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PETROLEUM SYSTEMS IN THE AUSTRIAN SECTOR OF THE NORTH ALPINE FORELAND BASIN: AN OVERVIEW

D. Gross[1], R. F. Sachsenhofer[1], A. Bechtel[1], R. Gratzer[1], M.-L. Grundtner[1], H.-G. Linzer[2], D. Misch[1], L. Pytlak[1] and L. Scheucher[2]

Two separate petroleum systems have been identified in the Austrian sector of the North Alpine Foreland Basin: a lower Oligocene – Cenomanian/Eocene oil and thermogenic gas system; and an Oligocene-Miocene microbial gas system. Recent studies by both academic and industry-based research groups have resulted in an improved understanding of these petroleum systems, which are reviewed in this paper.

Lower Oligocene organic-rich intervals (up to 12 %TOC; HI: 400-600 mgHC/gTOC), capable of generating slightly more than 1 t of hydrocarbons/m², are the source rocks for the thermogenic petroleum system in the Austrian sector of the North Alpine Foreland Basin. The present-day distribution of this source rock is controlled by submarine mass movements which removed a large part of the organic-rich interval from its depositional location during the late early Oligocene. The transported material was redeposited in locations to the south which are at the present day buried beneath Alpine thrust sheets. In addition, source rock units were incorporated into Molasse imbricates during Alpine deformation. Hydrocarbon generation began during the Miocene, and the oil kitchen was located to the south of the Alpine thrust front. Hence, lateral migration over distances of up to 50 km was required to charge the mainly Eocene and Cenomanian non- and shallow-marine sandstone reservoir units. Hydrocarbons are in general trapped in structures related to east-west trending normal faults, and differences in source rock facies resulted in the development of separate western and eastern oil families. Surprisingly, with the exception of some fields in the eastern part of the study area, associated gas contains varying (and sometimes very high) percentages of primary and secondary microbial methane. The composition of oil in some fields is influenced by both biodegradation and water washing. Post-Miocene uplift in the Austrian sector of the basin had further effects on biodegradation and the consequent formation of secondary microbial gas, and also resulted in re-migration.

The upper Oligocene to lower Miocene succession (Puchkirchen Group, Hall Formation) provides both source and reservoir rocks for the microbial petroleum system in the Austrian sector of the North Alpine Foreland Basin. TOC contents (<1.0 %) and HI values (<140

[1] Montanuniversitaet, Chair in Petroleum Geology, Department of Applied Geosciences and Geophysics, Peter-Tunner-Str. 5, A-8700 Leoben, Austria.
[2] Rohöl-Aufsuchungs AG, Schwarzenbergplatz 16, A-1015 Vienna, Austria.
* corresponding author: doris.gross@unileoben.ac.at

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mgHC/gTOC) of pelitic source rocks are typically low. Microbial gas was generated shortly after deposition during early diagenesis and was subsequently fixed in gas hydrates. Basin subsidence and high sedimentation rates resulted in decomposition of the hydrates below their stability zone, and reservoirs were filled during the early Miocene. Subsequent mixing of microbial gas with thermogenic gas and condensates is widespread. However, biodegradation has prevented precise determination of the fraction of thermogenic hydrocarbons present in gas samples. Reservoir sandstones were deposited within a deep-marine channel belt along the axis of the North Alpine Foreland Basin, and reservoir quality depends on the precise position within this belt. In the study area, gas is trapped in compaction anticlines or at channel margin pinch-outs and additional traps are formed by imbrication structures.

INTRODUCTION

The North Alpine Foreland Basin, located in the western Paratethys (Fig. 1), is a minor oil and a moderate gas province with 493 MM boe of recoverable reserves (Véron, 2005; Boote *et al*., 2018, *this issue*). Although shallow hydrocarbon accumulations and oil and gas seeps have been known for more than 100 years (Misch *et al*., 2017), major hydrocarbon production began only in the 1950s and more than 190 discoveries have since been made in the Mesozoic and Cenozoic basin fill (Fig. 2). Most hydrocarbon fields are located in the Bavarian and Austrian sectors of the basin. In the Swiss and German sectors, only minor exploration activity has taken place during recent decades and many fields have been abandoned (Misch *et al*., 2017). By contrast, a large number of new exploration wells have been drilled in the Austrian part of the basin by Rohöl-Aufsuchungs AG (Vienna). In combination with a comprehensive 3D seismic data-set, information from these wells has improved the general understanding of the sedimentological and tectonic evolution of the basin (e.g. Linzer, 2001; de Ruig and Hubbard, 2006; Grunert *et al*., 2013; Hinsch, 2013). Moreover, the significant number of producing fields presents an opportunity to obtain oil and gas samples, and this has helped to discriminate and characterize the separate thermogenic and microbial petroleum systems present (e.g. Schulz *et al*., 2002; Sachsenhofer and Schulz, 2006; Gratzer *et al*., 2011; Pytlak *et al*., 2016; Pytlak *et al*., 2017a,b).

The largest oil field in the Austrian sector of the North Alpine Foreland Basin is Voitsdorf (V in Fig. 1c), and the largest gas field is Haidach (Haid in Fig. 3a). The Voitsdorf field is 10 km long and 1 km wide. To date, more than 21 million brl oe have been produced from two oil-bearing intervals. The total volume of gas in the Haidach field is 4.3 B Nm³. The reservoir extends over an area of 17.5 km² and is locally 100 m thick (RAG, 2010). More than 16 million tons of oil and 26 B Nm³ of gas are reported to have been produced by Rohöl-Aufsuchungs AG in the Austrian sector of the basin up to 2015 (*unpublished data*).

The present contribution aims to summarise previous work on the regional and petroleum geology of the Austrian sector of the North Alpine Foreland Basin, which may serve as a model for other foreland basins in the Paratethys realm.

REGIONAL GEOLOGY

The North Alpine Foreland Basin extends along the northern margin of the Alps from Geneva to Vienna (Fig. 1). In the Austrian sector of the basin, the northern margin is delineated by the Bohemian Massif while the margin to the south is overthrust by Alpine nappes (Fig. 1b) (Wagner, 1996).

Basin Fill

During the final stages of the Variscan orogeny, NW- and NE-trending graben structures formed locally within the crystalline basement on the SW margin of the Central Swell Zone (Fig. 1) and were filled with Permian-Carboniferous sediments (Fig. 2). In the Austrian sector of the North Alpine Foreland Basin, the Mesozoic succession begins with Middle Jurassic fluvial and marine sandstones (Nachtmann and Wagner, 1987). From late Middle Jurassic to earliest Cretaceous times, carbonate rocks were deposited in a tropical climate on the shelf of the Bohemian Massif (Wagner, 1996), while Early Cretaceous tectonism resulted in uplift, erosion and karstification of the carbonate platform. Thereafter, a major Cenomanian transgression from the SW resulted in the deposition of storm-influenced, shallow-marine, fine- to coarse-grained glauconitic sandstones (Nachtmann and Wagner, 1987: Regensburg Formation *sensu* Niebuhr *et al*., 2009). Continuing subsidence during Turonian times led to the deposition of marls in deeper-water environments. The latter are overlain by glauconitic fine-grained sandstones and Coniacian to upper Campanian marls, mudstones and sandstones. Subsequent uplift of the European plate resulted in significant erosion of the Mesozoic succession.

The Molasse stage of basin evolution began in the late Eocene in response to loading of the southern margin of the European plate by the advancing Alpine nappes (Bachmann *et al*., 1987; Genser *et al*., 2007). The transgressive Eocene succession is characterized by floodplain, meandering channel and lacustrine deposits with thin coal seams (Voitsdorf Formation: Fig. 2), which are overlain by dark-grey claystones and tidal channel sandstones with abundant gastropods (Cerithian Beds), shallow-marine, often bioturbated sandstones (Ampfing Formation), and red-algal reefal

