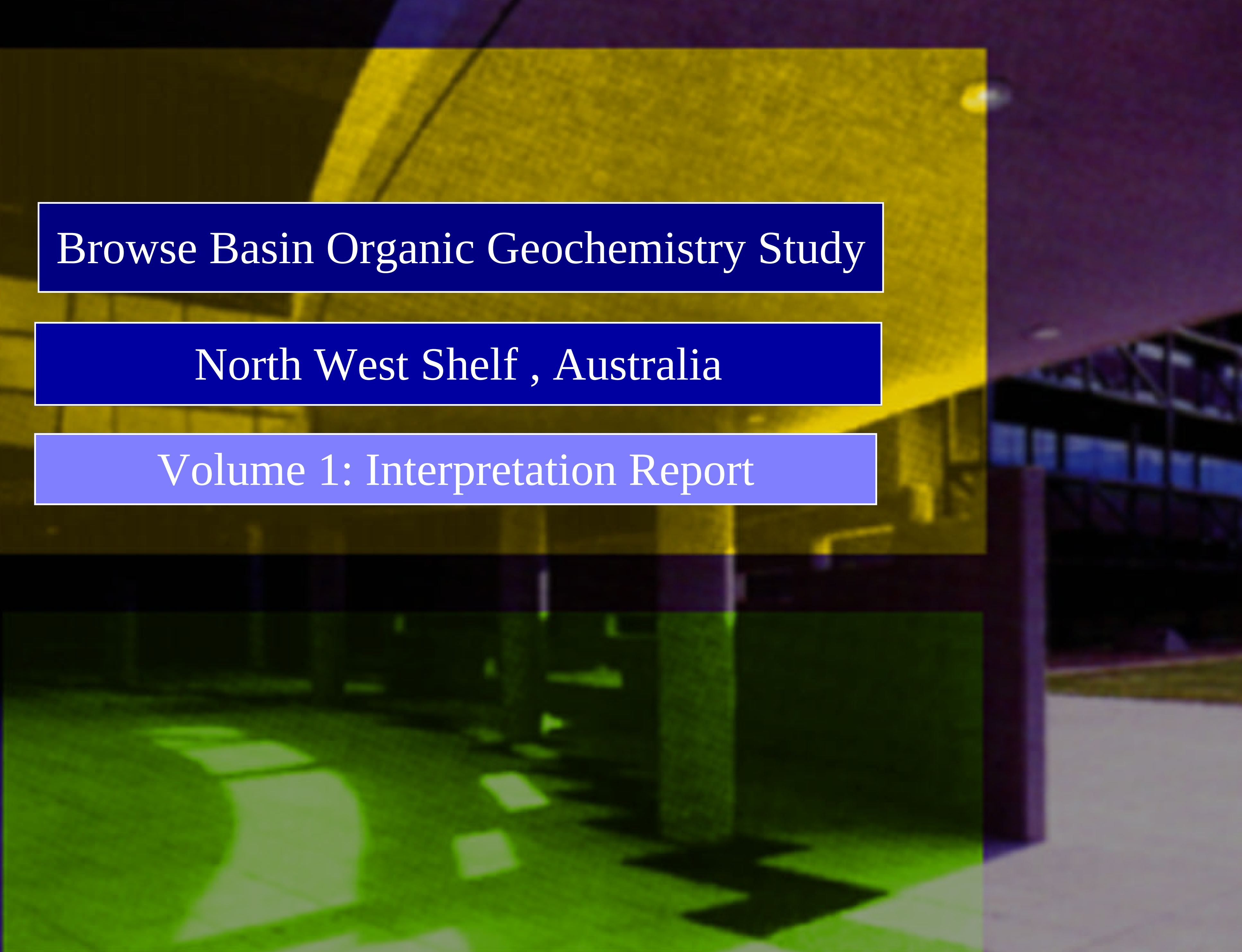
Browse Basin Organic Geochemistry Study

North West Shelf , Australia

Volume 1: Interpretation Report



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Browse Basin organic geochemistry study, North West Shelf, Australia

Volume 1: Interpretation report

C.J.BOREHAM, Z. ROKSANDIC, J.M. HOPE, R.E. SUMMONS, A.P. MURRAY, J.E.BLEVIN AND H.I.M. STRUCKMEYER

Petroleum and Marine Division, Australian Geological Survey Organisation, GPO Box 378, Canberra, ACT 2601

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EXECUTIVE SUMMARY

- Mature petroleum source rocks exist throughout the Browse Basin below a regional cutoff at approximately 1500m. Above this depth, potential source rocks are immature for oil and gas generation.

- Present-day source quality is rated as only poor-moderate although some thin, high quality source beds are present in Early to Middle Jurassic strata.

- After correction for lithological artifacts and their current maturity, some Late Jurassic (BB8) and Early Cretaceous (BB9-BB11) sediments are considered to have had initially moderate to good oil potential.

- Oil-oil correlation studies have demonstrated the presence of two main oil populations in the basin. Population A comprises Caswell-2 (A1), Gwydion-1(A1) and Kalyptea-1/ST-1 (A2). The latter oil is a variant justifying its classification into a second sub-population (A2). Population B oils comprise Brecknock-1, North Scott Reef-1 and Scott Reef-1 and the classification of these oils, based on multivariate statistical analysis of saturated hydrocarbon biomarkers and carbon isotopes, is supported by recognition of a unique (but unknown) terpane biomarker.

- Oil-source correlations have, for the first time, positively identified an Early Cretaceous Petroleum System on the North West Shelf. The chemistry of Population A oils correlates very strongly with that of a sediment extract from the BB10 horizon in Discorbis-1 and quite strongly with another extract from a similar dated sediment in Caswell-2 and from a younger BB11 horizon in Kalyptea-1/ST1.

- No source rock horizon has been clearly correlated with the Population B oils. Pre-Triassic sediments are considered unlikely based on biomarker evidence while an Early Cretaceous source is precluded by carbon isotope data.

- In the southern Browse Basin, oil-stains in the Lombardina-1 well could be evidence for the effectiveness of a Late Jurassic Petroleum System in this locality.

- Similar organic facies have contributed to all the Browse Basin liquids and this results in only subtle differences between and within oil populations. Maturity variations also blur the distinctions. Most of the oils appear to have been expelled from their source rocks at temperatures beyond the conventionally accepted 'main' oil window. The source rocks we have encountered here are, on a global scale, quite lean and this is an important factor controlling the timing of expulsion. Lean rocks generally do not yield liquid in sufficient quantities to support an early primary migration phase. It is only at higher maturities that gas-to-oil ratios are sufficiently high to lead to expulsion and migration. Caswell-2 is the least mature oil and because of this, can be reasoned to have been expelled from a more oil-prone source pod.

- Dry gas from deep, overmature sources may have assisted in re-distribution of petroleum along the secondary migration pathways or in the reservoirs.

- The Gwydion-1 oil has experienced mild biodegradation and this has removed most of the light, gasoline range hydrocarbons. Such secondary alteration of oils within shallow reservoirs at the margins of the basin is seen as a localised exploration risk.

- Statistical oil-oil correlations between Browse Basin oils, and others from the established Carboniferous to Jurassic petroleum systems across the North West Shelf, demonstrate the special nature of both Populations A and B. However, the analysis only produces this result when a sufficiently large and representative sample set is employed. This stems from the fact that most of the effective North West Shelf source rocks are clastic in nature and contain mixtures of marine and terrestrial organic matter deposited in near shore marine and deltaic environments. In other words, the organo-facies and sedimentary environments are quite similar. Population B oils appear to share more chemical affinities with oils in the Westralian Supersystem and we propose they be tentatively assigned to a new

Petroleum System W1B. In contrast, and despite their younger age, Population A oils, share more chemical affinities with W1 (Triassic-Early Jurassic) oils of the Carnarvon Basin than they do with the W2 (Late Jurassic) North West Shelf oils. We propose they should be assigned to a new W3 Petroleum System (Early Cretaceous).

INTRODUCTION

The objectives of this study were:

(a) Evaluate the hydrocarbon generative potential of strata within the Devonian to Cretaceous Browse Basin succession,

(b) Conduct oil-source correlations to identify effective source facies for reservoired hydrocarbons and

(c) Conduct oil-oil correlations of reservoired and migrated hydrocarbons in order to establish regional trends, if any, and to identify the presence of new or unrecognised petroleum systems.

Accomplishing objectives (a) and (b) allows the determination of source rock kinetics, the assessment of hydrocarbon yields, and the modelling of the timing of generation, expulsion, migration and entrapment. Objective (c) leads to the recognition of new or variant petroleum systems and opens new vistas, possibilities and strategies for the explorationist.

The present-day characteristics of borehole samples are often far removed from their initial state. Prior hydrocarbon generation can mask the petroleum potential, past and present. Wells drilled on structure do not generally intersect the effective source horizons and the prevalence of cuttings as opposed to core can lead to misleading results due to caving or through selective (unreported high-grading) sampling. Drilling additives make some geochemical measurements unreliable. These are caveats that should be borne in mind in any source rock analysis and subsequent predictions.

The composition of reservoired petroleum represents the average of all those source beds that have expelled into the drainage area over time and contributed to the accumulation. The composition of a bitumen in a single sample of source rock represents only that generated at a specific time and place. Accordingly, our evaluation has to consider a multitude of factors to do with maturity, source variations and mixing which alter composition and render comparison a subjective issue. Statistical evaluation of a large and systematically generated data set can help overcome these difficulties. Nevertheless, we are wary of incomplete interpretations and commend the accompanying database as a foundation for continuing and new studies of what is a complex issue.

One important task in effective source prediction is to place the ORR in a sequence stratigraphic context (eg Loutit et al, 1996). This approach is employed in recent reports by AGSO (Blevin et al., 1997; Blevin and Boreham, in prep) following a major structural and stratigraphic review of the basin. Using the lithostratigraphic and chronostratigraphic framework established by this work, we have chosen to analyse and interpret source rock potential in nine major intervals, BB1-BB3, BB4-BB5, BB6-BB7, BB8, BB9, BB10, BB11, BB12, and BB13-BB15 ranging in age from Devonian to Late Cretaceous, and based on the most significant sequence boundaries in the Browse Basin succession (Fig. 1 and Table 1).

METHODS

Standard operating procedures described in Boreham et al (1994) and AGSO and GeoMark Research (1996) were followed for TOC, Rock Eval, soxhlet extraction, gas chromatography, gas chromatography-mass spectrometry full scan (GCMS-full scan), selected ion recording (GCMS-SIR) and metastable reaction monitoring (GCMS-MRM) modes and carbon isotopes. Data manipulation of biomarker and carbon isotope analyses through the use of rigorous statistical analysis (Pirouette™) enabled standardisation with the recently completed ‘The Oils of Western Australia Study’ (AGSO and Geomark Research, 1996) as well as a convenient way of handling the large datasets involved.

A key to the digital file name for the data files generated in the interpretation phase is found in Appendix A while GCMS peak identification is shown in Appendix B. Given the use of hydrocarbon-based drilling fluids in a number of Browse Basin wells, there was a real likelihood of contamination of the source rock extracts by these drilling fluids. The GC and GCMS chromatograms for the diesel additive to the Kalyptea-1/ST1 well (Well Completion Report, unrestricted) was used as a reference for this contamination. Based on their GC character, it was not evident that any of the extracted sediments were contaminated by this drilling fluid.

RESULTS AND DISCUSSION

Database

The primary source of geochemical data available for our interpretation is AGSO’s ORGCHEM database. The database consists of information collected from well completion reports (WCRs), other external sources such as published papers, and internally generated data. All the basic data have been compiled in a digital format and is supplied with this report (see Appendix A for file names). The most recent data from WCRs entered into ORGCHEM database is to the end of January 1997. Only Rock Eval/TOC, rock extract and vitrinite reflectance data have been evaluated in reaching our conclusions with respect to source rock character. Interpreted ages (Ma) for the samples were obtained from age versus depth plots generated using AGSO’s STRATDAT database for individual wells.

The 29 wells (Fig. 2) in the Browse Basin geochemical database contain 968 records (Table 2), of which 1688, 898 and 320 records have TOC, Rock Eval and vitrinite reflectance data, respectively. These data include results of 177 Rock Eval and TOC analyses undertaken by AGSO’s Isotope and Organic Geochemistry Laboratory. The new analyses were performed on samples selected following an assessment of the existing ORGCHEM data, and targeting of intervals (shales and marls) where data was lacking or resampling of intervals which showed the best hydrocarbon potential (for oil-to-source rock correlation studies). Table 2 summarises these data while Figure 3 shows depth plots of age, source richness (TOC, S2), quality (HI) and maturity (Ro, Tmax, PI) for Yampi-1 (as the example).

Hydrocarbon Potential of Source Rocks

Maturation levels

The presence of significant petroleum accumulations in the Browse Basin (Table 3) demonstrates that mature, effective source rocks occur within the basin. As a preliminary step in defining the maturation process, the approximate boundaries of the oil generation window were established for each well in our data set (Fig. 4). Figures 4a to 4d show the depth profiles for three geochemical maturity parameters. Each parameter indicates a depth threshold of approximately 1500m, above which the sediments are immature. This has been supported by regional geohistory modelling which defined a 1800m threshold for the onset of oil generation (Blevin et al., 1997). However, the 'true' depth threshold is probably shallower since maturities based on vitrinite reflectance can be underestimated due to vitrinite suppression (R. Wilkins, in press).

On a well by well basis, the depth to the top of the oil window varies due to local burial and thermal histories. Table 4 and Figure 5 shows the depth, on a well-by-well basis, to the onset of oil generation based on a combination of maturity parameters (PI, Tmax and Ro; Fig. 3). In some cases, the vitrinite reflectance-vs-depth profile shows no increase in Ro after the onset of generation. This characteristic is attributed to the vitrinite reflectance 'suppression' which occurs in the Browse Basin, as well as other basins of the NW Shelf (R. Wilkins, in press).

Richness and quality

Present-day potential

Figures 6a and 7a show the present-day TOC and S2, respectively, plotted against age (Ma) for the Browse Basin succession. The data identified from WCRs as "hand-picked" cutting samples (118 records) has been excluded at this stage. Only "whole" sediment samples (1850 records) were used to generate the plots of Figures 6a and 7a.

In order to further high-grade the "whole" samples, they have been corrected for un-productive lithologies (sandstone and calcilutite) and are referred to as "lithology-corrected" in the discussion below. Clearly, the data density is concentrated within the Late Jurassic and Early Cretaceous and there is considerable variation in source rock potential.

Based on the interpretation guidelines in Table 5, the source richness and quality plots (Fig. 8) for each of the nine individual age intervals from Late Carboniferous to Late Cretaceous are not encouraging for the rocks containing disseminated organic matter. A 'first pass' evaluation would classify the majority of samples as showing only poor to fair oil potential. Furthermore, within each age interval the source richness (TOC and S2) is highly variable between wells (Figure 8). Although HI values >200 mg hydrocarbons/gTOC indicate that oil-prone sediments do occur, especially in the Late Jurassic and Early Cretaceous, their organic content is generally below 2% TOC. At these low to moderate TOC levels, the generated oil would most likely remain within the source rock and be subsequently cracked to gas at higher maturities. The exceptions are the Early and Late Jurassic coals and related carbonaceous shales which have good to excellent source rock potential, but are only found in thin beds.

The present-day data reflect only the residual source rock potential. In order to obtain a more realistic estimate of overall 'initial' source rock potential the 'present-day' source rock potential must be corrected for maturity, enabling a true source richness and quality to be determined prior to the onset of gas and oil generation. A simple method was applied to correct for the influence of past hydrocarbon generation for wells currently within the mature 'oil window'. As part of this process the depth to the onset of oil generation was first defined for each well (Fig. 5) based on a combination of VR, Tmax and PI data (Blevin et al., 1997).

Initial source rock potential

For samples with depths below the local onset threshold, an arbitrary value of HI ≈100 mg hydrocarbons/gTOC was added to the present-day source potential to approximate the initial source potential of mature sediments. This HI 'correction' is based on the average HI of the oil-prone immature sediments of 200-250 mg hydrocarbons/gTOC and assuming that 40-50% of the initial source potential has been transformed into oil and gas (Boreham et al., in press) during passage through the 'oil window' (Table 5). More accurately, the unit value of S2 (initial) = S2 (present-day) + HI(generated) x TOC(present-day) / 100 (where HI(generated)=100) within the mature zone. For immature sediments S2 (initial) = S2 (present-day). A limitation to this method is that the initial source rock potential will be overestimated for maturity levels at the beginning of oil generation.

A further correction was made for the lithological content of the whole sediment sample. For this, it was assumed that sandstone and calcilutite lithologies make a negligible contribution to organic content and source quality. The low TOC and S2 contents for rocks with these lithologies supports this view (data in file tot_data.xls). Although many of the sediments had quantitative lithological descriptions taken from WCR's, much of the data had no information on this parameter. Accordingly, and in order to remain fully consistent, lithological percentages (tot_data.xls) were picked from wire-line logs taking into account the end-member gamma-ray response for mudrock and non-source lithologies.

Figures 6b and 7b, show the interpreted or 'initial' source rock parameters which have been adjusted for maturity and lithology. The impact of these corrections on the bulk geochemistry on individual wells is illustrated in Figures 9a-i. The high-graded or 'hand-picked' samples that were identified in the total data set (tot_data.xls) and which have already been corrected for lithology, have also been included at this level of interpretation.

Inspection of the 'initial' source parameters for the Early Cretaceous sediments (Fig. 6b and 7b), reveal a consistent increase in source rock quality when compared with present-day data (Figs. 6a and 7a). The majority of samples in this age interval show moderate-good oil potential. On the other hand, the Late Jurassic sediments do not show such large increments in petroleum potential from present-day to initial and are considered to have fair-moderate oil potential. Figures 9a-i show the 'initial' bulk geochemical characteristics on a well-by-well basis over the nine sequence boundary age intervals. Overall for each age interval, the source rock quality shows much improvement in oil potential and there is a stronger linear correlation between S2 and TOC, consistent with similar organic facies within common age intervals for each well.

What is also apparent is that the S2 parameter is influenced by the 'mineral matrix effect', a common artefact in the Rock Eval method. The 'mineral matrix effect' artificially suppresses the S2 peak and consequently the estimate for HI of the organic matter. Assuming the organic matter type remains constant, the S2 versus TOC crossplot (Fig. 9) defines a straight line whose slope is a measure of the true HI. The line does not necessarily pass through zero, and the 'TOC offset' where the line crosses the TOC axis defines the extent of the mineral matrix effect. This effect is related to lithology, whereby a clay-rich lithology usually has a higher mineral matrix effect compared with a carbonate-rich sediment.

Indeed, for BB1-BB3 and BB4-BB5 age intervals the S2 versus TOC plot (Figs. 9a-i) defines a reasonably constant HI value with only a minimal mineral matrix effect (TOC offset ÷ 0; Table 6). In contrast, BB12 shows the widest range in HI values, suggesting a wider variation in organic facies and organic matter quality within this interval, while BB11 has the largest mineral matrix effect (Table 6). The interpreted average 'initial' HI for each of the sampled age intervals on a well-by-well basis is listed in Table 6.

The BB8-BB11 age intervals can be considered the most oil-prone (HI consistently > 200), BB12 contains both oil- and gas-prone organic matter, BB4-BB7 sediments have mainly gas/condensate potential, while BB1-BB3 and BB13-BB15 potential source rocks are predominantly gas-prone. Figure 1 (Source column) summarises this geochemical data by grading the gas and oil potential from Permian to Cretaceous ORR's. This information has been used in maturation history modelling to delineate the timing and quantity of gas and oil generation (Blevin et al., 1997; Blevin and Boreham, in press).

To further delineate which of the potential source rocks are the effective sources for known petroleum occurrences, oil-oil and oil-source rock correlation studies were undertaken.

Oil-Source and oil-oil correlations

Sample selection

The oils and sedimentary bitumen extracts used for the correlation study are shown in Table 7. The only non-confidential liquid petroleum sample was light oil from North Scott Reef-1 (AGSO#922). The data on other oil samples (North Scott Reef-1, AGSO#10152; Scott Reef-1, AGSO#10153; Brecknock-1, AGSO#10168; Caswell-2, AGSO#10169; Gwydion-1, AGSO#10170; Kalyptea-1/ST1, AGSO#10171; Cornea-1, AGSO#10262) remain confidential to the donating companies at the time of writing this report. Four sediments, two each from Lombardina-1 and Caswell-1 were classified as 'oil-stains' based on their high S1(>1) and PI(>0.5) values. Immature-to-mature with moderate or higher source potential (S2>2) sediments were targeted through interrogation of the ORGCHEM database. The samples cover the age range from Permian to Late Cretaceous. The final sample selection is shown in Table 7.

During the process of final sample selection, it was found that there was an unexpectedly poor correlation between the Rock Eval and TOC parameters based on WCR data and those derived from the analysis of re-sampled intervals (Fig. 10). The reason for this is unclear, although one explanation may be incomplete documentation whereby rocks reported as 'whole' may have been 'hand-picked' samples. This would account for some of the higher Rock Eval and TOC parameters as they appear in the WCRs. Our inability to reproduce basic geochemical parameters is of particular concern. Accordingly, we place a lower confidence level on regional organic geochemical evaluations that rely solely on published data.

GC of Oils

Extract and column chromatography data for the sample set (Table 7) can be found in the Microsoft Access database that accompanies this report. Whole oil gas chromatograms for the Browse Basin liquid hydrocarbons are shown in Figure 11. Although the North Scott Reef-1 and Scott Reef-1 liquids are classified as condensates, the occurrence of *n*-alkanes extending up to *n*-C_{30} and beyond, together with API gravities < 50^o show that these condensates have similar profiles to many light oils. Thus, the term oil will be used for all the Browse Basin liquid hydrocarbon samples.

The regular decrease in abundance of individual *n*-alkanes with increasing carbon number signifies the 'mature' character of the oils. The proportion of low molecular weight, gasoline-range hydrocarbons ($<C_{10}$) is highly variable for the Browse Basin oils. However, it is difficult to determine whether this is a reflection of original oil composition or related to evaporative losses associated with post-production sample handling. Biodegradation, which also preferentially removes light *n*-alkanes is unlikely since this alteration process is initially biased towards the $>C_{10}$ *n*-alkanes (Boreham, 1995). Only in the case of Gwydion-1 where there is significant losses of $<C_{15}$ components, especially *n*-alkanes, can these losses be definitely attributed to reservoir alteration processes (eg. biodegradation and/or water washing). As Gwydion-1 is reservoired at a shallow depth, the contact of liquid petroleum with nutrient-rich waters may present an exploration risk along the eastern margin of the Browse Basin.

The Pr/Ph ÷3 for all of the unaltered oils is consistent with a suboxic depositional environment for the source rock. The lower value for Gwydion-1 oil is most likely due to preferential biodegradation of pristane relative to phytane. Furthermore, there is a positive correlation between Pr/Ph and API gravity. Thus, those oils with the highest Pr/Ph ratios have the highest API gravities. Although possibly related to source or maturity, this trend is sometimes seen in oils and condensates derived from a common source rock. For the condensates (high API gravity) in particular, their higher Pr/Ph ratios have been attributed to compositional fractionation along a migration pathway (termed “migration fractionation” or “evaporative fractionation”; Thompson, 1987; Curiale and Bromley, 1996).

GC-MS of oils and potential source rocks

The GCMS-SIR data (Table 8) allowed derivation of the OilMod™ parameter set based on biomarker ratios that were used in the AGSO and GeoMark Research (1996) regional oil correlation study ‘The Oils of Western Australia’. For the present study, we utilised a sub-set of 13 parameters, targeting those which are derived from source and/or depositional environment-specific biomarkers (Table 9) and which are little affected by maturity. The selection of this sub-set was to minimise correlation uncertainties stemming from the wide maturation range of the sample suite which includes condensates to light oils, oil-stains and immature to mature source rock bitumens. The OilMod™ parameters derived from GC are not included since these are also strongly influenced by maturity.

Multivariate statistical analysis using the Pirouette™ software employed hierarchical cluster analysis (HCA) and principal component analysis (PCA) on the 13 biomarker parameters derived from GCMS-SIR traces (Appendix C) to generate the dendrogram (Fig. 12) and crossplot of PC1 and PC2 (Fig. 13). Maturity is shown to have a weak control on the variability within the dataset since there is no pattern to clustering based on whether the samples were immature or mature (Table 7). The first two principal components account for approximately 60% of the variability in the dataset. Figure 12 shows two main groupings with a low correlation coefficient of 0.3.

The first group includes the Caswell-2 oil from the central Browse Basin and the Gwydion-1 and Kalyptea-1/ST1 oils along the eastern margin. These are termed “Population A” oils. (The term “population” follows the definition of Horstad and Larter (1997): an oil population represents oils that have been generated from a common source rock, while the term “family”, a sub-division of population, groups those oils which have undergone the same alteration processes following primary migration from the source). The second group, termed “Population B”, contains the Browse Basin light oils Brecknock-1, North Scott Reef-1 and Scott Reef-1 situated along the basin's western margin. There is an additional small group containing exclusively Kalyptea-1/ST1 sediments below 4239m. For these samples, their high maturity, towards the end of the oil window, has resulted in maturity-induced changes in various source parameters effectively destroying any chance, if it existed, of a good correlation with the oils.

The most diagnostic biomarker parameters that distinguish the majority of the sediments from the oils are the C_{29}/C_{30} hopane ratio, the homohopane/hopane ratio and to a lesser extent the relative abundances of steranes (Fig. 13). The sensitivity to these parameters is mainly due to variation in depositional environment and the relative contribution of marine and land plant detritus to the sediments. The extent of post-depositional bacterial reworking of the organic matter was a subsidiary influence. For the Population A oils, the relative abundances of rearranged hopanes, $C_{30}X$ and $C_{29}D$ relative to C_{30} hopane, indicative of shale/clay-rich source rocks, differentiates these samples from the rest of the data set. Further, pattern distribution in C_{19}-C_{26} tricyclics and C_{24} tetracyclics is characteristic of the Population B oils.

Within the Population A oils, Caswell-2 and Gwydion-1 show a much closer correlation to each other than either has to Kalyptea-1/ST1 oil (Fig. 12). Thus, two subsets of Population A, termed "A1" and "A2" denote the differences between Caswell-2 and Gwydion-1 on the one hand and Kalyptea-1/ST1 on the other. These distinctions are also evident when the statistical analysis is performed on the oils in isolation from the sediments, as well as from comparison with other geochemical parameters discussed below.

From its GC character, Gwydion-1 oil was assumed to have had only a low level of biodegradation based on the presence of $>C_{15}$ *n*-alkanes, Pr and Ph and the absence of only the low molecular weight *n*-alkanes. This assumption was confirmed by the GCMS analysis since the tricyclic, hopane and sterane biomarkers have not been affected and are of similar relative abundances to the unaltered oil from Caswell-2. Thus, the GC and GCMS data show that the Gwydion-1 oil is only mildly biodegraded, to Stage 3 in the Stage 1 to 10 biodegradation classification scheme of Peters and Moldowan (1993). Furthermore, the low relative abundance of 25-norhopanes supports the present level of biodegradation of the Gwydion-1 oil is currently at its most intense. These biomarker characteristics infer that a multi-charge history for the Gwydion reservoir is unlikely.

The Population A1 oils show a strong correlation with the potential source rock at 3939-3942m (130.4Ma) from Discorbis-1 (Fig. 12). This is illustrated in the expanded GCMS traces of hopanes (Fig. 14) and steranes (Fig. 15) of the Caswell-2 oil and the Discorbis-1 source rock. This rock intersects the S. *areolata/S. tabulata* dinocyst zones in the BB10 age interval and represents the effective source rock for the Caswell-2 and Gwydion-1 oils. The strong correlation of the Caswell-1 extract at 3685-3690m; 109Ma) with the Caswell-2 oil suggest that this rock is indeed an oil-stain and representative of the composition of hydrocarbons migrating into the Caswell wells. The additional Caswell-1 extract (4080-4085m, 124Ma), assumed to be an oil-stain based on its Rock Eval response, does not show as strong a correlation with the Caswell-2 oil. Here, an overprint from local bitumen has masked the migrating oil signature resulting in a closer correlation with similar age BB10 rock extracts (Fig. 12).

The two Lombardina-1 oil-stains, both within the BB8 age interval (Late Jurassic) show a strong correlation with a BB8 representative from Yampi-2 (3104-3107m; 147Ma). This may suggest that the Lombardina geochemical signature is more influenced by local autochthonous organic matter, as is the case for the Caswell 1 4080-4085m sediment extract. Alternatively, there is a possibility of a Late Jurassic petroleum system in-place for the Lombardina oil-stains. Additional work needs to be done to confirm this.

The Population A2 oil from the Kalyptea-1/ST1 well shows a good correlation with the Kalyptea-1/ST1 rock extract at 4092-4095m (118Ma) within the BB11 age interval (Fig 12). The hopane and sterane traces (Fig. 14 and 15) of the Population A2 compared to the Population A1 oils and associated source rocks show slight increases in C_{29}/C_{30} hopane ratios and lower diasterane contents, indicating that the source rock possibly has a lower clay content. There is also a reasonably good correlation between the Kalyptea-1/ST1 oil and both the Caswell-2 sediment extract at 4350-4353m

(133Ma; within the BB10 age interval) and the Kalyptea-1/ST1 extract at 4092-4095m (118Ma; within the BB11 age interval). This suggests that similar source rock organic facies occur repeatedly in the Early Cretaceous and are effective source rocks for petroleum on the eastern margin of the Browse Basin. Although there is also a good correlation with the Kalyptea-1/ST1 extract at 3954-3960m (107Ma; within the BB12 age interval), the low TOC and relatively high PI of this sediment would suggest that this rock extract should be considered an oil-stain associated with the Kalyptea-1/ST1 oil.

The Population B light oils are situated on the western margin (outboard) of the Browse Basin. The four samples show a strong oil-oil correlation (and see below). Indeed the North Scott Reef-1 oil from AGSO's collection shows a slightly better correlation with Brecknock-1 oil than compared to a North Scott Reef-1 sample supplied by Woodside Petroleum. Although the slight chemical differences may be real, it also could be considered a measure of analytical accuracy associated with quantitative GCMS analysis. The Population B oils show some affinities with sediments ranging in age from Early Cretaceous to Late Permian. However, the correlations are not considered robust given the low number of samples and the long period of sedimentation. Thus, we cannot be sure that an effective source rock has been found within the current dataset. Compared to the Population A oils, Population B are characterised by their higher C_{19}/C_{23}, C_{24} tetracyclic/C_{23} tricyclic and C_{27}/C_{29} sterane ratios, indicating higher terrestrial input to the organic matter with possible deposition closer to the palaeo-shoreline. Further, the $C_{30}X$ /$C_{30}H$ ratio for the Population B oils is lower than for Population A1 (Fig. 16), but greater than Population A2.

A feature of the Population B oils is the presence of a compound of unknown structure peak X eluting immediately after $C_{27}Ts$ in the m/z 191 Da chromatogram for North Scott Reef-1 oil (Fig. 13). This compound is not a pentacyclic triterpane. Work is in progress to identify this distinguishing biomarker since it will most likely be an important criterion for source rock correlation.

Although some good oil-source correlations have been found, the majority of the sediment extracts show poor-to-no correlation with any of the Browse Basin oils. For the Population B oils there is, as yet, no known effective source rock (also see Oil-Oil Correlation below). This is to be expected as the total number of sediments so far analysed is relatively small. It has been suggested that over 90% of potential source intervals in the Browse Basin have not yet been sampled for any kind of geochemical analysis (Blevin et al., 1997). Thus, there is a strong need for additional geochemical investigations to be undertaken in order to further strengthen the evidence for those petroleum systems already identified or postulated, and to delineate the effective source rock for the more distal Browse Basin Population B oils.

We also investigated the possibility that the 13 distinctive OilMod™ biomarker parameters used in the correlations did not fully define the variability in the dataset, and thus biased the correlation results. Hence, additional source and age-specific biomarkers were examined on a subset of the samples using the more selective and sensitive gas chromatography-metastable reaction monitoring (GCMS-MRM) approach (Appendices D1 and D2). The additional classes of compounds include C_{15} and C_{16} bicyclic drimanes, higher plant-related C_{20} diterpanes, C_{30} desmethylsteranes, C_{30} 2-, 3- and 4-methylsteranes, and C_{31} methylhopanes. Exploring this expanded biomarker set (Table 10) with statistical analysis reaffirmed the oil-oil and oil-source associations seen with the GCMS-SIR data alone.

Again, only the Discorbis-1 extract at 3939-3942m (Early Cretaceous BB10 age interval) showed a strong correlation with the Population A Browse Basin oils. From the principal component analysis using only the oils, the plot of PC1 and PC2 values for the scores and loadings shows that two main populations are readily distinguished using PC1 alone and that the relative abundances of individual C_{19}-C_{26} tricyclics are still the dominant factor that distinguishes the Population B oils. Use of the expanded GCMS-MRM-derived biomarker set shows that there are subtle differences between oils within the same population. It is interesting to note that the two North Scott Reef-1 samples (from AGSO's and Woodside's petroleum collection) are more closely aligned in the expanded parameter set, as intuitively should be the case. This shows the utility of the GCMS-MRM approach in oil-oil correlations where biomarkers can be quantified with more certainty than with the standard GCMS-SIR procedure.

The C_{30} desmethylsterane (Appendix D2), a biomarker diagnostic of marine algae, is seen in all the samples (C_{30}/C_{27}-C_{29} sterane ratio in Table 10) in accord with the marine-dominated depositional environments throughout the Browse Basin succession. Indeed, the sole representative of the Permian potential source rock analysed has the lowest C_{30}/C_{27}-C_{29} sterane ratio, consistent with dominantly terrestrial organic facies at this time (BB1-BB3). From the Early Triassic there is a marked increase in the abundance of 4-methylsteranes in sedimentary organic matter record and so the high C_{30} 4-methylsterane/C_{29} sterane ratio for the Population A liquids is consistent with the Early Cretaceous age of the source. The Population B liquids also have high relative C_{30} 4-methylsterane/ C_{29} sterane ratios suggesting that Early Triassic or older sediments are not likely to be sources.

<u>Stable carbon isotopes of oils and potential source rocks</u>

Carbon isotopes have been shown to be an effective means of distinguishing Australian oil populations (Vincent et al., 1985; Boreham, 1995; Edwards et al., 1997; AGSO and GeoMark Research, 1996). In the Browse Basin, the two main oil populations can be readily identified using the carbon isotopes of the saturated hydrocarbons (Fig. 17). Population A oils are characterised by more negative $\delta^{13}C$ values compared to the Population B oils (Fig. 17a). Some overlap of populations exists when the carbon isotopes of the aromatic hydrocarbons are compared (Fig. 17b). However, the Population A oils are still, on average, the most depleted in ^{13}C.

A feature of the Kalyptea-1/ST1 oil is that the aromatic hydrocarbons are more depleted in ^{13}C than the saturated hydrocarbons, with $\Delta\delta^{13}C$ ($\delta^{13}C_{sat}$ - $\delta^{13}C_{arom}$) = 1.7$^{o}/_{oo}$ whereas for most oils $\Delta\delta^{13}C < 0$. In Australia, 6% (26 out of 413) of oils from AGSO's oil database have $\delta^{13}C$-depleted aromatic hydrocarbons (AGSO and GeoMark Research, 1996, 1998). On the North West Shelf, only oils from the Late Triassic reservoir of the West Tyral Rocks Field in the Carnarvon Basin have $\Delta\delta^{13}C>0.9^{o}/_{oo}$

(AGSO and GeoMark Research, 1996). Although the $\Delta\delta^{13}C$ for Brecknock-1 is <0, its aromatic fraction is more depleted in ^{13}C compared with the other Population B oils. This could point to a minor contribution from a specific Early Cretaceous source to the Brecknock-1 oil (see Notes added in Proof).

When the carbon isotopes of the oils are compared with sediment representatives within the 8 age intervals between BB1 to BB12, there is a good correlation between Population A oils and sediments in the BB9-BB10 age interval. These strata are characterised by isotopically light organic matter compared to that at other times in the Browse Basin. The origin of the Population B light oils could not be further elucidated using stable carbon isotopes, although Early Cretaceous BB9-BB10 sediments are unlikely since organic-C in these sediments is too depleted in ^{13}C compared to the oils.

Regional Oil-Oil correlations

Oil-oil correlations between the Browse Basin liquids, discussed above, resulted from statistical analysis of biomarker parameters derived from both GCMS-SIR and GCMS-MRM analysis. In this section, GC, GCMS and carbon isotope data for the Browse Basin oils have been combined with a more extensive dataset of oils from nearby Western Australian basins. This has enabled genetic relationships to be established for the Browse Basin oils within the constraints of the documented Western Australian Petroleum Supersystems (Table 11 and Fig. 18; AGSO and GeoMark Research, 1996). However, due the differences in GCMS instrument technologies used by AGSO and GeoMark Research, biomarker responses are not the same and result in different values for the OilMod™ parameter set depending on the method of analysis. In order for the Browse Basin oil data to be fully compatible with data collected for the AGSO and GeoMark Research (1996) study, the Browse Basin oils were re-analysed for saturated biomarkers by GeoMark Research Inc. This data is included in an Access database supplied with the report.

Crossplots of source and maturity parameters are displayed in Figure 19 for the Browse Basin oils in relation to other Western Australian oil populations. The plot of

n-C_{27}/n-C_{17} versus Pr/Ph (Fig 19a) shows the high terrestrial input and is also manifested in high %C_{29} steranes for the lacustrine A2 Petroleum Supersystem. The high n-C_{27}/n-C_{17} ratio seen for the Gwydion oil is an artefact of the preferential biodegradation of the low molecular weight n-alkanes. A C_{27}/C_{29} sterane ratio <1 (Fig. 19b) is consistent with source rock deposition under marine conditions and with a mixed marine and terrestrial organic matter input. The Browse oils have sterane contents within the range shown by other Western Australian oils (Westralian Petroleum Supersystem). Population B oils have the lowest C_{27}/C_{29} sterane ratio consistent with a higher terrestrial input. The Caswell-2 oil has the highest percentage of C_{27} steranes (Fig.19b; C_{27}>C_{29} sterane), suggestive of a more distal marine organic facies or a lower terrestrial input. The carbon isotope plot (Fig. 19c) shows that the Browse Basin Population A oils are clearly distinct from other Western Australian oil populations. On the other hand, the Population B oils have similar $\delta^{13}C_{sat}$ but are slightly enriched in ^{13}C for the aromatic hydrocarbons (Fig. 19c).

A good linear correlation exists between C_{29}Ts/29H versus Ts/Tm (Fig. 20. It is this strong trend that has been used to identify significant maturity differences between and within Western Australian oil populations (AGSO and GeoMark Research, 1996). Assuming that maturity is the overriding control on these parameter, then the Population B oils appear to be of slightly lower maturity than the Population A1 oil, while being higher than Population A2 oil. An alternate measure of maturity based on the highly stable diamondoid structure (Chen et al., 1996) has proven useful in identifying maturity effects at the high maturity end (past peak oil generation) where all hopane and sterane based maturity parameters are ineffective (except perhaps Ts/Tm). Figure 21 shows the plot of Ts/Tm versus MAI (methyl adamantane index = 1-methyl adamantane/(1-methyl adamantane + 2-methyl adamantane)) and MDI (methyl diamantane index = 4-methyl diamantane/(1-diamantane + 3-diamantane + 4-diamantane)) together with the inferred maturity on an equivalent vitrinite reflectance scale (Chen et al., 1996). Clearly, all the Browse Basin oils are of relatively high maturity (1.15%<Ro <1.35%) suggesting late stage (delayed) expulsion from the source rock. The Caswell-2 oil has the lowest diamondoid maturity parameters although having the highest Ts/Tm value. These seemingly contradictory results highlight the need to compare trends for a number of parameters to evaluate maturity in a more reliable way. Furthermore, it exposes the apparent interpretative shortfalls that can exist where source influences on commonly used maturity parameters (eg. Ts/Tm) are difficult to quantify. The lower maturity of the Caswell-2 oil is most likely a result of earlier expulsion from a source with enhanced oil potential. Indeed, the thickest BB10 age interval is in close proximity to the south of the Caswell wells (Blevin et al., 1997). Aromatic hydrocarbon maturity parameters (eg. MPI-1) support the diamondoid data and confirm that Caswell-2 is the least mature oil (see Notes added in Proof).

