Deposition recommenced in the Carboniferous and the sediments of the Parmeener Supergroup were accumulated (Figure 5, Figure 7 and Figure 8). A flattened stratigraphic section comprising well and outcrop data provides an indication of formation thicknesses and depths (Figure 9).

Carboniferous to Permian tillite deposits occur at the base of the supergroup and are widespread throughout the entire basin (Stockers, Wynyard and Truro Tillites, see Figure 5). These are followed by the Woody Island Formation, a 100 to 200 metre thick dark grey monotonous siltstone. In the base of this formation, beds of the alga *Tasmanites punctatus* occur. The Woody Island Formation and the *Tasmanites* Oil Shale beds are the main potential source rocks and are discussed in Section 3. The distribution of the Woody Island Formation source facies and Tasmanite Oil Shale distribution is shown in Figure 10.

The Woody Island Formation is overlain by the Bundella Formation, a muddy siltstone with little potential as a source rock. These are overlain by the Liffey Group, consisting of well sorted, laminated, fine to medium sands (Reid and Burrett, 2004). The sandstone beds are generally 3-5 metres thick and are interbedded with carbonaceous siltstones.

Permian palaeogeography of the Tasmania Basin is presented in Figure 11, and has been modified from Clarke, (1989). The thickness and distribution of the Liffey Group is shown in Figure 12. The facies become more marine to the south, suggesting regression in that direction. Recent work has identified a zero edge near Cygnet, which was established by Mineral Resources Tasmania (MRT) from outcrop and several stratigraphic diamond core holes.

The Liffey Group is overlain by silt/clay marginal marine to marine formations; the Malbina and Ferntree Formations.

Terrestrial environment of deposition becomes dominant around the end of the Permian. The Lower Parmeneer Supergroup was deposited from the Late Carboniferous to Late Permian. The Upper Parmeener Supergroup was deposited from the Late Permian to Late Triassic, in a non marine environment (Bacon *et al*, 2000). Within the Late Permian to Late Triassic sequence, four stratigraphic units have been defined (Leaman, 1971, and Forsyth, 1989). The following summary is derived from Bacon *et al,* (2000).

Unit 1 is dominantly felspathic and micaceous sandstones. Thin coal is seen in the south on Bruny Island and at Cygnet, and is known as the Cygnet Coal Measures. The entire section is generally 50 metres thick.

Unit 2 is 200 to 300 metres thick and was deposited by a fluvial system which flowed the north-west to the south-east.

Unit 3 is generally 80 metres thick and consists mainly of sandstones with minor conglomerates and rare thin coals.

Unit 4 is mainly lithic sandstone with minor claystone and contains most of Tasmania's economic coal reserves, located mainly in the north-east.

The Upper Parmeener Supergroup (mainly Triassic in age) appears to be a series of fluvial deposition cycles. There is no major marine influence on this group or in the time following, so a widespread regional seal for these sediments seems unlikely.

In the Early Jurassic, 400 to 600 metre thick intrusions of dolerite were emplaced into the existing Permo-Triassic sequences, essentially parallel to bedding. In any given section of the basin, one to three of these bodies may be present. Outcrop observations indicate that each of these bodies is a composite emplacement consisting of several sheets (Burrett, 1992).

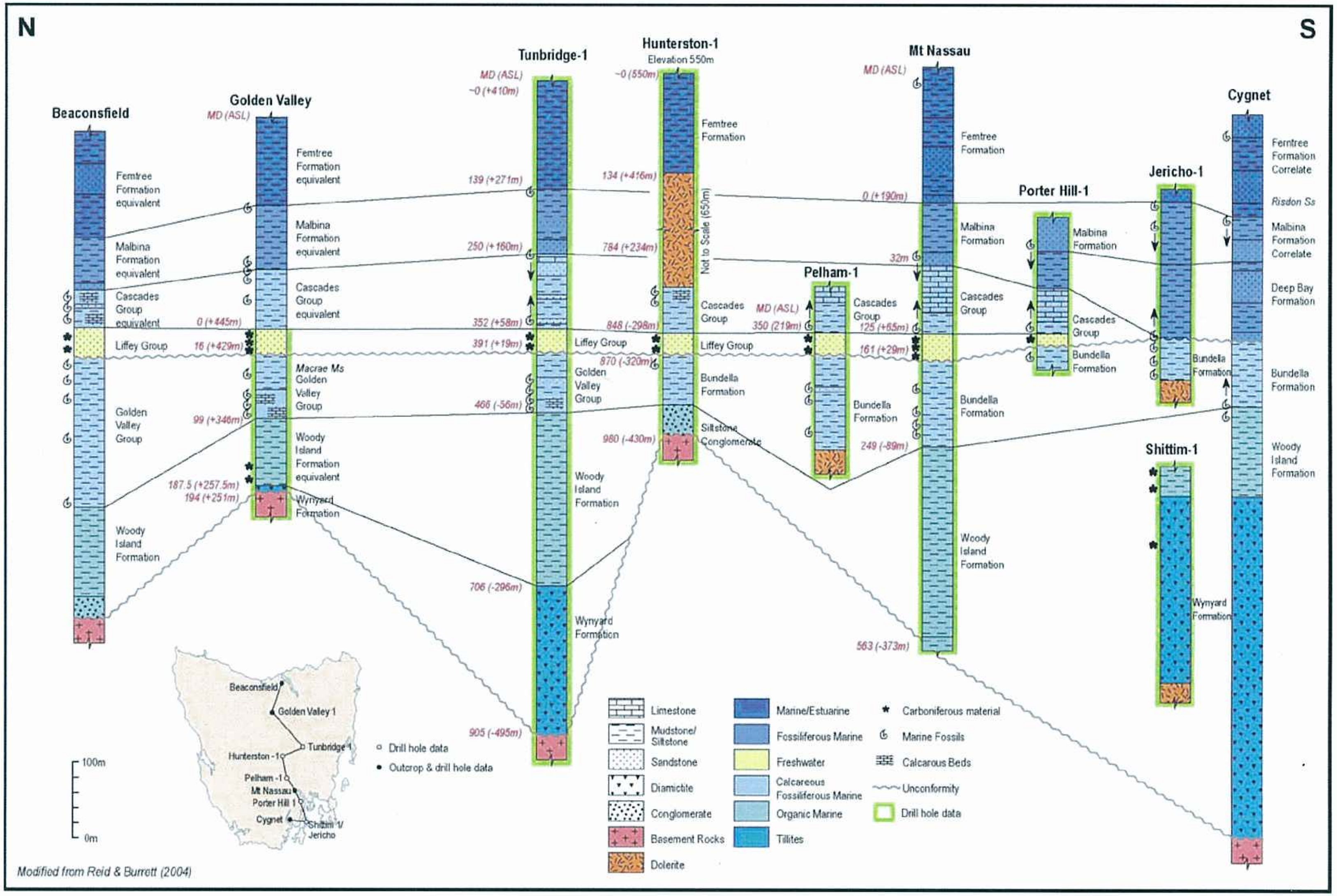

Figure 9 – Stratigraphic cross-section of the Tasmania Basin (modified from Reid and Burrett, 2004)

