regressive conditions in the Late Oligocene resulted in the deposition of the Ahwaz Sandstone. Fracturing of these reservoirs has contributed greatly to oil production (reservoir types V and VI, Table 4). In addition, ooid grainstones and dolomitised facies (reservoir types I and III, Table 4) also occur in the Asmari Formation and developed in an arid palaeoclimate during the Miocene (Aqrawi et al., 2006; Ehrenberg et al., 2007a).

CONCLUSIONS

Carbonate reservoirs in the Dehram, Khami and Bangestan Groups and the Asmari Formation contain most of the hydrocarbons in SW Iran and the adjacent Persian Gulf. Most gas and condensate accumulations occur in reservoirs in the Permo-Triassic Dehram Group, while more than 80% of Iran’s oil has been discovered in reservoirs in the Oligo-Miocene Asmari Formation and the Albion – Campanian Bangestan Group. Relatively minor production and considerable exploration potential occurs in Middle Jurassic – Aptian Khami Group carbonates. In addition, minor volumes of oil and gas have been found in the Dashtak, Neyriz, Najmeh, Pabdeh, Jahrum, Shahbazan, Razak and Mishan (Guri Member) Formations.

Porosity development and distribution in these carbonate reservoirs is complex and was strongly influenced by palaeoclimate. An analysis based on core data from 60 oil fields (115 reservoirs) showed that both pre-Cretaceous carbonates (Dehram Group and Surmeh Formation) and Asmari Formation carbonates have better reservoir properties than Cretaceous carbonates in the upper Khami and Bangestan Groups. Productive intervals in the former carbonates in general occur in ooidal grainstones and dolomitised facies which developed under arid palaeoclimatic conditions with dominant hypersaline diagenesis. The preferential development of fractures in dolomitised units has enhanced their permeability (e.g. the fractured Asmari reservoirs). These reservoirs are in general capped by tight evaporite seals (Dashtak, Hith and Gachsaran Formations).

In the Cretaceous (upper Khami and Bangestan) carbonates, by contrast, subaerial meteoric diagenesis is dominant and is typically associated with regional-scale unconformities. The main reservoir units are karstified limestones and organic build-ups dominated by Lithocodium and rudists which developed under humid climatic conditions. Although these reservoir rocks in general have comparatively high matrix porosity, average matrix permeability is relatively low. Due to the palaeoclimatic conditions during deposition, ooidal facies and hypersaline diagenesis (dolomitisation) occur only rarely, and reservoirs are commonly sealed by tight shales and argillaceous limestones.

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