Interim Gippsland Basin unconventional resource assessment

Geoscience Australia
Executive summary

The offshore Gippsland has a significant petroleum production history, yet relatively little unconventional exploration has been conducted onshore. New production from unconventional resources in these basins could offset declining production from the offshore fields to feed into the National Energy Market, if, policy settings and market conditions make extraction viable. This study provides an understanding of the potential for undiscovered unconventional liquids and gas in the Gippsland Basin, and highlights significant knowledge gaps.

A probabilistic volumetric assessment method has been used to assess the potential for unconventional liquids and gas resources, including shale gas and liquids, and tight gas in the Gippsland Basin.

The Cretaceous-aged Strzelecki Group was the only unit found to be potentially prospective for unconventional hydrocarbons and with sufficient publically-available data for an assessment to be performed. The table below summarises the potentially recoverable shale and tight gas-in-place (GIP), and shale liquids-in-place (OIP) resources estimated as 5% median assessed volume (P50) in the Gippsland Basin. The liquids-in-place assessment includes both oil and condensate, and is abbreviated to OIP.

<table>
<thead>
<tr>
<th></th>
<th>Potentially recoverable GIP (TCF) (5% @ P50)</th>
<th>Potentially recoverable OIP (B bbl) (5% @ P50)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gippsland Basin tight resources</td>
<td>13.6</td>
<td></td>
</tr>
<tr>
<td>Gippsland Basin shale resources</td>
<td>5.6</td>
<td>1.1</td>
</tr>
<tr>
<td><strong>Total Gippsland Basin (TCF)</strong></td>
<td><strong>19.2</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Total Gippsland Basin (B bbl)</strong></td>
<td></td>
<td><strong>1.1</strong></td>
</tr>
</tbody>
</table>

For all assessments completed, publically available data specifically relevant to Gippsland Basin shale and tight resource plays was limited, necessitating the use of analogues and geologically reasonable assumptions. Significant improvements could be made to the reliability of this assessment if more data was available.
## Contents

Executive summary ................................................................................................................................. iii
1 Introduction ............................................................................................................................................ 5
   1.1 Petroleum – conventional versus unconventional ............................................................... 6
   1.2 Petroleum systems ...................................................................................................................... 7
      1.2.1 Petroleum accumulation types ......................................................................................... 8
   1.3 Unconventional resource assessments .................................................................................... 9
      1.3.1 Assessment methods ......................................................................................................... 9
2 Regional geology .................................................................................................................................11
   2.1 Structural geology .....................................................................................................................11
   2.2 Basin evolution and depositional history ................................................................................11
3 Method .................................................................................................................................................16
   3.1 Shale resources method ..........................................................................................................17
      3.1.1 Data inputs and sources ..................................................................................................17
      3.1.2 Defining area, prospective area, thickness and net thickness .........................................20
      3.1.3 Estimating OIP and GIP using @Risk .............................................................................24
      3.1.4 Recovery factor ...............................................................................................................25
   3.2 Tight gas method ......................................................................................................................25
4 Results .................................................................................................................................................27
   4.1 Shale resource assessment ......................................................................................................27
      4.1.1 Strzelecki Group ..............................................................................................................27
   4.2 Tight gas assessment .............................................................................................................29
      4.2.1 Strzelecki Group ..............................................................................................................29
5 Assessment limitations .......................................................................................................................31
   5.1 Shale resource assessment ......................................................................................................31
   5.2 Tight resource assessment .....................................................................................................33
6 Conclusion ...........................................................................................................................................35
7 References ..........................................................................................................................................36
Appendix A @Risk input tables ..............................................................................................................39
1 Introduction

The offshore Gippsland Basin has a history of successful petroleum exploration, with more than 26,089 PJ of liquids and 9,120 PJ of gas being produced as at 2014, and an estimated 13,96 PJ of crude oil, 959 PJ of condensate, 609 PJ of LPG and 9,253 PJ of conventional gas remaining in numerous fields (Geoscience Australia & BREE, 2014). Despite exploration in the onshore Gippsland Basin since the late 1800s, success has proved more elusive. The first discovery in the onshore Gippsland Basin occurred in 1924 at Lake Bunga, followed by the Lakes Entrance field in the 1930’s from which a small amount of oil was produced.

Numerically quantifying the potential of unconventional plays in the onshore Gippsland Basin has been complicated by a lack of data, and thus previous estimates are limited. The only estimate of onshore unconventional potential to date in the Gippsland Basin is 1221 PJ of resource (Core Energy Group, 2012). The EIA (2011, 2013) and AWT International (for ACOLA, 2013) did not assess potential in the onshore Gippsland Basin as the basin did not meet their screening criteria. The estimated GIP for the Trifon/North Seaspray, Gangell and Wombat accumulations at P50 level is 1877 bscf (Lakes Oil, 2015) and is currently the only relatively well constrained estimate of tight gas potential in the basin. In 2015, four Gippsland Basin resources: conventional gas, tight gas, shale gas and coal seam gas were reviewed, but not quantified by the Victorian Department of Economic Development (Goldie Divko, 2015).

The aim of this study is to attempt to quantify the unconventional potential of the onshore Gippsland Basin where possible, by assessing the potential for shale gas and liquids, and tight gas plays using existing data. No assessment of coal seam gas or conventional gas plays will be included. The primary focus of this study is the eastern onshore Gippsland Basin, where there is sufficient data available to conduct an assessment (Figure 1-1).
1.1 Petroleum – conventional versus unconventional

The ‘shale gas’ revolution of the last ten years in the US has prompted other countries to assess their own unconventional gas and oil potential but as yet no other country has been able to repeat the success of the US. The apparent overnight success of shale production actually took more than 20 years to come to fruition. Much needed to be learnt about the hydrocarbon-bearing geology and technological development was required to maximise the liberation of oil and gas while minimising drilling (and hence cost). The availability of existing infrastructure, ready markets, and favourable landholding and resource ownership rights were also essential to the success of the US industry. Until massive scales of economy can be reached through the entire value chain, unconventional oil and gas remain expensive to develop, and present a barrier to early exploration and development investment.

The use of the terms ‘conventional’ and ‘unconventional’ to describe petroleum accumulations is very imprecise, and is an accident of history. Conventional petroleum accumulations are so called because they were the first to be accessed by shallow drilling and have provided the majority of oil produced worldwide to date. However, they are relatively rare, comprising a small part of the petroleum continuum. Conventional petroleum accumulations occur as discrete pools of oil and gas in geological traps, having migrated away from the petroleum source via permeable rock layers. Unconventional is
used to refer to a collection of other types of petroleum accumulations. These other accumulations include shale oil and gas, oil shales, tight oil and gas, basin-centred gas, coal seam gas and methane hydrates. Not all unconventional accumulation types are relevant in Australia.

Unconventional and conventional accumulations can form from the same source (Figure 1-2). To paraphrase an old advertisement – ‘oils ain’t oils’. Differences in expulsion, transport, and trap mechanisms results in the application of different extraction methods for conventional and unconventional reservoirs. Due to low formation permeabilities, many wells are required to produce from an unconventional reservoir as the sweep area of a single well plus its hydraulically-stimulated fracture cloud is much smaller than in a high permeability conventional reservoirs. This is often cited as the definitive difference between conventional and unconventional reservoirs.

In an effort to develop a geologically-based differentiation between conventional and unconventional gas systems, the USGS introduced the term ‘continuous accumulation’ (Gautier et al., 1995, Schmoker, 1995) for unconventional accumulations. A continuous accumulation is a single large field (commonly of regional dimensions) that is not significantly influenced by the water column. It does not owe its existence directly to the buoyancy of gas in water and is not composed of discrete, countable fields delineated by downdip water contacts. The fields that are identified within continuous accumulations are actually indistinctly bounded areas with better production characteristics known as sweet spots (Schmoker, 2002). Unconventional gas systems that are also continuous accumulations include coalbed methane, basin-centred gas, so-called tight gas, fractured shale (and chalk) gas, and gas hydrates. These types of accumulations, although diverse in many ways, all meet the geologic criteria of continuous accumulations (Schmoker, 2002).

1.2 Petroleum systems

In order to clarify the use of the various terms throughout this report, a brief process-oriented summary of petroleum systems is included.

The term ‘petroleum system’ describes the genetic relationship between an active source rock and the resulting oil and gas accumulations (Magoon and Dow, 1994). It includes all the essential elements and processes needed for oil and gas accumulations to exist. These include the source, reservoir, seal, and overburden rocks, and the trap formation, generation, migration and accumulation processes. All essential elements and processes must occur in the appropriate time and space in order for petroleum to accumulate (Magoon and Dow, 1994).

Organic material, incorporated during the deposition of sedimentary material, is heated during burial, converting the organic material to petroleum in a process called maturation. A portion of the petroleum formed may be expelled from the source rock, and may then migrate through permeable sediments and structures until it is trapped by an impermeable barrier forming a conventional accumulation; otherwise the petroleum escapes to the Earth’s surface. Alternatively, some or all of the petroleum may stay trapped in or quite near the source rock, forming an unconventional accumulation. Methane hydrates form differently and are not further discussed here.
1.2.1 Petroleum accumulation types

**Conventional oil and gas reservoirs**

Conventional reservoirs occur as discrete accumulations trapped by a geological structure and/or stratigraphic feature, typically bounded by a down-dip contact with water (Figure 1-2). The petroleum was not formed *in situ*; it migrated from the source rocks into the trap. The petroleum is extracted through relatively few wells; usually with no permeability enhancement required. In contrast in tight-discrete-gas reservoirs, migrated gas accumulates in low permeability rocks and hydraulic stimulation is required for extraction.

**Shale oil and gas**

Shales are a common petroleum source rock, and can retain more petroleum than they expel during maturation. They have low to moderate porosity with pore sizes on the nanomillimetre scale, and have very low permeability. They are sometimes referred to as 'self-sourcing reservoirs'. They occur with significant (10–100 km) lateral continuity, can be of considerable thickness (0.1–100 ms), and require hydraulic fracturing for extraction.

**Basin-centred gas, tight (pervasive) gas**

Basin-centred and tight gas reservoirs are abnormally pressured, gas-saturated accumulations in low-permeability reservoirs lacking a down-dip water contact. The hydrocarbons migrated and the gas was trapped as a ‘bubble’ within a high-pressure, water-saturated reservoir. This phenomenon is caused by the relative permeability of gas and water in the reservoir. The water pressure prevents the oil and gas from migrating through capillary pressure. The reservoir can be laterally and vertically extensive, with gas saturation pervasive throughout. The rate of migration of gas into the reservoir exceeds the rate of gas migrating out of the reservoir, which implies that these reservoirs exist only contemporaneously with active gas generation from a nearby source.
**Coal seam gas**

Coals release methane through either thermal or biogenic maturation. As gas is generated the significant increase in volume fractures the coal. The gas is transiently held in place by hydrostatic pressure. Removal of water by hydraulic fracturing and pumping extraction allows the release of adsorbed gas, so it, together with the free gas can flow to the surface.