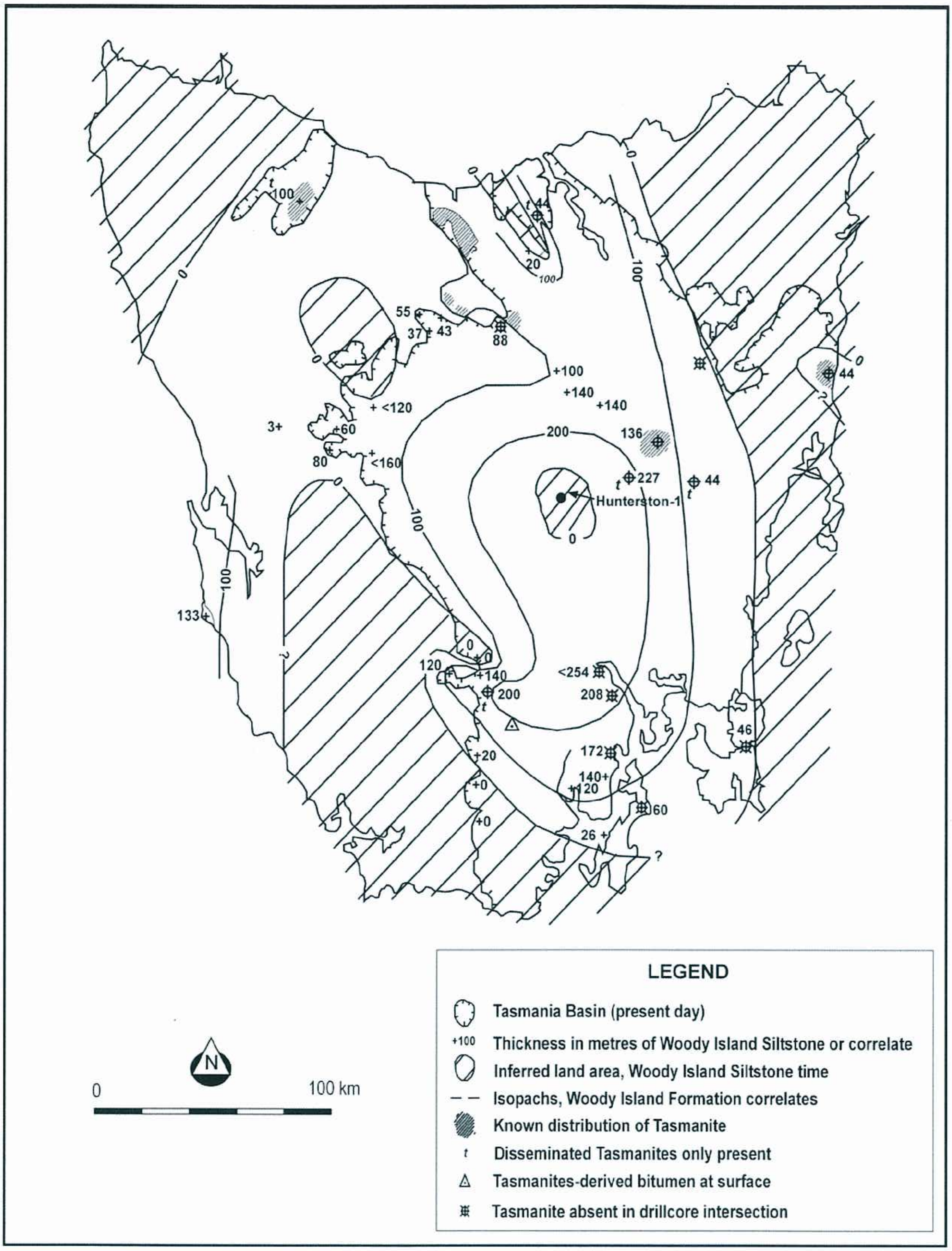

Figure 10 – Known distribution of the Tasmanite Oil Shale with an isopach of the Woody Island Formation (modified from Bacon *et al*, 2000)

The dolerite presents several challenges for petroleum exploration, including the reduction of seismic signal, variations in seismic velocity, hard drilling, localised over-maturation of vitrinite and source rocks, and possibly the reduction of reservoir quality.

At the present day, there are no Cretaceous sedimentary rocks of note in the basin. An apatite fission track study (O'Sullivan and Kohn, 1995) suggests that the basin was uplifted somewhere between 100 and 50 Ma (Late Cretaceous to Early Tertiary), and approximately 3 to 4 kilometres of previously deposited Jurassic to Middle Cretaceous rocks were completely eroded. Bacon *et al* (2000), suggest 2 kilometres of section is more likely, and points out the work of Sutherland (1977) who suggested that zeolites within the Jurassic dolerite indicated a possible burial depth of 2 kilometres.

Bacon *et al* (2000) suggest that the Mesozoic sediments of the Tasmania Basin were once more widespread. The western margin of the basin is defined by Permian formations truncated by outcrop. This erosion and reduction in basin sediments is inferred to have occurred between Late Cretaceous and Middle Tertiary time.

Some minor Tertiary deposition of some hundreds of metres occurred in the Longford Sub-basin. This deposition has negligible impact on the burial history and, therefore, thermal history of the basin. This section will be penetrated during a stratigraphic test of the Bracknell Dome area (see Section 3.6).