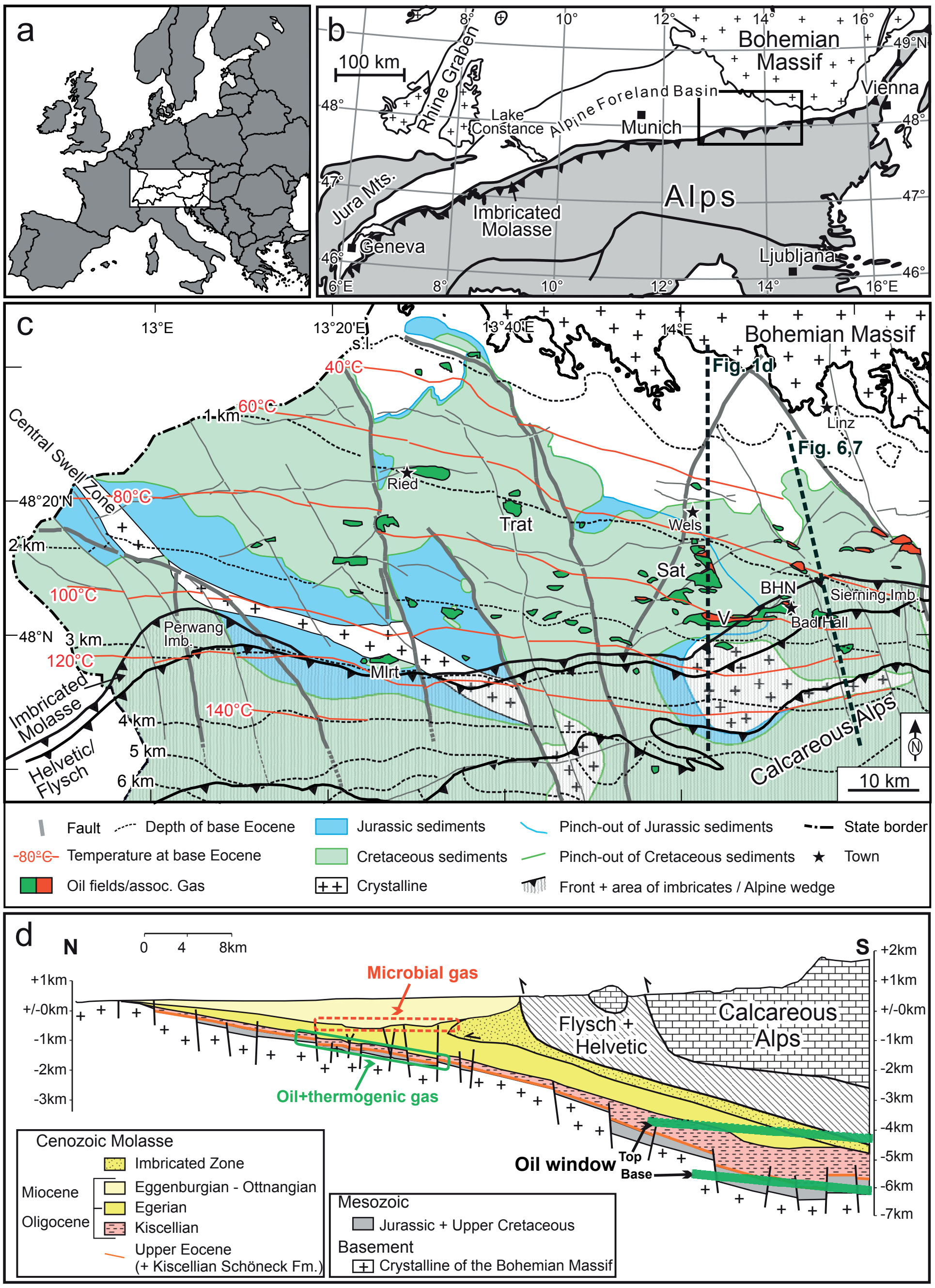

Fig. 1. (a, b) Maps of Europe at different scales showing the location of the study area in the North Alpine Foreland Basin. (c) Subcrop map of pre-Cenozoic units in the study area (after Wagner, 1998; and Kröll *et al.*, 2006) together with temperatures in the base-Cenozoic and the distribution of fields with (thermogenic) hydrocarbons in Cenomanian and Eocene reservoir units (after Pytlak *et al.*, 2016). Profiles of the cross-sections in Fig. 1d and Figs 6 and 7 are indicated by dotted lines. The outline of (c) is marked as the box in Fig. 1b. (d) Schematic north-south trending cross-section through the North Alpine Foreland Basin with the thermogenic and microbial petroleum systems (modified after Sachsenhofer and Schulz, 2006).

carbonates and associated debris (Lithothamnium Limestone) (Wagner, 1998; Rasser and Piller, 2004).

During early Oligocene time, the North Alpine Foreland Basin deepened and widened abruptly (Sissingh, 1997), resulting in the deposition of deeper-water sediments (Schöneck, Dynow, Eggerding, Zupfing Formations; Fig. 2); these units are equivalents to the organic matter-rich Menilite Formation in the Carpathians and the lower part of the Maikop Group in the Eastern Paratethys (Sachsenhofer *et al.*, 2017; 2018 *this issue*). The Schöneck Formation is in general about 10 to 20 m thick and consists of organic-rich marls and shales (Gier, 2000; Schulz *et al.*, 2002; Sachsenhofer and Schulz, 2006). The Dynow Formation (5-15 m thick) represents the Paratethys-wide low salinity "Solenovian event" (Popov *et al.*, 2004) and consists of light-coloured coccolith limestones and marls. This succession is overlain by the Eggerding Formation, 35 to 45 m thick, which comprises dark grey, laminated pelitic rocks with sandstone intervals in the northern

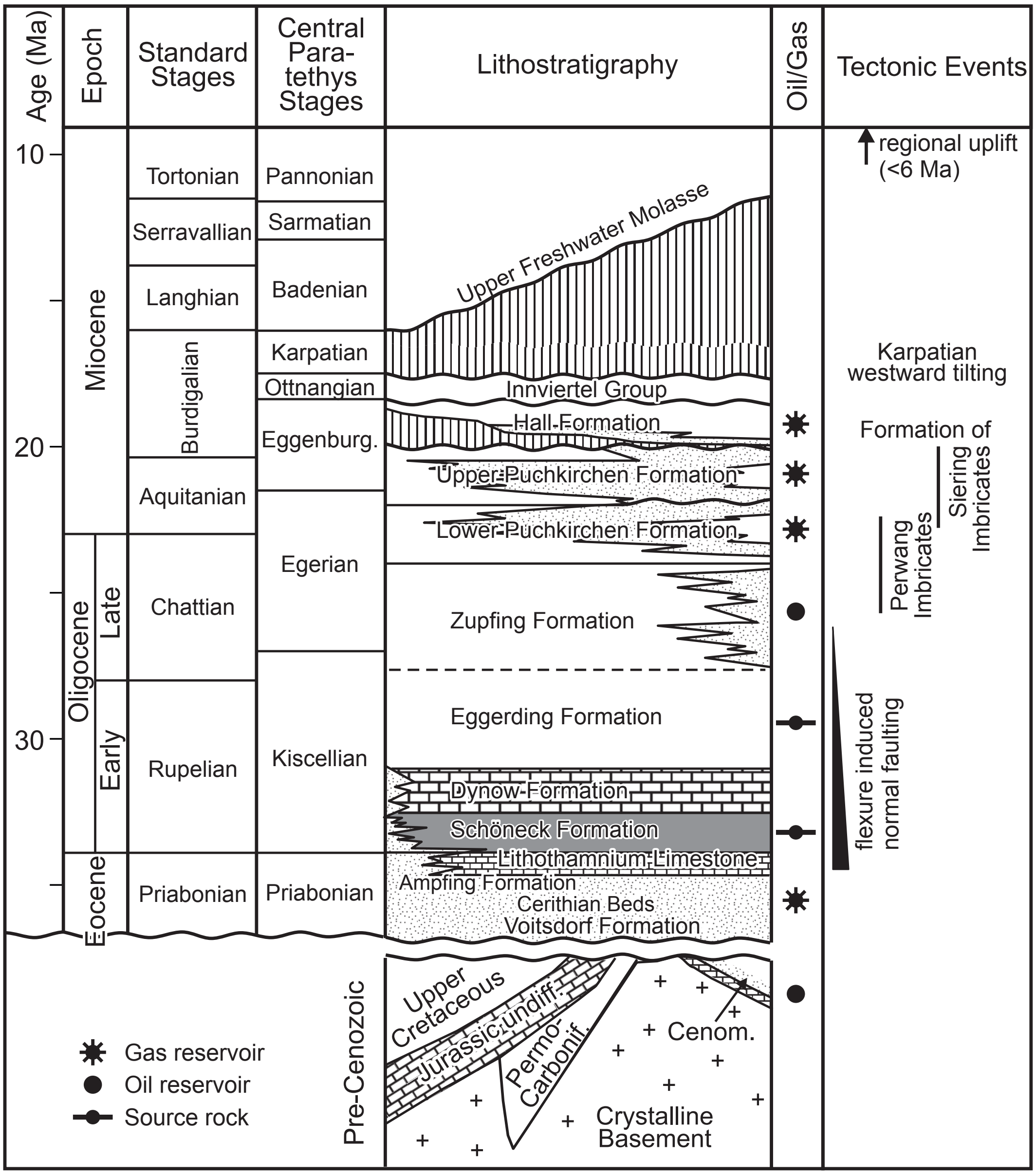

Fig. 2. Lithostratigraphy of the Austrian part of the North Alpine Foreland Basin with the main source and reservoir rocks (modified after Wagner, 1998; Hinsch, 2013; and Grunert *et al.*, 2015). Timing of Cenozoic tectonic events after Gusterhuber *et al.,* 2012; and Hinsch, 2013.

part of the basin. Submarine mass movements during deposition of the formation locally removed the underlying Oligocene units and reduced the thickness of the Eggerding Formation (Sachsenhofer and Schulz, 2006; Linzer and Sachsenhofer, 2010). The overlying Zupfing Formation is up to 450 m thick and consists of dark grey hemipelagic sediments and turbidites (Wagner, 1996; 1998).

During late Oligocene to early Miocene times, deep-marine conditions continued in the sector of the basin to the east of Munich, whereas a deltaic complex was formed in the western part of the basin (Fig. 3). The Puchkirchen Group (Lower and Upper Puchkirchen Formations) was deposited in the deep-marine Puchkirchen Trough and reaches a maximum thickness of ~2500 m near the Alpine thrust front. It includes coarse-grained siliciclastic rocks which have long been attributed to lobate turbiditic fans on the southern slope of the basin (e.g. Malzer, 1981). However, regional 3D seismic data, calibrated by a large number of wells, has shown that sedimentation occurred primarily in a basin-axial low-sinuosity channel belt, involving mass-transport complexes, overbank deposits and tributary channel sediments (Puchkirchen Channel; e.g. de Ruig and Hubbard, 2006; Hinsch, 2008) (Fig. 3).

The Puchkirchen Group is separated from the lower Miocene Hall Formation by a prominent subaqueous erosional hiatus (base Hall Unconformity). Turbiditic sediments in the lower part of the Hall Formation were deposited in the deep-marine Puchkirchen Channel (Borowski, 2006; Grunert *et al.*, 2013), while

