OVERSEAS ENERGY HOLDINGS LIMITED

EVALUATION OF HYDROCARBON RESOURCES OF EXPLORATION BLOCK SEL 05/2005

LOCATED
ONSHORE NORTH-CENTRAL TASMANIA
AUSTRALIA

December 31, 2012

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It should be understood that determination of reserves/resources, volumes and forecasts may be subject to significant variations as new information becomes available and perceptions change.

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Section One

Executive Summary

This report was prepared by S. A. Şehsuvaroğlu, BSc NE, PE, SPE Cert PE (SAS) with the collaboration of C-A Petrol Danışmanlık Hiz. San. Tic. Ltd. Şti (CAPD), at the request of Mr. Michael Roberts, CEO of the Overseas Energy Holdings Limited (OEHL), hereinafter referred to as "the Company". The effective date of this report is 31 December 2012, and it consists of an evaluation of the hydrocarbon resources of the Company's interests in the SEL 05/2005 Exploration Block, which is located onshore in the North-Central region of Tasmania, situated off the southeastern coast of Australian continent.

The evaluation has been carried out in accordance with the guidelines of Petroleum Resources Management Systems (PRMS) 2007, with respect to the classification of Prospective Resources, in conjunction with the standards set out in the London AIM Stock Exchange. This report has been prepared by a "Qualified Reserves Evaluator" as demonstrated on the accompanying "Certification of Competent Person".

OEHL owns a 100% interest in the oil and gas exploration licence block SEL 05/2005, which covers the potentially prospective north-central part of the Tasmania Basin, adjoining and bordering the prolific petroleum producing Bass Basin immediately to the North. OEHL has started exploration activities in the licence block with the well Westwood-1, drilled in the latter part of 2009. In addition, OEHL acquired extensive regional gravimetric data in early 2011 and later shot 11 lines of 2D seismic, amounting to 42.68 kilometers, in various prospective parts of the licence block in early 2012. CAPD Consulting and Engineering were asked to carry out a reprocessing and interpretation of this seismic data.

CAPD carried out the reprocessing and interpretation of the seismic data from September to November 2012 and made a preliminary assessment and estimation of the oil and gas resources which is quite encouraging and favorable with respect to further pursuing and continuing the exploration activities in the licensed block. No relevant well test data was provided that would indicate the quality of these onshore reservoir(s); however believe that reservoir quality could be analogous to Bass Straits fields to the north. In fact, the reservoir quality improves from the southern part of the block to the edge of the onshore platform, thus the onshore prospects could be comparable with the Bass Straits fields.

From the volumetric estimations of the prospective areas, it is estimated that OEHL Licence Block SEL 05/2005 contains total *Prospective Resources* of 195.76 million barrels of oil-in-place (*54.81 million barrels of recoverable oil*) in the crude oil case; or 103.92 billion cubic feet of gas-in-place (88.33 billion cubic feet of recoverable gas) in the natural gas case.

In summary, we consider block SEL 05/2005 to have significant exploration potential. The cost of exploring and developing reservoirs of this depth will be will be high by onshore standards due to the need to import all equipment from the mainland, although transport and logistics support are well developed and readily available. However, the potential size and commercial value of the resources, if successful, be very rewarding.

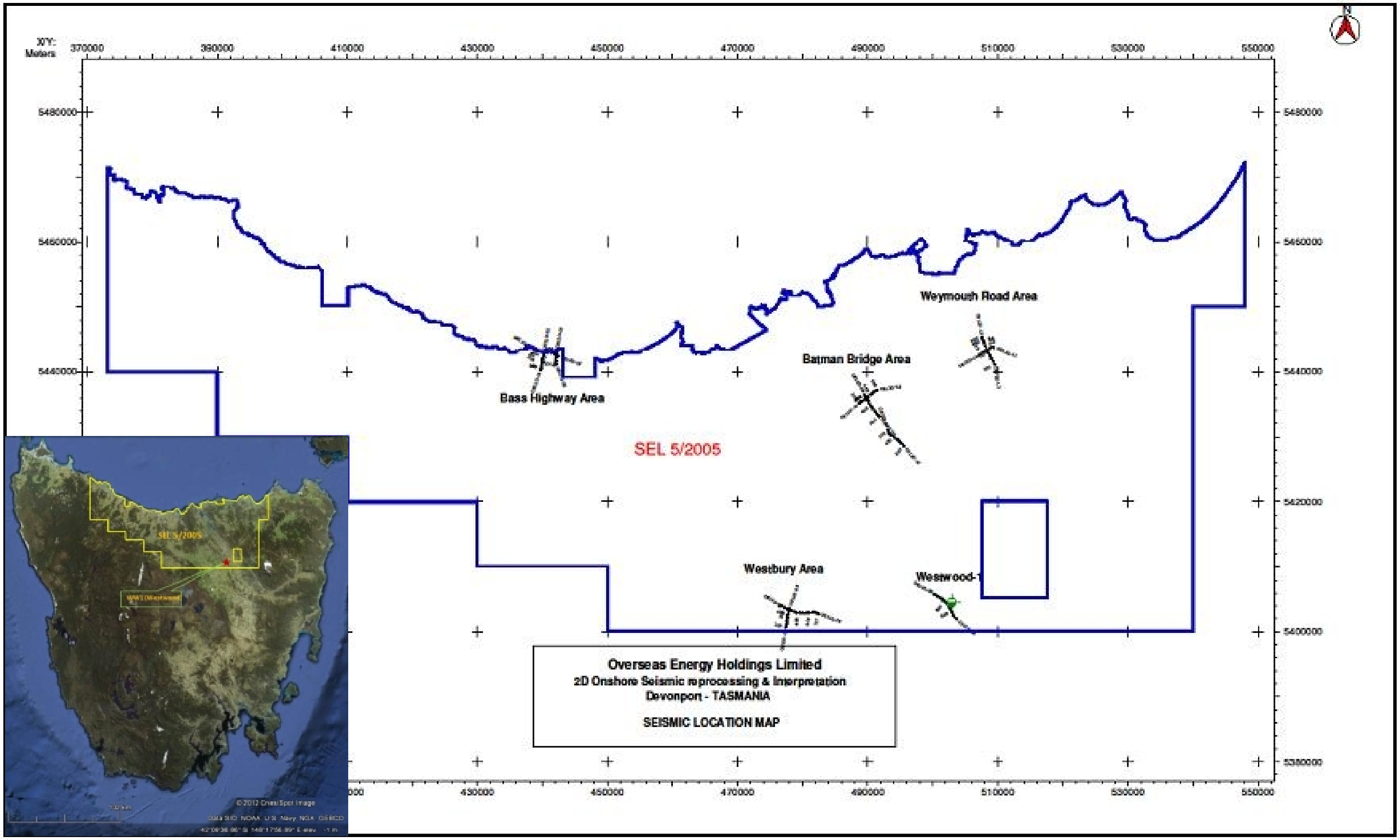


Figure 1- Seismic location map, showing OEHL 2D seismic lines, shot in 2012 and potential prospect areas

Section Two

Introduction

2.1 Study Objectives

C-A Petrol Danışmanlık Hiz. San. Tic. Ltd. Şti (CAPD) have carried out a study, including seismic data re-processing, interpretation and volumetric calculations on behalf of OEHL, on seismic data from the Exploration Block SEL 05/2005, located onshore in the north-central portion of Tasmania.

S. A. Şehsuvaroğlu, BSc NE, PE, SPE Cert PE (SAS) has added an economic model based on the volumetric estimates calculated by CAPD and formatted and certified the report to comply with London Stock Exchange AIM rules.

The data provided by the client:

- SEG-Y files of 2D seismic
- Gravity Survey data carried out from Dec 2010 to Feb 2011
- Existing seismic interpretation reports with graphical enclosures (digital images)
- Various Field data (geological, structural, tectonic maps, exploration degree scheme)
- Well logs (LAS format)
- Previous geologic and seismic reports from the region

Based on this information CAPD has prepared a seismic re-processing and interpretation and calculated oil/gas-in-place volumes. This report is based the results of this work, carried out during September-November 2012, as well as the accompanying economic model.

The scope of the combined CAPD / SAS project involved:

- Re-processing seismic data
- Building a data base
- Seismic data loading
- Preparation of horizon and fault interpretation
- Preparation of well interpretation
- Preparation of isopach and net-pay maps
- Collection of input data for volumetric calculations
- Deterministic resource calculation
- Reporting and recommendations
- Construction of an economic model
- Re-formatting the report to comply with London AIM rules

2.2 Deliverables

The results of the evaluation have been delivered in electronic format only.

Project Schedule (15th September – 15th December 2012)

Task	Wk 1	Wk 2	Wk 3	Wk 4	Wk 5	Wk 6	Wk 7	Wk 8	Wk 9	Wk 10	Wk 11	Wk 12
CAPD												
Re-processing seismic data												
Building a data base												
Data loading and QC												
Preparation of seismic and well interpretations												
Gridding, mapping,												
Collection of parameters for reserves calculation												
Summarizing oil or gas resources												
Final report & conclusions												
SAS												
Re-format Report to AIM												
Production profile & economic model												
Certification												

Table 1 - Project Schedule

Section Three

Overview of the Region, Location and Assets

3.1 Introduction

The island of Tasmania is situated off the south-eastern coast of Australian continent. Most of the central and eastern part of this island is covered by the Tasmanian Sedimentary Basin which is an erosional remnant of a larger, shallow intra-cratonic (epicrotonic) basin, consisting of sedimentary successions deposited in the Late Carboniferous to the Late Triassic and intruded heavily by the mid-Jurassic dolerite rocks. The basin was uplifted and deformed in the Late Cretaceous to the Early Tertiary times. It is also underlain by the deformed Ordovician to Early Devonian sedimentary and much older crystalline basement rocks.

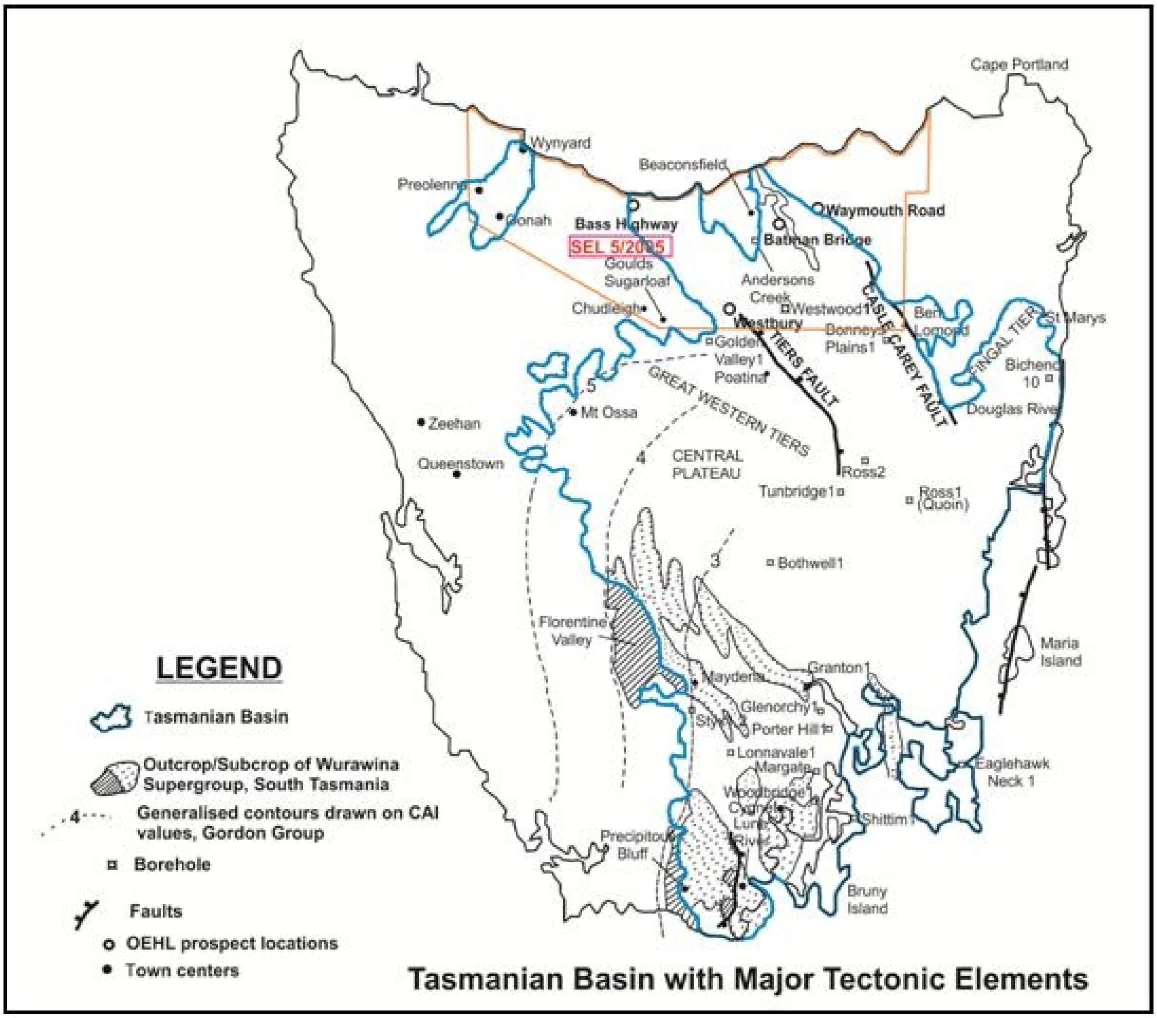


Figure 2 - The intra-cratonic Tasmanian Basin map, showing the outlines of the Late Carboniferous to Late Triassic Tasmanian sedimentary basin and distribution of pre-Carboniferous successions with OEHL License Block SEL 5/2005 overlaid.

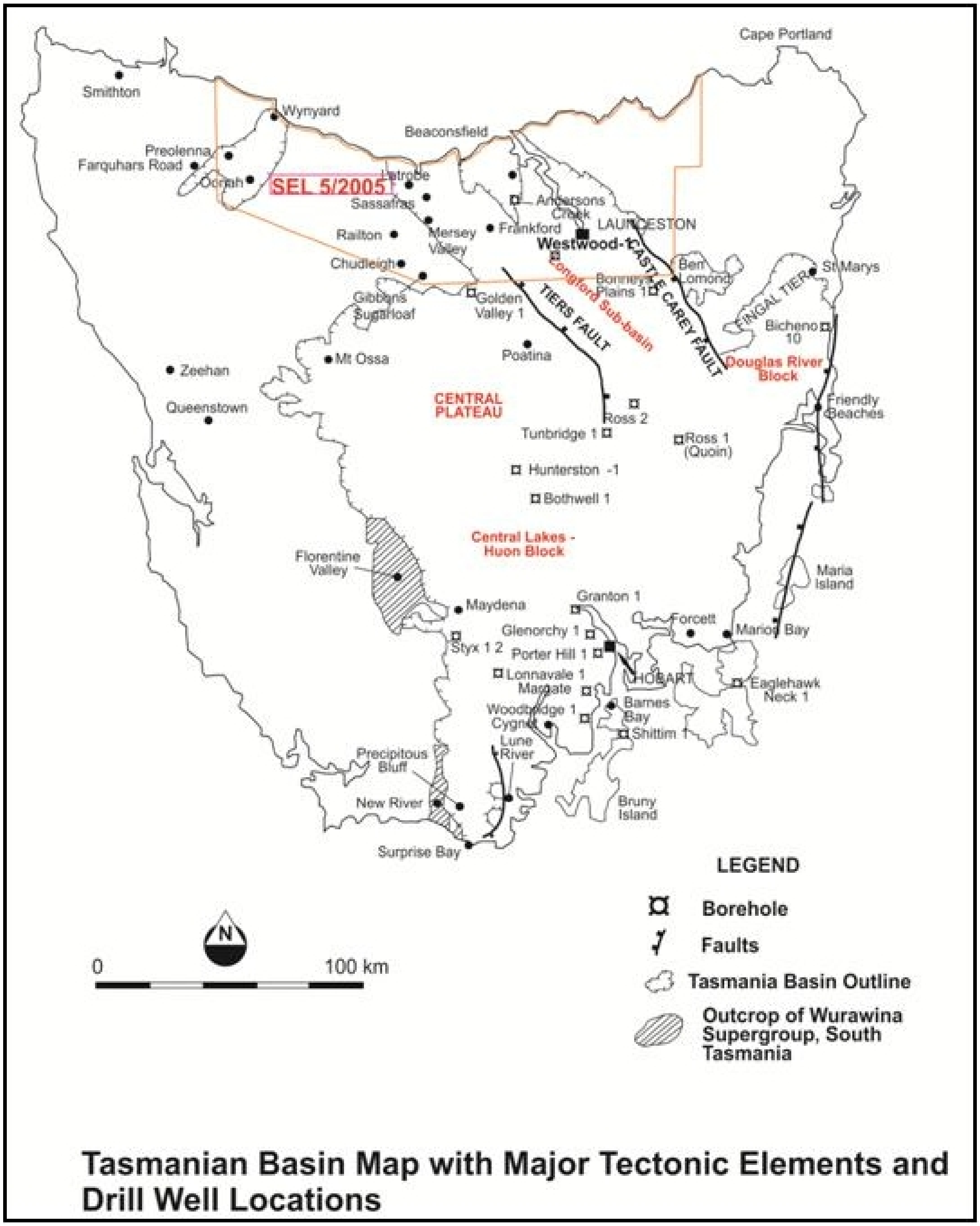
The Tasmania Basin itself is a shallow intra-cratonic – epicratonic basin, which contains a sedimentary sequence of predominantly flat–lying strata, accumulated in the Late Carboniferous to the Late Triassic and known as the Parmeener Supergroup. This sedimentary sequence has been intruded by thick sheets and sills of Jurassic dolerite that currently occupy most of the outcrop area of the basin. The total known thickness of the sequence, excluding the dolerite thickness is about 1.7 km. The Tasmanian Basin covers most of the central and eastern Tasmania (Figure 2). The present basin limits are erosional, not depositional, and the original basin limits were probably considerably larger than the present outline.

The Tasmania Basin basement rocks are comprised of a diverse and structurally complex array of Proterozoic and lower Paleozoic rocks. The basement rocks have been affected by a mid-Devonian tectono-metamorphic event correlated with the Tabberabberan Orogeny. Part of the basement complex of Tasmania Basin consists of a Late Cambrian to Early Devonian age Wurawina Super-group sediments with petroleum potential. The stratigraphy of the Tasmania Basin is known mainly from outcrop and the stratigraphic diamond boreholes. The sediments of the basin are separated into two major super-groups: (1) the Wurawina Super-group of the Early Paleozoic (Late Cambrian to Early Devonian age) and (2) the Parmeener Super-group of the Late Paleozoic to Early Mesozoic (Late Carboniferous to Late Triassic) age.

These two super-groups are separated by a major angular unconformity, associated with the Tabberabberan Orogeny. Each of the super-groups is sub-divided into a number of lower rank litho-stratigraphic units. The Wurawina Super-group consists of The Late Cambrian to Early Ordovician shallow marine to fluvial silici-clastic rocks known as the Denison Group overlain by about 1.5 km of predominantly micritic shallow marine, warm-water Ordovician limestone known as the Gordon Group, and then up to 5 km of shallow marine, Silurian to Early Devonian silici-clastic rocks known as the Eldon Group. A regional conodont alteration index (CAI) study of the Gordon Group carbonates shows that these rocks are mature for hydrocarbon generation in southern Tasmania (CAI typically between 1.5 and 4). By contrast, the rocks are over-mature in western and northern Tasmania (CAI being mainly 5).

The Tasmania basin can be divided into three major structural elements. The Longford Sub-basin, an onshore extension of the Bass Basin to the north, effectively divides the rest of the basin into a large western half called the Central Lakes-Huon Block, and an eastern half called the Douglas River Block (Figure 3). All of these areas are underlain by the folded Paleozoic rocks of Cambrian to the Devonian age. Over much of the basin, the Earlier Paleozoic rocks are covered by generally flat-lying Late Carboniferous to the Late Triassic sediments (the Parmeener Super-group) and the Jurassic dolerite.

In addition steep normal faults of Jurassic to Early Tertiary age are widespread in the Tasmania Basin. North to northwest fault trends are dominant. Among the more significant faults, affecting the Tasmania basin are the Tiers Fault which is partly Jurassic and has a throw of 700 – 1000 m near Poatina; the Castle Carey Fault with a throw of about 600 m, south of Ben Lomond, and the Lune River Fault (Figure 3). The Cascades Fault near Hobart is also partly Jurassic, with a displacement in excess of 1300 m in places.



Tasmanian Basin Map with Major Tectonic Elements and Drill Well Locations

Figure 3 - Tasmania Basin map, showing erosional Tasmania sedimentary basin, major tectonic elements and diamond boreholes with OEHL Licence Block overlaid.

There have been no oil or gas fields discovered to date in the Tasmania Basin, although several oil seeps have been reported. The seeps reported in the Tasmania Basin have had limited correlations made to the source rocks. However, there is a seep in a recent quarry at Lonnavale to the southwest of Hobart that has been correlated with the Permian age Tasmanite Oil Shale and is the best indication yet that a significant petroleum system possibly exist in the basin.

Figure 4 – Lonnavale oil seep, located southwest of Hobart, Tasmania. The oil from this surface seep has been correlated with the Permian age Tasmanite Oil Shale. (Photo Courtesy – the Author)

OEHL owns a 100% interest in oil and gas exploration licence block SEL 5/2005, which covers the potentially prospective north-central part of the Tasmanian Basin, adjoining and bordering the prolific petroleum producing Bass Basin to the North. OEHL has started exploration activities in the licence block with well Westwood-1, drilled in the latter part of 2009. In addition, OEHL acquired regional gravity data in Dec 2010 – Feb 2011 and later shot 11 lines of 2D seismic, amounting to 42.68 kilometers, in various prospective parts of the licence block in early 2012.

3.2 Structural and Stratigraphic Development

OEHL Licence Block SEL 5/2005 with an extensive areal coverage of 6,885 km² is located in the north-central part of Tasmania, bordered from the north by the Bass Strait and the prolific petroleum producing Bass Sedimentary Basin. Crystalline basement rocks, consisting of granites and various kind of metamorphic rock assemblages, Pre–Cambrian to Lower Cambrian in age, outcrop in the eastern and western parts of the licence block area.

Central part of the licence area contains thick sedimentary accumulations, associated with the greater Tasmania Basin depositional system, developed in the Late Carboniferous to the Late Triassic times. These sediments in the licence block area in particular and in the greater Tasmania Basin area in general were subjected to intense tectonics and faulting in the mid–Jurassic and in the Early Tertiary times, resulting in the intrusion of thick dolerite rocks in the mid–Jurassic and folding and faulting, but mostly in normal offset type in the Early Tertiary.

The oldest potential source rocks in the Tasmanian Basin are the Ordovician, although organic richness (organic matter content) data has not been adequately studied. Measurements of total organic carbon (TOC) and Rock–Eval pyrolysis have been made on a few samples of limestone within the Gordon Group. These analyses indicate TOC values above 1%, suggesting possibility of source rock potential in the shalier intervals of the Gordon Group.

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

The Permian aged Tasmanite Oil Shale is the most well-known source rock in Tasmania. It has been documented as having TOC content ranges from good to very good, containing TOC values of 2.5 % to over 60 % and a hydrogen index (HI) between 700 to 1000 mgHC/gTOC. The production index (S1+S2) levels are high (from 10 to 900 mg/gm of rock), and although the Tasmanite Oil Shale bands are thin, they can produce up to 3.7 bbls/m^2 of oil. The distribution of the Tasmanite Oil Shale is illustrated in Figure 4. It is observed that the Tasmanite Oil Shale is mostly known to occur in the northern and eastern areas of the basin. It appears that several regions of the basin were sufficiently low in oxygen for some algal beds to be preserved.

Shales in the lower levels of the Lower Freshwater Sequence (Liffey – Faulkner groups) and the coals within the Freshwater Sequence appear to be good, but volumetrically minor potential source rocks. The remaining parts of the Lower Parmeener Super-group, including the basal tillite are unlikely to be good source rocks.

Based on Rock-Eval analyses of samples from Preolenna and maceral analyses, coals from the Lower Freshwater Sequence are good potential source rocks with Type II – III kerogen, both oil and gas-prone type organic matter. The Late Triassic coal measures (Unit 4) are unlikely to be viable hydrocarbon sources. In the northeast coal fields and in central Tasmania, vitrinite reflectance data indicate that the coals are sub-mature to marginally mature, except where close to the dolerite. Coal consists predominantly of inertinite kerogen (Type III organic matter), a poorly gas-prone hydrocarbon source.

The primary reservoirs within the Pre–Carboniferous successions are the carbonates of the Gordon Group. Leached and dolomitized limestone, reefal and fractured reservoirs could be anticipated, but not much is known about these sequences. Likewise, the overlying sandstones of the Eldon Group are potential reservoirs, but no accurately documented information is available from these rocks. Sandstones in the Silurian – Devonian Eldon Group have also been suggested as the potential reservoirs, although no data are available on porosity and permeability. However, similar producing formations have already been exploited in Oman and it is thought that Tasmanian reservoirs properties may provide analogous results.

