Paleozoic petroleum systems of Saudi Arabia: a basin modeling approach

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ABSTRACT

The major Paleozoic petroleum system of Saudi Arabia is qualitatively characterized by a proven Silurian (Qusaiba Member, Qalibah Formation) source rock, Devonian (Jauf Formation), Permian and Carboniferous (Khuff and Unayzah formations) reservoirs, a laterally extensive, regional Permian seal (basal Khuff clastics and Khuff evaporites), and four-way closed Hercynian structures. Hydrocarbons found in these systems include non-associated gas in Eastern Arabia and extra light oil in Central Arabia. A basin modeling approach was used to quantify important aspects of the petroleum system. Firstly, seventeen regional wells were selected to establish a reference tool for the three-dimensional (3-D) basin model using multiple one-dimensional (1-D) models. This was accomplished by studying core material from source rocks and other lithologies for thermal maturity and kerogen quality. The major emphasis was on the Silurian section, other Paleozoic intervals and to a lesser extent on the Mesozoic cover from which only few samples were studied. Although vitrinite macerals, solid bitumen, and other vitrinite-like particles were not abundant in most of the investigated samples, enough measured data established valid maturity-depth trends allowing for calibrated models of temperature history. Sensitivity analyses for maturity support the view that thermal boundary conditions and Hercynian uplift and erosion did not greatly influence the Paleozoic petroleum systems. Secondly, a 3-D basin model was constructed using major geologic horizon maps spanning the whole stratigraphic column. This model was used to gain insight into the general maturity distribution, acquire a better control of the model boundary conditions and investigate charge, drainage, migration and filling history of the main Paleozoic reservoirs. The 3-D hydrocarbon migration simulation results qualitatively account for the present gas accumulations in the Permian-Early Triassic Khuff and Carboniferous-Permian Unayzah reservoirs in the Ghawar area. This kind of study illustrates the importance of basin modeling when used with other geologic data to describe petroleum systems. It provides a predictive exploratory tool for efficiently modeling hydrocarbon distribution from known fields. Real earth models can only be described in 3-D as pressure variations and fluid movements in the subsurface are impossible to address in 1-D and 2-D domains.

INTRODUCTION

Petroleum system analysis has become an increasingly important aspect in assessing the hydrocarbon potential of a given basin. Understanding the principal components of a petroleum system (source, reservoir, trap, seal, migration and timing; Demaison and Huizinga, 1991; Magoon and Dow, 1994) is a pre-requisite for a successful exploration program. Basin modeling, though focused on the source rock component of the petroleum system, is a major first step. Basin modeling assesses the potential of the basin in terms of source rock availability, temperature history and organic maturity (e.g. Lopatin, 1971; Ungerer et al., 1990; Yalcin et al., 1997).

This paper presents a 3-D basin model that focuses on the generation and migration of hydrocarbons for the Paleozoic sequence in the Ghawar anticline and Central Arabia, a region of about 162,000 sq km (Figure 1). The study is based on the analyses of the quality and thermal maturity of the principal Silurian Qusaiba “hot shale” source rock using organic petrology and Rock-Eval pyrolysis data. The thermal and maturation histories were calibrated using organic petrography and source
Figure 1: Location map showing wells used in the study area and major oil and gas fields. The 17 wells used in the study area are shown in black circles. The Tayma (TAYM) well falls outside the study area. The Hercynian subcrop map shows the formations that are encountered below the Carboniferous-Permian Unayzah and Permian part of the Khuff Formation.
Figure 2: Cambrian-Triassic Saudi Arabian Stratigraphic Column showing major reservoir and source intervals (modified after Haq and Al-Qahtani, 2005). Ages are in million years and calibrated to GTS 2004.
rock geochemistry data from 132 samples representing 17 key wells. Of the 132 samples, 126 were extracted from cores and only 6 from cuttings; this ensures that the samples represent true depth. This aspect of the study established a regional database on maturity distribution and source rock characteristics in the Paleozoic section of Saudi Arabia.

This data was used to construct 1-D burial history models for the individual wells. Based on the burial history models of the 17 wells, a 3-D model was developed using a coarse grid for maturity and general migration predictions. The 3-D model only covers 16 wells as the 17th well (TAYM) is located outside the study area. Silurian source rocks from the 16 wells represent either early-mature or post-mature early Silurian Qusaiba intervals. TAYM well was chosen because it provides geochemical data on organically immature Qusaiba source rock interval (Abu-Ali et al., 1999).

The next step was to build a 3-D basin model using regional geological maps that span the post-Ordovician stratigraphic column. The objective of the 3-D petroleum system analysis is to predict hydrocarbon properties, simulate general hydrocarbon migration trends and filling history, determine drainage areas and assess future hydrocarbon exploration areas.

**PETROLEUM SYSTEM**

The Paleozoic petroleum geology of Saudi Arabia has been discussed in several publications (Abu-Ali et al., 1991, 1999 and 2001; McGillivray and Al-Husseini, 1992; Mahmoud et al., 1992; Cole et al., 1994; Wender et al., 1998; Jones and Stump, 1999; Konert et al., 2001). Figure 2 displays the stratigraphic column of the Paleozoic strata in Saudi Arabia.

**Source Rocks**

The only proven source rock for the Paleozoic hydrocarbons in Eastern and Central Saudi Arabia is the early Silurian basal “hot shale” of the Qusaiba Member of the Qalibah Formation (Abu-Ali et al., 1991, 1999, 2001; Mahmoud et al., 1992; McGillivray and Al-Husseini, 1992; Cole et al., 1994; Jones and Stump, 1999). The basal Qusaiba contains type II organic matter with a “hot shale” thickness ranging from 10–250 ft (3–70 m, Mahmoud et al., 1992; Wender et al., 1998; Abu-Ali et al., 1999, 2001). Carbon isotopes strongly correlate hydrocarbons found in the Devonian, Carboniferous and Permian reservoirs to the Qusaiba source rock extracts. Biomarker data also clearly distinguishes the Silurian shales as the main source rock for the Paleozoic oils and condensates (Abu-Ali et al., 1991; Moldowan et al., 1994; Cole et al., 1994). The Silurian source rock is also well established in North Africa (Yahi et al., 2001; Lüning et al., 2000) and reflects a regional transgression that followed the deglaciation of Gondwana Land.

There are also, to a lesser extent, isotopic correlations between Paleozoic hydrocarbons and other potential source rocks; these include but are not restricted to the Ordovician Ra’an and Hanadir shales, Upper Devonian shales, Permian Unayzah shales, Permian basal Khuff shales (Abu-Ali et al., 1991; Cole et al., 1994). These rocks are of limited thickness and lateral extent and have not been thoroughly sampled and analyzed. Deeper infra-Cambrian units have not been penetrated in Saudi Arabia, but may be source rocks as proven in Oman (Grantham et al., 1987). Proterozoic-Cambrian basins have been identified on seismic in the western Rub’ Al-Khali Basin.

**Reservoir Rocks**

Sandstone reservoirs are proven in the Late Ordovician glaciogenic Sarah Formation in Northern Saudi Arabia (e.g., Kahf field) and Jordan (e.g., Risha field). This reservoir occurs immediately below the Qusaiba “hot shale”. The marine Devonian Jauf Formation is a good reservoir which tested gas and condensate along the eastern flanks of the Hawiyah and Shedgum fields (Figure 1).

The Late Carboniferous-Permian Unayzah Formation constitutes the main Paleozoic hydrocarbon-bearing reservoir (McGillivray and Al-Husseini, 1992; Senalp and Al-Duaiji, 1995; Evans et al., 1997; Wender et al., 1998). Above the Unayzah, the Permian-Early Triassic Khuff carbonates constitute the main reservoir for non-associated gas in Arabia (e.g., Ghawar Superfield, Qatar’s North Field).
Another reservoir is the Silurian mid-Qusaiba Member sandstones which tested non-associated gas in Tukhman (Figure 1). The sandstones of the Late Silurian-Early Devonian Tawil Formation have poor reservoir quality due to the development of diagenetic cements.

**Seal Rocks**

Amongst all petroleum system components, the nature of the sealing rocks is the least studied and understood. The seal of the Sarah reservoir is the Qusaiba shale.

The Jauf reservoir is sealed by interbedded shales and dolomites (D3B palynological marker) at the top of the Devonian Jauf Formation. A recent capillary pressure study of the Devonian D3B seal showed that a 15–45 ft interval of this unit can hold a gas column of approximately 2,000 ft before it is breached. Faulting with more than 50 ft throw will breach the Jauf D3B seal. Along the flanks of Ghawar, the Jauf reservoir is truncated and sealed by the Khuff Formation.

The shales of the basal Khuff clastics are the regional seal for the Carboniferous-Permian Unayzah reservoirs. The seal efficiency of the basal Khuff clastics may determine whether hydrocarbons leaked vertically due to thinning and/or fracturing, or laterally via fault seal sand juxtaposition.