**Oil shale**

In oil shales the organic matter has not been converted to petroleum and is immature. These shales can be mined and heated quickly to 550°C (retorted) in order to generate oil. This is a very energy intensive and expensive process, and hence is a relatively uncommon form of oil production.

### 1.3 Unconventional resource assessments

#### 1.3.1 Assessment methods

There are three main classes of resource assessments – generative, gas- or oil-in-place and estimated ultimate recovery (EUR). Generative assessments assess the ability of a petroleum system to generate petroleum. Gas- or oil-in-place assessments calculate the concentration of petroleum in the reservoir at the present day. This relies on having measured gas, condensate and oil concentration data. Estimated ultimate recovery assessments use petroleum production data and reservoir simulation models to forecast future production potential from the reservoir assuming a given set of parameters. EUR assessments can only be used for reservoirs with existing production, as they rely heavily on the known production characteristics of the reservoirs.

For all three of these approaches, it is possible to use a probabilistic assessment approach, defining parameters within the assessment as probability distributions in order to provide a statistically based range of possible outcomes. A probabilistic assessment incorporates probability distribution functions and Monte Carlo modelling to account for natural variability and uncertainty. Where there are many data points available, a distribution curve is fitted to the data. However, in most cases, statistically reliable data is not available, and a distribution curve is manually built to encompass the available data, with an allowance for expected natural variation. The estimation of gas- or oil-in-place (for example) is made using software which takes random draws from each parameters’ probability distribution function to calculate each iteration. After many thousands of iterations are run, the results of the simulation are presented as a series of probability distributions for each input and output parameter. This probabilistic method captures estimates of uncertainty in each parameter, and propagates these throughout each calculation, resulting in a range of estimates. Reports typically give a low estimate (P90 – 90% probability that at least this much oil or gas can be found in place), a middle estimate (P50 (median) – 50% chance of occurrence; or mean), and a high estimate (P10 – only a 10% chance that this volume of oil or gas will be found or exceeded).

An estimated recoverable volume is calculated by applying a recovery factor to the assessed volume of oil or gas. The recovery factor is intended to reflect risks in exploration (need to find ‘sweet spots’, data quality), risks in development (applying a Mechanical Earth Model to optimise drilling and hydraulic stimulation to the local stress regime for mobilisation of oil and gas), as well as other factors impacting development (e.g. government policy, uncertainties in project approvals, finance and infrastructure). In established reservoirs with high levels of knowledge, known production characteristics and current technology able to recover a high percentage of oil and gas from the
In this study, a probabilistic volumetric gas- and liquids-in-place assessment method was used to assess the potential for unconventional resources including tight gas and liquids, and shale gas and liquids in the Gippsland Basin. The P10, P50, mean and P90 GIP and OIP resources for each prospective area, and the cumulative P10, P50, mean and P90 GIP and OIP resources for each reservoir and basin is reported. The potentially recoverable tight and shale GIP and OIP resources estimated as 5% median assessed volume (P50) are reported as the final results of the assessment. The resource assessment was made using publically available data, which is sparse and possibly unrepresentative for some parameters. The application of a low (5%) recovery factor is intended to reflect the uncertainties in the resources in place and their path to commercialisation in the medium term.

Assessments of the unconventional potential of the Otway, Canning, Perth and Cooper basins have also been completed as part of Geoscience Australia’s unconventional resource assessment series. All of the assessment reports and the underlying digital data including map packages are available at http://www.ga.gov.au/.
2 Regional geology

2.1 Structural geology

The Gippsland Basin is aerially restricted (46 000 km²), with approximately two-thirds of the basin located offshore. The Gippsland Basin is bounded to the north by Paleozoic basement of the Eastern Uplands, to the west by uplifted Lower Cretaceous fault-blocks and to the southwest by the Bassian Rise, which separates it from the Bass Basin to the west (DRET and Geoscience Australia, 2011).

The Gippsland Basin trends east-west and is comprised of a deep central depression symmetrically bounded by faulted terraces and stable platforms on the north and south. The Northern, or Lakes Entrance Platform, is bounded on the south by the Lake Wellington fault and the Southern Platform is bounded on the north by the Foster fault system (Figure 2-1). Sediments of the basin crop out in the west and are deeply buried offshore and to the east. The deep Seaspray Depression continues offshore as the Central Depression (Central Deep) and lies between the Rosedale fault, which defines the southern edge of the Northern Strzelecki Terrace, and the Darriman fault, which defines the northern edge of the Southern Strzelecki Terrace (Figure 2-1).

Normal faults trending northwest to southeast, of Early Cretaceous to Early Eocene age, characterize the central depression. The major offshore fields are located in anticlinal traps formed by compressional events and shear faults associated with the opening of the Tasman Sea. Late Eocene to Early Oligocene and Late Miocene age anticlines are generally oriented southwest to northeast and are located in the central depression and on the northern terrace (Bishop, 2000).

2.2 Basin evolution and depositional history

The Gippsland Basin was formed as a consequence of the break-up of Gondwana in the latest Jurassic to earliest Cretaceous (Rahmanian et al., 1990; Willcox et al., 1992; Willcox et al., 2001; Norvick and Smith, 2001; Norvick et al., 2001). The initial rift architecture of the Gippsland Basin consisted of a rift valley complex which was composed of multiple, over-lapping to isolated, approximately east-west trending half-graben. Continued rifting into the Late Cretaceous generated a broader extensional geometry which consisted of a depocentre (the Central Deep, and its onshore extension the Seaspray Depression; Figure 2-1) flanked by fault-bounded platforms and terraces to the north and south. The Rosedale and Lake Wellington Fault systems marked the northern margin of the Seaspray Depression and Lake Wellington Depression respectively, with the Darriman and Foster Fault systems defining the southern margin of the Seaspray Depression, and the northern boundary of the Alberton Depression respectively (Figure 2-1). The western onshore extent of the basin is traditionally placed at the Mornington High. However, the Latrobe Group’s extent is effectively defined by the outcrops of the Lower Cretaceous Strzelecki Group (Hocking, 1988). The eastern boundary of the basin is defined by the Cape Everard Fault System (Moore and Wong, 2001).

The Gippsland Basin has been progressively infilled by three major sedimentary sequences: the thick basal non-marine volcanioclastic Strzelecki Group, the marine and non-marine siliciclastic Latrobe Group, and the carbonate dominated Seaspray Group. The Pliocene–Pleistocene Sale Group caps the succession (Figure 2-2).
Figure 2-1 Structural elements of the Gippsland Basin (Wong et al., 2001).
Figure 2-2 Stratigraphy of the Gippsland Basin (Goldie Divko, 2015).
The basal alluvial fan conglomerates (Tyers River Sub-group) of the Strzelecki Group were deposited into a complex system of graben and half-graben during the initial rifting phase in the Early Cretaceous. The Tyers River Sub-group may be confined exclusively to the newly proposed Monash Trough feature, potentially separated from the main body of the Gippsland Basin (the ‘Strzelecki Basin’) by a pre-existing Glengarry Basement Block (Holdgate et al., 2015), though further work is needed to distinguish between the Latrobe Valley units and seemingly lateral equivalents in the southern Gippsland Basin (e.g. Chiupka, 1996a, b). Volcanogenic sediments sourced from the east initiated additional subsidence in the Barremian-Albian, and triggered the deposition of a thick sequence of fluvial interbedded lithic and volcaniclastic sandstones and mudstones, and in the south Gippsland area, black coals forming the upper Strzelecki Group in the Gippsland Basin, and its lateral equivalent - the Eumeralla Formation in the Otway Basin (Tosolini et al., 1999).

Continued extension and subsidence caused the formation of a series of large lakes and associated fluvial feeder systems and the commencement of coal-rich Latrobe Group deposition with the basal-most of four constituent sub-groups – the Emperor Sub-group. The Emperor Sub-group includes the lacustrine Kipper Shale and fluvio-deltaic Curlip Formation (Marshall and Partridge, 1986; Marshall, 1989; Lowry and Longley, 1991).

The Latrobe Group is spatially restricted onshore, where it is found primarily in the Seaspray Depression. The Longtom unconformity separates the freshwater lacustrine dominated Emperor Sub-group from the fluvio-deltaic and paralic sediments of the Chimaera Formation in the Golden Beach Sub-group. It is likely this change in depositional environment was trigged by the onset of Tasman Sea rifting and the reactivation of earlier faults (Partridge, 1999; Bernecker and Partridge, 2001). Continued rift-related extensional tectonism continued until the early Eocene and produced pervasive northwest-southeast-trending normal faults, especially in the Central Deep. At about this time (85–80 Ma, Santonian–Campanian) the northward propagating Tasman spreading centre passed by the Gippsland Basin causing the eruption of mafic volcanics and widespread emplacement of related intrusions occurred across the Gippsland Basin (O’Halloran and Johnstone, 2001). This volcanic activity persisted until the early Oligocene, with a major pulse occurring in the late Paleocene (54.7–57.2 Ma) with the emplacement of the Carrajung Volcanics across the basin, but particularly intensely in the vicinity of the Balook Block and Narracan Blocks (Holdgate et al., 2004; Figure 2-1).

Following the deposition of the Golden Beach Sub-group a sequence of alluvial-fluvial, deltaic and marine sediments were deposited across the basin forming the Halibut Sub-group. In the onshore this sub-group comprises upper coastal plain fluvial sediments of the Barracouta Formation, the Yarram Formation and the lower coastal plain coal rich sediments of the Kingfish Formation. The Halibut Sub-group and is spatially restricted to coastal wells in the Seaspray Depression. By the middle Eocene, sea-floor spreading had ceased in the Tasman Sea and there was a period of basin sag during which the Cobia Sub-group was deposited. The most spatially extensive formations of the onshore Cobia Sub-group, the lower coastal plain coal-rich Burong Formation and the fluvial Traralgon Formation were deposited during this phase. This was followed by the transgressive shallow-to-open-marine Gurnard Formation, which is a condensed section characterised by fine- to medium-grained glauconitic siliciclastics (Figure 2-2).

