UNDISCOVERED RESOURCES

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Chapter 13

INTRODUCTION

Estimating undiscovered petroleum reserves of the Officer Basin in South Australia provides some quantitative expression of the potential, and a basis for comparison with other basins. As the basin is clearly oil prone, only undiscovered oil resources are calculated; however, gas discoveries may also be possible although it is unlikely that small gas discoveries would be economic.

As the Officer Basin has had only minimal exploration effort, with no economic discoveries so far, estimates of undiscovered resources are best carried out by a method 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, 1995, 1996b). This chapter presents a revised estimate of the undiscovered potential of the basin that reflects new knowledge of potential reservoirs and source rocks acquired since 1992.

In total, the average estimate of the potential of the Officer Basin plays in South Australia is ~400 million kilolitres (2.5 billion barrels) of recoverable oil. The increase from the 1992 estimate of ~300 million kilolitres is due mainly to the recognition of additional source rocks and reservoirs, particularly two new Neoproterozoic plays (Pindyin and Tarlina Sandstones), and the potential for stacked reservoirs in the Ouldburra Formation. These estimates may appear to be large in comparison to other, geologically younger, Australian petroleum basins, but are comparable to geologically more analogous (Proterozoic–Cambrian) petroleum provinces elsewhere in the world. The Lena–Tunguska province in the Siberian Platform has a predicted potential of 318 million kilolitres (2 billion barrels) of oil and gas liquids, with 2417 billion cubic metres (85 trillion cubic feet) of gas (Meyerhoff, 1982), the Moscow Basin has a potential of 2353 million kilolitres (16 billion barrels) of liquid hydrocarbons (V. Gorbachev, NEDRA, pers. comm., 1997) and, from geochemical evidence in oils from Oman, Proterozoic sediments are now believed to be a very significant source for the prolific oil and gas fields of the entire Persian Gulf area (Edgell, 1991). The proven oil reserves in Oman alone are 795 million kilolitres (nearly 5 billion barrels; Feld, 1997).

Potential (undiscovered) 'resources' should not be compared to traditional Proved, Probable and Possible reserves in known discoveries. Undiscovered resources 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 eastern Officer 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 them 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 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. This is usually an anticline, but stratigraphic traps can also be important, e.g. the Ouldburra Formation.

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

The method of estimating undiscovered resources 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, or outcrop). The oil potential for each play is then calculated using the following formula:

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

Where:

P_t	Total potential recoverable oil reserves of the play
A_p	Prospective area of the basin
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
RF	Recovery factor.

None of the above parameters is known with certainty but most can be estimated from available data to within at least broad limits. 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 1000 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 Microsoft EXCEL spreadsheet 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 <4500 m). This is a critical factor in determining the potential of the basin but can be mapped with reasonable accuracy from the available drillhole, source rock and regional depth to basement seismic mapping data (Lindsay, 1995). It is entered as a uniform distribution (equal probability between minimum and maximum limits). Maps for each play, taking into account distribution of source, seal and reservoir, are shown on Figures 13.1 to 13.4.

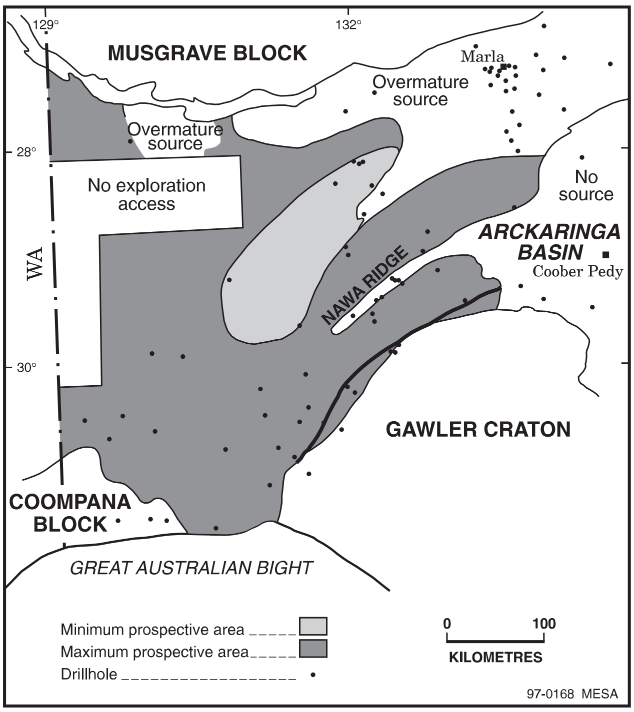

Fig. 13.1 *Pindyin, Tarlina Sandstone and Murnaroo Formation prospectivity, Officer Basin.*