The interbedded Khuff evaporites are the main seals for the Khuff A, B and C reservoirs (Figure 2). The overlying Sudair Formation shales provide a regional seal for the Khuff Formation.

**Structural Evolution and Traps**

The regional structural growth history of the Arabian Plate is illustrated in Figures 3–7. Figure 3 shows the regional compressional growth during the Carboniferous “Hercynian Orogeny” as mapped by isopach from the base Qusaiba Member to base Khuff Formation. Blank areas indicate Ordovician or older subcrops and highlight regions where structural growth was greatest. For example, over parts of the Ghawar structure the “Hercynian Unconformity” eroded down into the Ordovician and Cambrian, while the Carboniferous and early Permian section is absent. The blue color represents low areas during the “Hercynian Orogeny”. Significant removal of section occurred over Ghawar field and the areas to the west and southeast (red-yellow color depicting thin areas).

Most traps in the Paleozoic section are structural; a few traps are faulted, stratigraphic and combination stratigraphic-structural. Most of the structural closures were initiated in Hercynian times and continued to grow with time. The stratigraphic traps are Jauf reservoir bounded by the “Hercynian Unconformity” and/or Unayzah reservoir with strong lateral thickness and porosity variations.

Figure 4 shows the isopach map from base Khuff Formation to top Jilh Formation. It indicates minor extensional growth during the Middle Permian to Middle Triassic time (Figure 5), and a shift of the basin center towards the north. Most of the growth took place in the south. The Middle Triassic to Early Cretaceous (Aptian) time is represented by the isopach between the tops of the Jilh and Shu’aiba formations (Figure 5). During this phase a further shift of the basin center to the north occurred, while more section was removed in the south.

The Late Cretaceous period is marked by the obduction of the Neo-Tethys Ocean onto Oman and along the Zagros region. Deeper burial occurred in Eastern and Southern Arabia, while most of the structural growth was in the west (Figure 6). Tectonic compression caused significant structural growth over the majority of the existing structures. In the Tertiary regional tilting to the east and north is evident by comparing the Aruma structure (Figure 7) with the previous figures representing Triassic and Hercynian growths.

Figure 8 shows an east-west cross section across Arabia. The major structures of Ghawar (Saudi Arabia) and Dukhan (Qatar) are bounded by major faults. The section displays the basin in the middle, where hydrocarbons have been generated and migrating toward the Ghawar and Dukhan structures to the east and west flanks of the basin.
Figure 3: Carboniferous growth is represented by base Qusaiba Member to base Khuff Formation isopach. Red indicates areas of thinning and blue areas of thickening. Blank areas are where the base Qusaiba Member has been eroded.
Figure 4: Permo-Triassic growth is represented by base Khuff to top Jilh isopach. Red indicates areas of thinning and blue areas of thickening.
Figure 5: Triassic-Early Cretaceous growth is represented by Jilh to Shu'aiba isopach. Red indicates areas of thinning and blue areas of thickening. Notice the inversion of the basin to the northwest compared to Figures 3 and 4 which was to the east and south, respectively.
Figure 6: Late Cretaceous growth is represented by Shu'aiba to Aruma isopach. Red indicates areas of thinning and blue areas of thickening. The basin center is inverted back to the east as it was during the 'Hercynian' and Triassic times.
Figure 7: Maximum growth from Tertiary to present is represented by the present-day Aruma structure. Red indicates structural high areas and blue structural low areas.
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Migration and Trapping

The Tertiary regional eastwards tilt of Arabia may have played a major role on hydrocarbon migration/dismigration, drainage areas, and entrapment (Abu-Ali et al., 1999, 2001). In particular, structures with Cretaceous and Tertiary growth had a window of opportunity to trap gas that migrated during the Tertiary tilting. In contrast, structures that did not substantially grow after the Jurassic or Triassic times probably had a better chance to trap oil. Late migrating gas could have flushed oil out of the early formed traps. Therefore traps that formed after peak gas expulsion will be invariably dry (e.g. Udaynan structure). Currently fluid inclusion studies may better refine trap-filling history and explain the phase behavior in some fields (e.g. Tinat).

Hydrocarbons

Hydrocarbons found in the main Paleozoic reservoirs include non-associated gas in Eastern Arabia (Khuff, Unayzah and Jauf reservoirs) and extra light oil with associated gas in the Unayzah reservoirs of Central Arabia and parts of Eastern Arabia (Niban and Tinat fields).

Volatile oil, condensate and dry gas are found in both Central and Eastern Saudi Arabia’s Unayzah reservoirs (e.g. in Tinat field where oil and gas occur in different parts of the field). There is a regional trend in these reservoirs with volatile oil and condensate occurring mainly in Central Arabia (e.g. Hawtah trend fields) and more gas in Eastern Saudi Arabia (e.g. in the Ghawar superfield). This regional trend will be explained in the results section, and is related to deeper burial and higher maximum temperatures in the eastern area that led to more gas generation compared to the Central Arabia area. In detail; however, occurrence of dry gas and volatile oil/condensate is rather difficult to explain based on maturity pattern alone; phase behavior, migration/accumulation history and timing greatly influence the distribution. The API values for the volatile oils and condensates are in the 40-60° range, reflecting the high mature level of the liquids in both Central and Eastern Arabia.

Figure 8: An east-west structural cross-section across Arabia showing the major structures of Ghawar (Saudi Arabia) and Dukhan (Qatar). Formations are shown in color along with major bounding faults in solid lines and an approximate depth scale in meters (after Konert et al., 2001).
Gas/Oil ratios (GORs) are quite variable and can rapidly change from one well to the other. In general, GOR is much greater in the eastern gas-rich Ghawar reservoirs compared to the western gas-lean Hawtah trend fields of Central Arabia. In the Hawtah area of Central Arabia, the volatile oils and condensates were subject to water-washing that could have removed the soluble components such as methane and light aromatics. The GOR values also increase from south to north in the Ghawar reservoirs, suggesting a charging mechanism in the opposite direction. That is, the basin to the north of Ghawar charged its reservoirs with more liquid hydrocarbons followed by gaseous hydrocarbons, making the north more gas-rich than the south.

There is also a clear distinction between the quality of gas in the Khuff carbonate reservoir to that in the Unayzah and Jauf clastic reservoirs. The Khuff gas is sour with more H$_2$S content than the Unayzah and Jauf gas. This is attributed to the deficiency of iron metal in carbonate settings; therefore, the most probable form of sulfur will be the H$_2$S gas. In clastic settings; however, iron is more abundant and any sulfur will be picked up by iron as pyrite. The H$_2$S gas in carbonate reservoirs is also produced by thermochemical sulfate reduction (TSR) and is controlled by the reservoir temperature and formation of anhydrite (Worden et al., 1995, 2000). Fluid inclusion studies on some Ghawar Khuff samples indicate that TSR started at 120–130°C and that only finely crystalline anhydrite have undergone TSR (Worden et al., 2004).

**METHODOLOGY**

**Organic Carbon Content and Rock-Eval Pyrolysis**

The assessment of the carbon content was performed with a LECO multiphase C/H/H$_2$O analyzer. Rock-Eval analysis was performed with a Rock-Eval II instrument. Rock-Eval pyrolysis is a rapid screening method for the assessment of the quality and maturity level of petroleum source rocks (Espitalié et al., 1977; Katz, 1983). Samples with total organic carbon contents (TOC) in excess of 1.0% are analyzed and reproducible values are obtained with respect to hydrocarbon liberation (S1 and S2 values). The quality of the S3 data (CO$_2$ liberation) and the oxygen index (OI) derived from this parameter is; however, often poor. Temperatures of maximum product generation ($T_{max}$) usually show a reproducibility of around ± 2°C. The hydrogen index (HI) and the oxygen index (OI) are derived from the S2 and S3 parameters, respectively, by normalization to the organic carbon content. All analyses were performed in duplicate and results were averaged.

**Organic Petrology**

Detailed discussions on vitrinite reflectance (VR) measurement can be found in Schenk et al., (1990); Van Krevelen (1993) and Taylor et al. (1998).

One hundred and thirty-two samples (126 from core and 6 from cuttings), representing mainly shaly lithologies from 17 wells (Figure 1), were analyzed using this method. Most samples contained either vitrinite or solid bitumen. Attempts were made to measure 50 particles per sample; however, in some samples less than 50 particles were present and fewer measurements, therefore, were recorded. In addition, fluorescence observations were made to obtain initial, qualitative maturity and organic facies information. For all the samples, for which a valid vitrinite reflectance/solid bitumen reflectance could be established, only these reflectance values are recorded. No attempt was made to calculate vitrinite reflectance from solid bitumen reflectance as both are quite similar at the levels of maturation (1.5 to 2.3%) at which pyrobitumen was mainly observed (Jacob, 1989). Solid bitumen is mainly present in the Silurian samples and in porous carbonate lithologies in general and is regarded as a relic of former oil that has been generated. In many samples, higher reflecting reworked particles predominate, but measurements of these particles are not shown in order to provide valid maturity information. Several samples; however, contained too little vitrinite/solid bitumen to establish a valid reflectance value. In this case, a spectrum of all particles was measured (with up to 50 measurements per sample), but the mean reflectance value was not used for maturity or paleo-temperature interpretation.
For several wells, a clear depth trend could be established from the measured data, which are shown in solid triangles in Figures 11a to 11d. Due to the sample selection; however, most data are from the Paleozoic section. For some wells, for which no data from the Mesozoic section are available (JAWB, JAUF, ABQQ, BRRI, UTMN and SDGM wells), the data from Jurassic samples in the QTIF well were plotted in the vitrinite reflectance-depth diagrams as solid circles; this provided an approximate trend for the reflectance increase.

