

UNDISCOVERED RESERVES

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Chapter 11

INTRODUCTION

Estimating undiscovered petroleum reserves of the Otway Basin in South Australia provides a quantitative expression of the potential, and a basis for comparison with other basins. As the basin is probably more gas prone than oil prone, only undiscovered gas reserves are calculated, but oil discoveries are quite likely, as evidenced by the results of Sawpit 1 and Wynn 1.

As the basin is at an immature stage of exploration in South Australia, estimating undiscovered reserves using extrapolation of historical discovery trends, such as are commonly used overseas and in the Cooper Basin of South Australia, are not possible. Instead, a method has been developed that uses available geological data and Monte Carlo type statistical techniques to estimate, as a probability distribution, the undiscovered potential for each play (Morton, 1992).

No judgement is made that the potential reserves will be in fields large enough to be developed. Some of the results calculated for offshore South Australia would indicate that although potential gas-filled structures could occur, the fields would probably be uneconomic (e.g. the Troas discovery). For the Waarre play, CO₂ is considered a contaminant in this assessment but, if pure enough, may be a saleable product (e.g. Caroline Field).

Potential (undiscovered) 'reserves' should not be compared to traditional Proved, Probable and Possible reserves in known discoveries. Undiscovered reserves are calculated to give a quantitative indication of the potential of the basin, and require considerable exploration to establish their existence.

METHOD

For a commercial petroleum field to exist in the Otway Basin, four essential components are required:

- A mature 'source'; a rock unit that contains sufficient organic matter and which has been subjected to sufficient heat and pressure over time to have produced significant quantities of hydrocarbons, but not to have destroyed these through excessive heat and pressure.
- A 'reservoir' horizon; a rock unit that accumulates the generated oil or gas. A reservoir rock must be porous and have sufficient permeability to produce fluids economically.
- A 'seal' horizon; a rock unit that traps the petroleum in the reservoir and prevents further migration.

- A structure over the reservoir horizon that will concentrate the petroleum in economic quantities and that was present at the time of petroleum expulsion from the source rock. Usually this is an anticline, but stratigraphic traps can also be important.

When all four of these occur together, a petroleum 'play' or a potential target for exploration exists.

The method of estimating undiscovered reserves consists of identifying all of the 'plays' that may exist, either by discoveries made so far or by analysis of the available data (e.g. drillhole, geophysical, outcrop). The oil or gas potential for each play is then calculated by the following formula:

$$P_t = A_p * AB * FL * h * NG * FF * Por * S_h * FVF * SR * RS$$

P_t = Total potential recoverable reserves (oil or gas) of the play

A_p = Prospective area of the basin

FL = Fault leakage risk

AB = Anticline to total basin area ratio

h = Average gross reservoir thickness.

NG = Net to gross pay ratio

FF = Anticline fill factor

Por = Porosity (fraction)

S_h = Hydrocarbon saturation (1 - water saturation).

FVF = Formation volume factor

SR = Exploration drilling success ratio

RS = Recovery x shrinkage factors.

None of the above parameters is known with certainty, but most can be estimated from available data to within at least broad limits. The problem then arises as to how to multiply these factors together to produce an estimate of the petroleum potential of the 'play'. The most common method of combining and expressing the uncertainty associated with this type of equation is to use Monte Carlo simulation techniques (White and Gehman, 1979). A frequency distribution for each parameter is assumed, which is converted to a cumulative probability distribution, and a random number between 0 and 1 (corresponding to 0 to 100% probability) is used to sample each of the distributions; these are combined as in the equation above to give one estimate of the potential of the play. The process is repeated many times (in this case at least 1 000 times) to produce multiple estimates of the potential of each play. These are then used to produce a probability versus petroleum potential distribution for each play and for the basin as a whole. Because this is computationally intensive, the calculation is carried out by computer using a commercially available simulator ('RISK', a LOTUS 1-2-3 add in). This uses a more advanced stratified sampling technique called 'Latin Hypercube' that will converge in fewer iterations than with the traditional 'Monte Carlo' technique.

DISCUSSION OF PARAMETERS

Prospective area (A_p):

This is the area of the basin that is believed to contain the three essential components of source, reservoir and seal, and where the reservoir is at an economically drillable depth (assumed to be <4 500 m). This is the most critical factor in determining the potential of the basin but can be mapped with reasonable accuracy from available drillhole and seismic data; these maps are useful to potential explorers in assessing the relative prospectivity of different areas of a basin. It is

entered as a triangular distribution (minimum, most likely, maximum). Figures 11.1 and 11.2 summarise these for the Crayfish and Waarre plays, respectively.