Gas maturity estimates based on carbon isotopes of individual hydrocarbon gases (James, 1983) in the associated natural gases support the concept of late stage migration. For Kalyptea-1/ST1 gas, an interpreted vitrinite reflectance of 1.0% has been inferred based on the isotopic difference between the carbon isotopes of ethane ($\delta^{13}C$ = -33.9$^{o}/_{oo}$) and propane ($\delta^{13}C$ = -30.8$^{o}/_{oo}$) (data in Kalyptea-1/ST1 Well Completion Report). The vitrinite reflectance value is assumed to represent the maturity of the source rock at the time of primary migration. Alternatively, using the isotopic difference between methane ($\delta^{13}C$ = -40.3$^{o}/_{oo}$) and ethane, a vitrinite reflectance of 1.5% is obtained. In other words, the isotopic composition of methane is more enriched in ^{13}C than would be predicted from its association with the wet gas components. A sustainable explanation for the ^{13}C-enriched methane is that Kalyptea-1/ST1 gas is a mixture of wet gas associated with oil generation and dry gas from a deep, overmature source. Deeply sourced methane is characterised by enrichment in ^{13}C, and is usually accompanied by high nitrogen gas (N_2) contents (Boreham and de Boer, in press). The N_2 content of 4.3%, although not excessively high, in the Kalyptea-1/ST1 gas is considered further evidence for a minor contribution from a deep, overmature source. Indeed, elevated N_2 contents (>10%) occur in natural gases from the Bonaparte, Canning and Carnarvon basins (ORGCHEM digital database, AGSO, unpublished), and may indicate a more widespread, and previously underrated, dry gas input from deep, overmature source rocks on the North West Shelf.

As illustrated in the XY plots above, the multi-parameter source and maturity approach is necessary to clearly distinguish oils of different origins. However, multivariate statistical methods are the most efficient and reliable means of handling all the key geochemical variables. Figure 22 shows the cluster analysis dendrogram resulting from this combined dataset. Note that the inclusion of the Browse Basin oils does not affect the population relationships between the other Western Australian oil populations (compare Fig. 22 with Fig. 18) and shows that this is a robust analysis.

For the data within this closed sample set, statistical analysis reveals that the Population A oils show geochemical characteristics more aligned known Petroleum Systems with Permian to Middle Jurassic sources. Notably, Population A1 oils, Caswell-2 and Gwydion-1, group with the oils from W1 and W1' Petroleum Systems (sourced from Late Triassic to Early-to-Middle Jurassic source rocks) while Kalyptea-1/ST1 oil appears to have an affiliation with the Permian G1 Petroleum System. However, the correlation between the three Browse Basin Population A oils and their companion North West Shelf oil populations is not as strong when compared to Western Australian oil sets from within their known Petroleum Supersystems. This re-emphasises the chemical differences between oil populations of the North West Shelf are often very subtle and reflect slight variants on time-trangressive organic facies. Considering the Early Cretaceous age of the source rocks for the Population A, these oils are considered to represent a new sub-division in the Westralian Petroleum Supersystem and are accordingly classified as the W3 Petroleum System.

Population B liquids are closely correlated although they do share similar biomarker characteristics with Jurassic-sourced oils of the Westralian Petroleum Supersystem (Fig. 22), and in particular one W1' oil. However, the differences are such that the Population B oils are considered to form a petroleum system not previously recognised in Western Australia, and are tentatively assigned to a new W1B Petroleum System.

The main discriminants that separate the North West Shelf oils are associated with the primary organic matter input from either marine (%27, S/H, 24T/23T) or terrestrial (%29, 24Tet/23T and 19T/23T) source-specific biomarkers which carry the largest weightings for PC1 and PC2 (Fig. 23). Caswell-2 and Kalyptea-1/ST1 are characterised by their high C_{27} sterane content. Depositional environment appears to have a secondary influence (PC2; Fig. 23), with the organic facies associated with Gwydion-1 having a higher clay-content (29D/30H, 30X/30H) compared to the other two Population A oils. The enrichment in ^{13}C and Ph/Pr ratios >3 are the two dominant geochemical factors that distinguish Population B oils (Fig. 23).

CONCLUSIONS

The geochemical characterisation of organic-rich rocks (ORRs) in the Browse Basin has shown that potential source rocks exist throughout the Permian to Cretaceous succession. Mature source rocks have been identified across much of the region. After correction for maturation and rock lithology, consistently moderate to good ‘initial’ source potential can be identified in Early Cretaceous (123-141Ma) fine-grained sediments from several wells. Furthermore, some Late Jurassic and Middle-to-Early Jurassic horizons also show oil potential, although this is at a reduced level. ORRs of other ages do show some oil potential, but their restriction to thin intervals limits their capacity to be overall effective source rocks.

A minimum depth threshold has been established at 1500m, below which mature source rocks are capable of contributing to migrating hydrocarbons in the region. Along with the recent discoveries of significant reservoired hydrocarbons (eg, Gwydion-1 and Cornea-1), prevalent oil-staining throughout the stratigraphic column provides strong evidence for the existence of at least one effective source rock in the basin.

Two major oil populations (Population A and Population B) have been identified in the Browse Basin based on biomarker and isotopic analysis. Population A oils have been found inboard of the main depocentres in the Browse Basin and include Gwydion-1 and Kalyptea-1/ST1 as well as in the main depocentre in the Caswell sub-basin (Caswell-2), while Population B oils occur outboard of the major depocentres and included the Brecknock-1, North Scott Reef-1 and Scott Reef-1 light oils. Presently, the latter oil population cannot be correlated with any known source rocks. Early

Triassic and older sediments are considered unlikely sources although there are not a sufficient number of sediment samples to fully support this. Within Population A, each oil has its own distinctive geochemical signature which is related to slight differences in source rock chemistry and the timing of expulsion from the source rock.

Early Cretaceous sediments, and more particularly those within the 123-134 Ma age interval (BB10) have a biomarker signature that clearly correlates them with Population A oils. Kalyptea-1/ST1 oil shows a good oil-source correlation with a BB10 sediments that is different from those BB10 sediments that correlate with the Caswell-2 and Gwydion-1 oils. Furthermore, the Kalyptea-1/ST1 oil also shows a strong affinity with a BB11 sediment. Clearly, effective source rocks are time-transgressive throughout much of the Early Cretaceous and show slight differences in the source organic matter composition due to subtle changes in organic facies and depositional environments. This has enabled the Population A to be sub-divided into A1 (Caswell-2 and Gwydion-1) and A2 (Kalyptea-1/ST1) families.

Oil-stains at Lombardina-1 have been correlated to a BB8 source rock. This suggests that a Late Jurassic petroleum system may also be active in the Browse Basin, although not as prolific as in other Western Australian basins where Late Jurassic source rocks are more extensive.

Maturity estimates on the Browse Basin Populations A and B oils suggest that these liquids are a late stage expulsion product from their respective effective source rock. Primary migration occurred only after the source rocks attained maturity levels between 1.15 and 1.35% Ro. Similar maturity for natural gas at Kalyptea-1/ST1 supports gas and associated oil generation from the same effective source rock. In the Browse Basin, initial oil potential of Late Cretaceous potential source rocks is only rated as moderate. Accordingly, insufficient quantity of liquid hydrocarbons would have been generated from mature source rocks at peak oil generation to support a migrating liquid phase. Only at higher maturities when the gas-to-liquid ratio has increased (due to either gas generation from kerogen or cracking of entrained liquids) will primary migration occur at a significant rate. The influx of deep, overmature dry gas source from within the axes of the basin depocentres may also be a factor in assisting oil re-mobilisation from source to reservoir and within reservoirs. Caswell-2 appears to have been an earlier generated product which may have been the result of a locally 'sweeter' Early Cretaceous oil-prone source pod.

Inter-basin oil-oil correlations of Western Australian Petroleum Supersystems support the different character of the Browse Basin oil populations. Browse Basin Population B oils show no strong affiliations with known Western Australian Petroleum Supersystems. At present, no known effective source rocks have definitely been identified, although Late Triassic and Jurassic sediments are considered possible source rocks. Accordingly, Population B oils have been tentatively assigned to a new W1B Petroleum System. Population A oils sourced from effective Early Cretaceous source rocks form a new sub-division (W3) of the Westralian Petroleum Supersystem. Other published work suggests that an Early Cretaceous Petroleum System may have additional members in the Bayu/Undan gas-condensate discovery in the Timor Gap. Brooks et al. (1996) have reported a likely source interval in Callovian through Barremian sediments.

This report presents the first clear documentation of an Early Cretaceous source interval on the Shelf and confirms earlier predictions (Loutit et al., 1996) of the general occurrence of effective organic-rich rocks of this age on the North West Shelf.

Notes added in proof

Carbon isotopes of *n*-alkanes

The two oil populations established from biomarker and bulk carbon isotopes are also clearly evident in the *n*-alkane isotope profile (Figure 24) obtained from compound specific isotopic analysis (CSIA). Since *n*-alkanes are the major class of compounds in the Browse Basin 'unaltered' oils, and we conclude that they are representative of the oil chemistry as a whole, the distinctions made using the saturated biomarkers become even more robust. Data for the Gwydion-1 oil commences at n-C_{18} due to the loss of lower molecular weight *n*-alkanes through mild biodegradation. Biodegradation has been shown to have minimal effects on the carbon isotopic composition of the residual *n*-alkanes (Boreham et al., 1995). Thus, the carbon isotope composition of *n*-alkanes in the altered Gwydion-1 oil can be readily compared with the data from the other unaltered Browse Basin oils.

Population A oils are the more isotopically depleted compared to Population B. The $\delta^{13}C$ of -28.5‰ for the saturated hydrocarbons and used as the 'cutoff' to distinguish the two oil populations from this data can also be applied to the individual *n*-alkanes (Fig. 24). The fact that the $>C_{12+}$ *n*-alkanes have a similar isotopic composition within each oil implies that marine organic matter is the major source with a subordinate contribution from land plants (Murray, et al., 1994).

Brecknock-1 oil shows a slightly different isotope profile to the other Population B oils. The light *n*-alkanes ($<C_{12+}$) are more enriched in ^{13}C whereas the higher molecular weight *n*-alkanes ($>C_{12+}$) are more depleted in ^{13}C. This could due to a slight variation in the source organic facies or may indicate an minor input from an Early Cretaceous source to the heavier *n*-alkanes.

<u>Aromatic hydrocarbons</u>

GCMS, in the form of full scan data on diluted whole oils, was originally collected in order to assess the maturity of the Browse Basin oils based on the diamondoid parameter set. This full scan data set is further utilised to examine the light aromatic hydrocarbon distributions. The full scan mode is not as sensitive as for data collected under SIR mode, so that the full range of aromatic biomarkers could not be evaluated. Here, we offer preliminary interpretations on a few of the more abundant aromatic hydrocarbons that could be readily identified.

Aromatic hydrocarbons has been under-utilised in oil-oil correlation studies, primarily due to a traditional focus on saturated hydrocarbon biomarkers and to uncertainties in structural identification of the aromatic hydrocarbons. Nevertheless, oil-oil correlation have been successfully undertaken in the Cooper/Eromanga (Alexander et al., 1988), Bowen/Surat (Boreham, 1995) and Perth basins (Summons et al., 1995) using aromatic hydrocarbon distributions. Intuitively, there should be no reason why correlations based on saturated hydrocarbons should perfectly match those undertaken using aromatic hydrocarbons as there are a multitude of processes that can differentially act on compound classes and at the molecular level.

The Alexander et al (1988) plots are a powerful aid in distinguishing pre- from post-mid Triassic sourced oils due to Araucarian influence. One such plot is shown in Figure 25a. Clearly, these aromatic parameters do not clearly distinguish Population A from Population B oils.

The methylphenanthrene index (MPI-1) is one of the most robust chemical maturity parameters (Radke and Welte, 1983). The Caswell-2 oil has the lowest MPI-1 and hence is the least mature oil (Fig. 25a). This is consistent with the ranking defined by the diamondoid maturity parameter from the saturated hydrocarbons. The internal distribution of methylphenanthenes is also sensitive to maturity. The MPR-1 (3-methylphenanthrene/9-methylphenanthrene) reflects a more stable isomer relative to the isomer with lower stability, and is used here as an additional chemical maturity parameter. Since the 3- and 9-methylphenanthrene isomers have similar stabilities to biodegradation, Gwydion-1 oil can be readily compared to the remaining unaltered oils. From the Figure 25b, Population A oils lie on a common trend line and show similar characteristics to other North West Shelf oils from the Carnarvon and Bonaparte basins. Population B oils cluster together and lie away from the main trend line, suggestive of a source control to these aromatic maturity parameters.

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Appendix A. Key to digital files of Browse Reports and Data

Description	Digital file
Figure 1	paper copy
Figure 2	paper copy
Figure 3	tot_data.xls
Figure 4	depth1.xls
Figure 5	tab1_2_7.xls
Figure 6	fig6_7.ppt; data from age.xls
Figure 7	fig6_7.ppt; data from age.xls
Figure 8	fig8.ppt; data from re_toc.xls
Figure 9	fig9.ppt; data from re_toc.xls
Figure 10	fig10.xls
Figure 11	gc.ppt; data from browse.mdb
Figure 12	paper copy
Figure 13	pc1_pc2.ppt
Figure 14	gcms.ppt; data from browse.mdb
Figure 15	gcms.ppt; data from browse.mdb
Figure 16	gcms.ppt; data from browse.mdb
Figure 17	fig17.xls
Figure 18	paper copy
Figure 19	oil_oil.xls
Figure 20	oil_oil.xls
Figure 21	diamond.ppt; data from diamond.xls
Figure 22	paper copy
Figure 23	pc1_pc2.ppt
Table 1	tab1_3.doc
Table 2	tab2_4_9.xls
Table 3	tab1_3.doc
Table 4	tab2_4_9.xls
Table 5	table5.doc
Table 6	table6.xls; data from fig.9
Table 7	table7.xls; data from browse.mdb
Table 8	table8.xls; data from browse.mdb
Table 9	tab2_4_9.xls
Table 10	table10.xls; data from Appendix D1 & D2
Table 11	table 11.xls
Appendix A	report.doc
Appendix B	report.doc
Appendix C	922_pkid.ppt and agso_sir.ppt
Appendix D1	agso_mrm.ppt
Appendix D2	agso_mrm.ppt
Browse Rock Eval/TOC/VR data	tot_data.xls
AGSO's source rock kinetics	kinetics.xls
AGSO's extract data	browse.mdb
AGSO's GC data	browse.mdb
AGSO's GCMS data	browse.mdb
Geomark's GCMS data	browsegm.mdb

Appendix B. Key to GCMS Peak Identification

Peak No.	Compounds	OilMod ™ abbreviation
1.	C15 8β(H)-Drimane	
2.	C15 8α(H)-Drimane	
3.	C16 8β(H)-Homodrimane	
4.	C19 Tricyclic Terpane	C19T
5.	C20 Tricyclic Terpane	C20T
6.	C21 Tricyclic Terpane	C21T
7.	C22 Tricyclic Terpane	C22T
8.	C23 Tricyclic Terpane	C23T
9.	C24 Tricyclic Terpane	C24T
10.	C25 R & S Tricyclic Terpane	C25R & C25S
11.	C24 Tetracyclic Terpane	TET
12.	C26 R & S Tricyclic Terpane	C26R &C26S
13.	ent-Beyerane	
14.	Isopimarane	
15.	16β-Phyllocladane	
16.	16α-Kaurane	
17.	16α- Phyllocladane	
18.	16β- Kaurane	
19.	C27 18α(H)-22,29,30-Trisnorhopane	Ts
20.	C27 17α(H), 18α(H)-25,28,30-Trisnorhopane	C27T
21.	C27 17α(H)-22,29,30-Trisnorhopane	Tm
22.	C27 17β(H)-22,29,30-Trisnorhopane	
23.	C28 29,30-Bisnorhopane	
24.	C28 28,30-Bisnorhopane	C28H
25.	C29 Diahopane	
26.	C29 Neodiahopane	
27.	C29 17α(H), 21β(H)-30-Norhopane	29DM
28.	C29 17α(H), 21β(H)-30-Norhopane	29H
29.	C29 18α(H)-30-Norneohopane	29D (29Ts)
30.	C29 17β(H), 21α(H)-30-Normoretane	29M
31.	C30 17α(H)-Diahopane	C30X
32.	C30 Oleanane	OL
33.	C30 17α(H), 21β(H)-Hopane	C30H
34.	C30 Norhopane	C30NPR
35.	C30 17β(H), 21α(H)-Moretane	30M
36.	C30 Gammacerane	GA
37.	C27 13β(H), 17α(H)-Diacholestane (20S & 20R)	S1(20S) & S2(20R)
38.	C27 5α(H), 14α(H), 17α(H)-Cholestane (20S)	S3
39.	C27 5α(H), 14β(H), 17β(H)-Cholestane (20R & 20S)	S4(20R) & S5=S5B(20S)
40.	C27 5α(H), 14α(H), 17α(H)-Cholestane (20R)	S6
41.	C28 24-Methyl-13β(H), 17α(H)-Diacholestane (20S & 20R)	
42.	C28 24-Methyl-14α(H), 17α(H)-Cholestane (20S)	S8
43.	C28 24-Methyl-14β(H), 17β(H)-Cholestane (20R & 20S)	S9(20R), S10=S10B(20S)
44.	C28 24-Methyl-14α(H), 17α(H)-Cholestane (20R)	S11
45.	C29 24-Ethyl-13β(H), 17α(H)-Diacholestane (20S & 20R)	S4(20S), S7(20R)
46.	C29 24-Ethyl-14α(H), 17α(H)-Cholestane (20S)	S12
47.	C29 24-Ethyl-14β(H), 17β(H)-Cholestane (20R & 20S)	S13(20R), S14=S14B(20S)

48.	C29 24-Ethyl-14α(H), 17α(H)-Cholestane (20R)	S15
49.	C30 Propyl-13β(H), 17α(H)-Diacholestane (20S & 20R)	
50.	C30 Propyl-14α(H), 17α(H)-Cholestane (20S)	
51.	C30 Propyl-14β(H), 17β(H)-Cholestane (20R & 20S)	
52.	C30 Propyl-14α(H), 17α(H)-Cholestane (20R)	
53.	C30 ααα 2α-methyl-24-ethyl-cholestane (20R)	
54.	C30 ααα 3β-methyl-24-ethyl-cholestane (20R)	
55.	C30 ααα 4α-methyl-24-ethyl-cholestane (20R) + 4,23,24 trimethyl-cholestane (4 isomers)	
56.	C30 Bicadinane-W	
57.	C30 Bicadinane-T	
58.	C30 Bicadinane-T1	
59.	C30 Bicadinane-R	
60.	C30 Methyl-bicadinane-W	
61.	C30 Methyl-bicadinane-T	
62.	C30 Methyl-bicadinane-T1	
63.	C31 dia Homohopane	
64.	C31 17α(H), 21β(H)-Homohopane S & R	C31S & C31R
65.	C31 17β(H), 21α(H)-Homomoretane	
66.	C31 2α(H)-Methylhopane	
67.	C31 3β(H)-Methylhopane	
68.	C32 17α(H), 21β(H)-Bishopane S & R	C32S & C32R
69.	C33 17α(H), 21β(H)-Trihopane S & R	C33S & C33R
70.	C34 17α(H), 21β(H)-Tetrakishomohopane S	C34S
71.	C34 17α(H), 21β(H)-Tetrakishomohopane R	C34R
72.	C35 17α(H), 21β(H)-Pentakishomohopane S	C35S
73.	C35 17α(H), 21β(H)-Pentakishomohopane R	C35R
	Unknown	X

Ar1 Arquebus 1
As1 Asteras 1
C1 Caswell 1
C2 Caswell 2
B1 Brecknock 1
Bu1 Buccaneer 1
G1 Gwydion 1
Ka1 Kalyptea 1
M1 Maret 1
NSR1 North Scott Reef 1
S1 Scott Reef 1
S2 Scott Reef 2
Ta1 Tahbilk 1
Y1 Yampi 1
Y2 Yampi 2

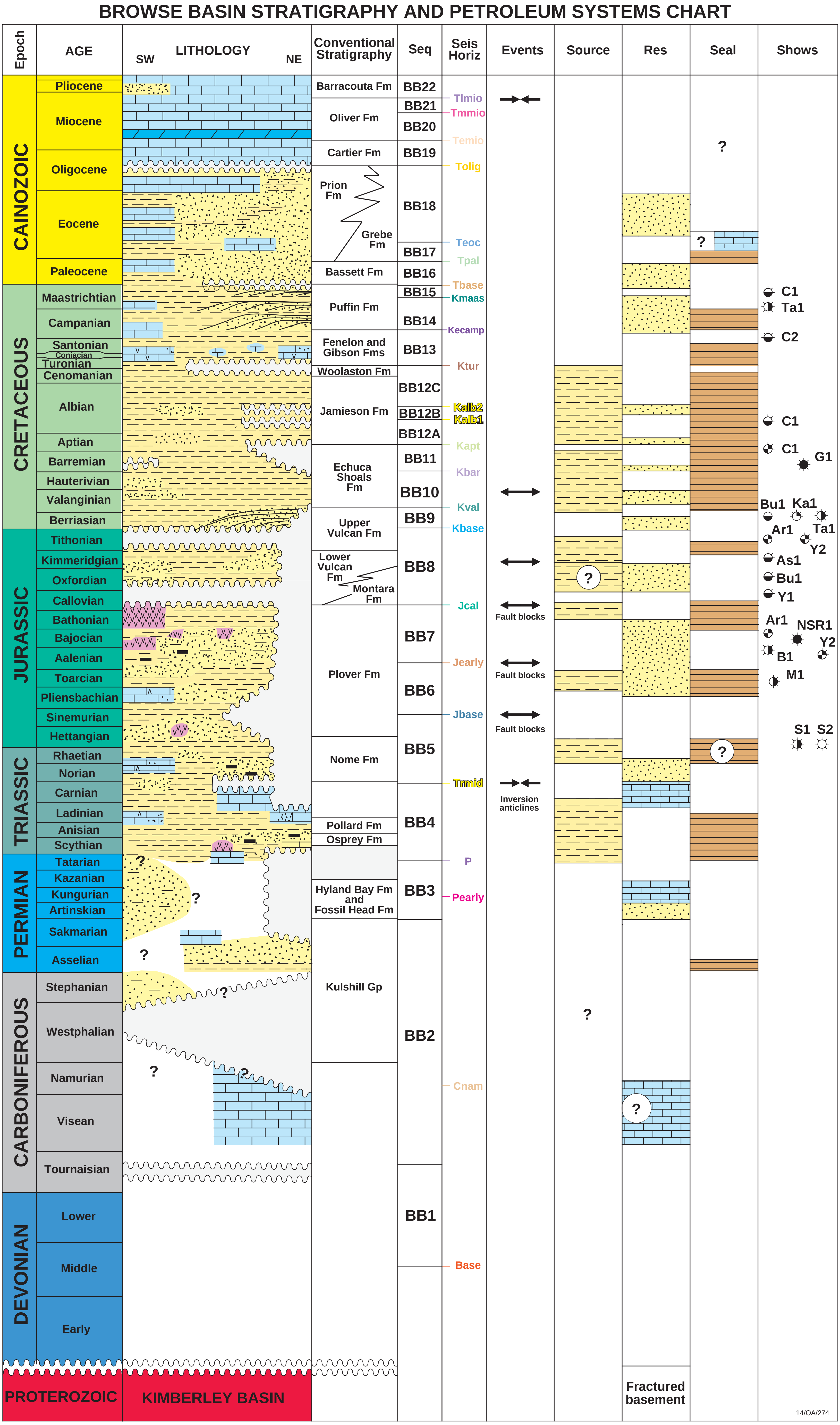


Figure 1 Browse Basin stratigraphy and petroleum systems chart (lithology modified from Symonds *et al.*, 1994), with hydrocarbon shows.

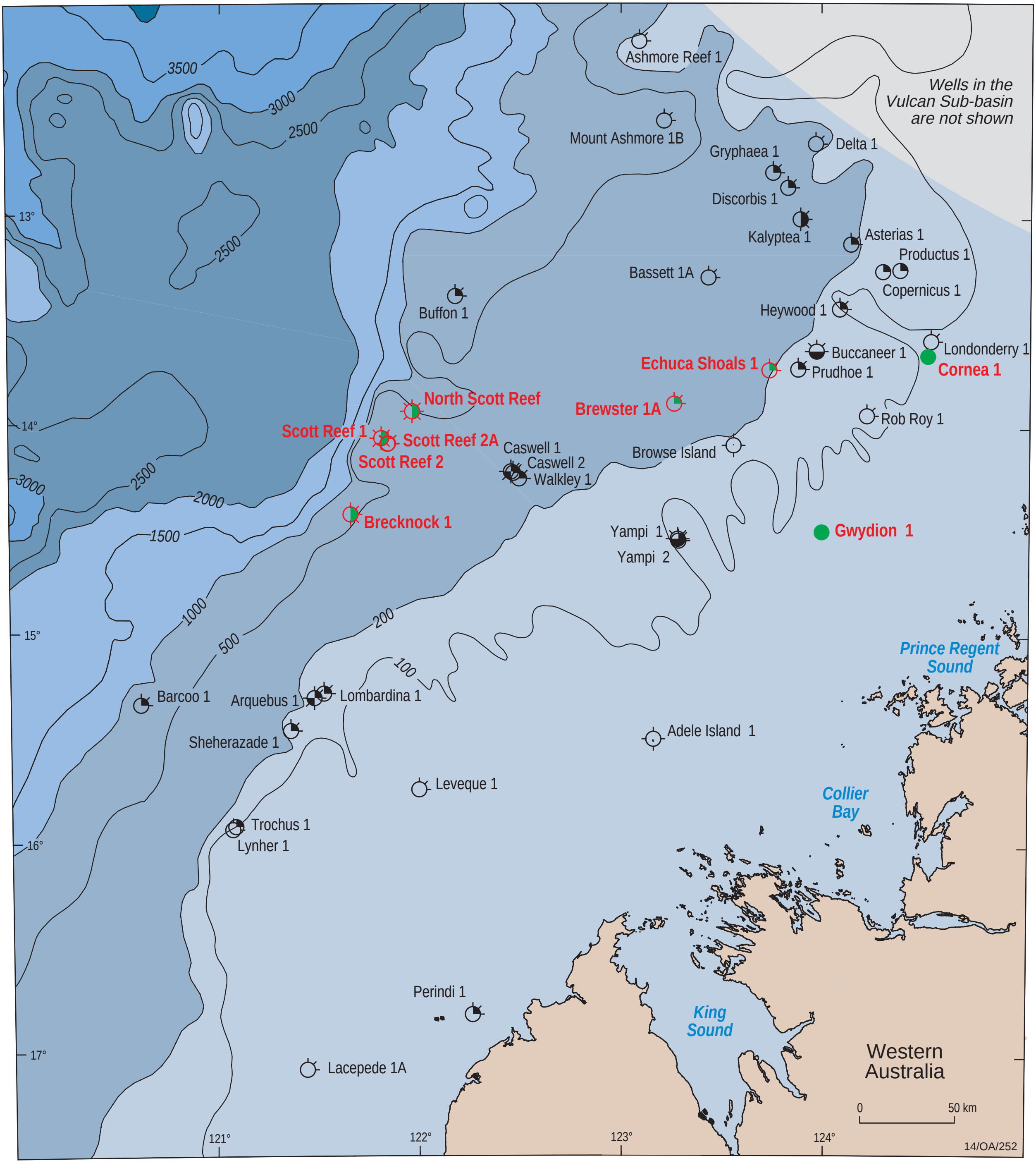
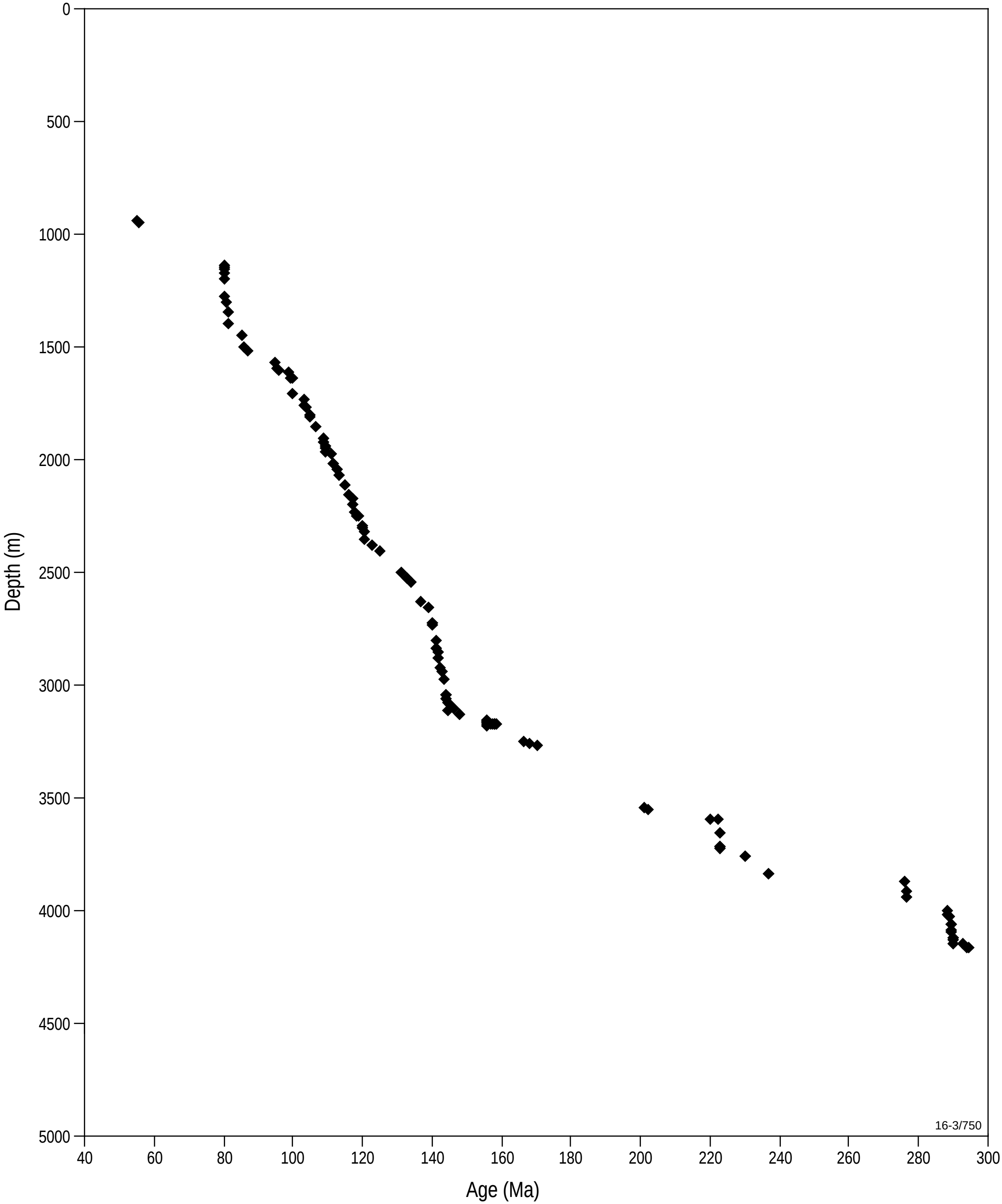


Figure 2 Browse Basin bathymetry and well location map.



Go to Figure 3b

Figure 3a Age-depth plot for Yampi-1

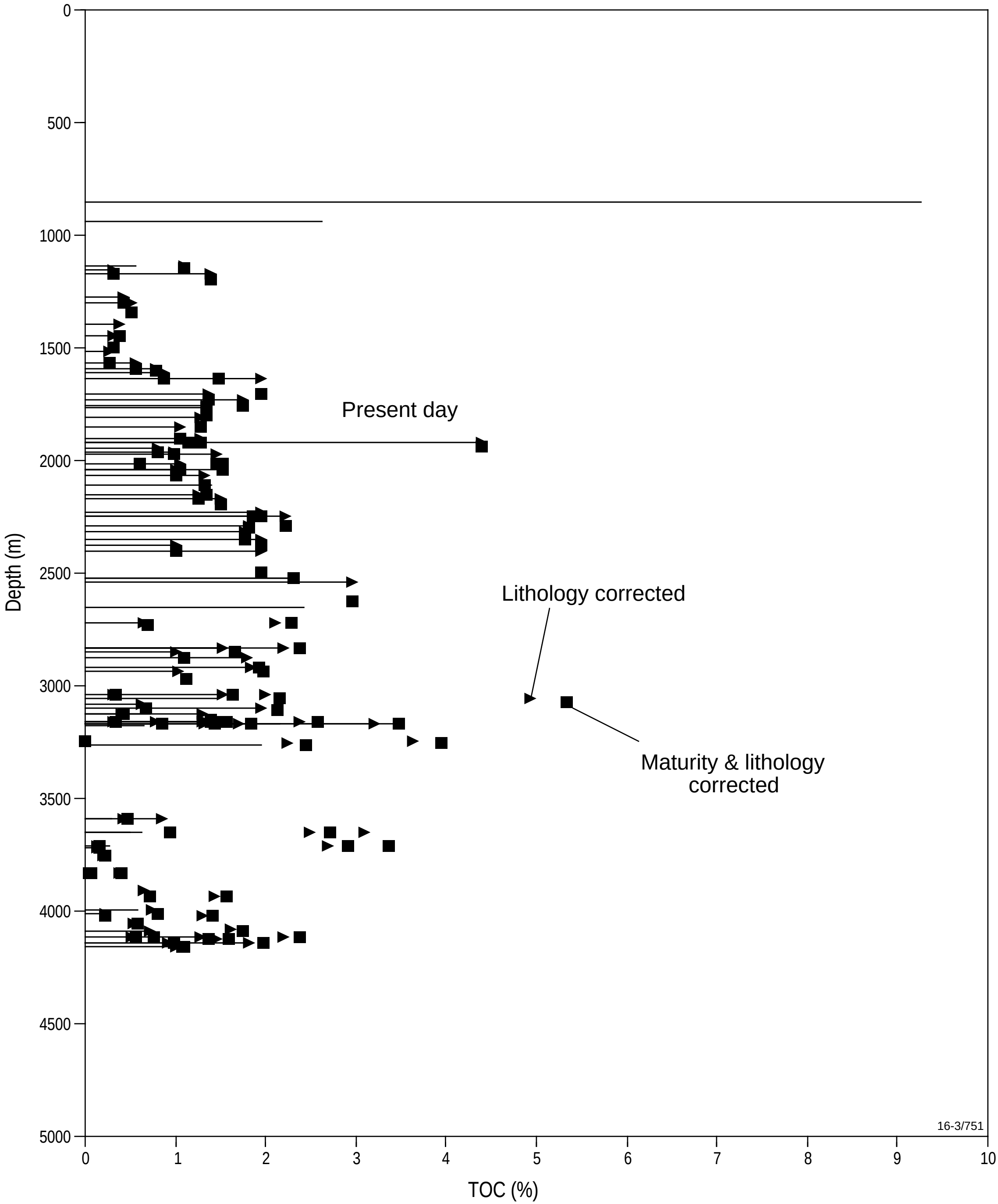


Figure 3b TOC-depth plot (present-day, lithology corrected and lithology+maturity corrected) for Yampi-1

Go to Figure 3c

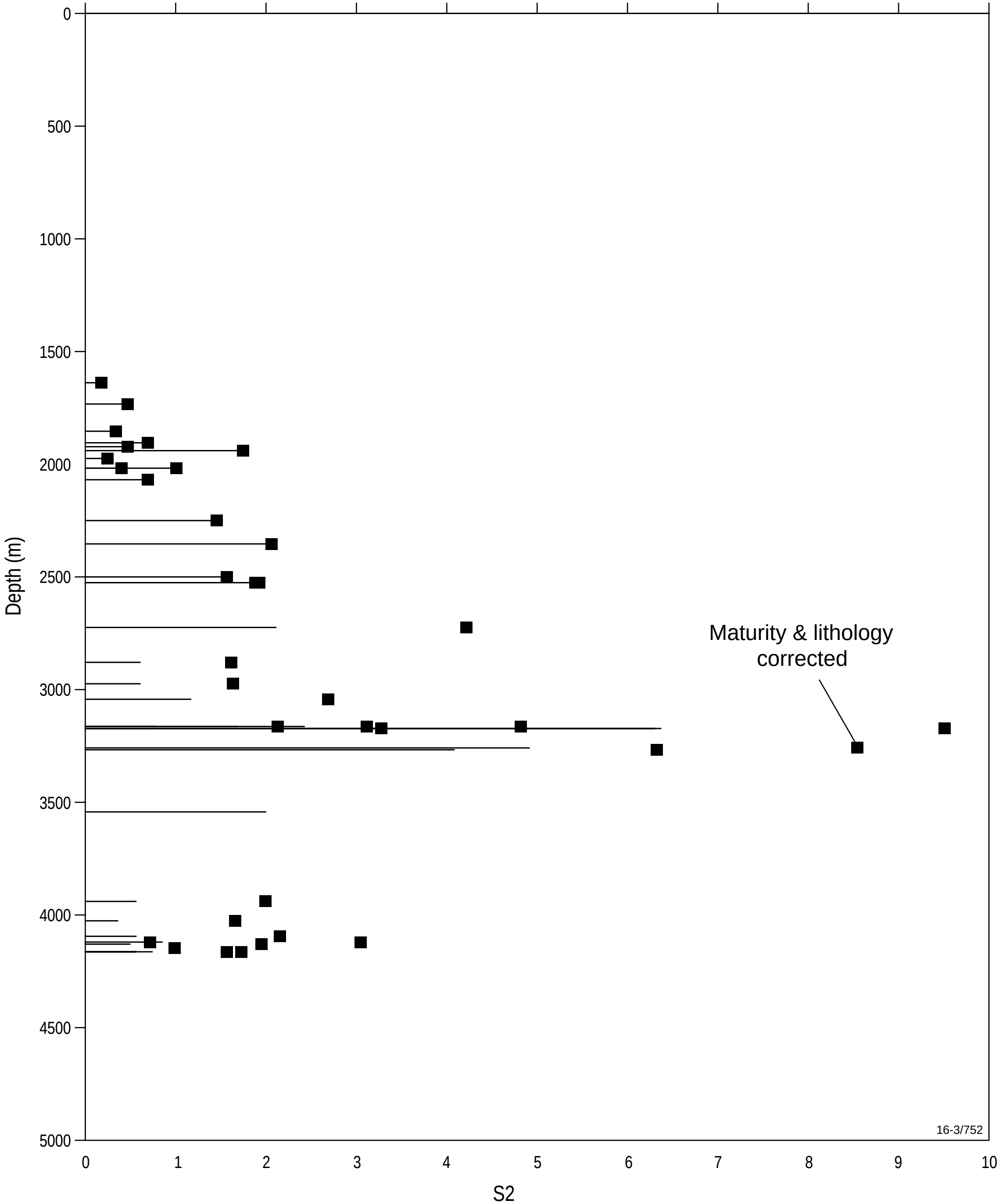


Figure 3c S2-depth plot (present-day, and lithology+maturity corrected) for Yampi-1