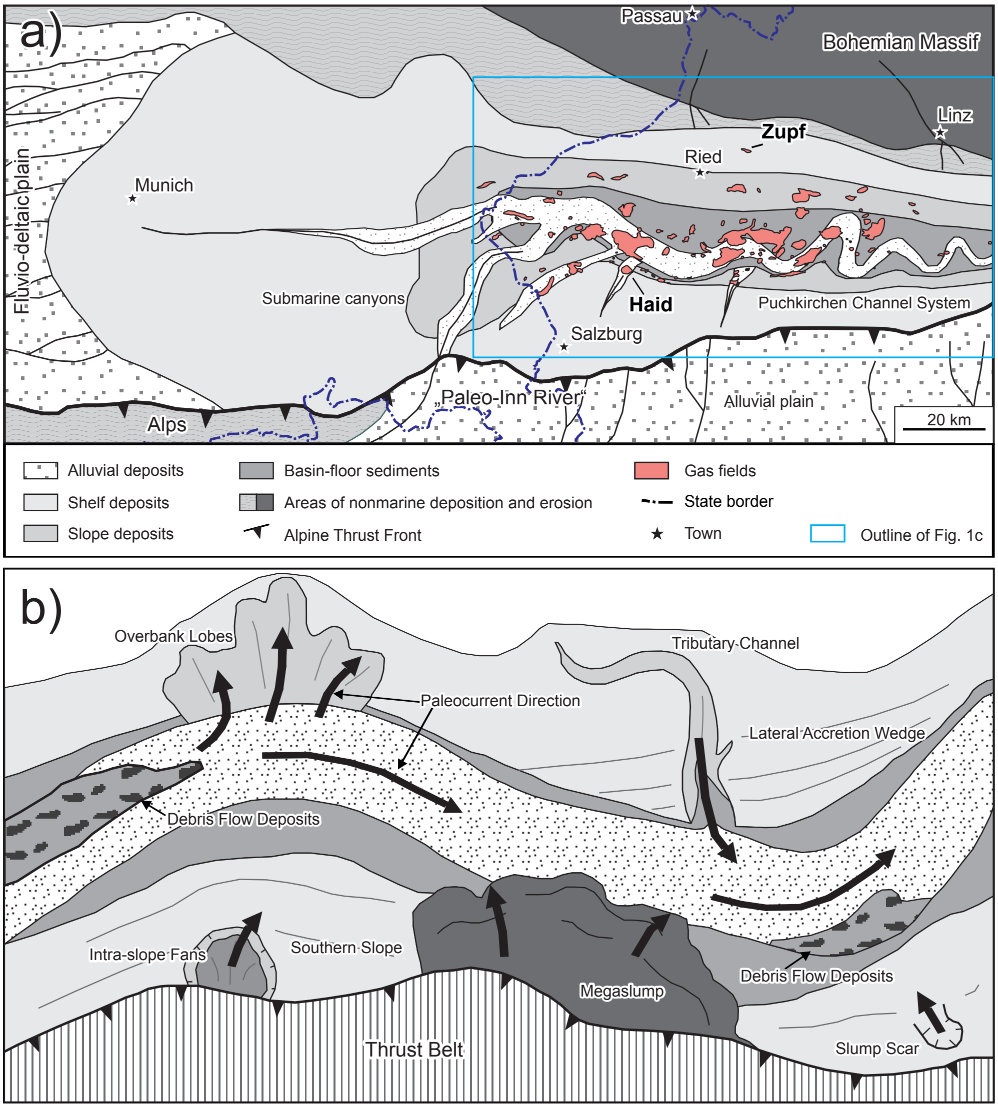

Fig. 3. (a) Schematic palaeogeographic reconstruction for the central and eastern part of the North Alpine Foreland Basin during deposition of the Puchkirchen Group (after de Ruig and Hubbard, 2006). Locations of gas fields within the Puchkirchen Group and the overlying Hall Formation are shown. The blue box marks the outline of Fig. 1c.
(b) Schematic model of the different types of channel deposits in the Puchkirchen Group and the basal Hall Formation (redrawn after de Ruig and Hubbard, 2006).

sediments in the upper part are characterized by tide- and wave-influenced deltaic deposits (Grunert *et al.*, 2013). The total thickness of the Hall Formation is up to 800 m.

The basin was finally filled with sediments of the Innviertel Group (Fig. 2). Coal-bearing freshwater sediments ("Upper Freshwater Molasse") were deposited during Badenian to Pannonian times above an erosional unconformity (Fig. 2).

Tectonic evolution

The pre-Cenozoic succession in the North Alpine Foreland Basin is dissected by cross-cutting faults (Fig. 1c). NW- to NNW- and NE-trending strike-slip faults formed during the late Variscan orogeny and were later reactivated in Mesozoic and Paleocene times (Wagner, 1998). East-west trending normal faults are related to downward flexure of the European margin in front of the Alpine thrust-sheets (Genser *et al.*, 2007). Fault activity was especially intense during early Oligocene time, but seismic data show that some faults were active until the earliest Miocene (e.g. Pytlak *et al.*, 2017a) .

The Alpine nappes were thrust over Molasse sediments in the southern part of the North Alpine Foreland Basin during Oligocene and early Miocene times, and the Molasse succession was partly incorporated into the fold-and-thrust belt forming structures known as the Molasse imbricates. Based on earlier work (e.g. Linzer, 2001, 2009), Hinsch (2013) presented an overview of the Molasse imbricates, showing that the timing and structural style vary along strike. In the Sierning imbricates in the east (Fig. 1c), a detachment is present within the Rupelian

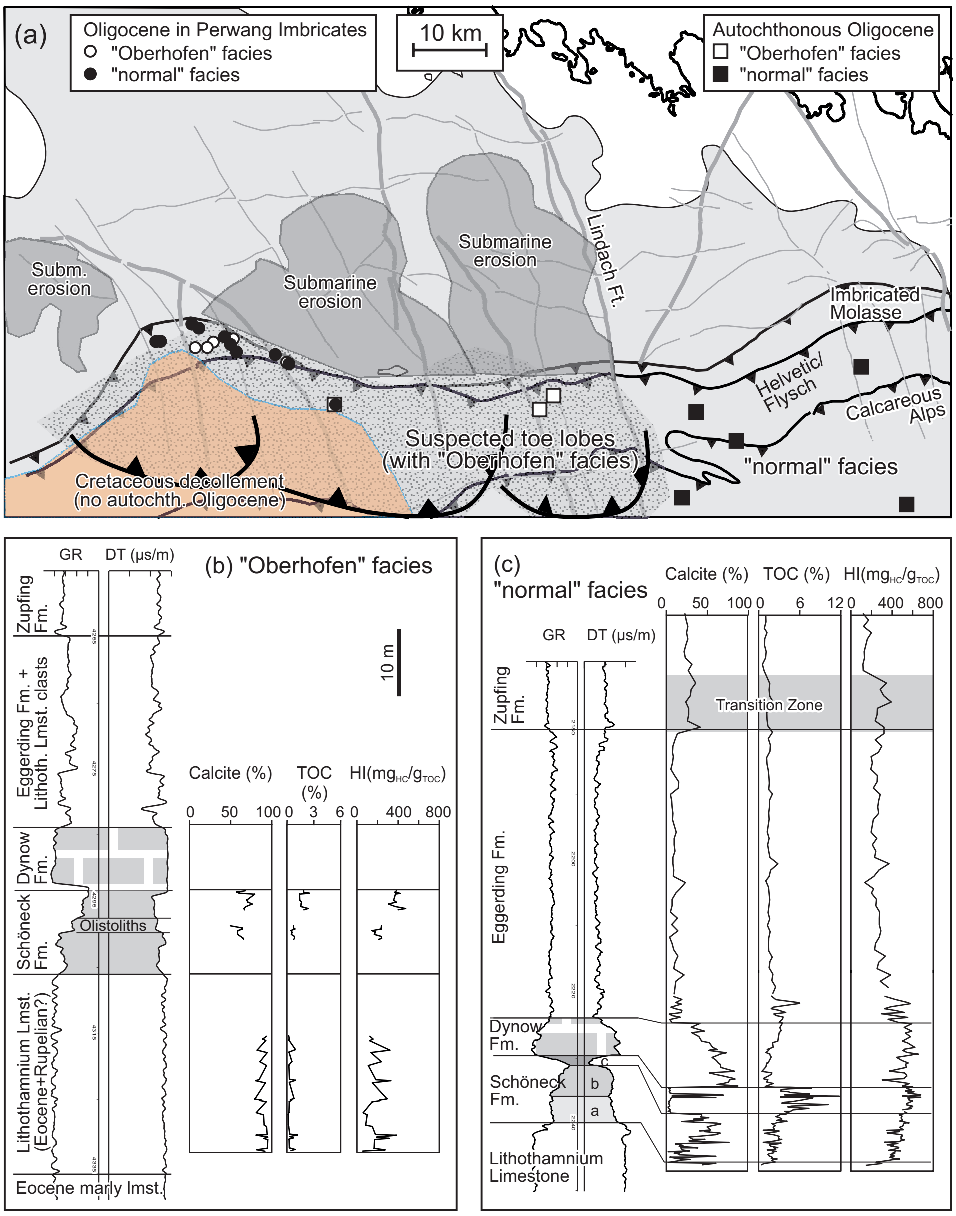

Fig. 4. Lower Oligocene source rocks in the North Alpine Foreland Basin. (a) Distribution of the Schöneck Formation (based on Sachsenhofer and Schulz, 2006; Sachsenhofer *et al.,* 2010; Linzer and Sachsenhofer, 2010). The profiles below show log patterns and bulk geochemical data for (b) "normal facies" and (c) "Oberhofen facies" (compiled after Schulz *et al.*, 2002; Sachsenhofer and Schulz, 2006; Sachsenhofer *et al.,* 2010).

marls of the Zupfing Formation which are overlain by the Burdigalian Hall Formation. Only thin thrust sheets with a shallow detachment are present in the central part of the basin. By contrast, the Perwang imbricates in the west show an Oligocene wedge with complex, deformed thrust sheets above a deep detachment horizon located in Upper Cretaceous marls. Thrust sheets consist of Cretaceous to Chattian (Lower Puchkirchen Formation) sediments, and are overlain by the Lower and Upper Puchkirchen Formations. Minimum shortening in the Molasse imbricates ranges from 6.2 km (Sierning imbricates) to close to zero (central segment), and to 18.5 km in the Perwang imbricates (Hinsch, 2013; Gusterhuber *et al*., 2013; 2014). However, the minimum amount of total shortening in the Chattian and Aquitanian (including overthrusting by Alpine nappes) is about 32 km (Hinsch, 2013).

Seismic data and isopach maps indicate a Karpatian phase of regional tilting of the basin to the west by about 0.5 % (Gusterhuber *et al*., 2012). Extensive uplift after deposition of upper Miocene fluvial deposits caused erosion of approximately 500 to 900 m of sediments; even greater amounts of erosion in the eastern part of the basin (by an additional 300 to 1000 m) is indicated by shale compaction data derived from sonic logs (Gusterhuber *et al*., 2012). While the regional uplift was probably related to isostatic rebound of the Alps at the end of thrusting, local uplift in the east may have been affected by late Neogene east-west compressional events within the Alpine-Pannonian system (Gusterhuber *et al*., 2012).

PETROLEUM SYSTEMS IN THE AUSTRIAN PART OF THE NORTH ALPINE FORELAND BASIN

In previous studies, separate thermogenic and microbial petroleum systems have been distinguished in the Austrian part of the North Alpine Foreland Basin (Fig. 1d; e.g. Wagner, 1998). Oil and gas fields attributed to the thermogenic petroleum systems are shown in Fig. 1b. The location of gas fields considered to have a microbial origin are shown in Fig. 3a. The thermogenic petroleum system comprises lower Oligocene source rocks which have charged Cenomanian and Eocene reservoir units; both source and reservoir rocks in the microbial system are located in upper Oligocene and lower Miocene intervals (Puchkirchen Group, Hall Formation). Petroleum systems elements and processes are described in the following section.