In the late Eocene, a compressional period began to affect the Gippsland Basin, initiating the formation of a series of northeast to east-northeast-trending anticlines (Smith, 1988). Compression and structural growth peaked in the middle Miocene and resulted in partial basin inversion. The major fold structures at the top of the Latrobe Group, which became the hosts for the large oil and gas accumulations in the offshore, including Barracouta, Tuna, Kingfish, Snapper and Halibut, are related to this tectonic episode.
Post-rift depositional architectures and settings became dominant in the Gippsland Basin from the early Oligocene. The shift from the siliciclastic sediments of the Latrobe Group to the cool water carbonates of the overlying Seaspray Group was triggered by a change in oceanic circulation on the southern Australian margin (Holdgate and Gallagher, 1997). The dominantly calcareous marine sediments of the Seaspray Group, including the regional seal of the Lakes Entrance Formation (Figure 2-2) and Gippsland Limestone were widely deposited at this time. The middle Miocene–Pliocene sequence of the Wuk Wuk Marl, Bairnsdale Limestone, Tambo River Formation and Jemmys Point Formation rests unconformably on the Gippsland Limestone. These units have a complex inter-fingering relationship with increasingly terrestrial influenced formations to the northwest including the barrier sands of the Balook Formation and the back-barrier swamp and coastal plain Latrobe Valley Sub-group. In the Latrobe Valley Depression, the Latrobe Valley Sub-group includes the Traralgon, Morwell, and Yallourn formations which host extensive brown coal deposits (Figure 2-3). In the South Gippsland area, the Alberton Coal measures are a lateral equivalent of the Morwell Formation (Holdgate, 2005).

Figure 2-3 Diagrammatic cross-section showing the main Latrobe Valley coal measures and their relationship with the Seaspray Group (Holdgate, 2005).
3 Method

A probabilistic volumetric analysis method was used to calculate shale and tight liquids- and gas-in-place in the Gippsland Basin. The method is similar to that applied in previous studies (EIA, 2011, 2013; AWT International, 2013). The mathematical approach used in this assessment is summarised as follows. Gas in shale reservoirs can be broken into two main parts: free gas and adsorbed gas. The calculation for free gas-in-place (FGIP) uses the following standard reservoir engineering equation:

\[ \text{FGIP} = \frac{Ah\Phi(1 - Sw)}{B_g} \]

Where:
- \( \text{FGIP} \) = free gas-in-place (sm³)
- \( A \) = prospective area (m²)
- \( h \) = net shale thickness (m)
- \( \Phi \) = porosity (fraction)
- \( Sw \) = water saturation (fraction)
- \( B_g \) = gas formation volume factor (volume at reservoir condition/volume at surface condition)

The adsorbed gas-in-place (AGIP) is calculated (after EIA, 2011; 2013) as:

\[ \text{AGIP} = GCa \times \rho_b \]

Where:
- \( \text{AGIP} \) = adsorbed gas-in-place (m³)
- \( GCa \) = adsorbed gas content in shale (sm³/g)
- \( \rho_b \) = bulk density of shale (g/cm³)

This method was chosen as it is a relatively simple approach, and is useful in dealing with the uncertainty associated with undertaking assessments in basins where data are sparse. The methodology used to produce an assessment of the shale and tight liquids- and gas-in-place can be broken down into the following key steps:

1. Collate available geological data and create required derivative datasets
2. Decide which formations are to be assessed in the basin
3. Define the prospective volume for each formation
4. Calculate the shale or tight gas- and liquids-in-place using distributions fitted to real or analogous data in @Risk
5. Apply a recovery factor

These steps will be discussed in more detail in the following sections.
3.1 Shale resources method

3.1.1 Data inputs and sources

Details of the input data used to characterise the Strzelecki Group shale resource play are shown in Table 3-1. Further details are discussed in the text following the tables. Selected input data and the related statistical analyses are contained in the spreadsheets which accompany this report.

Assessment extent

The primary focus of this study is the eastern onshore Gippsland Basin, where there is sufficient data available to conduct an assessment (Figure 1-1). Where appropriate, data from the ‘South Gippsland area’ (i.e. the Balook and Narracan blocks and the Tarwin Sub-basin) has been considered. In particular, data from the Megascolides 1 and 2 wells, which have been included in the Morwell area shale and tight resource assessment areas.

Datum

The GDA94 datum was used for all GIS data in the assessment. When calculating polygon areas the Albers equal area projection was used. All data uses the ground surface as the height datum.

Well locations

Well locations and basic statistics are compiled from sources including Geological Survey of Victoria (GSV), Geoscience Australia (GA) and GP Info in order to create a complete representation of the well locations. Where overt errors, particularly in total depth (TD), were observed during the course of the study these were manually corrected.
Table 3-1 Summary of data sources and associated assumptions/limitations of petrophysical parameters specific to the Strzelecki Group shale resource play.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Data source</th>
<th>Description/Assumptions</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation extent, thickness and depth</td>
<td>Stratigraphy compiled from GSV and GA databases with additional information from: Grosser (2005), Holdgate et al. (2015), Karoon Gas (2007b), and Lakes Oil (2007, 2008b, 2010, 2012).</td>
<td>This dataset is a compilation removing old stratigraphic names and attempting to resolve lateral equivalents. It also incorporates updates where available.</td>
<td>This stratigraphy does not represent a detailed stratigraphic reinterpretation of any kind.</td>
</tr>
<tr>
<td>Geochemistry data</td>
<td>Geochemistry data from GA and GSV database compiled with additional data from: Holdgate et al. (2015), Mehin and Bock (1998), and Karoon Gas, (2007b).</td>
<td>Rock Eval and vitrinite reflectance data were compiled and QC’d and used to underpin the prospective area and thickness mapping process.</td>
<td>Geochemistry data in parts of the Gippsland Basin are very sparse and from many different laboratories and vintages. While every attempt was made to include only the most reliable analyses, the compiled geochemistry dataset should be used with caution.</td>
</tr>
<tr>
<td>Net shale/sand ratio</td>
<td>Calculated for nine wells</td>
<td>Calculated for key wells from WCR composite logs and cuttings information</td>
<td>Relatively few values in some prospective area polygons. Poor composite log quality may result in unrealistic estimates.</td>
</tr>
<tr>
<td>Total porosity</td>
<td>Well completion reports (WCR’s) of Jolly 1 and Sawpit 2 (Beach Energy, 2013; 2014)</td>
<td>Lab measured total porosity</td>
<td>Data from the Sawpit Shale in Jolly 1 and Sawpit 2 in the South Australian Otway Basin have been used to characterise the Strzelecki Group. This data may not be a realistic representation.</td>
</tr>
<tr>
<td>Bulk density</td>
<td>WCR’s of Jolly 1 and Sawpit 2 (Beach Energy, 2013; 2014)</td>
<td>Lab measured bulk density</td>
<td>As above</td>
</tr>
<tr>
<td>Gas saturation</td>
<td>WCR’s of Jolly 1 and Sawpit 2 (Beach Energy, 2013; 2014)</td>
<td>Lab measured total gas saturation</td>
<td>As above</td>
</tr>
<tr>
<td>Oil saturation</td>
<td>WCR’s of Jolly 1 and Sawpit 2 (Beach Energy, 2013; 2014)</td>
<td>Lab measured total gas saturation</td>
<td>As above</td>
</tr>
<tr>
<td>Oil formation factor</td>
<td>Agrawal (1983).</td>
<td>Oil formation factor of the intra-Latrobe Group oil in Whiting Field, offshore Gippsland</td>
<td>The oil property in the intra-Latrobe Group may not be the same as that of the Strzelecki Group in the onshore Gippsland. As above</td>
</tr>
<tr>
<td>Gas expansion factor</td>
<td>Agrawal (1983).</td>
<td>Gas expansion factor of the intra-Latrobe Group in Whiting Field, offshore Gippsland</td>
<td>The gas property in the intra-Latrobe Group may not be the same as that of the Strzelecki Group in the onshore Gippsland.</td>
</tr>
<tr>
<td>Gas-to-oil ratio</td>
<td>Agrawal (1983).</td>
<td>Gas-to-oil ratio of the intra-Latrobe Group oil in Whiting Field, offshore Gippsland</td>
<td>As above</td>
</tr>
<tr>
<td>Adsorbed gas content</td>
<td>WCR’s of Jolly 1 and Sawpit 2 (Beach Energy, 2013; 2014)</td>
<td>Gas storage capacity from isotherm test</td>
<td>Data from the Sawpit Shale in Jolly 1 and Sawpit 2 in the South Australian Otway Basin have been used to characterise the Strzelecki Group. This data may not be a realistic representation.</td>
</tr>
</tbody>
</table>
Geochemistry data

TOC data

TOC values which indicate shale and coaly shale lithologies will be included for each formation. Values below 0.5% TOC will be regarded as not representing shales and hence excluded from the TOC average used to define the area and thickness of organically rich shales. The TOC thresholds used are shown below and are from Hall et al. (2016):

- Coal $\geq$ 50 wt%
- Shaly coal 20 wt%–50 wt%
- Coaly shale 10 wt%–20 wt%
- Shale 0.5 wt%–10 wt%

It is noted that these threshold values have been determined for fluvial, terrestrially derived shales and that in more marine influenced systems, the nomenclature of ‘coal’ is not appropriate. The 50 wt% cutoff threshold has been retained, however, on the premise that shale TOC values over 50 wt% are likely to have petrophysical properties significantly different to shales with <1 wt% TOC. However, at the same time, it is recognised the change in petrophysical properties that occurs with increasing TOC is a continuum (e.g. Wang et al., 2013) and that a case could be made for subdividing the TOC values into many more ‘lithological’ categories in order to best capture these changes.

Wells with no TOC >0.5 wt% for the whole formation as penetrated will be regarded as not containing any organically rich shales. However, data distribution will also be taken into account to ensure wells with insufficient data coverage (less than 10 TOC values within the formation) are not being excluded without good cause.

Rock Eval data

Three key steps were taken to ensure only reliable Rock Eval data was used in the maturity mapping process.

- remove any spurious S1+S2 values where there is only one of S1 or S2 in the analysis,
- calculate PI, HI, OI and PC values, and
- apply 0.1< PI < 0.4 cutoffs Ghori (2013) to exclude any data which may be indicative of contamination or migration.

Tmax reliability and Tmax-VR_o conversion

The following text documents the process used to ensure the most reliable Tmax to VR_o conversion possible. Tmax values where S2 is low are unreliable (e.g. S2<0.2 mg HC/g; Nuñez-Betelu and Baceta, 1994; Wallace and Roen, 1989; Peters, 1986; and S2< 0.5 mg HC/g; Dewing and Sanei, 2009) and TOC<0.1 wt% also produces unreliable Tmax values (Dewing and Sanei, 2009). Analyses where TOC<0.1 wt% will be removed from the Tmax dataset. The S2 cutoff values however necessitate an additional step for the maturity evaluation using Tmax. For the purposes of this study, a conservative threshold value of S2>0.5 mg HC/g has been used for all formations to ensure Tmax reliability is reasonable without decimating the dataset. While it is recognised that ideally the S2 cutoff value would be varied through the stratigraphic section in order to best represent factors such as kerogen type, maturity level and variable organic content, that level of analysis is beyond the scope of this study.
Tmax values meeting the TOC>0.1 wt%, S2>0.5 and 0.1<PI<0.4 thresholds which were converted into VR₀ values using the Jarvie equation (Jarvie et al., 2001) proved to have little relationship with the measured VR₀ data when plotted against depth (e.g. Figure 3-1), indicating the Jarvie equation conversion does not hold well for Gippsland Basin shales. As the Jarvie equation (Jarvie et al., 2001) was developed for the Barnett Shale, and so is representative of shales of different age, paleoenvironment, kerogen type and organic richness, the poor fit with measured VR₀ data in the Gippsland Basin is not particularly surprising. To ensure maximum reliability, measured VR₀ data has been preferentially used to map maturity in this assessment. The calculated VR₀ values have only been used to provide maturity indications in areas where there are currently no measured VR₀ values.