Go to Figure 3d

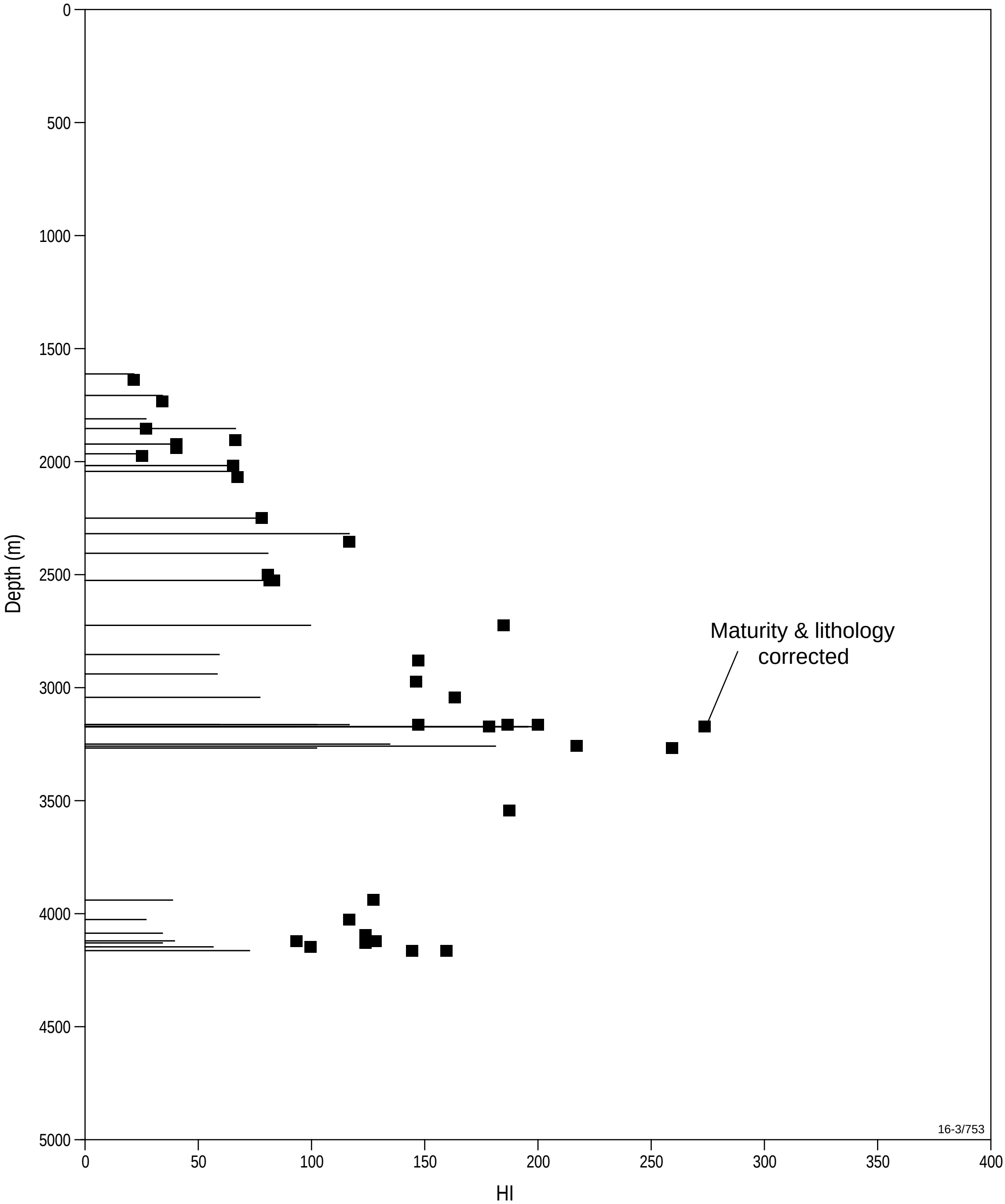


Figure 3d HI-depth plot (present-day, and lithology+maturity corrected) for Yampi-1

Go to Figure 3e

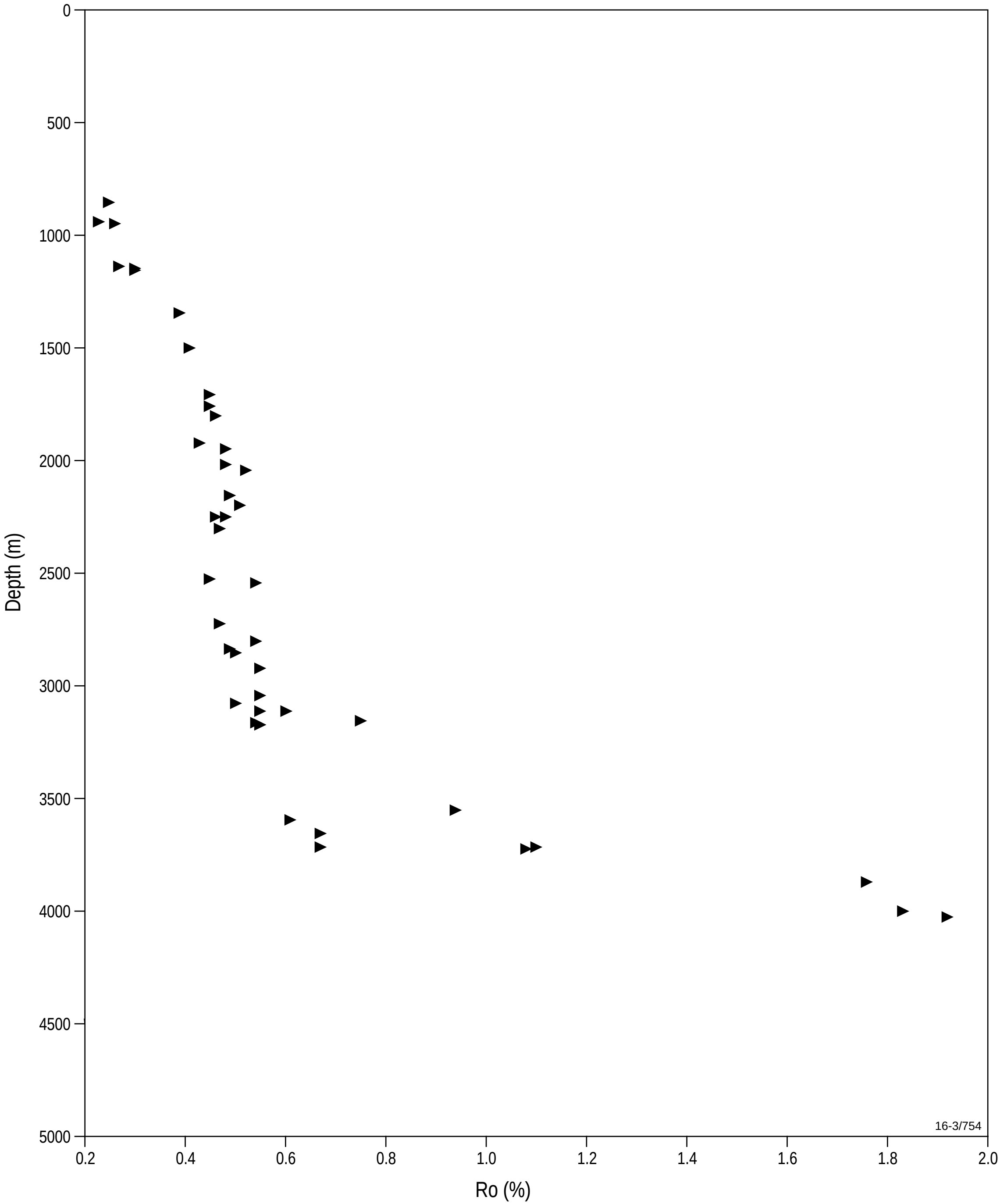


Figure 3e Ro-depth plot for Yampi-1

Go to Figure 3f

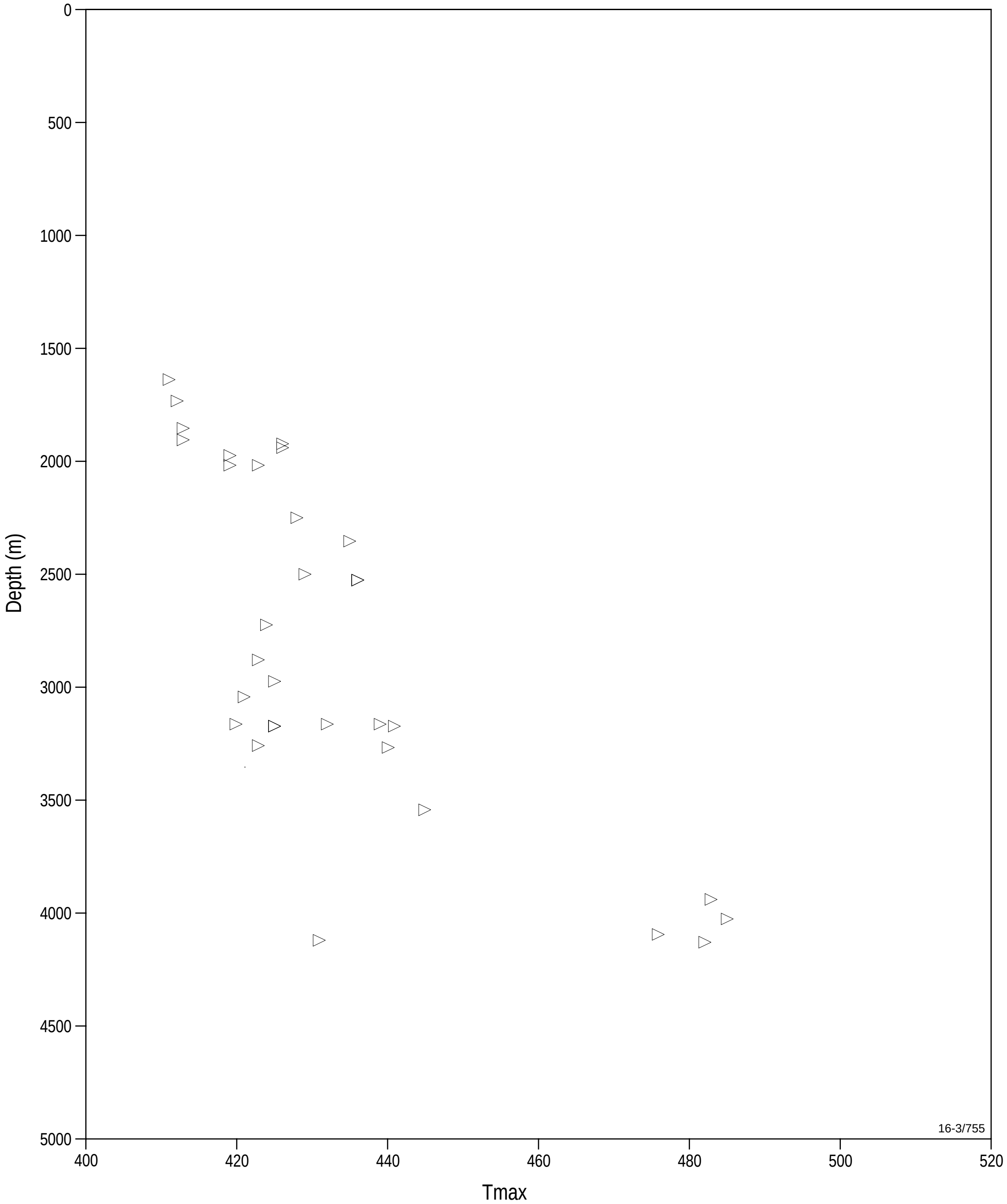


Figure 3f Tmax-depth plot for Yampi-1

Go to Figure 3g

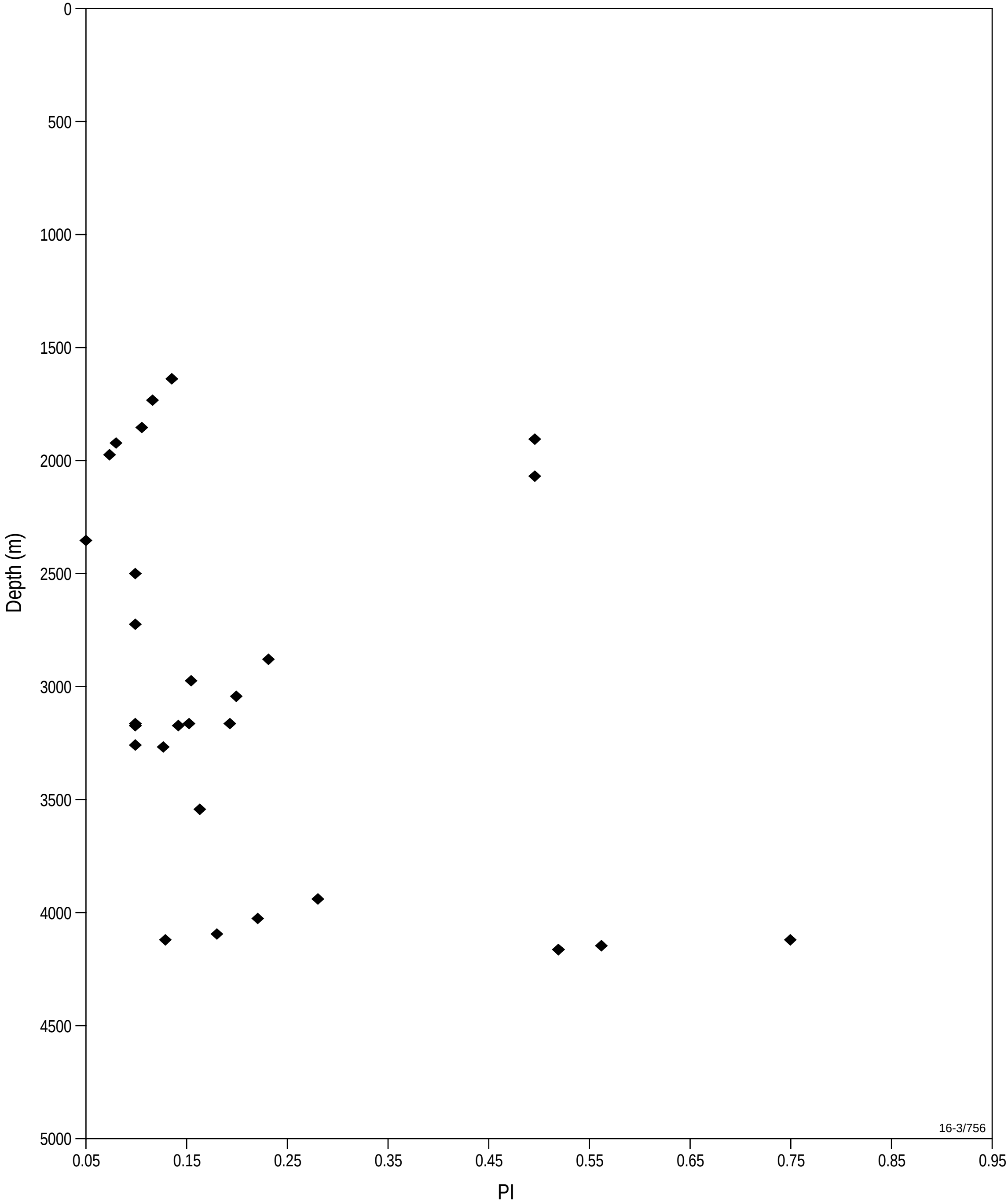


Figure 3g PI-depth plot for Yampi-1

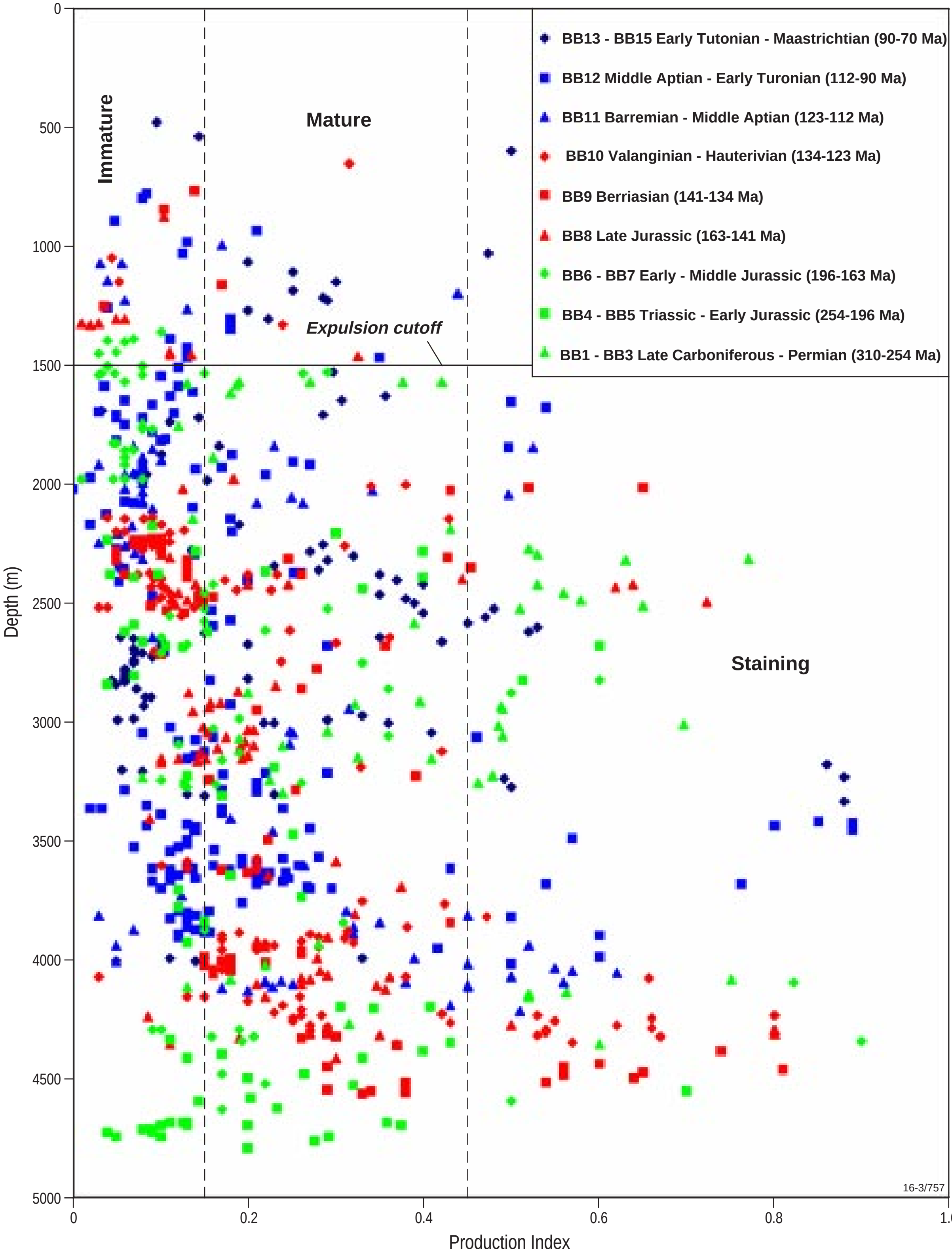


Figure 4a PI-depth plot for Browse Basin wells

Go to Figure 4b

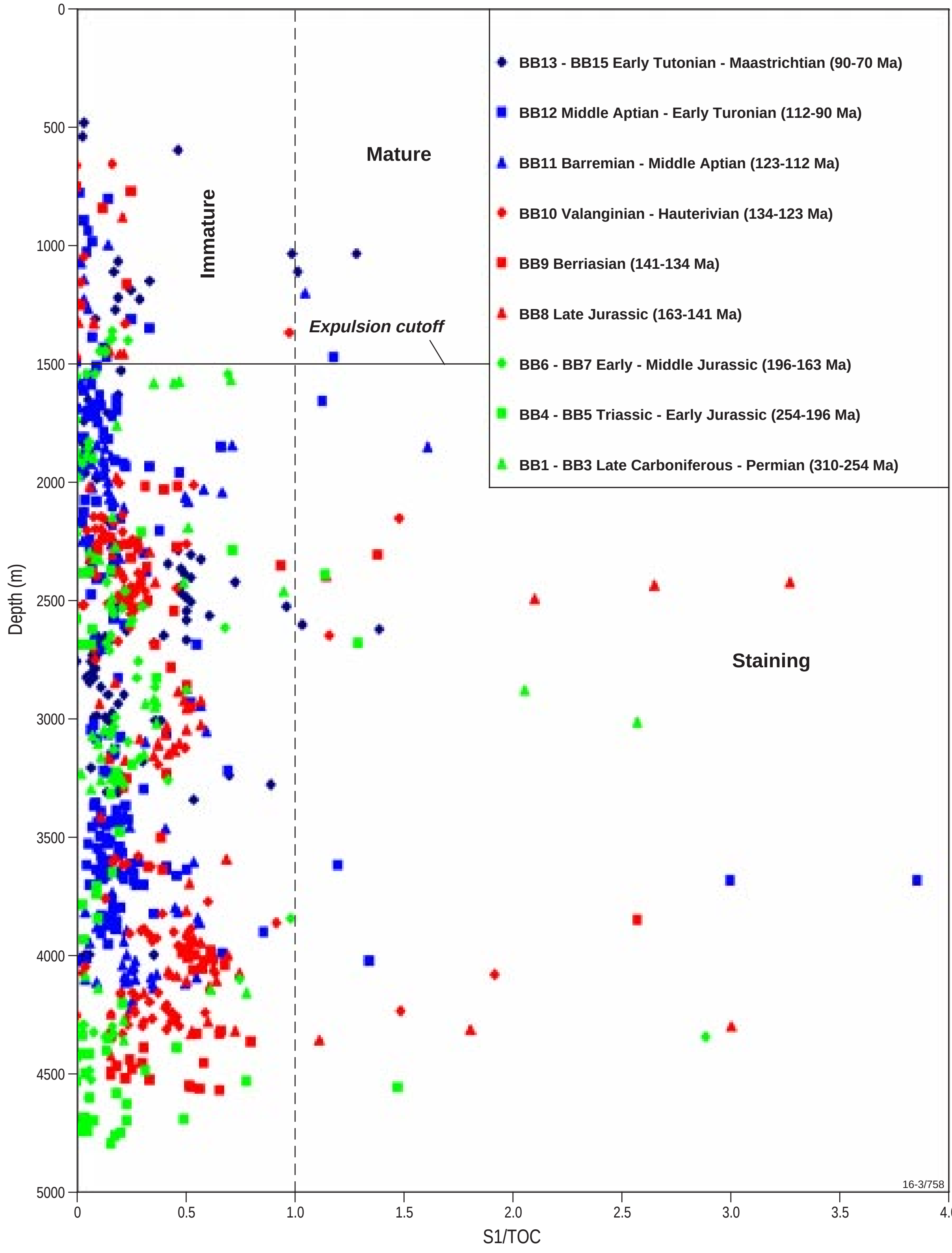


Figure 4b S1/TOC-depth plot for Browse Basin wells

Go to Figure 4c

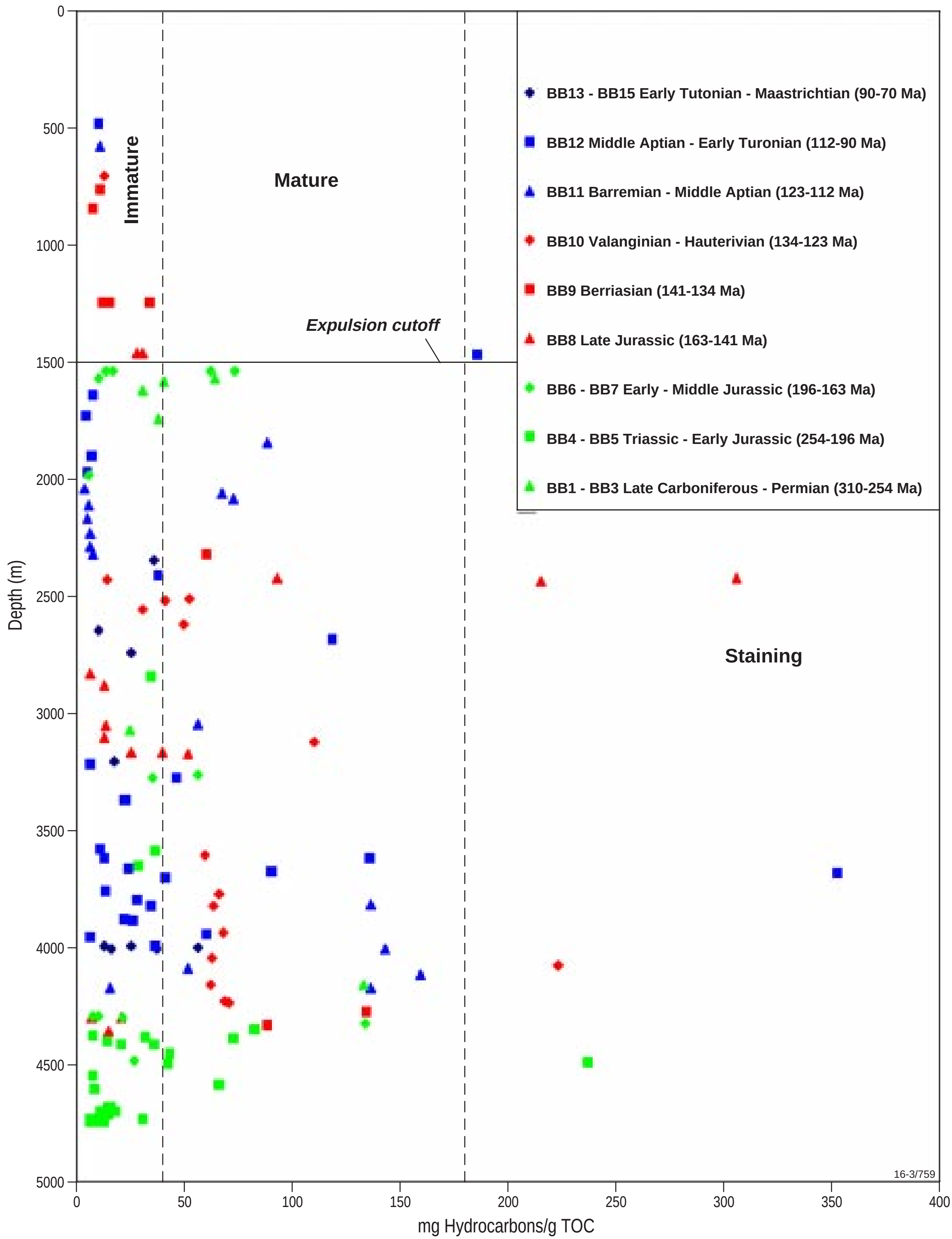


Figure 4c mg hydrocarbons/gTOC-depth plot for Browse Basin wells

Go to Figure 4d

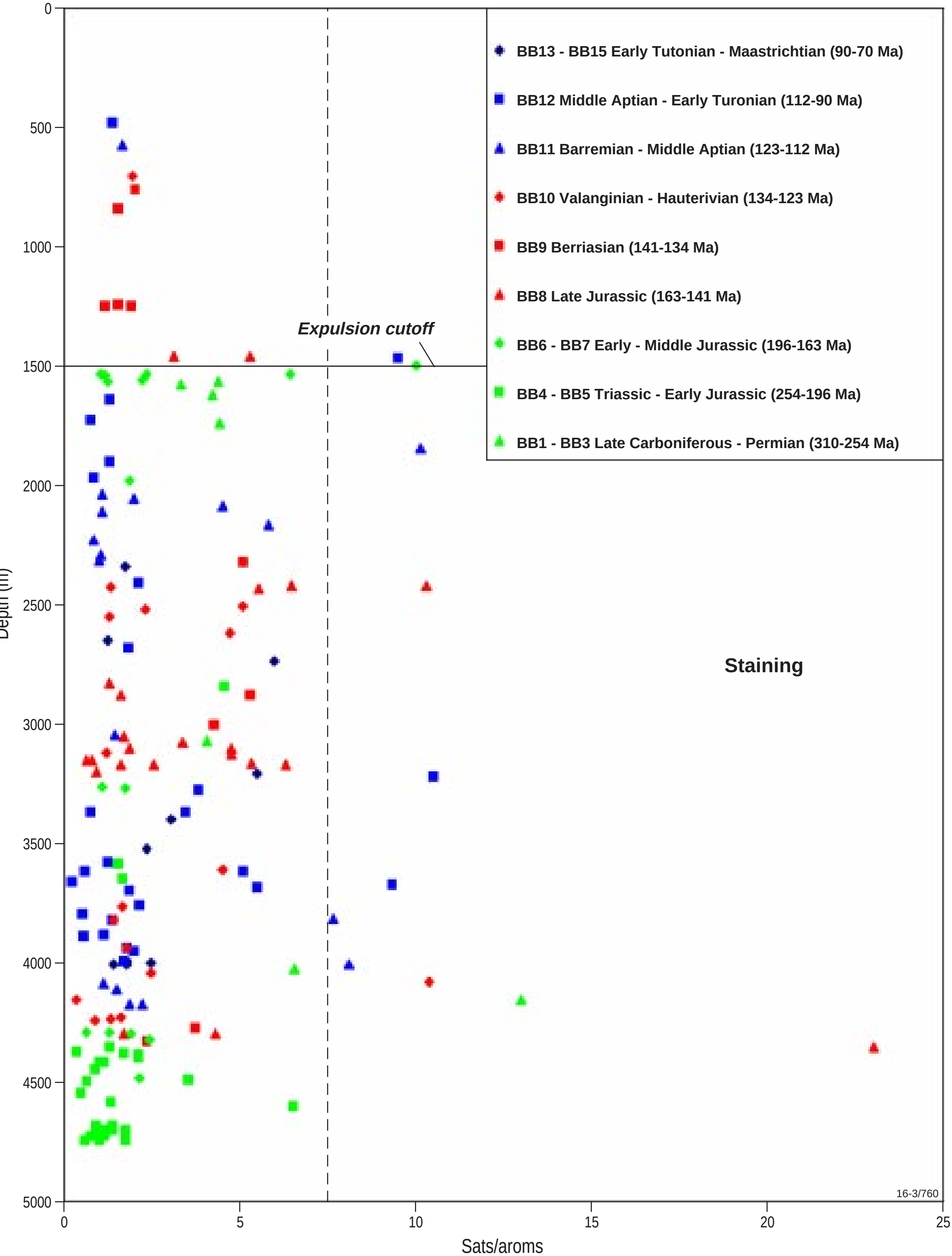


Figure 4d Sat/arom hydrocarbons-depth plot for Browse Basin wells

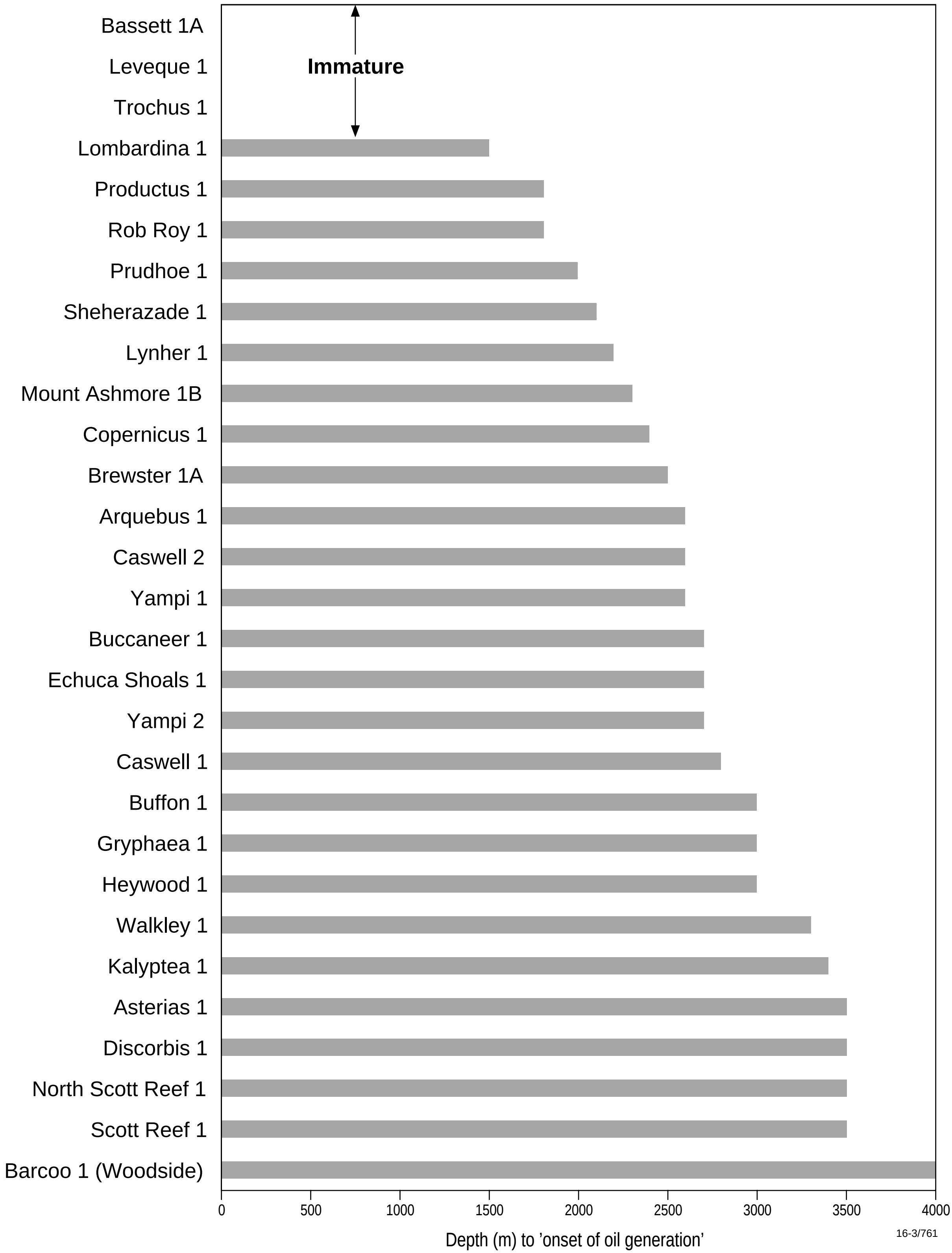


Figure 5 Depth to the top of the oil window for Browse Basin wells

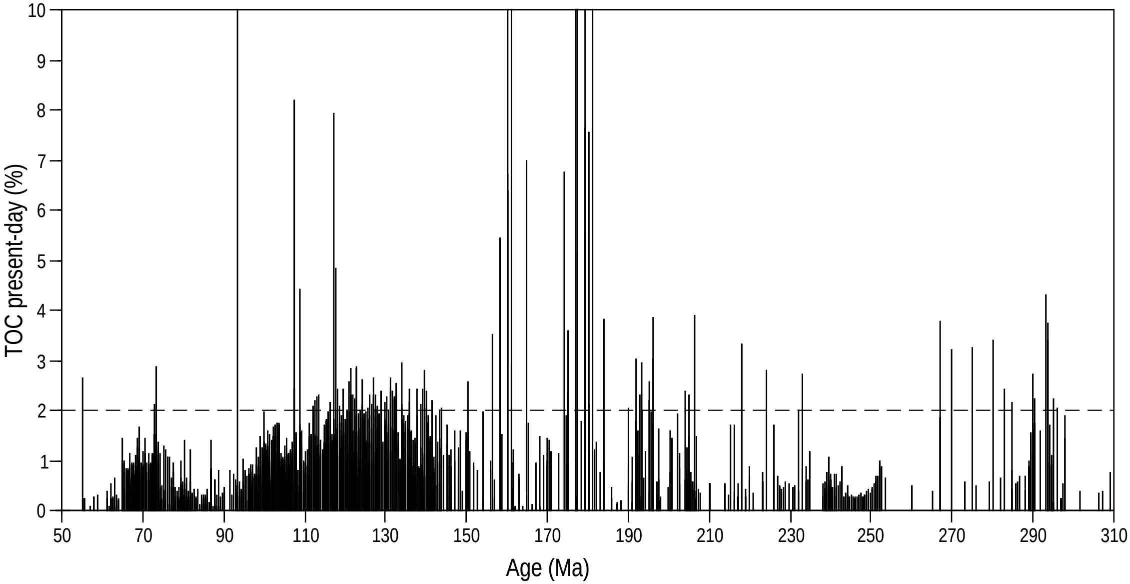


Figure 6a Age profile of present-day TOC

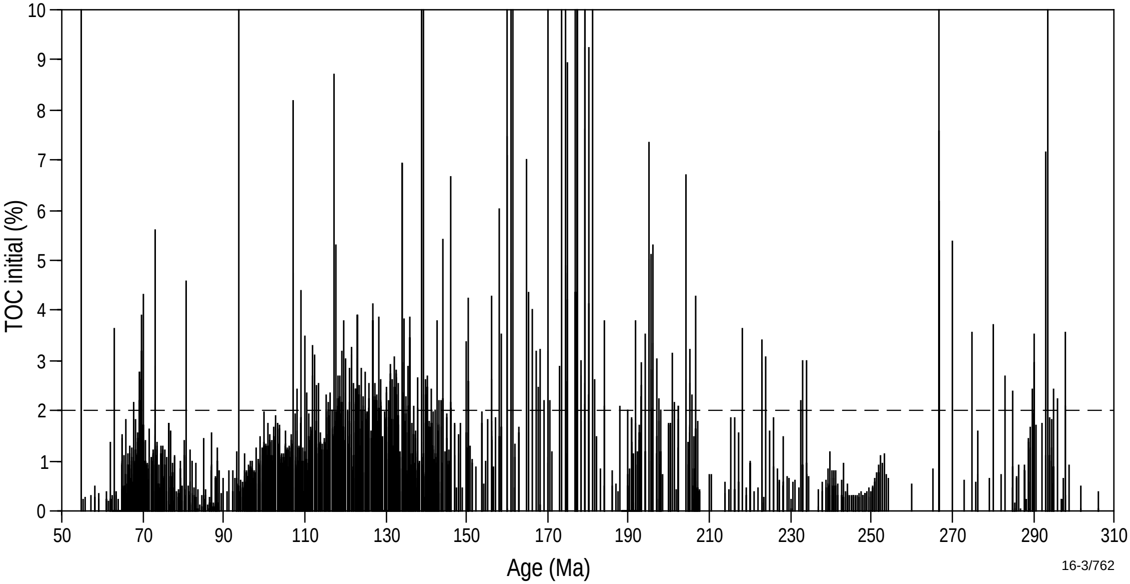


Figure 6b Age profile of initial TOC

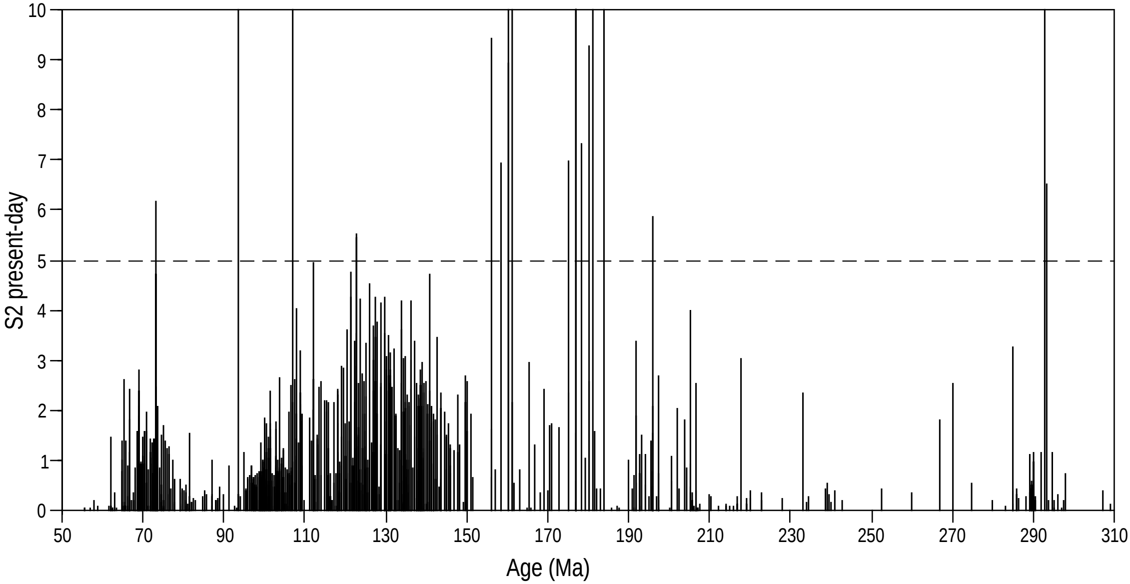


Figure 7a Age profile of present-day S2

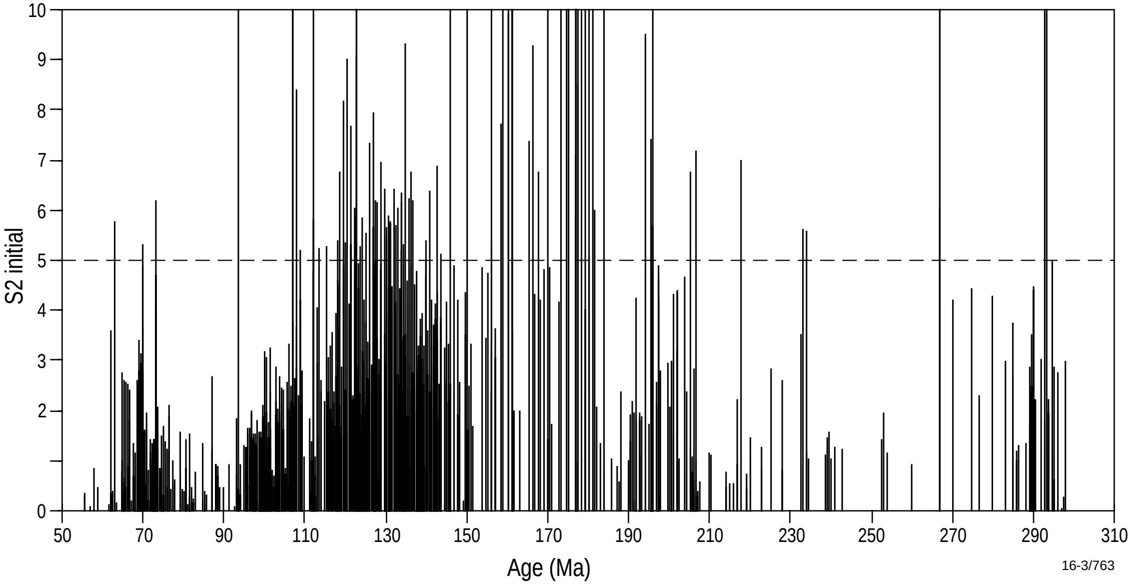
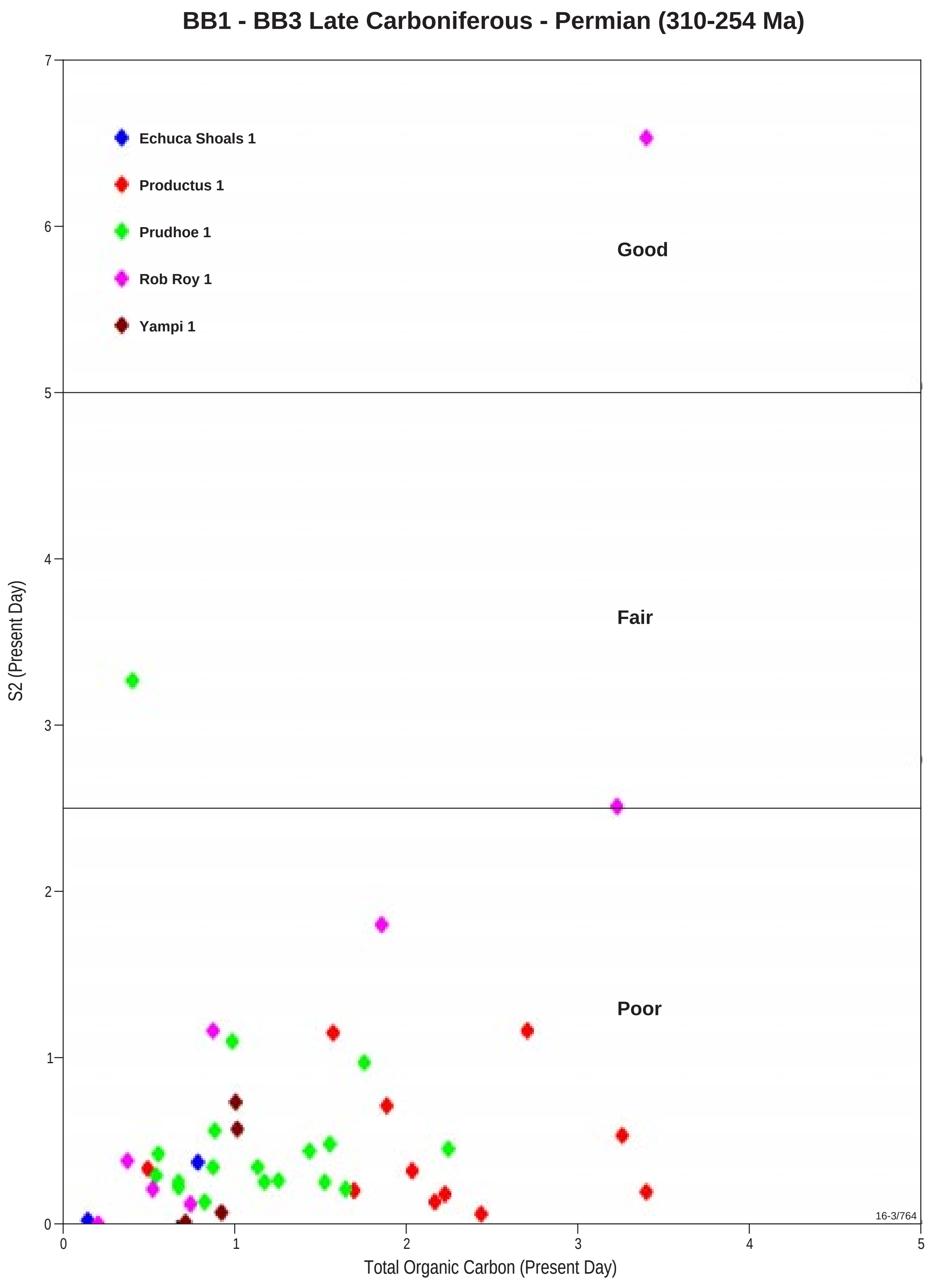