Notwithstanding the basalt flows and widespread dolerite rock exposures in the licence block area, Bouguer gravity data collected by OEHL in some of the potential prospect areas show that good and thick sedimentary successions exist, indicating good possibility of petroleum occurrence. Hence, good petroleum potential exists in the license block area. A Bouguer gravity anomaly map, compiled and constructed from the OEHL gravity data in Devonport area where the Bass Highway potential prospect located, shows a very well developed NE – SW trending sedimentary trough with possible occurrence of thick petroleum prospective sediments.

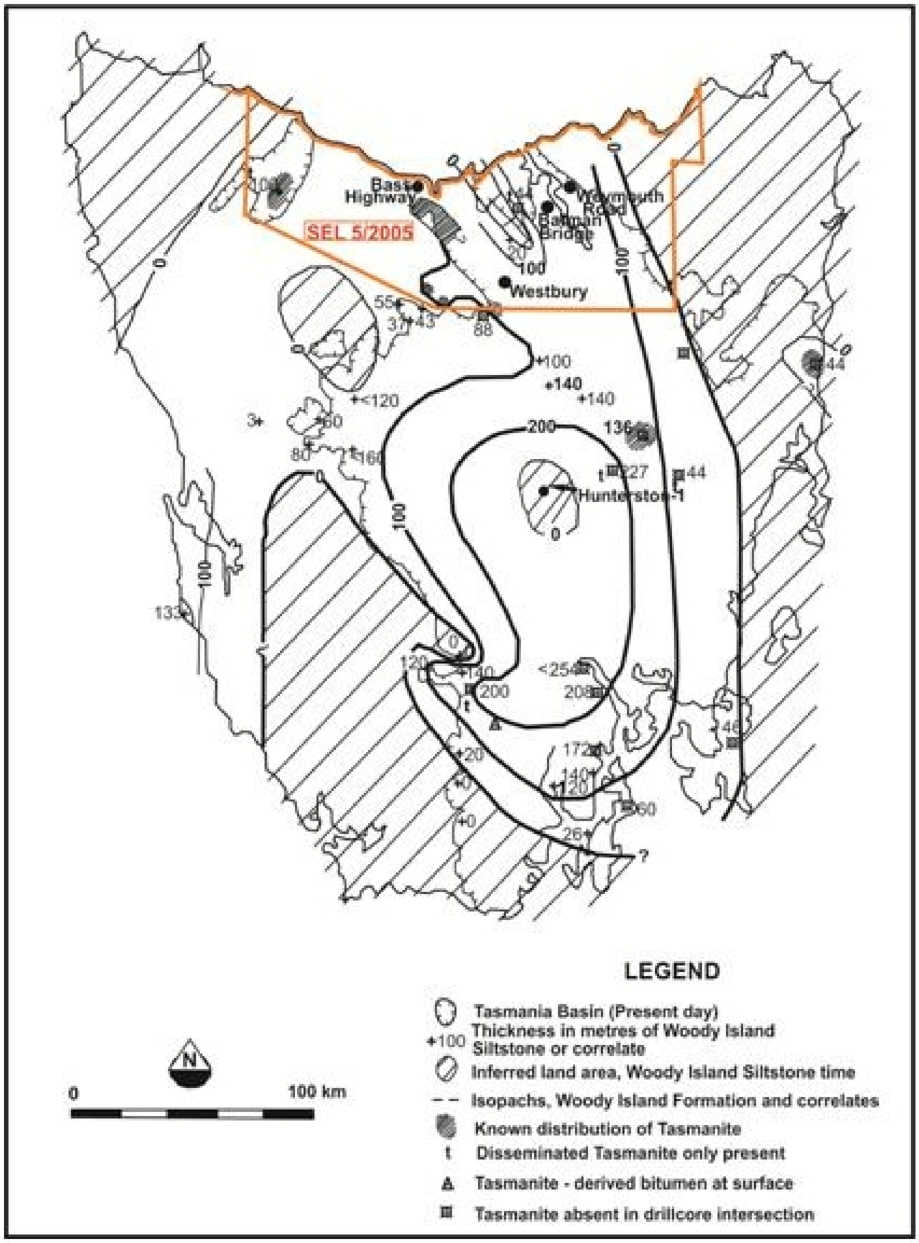


Figure 5 - Isopach map of the Woody Island Formation and known distribution of the Tasmanite Oil Shale with the posted thicknesses of the Woody Island Formation shown with OEHL License Block SEL 5/2005 overlaid.

Occurrence of such thick sedimentary successions in the Devonport area should have potential mature source rocks and reservoir facies that could contain commercial quantities of oil and gas, making the Bass Highway potential prospect area in Devonport region an especially attractive area with respect to oil and gas finds.

Likewise, Bouguer gravity anomaly maps, compiled and constructed by the OEHL consultants in the Westwood-1 well site area and the Weymouth Road potential prospect area show that good and thick sedimentary accumulations are observed in the south and southwest of the Westwood–1 well site area, but such sediment accumulation does not exist in the Weymouth Road potential prospect area.

These results show that the Westbury potential prospect area, located in the southwest of the Westwood-1 well site holds good petroleum potential with respect to finding mature source rocks and reservoir facies and hence prospectivity of petroleum occurrence is good in the area. It is further observed from the Bouguer gravity anomaly map that the Weymouth Road potential prospect area is seen to be covered by the deformed and partly crystalline basement type rocks which may show that the area may not possess good petroleum prospectivity as do the other areas discussed above.

Unfortunately, no gravity data were collected in the Batman Bridge potential prospect area to be able to assess the prospectivity and sedimentary characteristics of the area. Nevertheless, regional gravity and geological characteristics show that the region is covered with widespread dolerite exposures which represent uplift and extensive erosion.

Moreover, these mid–Jurassic dolerites conceal beneath them appreciable thicknesses of Parmeener Super-group of sediments in many parts of the Tasmanian Basin and if such properly preserved sedimentary sequences are found beneath the exposed dolerite rocks in the Batman Bridge potential prospect area, it would not be unreasonable to expect that the area could also hold good petroleum potential, because the whole sedimentary sequence from the Late Carboniferous to the Late Triassic could be preserved below the dolerite rocks and these rocks could contain both mature source rocks for petroleum generation and reservoir facies to hold and store them.

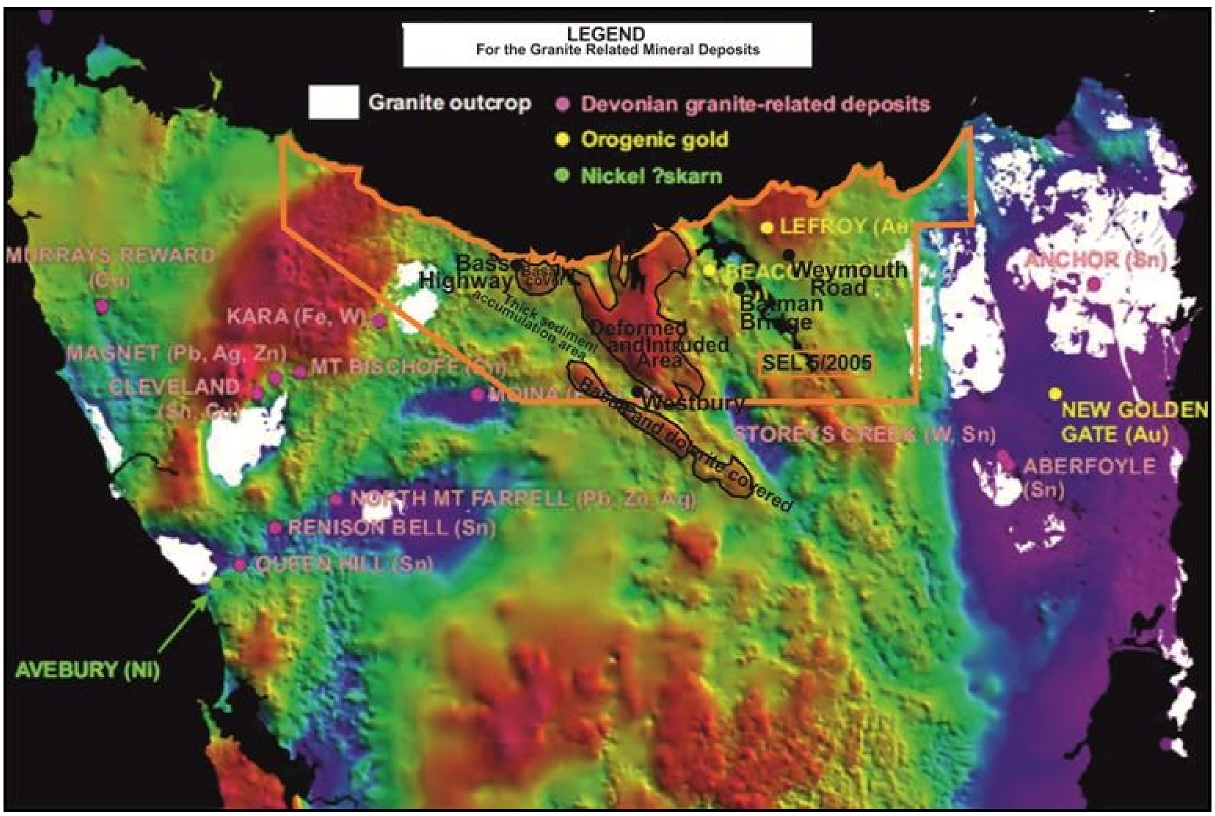


Figure 6 - Terrain-corrected residual gravity anomaly map of northern Tasmania, showing OEHL License Block SEL 5/2005 outlines, colored in orange and potential prospect locations with some of the surface structural features such as basalts and deformed areas outlined.

Section Four

Preparation of existing G&G interpretations

4.1 Introduction

After the reprocessing of 11 seismic lines which were grouped in three or two lines per potential prospect area within the SEL 5/2005 License Block (Figure 1), each one of the seismic sections were horizon correlated based on the geological horizons depth–picked from the Westwood – 1 exploration well drilled by OEHL in 2009 and these horizons were transferred to the seismic lines and interpreted and correlated.

After the correlation, structure depth maps of the individually correlated horizons were generated. Altogether, four structure maps per potential prospect area were generated. The names of these potential prospective areas were interpolated from previous studies and seismic survey work.

These potential prospective areas are: (1) the Bass Highway Potential Prospect area, located near the Devonport Gulf along the Bass Strait in the north of the license block area; (2) the Westbury Potential Prospect area, located in the south center of the license block near the northern tip of the large Tiers Fault line; (3) the Batman Bridge Potential Prospect area, located in the northeast part of the license block area near the town of Beaconsfield and (4) the Weymouth Road Potential Prospect area, located in the extreme northeast of the license block area near the northeastern erosional edge of the Tasmania Basin proper .

4.2 Regional Hydrocarbon Potential

Australia has more than 50 sedimentary basins[1]. Of these, only 12 are producing oil and gas and only four are known to have non-commercial reserves. There has been very little exploration of the remaining 34 basins. This means that many regions that could have hydrocarbons have not been drilled to any significant extent.

Australia's current oil and gas-producing provinces were all found to be hydrocarbon-bearing before 1972. The history of hydrocarbon exploration over the past four decades has been one of delineating these basins' full potential. Given the maturity of Australia's oil-producing areas, only the discovery of a significant new oil province can arrest the long-term decline in Australian oil production. OEHL believes onshore northern Tasmania, due to its proximity to currently producing basins, is one of these new oil provinces.

Australia's oil-producing regions include Western Australia, Bass Strait, the Northern Territory, the Timor Sea, South Australia and Queensland. Oil is used to produce transport fuels (petrol and diesel), and is used in the production of lubrication oils, kerosene, asphalt, plastics and pharmaceuticals.

Australia has nine percent of the world's coal reserves and is the world's largest exporter, mostly to Asia. Coal has been mined since the 1850s[2]. But on the contrary, Australia only has approximately half of one

[1] Australian Petroleum Production and Exploration Association Ltd., Oil and Petroleum Liquids, Nov, 2012, http://www.appea.com.au /oil-a-gas-in-australia/oil.html
[2] Brian J. Fleay, Oil and Australia, Hubbert Centre Newsletter # 2000/3, Petroleum Engineering Department, Colorado School of Mines, Golden CO 80401-1887

percent of the world's conventional oil endowment, a mere nine billion barrels. Most of that is offshore in the Bass Strait between the mainland and Tasmania, the rest is in Central Australia and offshore from the north-west coast while condensate from natural gas makes a significant contribution. More than half of this crude oil has been produced since the mid-1960s. The nation consumes 280 million barrels per year.

Australia's self-sufficiency in oil and condensate is declined from 85 percent in 1999 to 42 percent in 2010 (AGSO 1998, Fleay 1998). Net oil imports from the Middle East will rise fivefold by volume next decade based on business-as-usual consumption forecasts. The import bill will rise from AU$1,200 million to AU$8,000 million, depending on oil prices and the dollar exchange rate. Australian oil production will most likely cease before 2030. Earlier editions of the Hubbert Center Newsletter (HCN #97/1; 97/2) have described how world oil production is expected to peak by 2010 and commence decline in the world outside the Middle East any time now.

In fact, in recent years, oil production has fallen rapidly in Australia as the Bass Strait oil fields decline. Australia's production of petroleum liquids peaked in 2000 and has been steadily declining since then. Having noted that Bass Straits carries the highest existing potential of additional reserves, OEHL believes that onshore northern Tasmania present the best possible candidate for development of oil production from similar geological structures.

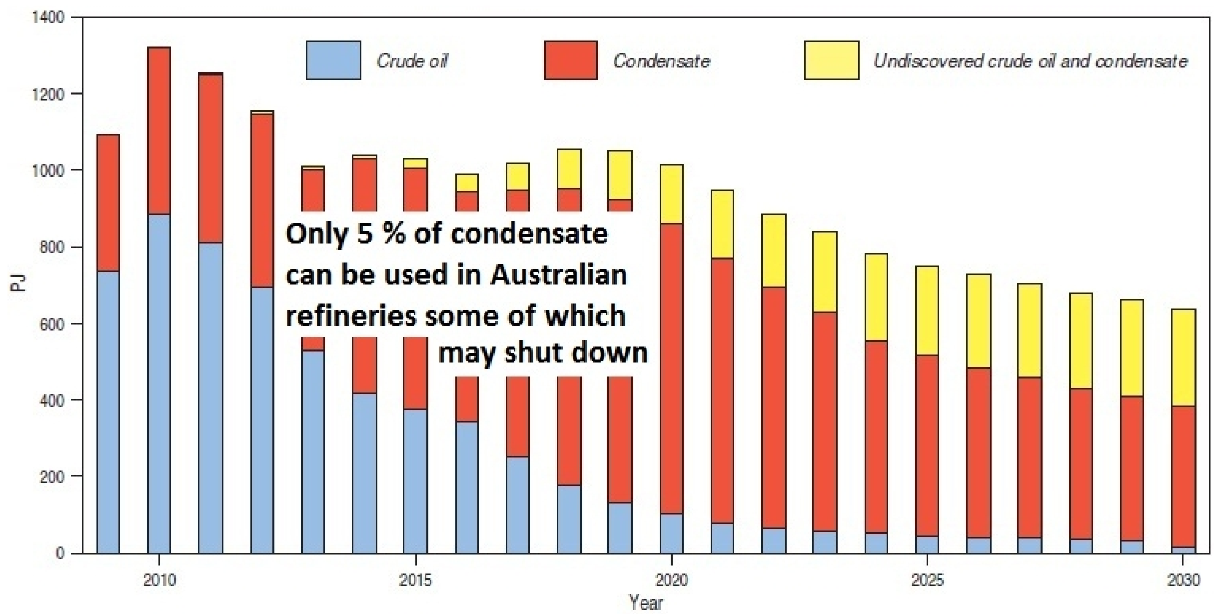


Figure 7 – Australian oil production outlook from proven hydrocarbon basins

Less than two percent of the world's natural gas endowment is in Australia, and we have produced nine percent of this since the late 1960s. Three quarters is located offshore from the north-west coast and in the Timor Sea between Australia and Indonesia. The remainder is in the Bass Strait and Central Australia. A pipeline from the west coast to supply the eastern seaboard will be needed within 10 years. Australia's natural gas endowment is larger than that for oil.

Australia's $28 billion per year oil and gas industry contributes 58 per cent of Australia's primary energy, 2.5 per cent of Australia's gross domestic product, and almost $9 billion in direct tax payments. Ever since the first significant Bass Strait discoveries in the mid-1960s, Australia's oil and gas industry has underpinned

Australia's economic prosperity and growth. World's insatiable thirst for energy means that energy security is one of the big issues confronting Australia and the world today. Access to energy resources is the key to continuing economic growth. And while oil companies in Australia been finding gas faster than they produce it for a quarter of a century, Australia has only about a decade of known oil resources remaining at today's production rates.

4.3 Horizon and Fault Interpretation

Within each one of these potential prospect areas, except the Batman Bridge Potential Prospect area, four structure - depth maps were generated, each representing from top down, (a) the top of the Lower Parmeener Group horizon, (b) the top of the Liffey Group horizon, (c) the top of the intra Eldon Group horizon and (d) the top of the Gordon Group limestone horizon. Following generation of these structure – depth maps of the individual reflective horizons, net pay isopach (thickness) maps of the individual reservoir horizons were generated from the structure - depth maps, assuming that the plunge of the individual structure contour maps defined oil(gas)/water contact or the zero(0) pay thickness for that particular horizon. A total of fourteen (14) pay maps were generated from the structure - depth maps, four isopach maps per potential prospect area except the Batman Potential prospect area.

Reflectivity of the seismic lines from the Batman Bridge Potential Prospect area was quite poor despite rigorous reprocessing work of the seismic lines. The poor reflectivity in the Batman Bridge Prospect area was caused by the widespread outcropping of the dolerite rocks in the area. Dolerite rocks are very high velocity rocks, when present on the surface, prevent seismic energy penetrating deep into the earth, thereby weakening of the down-going seismic energy and hence resolution loss on the seismic acquisition work.

Bass Highway Potential Prospect
Seismic sections from the Bass Highway Potential Prospect area were correlated and interpreted structurally. Reflectivity and resolution of the seismic sections after the reprocessing work were much improved. Therefore, horizon correlation and interpretation of the seismic sections were relatively good. The interpreted sections show the potentially prospective reflective horizons quite clearly.

The structure maps show clearly the development of structures that are partly defined by faulting which is quite strong and prevalent in the seismic sections interpreted and shown above. Structural closures that are observed in the southwest corner of the map show good potential with respect to oil and gas entrapment and a possible drill–site is prosed as BH-1, shown in Figure 8.

Furthermore, there is another partial structural development located in the western parts of the maps. But unfortunately, this structural closure is an artifact of the map contouring and lacks enough seismic control and coverage to be able to make it a potential prospective drill-site. If this partial structural development, observed on the western edge of the structural – depth contour maps, be defined and proved with further additional seismic acquisition work, then it may also be a viable potential structural lead that can be considered for testing by exploration drilling. If it is possible for the OEHL to shoot additional seismic lines over this partial structural closure, then there may be another good potentially prospective drill–site created.

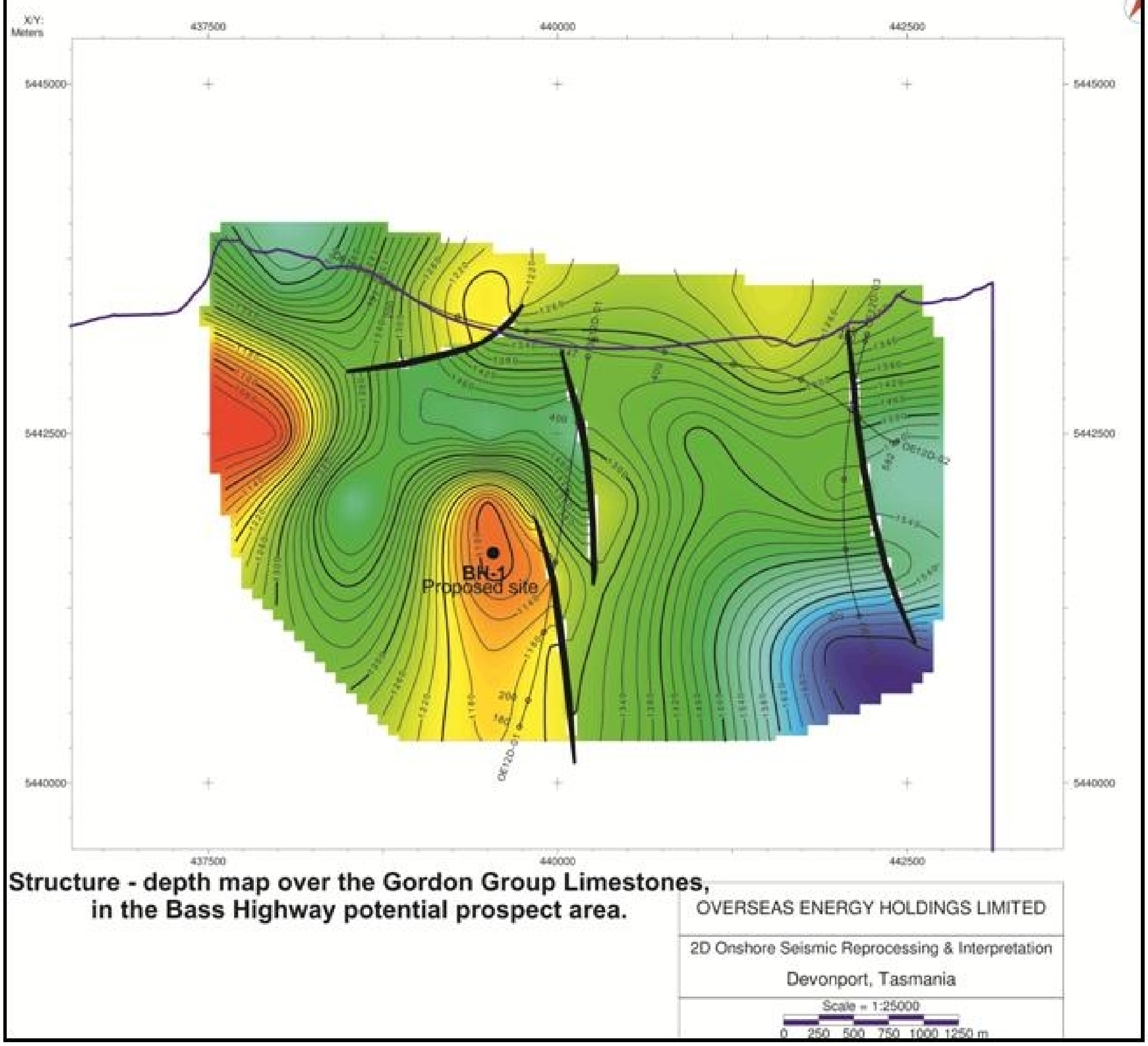


Figure 8 - Structure–depth map of the Gordon Gr. Limestone from the Bass Highway potential prospect area, illustrating a good fault controlled structure in the southwest corner of the map.

Westbury Potential Prospect

Similar seismic interpretation and structure–depth contour map generation works were carried out in the Westbury potential prospect area, as described above. Faulting is extensive in the Westbury area just as in the previous case. Structural closures were formed on all four correlated and interpreted reflective horizons, indicating that these horizons could be potentially prospective with respect to oil and gas accumulation. Seismic lines from the Westbury potential prospective area give reflective horizon correlation and interpretation and show good structural development on the reflective horizons interpreted with faults displaying a major role in the structuration. Reflectivity and resolution in both of the seismic sections is quite good and clear which makes horizon correlation easier. However, as both sections illustrate that reflectivity and resolution become quite weak with increasing depth and at greater depths.

Such rocks are similar to the high velocity crystalline basement rocks that usually underlie the sedimentary basins that show very weak or no reflectivity.