**Basin Modeling**

Petromod basin modeling software developed by Integrated Exploration Systems (IES) was used throughout this study. The software suite covers the entire 1-D to 3-D range, with a finite element solver for temperature and pressure coupled amongst others with hydrocarbon generation, migration and pressure-volume temperature (PVT) modules. A 1-D simulation performs in a couple of minutes whereas a full 3-D run with migration can take several hours or days depending on the lateral and vertical grid resolution and on the processor’s computing parameters.

Burial history analysis was performed on the sixteen wells investigated in this study using the PetroMod 1-D application software. Conceptually, numerical basin modeling is to forward model the present-day sedimentary succession. The process is collectively called simulation and is comprised of (Littke et al., 2000; Welte and Yalcin, 1998):

1. deposition of decompacted sediments,
2. compaction of sediments as a result of loading and the consequent expulsion of pore fill and porosity and permeability decrease, and
3. conductive and convective heat flow and changing thermal rock properties resulting in variations of temporal and spatial subsurface temperatures.

To perform a full 3-D simulation many input data are required. The framework of the model is the depth maps which are used to create finite element layers. The rock properties of these layers are described by facies maps and relating facies to typical physical properties. Facies maps are derived from Ziegler (2001) for the Mesozoic and Cenozoic and Konert et al. (2001) for the Paleozoic. Each map has been revised according to current knowledge and each facies has been related to a lithology or set of lithologies with specific rock properties. Each lithology is described with the following rock properties: porosity versus effective stress, matrix thermal conductivity and heat capacity, permeability versus porosity, capillary entry pressure versus permeability and porosity, and radiogenic heat production. Several geologic horizon maps were used in building the 3-D basin model. Some of the horizons are based on well and seismic data. These horizons include the Cretaceous Aruma Formation, the Jurassic Hith Formation and Arab-D reservoir, the Triassic Jilh dolomite, the Permian top and base Khuff Formation, the Silurian base Qalibah Formation and basement. In between all other maps were generated conformably using the horizon just above and below, and tying all penetrated wells. A total of 25 to 30 horizon maps including the topographic surface were used in the 3-D volume dataset. The maps were generated using Zmap application software and used as input into the PetroMod 3-D petroleum systems modeling software for simulation of petroleum generation and migration.

Some effort was invested in assessing the porosity versus effective stress as many other rock properties are dependent on this function. For solid thermal conductivity and heat capacity only minor changes were made compared to Petromod default data. Permeability versus porosity was grossly estimated; forthcoming studies involving overpressures should refine the relationships. Parameterization of the capillary entry pressures was done with available datasets and radiogenic heat production was estimated from natural gamma ray logs (Büker and Rybach 1996). The upper thermal boundary condition was created within PetroMod with a module generating top temperature as a function of time and geographic location (Wygrala, 1987). The lower thermal boundary conditions are defined using heat flow at the base of the sedimentary column. This heat flow is variable through space and increases from west to east with burial history. The increase is in the range of about 15–20 mW/m².
Furthermore, source rock properties have to be defined. The base Qusaiba source rock related data were modified from Abu-Ali et al. (1999). The typing of the kerogen is based on Rock-Eval data. Type II/III Qusaiba shale with an average remaining HI of 126 has lower TOC values but is thicker than type II “hot shale” with an average remaining HI of 339 (Cole et al., 1994). The original HI value for the type II Qusiaba “hot shale” was estimated at approximately 450 (Dow, 1977).

Vitrinite reflectance profiles measured from 132 samples representing 17 regional wells were constructed for each well. Both vitrinite reflectance and temperature data collected from log runs, production and drill stem (DST) tests were used to calibrate the burial history models. The bottom-hole temperature data was corrected using the Horner method to insure good quality and support the vitrinite calibration plots. The temperature calibrations are only shown for four wells in Figures 11a to 11d in solid triangles. In a few cases, if production temperature data is available, it is plotted in solid circles for additional control. The vitrinite reflectance data calibrations are also plotted in Figures 11a to 11d. Burial history models for the four wells are shown in Figures 12a to 12d.

RESULTS

TOC and Rock-Eval Data

Figure 9 shows a histogram of TOC values grouped according to stratigraphic age for all analyzed samples. The majority of the samples are either Silurian or Carboniferous-Permian in age. There is little coverage for Devonian and post-Triassic samples as well as the proven Silurian “hot shale” source rock. This is because sampling was focused on cored sections for sample quality purposes. There are fewer samples as TOC increases. This fact supports the unbiased nature of the sampling process as it emphasized the sample quality regardless of TOC. Above 1.0% TOC the Silurian “hot shale” and Carboniferous-Permian samples stand out.

When plotting the Rock-Eval S2 parameter versus TOC, a Hydrogen Index (HI) slope can be calculated. Since most of the samples in the study area represent mature to over-mature Silurian Qusaiba source rock, it was not attempted to generate such a plot. Initial HI values were much higher than those measured on the remaining potential of the matured samples. For example, an immature Silurian “hot shale” source rock sample from the Tayma well (TAYM) in northwest Saudi Arabia has an HI of 469 mg/g and a $T_{\text{max}}$ of 419°C, indicative of an oil-prone, immature Qusaiba source (Abu-Ali et al., 1999 and 2001). Therefore, Silurian Qusaiba source rock was oil-prone before generating and expelling hydrocarbons as the Tayma well data indicates. Today, most of the sampled area appears to be in the gas-generating stage or beyond as indicated from the present-day very low HI and very high $T_{\text{max}}$ values.

Organic Petrology

Figure 10a plots average vitrinite reflectance values versus subsea depth in meters for all core and cuttings samples from the 132 samples representing the 17 wells. Out of the 17 wells, 16 are within the study area and a single well (TAYM) falls outside the study area. This well was chosen because it is the only well with immature organic matter. It should give real data on the geochemical characteristics of an immature Silurian Qusaiba source rock that has neither generated nor expelled any hydrocarbons. The plot shows a wide scatter of the data which can be interpreted in two ways. One would be fitting a regional trend line through the data. Another interpretation would be drawing two trend lines breaking at about 3,500 meters subsea depth. This could be the depth at which the “Hercynian Unconformity” is approximately reworking some of the sediments above (Carboniferous and Permian) and the sediments below (Devonian and Silurian) resulting in younger sediments giving higher vitrinite readings than deeper ones. To further qualify the vitrinite data it was plotted by stratigraphic age to look for some more plausible interpretations.

Figure 10b sorts the data by stratigraphic age in order to differentiate each formation. The data was grouped into Ordovician/ Older, Silurian, Devonian, Carboniferous, Permian, Triassic and Jurassic ages. Like the previous plot, this one still shows a scatter in the data displaying more lateral variation...
(different vitrinite readings for the same depth interval) for each stratigraphic age group. Although there is less scatter in the Jurassic and Triassic data, there are large variations for the data representing the Silurian, Devonian, Carboniferous and Permian age groups. The Permian samples which are not affected by the Hercynian clearly follow both the “shallow” and “deep” trend lines, indicating that the increase in maturity above and below 3,500 m is more related to depth of burial. The Devonian and Carboniferous sections which should be affected by the “Hercynian Orogeny” are only displayed in the “deeper” trend, suggesting there is no effect of the Hercynian event on the maturity trends. Higher paleo heat flows during Cretaceous and Tertiary times in the east (Ghawar) area compared to the west may, therefore, explain the different trend lines. In addition, there is a small effect of solid bitumen occurring in the deeply buried Silurian section which has a slightly higher reflectance than vitrinite at reflectance values above 1.5-2.3% (Jacob, 1989; Taylor et al., 1998). Furthermore, the data were checked for the influence of data quality by distinguishing samples on which more than 20 measurements were made from those which contain only scarce vitrinite. Basically, the trend lines and information from the plots (Figures 10a and 10b) are not modified by selecting only the high quality samples. The vitrinite data trend, therefore, is not related to Hercynian effects as will be demonstrated in the sensitivity analysis discussion.