Figure 7b Age profile of initial S2



Go to Figure 8b

Figure 8a Present-day S2-present-day TOC plot for age interval BB1-3

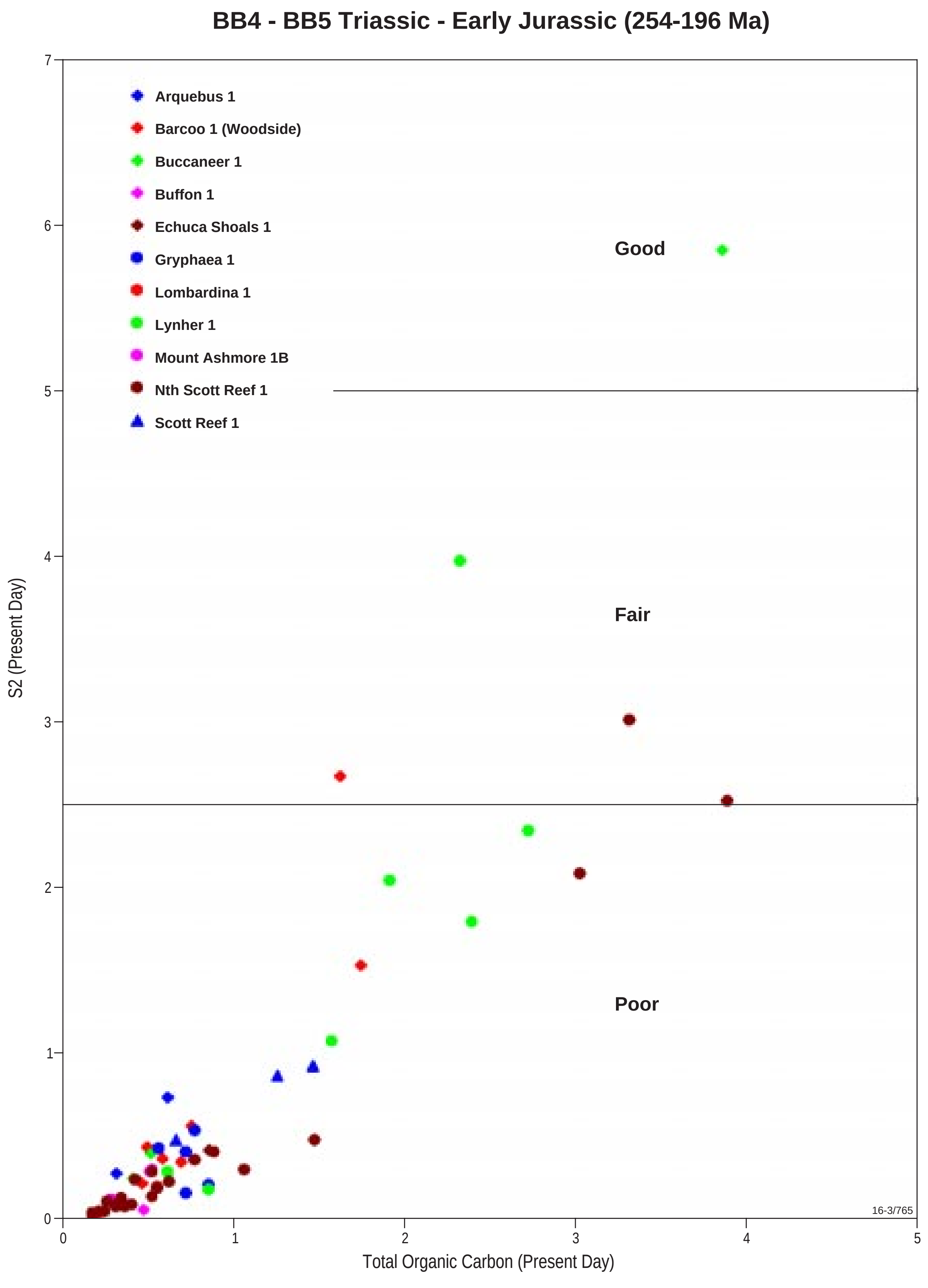
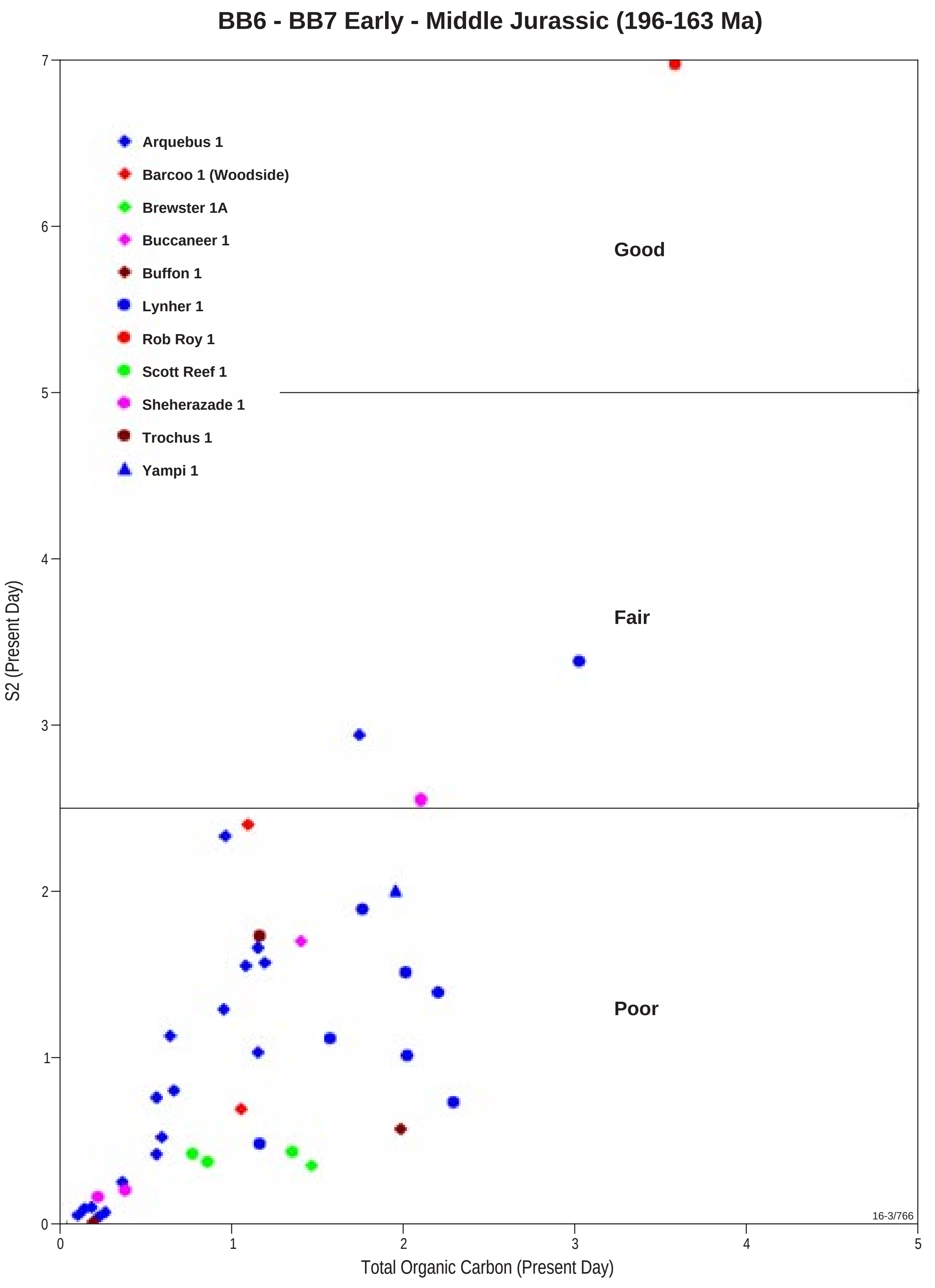


Figure 8b Present-day S2-present-day TOC plot for age interval BB4-5

Go to Figure 8c



Go to Figure 8d

Figure 8c Present-day S2-present-day TOC plot for age interval BB6-7

BB8 Late Jurassic (163-141 Ma)

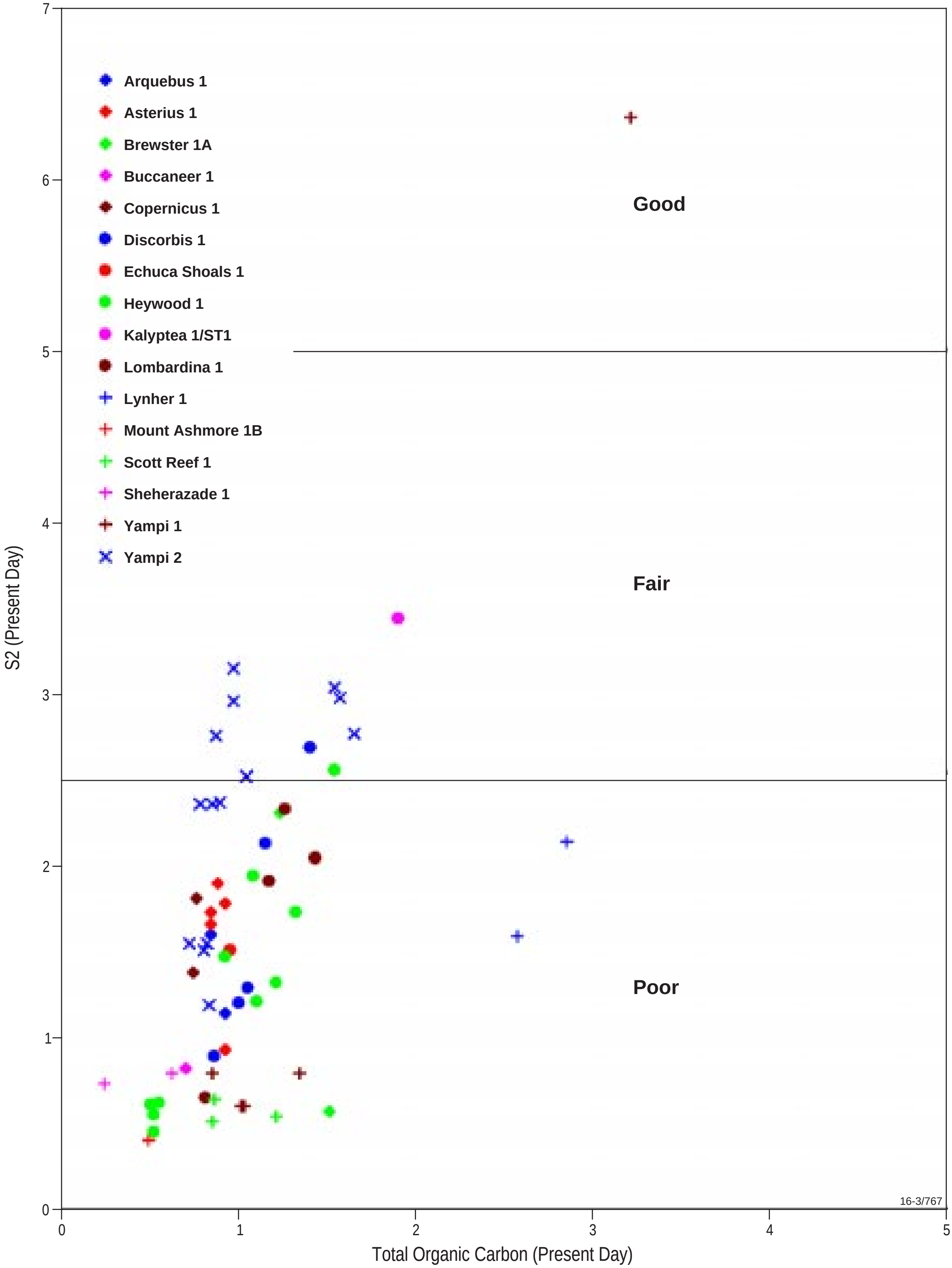
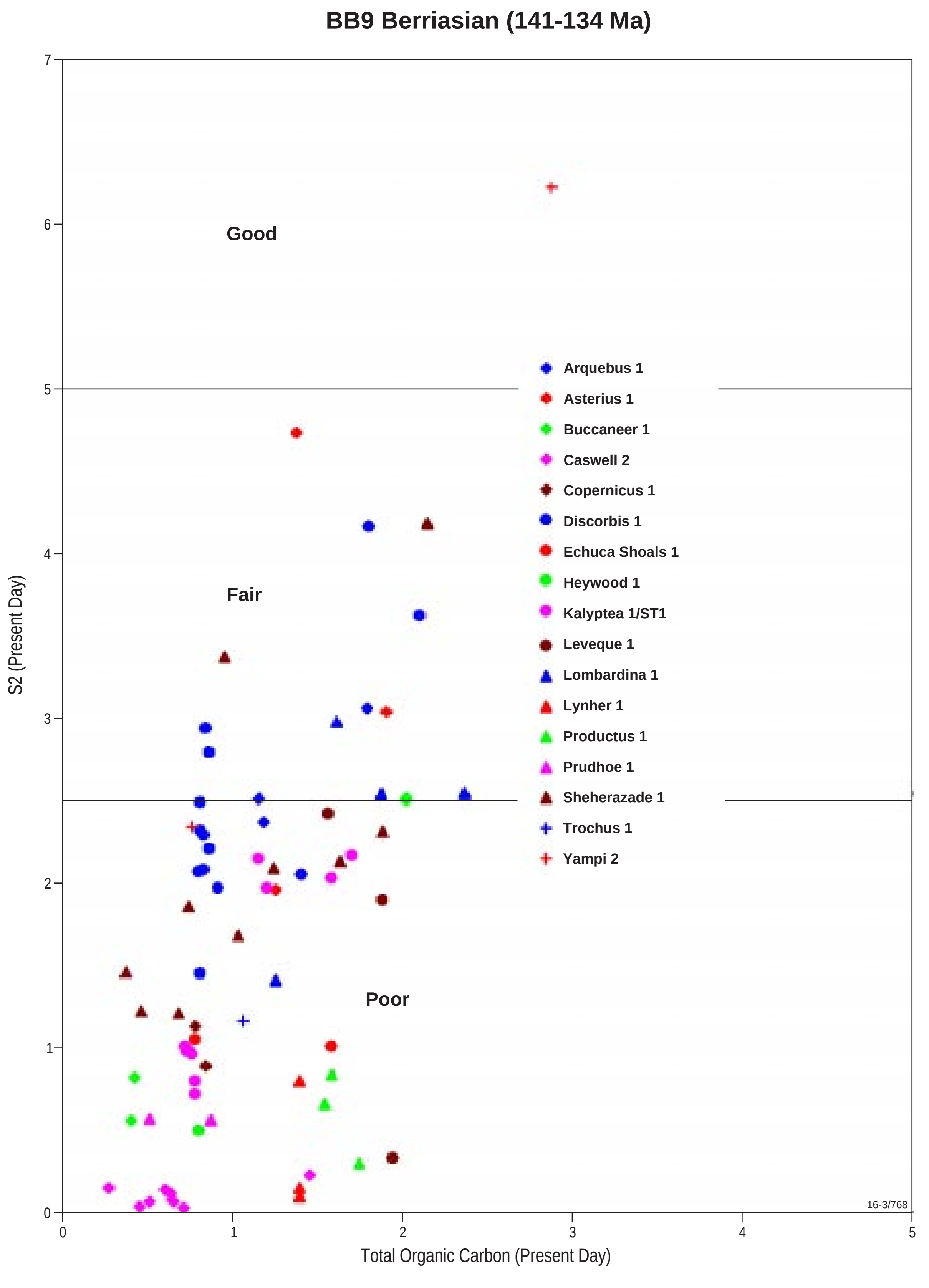


Figure 8d Present-day S2-present-day TOC plot for age interval BB8

Go to Figure 8e



Go to Figure 8f

Figure 8e Present-day S2-present-day TOC plot for age interval BB9

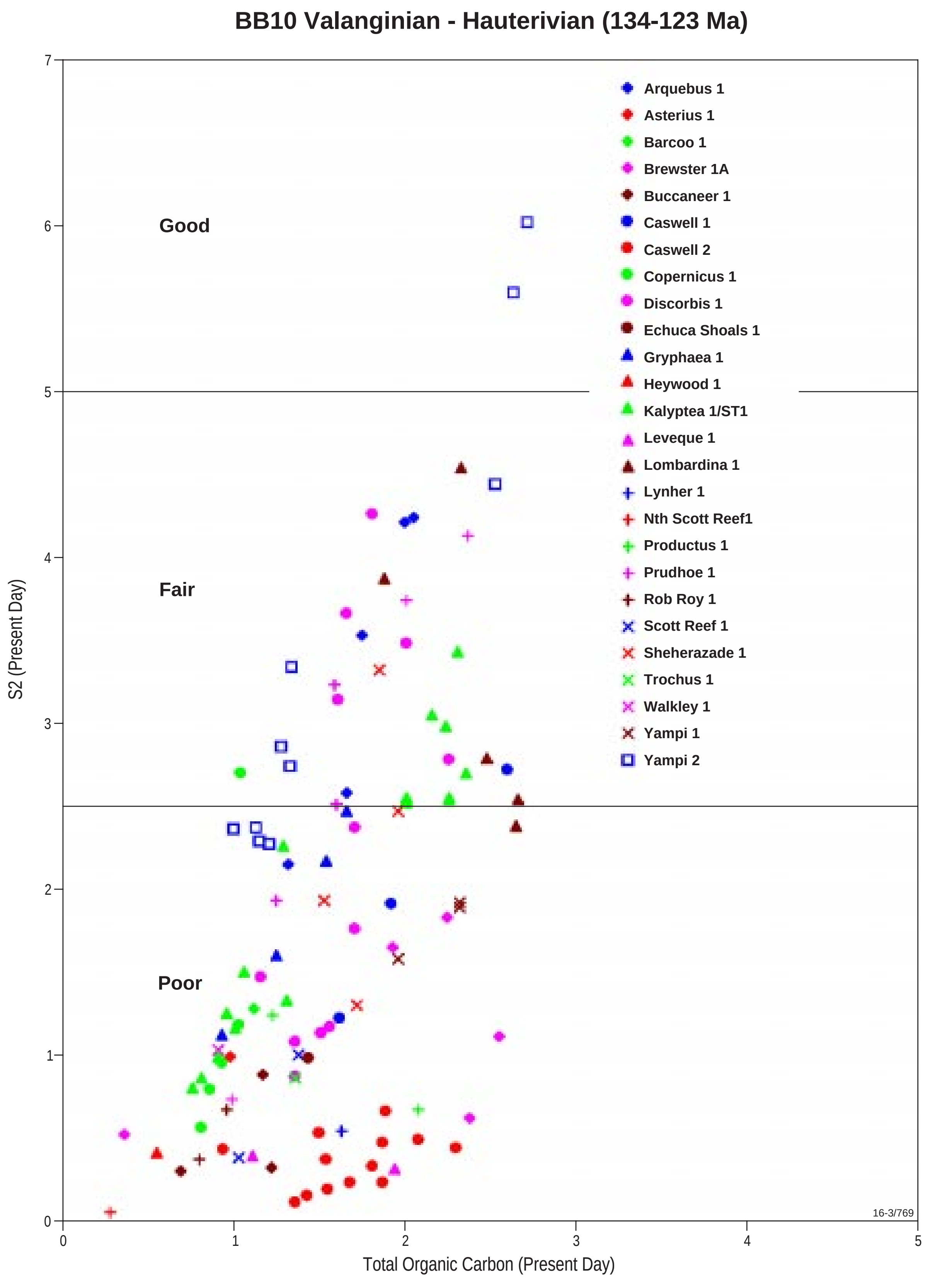


Figure 8f Present-day S2-present-day TOC plot for age interval BB10

Go to Figure 8g

BB11 Barremian - Middle Aptian (123-112 Ma)

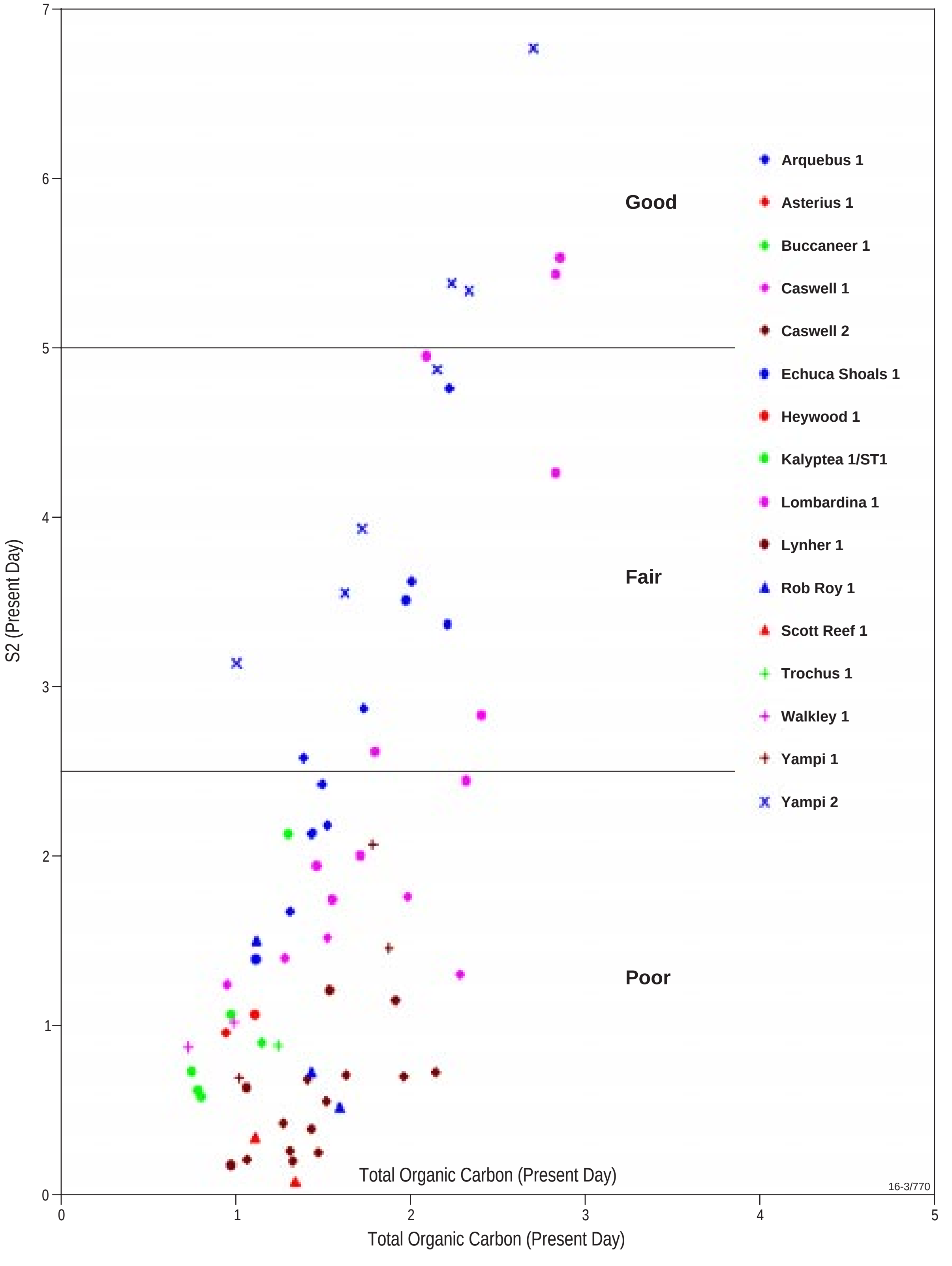


Figure 8g Present-day S2-present-day TOC plot for age interval BB11

Go to Figure 8h

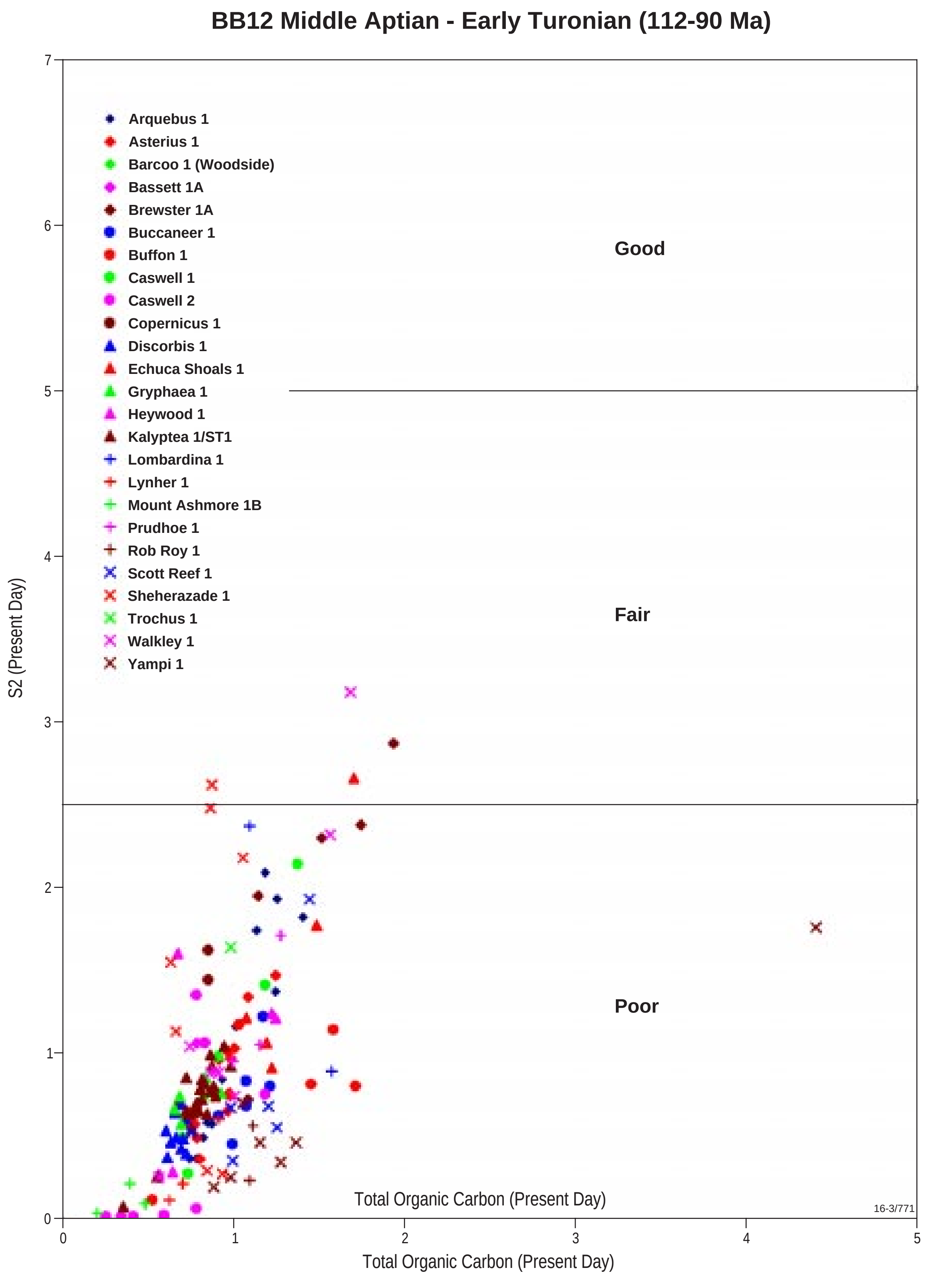


Figure 8h Present-day S2-present-day TOC plot for age interval BB12

Go to Figure 8i

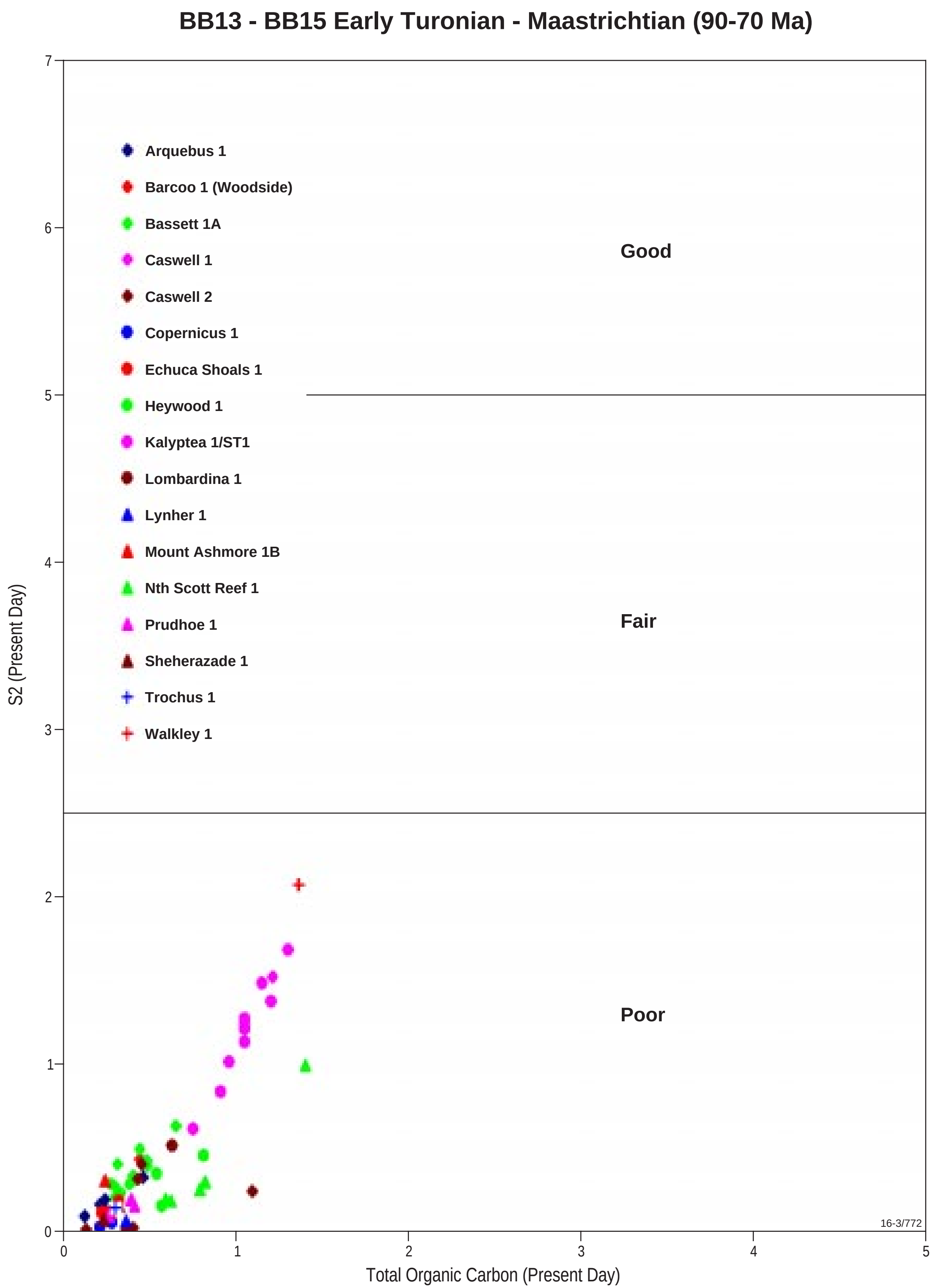
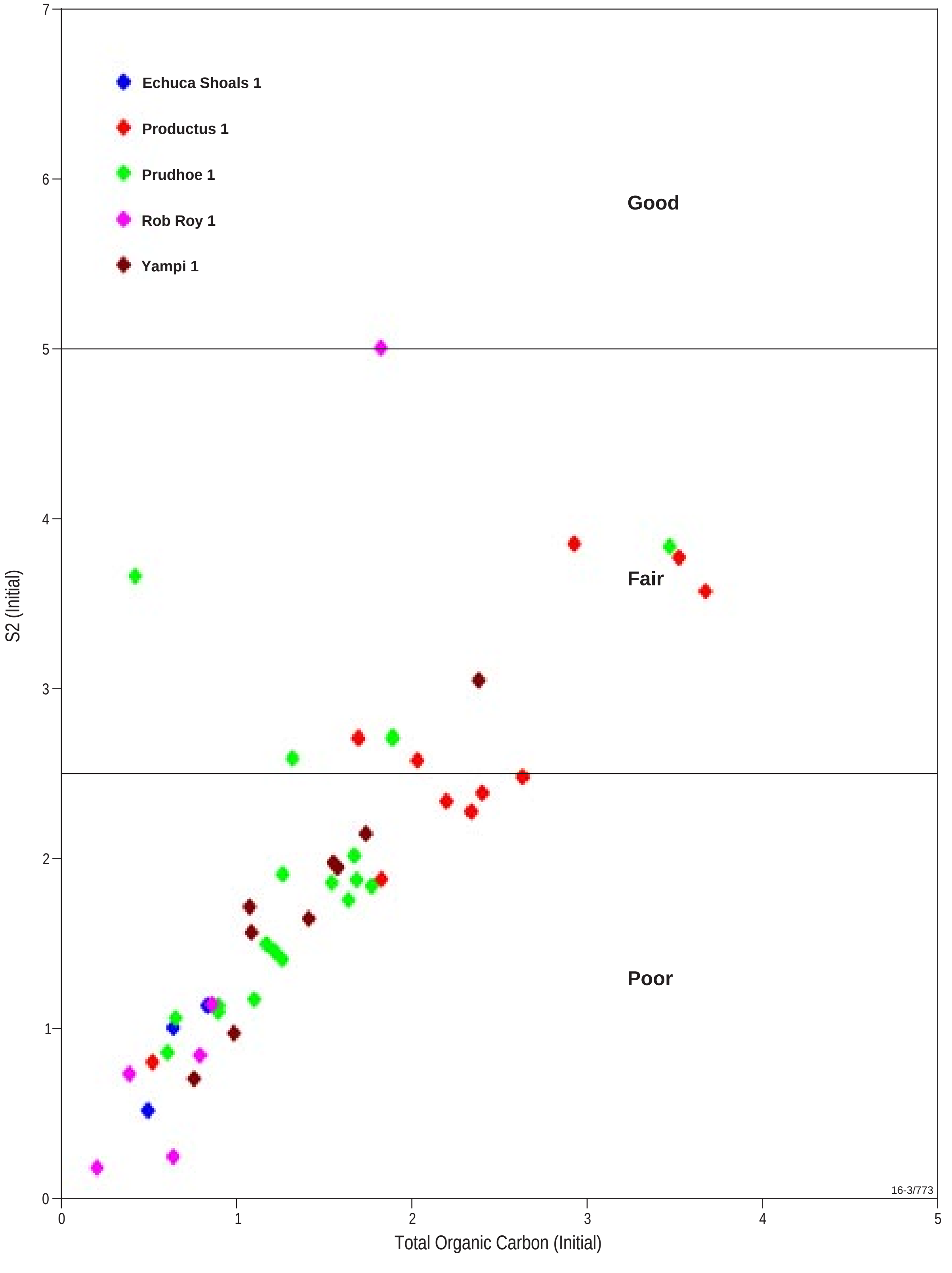