1. THE THERMOGENIC PETROLEUM SYSTEM

Source rocks

Thermogenic hydrocarbons in the Austrian sector of the North Alpine Foreland Basin are generated by lower Oligocene source rocks (Gratzer *et al*., 2011). The distribution of the Schöneck Formation, considered to be the most prolific source rock (Schulz *et al*., 2002), is shown in Fig. 4a. The lateral extent of the Dynow and Eggerding Formations, which also are organic matter-rich (Schulz *et al*., 2005; Sachsenhofer *et al*., 2010), is similar. However, log correlations together with seismic data show that large parts of the Lower Oligocene succession west of the Lindach Fault (Fig. 4a) were removed by submarine mass movements during deposition of the Eggerding Formation (Sachsenhofer and Schulz, 2006; Sachsenhofer *et al*., 2010). The redeposited material is probably present in toe lobes which are overthrust by the Alpine nappes (e.g. Linzer and Sachsenhofer, 2010) (Fig. 4a). This material has been recorded at a few wells and is termed the "Oberhofen facies" (Fig. 4b) (Sachsenhofer and Schulz, 2006) to distinguish it from the "normal facies" (Fig. 4c).

Logs and bulk geochemical data for the "normal facies", which has been penetrated by hundreds of wells (including some wells beneath the Alpine nappes), are shown in Fig. 4c. The Schöneck Formation is typically 10 to 25 m thick and comprises two lower marl members (referred to as members "a" and "b") and an upper black shale member "c" (Schulz *et al*., 2002). Average TOC contents are 2.3 % in members "a" and "b" and 5.5 % (up to 12 %) in member "c". The hydrogen index (HI) increases upwards from 400 to 600 mgHC/gTOC and indicates the presence of oil-prone Type II kerogen (Schulz *et al*., 2002). The Dynow Formation, 5 to 15 m thick, comprises marly limestones (~1% TOC) which grade upwards into organic-rich marls with up to 3 % TOC (Sachsenhofer and Schulz, 2006). HI values range from 500 to 600 mgHC/gTOC. The main part of the Eggerding Formation (and the base of the Zupfing Formation; "Transition Zone") contain a moderate amount of organic matter (~1.5 % TOC) dominated by Type II/III kerogen (200-400 mgHC/gTOC; Sachsenhofer *et al*., 2010). Using the Source Potential Index of Demaison and Huizinga (1994), Sachsenhofer *et al*. (2010) estimated that the lower Oligocene succession could generate about 1.1 t of hydrocarbons per m^2.

The log pattern of the "Oberhofen facies" (Fig. 4b) is clearly different from that of the "normal facies". Although only limited source rock data are available, the data suggest that TOC contents (<2.5 %) and HI values (<400 mgHC/gTOC; Sachsenhofer and Schulz, 2006) are lower than those in the "normal facies".

The distribution of source rock facies beneath the Alpine nappes where the kitchen area is located (see below) has been further modified by the late Oligocene formation of the Perwang tectonic imbricates, which removed the source rock interval from the autochthonous section and incorporated it into the thrust sheets (Fig. 4a). Consequently, it is expected that the "normal" source rock facies is dominant in the east and the "Oberhofen facies" in the west, except in areas where it has been tectonically removed (Fig. 4a). Within the Perwang imbricates, source rocks of both the "normal" and "Oberhofen" facies are present.

Reservoir rocks

The most important reservoir rocks for oil within the Austrian part of the North Alpine Foreland Basin consist of upper Eocene sandstones, although some oil also occurs in Mesozoic (e.g. Cenomanian) sandstones and Eocene limestones. Heavy oil and oil stains are also found in lower Oligocene siliciclastics. In the following section, Cenomanian and Eocene reservoir rocks are briefly described.

Cenomanian (Regensburg Formation)

Cenomanian sandstones are typically tens of metres thick (Nachtmann, 1994; Gross *et al*., 2015b) and can be divided into three units based on lithology and wireline log response (Nachtmann, 1994). The lower units CE3 and CE2 represent the main reservoir intervals; CE1 consists of calcareous sandstones, rich in shell fragments and echinoid remains (Nachtmann, 1994). Foraminifera and less abundant ostracods occur in units CE3 and CE2. Cenomanian sandstones are typically subarkoses with high quartz (>80 vol.%) and feldspar contents (up to 15 vol.%) (Fig. 5). Idiomorphic pyrite and illite/muscovite occur in minor amounts (Gross *et al*., 2015a). Glauconite-

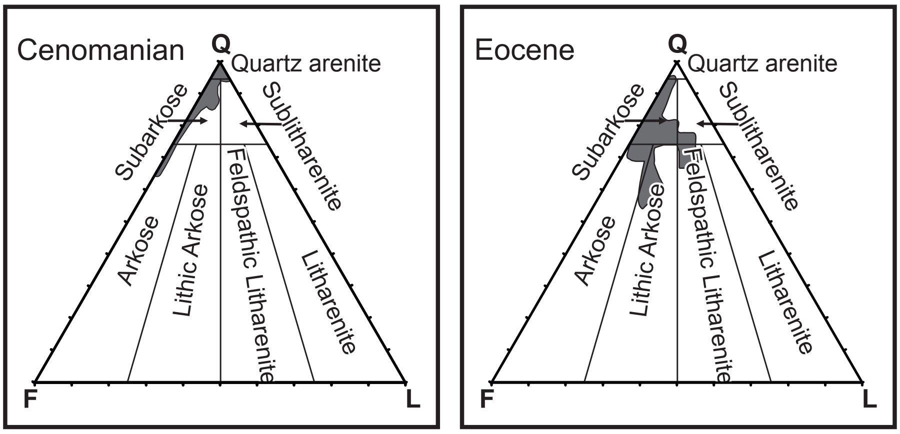

Fig. 5. QFL classification (Folk, 1968) of Cenomanian and Eocene reservoir sandstones (Q – quartz; F – feldspar; L – lithic fragments).

rich sandstones are common within the Cenomanian succession (Nachtmann, 1994) and indicate deposition in a shallow-marine environment with oxygen-depleted conditions during early diagenesis (Füchtbauer, 1988). A primary clay matrix is present in fine-grained sandstones and reduces the pore space significantly (Gross *et al*., 2015a). Detrital clay minerals are often recrystallized into chlorite. With the exception of the sandstone intervals which rest directly on Jurassic carbonates, carbonate cementation is generally weak in units CE3 and CE2. CE1 shows significantly more carbonate cementation which is probably a result of the presence of bioclasts and recrystallized lime mud (Gross *et al*., 2015a).

Porosity values in Cenomanian sandstones vary between 8 and 26 %; permeability values range from <1 mD to more than 3000 mD (Nachtmann, 1994; Gross *et al*., 2015a,b). The best reservoir properties are found in coarse-grained sandstones and in matrix-free storm deposits which are composed of fine-grained sandstones (Nachtmann, 1994).

Eocene (Voitsdorf Formation, Cerithian Beds, Ampfing Formation)

Coarse-grained and matrix-poor meandering channel (Voitsdorf Formation), tidal channel (Cerithian Beds) and shallow-marine sandstones (Ampfing Formation) form the most important Eocene reservoirs (Wagner, 1980; 1998).

Sandstones of the Voitsdorf Formation are in general about 2 m thick. In the Sat field (Fig. 1c), four sandstone intervals with low lateral continuity have a net thickness of 2.3 m (Nachtmann, 1989). The sandstones are poorly sorted and can be classified as lithic arkoses with 40 vol% quartz and 18 vol% feldspar on average (Grundtner *et al*., 2017). Lithic arkoses with a net thickness of up to 6.1 m also occur in the Cerithian Beds at the Sat field (Nachtmann, 1989).

Shallow-marine sandstones of the Ampfing Formation are laterally more continuous than the channel sandstones of the Voitsdorf Formation and the Cerithian Beds and have a net thickness of 10 m. Most sandstones show moderate sorting and are classified as lithic arkoses, but litharenites, subarkoses and sublitharenites are also observed in the northern part of the North Alpine Foreland Basin (Fig. 5) (Grundtner *et al*., 2017). Rare glauconite and the presence of foraminifera support a marine depositional environment.

In sandstones from all units, detrital muscovite, biotite, pyrite and clay minerals (kaolinite, illite, smectite, chlorite) occur in minor amounts. Kaolinite formed as an alteration product of feldspar. Whereas carbonate cement is typically rare in non-marine to brackish sandstones, the amount of carbonate cement in sandstones of the marine Ampfing Formation often exceeds >5 vol%. Early diagenetic carbonate precipitation, promoted by alkaline conditions, prevented further compaction but the carbonate was was later partly dissolved (Grundtner *et al*., 2017). The isotopic composition of the carbonate cement indicates the non-marine formation of carbonate minerals in the Voitsdorf Formation and the Cerithian Beds, and a meteoric flush in the laterally-continuous Ampfing Formation. Single well-cemented layers, up to 50 cm thick, may occur locally in all units. They formed either during advanced stages of sulphate reduction or are associated with fermentation (methanogenesis) (Grundtner *et al*., 2017).

Eocene sandstones may exhibit excellent reservoir properties with porosities up to 25% and permeabilities up to 3000 mD (Wagner, 1980; Gross *et al*., 2015a), but porosities and permeabilities are significantly reduced in samples with elevated kaolinite content or a high degree of carbonate cementation.

Seals

Cenomanian sandstones are sealed by Turonian to upper Campanian marlstones and mudstones (Wagner, 1996). Their thickness is highly variable (0-750 m) due to pre-Eocene erosion (Bachmann *et al*., 1987). In areas where post-Cenomanian Mesozoic rocks are completely eroded, Cenomanian and Eocene sandstones may form combined reservoirs (e.g. the V field near Bad Hall: Fig. 1c).

Eocene reservoir rocks are partly sealed by intraformational shales and lower Oligocene pelitic rocks. These intraformational shales include pelitic rocks in the Voitsdorf Formation and the Cerithian Beds (Brix and Schultz, 1993). The areal extent of these shales and marls is restricted, and they are only up to several tens of metres thick.

Fine-grained Oligocene to Miocene rocks, several hundreds of metres thick, are the principal seal rocks in the basin (Veron, 2005). Their sealing capacity is probably influenced by thickness variations of the Lower Oligocene succession caused by early Oligocene submarine erosion (Sachsenhofer *et al*., 2010) (Fig. 4a) and by the presence of varying fractions of coarse-grained clastic rocks in the Puchkirchen Group. This is supported by the fact that microbial gas in Oligocene and Miocene reservoir rocks contains elevated percentages of thermogenic gas (and condensates) in fields located above zones where erosion removed parts of the Oligocene fine-grained succession (Pytlak *et al*., 2017a) (*see below: Microbial Petroleum System*).