Figures 11a to 11d display vitrinite and temperature data versus subsea depth in meters for four key wells; SDGM, JAWB, TINT and NYYM (Figure 1). The vitrinite data are shown in solid triangles and represent average values of the total number of measurements. These four wells were selected on the basis of geographic distribution, maceral type and abundance of measured vitrinite reflectance data through a large stratigraphic section. All the four wells provided sufficient samples with abundant vitrinite-like macerals or solid bitumen, ensuring a good quality and quantity of vitrinite data. The temperature calibrations are also shown in solid triangles and they were all corrected using the Horner method based on the original bottom-hole temperature data provided in the well logs. In a few cases, where production temperature data is available, it is plotted in solid circles for additional control. The four wells will be discussed individually in the following section.

**Shedgum (SDGM) Well**

Seven samples were studied (Figure 11a). The upper four samples are from the late Silurian and contain no organic particles or only inertinite at very low TOC concentrations. In one sample there are some yellow fluorescing relics of a former primary kerogen or fluid inclusions which might represent former oil filling of part of the porosity. The lower three samples are from the early Silurian and contain abundant organic particles. Mean values of 2.0% to 2.2% were established, but the best particles (large, well-polished) had a reflectivity of 2.2%. Polishing was a problem due to the high quartz content. There are no shallow vitrinite data in this well, therefore, data from the Jurassic section in the QTIF well was plotted for guidance (Figure 11a, solid circles).
Figure 10a: Average vitrinite reflectance values for all core and cuttings samples from the 132 samples representing the 17 wells plotted against subsea depth in kilometers.

Figure 10b: Average vitrinite reflectance values for all core and cuttings samples from the 132 samples representing the 17 wells plotted against subsea depth in kilometers and sorted stratigraphically.
JAWB Well

Twelve samples were studied (Figure 11b). In the Jurassic sample, no organic particles are present and the Triassic sample contains almost only inertinite with very few (0.62%) vitrinite grains. In the Permian section, solution seams (stylolithes) in the carbonates contain most of the organic particles. In one sample many measurements were possible, but the high mean value suggests a predominance of reworked organic particles which seems to be typical of the Permian in Saudi Arabia as seen from the examination of several Permian samples in this study. A lower mean value of 1.4% was established for one sample, but is based on fewer measurements. The underlying Carboniferous section contains abundant vitrinite with mean reflectance values varying between 1.88 and 2.05%. The deepest Silurian samples contain mainly inertinite. Solid bitumen remains do occur, but are very small and could not be accurately measured; a value of roughly 2% reflectance was estimated. Solid circles indicate data from the QTIF well with data from the shallower Jurassic section since the JAWB well lacks data in this interval.

Tinat (TINT) Well

Fourteen samples were studied (Figure 11c). For the Jurassic sample, a low reflectance of 0.59% was established confirmed by a low \( T_{\text{max}} \) value. In the Permian section, the samples were rich in organic particles and reflectance values between 1.5 and 1.8% were established. In view of the results on one excellent sample from the Carboniferous, these may, however, be interpreted as re-sedimented vitrinite grains. The excellent sample from this well is from the Carboniferous, for which a reflectance value of 1.17% was established. Data show little scatter and the value is well supported by a Rock-Eval \( T_{\text{max}} \) value of 440° C. For the underlying Silurian, mean reflectance values between 1.54% and 1.87% were established for vitrinite-like macerals and solid bitumen.

Nuayyim (NYYM) Well

Seven samples were studied (Figure 11d). In the Permian section, one sample contains only little reworked organic matter. In contrast, the following sample is rich in organic matter and contains excellent vitrinite grains. A mean value of 0.6% was established, which is supported by the fluorescence of the liptinite particles. The \( T_{\text{max}} \) value of this sample (439° C) is slightly higher than expected, but still confirms that the rock is at an early stage of maturation. The following four samples are of late Silurian age and contain between 0.3% and 0.5% TOC. Nevertheless some reliable reflectance measurements were obtained at 0.7% to 0.9% on vitrinite-like macerals and solid bitumen, reflecting a later stage of oil generation.

BASIN MODELING

Thermal History, Burial and Maturation Modeling

Burial history curves for the four key wells in the study area are shown in Figures 12a to 12d (SDGM, JAWB, TINT and NYYM). A constant heat flow value of 60 mW/m² was first attempted to model the burial histories of the wells. When this simple approach is used, the calculated present-day maturity and temperature curves for all wells do not completely correlate with the observed vitrinite reflectance and temperature values, but are close to them. Consequently, another approach was employed using a slightly different, geographically varying heat flow trend.

In this approach, a heat flow decreasing westwards was applied, which more favorably reflects the evolution of the Arabian Peninsula. The latter is considered to be part of a tectonically stable platform influenced by compressive tectonic activities. In such settings heat flow values are not extraordinarily high, unlike in extensional regimes where much higher heat flows and heat flow variations are expected (Yalcin et al., 1997). In order to match the observed present-day temperature and vitrinite reflectance values, present heat flow values had to be increased to approximately 75 mW m-2. This increase is more pronounced in the east (SDGM, UTMN and JAWB) than in the west (NYYM).
Figure 11a: Temperature and vitrinite reflectance calibrations for the Shedgum (SDGM) well. Depth vs. Horner-corrected, bottom-hole temperature (left display) and depth vs. mean vitrinite reflectance data (right display) are shown respectively. Observed data is plotted in solid triangle and correlated to the modeled curve (solid line). Solid circles indicate vitrinite data from the QTIF well shown only for comparison. The SDGM well was modeled using a present-day heat flow value of 70 mW/m².

Figure 11b: Temperature and vitrinite reflectance calibrations for the JAWB well. Depth vs. Horner-corrected, bottom-hole temperature (left display) and depth vs. mean vitrinite reflectance data (right display) are shown respectively. Observed data is plotted in solid triangle and correlated to the modeled curve (solid line). Solid circles indicate vitrinite data from the QTIF well shown only for comparison. The JAWB well was modeled using a present-day heat flow value of 70 mW/m².
Figure 11c: Temperature and vitrinite reflectance calibrations for the Tinat (TINT) well. Depth vs. Horner-corrected, bottom-hole temperature (left display) and depth vs. mean vitrinite reflectance data (right display) are shown respectively. Observed data is plotted in solid triangle and correlated to the modeled curve (solid line). The TINT well was modeled using a present-day heat flow value of 60 mW/m².

Figure 11d: Temperature and vitrinite reflectance calibrations for the Nuayyim (NYYM) well. Depth versus Horner-corrected, bottom-hole temperature (left display) and depth vs. mean vitrinite reflectance data (right display) are shown respectively. Observed data is plotted in solid triangle and correlated to the modeled curve (solid line). The NYYM well was modeled using a present-day heat flow value of 50 mW/m².
steady, west (50 mW/m² in the NYYM well) to east (75 mW/m² in the UTMN well) increase in heat flow is consistent with the west-east increasing depth of burial and the present-day maturity map of the Silurian Qusaiba source rock (Figure 15a). The maturity map shows an increase in maturation from west (oil-mature) to east (gas mature to over-mature). A perfect fit between the modeled curve and the observed temperature and vitrinite data cannot be expected. This is due to data quality (temperature being uncorrected or less certain vitrinite macerals) or uncertain rock properties such as thermal conductivity.

By examining the burial history curves (Figures 12a to 12d), the deepest burial is attained in the Cretaceous and Tertiary. Early burial followed by Hercynian uplift and erosion only led to some limited early petroleum generation during this period, whereas highest temperatures were definitely only reached during the Cretaceous/Tertiary period of maximum burial. As a consequence, it can be deduced that major generation and migration of hydrocarbons from the Silurian source rock only started in Jurassic times (for oil) and even later for gas (Cretaceous and Tertiary). Apatite Fission Track Analysis (AFTA) data is being analyzed to confirm the period of deepest burial.

Uplift and erosion during the Cretaceous; however, would have had significant impact since it coincided with major oil and gas generation and migration. To quantify the amount of possible uplift and erosion during the Cretaceous different scenarios were tested in the models and the effects on present-day temperature and maturity profiles were studied. This is going to be discussed under sensitivity analysis for two wells in the study area (SDGM and NYYM). The burial histories of the four wells are going to be discussed in detail. The maturation window is overlaid in color to show the maturity of the Silurian Qusaiba source rock according to Sweeney and Burnham (1990).

**Shedgum (SDGM) well**

The burial history of the SDGM well (Figure 12a) was modeled using a constant heat flow value of 70 mW/m². The model does not apply uplift and erosion during the major tectonic periods as the effect is insignificant on present-day maturity and temperature trends. The well had continuous burial throughout its history with deepest burial attained in the Cretaceous and Tertiary times. The burial history curve shows that the Silurian Qalibah “hot shale” source rock has been in the “oil window” since the late Jurassic and is today in the late “gas window,” roughly at 2.0% VR using the Sweeney and Burnham 1990 scale. Figure 11a displays the present-day, calculated temperature and maturity profiles (solid lines) and the observed data is shown in solid triangles. At a heat flow value of 70 mW/m², there is an excellent fit between the calculated temperature curve (left plot) and the Horner-corrected, bottom-hole temperature values obtained from the logs. For the maturity profile (right plot) measured vitrinite data was only available in the Silurian “hot shale” source rock section (2.05%, 1.98% and 2.15% VR). The vitrinite data is quite reliable as it represents 18-50 measurements on abundant vitrinite-like macerals or solid bitumen. Due to the absence of vitrinite data in the shallow section, some Mesozoic data from the QTIF well are plotted as well (solid circles in Figure 11a). The QTIF VR data represents the same section (Dhruma) as the SDGM well at approximately the same depth interval.