Figure 8i Present-day S2-present-day TOC plot for age interval BB13-15

BB1 - BB3 Late Carboniferous - Permian (310-254 Ma)



Go to Figure 9b

Figure 9a Initial S2-initial TOC plot for age interval BB1-3

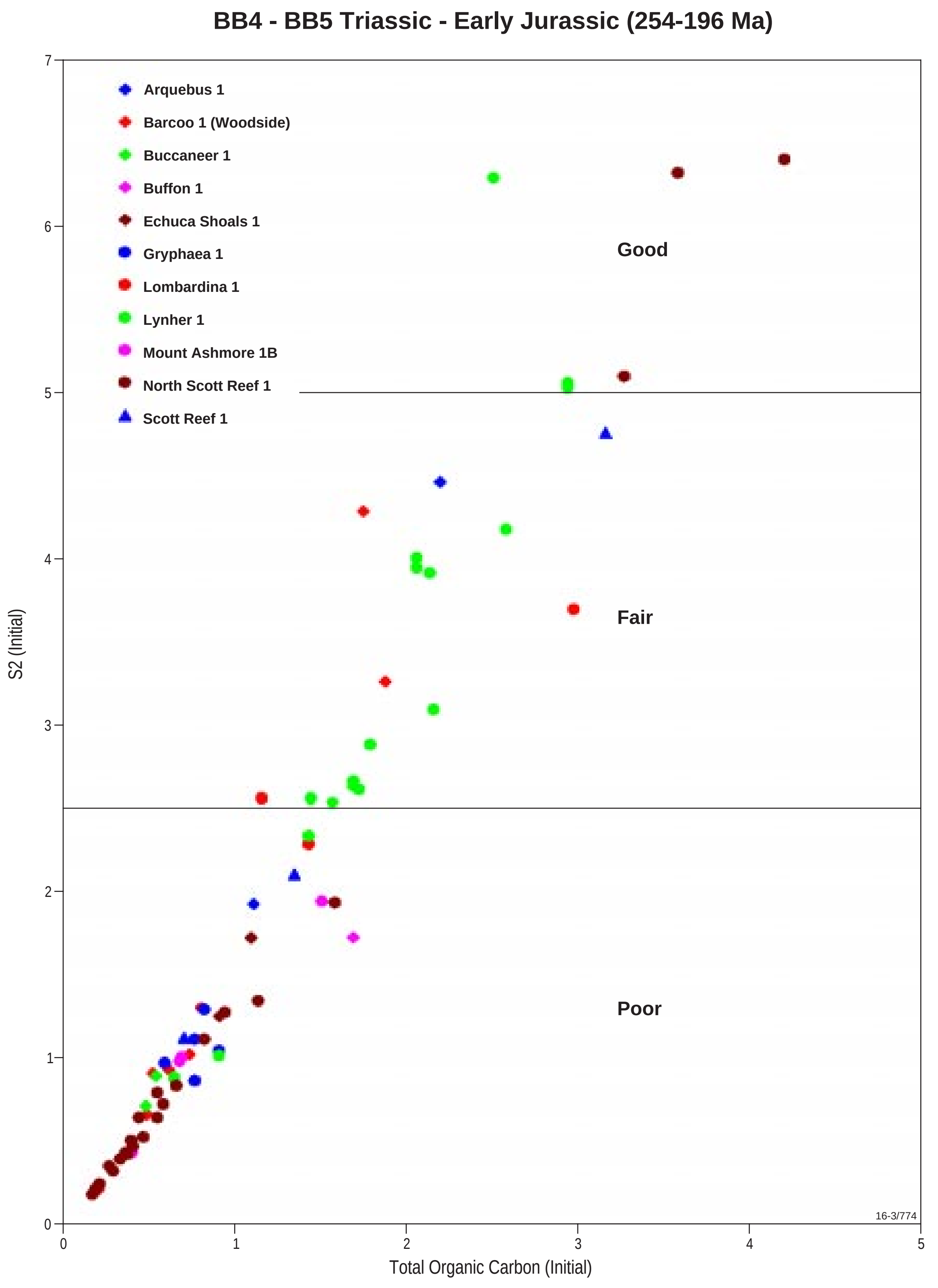


Figure 9b Initial S2-initial TOC plot for age interval BB4-5

Go to Figure 9c

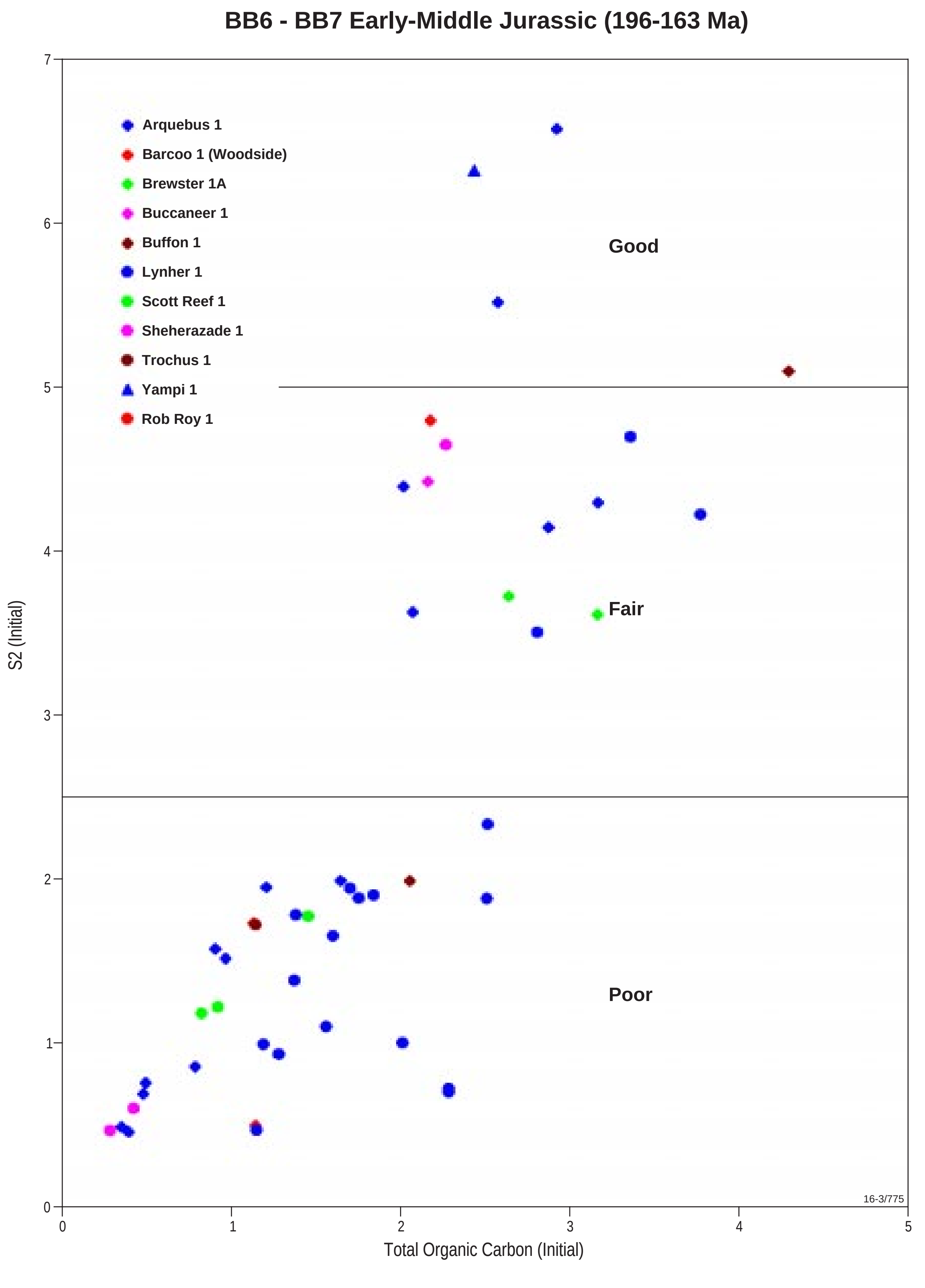


Figure 9c Initial S2-initial TOC plot for age interval BB6-7

Go to Figure 9d

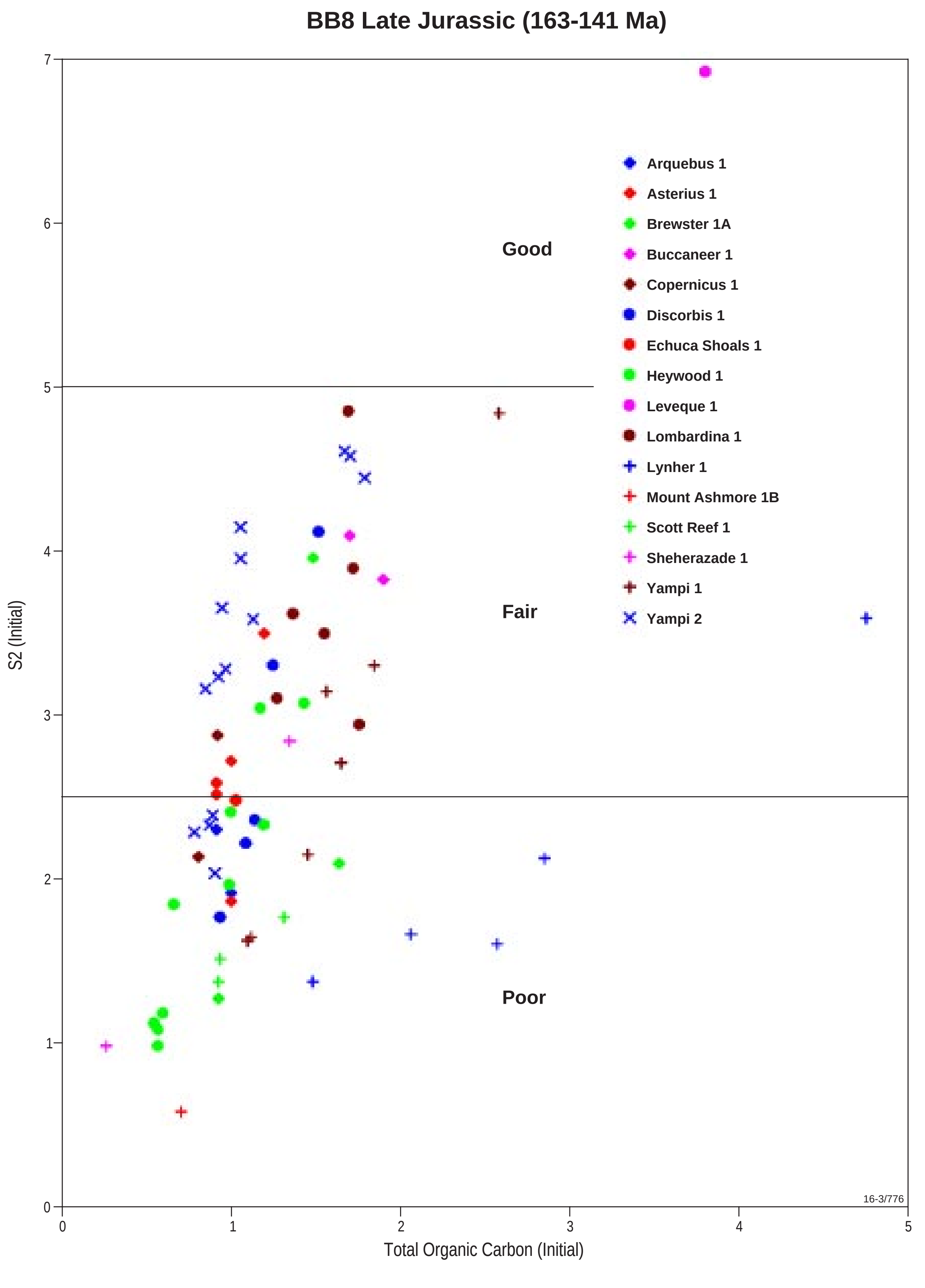


Figure 9d Initial S2-initial TOC plot for age interval BB8

Go to Figure 9e

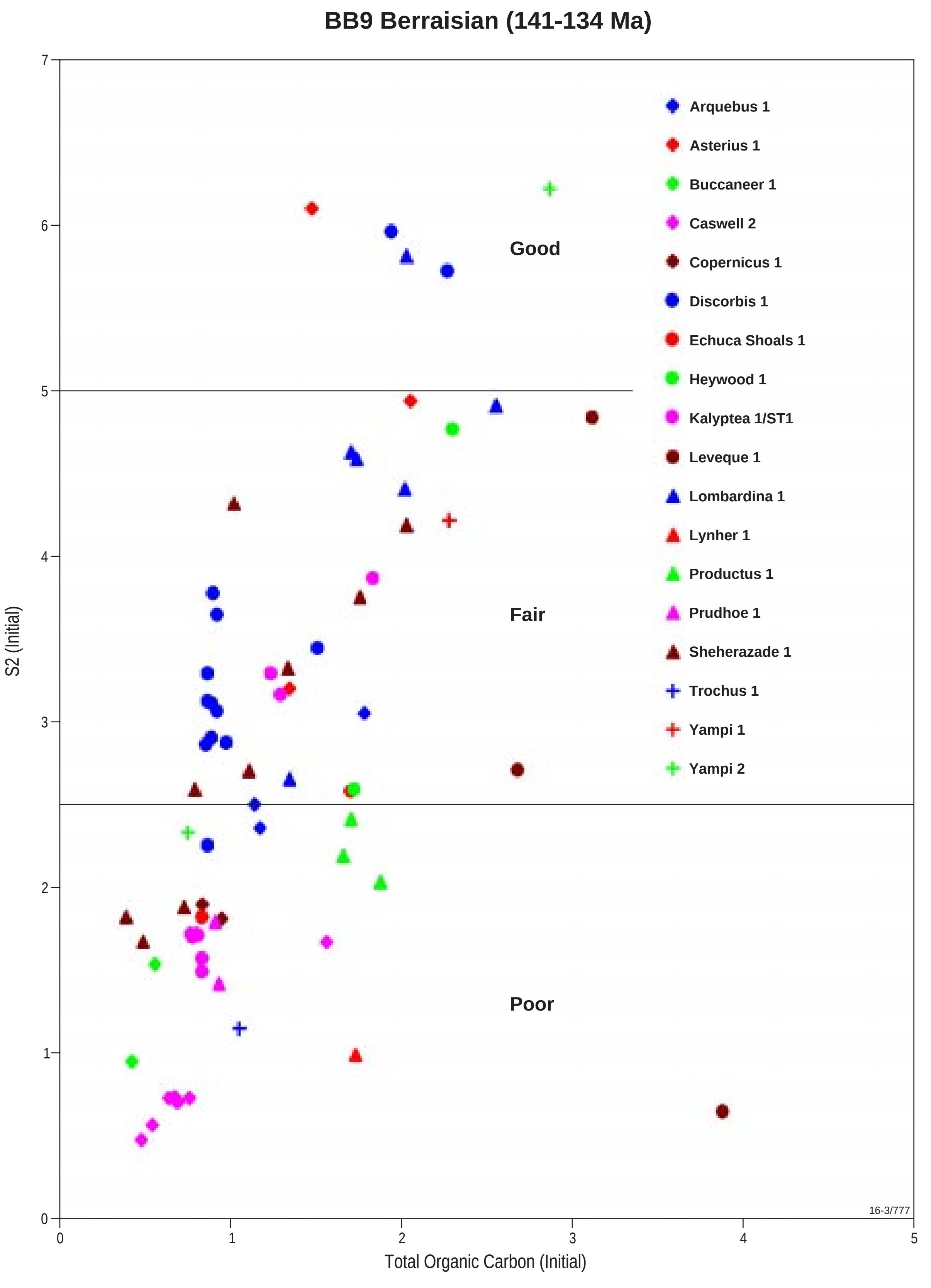


Figure 9e Initial S2-initial TOC plot for age interval BB9

Go to Figure 9f

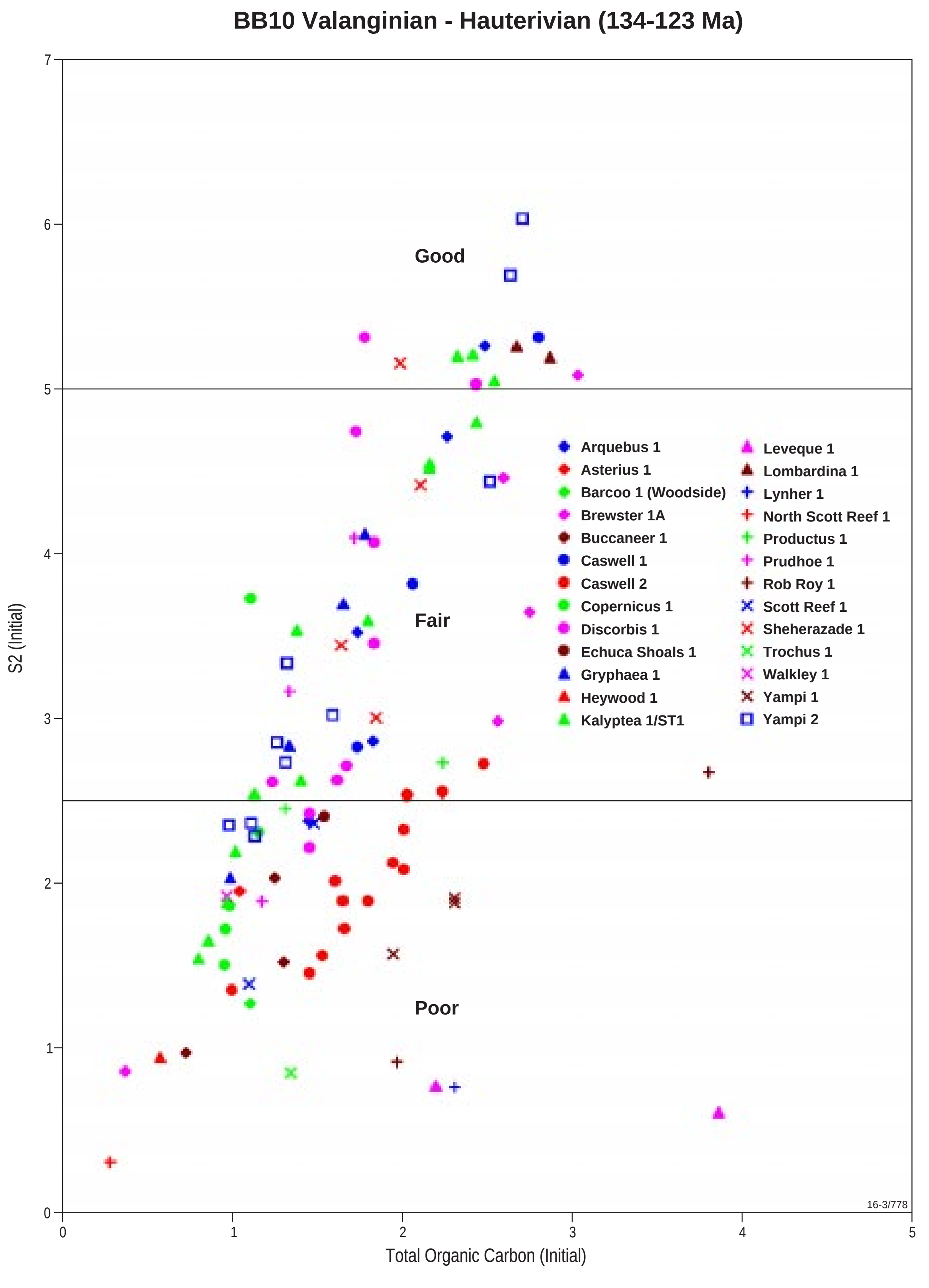


Figure 9f Initial S2-initial TOC plot for age interval BB10

Go to Figure 9g

BB11 Barremian - Middle Aptian (123-112 Ma)

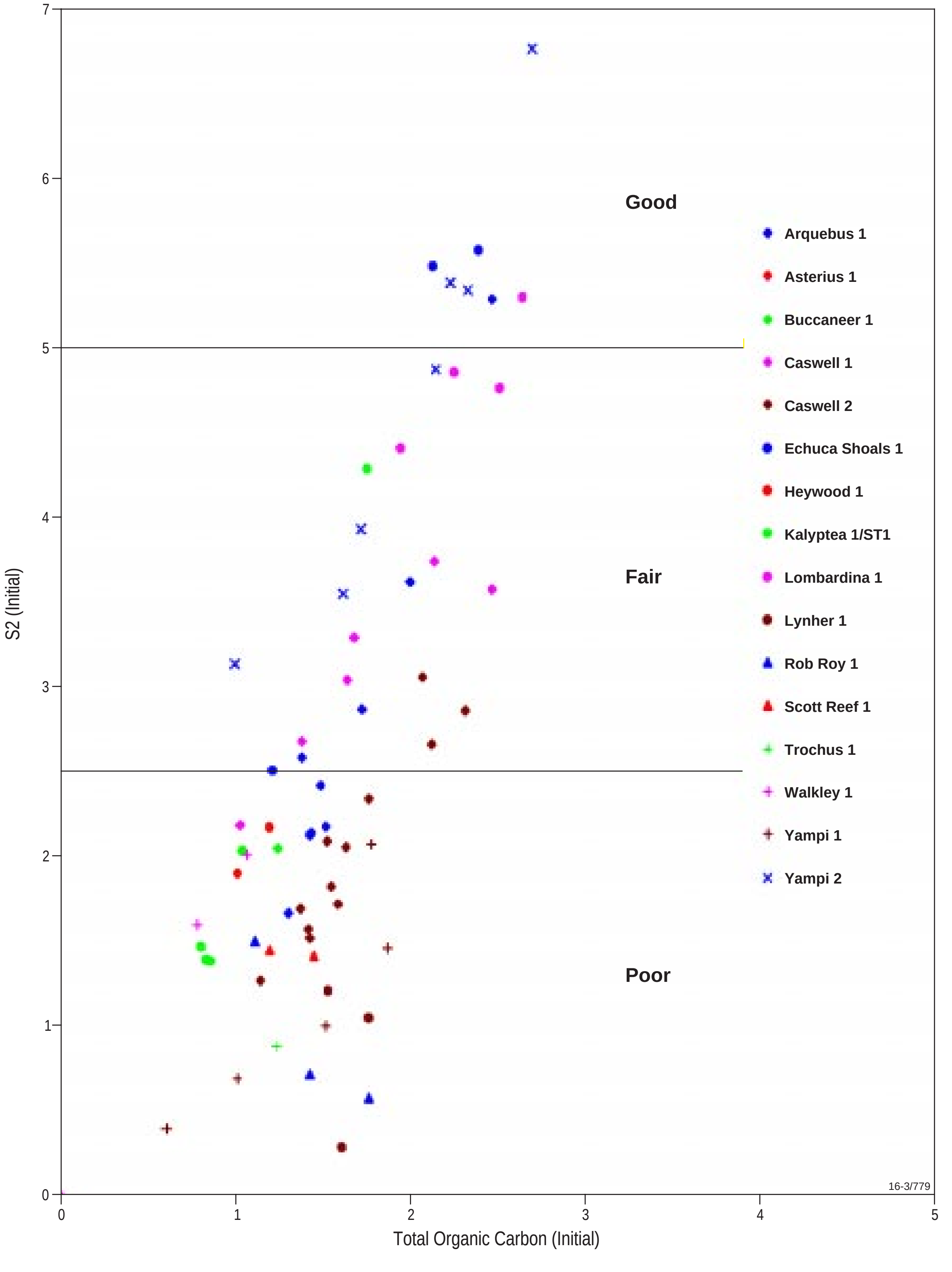


Figure 9g Initial S2-initial TOC plot for age interval BB11

Go to Figure 9h

BB12 Middle Aptian - Early Turonian (112-90 Ma)

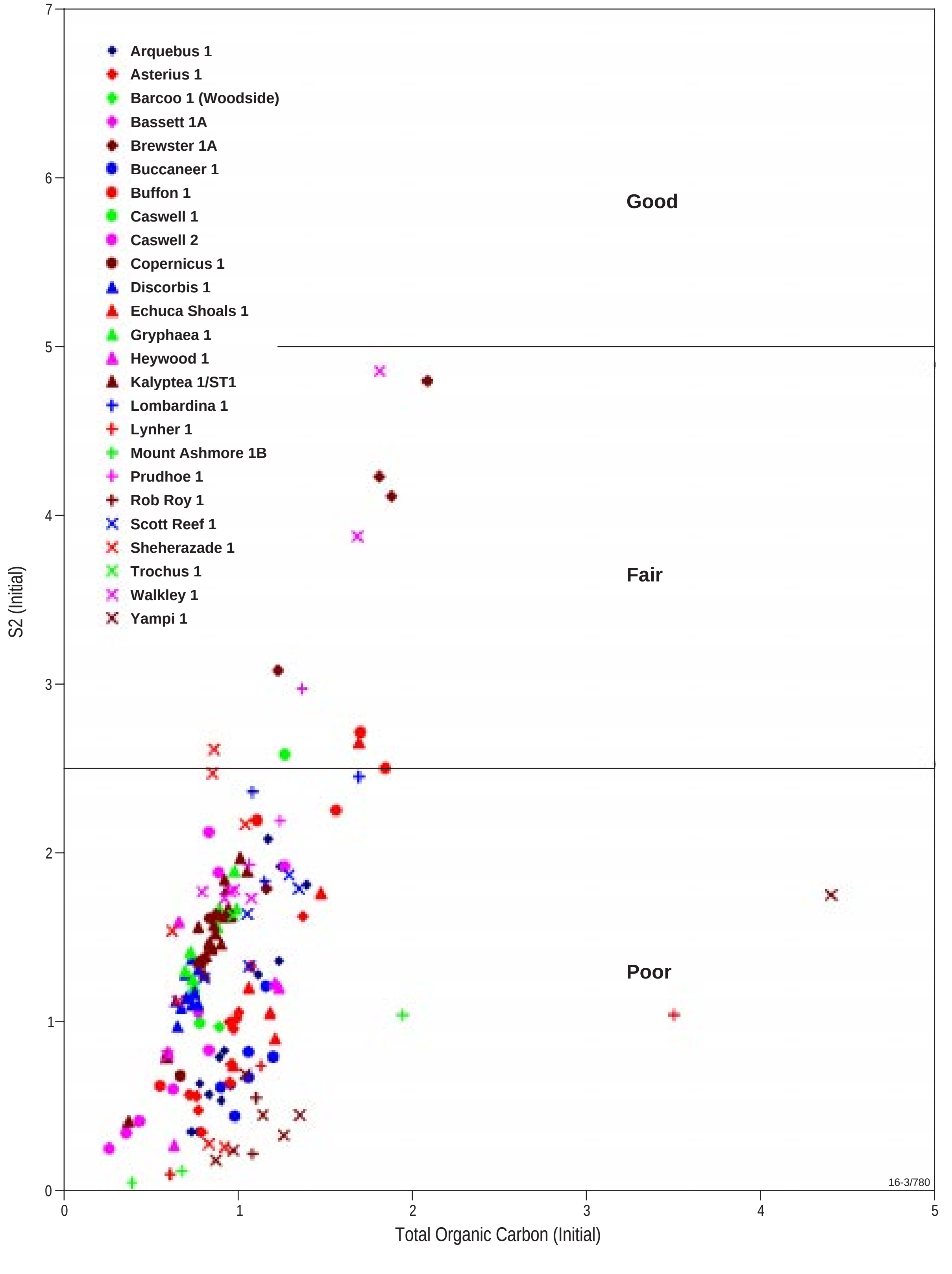


Figure 9h Initial S2-initial TOC plot for age interval BB12

Go to Figure 9i

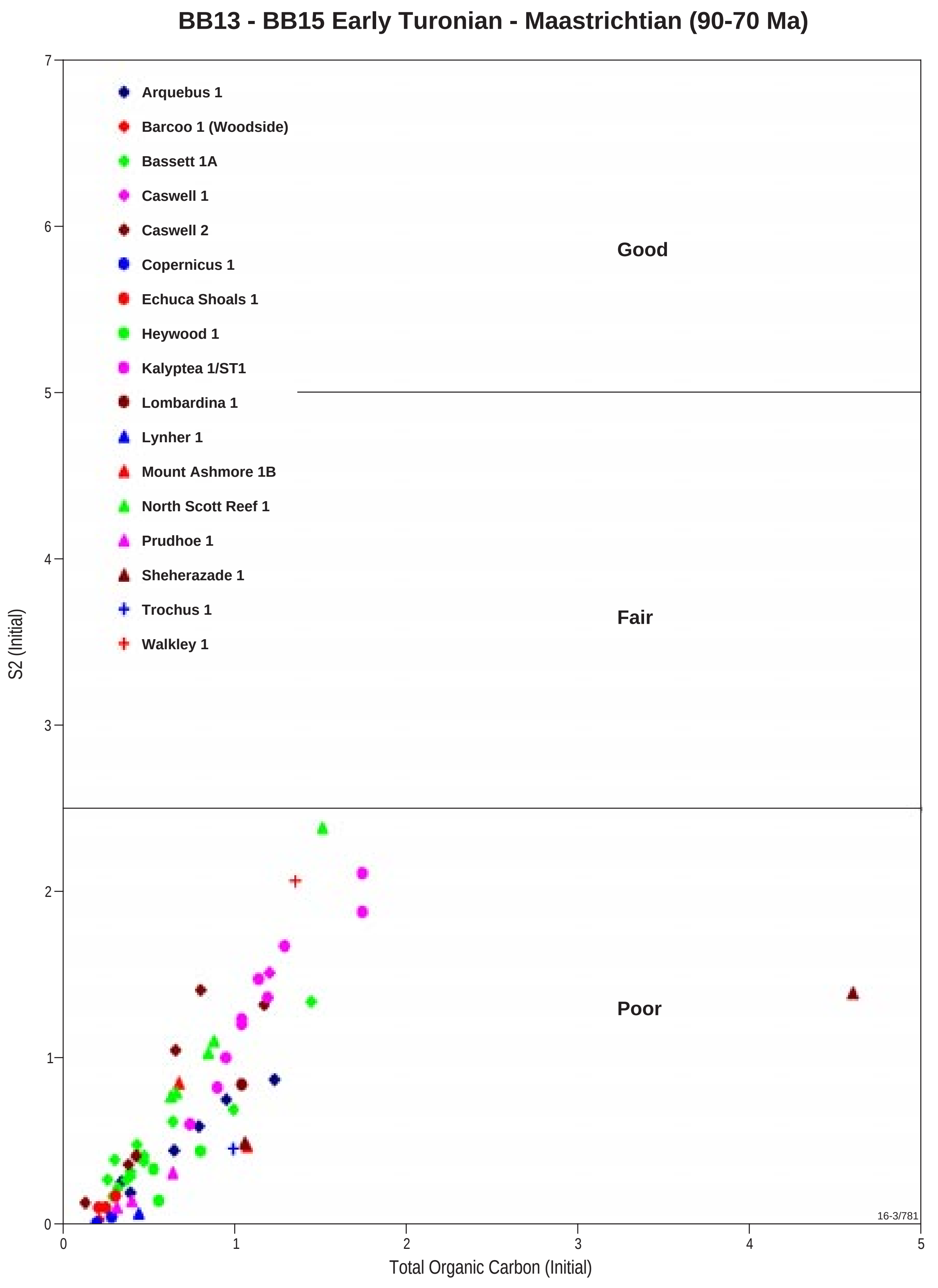


Figure 9i Initial S2-initial TOC plot for age interval BB13-15

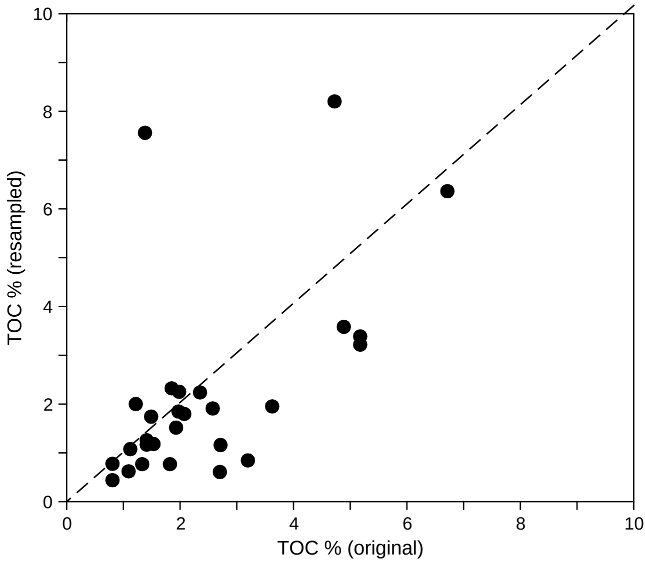


Figure 10a Plot of TOC for original (well completion report) versus re-sampled sediments (AGSO)

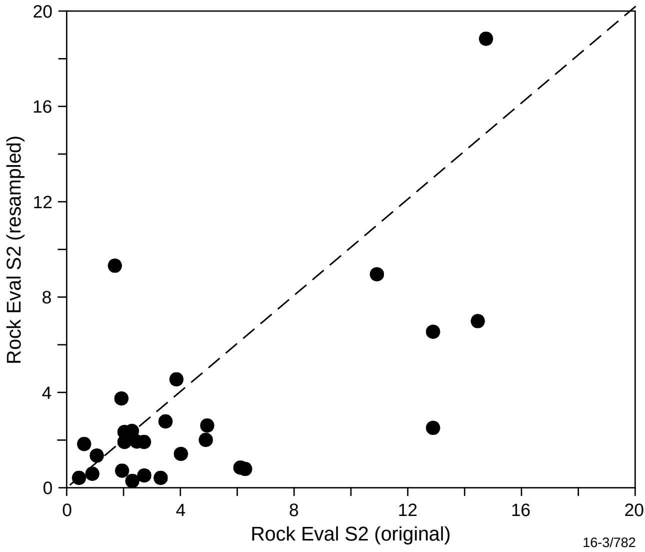


Figure 10b Plot of S2 for original (well completion report) versus re-sampled sediments (AGSO)

