UNDERSTANDING AUSTRALIA'S PETROLEUM RESOURCES, FUTURE PRODUCTION TRENDS AND THE ROLE OF THE FRONTIERS

T.G. Powell
Australian Geological Survey Organisation
GPO Box 378
Canberra ACT 2601
trevor.powell@agso.gov.au

ABSTRACT

Relative to its needs over the last 30 years, Australia has enjoyed a high level of self-sufficiency. Whilst the overall remaining reserves of oil have been relatively constant, reserves of condensate have grown substantially as major reserves of natural gas have been added to Australia's resource inventory. Oil and condensate reserves stand at 3.43 billion barrels (505 GL), of which 50% is condensate in gas fields. Australia's undiscovered oil potential in its major offshore hydrocarbon producing basins has been upgraded to an indicative 5 billion barrels (800 GL) at the average expectation, following evaluation of the assessment results for Australia in the authoritative worldwide assessment of undiscovered potential by the US Geological Survey.

Current reserves, however, are insufficient to sustain present levels of production in the medium term. Estimates of future production of oil and condensate suggest that at the mean expectation, production rates will drop by around 33% by 2005 and 50% by 2010, largely as a result of a decline in oil production. This forecast includes production from fields that have not yet been discovered. Condensate production will continue to grow, but the rate of growth is constrained by gas production rates and overall by the development timetable for the major gas fields.

The rate of discovery of new oil fields is insufficient to replace the oil reserves that are being produced. If Australia is to maximise the opportunity to maintain production at similar levels to the recent past, it is probable that exploration effort will have to diversify to the frontier basins to locate a new oil province whilst continuing to explore the full potential of the known hydrocarbon-bearing basins. Australia still has a remarkable number of basins which have received little or no exploration. Whilst there is no substitute for a discovery to stimulate exploration in poorly known areas, demonstrating that petroleum has been generated and migrated is the key to attracting continued exploration interest.

KEYWORDS

Australian petroleum reserves, undiscovered resources, production forecasts, discovery rates.

INTRODUCTION

In recent years there has been considerable debate as to how long the world's oil supplies will last (Campbell, 1995; Campbell and Laherrere, 1998). This issue has been prominent in the popular media, given the recent surge in the price of crude oil and its key role in the world economy. Several estimates show that oil production will peak in the next 10 years (Laherrere, 1997; Ivanhoe, 1997, Duncan and Youngquist, 1998). Other estimates push the date out to beyond 2020, or even to the mid-century, depending on the certainty of the resource estimates and the assumed demand (Energy Information Administration, 2000). Given these scenarios, it is important from a national policy perspective to understand Australia's domestic position in liquid hydrocarbon (oil and condensate) production.

During the last 30 years Australia has enjoyed a high level of oil self-sufficiency. This has been mainly due to the large oil fields discovered in the Gippsland Basin, Bass Strait in the 1960s followed by the discovery of numerous smaller fields in the Carnarvon Basin, North West Shelf and in the Bonaparte Basin, Timor Sea (Fig.1) in the 1980s and 1990s. As Bradshaw et al (1999) have pointed out, the basins that sustain current production were all found to be hydrocarbon-bearing by 1972. The history of hydrocarbon exploration over the last 30 years has been predominantly one of exploring the full potential of these basins. There remain many Australian basins that to date have received minimal exploration (Fig. 1).

Australia's reserves of natural gas have grown significantly as a result of further discoveries in northwestern Australia in the last 10 years. Australia's natural gas reserves represent a large strategic national resource, the development of which is dependent on the competitive global market and the economics of LNG exports and domestic gas markets.

The Commonwealth Government has maintained statistics on petroleum reserves and production since the inception of the Australian petroleum industry. Assessments of undiscovered petroleum resources commenced in the early 80s following the OPEC oil shocks. Initially, both these responsibilities fell to the Bureau of Mineral Resources Geology and Geophysics (BMR) but in 1992 were transferred to the newly formed Bureau of Resource Sciences (BRS). In 1998 they were transferred back to the BMR successor organisation, the Australian Geological Survey Organisation (AGSO). Estimates of reserves and undiscovered potential, production forecasts and statistics on the industry have been published in the annual series Oil and Gas Resources of Australia,

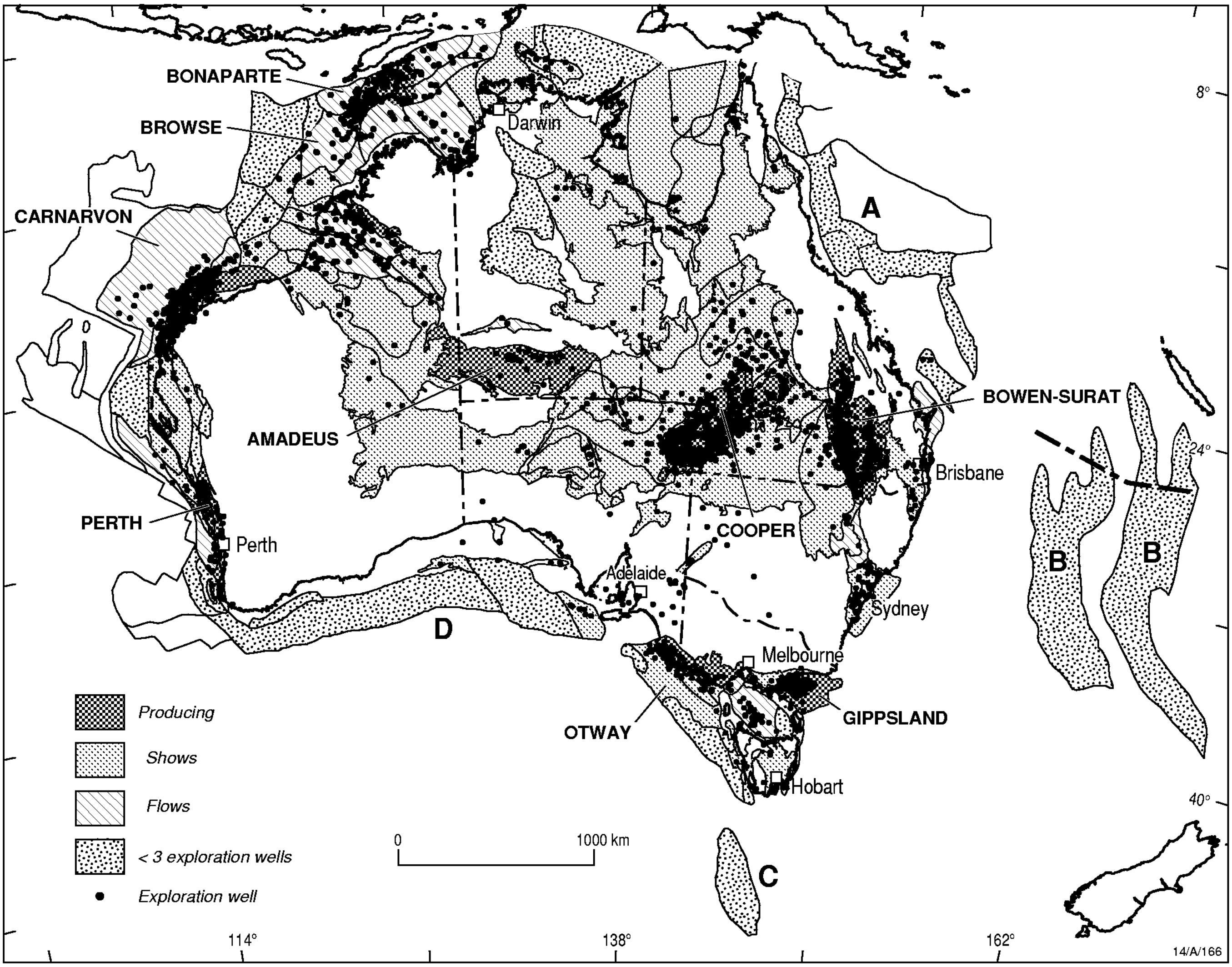

Figure 1. Map of the exploration maturity of Australian basins showing producing basins, those with flows and shows and unexplored areas. A—Northeast Queensland Basins—Capricorn, Papuan, Queensland and Townsville; B—Area with sediments thicker than 2,000 m on and adjacent to the Lord Howe Rise (Stagg et al, 1999); C—Area of the Ninene Basin with sediments estimated at thicker than 2,000 m, South Tasman Rise (Exon et al, 1997); D—Southern Margin Basins.