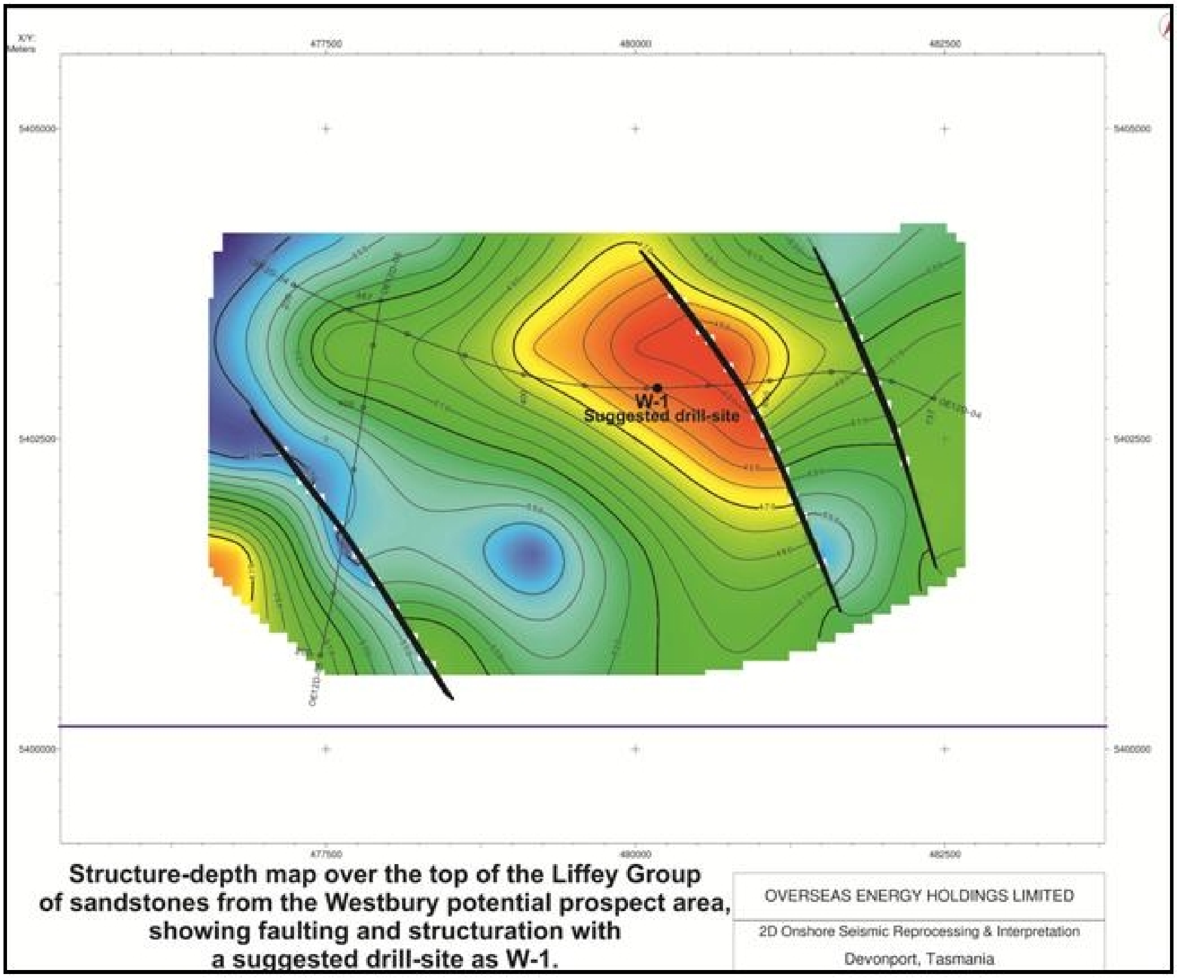


Figure 9 – Structure-depth map of the Liffey Group of sandstone from the Westbury potential prospect area, showing fault related structural development.

The above map shows good structural closure developments, controlled by the faulting. Structural closures seem quite large, indicating that the Gordon Group, the Eldon Group and the Liffey Group of sandstones may hold good potential with respect to oil and gas accumulation and entrapment. Although, seismic section coverage of the area is sparse and not sufficient to make such a decided judgment, it is quite clear from the interpreted and mapped seismic data available that good hydrocarbon potential exists. There was definitely a four–way structural development, which took place in the potential prospect area. Furthermore, because of the good structural development in the area as the map illustrates, a possible potential drill–site, named W-1 is suggested and shown in Figure 8. This well could test the Liffey, the Eldon and the Gordon groups potential all at once.

Weymouth Road Potential Prospect

A similar seismic section correlation, interpretation and mapping were carried out in the Weymouth Road potential prospect area as shown in Figure 10. Two crossing seismic lines were shot in the area, with relatively poor seismic reflectivity and resolution, because of the complex geological terrain and faulting.

Interpretation and mapping of the reflective horizons show large structural developments in the Lower Parmeener, the Liffey Group and in the Eldon Group horizons as shown in the structure–depth map in Figure 10.

Because of the geological complexity in region and poor seismic resolution of the seismic lines available, more and better seismic coverage is necessary to better define large structures shown in Figure 10 to be certain of their integrity.

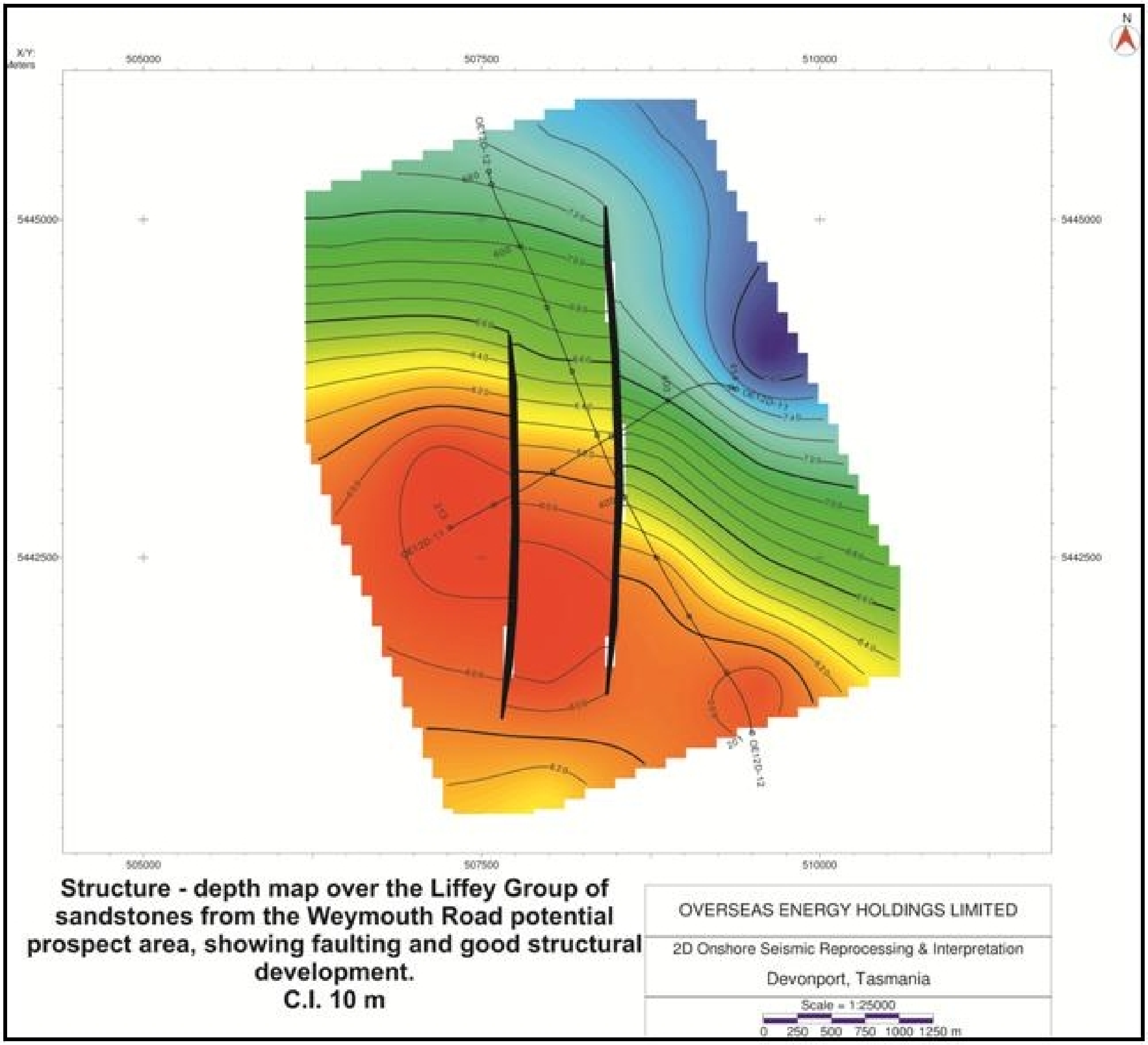


Figure 10 - Structure–depth map of the Lower Parmeener Group from the Weymouth Road, showing a large structural development on the west-southwest of the map area, possibly fault controlled.

With some additional seismic coverage in the area to better define these structures, good oil and gas prospective leads could be developed with good commercial upsides. At this stage no suggestion was made for any drill–sites in this area.

Batman Bridge Potential Prospect

Surface of this prospect is covered by high velocity dolerite rocks, which cause seismic resolution and reflectivity to be quite poor. Two seismic lines were shot in this area, with relatively poor resolution and reflectivity, which makes horizon correlation and interpretation very trying. Although much noise was removed from the seismic sections during the reprocessing work, resolution improvement was relatively limited. Because of limited success in resolution improvement after reprocessing, only two reflective horizons could be identified and correlated for the final map contouring, namely the top of the Liffey Group and the top of the intra-Eldon Group.

The open ended structural development in the left hand side of the map in Figure 11 is not fully defined, because only seismic line OE12D-10 defines this structural development and it is not sufficient for the integrity of this half structure. Additional seismic coverage is needed to define and verify it better, so that it could be developed into a commercially viable lead. Because of the poor seismic resolution and reflectivity in this area, additional and better designed seismic coverage is needed to define reflective horizons and structures better.

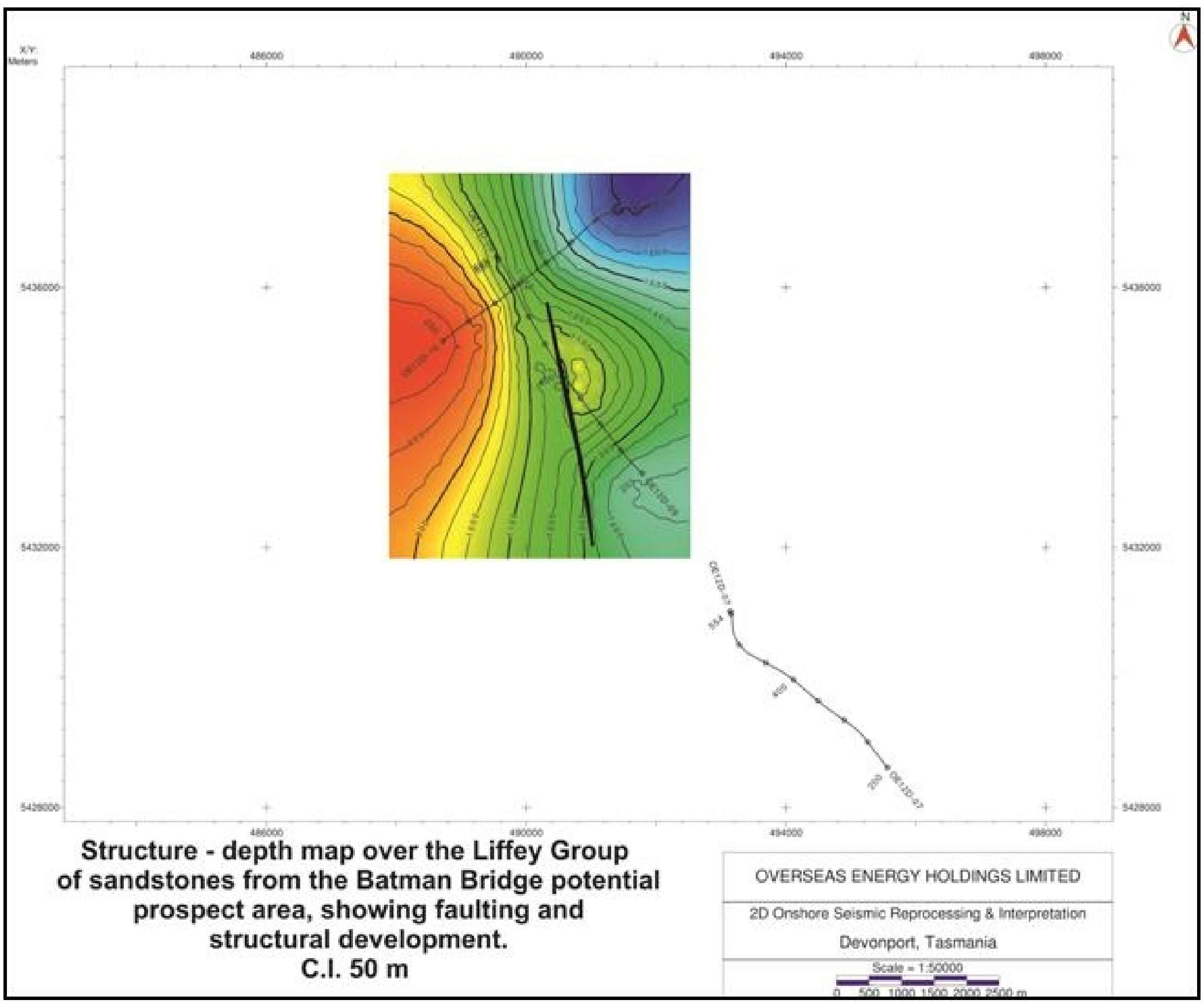


Figure 11 - Structure–depth map of the Liffey Group from the Batman Bridge potential prospect area, showing fault controlled structural development.

Westwood-1 Potential Prospect

After drilling Westwood-1 in the late 2009 in the license block area, OEHL had detailed Bouguer gravity survey and shot one–line of reflection seismic (Line OE12D-06) to see the geological conditions in the area and also to tie and correlate the well with the sedimentary sequences present in the area. The gravity mapping shows that the thick sedimentary sequences occur to the southwest of the seismic shot, which was shot over a much deformed area, where the crystalline basement rocks may be shallower than what they are to the southwest of the survey area. Should OEHL wants to further look into the potential of Westwood area, then they should concentrate in the southwest of the line OE12D-06, for a few regional lines shot in this particular area could determine and define where good and oil and gas prospective structural leads could be located.

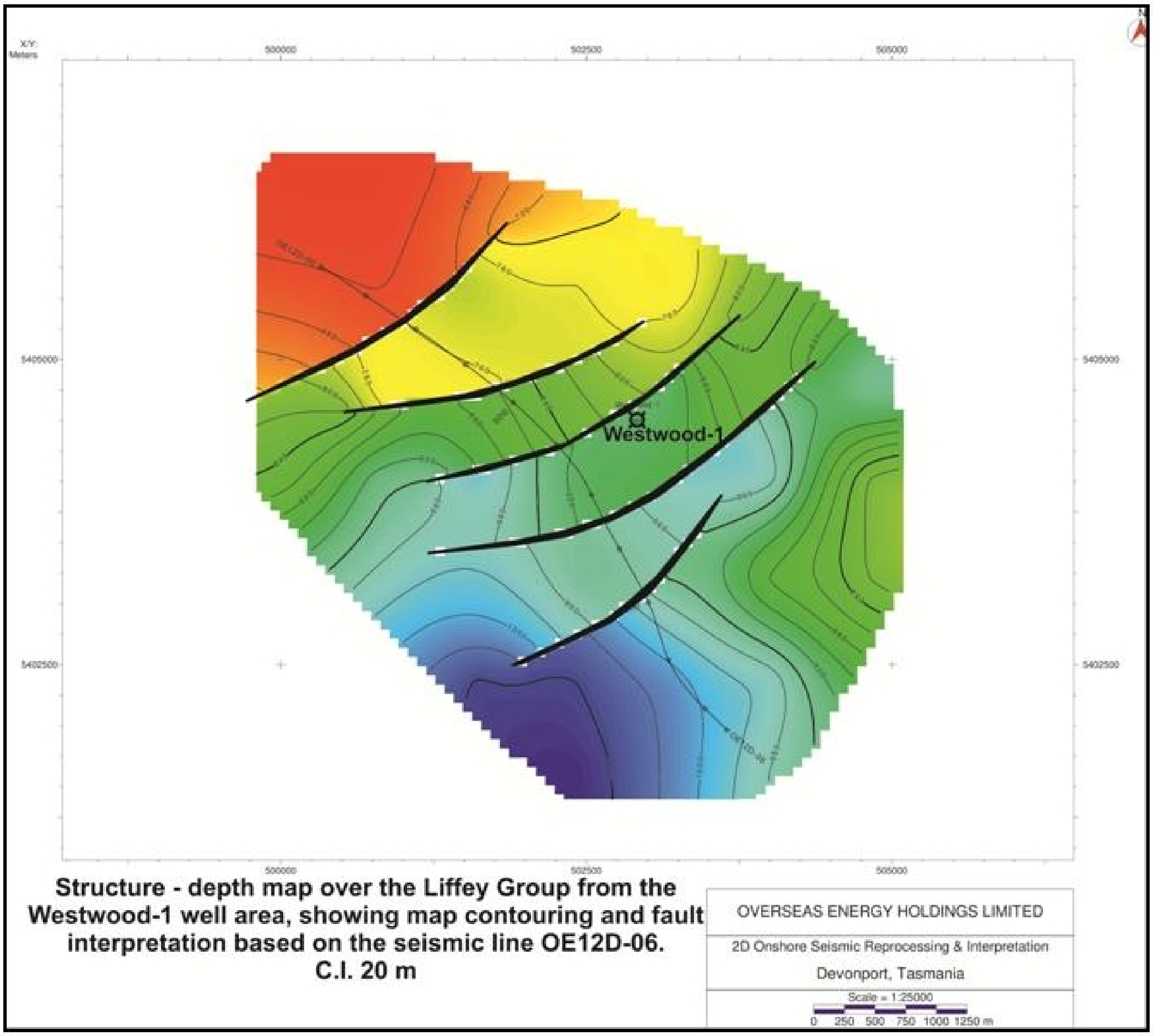


Figure 12 - Structure-depth map over the Liffey Group from the Westwood-1 well area, illustrating a general northwest rising structural trend with sub-parallel faulting pattern and deepening of the basement to the southwest.

4.4 Seal Rocks

Reservoirs within the Lower Paleozoic rocks, such as the palaeokarst reservoirs of the Gordon Group limestone could be sealed by the shale in Eldon Group, in anticlinal structural traps. In addition, the base-Parmeener Supergroup unconformity is overlain by tillite and mudstones. Relatively late timing of oil generation (post–Permian) in the Paleozoic section, or post Permian to Tertiary migration of pre–Carboniferous hydrocarbon accumulations into various sub–unconformity traps are conceivable and they could be sealed with the Eldon Group shale as the lateral seal and the basal Parmeener Supergroup unconformity could be a top seal for the Ordovician – Silurian reservoir rocks in general. The Malbina and Cascades Group formations are also marine mudstones and provide potential seal units above the Liffey – Faulkner Group sandstones. Marine mudstones and silty mudstones in the Lower Parmeener Supergroup, such as the Cascades Group of shale and the Ferntree Mudstones, and the Jurassic dolerite are the most likely potential seals for the post–Carboniferous reservoirs and traps (Figure 13).

4.5 Well Log Interpretation

The more data one can assemble for integrated stratigraphic interpretation, the better insight is gained into the field. The well section window, available with any well log analysis, is the perfect correlation canvas for all workflows—a myriad of logs, core images, seismic data, grid data, and even completions and simulation results with a time player can be displayed. Saved well-section templates provide straightforward sharing of customized displays, which saves time when creating new windows and facilitates consistency across your organization. The well correlation modules extend the well section functionality by enabling several additional tools for stratigraphic interpretation, including markers picking, log estimation by trained neural networks, and the interactive log conditioning toolbar.

In the case of OEHL, there have been no oil or gas fields discovered to date in the Tasmania Basin, although several oil seeps have been reported. The seeps reported in the Tasmania Basin have had limited correlations made to the source rocks. However, there is a seep in a recent quarry at Lonnavale to the southwest of Hobart that has been correlated with the Permian age Tasmanite Oil Shale and is the best indication yet that a significant petroleum system possibly exist in the basin.

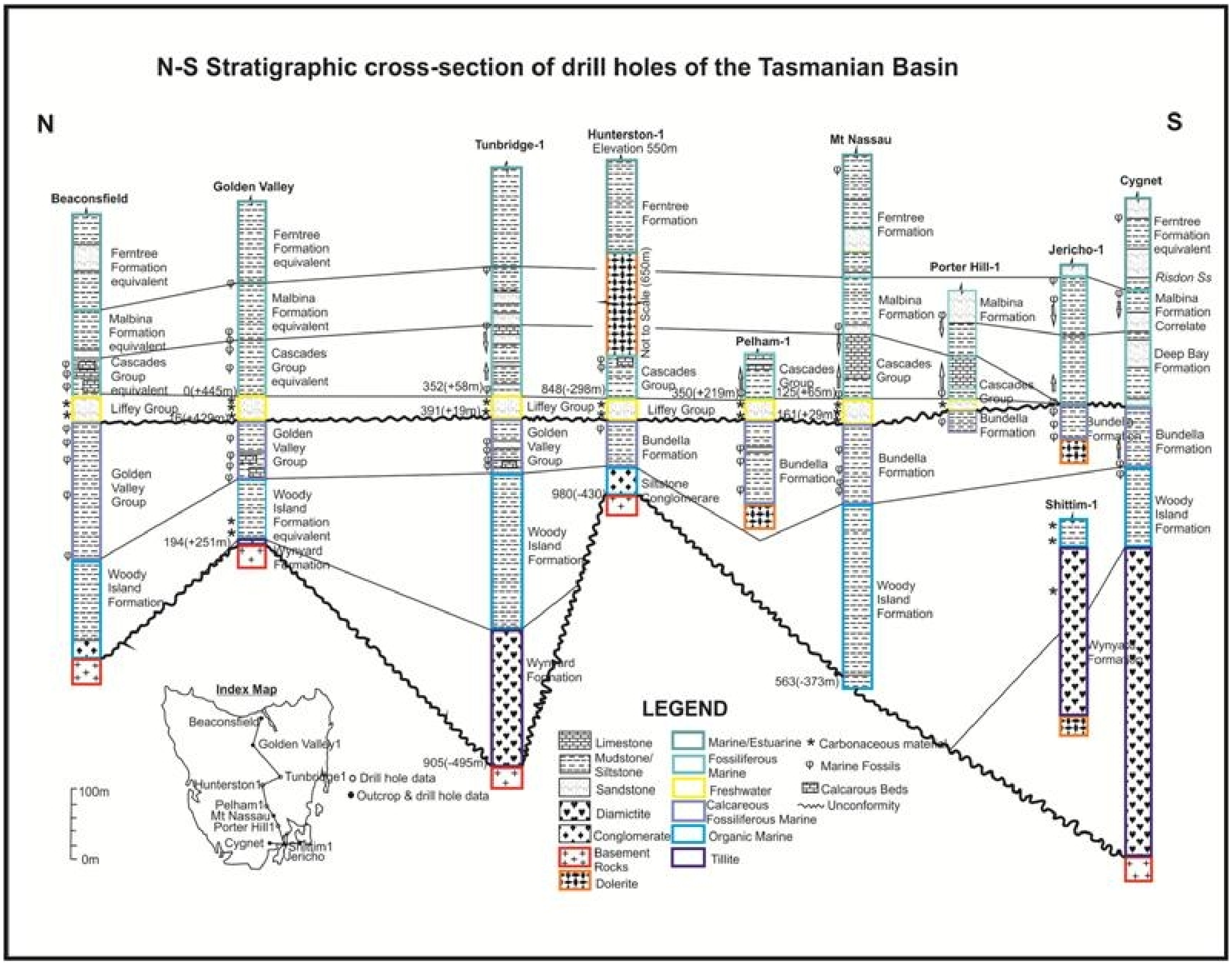


Figure 13 - Stratigraphic cross–section of drillholes and outcrops in north–south direction, showing relative position and thicknesses of various formations and sediments penetrated.

In terms of existing wire line logs, the log from OEHL's Westwood #1 well has been used to correlate seismic markers to various formations and associated depth. Given the immensity of the terrain (roughly 40 km^2 of net pay zones are thought to exist), one well log naturally does not provide a high degree of confidence, but as new drilling and wireline well logging progress in the region, additional data will be entered into the workstation to re-assess the size, situation and potential of the reservoirs encountered.

The primary reservoirs within the Pre–Carboniferous successions are the carbonates of the Gordon Group. Leached and dolomitized limestone, reefal and fractured reservoirs could be anticipated, but not much is known about these sequences. Likewise, the overlying sandstones of the Eldon Group are potential reservoirs, but no accurately documented information is available from these rocks.