Anticline to basin area ratio (AB):

This is the proportion of the prospective area that is within an anticlinal trap. It is extrapolated from detailed seismic maps of the particular reservoir horizon that are available for limited areas of the basin. Regional seismic maps are not adequate as they tend to map only the very large structures and result in very conservative estimates of the anticline to

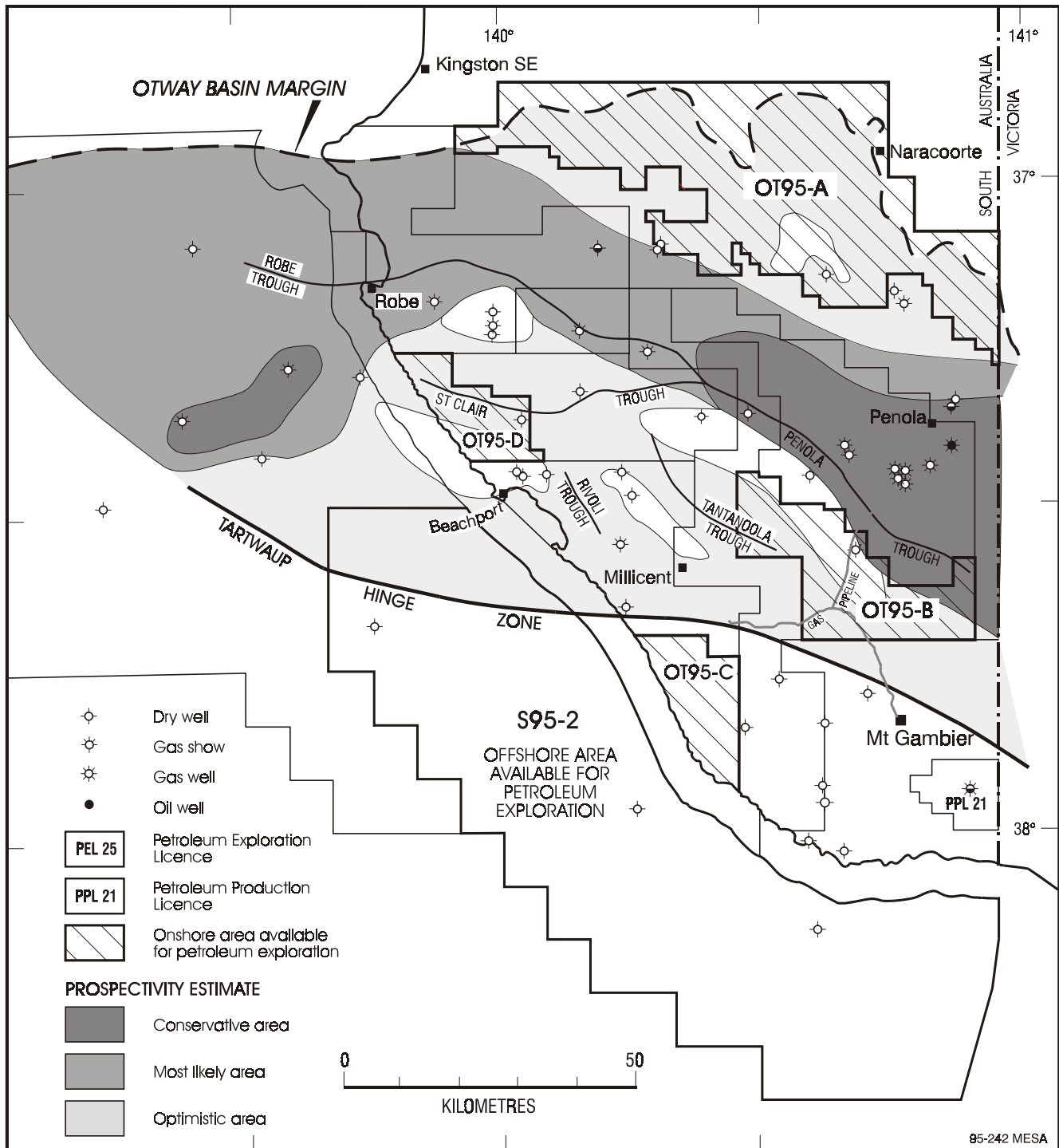


Fig. 11.1 Crayfish Group prospectivity, South Australia.

basin area ratio. In practice as many detailed maps as possible are used to gain an understanding of the range of possible values or, if none is available, substitutes are extrapolated from other producing horizons. This parameter is also entered as a triangular distribution.

Fault leakage risk (FL):

Recent drilling for Crayfish targets both on and offshore has indicated that post-migration fault leakage is a significant risk. Some structures appear to have been breached by

reactivation of faults in Tertiary to Recent time. The parameter is modelled as a triangular distribution. The risk is considered less for the Waarre play due to greater thickness of Tertiary shale units south of the Tartwaup Hingeline.