Figure 3-1 Measured VR₀ (blue) and Jarvie-converted Tmax (red) values versus depth in the Gippsland Basin.

3.1.2 Defining area, prospective area, thickness and net thickness

The key steps in determining the net prospective volume for each formation as used in the shale resource assessment are outlined as follows:

- The approximate areal extent of the formation was first evaluated using 3D surfaces and well intersections. Available well penetration/intersection data for the Strzelecki Group assessment can be seen in Figure 4-1.
- Cut-off thresholds for depth, thickness and average TOC were then applied with polygons for each parameter being drawn in ArcGIS. The final prospective area polygons were defined by the intersection of the TOC, depth and thickness polygons. The final prospective areas for the Strzelecki Group can be seen in Figure 4-1 and are summarised in Table 3-2.
- The net shale thickness within each prospective area was then calculated to create the prospective volume. This required two steps:
  - The initial thickness of the formation within each prospective area was calculated using the 3D model surfaces and/or well based stratigraphic picks.
  - The thickness of the formation within each maturity window in each prospective area was then calculated using vitrinite reflectance and Tmax data for each well, or a calculated regional trend. Due to the scarcity of well data and subsequent limited ability to define maturity in 3D, the same prospective area polygons were used to define the area which is prospective for oil, wet gas and dry gas. The inclusion of wells with zero results in the “thickness of each maturity
window' probability distributions was used as a rough proxy for how much of the area may be prospective in each maturity window.

- A net shale ratio was then applied to determine the prospective volume. As there is insufficient geochemistry data and highly variable well log quality all shales within each prospective area are assumed to be organically rich.

Three threshold values were used to find the prospective area. They are defined on the basis of:

- **Depth**: formation is found at depths between 1000–5000 m,
- **Formation thickness**: where true vertical thickness of the formation is ≥ 15 m, and
- **Total organic content**: where average TOC for shales in each well is ≥ 2 wt% +1 stdev.

A normal probability distribution function was assigned to all of the prospective areas during the final probabilistic modelling process, with the mean prospective area determining the central point. The maximum and minimum values for each prospective area probability function were ±10%.

Two threshold values were also used to find the prospective thickness, being defined on the basis of:

- **Maturity**: vitrinite reflectance (VRo, %) cutoffs for each maturity window: 0–0.7 VRo, oil: 0.7–1.0 VRo, wet gas: 1.0–1.3 VRo, gas: 1.3–3.0 VRo and over-mature: >3.0 VRo, and
- **Net shale thickness**: proportion of shale beds which are ≥ 15 m.

These thresholds are designed to ensure that shales within the prospective areas were organically rich and mature enough to have a reasonable chance of hosting hydrocarbons, be sufficiently pressured to preserve gas content and promote gas flow if developed, thick enough to potentially be commercially exploited, and to ensure the shales were at economically drillable depths given today's technology. Used together these thresholds define the 'prospective volume' for each formation. The following sections detail additional mapping and/or calculation information associated with the above key thresholds for the Strzelecki Group shale resource assessment.

**Prospective area definition**

**Formation mapping, depth and initial thickness**

For the Strzelecki Group shale assessment, all subdivisions within the formally defined Strzelecki Group, including the Tyers River Sub-group were classified as ‘Strzelecki Group’. The initial Strzelecki Group extent was initially defined by the ‘outer limit of preserved Strzelecki Group’ polygon (Wong et al., 2001).

The Strzelecki Group thickness distributions were calculated using the 2011 Gippsland 3D model top Strzelecki Group and Basement surfaces (Rawling et al., 2011). The model data was augmented by well data in the northern part of the basin to define the prospective area around the Megascolides 1, Yallourn Power 1 and Yallourn North 1A shale play. The surfaces were used to calculate the initial thickness of the Strzelecki Group between 1000 m and 5000 m. Depth thresholds of 1000 m and 5000 m were imposed to ensure that sufficient pressure was present in the shales to preserve gas content and promote gas flow if developed, and to ensure the shales were at economically drillable depths given today's technology.

A series of polygons were then drawn representing the spatial extent of where the Strzelecki Group meets the threshold criteria (i.e. where the Strzelecki Group is >15 m in thickness, and where it is found at depths between 1000 m and 5000 m).
The spatial extent of organically-rich shales for each assessed formation was mapped using measured TOC data. The extent of the prospective areas is highly dependent on the existing TOC dataset, and as such the prospective areas should be regarded as conservative.

Values defined as geochemically representing shales have modern-day TOC values of greater than 0.5 wt% and less than 50 wt%. These values were compiled from publically available sources, averaged for the shales in the assessed formation in each well, and then mapped in two dimensional space. An average TOC of ≥ 2 wt% +1 stdev was regarded as having shale resource potential for the purposes of this study.

Geologically reasonable polygons around the average TOC points were used to represent the spatial extent of organically rich shales in the Gippsland Basin. Polygons were drawn to best represent the major structural and paleoenvironmental subdivisions of the basin to ensure ‘like’ shales were assessed together. In the Strzelecki Group the Seaspray, Morwell and Wellington areas (Figure 4-1) were identified as areas with elevated TOC. The intersection of the high-TOC polygons with the 1000–5000 m and >15 m thickness polygons defined the prospective area polygons. The prospective area polygons for the Gippsland Basin shale resource assessment are summarised in Table 3-2. The prospective areas, as determined using the TOC polygons, were used together with the thickness distributions to define the prospective volume of each shale resource play.

### Table 3-2 Strzelecki Group shale resource assessment prospective area polygons summary.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Polygon</th>
<th>Area (m²)</th>
<th>Area (km²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strzelecki Group</td>
<td>Morwell</td>
<td>1 317 918 653</td>
<td>1317.9</td>
</tr>
<tr>
<td></td>
<td>Seaspray</td>
<td>369 598 609</td>
<td>369.6</td>
</tr>
<tr>
<td></td>
<td>Wellington</td>
<td>491 724 586</td>
<td>491.7</td>
</tr>
</tbody>
</table>

The maturity depth thresholds were generated using publically available VR₀ and Jarvie converted reliable Tmax data (Jarvie et al., 2001; see Section 3.1.1). EIA (2013) maturity windows were applied: immature: 0–0.7% VR₀, oil: 0.7–1.0% VR₀, wet gas: 1.0–1.3% VR₀, gas: 1.3–3.0% VR₀ and over-mature: >3.0% VR₀. The compiled maturity data were initially used to generate a vitrinite reflectance with depth trend line for each prospective area (areas defined by mapping TOC data, see later). These trends were calculated by plotting all available maturity data relevant to a prospective area polygon against depth and fitting a trend line. The depths at which the oil, wet gas, dry gas and over mature windows occur are shown in Table 3-3.

### Table 3-3 Depth of vitrinite reflectance thresholds in the high TOC Strzelecki Group polygons.

<table>
<thead>
<tr>
<th>VR₀</th>
<th>Seaspray (m)</th>
<th>Lake Wellington m</th>
<th>Morwell (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.7%</td>
<td>2208</td>
<td>1698</td>
<td>1051</td>
</tr>
<tr>
<td>1.0%</td>
<td>2739</td>
<td>2113</td>
<td>1510</td>
</tr>
<tr>
<td>1.3%</td>
<td>3130</td>
<td>2418</td>
<td>1847</td>
</tr>
<tr>
<td>3.0%</td>
<td>4376</td>
<td>3389</td>
<td>2923</td>
</tr>
</tbody>
</table>
The maturity window depth values were used in conjunction with the Strzelecki Group and Basement surfaces from the Gippsland 3D model (Rawling et al., 2011) and well data where necessary, to calculate the thickness of the Strzelecki Group between 1000 m and 5000 m which occurred within the oil, wet gas and dry gas windows.

**Net shale ratio**

The net shale ratio describes what proportion of the formation in question meets the prospective shale definition. The net shale ratios were derived visually from composite log and cuttings data for the formation between 1000–5000 m depth; suitable individual shale beds were defined as >15 m thick, and >70% shale/siltstone content. This definition of net shale ratio differs from the industry term which also describes the proportion of shales with sufficient organic richness. The net shale ratio was calculated for nine wells in the Strzelecki Group (Table 3-4). These wells were selected to ensure the full vertical and lateral extent of the Strzelecki Group was represented. The same net shale statistics were used for both coastal prospective areas – the Lake Wellington and Seaspray polygons. The premise being that the Strzelecki Group, as intersected along the coastline in those six wells, is likely to represent a similar (upper) part of the Strzelecki Group stratigraphy, while the three wells in the Morwell polygon are representative of the basal Strzelecki Group stratigraphy. Net shale ratio summary statistics at the formation level are shown in Table 3-5.

**Table 3-4 Net shale ratios calculated for the Strzelecki Group shale resource assessment.**

<table>
<thead>
<tr>
<th>Formation</th>
<th>Polygon</th>
<th>Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strzelecki Group</td>
<td>Morwell</td>
<td>Loy Yang 1A, Rosedale 1 and Megascolides 2</td>
</tr>
<tr>
<td></td>
<td>Lake Wellington and Seaspray</td>
<td>Duck Bay 1, Wellington Park 1, Trifon 1, Wombat 4, St Margaret Island 1 and Sunday Island 1</td>
</tr>
</tbody>
</table>

**Table 3-5 Strzelecki Group net shale ratio statistics by prospective area polygon.**

<table>
<thead>
<tr>
<th>Formation</th>
<th>Polygon</th>
<th>Average</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Median</th>
<th>Standard deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strzelecki Group</td>
<td>Morwell</td>
<td>0.40</td>
<td>0.21</td>
<td>0.56</td>
<td>0.44</td>
<td>0.18</td>
</tr>
<tr>
<td></td>
<td>Lake Wellington and Seaspray</td>
<td>0.10</td>
<td>0.00</td>
<td>0.22</td>
<td>0.13</td>
<td>0.09</td>
</tr>
</tbody>
</table>

There was insufficient measured TOC data, or detailed log interpretations to allow the application of a net ‘organically rich shale ratio’ (called net shale ratio by industry). Thus, all shales that met the definition of ‘prospective shale’ as defined here and that fell within the prospective area polygon were regarded as organically rich.