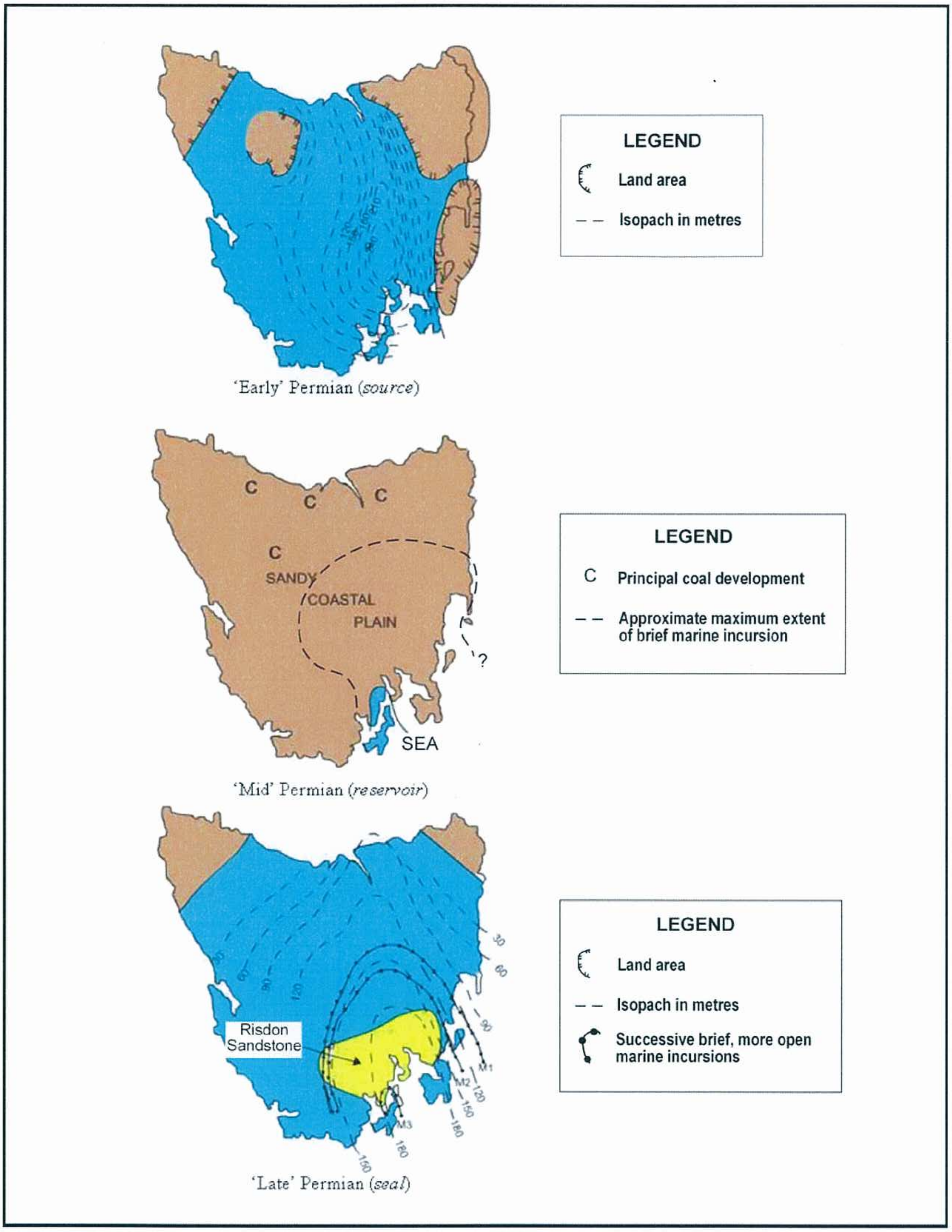

Figure 11 – Permian palaeogeography development of the Tasmania Basin (modified from Clarke, 1989)

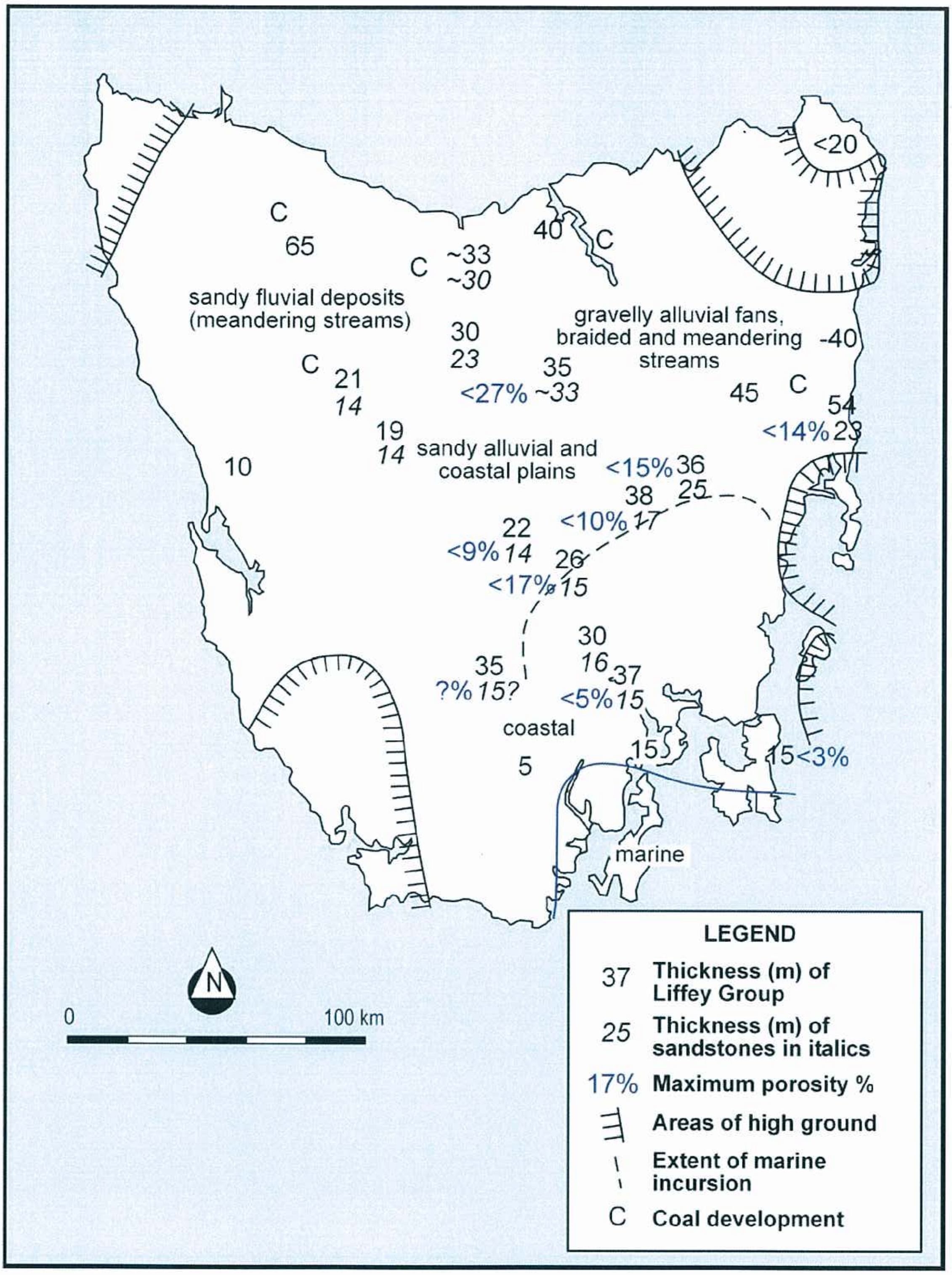

Figure 12 – Thickness and distribution of the Liffey Group. Total thickness of sandstone beds and cycles (black) and some upper porosity values (blue) are also shown (modified from Reid and Burrett, 2004, after Clarke 1989 and Martin and Banks, 1989).