(BMR, 1991; BRS, 1993, 1994, 1996, 1997; AGSO, 1999, 2000a). The forecasts have been used by the Australian Bureau of Agricultural and Resource Economics in their annual 'Outlook' conferences (e.g. ABARE, 2000).

This paper addresses the current understanding of Australia's petroleum resources and levels of production, with particular emphasis on future indigenous supply of oil and condensate in Australia. It draws on the reserves, resources, production and exploration statistics on the petroleum exploration and development industry that are published or are available to AGSO. These are considered in the context of the potential to discover additional oil reserves in Australia, the significance of estimates of undiscovered petroleum potential, and with special reference to the need to diversify exploration effort into areas that are now considered to be frontiers.

The paper attempts to provide a response to the following.

- What is the current status and distribution of Australia's petroleum resources and their capacity to sustain oil and condensate production?
- How good is the information upon which assessments of Australia's undiscovered potential are based?
- What is Australia's potential for further oil discoveries?
- What are the requirements of a balanced exploration strategy from the national viewpoint and in particular the role of the frontiers?

CONCEPTUAL FRAMEWORK

In any discussion of resources it is essential to set the conceptual framework to avoid confusion. This framework is necessarily broader than the proven and probable reserves used by the industry since it incorporates components of the resource base which are as yet undiscovered. The framework can be represented in a modified McKelvey diagram (Fig. 2) (BMR, 1984). This diagram uses scales of increasing geological certainty and increasing economic feasibility to separate various categories of reserves from the resource base, whilst acknowledging that the boundaries are loosely defined.

Petroleum resources can be divided into 'identified' and 'undiscovered' resources. As geological knowledge improves and exploration is successful, resources move from the undiscovered to the identified category. Identified resources can be sub-divided into 'commercial reserves', which are being exploited or for which firm plans for production exist, and 'non-commercial' reserves. Within the reserves category, there remains considerable uncertainty as to the absolute size of the reserves because of a variety of economic and technical factors and, hence, reserves are divided into 'proved', 'probable' and 'possible' categories. As economic conditions or technologies improve, reserves can move from the non-commercial to the commercial category, e.g. as markets for gas become available. Collectively the commercial reserves and that component of non-commercial reserves which is considered to be economically producible, are known as 'economic demonstrated resources.'

Geoscientists can identify where undiscovered fields might occur and then give an informed opinion about how many of these fields might exist and their possible sizes. These represent the undiscovered resources which we have the potential to discover and exploit with current techniques.

Even though ultimate resource potential is often discussed, in practice it is very difficult to estimate. We can predict a discoverable portion using well-supported hypotheses—typically where petroleum generation and migration has been demonstrated to have occurred. There is an additional, discoverable portion that can be defined using poorly supported speculations such as in frontier basins. These make up the 'hypothetical' and 'speculative' categories respectively. Undiscovered resources may not exist in nature. Estimates of undiscovered resources exist only at a stated probability level along with the specified assumptions. They are not part of a resource inventory until they are identified and demonstrated by drilling.

There is an additional 'unknown' potential, which cannot be defined because the geological circumstances for occurrence are not known from any existing data. It becomes possible to add resources to the speculative category from this area of unknown potential as geological knowledge and research, sometimes driven by technological development, adds to the geological knowledge of poorly known areas.

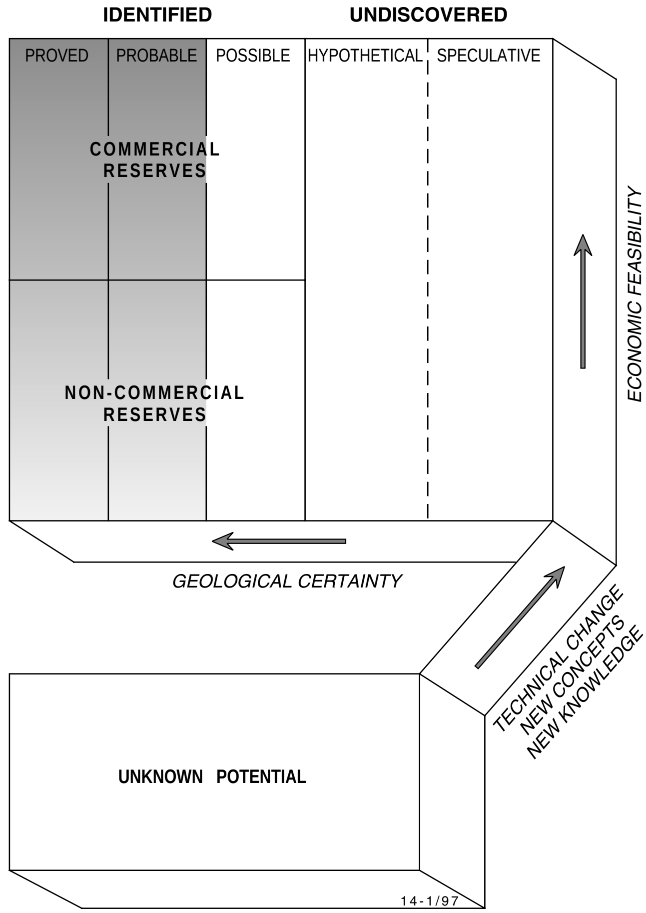

Figure 2. Modified McKelvey diagram showing conceptual framework for identified, undiscovered and unknown resources.

Australia's future oil supply will therefore come from Identified Resources comprising:

- established reserves in the proven and probable categories in known fields.
- incremental additions to reserves from the possible commercialisation category in known fields.

Undiscovered Resources in the Hypothetical Category to be discovered in:

- new fields belonging to plays containing known fields in established oil provinces
- new fields representing new plays in known oil provinces or extensions of known provinces, e.g. in deep water.

Undiscovered Resources in the Speculative Category to be discovered in new fields in as-yet-unproven oil provinces.

It is within this framework that Australian resources will be discussed.

AUSTRALIA'S IDENTIFIED PETROLEUM RESOURCES

Australia's proven and probable oil reserves grew rapidly in the late 1960s following discovery of the fields in Bass Strait, declined slightly in the 1970s and have subsequently fluctuated in the range 1.5 to 2 billion barrels (238 GL to 318 GL) (Fig. 3). The latest published reserves stand at 1.772 billion barrels (281 GL) of which 1.674 billion barrels (266 GL) are considered to be economic demonstrated resources (AGSO, 2000a). Australia's remaining reserves of oil have stayed relatively constant as production has been replaced by new discoveries and by growth in reserves from existing fields. Historically, it is the latter that has been the most important source of new reserves in Australia (Powell et al, 1990).

In contrast, Australia's reserves of condensate and natural gas have grown dramatically, reflecting the success in identifying and delineating gas discoveries (Fig. 3) (AGSO, 2000a). Condensate now represents 50 per cent of all of Australia's liquid hydrocarbon reserves, with total reserves standing at 1.758 billion barrels (279 GL) of which 1.209 billion barrels (192 GL) are considered to be in the economic category.