**JAWB Well**

The burial history curve for the JAWB well is shown in Figure 12b. The well was modeled with a heat flow value of 70 mW/m². The model does not apply uplift and erosion during the major tectonic periods as the effect is insignificant on present-day maturity and temperature trends. The well had continuous burial throughout its history with deepest burial attained in the Cretaceous and Tertiary times. The Silurian Qalibah Formation source rock is presently in the late gas stage, approximately at 2.0% VR using the Sweeney and Burnham 1990 scale. The base Qusaiba “hot shale” is missing in this well. The temperature calibration is shown in Figure 11b. The model is somewhat hotter than the observed, Horner-corrected bottom-hole temperature readings using the 70 mW/m² heat flow value. In order to fit the data, the heat flow has to be decreased to 60-65 mW/m². This; however, will result in lowering the maturity curve model leading to the observed vitrinite data being higher than the...
model (Figure 11b, right plot). The vitrinite reflectance data is based on abundant vitrinite macerals and 50 measurements, especially for the deepest samples (2.67, 1.88, 1.95, 2.01 and 1.97% values). It is therefore, more certain to honor the vitrinite calibration than the temperature calibration and use the 70 mW/m\(^2\) heat flow value for the model. The temperature calibration, though corrected, could be more uncertain due to drilling fluids cooling effect on the temperature readings. Two vitrinite data (0.62% in the Triassic Jilh and 2.67% in the Permian Khuff sections) do not fit in the curve as the former is on the low side and may not be representative as it is based only on three readings. The latter is on the high side because it is rich with re-sedimented particles which might lead to higher readings (Figure 11b). Similar to the SDGM well, the QTIF well data is plotted in solid circles. Both the JAWB and QTIF wells were modeled with a similar heat flow value of 70 mW/m\(^2\).

**Tinat (TINT) Well**

The burial history curve for the TINT well is shown in Figure 12c. The well was modeled with a heat flow value of 60 mW/m\(^2\). The model does not apply uplift and erosion during the major tectonic periods as the effect is insignificant on present-day maturity and temperature trends. The well had continuous burial throughout its history with deepest burial attained in the Cretaceous and Tertiary times. The Silurian Qalibah Formation “hot shale” source rock is presently in the late gas stage, approximately at 1.9% VR using the Sweeney and Burnham 1990 scale. The temperature and vitrinite calibrations are shown in Figure 11c. The temperature data shows a very good fit between the observed, corrected bottom-hole temperature readings (solid triangles) and the modeled curve (solid line). Additional temperature readings obtained from production data confirms the quality of the temperature data and it is shown in solid circles. The vitrinite data calibration (Figure 11c, right plot) shows a fair fit to the Silurian data (1.54% to 1.87%) and a scattered fit to the base Khuff data. This could be explained by the number of vitrinite readings and/or type of vitrinite macerals. The base Khuff data is dominated by re-sedimented vitrinite particles which could cause this scatter in the vitrinite reflectance data. On the other hand, the Silurian data is based mostly on vitrinite-like particles, although in both data sets the number of readings was more than 15. The overall calibration in the TINT well is considered to be good.

**Nuayyim (NYYM) Well**

The burial history curve for the NYYM well is shown in Figure 12d. The well was modeled with a heat flow value of 50 mW/m\(^2\). The model does not apply uplift and erosion during the major tectonic periods as the effect is insignificant on present-day maturity and temperature trends. The well had continuous burial throughout its history with deepest burial attained in the Jurassic time (Figure 12d). The Silurian Qalibah Formation “hot shale” source rock is presently in the oil stage, roughly at 0.7-0.8% VR using the Sweeney and Burnham 1990 scale. The source rock is at the onset of oil generation. This is in accordance with the regional dip to the east and the eastward deeper burial. Both the temperature and maturity trends (Figure 11d) have a reasonably good fit with the observed data. The temperature data was based on bottom-hole temperature readings from logs and was corrected using the Horner method. The vitrinite data represents mostly over 20 measurements and reflects vitrinite-like macerals and solid bitumen as the dominant organic matter type in the measured Silurian section (0.85, 0.83 and 0.87% VR).

**Sensitivity Analysis**

Having constructed the burial history, temperature and maturity trends for all 17 wells, it is important to examine the uncertainty by varying each geologic factor that may contribute to the present-day temperature and maturity trends. Amongst these factors are present-day and paleo-heat flow, burial history, uplift and erosion and source rock properties. A sensitivity test was performed using the SDGM and NYYM wells. The SDGM well in the east of the study area represents where the Hercynian erosion was at its maximum on the crest of the Gharaw structure (Wender et al., 1998). The NYYM well in Central Arabia west of the study area, where the Jurassic section outcrops and the Cretaceous section is eroded, represents effects of Cretaceous erosion on boundary conditions, thermal maturity
Figure 12a: Burial history plot for the Shedgum (SDGM) well showing depth versus age for all the geologic layers in the well. The maturation window is overlaid in color to show the maturity of the Silurian Qusaiba source rock. The Silurian Qalibah "hot shale" source rock has been in the "oil window" since Late Jurassic and is today in the late "gas window", roughly at 2.0% VR using the Sweeney and Burnham 1990 scale. The SDGM well was modeled using a present-day heat flow value of 70 mW/m².

Figure 12b: Burial history plot for the JAWB well showing depth versus geologic time for all the geologic layers in the well. The maturation window is overlaid in color to show the maturity of the Silurian Qusaiba source rock. The Silurian Qalibah Formation source rock is presently in the late gas stage, approximately at 2.0% VR using the Sweeney and Burnham 1990 scale. The base Qusaiba "hot shale" is missing in this well. The JAWB well was modeled using a present-day heat flow value of 70 mW/m².
Figure 12c: Burial history plot for the TINT well showing depth vs. geologic time for all the geologic layers in the well. The maturation window is overlaid in color to show the maturity of the Silurian Qusaiba source rock. The Silurian Qalibah Formation "hot shale" source rock is presently in the late gas stage, approximately at 1.9% VR using the Sweeney and Burnham 1990 scale. The TINT well was modeled using a present-day heat flow value of 60 mW/m².

Figure 12d: Burial history plot for the Nuayyim (NYYM) well showing depth versus time for all the geologic layers in the well. The maturation window is overlaid in color to show the maturity of the Silurian Qusaiba source rock. The Silurian Qalibah Formation "hot shale" source rock is presently in the oil stage, roughly at 0.7-0.8% VR using the Sweeney and Burnham 1990 scale. The NYYM well was modeled using a present-day heat flow value of 50 mW/m².
and temperature histories. To test the effect of erosion and boundary conditions on the Silurian source rock maturity, both SDGM and NYYM wells were used in the sensitivity study. The erosion effect on the SDGM well is displayed in Figure 13 while the boundary conditions effect on the NYYM well is shown in Figure 14.

A set of five different scenarios with different amounts of erosion was tested in both the Hercynian and Cretaceous/Tertiary times. Assumptions used in this sensitivity were constant heat flow (60 mW/m²) and constant surface temperature (20° C). It is important to note that the heat flow and surface temperature values used in the sensitivity study were slightly different than the values used in calibrating the SDGM and NYYM wells for burial history analysis. In all five scenarios the present-day results are the same with differences encountered only in paleo-history times of the well.

The first (1) case assumes neither Hercynian nor Cretaceous/Tertiary erosion and results in the lowest maturity values trough time. The next scenario (2) has an exaggerated Cretaceous/Tertiary erosion of 1,250 ft (250 ft on top of the Dammam Formation and 500 ft for each top Aruma and top Wasia formations). This case shows a maximum increase of maturity of 0.1% of vitrinite reflectance equivalent (VrE) at around 90 million years (my). Compared to case 1, case 2 reaches a maturity level of 1.0 VrE approximately 15 my earlier. The next three scenarios (3, 4 and 5) investigate the Hercynian erosion and take the best estimates for the Cretaceous/Tertiary erosion (133 ft on top of the Dammam Formation, 354 ft on top of the Aruma and 242 ft on top of the Wasia Formation). All three cases show a similar behavior during the Cretaceous/Tertiary time with maturity level in between scenarios 1 and 2. Scenario (3) does not take into account any Hercynian erosion and consequently has the lowest maturity level during the Paleozoic and Cenozoic times. In the extreme erosion case (4) maturity level increases by about 0.1% VrE by adding 3,000 ft of Upper Devonian and Lower Carboniferous sequences. The final case (5) with only 1,000 ft of erosion is quite similar to no erosion at all.