Anticline to basin area ratio (AB)

This is the proportion of the prospective area that is within an anticlinal trap. It was extrapolated from seismic structure mapping in the Marla and Munta areas (Mackie and Gravestock, 1993; Mackie, 1994). The top crystalline basement depth horizon was used for the Pindyin, Tarlina and Murnaroo plays, and the basal Cambrian depth horizon for the Relief, Ouldburra and Arcoeillinna plays. Although the seismic coverage in this area is the best available in the Officer Basin, it is still poor compared to that required to

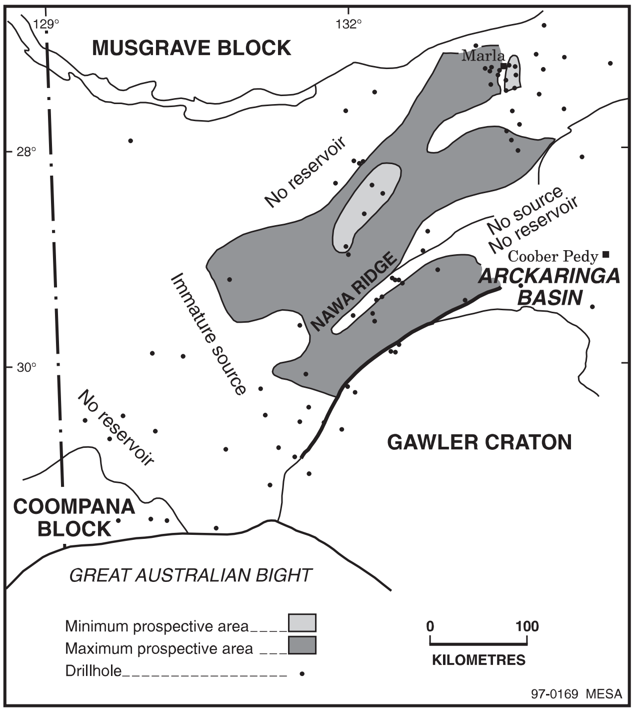

Fig. 13.2 *Relief Sandstone prospectivity, Officer Basin.*

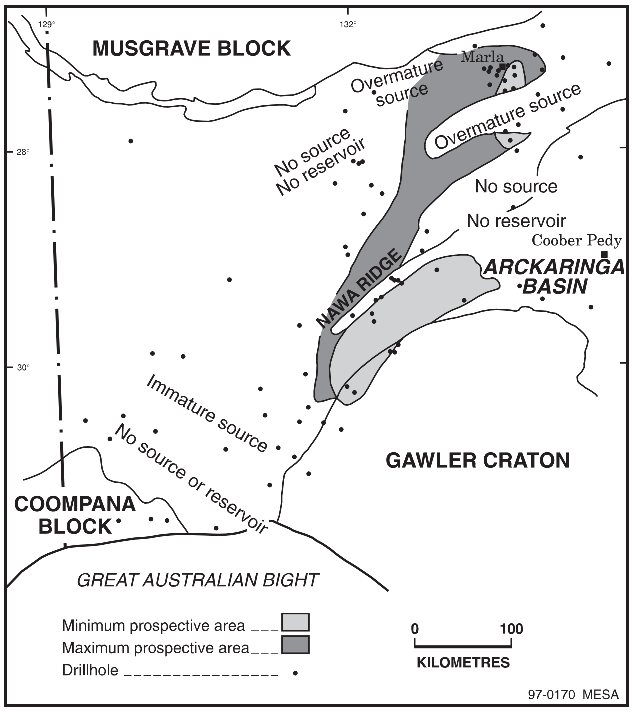

Fig. 13.3 *Ouldburra Formation prospectivity, Officer Basin.*

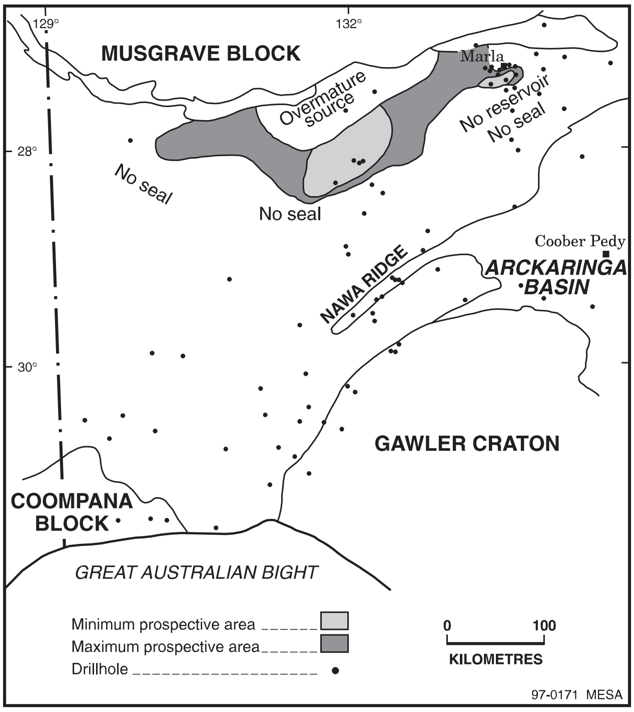

Fig. 13.4 *Arcoeillinna Sandstone prospectivity, Officer Basin.*

identify all of the smaller prospects, and may not be typical of trap styles elsewhere in the basin, hence the values used in this assessment may be conservative. This parameter is entered as a truncated lognormal distribution.

Gross reservoir thickness (h)

This is the maximum vertical closure of the trap. All reservoirs are modelled as a cone ('h' is reduced to one-third the volume of a cone = 1/3 x area x height) with the exception of the Ouldburra reservoirs, which are modelled as a slab and 'h' is not reduced. The parameter is modelled as a truncated lognormal distribution.

Net to gross pay ratio (NG)

The net to gross ratio reduces the maximum reservoir thickness to the anticipated pay (permeable reservoir) thickness. This has been estimated using core 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 subjective and has been assumed to average 50% for the Officer Basin, although it would be expected to be greater for plays with rich source potential. A triangular distribution is used.

Porosity (Por)

The average porosity of the reservoir was estimated from available routine core analysis data (Ch. 10). A truncated normal distribution is used.

Hydrocarbon saturation (S_h)

The average hydrocarbon saturation is partly dependent on the average porosity and the pay thickness, and the distributions are linked in the Monte Carlo simulator so that when a low value of porosity and/or pay thickness is chosen a low hydrocarbon saturation is also chosen. The range has been determined from capillary pressure data from the Murnaroo Formation, but modified for the better permeability reservoirs. A truncated normal distribution is used.