Overall, Australia's economic reserves of liquid hydrocarbons represented by both oil and condensate currently stand at a historic high point of 2.983 billion barrels (474 GL). However, as discussed in this paper, the capacity of these reserves to sustain current rates of production into the medium term is questionable.

AUSTRALIA'S UNDISCOVERED PETROLEUM POTENTIAL

Methods

The undiscovered resource potential of a region is a quantitative assessment of the potential to discover a stated level of new reserves if exploration were to take place in the region. In contrast to assessment of identified resources, there are no universally accepted methods of assessing undiscovered resource potential (Miller, 1986). An undiscovered resource assessment only has validity in the context of the method used and the purposes for which the assessment is required.

The concept of undiscovered oil potential relates to the qualitative or quantitative opinion of geoscientists on the chances of finding a commercial petroleum field in a given area. To be useful for planning, the opinion should address the following questions:

- How large is the resource and where is it located?
- In what size fields does it exist?
- How certain are we of these opinions?

Precise information can be obtained only after a resource is depleted. In the early stages of exploration there is enormous uncertainty, but even then conceptually finite limits can be set on the possible range of answers, although in practice this is difficult to achieve. As exploration proceeds and knowledge accrues, the range will narrow, rapidly at first and then more slowly. Because absolute answers are not attainable, they must be estimated indirectly, using whatever information is available. Decisions under uncertainty are inescapable. The important thing is to quantify the uncertainty and make it explicit. It is also clear that resource assessments are dynamic and will change as knowledge improves and uncertainties are resolved.

Assessments of the resource potential of prospects, plays and regions, and the accompanying risk analyses are carried out widely in the industry as part of the process of area selection and the identification of targets for drilling (Bradshaw et al, 1998). Such analyses are used to generate a portfolio of exploration opportunities appropriate to a particular company's commercial objectives. These techniques are, therefore, used in the context of commercial decision-making; they are relative and within a company they can have internal consistency and meaning. These numerical assessments of petroleum potential are produced in the form of probability distributions of petroleum resources. They integrate the current state of knowledge, together with objective and subjective opinions as to the favourability of petroleum occurrence using computer modelling.

When assessment processes are applied to form a national resource assessment, a further degree of uncertainty is introduced to the meaning of the assessment, because it is frequently not clear as to the purpose for which the numbers are generated. It is common for statistics for countries to be compiled and compared as to their ultimate resource potential (Campbell, 1995). Such compilations are frequently incomplete and do not clearly spell out the underlying assumptions, are often used out of context, and perhaps influence opinion in a way that is not intended.

Ideally, the undiscovered resource potential of a country represents a documented opinion as to the likelihood of predicted amounts of petroleum resources existing in particular sets of geological circumstances at specified levels of probability and with the associated assumptions explicitly stated.

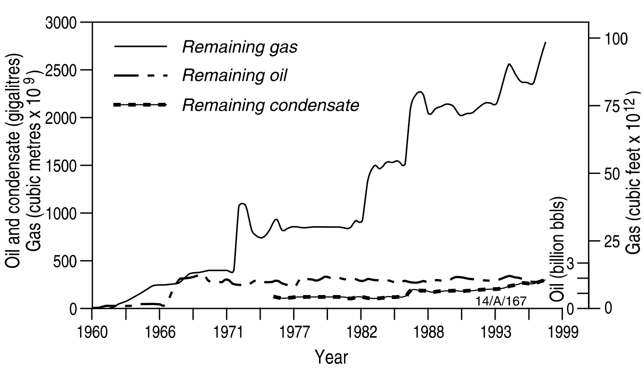

Figure 3. Australia's reserves of oil gas and condensate through time.

Table 1. Comparison of estimates of hypothetical petroleum resources for Australia's principal offshore hydrocarbon-bearing basins obtained by different methods (BRS, 1998; USGS 2000). P-95%, P- Mean and P-5% denote the probability of the resources exceeding the stated value. The USGS assessment is the preferred indicative estimate of ultimate resource potential for these basins.

	Oil ($\times 10^6$ Barrels; Gigalitres)					
Basin	**P-95%**		**P-Mean**		**P-5%**	
Bonaparte (BRS)	182	29	491	78	1195	190
Bonaparte (USGS)	383	61	1286	205	2605	414
Browse (BRS)	40	6	342	54	1079	172
Browse (USGS)	229	36	1055	168	2606	414
Carnarvon (BRS)	252	40	585	93	1101	175
Carnarvon (USGS)	862	137	2380	378	4052	644
Gippsland (BRS)	94	15	189	30	302	488
Gippsland (USGS)	103	16	309	49	583	98
Total (USGS)	**1577**	**251**	**5030**	**800**	**9846**	**1565**

	Gas ($\times 10^{12}$ Cubic feet; 10^9 Cubic Metres)					
Basin	**P-95%**		**P-Mean**		**P-5%**	
Bonaparte (BRS)	0.81	23	2.01	57	4.70	133
Bonaparte (USGS)	5.71	162	23.49	665	49.49	1401
Browse (BRS)	0.58	17	2.98	85	6.39	181
Browse (USGS)	4.85	137	20.09	569	45.66	1293
Carnarvon (BRS)	7.42	210	21.19	600	43.79	1240
Carnarvon (USGS)	21.62	612	64.71	1832	121.07	3428
Gippsland (BRS)	0.35	10	0.71	20	1.27	36
Gippsland (USGS)	1.24	35	5.66	160	12.12	343
Total (USGS)	**33**	**946**	**114**	**3227**	**228**	**6466**

	Condensate ($\times 10^6$ Barrels; Gigalitres)					
Basin	**P-95%**		**P-Mean**		**P-5%**	
Bonaparte (BRS)						
Bonaparte (USGS)	245	39	1080	172	2395	381
Browse (BRS)						
Browse (USGS)	211	34	934	148	2205	351
Carnarvon (BRS)						
Carnarvon (USGS)	1215	193	3682	585	6523	1037
Gippsland (BRS)						
Gippsland (USGS)	72	11	339	54	747	119
Total (USGS)	**1743**	**277**	**6035**	**959**	**11870**	**1887**

Hypothetical resources

Table 1 gives published assessments of undiscovered petroleum potential in Australia's principal hydrocarbon-bearing basins in the offshore. In addition to the estimates published in the Oil and Gas Resources of Australia Series, there are estimates available for these basins from the recent World Petroleum Assessment by the United States Geological Survey (USGS, 2000). The assessments by the USGS are consistently higher than those published by BRS. The influence of purpose and methodology can be illustrated by comparing assessments for the same area by the two different organisations.

Table 2 summarises the characteristics of the recent USGS world assessment and the characteristics of Australian assessments. It is immediately apparent that the two approaches have fundamentally different aims, which in turn lead to different approaches and conclusions. The USGS method is aimed at achieving an estimate, largely unconstrained by economic technological and social limits, for basins that are seen to have global significance for future petroleum supply. It relies upon an estimation of the geological potential of a Total Petroleum System centred on a mature source rock pod and the application of models of petroleum occurrence conditioned by discoveries made to date in the system. The Australian method is designed to underpin government advice relating to immediate decisionmaking and production on a 5–10 year time scale, hence the emphasis on discovery modelling. The Australian assessment of these hypothetical resources is more conservative, reflecting the shorter-term focus of the assessment and concentrates on the extrapolation of known exploration trends. The differences in the assessment are not surprising given

Table 2. Comparison of characteristics of USGS (2000) and BRS/AGSO (Forman and Hinde, 1985,1986) methods for estimation of undiscovered petroleum potential.