Traps

Oil fields in the Austrian sector of the North Alpine Foreland Basin are typically located on the upthrown side of east-west trending and south- and north-dipping normal faults, and these structural traps are partly supported by pinching- or shaling-out of the reservoir rocks (Nachtmann, 1995). Trap formation occurred during the early Oligocene (Fig. 2), when normal faults were partly inverted during the final stages of the Alpine orogeny. A single field (Trat) is located in a domal anticline formed during Paleocene compression (Gross *et al*., 2015b).

Thermal maturation and hydrocarbon generation

Lower Oligocene source rocks reach the oil window in the deep, southern part of the North Alpine Foreland Basin beneath the Alpine nappes at depths exceeding 4 km below sea level, a result of the very low palaeo-heat flows (<40 mW/m²) (Sachsenhofer, 2001).

Based on 2D numeric models, Gusterhuber *et al*. (2013, 2014) reconstructed hydrocarbon generation and migration along cross-sections in the western and eastern part of the Austrian sector of the North Alpine Foreland Basin. The evolution of the basin in the eastern part is shown in Fig. 6. According to these models, hydrocarbon generation began in autochthonous units during the early Miocene (~18 Ma) due to deep burial beneath Alpine nappes which resulted in increased temperatures at the source rock level (Fig. 7). Uplift and erosion in late Miocene times (~6 Ma) resulted in cooling and terminated hydrocarbon generation.

In addition to the autochthonous units, lower Oligocene source rocks are also present in the Perwang imbricates. However, Gusterhuber *et al*. (2014) determined that transformation ratios in the Perwang imbricates are in general low (< 20%).

Hydrocarbon migration

Hydrocarbon generation and migration started simultaneously (Gusterhuber *et al*., 2013). The long lateral distances between mature source rocks beneath the Alpine nappes and the locations of oil seeps at the northernmost basin margin (Gratzer *et al*., 2012) suggest lateral migration over distances of up to 50 km (Bechtel *et al*., 2013). Migration models indicate that liquid hydrocarbons migrated laterally along the source rock intervals until they reached faults juxtaposing the Lower Oligocene source rock interval against Cenomanian and Eocene reservoir units (Gusterhuber *et al*., 2013). At higher stratigraphic levels, diffusion likely enabled gas migration into overlying low-permeability layers. In addition, modeling predicts gas migration along fault zones into the Sierning imbricates (Gusterhuber *et al*., 2013). Regional tilting of the study area to the west during the Karpatian (~17 Ma; Fig. 2), as well as strong post-Miocene uplift of the eastern basin margin (Gusterhuber *et al*., 2012), may have caused re-migration of hydrocarbons from pre-existing accumulations.

Oil maturities in the eastern part of the study area increase northwards (Gratzer *et al*., 2011). Differences in hydrocarbon mobility and the changing stress field in front of the Alps during collision, which may have caused the opening or closure of specific faults at certain times, are possible reasons for the occurrence of different migration pathways of oils with different maturities (Gratzer *et al*., 2011).

Oil families and origin of associated gas

Biomarker ratios and stable carbon isotope data suggest the presence of two oil families in the Austrian sector of the North Alpine Foreland Basin (Gratzer *et al*., 2011; Bechtel *et al*., 2013) (Fig. 8a). An eastern oil family (type "B" oil) is characterized by relatively low sulphur contents and dibenzothiophene/phenanthrene (DBT/Ph) ratios, higher Ts/Tm (18α-22,29,30-trisnorneohopane/17 α -22,29,30-trisnorhopane) ratios, and less negative $\delta^{13}C$ values than the western oil family (type "A" oil). Mixing of type "B" and "A" oils occurs in a narrow north-south trending transition zone. The only sample which does not fit the west-east trend is an oil show in the Mlrt borehole (Fig. 8a), which is a type "B" oil despite its western position.

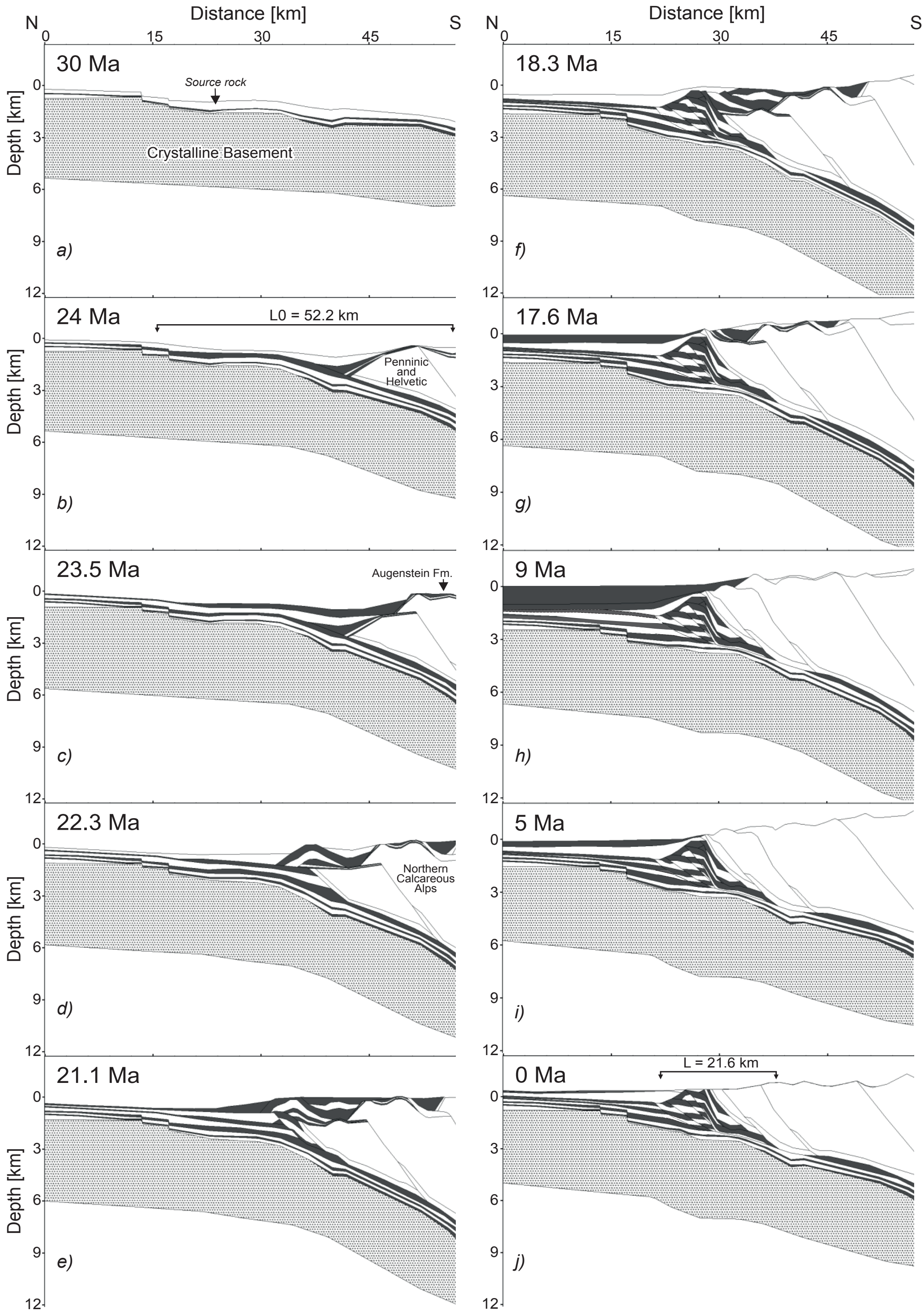

Fig. 6. 2D basin evolution shown on a north-south section in the Sierning imbricates area (profile location in Fig. 1c) (Gusterhuber *et al.*, 2013). The length between reference points for the calculation of tectonic shortening is shown in Fig. 6b and in the present-day section (Fig.6*j*).

This oil is also exceptional in that its reservoir rocks are of Oligocene age.

The different oil families probably reflect differences in source rock facies. Whereas type "B" oils clearly originate from the autochthonous "normal facies" of the lower Oligocene source rocks, type "A" oils may be related to the redeposited "Oberhofen facies". According to this interpretation, the Mlrt type "B" oil show may be derived from the "normal" source rock facies which is present in the Perwang imbricates. Alternatively, the difference may reflect varying oil contributions from a number of different lower Oligocene source rock intervals. For example, type "B" oil may contain a high proportion of sulphur-