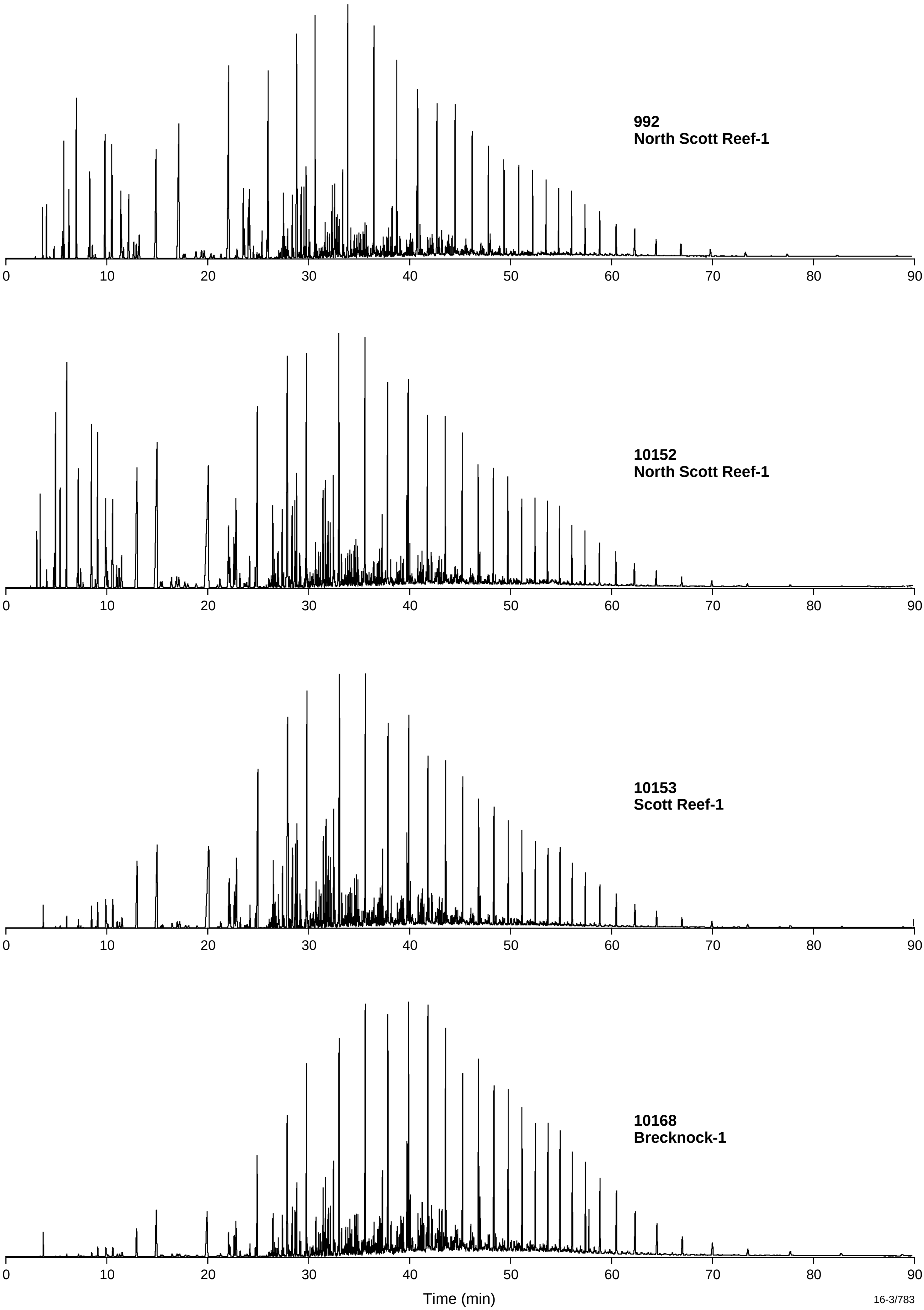


Figure 11 Whole gas chromatographic traces of Browse Basin oils

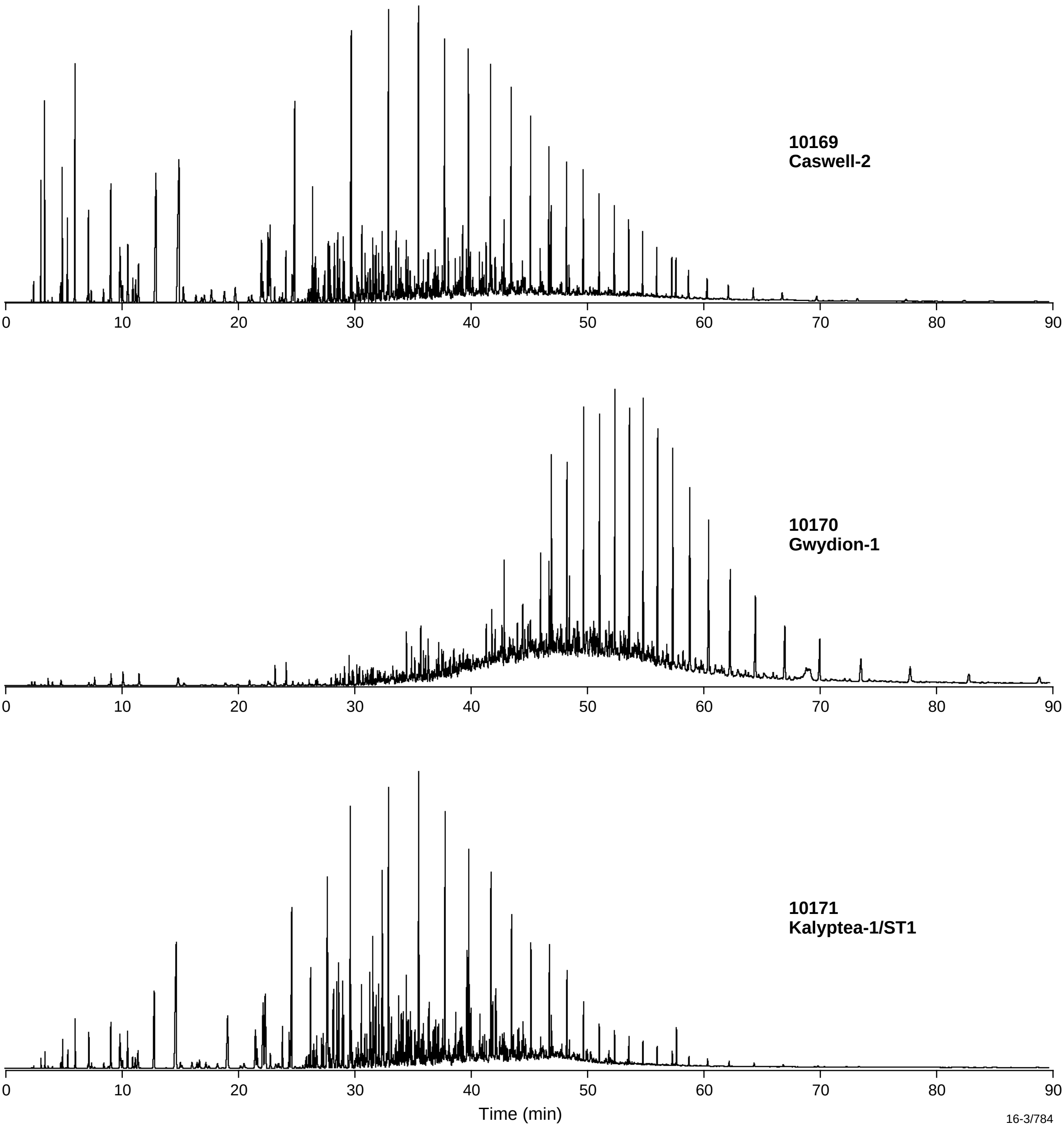


Figure 11 (cont.) Whole gas chromatographic traces of Browse Basin oils

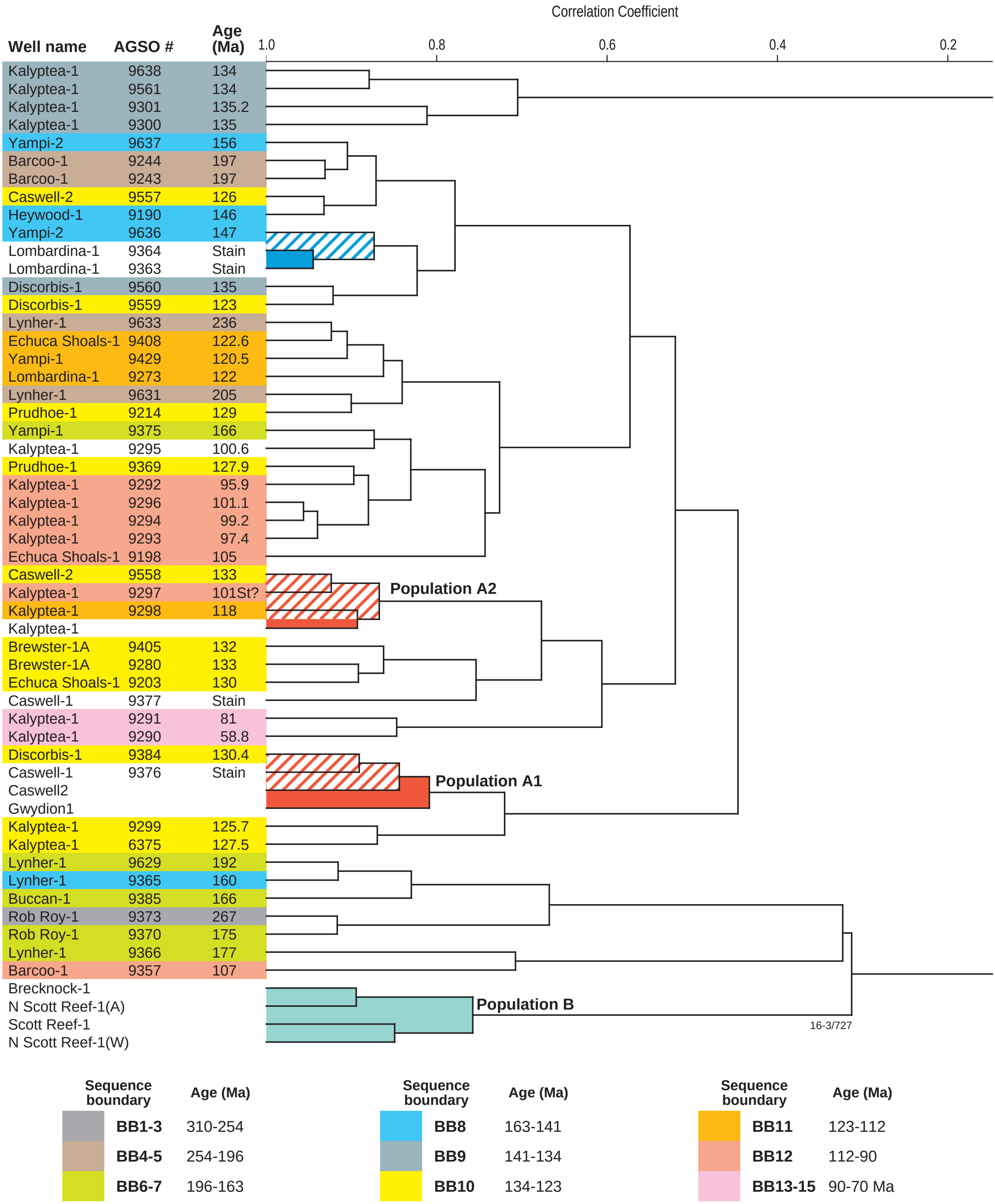


Figure 12 Dendrogram resulting from HCA on biomarker OilMod ™ parameters for the samples in Table 7

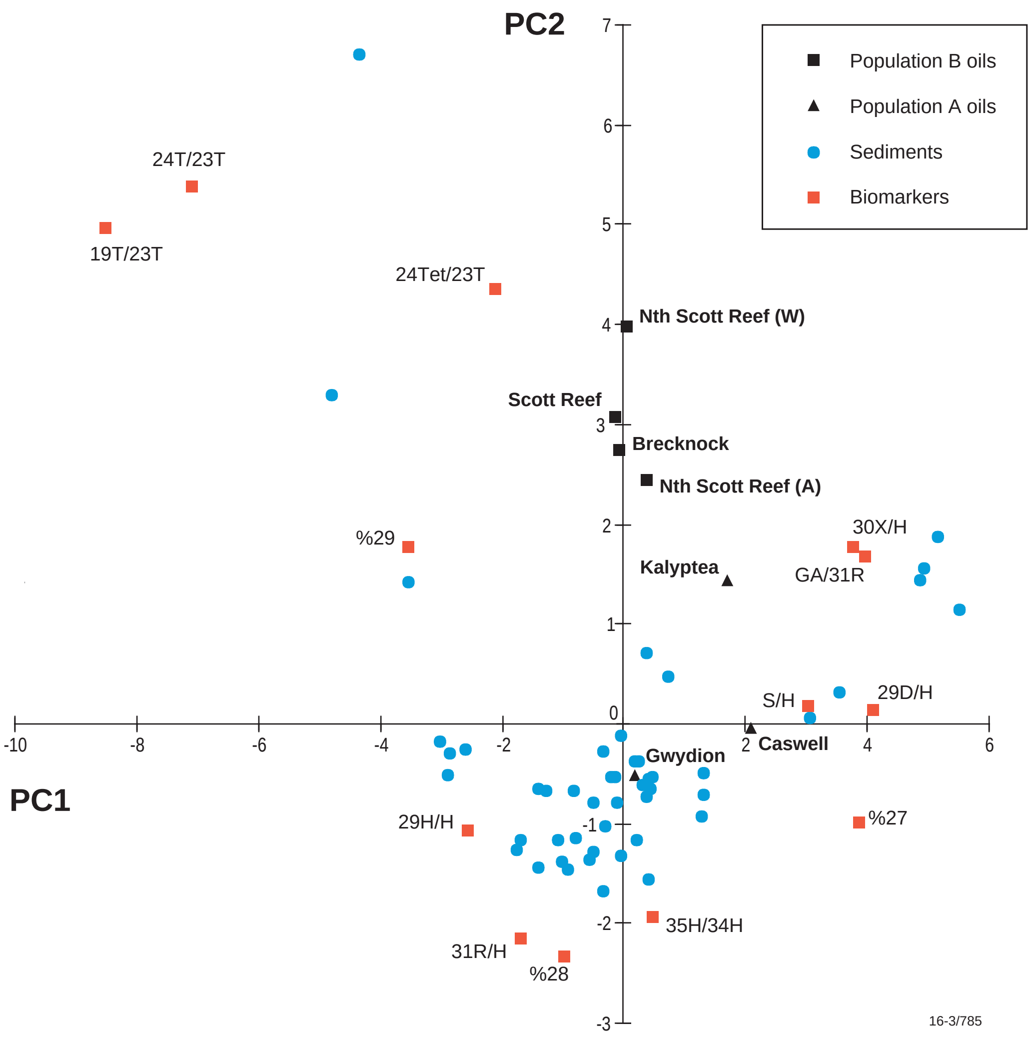


Figure 13 Crossplot of PC1 and PC2 for scores (samples) and loadings (OilMod TM parameters) from Principal Component Analysis. Biomarker OilMod TM parameters are for the samples in Table 7

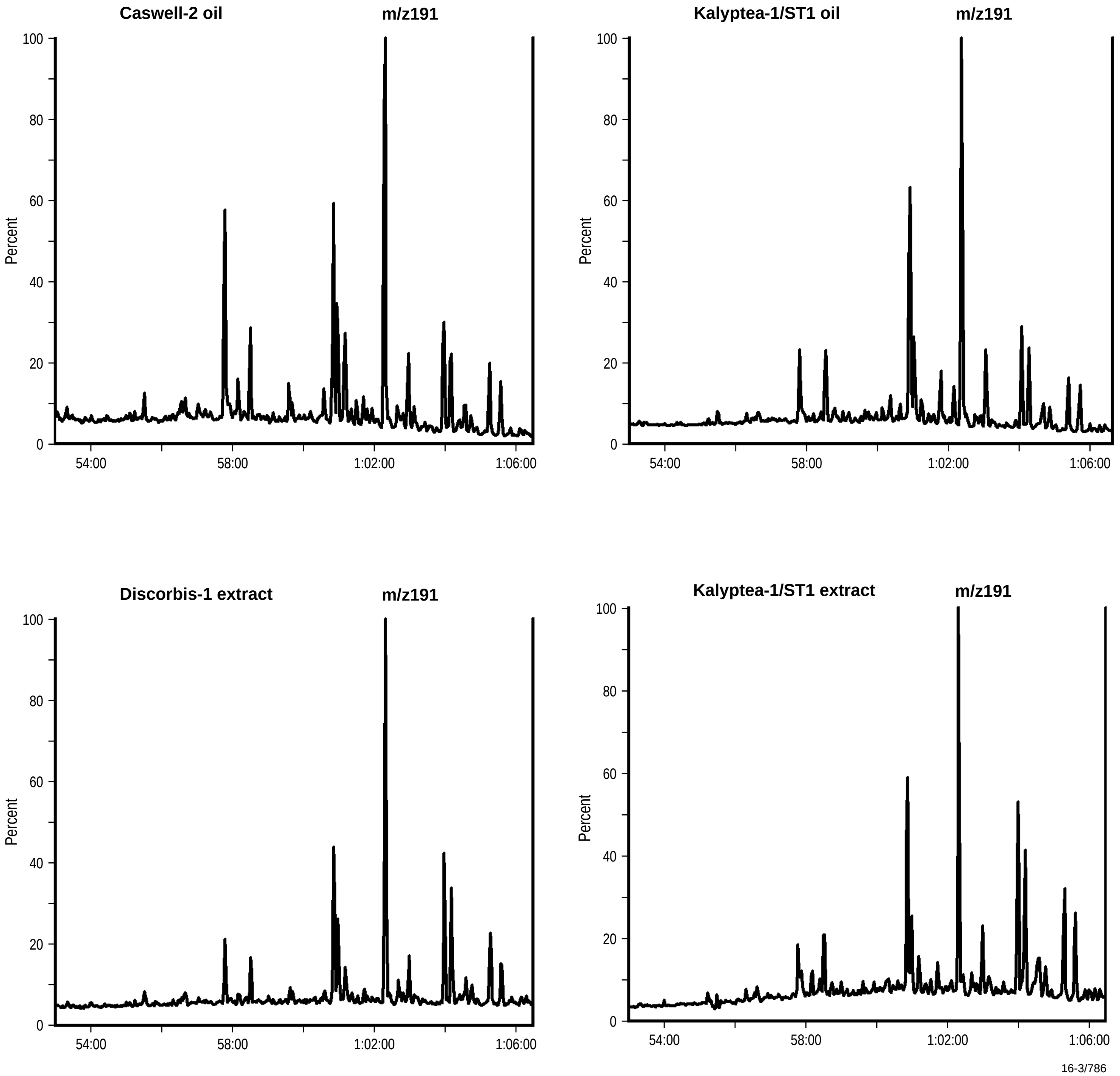


Figure 14 GCMS-SIR trace of m/z 191 Da for Population A1 oil from Caswell-2 well and associated source rock (AGSO# 9384) and Population A2 oil from Kalyptea-1/ST1 well and associated source rock (AGSO# 9298)

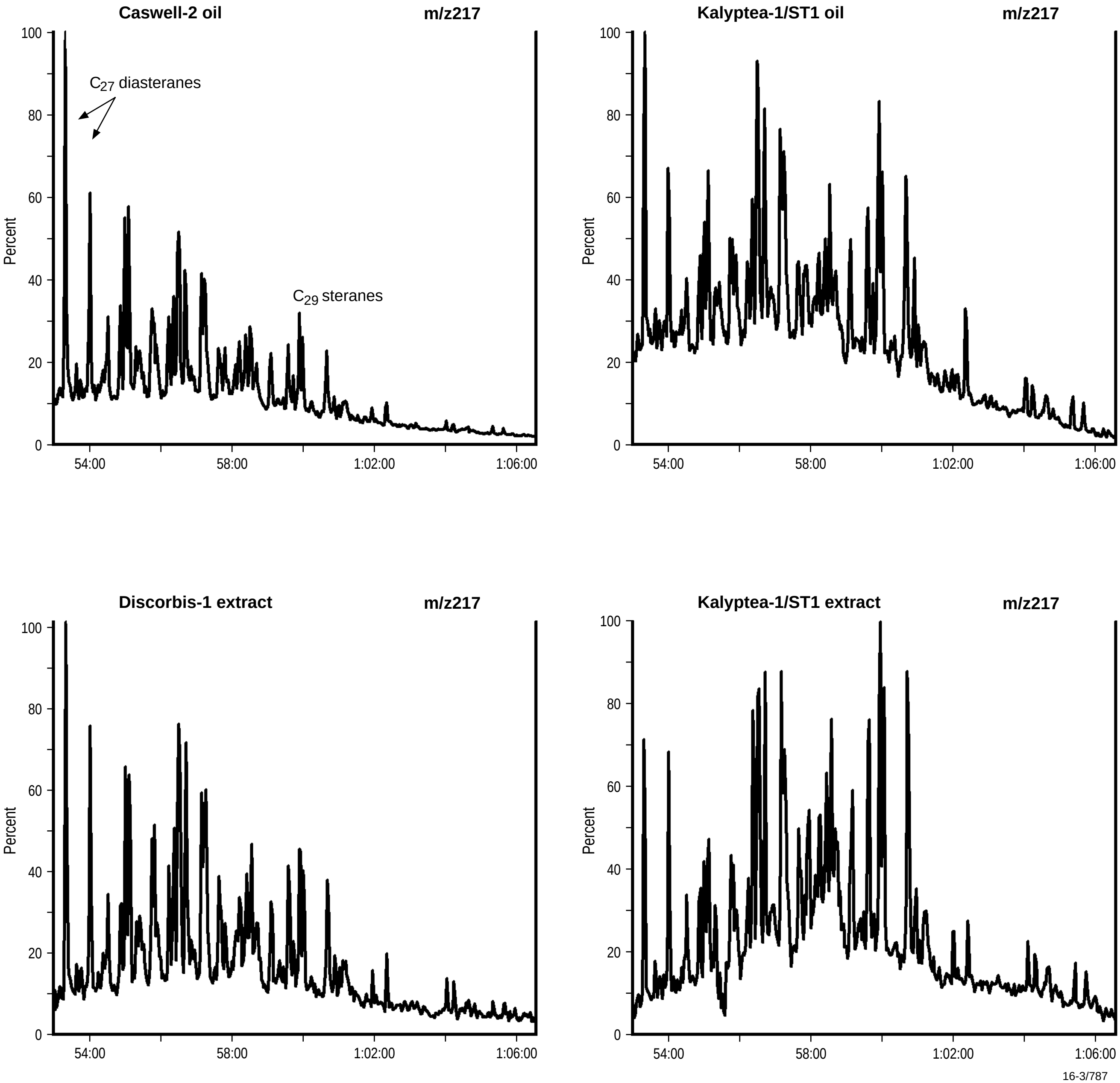


Figure 15 GCMS-SIR trace of m/z 217 Da for Population A1 oil from Caswell-2 well and associated source rock (AGSO# 9384) and Population A2 oil from Kalyptea-1/ST1 well and associated source rock (AGSO# 9298)

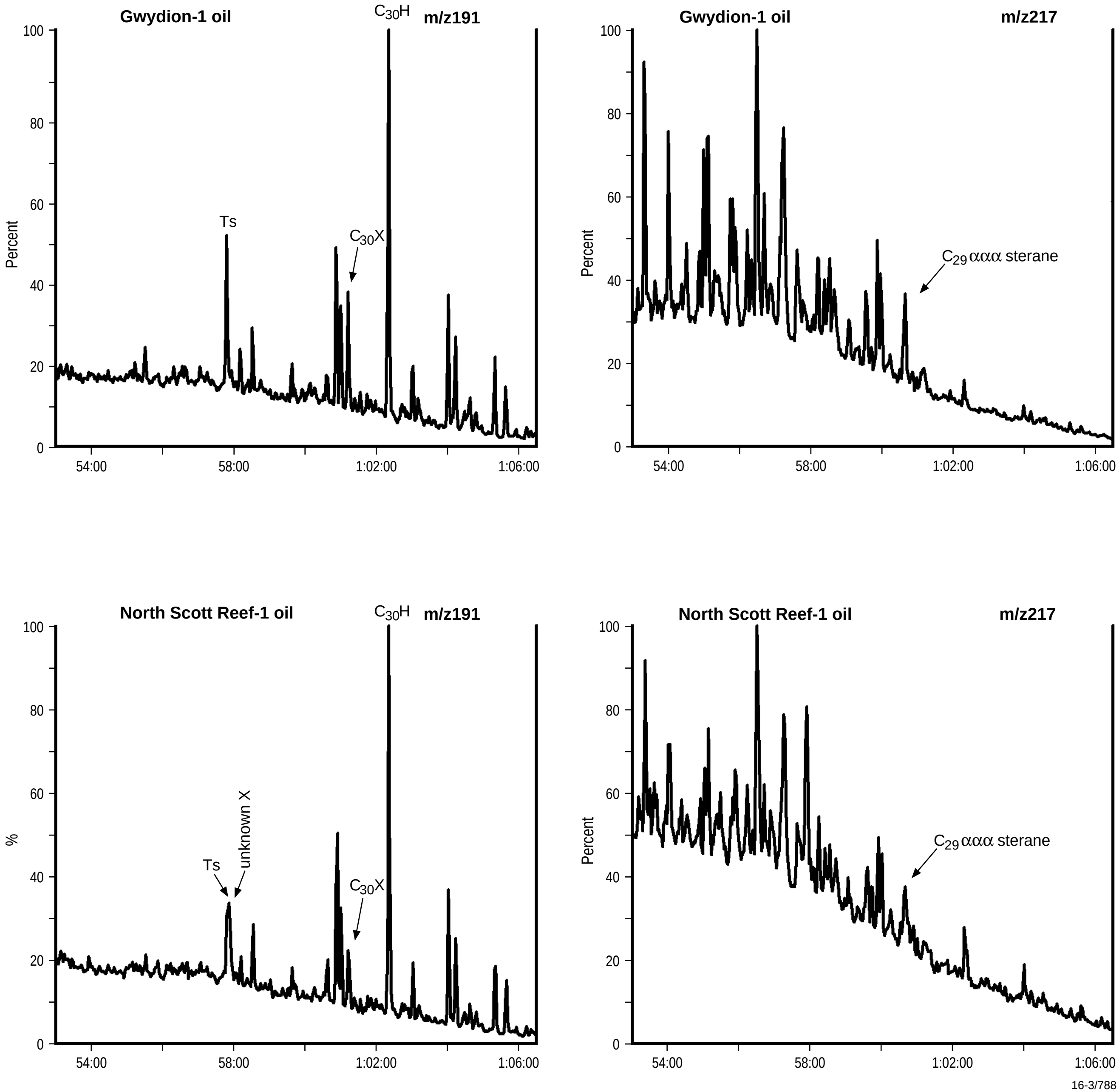


Figure 16 GCMS-SIR trace of m/z 191 and m/z 217 Da for Population A1 oil from Gwydion-1 (top) compared to Population B oil from North Scott Reef-1 (bottom)

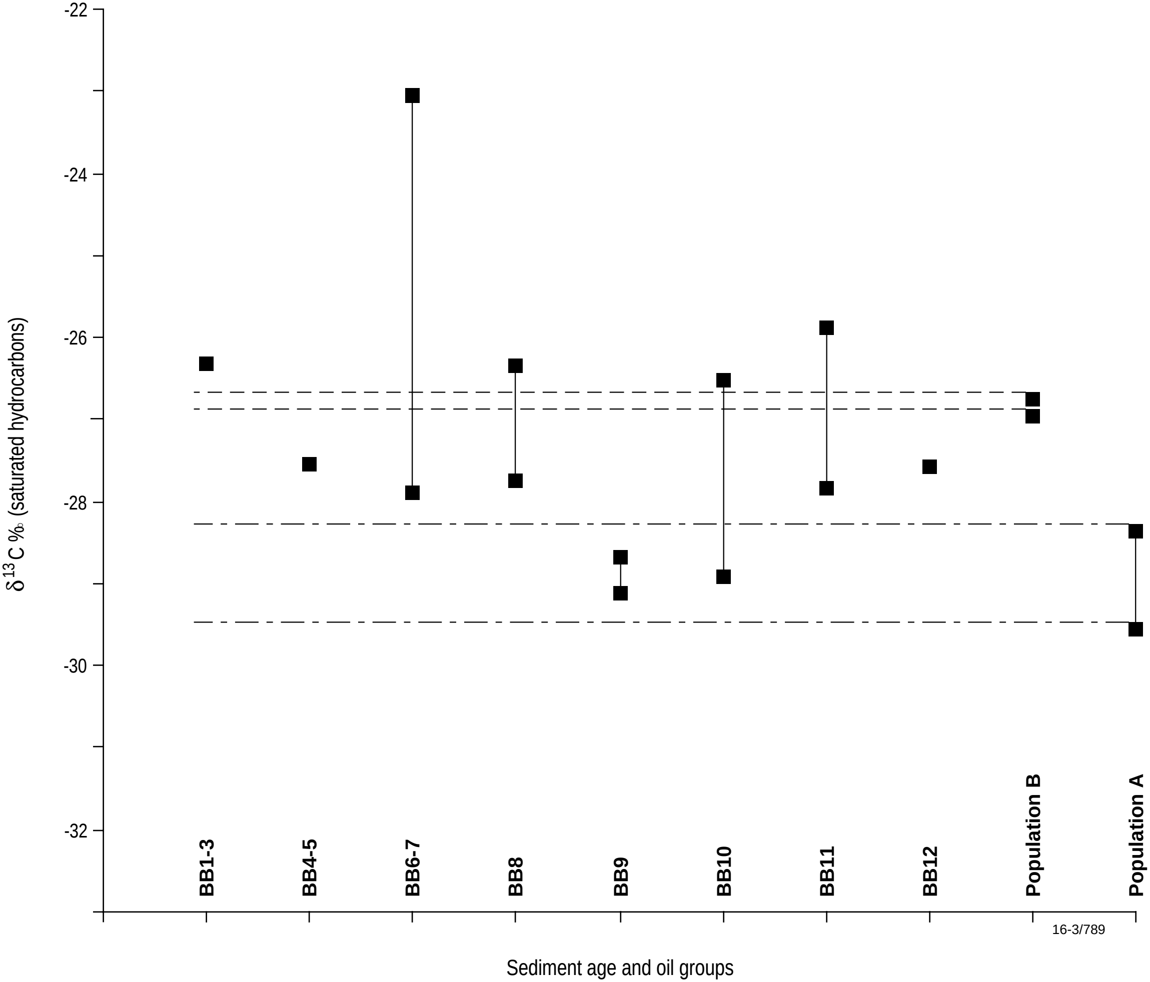


Figure 17a Summary of stable carbon isotope values for saturated hydrocarbons from BB1 to BB12 sediment extracts and Browse Basin oil Populations

Go to Figure 17b

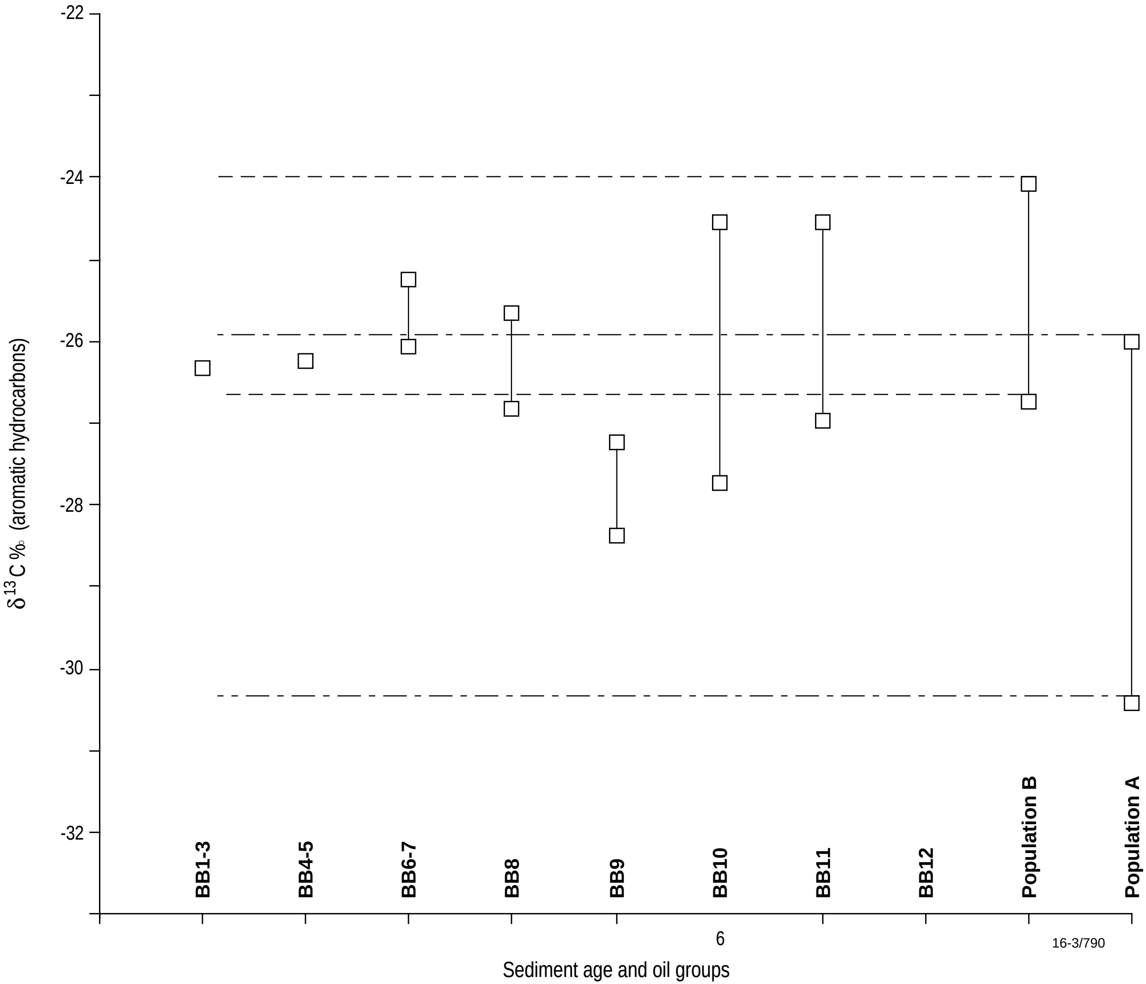
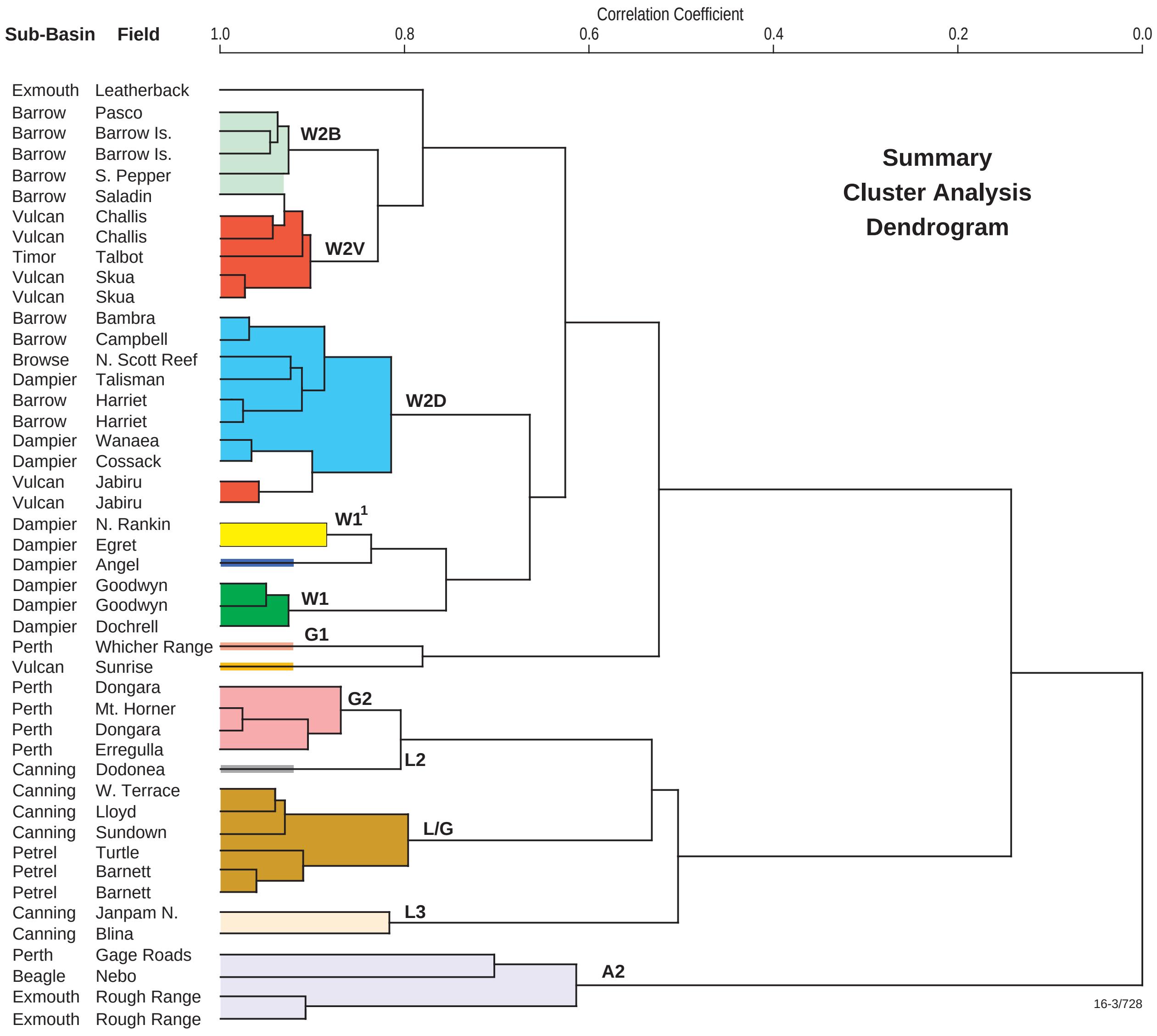


Figure 17b Summary of stable carbon isotope values for aromatic hydrocarbons from BB1 to BB12 sediment extracts and Browse Basin oil Populations



Western Australian Petroleum Systems

W2B	Westralian 2; Carnarvon/Barrow; Jurassic Shales (Earlier expulsion)
W2D	Westralian 2; Carnarvon/Dampier; Jurassic Shales (Later expulsion)
W2V	Westralian 2; Bonaparte/Vulcan; Jurassic Shales
W1	Westralian 1; Carnarvon/Dampier; Triassic Shales
G1	Gondwanan 1; Perth
G2	Gondwanan 2; Perth; Triassic Shales
L/G	Transitional: Larapintine/Gondwanan; Carboniferous Shales
L2	Larapintine 2; Ordovician Shales
L3	Larapintine 3; Devonian Restricted Shales
A2	Austral 2; Lacustrine Shales

Figure 18 Major petroleum supersystems identified for WA oils (modified after AGSO and GeoMark Research, 1996)