**Reservoir characterisation and volume factors**

**Petrophysical properties**

No measured values for petrophysical properties were available for Gippsland Basin shales. Data from the temporally analogous Sawpit Shale (Pretty Hill Formation, Otway Group) from Jolly 1 and Sawpit 2 in the south Australian Otway Trough were used to assume reasonable distributions in @Risk for these parameters. Nineteen total porosity, twenty six density and six oil and gas saturation analyses from the Sawpit Shale were incorporated in the assessment. A full summation of data used to inform a geologically reasonable estimation of these parameters for Strzelecki Group shales is shown below in Table 3-6.
### Table 3-6 Sawpit Shale petrophysical properties summary. Data summarised from WCR’s of Jolly 1 and Sawpit 2 (Beach Energy, 2013; 2014).

<table>
<thead>
<tr>
<th>Formation</th>
<th>Parameter</th>
<th>Average</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Standard deviation</th>
<th>Median</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sawpit Shale</td>
<td>Gas Saturation</td>
<td>0.23</td>
<td>0.01</td>
<td>0.40</td>
<td>0.15</td>
<td>0.27</td>
</tr>
<tr>
<td></td>
<td>Oil Saturation</td>
<td>0.04</td>
<td>0.00</td>
<td>0.16</td>
<td>0.06</td>
<td>0.03</td>
</tr>
<tr>
<td></td>
<td>Porosity</td>
<td>0.06</td>
<td>0.04</td>
<td>0.10</td>
<td>0.02</td>
<td>0.06</td>
</tr>
<tr>
<td></td>
<td>Bulk Density</td>
<td>2.69</td>
<td>2.66</td>
<td>2.75</td>
<td>0.02</td>
<td>2.67</td>
</tr>
</tbody>
</table>

**Condensate-to-gas ratio and gas-to-oil ratio**

There were no measured condensate-to-gas ratio (CGR) or gas-to-oil ratio (GOR) values available for the Strzelecki Group shales. The CGR and GOR distributions were assumed using data from the Whiting field (Agrawal (1983)).

**Formation volume factors**

There were no measured values available for gas (Bg) and oil (Bo) formation volume factors for the Strzelecki Group shales. Data from the Whiting field (Agrawal, 1983) were used to approximate the formation volume factors in the absence of any other measured data.

**Adsorbed gas content**

Five adsorbed gas content (GCa) values from Jolly 1 and Sawpit 2 (Beach Energy 2013; 2014) were used to characterise the Strzelecki Group shales in this assessment.

### 3.1.3 Estimating OIP and GIP using @Risk

Probability distributions for all parameters were generated in @RiskPro 6.3 (@Risk, an extension to Microsoft Excel) and used to calculate the OIP and GIP for the assessed shales using the equations shown in the @Risk spreadsheets accompanying this report. In most cases, statistically reliable data is not available, and a distribution curve is manually built to encompass the available data, with an allowance for expected natural variation. The number of different types of distribution types used was kept to a minimum.

The estimation of gas- or liquids-in-place is made 10 000 times using @Risk, taking random draws from each parameters’ probability distribution function. The decision to use 10 000 was based on initial sensitivity testing which indicated the result distributions were effectively static beyond this value. The ‘Function’ column as shown in the @Risk input parameters tables (e.g. Appendix Table A-1 and Appendix Table A-2) lists the scripted description of the probability distribution function in @Risk. Further information on these can be found directly in the @Risk spreadsheet associated with this report or in the @RiskPro 6.3 program documentation (http://www.palisade.com/risk/). Once all the parameters had distributions assigned in @Risk, the GIP and OIP were calculated. For this assessment all the input parameters are assumed to be independent. The underlying formulae used can be seen in full in the @Risk spreadsheet associated with this report.

This probabilistic method captures estimates of uncertainty in each parameter, and propagates these throughout each calculation, resulting in a range of estimates. The Gippsland Basin shale resource
assessment GIP and liquids-in-place OIP results were reported at P10, P50, mean and P90 levels for each assessed prospective area polygon and rolled up into 'formation level' values.

3.1.4 Recovery factor

Exploration for, and development of, unconventional resources in Australia is still in the very early stages. As a result, there is a lack of production data for unconventional resources, and in most cases international analogues are tenuous at best. Because of this, it is not feasible to predict recovery factors for Australian unconventional resources with any degree of certainty. There is also a high level of uncertainty associated with the estimated prospective volumes which is related to data availability more generally. A conservative recovery factor of 5% has been used in the recoverable GIP and OIP Gippsland Basin resource assessment to reflect this. As with other parameters, this factor can be updated as more data become available with the progress of future projects.

3.2 Tight gas method

The process of estimating tight GIP is very similar to the process outlined for the free GIP shale resource calculation previously, and uses the same underpinning stratigraphic data. For the purpose of this assessment, the initial volume of the Strzelecki Group tight gas play was defined as the volume between 1000 m and 5000 m depth, with a thickness of greater than 15 m. Key differences in the process are outlined in the following text. The prospective area for the Strzelecki Group tight gas assessment is shown in Table 3-7.

Table 3-7 Strzelecki Group tight gas assessment prospective area polygon summary.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Area (m²)</th>
<th>Area (km²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strzelecki Group</td>
<td>4,918,558,468</td>
<td>4,918.6</td>
</tr>
</tbody>
</table>

- Only the dry gas fraction was assessed in the Strzelecki Group tight resource assessment. Based on the results in the shale resource assessment and in results from wells (e.g. Wombat 1 and 3) along the modern-day coastline there could also be potential for tight wet-gas or even oil accumulations in the Strzelecki Group. Whether these are in situ or not is still in the future, as more data becomes available and understanding of the Strzelecki Group petroleum system becomes better understood, mapping the extent of these additional plays could enable an assessment of Strzelecki Group’s tight wet gas and oil potential.
- As with the shale resource plays, the raw spatial extent of the tight gas play was confined to the area within the ‘preserved Strzelecki Group’ polygon (Wong et al., 2001), and, excludes a large portion of the South Gippsland area, and western Gippsland Basin where there was deemed to be insufficient data to support an assessment (Figure 1-1). The Strzelecki Group tight gas thickness and spatial distributions were calculated using the 2011 Gippsland 3D model surfaces (Rawling et al., 2011). The 1000 m to 5000 m depth thresholds were retained.
- No maturity thresholds or organic content mapping were required to determine the Strzelecki Group tight gas volume as the gas is not necessarily generated in situ as is the case with shale plays.
- The net-to-gross ratio is used to estimate how much of the formation is an effective tight reservoir in a vertical sense. One well log interpretation from Megascolides 2 was used to estimate the net-to-gross ratio in the Strzelecki Group tight gas play.
No measured values were available for petrophysical parameters in the Gippsland Basin. Distributions for these values were assigned using interpreted data and analogues. The data sources used to inform a geologically reasonable estimation of these parameters for the Strzelecki Group tight gas assessment is shown below in Table 3-8. All data used in the assessment is presented in the accompanying spreadsheets.

Table 3-8 Summary of data sources and associated assumptions/limitations of petrophysical parameters for the Strzelecki Group tight gas play.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Data source</th>
<th>Description/Assumptions</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Effective porosity</td>
<td>WCR Megascolides 1</td>
<td>Well log interpretation results of the Strzelecki Group</td>
<td>The spatial facies variation may lead to different rock properties across the whole onshore Gippsland.</td>
</tr>
<tr>
<td></td>
<td>(Grosser, 2005)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Effective water saturation</td>
<td>WCR Megascolides 1</td>
<td>Well log interpretation results of the Strzelecki Group</td>
<td>As above</td>
</tr>
<tr>
<td></td>
<td>(Grosser, 2005)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net-to-gross ratio</td>
<td>WCR Megascolides 1</td>
<td>Well log interpretation results of the Strzelecki Group</td>
<td>As above</td>
</tr>
<tr>
<td></td>
<td>(Grosser, 2005)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas expansion factor</td>
<td>Agrawal (1983)</td>
<td>Bg of the intra-Latrobe Group in Whiting Field, offshore Gippsland</td>
<td>The Bg data in the intra-Latrobe Group may not be the same as that of the Strzelecki Group in the onshore Gippsland.</td>
</tr>
</tbody>
</table>
4 Results

4.1 Shale resource assessment

4.1.1 Strzelecki Group

Three prospective areas in the Strzelecki Group were identified: the Lake Wellington area, which includes the Wellington Park and Seacombe wells, the Seaspray area covering the Wombat, Gangell and Trifon/North Seaspray accumulations and the Morwell area, which includes the Yallourn wells. This latter area includes the Megascolides 1 and 2 wells, which have been included with the Yallourn area as there was insufficient data specific to the South Gippsland area to warrant creating a separate assessment area/polygon. The prospective area polygons are shown below in Figure 4-1.

![Map showing prospective areas for the Strzelecki Group shale resource assessment](image)

Figure 4-1 Prospective areas (Morwell, Seaspray and Wellington areas) for the Strzelecki Group shale resource assessment Average TOC + 1 stdev values for Strzelecki Group shales shown in green and red.

@Risk inputs

A summary of all @Risk inputs used to calculate the Strzelecki Group shale resource assessment are listed in Appendix Table A-1.
Results

Table 4-1 Estimated shale gas-in-place (GIP), and shale liquids-in-place (OIP) at P10, P50, mean and P90 levels, for the Strzelecki Group, Gippsland Basin.

<table>
<thead>
<tr>
<th>Name</th>
<th>Distribution</th>
<th>P90</th>
<th>P50</th>
<th>Mean</th>
<th>P10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Morwell shale GIP (TCF)</td>
<td></td>
<td>49.7</td>
<td>94.1</td>
<td>104.6</td>
<td>173.4</td>
</tr>
<tr>
<td>Morwell shale OIP (B bbl)</td>
<td></td>
<td>6.1</td>
<td>17.8</td>
<td>21.4</td>
<td>41.5</td>
</tr>
<tr>
<td>Seaspray shale GIP (TCF)</td>
<td></td>
<td>4.2</td>
<td>8.1</td>
<td>8.9</td>
<td>14.8</td>
</tr>
<tr>
<td>Seaspray shale OIP (B bbl)</td>
<td></td>
<td>0.6</td>
<td>1.8</td>
<td>2.2</td>
<td>4.2</td>
</tr>
<tr>
<td>Lake Wellington shale GIP (TCF)</td>
<td></td>
<td>3.4</td>
<td>7.1</td>
<td>8.3</td>
<td>14.8</td>
</tr>
<tr>
<td>Lake Wellington shale OIP (B bbl)</td>
<td></td>
<td>0.6</td>
<td>1.8</td>
<td>2.2</td>
<td>4.3</td>
</tr>
</tbody>
</table>

Table 4-2 Estimated potentially recoverable (5%) shale gas-in-place (GIP), and shale liquids-in-place (OIP) at P10, P50, mean and P90 levels, for the Strzelecki Group, Gippsland Basin.