Maximum reservoir thickness (h):

This is the maximum reservoir thickness or the maximum anticline vertical closure, whichever is the lesser. In both the Waarre and Crayfish plays it is assumed that the anticline height is the lesser, and the reservoir is modelled as a cone

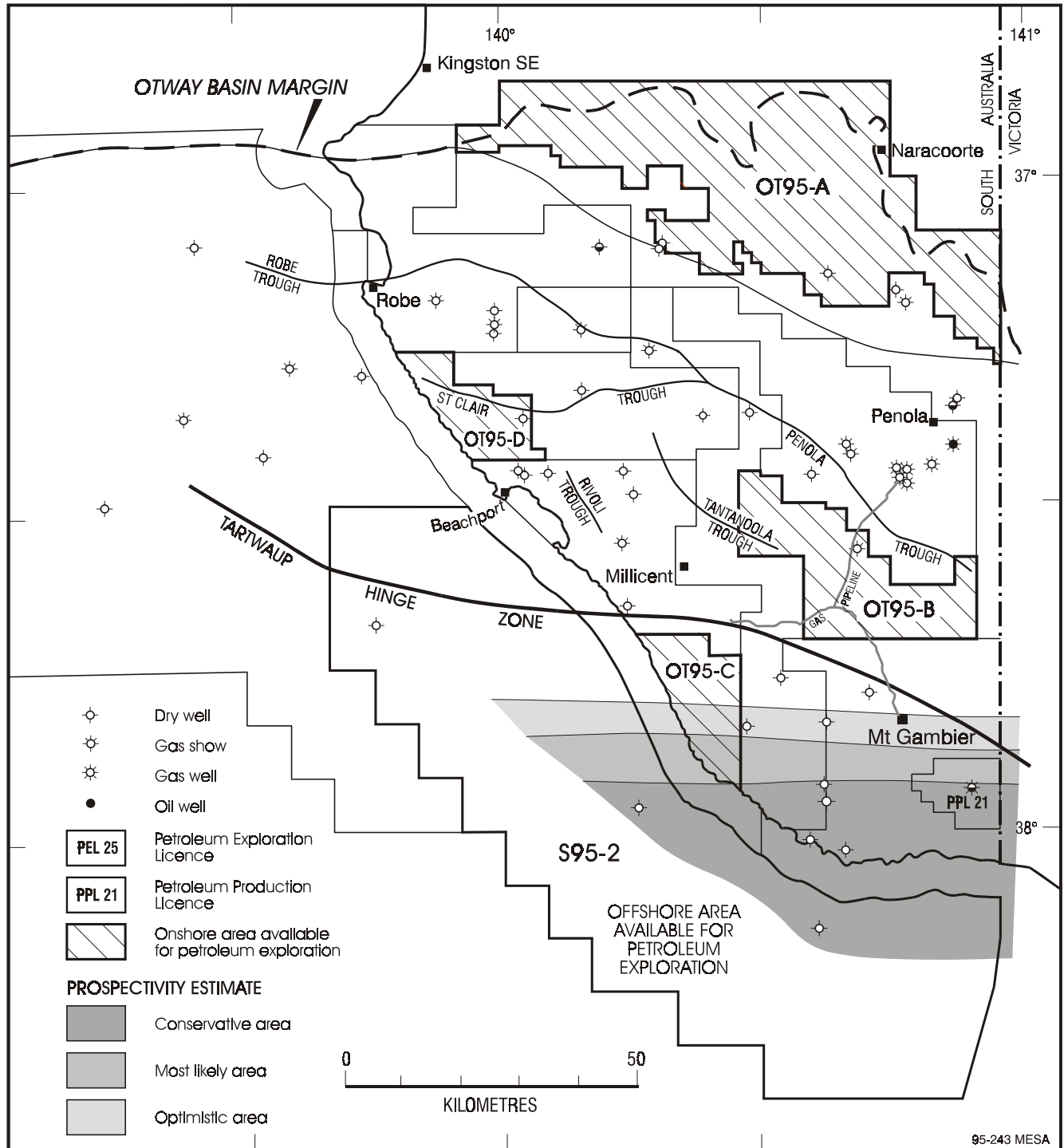


Fig. 11.2 Waarre Sandstone prospectivity, South Australia.

and 'h' is reduced to one-third (volume of a cone = $1/3 \times \text{area} \times \text{height}$). The parameter is modelled as a truncated lognormal distribution (mean, standard deviation, minimum, maximum).

Net to gross pay ratio (NG):

The net to gross ratio reduces the maximum reservoir thickness to the anticipated pay (permeable reservoir) thickness. This can be determined with good accuracy from existing well data. A truncated normal distribution is used.

Anticline fill factor (FF):

In oil or gas basins with commercial fields, anticlines can range from filled to spill to near 0% fill (0% = dry wells). The average fill is therefore less than one, and it is assumed that the richer the source rock the greater the average fill. This critical parameter is very subjective even when some fields have already been discovered due to the normally wide range of values found. Conservative estimates are made based on the relative richness of the source rocks compared to known producing basins, the estimated timing of anticline formation relative to petroleum generation, and the nature of the petroleum (the fill factor for gas will be greater than for oil). A triangular distribution is used.