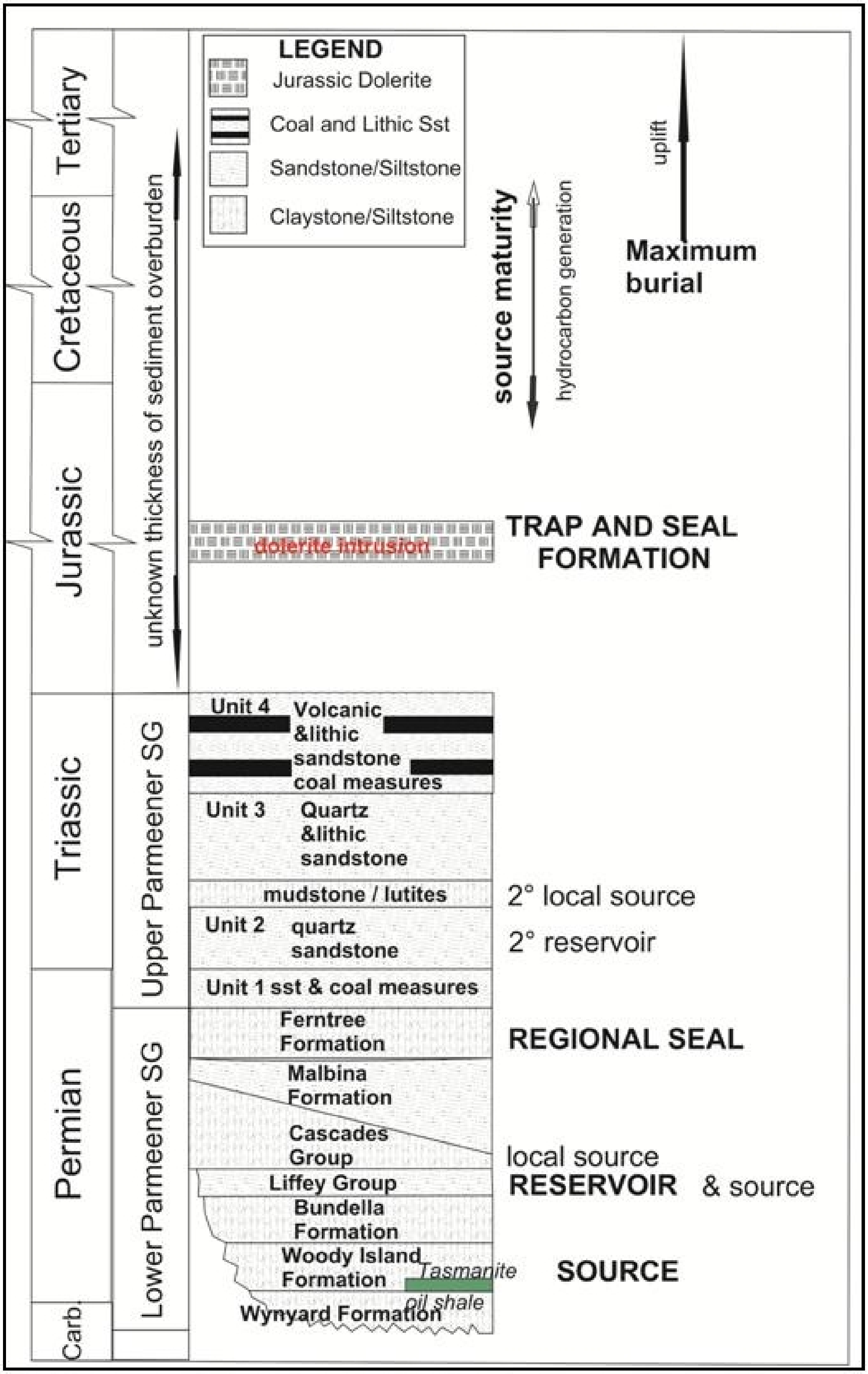


Figure 14 - Time-rock stratigraphic model of Parmeener Supergroup of rocks and mid-Jurassic dolerite,with source and reservoir rocks shown.

Apart from the Liffey – Faulkner group (the Lower Freshwater Sequence); a number of other marine sandstone units are possible reservoirs. They are in stratigraphic order, the Bundella Formation, the Malbina Formation, Minnie Point Formation and Risdon Sandstone (Figure 13).

Formation Name	Porosity (%)	Thickness (m)	Depositional Environment
Liffey-Faulkner Group	10.9	20 - 40	Coastal channel
Bundella Formation	7.4 – 22.3	120	Shallow marine shelf
Minnie Point Formation	14.1 – 16.6	50 - 90	Shallow marine shelf
Risdon Sandstone	13.7 – 14.7	8	Offshore barrier bar deposit

Table 2 - Reservoir parameters and environment of deposition of some of the reservoir rocks in the Lower Parmeener Super-group.

Section Five

Volume Calculations

5.1 Hydrocarbon Resources

Potential prospective resource reserve estimation calculations were carried out from the net pay isopach maps, assuming that the bottom hole formation temperature from the Westwood-1 well represented a general temperature distribution in the subsurface in the license block area and a uniform 0.465 psi/foot pressure gradient represented the general subsurface pressure distribution in the area. Prospective oil and gas resource estimations (calculation) were presented in the individual potential prospect area resource tables.

Net pay isopach (thickness) maps were generated over the potential prospective horizons mapped structurally in the Bass Highway, Westbury, Weymouth and Batman Bridge areas. As explained and described in the preceding pages, net pay isopach mapping was carried out based on the structure–depth map contouring over the potential prospective horizons, sequentially from bottom to top, namely the Gordon Group of limestone (Ordovician in age), the Eldon Group of sandstones (Silurian in age), the Liffey Group of sandstones (Late Carboniferous to Early Permian in age), and the Lower Parmeener Group of sandstones (Late Permian in age).

A total of fourteen (14) net pay isopach maps were generated and shown in Figures 15 to Figure 28, four (4) each from the Bass Highway, Westwood, and Weymouth Road area, and two from the Batman Bridge area where the seismic coverage were carried out. Net pay isopach mapping assumed that the steep plunge of every potential prospective horizon constituted an oil (or gas)/water contact and hence zero (0) pay line and the remaining inside contouring was carried out based on the overall thickness of the particular formation and its reservoir characteristics (i.e. porosity, permeability and grain size distribution), deduced from the published information pertaining to the geology of the area and the formations under consideration.

As a result both the structure – depth map generation and net pay isopach mapping indicate that the most prospective areas are the Bass Highway and the Westbury where there is thicker and quieter sedimentation. On the other hand, the Batman Bridge and the Weymouth areas are highly deformed and faulted. Additional and better seismic data coverage is needed to define and delineate the potential prospective structural leads.

No data was provided that would indicate the quality of the reservoir(s); however we see no reason that quality couldn't be very similar to Bass Straits fields to the north. In fact, the reservoir quality improves from the southern part of the block to the edge of the onshore platform, thus the prospects could be comparable quality with the Bass Straits fields.

In estimating hydrocarbons initially-in-place and recoverable, standard petroleum engineering techniques have been used. These techniques combine geophysical and geological knowledge with detailed information on reservoir properties distribution and fluid characteristics. However, there is uncertainty inherent in the measurement and interpretation of the basic data.

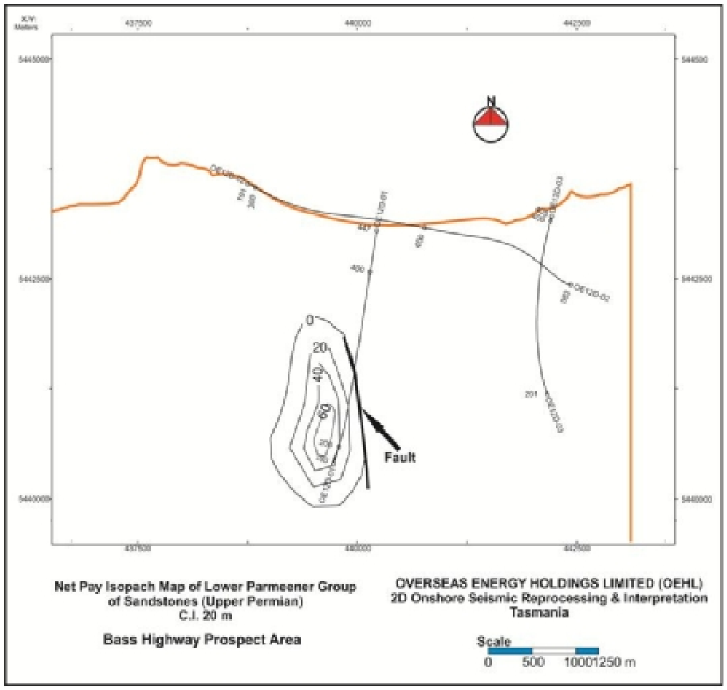


Figure 15 - Net pay isopach map of the Lower Parmeener Group of sandstone from the Bass Highway potential prospect area.

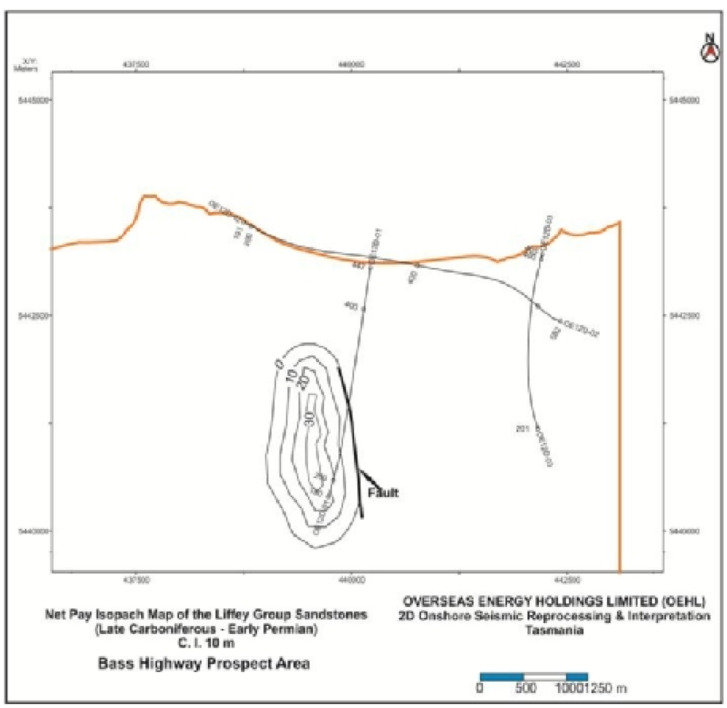


Figure 16 - Net pay isopach map of the Liffey Group of sandstone from the Bass Highway potential prospect area.

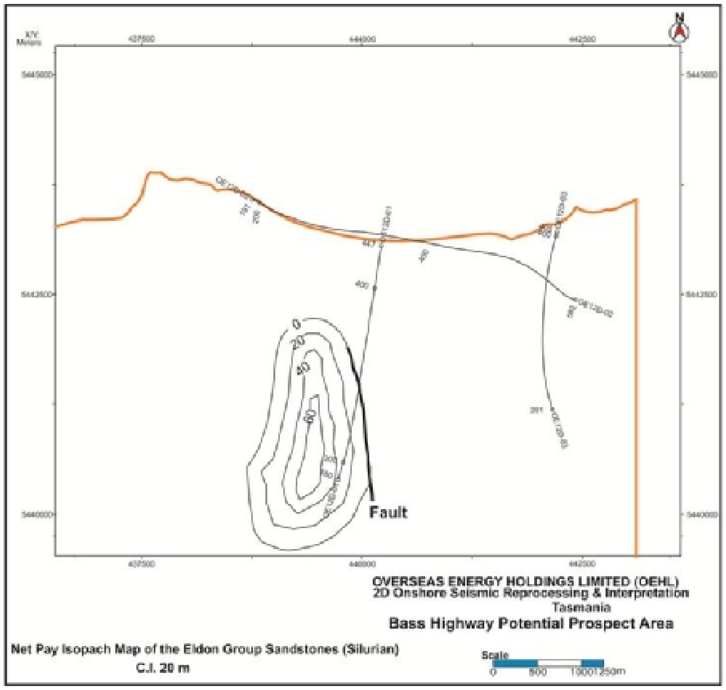


Figure 17 - Net pay isopach map of the Eldon Group of sandstone from the Bass Highway potential prospect area.

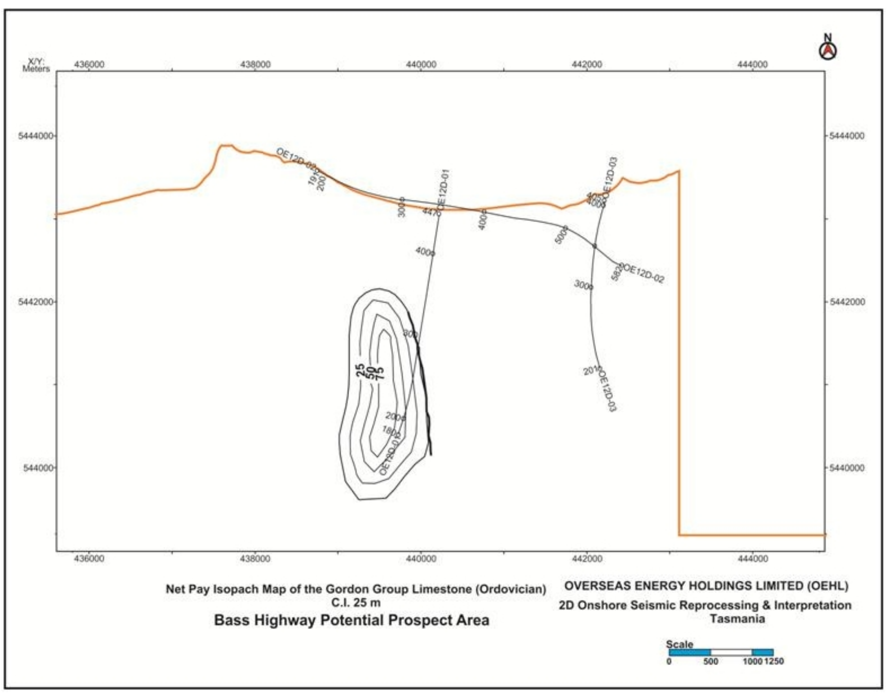


Figure 18 - Net pay isopach map of the Gordon Group limestone from the Bass Highway potantial prospect area.

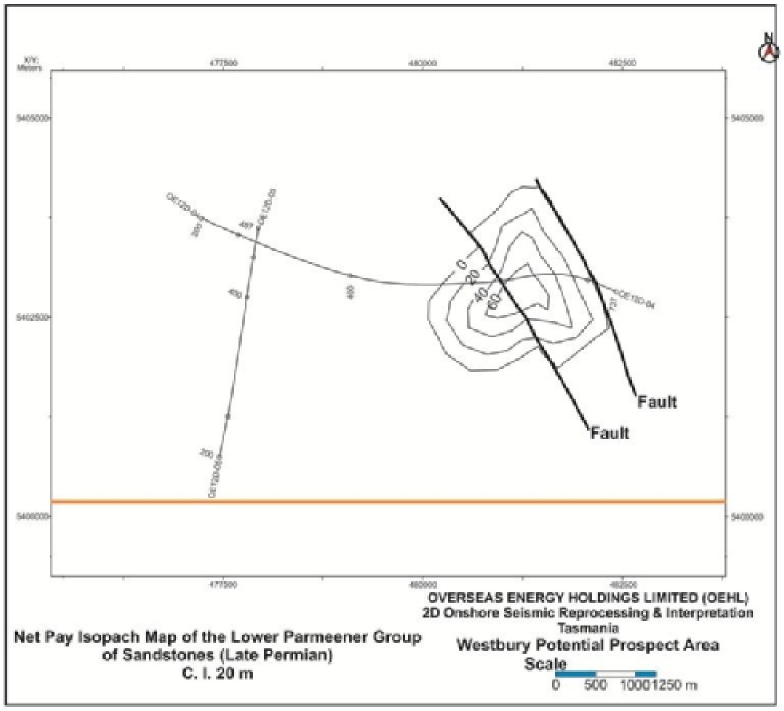


Figure 19 - Net pay isopach map of the Lower Parmeener Group of sandstone from the Westbury potential prospect area.

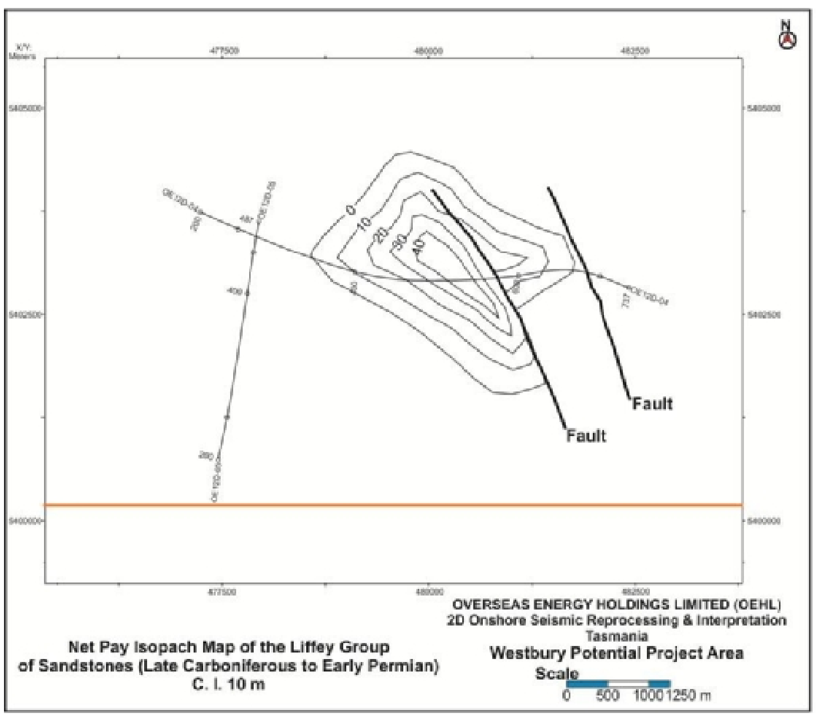


Figure 20 - Net pay isopach map of the Liffey Group of sandstone from the Westbury potential prospect area.

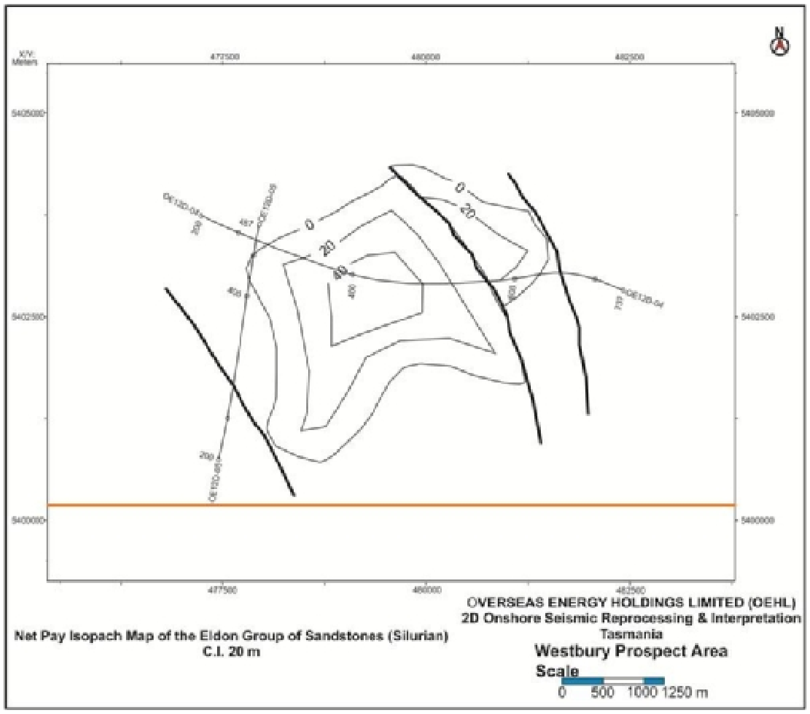


Figure 21 - Net pay isopach map of the Eldon Group of sandstone from the Westbury potential prospect area.

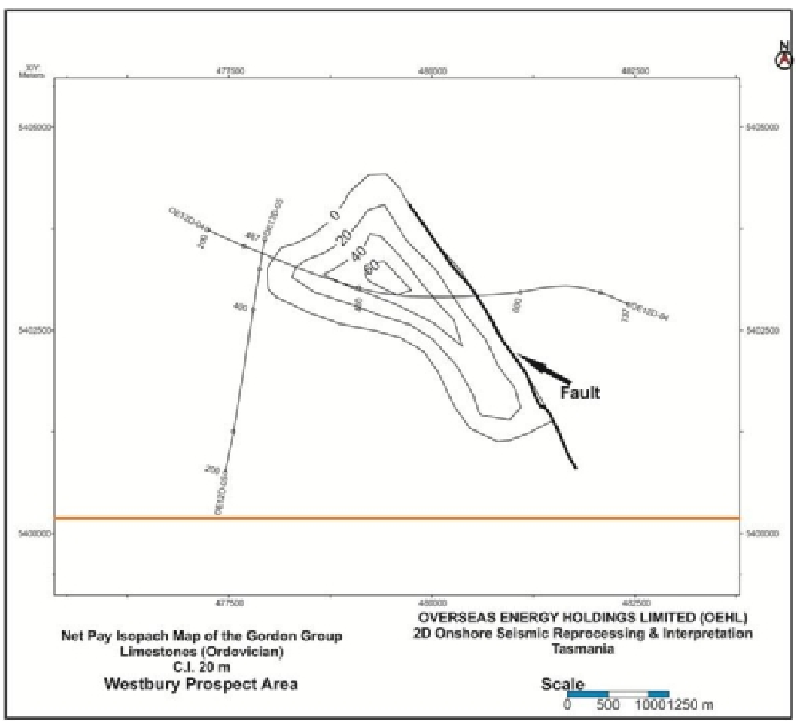


Figure 22 - Net pay isopach map of the Gordon Group limestone from the Westbury potential prospect area.

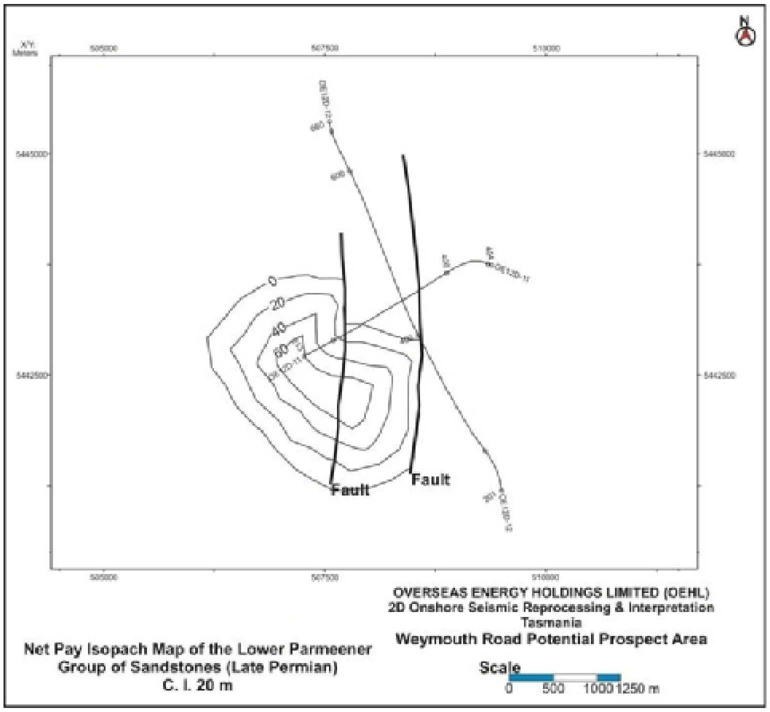


Figure 23 - Net pay isopach map of the Lower Parmeener Group of sandstone from the Weymouth potential prospect area.

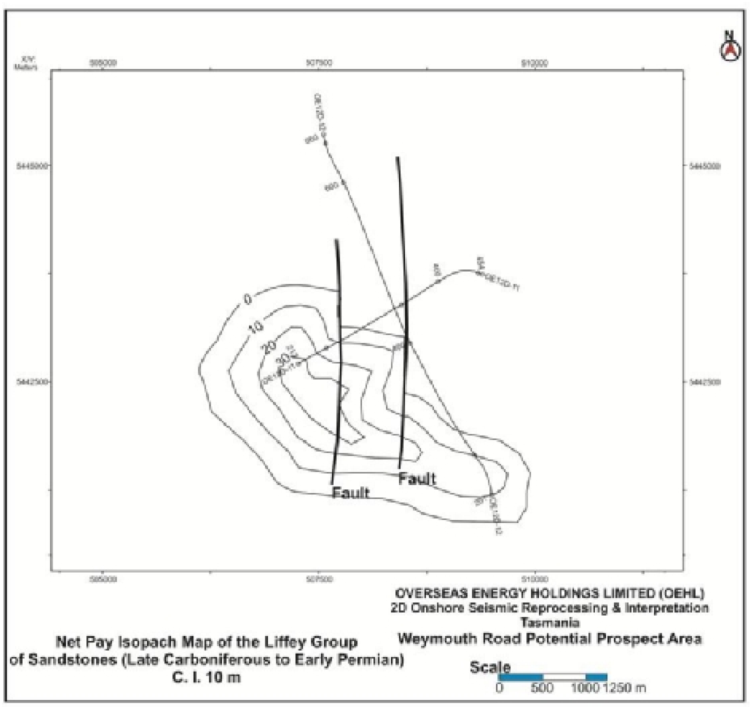


Figure 24 - Net pay isopach map of the Liffey Group of sandstone from the Weymouth potential prospect area.

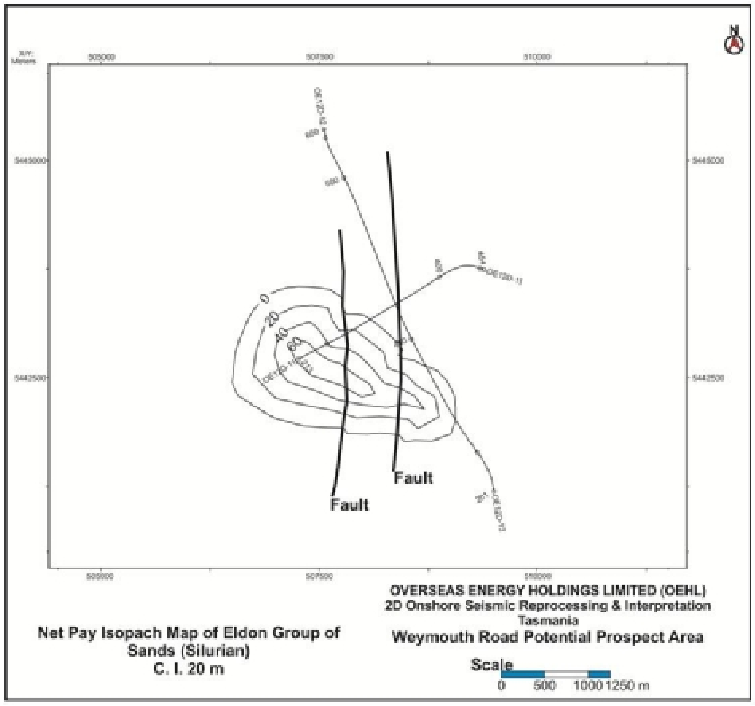


Figure 25 - Net pay isopach map of the Eldon Group of sandstone from the Weymouth potential prospect area.