<table>
<thead>
<tr>
<th>Name</th>
<th>Distribution</th>
<th>P90</th>
<th>P50</th>
<th>Mean</th>
<th>P10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Morwell potentially recoverable shale GIP (TCF)</td>
<td></td>
<td>2.5</td>
<td>4.7</td>
<td>5.2</td>
<td>8.7</td>
</tr>
<tr>
<td>Morwell potentially recoverable shale OIP (B bbl)</td>
<td></td>
<td>0.3</td>
<td>0.9</td>
<td>1.1</td>
<td>2.1</td>
</tr>
<tr>
<td>Seaspray potentially recoverable shale GIP (TCF)</td>
<td></td>
<td>0.2</td>
<td>0.4</td>
<td>0.4</td>
<td>0.7</td>
</tr>
<tr>
<td>Seaspray potentially recoverable shale OIP (B bbl)</td>
<td></td>
<td>0.0</td>
<td>0.1</td>
<td>0.1</td>
<td>0.2</td>
</tr>
<tr>
<td>Lake Wellington potentially recoverable shale GIP (TCF)</td>
<td></td>
<td>0.2</td>
<td>0.4</td>
<td>0.4</td>
<td>0.7</td>
</tr>
<tr>
<td>Lake Wellington potentially recoverable shale OIP (B bbl)</td>
<td></td>
<td>0.0</td>
<td>0.1</td>
<td>0.1</td>
<td>0.2</td>
</tr>
</tbody>
</table>
4.2 Tight gas assessment

4.2.1 Strzelecki Group

The area of the Strzelecki Group interpreted to potentially be prospective for tight resources is shown below in Figure 4-2.

![Figure 4-2 Spatial extent of the Strzelecki Group tight gas assessment, and wells with Strzelecki Group at >1000 m.](image)

@Risk inputs

A summary of all @Risk inputs used to calculate the Strzelecki Group tight gas assessment are listed in Appendix Table A-2.
Results

Table 4-3 Estimated tight gas-in-place (GIP) at P10, P50 mean and P90 levels of the Strzelecki Group, Gippsland Basin.

<table>
<thead>
<tr>
<th>Name</th>
<th>Distribution</th>
<th>P90</th>
<th>P50</th>
<th>Mean</th>
<th>P10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strzelecki Group tight GIP (TCF)</td>
<td></td>
<td>97.3</td>
<td>272.8</td>
<td>307.0</td>
<td>555.7</td>
</tr>
</tbody>
</table>

Table 4-4 Estimated potentially recoverable (5%) tight gas-in-place (GIP) at P10, P50, mean and P90 levels of the Strzelecki Group, Gippsland Basin.

<table>
<thead>
<tr>
<th>Name</th>
<th>Distribution</th>
<th>P90</th>
<th>P50</th>
<th>Mean</th>
<th>P10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strzelecki Group potentially recoverable tight GIP (TCF)</td>
<td></td>
<td>4.9</td>
<td>13.6</td>
<td>15.4</td>
<td>27.8</td>
</tr>
</tbody>
</table>
5 Assessment limitations

The following section outlines some of the key limitations and assumptions associated with the shale and tight resource assessments.

5.1 Shale resource assessment

- This assessment is not a generative assessment. The GIP and OIP estimate does not capture the degree to which the assessed formations are able to produce and expel hydrocarbons, which enables a better understanding of petroleum systems in the basin and can be used to evaluate areas with sparse measured gas and oil saturation and reservoir data.

- This study has been completed using only publically available data in order to improve the transparency of the results. As the unconventional, and in particular shale gas, industries are immature in the Gippsland Basin this has limited the amount of data available to characterise the shales as many wells drilled for the purpose are still within the confidentiality period.

- The Strzelecki Group extends across the majority of the onshore Gippsland Basin and South Gippsland region. However, the 3D model used to calculate thickness values only covered a portion of this area. Well data was used to ensure the thickness distribution generated from the 3D model represented the thickness of the Strzelecki Group in areas beyond the model extent where necessary. This partial coverage by the 3D surfaces introduced some uncertainty into the thickness parameter, but was considered to be negligible and acceptable for the purposes of this regional-scale assessment.

- During the course of this study it became apparent that differentiating between the bottom of the Strzelecki Group and the underlying metasedimentary basement is challenging and has possibly impact on the volume of the Strzelecki Group modelled. Thus the true subsurface extent of the Strzelecki Group, including the Rintoul Creek Sandstone and Tyers Conglomerate (the `Tyers River Subgroup`) is unknown. Intersections of `Strzelecki Group` in the Latrobe Valley may possibly represent older Palaeozoic basement rocks (e.g. in Yallourn Power 1 and Megascolides 2 (Partridge, 2011; Holdgate, 2015). For the purposes of this assessment, the publically available stratigraphic picks were used with the result that Strzelecki Group was modelled to be present across the area. However, this difficulty in accurately identifying the base of the Strzelecki Group can also be seen at a more regional scale in the highly variable nature of the geophysically and seismically-derived ‘Top Basement’ surfaces assessed for this study suggesting potential for larger scale impact on the modelled volume of Strzelecki Group tight resource play.

- The stratigraphic uncertainty has implications for the maturity modelling as extreme VR_0 values potentially from Palaeozoic basement may have strongly skewed the results. For this reason, the very high VR_0 values from Hazelwood 1 (5.75–7.96 VR_0), which may be attributed to sub-Strzelecki Group ‘basement’ have been omitted from the modelling. If these values are later revealed to definitively be from Strzelecki Group equivalents this will significantly alter the volume of Strzelecki Group with shale resource potential.

- The definition of ‘shale’ in this assessment as ‘70% fine grained lithology’ will likely overestimate the proportion of ‘true’ shale in each formation. Ideally a carefully calibrated log derived electro-facies lithology assignation process would be undertaken, a process which is hindered significantly by the highly variable quality of the available log data in the basin. The feasibility of
this approach was considered but the required investment of time to get an acceptable outcome was found to be beyond the scope of this study.

- Due to the scarcity of well data and subsequent limited ability to define maturity in 3D, the same prospective area polygons were used to define the area which is prospective for oil, wet gas and dry gas. The inclusion of zeros in the modelled thickness distribution grid provided a rough proxy for how much of each prospective area was likely to be prospective for oil, wet gas or dry gas.

- The depth at which the maturity windows occur within the prospective area polygons was considered constant across the polygon. This assumption would be realistic if the formations in question were flat lying, but was a simplification given the complex structural deformation that has occurred, particularly in the Morwell polygon where dip angles reach 70° in places (Holdgate, 2015).

- While the assessment of the Strzelecki Group used the full modelled thickness and extent of the sequence as part of the volume determination process, all other parameters were defined (where available) using ‘as penetrated’ values from wells. While every attempt was made to ensure the full stratigraphic succession of the Strzelecki Group was represented, the data distributions used in @Risk can only represent the current state of data. Large areas of the Strzelecki Group, and the onshore Gippsland Basin more generally, have very limited or no data available, particularly at depth, and in the central west. There is a high degree of uncertainty associated with these data limitations.

- The TOC values used in this assessment are modern day values not back-calculated original TOC values. This means that the TOC average + 1 stdev values calculated for each well are likely to be somewhat conservative in terms of generative potential (assuming any). However, the generosity of prospective area polygons to include sparse data points likely more than compensates volumetrically for this.

- Estimating the volume of high TOC shales is complicated by coals in a the sequence in a few wells (Wellington Park 1, Wrinxondale 1, Duck Bay 1, Merriman 1 and Loy Yang 1). While true coals have been removed by imposing the 50 wt% TOC maximum, how many of the ‘shales’ with TOC values between 20–50 wt% are in fact claystones with coaly components was not quantified.

- There was no adjustment of the ‘TOC averages by well’ data to only exclude values outside the assessed 1000–5000 m depth range as this would have reduced an already sparse dataset even further. This raises the possibility that the average TOC values used are not a fair representation of organic richness in the assessed volume. Of the 148 compiled analyses directly used in the Strzelecki Group shale assessment, only 30 are at depths <1000 m. Many of these are from Yallourn North 1A and Megascolides 2 in the far northwest of the Gippsland Basin. This suggests that the impact of including these analyses in the TOC averages in the assessment process is likely to be quite small across most of the basin, though may potentially be an issue in the northwest part of the basin.

- As defined, the prospective areas are highly dependent on the distribution of available TOC data. As only a small proportion of organically rich shales are likely to have been sampled, this is likely to underestimate the area of the basin that contains prospective shales. The addition of more TOC data or the incorporation of additional predictive facies mapping techniques would allow a more ‘whole of basin’ resource assessment to be completed.

- As the TOC values in each formation in each well are often highly variable, using an ‘average TOC’ per well method excludes wells which do have some high TOC shales, but which fall below the 2 wt% +1 stdev threshold during the averaging process due to the presence of some very low TOC shales. Where there are only a few TOC analyses for a formation in each well this is also likely to be statistically non-representative of the formation in that location. If more TOC data was acquired in the future, this could significantly alter the prospective areas.
All the shales within the prospective areas are assumed to be of >2% + 1 stdev TOC. This is an unrealistic expectation. If sufficient high-resolution log data and/or TOC measurements were available the proportion of lithologically defined shales could be constrained further to define a 'net organically rich ratio', giving a more geologically realistic indication of the volume of organically rich shale present and further improving the reliability of resource assessments.

The scarcity of maturity data has necessitated the calculation of regional trends in maturity with depth to complement the individual well by well trends. In areas of highly localised structuring, mineralisation or intrusive emplacement these regional maturity with depth estimations will not be sufficient to model the localised variation in thermal maturity. The regional maturity estimations are also reliant on existing data. In areas of relatively lower data density the regional estimations are likely to be less representative of the regional thermal maturity, even in the absence of any localised effects.

The @Risk distributions for shale petrophysical properties were constructed based on a small number of analyses from just a few key wells. Key assumptions and limitations associated with the petrophysical data are listed in Table 3-1. Basing the @Risk distributions on such a small number of analyses means there is a risk that they do not represent the full spatial distribution (laterally and vertically) of the formations assessed. The reliability of this assessment could be significantly improved by increasing the number and spatial spread of petrophysical analyses available to characterise the shale resource plays.

The near complete absence of publically available gas contained, gas and oil formation volume factors, and condensate-to-gas and gas-to-oil ratios (GCa, Bg and Bo, CGR and GOR) specific to the Strzelecki Group, could be a significant source of error in this resource assessment. Published values for these parameters or sufficient data to enable the calculation of these parameters (e.g. composition analyses, well test data, isotherm tests, pressure and temperature data etc.) would significantly improve the reliability of this assessment.