3. PETROLEUM SYSTEM ANALYSIS

To date, there have been no oil or gas fields discovered in the Tasmania Basin although several oil seeps have been reported in Tasmania. Oil seeps can be valuable in signifying the occurrence of mature source rocks in frontier exploration. Currently, the seeps reported in the Tasmania Basin have had limited correlations made to petroleum systems, however, there is a seep in a recently used quarry at Lonnavale, to the southwest of Hobart, that has been correlated with the Permian Tasmanite Oil Shale and is the best indication yet that a significant petroleum system possibly exists in the basin. Two potential petroleum systems could be present, these are the Pre-Carboniferous system (Larapintine) and the Permian System (Gondwana). These two systems are discussed below and schematics are provided in Figure 13 and Figure 14.

3.1 Hydrocarbon Occurrences

Hydrocarbon indications have been reported to the Tasmanian government over the past century. A tabulation of all of these shows and their assessments are provided in Bacon *et al* (2000).

According to Wakefield (2000), over 130 reports of oil and gas seeps have been registered with Mineral Resources Tasmania (MRT). Approximately 10% of these reports have confirmed the presence of naturally occurring hydrocarbons in the form of seeps, tars and bitumens. To date, no bore hole has ever yielded core or cuttings that contained macroscopic hydrocarbon fluorescence although very few wells have been drilled to specifically explore for oil and gas. Of these wells, including those drilled since 1997 by GSLM, none have been drilled on a trap defined by modern seismic.

Mud gas was detected in several of the GSLM wells (Table 1). Most samples were contaminated with significant amounts of air but, after adjusting for this, levels of C6 up to 50 ppm were detected in Shittim-1 and Jericho-1. Isotopic analysis of the gas at Jericho-1 shows it is thermogenic. Results at Shittim-1 range from biogenic to possible mixed biogenic/thermogenic. However, traces of C3-C6 are encouraging and indicate that there are rocks with the capacity to produce wet gas in the basin.

Low yields of hydrocarbon extracted from a Proterozoic core sample from 1,676 metres in Shittim-1 on Bruny Island and a hydrocarbon extract from a Gordon Group limestone from a quarry were compared by Burrett (1997). The Gordon Group traces are similar in the dominance of n-C18 alkane. The pristane to phytane ratios are reported to be approximately 1 in both (Bacon *et al,* 2000). The Shittim-1 sample seems biodegraded or water washed but, surprisingly, the quarry sample does not appear biodegraded. It has been interpreted that this extracted hydrocarbon probably originated in Ordovician rocks down dip.

Oil and bitumen in Permian sandstone outcrops near Zeehan, Tasmania, have been reported by Cook (2003). The author examined samples from these Permian outcrops, one sample of a carbonaceous shale grading to a shaly coal and two sandy samples thought to have contained possible bitumens. The silty sandstone contains prominent oil inclusions within the sand grains and abundant brightly fluorescing oil, presumably being originally part of the same petroleum system as the bitumens (Cook, 2003).

Cook (2003) also observed that the presence of gas bubbles indicates that the oil to gas ratio of the system was originally relatively high. The Permian sandstones' maturation level is best estimated at 0.7% and may be as high as 0.8% (Cook, 2003) which is consistent with the findings from the previous geochemical reports. Another study by Revill *et al*, (1994), which represented the first organic geochemical comparison of thermally mature and immature Tasmanite Oil Shale samples in relation with a geological evaluation of the sedimentary setting, concluded that at least some deposits of the Tasmanite Oil Shale in Tasmania are near the "oil window".

Rare (< 0.1%) microscopic oil inclusions, in fractures in samples from Hunterston-1, were also observed by Cook (2003). These inclusions appear apparently on fractures through cements in the Liffey Group. They could have emplaced at any point post deposition (i.e. post-Permian). No inclusions have been extracted to determine their source (Reid 2004). An occurrence of oil inclusions < 0.1% does not indicate a breached oil column or migration.

This assessment is based on empirical limits developed by CSIRO in their oil inclusion counting studies GOI™ (Eadington *et al*, 1996). The very low occurrence of inclusions (<0.1%) and the proximity to an intrusion suggests localised maturation of a very small amount of organic matter to the point of expulsion. Oil inclusions of <2% were also observed in samples of the Liffey Group from Ross-1 where maturity is VR% 0.57 (Reid, 2004).

Rare oil inclusions were also observed in Liffey Group samples from Douglas River with a mean maturity of VR% 0.55 (range VR% 0.48-0.64) – just barely at the oil window.

3.1.1 The Lonnavale Seep

The hydrocarbon show at the Lonnavale quarry is a bitumen found within Jurassic dolerite joints. The quarry is based on a Jurassic dolerite deposit which has a possible contact with a Permian mudstone, exposed in a nearby older quarry, and is known, in other areas of Tasmania, to contain the Tasmanite Oil Shale (Revill, 1996). Geochemical studies were undertaken at the request of Tasmanian Development and Resources (TDR) in 1996. Two samples of possible hydrocarbons were studied. One sample was a swab of what appeared to be hydrocarbon staining and the second was a bitumen from within a fracture in the dolerite.

Seeps were examined at a quarry in Lonnavale (personal observation by P. Vytopil, 2007). The rock was a fractured dolerite, with one section of the quarry showing good oil shows with strong petroliferous odour along fracture planes. The oil effortlessly smeared when samples were handled and left a dark reddish streak. In areas where samples were not fresh, there was a dark bituminous stain and some samples had a faint odour of H_2S.

The presence of oil shows at Lonnavale has been previously recorded by numerous authors. Bottrill (1996) provides a detailed description of oil shows along two generations of fractures within the dolerite. These factures were filled with calcite and minor globules and flecks of bitumen. The bitumen was dark brown to black, vitreous, soft and sticky on fresh surfaces, as well as hardened and dark on exposed surfaces.

Geochemical analysis indicates that the n-alkane profile from the swab sample is characteristic of a light oil or petroleum fraction such as diesel. The sample was a stain and had a more liquid character than the bitumen sample taken (Revill, 1996). There are maturity differences between the liquid (oil) and solid (bitumen) although hydrocarbons in both samples share a similar source (Revill, 1996).

Conclusions from the geochemical reports indicate that the seep appears to have been subjected to light biodegradation and the samples taken are likely to have undergone some migration since generation from the source rock. Aromatic maturity indicators indicate that the seep was generated and expelled from a moderately mature source interval (Vitrinite Reflectance (VR_{equiv} = 0.80%) and saturated biomarker maturity indicators support this level of maturity (Wythe and Watson, 1996). Revill (1996) classifies maturity of between 0.57–0.62% for the swab sample and 0.61-0.70% for the bitumen sample.