Formation volume factor (FVF)

The volume of oil in a reservoir decreases when brought to the surface due to the drop in pressure, and consequent loss of volatiles. The value for this factor was estimated from Eromanga Basin data (Morton, 1996b).

Success ratio (SR)

This is an estimate of the proportion of prospects to be drilled that will contain oil (i.e. the drilling success ratio). Like the fill factor (FF) above, this ratio is related in part to the richness of the source rocks, but other factors such as the degree of structural complexity, trap integrity and quality of seismic data are also important. A value was estimated from Australian and world average drilling results, and a truncated normal distribution is used.

Recovery factor (RF)

The recovery factor converts petroleum in-place reserves to recoverable oil, and is mostly dependent on the degree of mobility of the underlying aquifer and height of the oil column. Estimates were derived from averages in the Cooper Basin. A truncated normal distribution is used.

POTENTIAL PLAYS

There are six major plays that have potential for discoveries:

1. Pindyin Sandstone

Reservoir: Pindyin Sandstone. **Seal:** Alinya Formation.
Source: overlying Alinya Formation or the underlying, undrilled, possibly pre-Adelaidean sequence.

Summary of Monte Carlo input parameters:

	Minimum	*Mean*	*Maximum*
Prospective area of the basin (km^2)	15 620	65 874	116 070
Anticline to total basin area ratio	0.02	0.06	0.15
Average gross reservoir thickness (m)	13	69	192
Net to gross pay ratio	0.30	0.60	0.91
Anticline fill factor	0.01	0.5	0.99
Porosity (fraction)	0.10	0.12	0.14
Water saturation	0.2	0.3	0.45
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.04	0.10	0.17
Recovery factor	0.18	0.25	0.32

2. Tarlina Sandstone

Reservoir: Tarlina Sandstone. **Seal:** Meramangye Formation.
Source: Alinya Formation

Summary of Monte Carlo input parameters:

	Minimum	*Mean*	*Maximum*
Prospective area of the basin (km^2)	15 667	65 874	116 108
Anticline to total basin area ratio	0.02	0.06	0.17
Average gross reservoir thickness (m)	17	69	194
Net to gross pay ratio	0.30	0.55	0.84
Anticline fill factor	0	0.5	0.99
Porosity (fraction)	0.13	0.15	0.17
Water saturation	0.35	0.41	0.50
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.04	0.10	0.18
Recovery factor	0.01	0.18	0.30