The NYYM well illustrates the effect of changing boundary conditions on the Qusaiba “hot shale” maturity (Figure 14). Three scenarios were tested with all other conditions remaining constant. No Hercynian erosion was taken into account whereas the Cretaceous/Tertiary erosion was estimated to be 4,500 ft (1,640 ft of missing Wasia, 1,181 ft of missing Aruma, 230 ft of missing Rus and Umm er Radhuma and 328 ft of missing Dammam).

The first scenario (1) investigates a constant surface temperature (20° C) and a constant heat flow (50 mW/m²). The second scenario (2) applies a constant surface temperature and a variable heat flow history attempting to take into account the Late Proterozoic rifting followed by a thermal relaxation, the Hercynian inversion and the Permian rifting event followed by a thermal relaxation. The third scenario (3) introduces a variable heat flow and a variable surface temperature derived from the change of latitude of the Arabian Platform through time, temperature change through time, water depth and glaciation event. The present-day temperature is the same for all three scenarios but maturity varies in a range of 0.1% VrE. When varying both heat flow and surface temperature, a slightly higher maturity is reached (scenario 3) than when the two variables are constant (scenario 1). Scenario 3 enters the “oil window” 40 my earlier than when using constant heat flow and constant surface temperature.

To summarize, the SDGM well sensitivity study shows that the uncertainty of the Hercynian erosion has a lasting impact on the Silurian Qusaiba “hot shale” at the immature level. When entering the “oil window,” all three scenarios behave the same. The differences of the boundary conditions on the NYYM well demonstrate sensitivity of the variable heat flow and variable surface temperature in the “oil window” stage being reached about 40 my earlier than when the two same variables are held constant. Sensitivity on fluid properties was not analyzed. The fluids are controlled by the degree of hydrocarbon cracking in the “kitchen” and water-washing in the reservoir. Additionally, the difference in timing of oil and gas generation may have influenced present-day fluid properties, because earlier generated, less mature petroleum stands a greater chance of being lost from the system. In this case, more mature petroleum with higher API gravity will be increasingly preserved than what was generated during an earlier stage of maturation.
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Figure 13: Shedgum (SDGM) well sensitivity analysis shows that the uncertainty of the Hercynian erosion has a lasting impact on the Silurian Quaiba “hot shale” at the immature level. When entering the “oil window”, all three scenarios behave the same.

Figure 14: Nuayyim (NYYM) well sensitivity analysis demonstrates sensitivity of the variable heat flow and variable surface temperature in the “oil window” stage being reached about 40 my earlier than when the two variables are held constant.
Source Rock Maturation, Hydrocarbon Generation and Migration

Figure 15a is a present-day vitrinite reflectance map for the base Qusaiba “hot shale”. The map results from a convolution of a 3-D simulation with measured data. The color coding represents the following maturity zones, heavy oil (dark green), light oil (light green), wet gas (blue), dry gas (pink), over-mature (gray). The scale is not the same as the Sweeney and Burnham 1990 scale, which is used in the burial history models shown in Figures 12a to 12d. Missing Qusaiba “hot shale” due to erosion is marked as blank areas. The map shows that most of the “hot shale” in the study area is now in the gas maturity zone with even over-mature stages in the deeper parts of the basin. The Silurian base Qusaiba maturation at Jurassic time (approximately 140 million years ago) is shown in Figure 15b, which can be compared to the present-day maturation. At Jurassic times, most of the Qusaiba “hot shale” was in the “oil window,” whereas it remained immature in the western part of the area leaving the complete oil generation potential for later times. Most of the source rock is presently gas-mature except in Central Arabia (to the west, where it is oil-mature). The highly mature oil and gas cap found in Central Arabian fields (Hawtah, Nuayyim, Raghib, Hilwah, etc.) can be explained by migration from the deeper, over-mature basin to the east (Abu-Ali et al., 1991, 1999, 2001). Other factors that contribute to different phases of hydrocarbons beside source rock maturity are migration timing, water washing, dismigration and cracking, all of which cannot be conclusively addressed given the available data in this study.

The “oil and gas windows” concept is based on primary generation consideration. In its simplicity it may; however, be misleading, as other important factors such as oil/gas expulsion are ignored. The Silurian Qusaiba source rocks under investigation originally contained oil prone type II or type II/III kerogen. Qusaiba sourced oils have been found in Tinat and Niban fields, southeast of Ghawar (Figure 1). Huge amounts of Qusaiba-derived gas; however, are found in the satellite fields to the south and southwest of Ghawar field, where the source rock is gas mature and where previously generated oil has been either lost or cracked to gas. Strong secondary cracking in some areas of the basin may have been related to fluid retention, often coupled with the development of strong overpressures. This may have occurred during mainly Cretaceous times when rapid sedimentation and gas generation coincided. Thus, the amount of oil expelled may have been reduced allowing for secondary cracking into gas in situ within the source rock (Schenk and Horsfield, 1993). At present however, the pressure system is quite open in the direction of the Arabian Shield and shows a regular pressure increase towards the east. Before the Tertiary tilting, higher overpressure could be expected. Investigating overpressure for expulsion modeling is quite time consuming particularly as it also involves the consideration of fault permeability which is difficult to predict and partly controlled by diagenesis. Taking structural evolution, fault permeability and overpressure development into account are regarded as an important future step in petroleum system analysis in this basin.

The relative amount of expelled gas and oil depends also on migration fractionation and PVT aspects and can be, with limitation, calibrated with known field data. Several expulsion models consider fractionation during primary migration as relevant such as the diffusion model by Stainforth and Reinders (1990) or the absorption model by Pepper and Corvi (1995). This was not considered in this modeling approach but is considered as an important future step to refine the knowledge of the Paleozoic petroleum system of Saudi Arabia. In this study, the Darcy flow expulsion method was used for primary migration and the “Hybrid” method for secondary migration. The “Hybrid” method uses Darcy flow for vertical migration from the source rock and flow path for lateral (long distance) migration within the carrier/reservoir bed. Faults were not considered in modeling hydrocarbon migration.

Another aspect strongly influencing the Gas/Oil Ratio and/or the Condensate/Oil Ratio (GOR/CGR) is related to the Thermochemoal Sulfate Reduction (TSR) present in the Khuff reservoir (Worden et al., 1995, 2000). TSR produces H2S and destroys hydrocarbons but with a fractionation which relatively enriches light hydrocarbon gas, particularly methane. This will result in a decrease of the gas wetness. Almost all Khuff gas accumulations in the Ghawar field are mainly dominated by methane dry gas (more than 70 %) with minor contributions of the C2 and C3 components. TSR also increases the proportion of N2 as this component remains inert to the reaction. TSR has not been modeled in this study, but will be included in the near future.
Hydrocarbons can either migrate vertically through faults and fractures and/or laterally through the carrier bed. In cases like the Sarah reservoir, which is immediately below the Silurian source rock, hydrocarbons will be expelled directly from the source rock down to the reservoir (downward migration). This makes the Sarah reservoir very attractive for exploration as the migration pathway risk is minimized compared to other reservoirs. For the Khuff, Unayzah and Jauf reservoirs the presence of faults that connect the source rock to the reservoir become the critical issue for migration. For example, the Ghawar structure is bounded by major faults to the east and west making the hydrocarbon journey from source to trap less tortuous; thus, all the Ghawar Paleozoic reservoirs (Khuff, Unayzah, Jauf, Sarah) are hydrocarbon bearing when present. On the other hand, the presence of faults in Central Arabia’s Hawtah trend fields (Hawtah, Hilwah, Nuayyim Raghib, Dilam, etc.) are not essential since migration is predominantly lateral due to the fact that the Qusaiba source rock is marginally oil-mature to immature in the area. Hydrocarbon migration in Central Arabia will; therefore, be long-distance from the basin south of Ghawar (Figure 15 a and 15b).

In addition to the presence of faults as conduits for hydrocarbon migration, the thickness and the internal lithofacies distribution of the interval from the source rock to the reservoir is another important factor in the migration process. In the absence of faults, the thicker the section the longer it takes to migrate hydrocarbons through the pore network. For further explanation, a Hercynian subcrop map is shown in Figure 1. If what is subcropping below the Hercynian is the Silurian Qalibah Formation, then the migration pathway to the overlying Jauf, Unayzah and Khuff reservoirs is less complex and requires less time to migrate hydrocarbons from the source to the reservoir. In this case the reservoir rock is the carrier rock at the same time. On the other hand, if the section below the “Hercynian Unconformity” is thicker the migration pathway is more complex and requires the layers between the source and reservoir to be more porous and permeable for oil and gas migration in spite of the presence of faults. Age-dating of the faults is another factor to consider in future migration studies. Faults penetrating higher up in the section are conduits for oil and gas migration into the overlying Jauf, Unayzah and Khuff reservoirs as opposed to faults just terminating at the Unayzah reservoir level. Having this in mind will better assess the Hercynian subcrop map. In Figure 1, the Silurian Qusaiba source rock is subcropping over most of the Ghawar structure. The Ghawar structure has; therefore, better access to hydrocarbon charge. Central Arabia’s fields have a Devonian section subcropping (Tawil, Jubah and Jauf) which can act as carrier beds to hydrocarbons migration from the east. The Khurais and Abu-Jifan structures to the west of Ghawar will have a higher risk for hydrocarbon migration. In that area what is subcropping below the “Hercynian Unconformity” is Cambrian/Ordovician section and lateral migration from the Qusaiba to the east and north is implied since the Qusaiba source to the west is marginally mature.