Revill (1996) states that the source is likely to be Permian mudstone containing Tasmanites Oil Shale and Wythe and Watson (1996) indicate that the oil seep is likely to have been derived from a mixed algal/terrestrial source containing abundant Tasmanites Oil Shale alga deposited in an anoxic, marine environment.

The value of VR_{equiv} = 0.80% given by Wythe and Watson (1996) is not anomolous and does fit the regional maturity trend. However, it is still difficult to assess whether this hydrocarbon was expelled as a result of localised heat from dolerite emplacement or of more widespread burial maturation.

The models put forward above by Wythe and Watson (1996) and Revill (1996) that the oil seep, consisting of a migrated, low sulphur oil derived from a moderately mature Tasmanites-rich source rock, was migrated into the late stage dolerite joints when they were open, can be supported by the data.

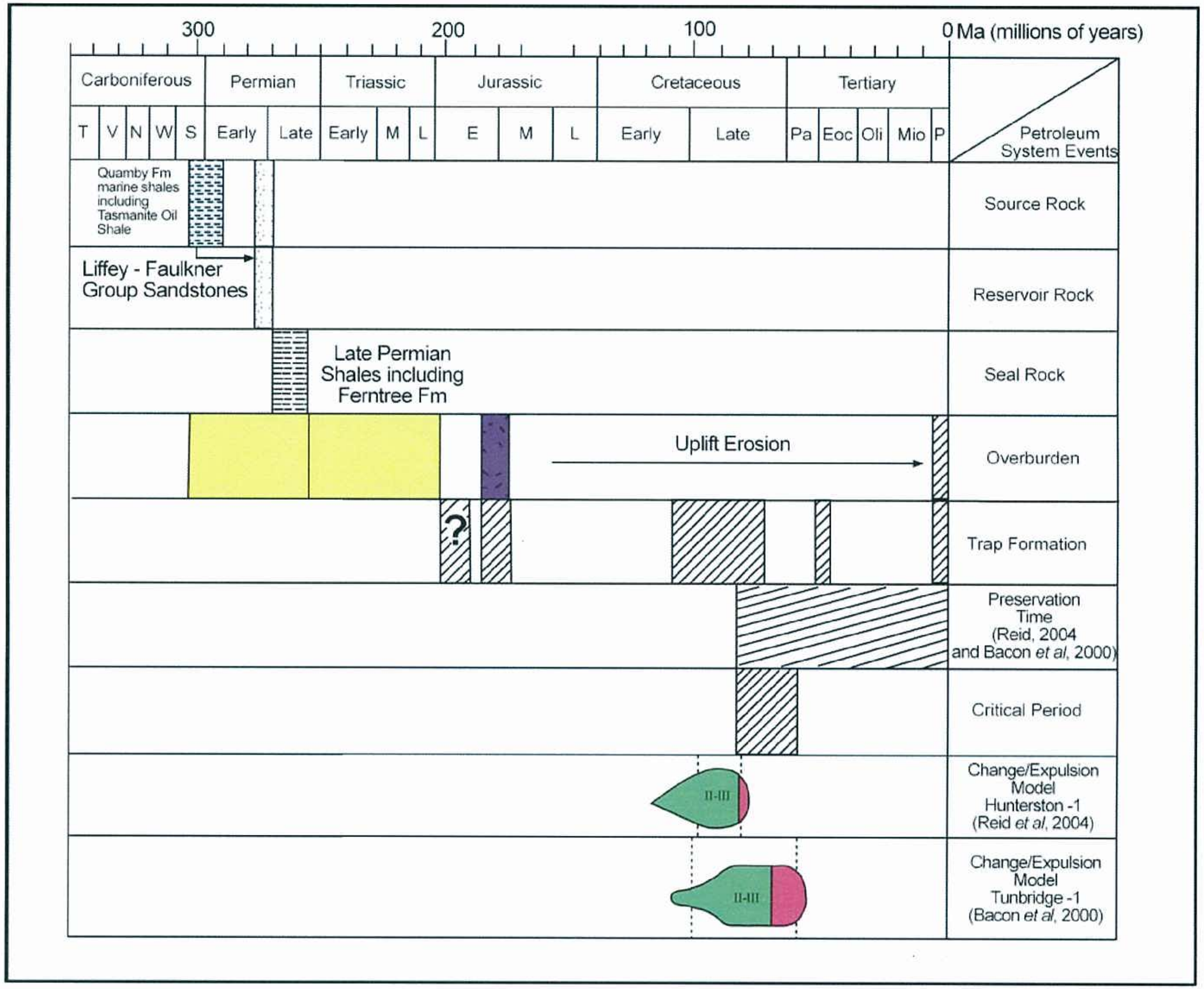

Figure 13 – Hypothetical Pre-Carboniferous Petroleum System (modified from Wakefield, 2000)