USGS Method	**BRS/AGSO Method**
• Purpose: To provide impartial, scientifically based, societally relevant petroleum-resource information essential to the economic and strategic security of the United States.	• Purpose: To provide information on Australia's resource potential to underpin technical advice relating to government decisions on energy policy, energy management and land use.
• Scope: Geologic-based assessment confined to the projected geologic limits of known petroleum systems but unconstrained by technological, political, societal and exploration activity factors. The assessment is limited to conventional potential resources that could be added to reserves in a 30 year time frame.	• Scope: Discovery process model applied to explored and unexplored provinces where development is likely to be economic on a 25 year time frame. In practice some parts of prospective basins and some potentially prospective basins have not been assessed. Assessments have not been carried out beyond 500 m water depth.
• Timing: A world-wide assessment conducted over five years by a large team (40 staff) using a single methodology culminating in publication in 2000	• Timing: Progressive assessment from late 1980s of basin areas, with periodic updates of active areas by several individuals.
• Assessment Unit: Total Petroleum System comprising a generative source rock pod and its derived fluids. May be divided into individual Assessment Units to maintain homogeneity in the assessment process.	• Assessment Unit: Play defined as a single migration fairway comprising a system of traps that is contained within a sequence of source, reservoir, and cap rocks and is separated from adjacent systems by geological barriers to tertiary migration of petroleum.
• Technical Characteristics: Geological opinion is used to establish probabilities for chance of occurrence, number and ratios, size of fields, proportions of oil, gas and gas liquids. Pre-existing discoveries are used to calibrate the probability curves. Provision for field growth is explicitly made. Probability distributions for undiscovered resources are then computed. For Australian examples, minimum pool sizes range 1–10 million barrels depending on basin.	• Technical Characteristics: The method simulates drilling each untested trap in a play. From the input data, which are captured in order of drilling or discovery as log linear models, it estimates the size of the simulated discovery. It takes into account existence risk, success rate, proportion of oil and gas and the smallest size to be included as a resource. Probability distributions are calculated and the averages and standard deviations of the accumulation sizes are created.

the different philosophies, which are compounded by the fact that Australian assessments to date have not included water depths greater than 500 m or the potential for reserves growth in the yet-to-be discovered fields.

The value of the USGS approach is that it emphasises longterm potential, but much more work is required to determine how that resource potential might be realised and in what time frame. As such, it emphasises the upside potential which is appropriate for focussing exploration interest. The value of the discovery modelling approach used in BRS/AGSO is that it emphasises the results to be obtained from continuation of current exploration trends for production forecasting and planning purposes in the near term. It explains why the Australian government assessments may be viewed as not attractive by the international exploration investment community which, given the risk taking nature of the business, focuses on upside potential.

The results (Table 1) show the USGS estimates to be more optimistic than the BRS assessment. The mean expectation in the USGS result for oil more closely resembles the values at the 5% probability in the BRS assessments whilst the estimates for gas are much higher. Whilst it is acknowledged that the Australian result will systematically underestimate the potential, the USGS assessment may be over optimistic. It does not appear to have factored in the preservation issues associated with hydrocarbon accumulations encountered on the North West Shelf and particularly in the Timor Sea (Lisk et al, 1998—the USGS assessment has a 1995 cut off and references are all prior to 1995). Given the tendency of larger fields to be found first, at this stage of exploration it is hard to reconcile the projected resource potential by the USGS with the discoveries found to date. Similarly, the condensate to gas ratio in the USGS assessment averages 53 barrels per million cubic feet (297.5 kL per Mm^3) compared with the average of 42 barrels per million cubic feet (235.6 kL per Mm^3) in known fields. Within the broad context of the USGS study these are not issues, but it certainly is of considerable relevance for exploration in Australia. Clearly there remains significant oil potential, but as discussed above, the oil pools remaining to be found are unlikely not be of large size individually (see also USGS, 2000). It is worth noting that both assessments for the Browse Basin have been strongly influenced by the promise of the Cornea discovery, which has subsequently been found to be a much smaller field than originally thought (Ingram et al, 2000). There remains a very large gas potential with very significant associated condensate resource.

Moreton (1998) provides a much more disturbing comparison of methods (Table 3). He gives estimates of undiscovered, recoverable petroleum resources in the Cooper Basin in South Australia using five different approaches based on discovery modelling play assessment and basin analogues. The range of variation between those methods

Table 3. Estimates of speculative resources in selected offshore frontier basins (BMR, 1991; BRS 1993, 1994). P-95%, P- Mean and P-5% denotes the probability of the resources exceeding the stated value. Risk denotes the perceived chance that petroleum resources exist in the basin.

Basin	Undiscovered oil assessment							Undiscovered gas assessment (Bcm)						
	P–95%		P–Mean		P–5%		Risk	P–95%		P–Mean		P–5%		Risk
	(x 10^6 Barrels; Gigalitres)							(x 10^{12} Cubic Metres; 10^9 Cubic Metres)						
Duntroon	0	0	16	3	94	15	0.2	0	0	0.06	2	0.34	10	0.3
Papuan	0	0	201	32	849	135	0.3	0	0	0.25	7	0.99	28	0.3
Queensland	0	0	107	17	1,006	160	0.1	0	0	0.28	8	0.32	9	0.08
Townsville	0	0	107	17	214	34	0.1	0	0	0.25	7	0.49	14	0.09

deemed to be 'reliable' is very large and must indicate a systematic bias in the methods. These variations in estimates of remaining resource are quite surprising given the large amount of data that exists for the Cooper Basin.

The variation in the results obtained by different assessment methods indicates that the resource question being addressed by each of the methods is different. They are clearly addressing different proportions of the undiscovered potential (Fig. 2). Whilst some techniques address potential based on fundamental evaluation of the processes that lead to generation migration and accumulation, others are measuring a discoverable resource based on extrapolation of exploration results. Both approaches are valid in particular contexts and for particular purposes, but one cannot be used as substitute for the other.

Speculative resources

Assessments of the potential of unexplored or lightly explored basins raise a different set of issues. They are classed in the speculative category of the McKelvey diagram (Fig. 2). Australia still has many basins that have received only cursory examination from an exploration viewpoint (Fig. 1). Conceptually, all assessment methods can be adapted to any level of knowledge about an area, but the reliability of the assessment, and frequently the magnitude of the assessment, varies with the level of knowledge and the manner in which the assessment units have been delineated.

In poorly explored basins, little is known about the petroleum geology and there is a wide range of possible sizes of petroleum occurrence, ranging from very small at a high level of probability to very large at a low level of probability. There is a chance that in one such region a large resource potential may exist. Before exploring, it will be uncertain as to which region this may be. We are therefore faced with a conundrum in resource assessment terms. All unexplored or poorly explored basins have a wide range of possible outcomes reflecting the uncertainty surrounding the petroleum geology. Geologists will be reasonably confident in predicting conservative values for the input parameters, but will not be confident about postulating extreme values required for definition of a large resource which is rare in nature.

The difficulty in dealing with the implications of a low probability scenario can be illustrated by the 1990 assessment of North West Shelf gas potential (Powell et al, 1990). At that time, large gas fields had been discovered in which 13 trillion cubic feet (368 x 10^9 m^3) of reserves had been identified. The undiscovered resource assessment estimated a potential of 45 trillion cubic feet (1.27 x 10^{12} m^3) of undiscovered gas at the 5% probability level. Ten years later, the discovered volumes of gas on the North West Shelf are estimated to be in excess of 100 trillion cubic feet (2.832 x 10^{12} m^3) with significant potential remaining (Longley et al, in press). This observation illustrates that the potential of basins known to be hydrocarbon-bearing is often significantly underestimated in the early phases of exploration, because of failure to recognise upside potential. It is an analogous situation to the growth in reserves of existing fields. It reflects the recognition of the opportunities that flows from intensive exploration once the basic parameters for petroleum occurrence have been established.