The same applies to the Summan Platform and Dibdibah Trough areas northwest of Ghawar, where the Cambrian-Ordovician section subcrops the “Hercynian Unconformity”. To the north of Ghawar in the onshore and offshore areas, the Silurian section subcrops in the Safaniyah and Manifa structures. Thus, hydrocarbon migration risk is lower than in the areas where the Devonian and pre-Silurian sections are subcropping, like the Berri, Qatif, Khursaniyah and Abu Hadriyah structures. In the areas where the Devonian section is subcropping, the risk of finding hydrocarbons in Devonian reservoirs is much lower than in Unayzah and/or Khuff reservoirs as the Devonian is in the “migration shadow zone” of the Silurian-generated hydrocarbons. That is, where the Devonian seal is present hydrocarbons would have been captured by the Devonian Jauf reservoir first before any hydrocarbons could have made it through to the overlying Unayzah and Khuff reservoirs. South of Ghawar and toward the Rub’ Al-Khali Basin the Devonian section is most probably subcropping, making the Devonian Jauf and Ordovician reservoirs less risky for hydrocarbon exploration than the Carboniferous-Permian Unayzah and Permian Khuff reservoirs. The reservoir quality in the Devonian and Ordovician reservoirs; however, will become the main issue. Similarly, the Unayzah reservoirs would have been on the “migration shadow zone” of the overlying Khuff reservoirs. Hydrocarbons will charge the Unayzah reservoirs before the Khuff reservoirs. Charging both the Unayzah and Khuff reservoirs will depend on whether faults cut the Khuff reservoirs and if these faults are sealing or leaking.
Figure 15a: Silurian Qusaiba source rock maturity map at present. The color scale is in vitrinite reflectance %, green represents oil-mature areas, pink dry gas-mature areas and grey over-mature areas. Scale is not the same as the Sweeney and Burnham 1990 scale. Blank areas indicate Qusaiba erosion.
Figure 15b: Silurian Qusaiba source rock maturity map at Jurassic time (140 Ma). The color scale is in vitrinite reflectance %, green represents oil-mature areas, pink dry gas-mature areas and grey over-mature areas. Scale is not the same as the Sweeney and Burnham 1990 scale. Blank areas indicate Qusaiba erosion.
Hydrocarbon Accumulation Modeling

The objective of hydrocarbon accumulation modeling was not to quantitatively account for all the hydrocarbon volumes/columns/phases and PVT characteristics found in the reservoir, but rather to qualitatively test the model outcome and gain an understanding of what factors seem to control the accumulations. The simulated accumulations are therefore highly model driven and strongly dependent on parameter setups and facies maps, particularly for the Unayzah reservoirs. After constructing the geologic structure maps, formation lithologies, facies distributions and source rock properties, the 3-D data set was ready for simulation. Simulation runs were specifically made for gas as the study area at the time was focused on gas exploration. In addition, the source rock maturity map shows that most of the study area is within the “gas window” at present (Figure 15a). Oil accumulations were more critical at Jurassic and Cretaceous times, but were not modeled.

3-D basin modeling for a regional area such as the size of this study will largely depend on the quality of the structure maps, facies distributions and properties, lateral migration effects and regional source rock properties. Predicting hydrocarbon accumulations is easier using smaller areas or prospects since variations in these parameters are smaller than in large areas. With large models, this task becomes more challenging as more uncertain variables get introduced into the modeling process. Figures 16a to 16d show a series of 3-D simulated hydrocarbon accumulation maps for four reservoirs (Permian Khuff carbonates, Carboniferous-Permian Unayzah, Devonian Jauf and Ordovician Sarah).

Figure 16a shows the Khuff reservoir accumulations. The Ghawar Khuff accumulations were qualitatively predicted; however, the absence of Khuff hydrocarbons outside Ghawar does not necessarily mean that there are no accumulations to be found there. Figure 16b shows the simulated Unayzah accumulations. There are more Unayzah accumulations to be found in both the A and B reservoirs than what has been found so far. What the model can not predict are the volatile oil accumulations in the Hawtah trend fields of Central Arabia. This could be largely dependent on the paleo-structure and lithology maps, which were not accurately accounted for in this current study. For the Ghawar gas accumulations, the 3-D kinetic model used in this study was primarily based on the primary kinetics data by Abu-Ali et al. (1999, 2001). The data has, however, been modified to take into account secondary cracking within the source rock using literature and research data. This model accounts for the gas and condensate accumulations in the Ghawar area as the source rock maturity is already beyond the gas stage on the eastern flank of the drainage area. What is not certain is whether the gas in the Ghawar reservoirs and the fields to the north was a result of TSR secondary cracking, source rock over-maturity or both. From the vitrinite reflectance work, the presence of fluid inclusions and/or solid bitumen in the northern part of Ghawar (SDGM well) as a sign of early oil charge before TSR cracking into gas could possibly explain this situation. The model remains speculative at this stage and needs more fluid inclusions data and new closed system kinetics for source rock analysis. In the Hawtah trend area; however, the source rock was not mature locally and the hydrocarbons were charged mainly laterally from the east. The filling history of Central Arabia’s fields is quite complex due to the variability of the lateral and vertical migration pathways, hydrocarbon phase separation, water washing and hydrodynamics. Central Arabia’s hydrocarbon accumulations are, therefore, more difficult to predict than the vertically-migrated Ghawar accumulations. Also, a more detailed handling of fluid compositional aspect as related to PVT conditions is required, but it is beyond the scope of this paper.

Figures 16c and 16d illustrate future potential for the Devonian Jauf and Ordovician Sarah reservoirs. These two are less facies-controlled than the Khuff and Unayzah reservoirs. Therefore, the model remains uncertain until more rock properties data are available. From the model, it is quite evident; however, that there are more Sarah accumulations than Jauf only. The fact that the Sarah reservoir is directly underlying the Silurian Qusaiba source rock makes the Sarah reservoir more accessible to the gas/oil expelled from the source rock (downward migration). This will eliminate the need for secondary migration through a carrier bed. Other assumptions have to hold like presence of a seal for the Sarah reservoir, which would be the “hot Qusaiba shales” at the base of the Silurian source rock and presence of good quality reservoir rocks. On the other hand, limited accumulations for the Jauf reservoir can be attributed to the absence of good reservoir and seal lithofacies maps, as well as having less structural closure at the Jauf level than deeper at the Sarah level.
Figure 16a: Modeled gas accumulations in the Permian Khuff reservoir.

Figure 16b: Modeled gas accumulations in the Carboniferous-Permian Unayzah reservoir.
Figure 16c: Modeled gas accumulations in the Devonian Jauf reservoir.

Figure 16d: Modeled gas accumulations in the Ordovician Sarah reservoir.
GENERAL DISCUSSION

A basin modeling approach to describe petroleum systems provides a logical process by which parameters of a petroleum system can each be assessed and tested for different geologic scenarios of basin evolution. Although 1-D basin modeling calibrated by present-day temperature data derived from electric logs, production and DST tests; and by vitrinite reflectance can be used as input, petroleum generation and migration modeling through geologic time remains quite challenging. Here, it has been attempted to fulfill this task by varying different geologic parameters such as burial history, heat flow and amount of uplift and erosion. Results indicate that applying significant uplift and erosion in both Hercynian and Cretaceous times does not drastically affect hydrocarbon generation and migration history; in particular, the present-day distribution of maturity and hydrocarbon accumulations is hardly affected. Varying heat flow; however, produces more pronounced effects on the present-day scenario and the measured data do not correlate well with the simulated results, if assumptions are made which differ greatly from the proposed, calibrated temperature history model. The assumptions and parameters on temperature history used in this study are, therefore, most probably quite well-constrained. A greater uncertainty exists with respect to source rock quality and kinetics of hydrocarbon generation and expulsion from the source rock. This uncertainty is due to the fact that too little immature/early mature equivalents of the now highly mature/over-mature known Silurian source rock could be studied and that the possible contribution of other possible source rocks is not sufficiently known. Further geochemical studies might help to solve this problem.