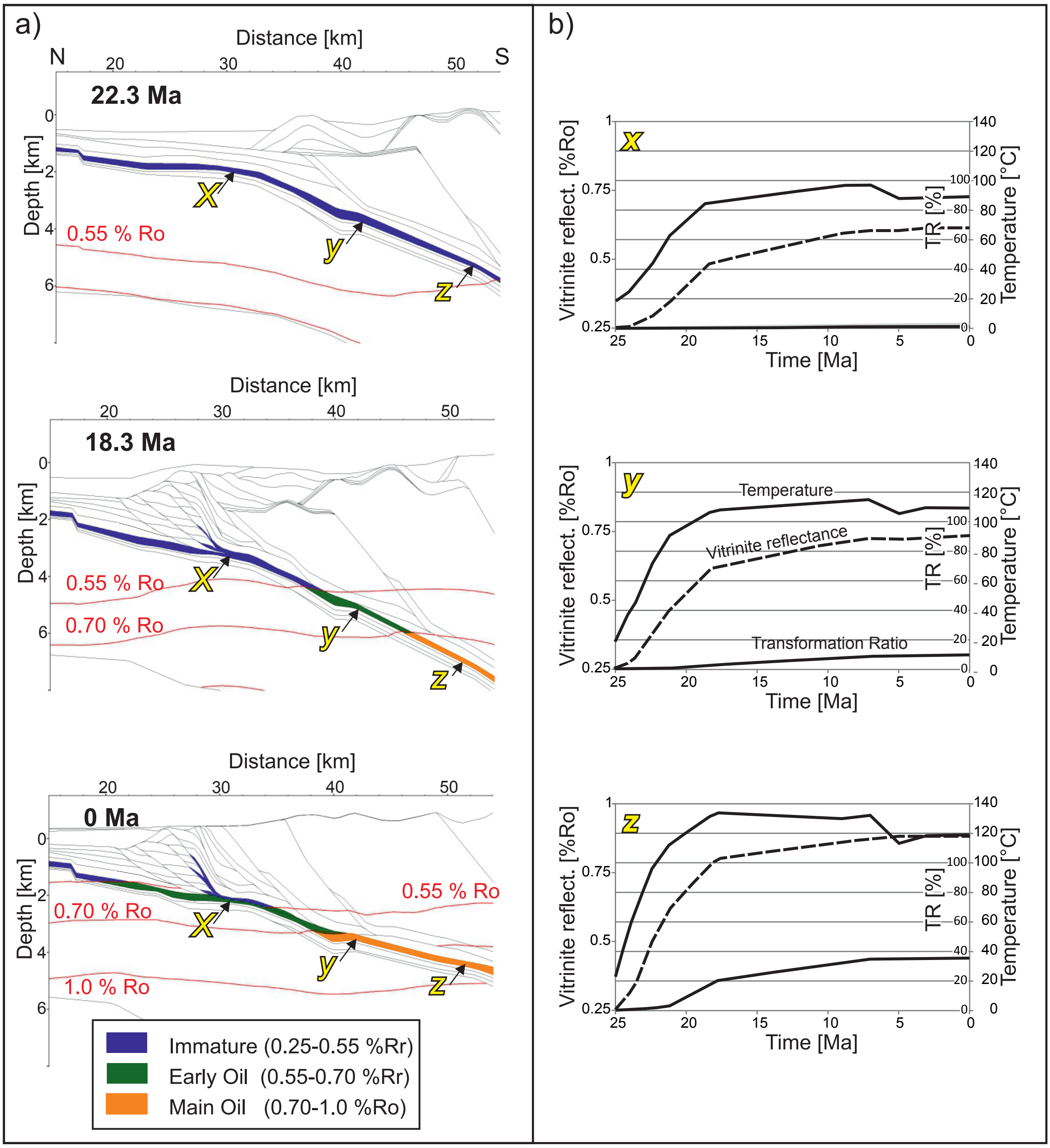

Fig. 7. Petroleum generation beneath the Alpine nappes. (a) Generation zones at different time-slices along a north-south section (see profile location in Fig. 1c). Red lines indicate the boundaries between different maturity stages. (b) Time plots showing the evolution of temperature, vitrinite reflectance and the transformation ratio (TR) over time for three different sites (X, Y, Z) beneath the thrust belt. The TR considers kinetic data for Lower Oligocene source rocks (modified after Gusterhuber *et al.*, 2013).

poor oil generated from the Schöneck Formation unit "c", whereas type "A" oil may contain a higher contribution of the marly "a/b" units, which generates oil with a slightly higher sulphur content (Gratzer *et al.*, 2011). Both oil families were generated by source rocks with similar maturity (0.7-0.9 %R_r; Gratzer *et al.*, 2011). The lack of commercial oil discoveries in the western part of the study area may also be related to the absence of potential lower Oligocene source rocks due to tectonic erosion.

Stable carbon isotope ratios of ethane and propane suggest that the associated gas was expelled at oil window maturities (0.6-1.2 %R_r; Pytlak *et al.*, 2016). However, the methane may have different origins. Pure thermogenic gas (group I gas according to Pytlak *et al.*, 2016) is restricted to a number of oil fields with gas caps in the eastern part of the study area (e.g. V field; Figs. 8b, 9a). Group II gases in fields located along the southern basin margin and in the NE part of the North Alpine Foreland Basin are characterized by

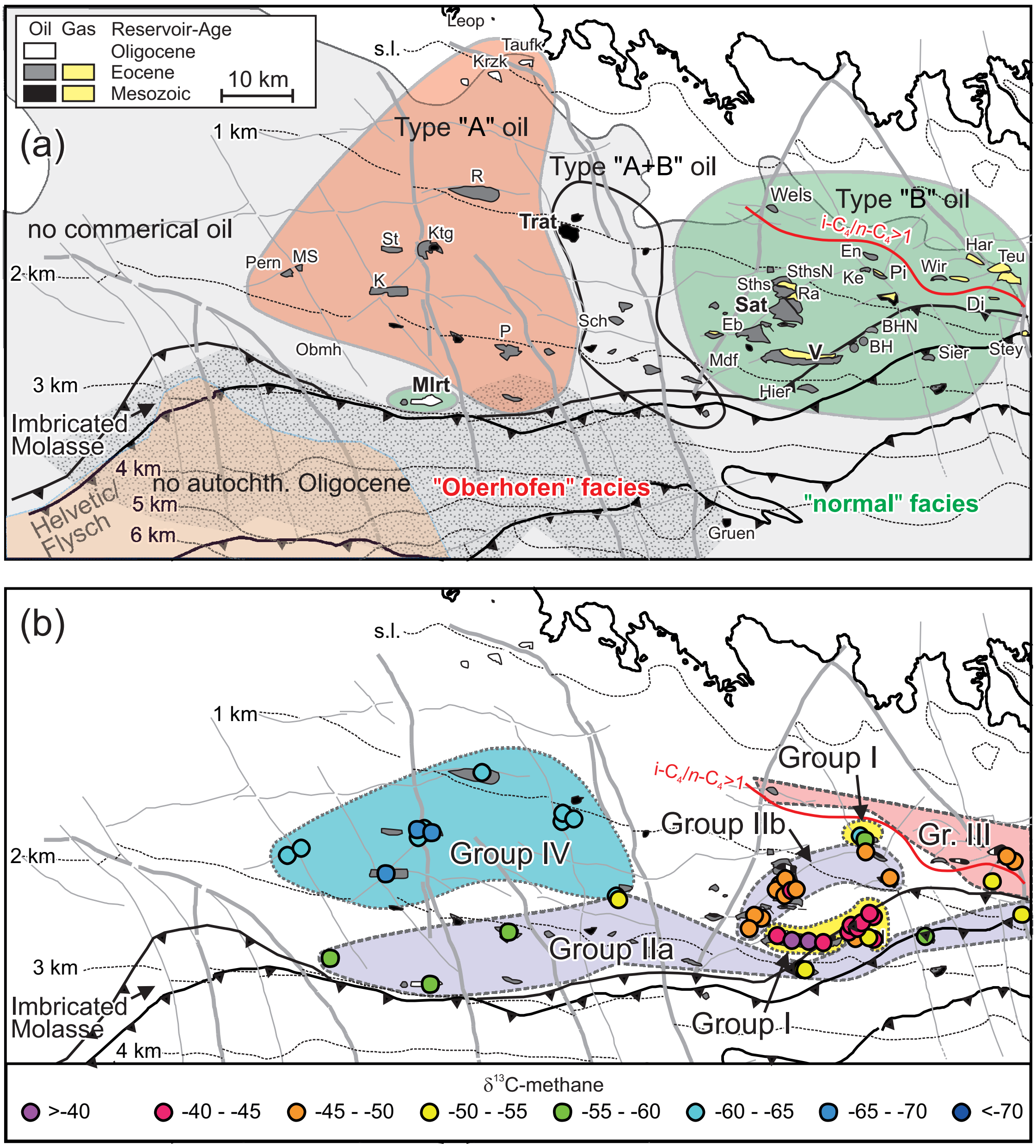

Fig. 8. (a) Distribution of oil fields, together with the types of oil and source rock facies in the study area (modified after Sachsenhofer and Schulz, 2006; Gratzer *et al.*, 2011 Pytlak *et al.*, 2017b). Most gas is present as gas caps above reservoired oil. (b) Stable carbon isotope ratios of methane with the differentiation of gas groups I-IV (modified after Pytlak *et al.*, 2016).

a mixture of thermogenic gas with varying amounts of microbial methane; whereas methane in group III gases is classified as mainly microbial. A primary microbial origin was postulated for methane in fields with reservoir temperatures exceeding 80 °C (Fig. 8b) (Pytlak *et al.*, 2016). This pre-existing microbial gas may originate from the Eocene Cerithian Beds and/or the lower Oligocene mudstones (Pytlak *et al.*, 2016). A secondary microbial origin (due to in-reservoir biodegradation of oil) is suggested for some shallow samples of group III gas and for methane in group IV gas samples. Group IV gas is found in accumulations with a relatively wet composition which are often underlain by a strongly biodegraded oil rim (Pytlak *et al.*, 2016; *see below*).

Hydrocarbon alteration

Biodegradation commonly occurs in oil accumulations along the northern margin of the North Alpine Foreland Basin. API degrees (Fig. 10) and geochemical data show that biodegradation affects oil and gas down to a depth of about 1 km subsea, corresponding to present- day formation temperatures of up to 60°C. Gusterhuber *et al.* (2013) showed that deeper reservoirs with reservoir temperatures between 60 and 80°C were palaeo-pasteurized, prior to late-stage (Pliocene) uplift which resulted in the inactivation of hydrocarbon-degrading microorganisms.

Biodegradation resulted in the formation of heavy oil, which was produced at Leoprechting (Leop. in Fig. 8a) until 1952 by steam injection from boreholes 100

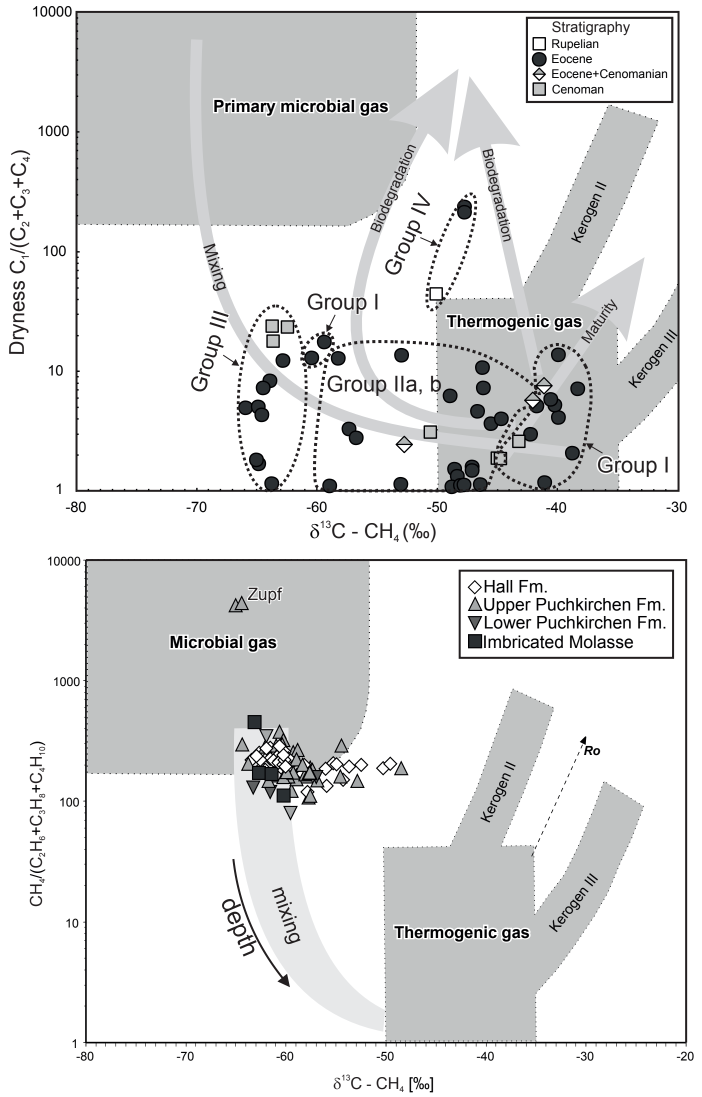

Fig. 9. Genetic characterization of gas from the Austrian part of the North Alpine Foreland Basin using the discrimination plot of Bernard *et al.* (1978). The effects of different processes on gas composition are indicated by grey arrows and curves (after Milkov, 2011; Jones *et al.*, 2008). (a) Oil-associated gas in Cenomanian and Eocene reservoirs; (b) Gas in Oligocene and lower Miocene reservoirs. Groups I-IV shown in Fig. 8b are indicated in (a) (simplified after Pytlak *et al.*, 2016, 2017).

to 200 m deep (Nachtmann, 2001). Recently it became clear that the gas produced from shallow accumulations south of Linz (e.g. Teu) was formed by anaerobic biodegradation of pre-existing oil, and at the present day the oil forms a non-producible tar rim along the gas-water contact (Pytlak *et al*., 2016).