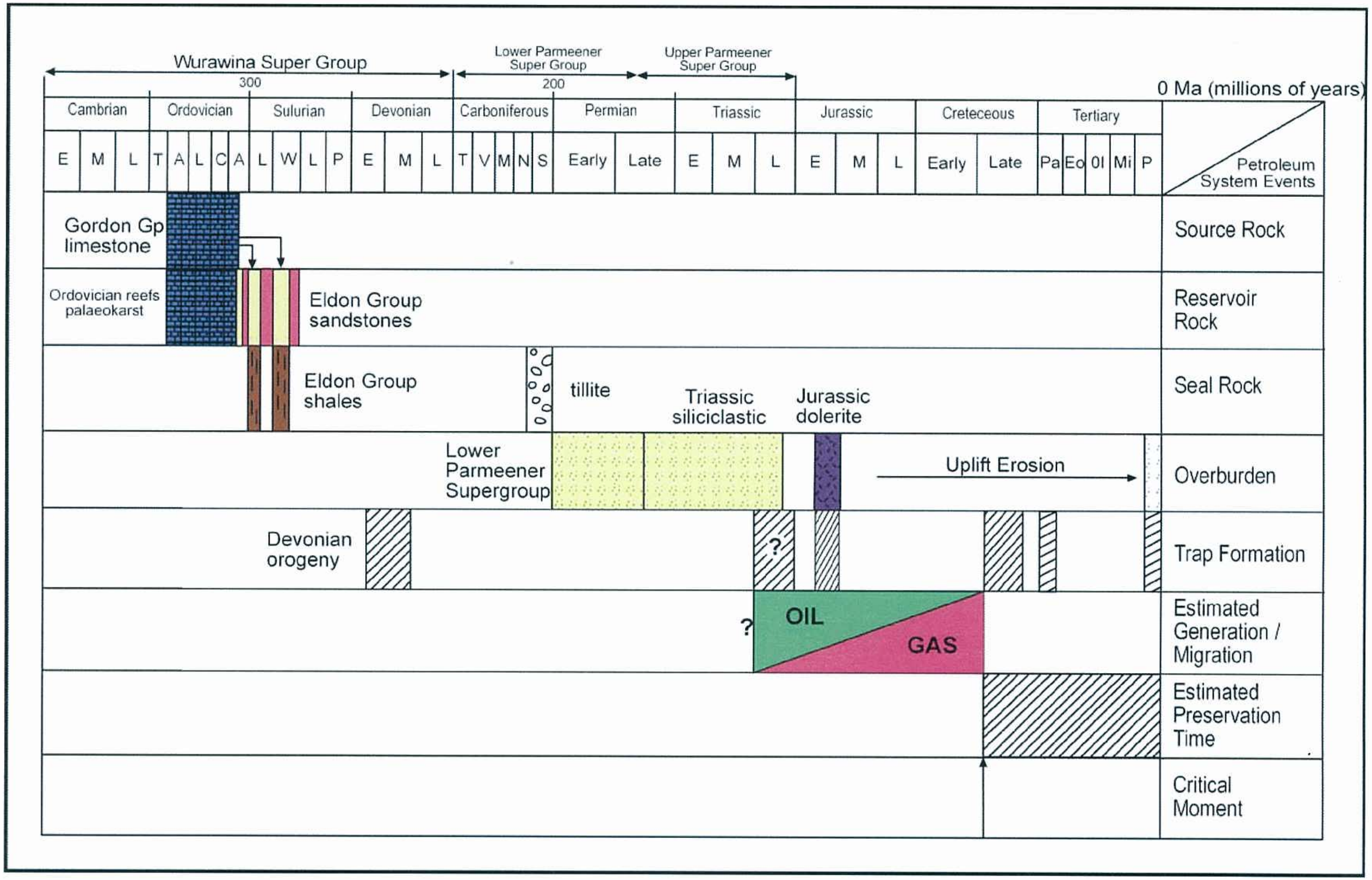

Figure 14 – Hypothetical Permian Petroleum System (modified from Wakefield, 2000)

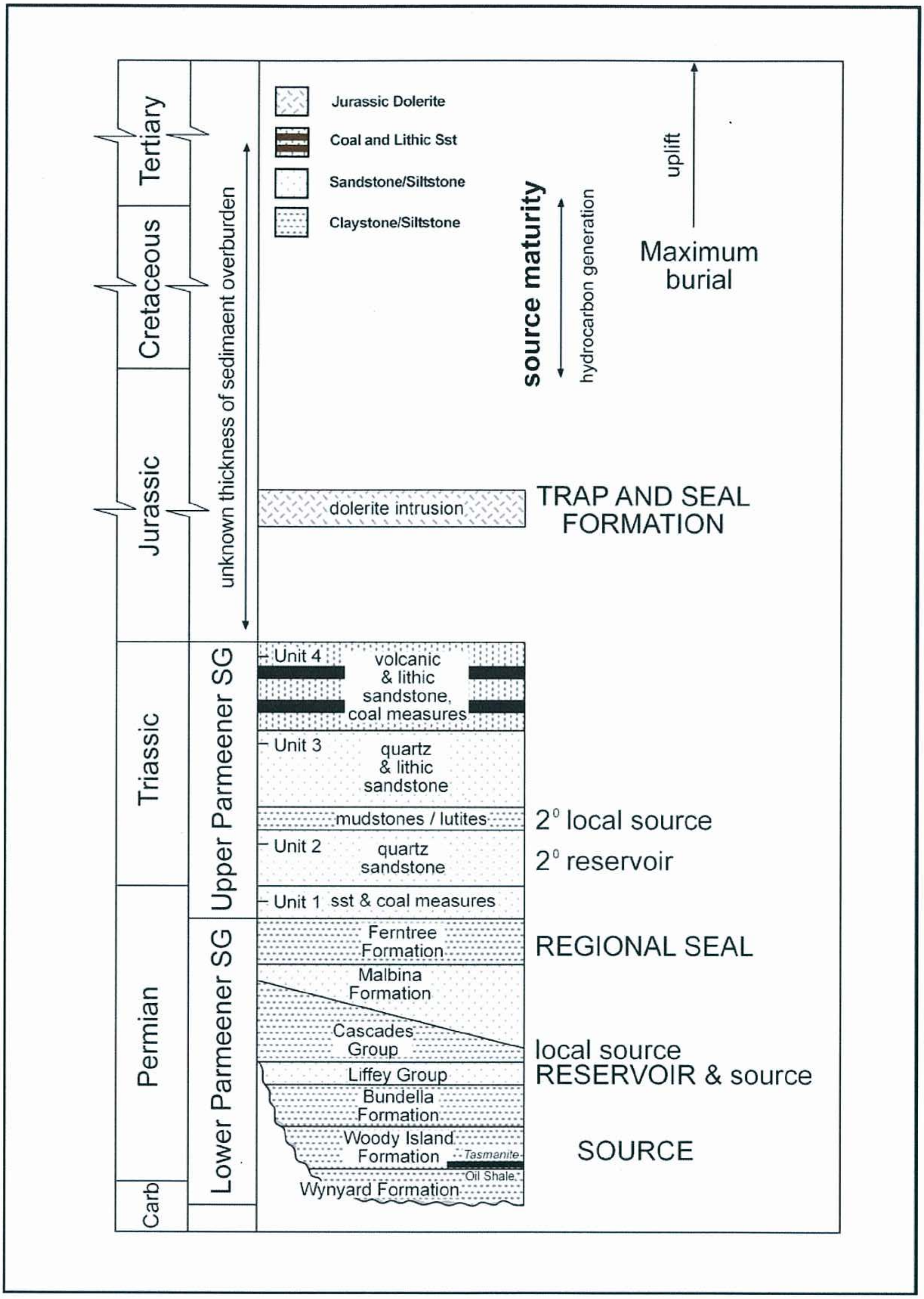

Figure 15 – Stratigraphic model of Permian plays (modified from Reid and Burrett, 2004)

3.2 Source Rocks

3.2.1 Pre-Carboniferous (Larapintine) Source Rocks

The oldest potential source in the Tasmania Basin is Ordovician, however, organic richness data has yet to be adequately verified. Measurements of total organic carbon (TOC) and Rock-Eval (RE) have previously been made on a few samples of limestones within the Gordon Group but these data do not indicate that these limestones have any viable source potential (Reed and Beauchamp, 2001). However, more recent analyses of the shalier Gordon Group facies indicates higher TOC values, some above 1.0%, suggesting the possibility of source rocks in this interval.

Two samples, one from Queenstown and one from Ida Bay (Volkman ,1989; Bendall *et al,* 1991), were analysed and the distribution of n-alkanes was typical of mature hydrocarbon (Bacon *et al*, 2000). Ordovician aged rocks provide a source in other parts of Australia (Amadeus and Canning Basins) and other parts of the world.