Moving from the 1-D world to the 3-D reality, the problem becomes more pronounced. Building a 3-D dataset takes into account all possible variables of the petroleum system: accuracy of the maps, exact boundary conditions, efficiency of the carrier beds, seals, behavior of the faults, homogeneity of the reservoir and source rock, facies distribution in intermediate layers, adequacy of the structure and many other parameters. The real measure of how well the 3-D model is close to reality is the ability of the model to explain the present-day hydrocarbon accumulations. Although this study did not quantitatively arrive at that level, it qualitatively described the hydrocarbon migration journey with good confidence at least for the petroleum systems considered thus far. Additionally, the size of this regional study did not allow for predicting exact accumulations. Hydrocarbon accumulations can be simulated more accurately using smaller areas or better predicted for prospect-size accumulations since the geologic uncertainties are smaller.

Hydrocarbons can either migrate vertically through faults and fractures and/or laterally through the carrier bed. In cases like the Sarah reservoir, which is immediately below the Silurian source rock, hydrocarbons will be expelled directly from the source rock down to the reservoir (downward migration). This makes the Sarah reservoir very attractive for exploration as the migration pathway risk is minimized compared to other reservoirs. For the Khuff, Unayzah and Jauf reservoirs presence of faults that connect the source rock to the reservoir becomes the critical issue for migration. For example, the Ghawar structure is bounded by major faults to the east and west making the hydrocarbon journey from source to trap less tortuous; thus, all the Ghawar Paleozoic reservoirs (Khuff, Unayzah, Jauf, Sarah) are hydrocarbon-bearing where present. On the other hand, the presence of faults in Central Arabia’s Hawtah trend fields (Hawtah, Hilwah, Nuayyim Raghib, Dilam, etc.) are not essential since migration is predominantly lateral due to the fact that the Qusaiba source rock is marginally oil-mature to immature in the area. Hydrocarbon migration in Central Arabia will, therefore, be lateral (long-distance) from the basin south of Ghawar (Figure 16a and 16b).

In addition to the presence of faults as conduits for hydrocarbon migration, the thickness of the interval from the source rock to the reservoir is another important factor in the migration process. The thicker the section the longer it takes to migrate hydrocarbons through faults. To further explain this a Hercynian subcrop map is illustrated in Figure 1. If what is subcropping below the Hercynian is the Silurian Qalibah Formation, then the migration pathway to the overlying Jauf, Unayzah and Khuff reservoirs is less complex and less time is required to migrate hydrocarbons from the source to the reservoir. In this case the reservoir rock is the carrier rock at the same time. On the other hand, if the section below the “Hercynian Unconformity” is thicker the migration pathway is more complex and requires the layers between the source and reservoir to be more porous and permeable for oil and gas migration. Another important factor is the presence of open faults. Age-dating of the
faults will be a major step in future migration studies. Faults penetrating higher up in the section are conduits for oil and gas migration into the overlying Jauf, Unayzah and Khuff reservoirs as opposed to faults just terminating at the Unayzah reservoir level. In Figure 1, the Silurian Qusaiba source rock is subcropping over most of the Ghawar structure. The Ghawar structure has, therefore, better access to hydrocarbon charge. Central Arabia’s fields have a Devonian section subcropping (Tawil, Jubah and Jauf) which can act as carrier beds to hydrocarbon migration from the east. The Khurais and Abu Jifan structures to the west of Ghawar will have a higher risk for hydrocarbon migration. In that area, below the Hercynian unconformity Cambrian/Ordovician rocks are subcropping and lateral migration from the Qusaiba to the east and north is implied since the Qusaiba source to the west is marginally mature.

The same applies to the Summan Platform and Dibdibah Trough areas northwest of Ghawar, where the Cambrian-Ordovician section is subcropping below the “Hercynian Unconformity”. To the north of Ghawar in the onshore and offshore areas the Silurian section is subcropping in the Safaniyah and Manifa structures, thus, hydrocarbon migration risk is lower than in the areas where the Devonian and pre-Silurian sections are subcropping like in the Berri, Qatif, Khursaniyah and Abu Hadriyah structures. In the areas where the Devonian section is subcropping migration risk has to be taken into consideration. The Devonian Jauf reservoir could be on the “migration shadow zone” of the Unayzah and/or Khuff reservoirs. That is, when the Devonian seal is present hydrocarbons will be captured by the Devonian Jauf reservoir first before any hydrocarbons can make it through to the overlying Unayzah and Khuff reservoirs. South of Ghawar and toward the Rub‘ Al-Khali Basin the Devonian section is most probably subcropping, making the Devonian Jauf and Ordovician reservoirs less risky for hydrocarbon exploration than the Carboniferous-Permian Unayzah and Permian Khuff reservoirs. The reservoir quality in the Devonian and Ordovician reservoirs; however, will become the main issue. Similarly, the Unayzah reservoirs will be on the “migration shadow zone” of the overlying Khuff reservoirs. Hydrocarbons will charge the Unayzah reservoirs before the Khuff reservoirs. Charging both the Unayzah and Khuff reservoirs will depend on whether faults cut the Khuff reservoirs and if these faults are sealing or leaking.

For the Paleozoic petroleum systems of Saudi Arabia, the accumulation maps (Figures 16a to 16d) clearly illustrate the strong dependency of the modeled hydrocarbon accumulations on the facies maps. The more accurate the facies maps are the closer to reality are the simulated hydrocarbon accumulations. In addition to the parameters usually studied in the framework of basin modeling sensitivity analysis (burial history including uplift/erosion, heat flow, source rock properties, permeability and fault distribution), facies maps provide the most important parameter when modeling hydrocarbon accumulations. This conclusion implies that having accurate facies maps significantly increases the credibility of any modeling results on location, quality and quantity of any hydrocarbon accumulations. It has also been demonstrated that hydrocarbon migration is strongly influenced by the presence of faults as conduits for vertical migration and the Hercynian subcrop map. In the Ghawar area, the current model accounts for the gas and condensate accumulations. The filling history of Central Arabia’s fields; however, is quite complex due to the variability of the lateral and vertical migration pathways, hydrocarbon phase separation, water washing and hydrodynamics. Central Arabia’s hydrocarbon accumulations are, therefore, more difficult to predict than the vertically-migrated Ghawar accumulations.

**SUMMARY, CONCLUSIONS AND RECOMMENDATIONS**

- The Silurian Qusaiba source rock has been quantitatively and qualitatively analyzed with respect to organic richness, pyrolysis and thermal maturity.
- Burial history for the Paleozoic section of Saudi Arabia has been constructed using measured thermal maturity of the Silurian source rock and other stratigraphic layers for 17 key regional wells. Based on this data set, a maturity map for the principal source rock has been established for a large 3-D area (Figure 15). Maturity data are mainly from the Paleozoic and more Mesozoic data are needed to verify, falsify or modify the temperature history models calibrated by the existing data. Additional thermal maturity data would be very important for better calibration of temperature history models, especially from the Jurassic and Cretaceous sections.
Sensitivity analysis has been performed for the 1-D basin models by varying several input parameters such as the rate of uplift/erosion during periods not documented by sediments and boundary conditions. Based on the initial model and the alternative scenarios calculated, a rather well-constrained burial and temperature history could be established for large parts of Saudi Arabia.

A 3-D petroleum system has been established for the first time in Saudi Arabia. Hydrocarbon generation and migration has been qualitatively modeled in 3-D and gas accumulations in the Permian Khuff and Carboniferous Unayzah reservoirs in the Ghawar area are accounted for. The filling history of Central Arabia fields is quite complex due to the variability of the lateral and vertical migration pathways, hydrocarbon phase separation, water washing and hydrodynamics. Central Arabia’s hydrocarbon accumulations are, therefore, more difficult to predict than the vertically-migrated Ghawar accumulations. This model should serve as a basis for future models as more data becomes available and uncertainty in some data parameters (reservoir, seal and fault) are reduced.

3-D basin modeling should be the basis for any petroleum system analysis as it far exceeds 1-D and 2-D modeling in describing real earth models and fluid movements in the subsurface. Subregional models or prospect-size accumulations can be predicted with more confidence than large, regional areas.

Future exploration opportunities exist in the Paleozoic reservoirs of Saudi Arabia (Devonian Jaf, Ordovician Sarah, Infracambrian, etc.) as there are more generated/migrated hydrocarbons than what has been discovered to date from the Silurian source rock alone. An even greater potential may exist, if other Paleozoic source rocks also contributed to the petroleum system.

Quantitative and qualitative analysis of additional source rock units can substantially add to the resources of the Paleozoic petroleum systems in Saudi Arabia. These analyses are currently underway.

Future steps in petroleum system analysis should take into account new laboratory-derived, closed system secondary cracking kinetics for the Silurian Qusaiba source rock. This can lead to a better modeling of the different hydrocarbon phases. Furthermore, seal efficiency studies should be performed to better assess the preservation of the Paleozoic petroleum systems and continuous and consistent mapping of the geologic layers and facies will definitely lead to building more accurate 3-D petroleum systems. Finally, mapping and age-dating faults should lead to a better assessment of the petroleum systems and the more accurate prediction of migrated hydrocarbons.

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