Porosity (Por):

The average porosity of the reservoir can be reliably estimated from available well data. A triangular distribution is used.

Hydrocarbon saturation (S_h):

The average hydrocarbon saturation is partly dependent on the average porosity, and the two distributions are linked in the Monte Carlo simulator so that when a low value of porosity is chosen a low hydrocarbon saturation is also chosen. The range is determined from known porosity/hydrocarbon saturation relationships in discovered fields. A truncated normal distribution is generally used.

Formation volume factor (FVF):

The volume of gas in a reservoir increases when brought to the surface due to the drop in pressure, and oil decreases in volume due to loss of volatiles. The value for these factors is determined from existing fields in the basin or from other analogous basins with known fields at a similar depth to the potential plays.

Success ratio (SR):

The success ratio is an estimate of the proportion of exploration wells to be drilled that will find a field. Like the fill factor (FF), this ratio is related in part to the richness of the source rocks, but other factors such as the degree of structural complexity and quality of seismic data are also important. Values are estimated from recent drilling results, which are currently about 1 in 3 overall for the 1990s.

Recovery and shrinkage factors (RS):

The recovery factor converts petroleum in-place reserves to sales gas or recoverable oil, and is dependent on composition of the petroleum, depth of the reservoir and the degree of mobility of the underlying aquifer. Recovery factors range up to 85% for gas reservoirs with negligible water drives, to <60% for water-drive reservoirs. The shrinkage factor, which applies only to gas, reflects impurities that may be found in natural gas; in the Otway Basin this is commonly CO₂. CO₂ content is dependent on temperature and pressure in the reservoir and proximity to igneous rocks. A triangular distribution is used.

POTENTIAL PLAYS

There are two major plays that have potential for further discoveries.

CRAYFISH GROUP

Reservoir: sands of Pretty Hill Formation, Katnook Sandstone, Windermere Sandstone Member

Seal: Laira or Eumeralla Formation

Source: basal Pretty Hill, Casterton Formation

Summary of Monte Carlo input parameters:

	Minimum	Average	Maximum
Prospective area of the basin (km ²) - Offshore	223	2 986	4 265
Prospective area of the basin (km ²) - Onshore	1 349	3 174	7 633
Anticline to total basin area ratio	0.2	0.25	0.28
Fault leakage factor	0.4	0.75	0.95
Average gross reservoir thickness (m)	10	110	220
Net to gross pay ratio	0.1	0.35	1.0
Anticline fill factor	0.1	0.5	1.0
Porosity (fraction)	0.11	0.14	0.20
Water saturation	0.35	0.50	0.65
Formation volume factor (SCF/RCF)	150	211	250
Exploration drilling success ratio	0.1	0.33	0.66
Recovery x shrinkage factors	0.3	0.5	0.7

WAARRE AND FLAXMAN FORMATIONS

Reservoir: Waarre Formation, Flaxman Formation

Seal: Belfast Mudstone

Source: Eumeralla Formation, Crayfish Group

Summary of Monte Carlo input parameters:

	Minimum	Average	Maximum
Prospective area of the basin (km ²) - Offshore	962	1106	1 299
Prospective area of the basin (km ²) - Onshore	540	897	1 250
Anticline to total basin area ratio	0.2	0.25	0.28
Fault leakage factor	0.75	0.80	1.00
Average gross reservoir thickness (m)	10	70	200
Net to gross pay ratio	0.15	0.85	1.0
Anticline fill factor	0.1	0.5	1.0
Porosity (fraction)	0.11	0.14	0.15
Water saturation	0.20	0.35	0.65
Formation volume factor (SCF/RCF)	150	211	250
Exploration drilling success ratio	0.1	0.33	0.66
Recovery and shrinkage factors	0	0.5	0.7

These plays are in anticlines or faulted anticlines, but additional potential may exist in reservoirs of the basal Tertiary sequence, in isolated sands of the Belfast Mudstone and Eumeralla Formation, or in fractured basement. However, as these units have no mature source, their potential is possibly already included in the other plays.

The table below summarises the results of the assessment of the undiscovered potential (PJ) of the onshore basin at various probability levels.

Play	Probability that the ultimate potential will exceed the stated value		
	90%	50%	10%
WAARRE and FLAXMAN FORMATIONS			
Onshore	30	150	560
Offshore	40	210	680
Total	90	380	1 160
CRAYFISH GROUP			
Onshore	120	680	2 330
Offshore	70	400	1 340
Total	240	1 190	3 560
Total Onshore Otway	180	900	2 760
Total Offshore Otway	140	660	2 000
Total South Australian Otway	350	1 630	4 650