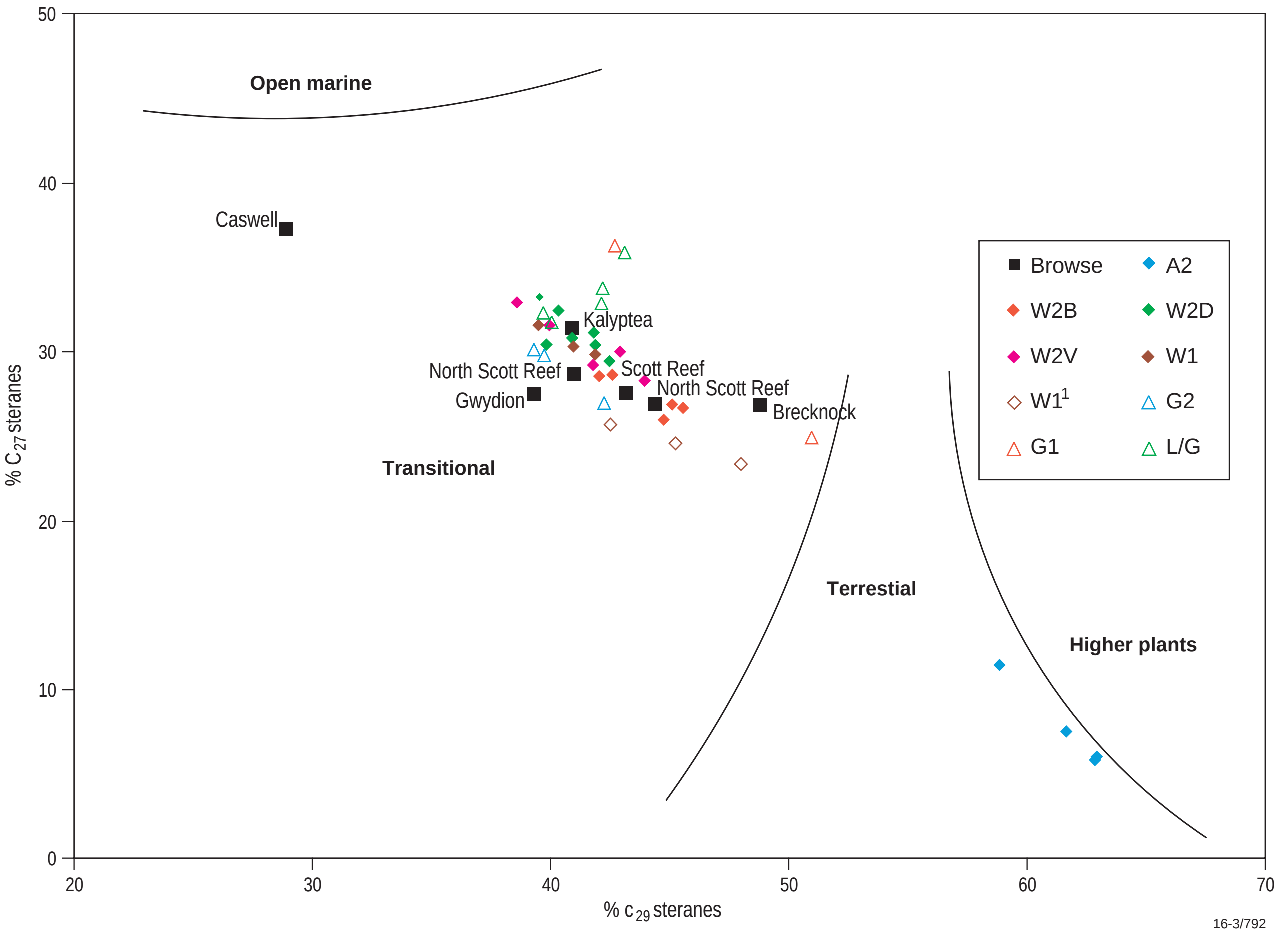


Figure 19b Plot of %C_{27} sterane versus %C_{29} sterane

Go to Figure 19c

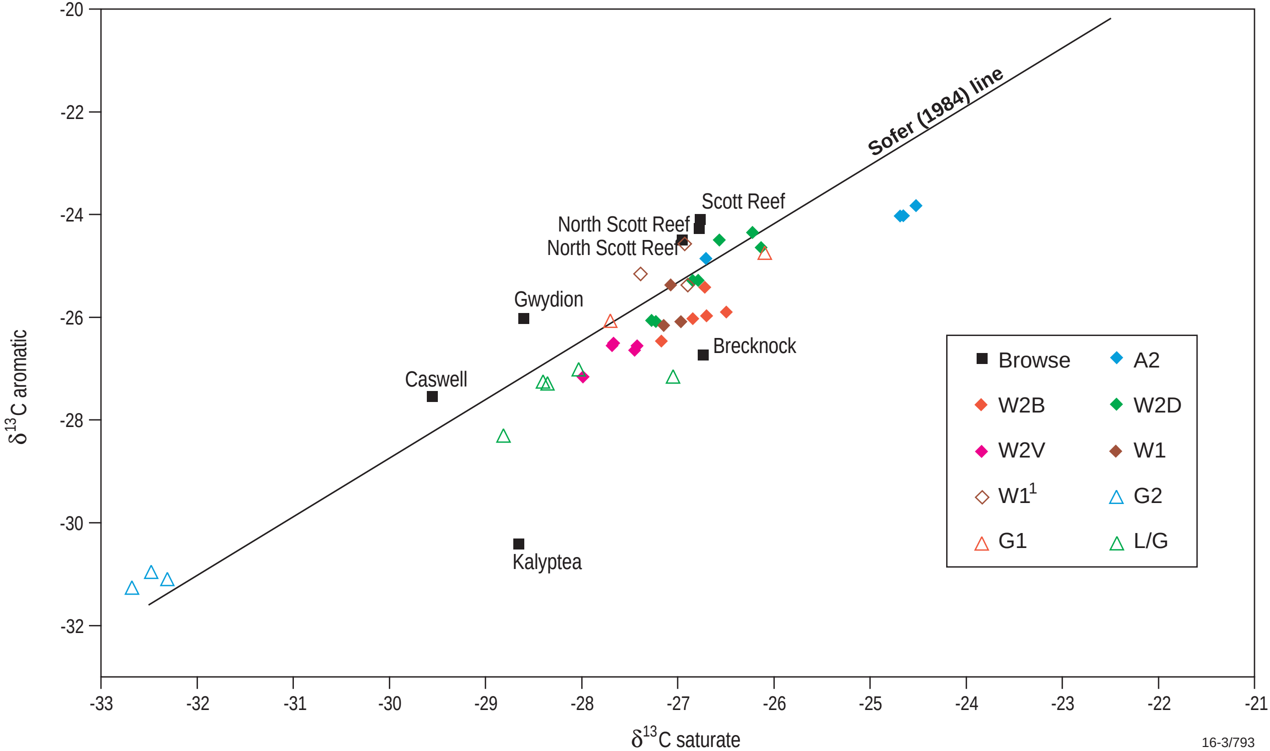


Figure 19c Plot of δ^{13}C aromatic versus δ^{13}C saturate

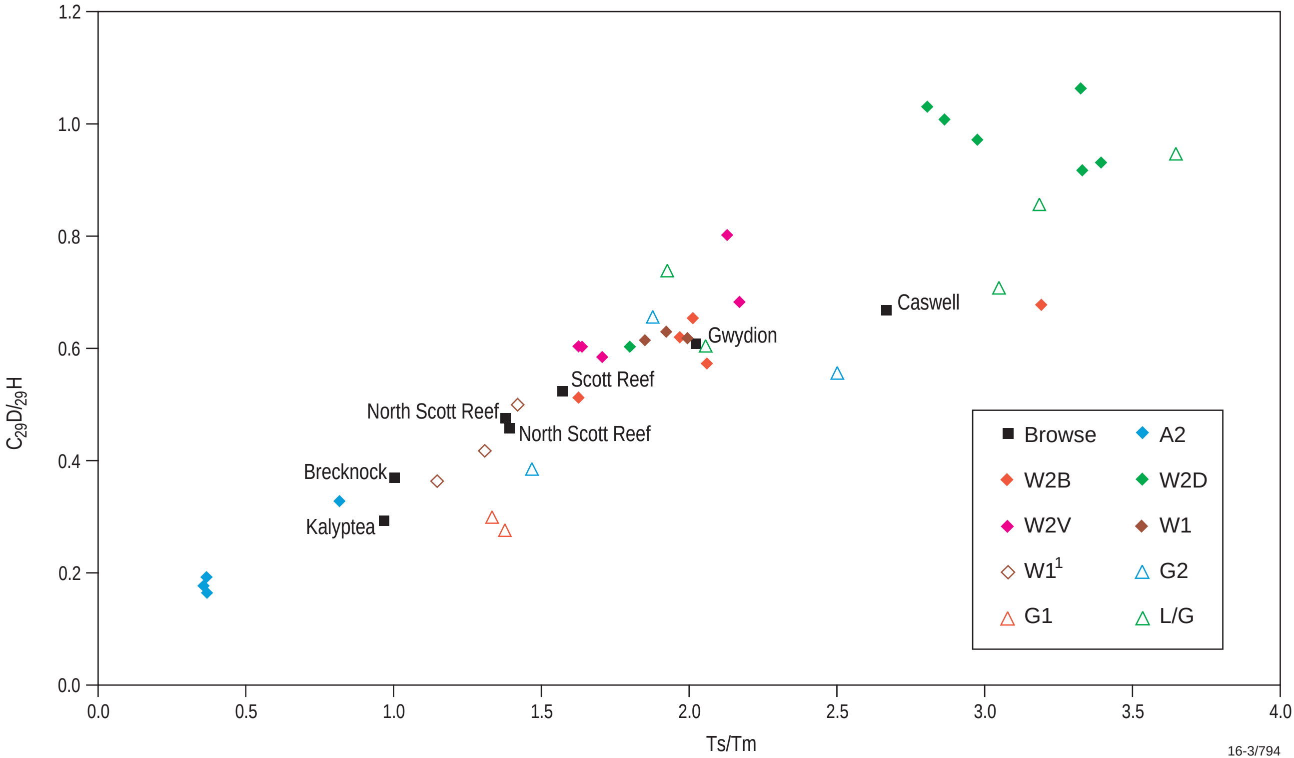


Figure 20 Plot of $C_{29}D/C_{29}H$ versus Ts/Tm

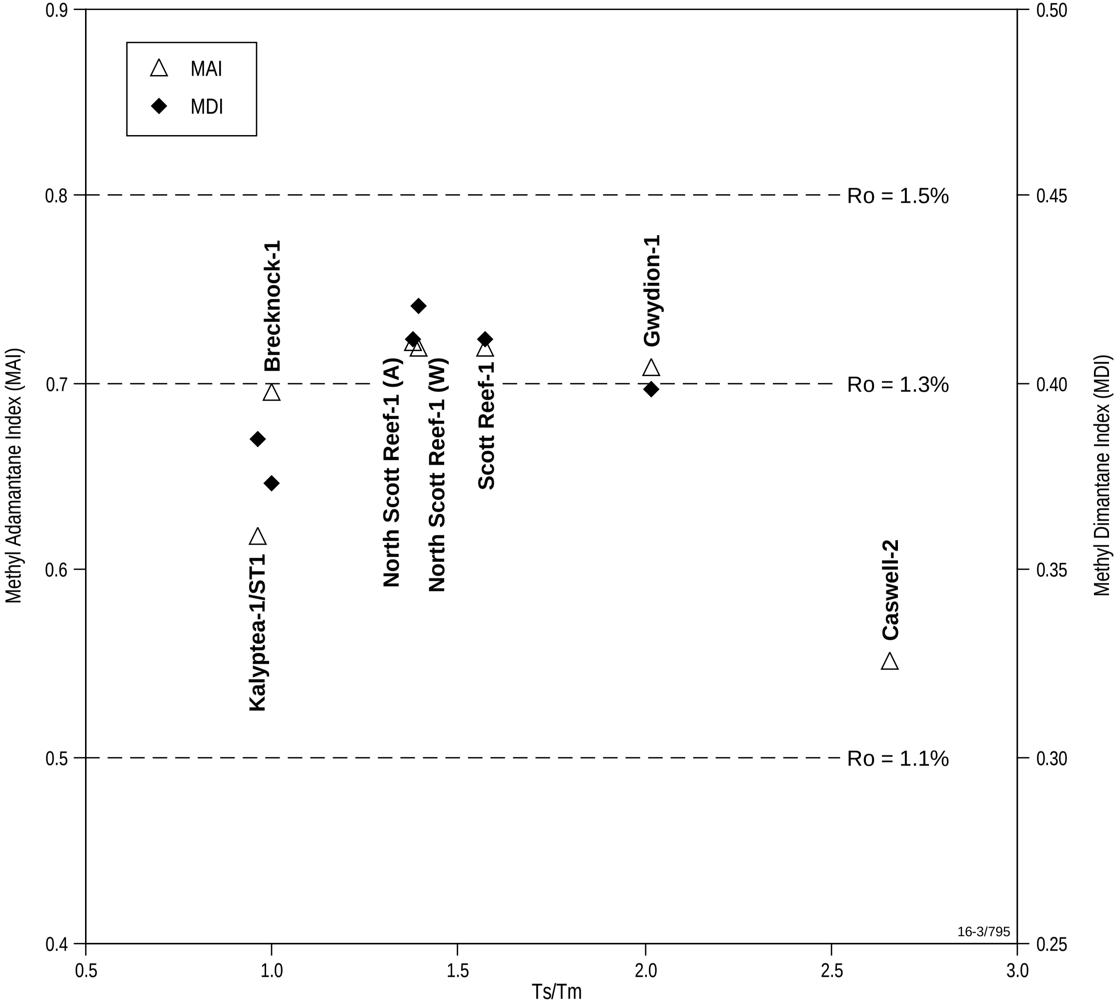


Figure 21 Plot of Ts/Tm against diamanoid maturity parameters MAI and MDI

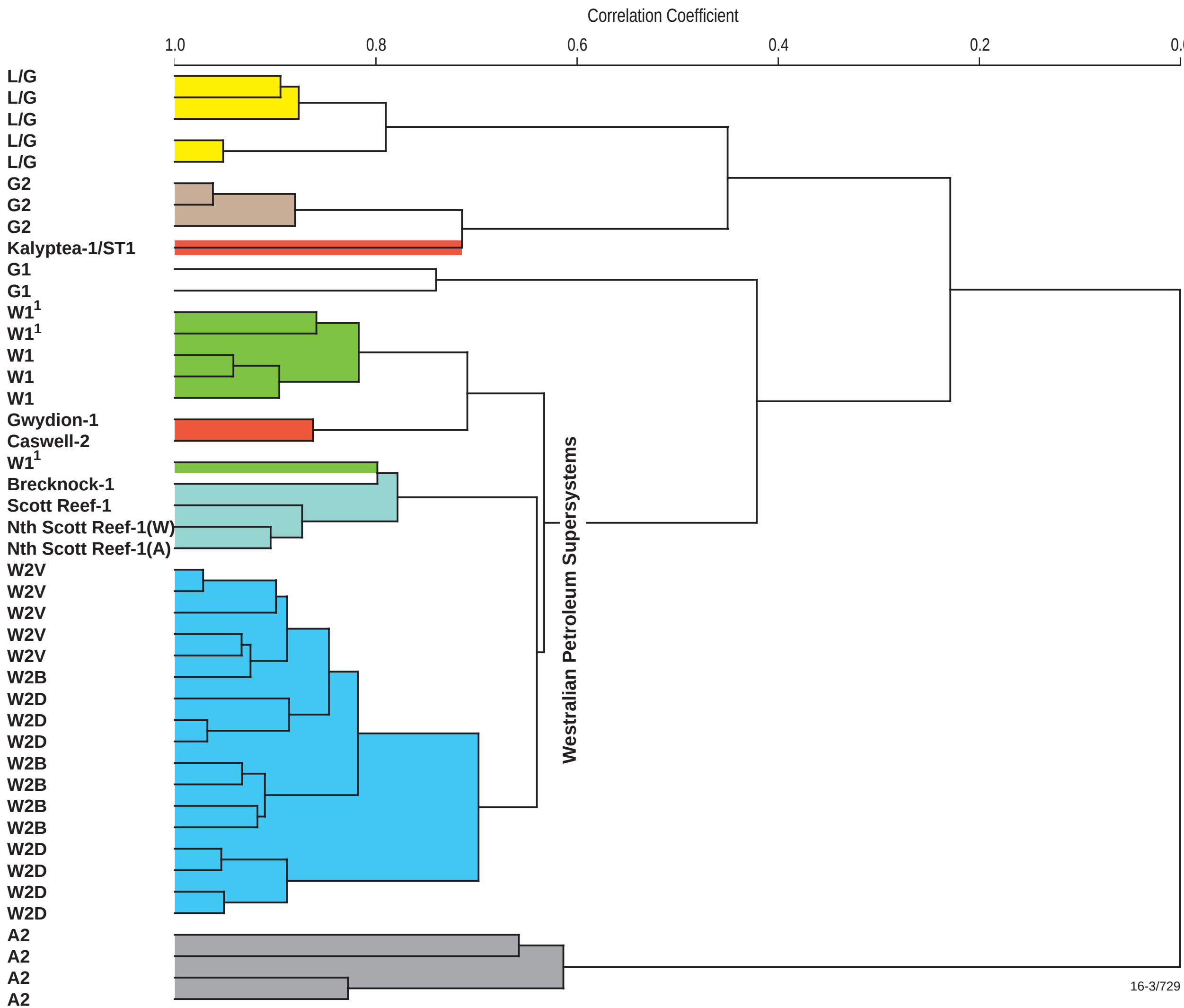


Figure 22 Cluster Analysis Dendrogram obtained using GC, GCMS-SIR and carbon isotope data for the Browse Basin and WA oils Fig.18 (excluding the L2 and L3 petroleum supersystems) showing Petroleum Supersystem relationships

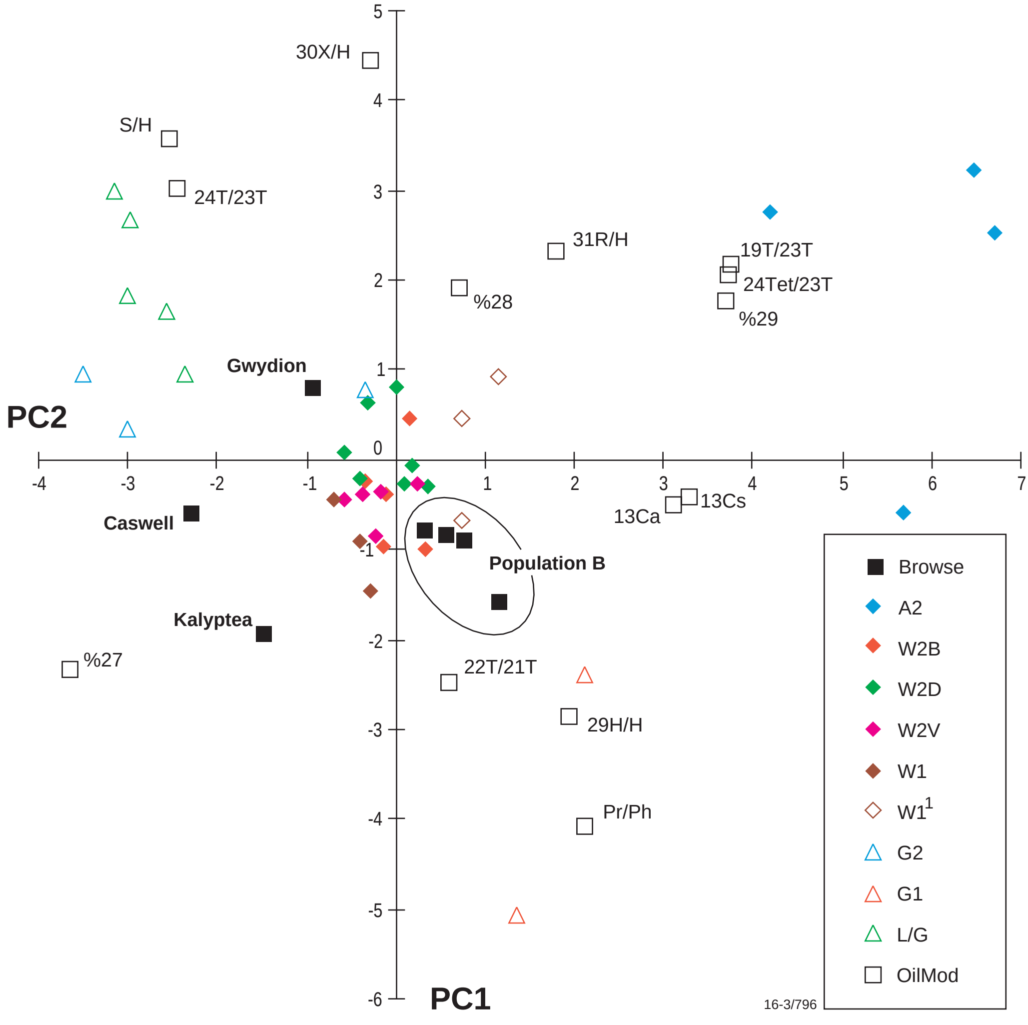


Figure 23 Crossplot of PC1 and PC2 for scores and loadings from Principal Component Analysis on oil set from Figure 22

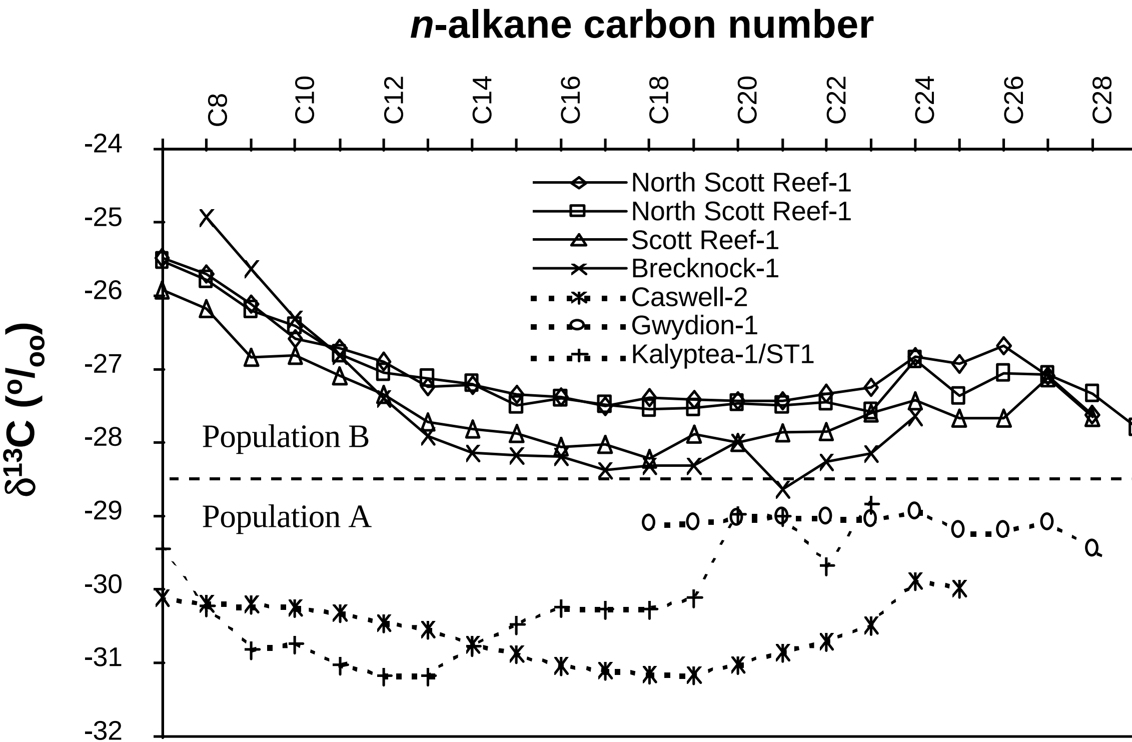
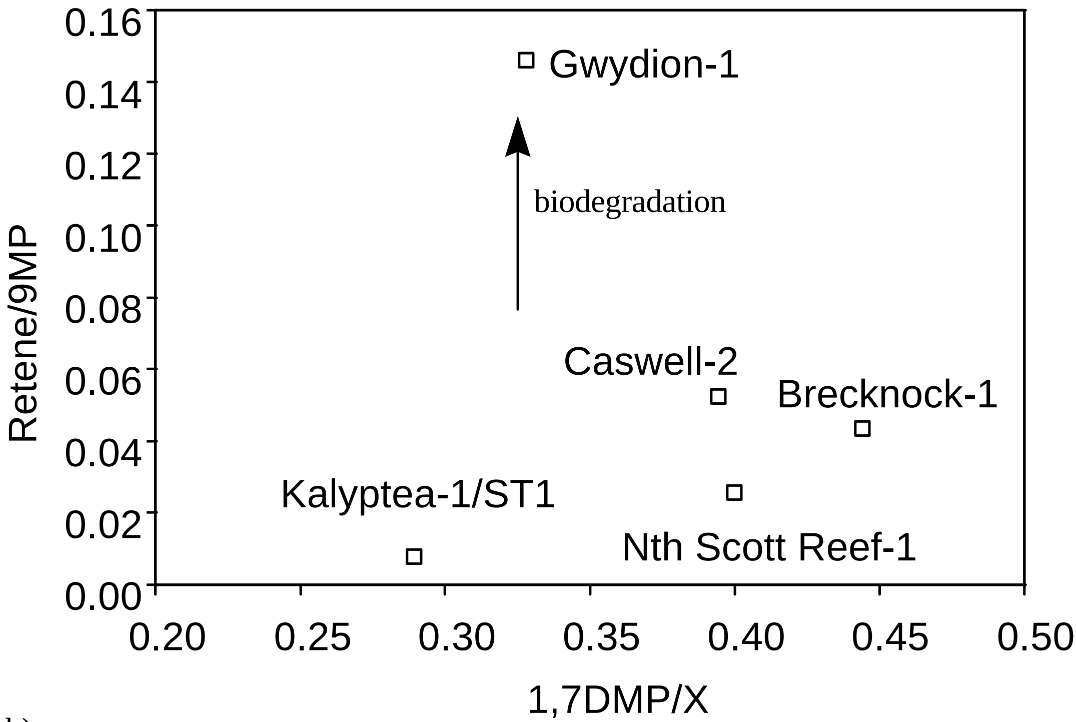


Figure 24. Carbon isotopic composition for individual *n*-alkanes

a)



b)

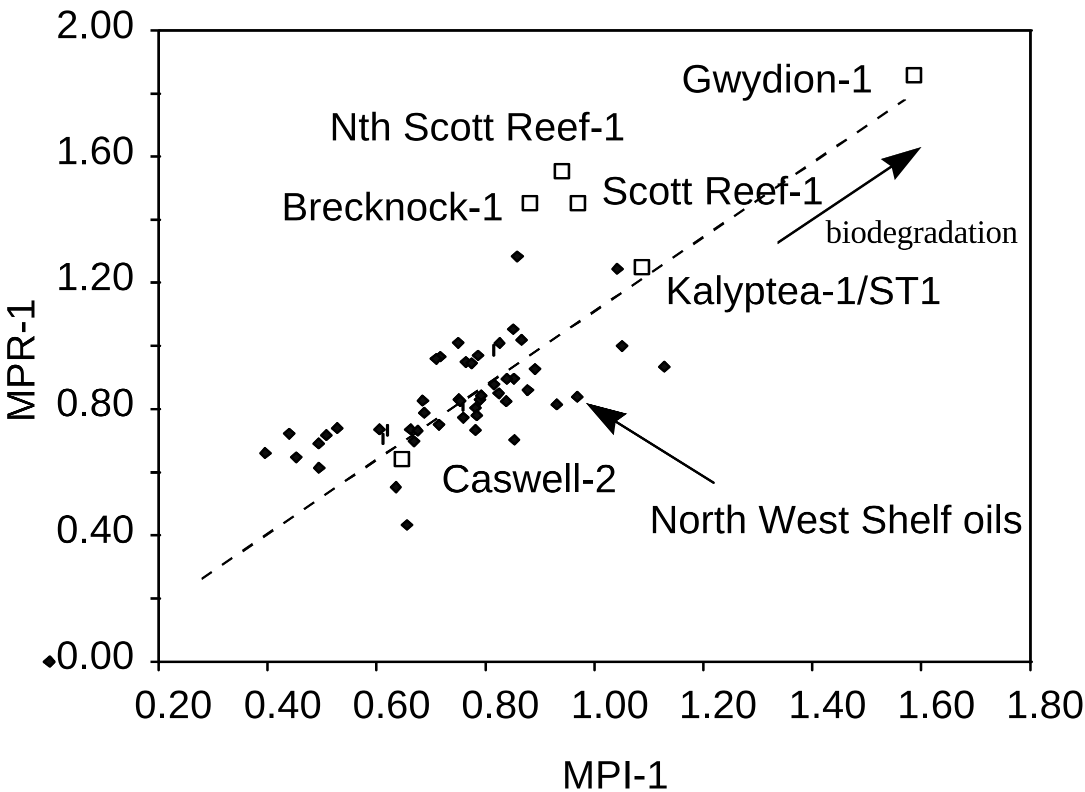


Figure 25. Plot of: a) retene/9-methylphenanthrene versus 1,7-dimethylphenanthrene/X, and b) methylphenanthrene ratio (MPR-1) versus methylphenanthrene index (MPI-1)

Table 1. Summary of seismic horizons and sequences mapped by Blevin et al (1997).

Sequence	Horizon (Base)	Age (Ma) (Base)	Biozonation (Base)	Tectono-stratigraphic Event(s)	Reference Well(s)
BB 22	Tlmio	7	mid-N17	Late Miocene compression	Lombardina 1
BB 21	Tmmio	13	N10/11	Middle Miocene regional unconformity	Buffon 1 Yampi 1
Base of Basin Phase - Inversion 2					
BB 20	Temio	20	mid-N5	Early Miocene regional unconformity (base of carbonate platforms)	Buffon 1
BB 19	Tolig	28.5	P21/22	Oligocene regional unconformity (start of northern margin collision)	Buffon 1
BB 18	Teoc	50	T10	Early Eocene regional unconformity	Brecknock 1
BB 17	Tpal	56	T6	Paleocene regional unconformity	Brecknock 1
BB 16	Tbase	65.5	base C13 & *M. druggii*	near base Tertiary regional unconformity; K/T boundary is a flooding surface at T1/C13	Brecknock 1
BB 15	Kmaas	70	KCCM 8/9 upper *I. korojonense*	base of Maastrichtian sands (SB between Kecamp & Kmaas [KCCM 14] at base of Caswell fan	Heywood 1 Asterias 1 Echuca Shoals 1
BB 14	Kecamp	79	KCCM 20/21 mid-*x. australis*	base of Campanian sands (“top Toolonga” equivalent)	Yampi 1 Kalyptea 1/ST1
BB 13	Ktur	90	KCCM 33 lower *striatoconus*	base Turonian unconformity	Caswell 2 Heywood 1
BB 12C	*Kalb2*	*102*	*KCCM 43, P. ludbrookiae*	*mid-Albian unconformity*	*Brewster 1* *Echuca Shoals 1*
BB 12B	*Kalb1*	*105*	*mid M. tetracantha*	*early Albian unconformity*	*Brewster-1* *Echuca Shoals 1*
BB 12A	Kapt	112	mid-*O. operculata*	mid-Aptian unconformity	Arquebus 1 Kalyptea 1/ST1
BB 11	Kbar	123	base *M. australis*	Barremian unconformity	Heywood 1 Kalyptea 1ST1
BB 10	Kval	134	*S.areolata/E. torynum*	Valanginian unconformity	Heywood 1 Discorbis 1 Yampi 1
BB 9	Kbase	141	upper/lower *P. iehiense*	Near base Cretaceous; base of Berriasian sands	Yampi 1
Base of Basin Phase - Thermal Subsidence 2					
BB 8	Jcal	163	base *W. digitata*	Break-up unconformity (sea-floor spreading in Argo Abyssal Plain)	Discorbis 1 Sheherazade 1
BB 7	Jearly	183	intra-*C. turbatus*	Early Jurassic intra-rift unconformity	Arquebus 1/ST1 Brecknock 1
BB 6	Jbase	196	mid-*C. torosa*	Early Jurassic rifting event	Brecknock 1 Lacepede 1

Base of Basin Phase - Extension 2					
BB 5	Trmid	220	upper/lower *S. speciosus*	Regional inversion	Yampi 1
Base of Basin Phase - Inversion 1					

Horizons listed in italics were recognised as significant sequence boundaries, but were not mapped due to problems in seismic resolution.

See Figure 1 for an explanation of "Basin Phases".

Table 2 Summary information for Browse Basin wells with geochemical data

WELL	TOP (m)	Bottom (m)	Top (Ma)*	Bottom (Ma)*	No. of Records
Arquebus 1	915.0	3256.0	57.0	197.6	63
Asterias 1	2492.0	4331.5	69.7	141.6	120
Barcoo 1 (Woodside)	2740.0	5060.0	70.0	207.1	54
Bassett 1A	1945.0	2690.0	63.6	100.1	38
Brewster 1A	2000.0	4650.0	74.5	178.4	34
Buccaneer 1	804.0	3474.0	28.0	218.1	37
Buffon 1	2355.0	4770.0	20.0	204.0	43
Caswell 1	2600.0	4095.0	65.0	125.0	43
Caswell 2	2647.0	4880.0	66.0	180.0	171
Copernicus 1	1740.0	2750.0	72.6	238.0	20
Discorbis 1	2784.0	4197.0	68.8	234.0	143
Echuca Shoals 1	1880.0	4360.0	80.7	295.0	138
Gryphaea 1	2238.0	3948.0	65.0	244.0	62
Heywood 1	1340.0	4250.0	50.0	150.3	30
Kalyptea 1	2547.0	4572.0	67.0	139.0	128
Leveque 1	274.0	877.8	70.0	142.5	24
Lombardina 1	950.0	2855.0	57.0	198.0	73
Lynher 1	427.0	2697.4	58.0	235.0	106
Mount Ashmore 1B	1650.0	2660.0	71.5	217.5	19
North Scott Reef 1	2070.0	4760.0	15.0	223.0	62
Productus 1	1655.0	2587.0	91.4	298.0	26
Prudhoe 1	735.0	3300.0	12.5	290.5	77
Rob Roy 1	582.0	2209.0	24.1	309.4	65
Scott Reef 1	732.0	4730.5	8.0	207.0	98
Sheherazade 1	1100.0	2544	68.6	190.0	29
Trochus 1	399	1561	62.0	193.0	20
Walkley 1	2512	3885.5	65.0	125.0	35
Yampi 1	600	4170	10.8	294.5	148
Yampi 2	2180	3274	116.8	167.0	62

* Interpreted age using the age-to-depth curve from the STRATDAT biostratigraphic database

Table 3. A summary of hydrocarbon shows in Browse Basin wells present by sequence. Refer to Figure 1 and Table 1 to cross-reference sequence name and age.

Sequence	Well name	Show	Comments
BB1	Perindi 1	oil show and gas indication	could be BB2
BB2	Echuca Shoals 1	gas indication	could be BB3
	Perindi 1	oil show and gas indication	could be BB1
	Prudhoe 1	gas indication	could be BB3
	Yampi 1	gas and oil indication	could be BB3
BB3	Echuca Shoals 1	gas indication	
	Prudhoe 1	gas indication	could be BB2
	Yampi 1	gas and oil indication	could be BB2
BB4	Brecknock 1	gas indication	
	Copernicus 1	oil indication	
	Gryphaea 1	gas and oil indication	
	Yampi 1	gas and oil indication	
BB5	Brecknock 1	gas indication	
	Buccaneer 1	oil indication	
	Buffon 1	oil indication	
	Lynher 1	gas indication	
	Perindi 1	oil show and gas indication	
	Scott Reef 1	proven gas and condensate zone	DST, recovered condensate and gas
	Yampi 1	gas and oil indication	
BB6	Brecknock 1	gas indication	
	Lynher 1	gas indication	
	Maret 1	gas and condensate show	RFT, recovered condensate and gas
	Scott Reef 2	proven gas zone	FIT, recovered gas
	Yampi 1	gas indication	
BB7	Arquebus 1	strong oil indication	formation damage, no oil flow
	Barcoo 1	gas and oil indication	
	Brecknock 1	proven gas and condensate zone	RFT, condensate and gas recovered
	Brewster 1	gas and oil indication	
	Buffon 1	gas and oil indication	
	Caswell 1	gas and oil indication	
	Discorbis 1	oil indication	
	Echuca Shoals 1	oil and gas indication	
	Lacepede 1	gas indication	
	Lombardina 1	oil and gas indication	
	North Scott Reef 1	proven oil and gas zone	full production runs
	Sheherazade 1	gas and oil indication	
	Trochus 1	oil indication	
	Yampi 1	gas and oil indication	
	Yampi 2	strong oil indication	40 RFT run, tight
BB8	Arquebus 1	strong oil and gas indication	formation damage, no oil flow
	Asterias 1	oil show and gas indication	oil in SWC
	Barcoo 1	gas and oil indication	
	Brewster 1	gas & oil indication	
	Buccaneer 1	oil show and gas indication	oil extracted from SWC
	Caswell 1	gas and oil indication	
	Discorbis 1	oil indication	
	Heywood 1	gas and oil indication	
	Lombardina 1	oil indication	
	Prudhoe 1	gas and oil indication	
	Sheherazade 1	gas and oil indication	
	Trochus 1	oil indication	
	Yampi 1	oil show and gas indication	
	Yampi 2	strong oil indication	40 RFT run, tight

Go to Table 3 continiued

BB9	Asterias 1	gas and oil indication	
	Barcoo 1	gas indication	
	Brecknock 1	gas indication	
	Brewster 1	gas and oil indication	
	Buccaneer 1	oil show	oil extracted from SWC
	Caswell 1	gas and oil indication	
	Discorbis 1	oil indication	
	Echuca Shoals 1	oil and gas indication	
	Heywood 1	gas and oil indication	.
	Kalyptea 1 1ST	gas show & oil indication	RFT gas/condensate recovered
	Lombardina 1	oil indication	
	Prudhoe 1	gas and oil indication	
	Tahbilk 1	proven gas and condensate zone	RFT gas/condensate recovered
	Yampi 1	gas and oil indication	
BB10	Asterias 1	gas and oil indication	
	Barcoo 1	gas indication	
	Brewster 1	gas and oil indication	
	Caswell 1	gas and oil indication	
	Copernicus 1	oil indication	
	Discorbis 1	oil indication	
	Echuca Shoals 1	oil and gas indication	
	Gryphaea 1	gas and oil indication	
	Heywood 1	gas and oil indication	
	Kalyptea 1 1ST	oil indication	
	Lombardina 1	gas and oil indication	
	Lynher 1	gas indication	
	Prudhoe 1	gas indication	
	Yampi 1	gas indication	
BB11	Asterias 1	gas indication	
	Barcoo 1	gas indication	
	Brewster 1	gas and oil indication	
	Buffon 1	gas and oil indication	
	Caswell 1	gas and strong oil indication	
	Echuca Shoals 1	oil and gas indication	
	Gwydion 1	proven oil and gas zone	RFT, flow of gas/oil
	Heywood 1	gas indication	
	Kalyptea 1 1ST	oil indication	
	Lombardina 1	gas and oil indication	
	Prudhoe 1	gas and oil indication	
	Walkley 1	oil indication	
	Yampi 1	gas indication	
BB12	Asterias 1	gas and oil indication	
	Bassett 1	gas indication	
	Brecknock 1	gas indication	
	Buffon 1	gas and oil indication	
	Caswell 1	oil show and gas indication	FIT, oil recovered
	Discorbis 1	oil indication	
	Echuca Shoals 1	oil and gas indication	
	Gryphaea 1	gas and oil indication	
	Gwydion 1	gas indication	
	Heywood 1	gas indication	
	Productus 1	oil indication	
	Yampi 1	gas indication	
BB12A	Barcoo 1	gas and oil indication	
	Brewster 1	gas and oil indication	
	Lombardina 1	gas indication	
	Walkley 1	oil indication	
BB12B	Lombardina 1	gas indication	
	Prudhoe 1	gas indication	
BB12C	Brewster 1	gas and oil indication	
	Lombardina 1	gas indication	

Go to Table 3 continiued

	Prudhoe 1	gas indication	
BB13	Asterias 1	gas indication	
	Bassett 1	gas indication	
	Brecknock 1	gas indication	
	Discorbis 1	gas and oil indication	
	Lombardina 1	gas indication	
	Prudhoe 1	gas indication	
BB14	Bassett 1	gas indication	
	Discorbis 1	gas and oil indication	
	Prudhoe 1	gas indication	
	Tahbilk 1	proven gas and condensate zone	RFT gas/condensate recovered
BB15	Brecknock 1	gas indication	
	Caswell 1	oil show and gas indication	RFT oil/gas recovered
	Delta 1	gas indication	
	Discorbis 1	oil indication	
	Gryphaea 1	gas and oil indication	
	Lombardina 1	gas indication	
	Prudhoe 1	gas indication	
BB16	Delta 1	gas indication	
	Prudhoe 1	gas indication	
BB17	Buffon 1	gas indication	
	Prudhoe 1	gas indication	
BB18	Buffon 1	gas indication	
	Delta 1	gas indication	
BB19	Buffon 1	gas indication	
	Prudhoe 1	gas indication	
BB20	Buffon 1	gas and oil indication	
	Prudhoe 1	gas indication	
BB21	Prudhoe 1	gas indication	
BB22	Prudhoe 1	gas indication	

Table 4 Interpreted onset of oil generation for Browse Basin wells

WELL	**Depth (m)**	**Age (Ma)***	**Weighting****		
			Ro	Tmax	PI
Arquebus 1	2600	175		xx	xxx
Asterias 1	3500	118	xx	x	xx
Barcoo 1 (Woodside)	4000	185	xxx	x	xxx
Bassett 1A	immature to 2700		x	x	xxx
Brewster 1A	2500	99	xxx	x	xx
Buccaneer 1	2700	122	xxx	xx	xx
Buffon 1	3000	50	xx	x	xx
Caswell 1	2800	96	xxx	xx	x
Caswell 2	2600	66		xx	xxx
Copernicus 1	2400	104		x	xx
Discorbis 1	3500	86	xxx	xx	x
Echuca Shoals 1	2700	115		x	xxx
Gryphaea 1	3000	73	xx	x	x
Heywood 1	3000	104	x	xx	xxx
Kalyptea 1	3400	79	xx	xx	x
Leveque 1	immature to 1000		xx	xx	xx
Lombardina 1	1500	102	xx	xx	xx
Lynher 1	2200	200	xx	xx	x
Mount Ashmore 1B	2300	210		x	xx
North Scott Reef 1	3500	56		xx	xx
Productus 1	1800	100	xxx	x	xxx
Prudhoe 1	2000	101	xxx	xx	xxx
Rob Roy 1	1800	302	x	x	xxx
Scott Reef 1	3500	61	xx	xx	xx
Sheherazade 1	2100	125		x	x
Trochus 1	immature to 1500m		xx	xx	xx
Walkley 1	3300	95	xx	xx	xxx
Yampi 1	2600	139	xx	x	x
Yampi 2	2700	142		xx	xx

* Interpreted age using the age-to-depth curve from the STRATDAT biostratigraphic database
** x=importance placed on data x=poor, xx moderate, xxx high

Table 5. Guidelines for interpreting (a) source rock generative potential and (b) type of petroleum generated from immature sediments (Ro<0.6%), and, c) degree of thermal maturation. (Modified after Peters, 1986; Espitalié J. and Bordenave M.L.,1993).

a)

Quantity	TOC (%)	Rock Eval S2 (mg HC/g rock)	EOM Wt %	HC (ppm)
Poor	<0.5	<2.5	<0.05	<200
Fair	0.5-1	2.5-5	0.05-0.1	200-500
Good	1-2	5-10	0.1-0.2	500-800
Very Good	>2	>10	>0.2	>1200

TOC = total organic carbon; S2 = yield of hydrocarbons(HC) released during Rock Eval pyrolysis; EOM = extractable organic matter; HC = free saturated and aromatic hydrocarbon content of rock

b)

Type	Hydrogen Index (mg HC/g TOC)	Rock Eval S2/S3	Extract Yield (mg HC/gTOC)*	Atomic H/C
Gas	50-200	1-5	<20	0.6-0.9
Gas and Oil	200-300	5-10	20-50	0.9-1.1
Oil	>300	>10	50-200	>1.1
			* mature samples	

c)

Maturation Level	Production Index (PI)	Tmax for Type I	Tmax for Type II	Tmax for Type III
immature	<0.15	<445	<435	<440
mature	0.15-0.4	445-455	435-460	440-470
overmature	<0.15	>455	>460	>470

Table 6 Interpreted initial HI values for specific age intervals within Browse Basin wells.

Well	Hydrogen Index (initial)								
	BB1-BB3	BB4-BB5	BB6-BB7	BB8	BB9	BB10	BB11	BB12	BB13-BB15
Mineral matrix 'TOC offset'	0	0.1	0.1	0.2	0.15	0.2	0.45	0.2	0.2
Arquebus 1		210	200	350	220	240	220	150	220
Asterias 1				350	300	240	300	150	
Barcoo 1 (Woodside)		210	240			140		180	130
Bassett 1A								230	130
Brewster 1A			140	300		160		310	
Buccaneer 1		180	210	250	330	170	300	140	
Buffon 1		130	140					210	
Caswell 1						210	250	300	130
Caswell 2					160	130	200	260	110
Copernicus 1				350	280	240		290	60
Discorbis 1				250	450	240		280	
Echuca Shoals 1	100	170		300	200	190	280	200	100
Gryphaea 1		160				250		280	
Heywood 1				300	210	210	280	250	65
Kalyptea 1					260	240	300	280	140
Leveque 1				xxx	130	50			
Lombardina 1		180	150	300	300	240	250	250	80
Lynher 1		190		100	70	50	70	50	40
Mount Ashmore 1B		150		100				50	150
North Scott Reef 1		150				200			150
Productus 1	120				150	240			
Prudhoe 1	120				220			260	60
Rob Roy 1	90		xxx			50	100	100	
Scott Reef 1		180	150	120		180	150	230	
Sheherazade 1			210	300	310	240		330	60
Trochus 1			150			70	100	260	60
Walkley 1						240	320	300	60
Yampi 1	130		230	200	210	90	130	120	
Yampi 2				450	350	260			

Table 7 Samples used in oil-oil and oil-source correlation studies.