Water-washing is the removal of light hydrocarbons with a relatively high solubility (e.g. benzene, toluene) via selective dissolution in a connected active aquifer (Elliott, 2015), and this process has recently been recognized in the North Alpine Foreland Basin (Pytlak *et al*., 2017c; Fig. 11). Water-washing affects oil fields in which the Cenomanian reservoirs directly overlie Upper Jurassic carbonate rocks (e.g. Trat field). In this case, water-washing is clearly related to the flow of low-salinity hydrothermal fluids within the Upper Jurassic aquifer (e.g. Goldbrunner, 2000). However, water-washing is also recognized in Eocene reservoirs and in areas where Upper Jurassic rocks are missing, and existing flow models for the regional Upper Jurassic aquifer must therefore be modified.

Asphalthene precipitation is rare in the North Alpine Foreland Basin and has only been observed in a single well with Eocene reservoir sandstones (BHN), where the presence of tar impedes economic petroleum production despite the good reservoir properties (Sachsenhofer *et al*., 2006). Geochemical investigations proved that the solid bitumen was formed by natural deasphalting of the original oil. Gas injection and migration-related asphaltene precipitation are possible formation mechanisms. There is a close relationship between solid bitumen and authigenic kaolinite, implying a major role for this mineral in the fixing of asphaltenes during deasphalting (Sachsenhofer *et al*., 2006).

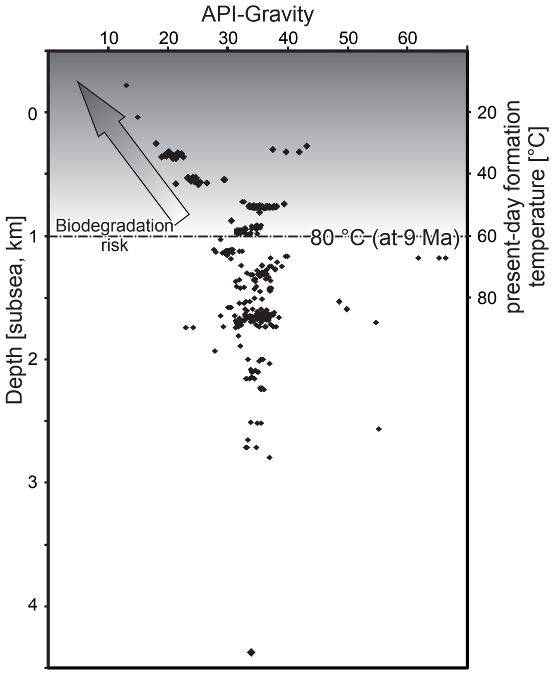

Fig. 10. Plot of API gravity of Molasse oils versus depth. Biodegraded oils with low API grades occur at shallow depth (above 1000 m subsea) corresponding to present-day formation temperatures of about 60 °C. The modelled 80 °C isotherm for the time of maximum burial (9 Ma; after Gusterhuber *et al.*, 2013) is also shown.

2. THE MICROBIAL PETROLEUM SYSTEM

Source rocks

In addition to siliciclastic reservoir rocks, pelitic intervals occur in the Puchkirchen Group and the Hall Formation and are source rocks for the microbial gas in the Austrian part of the North Alpine Foreland Basin (Schulz *et al.*, 2009; Schulz and van Berk, 2009). Average TOC contents for the pelitic intervals in the Puchkirchen Group are 0.8 %, and HI values are typically low (<100 mgHC/gTOC). Low TOC contents (<1.0 %) and HI values (10-140 mgHC/gTOC) also occur in the lower part of the Hall Formation (Sachsenhofer *et al.*, 2017). Organic matter-rich rocks with TOC contents up to 3.4 % and HI values up to 300 mgHC/gTOC are limited to the uppermost part of the Upper Puchkirchen Formation ("A1 fish shale"; Schulz *et al.*, 2009; Sachsenhofer *et al.*, 2017). However, their lateral extent is limited due to submarine erosion (base-Hall Unconformity). Because of shallow burial, the organic matter in the Puchkirchen Group and the Hall Formation is immature with T_{max} <435°C (Sachsenhofer *et al.*, 2017). Biomarker analyses suggest a dominance of terrigenous organic matter deposited in a marine basin under mesosaline conditions (Schulz *et al.*, 2009). Pristane/phytane ratios and palaeontological proxies indicate oxygen depletion (Schulz *et al.*, 2009; Grunert *et al.*, 2013).

Reservoir rocks

Sandstones and sandy conglomerates of the Puchkirchen Group and the basal Hall Formation, deposited in a basin-axial low-sinuosity channel belt, form reservoir rocks for microbial gas in the Austrian sector of the North Alpine Foreland Basin (de Ruig and Hubbard, 2006; Hubbard *et al.*, 2009). de Ruig and Hubbard (2006) determined the reservoir characteristics of different depositional elements (Fig. 3b) which are described in the following section.

Reservoirs in channel belt thalweg deposits typically occur in stacked, non-amalgamated turbidite beds with a thickness of between 0.1 and 2 m. Reservoir quality is generally good and the net-to-gross ratio is typically high (30-60%). Many of the largest gas fields in Upper Austria produce from these sandstones and sandy conglomerates.

Ponded sand-rich turbidite fans occur directly in front of the Alpine thrust belt or in piggyback basins on top of Molasse imbricates (see Covault *et al.*, 2009) and host at least five fields including the Haid field, the largest single-reservoir gasfield in the Austrian part of the North Alpine Foreland Basin. The reservoir consists of a wedge-shaped, northward-dipping succession of stacked, medium- to coarse-grained sandstones, up to 180 m thick. Due to the low matrix content, the reservoir permeability is generally very high (400 mD to 1000 mD). Slope-fan reservoirs are characterized by very high net-to-gross ratios (up to 90%).

Other reservoirs are associated with overbank deposits and tributary channels. Overbank deposits are characterized by thin-bedded (cm- to dm-scale) fine-grained turbiditic sandstones. The average net-to-gross ratio decreases from 60 to 10% with increasing distance from the channel axis. Reservoir continuity and horizontal permeability is generally good within individual lobes, but the connectivity between separate lobes is poor. Tributary channels contain some small gas accumulations in thin (0.1-1 m) but laterally continuous fine- to medium-grained turbidite sandstone beds, which are often separated by thicker mudstone

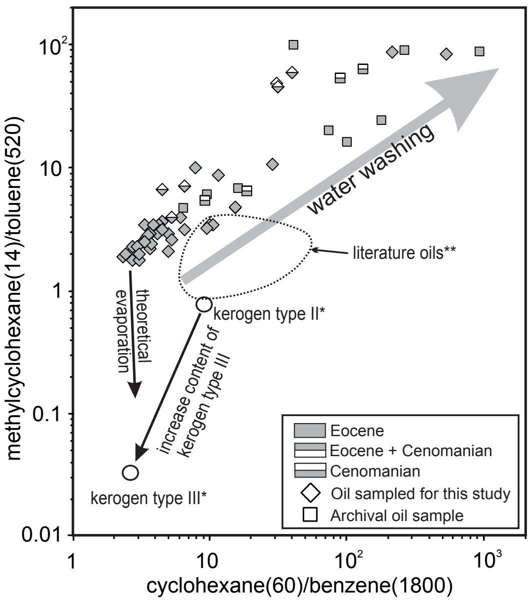

Fig. 11. Cross-plot of the methylcyclohexane/toluene (Mch/T) ratio versus the cyclohexane/benzene (Ch/B) ratio. Solubilities (mg/l) of different compounds in water are given in brackets. Because aromatic compounds are more soluble in water than saturated compounds, water washing results in an increase in Mch/T and Ch/B ratios (details were presented by Pytlak *et al.,* 2017c).

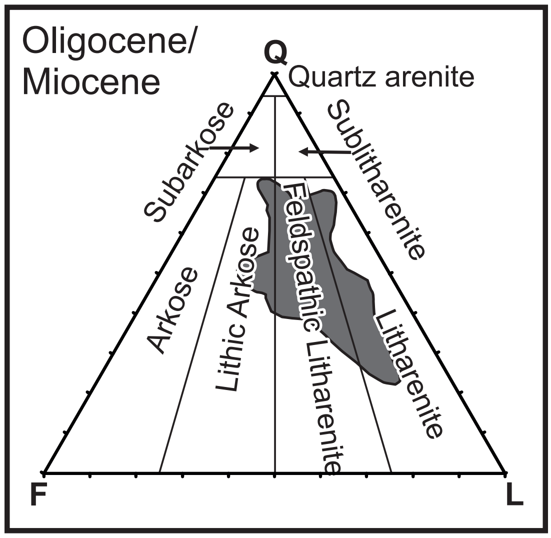

Fig. 12. QFL classification (Folk, 1968) of Oligocene/Miocene reservoir sandstones from the Austrian part of the North Alpine Foreland Basin (Q – quartz; F – feldspar; L – lithic fragments).

intervals. In these cases, average net-to-gross ratios are 10 to 30%.