### 5.2 Tight resource assessment

A key assumption in the tight resource assessment is that the entirety of the Strzelecki Group is considered a potential tight resource play. We know this is not the case, as in some intervals there are sandstones with conventional reservoir potential. Parts of the Strzelecki Group have already been drilled as potential conventional gas targets by explorers, with the Karoon Gas well Megascolides 1 encountering Strzelecki Group reservoirs with porosities of 10–15%, and in one sample 56 mD permeability (Grosser, 2005). These horizons clearly represent a more conventional play type. The use of the net-to-gross ratio attempts to characterise the proportion of effective tight reservoir in a vertical sense, but as there is only one well log interpretation for the Strzelecki Group (Megascolides 2) there is no ability to spatially characterise the reservoir effectiveness. Thus there is a very high level of uncertainty associated with the net-to-gross distribution in @Risk, which in turn increases the uncertainty of the tight GIP assessment. This means that the current tight resource assessment is likely to over-represent the tight resource potential of the basin, by under representing the conventional reservoir potential. Detailed work which is beyond the scope of this assessment is needed to spatially map, using modern data and well interpretations, the parts of the Strzelecki Group with the effective porosity required for tight resource play.

Tight gas in the Strzelecki Group as found in the Wombat, Gangell and Trifon/Seaspray gas accumulations is partly diffuse gas, and partly associated with structural traps, and is found in an area where the Strzelecki Group as penetrated is immature to oil-mature (e.g. Seaspray 1 at 1524 m VR, is 0.37%; North Seaspray 1 at 1524 m VR, is 0.39%), with minor condensate and oils in the Wombat field. Further petroleum systems work is required to discriminate spatially between
oil, wet and dry gas tight reservoirs in the Gippsland Basin. The same low-maturity trend is also
seen more broadly along the modern-day coastal fringe (e.g. at 2248.2 m in the Wellington Park 1
well; VR_o of 0.63%). This suggests the tight gas found throughout the coastal area of the onshore
Gippsland Basin has migrated vertically from significantly deeper in the section onshore, and/or,
has migrated laterally up-dip from deeper sources in the offshore Gippsland Basin. If the latter
mechanism constitutes the primary source of gas in the tight gas plays of the Strzelecki Group,
more detailed modelling when expulsion and migration have occurred relative to the development
of Strzelecki Group tight reservoir characteristics, and assessing how far that migration front may
have travelled must be undertaken before an assessment of how far onshore significant
centration of gas may be found can be made. While the presence of elevated gas readings
further onshore in the Strzelecki Group (e.g. Megascolides 1) are suggestive either of an active
onshore source, or an effective long range migration pathway, further work to understand the
source mechanism of the Strzelecki Group gas is required. In light of this uncertainty regarding in
situ vs. migrated gas and liquids, we have assumed that tight resource reservoired in the Strzelecki
Group is all dry gas, and is not necessarily generated in situ.

- The limited amount of measured petrophysical data is a key source of uncertainty in the calculated
tight GIP values. Key assumptions and limitations associated with the petrophysical data are
covered in Table 3-8. The absence of a suitable onshore analogue (as was used in the shale
resource assessment), further compounds the problem and introduces an even higher level of
uncertainty into the GIP calculations.

- Similarly, the net-to-gross distribution is based on only one conventional well log interpretation for
the Eumeralla Formation (Killarney 1 (EPRL)) and Crayfish Sub-group (Glenaire 1 ST1). There is a
high level of uncertainty associated with using only one interpretation to build the net-to-gross
distribution in @Risk, which in turn increases the uncertainty of the GIP assessment.

- In the absence of a good onshore analogue for the gas formation volume factor (B_g) in the
Crayfish Sub-group, a value from the basal Waarre Formation was used in the absence of any
other data. While this Waarre Formation B_g value may be a geologically plausible analogue for the
Eumeralla Formation which shares a common petroleum system with the Waarre Formation
(Austral 2), the Crayfish Sub-group is part of the older Austral 1 petroleum system. This introduces
a higher level of uncertainty into the GIP calculations.

- The condensate-to-gas ratio (CGR) used for the Eumeralla Formation tight resource assessment is
also based on analyses from the Waarre Formation in the absence of any measured values and
may not provide a good indication of Eumeralla Formation gases. The Crayfish Sub-group CGR is
based on a series of analyses from the Pretty Hill Formation in four wells in the Penola Trough.
This likely provides a good local indication of the CGR in the Penola Trough, but how well this
represents gases in the Crayfish Sub-group more broadly is highly uncertain. Together these
uncertainties around CGR introduce a higher level of uncertainty into the GIP calculations.
6 Conclusion

In the Gippsland Basin, Strzelecki Group shales are potentially prospective for oil through to dry gas. Three areas with sufficiently organically-rich Strzelecki Group shales were identified: the Morwell, Seaspray and Lake Wellington areas. The Strzelecki Group was also found to have tight reservoir intervals, which may be gas saturated. The area interpreted as prospective for tight gas extends across a significant portion of the onshore Gippsland Basin.

This assessment suggests that the onshore Gippsland Basin may contain large volumes of gas- and liquids-in-place. These volumes are to be regarded as undiscovered potentially prospective resources. There is significant uncertainty around their location and estimated magnitude. Recognising the uncertainty associated with estimated in-place resources and their path to commercialisation, a 5% recovery factor was applied. The total gas- and liquid-in-place for the combined Gippsland Basin resource assessment is approximately 383.6 TCF and 22.4 B bbl, of which 19.2 TCF and 1.1 B bbl may potentially be recoverable. The P10, P50, mean, and P90 GIP and OIP results and the recoverable GIP and OIP results are summarised in the table below.

Estimated total and potentially recoverable (estimated as 5% median assessed volume (P50)) shale and tight gas-in-place (GIP) and shale liquids-in-place (OIP) at the P10, P50 and P90 levels in the Gippsland Basin. NB: probabilistic summation has been used.

<table>
<thead>
<tr>
<th></th>
<th>P10</th>
<th>P50</th>
<th>Mean</th>
<th>P90</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gippsland Basin Total Tight GIP (TCF)</td>
<td>558.7</td>
<td>271.9</td>
<td>307.3</td>
<td>98.0</td>
</tr>
<tr>
<td>Gippsland Basin Total Shale GIP (TCF)</td>
<td>189.2</td>
<td>111.7</td>
<td>121.7</td>
<td>66.5</td>
</tr>
<tr>
<td>Gippsland Basin Total Shale OIP (B bbl)</td>
<td>46</td>
<td>22.4</td>
<td>25.8</td>
<td>10.1</td>
</tr>
<tr>
<td>Gippsland Basin Potentially Recoverable GIP (TCF)</td>
<td>19.2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gippsland Basin Potentially Recoverable OIP (B bbl)</td>
<td>1.1</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

In the Gippsland Basin significant conventional gas has been produced from the offshore, but only limited exploration for unconventional resources has occurred. This has resulted in limited data availability for this assessment, and necessitated the use of geologically reasonable assumptions and analogues to characterise the geochemical and petrophysical properties of shale and tight reservoirs. Higher levels of uncertainty will therefore be inherent in the GIP and OIP calculations.

Additional publically available data would be required to improve the certainty around these preliminary estimates and enable a more detailed unconventional resource assessment to be carried out. Commercialising Victorian unconventional resources would require identifying the highest-grade occurrences, then developing an understanding of the interplay between stress regime and drilling and hydraulic stimulation practises for the extraction of liquids and gas. Liquids and gas from these unconventional resources are likely to remain relatively expensive as compared to conventional resources until high economies of scale can be achieved.
Agrawal, B. B. 1983: Estimates of hydrocarbons in place, Whiting Field, Gippsland Basin. Exploration Branch, Oil and Gas Division, Department of Minerals.


Appendix A @Risk input tables

A summary of all @Risk inputs used to calculate the Strzelecki Group shale resource assessment are listed in Appendix Table A-1.