AGSO No	Well	TOP m	BASE m	Age (Ma)	extract	GC	Biomarkers*	^{13}C isotope sats&arom	^{13}C isotope kerogen	Maturity
9190	Heywood 1	4075.0	4085.0	145.3	x	x	x	x		mature
9198	Echuca Shoals 1	2410.0	2415.0	105	x	x	x	x	x	immature
9203	Echuca Shoals 1	3125.0	3130.0	130	x	x	x	x		mature
9214	Prudhoe 1	2555.0	2560.0	129	x	x	x			immature
9243	Barcoo 1	4330.0	4335.0	191.2	x	x	x	x		mature
9244	Barcoo 1	4485.0	4490.0	196.1	x	x	x	x		mature
9273	Lombardina 1	2060.0	2065.0	122	x	x	x	x	x	immature
9280	Brewster 1A	3825.0	3830.0	133	x	x	x			mature
9290	Kalyptea 1	2649	2655	58.8	x	x	x			immature
9291	Kalyptea 1	3207	3210	81.0	x	x	x			immature
9292	Kalyptea 1	3579	3585	95.9	x	x	x			immature
9293	Kalyptea 1	3618	3621	97.4	x	x	x			immature
9294	Kalyptea 1	3663	3666	99.2	x	x	x			immature
9295	Kalyptea 1	3798	3801	100.6	x	x	x			immature
9296	Kalyptea 1	3888	3891	101.1	x	x	x			immature
9297	Kalyptea 1	3954	3960	101.4	x	x	x			oil stain?
9298	Kalyptea 1	4092	4095	118.0	x	x	x			mature
9299	Kalyptea 1	4160.15	4160.15	125.7	x	x	x			mature
9300	Kalyptea 1	4239	4249	135.0	x	x	x			mature
9301	Kalyptea 1	4329	4335	135.2	x	x	x			mature
9357	Barcoo 1	3370.0	3380.0	107	x	x	x	x	x	mature
9363	Lombardina 1	2425.0	2425.0	143	x	x	x			oil stain
9364	Lombardina 1	2435.0	2435.0	151	x	x	x			oil stain
9365	Lynher 1	1460.0	1463.1	160	x	x	x	x	x	immature
9366	Lynher 1	1539.3	1542.3	177	x	x	x	x	x	immature
9369	Prudhoe 1	2520.0	2520.0	127.9	x	x	x			immature
9370	Rob Roy 1	1539.3	1542.3	175	x	x	x	x	x	immature
9373	Rob Roy 1	1581.9	1581.9	267	x	x	x	x	x	immature
9375	Yampi 1	3265.0	3270.0	166	x	x	x			mature
9376	Caswell 1	3685.0	3690.0	109	x	x	x			oil stain
9377	Caswell 1	4080.0	4085.0	124	x	x	x			oil stain
9384	Discorbis 1	3939.0	3942.0	130.4	x	x	x	x	x	mature
9385	Buccaneer 1	3273.0	3276.0	166	x	x	x	x	x	mature
9405	Brewster 1A	3770.0		132	x	x	x			mature
9408	Echuca Shoals 1	3050.0	3055.0	122.6	x	x	x	x	x	mature
9429	Yampi 1	2320.0	2340.0	120.5	x	x	x		x	immature
9557	Caswell 2	4275.0	4280.0	126.5	x	x	x	x		mature
9558	Caswell 2	4350.0	4355.0	133	x	x	x	x		mature
9559	Discorbis 1	3888.0	3891.0	138	x	x	x	x		mature
9560	Discorbis 1	3963.0	3966.0	138.1	x	x	x	x		mature
9561	Kalyptea 1	4257.0	4260.0	129.5	x	x	x	x		mature
9629	Lynher 1	1828.8	1831.9	191.9	x	x	x	x		immature
9631	Lynher 1	2389.7	2392.7	205.1	x	x	x	x		immature
9633	Lynher 1	2679.2	2682.3	233	x	x	x	x		immature
9636	Yampi 2	3104.0	3107.0	147.1	x	x	x	x		mature
9637	Yampi 2	3119.0	3122.0	153.9	x	x	x	x		mature
9638	Kalyptea 1	4281	4284	131.5	x	x	x	x		mature
922	North Scott Reef 1				x	x	x	x		oil
10152	North Scott Reef 1**				x	x	x	x		oil
10153	Scott Reef 1**				x	x	x	x		oil
10168	Brecknock 1**				x	x	x	x		oil
10169	Caswell 2**				x	x	x	x		oil
10170	Gwydion 1**				x	x	x	x		oil
10171	Kalyptea 1**				x	x	x	x		oil
10262	Cornea 1**				x	x	x	x		oil

* Biomarker run for the saturated hydrocarbons under GCMS-SIR aquisition for all samples.
A subset of samples were run under the more selective and sensitive GCMS-MRM aquisition.
** subject to confidentiality period

Table 7 (Revised) Samples used in oil-source biomarker correlation studies.

AGSO No	Well	TOP m	BASE m	Age (Ma)	Age (Ma) Revised 1 May 98	extract	GC	Biomarkers*	^{13}C isotope sats&arom	^{13}C isotope kerogen	Maturity
9190	Heywood 1	4075.0	4085.0	145.3	146	yes	yes	yes	yes		mature
9198	Echuca Shoals 1	2410.0	2415.0	105	106.5	yes	yes	yes	yes	yes	immature
9203	Echuca Shoals 1	3125.0	3130.0	130	128	yes	yes	yes	yes		mature
9214	Prudhoe 1	2555.0	2560.0	129	125	yes	yes	yes			immature
9243	Barcoo 1	4330.0	4335.0	191.2	200	yes	yes	yes	yes		mature
9244	Barcoo 1	4485.0	4490.0	196.1	203	yes	yes	yes	yes		mature
9273	Lombardina 1	2060.0	2065.0	122	120	yes	yes	yes	yes	yes	immature
9280	Brewster 1A	3825.0	3830.0	133	133	yes	yes	yes			mature
9290	Kalyptea 1	2649	2655	58.8	69.0	yes	yes	yes			immature
9291	Kalyptea 1	3207	3210	81.0	73.0	yes	yes	yes			immature
9292	Kalyptea 1	3579	3585	95.9	95.9	yes	yes	yes			immature
9293	Kalyptea 1	3618	3621	97.4	96.0	yes	yes	yes			immature
9294	Kalyptea 1	3663	3666	99.2	97.0	yes	yes	yes			immature
9295	Kalyptea 1	3798	3801	100.6	98.0	yes	yes	yes			immature
9296	Kalyptea 1	3888	3891	101.1	100.0	yes	yes	yes			immature
9297	Kalyptea 1	3954	3960	101.4	104.0	yes	yes	yes			oil stain
9298	Kalyptea 1	4092	4095	118.0	118.0	yes	yes	yes			mature
9299	Kalyptea 1	4160.15	4160.15	125.7	125.7	yes	yes	yes			mature
9300	Kalyptea 1	4239	4249	135.0	133.0	yes	yes	yes			mature
9301	Kalyptea 1	4329	4335	135.2	134.0	yes	yes	yes			mature
9357	Barcoo 1	3370.0	3380.0	107	107	yes	yes	yes	yes	yes	mature
9363	Lombardina 1	2425.0	2425.0	143	143	yes	yes	yes			oil stain
9364	Lombardina 1	2435.0	2435.0	151	144	yes	yes	yes			oil stain
9365	Lynher 1	1460.0	1463.1	160	175	yes	yes	yes	yes	yes	immature
9366	Lynher 1	1539.3	1542.3	177	180	yes	yes	yes	yes	yes	immature
9369	Prudhoe 1	2520.0	2520.0	127.9	124	yes	yes	yes			immature
9370	Rob Roy 1	1539.3	1542.3	175	168	yes	yes	yes	yes	yes	immature
9373	Rob Roy 1	1581.9	1581.9	267	295	yes	yes	yes	yes	yes	immature
9375	Yampi 1	3265.0	3270.0	166	170	yes	yes	yes			mature
9376	Caswell 1	3685.0	3690.0	109	109	yes	yes	yes			oil stain
9377	Caswell 1	4080.0	4085.0	124	124	yes	yes	yes			oil stain
9384	Discorbis 1	3939.0	3942.0	130.4	133.5	yes	yes	yes	yes	yes	mature
9385	Buccaneer 1	3273.0	3276.0	166	175	yes	yes	yes	yes	yes	mature
9405	Brewster 1A	3770.0		132	132	yes	yes	yes			mature
9408	Echuca Shoals 1	3050.0	3055.0	122.6	120	yes	yes	yes	yes	yes	mature
9429	Yampi 1	2320.0	2340.0	120.5	120.5	yes	yes	yes		yes	immature
9557	Caswell 2	4275.0	4280.0	126.5	133	yes	yes	yes	yes		mature
9558	Caswell 2	4350.0	4355.0	133	134	yes	yes	yes	yes		mature
9559	Discorbis 1	3888.0	3891.0	138	124	yes	yes	yes	yes		mature
9560	Discorbis 1	3963.0	3966.0	138.1	134	yes	yes	yes	yes		mature
9561	Kalyptea 1	4257.0	4260.0	129.5	133.5	yes	yes	yes	yes		mature
9629	Lynher 1	1828.8	1831.9	191.9	190	yes	yes	yes	yes		immature
9631	Lynher 1	2389.7	2392.7	205.1	204	yes	yes	yes	yes		immature
9633	Lynher 1	2679.2	2682.3	233	233	yes	yes	yes	yes		immature
9636	Yampi 2	3104.0	3107.0	147.1	155	yes	yes	yes	yes		mature
9637	Yampi 2	3119.0	3122.0	153.9	157	yes	yes	yes	yes		mature
9638	Kalyptea 1	4281	4284	131.5	134	yes	yes	yes	yes		mature
922	North Scott Reef 1	4223	4283			yes	yes	yes			oil
10152	North Scott Reef 1**					yes	yes	yes			oil
10153	Scott Reef 1**	4299	4305			yes	yes	yes			oil
10168	Brecknock 1**	3878				yes	yes	yes			oil
10169	Caswell 2**	3265.5				yes	yes	yes			oil
10170	Gwydion 1**	813				yes	yes	yes			oil
10171	Kalyptea 1**	4541				yes	yes	yes			oil
10262	Cornea 1**	804.2				yes	yes	yes			oil

* Biomarker run for the saturated hydrocarbons under GCMS-SIR aquisition for all samples.
A subset of samples were run under the more selective and sensitive GCMS-MRM aquisition.
** subject to confidentiality period

Table 8. Biomarker OilMod™ ratios[1] from GCMS-SIR data (Appendix C).

Sample[2]	C19/23	C22/21	C24/23	C26/25	T/23	27T/27	C28/H	C29/H	X/H	OL/H	31R/H	GA/31R	35S/34S	35R/34R
oil 922	4.056	0.486	0.825	2.230	0.870	0.023	0.015	0.492	0.170	0.000	0.227	0.236	0.547	0.575
oil 10152	8.709	0.377	1.132	1.315	1.451	0.037	0.021	0.435	0.138	0.015	0.221	0.261	0.525	0.489
oil 10153	4.878	0.527	1.183	0.052	1.691	0.064	0.031	0.533	0.195	0.017	0.213	0.272	0.459	0.496
oil 10168	5.205	0.518	0.740	0.879	2.269	0.018	0.020	0.702	0.135	0.026	0.211	0.245	0.425	0.496
oil 10169	1.334	0.293	0.577	1.473	1.101	0.005	0.018	0.561	0.227	0.006	0.194	0.324	0.638	0.649
oil 10170	2.442	0.483	0.742	2.063	0.730	0.009	0.040	0.408	0.299	0.011	0.233	0.350	0.531	0.509
oil 10171	0.896	0.756	0.512	1.531	0.948	0.022	0.034	0.608	0.053	0.087	0.202	0.300	0.750	0.784
Kaly1 6375 127.5	0.497	0.437	0.576	1.564	0.781	0.027	0.104	0.401	0.623	0.032	0.437	0.407	0.540	0.477
Heyw1 9190 145.3	0.422	0.483	0.574	1.587	0.751	0.000	0.000	0.766	0.211	0.077	0.230	0.299	0.803	0.730
E.Sh1 9198 105	0.240	0.998	0.000	1.065	0.817	0.009	0.000	0.553	0.057	0.000	0.601	0.122	1.533	0.000
E.Sh1 9203 130	0.220	0.457	0.492	1.741	1.786	0.008	0.009	1.108	0.041	0.000	0.443	0.220	0.804	0.644
Prudh1 9214 129	0.434	0.606	0.357	1.393	0.945	0.000	0.074	1.171	0.055	0.000	0.477	0.157	0.389	0.345
Barcoo1 9243 197	0.251	0.433	0.449	1.686	0.884	0.000	0.000	0.796	0.034	0.068	0.244	0.158	0.601	0.562
Barcoo1 9244 197	0.096	0.518	0.641	1.798	0.794	0.011	0.000	0.638	0.040	0.074	0.180	0.243	0.674	0.570
Lomb1 9273 122	0.709	0.513	0.411	0.934	0.749	0.000	0.017	0.842	0.061	0.004	0.481	0.173	0.507	0.393
Brew1A 9280 133	0.361	0.887	0.605	1.446	0.905	0.008	0.008	1.380	0.045	0.000	0.535	0.276	0.907	0.818
Kaly 9290 58.8	1.192	0.423	0.659	1.447	0.841	0.000	0.203	0.557	0.016	0.000	0.836	0.102	1.742	0.833
Kaly1 9291 81	0.410	0.604	0.508	1.811	0.946	0.010	0.040	0.549	0.047	0.011	0.768	0.056	1.142	0.599
Kaly1 9292 95.9	0.073	0.432	0.447	2.142	1.299	0.008	0.000	0.817	0.019	0.000	0.490	0.115	0.925	0.318
Kaly1 9293 97.4	0.317	0.201	0.394	1.930	1.976	0.006	0.015	0.709	0.029	0.000	0.526	0.131	0.540	0.445
Kaly1 9294 99.2	0.535	0.229	0.400	2.033	1.904	0.000	0.022	0.705	0.038	0.000	0.489	0.157	0.480	0.410
Kaly1 9295 100.6	0.760	0.320	0.400	1.606	2.064	0.000	0.020	0.701	0.106	0.002	0.399	0.121	0.413	0.410
Kaly1 9296 101.1	0.886	0.335	0.381	1.634	2.079	0.000	0.015	0.682	0.083	0.002	0.430	0.165	0.533	0.441
Kaly 9297 101St?	0.071	0.252	0.428	1.687	0.526	0.000	0.014	0.637	0.042	0.015	0.425	0.266	0.931	0.953
Kaly1 9298 118	0.461	0.471	0.583	1.867	1.274	0.071	0.012	0.560	0.088	0.020	0.377	0.253	0.856	0.981
Kaly1 9299 125.7	0.330	0.350	0.489	1.010	0.743	0.000	0.047	0.275	0.368	0.011	0.268	0.385	0.598	0.479
Kaly1 9300 135	0.572	0.482	0.517	1.973	0.975	0.000	0.106	0.277	0.821	0.020	0.378	0.554	0.540	0.428
Kaly1 9301 135.2	0.619	0.263	0.907	1.694	0.642	0.000	0.224	0.687	1.065	0.030	0.471	0.816	0.795	0.505
Barcoo1 9357 107	4.878	0.265	2.207	0.000	7.916	0.004	0.004	0.727	0.015	0.001	0.351	0.088	0.179	0.183
Lomb1 9363 Stain	1.378	0.452	0.280	1.218	0.555	0.010	0.015	0.671	0.128	0.005	0.274	0.276	0.415	0.378
Lomb1 9364 Stain	0.919	0.628	0.295	1.203	0.501	0.010	0.014	0.599	0.135	0.005	0.335	0.257	0.442	0.410
Lynher1 9365 160	1.167	0.450	0.364	1.163	0.978	0.007	0.027	0.952	0.016	0.002	0.434	0.079	0.308	0.424
Lynher1 9366 177	3.264	0.579	1.200	1.027	5.324	0.003	0.051	1.311	0.032	0.002	0.427	0.153	0.187	0.241
Prud1 9369 127.9	0.369	0.486	0.398	1.862	0.799	0.005	0.024	0.548	0.052	0.028	0.369	0.126	1.410	0.391
RRoy1 9370 175	1.618	0.505	0.317	1.100	0.732	0.008	0.034	0.540	0.020	0.002	0.612	0.043	0.000	0.616
RRoy1 9373 267	1.410	0.651	0.345	0.756	0.498	0.017	0.043	0.512	0.044	0.002	0.750	0.064	19.706	0.590
Yamp1 9375 166	0.878	0.698	0.379	1.574	1.405	0.012	0.006	0.954	0.168	0.008	0.355	0.208	0.571	0.628
Casw1 9376 Stain	1.080	0.422	0.343	1.102	0.441	0.026	0.008	0.387	0.057	0.010	0.272	0.233	0.778	0.667
Casw1 9377 Stain	1.353	0.386	0.336	0.989	0.554	0.008	0.042	1.219	0.360	0.028	0.346	0.347	0.807	0.606
Disc1 9384 134	0.408	0.400	0.386	1.463	0.702	0.021	0.000	0.404	0.091	0.010	0.301	0.226	0.512	0.521
Buccan1 9385 166	2.228	0.773	0.601	0.828	2.973	0.006	0.006	1.175	0.052	0.004	0.431	0.124	0.365	0.345
Brew1A 9405 132	0.280	0.494	0.495	1.000	0.270	0.014	0.016	1.367	0.167	0.014	0.558	0.278	0.903	0.788
E.Sh1 9408 122.6	0.391	0.450	0.320	1.649	1.075	0.003	0.009	0.787	0.057	0.000	0.409	0.171	0.660	0.490
Yamp1 9429 120.5	0.410	0.435	0.340	2.223	0.869	0.000	0.017	0.615	0.044	0.009	0.551	0.083	0.499	0.426
Casw2 9557 126	0.535	0.359	0.458	1.317	0.619	0.000	0.000	0.937	0.253	0.039	0.296	0.272	0.750	0.720
Casw2 9558 133	0.335	0.437	0.500	1.184	0.440	0.000	0.000	0.824	0.072	0.021	0.306	0.219	0.945	0.895
Disc1 9559 123	0.161	0.278	0.445	1.625	0.631	0.000	0.000	0.479	0.041	0.006	0.227	0.191	0.504	0.494
Disc1 9560 135	0.414	0.299	0.406	1.722	1.229	0.000	0.000	0.477	0.090	0.010	0.242	0.229	0.468	0.406
Kaly1 9561 134	0.832	0.325	0.687	1.230	0.909	0.000	0.000	0.314	1.008	0.036	0.259	0.779	0.499	0.428
Lynher1 9629 198	0.533	0.426	0.402	1.235	0.949	0.000	0.000	0.962	0.039	0.007	0.415	0.112	0.241	0.259
Lynher1 9631 204	0.172	0.452	0.449	1.026	0.330	0.000	0.000	1.131	0.030	0.011	0.370	0.096	0.412	0.403
Lynher1 9633 236	0.176	0.458	0.434	1.344	0.462	0.000	0.000	0.830	0.024	0.014	0.449	0.067	0.456	0.404
Yamp2 9636 147	0.960	0.306	0.504	1.354	1.258	0.000	0.000	0.453	0.391	0.018	0.326	0.308	0.444	0.410
Yamp2 9637 156	0.537	0.351	0.631	1.712	1.423	0.000	0.000	0.569	0.154	0.049	0.342	0.216	0.607	0.586

Table 8. cont											
Sample[2]	S1/S6	%C27	%C28	%C29	%C27	%C28	%C29	S12/S15	Ts/Tm	29D/H	S/H
		S5B	S10B	S14B	S6	S11	S15				
oil 922	3.85	27.1	22.8	50.2	46.3	3.8	49.8	0.79	1.26	0.21	0.64
oil 10152	3.30	28.2	24.2	47.6	43.1	13.9	42.9	0.82	1.28	0.24	0.64
oil 10153	4.06	24.0	21.3	54.8	40.3	12.8	46.9	0.69	1.36	0.19	0.64
oil 10168	2.85	23.2	22.0	54.8	48.5	6.7	44.8	1.04	0.88	0.18	0.58
oil 10169	3.29	40.0	26.3	33.7	53.8	18.8	27.4	0.93	2.33	0.30	1.39
oil 10170	3.04	33.1	31.1	35.8	44.6	12.1	43.2	0.76	2.47	0.26	1.46
oil 10171	1.68	35.5	25.1	39.3	40.6	20.0	39.4	0.73	1.02	0.22	0.50
Kaly1 6375	4.71	35.7	32.7	31.7	49.9	19.4	30.7	0.65	2.90	0.49	1.55
Heyw1 919	1.72	41.6	12.5	45.9	47.2	17.1	35.6	0.73	1.12	0.26	0.26
E.Sh1 919	0.80	35.5	28.6	35.9	51.7	16.6	31.8	0.19	0.41	0.14	1.04
E.Sh1 920	1.05	26.8	19.0	54.3	36.6	16.8	46.6	0.91	0.85	0.23	0.36
Prudh1 92	1.24	29.7	30.3	40.0	42.5	17.8	39.7	0.28	0.16	0.12	0.54
Barcoo1 92	1.22	36.2	26.2	37.6	44.3	16.5	39.1	0.89	0.35	0.16	0.21
Barcoo1 92	1.34	36.6	24.7	38.7	46.2	17.3	36.5	0.98	0.73	0.19	0.29
Lomb1 927	1.08	35.5	24.8	39.6	40.0	23.3	36.7	0.45	0.26	0.15	0.92
Brew1A 92	0.64	25.1	21.8	53.1	34.5	18.1	47.4	0.84	0.50	0.15	0.33
Kaly 9290	0.36	19.5	42.1	38.5	33.5	24.8	41.6	0.17	0.48	0.39	0.82
Kaly1 9291	0.59	27.4	31.0	41.7	37.3	19.2	43.5	0.22	0.21	0.10	0.45
Kaly1 9292	0.25	30.1	34.4	35.5	40.8	14.9	44.3	0.47	0.44	0.08	0.32
Kaly1 9293	0.38	32.1	33.0	34.9	43.7	15.6	40.7	0.37	0.29	0.07	0.63
Kaly1 9294	0.45	36.0	31.4	32.6	49.8	14.3	35.9	0.46	0.52	0.07	0.75
Kaly1 9295	1.55	35.3	28.9	35.8	48.9	16.3	34.8	0.70	0.22	0.10	1.27
Kaly1 9296	1.00	50.5	46.3	3.2	48.0	14.5	37.5	0.77	0.26	0.06	0.59
Kaly 9297	0.82	35.9	27.6	36.5	41.2	15.6	43.2	0.66	6.62	0.16	0.52
Kaly1 9298	1.07	32.0	28.0	40.0	37.5	20.0	42.5	0.76	0.85	0.19	0.65
Kaly1 9299	7.65	36.5	24.5	39.0	48.1	17.1	34.8	0.75	2.04	0.46	1.94
Kaly1 9300	4.88	39.2	33.0	27.9	62.3	10.5	27.2	0.82	4.70	0.58	2.00
Kaly1 9301	5.88	33.3	22.2	44.4	53.3	10.2	36.5	0.80	3.83	1.14	2.44
Barcoo1 93	0.52	8.8	62.8	28.4	24.0	18.0	58.0	0.72	0.02	0.03	0.03
Lomb1 936	2.30	37.0	23.3	39.7	47.3	18.9	33.9	0.79	0.76	0.29	0.31
Lomb1 936	1.41	43.9	25.9	30.2	47.0	16.3	36.7	0.61	0.75	0.23	0.32
Lynher1 93	0.56	15.0	45.3	39.7	20.7	18.4	60.9	0.38	0.02	0.04	0.14
Lynher1 93	0.39	3.4	51.5	45.0	10.0	21.8	68.2	0.52	0.01	0.04	0.17
Prud1 9369	0.93	36.8	34.4	28.8	42.8	14.4	42.8	0.29	0.43	0.16	0.68
RRoy1 937	0.46	22.3	27.7	50.0	13.7	11.9	74.5	0.08	0.05	0.02	0.37
RRoy1 937	0.44	10.3	21.4	68.3	11.8	11.2	76.9	0.05	0.06	0.03	0.73
Yamp1 937	0.85	36.4	29.6	34.0	49.6	14.8	35.6	1.10	0.69	0.26	0.87
Casw1 937	1.90	42.8	31.5	25.7	50.1	18.3	31.6	0.94	1.32	0.20	0.84
Casw1 937	4.32	39.6	24.5	35.9	59.7	12.3	28.0	1.06	1.50	0.40	0.64
Disc1 9384	2.15	41.3	32.6	26.1	53.5	12.5	34.0	1.02	1.41	0.22	0.71
Buccan1 9	0.81	6.1	21.1	72.8	16.6	14.6	68.8	1.05	0.06	0.04	0.35
Brew1A 94	1.68	29.5	23.1	47.4	45.7	17.0	37.3	0.99	0.73	0.23	0.73
E.Sh1 940	1.34	32.8	21.5	45.7	40.0	19.6	40.4	0.83	0.67	0.19	0.34
Yamp1 942	0.78	39.8	32.7	27.5	44.3	18.4	37.3	0.18	0.17	0.11	0.59
Casw2 955	1.99	5.2	21.0	73.8	47.6	14.8	37.6	0.83	1.59	0.29	0.38
Casw2 955	1.45	33.2	24.5	42.3	40.8	16.0	43.2	0.74	1.11	0.25	0.33
Disc1 955	1.63	35.0	31.0	34.0	44.1	24.4	31.5	0.96	1.50	0.21	0.27
Disc1 956	2.47	32.3	25.3	42.4	46.6	20.4	33.0	1.20	1.41	0.24	0.27
Kaly1 9561	5.50	35.6	28.0	36.4	53.9	17.4	28.7	0.81	4.90	0.58	0.81
Lynher1 96	0.95	22.8	43.1	34.0	24.6	15.0	60.4	0.51	0.03	0.02	0.07
Lynher1 96	0.84	9.4	19.0	71.6	36.2	19.1	44.6	0.35	0.10	0.05	0.13
Lynher1 96	0.69	45.2	29.1	25.8	43.6	18.3	38.0	0.35	0.26	0.08	0.28
Yamp2 963	2.95	32.2	23.6	44.2	44.2	14.7	41.0	0.77	1.00	0.28	0.20
Yamp2 963	1.20	32.0	27.5	40.6	43.0	17.7	39.3	0.63	0.61	0.25	0.30
Kaly1 9638	4.62	33.9	30.5	35.6	54.4	14.8	30.8	0.69	4.66	0.56	0.82

[1] peak#./pe C19/23=4/8; C22/21=7/6; C24/23=9/8; C26/25=12/10; T/23=11/8; 27T/27=20/(19+21); C28/H=24/33; C29/H=28/33;
X/H=31/33; OL/H32/33; 31R/H=64/33; GA/31R=36/33; 35S/34=72/70; 35R/34=73/71; S1/S6=37/40;
%C27S5B=%39/(39+43+47); %C28S10B=%43/(39+43+47); %C28S14B=%47/(39+43+47);
%C27S6=%40/(40+44+48); %C28S11=%44/(40+44+48); %C29S15=%48/(40+44+48); S12/S15=46/48;
Ts/Tm=19/21; 29D/H=29/33; S/H=(S1-S15)/(19+21+24+28+30+33+35+64+68+69+70+71+72+73)

[2] well name (abbreviation) AGSO# age(MA)

Table 9 OilMod^{TM} parameters used in hierachical cluster analysis

OilMod	Definition	Source/Environment Indicator*
C19T/C23T	tricyclic ratio (C19=no. of carbons)	land plant vs. marine input
C22T/C21T	tricyclic ratio	bacterial communities
C24Tet/C23T	tetracyclic/tricyclic	bacterial communities in carbonate sediments
C29H/C30H	hopanes (C29=no. of carbons)	carbonate vs silicoclastic
C31H/C30H	hopane ratio	bacterial communities
C35H/C34H	hopane ratio	anoxic marine bacterial input
C29D/C30H	C29D = C29Ts rearranged hopane/hopane ratio	bacterial input in clay-rich sediments
C30X/C30H	diahopane/hopane ratio	bacterial input in oxic clay-rich sediments
GA/31R	gameracane/C31hopane	water column salinity
%C27S	% C27 steranes (C27=no. of carbons)	marine algal input
% C28S	% C28 steranes	marine algal (diatoms) input
% C29S	% C29 steranes	terrestrial plant input
S/H	ratio of ΣC27-29steranes to /ΣC27-35hopanes	eucaryote vs procaryote input

* leads to higher values

Table 10. Biomarker ratios from GCMS-MRM data (Appendix D1 and D2).

Sample*	C19/C23	C22/C21	C24/C23	C26/C25	Tet/C23	C28/C30H	C29H/C30H	C30X/C30H	OL/C30H	C31R/C30H	GA/C31R	C35S/C34S
NS Reef 1 922	8.015	0.268	0.546	0.789	1.253	0.032	0.594	0.206	0.018	0.210	0.058	0.101
NS Reef 1 10152	4.829	0.606	0.393	1.849	0.621	0.048	0.580	0.233	0.019	0.224	0.136	0.071
Scot Reef 10153	11.713	0.294	0.602	0.975	1.624	0.019	0.523	0.195	0.011	0.198	0.091	0.125
Brecknook 10168	7.595	0.473	0.552	0.958	1.895	0.046	0.659	0.154	0.044	0.199	0.076	0.067
Caswell 2 10169	2.269	0.231	0.462	0.930	1.313	0.031	0.494	0.255	0.019	0.192	0.097	0.068
Gwydion 1 10170	3.794	0.259	0.558	0.777	0.769	0.151	0.541	0.379	0.013	0.259	0.127	0.054
Kalyptea 1 10171	1.829	0.411	0.504	0.793	0.913	0.064	0.703	0.074	0.108	0.202	0.121	0.087
ES 9198 103.6	0.806	0.448	0.399	1.298	0.862	0.026	0.767	0.061	nd	0.540	nd	0.860
ES 9203 130	0.639	0.391	0.443	0.733	2.473	0.007	1.133	0.031	nd	0.458	nd	0.914
Prud 9214 129	1.006	0.531	0.359	0.567	1.201	0.159	1.118	0.046	nd	0.365	nd	0.465
Lomb 9273 121.6	0.109	0.426	0.311	0.998	0.652	0.013	0.842	0.056	nd	0.360	nd	0.579
Brew 9280 132.6	0.619	0.829	0.323	1.206	0.707	0.009	1.385	0.046	nd	0.461	nd	0.884
Barc 9357 107.2	5.573	0.360	0.226	0.755	6.828	0.013	1.121	0.022	nd	0.300	nd	0.262
Lomb 9363 143.4	0.159	0.495	0.294	0.500	0.547	0.037	0.614	0.146	nd	0.272	nd	0.486
Lomb 9364 151	2.785	0.505	0.318	1.040	0.555	0.024	0.732	0.138	nd	0.302	nd	0.596
Lynh 9365 160.1	0.298	0.470	0.286	0.399	0.967	0.061	1.272	0.016	nd	0.358	nd	0.380
Lynh 9366 177.2	6.032	0.543	0.218	0.974	4.455	0.085	1.316	0.026	nd	0.282	nd	0.263
Prud 9369 129	1.140	0.509	0.403	0.673	1.124	0.050	0.858	0.056	nd	0.316	nd	0.013
RRoy 9370 175	0.249	0.576	0.288	0.322	0.553	0.091	0.615	0.019	nd	0.548	nd	0.563
RRoy 9373 293.5	0.453	0.015	0.279	0.449	0.631	0.104	0.567	0.046	nd	0.595	nd	0.767
Yamp 9375 170	1.685	0.507	0.385	1.566	1.751	0.043	1.395	0.191	nd	0.267	nd	0.652
Casw 9376 108	2.492	0.046	0.388	0.633	0.573	0.027	0.631	0.061	nd	0.208	nd	1.007
Casw 9377 124.5	2.326	0.985	0.384	0.611	0.469	0.074	1.228	0.445	nd	0.291	nd	0.896
Disc 9384 130.4	0.578	0.313	0.453	0.841	1.036	0.010	0.579	0.077	nd	0.244	nd	0.579
Bucc 9385 180	3.980	0.528	0.364	1.091	2.592	0.011	1.388	0.065	nd	0.352	nd	0.306
Brew 9405 132	0.440	0.454	0.313	0.863	0.236	0.032	1.310	0.138	nd	0.416	nd	0.862
ES 9408 122.6	0.786	0.430	0.325	0.688	1.410	0.014	0.853	0.050	nd	0.365	nd	0.615
Yamp 9429 120.4	0.887	0.379	0.396	0.731	1.499	0.038	0.778	0.060	nd	0.529	nd	0.512

Table 10 cont.

Sample*	Ster/Terp	%C27	%C28	%C29	S1/S6	C29 20S/R	Ts/Tm	C29D/C30H	MeSt/St	MeSt23/4	MeSt24/D
NS Reef 1 922	1.211	28.4	25.7	45.9	5.800	1.189	2.097	0.303	1.382	0.449	0.362
NS Reef 1 10152	1.191	27.9	16.9	55.2	8.135	0.732	1.893	0.355	0.998	0.516	0.519
Scot Reef 10153	1.270	28.4	19.4	52.1	7.173	0.965	2.314	0.322	1.443	0.481	0.252
Brecknook 10168	1.028	24.2	26.0	49.8	3.894	1.108	1.319	0.298	0.767	0.582	0.311
Caswell 2 10169	2.285	38.6	32.6	28.9	4.805	1.118	3.493	0.365	0.490	0.615	0.402
Gwydion 1 10170	2.679	28.4	31.6	40.0	5.775	1.141	2.966	0.393	0.613	0.586	0.095
Kalyptea 1 10171	0.629	30.7	25.9	43.4	2.534	0.794	1.168	0.321	0.501	0.545	0.361
ES 9198 103.6	1.685	25.2	34.1	40.7	1.191	0.175	0.482	0.164	nd	nd	nd
ES 9203 130	0.527	27.4	21.2	51.4	0.912	1.033	1.236	0.333	nd	nd	nd
Prud 9214 129	0.954	23.2	31.0	45.7	1.922	0.399	0.181	0.165	nd	nd	nd
Lomb 9273 121.6	1.523	47.3	24.2	28.5	1.528	0.534	0.299	0.140	nd	nd	nd
Brew 9280 132.6	0.340	26.7	24.3	49.0	0.778	0.845	0.665	0.142	nd	nd	nd
Barc 9357 107.2	0.051	14.8	25.1	60.1	0.902	0.800	0.008	0.039	nd	nd	nd
Lomb 9363 143.4	1.055	36.4	27.7	35.9	3.294	1.106	1.263	0.326	nd	nd	nd
Lomb 9364 151	1.244	41.6	25.7	32.6	2.742	0.814	0.770	0.295	nd	nd	nd
Lynh 9365 160.1	0.131	16.2	30.0	53.9	0.849	0.448	0.000	0.050	nd	nd	nd
Lynh 9366 177.2	0.126	7.3	29.9	62.8	0.988	0.624	0.009	0.084	nd	nd	nd
Prud 9369 129	1.093	25.3	28.0	46.7	1.807	0.411	0.400	0.154	nd	nd	nd
RRoy 9370 175	0.379	18.2	20.9	60.9	1.037	0.097	0.089	0.037	nd	nd	nd
RRoy 9373 293.5	1.232	6.5	20.6	72.9	0.994	0.108	0.071	0.055	nd	nd	nd
Yamp 9375 170	0.985	30.8	25.8	43.4	1.386	1.248	0.682	0.253	nd	nd	nd
Casw 9376 108	1.321	37.3	30.4	32.3	3.399	1.194	1.449	0.248	nd	nd	nd
Casw 9377 124.5	2.345	43.8	25.3	31.0	6.369	1.391	2.122	0.526	nd	nd	nd
Disc 9384 130.4	1.191	35.8	31.6	32.7	3.428	1.229	1.694	0.275	nd	nd	nd
Bucc 9385 180	0.369	11.1	19.5	69.5	1.869	1.451	0.065	0.061	nd	nd	nd
Brew 9405 132	0.827	30.8	27.0	42.2	2.065	1.468	1.208	0.169	nd	nd	nd
ES 9408 122.6	0.710	29.6	28.8	41.6	1.487	0.973	0.964	0.264	nd	nd	nd
Yamp 9429 120.4	1.166	23.8	32.1	44.1	1.277	0.206	0.203	0.123	nd	nd	nd

* abbreviated well name, agso#, age(Ma)

peak#/peak# C19/C23=4/8; C22/C21=7/6; C24/C23=9/8; C26/C25=12/10; Tet/C23=11/8; C28/C30H=24/33; C29H/C30H=28/33; C30X/C30H=31/33; OL/C30H=32/33; C31R/C30H=64(R)/33; GA/C31H=36/64; Ster/Tep=(46+47+48)/(33+35); %27=%40/(40+44+48); %28=%44/(40+44+48); %29=%48/(40+44+48); S1/S6=37/40; C29 20S/R=46/48; Ts/Tm=19/21; MeSt/St=(53+54+55)/48; MeSt23/4=(52_53)/54; MeSt24/D=54(4-methyl,24-ethyl)/54(4,23,24-trimethyl); nd=not determined

Table 11. Australian Petroleum Supersystems (after Bradshaw, 1997)

Supersystem	sub-unit	age	source facies	examples	distribution - basin	key discoveries
LARAPINTINE	1	Cambrian	marine calc. shale	Goulburn Gp., Tempe	Arafura, Amadeus	Arafura 1 oil shows
lower Palaeozoic	2	Ordovician	marine	Horn Valley, Goldwyer	Amadeus, Canning	Mereenie oil field
tropical climate	3	Middle-Late Devonian	marine carbonate	Gogo, Ningbing	Canning, Bonaparte	Blina oil field
carbonates, evaporites,	4	Early Carboniferous	marine anoxic shale	Anderson, Milligans	Canning, Bonaparte	Sundown oil field
marine clastics						
GONDWANAN	1	Early Permian	non-marine	Irwin River,Patchawarra	Perth, Cooper, Bowen	Tirrawarra gas & oil field
Late Carb.- Early Triassic			marine	Treachery, Keyling	Bonaparte	
glaciation, clastics	2	Late Permian	non-marine	Blackwater Gp.	Bowen	Rolleston gas field
higher plant			marine	Wagina	Perth	
contribution to			deltaic	Hyland Bay	Bonaparte	Petrel gas field
source rocks	3	earliest Triassic	marine	Kockatea	Perth	Dongara oil & gas field
WESTRALIAN	1	Late Trias.-E/M Juras.	deltaic	Mungaroo	Carnarvon	Rankin Trend giant gas fields
Traissic-Cenozoic	2	Late Jurassic	marine, anoxic?	Dingo, Flamingo	Carnarvon, Bonaparte	Barrow Island oil field
Break-up of northern	3	Early Cretaceous	marine	Echuca Shoals	Bonaparte, Browse	Undan/Bayu; Cornea?
and western margin	4 ***SAHUL***	Mesozoic	marine carbonate	?	Bonaparte, Timor, Seram	
marine rift environments						
AUSTRAL	1	Late Jur.- Early Cret.	fluvio-lacustrine shale	Casterton, Pretty Hill,	Otway,	Katnook,
Late Jurassic-Cenozoic				Parmelia	Perth, Carnarvon?	Gage Roads
Break-up of southern and	2	Early Cretaceous	fluvial - coaly	Eumeralla	Otway	Windermere, Minerva
south-western margins	3	Late Cretaceous	fluvio-deltaic	Latrobe Gp.	Gippsland, Bass	Kingfish
terrestrial rift environments						