Sediments in the Gordon Group are reported to have a petroliferous odour when struck by a hammer, and bituminous films have been seen along stylolites, providing evidence of generation and migration (Chester, 2003). Further occurrences of pyrobitumen have been sighted at road cuttings within and proximal to the limestones east of Queenstown. A sample of upper Gordon Limestone from Florentine Valley liberated gas on crushing.

Black shales of the Benjamin Formation have poor to good source potential. TOC in these rocks ranged from 0.43 to 1.83 (poor to fair), averaging 0.78%, with 80% of the samples below 1%. T_{max} ranged from 439° to 546° and averaged 490°. Most of these samples (66%) were in the oil window and the remainder were in the gas generation window (Chester, 2003).

3.2.2 Permian (Gondwana) Source Rocks

3.2.2.1 Early Permian Tasmanite Oil Shale (Basal Woody Island Formation)

The Permian aged Tasmanite Oil Shale is the most well known source rock in Tasmania. It has been previously documented as having TOC content ranges from good to very good, containing from 2.5% to over 60% (Burrett and Reid, 2004) and a hydrogen index between 700-1000mgHC/gTOC. These high measurements come from thermally immature sediments and represent the hydrocarbon potential of *Tasmanites*-rich source rock within Tasmania.

S_1+S_2 levels are high (from 10 to 900 mg/gm of rock) and although these bands are thin they can produce up to 3.7 bbls/m² (Demaison and Huizinga, 1991).

The distribution of the Tasmanite Oil Shale, as known at present, is shown in Figure 10. It is only known to occur in the north and eastern areas of the basin. The Tasmanite Oil Shale was not present in several wells in the south of the Tasmania Basin. It appears that several parts of the basin were sufficiently low in oxygen for some algal beds to be preserved.

The Tasmanite Oil Shale is a rich concentration of alga type kerogens present in the lower part of the Woody Island Formation. The individual algal bands range from 3 to 30 centimetres thick.

3.2.2.2 Early Permian Woody Island Formation Siltstone

The Woody Island Formation is present over a wide area as shown in Figure 10. Most of the Woody Island Formation is a carboniferous siltstone, deposited in proximity of retreating glaciers and is characterised by glacial peddle dropstones. The formation has poor to fair source potential with TOC values of 0.5 to 2% and contain Type III gas prone kerogens. Most of the siltstones have a low to fair S_1+S_2 (0.2 to 2) (Reid, 2004).

Organic rich shale show a higher TOC of >2 to over 10, with HI correspondingly higher (Reid and Burrett, 2004).

In Bicheno 10, ten source rock quality samples have been tested. Of the ten samples, three rank as good potential (TOC 1-2 %) Type III source rock, one ranks as good potential Type II/III (TOC 1.72%, HI 300) and one ranks as very good potential Type II (TOC 2.42%, HI 433). Another four samples rank as fair (0.5 -1% TOC) Type III. This implies a mixed gas/oil source with a generally higher proportion of gas-prone source.

It is clear that the basin produced marine organic matter and it was preserved in thin highly concentrated beds, eg. Tasmanite Oil Shale beds. The quality of the Woody Island siltstone at Bicheno 10 and other locations suggest that the basin had favorable conditions for the preservation of other organic matter.

T_{max} for the majority of the Woody Island Formation samples analysed varies from approximately 430°, which is below the oil window, and up to 465° and well within the oil window. Similarly, vitrinite reflectance is shown to range from Ro=0.55% (marginal) in the north east at Bicheno, to Ro=0.8% at Lonnavale and Ro=1.3% (gas and condensates) at Styx Valley in the southwest (Reid, 2004).

3.2.2.3 Permian Liffey Group

The Liffey Group is a non marine sequence within the overall marine sequences of the Lower Parmeener Supergroup. It consists of carbonaceous siltstone and sandstones and also included coal horizon in northern Tasmania.

The carbonaceous siltstones have less than 5% TOC, whereas the coal horizons have up to 65% TOC. The majority of the disseminated organic matter contains Type III kerogens. The disseminated carbonaceous material shows a similar characteristic and level of maturity to the underlying Woody Island Formation. However, the calculated yield from this potential source is three times lower at 0.87 bbls/m², primarily due to the thinner interval (Reid and Burrett, 2004).

A study of the Liffey Group samples from Hunterston-1 showed the presence of total organic matter of 0.22 to 2.9%. Some coal is present. The HI (hydrogen index) is < 78 in all cases, indicating that there is gas potential only. As the Liffey Group at Hunterston-1 has been over matured by contact metamorphism and perhaps burial maturation, the full potential of these rocks may not be indicated by these results.

3.2.2.4 Late Permian to Triassic Coal Measures

The Upper Parmeener Subgroup contains up to 600 metres of fluvial sandstone, including significant coal measures. These include the Cygnet Coal Measures in the northeast, and equivalents (Unit 1), and the Late Triassic lithic sandstones and coal measures (Unit 4).

The Cygnet interval comprises carbonaceous sandstones with interbedded cross bedded and ripple laminated channel sands and lie between the underlying Lower Parmeener Supergroup and the overlying massive sandstones of Triassic age. In southern Tasmania, the sandstones are feldspathic and grade into mudstones and thin coal seams. The interval varies in thickness and is restricted in extent, but is reported to be up to 100 metres thick.

The upper most Triassic coal measures are up to 300 metres thick and are dominated by volcanic lithic sandstones, minor claystones and also contain commercial coal reserves in north eastern Tasmania.

The following results are extracts from Bedi (2003). Five samples were taken from drill cores from Unit 4. Three were from the northeast of which one was a carbonaceous sandstone (Dalmayne); two were from 2 metre thick coal seams (Mt. Nicholas and Dalmayne) and two samples were of carbonaceous sandstone and siltstone from the south (Catamaran).

The TOC values are good to high ranging from 1.28 and 3.70 to 27.40 in the clastics and 25 and 63 in the coal seams. HI values are generally very low, below 100, but with one of the samples it is up to 188. This indicates Type III kerogens with a dominance of inertinite, a deficient gas prone marcel.

Vitrinite Reflectance from Catamaran, in the south, are in the wet gas to dry gas window ranging from 1.18% to 1.41%. T_{max} values of 523° and 535° show that these are over-mature for oil generation.

Vitrinite Reflectance from the samples taken in the northeast have Rv_{max} ranging from 0.59 to 0.93 and corresponding T_{max} values from 438° to 491°. The high valves are from one of the coal samples and represent maturity within the transition from the oil to wet gas window.

3.3 Maturity Indicators and Burial History

In summary, understanding the maturity and expulsion timing of the basin is difficult due to the influence of dolerite on vitrinite maturity, the scarcity of easily identified vitrinite, the mixture of maturity indicators and the apparent major uplift and erosion or "unroofing" across the basin.