Commonly, the estimates for unexplored basins are further discounted by the application of the existence risk—ie the risk that no hydrocarbons will be found at all. Because there is little known about these areas the existence risk has to be assumed. The risk assumed is

Table 4. Comparison of estimates of hypothetical petroleum resources for the Cooper Basin obtained by different methods (Moreton, 1998). High, Average and Low denote the probability of the resources exceeding the stated value.

	Oil						Gas					
	High		Average		Low		High		Average		Low	
	((x 10^6 Barrels; Gigalitres))						(x 10^{12} Cubic Metres; 10^9 Cubic Metres)					
Basin Analogue	138	22	170	27	208	33	11.90	337	14.90	422	17.87	506
APRAS (USGS)	0	0	0	0	25	4	1.38	39	8.05	228	24.30	688
Pareto	13	2	38	6	126	20	1.45	41	2.12	60	2.93	83
Basin Plays	0	0	88	14	264	42	0.00	0	0.88	25	7.59	215
Lognormal	2	0	13	2	25	4	0.25	7	0.42	12	0.67	19

frequently high and is subjective. The application of this existence risk results in a further discounting of the potential. Almost inevitably therefore unexplored or poorly explored basins will contribute little to the resource potential of a nation under a system of reporting that focuses at the average probability level (Table 4).

This conservative approach to estimating resource potential of unexplored basins is not in tune with the psychology or risk management strategies of the exploration business. Resources are not distributed evenly and the world's oil supply comes mainly from the very large fields that represent rare events in nature. In a portfolio of say five basins the normal expectation will be that only one will ultimately be significant in terms of hydrocarbon resources. In other words, in practice the existence risk for four of these basins will be zero, i.e. there is no chance of commercial hydrocarbon accumulations occurring. Prior to exploration it is not known with any certainty which basin is favoured. Further, the target for exploration in a frontier basin is always the most economically attractive field, which may also be the largest. Thus, in the absence of evidence to the contrary, initial exploration in a frontier basin should focus on a large potential resource that exists only at a low probability level with an assumed existence risk of unity (i.e. commercial hydrocarbons will be assumed to exist).

Australia's undiscovered resource assessments and their significance

This discussion suggests that estimates of petroleum potential of sedimentary basins that purport to represent their ultimate potential are indicative only. This is, perhaps, not surprising given the chances of success of drilling individual prospects in known hydrocarbon basins and the opportunities for new plays to be identified. As stated by Bradshaw et al (1998), 'Drilling for hydrocarbons is a complex adaptive system like those modelled in computer simulations for financial markets or biological systems where the independent agents learn and adapt their behaviour accordingly. This, in turn, operates upon another complex system (sedimentary basins).' In other words, industry assessments continually change and adapt to the results obtained to aid short-to-medium term decision-making.

In contrast, national or global assessments of the resource potential of basins are periodic and attempt in some way to predict a future outcome. However, as stated by Miller, (1986), 'The volumetric yield and geologic analogue techniques invariably generate the most optimistic resource estimates, whereas the historical performance projections generate just as consistently the most pessimistic estimates of undiscovered resources. A combination of several different appraisal methods usually generates an estimate that falls somewhere between these extremes. The magnitude of the estimate and its position in the range of extremes is dependent upon the choice of the methods used in the combination of method approach and on the varying assumptions of the geologic and economic constraints that the estimators use in the estimation procedures. This, in turn, contributes to a variety of limitations that affect the resources estimates.'

These considerations require a different approach to the reporting of Australia's resource potential than has occurred in the past. Accordingly, despite the reservations expressed above, AGSO considers the best current indicative estimate of the ultimate oil potential of Australia's current offshore hydrocarbon bearing basins is the USGS estimate (Table 1). This gives a total of 5 billion barrels (800 GL) of undiscovered oil, 109 trillion cubic feet (3.2 x10^{12} m^3) of gas and 6 billion barrels (959 GL) of condensate at the average expectation: and 9.8 billion barrels (1,565 GL), 228 trillion cubic feet (6.46 x 10^{12} m^3) and 11.8 billion barrels (1,887 GL) respectively at the 5% probability level (Table 1). Adoption of this estimate at this point in time enables Australia's potential to be benchmarked against other regions internationally for which the USGS has made estimates. It must be emphasised that this estimate is unconstrained by economic, technological or other constraints. AGSO is now reviewing and updating this assessment based on the exploration results and additional data and information that has become available since 1995 and comparing the result with an updated discovery modelling method that will incorporate reserves growth and be extended beyond 500 m water depth.

For production forecasting, the discovery modelling process (Forman and Hinde, 1990) will continue to be used since it best represents the short to medium term indication of the undiscovered resources that will be brought into production. This is discussed further in the production forecast.

Resources assessments for frontier basins, for which it is not known if petroleum systems exist (e.g. basins in Table 3), will no longer be reported because of the difficulty in obtaining meaningful estimates. AGSO's focus will be on providing evidence for the existence of petroleum systems and the indicative size of targets that may exist. In time this may enable formal resource assessments to be made with more confidence.

OIL AND CONDENSATE PRODUCTION FORECASTS

Method

AGSO's current production forecast for the period 2000–2010 (Fig. 4) incorporates several elements. A periodic questionnaire is circulated to field operators by the Department of Industry Science and Resources, in which they are asked to estimate their production forecasts on individual fields at the 50% probability level. Because it has been found that companies often underestimate their future production, AGSO considers remaining reserves, current and historic production to adjust the forecast and also produce estimates at the 10% and 90%

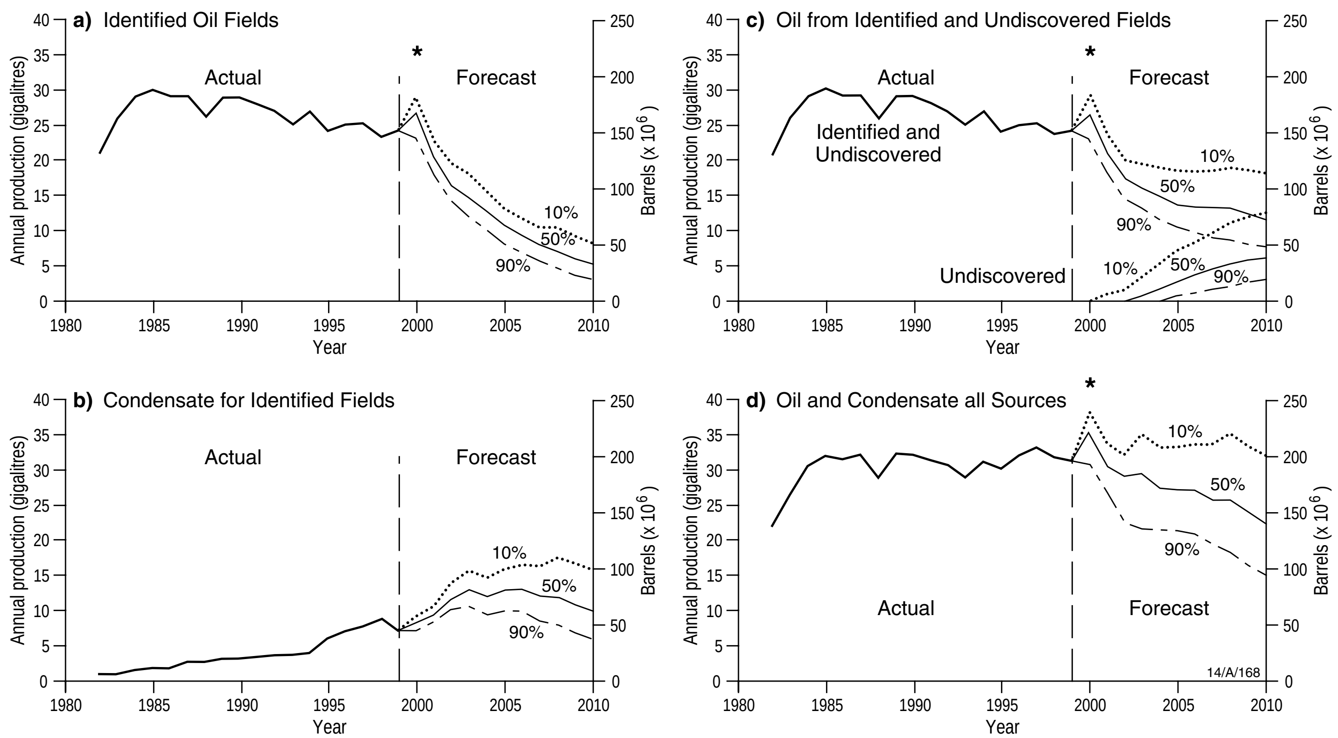

Figure 4. Australia's historical production of crude oil, and condensate through time and forecast annual production at various probabilities. * Denotes calculated annual rate of production from preliminary figures released by APPEA (2000) for the first six months of the year 2000.