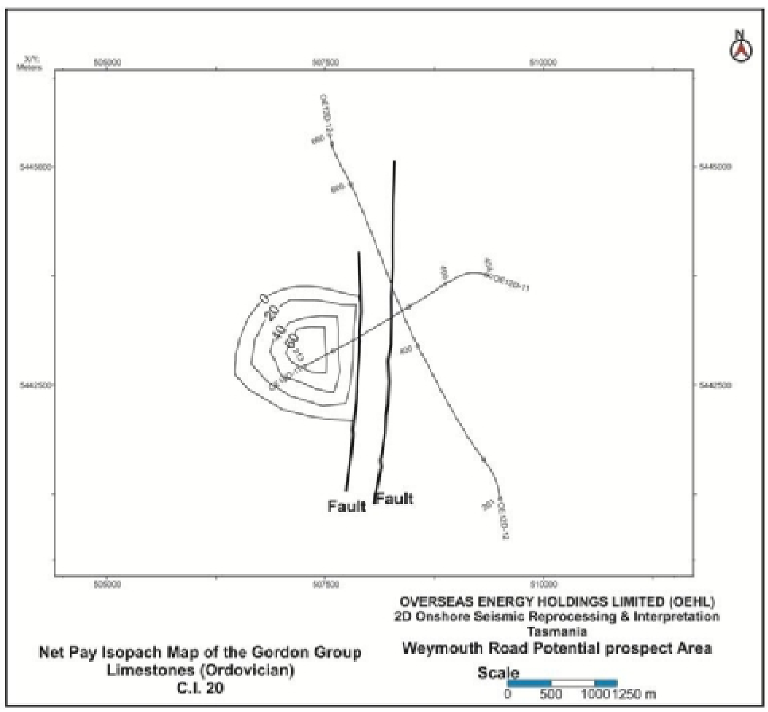


Figure 26 - Net pay isopach map of the Gordon Group limestone from the Weymouth potential prospect area.

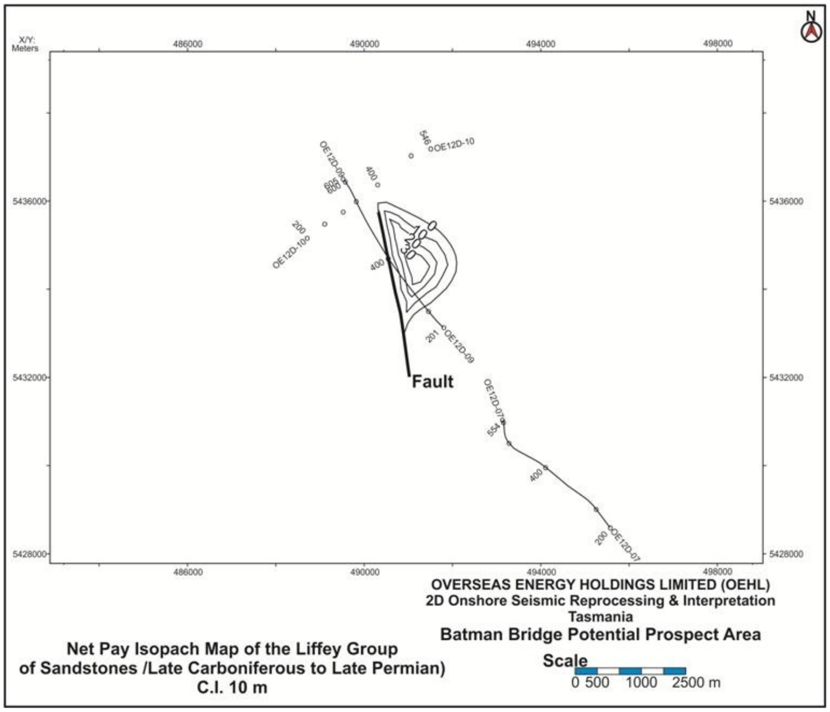


Figure 27 - Net pay isopach map of the Liffey Group of sandstone from the Batman Bridge potential prospect area.

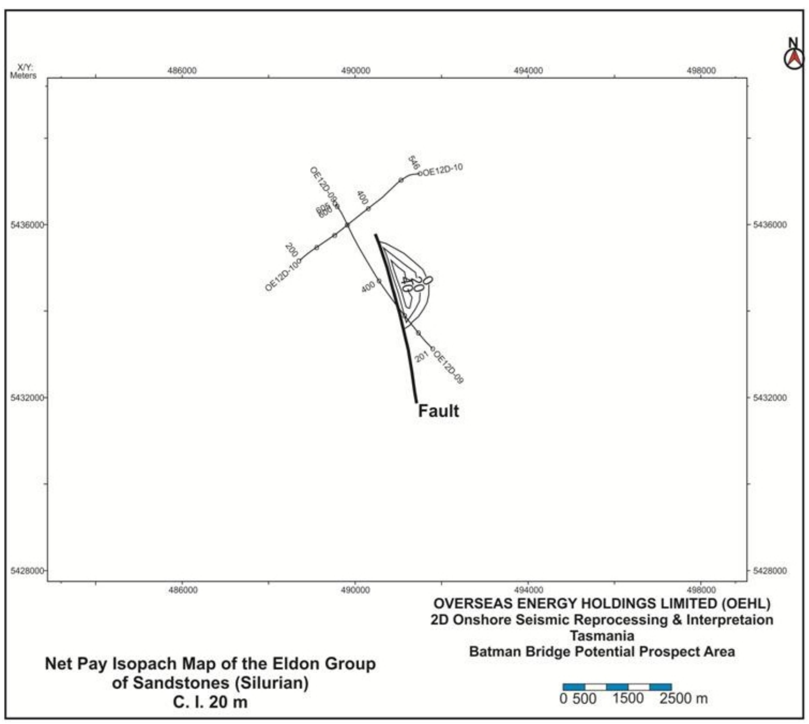


Figure 28 - Net pay isopach map of the Eldon Group of sandstone from the Batman Bridge potential prospect area.

OVERSEAS ENERGY HOLDINGS LIMITED (OEHL) SEL 5/2005 License Block 2D Onshore Seismic Reprocessing and Interpretation, Devonport Area, Tasmania Bass Highway Potential Prospect Area Reserve Calculations				
Reservoir Parameters	Potentially Prospective Horizons			
	Top of Lower Parmeener	Top of Liffey Sandstone	Top of Eldon Sandstone	Top of Gordon Limestone
Reservoir depth(m)	340	575	840	1,150
Area (m^2)	990,586	1,972,765	2,387,128	2,132,852
Area (acres)	245	487	590	527
Gross Pay (m)	60	40	90	90
Net Pay (m)	45	22	45	50
NP/GP (%)	75	55	50	56
Sw (%)	45	45	45	45
Porosity-Φ (%)	14	11	7	7
Pressure-P (MPa)	4	6	9	12
Pressure-P (psi)	517	877	1281	1754
For. Temp. (°C)	32	38	51	65
Gas Comp. (z)	0.8	0.8	0.8	0.8
Recov.(Ro-Rg)(%)	28-85	28-85	28-85	28-85
Res. (mmbbls)	17.33	13.17	20.86	20.65
Rec.Res.(mmbbls)	4.85	3.7	5.84	5.78
Resgas(mmmcf)	4.9	6.2	13.7	15.4
Rec.Resg(mmmcf)	4.2	5.3	11.65	13.1
1MPa = 145.04 psi				
T(F) = t(°C)x1.8+32				
1acre = 4046.8 m^2				

Table 3 - Bass Highway potential prospect area oil case and gas case resource estimations with reservoir parameters shown.

OVERSEAS ENERGY HOLDINGS LIMITED (OEHL) SEL 5/2005 License Block 2D Onshore Seismic Reprocessing and Interpretation, Devonport Area, Tasmania Westbury Potential Prospect Area Reserve Calculations				
Reservoir Parameters	Potentially Prospective Horizons			
	Top of Lower Parmeener	Top of Liffey Sandstone	Top of Eldon Sandstone	Top of Gordon Limestone
Reservoir depth(m):	130	450	700	1,050
Area (m^2)	2,800,000	3,727,110	5,425,000	4,225,000
Area (acres)	692	921	1,341	1,044
Gross Pay (m)	80	40	90	90
Net Pay (m)	40	25	25	25
NP/GP (%)	50	62.5	28	28
Sw (%)	50	50	50	50
Porosity-Φ (%)	14	11	7	7
Pressure-P (MPa)	1.4	5	7.4	11
Pressure-P (psi)	200	687	1,068	1,600
For. Temp. (ºC)	23	34	45	60
Gas Comp. (z)	0.83	0.83	0.83	0.83
Recov.(Ro-Rg)(%)	28-85	28-85	28-85	28-85
Resoil. (mmbbls)	39.4	26.00	23.9	18.6
Rec.Resoil.(mmbbls)	11.00	7.00	6.7	5.2
Resgas(mmmcf)	4.43	10.00	13.35	14.9
Rec.Resg(mmmcf)	4.00	8.5	11.35	12.7
1MPa = 145.04 psi				
T(F) = t(ºC)x1.8+32				
1acre = 4046.8 m^2				

Table 4 - Westbury potential prospect area oil case and gas case resource estimations with reservoir parameters shown

OVERSEAS ENERGY HOLDINGS LIMITED (OEHL) SEL 5/2005 License Block 2D Onshore Seismic Reprocessing and Interpretation, Devonport Area, Tasmania Weymouth Road Potential Prospect Area Reserve Calculations				
Reservoir Parameters	Potentially Prospective Horizons			
	Top of Lower Parmeener	Top of Liffey Sandstone	Top of Eldon Sandstone	Top of Gordon Limestone
Reservoir depth(m)	400	600	880	1,375
Area (m^2)	4,040,620	5,945,192	2,756,352	1,830,593
Area (acres)	999	1469	681	452
Gross Pay (m)	70	40	80	85
Net Pay (m)	30	18	30	30
NP/GP (%)	43	45	38	35
Sw (%)	45	45	45	45
Porosity-Φ (%)	14	11	7	7
Pressure-P (MPa)	4.2	6.3	9.3	14.5
Pressure-P (psi)	610	915	1,342	2,097
For. Temp. (ºC)	34	40	53	75
Gas Comp. (z)	0.83	0.83	0.83	0.83
Recov.(Ro-Rg)(%)	28-85	28-85	28-85	28-85
Resoil. (mmbbls)	46.3	32.54	16	10.6
Rec.Resoil.(mmbbls)	13	9.11	4.5	3
Resgas(mmmcf)	15.5	15.8	10.9	10.62
Rec.Resg(mmmcf)	13.2	13.5	9.3	9
1MPa = 145.04 psi				
T(F) = t(ºC)x1.8+32				
1acre = 4046.8 m^2				

Table 5 - Weymouth Road potential prospect area oil case and gas case resource estimations with reservoir parameters shown

OVERSEAS ENERGY HOLDINGS LIMITED (OEHL) SEL 5/2005 License Block 2D Onshore Seismic Reprocessing and Interpretation, Devonport Area, Tasmania Batman Bridge Potential Prospect Area Reserve Calculations				
Reservoir Parameters	Potentially Prospective Horizons			
	Top of Lower Parmeener	Top of Liffey Sandstone	Top of Eldon Sandstone	Top of Gordon Limestone
Reservoir depth(m):		1,100	2,100	
Area (m^2)		1,148,437	406,000	
Area (acres)		284	100	
Gross Pay (m)		40	60	
Net Pay (m)		15	20	
NP/GP (%)		37.5	33	
Sw (%)		45	45	
Porosity-Φ (%)		11	7	
Pressure-P (MPa)		11.6	22	
Pressure-P (psi)		1,678	3,200	
For. Temp. (ºC)		62	101	
Gas Comp. (z)		0.83	0.83	
Recov.(Ro-Rg)(%)		28-85	28-85	
Resoil. (mmbbls)		5.23	1.6	
Rec.Resoil.(mmbbls)		1.5	0.442	
Resgas(mmmcf)		4.4	2.25	
Rec.Resg(mmmcf)		3.7	1.9	
1MPa = 145.04 psi				
T(F) = t(ºC)x1.8+32				
1acre = 4046.8 m^2				

Table 6 - Batman Bridge potential prospect area oil case and gas case resource estimations with reservoir parameters shown.

5.2 Risk Analysis

Risk evaluation of Exploration Block SEL 05/2005

The SEL 05/2005 prospect is located in the vicinity of resourceful and producing hydrocarbon saturated reservoirs of the Bass Straits, mitigating some risk about the presence of hydrocarbons on the island.

The most uncertain factor in this case is the presence of structures. Thus the main objective of the CAPD report – to depict a sound trap, which with a certain probability and related geological risk may contain large deposits of hydrocarbon deposits in the Top of Lower Parmeener, Top of Liffey Sandstone, Top of Eldon Sandstone and Top of Gordon Limestone horizons is not resolved with a great certainty. Drilling in this case, remains to be the only sure way to mitigate any risk.

However, if we take the deterministic volume calculations performed by CAPD for the Economic Model used in this report, there must be a certain amount of risk calculation, taking into account the type and quality of the structures, in which we assume the hydrocarbons to have amassed.

In the late 1980's, White et al, have made certain empirical calculations to determine "trap volume geometry multiplier" by considering the shape and volume of various structures into which hydrocarbons could have accumulated. By taking certain multipliers according to the size and shape of the structures, they have made the volume determinations much more realistic.

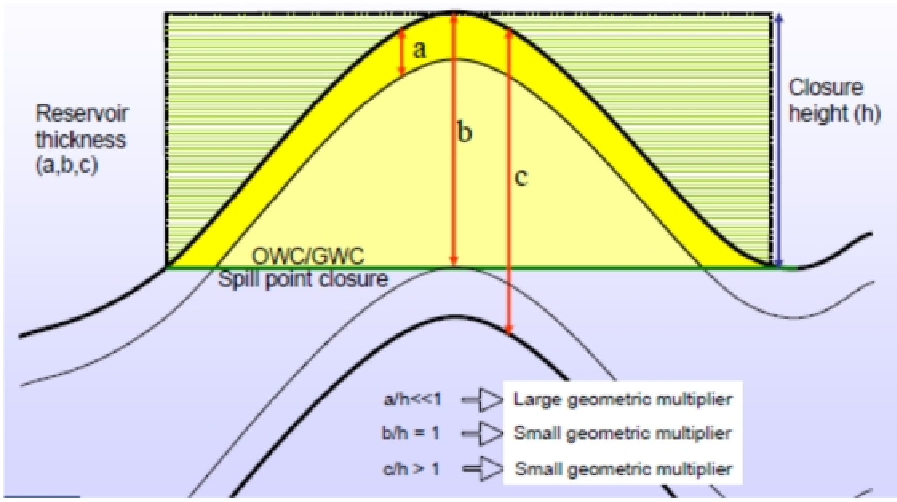


Figure 29 - Anticline geometry corrections, assuming no internal seals

In view of the shape of structures determined from the structure-depth and isopach maps plotted by CAPD, we can ascertain that the geometry multiplier for an estimated "anticline, prism, cylinder" to be 0.67 for the oil case and 0.73 for the natural gas case.

Volumetric estimation is based on core and wireline log analyses as well as geological maps. CAPD did its own area estimation and after interpretation of the 2D seismic data. Knowledge of the depositional environment, structural complexities, trapping mechanism and well fluid interactions have been taken into account to estimate the gross rock volume.

In estimating petroleum initially-in-place and recoverable, standard petroleum engineering techniques have been used. These techniques combine geophysical and geological knowledge with detailed information on reservoir properties distribution and fluid characteristics. However, there is uncertainty inherent in the measurement and interpretation of the basic data.

The standard formula used to calculate hydrocarbon volumes has been taken from the SPE library and is in compliance with PRMS guidelines. For Crude Oil Volume Calculations:

*Imperial: OOIP (STB) = Rock Volume * 7,758 * **Φ** * (1- S_w) * 1/ B_o*

*Where: Rock Volume (acre feet) = A * h*

A = Drainage area, acres

h = Net pay thickness, feet

7,758 = API Bbl per acre-feet (converts acre-feet to stock tank barrels)

Φ = Porosity, fraction of rock volume available to store fluids

S_w = Volume fraction of porosity filled with interstitial water

B_o = Formation volume factor (Reservoir Bbl/STB)

1/ B_o = Shrinkage (STB/Reservoir Bbl)

For Natural Gas Volume Calculations:

Imperial: OGIP (MMMCF) = $\boldsymbol{Rock\ Volume} * \mathbf{43,560} * \emptyset * \mathbf{(1 - } \boldsymbol{S_W}\mathbf{)} \ \frac{(\boldsymbol{T_s} * \boldsymbol{P_i})}{(\boldsymbol{P_s} * \boldsymbol{T_f} * \boldsymbol{Z_i})}$

Where: Rock Volume (acre feet) = A * h

A = Drainage area, acres, (1 acre = 43,560 sq. ft)

h = Net pay thickness, feet

Φ = Porosity, fraction of rock volume available to store fluids

Sw = Volume fraction of porosity filled with interstitial water

Ts = Base temperature, standard conditions, °Rankine (460° + 60°F)

Ps = Base pressure, standard conditions, 14.65 psia

Tf = Formation temperature, °Rankine, (460° + °F at formation depth)

Pi = Initial Reservoir pressure, psia

Zi = Compressibility at Pi and Tf

In order to mitigate geologic risk, we have added one more parameter, which is the 'Trap Geometry Multiplier', as highlighted above in this Section.

To calculate recoverable oil volumes the OOIP must be multiplied by the Recovery Factor. The recovery factor is one of the most important, yet the most difficult variable to estimate. Fluid properties such as formation volume factor, viscosity, density, and solution gas/oil ratio all influence the recovery factor. In addition, it is also a function of the reservoir drive mechanism and the interaction between reservoir rock and the fluids in the reservoir.

In the case of SEL 05/2005, a recovery factor of 28% for oil and 85% for gas was utilized, implying that at some point in the development of the reservoir(s) an active water drive, created by placing strategically located water injection wells, will be required. The Economic Model does take into account these injection wells.

OVERSEAS ENERGY HOLDINGS LIMITED (OEHL)
SEL 5/2005 License Block 2D Onshore Seismic Reprocessing and Interpretation, Devonport Area, Tasmania
Bass Highway Potential Prospect Area Reserve Calculations

Reservoir Parameters	Potentially Prospective Horizons: Top of L. Parmeener	Top of Liffey Sst.	Top of Eldon Sst.	Top of Gordon Lst.
Reservoir depth (m)	340	575	840	1150
Area (m²)	990,586	1,972,765	2,387,128	2,132,852
Area (acres)	245	487	590	527
Gross Pay (m)	60	40	90	90
Net Pay (m)	45	22	45	50
NP/GP (%)	75	55	50	56
Sw (%)	45	45	45	45
Porosity (%)	14	11	7	7
Pressure-P (MPa)	4	6	9	12
Pressure-P (psi)	517	877	1,281	1,754
For. Temp. (ºC)	32	38	51	65
Gas Comp. (z)	0.8	0.8	0.8	0.8
In-Situ Res. Oil (mmbbls)	17.33	13.17	20.86	20.65
In-Situ Res Gas (mmmcf)	4.9	6.2	13.7	15.4
Recov. (Ro-Rg)(%)	28-85	28-85	28-85	28-85
Oil Geom. Mult. (%)	67	67	67	67
Gas Geom. Mult. (%)	73	73	73	73
STOOIP (mmbbls)	11.61	8.82	13.98	13.84
Rec.Res. (mmbbls)	3.25	2.47	3.91	3.87
OGIP (mmmcf)	3.58	4.53	10.00	11.24
Rec.Resg (mmmcf)	3.04	3.85	8.50	9.56

OVERSEAS ENERGY HOLDINGS LIMITED (OEHL)
SEL 5/2005 License Block 2D Onshore Seismic Reprocessing and Interpretation, Devonport Area, Tasmania
Westbury Potential Prospect Area Reserve Calculations

Reservoir Parameters	Potentially Prospective Horizons: Top of L. Parmeener	Top of Liffey Sst.	Top of Eldon Sst.	Top of Gordon Lst.
Reservoir depth (m)	130	450	700	1,050
Area (m²)	2,800,000	3,727,110	5,425,000	4,225,000
Area (acres)	692	921	1,341	1,044
Gross Pay (m)	80	40	90	90
Net Pay (m)	40	25	25	25
NP/GP (%)	50	63	28	28
Sw (%)	50	50	50	50
Porosity (%)	14	11	7	7
Pressure-P (MPa)	1	5	7	11
Pressure-P (psi)	200	687	1,068	1,600
For. Temp. (ºC)	23	34	45	60
Gas Comp. (z)	1	1	1	1
In-Situ Res. Oil (mmbbls)	39	26	24	19
In-Situ Res Gas (mmmcf)	4	10	13	15
Recov. (Ro-Rg)(%)	28-85	28-85	28-85	28-85
Oil Geom. Mult. (%)	67	67	67	67
Gas Geom. Mult. (%)	73	73	73	73
STOOIP (mmbbls)	26.40	17.42	16.01	12.46
Rec.Res. (mmbbls)	7.39	4.88	4.48	3.49
OGIP (mmmcf)	3.23	7.30	9.75	10.88
Rec.Resg (mmmcf)	2.75	6.21	8.28	9.25

OVERSEAS ENERGY HOLDINGS LIMITED (OEHL)
SEL 5/2005 License Block 2D Onshore Seismic Reprocessing and Interpretation, Devonport Area, Tasmania
Weymouth Road Potential Prospect Area Reserve Calculations

Reservoir Parameters	Potentially Prospective Horizons: Top of L. Parmeener	Top of Liffey Sst.	Top of Eldon Sst.	Top of Gordon Lst.
Reservoir depth (m)	400	600	880	1,375
Area (m²)	4,040,620	5,945,192	2,756,352	1,830,593
Area (acres)	999	1,469	681	452
Gross Pay (m)	70	40	80	85
Net Pay (m)	30	18	30	30
NP/GP (%)	43	45	38	35
Sw (%)	45	45	45	45
Porosity (%)	14	11	7	7
Pressure-P (MPa)	4	6	9	15
Pressure-P (psi)	610	915	1,342	2,097
For. Temp. (ºC)	34	40	53	75
Gas Comp. (z)	1	1	1	1
In-Situ Res. Oil (mmbbls)	46	33	16	11
In-Situ Res Gas (mmmcf)	16	16	11	11
Recov. (Ro-Rg)(%)	28-85	28-85	28-85	28-85
Oil Geom. Mult. (%)	67	67	67	67
Gas Geom. Mult. (%)	73	73	73	73
STOOIP (mmbbls)	31.02	21.80	10.72	7.10
Rec.Res. (mmbbls)	8.69	6.10	3.00	1.99
OGIP (mmmcf)	11.32	11.53	7.96	7.75
Rec.Resg (mmmcf)	9.62	9.80	6.76	6.59

OVERSEAS ENERGY HOLDINGS LIMITED (OEHL)
SEL 5/2005 License Block 2D Onshore Seismic Reprocessing and Interpretation, Devonport Area, Tasmania
Batman Bridge Potential Prospect Area Reserve Calculations

Reservoir Parameters	Potentially Prospective Horizons: Top of L. Parmeener	Top of Liffey Sst.	Top of Eldon Sst.	Top of Gordon Lst.
Reservoir depth (m)		1,100	2,100	
Area (m²)		1,148,437	406,000	
Area (acres)		284	100	
Gross Pay (m)		40	60	
Net Pay (m)		15	20	
NP/GP (%)		38	33	
Sw (%)		45	45	
Porosity (%)		11	7	
Pressure-P (MPa)		12	22	
Pressure-P (psi)		1,678	3,200	
For. Temp. (ºC)		62	101	
Gas Comp. (z)		1	1	
In-Situ Res. Oil (mmbbls)		5	2	
In-Situ Res Gas (mmmcf)		4	2	
Recov. (Ro-Rg)(%)		28-85	28-85	
Oil Geom. Mult. (%)		67	67	
Gas Geom. Mult. (%)		73	73	
STOOIP (mmbbls)		3.50	1.07	
Rec.Res. (mmbbls)		0.98	0.30	
OGIP (mmmcf)		3.21	1.64	
Rec.Resg (mmmcf)		2.73	1.40	

	Bass Highway	Westbury	Weymouth Road	Batman Bridge
Rec. Oil Sub-Total	13.5091	20.2420	19.7805	1.2813
Rec. Gas Sub-Total	24.9441	26.4829	32.7748	4.1263

Total Recoverable Oil	54.8130
Total Recoverable Gas	88.3282

1MPa = 145.04 psi

T(F) = t(ºC) x 1.8 + 32

1acre = 4,046.8 m²

Table 7 – Deterministic volume estimations including geometric risk calculations for recoverable crude oil and natural gas volumes

Section Six

Economic Model

6.1 Fiscal Parameters Pertaining to Australian Oil & Gas Exploration

The fiscal regime that applies in Australia to the petroleum industry consists of a combination of corporate income tax (CIT) and either a petroleum resource rent tax (PRRT) or royalty-based taxation[3].