3.3.1 Permian Maturity Indicators

Bacon *et al,* 2000, observe an obvious bimodal distribution in VR data due to over maturity of many samples due to heat from Jurassic intrusions. Reid (2004) produced a basin-wide maturity map (Figure 16). The main feature of this map is the lower maturity in the north of the basin and the very reliable low maturity in the east at Douglas River. Confidence in the maturity of samples at Hunterson-1 and Styx Valley is qualified due the presence of dolerite at these locations.

3.3.2 Timing of Maturity

Bacon *et al* (2000), following on from the apatite fission track (AFT) work of O'Sullivan and Kohn (1997) and Sutherland (1977), suggest the maximum burial of the basin occurred just before 100 Ma. This puts useful constraints on any attempt to model the burial history and the maturity of the source rocks.

The burial history was modelled at Tunbridge-1 and Douglas River (Bacon *et al,* 2000) and at Hunterston-1 and the Styx Valley (Reid, 2004). In the Tunbridge-1, Hunterston-1 and Styx Valley models, it was suggested that a peak maturity of 1.2 to 1.3 VR% was reached during the second half of the Cretaceous. In all models, a constant 35 degrees C/km has been assumed from the Permian to the present, for useful simplification. Models presented in Reid *et al* (2004) were described by the author as "best case" and were similar to those in Bacon *et al,* (2000) but indicating a charge later in the Cretaceous. The timing of both models is illustrated in Figure 14.

The fundamental feature of these models is the maximum burial in the Cretaceous, which is constrained by the AFT data. This implies expulsion at around the Middle Cretaceous just before the entire basin begins to uplift and perhaps tilt in various directions while expulsion was occurring. This timing implies the risk that hydrocarbons formed before traps or before traps were stabilised. However, the uplift may have been very gentle, preserving the existing traps. The very limited structuring of the Carboniferous to Jurassic seems to give support to this idea. Extension in the Middle Tertiary and compression at the close of the Tertiary presents some trap preservation risk. Long preservation times are of course possible in Palaeozoic basins (eg. Amadeus Basin in Central Australia, Appalachian Basin in the USA).

3.3.3 Pre-Carboniferous

Not all of the Pre-Carboniferous section in southern Tasmania is over matured at the present day (Burrett, 1992) (Figure 6). However, there is still a risk that Pre-Carboniferous rocks were expelled before the stabilisation of traps during the Tabberabberan Orogeny.

No models of this concept have been made because there is not enough constraining data available. However, we can infer from the burial models of Bacon *et al* (2000) in Figure 17 and Reid (2004) that these rocks (lying some kilometres deeper than the Permian) could have re-entered the oil gas window in the Mesozoic to Tertiary. Under this scenario the most likely charge phase would be gas from an already partly depleted hypothetical Ordovician source.

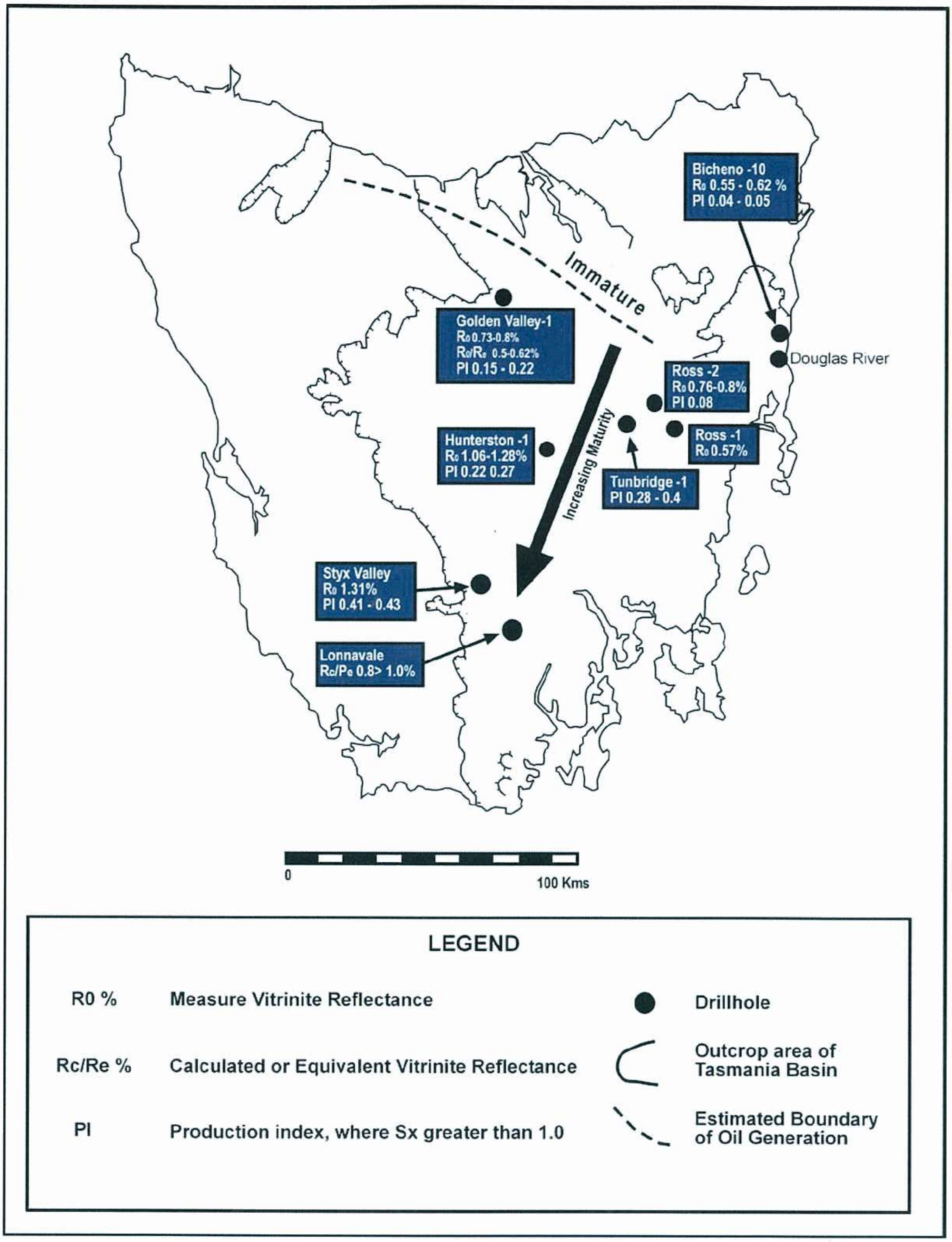

Figure 16 – Maturity of the Lower Parmeener Super Group (modified from Reid, 2004)