Sandstones of the Puchkirchen Group and the basal Hall Formation are mostly moderately to well sorted litharenites, feldspathic litharenites and lithic arkoses (Fig. 12) (Gross *et al*., 2015a). The main cement phases are diagenetic carbonate minerals (Gross *et al*., 2015a). Rare clay mineral cements consist of Fe-rich chlorite, illite, smectite and occasionally kaolinite (Bottig *et al*., 2017). Grundtner *et al*. (2016) observed strongly carbonate cemented zones formed during late diagenesis near the gas-water contact, which may have a significant influence on hydrocarbon production.

Gross *et al*. (2015a) investigated sandstone from the channel axis and ponded sand-rich turbidite fans. According to their data, porosity values within the Puchkirchen Group and the basal Hall Formation range up to 30%. Permeabilities can exceed 1000 mD in samples from the thalweg and decrease to values <100 mD with increasing distance from the channel axis, as a result of increasing matrix contents. Ponded sand-rich turbidite fans show porosities and permeabilities comparable to those of thalweg deposits.

Seals

Coarse-grained reservoir rocks are isolated by pelitic sediments. In addition, sandstone-shale intercalations occur in the reservoir succession. de Ruig and Hubbard (2006) classified seal rocks of different depositional elements. According to these authors, overbank wedge deposits represent an important top-seal for channel belt thalweg deposits, whereas debris-flow deposits sometimes act as lateral seal. Overbank lobe and tributary channel deposits are characterized by pinch-out and/or shale-out, whereas ponded slope fans may be sealed to the south by the Alpine thrust sheets.

Traps

Microbial gas has in general accumulated in broad, low-relief compaction anticlines or is stratigraphically trapped as channel margin pinch-outs (de Ruig and Hubbard, 2006). In addition, imbrication structures may form major traps along the southern basin margin. For example, the Haid field is a structural trap formed by the truncation of a northward dipping slope-fan by southward dipping overthrusts (Covault *et al.*, 2009). Within this context, differences in the timing of deformation between the eastern Sierning imbricates (Chattian to Aquitanian) and the Perwang imbricates to the west (Chattian; Hinsch, 2013) should be considered (see Fig. 2).

Hydrocarbon generation

Isotopically light methane in the Puchkirchen Group and the Hall Formation has been interpreted to be of microbial origin (e.g. Schoell, 1977; 1984). Based on the diagenetic pathway of the reservoir cements and hydrochemical thermodynamic modelling, Schulz *et al*. (2009) and Schulz and van Berk (2009) proposed a model for bacterial methane generation in the North

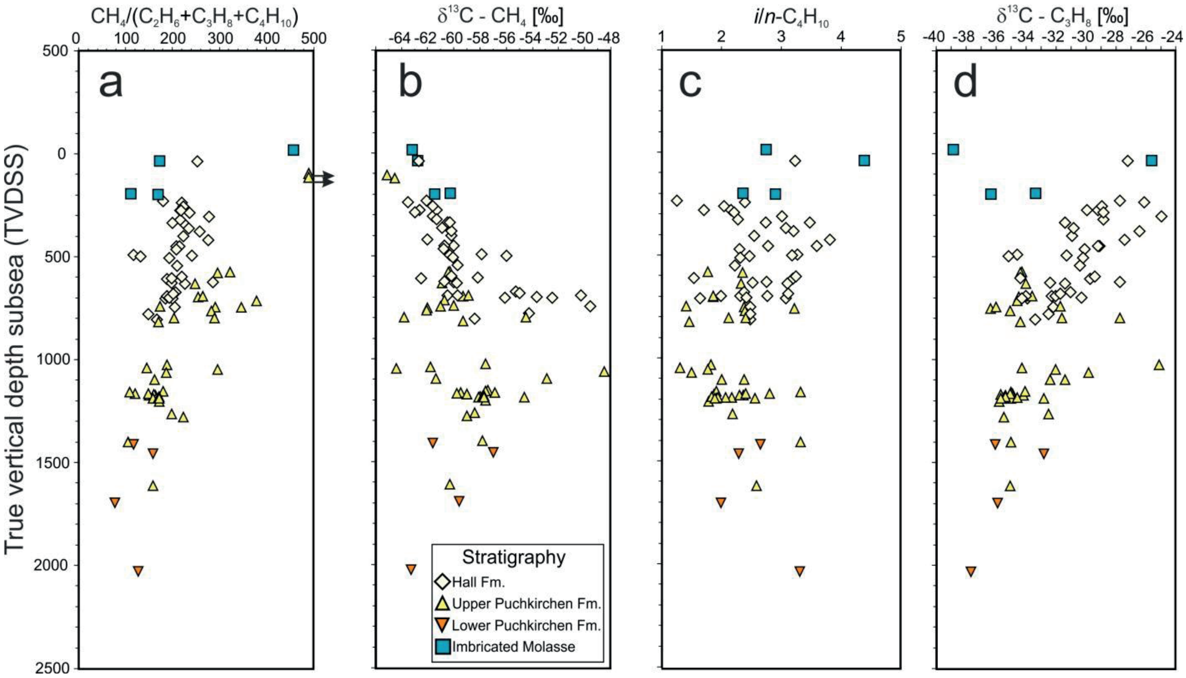

Fig. 13. Depth distribution of selected geochemical parameters for gas samples in Oligocene-Miocene reservoirs (after Pytlak *et al.*, 2017a). *i*/*n*-C_4H_{10} ratios >1 indicate that all gases are biodegraded. However, dryness and $\delta^{13}C$–C_3H_8 trends indicate that biodegradation decreases with depth.

Alpine Foreland Basin. According to this model, labile organic matter was decomposed by fermentation and subsequent CO_2 reduction. Whereas CO_2 was fixed as carbonate cement, methane generated during early diagenesis (< 100 m depth within the sediment) was dissolved in pore waters until saturation was reached. After exsolution as a free gas phase, methane may have been fixed as hydrates within open pores due to the prevailing depositional conditions (>1000 m water depths; temperatures of ~4°C). The temperature increase accompanying high sedimentation rates led to the decomposition of the gas hydrates and to the charging of reservoir sandstones with methane during the Aquitanian. A further consequence of hydrate decomposition was the reduction of pore water salinity due to dilution.

Hydrocarbon mixing and biodegradation

The stable carbon isotope ratios of methane are significantly lower in microbial gas ($\delta^{13}C_{CH4}$ < -50 ‰) than in thermogenic gas ($\delta^{13}C_{CH4}$ > -45 ‰; e.g. Schoell, 1977). Moreover, microbial gas is very dry (C_1/C_2+C_3) > 500), as only small amounts of ethane and propane are formed by microbial activity (Hinrichs *et al*., 2006).

Pytlak *et al*. (2017a) investigated the molecular and isotopic composition of 87 gas samples produced from the Puchkirchen and Hall reservoirs. Purely microbial gas was found in a single field at the northern flank of the basin (Zupf field; Fig. 9b). All the other fields contain varying amounts of thermogenic gas which has been generated from a source rock with oil-window maturity. The presence of condensates in several Oligocene-Miocene reservoirs provides additional evidence for mixing of the microbial and the thermogenic petroleum systems. Geochemical evidence shows that there is a clear relationship between the condensates and oils in Cenomanian/Eocene reservoirs (Pytlak, 2017). This suggests that the condensates are products of evaporative oil fractionation. Upward migration occurred along discrete fault zones or through low-permeability caprocks. Local erosion of lower Oligocene sediments (Fig. 4a), which are the principal seal for the thermogenic petroleum system, as well as a high fraction of permeable rocks within the Puchkirchen Channel, favoured upward migration and mixing of thermogenic and microbial gases.

Enhanced *i*/*n*-C_4 ratios and an enrichment of ^{13}C in propane shows that most gas samples in Oligocene–Miocene reservoirs are biodegraded (Fig. 13). Biodegradation and the formation of secondary microbial gas resulted in gas drying, causing the investigated gas samples to be relatively dry despite the significant contribution of thermogenic hydrocarbons. The presence of ethene and propene, which are considered to be unstable over geological time periuods (Whiticar, 1994), suggests that biodegradation probably continues at the present day (Pytlak *et al*., 2017a). The degree of biodegradation, however, decreases with depth (Fig. 13) as the reservoir temperatures increase.

CONCLUSIONS

The North Alpine Foreland Basin is a small to moderate-sized hydrocarbon province. Aspects of the thermogenic and microbial petroleum systems in the Austrian part of the basin may serve as analogues for other, potentially more important but less well-understood hydrocarbon provinces within the Paratethys area and beyond.

Lower Oligocene successions are prolific source rocks in the North Alpine Foreland Basin. Strong vertical variability of source rock parameters in combination with a very high lateral continuity is notable, and different units within the lower Oligocene succession generate oils with varying compositions. This implies that different oil families do not necessarily reflect different source rocks, but may result from vertical facies variations.

Submarine mass movements locally removed the source rock. These mass movements have modified the present-day distribution of source rocks and may also influence the sealing capacity of the fine-grained units. Apart from mass movements, the distribution of source rocks was also controlled by "tectonic erosion". It is reasonable to assume that similar processes were active in other Paratethyan foreland basins.

Methane in associated gas in the North Alpine Foreland Basin is often of primary and/or secondary microbial origin but similar observations have not yet been reported elsewhere in the Paratethys.

Recent studies have shown that the Austrian part of the North Alpine Foreland Basin experienced strong post-Miocene uplift. Deep Miocene burial caused palaeo-pasteurization and locally prevented biodegradation in reservoirs, which are now at shallow depths. In addition, uplift resulted in re-migration. Hence, it may also be useful to explore the consequences of recent uplift in other Paratethyan petroleum provinces. In addition to biodegradation, water-washing also occurs and has been overlooked in studies of basin-scale hydrodynamics.

The Oligocene-Miocene reservoir rocks of the microbial petroleum system have been re-interpreted as sediments deposited in a deep-marine channel belt. This shows the outstanding significance of large-scale 3D seismic data in combination with core and well data for the correct interpretation of reservoir architecture.

Microbial gas within the Puchkirchen Group and the Hall Formation was formed during early diagenesis and may have been trapped in gas hydrates. Decomposition of the hydrates during deeper burial led to the filling of the reservoirs and to a decrease of water salinities. It would be worthwhile to test the applicability of this model in other basins.

The presence of varying amounts of thermogenic gas and condensates in reservoirs of the microbial petroleum system clearly demonstrate that microbial and thermogenic petroleum systems in the North Alpine Foreland Basin are not strictly separated, and that hydrocarbon mixing plays an important role.

The structural style and timing of deformation varie significantly along strike. Because the timing of thrusting is relevant for both hydrocarbon generation and trap formation, this observation may also be of relevance for other basins.

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