**Appendix Table A-1 Strzelecki Group shale play @Risk input parameters.**

<table>
<thead>
<tr>
<th>Name</th>
<th>Distribution</th>
<th>Function</th>
<th>Min</th>
<th>10%</th>
<th>Mean</th>
<th>Median</th>
<th>90%</th>
<th>Max</th>
</tr>
</thead>
<tbody>
<tr>
<td>All areas</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total porosity (fraction)</td>
<td></td>
<td>RiskTriang(0.022,0.022,0.109462,RiskName(&quot;Total porosity&quot;))</td>
<td>0.02</td>
<td>0.03</td>
<td>0.05</td>
<td>0.05</td>
<td>0.08</td>
<td>0.11</td>
</tr>
<tr>
<td>Water saturation (fraction)</td>
<td></td>
<td>RiskNormal(0.72146,0.15125,RiskTruncate(0,1),RiskName(&quot;Water saturation&quot;))</td>
<td>0.16</td>
<td>0.52</td>
<td>0.71</td>
<td>0.72</td>
<td>0.89</td>
<td>1.00</td>
</tr>
<tr>
<td>Gas formation volume factor (sm^3/rm^3)</td>
<td></td>
<td>RiskNormal(211.2,10,RiskTruncate(195,228),RiskName(&quot;Gas formation volume factor (sm3/rm3)&quot;))</td>
<td>195.0</td>
<td>200.5</td>
<td>211.3</td>
<td>211.3</td>
<td>222.2</td>
<td>228.0</td>
</tr>
<tr>
<td>Bulk density (g/cc)</td>
<td></td>
<td>RiskNormal(2.596333,0.053928,RiskName(&quot;Bulk density (g/cc)&quot;))</td>
<td>2.39</td>
<td>2.53</td>
<td>2.60</td>
<td>2.60</td>
<td>2.67</td>
<td>2.81</td>
</tr>
<tr>
<td>Adsorbed gas content (scf/ton)</td>
<td></td>
<td>RiskNormal(19.816,10.168,RiskTruncate(0.35),RiskName(&quot;Adsorbed gas content&quot;))</td>
<td>0.01</td>
<td>7.68</td>
<td>19.02</td>
<td>19.28</td>
<td>29.99</td>
<td>35.00</td>
</tr>
<tr>
<td>Gas condensate ratio (m^3/KL)</td>
<td></td>
<td>RiskNormal(8176,100,RiskStatic(8176),RiskTruncate(7800,8500),RiskName(&quot;Gas condensate ratio&quot;))</td>
<td>7813.7</td>
<td>8047.8</td>
<td>8175.8</td>
<td>8175.9</td>
<td>8303.8</td>
<td>8498.5</td>
</tr>
<tr>
<td>Name</td>
<td>Distribution</td>
<td>Function</td>
<td>Min</td>
<td>10%</td>
<td>Mean</td>
<td>Median</td>
<td>90%</td>
<td>Max</td>
</tr>
<tr>
<td>-------------------------------------</td>
<td>--------------</td>
<td>---------------------------------------------------------------------------</td>
<td>---------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>--------</td>
</tr>
<tr>
<td>Oil formation volume factor</td>
<td></td>
<td>RiskNormal(1.093,0.05, RiskTruncate(1.01, 1.18),RiskName(&quot;Oil formation volume factor&quot;))</td>
<td>1.010</td>
<td>1.039</td>
<td>1.094</td>
<td>1.093</td>
<td>1.149</td>
<td>1.180</td>
</tr>
<tr>
<td>Gas oil ratio (scf/bbl)</td>
<td></td>
<td>RiskNormal(225,0.1,RiskTruncate(224.8, 225.2),RiskName(&quot;Gas oil ratio&quot;))</td>
<td>224.8</td>
<td>224.9</td>
<td>225.0</td>
<td>225.0</td>
<td>225.1</td>
<td>225.2</td>
</tr>
<tr>
<td><strong>Morwell</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Morwell Area (m²)</td>
<td></td>
<td>RiskNormal(1317918652.93,(1317918652.93*0.05),RiskTruncate(1100000000,1500000000),RiskName(&quot;Morwell Area&quot;))</td>
<td>1.10E+09</td>
<td>1.23E+09</td>
<td>1.32E+09</td>
<td>1.32E+09</td>
<td>1.40E+09</td>
<td>1.50E+09</td>
</tr>
<tr>
<td>Thickness Morwell Dry Gas (m)</td>
<td></td>
<td>RiskLaplace(1076,110.2008,RiskName(&quot;Thickness Morwell Dry Gas&quot;))</td>
<td>379</td>
<td>951</td>
<td>1076</td>
<td>1076</td>
<td>1201</td>
<td>1772</td>
</tr>
<tr>
<td>Thickness Morwell Wet Gas (m)</td>
<td></td>
<td>RiskLaplace(337,1.4483,RiskName(&quot;Thickness Morwell Wet Gas&quot;))</td>
<td>328</td>
<td>335</td>
<td>337</td>
<td>337</td>
<td>339</td>
<td>347</td>
</tr>
<tr>
<td>Thickness Morwell Oil (m)</td>
<td></td>
<td>RiskLaplace(459,0.979999,RiskTruncate(204.585, 459),RiskName(&quot;Thickness Morwell Oil&quot;))</td>
<td>452</td>
<td>457</td>
<td>458</td>
<td>459</td>
<td>459</td>
<td>459</td>
</tr>
<tr>
<td>Net Shale Ratio Morwell (fraction)</td>
<td></td>
<td>RiskNormal(0.4,0.1, RiskTruncate(0.23,0.57),RiskName(&quot;NetShaleRatio Morwell&quot;))</td>
<td>0.23</td>
<td>0.29</td>
<td>0.40</td>
<td>0.40</td>
<td>0.51</td>
<td>0.57</td>
</tr>
<tr>
<td><strong>Seaspray</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Seaspray Area (m²)</td>
<td></td>
<td>RiskNormal(369598608.65,(369598608.65*0.05),RiskTruncate(320000000,420000000),RiskName(&quot;Seaspray Area&quot;))</td>
<td>3.20E+08</td>
<td>3.46E+08</td>
<td>3.70E+08</td>
<td>3.70E+08</td>
<td>3.93E+08</td>
<td>4.20E+08</td>
</tr>
<tr>
<td>Name</td>
<td>Distribution</td>
<td>Function</td>
<td>Min</td>
<td>10%</td>
<td>Mean</td>
<td>Median</td>
<td>90%</td>
<td>Max</td>
</tr>
<tr>
<td>-------------------------------------------</td>
<td>--------------</td>
<td>--------------------------------------------------------------------------</td>
<td>---------</td>
<td>--------</td>
<td>-------</td>
<td>--------</td>
<td>--------</td>
<td>---------</td>
</tr>
<tr>
<td>Thickness Seaspray Dry Gas (m)</td>
<td></td>
<td>RiskTriang(249.29,1246,1246,RiskName(&quot;Thickness Seaspray Dry Gas&quot;))</td>
<td>255</td>
<td>564</td>
<td>914</td>
<td>954</td>
<td>1195</td>
<td>1246</td>
</tr>
<tr>
<td>Thickness Seaspray Wet Gas (m)</td>
<td></td>
<td>RiskNormal(391,1,RiskName(&quot;Thickness Seaspray Wet Gas&quot;))</td>
<td>386.9</td>
<td>389.7</td>
<td>391.0</td>
<td>391.0</td>
<td>392.3</td>
<td>394.7</td>
</tr>
<tr>
<td>Thickness Seaspray Oil (m)</td>
<td></td>
<td>RiskLaplace(531,4.3054,RiskTruncate(330.91,531),RiskName(&quot;Thickness Seaspray Oil&quot;))</td>
<td>502</td>
<td>524</td>
<td>528</td>
<td>529</td>
<td>531</td>
<td>531</td>
</tr>
<tr>
<td>Net Shale Ratio Seaspray and Wellington (fraction)</td>
<td></td>
<td>RiskNormal(0.125,0.03,RiskTruncate(0,0.25),RiskName(&quot;Net Shale Ratio Seaspray and Wellington&quot;))</td>
<td>0.01</td>
<td>0.09</td>
<td>0.13</td>
<td>0.12</td>
<td>0.16</td>
<td>0.24</td>
</tr>
<tr>
<td>Lake Wellington</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellington Area (m$^2$)</td>
<td></td>
<td>RiskNormal(491724585.67,(491724585.67*0.05),RiskTruncate(420000000,560000000),RiskName(&quot;Wellington Area&quot;))</td>
<td>4.20E+08</td>
<td>4.60E+08</td>
<td>4.92E+08</td>
<td>4.92E+08</td>
<td>5.23E+08</td>
<td>5.60E+08</td>
</tr>
<tr>
<td>Thickness Wellington Dry Gas (m)</td>
<td></td>
<td>RiskTriang(0,0,1720.7,RiskName(&quot;Thickness Wellington Dry Gas&quot;))</td>
<td>0</td>
<td>88</td>
<td>574</td>
<td>504</td>
<td>1176</td>
<td>1711</td>
</tr>
<tr>
<td>Thickness Wellington Wet Gas (m)</td>
<td></td>
<td>RiskLaplace(305,28.4337,RiskName(&quot;Thickness Wellington Wet Gas&quot;))</td>
<td>83.8</td>
<td>272.6</td>
<td>305.0</td>
<td>305.0</td>
<td>337.4</td>
<td>478.8</td>
</tr>
<tr>
<td>Thickness Wellington Oil (m)</td>
<td></td>
<td>RiskLaplace(415,15.3553,RiskTruncate(0,415),RiskName(&quot;Thickness Wellington Oil&quot;))</td>
<td>310</td>
<td>390</td>
<td>404</td>
<td>407</td>
<td>414</td>
<td>415</td>
</tr>
<tr>
<td>Net Shale Ratio Seaspray and Wellington</td>
<td></td>
<td>RiskNormal(0.125,0.03,RiskTruncate(0,0.25),RiskName(&quot;Net Shale Ratio Seaspray and Wellington&quot;))</td>
<td>0.01</td>
<td>0.09</td>
<td>0.13</td>
<td>0.12</td>
<td>0.16</td>
<td>0.24</td>
</tr>
</tbody>
</table>
A summary of all @Risk inputs used to calculate the Strzelecki Group tight gas assessment are listed in Appendix Table A-2.

**Appendix Table A-2 Strzelecki Group tight gas play @Risk input parameters.**

<table>
<thead>
<tr>
<th>Name</th>
<th>Distribution</th>
<th>Function</th>
<th>Min</th>
<th>10%</th>
<th>Mean</th>
<th>Median</th>
<th>90%</th>
<th>Max</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Sand Ratio (fraction)</td>
<td></td>
<td>RiskNormal(0.507,0.19079,RiskTruncate(0.05,1),RiskName(&quot;Net Sand Ratio&quot;))</td>
<td>0.05</td>
<td>0.27</td>
<td>0.51</td>
<td>0.51</td>
<td>0.75</td>
<td>1.00</td>
</tr>
<tr>
<td>Ratio of Pay/Sand (fraction)</td>
<td></td>
<td>RiskNormal(0.099575,0.01,RiskTruncate(0.083,0.116),RiskName(&quot;Ratio of Pay/Sand&quot;))</td>
<td>0.08</td>
<td>0.09</td>
<td>0.10</td>
<td>0.10</td>
<td>0.11</td>
<td>0.12</td>
</tr>
<tr>
<td>Area Tight Gas (m²)</td>
<td></td>
<td>RiskNormal(4918558467.97,(4918558467.97*0.05),RiskTruncate(3900000000,5900000000),RiskName(&quot;Tight Gas Area in Strzelecki&quot;))</td>
<td>4.00E+09</td>
<td>4.60E+09</td>
<td>4.92E+09</td>
<td>4.92E+09</td>
<td>5.23E+09</td>
<td>5.86E+09</td>
</tr>
<tr>
<td>Tight Reservoir Thickness (m)</td>
<td></td>
<td>RiskTriang(26.982,3997.4,4045.3,RiskName(&quot;TightReservoirThickness&quot;))</td>
<td>45</td>
<td>1289</td>
<td>2690</td>
<td>2851</td>
<td>3816</td>
<td>4043</td>
</tr>
<tr>
<td>Effective porosity (fraction)</td>
<td></td>
<td>RiskLoglogistic(0.095144,0.042762,2.967,RiskTruncate(0.09,0.35),RiskName(&quot;Effective porosity_TightGas_Strzelecki&quot;))</td>
<td>0.10</td>
<td>0.12</td>
<td>0.15</td>
<td>0.14</td>
<td>0.18</td>
<td>0.35</td>
</tr>
<tr>
<td>Effective Water Saturation in Tight Reservoir (fraction)</td>
<td></td>
<td>RiskTriang(0.33574,0.6976,0.6976,RiskTruncate(0,1),RiskName(&quot;Effective water saturation Tight gas Strezelecki&quot;))</td>
<td>0.34</td>
<td>0.45</td>
<td>0.58</td>
<td>0.59</td>
<td>0.68</td>
<td>0.70</td>
</tr>
<tr>
<td>Gas formation volume factor (sm³/rm³)</td>
<td></td>
<td>RiskNormal(211.2,10,RiskTruncate(195,228),RiskName(&quot;Gas formation volume factor&quot;))</td>
<td>195.0</td>
<td>200.5</td>
<td>211.3</td>
<td>211.3</td>
<td>222.2</td>
<td>228.0</td>
</tr>
</tbody>
</table>