probability levels to reflect the uncertainty surrounding future production and reserves growth. The 90% forecast represents a high degree of certainty of a low level of production, whilst higher levels of production are represented at progressively lower levels of probability.

AGSO figures incorporate estimates of production from individual developed fields as well as estimates of production and timing of development of identified, but undeveloped fields. The major factors affecting the accuracy of oil production estimates for identified fields are growth in reserves, delays in start up and interruptions to production from offshore fields. As a result, the lower probability forecasts in part reflect the scope for increases in the reserve estimates on which the forecasts are based. The accuracy of the estimates of condensate production from identified fields is critically dependent on the timing of future gas developments. The forecast is based on company and AGSO estimates of production from accumulations which had been discovered by March 2000 and for which some production planning has been carried out.

The future discovery and production of undiscovered resources of crude oil is predicted using the computer program SEAPUP (Forman and Hinde, 1990). The program simulates the drilling of petroleum traps, discovery of petroleum and subsequent future production. Various stochastic models are built into the program to allow for the uncertainty in the discovery process. These include models of discovery order, future drilling rates, economic accumulation sizes, production rates and lead times. Inputs to these models are in the form of distributions. The results of each iteration are accumulated into histograms of the predicted total of undiscovered resources that will be found for the forecast period. The program reports the number of wells drilled, number of accumulations discovered, number of accumulations brought into production, discovery rate, success rate, amount of crude oil discovered, and amount of crude oil produced. Estimates of production of condensate from undiscovered gas resources are not made because of the large undeveloped gas resources that already exist.

Since both the forecast of production from identified fields and from undiscovered fields exist as probability distributions, they are summed using the Monte Carlo method. The forecast includes 100% of production from the Area A of the Timor Gap Zone of Cooperation, which is subject to production sharing agreements between the operating companies and the Joint Authority (Fig. 4).

Production of oil from identified resources

Figure 4a shows the actual production of oil to the end of 1999 and the forecast production from currently identified resources over the period 2000–2010 (AGSO, 2000a). Oil production has declined steadily from a peak of 188 million barrels (30 GL) per annum in 1985 to 151 million barrels (24 GL) per annum in 1999. An increase in production was predicted, and occurred, in 2000 in response to the Laminaria-Corallina field coming on stream, but in subsequent years the decline in oil production is forecast to resume. The production from the Laminaria-Corallina project of the first six months of 2000 has been considerably higher than forecast. The implications of this are discussed further below. There is a 50% probability that in five years time production of oil from identified resources will only exceed 68 million barrels (10.8 GL) per annum.

Production of condensate from identified gasfields

In contrast to oil production, condensate production has grown steadily (Fig 4b) and is forecast to continue to grow (AGSO 2000a). There is a 50% probability that in five years time production of condensate from gas fields will exceed 82 million barrels (13 GL) per annum representing about 50% of total liquid hydrocarbon production. However, the increase in condensate production will be insufficient to offset the decline in oil production.

Some very large gas fields have not been included in the forecast (AGSO, 2000). Chrysaor and Scarborough in the Carnarvon Basins and Scott Reef and Brecknock in the Browse Basin occur in generally deeper water and could conceivably be brought into production. They contain about 42 trillion cubic feet (1.189×10^{12} m^3) of natural gas and have a condensate to gas ratio averaging 12 barrels per million cubic feet (67.3 kL per Mm^3) compared with the average for Australian production of 42 barrels per million cubic feet (235.6 kL per Mm^3). Other accumulations which have been included in the forecast, but which are not presently in production, such as Angel and Flamingo/Bayu/Undan are richer than the average. Hence the omission of the large gas fields in deeper water is unlikely to cause the condensate forecast to be an underestimate if some production from these fields were to proceed in the forecast period.

Production of oil from undiscovered resources

Production of oil from as yet undiscovered fields and newly discovered fields undergoing appraisal will represent a significant proportion of Australia's oil production by 2005 (Fig 4c). This would include, for example, the recently discovered Enfield, Vincent and Laverda fields in the Carnarvon Basin. At 50% probability, production of oil from undiscovered resources will only exceed 16 million barrels (2.5 GL) per annum in 2005 and 40 million barrels (6.4 GL) per annum in 2010. These predictions assume rates of additions to reserves from currently unknown fields are similar to current rates of discovery.

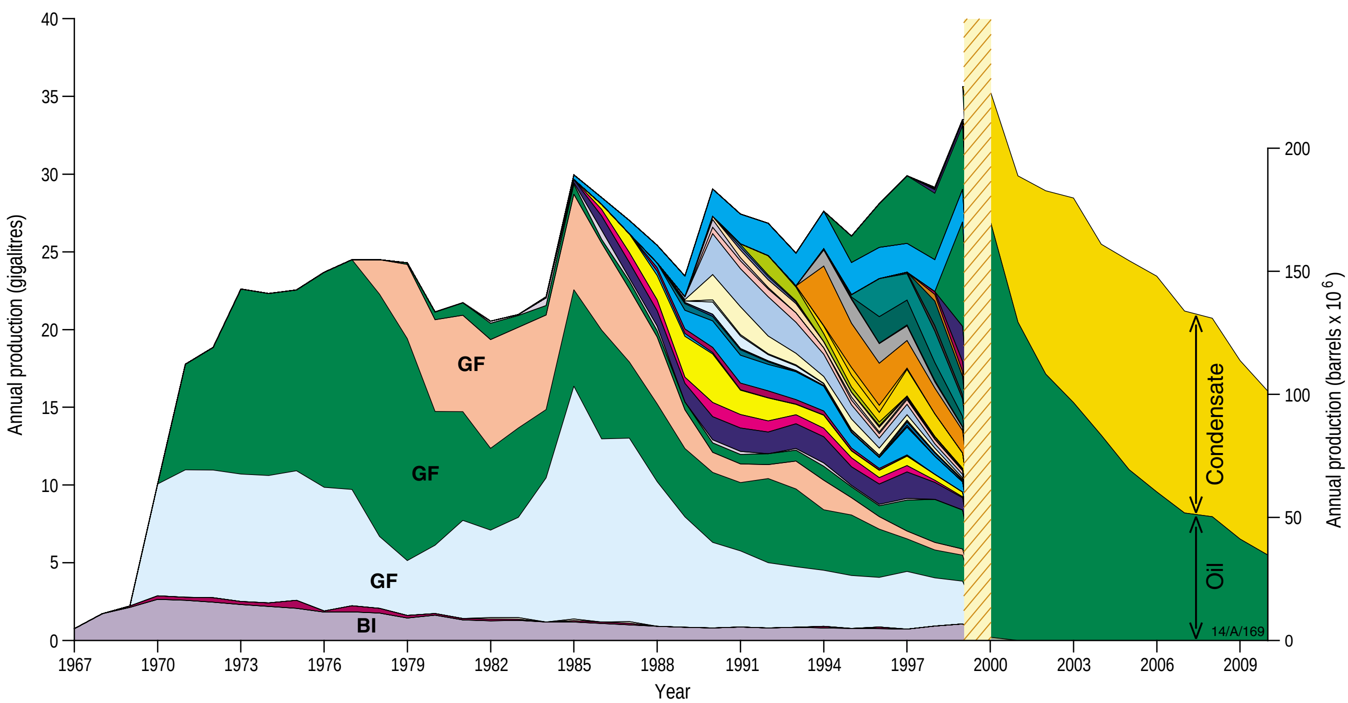

Figure 5. Production profiles of individual Australian fields and cumulative production forecast at 50 per cent probability derived from industry data. BI denotes Barrow Island field; GF denotes giant Gippsland Basin Fields.

Reliability of estimates

Taking into account all sources of production (Fig 4d), there is a 50% probability that production of oil and condensate will exceed only 170 million barrels (27 GL) per annum within five years or 66% of present levels. There is a 10% probability liquids production will exceed only 212 million barrels (32 GL) per annum in five years time or roughly match existing levels. Condensate will represent approximately half of this production compared with 18% in the first half of 2000 (APPEA, 2000). The immediate question is how reliable are these estimates.

The approach used to develop this forecast has been generally applied in the last 15 years. Comparison with actual production rates has shown that of the 13 forecasts made, on only four occasions have actual production rates fallen outside the 20% and 80% probability range within five years of the forecast (see BRS, 1996 for examples and discussion). Two of these occasions have been where production trends have exceeded the 20% probability prediction and on two occasions the production trend has fallen below the 80% probability prediction. Preliminary average daily production rates of oil and condensate published by APPEA (2000) for the first half of 2000 correspond to annual production rates of 266 million barrels (42 GL) per annum and exceed the 10% probability estimate of the 1999 production forecast (Fig. 4) for the year 2000. This is largely due to the superior performance of the recently commissioned Laminaria-Corallina project. This observation, however, does not negate the long-term trend of decreasing oil production over time. Only if discoveries are made which result in a net increase in reserves will this downward trend be mitigated.

The underlying reasons for the production outlook are illustrated in figure 5, which shows the actual and predicted production profiles for Australia's oil and condensate fields. Production profiles and the longevity of fields vary widely with the size of the field, the quality of the host reservoir and the means of development. The Barrow Island field is a giant field hosted in a poor quality reservoir with low recovery rates, but it is accessible from land. It has produced consistently over a long period of time (Fig. 5) because of the ability to implement improved recovery practices relatively easily and economically. However, maintenance of and/or additional production depends on profitability, which in turn is related to the price of oil and capacity for technological innovation.

In the past, the giant fields in the Gippsland Basin have underpinned Australian oil production (Fig. 5). These fields have high-performing reservoirs and associated fixed infrastructure. Growth in reserves in these fields, plus the ability to economically tie-in small fields to the infrastructure, has meant that these assets have sustained production for a long period of time. Similarly, production of condensate from the large gas developments on the NW Shelf and Timor Sea are expected to have relatively long lives, but with very even production profiles reflecting the constraints on the associated gas production. In supply terms, they will provide the very long term underpinning to Australian production that the Bass Strait fields have traditionally supplied, but obviously not at the same level.

Production of oil from the Gippsland fields peaked in 1985 and subsequently has declined steadily. The industry has been successful in replacing this production by the development of the gas fields on the NW Shelf and in the discovery and development of many smaller oil fields on the north west margin. In contrast to the Gippsland Basin oilfields, the remote and relatively small oilfields of the NW Shelf and Timor Sea have much shorter lives. They have been discovered and developed in a very uncertain period for oil prices and their location and size has required physical facilities with lower capital costs which in some cases constrains their flexibility for secondary developments. The year-by-year production performance of these developments has been harder to predict. However, it is evident from Figure 4a that the recent spurt in oil production is superimposed upon a decline from a peak in production in the mid 80s. Whilst overall liquids production has increased due to the contribution from condensate (Figs 4d and 5), production in the longer term can only be sustained at current levels from new reserves in new oil fields as the Laminaria-Corallina example clearly illustrates.

Notwithstanding the increased contribution from condensate production to Australia's national liquid hydrocarbon supply, maintenance of liquid hydrocarbon production is critically dependent on the ability to increase the rate of discovery, production and development of new oil fields.

CURRENT EXPLORATION TRENDS

The factors affecting petroleum exploration in Australia have been discussed by Bradshaw et al (1999). Of crucial importance is the perception of prospectivity. 'A discovery itself affects the exploration process: it adds geological knowledge and improves the perception of prospectivity and positive feedback may lead to more exploration and further discoveries.' (Bradshaw et al, 1999; see also Powell et al, 1990 and Robertson, 1988). In other words, activity level combined with success rate and reserves added to the national inventory should be a reliable indicator of future supply trends.

Current offshore exploration levels are close to their historic highs in terms of wells drilled (Fig. 7, AGSO, 2000b). This reflects the commitments made to exploration in the mid-90s in response to a string of discoveries of both oil and gas ranging from the Timor Sea to the Carnarvon Basin (Cornea, Undan/Bayu, Laminaria, Perseus and Chrysaor). However, future trends in exploration are best represented by company intentions as expressed by work program bids for new acreage released by the Government. Figure 6 shows the indicative expenditure represented by successful acreage bids in

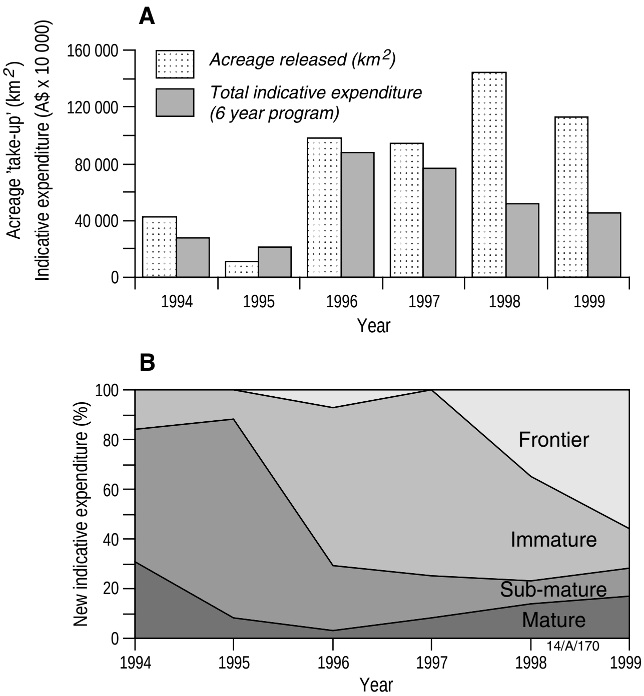

Figure 6. Indicative exploration expenditure in primary and secondary work programs committed by successful bidders for new Australian offshore petroleum acreage in the period 1994–1999 excluding Timor Sea Zone of Cooperation. A—Commitment by year. B—Distribution according to basin exploration maturity. Exploration maturity status is that defined in the Australian Offshore Petroleum Strategy (Industry Science and Resources, 1999)

each of the years from 1994 to 1999 inclusive. The peak in new financial commitments occurred in 1996 and 1997. The 1996 figures include the large bid for the vacant block presumed to include an extension to the Cornea discovery (Ingram et al, 2000). Subsequently, expenditure commitments have declined as an increasing proportion of frontier acreage was taken up by the industry after the 1997 peak in expenditure commitment (Fig. 6). Less mature exploration areas commonly attract lower exploration commitments per unit area than the more mature exploration areas. However, this uptake of frontier acreage is still focused primarily on the fringes of the established areas in north-western Australia rather than in other basins elsewhere in Australia.

The commitments, put in place in the mid-90s, are now being met in the current drilling activity (AGSO, 2000a). The overall discovery success rate in terms of oil and gas discovered remains in excess of 20% (e.g. Bradshaw, 1999; AGSO, 2000a). However, the discovery rate for commercial oil accumulations is substantially lower (Fig. 7). In the period 1990 to 1997 inclusive, 0.641 billion barrels (102 GL) of oil were discovered in 15 fields as a result of the drilling of 339 offshore exploration and appraisal wells. During this period, Australia produced 1.163 billion barrels (185GL) of oil. Discoveries made subsequently are still not fully documented, but there appears to be no change in the overall rate and sizes of discoveries. Assuming similar rates of discovery and additions to reserves, drilling rates would have to be, on average, nearly twice the level experienced in this period (Fig.7) to replace reserves being produced and sustain production into the medium term.

Clearly there remains considerable potential to find oil accumulations in north-western Australia as the recent discoveries of the Enfield, Vincent and Laverda fields demonstrate. However, it appears that chances of finding large oil fields in these established hydrocarbon-bearing areas, sufficient to arrest the projected decline in Australia's liquid hydrocarbon supply, is limited, given the well known phenomenon that the larger fields are found earlier in the exploration cycle. If Australia is to maximise the opportunity to maintain its indigenous liquid hydrocarbon supply, there is a need to broaden the base for Australian exploration to maximise the opportunity of discovering a new hydrocarbon province whilst fully exploring the northwestern basins and their deepwater fringes.

As indicated in Figure 1, there remain many Australian basins for which exploration has been very limited to date. The challenge lies in generating enough confidence in the industry to initiate a modern exploration program in the frontier provinces along the southern margin, in northern and northeastern basins if environmental concerns can be overcome, and in the more promising onshore basins such as the Canning Basin. The task for Government in setting the scene for exploration investment is to present the opportunities on offer emphasising the upside potential based on a realistic assessment of the range of possibilities and to provide as much evidence as possible to mitigate the existence risk. In particular, this entails demonstrating an active petroleum system through, for example, seepage studies and indirect indicators of petroleum occurrence.

SUMMARY

Australia's reserves of oil and condensate are at their historical high point, largely due to the increase in reserves of condensate as large new gas reserves have been discovered and delineated. Oil production has declined slowly since 1985 and despite an increase in 2000 and 2001 to near record levels, this decline is expected to resume. This decline can only be mitigated if substantial new reserves of oil are discovered. Condensate produced from Australia's large gas fields will represent around 50 per cent of production within five years. The rate and size of oil discoveries made in north-western Australia in recent years are not large enough to replace depleted fields.

Estimates of remaining oil potential in Australia's producing basins vary widely and reflect differing objectives for the assessments. National assessments conducted to date in Australia have been focussed on discovery modelling for short tem decision-making on a 5–10

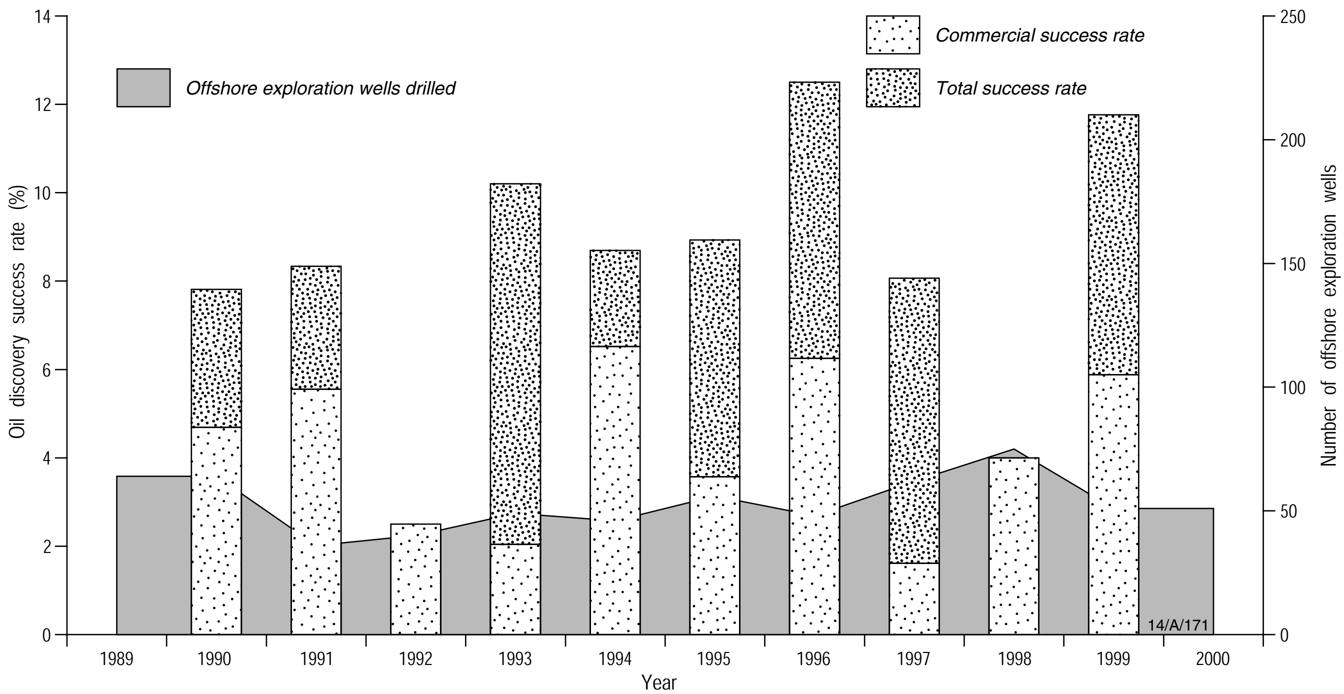

Figure 7. Offshore exploration and oil discovery success rates. Wells for which gas may have been a target are included.

year frame. They are suitable for contributing to estimates of petroleum supply in this timeframe, but are not appropriate for indicating ultimate potential required for evaluation of overall prospectivity. The recent USGS world assessment of undiscovered oil potential includes Australia's major producing basins. Despite some reservations as to the results, the USGS assessment has been adopted as the best current indicative estimate of the ultimate petroleum potential of Australia's offshore producing basins (Table 1).

Despite the remaining potential in north-western Australia, indigenous oil production can only be sustained in the longer term if a significant new oil province can be found. Australia's oil discovery rate can be maximised by diversifying exploration effort into frontier basins whilst fully exploring the prospective limits of the established hydrocarbon bearing basins. Australia has large areas of unexplored sedimentary basin in its offshore areas and some promising onshore areas. Current average resource assessments of these areas based on the discovery modelling method do not adequately define the target for exploration. Rather, the focus should be on the high-risk potential given the uncertainty of the knowledge of the petroleum geology.

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THE AUTHOR

Trevor Powell graduated with a BSc and PhD in organic geochemistry from the University of Newcastle-upon-Tyne England. He is Deputy Chief Executive Officer and Chief of the Petroleum and Marine Division with AGSO. He has held positions with AGSO as Deputy Executive Director responsible for overall scientific strategic planning, Associate Director, Minerals and Environment Group and Chief of the Onshore Sedimentary and Petroleum Geology. He began his career with BMR as a petroleum geochemist. He re-joined AGSO (then BMR) in 1983 following 10 years with the Geological Survey Canada where he was Head of the Petroleum Geology Program. His research interests have been mainly in organic and petroleum geochemistry, paleogeography, sediment hosted Pb/Zn deposits, petroleum resource assessment and environmental geochemistry. Member: PESA.

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