3. Murnaroo Formation

Reservoir: Murnaroo Formation sand. **Seal:** Dey Dey Mudstone.
Source: Alinya Formation and Dey Dey Mudstone

Summary of Monte Carlo input parameters:

	Minimum	*Mean*	*Maximum*
Prospective area of the basin (km^2)	15 696	65 874	116 059
Anticline to total basin area ratio	0.02	0.06	0.16
Average gross reservoir thickness (m)	14	69	194
Net to gross pay ratio	0.55	0.87	1.00
Anticline fill factor	0.01	0.5	0.98
Porosity (fraction)	0.13	0.15	0.18
Water saturation	0.25	0.35	0.45
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.03	0.10	0.17
Recovery factor	0.18	0.25	0.32

4. Relief Sandstone

Reservoir: Relief Sandstone. **Seal:** Ouldburra Formation or Observatory Hill Formation.
Source: Alinya Formation (as shown from oil extracts), Dey Dey Mudstone, Karlaya Limestone, Ouldburra Formation and Observatory Hill Formation.

Summary of Monte Carlo input parameters:

	Minimum	*Mean*	*Maximum*
Prospective area of the basin (km^2)	3459	25 711	47 963
Anticline to total basin area ratio	0.01	0.05	0.16
Average gross reservoir thickness (m)	15	69	195
Net to gross pay ratio	0.28	0.60	0.94
Anticline fill factor	0.02	0.5	0.98
Porosity (fraction)	0.09	0.18	0.25
Water saturation	0.15	0.25	0.44
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.04	0.11	0.16
Recovery factor	0.18	0.25	0.32

5. Ouldburra Formation

Reservoir: Ouldburra Formation sand. **Seal:** intra-Ouldburra Formation shale and micrite.
Source: Ouldburra Formation, with possible contribution from Dey Dey Mudstone, Karlaya Limestone.

Summary of Monte Carlo input parameters:

	Minimum	*Mean*	*Maximum*
Prospective area of the basin (km^2)	10 860	19 626	28 389
Anticline to total basin area ratio	0.01	0.05	0.21
Average gross reservoir thickness (m)	45	99	171
Net to gross pay ratio	0.25	0.35	0.64
Anticline fill factor	0.01	0.50	0.98
Porosity (fraction)	0.12	0.14	0.16
Water saturation	0.20	0.30	0.40
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.03	0.10	0.17
Recovery factor	0.01	0.18	0.3

6. Arcoeillinna Sandstone

Reservoir: Arcoeillinna Sandstone. **Seal:** Apamurra Formation.
Source: Observatory Hill Formation and Ouldburra Formation.

Summary of Monte Carlo input parameters:

	Minimum	*Mean*	*Maximum*
Prospective area of the basin (km^2)	5387	13 134	20 893
Anticline to total basin area ratio	0.01	0.05	0.16
Average gross reservoir thickness (m)	25	50	92
Net to gross pay ratio	0.31	0.65	0.96
Anticline fill factor	0.02	0.5	0.99
Porosity (fraction)	0.16	0.175	0.19
Water saturation	0.25	0.35	0.50
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.03	0.10	0.17
Recovery factor	0.01	0.18	0.3

Additional potential may exist in carbonate reservoirs of the Ouldburra Formation (Kamali *et al.*, 1995b), and sand of the Tanana and Narana Formations. The Trainor Hill and Mount Chandler Sandstones (sealed by Indulkana Shale) are also a possible play, but seal and source are significant risks.

The table below summarises the assessment of the undiscovered recoverable oil potential of the Officer Basin in South Australia at various probability levels.

Play	**Probability that the ultimate potential will exceed the stated value** million kilolitres (million barrels)					
	90%		**50%**		**10%**	
Arcoeillinna	3.3	(20.6)	10.8	(68.1)	27.8	(174.9)
Ouldburra	29.4	(185.1)	85.1	(535.5)	209.9	(1320.4)
Relief	6.3	(39.8)	30.3	(190.7)	95.0	(597.8)
Murnaroo	21.7	(136.7)	69.1	(434.6)	210.4	(1323.7)
Tarlina	18.6	(117.2)	63.7	(400.6)	186.1	(1170.7)
Pindyin	18.0	(113.2)	62.6	(394.1)	172.9	(1087.4)
Total	**236.4**	**(1486.9)**	**399.0**	**(2510.0)**	**674.0**	**(4239.6)**