Royalties[4]	0% to 12.50%
Corporate Income Tax	CIT rate 30%
Petroleum Resource Rent Tax	40%[5]
Capital allowances	D, E, O[6]
Investment incentives	L, RD[7]

The current fiscal regime that applies in Australia to the petroleum industry consists of a combination of CIT and either a PRRT or royalty-based taxation.

Royalty Regimes

For onshore projects, wellhead royalties are applied and administered at the state level. Wellhead royalties are generally levied at a rate of between 10% and 12.5% of either the gross or net wellhead value of all the petroleum produced. In some states, the rate for the first five years is nil, increasing to 6% in year six and thereafter at 1% per annum up to a maximum of 10%. We will use 12.5% for SEL 05/2005.

Each state has its own rules for determining net wellhead value; however, it generally involves deducting deductible costs from the gross value of the petroleum recovered. Deductible costs are generally limited to the costs involved in processing, storing and transporting the petroleum recovered to the point of sale (i.e., a legislative net back).

Corporate Income Tax

Australian resident corporations are subject to income tax on their non-exempt, worldwide income at a rate of 30%. The net income of nonresident corporations from Australian sources that is not subject to final withholding tax or treaty protection is also subject to tax at 30%. The 30% rate applies to income from Australian oil and gas activities. An expenditure on exploration is immediately deductible for income tax purposes.

[3] Global Oil & Tax Guide, June 2012 – Ernst & Young, www.ey.com/oilandgas, 01 January 2012
[4] Under the current law, depending on the location of the production, either a PRRT or royalty will apply. PRRT is proposed to apply to all onshore projects from 1 July 2012.
[5] PRRT paid is deductible for income tax purposes.
[6] D: accelerated depreciation; E: immediate write-off for exploration costs and the cost of permits first used in exploration; O: PRRT expenditure uplift.
[7] L: losses can be carried forward indefinitely; RD: R&D incentive.

CIT is levied on taxable income. Taxable income equals assessable income less deductions. Assessable income includes ordinary income (determined under common law) and statutory income (amounts specifically included under the Income Tax Act). Deductions include expenses, to the extent they are incurred in producing assessable income or are necessary in carrying on a business for the purpose of producing assessable income. However, an expenditure of a capital nature is not deductible.

Deductions for expenditures of a capital nature may be available under the "uniform capital allowance regime." This would most relevantly be in the form of a capital allowance for depreciating assets (see below). However, there may be deductions available for other types of capital expenditures (e.g., an expenditure incurred to establish an initial business structure is deductible over five years).

In 2010, following an extensive review of Australia's taxation system, the Australian Government announced a proposed reduction of the corporate tax rate from 30% to 29% from 2013–14. Small companies will benefit from an early cut to the company tax rate to 29% from 2012–13. These changes are yet to be legislated, and the Government announcement indicated that these reductions are dependent on the introduction of the proposed resources taxation regime for iron ore, coal and onshore oil and gas (see PRRT section).

PRRT

PRRT is a federal tax that applies to petroleum projects undertaken in certain offshore areas under the jurisdiction of the Commonwealth of Australia. Generally, PRRT applies to all production licenses issued under the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (OPGGSA) (Commonwealth) or its predecessor Acts. A liability to pay PRRT exists where assessable receipts exceed deductible expenditures. PRRT applies at the rate of 40%. PRRT applies to the taxable profit of a project generated from a project's upstream activities. The taxable profit is calculated by reference to the following formula:

Taxable profit = assessable receipts — deductible expenditure

Assessable receipts include all receipts, whether of a capital or revenue nature, related to a petroleum project. *PRRT is levied before income tax and is deductible for income tax purposes*. A PRRT refund received is assessable for income tax purposes. Under the current law, projects subject to PRRT are generally not subject to excise tax or royalties.

Deductible expenditures include expenses of a capital or revenue nature. There are *three categories of deductible expenditures: exploration expenditures* (e.g., exploration drilling costs, seismic survey), general *project expenditures* (e.g., development expenditures, costs of production) and *closing-down expenditures* (e.g., environmental restoration, removal of production platforms). Certain expenditures are not deductible for PRRT purposes, for example: financing type costs (principal, interest and borrowing costs); dividends; share issue costs; repayment of equity capital; private override royalties; payments to acquire an interest in permits, retention leases and licenses; payments of income tax or good and services tax (GST); indirect administrative or accounting type costs incurred in carrying on or providing operations or facilities; and hedge expenses.

Currently, it is proposed that PRRT will apply to onshore projects, and the Northwest Shelf, from 1 July 2012. The PRRT amendments were passed by the House of Representatives on 23 November 2011. As at 1

January 2012, the PRRT amendments had been referred to the Senate Economics Legislation Committee for enquiry and report by 14 March 2012.

Capital allowances

In calculating a company's CIT liability, tax depreciation deductions may be available.

Depreciating assets include assets that have a limited effective life and that decline in value over time. Examples of depreciating assets include plant and equipment, certain items of intellectual property, in-house proprietary software and acquisitions of exploration permits, retention leases, production licenses and mining or petroleum information, after 30 June 2001.

A capital allowance equal to the decline in the value of the asset may be determined on a diminishing value (DV) or a prime cost (PC) method. The DV method allows a taxpayer to claim a higher decline in value earlier in the effective life of a depreciating asset.

The formula under each method is as follows:

- DV = base value x days held/365 days x 200%/asset's effective life
- PC = asset's cost x days held/365 days x 100%/asset's effective life

A taxpayer can elect to use either the effective life determined by the Commissioner or to independently determine the effective life of an asset.

A specific concession under the capital allowance provisions relevant to the oil and gas industry is the immediate write-off available for costs incurred in undertaking exploration activities. For example, the cost of acquiring a permit or retention lease can be immediately deducted, provided it is first used for exploration. To the extent the asset is first used for development drilling for petroleum or for operations in the course of working a petroleum field, an immediate deduction is not available and the cost may be claimed as a capital allowance over the effective life of the asset.

The effective life of certain tangible assets used in petroleum refining, oil and gas extraction and the gas supply industry is capped at between 15 and 20 years, with taxpayers able to self-assess a lower effective life.

According to Australian Taxation Office rules one can pool most depreciating assets with an effective life of 25 years or more, such as wharves and cement silos, in a long-life small business pool and depreciate at the rate of 5%.

Goods and Services Tax

A GST regime applies in Australia. All transactions that take place within Australia (and some from offshore) are subject to GST. This tax, which was introduced in July 2000, is a multi-staged VAT that applies at each point of sale or lease. It is applied at a standard rate of 10%, with GST-free rates for qualifying exported products and services and other transactions, and input tax rates generally apply to financial services and residential housing.

Both Australian resident and nonresident entities engaged in the oil and gas industry may be subject to GST on services and products supplied. All commercial transactions have a GST impact, and this should be considered prior to entering into any negotiation or arrangement.

Capital Gains

Oil and gas exploration permits, retention leases and production licenses acquired after 30 June 2001 are treated as depreciating assets and, therefore, are not subject to CGT. Permits, leases and licenses acquired on or before 30 June 2001 are subject to the CGT provisions.

Functional Currency

Provided certain requirements are met, taxpayers may calculate their taxable income by reference to a functional currency (i.e., a particular foreign currency) if their accounts are solely or predominantly kept in that currency. In the case of this Economic Model, we will use United States Dollars (US$).

Tax Year

A company's tax year runs from 1 July to 30 June of each year. It is, however, possible to apply for a different accounting period to align a taxpayer's tax year with the financial accounting year.

6.2 Crude Oil and Natural Gas Pricing

Crude Oil

Although a slight economic growth has returned in 2010, there is a growing perception that the economic slowdown will be 'U-shaped' and the recovery will gather momentum only gradually. Global liquids demand (oil, biofuels, and other liquids) nonetheless is likely to rise by 16.5 Mb/d, exceeding 102 Mb/d by 2030. For the Reference Case, it is assumed that by 2014, economic growth is back to trend values.

In the AEO2012[8] Reference case, oil prices [West Texas Intermediate (WTI)] rise from $79 per barrel in 2010 to about $117 per barrel in 2015 and $127 per barrel in 2020. From the 2020 level, prices increase slowly to $145 per barrel in 2035. This price trend is slightly higher than the trend shown in last year's AEO2011 Reference case.

Market volatility and different assumptions about the future of the world economy are reflected in the range of price projections for both the short term and the long term; however, most projections show prices rising over the entire course of the projection period. The projections range from $82 per barrel to $117 per barrel in 2015 (a span of $35 per barrel) and from $98 per barrel to $145 per barrel in 2035 (a span of $47 per barrel). The wide range underscores the uncertainty inherent in the projections. The range of the projections is encompassed in the range of the AEO2012 Low and High Oil Price cases, from $58 per barrel to $182 per barrel in 2015 and from $62 per barrel to $200 per barrel in 2035.

The strongest growth is expected in developing countries and regions, in particular, China and South Asia, which expand at an average rate of 6.3% per annum (p.a.) and 4.7% p.a., respectively, over the period 2013–2030. The average global growth rate is 3% p.a. Overall consumption growth will be restrained by

[8] U.S. Energy Information Administration - Annual Energy Outlook, June 2012

the increase in crude oil prices seen in recent years and by the continued, gradual reduction of subsidies in non-OECD countries. China is the largest source of oil consumption growth in our outlook, with consumption forecast to grow by 8 Mb/d to reach 17.5 Mb/d by 2030, overtaking the US to become the world's largest oil consumer.

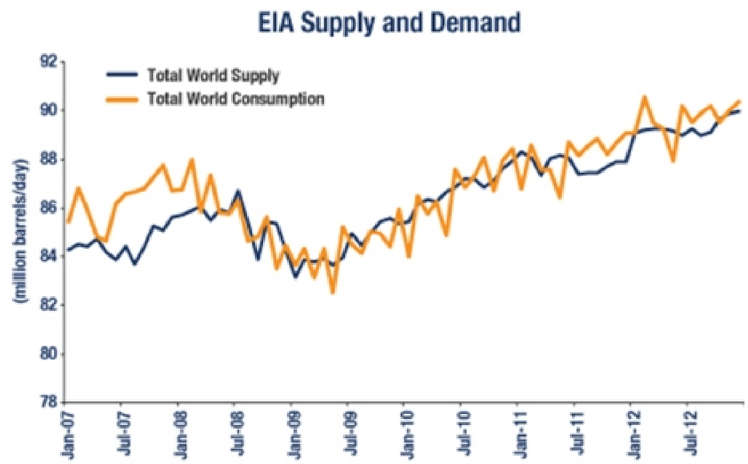


Figure 30 - EIA expects oil prices to remain strong, with West Texas Intermediate spot prices averaging $104 per barrel in 2013 and $111 in 2014

Between 2003 and 2008, demand really skyrocketed. In 2004, there was demand growth of 3 million barrels per day. World primary energy use is projected to grow by an annual average of 1.7% (or a total of 40%) in 2010-35, not much lower than during the previous two decades (1.9% p.a. or 45%).

Against the backdrop of extreme oil price volatility, the global financial crisis and an economic crisis unseen since the Great Depression, a host of new challenges have arisen in preparing an oil outlook to 2035. One of these challenges relates to assumptions for future price developments. For the Reference Case, the key to the oil price assumption is the perception of the behavior of supply costs in general, and the medium- to long-run cost of the marginal barrel in particular. High costs have peaked and will continue to decline as cyclical elements separate from structural ones.

Nevertheless, costs are expected to remain higher than in the past in developing the marginal barrel, and it is likely that in the longer term some environmental externalities will be internalized. For the next decade, nominal US DOE/EIA prices are assumed to stay in the range $100–125/bbl, while longer term they remain in the range $110–145/bbl. However, it is important to note that this is an assumption, and does not reflect or imply any projection of whether such a price path is likely or desirable. This price assumption reflects the broadly accepted view that prices that are too low are not sustainable as they will limit the flow of upstream investment, while prices that are too high could hamper the recovery of the global economy and medium- to long term growth prospects.

The Company expects to receive the "Australia Blend" spot crude oil price as the 2013 average "wellhead" export market price, assumed at US$ 106.46 per barrel (when using a Brent spot price of 108.71) as a base price. The average "net-back" export market price, taking into account discounts for transportation, oil quality and customs and loading fees, is assumed at US$ 79.46 per barrel, or US$ 27/bbl general cost involved in processing, storing and transporting the petroleum recovered to the point of sale, which is then used to calculate the appropriate hydrocarbon tax paid.

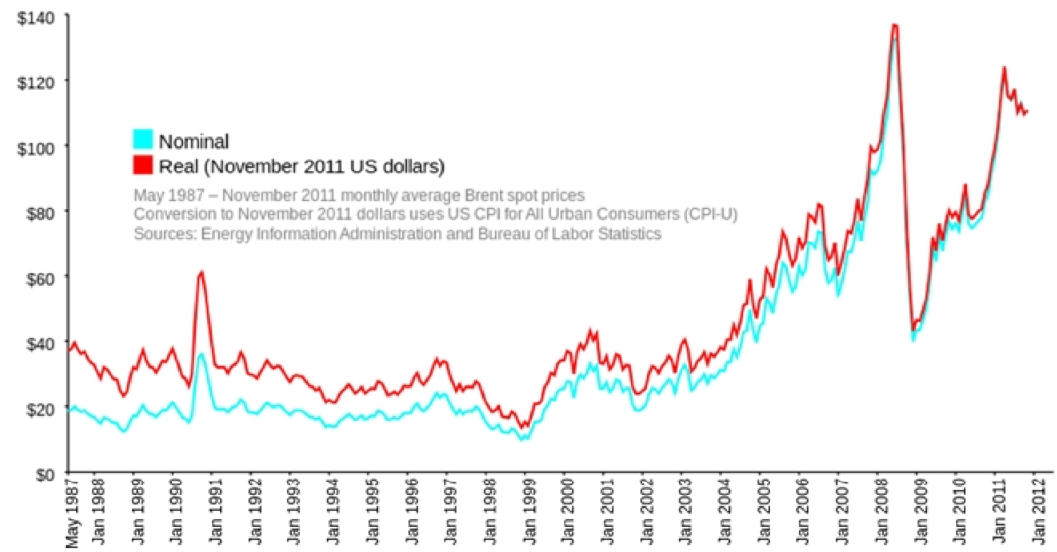


Figure 31 - The price of oil underwent a significant decrease after the record peak of US$145 it reached in July 2008. On December 23, 2008, WTI crude oil spot price fell to US$30.28 a barrel, the lowest since the financial crisis of 2007–2010 began, and traded at between US$35 a barrel and US$82 a barrel in 2009. On 31 January 2011, the Brent price hit $100 a barrel for the first time since October 2008, on concerns about the political unrest in Egypt.

Natural Gas

The projections of natural gas consumption, production, imports, and prices vary significantly as a result of differences in assumptions[9]. Each of the projections shows an increase in overall natural gas consumption from 2010 to 2035, with the IHSGI projection showing the largest increase, 39 percent. The ExxonMobil projection includes an increase of around 20 percent. The EVA projection shows an increase of 26 percent from 2010 to 2030 (EVA does not extend to 2035). Total natural gas consumption in the AEO2012, Deloitte, and SEER projections increases from 2010 to 2035, with total natural gas consumption growing from 4 to 31 percent. IHSGI shows the largest increase and INFORUM the smallest. The IHSGI projection for total natural gas consumption in 2035 is 36 percent higher than the INFORUM projection. In the AEO2012 Reference case, total natural gas consumption grows by 5 percent from 2015 to 2035.

SAS's long term gas price forecasts are based on (1) the NYMEX Division Natural Gas Spot Price: Henry Hub, Louisiana, (2) the US Department of Energy / Energy Information Administration's (USA DOE/EIA) 2012 Outlook Report and (3) Organization of Petroleum Exporting Countries (OPEC) 2012 Outlook Report.

As of January 1, 2010, total proved and unproved natural gas resources are estimated at 2,203 trillion cubic feet. Development costs for natural gas wells are expected to grow slowly. Henry Hub spot prices for natural gas rise by 2.1 percent per year from 2010 through 2035 in the Reference case, to an annual average of $7.37 per million Btu (2010 dollars) in 2035.

[9] U.S. Energy Information Administration - Annual Energy Outlook, June 2012

With increased production, average annual wellhead prices for natural gas remain below $5 per thousand cubic feet (2010 dollars) through 2021 in the AEO2012 Reference case. The projected prices reflect continued industry success in tapping the Nation's extensive shale gas resource. The resilience of drilling levels, despite low natural gas prices, is in part a result of high crude oil prices, which significantly improve the economics of natural gas plays that have high concentrations of crude oil, condensates, or natural gas liquids.

The rate at which natural gas prices change in the future can vary, depending on a number of factors. Two important factors are the future rate of macroeconomic growth and the expected cumulative production of shale gas wells over their lifetimes — the estimated ultimate recovery (EUR) per well.

After 2023, natural gas prices generally increase as the numbers of tight gas and shale gas wells drilled increase to meet growing domestic demand for natural gas and offset declines in natural gas production from other sources. Natural gas prices rise as production gradually shifts to resources that are less productive and more expensive. Natural gas wellhead prices (in 2010 Dollars) reach $6.28 per thousand cubic feet in 2035, compared with $6.48 per thousand cubic feet (2010 dollars) in AEO2011[10].

Henry Hub Natural Gas Spot Price is at a current level of $3.77 per million British thermal units (MMBtu), up from 3.75 the previous market day and up from 3.09 one year ago. This is a change of 0.53% from the previous market day and 22.01% from one year ago[11].

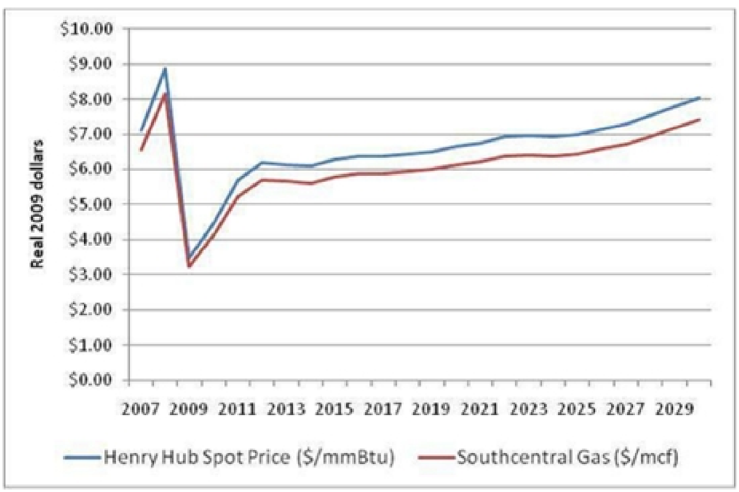


Figure 32 - Natural Gas Henry Hub in spot prices US Dollars per MBtu for 2006 - 2030[12]

Natural gas prices, as with other commodity prices, are mainly driven by supply and demand fundamentals. However, natural gas prices may also be linked to the price of crude oil and/or petroleum products, especially in continental Europe.

In February 2011 North Sea Brent crude cost about $50 a barrel more than U.K. gas. While North Sea Brent crude oil settled at $101.64 a barrel on the ICE Futures Europe exchange in London on 16 Feb 2011, U.K.

[10] U.S. En Inf Adm - Annual Energy Outlook 2012 Early Release Overview, Report Number: DOE/EIA-0383ER(2012)
[11] ycharts.com/indicators/natural_gas_spot_price, Henry Hub Natural Gas Spot Price: 3.77 USD for Nov 27 2012
[12] Source: EIA, Report: An Updated Annual Energy Outlook 2010, Reference Case. ISER calculations

natural gas closed at 52.89 pence a therm (US$ 8.46 per MBtu or US$ 291.32 per Thou m^3), or $48.45 a barrel when converted into similar units.

As US domestic gas prices show a small fall, with the advent of more domestic shale gas and coal seam gas, in Australia gas price may likely rise. The US Henry Hub price for example has fallen about 15% a month on average for the last four months - but the oil price rose. If that US gas price was linked to the crude oil price US gas price would be four times higher, and rising - and domestic gas price would not respond to competition.

The sensitivity of reserve availability to natural gas outlook meant that gas contract prices could be linked to gas export prices, with a discount depending on the number of projected natural gas developments that would occur. However, this is a complex dynamic where the key drivers are exogenous to Australia, are difficult to assess and largely based on factors that include natural gas proponents' longer term aspirations, oil price outlook to the extent this impacts gas development economics and competing LNG developments in North America and East Africa[13].

What Australian investors want: If gas-supply investors' lobby-efforts succeed, Australia's domestic gas price - for electricity generation, city and industrial gas - may rise to match LNG export price. The winners here would be energy investors. Natural gas priced like oil - that's the apparent plan: Energy investors are lobbying hard for a world gas price linked to oil price.

6.3 Economic Modelling for Crude Oil and Natural Gas Production

The Company did not provide SAS with revenue and field development plans upon which to determine certain economic parameters. A basic field development plan was prepared by SAS and incorporated into the Economic Model. The economic parameters used in this report were those obtained from the Company during discussions with Company personnel and those that are deemed appropriate by SAS based on current regional experience.

The forecast of crude oil and natural gas prices used in this evaluation were based on SAS's 01 November 2012 price forecasts, based on industrial indices such as US DOE/EIA and OPEC. Production forecasts were extrapolated by SAS and are based on certain assumptions discussed later on in this report.

The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance subsequent to the date of the estimates may necessitate revision. These future revisions may be material.

[13] Department of Energy and Water Supply - 2012 Gas Market Review, Queensland, CS1645 07/12, © State of Queensland, 2012.

It is important to note that the estimate of the reserves to be recovered from an oil or gas field is the sum of all the cumulative production until an economic limit is reached. The economic limit is a function of the production forecast, future prices and operating costs (including export fees and taxes) to maintain production. Consequently, when estimates of future prices and costs are changed, economic limits are also altered. In the evaluation process, production forecasts may be truncated at the economic limits and thus, reserves estimates may vary with price and cost sensitivities. The economic model used in the evaluation was provided as a Microsoft ® Excel file and was built by SAS. We have checked the economic model for reasonableness against the Exploration Contract. The economic model appears to be functioning properly.

The Economic Model built for the OEHL also includes a basic production profile for the life of the Exploration Block SEL 05/2005. The following assumptions have been used to derive this production profile:

a. Since no commercial quantities of oil or gas have ever been produced in Tasmania, we cannot ascertain, with a great degree of accuracy, the nature of the hydrocarbon fluids found in the structures identified by CAPD. Thus we have modelled both for crude oil and for natural gas, in two separate cases.

b. Oil Production Rates: starting at 1000 bopd, based on well test results at 4000 bopd[14]; reduced to initially acceptable rate by SPE for modelling purposes.

c. Gas Production Rates: starting at 4.25 mmcfd, based on average well test results at 30[15] mmcfd; reduced to initially acceptable rate by SPE for modelling purposes.

d. Number of Wells to Drill: Used 4,000 total acres for wells, based on best net-pay areas (16.2 km^2 or ~4,000 ac), using 900 m drainage (ca. 220 ac) for gas wells and 600 m drainage (ca. 90 ac) for oil wells, with 1/8 inj/prod well ratio for natural gas and 1/4 inj/prod well ratio for oil wells. Model assumes that not all net area is available for drilling due to existence of farms, roads, etc.

e. Gas Well Production profile calculations: Initial well production regressed by 2% per year to compensate for partial reservoir pressure drop with additional wells and well production depletion set at 20% per annum. Gas depletion is taken to 2037 in the model to show reserve vs. potential production years.

f. Oil Well Production profile calculations: SAS has used the Recoverable Deterministic Reserves calculated by CAPD as the reserve base for the Model. Initial well production was regressed by 2% per year to compensate for partial reservoir pressure drop with additional wells drilled and standard oil well production depletion set was at 12% per annum. Oil depletion is taken to year 2037 in the model to show reserve vs. potential production for the life of the license.

g. The number of wells and realistic well production rates will naturally be revised for actual operations, once a proper reservoir model has been prepared and submitted to the government for each production horizon. The above calculations are meant for internal corporate planning reasons and are based uniquely on analogue field data or personal experience from operating similar wells in Australia.

h. The net present values of the resources presented in this report simply represent discounted future cash flow values at several discount rates. Though net present values form an integral part of fair market value estimations, without consideration for other economic criteria, they are not to be construed as SAS's opinion of fair market value.

i. Drilling, work-over and abandonment costs were estimated jointly by SAS and Company included in this report; however, site reclamation and salvage values have not been considered.

The dollar values presented throughout the report are in United States dollars, unless otherwise stated.

[14] BassGas development testing program - Yolla-4 gas flows hit target - Tuesday, 3 August 2004 / Hayden Lilienthal
[15] ibid

EVALUATION OF HYDROCARBON RESOURCES OF EXPLORATION BLOCK SEL 05/2005
Forecast Production and Cash Flow After Tax
Best Estimate 'Risked' Probable Crude Oil Resources - SEL 05/2005
Forecast Prices and Costs as of 01 November, 2012
(All Values Expressed in United States Dollars)

Year	Gross Annual Crude Oil Production Bbl	Forecast Netback Oil Price $/Bbl	Grosss Revenue $	Historical Costs & Exploration Expense $	Develop't Capex & Opex, Aband'nt & Deprec'n $	Earnings Before Taxation $	Australia Taxes1 $	Net Cash Flow After Australia Taxes $	Crude Oil Production Discounted Net Cash Flow (NPV) After Australia Taxes 5% US $	10% US $	15% US $	20% US $
2013	182,500	79.46	14,500,683		3,807,825	10,907,683	5,498,471	5,194,387	5,069,203	4,952,654	4,843,791	4,741,805
2014	543,850	86.65	47,122,039		3,985,959	43,520,039	21,470,239	21,665,841	21,143,696	20,657,569	20,203,501	19,778,117
2015	854,173	92.60	79,098,173	608,246	4,165,311	74,869,926	36,969,856	37,354,759	34,718,583	32,378,514	30,289,994	28,416,728
2016	1,291,513	95.61	123,480,257	608,246	7,934,220	115,725,011	57,159,739	57,778,052	51,143,406	45,528,273	40,739,744	36,627,711
2017	1,857,955	98.58	183,159,211	608,246	11,364,109	172,367,965	85,134,752	86,052,104	72,543,573	61,643,472	52,761,733	45,459,759
2018	2,341,996	99.70	233,489,290	608,246	8,776,104	225,662,044	111,454,247	112,650,693	90,444,470	73,361,260	60,061,142	49,592,758
2019	2,753,812	100.92	277,908,862	608,246	12,171,099	267,045,616	131,872,252	133,257,265	101,894,267	78,891,666	61,780,693	48,887,074
2020	3,102,352	102.37	317,584,745	608,246	9,549,944	309,685,499	152,917,945	154,508,610	112,518,062	83,157,272	62,289,769	47,236,160
2021	3,395,488	103.68	352,053,842	608,246	12,913,446	341,118,596	168,410,642	170,121,507	117,988,445	83,236,552	59,638,322	43,341,095
2022	3,640,140	105.11	382,628,544	608,246	10,262,374	374,657,298	184,951,736	186,806,188	123,390,640	83,090,895	56,945,527	39,659,813
2023	3,842,390	106.17	407,960,870	608,246	13,597,455	396,953,624	195,921,750	197,833,418	124,451,838	79,996,161	52,440,904	35,000,788
2024	3,861,456	107.23	414,063,345	608,246	7,322,658	409,529,099	202,100,449	204,031,992	122,239,237	75,002,385	47,029,563	30,081,202
2025	3,704,962	108.25	401,075,959	608,246	10,442,575	393,523,713	194,133,823	195,891,316	111,773,344	65,463,512	39,263,591	24,067,493
2026	3,561,109	109.17	388,762,133	608,246	7,609,546	384,141,887	189,452,673	191,091,667	103,842,590	58,054,139	33,305,714	19,564,834
2027	3,290,964	110.04	362,130,334	608,246	4,051,994	361,001,088	177,996,451	179,473,643	92,884,905	49,567,775	27,200,685	15,312,773
2028	2,896,049	111.07	321,675,652	608,246	3,901,494	320,546,406	157,978,619	159,187,293	78,462,756	39,968,188	20,979,238	11,318,277
2029	2,548,523	112.72	287,275,498	608,246	3,758,519	286,146,252	140,961,046	141,947,687	66,633,739	32,399,753	16,267,162	8,410,446
2030	2,242,700	114.18	256,076,522		3,622,693	255,555,522	125,830,492	126,623,336	56,609,630	26,274,499	12,618,258	6,252,061
2031	1,973,576	115.54	228,018,756		3,493,659	227,497,756	111,954,066	112,571,031	47,930,715	21,235,117	9,754,712	4,631,854
2032	1,736,747	116.83	202,907,258		3,371,076	202,386,258	99,536,823	99,999,359	40,550,404	17,148,753	7,535,068	3,428,816
2033	1,528,337	118.04	180,404,840		3,254,622	179,883,840	88,411,646	88,738,572	34,270,552	13,834,233	5,814,395	2,535,585
2034	1,344,937	119.49	160,704,137		4,278,091	159,039,137	78,109,712	78,316,334	28,805,255	11,099,472	4,462,175	1,864,820
2035	1,183,544	120.67	142,817,731		2,613,686	142,692,731	70,039,606	70,164,438	24,578,033	9,040,123	3,476,270	1,392,260
2036	1,041,519	123.77	128,904,739		2,495,502	128,779,739	63,174,427	63,234,810	21,095,848	7,406,633	2,724,299	1,045,630
2037	919,168	125.46	115,314,287		2,383,227	115,189,287	56,467,482	56,463,579	17,939,894	6,012,295	2,115,286	778,053
Total	55,639,760		6,009,117,709	9,123,693	161,127,188	5,898,426,016	2,907,908,947	2,930,957,881	1,702,923,085	1,079,401,165	734,541,535	529,425,910

1 *Australian taxes include Petroleum Resource Rent Tax and Corporate Tax*

Table 8 – Best estimate, risked, recoverable crude oil resources and the associated life-of-the-field Net Present Values after Australian taxes

EVALUATION OF HYDROCARBON RESOURCES OF EXPLORATION BLOCK SEL 05/2005
SEL 05/2005
Best Estimate Probable Cases
Capex and Opex - All Fields[1]
(All Values Expressed in United States Dollars)

Year	Total Number of Production Wells		Total Number of Injection Wells		Total Number of Wells[2]	Cost of Drilling Production Wells US$		Cost of Drilling Injection Wells US$		Workover & Completions US$		Equipment and Facilities Cost US$		Total Maint. US$	Total CapEx and OpEx Cost for SEL 05/2005 US$	
	Gas	Oil	Gas	Oil		Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil		Gas	Oil
2013	1	1				3,500,000	3,250,000			250,000	250,000	18,000	18,000	150,000	3,843,000	3,593,000
2014	1	1				3,500,000	3,250,000			250,000	250,000	27,000	27,000	150,000	3,852,000	3,602,000
2015	1	1				3,500,000	3,250,000		0	250,000	250,000	45,000	45,000	150,000	3,870,000	3,620,000
2016	1	2				3,500,000	6,500,000			250,000	500,000	63,000	72,000	150,000	3,888,000	7,147,000
2017	1	2		1		3,500,000	6,500,000		3,000,000	250,000	500,000	81,000	108,000	150,000	3,906,000	10,183,000
2018	1	2				3,500,000	6,500,000			250,000	500,000	99,000	144,000	150,000	3,924,000	7,219,000
2019	1	2	1	1		3,500,000	6,500,000	3,250,000	3,000,000	250,000	500,000	117,000	180,000	150,000	7,192,000	10,255,000
2020	1	2				3,500,000	6,500,000			250,000	500,000	135,000	216,000	150,000	3,960,000	7,291,000
2021	1	2		1		3,500,000	6,500,000	0	3,000,000	250,000	500,000	153,000	252,000	150,000	3,978,000	10,327,000
2022	1	2				3,500,000	6,500,000			250,000	500,000	171,000	288,000	150,000	3,996,000	7,363,000
2023	1	2	1	1		3,500,000	6,500,000	3,250,000	3,000,000	250,000	500,000	189,000	324,000	150,000	7,264,000	10,399,000
2024	1	1				3,500,000	3,250,000			250,000	250,000	207,000	351,000	150,000	4,032,000	3,926,000
2025		1		1		0	3,250,000	0	3,000,000	0	250,000	216,000	369,000	150,000	291,000	6,944,000
2026		1				0	3,250,000			0	250,000	216,000	387,000	250,000	341,000	4,012,000
2027						0	0	0	0	0	0	216,000	396,000	250,000	341,000	521,000
2028						0	0			0	0	216,000	396,000	250,000	341,000	521,000
2029						0	0	0	0	0	0	216,000	396,000	250,000	341,000	521,000
2030						0	0			0	0	216,000	396,000	250,000	341,000	521,000
2031						0	0	0	0	0	0	216,000	396,000	250,000	341,000	521,000
2032						0				0	0	216,000	396,000	250,000	341,000	521,000
2033										0	0	199,800	396,000	250,000	324,800	521,000
2034										0	0	184,815	0	250,000	309,815	125,000
2035										0	0	170,954	0	250,000	295,954	125,000
2036										0	0	158,132	0	250,000	283,132	125,000
2037										0	0	146,272	0	250,000	271,272	125,000
Total	12	22	2	5		42,000,000	71,500,000	6,500,000	15,000,000	3,000,000	5,500,000	3,892,974	5,553,000	4,950,000	57,867,974	100,028,000

Individual Well Cost, $[1]						
	Gas Production Well Cost	3,500,000	Oil Production Well Cost	3,250,000	Convert Gas Well to Oil Well	250,000
	Gas Injection Well Cost	3,250,000	Oil Injection Well Cost	3,000,000		
	Water Well Cost	70,000	Average Well Workover Cost	250,000		

(1) *All per well capital costs and total facility costs were forecasted by OEHL*
(2) *Total number of wells excludes the Gasensate wells converted to oil producer*

Table 9 – Best estimate, risked, recoverable resources crude oil or natural gas CapEx and OpEx development estimations

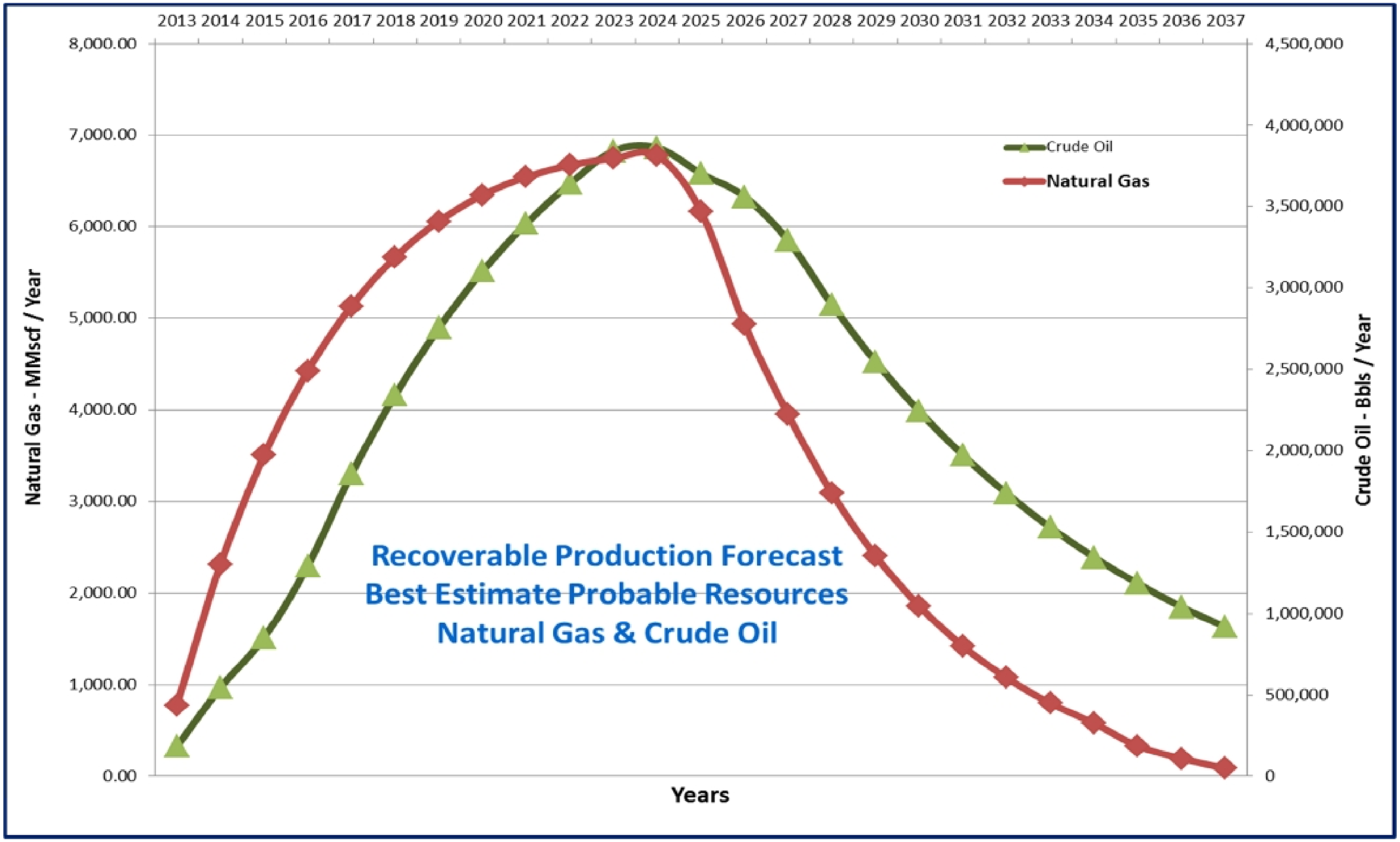


Table 10 – Best estimate, risked, recoverable resources crude oil or natural gas life-of-the-field production forecasts

Overseas Energy Holdings Limited
EVALUATION OF HYDROCARBON RESOURCES OF EXPLORATION BLOCK SEL 05/2005
Summary of Selected Price Forecasts
(EffectiveNovember 1, 2012)

Year	US DOE/EIA Reference Prices (1) US$/bbl	Average WTI Spot Prices US$/bbl	Brent Crude Oil Spot Prices US$/bbl	Australia Blend Prices US$/bbl	OEHL Crude Oil Netback[3] Price US$/bbl	US DOE/EIA Reference Prices (2) US$/Mcf	Average Henry Hub Gas Prices US$/Mcf	Average North Sea Gas Prices US$/Mcf	OEHL Natural Gas Netback[4] Price US$/Mcf
2013	70.00	103.71	108.71	106.46	79.46	3.65	3.80	7.60	5.60
2014	73.06	110.90	115.90	113.65	86.65	3.74	4.77	9.53	7.53
2015	76.41	116.91	121.91	119.60	92.60	3.83	4.86	9.72	7.72
2016	79.74	119.92	124.92	122.61	95.61	3.93	4.96	9.91	7.91
2017	86.91	122.89	127.89	125.58	98.58	4.03	5.05	10.11	8.11
2018	92.46	124.00	129.00	126.70	99.70	4.13	5.15	10.31	8.31
2019	99.23	125.22	130.22	127.92	100.92	4.23	5.26	10.52	8.52
2020	102.35	126.68	131.68	129.37	102.37	4.34	5.36	10.73	8.73
2021	104.41	127.99	132.99	130.68	103.68	4.45	5.47	10.94	8.94
2022	106.47	129.42	134.42	132.11	105.11	4.56	5.58	11.17	9.17
2023	108.28	130.48	135.48	133.17	106.17	4.67	5.70	11.39	9.39
2024	109.52	131.54	136.54	134.23	107.23	4.79	5.81	11.63	9.63
2025	110.92	132.56	137.56	135.25	108.25	4.91	5.93	11.87	9.87
2026	112.32	133.48	138.48	136.17	109.17	5.03	6.06	12.11	10.11
2027	113.63	134.34	139.34	137.04	110.04	5.16	6.18	12.36	10.36
2028	115.09	135.38	140.38	138.07	111.07	5.29	6.31	12.62	10.62
2029	116.61	137.03	142.03	139.72	112.72	5.42	6.44	12.89	10.89
2030	118.32	138.49	143.49	141.18	114.18	5.55	6.58	13.16	11.16
2031	120.13	139.84	144.84	142.54	115.54	5.69	6.72	13.44	11.44
2032	122.04	141.14	146.14	143.83	116.83	5.84	6.86	13.72	11.72
2033	123.50	142.35	147.35	145.04	118.04	5.98	7.01	14.01	12.01
2034	126.25	143.79	148.79	146.49	119.49	6.13	7.16	14.31	12.31
2035	128.75	144.98	149.98	147.67	120.67	6.28	7.31	14.62	12.62
2036	131.50	148.07	153.07	150.77	123.77	6.44	7.47	14.93	12.93
2037	133.00	149.76	154.76	152.46	125.46	6.60	7.63	15.25	13.25

(1) *Average annual world oil prices in three cases, 2013-2037 (2010 dollars per barrel)*
U.S. Energy Information Administration, Annual Energy Review 2012, DOE/EIA-0384 (2012) (Washington, DC, June2012). Projections: AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, LP2010.D011910A, and HP2010. D011910A. ref2012.d020112c

(2) *Natural gas wellhead prices in three cases, 2013-2037 (2010 dollars per thousand cubic feet)*
U .S. Energy Information Administration, Annual Energy Review 2012, DOE/EIA-0384 (2010) (Washington, DC, June 2012). Projections: AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A, ref2012.d020112c

(3) *Crude oil Netback prices include an initial discount (for transportation and Non-Official Quality bank) of US$ 12/bbl and a second reduction (for oil treatment and Custom's clearance costs) of US$ 15/bbl, as extrapolated from historical sales records Australia. Gas Export cost has been estimated at US$4/Mscf.*

(4) *Gas demand, excluding LNG and non-GPG, was based on the 2011 AEMO GSOO. Indications are that gas prices are in the process of moving from cost-based to exportopportunity value. Export-opportunity value is based on the price of LNG sold ex-Gladstone, less the costs associated with liquefaction and upstream pipeline transportation (assumed to be $5/GJ). This is referred to as netback pricing.*

Table 11 – Best estimate, crude oil and natural gas price forecasts for the life-of-the-field

Section Seven

Conclusions

7.1 Conclusions and Observations

A summary of our observations and conclusions about the exploration potential of this Contract are as follows:

1. CAPD have ascertained that oil source rocks, reservoirs & seals could easily exist in the area and that hydrocarbons were generated in the vicinity and could have migrated to structural traps in northern Tasmania. The main exploration objective is therefore to find hydrocarbon traps in the target areas CAPD have identified.
2. The Contract Area has seismic data of moderate to good quality due to the presence of thick dolerite sheets but very little drilling has taken place in Tasmania, in part due to difficult access of the region and partly due to the Government emphasis on the development of the nearby offshore fields such as Bass, Gippsland, Sorell and Otway Basins, shown in Figure 28.
3. 2D seismic and various other reports were provided for evaluation of SEL 05/2005 prospect. This data indicated the likelihood of numerous structures; however, additional acquisition of 2D seismic data should be performed to determine the optimum locations for additional exploratory wells.
4. No relevant well test data was provided that would indicate the quality of these onshore reservoir(s); however believe that reservoir quality could be analogous to Bass Straits fields to the north. In fact, the reservoir quality improves from the southern part of the block to the edge of the onshore platform, thus the onshore prospects could be comparable with the Bass Straits fields.
5. The cost of exploration and development will be high by onshore standards due to the need to import all equipment from the mainland, although transport and logistics support are well developed and readily available.
6. A gas pipelines crosses the eastern end of the Block and gas processing facilities are located across the Straits on the mainland. The possibility of using oil and gas treatment facilities on the mainland should be investigated.

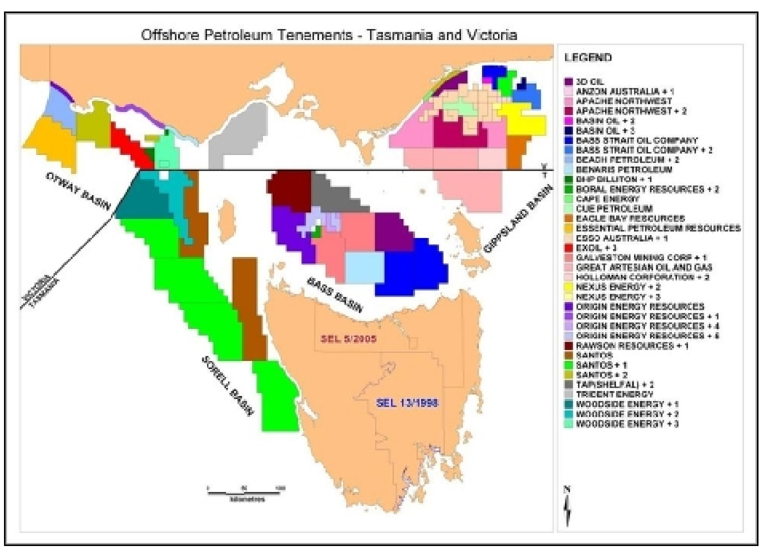


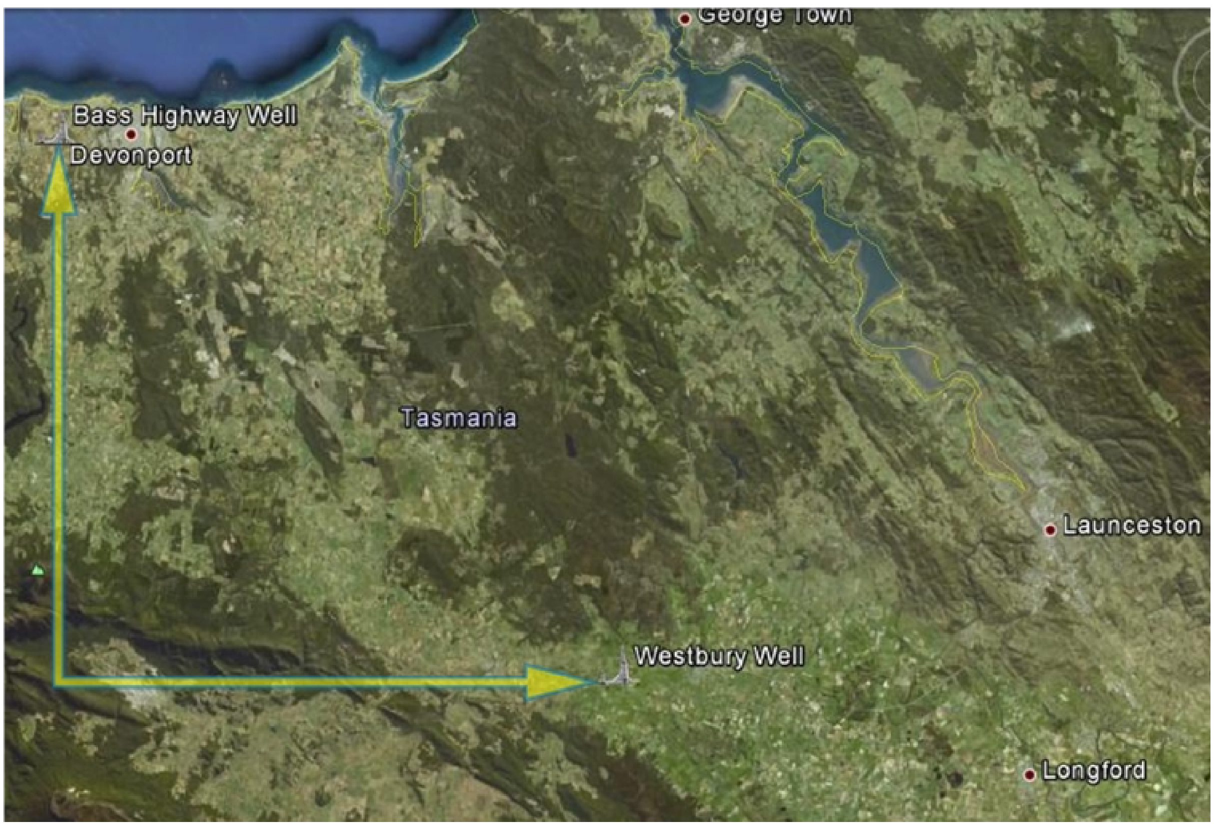
Figure 33 - Offshore petroleum tenements in Tasmania and Victoria

In summary, we consider SEL 05/2005 prospect and the Contract Area to have a significant exploration potential. The cost of exploring reservoirs of this depth will be moderate and there is some risk as with any exploration prospect but the potential size and commercial value of the resources, if successful, be very rewarding.

7.2 Proposed Well Locations

The proposed well site coordinates for Bass Highway (BH-1) and Westbury (W-1) are given in Southerly Latitude(S) and Easterly longitude (E) as well as XY coordinates.

Bass Highway è BH-1	
Latitude	Longitude
41° 10' 29.05197''S	146° 16' 45.98784''E
439560 X	5441595 Y
Westbury Well è W-1	
41° 31' 30.74573''S	146° 45' 43.90945''E
480160 X	5402910 Y



34 - Location of Bass Highway and Westbury Wells in general view

35 - Location of the Bass Highway Well

36 - Location of the Westbury Well

Section Eight

Qualifications and Basis of Opinion

4.1 Details and Qualification of Competent Person

A graduate Nuclear Engineer since 1978, a Registered Professional Petroleum Engineer since 1990, and an SPE Certified Petroleum Engineer since 2011, S. A. Şehsuvaroğlu, BSc NE, PE, SPE Cert PE (SAS) is an independent upstream energy consultant and specialist. In his capacity as a Registered Professional Engineer, SAS is fully qualified to sign-off on oil & gas expert reports and bankable reserve evaluations.

SAS has on-going strategic alliances with CAPD Petro-Consulting, PGS Kazakhstan LLP and Klarenco Oil & Gas Consulting LLC as his Geology & Geophysics solutions partners. CAPD was established in 2006 and operates out of Ankara (Turkey). PGS Kazakhstan LLP is the Almaty based subsidiary of Petroleum Geo-Services (PGS), one of the leading providers of geophysical services to the oil and gas industry worldwide, for the past 20 years. Klarenco is also a Moscow based energy consulting firm, established in 2000.

Therefore SAS and his associates have a considerable amount of experience in the evaluation of oil and gas properties and have already provided numerous similar reports to Clients in various countries.

The geological and geophysical portions of the report, entitled “EVALUATION OF HYDROCARBON RESOURCES OF LICENCE BLOCK SEL 05/2005, December 2012” from which the data for this report was taken were prepared by CAPD; the Economic Model and the associated certification were prepared by SAS.

8.2 Certificate of Qualifications of Competent Person

I, S. A. (AL) ŞEHSUVAROĞLU, BSc N.E., Professional Engineer of the city of Nice, France, hereby certify that:

1. I am a registered Professional Engineer in the State of Texas (USA), a member of Texas State Board of Professional Engineers and Society of Petroleum Engineers and I reside at 3 Avenue des Baumettes, 06000 Nice, France.

2. I graduated from the Kansas State University (USA) with a Bachelor of Science degree in Nuclear Engineering in 1978. I have obtained my Professional Engineering qualification in 1990 and Cert SPE Petroleum Engineer qualification in 2011.

3. I am a qualified evaluator and auditor as defined in PRMS 2007.

4. I have been employed in the petroleum industry since graduation by various companies and have been directly involved in reservoir engineering, petrophysics, operations and evaluations during that time.

5. I have in excess of 30 years in the conduct of evaluation and engineering studies relating to oil & gas fields around the world.

6. I have participated directly in the evaluation of these assets and properties and preparation of this resource evaluation report for OEHL, dated December 2012 and the parameters and conditions employed in this evaluation were examined by me and adopted as representative and appropriate in establishing the value of these oil and gas properties according to the information available to date.

7. I did not undertake a field inspection of the property for the purposes of this report, but I had visited Exploration Block SEL 05/2005 during a technical and management role I was engaged in Tasmania during 2007.

8. I have not, nor do I expect to receive, any direct or indirect interest in the properties or securities of OEHL, its participants or any affiliate thereof.

9. I have not examined all the documents pertaining to the ownership and agreements referred to in this report, or the chain of Title for the oil and gas properties discussed.

S. A. (Al) Şehsuvaroğlu, B[illegible] NE, SPE, Reg. Prof. Petr. Eng.
Qualified Reserves Evaluator

SPE International
SPE Certified Petroleum Engineer 2012

Permit to Practice

S. A. (Al) Şehsuvaroğlu is a current member of the State of Texas Board of Professional Engineers and hereby attests to its qualifications by signing this permit to practice stamp.

PERMIT TO PRACTICE

S. A. (AL) SEHSUVAROGLU, P.E.

Signature ____________________

Date **31 December 2012**

PERMIT NUMBER: 68358

Texas Board of Professional Engineers

STATE OF TEXAS
S. A. SEHSUVAROGLU
68358
REGISTERED
PROFESSIONAL ENGINEER

8.3 Basis of Opinion

This report has been prepared by SAS with the collaboration of CAPD using modern geological & petroleum engineering knowledge, techniques and the geological and seismic interpretation computer software. It has furthermore been reviewed and edited within the Code of Ethics of the State of Texas Board of Professional Engineers. This report adheres in all material aspects to the 'best practices' recommended in PRMS 2007 handbook, which are in accordance with principles and definitions established by the Society of Petroleum Engineers Oil & Gas Reserves Committee in 2007.

PRMS 2007 was approved by the Society of Petroleum Engineers (SPE) Board of Directors in March 2007, culminating two years of intense collaboration by SPE, the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE). The system also was approved by the boards of the other societies following a significant industry review and comment period.

Definitions particular to PRMS 2007 were reviewed from the following organizations:

- U.S. Securities and Exchange Commission
- U.K. Statement of Recommended Practices
- Canadian Security Administrators
- Russian Ministry of Natural Resources
- China Petroleum Reserves Office
- Norwegian Petroleum Directorate
- U.S. Geological Survey
- United Nations Framework Classification

According to the rules of PRMS 2007, we have classified the hydrocarbon accumulations of SEL 05/2005 as "Prospective Resources" and estimate that these are volumes associated with undiscovered accumulations. Prospective Resources represent quantities of hydrocarbons which are estimated, as of a given date, to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have not yet been drilled.

The Company did not provide SAS with revenue and field development plans upon which to determine certain economic parameters. The economic parameters used in this report were those obtained from analogous fields and other similar operations that are deemed appropriate by SAS based on current regional experience.

The data was of generally fair to good quality, consistent with the type and quality of information usually available in Australia. This study is based on 2D seismic data, various technical reports in digital format and regional information from public domains. The existing 2D seismic is of good quality and in 'depth' domain (PSDM version).

The forecast of crude oil and natural gas prices used in this evaluation were based on SAS's 01 November 2012 price forecasts, gathered from industrial indices such as US DOE/EIA and OPEC. Drilling, work over and abandonment costs were included in this report; however, site reclamation and salvage values have not been considered.

The accuracy of resource estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material.

It is important to note that the estimate of the resources to be recovered from an oil or gas field is the sum of all the cumulative production until an economic limit is reached. The economic limit is a function of the production forecast, future prices and operating costs (including royalties and taxes) to maintain production. Consequently, when estimates of future prices and costs are changed, economic limits are also altered. In the evaluation process, production forecasts may be truncated at the economic limits and thus, resources estimates may vary with price and cost sensitivities.

Section Nine

Appendices

9.1 Summary Table of Assets

Appendix 1

SUMMARY TABLE OF ASSETS

Oil & Gas

Asset (1)	**Operator**	**Interest (%)**	**Status** (2)	**License Expiry Date**	**License Area km^2**	**Comments**
Special Exploration Licence: SEL 05-2005 North-Central Tasmania, Australia	OEHL	100	Exploration	Dec 31st 2037	6,885.00	Initial Gravity and Seismic Surveys Complete and One Stratigraphic Well Drilled

(1) Asset - Country, license and block

(2) Status - Exploration, Development or Production only

9.2 Summary Resources by Status

Appendix 3

SUMMARY OF RESOURCES BY STATUS

Oil & Gas - Prospective Resources

(all figures in barrels)	Horizon	Geologic Object	Gross (OGIP) Low Est.	Gross (OGIP) Best Est.	Gross (OGIP) High Est.	Net attributable Low Est.	Net attributable Best Est.	Net attributable High Est.	Risk Factor	Operator
Oil & Liquids Prospective Resources per asset From prospect to play	Lower Permeneer	Bass Highway	13.00	17.33	21.66	13.00	17.33	21.66	18.76%	Overseas Energy Holdings Limited
		Risked	2.44	3.25	4.06	2.44	3.25	4.06		
		Westbury	29.55	39.40	49.25	29.55	39.40	49.25	18.76%	
		Risked	5.54	7.39	9.24	5.54	7.39	9.24		
		Weymouth Road	34.73	46.30	57.88	34.73	46.30	57.88	18.76%	
		Risked	6.51	8.69	10.86	6.51	8.69	10.86		
		Batman Bridge	0.00	0.00	0.00	0.00	0.00	0.00	18.76%	
		Risked	0.00	0.00	0.00	0.00	0.00	0.00		
Total for Oil & Liquids			**77.27**	**103.03**	**128.79**	**77.27**	**103.03**	**128.79**		
Total Risked for Oil & Liquids			**14.50**	**19.33**	**24.16**	**14.50**	**19.33**	**24.16**		
(all figures in barrels)	Horizon	Geologic Object	**Gross (OGIP)** Low Est.	Best Est.	High Est.	**Net attributable** Low Est.	Best Est.	High Est.	**Risk Factor**	
Oil & Liquids Prospective Resources per asset From prospect to play	Liffey Sandstone	Bass Highway	9.88	13.17	16.46	9.88	13.17	16.46	18.76%	
		Risked	1.85	2.47	3.09	1.85	2.47	3.09		
		Westbury	19.50	26.00	32.50	19.50	26.00	32.50	18.76%	
		Risked	3.66	4.88	6.10	3.66	4.88	6.10		
		Weymouth Road	24.41	32.54	40.68	24.41	32.54	40.68	18.76%	
		Risked	4.58	6.10	7.63	4.58	6.10	7.63		
		Batman Bridge	3.92	5.23	6.54	3.92	5.23	6.54	18.76%	
		Risked	0.74	0.98	1.23	0.74	0.98	1.23		
Total for Oil & Liquids			**57.71**	**76.94**	**96.18**	**57.71**	**76.94**	**96.18**		
Total Risked for Oil & Liquids			**10.83**	**14.43**	**18.04**	**10.83**	**14.43**	**18.04**		
(all figures in barrels)	Horizon	Geologic Object	**Gross (OGIP)** Low Est.	Best Est.	High Est.	**Net attributable** Low Est.	Best Est.	High Est.	**Risk Factor**	
Oil & Liquids Prospective Resources per asset From prospect to play	Eldon Sandstone	Bass Highway	15.65	20.86	26.08	15.65	20.86	26.08	18.76%	
		Risked	2.94	3.91	4.89	2.94	3.91	4.89		
		Westbury	17.93	23.90	29.88	17.93	23.90	29.88	18.76%	
		Risked	3.36	4.48	5.60	3.36	4.48	5.60		
		Weymouth Road	12.00	16.00	20.00	12.00	16.00	20.00	18.76%	
		Risked	2.25	3.00	3.75	2.25	3.00	3.75		
		Batman Bridge	1.20	1.60	2.00	1.20	1.60	2.00	18.76%	
		Risked	0.23	0.30	0.38	0.23	0.30	0.38		
Total for Oil & Liquids			**46.77**	**62.36**	**77.95**	**46.77**	**62.36**	**77.95**		
Total Risked for Oil & Liquids			**8.77**	**11.70**	**14.62**	**8.77**	**11.70**	**14.62**		
(all figures in barrels)	Horizon	Geologic Object	**Gross (OGIP)** Low Est.	Best Est.	High Est.	**Net attributable** Low Est.	Best Est.	High Est.	**Risk Factor**	
Oil & Liquids Prospective Resources per asset From prospect to play	Gordon Limestone	Bass Highway	15.49	20.65	25.81	15.49	20.65	25.81	18.76%	
		Risked	2.91	3.87	4.84	2.91	3.87	4.84		
		Westbury	13.95	18.60	23.25	13.95	18.60	23.25	18.76%	
		Risked	2.62	3.49	4.36	2.62	3.49	4.36		
		Weymouth Road	7.95	10.60	13.25	7.95	10.60	13.25	18.76%	
		Risked	1.49	1.99	2.49	1.49	1.99	2.49		
		Batman Bridge	0.00	0.00	0.00	0.00	0.00	0.00	18.76%	
		Risked	0.00	0.00	0.00	0.00	0.00	0.00		
Total for Oil & Liquids			**37.39**	**49.85**	**62.31**	**37.39**	**49.85**	**62.31**		
Total Risked for Oil & Liquids			**7.01**	**9.35**	**11.69**	**7.01**	**9.35**	**11.69**		

Source: CAPD and MX Consulting Limited

Note: "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted

"Operator" is name of the company that operates the asset

"Gross" are 100% of the reserves and/or resources attributable to the licence whilst "Net attributable" are those attributable to the AIM company

bbls – Barrels

scf – Standard Cubic Feet

9.3 List of Disclosures as per London AIM

The CPR should cover (as a minimum) the following:

Executive summary

Table of contents

Introduction

- explanation of the sources of all information on which the CPR is based (for example any site visits (including details of who undertook such visit and when), drilling results, seismic data, reservoir or well data, sample analysis, interviews with directors, details of desktop research).
- description of reserves and/or resources, where applicable detailing characteristics, type, dimensions and grade distribution, and the methods to be employed for their exploration and extraction (including Appendix 9.1 disclosure).

Overview of the region, location and assets

- description of the applicant's assets and liabilities, the rights in relation to them and a description of the economic conditions for the working of those licences, concessions or similar including any environmental, land access, planning and obligatory closure costs.
- details of any interest (current or past) any director, CP or promoter has in any of the assets.
- appropriate maps, some background on the country and location plans demonstrating the major properties comprising the assets, their workings and geographical characteristics and wells, platforms, pipelines, bore holes, sample pits, trenches and similar, to the extent they exist .

Reserves & resources (separately disclosed)

- statement of reserves (if any), and where applicable resources including an estimate of volume, tonnage and grades, (in accordance with a Standard, which should be consistently applied and disclosed in line with the tables in Appendix 3), method of estimation, expected recovery and dilution factor, expected extraction and processing tonnage or volume, as appropriate, depending on whether the reserves and/or resources are of minerals or oil and/or gas. Where there are resources that have not been sufficiently appraised in order to provide the previous information, a separate statement of such resources together with any other quantified information which has been appraised in accordance with a Standard.
- estimate of net present value (post tax) at a discount rate of 10% of reserves (or equivalent depending on Standard used) analyzed separately and the principal assumptions (including cost assumptions, effective date, constant and or forecast prices, forex rates) on which valuation is based together with a sensitivities analysis. Additional valuations may be included within the CPR and should include an explanation of the basis of such a valuation and the method used.

Other assets

- any other assets material to the applicant.
- commentary on the plant and equipment which are or will be significant to the applicant's operations, bearing in mind any forecasted rates of extraction included within the admission document.

9.4 Definition of Terms Used

OIL FIELD ABBREVIATIONS

applicant	Shall have the meaning set out in the AIM Rules for Companies, however, for the avoidance of doubt, for the purposes of this Note it shall include all subsidiaries and interests of the applicant and shall also include a quoted applicant
assets	All assets, licences, joint ventures or other arrangements owned by the applicant or AIM company or proposed to be exploited or utilised by it
CP	Competent Person
CPR	Competent Person's Report
liabilities	All liabilities, royalty payments, contractual agreements and minimum funding requirements relating to the applicant or AIM company's work programme and assets
Professional association	Self-regulatory organisation of engineers and/or geoscientists
qualified person	Professionally qualified and a member in good standing of an appropriate recognised professional association and have at least five years relevant experience within the sector
reserves	Oil & Gas – Proved, Proved + Probable and Proved + Probable + Possible reserves except when referring to net present value calculations when reserves should only include Proved and Proved + Probable reserves
resource companies	Companies operating in the mining and oil & gas sectors which are admitted or are seeking admission to AIM
resource update	Any notification that contains a statement on reserves and/or resources
resources	Oil & Gas – Contingent and Prospective Resources
Russian	'Gosstandart' of Russia (GOST), the national Russian standard on mining and minerals as published by the National Certification Body of the Russian Federation. For data to be included under this standard it must have been approved by the Russian State or Federal body.
SPE	The Society of Petroleum Engineers
Standard	An Internationally recognised standard that is acceptable under the following codes and/or organisations: Mineral resources and reserves – CIM, IMMM, JORC, Russian, SAMREC and SME. Oil & Gas resources and reserves – CIM and SPE. Submissions can be made to AIM Regulation to consider other codes that may be comparable with any of the above
API	Standard of measuring specific gravity of fluid (oil) on an expanded scale by the American Petroleum Institute in degrees

BBL	Barrels of oil or natural gas liquids (one barrel is 34.972 Imperial gallons or 42 U.S. gallons)
BCF	One billion cubic feet
BOE	barrels of oil equivalent (6,000 cubic feet of natural gas being equivalent to one barrel of oil)
BOPD	barrels of oil per day
BWPD	barrels of water per day
DSU	drilling spacing unit
GCA	gas cost allowance
GOR	Gas-Oil ratio (standard cubic feet of solution gas per stock tank barrel of oil) in (scf/STB)
LPG	liquid petroleum gas
MBBLS	Thousand barrels
MCF	Thousands of cubic feet
Mm3	Thousands of cubic meters
MMCF	Millions of cubic feet
MCFD	thousands of cubic feet per day
MMCFD	Millions of cubic feet per day
MPR	maximum permissive rate
MRL	maximum rate limitation
MSTB	Thousand stock tank barrels
NCI	net carried interest
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
OGIP	original gas in place
ORRI	overriding royalty interest
PSU	production spacing unit
PVT	pressure-volume-temperature
UOCR	Unit Operating Cost Rates for operating gas cost allowance
WI	working interest
Note	*This AIM Note for Mining and Oil & Gas companies as may be amended and/or updated from time to time by the Exchange*

STANDARD OIL FIELD CONVERSION FACTORS

Unit	Multiplied by	Approximate Conversion Factor	Equals	Unit
barrels of oil (bbl)	X	42	=	US gallons (gal)
barrels of oil (bbl)	X	34.97	=	Imperial gallons (UK gal)
barrels of oil (bbl)	X	0.136	=	tonnes of oil equivalent (toe)
barrels of oil (bbl)	X	0.1589873	=	cubic metres (m3)
barrels of oil equivalent (boe)	X	5,658.53	=	cubic feet (f3) of natural gas
tonnes of oil equivalent (toe)	X	7.33 [1]	=	barrels of oil equivalent (boe)
cubic yards (y3)	X	0.764555	=	cubic metres (m3)
cubic feet (f3)	X	0.02831685	=	cubic metres (m3)
cubic feet (f3) of natural gas	X	0.0001767	=	barrels of oil equivalent (boe)
US gallons (gal)	X	0.0238095	=	barrels (bbl)
US gallons (gal)	X	3.785412	=	litres (l)
US gallons (gal)	X	0.8326394	=	Imperial gallons (UK gal)
Imperial gallons (UK gal)	X	1.201	=	US gallon (gal)
Imperial gallons (UK gal)	X	4.545	=	litres (l)
[1] This conversion can range from 6.5 to 7.9 depending on the type of crude oil.				

The barrel of oil equivalent (BOE) is a unit of energy based on the approximate energy released by burning one barrel (42 U.S. gallons) of crude oil. The US Internal Revenue Service defines it as equal to 5.8×10^6 BTU.[1]
5.8×10^6 $BTU_{59\,°F}$ equals 6.1178632×10^9 J or about 6.1 GJ.
A BOE is roughly 6000 cubic feet (170 cubic meters) of typical natural gas.
A commonly used multiple of the BOE is the kilo barrel of oil equivalent (kboe or kBOE), which is 1,000 times larger.
Other common multiples are the BBOe, (also BBOE), or billion barrel of oil equivalent, representing 10^9 barrels of oil, used to measure petroleum reserves, and million barrels per day, MMbd (or MMBD), used to measure daily production and consumption. Also used is the Mtoe, or Millions of tonnes of oil equivalent, a metric measurement equivalent to approximately 0.006841 BBOE.

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
miles (mi)	X	1.609344	=	kilometres (km)
yards (yd)	X	0.9144	=	meters (m)
feet (ft)	X	0.3048	=	meters (m)
inches (in)	X	2.54	=	centimetres (cm)
kilometre (km)	X	0.62137	=	miles (mi)

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
acres	X	0.40469	=	hectares (ha)
square miles (mi^2)	X	2.589988	=	square kilometres (km^2)
square yards (yd^2)	X	0.8361274	=	square meters (m^2)
square feet (ft^2)	X	0.09290304	=	square meters (m^2)
square inches (in^2)	X	6.4516	=	square centimetres (cm^2)

9.4 PRMS 2007

This report was prepared for the purpose of evaluating the Company's Natural Gas & Crude Oil resources according to Petroleum Resources Management System 2007 Handbook (PRMS 2007) reserve definitions and standards, which is consistent with 2007 SPE/WPC/AAPG/SPEE Reserves and Resources System. In accordance with these standards, and by reference in PRMS 2007, certain tables are presented for forecast prices and costs, which summarize the reserves and net present values, as of December 31, 2012.

Completed in 2007, the PRMS provides updated definitions and the related classification system for hydrocarbon reserves and resources that reflect advances in technology, the international expansion and the increasing role of unconventional resources in the industry. These updated definitions establish a universal language which can be used for estimating and classifying quantities of oil and gas discovered in a reservoir.

Forecast Prices and Costs

In this report Table 8 presents a summary of crude oil net present values of future net revenue after Australian taxes. Table 9 presents the estimated Capital and Operational expenses. Table 11 presents a forecast of crude oil pricing and inflation rate assumptions.

The four major recoverable resources classes defined by the PRMS 2007 are production, reserves, contingent resources, and prospective resources. There is also a distinct class for unrecoverable petroleum. These classes are shown on the vertical axis of the PRMS framework.

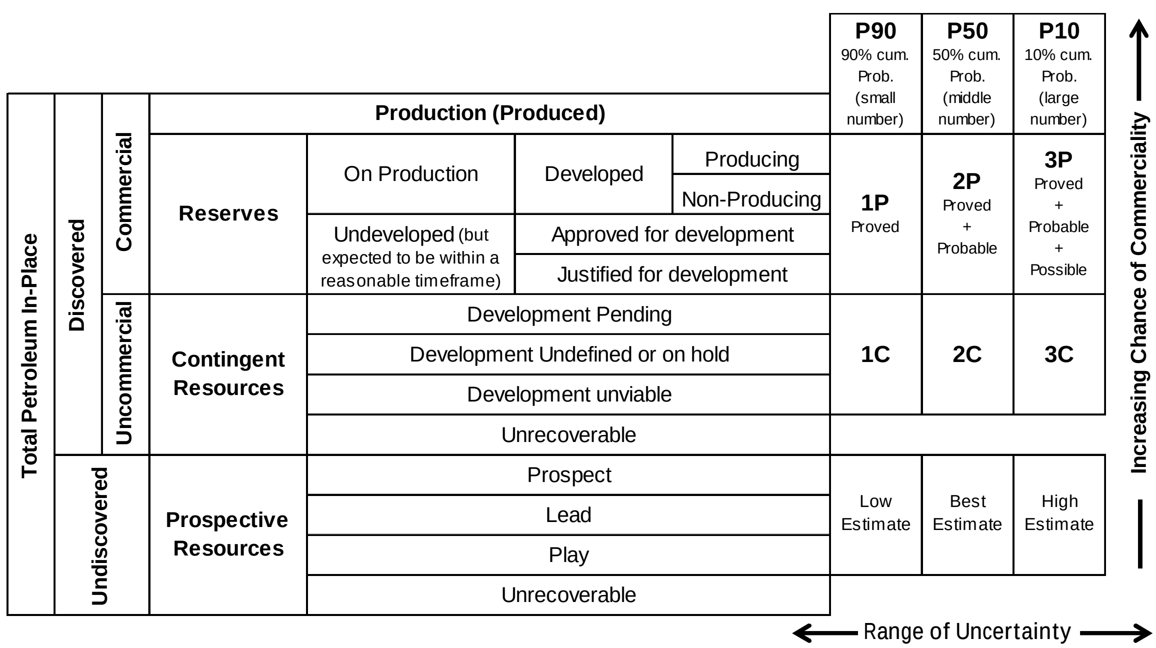


Figure 37 - PRMS 2007 Graphical Depiction

Production is the quantity of oil and natural gas that has been recovered already (by a specified date). This is primarily output from operations that has already been produced for use by consumers.

Reserves represent that part of resources which are commercially recoverable and have been justified for development, while contingent and prospective resources are less certain because some significant commercial or technical hurdle must be overcome prior to there being confidence in the eventual production of the volumes.

Contingent resources are less certain than reserves. These are resources that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles. For contingent resources to move into the reserves category, the key conditions, or contingencies, that prevented commercial development must be clarified and removed.

Prospective resources are estimated volumes associated with undiscovered accumulations. These represent quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have not yet been drilled.

Some petroleum will be classified as “unrecoverable” at this point in time, not being producible by any projects that the company may plan or foresee. While a portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur, some of the remaining portion may never be recovered due to physical or chemical constraints in the reservoir.

The volumes classified using the system represent the analysis of the day, and should be regularly reviewed and updated, as necessary, to reflect changing conditions. A project may have recoverable quantities in several resource classes simultaneously. As barriers to development are removed, some resources may move to a higher classification. One of the primary distinctions between resources and reserves is that while resources are technically recoverable, they may not be commercially viable. Reserves are always commercially viable and there is intent development them.

Within any resource class other than production, volumes are placed into different categories based on their certainty of eventually coming out of the ground. Decisions to upgrade volumes to any category within a class are generally based on the technical certainty of recovering the volumes. In this discussion, the focus is on the reserve class, as these volumes are commonly the focus of public discussions of oil and gas company producing assets.

The highest valued category of reserves is “proved” reserves. Proved reserves have a “reasonable certainty” of being recovered, which means a high degree of confidence (90%) that the volumes will be recovered. To be clear, reserves must have all commercial aspects addressed. It is technical issues which separate proved from unproved categories.

“Probable” or “possible” reserves are lower categories of reserves, commonly combined and referred to as “unproved reserves,” with decreasing levels of technical certainty. Probable reserves are volumes that are defined as “less likely to be recovered” than proved, but more certain (50%) to be recovered than Possible Reserves”. Possible reserves are reserves which analysis of geological and engineering data suggests are less likely (10%) to be recoverable than probable reserves.

The term 1P is frequently used to denote proved reserves, 2P is the sum of proved and probable reserves and 3P the sum of proved, probable and possible reserves. The best estimate of recovery from committed projects is generally considered to be the 2P sum of proved and probable reserves.

When summarizing these volumes, some key points must be kept in mind:

1) All oil and gas reserve and resource volumes are not the same, and should generally not be added together without taking into consideration the risk and uncertainty associated with each volume. Some volumes are clearly less certain and more risky than others. Whether the focus is only on reserves, or on the resource base as a whole (remember, reserves are a subset of resources!), expressing these volumes as one number may be misleading.

2) Risk and uncertainty are key but significantly different concepts. Risk is primarily associated with the classification of volumes and is a measure of the certainty of a project progressing to production. Uncertainty is the driver for categorization and is a measure of the technical factors impacting the volumes ultimate producibility.

NOTES: