Written primarily for the layman, this book is an account of the history, development and current activities in the search for oil in Australia. It outlines the geological factors controlling the generation of oil and natural gas in sedimentary basins and surveys the petroleum potential of onshore and offshore regions. Geological, technological and economic factors are defined and the present and possible future production of crude oil and natural gas in Australia are discussed. Mention is also made of the potential production of synthetic oil from oil shale and coal.

This is an authoritative reference work which explains in simple terms the scientific, technological and economic aspects of the search for oil in Australia.

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Oil Search in Australia
This book has been written for the layman. Its purpose is to set down a readable and informative account of the history, activities, and other various aspects of exploration for oil and natural gas in Australia. It is intended to present an objective view of the search for petroleum, and to explain the nature of petroleum, its accumulation, and production, concerning which so many misconceptions have been reported in the press. The use of technical and geological terms has been kept to a minimum, but some have been necessary for the sake of accuracy. Where such terms are introduced, their meanings are defined in a glossary.

Although the book is essentially about the search for oil in Australia, reference is also made to political and economic considerations and constraints in the planning and carrying out of exploration programs, and in the development to the production stage of oil and gas fields. No attempt is made to enter into such controversial matters as national ownership of petroleum resources, or pricing policies for crude oil, LPG, and natural gas. These arguments are left to the political scientists, economists, and ultimately to the public. But it is emphasised that petroleum resources are not necessarily reserves, and that reserves must be defined in terms of economics. It is also pointed out that exploration for petroleum, and the development of oil and gas fields, require the advanced technology of the international oil industry, and the expenditure of vast sums of money. Also, the time lag between launching an exploration program and bringing an offshore field on stream is likely to be several years. Because of the time required to develop petroleum resources, and the forward planning needed to provide the necessary financial and marketing arrangements, a large measure of stability with provision for flexibility is needed in the contractual arrangements or policies agreed upon between the operating companies and the governments concerned. These matters, from the view point of exploration and production of petroleum, are briefly discussed in the book.

For those readers interested in particular aspects of the book, reference is made to a number of authors whose papers appeared in various journals available in large libraries throughout Australia. Some of these are of a technical nature, others deal with broad
aspects of exploration or of the petroleum industry; some present
particular points of view, but all are well informed. In this regard it
cannot be stressed too much that accuracy of information is essential
not only for exploration for petroleum, but also for an appreciation
of the rationale and problems of the oil exploration and production
industry.

This book is mainly about the oil industry, but the author wishes
to emphasise the vital role of the Bureau of Mineral Resources and
State Geological Surveys in assisting the industry in its search for oil.
Since its inception the BMR has carried out essential stratigraphic
investigations of sedimentary basins, including geological and
geophysical surveys, and drilling. This work has been instrumental
in pointing out the oil and gas potential of Australia, and in
encouraging the search by national and international oil companies.

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The history of petroleum in Australia is one of persistence over a long and luckless 70-year period from 1892 to 1962, and of industrial expertise and good luck during the following 10-year period from 1962 to 1972. The latter years of discovery have been followed by a few years of consolidation and development as a prelude to further expansion and exploration of the deeper offshore regions of the continental shelf and slope.

In terms of number of wells drilled in the search for petroleum Australia is well behind North America, although the area of Australia is approximately the size of the continental United States or Canada. During 1977 a total of 6197 exploratory and development wells were drilled in Canada and 46,479 in the United States (Johnston, 1978). In Australia, 2769 exploratory and development wells were drilled between 1892 and 1977, of which 1775 were exploratory.

This account does not purport to be a detailed or comprehensive record, but sets out the sequence of events that have highlighted the saga of petroleum exploration in Australia, and comments on the significance of particular discoveries or developments.

The search for petroleum in Australia has aroused considerable interest at various times since 1892 when the first well drilled for oil was spudded-in on the shore of the Coorong district in the southeastern corner of South Australia. The Salt Creek well, owned by the Salt Creek Petroleum Company, is reported (Bureau of Mineral Resources (BMR), 1960) to have drilled through 110 m of Tertiary sediments into basement rock consisting of Precambrian marble. It was a dry hole. In the following years of the 1890s six more dry holes having an aggregate depth of 1200 m were drilled in the same district. The incentive for drilling was the presence of a rubbery, bitumen-like substance found on the surface. Tests had shown that this substance, called coorongite, could on distillation yield liquid hydrocarbons. It was thought that the coorongite was formed from seepages of crude oil. We now know that this substance is the remains of the algae Botryococcus braunii that periodically blooms as a scum in the lagoons. Between the years 1915 and 1930 several more holes were drilled in adjacent areas, all of which proved to be dry. No oil was found and interest in the region lapsed.
In 1900 interest focused on the Roma area of Queensland where natural gas flowed from a depth of 1123 m in a water bore named Roma 2. In 1904 the gas was still flowing at the rate of more than 2000 m³ a day. The town of Roma was reticulated and the streets lit for ten days before the pressure failed, and the gas flow diminished. In 1908 Roma 3 was drilled, and at a depth of 1129 m struck gas which flowed at the estimated rate of nearly 300,000 m³ a day. This well caught fire and burned for six weeks. In the latter part of the 1920s until early in the 1930s drilling in the Roma area produced a wet gas from which the condensate was stripped and sold locally as motor spirit.

During the 1920s anticlinal structures in the northern part of the Sydney Basin were also drilled; but the main interest was centred on the Lakes Entrance area of south-eastern Victoria, in the Gippsland Basin. Here, in 1924 the Lakes Entrance Development Company drilled a borehole that struck a flow of natural gas and artesian water having a trace of oil, at a depth of 320 m. Within the next three decades more than fifty boreholes were sunk in the Lakes Entrance area, twelve of which were drilled by the Victorian Mines Department and the Commonwealth Government. Numerous flows of gas and shows of oil were encountered, but no significant commercial production was obtained; although during the period 1930-41 more than 480,000 litres of oil were produced and sold (BMR, 1960).

It is of interest to ponder, in the light of hindsight, on how near and yet how far away from discovery these early explorers were in the Lakes Entrance area. The sedimentary layers into which they drilled dip seaward and lie above the present oil and gas-producing beds of the offshore Gippsland fields, the nearest of which lies just 20 km from shore. At that time, even had they known of the possible existence of offshore fields, lack of technology would have precluded drilling in such depths of water.

The first promise of commercial production came in December 1953, from the drilling by West Australian Petroleum Pty Ltd (WAPET) of Rough Range 1. Situated on the peninsula south-west of Dampier and west of Exmouth Gulf in Western Australia, Rough Range 1 yielded a flow of oil of approximately 500 barrels (nearly 80,000 litres) a day (Johnstone, 1979) from the basal Cretaceous Birdrong Sandstone, an excellent aquifer that provides slightly brackish water for cattle grazing in the region. This discovery was heralded as Australia’s first potential commercial oil well, and aroused tremendous interest through press reports. Unfortunately, the drilling of a further eleven wells in the immediate area indicated that the structure containing the oil was so small that the accumulation was in fact a one-well oil field. Subsequent wells drilled on the structure, with one exception, proved to be dry and the
program was abandoned. This disappointing experience by no means dampened enthusiasm of the exploration staff of WAPET, and the search for petroleum continued for years in other regions of Western Australia.

It was not until July 1960 that the drilling of AAO Pickanjinnie 1, in the Roma area of Queensland, led to the development of Australia’s first producing gas field. Production is obtained mainly from the Triassic Showgrounds Sandstone.

In December 1961 Union Oil Development Corporation, in partnership with Kern County Land Company and Australian Oil and Gas Corporations, discovered the Moonie oil field in southeastern Queensland. The discovery was based on sound geological premises. It was known that the Jurassic Precipice Sandstone, deposited as river sands nearly 200 million years ago, cropped out as magnificent cliffs around the northern rim of the Surat Basin, and thinned over the western flank of the basin underlaying the Roma area. This sandstone formation was thought to extend well into the Surat Basin where it has since proved to form the basal member throughout much of the basin. It has good to excellent porosity and permeability and was therefore considered to be a potential reservoir bed in which oil and gas could accumulate in closed structures. Consequently, a seismic survey program was launched which culminated in the delineation of an elongate dome structure in the basal Mesozoic section. This structure, which was subsequently drilled by the discovery well Moonie 1, overlies a major erosional surface locally underlain by a basement hill of block-faulted and truncated Paleozoic beds. The geological interpretation proved correct, and a light oil (45° API) having a high petrol fraction was found in the Precipice Sandstone which forms the basal Mesozoic bed in the structure. This structure, approximately 10 km long and 3 km wide, was subsequently estimated to contain 55 million barrels (1 barrel = approx. 35 Imperial gallons) or approximately 8.7 million m³ of oil. Within the three years following discovery of the Moonie field another oil field, called Alton, was found. Located 100 km west of Moonie this very small field, which also yields oil from the Precipice Sandstone, is still producing minor quantities of oil.

Ultimate recovery of oil in the Moonie field from primary and possible enhanced recovery methods will probably not exceed 25 million barrels because of formation water invasion into the producing zones, and other problems. A marked increase in water/oil ratios occurred after 1969, to the point where Union Oil’s profit was no longer satisfactory to them. In January 1973, Union’s interest was sold to International Oil Ltd, an Australian company which has continued to operate the wells on a reduced but profitable basis. Peak production was reached early in 1966 when the Moonie field
produced oil at the rate of 9000 barrels a day, supplemented by less than 1000 barrels a day from the Alton field. Alton oil is trucked to Moonie where oil from both fields is pumped through a pipeline to Ampol's Lytton refinery at Brisbane. Increases in the prices for crude oil, and the need for encouragement of indigenous production, has encouraged optimism that enhanced recovery methods may further prolong the life of this dying field.

The next major discovery was made on the last day of 1963 by Delhi International Oil Corporation in partnership with an Australian company, Santos Ltd. This discovery was the Gidgealpa gas field in the Cooper Basin in north-eastern South Australia. The gas-bearing beds are of Permian sandstone deposited as river and lake sediments some 250 million years ago when Australia was joined to Antarctica as part of Gondwanaland. These sediments indicate that during the Permian in Australia there were glacial periods separated by periods, lasting tens of thousands of years, of cold-temperate to warm-temperate climates. The twin to Gidgealpa, the nearby Moomba gas field, was discovered in 1966. Subsequently, a total of twenty-seven gas fields were found in the Cooper Basin, twenty-two of them being in South Australia and five in Queensland. Other companies participating in exploration of the region include South Australian Oil and Gas Corp. Pty Limited (controlled by the State Government), Bridge Oil Ltd, Vamgas Ltd, Total Exploration Aust. Pty Limited, Pursuit Oil NL, Alliance Petroleum Aust. NL, Basin Oil NL, and Reef Oil NL. Three of these gas fields, the Tirrawarra, Fly Lake, and Moorari fields, also contain oil. The gas is wet, that is to say it contains condensate which is recovered when the warm gas flowing up the borehole expands and cools at the surface. The gas is piped to both Adelaide and Sydney after the removal of its CO₂ content. There are several proposals to utilise the Cooper Basin liquid hydrocarbons, one of which is to construct a crude oil and natural gas liquids pipeline to Redcliffe or some other appropriate site on Spencer Gulf. At the end of June 1978, the known remaining recoverable reserves of natural gas in the Cooper Basin were estimated to be approximately 93,000 million m³, those of condensate and LPG (liquid petroleum gases, propane and butane) to be 40 million m³, and those of crude oil to be nearly 8 million m³ (BMR, 1978). On this basis it is believed that cumulative gas production from the fields will be available to Adelaide and Sydney until at least the turn of the century at present estimates of future demand.

Geological and geophysical expertise, persistence, economic incentives, government encouragement and assistance, and not the least good luck continued to pay off in a winning streak of discoveries. In August 1964 the Barrow Island oil field off the North West Cape of Western Australia was found by West Australian Petroleum
Pty Ltd, a consortium including Ampol Exploration Ltd, California Asiatic Oil Co., Shell Development (Australia) Pty Ltd, and Texaco Overseas Petroleum Co. Production of 38° API oil was obtained from a bed in the Cretaceous Windalia Formation, a very fine, silty sandstone, approximately 40 m thick, deposited in a marine environment about 130 million years ago. The reservoir has good porosity (28 per cent), but poor permeability resulting in a low flow capacity. Formation fracturing is required to improve productivity. The natural solution gas drive mechanism has been augmented by a secondary waterflood since 1966. Currently, there are four water injection wells for every well producing oil in this field. Deeper oil-bearing horizons of Jurassic age have since been brought into production.

The Barrow Island production ranks second to the cumulative production from the Gippsland fields. During its peak production from the Windalia Formation the field yielded about 45,000 barrels a day. This volume had dropped to about 30,000 barrels by the end of 1977, accounting for less than 8 per cent of Australian oil production, the bulk of which comes from offshore fields of the Gippsland Basin, Victoria. Natural gas is produced with the oil, some of which is pumped back and used for improved production by gas lift in the producing wells. Liquid petroleum gas is stripped from this natural gas and used as local fuel on the island. Estimates of the probable ultimate production that will be obtained from the Barrow Island field are subject to economic factors such as the price for oil. They also depend significantly on the recovery efficiency that may be effected by secondary or tertiary production methods, and also by infill-drilling in the field. Although such estimates are ephemeral, it was stated as early as 1965 that the field would yield less than 100 million barrels (nearly 16 million m³) by primary production methods. This figure was later up-dated to 114 million barrels or about 18 million m³ (Parry, 1967) after studies of the results of water injection in the producing sandstone. In June 1968, WAPET estimated that ultimate recovery of oil would probably exceed 200 million barrels (nearly 32 million m³). Ten years later the initial recoverable reserves of crude oil were given as 257 million barrels (nearly 41 million m³), of which 136 million barrels (about 21.5 million m³) had already been produced (Aust. Inst. Petrol., 1977).

This example points out the technological and economic constraints in estimating the proven, probable, or possible reserves of oil and gas in any field.

Mention has been made of the gravity of oils produced in the Moonie and Barrow Island fields, expressed in degrees API (American Petroleum Institute). This scale is purely arbitrary but is related to the specific gravity of the oil in that the higher the API
rating the lower the specific gravity. For example, petrol (sp.gr.-0.7796) has an API rating of 50, kerosene (sp.gr.-0.8109) has a rating of 43, SAE 30 lubricating oil (sp.gr.-0.8871) has a rating of 28, and a heavy, tarry oil (sp.gr.-0.9659) has a rating of 15. Oils having an API rating above 35 contain a higher proportion of the lighter hydrocarbon fractions and a lower proportion of the heavier fractions that constitute the bulk of diesel fuel and lubricating oils. Consequently, they can yield a large volume of petrol and fetch a higher price on the market.

An interesting discovery had been made a few months before the Barrow Island field was tapped. In February 1964, an Australian exploration company Exoil NL, in partnership with the Magellan Petroleum Corporation and United Canso, encountered substantial flows of gas and shows of oil in a wildcat well, East Mereenie 2, drilled on an anticlinal structure in the Amadeus Basin, about 225 km west-south-west of Alice Springs in Central Australia. The gas flowed from the Ordovician Pacoota Sandstone deposited as a quartzose marine sand nearly 500 million years ago. This ancient formation is overlain by a caprock, the Horn Valley Shale, and is folded into anticlinal structures, some of which have closures which could trap hydrocarbons. Other similar structures in the area have been eroded to the core and no longer have prospects for the entrapment of oil and gas.

The following year Magellan discovered an accumulation of gas in the Pacoota Sandstone of the Palm Valley structure situated about 65 km to the east of the Mereenie structure. Follow-up drilling was delayed until 1969 when Magellan’s Palm Valley 2 well struck gas which flowed at the initial rate of 2 million m³ a day. The presence of a substantial gas accumulation was established.

Of particular interest is the occurrence of oil and gas in such ancient rocks. Although several oil and gas fields have been found in Ordovician formations in the United States, hydrocarbon occurrences in sediments older than those of the Ordovician Period are very rare throughout the world. The finding of oil and gas in the Pacoota Sandstone established the prospect of finding hydrocarbon accumulations in Australia within beds deposited over a long period.

The Pacoota Sandstone is commonly hard and well cemented with poor permeability, although local streaks and lenses of friable sandstone occur within the formation. Gas production is improved by hydraulic fracturing of the sandstone, and later reservoir studies based on initial production tests proved disappointing, reducing estimates of probable producible reserves to less than 25,000 million m³. Such low reserves militate against building a pipeline to industrial markets on the coast, and the only local outlet for gas consumption is in Alice Springs. In September 1967, Magellan
announced that a project to supply natural gas to Alice Springs was being investigated, but that the project depended substantially on the recoverable reserves of condensate and of oil in the Mereenie field. It was stated that 75 million barrels (about 12 million m³) would have to be found; but estimates dated 30 June 1977 (Australian Institute of Petroleum) show reserves of only 65 million barrels (10.3 million m³) for the Mereenie field. Consequently, these potential oil and gas reserves remain undeveloped.

In 1964 another gas accumulation was discovered by Phillips Petroleum in the Adavale Basin, west of the Roma shelf in southern Queensland. This was called the Gilmore gas field, a very small field having estimated recoverable reserves of only 600 million m³ of gas. The gas-bearing bed is a Devonian sandstone deposited in a coastal marine environment nearly 400 million years ago. It is commonly hard with poor permeability, and this makes it an unattractive target for exploration. In addition, the remoteness of the Gilmore field from a market for the gas precludes its development and the construction of a pipeline. This situation could change if other accumulations, particularly in carbonate reefs, are found. Of particular interest is the possibility that stromatoporoid reefs, similar to the oil-bearing reefs of western Canada, may be found. Such reefs may be associated with limestone, dolomitic limestone, and shale beds of the sequence in which the Gilmore sandstone occurs.

During the early part of these years of discovery, there occurred the most important find to date in Australia’s history of petroleum exploration. The offshore Barracouta gas field was discovered by Esso Exploration Australia Inc. in equal partnership with Hematite Exploration Pty Ltd, a wholly owned subsidiary of Broken Hill Pty Ltd. The background to this discovery was the acquisition of offshore oil search rights in the Gippsland area by BHP, on the advice of an internationally known geologist, Dr Lewis G. Weeks. At that time BHP had neither experience in exploration for oil and gas nor a staff of petroleum geologists, geophysicists, and petroleum engineers. They looked around for a partner with the necessary expertise in offshore exploration and signed an agreement with Esso who had for the previous two years maintained a small but competent group of geologists and geophysicists in an assessment of the petroleum prospects of Australia. Under this agreement Esso bore the cost of exploration, but in the event of a discovery Esso and BHP would share the development costs equally, or alternatively BHP could take a carried interest as a percentage of profits. Dr Weeks had himself gambled on the outcome by waiving a professional fee for services and accepting a 2½ per cent interest in possible revenues to BHP from the venture. This gamble was to pay off handsomely and made Dr Weeks a millionaire many times over.
PLATE I
Drillship *Glomar III* which drilled several of the early oil and gas discovery wells in Bass Strait. View shows drill pipe stacked on the deck beneath the derrick which reaches to a height of nearly 60 m. (Courtesy of ESSO Australia Ltd.)
The offshore search in the Gippsland Basin began with seismic surveys which outlined several promising structures. The first to be drilled in April 1965 proved to be a winner when Gippsland Shelf 1 struck excellent flows of wet gas. During a 3½ hour production test the well flowed gas from a depth of about 1125 m, at the rate of 300 thousand m³ a day, and from a depth of about 1145 m at the rate of 85 thousand m³ a day. The producing zones are sandstone beds of the Eocene Latrobe Formation deposited as deltaic and marine shoreline sands about 50 million years ago. This sequence of sedimentary beds includes seams of coal which thicken shoreward. Where the sequence crops out on the mainland these seams of brown coal (one of which has a thickness of up to 100 m) are mined for use in power plants generating electricity in Victoria.

During the following weeks a second well was drilled about 4 km south-west of Gippsland Shelf 1. This well also yielded wet gas flowing at the rate of approximately 275 thousand m³ a day from depths of about 1050 m and 1120 m in the same formation. This confirmed the existence of a gas field within the structure outlined by seismic surveys. The field, named Barracouta, lies within a structure nearly 30 km in length and more than 6 km in width.

Esso's next venture, drilled with the Glomar III offshore rig (Plate I), was situated about 45 km north-east of the discovery well on another promising seismic structure. This rig began drilling late in 1965, and in February 1966 Gippsland Shelf 4 was reported to have struck oil which flowed at rates of up to 1000 barrels a day from Eocene beds at a depth of about 1530 m. This structure was subsequently named the Marlin gas and oil field (Fig. 1). The winning streak still held, and subsequent drilling during the following years discovered several more fields, of which the Kingfish (discovered in May 1967), Halibut (June 1967), Mackerel, Fortescue, Flounder, and Cobia oil fields are in production or in planned development as of 1979. The Tuna and Dolphin oil fields, and the Bream and Snapper oil and gas fields are under consideration for future development. The fields currently in production supply two-thirds of Australia's oil requirements and will remain the chief source of indigenous oil until well into the 1980s. The Cobia oil field discovered in 1972, and the West Kingfish oil field discovered in 1977 will probably not be brought into production until 1982. The Snapper gas field will probably be brought on stream to supplement gas production from the Barracouta and Marlin fields late in 1980 (Petroleum Gazette, Vol. 20, No. 3, 1978). It is of interest to note that on 3-hour tests the Kingfish A-1 well flowed 49° API oil at a rate of 1500 barrels a day from a depth of 2275 m, and the Halibut A-1 well flowed 44° API oil at a rate of 3230 barrels a day from a depth of 2340 m. Both oils are of light gravity having a high content of petrol
FIGURE 1
Cross-section of Marlin oil and gas field, Bass Strait, showing gas, oil, and water contacts in sandstone bodies of the Latrobe Group (Eocene). The Latrobe is separated by an unconformity (erosional surface) from the mudstone cap rocks of the Lakes Entrance Formation (Oligocene). Vertical scale in metres. (Modified after Griffith and Hodgson, 1971.)
fractions. By the middle of 1979 approximately ninety oil wells had been drilled offshore Gippsland, including thirty-six in the Kingfish field and eighteen in the Halibut field. Total daily oil production from the Gippsland Basin amounts to about 420,000 barrels. Average daily production per well exceeds 4000 barrels, but some wells yield up to 10,000 barrels.

By August 1966, the score for offshore discoveries stood as follows: Barracouta gas field found by Gippsland Shelf 1 and 2 wells, and Marlin oil and gas field found by Gippsland Shelf 4 and 5 wells. Gippsland Shelf 3 was drilled on a separate seismic structure and was abandoned as a dry hole. The Dolphin field was discovered early in 1968 but at that time was not considered to be a viable economic proposition for development. Soon after, in May 1968, oil was discovered in the Tuna field, and both gas and oil in the Snapper field. A second well, Tuna A-2 situated about 3 km south-west of Tuna A-1, encountered gas at 1290 m and oil at 1920 m while drilling during October 1968. The Flounder structure was drilled in August 1968, but drilling was suspended at a depth of 3522 m when high pressure gas was encountered. The drilling equipment in use was not considered adequate for safety reasons and the rig was moved to a new location on the Snapper structure. Testing of a zone below 2460 m in the Flounder structure resulted in the recovery of a small quantity of oil.

On 2 December 1968 a gas blowout occurred on the Marlin production platform while the drilling of Marlin A-7 development well was in progress. The gas erupted from the seabed at the base of the platform, and fortunately did not catch fire. After considerable delays caused by bad weather, the necessary personnel and equipment were assembled and the blowout was brought under control on 1 January 1969. In May 1971 a minor gas fire on the Marlin platform was quickly extinguished by closing control valves on the well head.

Offshore discoveries continued in quick succession. In March 1969 oil was encountered in the Bream No. 2 well. The Bream structure was later determined to be an oil and gas field, after the drilling of Bream No. 3 in November 1969; although at that time its development was not considered to be economically viable. Also, in March the Mackerel No. 1 well was spudded-in on a structure that later proved to be the Mackerel oil field. Initial results were disappointing and although Mackerel No. 1 had a show of oil at a depth of 2370 m, and was drilled to a total depth of 3000 m, the well was plugged and declared non-commercial. Later wells drilled on the Mackerel structure proved it to be a commercial field. Several other wells drilled on offshore seismic structures in the Gippsland Basin were unsuccessful in finding commercial accumulations of oil or gas.
While discoveries were being made in eastern and central Australia exploration also continued in Western Australia. In 1966 West Australian Petroleum drilled a structure located about 300 km north of Perth and found the Dongara gas field. The field was not developed until 1969 when several wells were drilled, nearly half of which proved to be uneconomic. Others yielded gas flowing at rates of up to 300,000 m³ a day during 3-hour tests. Light oil having a gravity of 40° API was also recovered from Dongara No. 8, 14 and 17 wells, and initial production tests yielded flows of up to 600 barrels a day. Currently, the field yields gas from twelve wells producing from a Triassic sandstone reservoir deposited as a marine near-shore sand about 220 million years ago. In 1971 a pipeline was built to supply gas to Perth and the industrial area of Kwinana. It is estimated that supply can be maintained until 1988 when the Dongara field will be nearly depleted. The field may then be converted to a gas storage reservoir for Perth’s supply during the 1980s, utilising gas from the giant North Rankin structure of the North West Shelf.

During the period of proving-up the Dongara field, exploration was carried out in the Joseph Bonaparte Gulf west of Darwin. Wells had been drilled several years before on the southern coast of the gulf, and gas flows were recorded from Carboniferous or Permian beds deposited in a marine environment possibly 280 million years ago. In February 1969, Atlantic Refining Company began a program of drilling two offshore wells, Lacrosse 1 and Petrel 1. On completion of the former well, which proved to be dry, the rig was moved to the Petrel site early in April. In August this well, located about 225 km north of Wyndham, struck high pressure gas at a depth of 3918 m and blew out. The drilling rig, SEDCO 135 G, suffered considerable damage from fire and was moved off the site. Plans were made to bring in another rig from overseas and drill a directional hole to the blowout well from a site about 600 m away. This relief well was planned to drill into Petrel 1 in order to quench it, a feat made possible by techniques in boreholes surveying and drilling. Petrel 1 well blew wild for eighteen months, indicating a substantial reservoir of gas within the Permian beds, and was ultimately brought under control following a tragic loss. The SEDCO Helen, a supply vessel, was re-setting an anchor of the relief drilling rig when it apparently reversed over a buoy and sank rapidly with the loss of nine lives.

Gas may be present in substantial quantities in offshore areas of the Joseph Bonaparte Gulf region, (Fig. 2), as indicated by gas shows in Penguin 1, Tern 1, Petrel 1, Flamingo 1, and Swan 1. Also of interest is Puffin 1, situated adjacent to the western flank of the Bonaparte Gulf Basin, and Lacrosse 1 drilled in the southern part of the basin. The latter yielded oil on test, and the former yielded flows
of up to 4000 barrels a day. Currently there is no local market and very large fields would have to be found in order to justify the cost of development for domestic markets and export of liquified natural gas. The only off-shore gas accumulations planned for development in the early 1980s, apart from those of the Gippsland Shelf in Victoria, are those in the area of the Rankin structure near Dampier in Western Australia. These will be mentioned later.

During the period 1960-70 exploration by the Associated Group of companies and others in the Roma area of Queensland resulted in the finding of a number of small oil and gas fields producing from Triassic and Jurassic sandstone beds deposited as river sands about 180 to 200 million years ago. These fields include the Richmond, Duarran, Pringle Downs, and Maffra oil and gas fields, and the Bony Creek, Tarrawonga, Snake Creek, Beaufort, Pine Ridge, Pickan-jinnie, Kincora, and Wallumbilla South gas fields. All of these, and several other smaller fields, are now joined by a system of gathering pipelines connected to the main transmission pipeline to Brisbane. Other producing gas fields in the Surat Basin situated between Alton oil field and the Roma area, are the Boxleigh and Silver Springs fields, the former discovered in 1970 and the latter in 1974 by Bridge Oil NL. Exploration in the Surat Basin, in areas other than the Roma
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Shelf, was neglected for many years because it was thought that large structural traps for oil were unlikely to be found, and that small accumulations of oil and gas were economically unattractive. Increases in the price for both oil and gas have given rise to a re-evaluation of prospects in the Surat Basin, which is believed to hold a number of undiscovered and hard-to-find stratigraphic traps.

A discovery of outstanding importance was made by Burmah Oil Company of Australia Limited in 1971. Drilling offshore on the North West Shelf of Western Australia BOC, the operator for the North Shelf Group of companies, found substantial flows of wet gas in the Goodwyn, Rankin, and North Rankin structures (Fig. 3) situated about 140 km from the Dampier coast in 90 to 120 m of water. Drillstem tests of selected intervals within the producing zone at a depth range of 2650 to 3180 m in North Rankin 1 well indicated gas flows of up to 400,000 m$^3$ a day. The Rankin 1 well also produced gas which yielded condensate at the rate of 35 barrels per 300,000 m$^3$ of gas, and oil from a thin basal column. Gas is trapped in a number of separate zones in Triassic sandstone beds having a net cumulative thickness of more than 300 m. These sandstones were deposited as deltaic and nearshore marine sands some 200 million years ago. The structures in which these gas accumulations occur result from the tilting of faulted blocks of Triassic sediments which are flanked on the up-dip edges of the sandstone beds by impervious shale beds. Contemporary discoveries, the Angel, Goodwyn and Dockerel gas fields, will contribute further to the recoverable reserves of gas totalling about 400,000 million m$^3$ for all of the North West Shelf gas fields. Feasibility and project delineation studies of planned development in the North Rankin and adjacent fields indicate that production of gas for the market in Western Australia, and of liquefied natural gas for export, may come on stream in the mid-1980s. Development costs are expected to amount to $3000 million in terms of 1977 dollars. Exploration companies with major interests in the region through a network of interlocking companies are Shell Australia Ltd, Woodside Petroleum Ltd, California Asiatic Oil Co., and BP Australia Ltd. Broken Hill Pty is also a partner, having bought out Burmah’s original ownership for $62 million. In addition to these companies the following also have interests in deeper water areas of the adjacent Exmouth Plateau: Esso Exploration, Australian Oil and Gas, Pan Canadian Petroleum, Canadian Superior Oil, Hudbay Oil, Mount Isa Mines, Australian Gulf Oil, Mobil Oil, Phillips Petroleum, and Gulf Oil.

Future exploration will look to regions of deeper water overlying the continental shelf and slope. Such programs will necessitate further advances in drilling technology, particularly in the construction of undersea production facilities. It will also entail the expendi-
FIGURE 3
Cross-section of North Rankin gas field, North West Shelf, Western Australia, showing multiple gas-bearing Upper Triassic and Lower Jurassic sandstone beds. The elevations of the gas-water contacts vary slightly in different fault blocks. (After Powell, 1976.)
ture of vast amounts of money. But these constraints will not deter the search for large reservoirs of oil provided that there are incentives of profitability and that developments to meet national energy requirements are given encouragement by government policies and legislation.
Crude oils are complex solutions of hydrocarbons that commonly are liquids within the normal ranges of temperature and pressure that obtain naturally at the earth's surface. Exceptions include oils with a high wax content, such as the oil from the Yardarino field near the Dongara gas field north of Perth. This oil does not pour at normal room temperature, and must be slightly warmed before it flows. Such oils cause problems as they leave waxy deposits that impede the flow through pipelines. Other exceptions are tarry oils having a gravity of 15° API or less. When warmed these heavy oils flow like treacle.

Crude oils are commonly referred to as either paraffinic or naphthenic depending on their relative contents of the normal and isoparaffin series of hydrocarbons, or of the naphthene series. Some oils contain substantial amounts of hydrocarbons in the aromatic series, but these compounds are rarely predominant. Also, oils that contain large amounts of heavy residue, such as hydrocarbons that have a high boiling range above 450°C, are referred to as asphaltic. The basic formula for the paraffin series is \( \text{C}_n\text{H}_{2n+2} \) (Fig. 4), for the naphthene series \( \text{C}_n\text{H}_{2n} \), and for the aromatic series \( \text{C}_n\text{H}_{2n-6} \). Basal members for these three series are \( \text{CH}_4 \) (methane), \( \text{C}_3\text{H}_6 \) (cyclopropane), and \( \text{C}_6\text{H}_6 \) (benzene).

No two crude oils are exactly alike in their chemical compositions. Also, when an oil is brought to the surface from a reservoir at depth it changes composition because of the decrease in temperature and pressure. One such change results from the loss of dissolved hydrocarbons that are gases within the range of atmospheric temperatures and pressures. The physical characteristics of crude oils are also variable. Differences in specific gravity range from heavy oils that barely pour to light oils having the consistency of kerosene. Colour ranges from black, through greenish browns, to amber and pale yellow. Crude oils may contain variable amounts of sulphur in compounds such as hydrogen sulphide, mercaptans, and disulphides. These tend to decompose, yielding free sulphur, and can cause problems in the refinery processing. Sulphur, in the calcium sulphates gypsum and anhydrite, and in the gas hydrogen sulphide, is commonly found in limestones. Oils produced from limestone reservoirs commonly contain more sulphur than those
produced from sandstone reservoirs. With the exception of a few traces of oil in limestones, Australian oils discovered to date are all in sandstones and have a very low content of sulphur compared with some oils from the Middle East.

![Chemical structures of hydrocarbons](image)

**FIGURE 4**
Diagram representing a few members of the paraffin series \((C_n \ H_{2n+2})\) of hydrocarbons, from the basic member methane \((C_1)\) to normal butane \((C_4)\). These members are gases within the range of normal atmospheric pressure above a temperature of 0°C.

Natural gases can also have a high content of hydrogen sulphide, particularly those produced from carbonate beds containing lenses or disseminated crystals of gypsum and anhydrite. Gases that contain hydrogen sulphide are referred to as sour, those that do not are called sweet. Most Australian gas found to date is of the latter category. Exceptions include some of the gas samples from the Tuna field in Bass Strait which had a hydrogen sulphide content as high as 45 parts per million, and gas in the Barrow Island field of Western Australia where hydrogen sulphide has corroded some of the older pipe fittings. In the Bass Strait area the sulphur is probably derived from coal associated with the gas-bearing sandstone beds. These coal seams are known to contain iron sulphide in the form of pyrite. The sulphur in natural gas, where abundant, can be extracted for industrial uses, but can be very troublesome while being produced and transported through pipelines. On contact with moisture hydrogen sulphide forms an acid which corrodes the metal with which it comes in contact.
Hydrogen sulphide is also a lethal gas in high concentrations, and 10 parts per million is considered to be the maximum concentration that can be breathed safely for short periods of time. Very low concentrations are readily detected by the smell of rotten eggs, but high concentrations deaden the sensory nerves and consequently have no offensive smell. This has occasionally, but rarely, caused fatalities at well sites in North America when sour gas has been encountered.

Natural gas commonly consists of more than 80 per cent methane by volume, with variable amounts of ethane, propane, and butane which are gaseous in the ranges of atmospheric temperatures and pressures. In addition, variable amounts of the liquid hydrocarbons in the paraffin series, such as pentane, hexane, etc. may also be in solution in the methane gas. Where the vapour phases of these liquid hydrocarbons are in solution the natural gas is referred to as wet gas. Otherwise it is dry gas. This wet constituent is stripped off as condensate, a form of raw motor spirit, during the refining process. Also separated from the methane are the gaseous fractions, such as propane, which are contained under pressure in cylinders as liquefied petroleum gas (LPG).

The Moomba field of South Australia yields gas having a methane content of 77 per cent by volume and an unusually high content (20 per cent) of carbon dioxide. This carbon dioxide is separated from the gas before transmission through the pipelines to Adelaide and Sydney. The gas is also wet and yields up to 7900 litres (approx. 50 barrels or 1750 Imperial gallons) of condensate for every 30,000 m³ of natural gas produced.

**Hydrocarbon Generation**

How are crude oil and natural gas formed? From what substances are they derived, and under what conditions are they generated? These and associated questions have been asked by geologists and geochemists for many years. Slowly, the physicochemical and geological relationships that control the generation of hydrocarbons in sedimentary rocks have become better understood in general terms, although some of the specific chemical reactions and physical processes that characterise particular geological situations are open to various interpretations. In other words, geologists and geochemists are still uncertain about some aspects of the generation and primary migration of crude oil and natural gas.

In general, it is agreed that hydrocarbons are derived from the maturation of organic matter disseminated in sediments and buried over long periods at ranges of temperature and pressure that obtain at depths of several hundreds to thousands of metres. Certainly methane, the main constituent of natural gas, forms in marshes from
the decomposition of vegetation, and in sediments buried a few tens of metres below the floor of lakes and seas. Methane is also generated at depths of several thousand metres, and so has a wide range of pressure-temperature conditions at which it can form. But light oils are not known to be generated at or near the surface, and experimental work by Tissot and Welte (1978) and many others indicates that the optimum temperature range for the generation of crude oil is found at a depth of 1.5 to 3 km. Gas also forms within this range but appears to have its optimum development at depths of more than 3 km. The geothermal gradient or rate of increase of temperature with depth varies from place to place on the earth's surface but averages about 1°C per 30 m of depth. This increase in temperature at any determined depth is added to the mean temperature at the surface. On this basis, allowing a surface temperature of 15°C, the depth range 1.5 to 3 km has a temperature range of 65°C to 115°C. In other words, the optimum temperature range at which light oil forms is hot to boiling, with reference to water at sea level. Assuming that the pressure gradient is hydrostatic, that the rock layers are saturated with salt water, and that the pressure gradient is 0.44 psi (pounds per square inch) per foot of depth, the pressures within the depth range 1.5 to 3 km vary from 2200 psi to 4400 psi. That is to say, the temperature is that of hot to boiling water at sea level, and the pressure ranges from one to two tonnes per square inch. It is under these conditions, and probably during a period of tens or hundreds of thousands of years that the maturation of organic matter and the generation of crude oil takes place. Available data indicated that temperature is the important factor in the generation of oil, but that pressure is the significant factor in primary migration.

The period of time necessary for the generation of oil under these conditions of temperature and pressure is not known. Organic matter disseminated with the sediments is gradually buried, but at various rates depending on the depositional environment. In active deltas of very large rivers the rates of sedimentation of prodelta muds and silts deposited out to sea can be up to 4 m in 1000 years. At a depth of 3 km compaction will have reduced this thickness to possibly 2.5 m, so that at the very least it will have taken well over 1 million years to bury the organic matter to depths at which the optimum temperature range for the generation of oil is obtained. Even assuming continuous sedimentation, it is probable that many millions of years are required to bury the sediments to depths where the oil is generated. This is not to say that several million years are required to generate oil. The organic matter or the precursors of oil formed from organic matter may remain essentially unaltered as kerogen and other matter until the optimum temperature range, at a depth range of 1.5 to 3 km, is reached.
It is possible that given the required temperature range the time required for the generation of oil may be comparatively short compared to the time during which the organic matter was buried with the sediments.

Organic matter, derived predominantly from algae, pollen, and vegetation, or from pelagic and benthonic organisms, is disseminated in all sediments but is particularly prevalent in muds, both non-carbonate and carbonate. The muds can accumulate in fresh or salt-water lakes, or in the oceans. Where organic matter has been deposited in oceans it may have been partly derived from the land. This especially applies to delta muds of large rivers which carry vast quantities of macerated and colloidal organic matter. It is believed that crude oils derived from such terrigenous matter are characterised by a relatively high content of wax (Hedberg, 1968).

The following examples have been given to illustrate the quantity and fate of organic matter deposited in large inland bodies of water. Deuser (1971) found that of the approximately 100 million tonnes of organic carbon discharged into the Black Sea every year, only about 4 per cent was preserved under anoxic conditions in the muds. The rest was recycled in the upper zones of the sea by oxidation and photosynthesis. This is a considerably higher rate of preservation than is general in the open oceans where, according to Tissot and Welte (1978) the average rate throughout geological history is probably less than 0.1 per cent. In land-locked bodies of water such as inland seas and large lakes, where there is no adequate outlet of water to balance the intake and allow circulation, conditions for the preservation of organic matter are favourable. Such conditions are likely to produce organic-rich sediments that on burial are transformed to kerogen-rich oil shales.

Another example can be cited of organic matter transported to the delta of a great river. Williams (1968) estimates that the Amazon, which has a water discharge into the Atlantic Ocean amounting to about 20 per cent of the total discharge from all the rivers in the world, annually carries 10,000 million tonnes of organic carbon to the sea, of which only 10 million tonnes is dissolved. If 0.1 per cent of this organic carbon is preserved in the delta muds, by sedimentation of particles of organic matter, or by precipitation of colloidal organic matter resulting from the mixing of fresh and salt water, then 100 million tonnes of organic carbon is buried each year in the sediments of the Amazon delta. This may appear to be a tremendous volume of organic carbon; but assuming that the area of sedimentation within and adjacent to the Amazon delta covers 400,000 km², the thickness of a carbon layer spread over this area would be only a fraction of a millimeter. The organic carbon is not in the form of free carbon, but incorporated in organic compounds. To convert the
weight of organic carbon to the weight of terrigenous organic matter in which it is contained, the figure for carbon is multiplied by 1.7 which is the approximate factor used by soil chemists. On this basis the estimate of organic matter buried annually in the Amazon delta amounts to nearly 200 million tonnes.

Analyses of near-shore marine sediments in various parts of the world (Trask, 1939; Stetson and Trask, 1953; Rao, 1960; Gehman, 1962) indicate that the organic matter in clay and carbonate muds is commonly 1 to 3 per cent by weight. On the other hand, analyses of shales formed from clay muds, and of limestones formed from carbonate muds, show different ranges of organic content. Commonly, the shales range up to 1.5 per cent whereas the limestones contain less than 0.5 per cent (Ronov, 1958; Hunt, 1962). These differences indicate that whereas both clay muds and carbonate muds contained approximately the same average content of organic matter, the shales derived from the clay muds have retained much more than the carbonates. The explanation probably lies in the ability of clay minerals to adsorb organic compounds.

It must be kept in mind that the organic content of a sediment should be considered in context with its depositional environment and rate of sedimentation. For example, the sediments in a delta may annually be receiving much greater quantities of organic matter than sediments in adjacent coastal areas. Yet because of the relative high rates of sedimentation in the delta, the sediments may contain less organic matter by percentage of weight than sediments from the other coastal areas. Consequently, with reference to the possibility that certain sedimentary strata may have generated petroleum and qualify for classification as source beds, the volume of rock involved (and the percentage weight of contained organic matter) are prime considerations.

The geochemistry of the transformation of organic matter to hydrocarbons is discussed in detail by Tissot and Welte (1978). Much of the matter is converted through various stages to kerogen, an amber to black solid, of variable physical and chemical composition, that is not soluble in water or organic solvents. Other organic compounds buried with the sediments may remain essentially unchanged as geochemical fossils. These include fatty acids, porphyrins, alkanes, terpenes, and steroids. Porphyrins are of particular interest as they are commonly present in crude oils, and significantly are chemically and molecularly related to the green pigment chlorophyll in plants and the red pigment hemin in animals. On deeper burial the kerogen suffers thermal degradation within the depth zone 1.5 to 3 km, resulting in the generation of crude oil. At still greater depths the remaining fractions of kerogen undergo a cracking process that generates natural gas consisting of
methane and light hydrocarbons. The end product is a carbon-rich black residue termed pyrobitumen.

It has been argued by some earth scientists, particularly in the USSR (Porfir'ev, 1974) that crude oil and natural gas are formed by inorganic processes. Such processes can be carried out in the laboratory at high temperatures which would destroy the porphyrins found in crude oils. The presence of porphyrins is inferred (by the proponents of an organic origin) to indicate derivation of the oil from organic sources. The proponents of an inorganic origin argue that the oils may have dissolved the porphyrins from organic matter in the rocks through which they passed during primary migration. A simple example of an inorganic process that produces a hydrocarbon is the generation of acetylene ($\text{C}_2\text{H}_2$) from calcium carbide and water. Acetylene gas burns brightly and was used decades ago in carbide lamps. The calcium carbide is formed by heating limestone to drive off carbon dioxide and form calcium oxide which is heated with coke (carbon) to form calcium carbide. A further conversion from the hydrocarbon acetylene to hydrocarbons of the paraffin series can be carried out in the presence of a nickel catalyst by adding hydrogen to form ethane or propane. But these and similar reactions require much higher temperature than those which occur in sedimentary basins; and although the generation of hydrocarbons (particularly of methane) by inorganic processes may take place in nature, the known geological situations and volumes of oil preclude derivation from other than organic sources within the sediments themselves.

Within a pile of sediments several thousand metres thick there may be one or more accumulations of oil and gas that have been generated within the pile. These hydrocarbons have migrated from their source to a reservoir bed; but how they migrated and where they came from are open questions. A great deal of research over many years has been carried out on source-rock analysis, and chemical analyses may point to certain layers of rock as likely sources, as discussed by Tissot and Welte (1978). Yet in many areas of oil and gas fields the geological factors, particularly stratigraphic and structural relationships, are such that the probable paths and processes of migration, and hence the probable source beds, are not well understood.

In Australia considerable attention to the problems of source-rock identification and analysis has been given by de Jersey and Allen (1966); Conybeare (1966); Brooks and Smith (1969); Brooks (1970); Mathews, Burns and Johns (1970, 1971); Powell and McKirdy (1972, 1973, 1975); Shibaoka, Bennett, and Gould (1973); McKirdy and Powell (1974); Powell (1975); Kantsler, Smith, and Cook (1978); Saxby (1978); and Shibaoka, Saxby and Taylor (1978).
On the basis of stratigraphic relationships (Conybeare, 1966), the age of plant microfossils such as pollens and spores found in oil samples (de Jersey and Allen, 1966), and concentrations of extractable hydrocarbons (Mathews, Burns, and Johns, 1970, 1971) it appears that the most likely source for oil in the Moonie field of Queensland is the shaly mudstone sequence of the Early Jurassic Evergreen Shale, although a Permian source is not excluded. These sediments immediately overlie the oil-producing Precipice Sandstone. They are thought to have been deposited in a non-marine coastal to near-coastal environment, although a thin zone in the middle of the sequence contains marine microfossils and evidently represents a brief incursion of the sea.

In the Cooper basin of South Australia the Moomba and Gidgealpa gas fields, and the Tirrawarra oil and gas field appear to have derived their hydrocarbons from adjacent beds of carbonaceous and coal-bearing mudstones. The presence of oil in the Tirrawarra structure appears to be related to a much lower temperature than that characterising the areas of gas-bearing structures, as indicated by the lower degree of carbonisation of fossil plant matter (Kantsler, Smith and Cook, 1978). The variations in geothermal gradients that caused these temperature differences are believed to reflect proximity to intrusions of magma.

Studies by Saxby (1978) and Shibaoka, Saxby and Taylor (1978) indicate that the source of oil in the offshore fields of the Gippsland basin in Victoria is solid organic matter, derived from algae and land plants, buried in sediments of the Latrobe Formation at depths greater than those of the producing zones. It is inferred that the oil was generated in beds of Late Cretaceous to Paleocene age, and migrated up-dip to structural-stratigraphic sandstone traps beneath the unconformity with the overlying mudstone caprock of the Oligocene Lakes Entrance Formation. It is possible that oil and gas are still being generated and migrating upward. Comparison of the Cooper Basin and Gippsland Basin fields suggests that the predominant gas content of the former results from the fact that its organic matter has been buried at higher temperatures than that in the Gippsland Basin, as indicated by the higher reflectivity of vitrinite in the sediments of the Cooper Basin.

In the North West Shelf and Exmouth Plateau regions of Western Australia the very large gas and minor oil accumulations in Triassic sandstones of the Goodwyn, North Rankin, and Angel fields are believed to have been derived principally from Jurassic but possibly also from Triassic sediments.

**Primary Migration of Hydrocarbons**

Primary migration refers to the initial movements of oil and gas from sediments in which they were generated to porous and permeable
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beds in which they are accumulated. Sedimentary piles consist of many hundreds to several thousand metres of compacting beds of clay, sand, and carbonate deposits. Most of the organic matter in such a pile is in the clays and carbonates. As the pile is buried deeper and is subjected to increasing temperatures, much of the organic matter is converted to kerogen which subsequently is transformed by a chain of reactions to hydrocarbons. The sedimentary pile becomes a natural refinery in which thermal degradation and cracking processes occur. During these processes a percentage of some of the hydrocarbons formed is squeezed out, either as a separate phase or removed in solution with water expelled by compaction of the sediments. The mechanisms by which this primary migration of hydrocarbons is effected are not understood with certainty, although the probable physicochemical principles involved are well known.

When first deposited, muds contain up to 60 per cent water by volume. These mud slurries are soon compacted by settling of the solid matter consisting of very fine particles of rock minerals and colloids of clay minerals. The results of studies (Dickinson, 1953; Hedberg, 1974; O'Connor and Gretner, 1974) on the loss of porosity with depth in different sedimentary basins vary according to the nature and volume of the sedimentary layers in each; but in general, at a depth beneath the ocean floor of 1 km, the porosity of the silty clay sediments lies in the range 20 to 25 per cent. In the original mud slurry the total solids component of the mud is 40 per cent by volume. In the compacted sediment at a depth of 1 km the total solids component of the sediment is 80 per cent by volume. Expressed another way, if the mud slurry contains 20 cc of solids and 300 cc of water, the compacted sediment contains 20 cc of solids and 5 cc of water. In other words, 25 cc, amounting to more than 80 per cent of the original water, has been squeezed out. Most of this reduction of pore volume takes place at shallow depths within the first 500 m. At depths of more than 1 km it becomes progressively more difficult to squeeze water from the sediments until, at a depth range of 1.8 to 2.4 km an additional amount of molecular-bound water is released as the result of a transformation of clay minerals from montmorillonite (smectite) to illite. This final expulsion of water may be a significant factor in the primary migration of hydrocarbons from the source beds, especially as it takes place within the depth range most favourable for the generation of oil.

It has been known for a long time that many hydrocarbons are soluble in water. Methane, the main constituent of natural gas, is relatively more soluble than ethane, and much more soluble than propane and butane which are the other constituents of natural gas. McKetta and Wehe (1962) point out that at a temperature of 38°C and a pressure of 70 kg/cm² (approx. 1000 psi) the solubility of methane in fresh water is 1.5 times that of ethane, 5 times that of
propane, and 20 times that of butane. Differential solubility increases with pressure, and at the same temperature but at 700 kg/cm² (10,000 psi) methane is 4 times more soluble than ethane, 20 times more than propane, and 50 times more than butane. We have already seen that the depth zone for optimum generation of methane has pressures in excess of 4400 psi, and it is probable that fractionisation of these lighter hydrocarbons takes place by means of differential solution and squeezing out of the water by compaction of the sediments. The solubility of hydrocarbons in fresh water is greater than that in salt water, but the same general relationships of solubility to pressure apply also to salt water, which is the normal pore fluid of buried sediments. At a pressure of 5000 psi the solubility of the hydrocarbon components of natural gas (approx. 95 per cent methane, 5 per cent ethane, propane, and butane) may be as much as 0.5 m³ (20 cubic feet at sea level pressure) in 1 barrel of water (Levorsen, 1967). The components of crude oil (particularly those in the petrol range C5 to C10) are also soluble in water within the pressure ranges found at depths of 1.5 to 3.0 km (the optimum zone of oil generation). At atmospheric pressure 1.4 volumes of the lighter constituents of crude oil can be dissolved in 10,000 volumes of water (Levorsen, 1967). At depths of more than 750 m and at corresponding pressures above 70 kg/cm² (1000 psi) the solubility is considerably increased.

By the time sediments have been buried to the depths at which the optimum generation of oil takes place, the porosity of fine-grained non-carbonate sediments such as clay muds and silts has been reduced to about 20 to 25 per cent. Further burial to depths at which the optimum generation of natural gas (methane) takes place reduces the porosity to about 15 per cent. In other words, in passing through the depth zone at which the optimum generation of oil occurs the sediment undergoes a loss of porosity, and consequent expulsion of water by compaction, of about 7 per cent. A further 5 per cent is lost in passing through the deeper optimum zone of generation of methane. These figures are generalised, as they vary somewhat with the sequence and lithology of strata in different sedimentary basins.

The magnitude of hydrocarbon loss by solution in expelled water can be estimated in the following example. Consider a thin and local lenticular bed of silty clay, averaging 30 m thick and having an area of 40 km², that has been buried to the zone of oil and gas generation. The volume of sediment is 1200 million m³, of which 5 per cent or 60 million m³ (375 million barrels) is expelled as water. This volume of water can dissolve 60,000 m³ (375,000 barrels) of oil or 200 million cubic metres (7.5 billion cubic feet) of methane.

Other beds of silty clay may have areal dimensions that are 100 or more times larger, and the water expelled from these beds may carry
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up to 4 million barrels of oil, or 20 billion m³ (700 billion cubic feet) of methane in solution. In addition, the sedimentary sequence in a sedimentary basin may have several such beds, or one measuring a few hundred metres thick, in which case the cumulative amount of hydrocarbons removed in solution could be up to 40 million barrels of oil or 200 billion m³ (7 trillion cubic feet) of gas. By way of comparison, the Moonie oil field in Queensland originally contained about 55 million barrels of oil, of which not much more than 25 million barrels may ultimately be recovered; and the proven initial recoverable reserves of natural gas in the offshore fields of Victoria amount to about 220 billion m³. From these figures it would appear that although much of the natural gas may have primarily migrated from the source beds in solution.

The possible processes by which oil has migrated through sedimentary rocks have been under investigation for many years. Because of surface tension, droplets of oil do not readily move through water-saturated rocks from one pore space to another. So oil dispersed throughout such rocks as minute globules is highly resistant to mobilisation through pressure. Clots of oil move more readily, depending on the porosity and permeability of the rock. Also, oil will move with comparative ease from a finer-grained rock into a coarser-grained rock, such as from a silty mudstone into a sandstone, but resists movement in the reverse direction. This selective movement is obviously an important factor in the primary migration of oil into beds of permeable sandstone and carbonates. The degree of water saturation of the porous rocks is another factor, as the oil must displace, or be carried by the water. A further consideration is the fact that water and oil, at depths where primary migration commonly takes place, are at temperatures close to or in excess of the boiling point of water at sea level. Such a temperature range will considerably lower the viscosity of oil.

Recent investigators of the problems of primary migration of petroleum include Cartmill and Dickey (1970); Chapman (1972); Schmidt (1973); Cordell (1972, 1973); McIver (1974); Magara (1974, 1976); Perry and Hower (1974); Saxby and Shibaoka (1975); Wilson (1975); Cartmill (1976); Price (1976); Hunt (1977). Several of these are of the opinion that an important factor in the primary migration of oil from source beds is the presence in formation water of soaps such as sodium naphthenate which has probably been derived from naphthenic acids. Carboxylic acids have also been reported in crude oils and can forms soaps in formation water. These soaps form micellar solutions in which the individual micelles consist of numerous molecules. Hydrocarbons can be selectively dissolved in micelles of various types and sizes. However, the size of solubilising micelles may be a limiting factor to the depth range in which they
can move through the pore spaces of fine grained source rocks. According to Tissot and Welte (1978), the decrease of pore space caused by compaction at depths exceeding 2000 m may prevent further movement of the larger micelles. This depth is within the upper part of the range for optimum generation of oil. Such a mechanism, by which hydrocarbons in solution in soaps are transported with the formation water squeezed out by compaction, may be of significance in the primary migration of oil at comparatively shallow depths.

To what extent primary migration of hydrocarbons is effected by dissolution in formation water, in colloidal or miscellar solutions, or by pressure-drive of hydrocarbons through pore spaces and minute fractures is not known. The answer probably depends on the particular geological conditions and depths that obtain in the zones of petroleum generation within various sedimentary basins. The time of migration is another problem to which there is no satisfactory answer. It seems probable that oil and gas will be generated when the organic matter in the sediments is subjected during a certain period of time to the appropriate range of temperature for the optimum generation of various hydrocarbon fractions. This condition depends on the rate of burial, which is a function of the rates of basement subsidence and sedimentation. Basement subsidence is related to tectonic movements of the earth’s crust; and rates of sedimentation are related to the geomorphology of the coastline and sea floor. Migration of hydrocarbons may occur as soon as they are generated and be a continuing process over a very long period. Cores of sediments taken from beneath the sea floors in deep water of the Gulf of Mexico, on the Shatsky Rise of the Pacific Ocean east of Japan, and in the Mediterranean Sea contained traces of both tarry and light oils (McIver, 1974). The tarry oil or bitumen may be a young, immature hydrocarbon formed at comparatively shallow depths, or a biodegraded lighter hydrocarbon that migrated from deeper zones. The presence of light fractions suggests rapid migration from deeply buried sediments in the zone of oil generation, or more likely seepage from subcrops of older oil-bearing rocks. Such marine seepages are known to occur off the coast of California where lighter oil moving upward through the sea floor sediments becomes oxidised and tarry in consistency, forming stringers of bitumen which break off and float to the surface, where they are washed ashore. Similar occurrences of natural bitumen have been found along the coast of Victoria and South Australia, but the origin of these is obscure. It has been suggested that hydrocarbons in the Gippsland Basin and North West Shelf are still being generated and migrating up-dip into present structural traps and sub-cropping beds beneath the sediments of the ocean floor. Some credence to this idea
is supported by the hydrostatic continuity between the ocean and the oil-bearing reservoirs of the Halibut and Kingfish oil fields, as indicated by the fact that reservoir pressures rise and fall in sympathy with but lagging behind fluctuations of the tides (Khurana, 1976).

Accumulation of Oil and Gas
Primary migration of hydrocarbons results from the movement of oil (or its precursors) and gas from the sediments in which they are generated to more porous and permeable sediments in which they may be stored. Water moves freely, albeit very slowly, from one porous and permeable bed of sediment to another, but oil tends to be selectively trapped in the coarser sediments, depending on the degree of pressure to which it is subjected. Thus, if oil and water are forced through a tube containing alternating layers of fine silt and coarse sand, the water will pass through all the layers, but the oil will be trapped in the first layer of sand. When that layer is saturated with oil the mixture will then move through the adjacent layer of silt to the second layer of sand where more oil becomes trapped. Only when all the layers of sand are filled with oil will both water and oil be expelled from the end of the tube. This type of selective absorption of oil conforms with the capillary behaviour of immiscible fluids in porous media. On the other hand, extremely fine droplets of oil, much smaller than the pore diameters through which they pass, are apparently not so much affected by capillarity as by electrostatic forces, and appear to flow freely through sand. Cartmill and Dickey (1970) report that when a fine oil-water emulsion consisting of 20 to 40 parts oil per million parts water is passed through a coarser layer to a finer, the oil accumulates at the interface. The reason for this phenomenon is not understood but may be related to electrical charges on the surface of the oil droplets.

It is unlikely that saturation points are reached during the natural migration of oil into sandstone or porous limestone beds, except possibly where thin lenses of sandstone are enclosed in source beds of claystone or shale. Commonly, the oil or gas accumulation is underlain by water in the sandstone or limestone reservoir. These gases and fluids occupy the connected pore spaces and fractures in the rock and cannot be considered to constitute a ‘pool’ in the popular concept of the word. Such primary accumulations may continue to grow. Alternatively, they may cease to grow because the source of hydrocarbons becomes depleted or is cut off by earth movements. For every accumulation of oil or gas that is economically viable to produce, there are many very small accumulations that would yield only traces of oil or puffs of gas on drill-stem tests. Yet
the cumulative volume of such dispersed accumulations in a sedimentary basin may be huge.

As the layers in a sedimentary basin subside by compaction, are tilted, and become deformed by faulting and folding, the initial accumulations of oil and gas adjust themselves to accommodate new hydrostatic equilibria, or move upward along the sedimentary layers to other structural-stratigraphic traps. This process of secondary movement may not take place until the original trap is full and spills over into another trap. This situation could arise where the oil-bearing bed has been tilted and deformed by two or more adjacent anticlinal folds which form potential traps. Alternatively, migration may be a continuous process that takes place as the result of penecontemporaneous movements of the sedimentary strata during the period of hydrocarbon generation. In some sedimentary basins the spill-over of hydrocarbons from one trap to another may result in the differential entrapment of hydrocarbons, gas being trapped in the lower structures and oil in the higher (Gussow, 1953). In a single trap gas occupies the structurally highest position, underlain by oil which in turn is underlain by water. The addition of gas will force down the gas-oil level and eventually cause the oil to spill over to the adjacent and structurally higher trap. In all such cases there must be continuity of permeability from one trap to the other, such as provided by a sequence of anticlinal folds at various elevations within the same sandstone bed, by interconnected lenses of sandstone in tilted strata, or by a connected chain of carbonate reefs. Distinctions between primary and secondary migration of hydrocarbons, primary and differential entrapment, or flushed and productive reservoirs can only be made on the basis of inference or knowledge of the geological history of the sedimentary basin.

In Australia, oil and gas have probably been generated and accumulated in various sedimentary basins for hundreds of millions of years. Geological evidence suggests that some pre-existing reservoirs may have been destroyed by erosion which allowed the oil and gas to seep out and escape to the surface. The earliest record of an oil-seep in Australia is that mentioned by Stokes (1846) of bitumen in a well situated close to the estuary of the Victoria River where it flows into Joseph Bonaparte Gulf; but this seep has never been relocated. Although no oil or gas field has been discovered in the Cambrian carbonates of the Georgina Basin in north-central Australia, the sediments are reported to be locally impregnated with bitumen (BMR Report 41A). This suggests that at one time there may have been oil accumulations in the Cambrian limestone beds, and that erosion has long since removed them. In the Amadeus Basin of central Australia the gas-bearing Pacocka Sandstone forms the reservoirs in the anticlinal Mereenie and Palm Valley fields. Else-
where the Pacoota is exposed in the cores of anticlines that have been breached by erosion. These may also, at some time in the past, have been petroleum-bearing.

The oil and gas fields discovered in Australia to 1979 are essentially structural traps with elements of stratigraphic control. In the Moonie field of Queensland the oil is trapped in two separate sandstone layers within the Jurassic Precipice Sandstone of the Surat Basin. These layers have been locally deformed into an elongate dome by compaction and draping over a basement ridge of Permian and Triassic rocks. This ridge is bounded by a fault which appears to have been active since the deposition of the Precipice Sandstone. The source of the oil is most likely the Jurassic Evergreen Shale which stratigraphically overlies the Precipice, although the underlying Permian may also be a source. Primary migration of oil from a source bed to a potential reservoir bed may be in any direction as fluids will follow the more permeable paths of least resistance. As the permeability of a sedimentary bed is commonly higher along the bedding planes, oil migrating from the Evergreen in deeper parts of the basin was probably carried upward along the sandstone layers of the Precipice. The mechanisms and physicochemical processes by which the oil may have been transported are not known; but Conybeare (1970) has suggested that, as the comparative freshness of the Precipice formation water (up to 4000 parts per million) indicates a hydrodynamic condition, oil may have been carried upward in solution from deeper zones within the sedimentary basin. The sandstone layers of the Precipice offer little impediment to the flow of water as they have good permeability which locally ranges up to 2 darcys.

It is of interest to note that the present depth of the Moonie field is approximately at the top of the range for optimum oil generation. One can speculate that unless the sedimentary strata of the Surat Basin have been buried appreciably deeper, only a minor volume of the Evergreen Shale (that portion presently at depths of more than 1500 m) will have largely contributed to the generation of oil. The implication of this premise to exploration for oil in the Surat Basin is that most of the oil generated in the Evergreen will be trapped in closed structures within the Precipice in areas peripheral to the central and deepest part of the Surat Basin. A structure map of the upper surface of the Precipice shows that the deepest area lies between the Moonie and Alton oil fields, both of which are at about the same depth. Oil and gas moving in an aqueous solution from deeper to shallower depths will come out of solution as decreases of temperature and pressure cause the solubilities of hydrocarbons to reach saturation points. They will then migrate upward through sandstone beds until they become trapped in closed structures.
formed by folding, faulting, and pinching out of beds. The first traps reached will be the ones to be filled, and these are likely to be peripheral to the deepest part of the Surat Basin.

From the foregoing it might be concluded that exploration for oil and gas in sandstone beds of the Precipice and other Mesozoic formations in Queensland is simply a matter of drilling structures indicated by seismic surveys to be potential traps. Unfortunately, the exploratory boreholes drilled into many good seismic structures have proved to be dry. For example, some of the oil and gas-bearing Triassic and Jurassic sandstone intervals of the Surat Basin were deposited by rivers. Consequently, they have internal differences in the distribution, porosity, and permeability of individual sandstone members. This factor complicates the search for hidden reservoirs in that some of the coarser sands, which were deposited in topographically low areas, pinch out on the flanks of ancient buried hills, which are reflected as seismic anomalies. Also, the sandstone beds draped over such hills may form structures that are closed but tight, whereas the coarser sandstone beds in structurally lower positions may contain oil or gas. In the search for these elusive traps it may be necessary not only to map the present structural configuration of the prospective sandstone bed, but also to reconstruct the topography of the surface as it was when the river sands which formed the sandstone were deposited. This aspect of geomorphology is an important consideration in estimating the possible paths of migration and areas of entrapment of oil and gas.

The Barrow Island oil field off the North West Cape of Western Australia lies within the culmination of a gentle northward-plunging anticline. This plunge or inclination is toward the general direction in which the sedimentary basin thickens, and probably also in the direction from which the oil has migrated up-dip along the beds of sandstone. The producing Cretaceous Windalia Sand is broken into numerous blocks by small faults trending north-east and south-east, and bounded on the south-east flank by a major north-east-trending fault. Structural complications, variable distribution of interbedded tight shale layers, and inhomogeneity of porosity and permeability of the sandstone have caused problems in oil production. Consequently, it has been difficult to make estimates of ultimate oil recovery; although detailed geological and reservoir engineering studies of the Barrow Island field (Williams, 1977) carried out over a period of years have greatly added to West Australian Petroleum's knowledge of the field and expertise in its exploitation.

Anticlinal structures are also key features in the entrapment of gas in the fields of the Cooper Basin in north-eastern South Australia. These anticlines trend north-east and form a complex tectonic pattern. Other factors in the accumulation of gas in this area are tilting of the strata caused by compaction of the sedimentary beds
over buried hills of basement rock, faulting of the strata, and variations in porosity and permeability resulting from the original depositional distribution of the fluvial and lacustrine sediments in which the gas occurs. The latter factors in particular have been described by Thornton (1973).

The Barrow Island field and the Cooper Basin fields all occur in folds or domes (Fig. 5), but have stratigraphic differences. The Windalia Sand is marine, very fine grained, tight, and relatively widespread, whereas the Permian sandstones of the Cooper Basin (the Patchawarra and Toolachee formations in particular) were deposited as river sands and have variable petrophysical characteristics and distributions. Although classifications of oil and gas reservoirs are seldom entirely satisfactory, because in many cases they must be qualified, it can be said that the Barrow Island oil field is primarily a structural trap, whereas the Cooper Basin gas fields are structural-stratigraphic traps.

The Kingfish oil field and the Marlin oil and gas field of the Gippsland Basin, Victoria, are interesting examples of hydrocarbon accumulations in multiple sandstone layers of the Eocene Latrobe Formation. These layers are gently folded, inclined, eroded, and capped by tight mudstone of the Oligocene Lakes Entrance Formation. The Eocene sandstones, which are interbedded with mudstones and coal seams, were deposited in coastal environments and buried by younger sediments. Warping and gentle folding, possibly resulting from compaction, may have occurred. Subsequently, the beds were uplifted, tilted, eroded, and again buried as they subsided beneath the Oligocene sea. Submarine valleys, such as that flanking the Marlin field (Griffith and Hodgson, 1971) were present on the sea floor, possibly following channels formed during the period of uplift by subaerial erosion. These submarine valleys became filled with marine muds which formed a thick blanket over the buried topography.

The essential feature of entrapment in both the Kingfish and Marlin fields is that the oil and gas are trapped within inclined sandstone beds of the Latrobe Formation in buried hills overlain by mudstone caprock of the Lakes Entrance Formation. The configuration of the erosional surface between the Latrobe and Lakes Entrance is thus a key element in the accumulation of oil and gas. These fields in the Gippsland Basin have both structural and stratigraphic features; but if the erosional surface is defined as a stratigraphic feature, then the field can be classified as essentially stratigraphic-structural.

The Rankin field of the North West Shelf in Western Australia comprises a number of Triassic sandstone beds within a thick sequence of sandstones and mudstones. The sandstone beds in the field have a cumulative thickness of approximately 300 m (Kaye,
FIGURE 5
Structural cross-section of the Della gas field, Cooper Basin, South Australia, showing gas (black) trapped in a dome of sandstone beds draped over a pre-Permian hill. Vertical exaggeration x10. (Modified after Pyecroft, 1973.)
FIGURE 6
Generalised structural cross-section of the continental shelf and slope off the north-west coast of Western Australia, midway between Dampier and Darwin. No vertical scale. (Modified after Powell, 1976.)
Edmond, and Challinor, 1972). These beds are inclined basinward, truncated by faults, and locally thrust upward as blocks of strata termed horsts. The blocks are largely buried under mudstone deposited as marine muds in the Jurassic sea, although the higher parts remained as landmasses or islands until they were finally inundated by muds of the Cretaceous sea. These mudstones form the caprock for gas trapped within the sandstone beds. The faults bounding the blocks were initiated during the latter part of the Jurassic Period and continued to grow during the early part of the Cretaceous Period. These fields can be classified as essentially structural. Migration of gas, possibly from deeper zones of the Dampier Basin, may have begun during the Jurassic, but the major accumulation of gas probably took place during the Cretaceous and Tertiary.

Other accumulations of hydrocarbons in structural traps are the non-producing Mereenie oil and gas field and the Palm Valley gas field of the Amadeus Basin in the Northern Territory. This gas is contained within the Ordovician Pacoota Sandstone which is anticlinally folded and capped with impermeable shale.

A noticeable feature of all the Australian oil and gas accumulations discovered to 1979 is that they are in beds of sandstone. Also, Australian oils have a comparatively high content of the lighter hydrocarbons that constitute petrol, and are very probably derived in large part from terrestrial and deltaic organic matter. Middle East crudes, derived from marine organic matter and produced from limestone, are heavier crudes with a higher content of the hydrocarbon fractions in diesel fuels, lubricating oils, and tar. Limestones are also important oil and gas producing beds in North America. Australian limestones of Cambrian age in the Georgina Basin of north-central Australia appear to have contained accumulations of hydrocarbons at one time, as indicated by the presence of bitumen stain within the rocks. Ordovician limestones are present in the southern and deepest part of the Georgina Basin. Their petroleum content is unknown, although seismic studies carried out by the Bureau of Mineral Resources in 1977 have up-graded their prospects (Harrison, 1979). Devonian limestone reefs of the Canning Basin in Western Australia may offer prospects, and Devonian reefs may be present in the Adavale Basin of central Queensland.

Large areas of the Australian continental shelf (Fig. 6) are underlain by Tertiary limestone beds, some of which have good porosity. The main deterrent to the entrapment of oil or gas in these limestones appears to be the lack of adequate caprocks such as beds of mudstone. On the other hand, it must be emphasised that very little is known of the details of the Australian continental shelf stratigraphy.
For many years the question was asked whether petroleum prospects are better onshore or offshore. The answer has always depended on the discoveries made to date, the state of geological knowledge at the time, and the development of offshore drilling technology. Qualifications to the answer may also depend, particularly in the case of smaller exploration companies with limited resources, on economic and technological constraints arising from budgetary restrictions and consequent limitations to the services of personnel and the use of equipment (Swindon, 1978). For example, a small company might have the choice of drilling one offshore well or four onshore wells for the same price. Weighing up the chances of discovering a large oil or gas field with one well against the possibility of discovering a much smaller field with four wells, the decision may favour the onshore venture. Large international companies, with much greater financial resources, may decide to aim for the larger target, particularly as they can afford to drill more than one offshore well. The answer seems to be that there are different classes of prospects, suited to different sizes of purses. There are probably many small fields still to be discovered onshore, and it is to be hoped there are large fields awaiting discovery offshore. The cumulative production from several small fields in the Cooper or Surat basins can be appreciable; but the discovery of one large offshore oil field would be of major national significance.

During the 1950s the question of onshore and offshore prospects would hardly have been asked, primarily because nothing was known of the geology beneath the sea floor; but also because the only area that had yielded any significant quantities of oil or gas, other than the interesting discovery of the one-well Rough Range field in Western Australia, was the Roma area of the Surat Basin. For this reason, the Surat Basin was the main area of interest for exploration. Even so, there were those who were not favourably impressed with prospects in the basin because they equated petroleum with a marine environment, and saw only non-marine sandstones and mudstones cropping out around the rim of the basin. Today, most geologists and geophysicists engaged in exploration for petroleum would argue that the greatest volumes of oil and gas are much more likely to be found offshore than onshore. Whether these can be exploited as an
economically viable operation is another question, and will ultimately depend on the price the public is willing to pay for the energy it demands. This aspect of the question opens entirely new vistas relating to conservation of energy and socio-economic considerations that are beyond the scope of this chapter. But it should be said that, contrary to the view of many pessimistic experts of past decades who maintained that geologically Australia was too old a continent to have any worthwhile petroleum prospects, there are probably many onshore and offshore oil and gas fields waiting to be discovered and exploited when the need is sufficiently urgent. The danger lies in not looking far enough ahead to see the shortfalls in supply and the lag in time to discover and bring into production new fields.

Prospects that appear attractive to one company, authority, or government instrumentality may not necessarily appear attractive to another, and must be assessed in the light of what may be termed the philosophy of exploration of each company. Such a philosophy or outlook is subject to economic and political pressures. The development of some oil accumulations may be considered as only marginally profitable or uneconomic, yet in the future may proceed because of the urging of governments on the basis of conservation and maximum utilisation of energy resources, or for other reasons of national energy policies. Concessions to the oil companies concerned may be involved, and trade-offs on both sides may be determined during negotiations. The exploration outlook of major international companies operating in the North Sea, for example, is reflecting a reappraisal of smaller prospects which cannot possibly be as remunerative as the larger fields discovered in earlier years of exploration. The same processes of evaluation of offshore prospects in Australia will no doubt be required as exploration proceeds on the North West Shelf.

A review of onshore and offshore petroleum prospects in Australia, as in any other part of the world, involves basic questions with reference to geology, petroleum technology, economics, and politics. Firstly, does the geology of an area favour the possibility of finding oil and gas fields, and if so are they likely to be large or small? Secondly, can the oil or gas, if present, be produced, and what are the possible technological limitations? Thirdly, is it desirable from economic or political points of view to produce the oil or gas?

Answers to the first question depend on consideration of three main factors, the size of the area being evaluated, the geological history of each sedimentary basin being evaluated, and the petroleum generation potential and entrapment prospects of selected sedimentary basins. Australia has an onshore area of 7,682,300 km² (Atlas of Australia, 1977), is approximately the size
FIGURE 7
Map of Australia and Papua New Guinea, showing sedimentary basins and sub-basins. (Courtesy of ESSO Australia Ltd, from ‘Oil—The Vital Search’, ESSO Report, 1979.)

of the United States, excluding Alaska, and more than one and a half times the size of Europe. More than half of Australia is underlain by sedimentary basins (Fig. 7). The other areas are underlain by granitic and metamorphic rocks of Precambrian or Paleozoic age. Not all of the sedimentary basins are prospective. Some are too shallow, having basements of granitic rock at depths of less than 500 m. Others have thick sections of low-grade metamorphic rocks such as quartzite, argillite, and crystalline dolomite that have been buried too deep for the preservation of hydrocarbons, then uplifted and bevelled. Still others are essentially of sandstone, volcanics, and tuffaceous rocks that have insufficient organic matter to generate hydrocarbons in the quantity required to form oil or gas fields. The evaluation of areas, and determination of the percentage of area of the Australian continent that is prospective for oil and gas, depends
on a knowledge of the geological history of every sedimentary basin, and on basic premises regarding the generation and entrapment of hydrocarbons. The state of knowledge in these respects is increasing with the passage of years, but not necessarily at a uniform rate. Also, with increasing knowledge come modifications to old ideas, or new concepts which may result in a break-through in exploration outlook or practice, and consequently in the discovery of new oil and gas fields. One has only to look back thirty years and cast oneself in the situation of an exploration manager of an oil company to see how the advances in geological knowledge have had an impact on geological appraisals and exploration philosophy.

In addition to the land area of more than 7 million km² must be added approximately 2 million km² of the Australian continental shelf. The precise area cannot be stated, as rights to the sea bed have not yet been firmly delineated. The North West Shelf and Exmouth Plateau (off the continental shelf of Western Australia) occupy approximately 1 million km² and 250,000 km² respectively. By way of comparison, the area of the North Sea is approximately 500,000 km². The continental shelf of Australia lies between the coastline and the 200 m bathymetric contour. It is flanked on the seaward side by the upper part of the continental slope, the base of which flattens and merges into submarine rises or plateaus. The Exmouth Plateau (Fig. 8) extends seaward from the base of the continental slope off the coast between Onslow and Port Hedland, to depths of up to 3000 m, and is terminated by a second slope that extends downward to an abyssal plain.

Answers to the second question, whether oil or gas can be produced, and if so whether there are technological limitations to production, depend on many factors. These include depth of drilling beneath the sea floor, depth of water, production techniques employed, field reservoir characteristics, oil and gas characteristics, and other factors related to local geographical or climatic conditions.

Depth of drilling is an obvious limiting factor, not only because the cost per metre of drilling increases with depth, but because of mechanical problems in drilling at great depths. Some of these problems arise from increasing stress on the derrick structure, increasing torque on the drill pipe, and sudden sharp rises in pressure caused by drilling into overpressurised gas-bearing beds. Apart from mechanical difficulties, the overall rate of metreage drilled per day decreases dramatically with depth because every change of drilling bit requires the withdrawal, disconnection, stacking, reconnection, and lowering down the hole of the entire length of drill pipe (Fig. 9). This means that a change of drilling bit at a depth of 5000 m requires the drill pipe to be hauled up and disconnected into 166 lengths of approximately 30 m each. By the time
FIGURE 8
Map showing edge of continental shelf (200 m contour), gas fields of the Rankin trend, Barrow Island oil field, and exploration permit areas on Exmouth Plateau. (Courtesy of ESSO Australia Ltd, adapted from 'Oil—The Vital Search', ESSO Report, 1979.)

these lengths are reconnected and lowered down the hole it may have taken two full shifts to effect the change. Also, the metreage drilled by a new or reconditioned bit will vary with the rock type, and drilling into a hard rock such as quartzite may wear out a bit after 5 m of penetration. This limiting factor results in a situation where depths are reached beyond which the diminishing returns from drilling prohibit or discourage further continuation. It is not possible to quantify such depths without reference to the types of drilling equipment, and to the geological conditions and geographical situation in which it is used. In the United States, wells in the Great Plains and Gulf Coast areas have been drilled to depths well in excess of 7000 m. In Australia, several wells have been drilled to depths of up to 4000 m, and WAPET's Warro well in the Perth Basin terminated at a depth of 4854 m. This is the deepest well drilled in Australia to 1979. Innovations and improvements in drilling technology will continue to increase our ability to penetrate still greater depths within economically acceptable limits.
Diagram of an onshore drilling rig. (Courtesy of ESSO Australia Ltd, adapted from ‘Oil—The Vital Search’, ESSO Report, 1979.)
This last comment is equally applicable to the problems of offshore drilling in regions subject to severe turbulence of wind and waves, and in regions of deep water off the continental slopes. The history of offshore drilling has been one of gradual encroachment of the sea bed, from shoreline to shallow water and on to depths of several hundred metres. In earlier days the drilling rigs were fixed structures anchored to the sea floor. These types are still employed in shallow water. But deeper regions required floating drilling rigs that could be anchored by cables or made firm by legs that were lowered to the sea floor. A number of different types of such drilling rigs have been employed and will continue to be used in the exploration of continental shelves throughout the world. But as the search moved out to very much deeper water of the continental slopes and plateaus it became necessary to evolve new methods for drilling in water depths of up to 2000 m. The technology of deeper-sea drilling has advanced to the stage where exploration of the Exmouth Plateau is being carried out. Drilling in these depths requires the use of dynamically positioned drillships capable of maintaining the same position by means of several propellers positioned around the ship and programmed to react to variations in the movements of the ship. The first of such ships to be employed in the exploration of Exmouth Plateau is *Sedco 472* which drilled the Esso-BHP Zeewulf 1 well in a water depth of nearly 1200 m.

Problems arising from the effects of wind and water movements on ice floes are of no consequence in Australia, but of considerable relevance to petroleum exploration in the Arctic regions of Canada and the USSR where drilling rigs may be positioned on masses of ice, and where ice heaving can disrupt pipelines and other installations. These problems call for oceanographic and engineering studies that can lead to improved technology in drilling operations in the Arctic. It is hoped that this technology will allow the economic extraction of petroleum from Arctic, and possibly also from Antarctic regions, without undue harm to the ecology. Considerations of this nature add another facet to the question of whether oil or gas can be produced, subject to certain limitations. Such limitations are not only of a technological and economic nature, but are also of relevance to conservation of the quality of the environment.

Other aspects relating to the question of whether it is technologically feasible to produce hydrocarbons, and to the limitations imposed on production, are those concerned with the petrophysical and reservoir characteristics of hydrocarbon accumulations. Factors involved include the physical and chemical characteristics of the oil and gas, and the relative efficiency and practicability of different production methods and techniques. These aspects are related and mutually relevant. Production methods will depend directly on the
hydrocarbon and reservoir characteristics. For example, if the oil is heavy and tarry, having a specific gravity of less than 15° API, it may not be technologically feasible to produce the oil without using special recovery methods such as fire-flooding or flushing by steam. On the other hand, a rock layer may contain light oil or gas, but have such low porosity and permeability that it will not yield hydrocarbons unless it is artificially fractured. This can be done by pumping fluid, with clean sand or plastic pellets, into the formation at great pressure. The fractures formed are filled with sand and become permeable avenues for the transmission of oil and gas to the borehole. Examples are known of gas-bearing beds of quartzose rock, 200 m or more thick, which are too tight to yield the gas, but which might be brought into production by an underground explosion to shatter a column of rock in which gas could collect. A controlled atomic explosion has been suggested as a possible method for the production of gas from the tight, quartzose Pacoota Sandstone of Central Australia, but has obvious technical, environmental, and political constraints. Although most of the radioactivity would be contained in glass of melted rock at the bottom of the cavern formed by the explosion, some residual radioactivity would remain in the gas. Also, the gas-collecting cavity could itself be sealed by glass, as suggested by tests using this technique in the United States.

An excellent example of oil accumulations which pose the question of whether or not it is technologically feasible to put them into production, are those in the Cretaceous oil sands of Alberta, Canada. These accumulations are estimated to contain 600,000 million barrels of oil. The oil is contained in quartzose sand or friable sandstone that crops out or is buried at shallow depths. Current production is obtained by open pit mining methods where the overburden is not too thick. The sand is heated with steam to separate the tarry oil which is then processed to extract the sulphur and convert it to a lighter oil for transmission by pipeline to a refinery in Edmonton. Most of the oil in these beds is buried too deep for recovery by open pit methods, and for the past several decades investigations have been carried out to determine the effectiveness of methods designed to recover the oil from shallow boreholes. These include the fire-flood method, whereby the oil is set alight in some wells to heat and lower the viscosity of oil which is recovered by production wells ahead of the burning zone. Another method utilises superheated steam instead of fire. Other methods employ hot water and soaps to flush the sand from which an emulsion of oil and water is recovered. These methods are not to be confused with production of oil from so-called oil shales in Australia and elsewhere. These consist of torbanite (a coaly substance formed from an accumulation of pollen
and spores), or a kerogen (organic)-rich shaly rock which yields hydrocarbons only by destructive distillation at high temperatures.

Other technological limitations or constraints on the production capacity of oil and gas fields are related to the reservoir characteristics of the field or to structural and stratigraphic situations such as faulting or pinching out of beds. A reservoir may contain various proportions of oil and gas, the latter lying above the former, separated by a horizontal contact. Some gas is dissolved in the oil, and the gas may contain some condensate in the gaseous phase. Formation water commonly underlies the oil, or the gas where no oil is present. Where the water is salty it is probably connate water and is in large part residual, having been buried with the sediment and later migrated from one sedimentary bed to another. In such cases the oil-water contact is horizontal, and the situation is hydrostatic. Where the formation water is fresh, it commonly indicates an intake from meteoric sources. In these situations the water is slowly flowing, the oil-water contact is consequently slightly tilted, and the situation is hydrodynamic. Different elevations of oil-water contacts in various parts of a field do not necessarily indicate a tilted oil-water contact, as the field may be broken by faults into several separate traps. Such geological complications must be understood in bringing the field into production.

The proportions of oil and gas in a field, expressed as gross or net thickness in metres of oil or gas-bearing rock, are also important factors in reservoir engineering calculations designed to facilitate optimum production over a period of time. Most oil has to be pumped from the producing wells, although some fields will initially produce 'gusher' wells. Important elements in the production record of any field are the initial reservoir pressure, and the maintenance of pressure during the life of the field. Three factors are commonly involved: firstly, water drive resulting from pressure of the hydrostatic head of water pressing upward on the oil column; secondly, gas drive resulting from pressure of the overlying cap of compressed gas; and thirdly, solution drive resulting from the pressure of gas dissolved in the oil. The last factor can be compared to the pressure exerted by carbon dioxide dissolved in a bottle of soda water. All three factors, in varying degrees, may be significant in assisting or hindering the production of oil. For example, where a thick gas cap is underlain by a thin column of oil which in turn is underlain by water, it may be difficult to produce the oil. If production is obtained from too high in the oil-bearing section, the downward coning of oil will pull gas in with the recovered oil, thereby resulting in a loss of gas pressure. If the producing zone is too low, water will preferentially cone upward at the expense of the oil. In the former situation
the gas, along with gas that comes out of solution at the surface, may be burned in flares, or it may be used locally for heating and power generation. In other situations it may be economically feasible to re-cycle the gas back into the field. But in all cases decisions must be made as to technological and economic limitations of production.

The main drive may be a primary natural water drive, as in the case of the Gippsland fields of Victoria. Or it may be a secondary water drive, as in the case of the Barrow Island field of Western Australia, where more than half of the wells are used to pump water into the producing formation to maintain reservoir pressure during oil production. This method is referred to as water flooding and may introduce further problems arising from the invasion of water into permeable zones within the oil or gas-bearing sections (McKay, 1974). Technological and economic considerations played an important part in the decision to go ahead with the development of the Barrow Island field. These two considerations are closely related. From a technological point of view it may be asked whether it is physically possible to produce the oil, and if so, what limitations to production are likely to arise. In practice these questions must be considered with reference to economic factors such as the costs of bringing the accumulation into production, the price of oil, and the availability of markets.

A further limiting factor involving technological developments is the increasing difficulty in producing oil from an ageing field. By conventional production methods a situation of diminishing returns eventuates during the life of every field. This stage is commonly reached a few years after the field is first brought on stream, but will depend on the reservoir characteristics of each field and its production history. As the reservoir pressure declines and the rate of production falls, a point is reached where, depending on economic factors, it may no longer be sufficiently profitable for a company to continue its operations in a particular field. The company’s interests in that field may then be sold or transferred to another operator who may continue to produce oil at lower rates (possibly a few barrels of oil per well per day) or may attempt to revitalise the field and extract additional oil by enhanced recovery methods. For this reason the interests of Union Oil Development Corporation in the Moonie oil field of Queensland were sold to International Oil Ltd in 1973. Possible enhanced recovery methods for this field have been investigated.

It is unfortunate that 30 to 80 per cent of the oil in any field will ultimately remain in the ground unless technological developments in enhanced recovery enable this residual oil to be produced on an economically viable basis. Enhanced recovery can be obtained by several possible methods. Thermal stimulation by means of heat
treatment involving *in situ* combustion or steam injection has already been mentioned. The use of solvents injected into the oil-bearing formation is applicable in some situations where the solvents can soak through the reservoir to recover residual oil by miscible displacement. Another method involves the use of carbon dioxide which is injected into the reservoir to extract the lighter fractions from the oil. Some oil is also recovered by swelling of the gas-oil solution. In strata of variable porosity and permeability, or where the oil has a higher viscosity, the polymer flooding method may be effective when used in conjunction with brackish to fresh water injection of the oil-bearing formation. This involves the use of polyacrylamide and polysaccharide polymers. Another method involves the injection of detergents to lower the surface tension of oil in water-wet sedimentary rocks. Caustic soda may also be used as it reacts with organic acids in the oil to form emulsifying soaps which can be recovered and the oil separated.

A review of onshore and offshore petroleum prospects in Australia involves three basic questions with reference to geology, petroleum technology, economics, and energy policies. So far, the first two have been discussed, with some reference to economics as it relates to technology. The third question is whether it is desirable to produce the oil or gas that may be present and recoverable in sedimentary basins. The answer to this question hinges largely on economics and energy policies. Consequently, the answer may be equivocal, and is certainly subject to modification or fundamental changes from time to time.

From an economic point of view a number of questions can be asked, including the following. What is the minimum production required to justify the costs of exploration, and the installation of production equipment, pipelines, and associated infrastructure? Is there a stable or growing market for the volumes of oil or gas that will have to be produced to make the operation economically viable? What are the present and possible future trends of costs and prices for oil and gas, and what changes may occur in world markets? In addition, every company or government instrumentality exploring for petroleum must periodically raise questions as to whether budgetary or fund-raising constraints will place restrictions on exploration or subsequent exploitation of discovered fields. All of these questions are related and impinge on one another. The rationale on which an exploration or development program is based may be significantly altered by changing economic circumstances and political events. It is perhaps trite to say that exploration and exploitation can be a risky business in an unstable national or international climate, but the fact is that the search for petroleum is a gamble in which both potential profits and losses are high. Some oil
fields repay the costs of exploration and drilling within the first 2 to 3 years of production, others take longer in a life-span of 15 to 20 years. Exploration costs may run to a few hundred million dollars before there is any sight of recovering the expenditures. Conversely, when no commercial fields are found the apparent losses are high, although the real losses may be considerably alleviated by taxation concessions. The intricacies of such balance sheets vary with the country in which the operator is registered or incorporated, and in which he is exploring. Apart from consortiums of Australian companies which raise funds at home and abroad, most of the large expenditures on exploration are made by multi-national companies which allocate or divert moneys to various parts of the world depending on geological prospects and on their assessments of expediency in view of changing economic and political situations.

From a national point of view several energy policy considerations are involved in the decision to produce oil or gas, provided commercial accumulations can be found. Paramount among these is the question whether it is in the national interest to develop indigenous supplies of petroleum with reference to problems of national security, self-sufficiency, and balance of trade. It is not the intention here to express opinions on these matters which lie particularly within the areas of interest and expertise of persons knowledgeable in problems of national defence, economics, and political science. Suffice it to say that these questions are considered within the overall context of any review of onshore and offshore petroleum prospects. With reference to onshore and offshore prospects in Australia, from a purely geological point of view, brief and general statements have been made by the National Energy Advisory Committee in NEAC Report No. 6 (1979).

Onshore Prospects
Before 1960 little thought was given to the possibility that the Australian continental shelf might have prospects for the discovery of oil and gas fields. Onshore regions were the only ones seriously considered for exploration. In part, this outlook stemmed from lack of marine seismic data, and consequently of stratigraphic and structural information on the continental shelf; but mainly from lack of funds and expertise of the Australian operators. Australian companies lacked the equipment and personnel to undertake offshore exploration on their own behalf. This could only be done by the large international companies with adequate resources and years of experience in offshore geophysical surveys, drilling, and well completion. Australian companies could participate only by way of holding the original exploration permits, and by contributing to the costs of exploration or exploitation of discoveries. Various terms of
agreement were possible. An Australian company could farm out the permit rights to an overseas company and retain a carried interest. Such an arrangement was made in 1959 between Australian Oil and Gas Corporation and the partnership of Union Oil of California and Kern County Land Company. Under the terms of this agreement, which related to permits in the Surat Basin of Queensland, all exploration and production costs were borne by Union and Kern, with AOG receiving 20 per cent of the net profits. Other arrangements could include a working interest whereby the Australian company contributed part of the costs of exploration or development. Negotiations were strictly on a bargaining basis. In the case of the BHP-Esso agreement of the early 1960s, in which BHP through its subsidiary Hematite Explorations held the offshore exploration permits in the Gippsland Basin region, the terms called for Esso to bear the full costs of certain additional exploration. In the event of a discovery, BHP then had the option of retaining a carried interest, or of contributing on a 50-50 basis to the costs of bringing the well or field into production. They wisely chose the latter course.

Australian companies were not lacking in enterprise or imagination and were commonly in a strong bargaining position because of their holdings of exploration permits. This pattern of development was somewhat similar to that of the 1960s in Western Canada where some Canadian companies had extensive permits but very limited funds with which to explore them. The enthusiasm of some companies operating in the early 1960s was based on optimum and, in some cases, on imaginative interpretations of the geological data. There was, for example, a well drilled on Gosses Bluff in the Amadeus Basin of central Australia. This remarkable structure was thought to be the surface expression of an underlying salt dome, overlying which there might have formed reservoirs of oil, similar to those of the Gulf Coast region of the United States. No petroleum was found, and subsequent geological investigations have shown Gosses Bluff to have been formed by a tremendous explosion, probably caused by the impact of a meteorite. Coincidentally, Gosses Bluff is situated on the crest of an anticline, and deeper drilling may find hydrocarbons within the shattered rock of this older structure. Other exploratory programs appeared to be based on improbable but optimistic geological interpretations, some of which could not sustain the cost of follow-up seismic surveys or drilling. These comments are not intended to denigrate the efforts of some of the exploration companies with limited financial means; but rather to point out the element of chance which can be carried by large companies but could cripple the finances of smaller companies. During the 1960s and until government financial assistance ceased in 1974, many small companies depended largely on shareholders' funds and subsidy from the
Commonwealth Government. On the basis of indices quantifying the relationship of metreage drilled to reserves of oil and gas discovered, comparisons have been made between various areas in the United States (Moody, 1978) and parts of Australia (Sykes, 1979). Comparisons are made difficult by lack of quantitative data and by very considerable differences in the metreages drilled. Also, depending on the depth to potential oil and gas accumulations, the relevant factor may be the number of wells rather than the total metreage drilled. For example, it would be inappropriate to compare, on the basis of metreage drilled, an onshore sedimentary basin where the accumulations are at an average depth of 1500 m with an offshore basin where the accumulations are at an average depth of 3500 m. Meaningful comparisons can only be made where the geological parameters are similar. In general, it appears that success ratios are higher during the early years of exploration of any region, but these can be altered by the introduction of new technology that enables better geological interpretation or more efficient exploitation. Thus, it is possible that the success ratio during later years in the exploration history of a region may be better than that of earlier years. It is also probable that, depending on the technology available, the initial success ratio will vary for the same region depending on the dates of the early exploration period.

Comparisons between onshore and offshore prospects for oil and gas accumulations in Australia are valid only in terms of reference to which they are applied. If the question is asked as to the comparable chances of finding an oil or gas field onshore and offshore the terms oil field and gas field must be defined. An accumulation of hydrocarbons does not necessarily constitute a field. A field may be defined as an accumulation that can be exploited on a technologically and economically viable basis. As such, comparatively small onshore accumulations at shallow depths may be brought into production, whereas similar accumulations at the same depth offshore, or at a much greater depth onshore, might be uneconomic. If the question is phrased with reference to the chances of finding a large oil or gas accumulation the answer must favour the offshore regions. The question of whether such a large accumulation would constitute a field depends on technological and economic factors that could vary considerably over any period. Found onshore, at a depth of 1500 m in a region reasonably accessible to a market, pipeline, or the coast, such an accumulation would probably be brought into production; but if found offshore at a depth of 4000 m beneath the sea floor it might be considered as uneconomic or marginally profitable.

From a geological point of view there are probably many more comparatively small accumulations of oil and gas to be found
onshore, and the chances of finding gas in the Paleozoic basins are possibly greater than those of finding oil. Although many small accumulations of oil and gas may also be present offshore in strata underlying the Australian continental shelf, and in deeper water of the continental slopes and plateaus, the chances of large accumulations being present are much better than they are onshore, largely because the rocks have not been exposed and eroded to the same extent. With reference to the chances of finding additional offshore oil and gas accumulations, it is relevant to note that the technology of marine seismic surveys (Fig. 10) has progressed remarkably over recent years, and the internal structural and stratigraphic relationships of sedimentary layers beneath the ocean floor can now be revealed in much greater detail than was possible a few years ago. Consequently, there is improvement in the chances of locating major structures in which oil or gas accumulations may be trapped. Furthermore, it may be possible to determine, from the character of the seismic records, whether gas accumulations are present.

A report of the National Energy Advisory Council (NEAC, Report No. 6, 1979) states that there are five onshore sedimentary

![Figure 10](image-url)

**FIGURE 10**

Marine seismic survey. Shock waves generated by the towed sleeve exploder penetrate the sea floor and are reflected from underlying layers of rock. The reflected waves of energy are detected by the receiving cable and their arrival times are recorded by instruments on the ship. From this data the configuration and depths of strata are calculated. (Courtesy of ESSO Australia Ltd, adapted from 'Oil—The Vital Search', ESSO Report, 1979.)
basins in Australia that are proven petroleum provinces, the Cooper Basin of South Australia, the Surat and Bowen Basins of Queensland, the Amadeus Basin of the Northern Territory, and the Perth Basin of Western Australia. The hydrocarbon-producing beds of the Cooper Basin are Permian in age (although gas has also been found in Jurassic beds), those of the Surat Basin are Triassic and Jurassic, and those of the Perth Basin are Triassic. Permian beds of the Bowen Basin, which partly underlies the Surat Basin, are locally hydrocarbon-bearing; but exploration to 1979 has not resulted in the discovery of a producing field. Oil and gas occurs in Ordovician sandstones in the Amadeus Basin, but these accumulations are not at present economic.

The report lists the Adavale and Galilee Basins of Queensland, the Otway Basin of South Australia and Victoria, and the Perdika Basin of the Northern Territory as being considered to have good chances of containing petroleum accumulations. Further prospects listed include the Ngalia Basin and the Toko Syncline of the Georgina Basin in the Northern Territory, the Canning Basin of Western Australia, the Bonaparte Gulf Basin of Western Australia and the Northern Territory, and the Darling Basin and Bancannia Trough of New South Wales.

In the southern part of the Cooper Basin eighteen separate accumulations of oil and gas have been discovered to 1979, some of which have been brought into production as gas fields. Of these, the first two fields discovered, Moomba and Gidgealpa, are the largest. Three smaller fields, Tirrawarra, Fly Lake, and Moorari, also contain oil. Production is obtained from Permian sandstones deposited by rivers that flowed north-eastward to a delta building into a shallow sea that occupied the central part of the basin. The paleogeography of these Permian beds is described by Thornton (1978). The present stratigraphic-structural configuration of the Permian comprises north-east-trending troughs and ridges. The accumulations result from both structural and stratigraphic features. Exploration depends essentially on seismic surveys to determine structurally high locations for drilling sites, but future exploration may place increasing emphasis on the delineation of sandstone trends by means of stratigraphic studies.

The Cooper Basin is overlain by Mesozoic beds of the Eromanga Basin, and stratigraphic information on the Permian is consequently available only by means of geophysical surveys and drilling. The Permian beds are underlain by Paleozoic beds which have been more extensively folded and faulted, and are not considered to be prospective for oil or gas. Very little is known of the Permian and Triassic stratigraphy over much of the Cooper Basin. Permian beds in the area of the Moomba and Gidgealpa fields were deposited as a
prograding deltaic sequence of river channel, flood plain, and lake sediments in a coastal environment. To the north-east of this area, in more central parts of the Cooper Basin, it is possible that near-shore sandbodies containing accumulations of hydrocarbons may be discovered. This central region is considered to be an attractive area for exploration.

To 1979, more than thirty separate accumulations of oil and gas have been discovered in Jurassic and Triassic sandstone beds of the Surat Basin. Most of these are small gas fields in the Roma-Surat area. Farther south, other discoveries include the Silver Springs and Boxleigh gas fields. The Alton and Moonie oil fields lie still farther south and to the south-east respectively. These gas and oil bearing beds are underlain by Permian and Carboniferous sediments and volcanics of the Bowen Basin. Traces of oil and gas have been obtained from the Permian, but no commercial accumulations have been found. Some geologists are of the opinion that the oil in the Moonie and Alton fields has been derived from Permian rocks, but most believe that the source rock is the Jurassic Evergreen Shale overlying the oil producing Jurassic Precipice Sandstone. The question is still unresolved, but it is known that Permian beds of the Bowen Basin contain suitable source rocks for oil.

The main prospects appear to be in the Surat Basin which, compared with drilling coverage in areas of North America, has been sparsely explored. The accumulations found have been controlled by both stratigraphic and structural factors; and it is expected that the discovery of other accumulations will depend on detailed seismic surveys and stratigraphic studies. It is generally considered that the chances of finding a number of small accumulations are good, and those of finding a large field are poor. This evaluation of prospects has been a deterrent to extensive search by most international companies, although some have shown a passing interest. On the other hand, the smaller targets can be attractive to Australian companies with much more limited financial resources, particularly in areas where several small fields can be joined by gas pipelines to yield a more substantial cumulative production. Condensate stripped from the wet gas that is commonly found in this region makes the gas a more profitable commodity and gives an added incentive to exploration.

In the Amadeus Basin of central Australia the Mereenie and Palm Valley gas accumulations occur in the Ordovician Pacoota Sandstone and Stairway Sandstone within large anticlines. The gas, from separate reservoirs, has a variable content of condensate. A light paraffinic oil (44-47° API) occurs at the base of the gas column in the Pacoota Sandstone of the Mereenie field (Kurylowicz, et al., 1976). This oil cannot be produced without also producing gas for which, to
1980 and probably for some years after, there is no market. Prospects for the discovery of further oil and gas accumulations in sandstone and limestone beds of Paleozoic formations in the Amadeus Basin are considered to be good. The area is large and drilling has been carried out mainly in the northern part of the basin. The geology of the region, as described by Wells et al. (1970), suggests that other structural and stratigraphic traps for petroleum are probably present in the central to southern areas of the basin, although some anticlinal structures are deeply eroded and consequently have no closure.

The Perth Basin extends south from the area of Dongara to south of Pinjarra on the west coast of Western Australia. The basin is bounded on the east by the Darling Fault which separates it from the Precambrian granitic terrain. The basin locally has a thickness of up to 5000 m or more of Permian, Triassic, Jurassic, Cretaceous, and Tertiary sandstones, siltstones and shales overlying Paleozoic and Precambrian rocks. These are folded and highly faulted into a complex of blocks. Five gas fields have been discovered in the northern to central areas of the basin. The Dongara, Yardarino, and Mondarra fields produce from Triassic sandstones; the Walyering and Gingin fields yield gas from Jurassic sandstones. The only significant gas production comes from the Dongara field which also yields some waxy oil. The gas is piped 415 km to Perth and the industrial area of Kwinana; the oil is transported by trucks. The Dongara field will be exhausted by the latter part of the 1980s and may subsequently be used for the storage of gas produced from the North West Shelf and destined for the Perth market.

Apart from field wells, a number of exploratory wells have been drilled throughout the 600 km length of this narrow basin. Prospects for oil and gas accumulations in structural-stratigraphic traps within the Triassic and Jurassic are considered to be good, but difficult to find because of the structural complications caused by faulting, and the poor seismic records obtained in coastal areas underlain by porous limestone. Further search in this very sparsely drilled basin may lead to the discovery of several fields comparable in size to Dongara. In particular, accumulations may be found in Triassic sandstones associated with features, such as buried hills, of the ancient erosional surface over which these sands were deposited by a transgressing sea. The pinching out of sand bodies along cuestas or against the flanks of buried hills are possible controlling features. These, modified by faults, may form numerous small traps for oil and gas.

Other regions that are considered to have reasonable prospects for petroleum accumulations are the Adavale and Galilee Basins of Queensland, and the Otway Basin of South Australia. The geology of the first two has been described by Allen (1973). Situated in the
south-western region of Queensland, the Adavale Basin comprises a thick sequence of Devonian sandstone, shale, limestone, and salt beds that attracted the interest of petroleum exploration companies during the early 1960s. In 1964 Phillips Petroleum discovered a small accumulation of gas which was named the Gilmore field. To date, this accumulation has proved to be uneconomic. The gas-bearing bed is a sandstone, possibly deposited in part as a marine shoreline sand, and in part as a delta distributary sand. The sandstone is tight, and as such is not an attractive target for exploration. Several widely scattered exploratory wells have been drilled in the area, and on the basis of regional stratigraphic studies the general lithofacies relationships have been outlined. These suggest that limestone reefs may be associated with the carbonates and evaporite beds. If so, the postulated reefs could be prospective for oil and gas. In western Canada, some of the largest oil fields, such as Leduc and Redwater, are in Devonian reefs of dolomitic limestone composed largely of the remains of stromatoporoids, corals, and other organic debris. From a geological point of view the area warrants further seismic surveys and follow-up drilling to determine the nature of the carbonate facies. But the costs of drilling to depths of about 3500 m, and the remoteness from a market for oil and gas, have been discouraging factors.

The Galilee Basin is situated in the central region of Queensland and comprises up to 2800 m of Permian and Triassic sandstone and shale beds deposited in fluvial and deltaic environments. These beds are overlain by up to 1500 m of Jurassic and Cretaceous sediments of the Great Artesian Basin. During the 1960s and early 1970s about twenty exploratory wells were drilled in the basin, some oil and gas being recovered from a Permian sandstone bed in Exoil NL Lake Galilee 1 well, situated in the north-eastern part of the basin in the Koburra Trough. The sedimentary sequence is essentially non-marine. In this respect it is of interest to note that although the sequence of Jurassic beds in the nearby Surat Basin is also essentially non-marine, a brief marine incursion took place during mid-Evergreen time, as indicated by the presence of forams (Evans, 1962; Terpstra, 1962). The structure and stratigraphy of the Galilee Basin are favourable for the occurrence of oil and gas. Also, the beds have been buried sufficiently deep to effect the maturation of organic matter to petroleum. The number of dry holes drilled reflects, in part, an exploration enthusiasm based on too little information. Future exploration, based on surveys using modern seismic technology, and on a better informed selection of drilling sites, may result in the discovery of petroleum accumulations, particularly in the Koburra Trough.

The Otway Basin is situated mainly off the south-west coast of
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Victoria. It comprises up to 6000 m of highly faulted Upper Cretaceous and Tertiary mudstones, siltstones, and sandstones, but includes Miocene and Oligocene limestones in the uppermost part of the sequence. Several onshore and offshore wells have been drilled, of which the onshore well Port Campbell 4 yielded oil and gas, and the offshore well Pecten 1A yielded gas from the basal part of the Upper Cretaceous. Exploration is made difficult by the complexity of faulting which has broken the sequence into a succession of blocks, and by lack of information as to depositional trends and the possible history of migration and entrapment of petroleum. The search for structures with closure is complicated by the possibility that oil and gas may have migrated past the locality of closure before its formation. Future exploration will depend on the acquisition of more detailed geological information based on reliable interpretations of seismic surveys and further drilling. Probably the best prospects will lie offshore.

The Ngalia Basin, situated north of the Amadeus Basin in central Australia, contains up to 6000 m of Late Proterozoic and Early Paleozoic sandstones, siltstones, and carbonates. The basin is asymmetrical, having the thickest and most folded and faulted part of the sequence to the north. Prospects for hydrocarbon accumulations may exist within the basin, particularly in the Cambrian and Ordovician sandstones and dolomites. Another area of central Australia that may have petroleum prospects is the southern part of the Georgina Basin, within a trough of Cambrian and Ordovician sedimentary rocks.

The Canning Basin, situated inland between the coastal towns of Port Hedland and Broome, has attracted a considerable amount of exploration activity over a period of many years. This asymmetrical basin has its deepest part in the south-east-trending Fitzroy Trough lying in the northern part of the basin. In this trough the Paleozoic and Mesozoic sequence attains a thickness of up to 12,000 m of sandstones, siltstones, shales and carbonates. A good summary of the geology of this region is presented by Drew and Evans (1975). Several wells have been drilled in the Canning Basin and shows of oil in Ordovician rocks, and of gas in Devonian rocks, have been detected. In Meda 1, drilled by West Australian Petroleum, a few litres of oil were recovered from the Carboniferous Laurel Formation. The presence of Devonian reefs in outcrops has drawn attention to the possibility that they may be present in the subsurface where they could be considered as targets for drilling. Locating such reefs depends on the interpretation of seismic records which are not always of sufficient quality to be definitive.

In the region of Bonaparte Gulf Basin several onshore and offshore wells have been drilled, and a good flow of gas was encountered in a
thin sandstone of the Carboniferous Milligans Beds penetrated by
the onshore Bonaparte 2 well drilled by Alliance Oil Development
in 1964. Offshore, large flows of gas have been struck in beds of
Permian age. Prospects onshore do not appear to be very attractive,
but the possibility of finding large accumulations of gas offshore
have been demonstrated by the prolonged gas blowout in Petrel 1
drilled in 1969 by Atlantic Refining Company, as mentioned in
Chapter 1.

Offshore Prospects
Looking into the future it can be said, with general agreement among
those engaged in or associated with the search for petroleum, that
although many accumulations of oil or gas may be found onshore,
the best prospects for finding large accumulations lie offshore. With
reference to accumulations that are designated as fields, the terms
small and large are relative. When used they must be qualified as to
hydrocarbons in place, or recoverable. Recoverable reserves of
hydrocarbons are expressed in figures that relate to technological
constraints and economic considerations such as the prices paid for
crude oils. Such reservations are necessary in expressing the relative
recoverable reserves of different fields, because some of the factors
by which the reserves are quantified are subject to change. In the
final analysis, the recoverable reserves of any field are known
accurately only when that field has been depleted. Comparisons of
approximate sizes of fields can be useful in estimating the potential
of offshore and onshore fields, and in defining the limits of terms
such as large or small. A giant oil field such as the East Texas field,
the largest single field in the United States, is estimated by Halbouty
(1968) to have originally contained more than 5000 million barrels
(795,000 million litres) of recoverable oil. The Forties field, one of
more than fifty fields discovered in the North Sea, is estimated to
have originally contained about 1800 million barrels of recoverable
oil. During 1979 production from the Forties field amounted to
about 400,000 barrels (63.6 million litres) a day from more than 100
wells. Depending on its depth beneath the ocean floor (commonly
less than 100 m below sea level) a field in the North Sea containing
300 million barrels of recoverable oil might be only marginally
profitable. By the same token, an oil accumulation beneath the
Exmouth Plateau of Western Australia would probably have to
contain several hundred million barrels of recoverable oil to be an
economically viable field, although much would depend on the
permeability of the reservoir and the rates at which the wells could
produce. Bein et al. (1973) estimate the initial proven and probable
reserves of the Kingfish oil field to be more than 1000 million
barrels. By comparison, the first Australian oil field brought into
production, the Moonie field of Queensland, probably contained no more than 55 million barrels of oil in place, of which about 25 million barrels will ultimately be recovered.

Comparing onshore and offshore prospects, the average size of discovered and undiscovered offshore accumulations of oil and gas is probably larger than the average size of onshore accumulations in the same categories. It can also be said that prospects are probably better in any offshore area than on the adjacent onshore area. But quantitative comparisons cannot be made until there is sufficient offshore drilling.

These statements do not imply that any offshore area has better prospects than any onshore area, or that the prospects in all offshore areas are the same. Geological considerations upgrade or downgrade prospects on the basis of the geological history of the area. For example, during the Permian Period, Australia was joined to Antarctica along its present southern margin. The two continents began to split apart during the latter part of the Mesozoic Era but did not finally separate until early in the Paleogene Period. The geological history of any particular portion of the Australian continental shelf and adjoining mainland determines the thickness, sediment types, depositional environment of the strata deposited, and the structural complexity of the sedimentary basin being explored. These factors have a very significant bearing on the prospects for petroleum accumulations.

Initially, exploration for oil and gas in offshore regions depends on bathymetric and geophysical surveys to delineate the topography and depth of the sea floor, and to define the main structural and stratigraphic features of the underlying sedimentary layers. The principal method of geophysical investigation is marine seismic surveying carried out by means of an interlocking system of ship traverses along which readings are recorded of time taken by shock waves, generated at the surface, to be reflected from the sea floor and underlying layers of strata. For best results, the recording must be carried out in the absence of extraneous noise. (The vibrations of a coastal steamer passing 3 km away will be recorded by the geophysical instruments and consequently damage the records.) These records can be plotted as profiles for each traverse, producing effective cross-sectional views of the pile of sedimentary layers. Where the data are plotted as structure or isopach maps, certain anomalies may be interpreted as stratigraphic or structural features having closures that may have trapped oil or gas. High resolution seismic profiles may, in some such cases, actually show a horizontal reflection from a gas-oil, or gas-water contact. Where present, such reflections appear on the profile as a horizontal white line called a ‘bright spot’, commonly bounded by a darker line. Processing and reviewing of
seismic records is carried out as the operation proceeds, so that areas of interest can be further investigated during the period of the marine survey. Selection of drilling sites, and the order in which they will be drilled, depends on evaluation of the prospective structures and on other considerations of a technical or economic nature. Drilling is the ultimate test that determines the presence or absence of hydrocarbons within particular intervals of the strata, and the possible or probable capability of the strata to produce hydrocarbons. Further drilling is required to delineate the boundaries of a field, to determine the structural, stratigraphic, and petrophysical characteristics of the field, and to estimate the possible recoverable reserves of oil or gas. These matters take time, and evaluation of offshore petroleum prospects in a large region of the continental shelf or slope is likely to proceed over a period of several years.

Most of Australia's oil production comes from offshore fields in the Gippsland Basin of Victoria. The best prospects in this basin, as indicated by seismic surveys, have already been drilled, and possibly the undiscovered remaining accumulations amount to less than half of the presently known producible reserves (NEAC, Report No. 6, 1979). This report considers the Exmouth Plateau off the coast of north-west Western Australia, much of which is overlain by more than 1000 m of water, to offer the best prospects for finding very large accumulations of oil or gas. Other deep-water areas include the Naturaliste Plateau off the coast of south-west Western Australia, the Lord Howe Rise seaward from New South Wales, and the Heard Island Rise in the Antarctic region. The report also lists the offshore regions of the Bonaparte Gulf, Browse, Carnarvon, and Perth Basins as having prospects for additional discoveries of oil or gas. Other offshore regions not mentioned in the report will be discussed later.

In the offshore region of the Gippsland Basin drilling has been concentrated on structural features delineated by seismic surveys. Lack of detailed stratigraphic information has precluded interpretation that might indicate the presence of purely stratigraphic prospects. As further drilling proceeds, and is correlated with seismic surveys in the manner shown by Steele (1976), and Partridge (1976), interpretation of the geological history of the basin may lead to the application of concepts of deltaic and coastal sedimentation that could indicate additional prospects for petroleum accumulations in hitherto unsuspected locations. These subtle stratigraphic traps may be small in comparison to the structural traps, and as such may have a low priority in the drilling program of any company. As the structurally high locations under the continental shelf are drilled, exploration may move farther seaward to structures beneath the continental slope, or may test possible prospects for stratigraphic traps, as suggested by Hocking (1972), and Haskell (1972).
The offshore region that has attracted by far the greatest exploration effort and expenditure of money since the discovery of the Gippsland Basin oil and gas fields is the North West Shelf and adjoining Exmouth Plateau of Western Australia. Large gas reserves have been discovered in the North Rankin, Goodwyn and Angel fields. In addition, the nearby wells Haycock 1 and Spar 1 are designated as potential gas wells. Oil shows were found in Legendre 1, Eaglehawk 1, Goodwyn 3, Dockerell 1, and Lambert 1 during the years to 1974. To the north-east the East Swan 1 well, near the boundary between the Browse and Bonaparte Gulf Basins, and Scott Reef 2A well had flows of gas, and the Caswell 1 well in the Browse Basin encountered a thin column of oil. Puffin 2, situated near Swan 1, had a flow of 3200 barrels of oil a day. Also, the Sunrise, Troubadour, and Tern wells in Bonaparte Gulf Basin had flows of gas and condensate. All of these discoveries of oil and gas have encouraged the belief that apart from the very large (probably about 400,000 million m³) recoverable reserves of gas already found in the North Rankin, Goodwyn, and Angel fields, there are other sizeable accumulations to be discovered.

The North West Shelf comprises the continental shelf extending from the area of Exmouth Gulf to the region of the Timor Sea north of Darwin. It is underlain by several sedimentary basins and sub-basins, and by structural-stratigraphic platforms and ridges. The sedimentary layers of these basins are faulted beneath the Tertiary cover consisting predominantly of limestones. The rocks within these basins are Mesozoic. They lie unconformably on a basement of Precambrian granites and metamorphic rocks, and Paleozoic sedimentary rocks. The best prospects are considered to be in the Triassic and Jurassic sediments of the Mesozoic sequence which were deposited in predominantly marine and deltaic environments. The search for new oil and gas fields will depend initially on the delineation, by marine seismic surveys, of structurally high locations. Such locations include the tilted horst block of Triassic and Jurassic sediments that contain the gas accumulations in the North Rankin field. Very large stratigraphic traps may also exist where permeable sandstone beds pinch-out by depositional thinning against ridges and platforms.

The Dampier Sub-basin lying between the Rankin Platform and the mainland comprises a folded and faulted sequence of Triassic, Jurassic, and Cretaceous sedimentary beds overlying the Paleozoic. Structural trends are north-east, parallel to the coast and to the trend of the Rankin Platform on which the Eaglehawk and North Rankin gas and oil fields are situated. Up to 1978 eleven hydrocarbon accumulations had been discovered in the outer area of the Dampier Sub-basin. The basin appears to be gas prone, but further explora-
tion may discover economic accumulations of oil. Crostella and Chaney (1978) say that two oil types have been found in the basin, a light paraffinic oil, possibly derived from Triassic or Jurassic rocks, and a heavier napthenic-aromatic oil probably derived from Lower Cretaceous shales. The paraffinic oil, found in the Rankin, Dockerell, and Goodwyn fields, also occurs in the Lambert 1 well situated between the Angel and Eaglehawk fields. The napthenic-aromatic oil, present in the Eaglehawk, North Rankin, and Barrow Island fields, is derived from Cretaceous shales and appears to be an immature oil formed within the upper part of the temperature range for oil generation. Better prospects for large accumulations, particularly of lighter oil, may be found in the Triassic and Jurassic sequence.

The offshore region of the Canning Basin lies between the Dampier Sub-basin to the south-west and the Browse Basin to the north-east. The main structurally high features are a continuation of the Rankin Platform, and the Broome Swell. The latter lies to the north-east, on the same trend as the Rankin Platform, but curves to the east and south-east to run parallel with the Fitzroy Trough of the Canning Basin. The main structurally low features are the Beagle Trough and Bedout Sub-basin which lie on the same trend as the Dampier Sub-basin. These basins and troughs also comprise Triassic, Jurassic, and Cretaceous strata overlying Permian and older Paleozoic beds, and are overlain by a Tertiary sequence. Block faulting is a common feature of the Paleozoic and Mesozoic section. Numerous potential structural traps are probably present; also the truncation of Mesozoic beds by unconformities, and depositional pinching out of beds against the flanks of the Broome Swell may provide possible stratigraphic traps.

The Browse Basin lies to the north-east of the offshore part of the Canning Basin, and to the south-east of the Scott Plateau. It comprises a sequence of Permian, Triassic, Jurassic, Cretaceous and Tertiary sedimentary strata deposited in deltaic to marine environments. Structural trends of folds and faults are to the north-east. The Scott Reef 1 well, drilled in 1971 on an upthrust block of strata on the north-west flank of the basin, discovered an accumulation of gas and condensate in Upper Triassic and Lower to Middle Jurassic sandstones separated by an unconformity (Allen et al., 1978). Provided that the depth of water does not preclude drilling, future exploration may discover a number of accumulations in structural-stratigraphic traps along the main structurally high trends.

The Scott Plateau lies off the north-west flank of the Browse Basin in water depths of 1000 to 3000 m, and is terminated by the Argo Abyssal Plain. Beneath the plateau lies a sequence of possible Triassic, Jurassic, Cretaceous, and Tertiary strata overlying
Paleozoic and Precambrian rocks. Structural and stratigraphic relationships with the adjacent Browse Basin suggest that the Scott Plateau is underlain by a sunken portion of the earth's crust that once was marginal to the Browse Basin (Stagg, 1978). The stratigraphic section is comparatively thin and broken by block faulting. Prospects for hydrocarbon accumulations are considered to be only fair; and this factor, combined with the costs of drilling in deep water, tend to substantially downgrade the prospects for Scott Plateau.

The Bonaparte Gulf Basin underlies the Joseph Bonaparte Gulf and adjoining region of the Timor Sea in northern Australia. The main structural and stratigraphic features, described by Edgerley and Crist (1974), consist of a complex system of north-west-trending faults cutting a thick sequence of Carboniferous, Permian, Triassic, Jurassic, and Cretaceous sedimentary strata. These overlie older Paleozoic rocks and are overlain by comparatively undisturbed Tertiary sediments. Diapiric salt structures penetrate the section, resulting in local doming of the overlying beds.

This sequence of beds thickens basinward from the southern shore of Joseph Bonaparte Gulf, and attains a thickness of many thousands of metres of marine and deltaic deposits consisting of limestone, shale, siltstone, and sandstone. Offshore, seismic surveys culminated in the drilling of several wells, some close to salt diapirs. Gas was found in the Tern and Petrel structures, and flows of gas and condensate were encountered in the Sunrise and Troubadour wells. A significant accumulation of gas was encountered in Petrel 1 which blew wild for several months. This accumulation was trapped in a broad anticlinal structure within Upper Permian beds.

For such a large area of approximately 100,000 km² the drilling of a dozen or more exploratory wells is hardly sufficient to test the hydrocarbon potential of this basin, and much more exploration is needed. Although encouraging shows of oil and gas have been obtained, a major oil discovery would lend great encouragement to the search.

Other offshore regions in Western Australia that are considered to have variable degrees of prospects are the Exmouth Plateau, Wallaby Plateau, Carnarvon Basin, Perth Basin and the Naturaliste Plateau. Of these, the Exmouth Plateau appears to be particularly attractive, and a number of drillable prospects have been outlined by marine seismic surveys. The first well drilled was Esso's Zeewulf 1, located in a water depth of nearly 1200 m. Tentative plans look to the drilling of more than twenty wells over the next few years. Targets for exploratory drilling are structures within the Mesozoic sequence. Sections within the Triassic, Jurassic, and Lower Cretaceous are considered to be particularly attractive. These beds
are believed to have been deposited in deltaic to marine environments, and may offer a number of types of structural and structural-stratigraphic trapping situations for hydrocarbons. The geology of the Exmouth Plateau has been described by Willcox and Exon (1976) who say that the basic structural features are a major arch flanked on the landward side by a syncline, both trending north-east parallel to the adjacent North West Shelf. The Mesozoic section is thought to include up to 4000 m of Triassic shallow marine and deltaic sediments, 2000 m of Jurassic to Lower Cretaceous deltaic sediments, and up to 1000 m of Upper Cretaceous and Tertiary marine carbonates.

Wallaby Plateau, lying 2000 to 3000 m below the surface of the sea off the edge of the continental shelf, is situated west of Carnarvon, and is separated from the Exmouth Plateau to the north-east by the Cuvier Abyssal Plain. Extrapolation of tectonic trends on the mainland, and interpretation of geophysical surveys, indicate that the main structural trends underlying the Wallaby Plateau are probably to the north-west (Symonds and Cameron, 1977). The stratigraphy can only be inferred, but it is thought that a folded and faulted Paleozoic sequence of beds is overlain by up to 4000 m of Mesozoic sediments that are considered to be prospective for hydrocarbons. But the great depth of water may preclude drilling until the Exmouth Plateau has been explored.

Carnarvon Basin forms a long crustal depression, trending more or less south and north of Carnarvon adjacent to the inland Pilbara Block of Precambrian granitic rocks. The basin includes sub-basins of down-faulted Paleozoic strata which, in the northern part of the basin, are overlain by a thick sequence of Mesozoic beds. These are considered to be prospective and have been drilled by several offshore wells situated between Barrow Island and North West Cape. None of these wells had any significant shows of oil or gas; but this in no way rules out the possibility that the offshore area to the north-east of North West Cape may have prospects for hydrocarbon accumulations. The offshore region to the south-west of the North West Cape peninsula may also have hydrocarbon prospects within the Paleozoic sequence, particularly within Devonian shelf carbonates where fringing reefs developed locally along the margins of low-lying land masses. Of particular interest is the sequence penetrated by the offshore well Pendock 1. This well drilled through more than 300 m of Devonian reef, establishment a new exploration objective (Geary, 1970). There has been no follow-up drilling to Pendock, but experience in Western Canada has shown that it can be difficult to delineate the structure of some reefs by seismic surveys, and that dry holes drilled into reefs can be situated nearby to wells producing from the same reef.
Perth Basin lies between the regions of Dongara and Pinjarra. To the east it is separated from the Western Australian Shield of Precambrian granitic rocks by the Darling Fault. The basin comprises several north-trending sub-basins and ridges of Mesozoic and Permian strata, including the Abrolhos and Vlaming Sub-basins which lie entirely offshore, the former being situated west of Dongara and the latter west of Perth. The Abrolhos Sub-basin is a major tectonic and depositional feature containing up to 9000 m of Paleozoic and Mesozoic strata, half of which is believed to be Jurassic and younger (Jones and Pearson, 1972). The Dongara gas field is located on a ridge separating the southern part of the Abrolhos Sub-basin and the northern part of an onshore sedimentary trough. Other prospects for hydrocarbon entrapment may be found in Triassic marine sandstones along the eastern flank of the Abrolhos Sub-basin. The Vlaming Sub-basin developed rapidly by down-faulting of blocks of strata, and the deposition of more than 6000 m of Cretaceous and Tertiary sediments. Oil and gas were recovered from the Upper Jurassic to Lower Cretaceous Yarragadee Formation in the offshore well Gage Roads 1 located west of Perth on the east flank of the Vlaming Sub-basin. Possible hydrocarbon accumulations may be found in stratigraphic-structural traps associated with the unconformity separating Cretaceous and Jurassic sediments.

Little is known of the stratigraphy of the Naturaliste Plateau situated off the south-west coast of Western Australia. Bathymetric surveys indicate the plateau to be broad and relatively flat, lying approximately 2500 m beneath the surface of the sea. Seismic surveys indicate up to 1000 m of Cretaceous and younger beds, underlain by up to 3000 m of older faulted and folded strata. Prospects for locating petroleum accumulations appear to be poor because the younger sediments have not been buried to depths for optimum generation of oil, and the older sediments are extensively folded, faulted, and eroded. In addition, drilling in such depths of water, where possible, precludes all but very large prospective structures.

Looking northward to the region of the Arafura Sea, prospects for large hydrocarbon accumulations are not attractive. The region occupies the continental shelf lying between Australia and Irian Jaya. It is underlain by the Money Shoal Basin which consists of nearly flat-lying sequences of Mesozoic and Cenozoic marine, deltaic, and coastal sediments having a thickness of up to 4500 m. These overlie folded and faulted Paleozoic rocks of the Arafura Basin. In 1971-2 a dry hole, Shell Money Shoal 1 well, was drilled into a closed structure situated in the south-western part of the Arafura Basin. Further drilling has been discouraged by the lack of
adequate geological structures. It is possible that stratigraphic traps may be present, particularly where depositional trends of coastal and deltaic sands cross flexures or gentle warps of the strata. A further consideration is the question of territorial rights to the seabed lying between Australia and Indonesia.

The Timor Sea, between Joseph Bonaparte Gulf and Timor, overlies a section of the Australian continental shelf that is of particular interest from geological and geographical points of view. Separated from Timor by a deep ocean trough, the continental shelf is underlain by a thick prospective sequence of Mesozoic sandstones and shales that thicken seaward from the Bonaparte Basin. The tectonic framework of the earth's crust in this region is partly the result of subduction of the leading edge of the Australian continental plate beneath the Asian plate underlying the Banda Sea to the north of Timor. This movement, which took place during the Tertiary, thrust up sediments deposited on the Australian continental shelf to form the folded and faulted sequence of strata seen today in Timor. The tectonic framework is also partly the result of earlier earth movements caused by the rifting apart of continental masses during the Late Jurassic to Early Cretaceous (Warris, 1973). Several wells have been drilled in the region, but no significant flows of oil or gas have been encountered. Should oil or gas fields be found on the continental shelf adjacent to the Timor Trough, the question of ownership of the sea floor, and the minerals and petroleum below, could become an international issue. From a geographical and geological point of view the Timor Trough, a very deep submarine trench, would appear to be a logical boundary between Australia and Indonesia; but legal rulings based on sea level boundaries may raise conflicting opinions. The offshore boundary between Indonesia and Australia has been fixed by agreement, except for that part lying between Australia and the former Portuguese territory which is now part of Indonesia.

The petroleum potential of offshore regions adjacent to the Great Australian Bight, south of Western Australia and South Australia, cannot be regarded with any great enthusiasm. Offshore, the Eucla Basin underlying the Nullarbor Plain extends as a thin veneer of Tertiary carbonates overlying Precambrian rocks. Locally, Lower Cretaceous shales and sandstones underlie the carbonates. The total section to the Precambrian basement is commonly less than 600 m thick, and has not been buried sufficiently deeply to generate hydrocarbons. Also, there do not appear to be suitable structures or caprocks to entrap any hydrocarbons that may have migrated from deeper zones beneath the continental shelf overlying the Great Australian Bight Basin. Lying adjacent to the seaward edge of the Eucla Basin, and trending south-east toward the Duntroon Embayment off
Spencer Gulf, the Great Australian Bight Basin comprises several thousand square kilometres of Cretaceous fluvial, lacustrine, and deltaic deposits of sandstone and mudstone overlain by Tertiary carbonates (Boeuf and Doust, 1975). In 1975, Shell Potoroo 1 was drilled into the northern margin of the Great Australian Bight Basin at a water depth of about 250 m. The well penetrated a Tertiary section of carbonates, and a Cretaceous section of sandstones and mudstones, terminating in Precambrian basement rocks at a depth of 2663 m below the sea floor. No shows of oil or gas were found. Hydrocarbons may have formed a number of accumulations in this basin, probably in structural-stratigraphic traps but the sequence resembles that of the Otway Basin in being severely disrupted by faults. Locating accumulations may consequently be especially difficult, and as with the Otway Basin, the prospects do not appear to be particularly attractive.

Offshore prospects in the Otway Basin have previously been mentioned in connection with prospects for the onshore part of the basin. The basin forms an elongate, south-easterly-trending trough comprising up to 6000 m of Upper Cretaceous and Tertiary sediments. Cretaceous beds form a sequence prograding to the south-west, and the present elongate shape of the basin appears to reflect depositional trends during the Tertiary. The north-eastern flank of the basin consists of a series of down-to-basin faults which were active during sedimentation, resulting in the growth of prograding wedges of Cretaceous sediments (Denham and Brown, 1976). Because of structural complications the basin is difficult to explore, particularly with reference to finding closed structures. For this and other reasons, offshore drilling in the Otway Basin will no doubt continue to be low on the priority list of most oil companies.

The Bass Basin, situated between Victoria and Tasmania, is flanked on the east by the Gippsland Basin, and on the west by the Otway Basin. It is an oval, symmetrical basin containing up to 5000 m of sediments, including Cretaceous non-marine sandstones, mudstones, and coal, but consisting mainly of Tertiary marine limestones with local lenses of intruded and extruded volcanic rocks. These features are discernible in seismic profiles and it was originally thought they might be reefs. Both Esso Bass 1 and Esso Cormorant 1 were drilled on such features, the former encountering an extruded pile of volcanic debris, and the latter an intruded lens of basic igneous rock. Of the several wells drilled on structural features, Bass 3 recovered gas and condensate from a Paleocene sandstone, Cormorant 1 recovered oil from an Eocene sandstone, and Pelican 1 and 2 recovered gas and condensate, also from an Eocene sandstone (Robinson, 1974). All of these hydrocarbon-bearing sandstones are non-marine, and are believed to have been deposited on a delta.
Looking to eastern Australia, the geology of the Queensland Trough, Townsville Trough, and Coral Sea Plateau (Queensland Plateau) has been described by Pinchin and Hudspeth (1975) and by Taylor and Falvey (1977). In this region the continental shelf forms a narrow fringe flanked by a trough which, east of Cooktown and Cairns, has depths below sea level of 1000 to 3000 m. North-east of Townsville the Coral Sea Plateau lies to the south of the Coral Sea Basin at depths of about 1000 m. It is a down-faulted block of the Eocene continental shelf, separated from the present shelf by the Queensland and Townsville Troughs. Seismic surveys and deep-sea drilling in 1971 by the research ship *Glomar Challenger* have established the stratigraphic section overlying the Paleozoic basement in this region. It consists of a shallow marine sequence of Eocene sandy to cherty limestones and reefs, overlain by Oligocene to Pleistocene deep-water carbonate muds. Two unconformities are recognised, one between the Late Eocene and Late Oligocene, and another between the Late Miocene and Pliocene, each signifying periods of non-deposition or slight erosion. The former is related to the time of rifting apart of the Australian and Antarctic continental plates. To the south of the Townsville Trough and Marion Plateau the continental shelf comprises a basement of Paleozoic metamorphic rocks overlain by up to 600 m of Tertiary non-carbonate and carbonate rocks, including the present-day reefs.

Over much of the plateau region the thickness of the Tertiary section probably does not exceed 1000 m, but in the trough regions geophysical data indicate a sequence up to 3000 m thick. On the basis of the relationship between depth of burial of sediments and the generation of hydrocarbons it does not seem likely that the Tertiary sections underlying the plateau regions will have generated any oil. The thicker sections in the troughs could have produced oil which may be accumulated largely in stratigraphic traps on the flanks of the ocean rises. But these, if present, would lie in water depths of up to 3000 m. Possible prospects in older and deeper Mesozoic sediments are not known. Cretaceous sediments of the Laura Basin underlie the offshore region of Princess Charlotte Bay on the east coast of Cape York Peninsula; and Mesozoic sediments of the Maryborough Basin also underlie the continental shelf north-east of Rockhampton. The best that can be said of offshore prospects for petroleum in eastern Australia is that they are not particularly attractive.
The continental shelf of Australia occupies an area of approximately 2.5 million km$^2$ and extends seaward from the coast to depths of about 200 m where the surface of the sea floor steepens on the continental slope. The width of the continental shelf varies considerably off various parts of the Australian coasts. It has its greatest extent in the northern regions where it underlies the Gulf of Carpentaria, Arafura Sea, and Timor Sea, extending to the mainland of Papua New Guinea and Irian Jaya. The continental shelf of Western Australia ranges in width from 20 km at North West Cape to 250 km on the North West Shelf extending north-east from Dampier. Off the west coast of Western Australia, from North West Cape south to Perth, the continental shelf is comparatively narrow, ranging in width from 40 to 100 km. It maintains the same width along the southern coast of Western Australia, then widens in the Great Australian Bight before again narrowing to less than 100 km off Kangaroo Island and the Mount Gambier coast. The shelf widens again to approximately 200 km in Bass Strait between Tasmania and the mainland, but is narrowest off the coast of New South Wales where, for more than 1000 km, it has a width of less than 40 km.

In Queensland the continental shelf has a width of about 60 km along the east coast of Cape York Peninsula, and ranges up to 300 km in the area between Mackay and Rockhampton. Off the coast of Cape York Peninsula the entire continental shelf is occupied by hundreds of individual coral reefs. To the south-east the Great Barrier Reef extends through the east-central region of the continental shelf. Seaward of the main reef trend there are no reefs on much of the remaining narrow strip of continental shelf; landward there are scattered reefs, except on the shelf lying south of the Capricorn Group of Islands (Swain Reefs) and east of Rockhampton.

In the Great Australian Bight the continental shelf extends seaward from the coasts of Western Australia and South Australia for a distance of up to 200 km. The sea floor then steepens on the continental slope to a horizontal distance of up to 50 km and a depth of about 1000 m. At this depth the base of the continental slope flattens and merges with the Ceduna Terrace, which extends seaward for 125 km to a depth of about 2000 m. The sea floor then steepens markedly
Exploration on the Continental Shelf, Slope, and Plateaus

(Fraser and Tilbury, 1979) along a slope that marks the edge of the continental mass. This slope falls away, over a horizontal distance of about 50 km, to an abyssal plain at a depth of 4000 m.

The Ceduna Terrace and other terraces and plateaus are believed to be parts of the Australian continental shelf that broke away and were down-faulted during the period (Late Mesozoic to Cenozoic Eras) when the continents of Australia and Antarctica were splitting apart, some 50 to 70 million years ago. Having originally been parts of the continental shelf, these sunken blocks have the same or similar sequences of rock layers and are consequently prospective for oil and gas. From a geological point of view the rock layers they contain may have been deposited in deeper water, may include more source beds for hydrocarbons, and may have been buried to depths more favourable for the generation of oil than those of the continental shelf. But unfortunately they are also much more costly to explore in depths of 1000 to 2000 m.

Plateaus lying off the edge of the North West Shelf are the Scott Plateau at a depth of 2000 to 2500 m (Stagg, 1978), and the Exmouth Plateau at a depth of 1000 to 1500 m (Willcox and Exon, 1976). The Wallaby Plateau west of Carnarvon has a depth of 2500 to 3000 m (Symonds and Cameron, 1977), and the Naturaliste Plateau west of Perth has a depth of 2200 to 2500 m (Jongsma and Petkovic, 1977). An interesting feature flanking the continental shelf of Western Australia is the Carnarvon Terrace which lies at a depth of about 600 m. This feature, which lies along the continental slope, is probably underlain by parts of the Carnarvon and Perth Basins. Another interesting feature is the Coral Sea Plateau (Queensland Plateau) which lies at a depth of 500 to 1000 m off the east coast of Cape York Peninsula, separated from the Great Barrier Reef by a submarine valley which to the north is called the Queensland Trough, and to the south the Townsville Trough. The Coral Sea Plateau is believed to have pulled away from the Australian continental shelf by sea floor spreading about 51 million years ago (Taylor and Falvey, 1977).

The physiography of a continental shelf is essentially that of a gently undulating to flat plain. The North West Shelf, for example, has an average width of about 200 km, and consequently an average sea floor slope of 1 m in 1 km. The continental slope flanking the Ceduna Terrace drops about 800 m in every 50 km of horizontal distance, a fall of 16 m in 1 km. Although sixteen times that of the continental shelf, this is still a gentle slope, commonly smooth and undulating but locally incised by submarine valleys. Clusters of these valleys cutting the continental slope south-east of the Ceduna Terrace and opposite Kangaroo Island are shown by Von der Borch
The origin of submarine valleys is not well understood, but they may be related to the movements of ocean currents moving seaward off the continental shelf.

**Shelf Sediments**

Ocean currents, waves, and tides are also important agents in the transportation and distribution of sediments on the continental shelf and slopes. Other factors such as climate, weathering of the landmass being drained by a river system running to the sea, and the development of estuaries or deltas along the coast are primary features that determine the nature of non-carbonate sediments. The products of weathering of a landmass are determined by the nature of the rocks and by the climate. These products, as sand, silt and clays in colloidal suspension, are transported to the sea by rivers. The fresh water carrying the clays, being less dense than the sea water, forms a surface layer that rides out to sea as a great fan. Longshore currents move this fan along the coast for many tens of kilometres. Eventually the fresh water is dispersed, and the colloidal clays precipitated by mixing with the sea water. The sands and silts are carried along the distributary channels of large rivers to the sea where they are winnowed by wave action and moved along the coast by currents. The action of waves is more vigorous in shallow water, and separation of the sands and silts commonly takes place along the coast. The effectiveness of this separation depends not only on the energy of the waves but also on the amount of sediment that is winnowed. Some areas of coastline may be more muddy than others because of proximity to the mouth of a river. The coastline also migrates depending on the amount of sediment deposited. Some coastlines build out to sea, a prograding process that is common close to deltas where large amounts of sediment are deposited. Others may retreat, as waves erode the beach and foreshore.

In areas where the continental shelf is very shallow and the climate is warm to tropical, coral and algal mounds may develop as barrier and patch reefs. These are eroded by waves and the fragments, including broken pieces of shells and other such debris, are worn to white carbonate sand which fringes the reef and forms banks and shoals. Carbonate muds are also deposited in the quiet water within the encircling reefs, and on the inter-tidal mud flats of the coast. These are formed by the accumulation of carbonate shells of dead microscopic organisms such as forams, and by the chemical precipitation of minute crystals of aragonite, a calcium carbonate mineral. Precipitation occurs where cold ocean currents, carrying carbon dioxide and calcium carbonate in solution, flow on to a shallow carbonate shelf where the water is warmed. Warming of the cold ocean water causes it to lose some of the carbon dioxide in
solution, thus lowering its acidity and ability to dissolve calcium carbonate. When the saturation point is reached, calcium carbonate, as minute crystals of aragonite, is precipitated like a snowfall that whitens the water. This phenomenon has been observed from the air, and was at first thought to be caused by a school of fish stirring up the sea floor.

The types of sediments deposited on ancient seabeds at any fixed location, such as might be determined by a borehole, may vary depending on changes in any of the factors mentioned. Where the shoreline either progrades or retreats the seabed sediments at such a location are deposited in progressively shallower or deeper water respectively. These changes of depth will affect the vigour of wave action and consequently the effectiveness of sediment winnowing. Changes in the pattern of river distributaries will alter the amounts of sediment brought to various areas of the coastline. Earth movements such as uplift or subsidence will also change the physiography of a coastline, and the drainage pattern of the landmass. Over long periods climatic changes may bring about marked changes in the sediment types deposited. All these factors, singly or in combination, produce a sedimentary record that is revealed in the borehole and tells the geological history of that particular part of the continental shelf.

**Sedimentary History of Shelf**

The history of sedimentation interpreted from a borehole may reveal that during the past tens of millions of years the water depth at that location has fluctuated up to 200 m or more, and that the depositional environment has varied from the shoreline to the continental slope. The stratigraphic sequence and lithology of the layers penetrated in the borehole may also reveal details of the type of coast, the geomorphology, and climatic changes. Coal seams indicate coastal marsh and probable deltaic sedimentation, carbonaceous claystone with abundant arenaceous forams suggests deposition of organic-rich mud in a coastal bay or lagoon, and sandstone layers consisting of well-sorted grains that show upward coarsening of grain size indicate an origin as a prograding sand body that could have formed along a coastline or as a barrier island. Climatic change may be indicated by the upward change in deposition from non-calcareous to calcareous layers of limestone and coralgal reef rock such as formed on much of the Australian continental shelf during various Epochs of the Tertiary Period, some 2 to 65 million years ago. During the past 2 million years Australia has seen cold, wet periods, and marked fluctuations in sea level resulting from accretion and partial melting of the polar ice caps. Investigations in the Great Barrier Reef suggest that as recently as 15,000 years ago
the sea level may have been 180 m lower than it is today; but the
evidence for this conclusion is controversial. In many other parts of
the world it has been estimated that, in periods of glaciation during
the Pleistocene Epoch that began 1.8 million years ago, the sea level
fell by up to 100 m. Estimates must take into consideration possible
crustal movements such as elevation or subsidence of coastal areas
caused by movements along faults. These have been observed in
recent years along the eastern coast of the north island of New
Zealand. Estimates must also consider the effects of elasticity of the
earth's crust, causing upward rebound when the weight of several
hundred metres of melted ice has been lifted. Such effects are seen in
the raised beach ridges of the Canadian Arctic and some Scandi­
avian islands.

Present day sedimentation on the Australian continental shelf
reflects both climate and drainage patterns of the adjacent terrain. In
northern Australia vast quantities of clay mud and silt are carried
into King Sound, Joseph Bonaparte Gulf, Van Diemen Gulf, and the
Gulf of Carpentaria during times of flood. In the Great Barrier Reef
area, with some local exceptions, the quantities of mud deposited in
the sea are very much smaller, as the coastal ranges flank the coast­
line and most drainage is to the west. This situation is compatible
with the growth of coral reefs which thrive best in clear water.
Sediments in the Great Barrier Reef area consist of carbonate sands
and muds in the vicinity of reefs, and of calcareous muds and silts
elsewhere. In proximity to the coastline sand deposits are common.
Sand is normally deposited near the shore, but can be transported
seaward by strong currents, and where deposited in submarine
valleys on the outer shelf and continental slope may periodically be
swépt by turbidity currents into bathyal and abyssal depths of a few
thousand metres. The presence of sand in deeper parts of a con­
tinental shelf does not necessarily imply that it was swept out to that
depth from the shore, although it may have been reworked at that
depth by ocean currents. Fluctuations of sea level must be taken into
consideration in any such interpretation. As mentioned before,
much of the present area of the Great Barrier Reef was a low coastal
plain 15,000 years ago, and sands may have been originally
deposited by streams meandering over that flat terrain. Also, much
of the present mud and silt, originally deposited on a floodplain,
must have been reworked and mixed with the calcareous remains of
shells, forams, and other organisms.

The continental shelf off the coast of south-eastern Queensland
and New South Wales is narrow. Sediments derived from erosion of
the headlands during the past several tens of thousands of years, and
deposited on the shelf, have been predominantly sandy and silty.
Sediments deposited on the continental shelf off Victoria, South
Australia and Western Australia are mainly of sand, silt, and clay mud, with local carbonates such as in the area of Shark Bay south of Carnarvon. Underlying these recent sediments are Pleistocene non-carbonate sediments deposited locally on coastal plains that were periodically inundated by the sea during intervals in the past 1.8 million years when the polar ice caps partly melted. Beneath these sediments, underlying large areas of the continental shelf off the southern, western, and northern and north-eastern coasts of Australia, lie Tertiary beds of limestone and marl, in places several hundred metres thick, evidence of the warmer seas and climates that prevailed during intervals of the Tertiary Period.

**Sea Floor Topography and Subsurface Geology**

In the days of sailing ships the topography of the ocean floor was unknown, with the exception of shallow coastal areas used for anchorage, ships channels close to shore, and the waters surrounding or adjacent to land features of particular interest to navigation or naval surveys. Depths to the sea floor were determined by means of a lead weight on the end of a cable. The nature of the sea floor, whether of sand or mud, could also be gauged by fixing wax to the lead weight. Today, the topography of the ocean floor is mapped by sonic and seismic surveys. The nature of the sea floor is revealed by photography. The composition of the sea floor and underlying sediments can be determined from samples obtained by submersible craft, drilling, dredging, and coring devices lowered to the sea floor.

Sonic surveys are carried out by ships equipped with apparatus to generate and record sound waves within a certain range of frequencies. The sound waves generated in short blips from the ship are reflected from the sea floor back to the ship where they are recorded by hydrophones. The interval of time between generation and recording of each blip is shown by means of a graph which depicts the variations in depth below sea level to the sea floor along the traverse of the survey ship. By covering an ocean area with intersecting traverses a grid system can be established, whereby the readings along each traverse can be tied to one another, and the sea floor topography illustrated by means of a contoured bathymetric map.

A bathymetric map is the subsea equivalent of a topographic map of the land surface. It depicts the topography with contours at determined intervals below sea level. The contour interval may be at any convenient difference of elevation, such as 100, 200, or 500 m, and the elevation of each contour line is designated. It is not essential to a bathymetric map that all contour lines are shown. Where the sea floor slope is so steep that the contour lines appear to run together it is common practice to omit certain contours. In such cases the
contour interval may be 100 m on the continental shelf, and 500 m on the continental slope. The interval chosen depends on the data available and the detail required. In the case of navigation charts of shallow areas of the continental shelf the interval will be 10 m or less. Hydrographic charts for naval and scientific use commonly show the maximum available detail.

Marine seismic surveys also depict the topography of the sea floor, although their prime purpose is to illustrate the structural and stratigraphic configuration of the rock layers beneath the sea floor. The method employs an energy source, commonly a sleeve exploder, which is fastened to or towed beneath the ship. The sleeve exploder consists of an expanding rubber sleeve within which a gas mixture is exploded. This restricts the explosive force, greatly reducing the impact on fish and other marine life, but allows sufficient energy generated by the explosion to penetrate the rock layers and be reflected. The reflected energy is recorded by hydrophones at set intervals along a receiving cable that is towed behind the ship. The receiving apparatus operates on the same principle as that employed in sonic surveys of the sea floor, recording the interval of time between generation and arrival of the reflected sound or shock wave. In the case of seismic surveys, multiple reflections are received and recorded. These must be filtered to exclude unwanted frequencies and thereby sharpen the definition of the records. Various techniques are employed and experimentation is continually carried out, leading to important developments in seismic technology. The generation of other vibrations, including those caused by offshore drilling and coastal shipping, affect the quality of the records.

Sea floor samples are commonly obtained by dredging. Where samples of the sediment lying up to 2 m beneath the sea floor are required, coring devices are used. These may be spring-loaded or compressed air piston type cylinders that are forced into the sediment on contact with the sea floor. Deeper cores require drilling. During the 1960s and 1970s the research ship *Glomar Challenger* obtained samples of sediment and rocks from many tens of metres beneath the sea floor at bathyal to abyssal depths in various parts of the world. Submersible craft, commonly operated by two persons, are capable of working to depths of more than 600 m. They are equipped with grappling arms capable of sampling rock outcrops on the sea floor. Data compiled from the records of these various methods can be collated to construct maps showing the distribution of sediment types in various areas of the sea floor. Areas in shallow regions of the continental shelf will be characterised by either carbonate or non-carbonate sedimentation, depending on such factors as climate and input of muddy sediments from a nearby river distributary system. Where carbonates develop, sediments will be
carbonate muds and sands that form banks and shoals, possibly associated with coralgal reefs. Where non-carbonates are deposited, the sediments will be clay muds, silts, and sands. Sands or muds may predominate in particular areas. In deeper water of the continental shelf, and on the continental slope, muds and silts are commonly predominant; but sands may be present in submarine valleys of the shelf, and on submarine cones in abyssal depths at the base of these valleys where sands have been swept by turbidity currents. Muds deposited in middle to outer depths of the continental shelf, and on the continental slope, are commonly rich in organic remains and consequently consist of a calcareous, clay ooze. In deep water of abyssal depths, where rates of sedimentation may be as low as 2 to 3 cm in 1000 years, the sediments are commonly clay muds mixed with wind-blown volcanic ash and the hard parts of organisms, including locally abundant sharks’ teeth.

The nature of the sediments on the sea floor, and the depth to solid rock beneath it, are of significance to the emplacement of structures such as drilling and production platforms. Shallow seismic surveys are carried out to determine such conditions. For example, in the area of the North Rankin gas field of the North West Shelf, Western Australia, it was found that the sea floor consists of unconsolidated calcareous sediments having a low bearing and shear strength. In order to investigate the suitability of the sea floor in this area, as a base for drilling and production structures, a survey was carried out by geotechnical consultants for the operator, Woodside Petroleum Developments Pty Ltd. This survey used a drill ship specially equipped to test and sample the sea floor and underlying sediments. Drilling and production platforms resting on sediments of the continental shelf may weigh well in excess of 50,000 tonnes, and rise more than 250 m from the sea floor to the top of the drilling derrick. Drilling and production of oil in deeper water of the continental slopes and plateaus will require a different technology, necessitating floating drilling and production platforms and a remote controlled submerged production system on the sea floor.

Offshore Drilling and Construction
Exploration for oil and gas under the sea begins with surveys to determine the topography of the ocean floor and the main structural and stratigraphic features of the underlying sedimentary layers. Prospective areas are then selected on the bases of interpretation of geology from seismic records, and depth to the sea floor. In the final analysis the drill must be used to test the prospective structures outlined.

The first offshore operations were in water depths of only a few metres, in areas such as Lake Maracaibo in Venezuela, the Gulf of
Oil Search in Australia

Mexico, and the Caspian Sea in the USSR. These initial steps were followed by ventures into deeper water. The technology of constructing and operating offshore drilling structures employed several methods, including the use of hollow cylindrical concrete legs that can (with the drilling platform mounted on top) be towed upright to the drilling site and submerged; steel legs that can be lowered through a floating platform to the sea floor, anchored, then used as support to jack up the drilling platform; and buoyed or guyed steel towers that can be towed horizontally to the site, tilted to the vertical by means of submerging pontoons, and lowered to the sea floor. The buoyed tower is slim, somewhat resembling a television tower. It is fixed to a basal plate on the sea floor by a mechanical pivot, and held upright by buoyancy chambers. The guyed tower penetrates the sea floor and is held upright by cables set in the sea floor by weights. The techniques and types of structure used depend on depth of water, weather conditions, and the uses required of the platform. In the area of the North Rankin gas field of the North West Shelf, Western Australia, a drilling platform will rise nearly 200 m from the sea floor to the top of the derrick. The Statfjord A production platform in the Norwegian section of the North Sea rises 260 m. This remarkable structure, one of the world's largest, is operated by Mobil Exploration Norway Inc. It consists of three hollow cylindrical legs of concrete on which stands a drilling and production platform that houses 200 workers and weighs more than 19,000 tonnes. Construction was carried out in a deep-water site and the structure was towed to sea. One of the tallest structures is a buoyed tower, in use in the Gulf of Mexico, which has an overall height of 420 m. For comparison, the height of the Sydney Harbour Bridge is about 135 m above sea level. Structures of these types cannot be used in deeper water of the continental slopes or adjacent plateaus. Drilling in water depths of 1000 to 2000 m must be carried out by dynamically positioned drillships such as Sedco 472 which drilled Esso-BHP, Zeewulf 1, Australia's first deep-water well, at a depth of approximately 1200 m on the Exmouth Plateau. This drillship, which can operate in up to 1800 m of water, maintains its position over the drilling site by means of a computer-controlled anchoring system referred to as Automatic Station Keeping. This system utilises acoustic signals beamed from a beacon on the sea floor to hydrophones mounted on the hull of the ship. These signals, with other data, are fed to a computer which controls twelve thruster propellers to counteract the effects of ocean currents and wind that would otherwise cause the ship to drift. In service around the world there are no more than a dozen ships of this type capable of drilling the Exmouth Plateau. One of these is the Discover 534 owned by Deep Ocean Drilling Inc. of Panama, an affiliate of Offshore Co. of the
United States. This vessel, one of the world's largest of its type, is capable of drilling to a depth of more than 7000 m beneath the sea floor.

Offshore records for drilling in deep water have been graphically illustrated (Fig. 11) in a report by Esso (1979). These show that during the period 1969-73 inclusive, wells were drilled in water depths of 400 to 500 m in Brunei and the Santa Barbara Channel of California. During 1974-5 drilling was carried out at water depths of 600 to 700 m in Gabon. In the succeeding years of 1976, 1977, and 1978 records were established of nearly 1100 m, 1200 m, and 1350 m in Thailand, Surinam, and Congo respectively. These records will certainly be broken during the following decade when the Exmouth Plateau will be one of the world's main proving grounds for the technology of deep-water drilling and production.

Inevitably, during the first stages of exploration and exploitation of the Exmouth Plateau, drilling technology will be ahead of that for production. Various schemes have been proposed for deep-water
well completion (Fig. 12) and recovery of oil; but systems that work satisfactorily in one part of the world may not, for reasons of climatic and ocean conditions, be adequate elsewhere. In this respect there is bound to be a good deal of room for innovations and modifications based on preliminary investigations and experimentation. One notable example of an Australian contribution to the technology of drilling and production platform construction was the worldwide acceptance of tubular steel joint fatigue designs developed by Esso Australia Ltd and Broken Hill Proprietary for the Tuna and Mackerel platforms in the Gippsland offshore area of Victoria. Structures of various types, including buoied and guyed towers, could not be used in the deep water overlying Exmouth Plateau where submerged production systems will have to be employed. Such sea floor systems will be automated and accessible only by remote control. They will have to be highly reliable and capable of being maintained from the surface. In many cases where it is necessary to make repairs or adjustment on the sea floor, the operations will be carried out by submersible craft.

The drilling of production wells in water depths of 1000 m or more can be done from an anchored floating platform supported by a
large hollow concrete hull which can be used for oil storage. The
drillpipe is lowered to a permanent sea floor template which guides
it and by means of directional drilling, up to twenty-five wells can be
drilled from a single template. Completion of the wells and produc­
tion of oil is managed by a submerged production system monitored
and controlled by a maintenance support vessel. The submerged
production system is connected to a manipulator operated by the
maintenance support vessel, and also to the oil wells by means of
pipelines. Oil is pumped to the surface through a floating production
riser connected to the wells, and is stored in floating containers or a
tanker. Variations and modifications to this generalised scheme will
be investigated as exploration and exploitation of deep-water regions
proceeds.

The costs of offshore exploration, quite apart from the enormous
subsequent costs of bringing discovered fields into production, can
be very high. In terms of 1979 Australian dollars (in which all figures
below are quoted), the cost of a marine seismic survey is about
$300/km. This is considerably less than the cost for a seismic survey
on land where progress is slowed by topography, weather, and the
necessity to drill holes for explosives and set out strings of
graphophones. Nevertheless, the cumulative costs for a single marine
seismic survey commonly run to $500,000. These costs can be well
in excess of those required of exploration permit holders by govern­
ment regulations. Such regulations call for a minimum of 30,000 km
of marine seismic survey work to be carried out before the end of
1983 on the five permits covering the Exmouth Plateau. The
minimum total cost of these surveys will amount to $9 million.
These costs are small compared with those of drilling. On the North
West Shelf exploration companies plan to spend at least $150
million on marine seismic surveys and drilling within the five-year
period to the end of 1983, by far the largest amount being allocated
for drilling. On the Exmouth Plateau the costs of drilling one well
may be as much as $10 million. Dynamically positioned drillships
such as Sedco 472 cost up to $125,000 a day (Esso, 1979) and com­
mmonly take 60 to 90 days to complete the drilling of a well. Govern­
ment requirements call for the drilling of thirty or more wells on the
Exmouth Plateau before 1983. This commitment, together with that
for seismic surveys, will cost at least an additional $250 million, over
and above whatever amounts have already been spent. Should oil be
found in a sufficiently large accumulation to warrant exploitation,
costs of bringing a field into production could run to more than
$3000 million. These figures point out the huge costs involved in
developing Australia's offshore resources of oil and gas. It is of
interest to note (Australian Institute of Petroleum, 1978) that the
metreage of offshore exploration drilling fell to its lowest level in a
10-year period in 1976, but showed signs of gathering momentum in 1978. By itself, metreage drilled is not necessarily a sufficient gauge of offshore exploration effort or costs, as depth of water must be considered. But as all the offshore wells drilled in Australia to 1978 were in water depths of the continental shelf, the nadir shown for 1976 can be taken as an indication of the wane in offshore exploration activity. Looking to the future, it can be expected that drilling on the continental shelf and Exmouth Plateau will continue, probably at an accelerating pace, until 1985, after which much will depend on what has been found and the consequent assessment of future prospects. Of particular significance to Australia is the interval of several years between the time of discovery and the time when that discovery can be brought into production. Fortunately, within the period to 1985, additional production from the offshore Gippsland oil fields probably will be able to fill much of the extra demand for petroleum products, assuming that Australia's oil requirements continue to increase. But this situation could not continue for long; and ultimately, unless new fields are brought on stream or alternative production of liquid fuels is obtained from the development of other sources, Australia will be faced with a situation of increasing imports. The greatest hope to alleviate this possible scenario lies in the exploration and exploitation of the continental shelf, slope, and adjacent plateaus.
A great deal of ill-informed comment has been published in the press from time to time on the subject of petroleum reserves and resources. Resources are commonly referred to as though they were reserves, and no distinction is made between various categories of reserves, to say nothing of the technological or economic parameters by which they must be defined. The same simplistic and often misleading treatment is accorded the subject of petroleum resources. Possible resources are included in the same category as known resources.

It has been pointed out by McKay and Taylor (1979) that realistic estimations of resources and reserves are important not only to those engaged in the exploration for and production of hydrocarbons, but also to those in various fields of business activities such as accounting, taxation, and banking, to governments, and to the public at large who are shareholders in a great many enterprises directly or indirectly connected with the oil industries. With reference to known accumulations of oil and gas, the oil industry defines reserves as hydrocarbons which can be economically recovered under current technological and financial expectations. Both of these factors are subject to change. Further, such a definition precludes the possibility that government policies might prohibit or restrict the exploitation of certain accumulations.

Historically, the oil industry has placed reserves in the categories proven, probable, and possible. Proven reserves are those that are declared commercially viable under known economic situations, geological conditions, and technological constraints. Probable reserves are those that are expected to be declared commercially viable, but which require further evaluation with reference to economics, geology, or technology. Possible reserves are those that cannot currently be declared commercially viable but which could be commercially viable given sufficient increases in the price for hydrocarbons, or developments in technology that will considerably enhance the production of oil or gas. But as pointed out by McKay and Taylor, in the world today economic climates and developments in technology change rapidly and necessitate a classification of reserves based on forward expectations as well as current situations. In view of these considerations the oil industry bases its evaluation of reserves on current information and prognostications derived from
probability analyses of a number of economic, geological, and engineering factors. The need to clarify the definition of the term reserves was also pointed out by Keplinger (1977), who noted the lack of understanding of oil and gas reserves by the general public.

The term resource, as distinct from reserve, implies some available physical or biological reservoir that can be tapped. Resources are designated by various terms under such general headings as human resources and natural resources. Under the latter must be included the term petroleum resources, which by definition refers to oil and gas accumulations that technology may be capable, either now or in the future, of bringing into production. The procedures involved in bringing a petroleum accumulation on stream may be technologically feasible, but they may not be economically viable at any one time. Developments in technology, or increases in the price of petroleum, may from time to time change a situation of potential loss to one of marginal or reasonable profitability. Marginally profitable or even poorer fields may also be placed on production in times of emergency when petroleum is needed regardless of cost. In such situations technological considerations outweigh those of economics. To illustrate further the relevance of technology and economics to petroleum resources one can consider the large deposits of bauxite, now a valuable natural resource for the production of alumina and aluminium, that would have been of no value before the development of the technology that made the production of aluminium an economically viable operation. Radiation from the sun is also a vast natural and physical resource. In recent years studies have been carried out to develop technically efficient heating systems that are economical in operation. The point has now been reached where the sun's radiation can be regarded as a proven or probable resource, rather than possible, depending on the geographical situation and use for which the heating plant is required.

With reference to petroleum resources the term implies that technology is capable of bringing into production accumulations of oil or gas, without particular reference to the economic viability of such an operation. These resources can be defined as known, probable, and possible. Known resources constitute known accumulations of oil or gas that technically can be placed in production now or in the future. An example is the very extensive deposit of oil sands in Alberta. Where these are situated under a cover of overburden too thick to be mined by the open-pit method, it is possible to produce the oil by subsurface fire-flood or steam-flood methods, the oil being retrieved from boreholes. The technology of this method is demonstrably feasible, but the economic profitability is marginal at best in terms of 1979 oil prices.

The categories probable and possible resources cannot always be
Proven Reserves and Potential Resources

clearly defined, but depend on geological and technological considerations. For example, a 200 m thick bed of tight, gas-bearing sandstone, from which production cannot be adequately obtained by conventional methods might be brought on stream by techniques devised to facilitate and sustain the flow of gas from fractures created by a subsurface explosion. Geological evaluation of such a sandstone bed might indicate a substantial volume of sandstone structurally situated to provide a potential gas field. But whether such an accumulation of gas is designated as a probable or possible resource depends essentially on the state of technology. If bringing the accumulation into production depends on an atomic blast, rather than on conventional explosives, then the gas accumulation would surely be included in a lower category of possible resources. Other examples of possible resources are the probable huge volumes of natural gas dissolved in formation water in low-porosity sandstones at depths of more than 3000 m in deep sedimentary basins (Masters, 1979). Other possible sources of natural gas are the large volumes of methane, the main constituent of natural gas, that are believed to be present in a frozen state, as methyl hydrate, at shallow depths in Arctic and Antarctic regions. Methane and other gases of the paraffin series react with water, under pressure and at low temperatures, to form hydrates which melt within a temperature range of several degrees above 0°C (freezing point of water). These hydrates, which can accumulate in the valves of gas wells and gas lines, are formed where high-pressure gas containing water vapour is expanded to a lower pressure. The hydrates resemble hard snow. Technology has not yet devised a method to utilise this possible vast store of gas.

Examples of an oil source that can be regarded as a probable resource are the deposits of oil shales in various parts of the world. These sediments do not contain oil as such, but kerogen which is converted to oil by destructive distillation. Mining and processing of oil shale is technologically feasible, and pilot plant studies to improve efficiency and economy are constantly undertaken by government authorities and the oil industry. The main deterrents to production are costs (although production of some deposits is claimed to be marginally profitable in terms of 1979 oil prices), and environmental constraints resulting from the large volumes of waste (more than the volumes mined) that must be disposed of, and the large quantities of water required in the process. Nevertheless, many of these oil shale deposits can be placed in the category of probable resources.

Known resources include reserves which must be defined in terms of economic viability of extraction. Reserves can be expressed as proven, probable, and possible. Possible reserves may be up-graded
to probable, and probable to proven, depending on technological developments, reassessment of reservoir and other geological conditions, and improvements in the price of oil. Consequently, the reserves of oil that can be economically extracted from any field can be stated accurately only when the field has been ultimately abandoned. Temporary abandonment may occur from time to time for various reasons, commonly a loss of adequate profitability. An increase in the price of oil, some new development in enhanced recovery, or the transfer of a field from one company to another with a different financial outlook or approach to oil recovery operations may result in the revitalisation of an old field. But in general terms the volumes of proven recoverable oil and gas in any field that has been in production for a period of two or three years can be stated within reasonable limits. A clear distinction must be made between the volumes of oil and gas recoverable from a field at any particular time under existing technological and economic constraints, and the actual volumes in place in the field. Some fields may yield only 20 per cent of the oil in place, others may yield up to 60 per cent by conventional production methods. The cumulative percentage yields obtained by using enhanced recovery methods, after conventional methods have been terminated, show a measure of overlap with the percentages stated. For example, a field that yields only 20 per cent of its oil by conventional production methods may yield up to 30 per cent or more by enhanced recovery methods. Similarly, the 60 per cent might be raised to 70 per cent. But ultimately a point is reached at which technological limitations and diminishing rates of return result in final abandonment of the field.

The term petroleum potential is commonly used in the assessment of a region or country. In its broadest usage the term includes known, probable, and possible petroleum resources, and as such also includes, under the category of known petroleum resources, the proven, probable and possible reserves. Commonly, the term petroleum potential refers to probable and possible resources in addition to those that are known to be producible by current technology.

**Australian Reserves and Resources**
The National Energy Advisory Committee (NEAC, 1979) state that the best available average estimate of Australia’s undiscovered crude oil resources is 570 million m³ (3600 million barrels). They state further that estimates indicate a 90 per cent chance of there being at least 250 million m³ (1550 million barrels), and a 10 per cent chance of there being at least 1050 million m³ (6600 million barrels). These figures do not imply that such volumes will necessarily be found, only that they may exist. Also, there is no implication as to the
relative volumes of individual accumulations included in these cumulative figures, a factor of prime importance in offshore exploration where only the large accumulations can be profitably exploited. For comparison, the above report states that proven economic reserves of oil in Australia amount to 298 m$^3$ (1870 million barrels), and known sub-economic resources amount to 48 m$^3$ (300 million barrels). The proven economic reserves are largely in the offshore Gippsland fields of Victoria.

The report also states that, on the basis of probability, there is an 80 per cent chance that at least 850 billion m$^3$ (30 trillion cubic feet) of undiscovered natural gas exists in Australian sedimentary basins, mainly in offshore areas. A more tentative estimate places a 20 per cent chance on the existence of 1700 billion m$^3$ (60 trillion cubic feet) of undiscovered gas. Proven economic reserves amount to 334 billion m$^3$ (11.8 trillion cubic feet), and known sub-economic resources amount to 812 billion m$^3$ (28.7 trillion feet). The proven reserves are largely in the Gippsland fields of Victoria, and the fields of the Cooper Basin in South Australia. About half of the known sub-economic gas resources are in the North Rankin, Angel, and Goodwyn fields on the continental shelf of Western Australia. These fields are under planned development which will result in much of the gas being re-classified from the category of a sub-economic resource to that of a proven reserve.

Estimates for the undiscovered natural gas liquids, condensate and liquefied petroleum gas (LPG), are also stated. Condensate comprises hydrocarbons that are liquids within the range of normal surface temperatures; LPG includes hydrocarbons that are gases within the same range but can be liquefied under pressure. The figures given for 80 per cent probability of existence (actually stated in terms of finding) total 200 million m$^3$ (1260 million barrels), and those for 30 per cent probability total 640 million m$^3$ (4030 million barrels). Proven remaining reserves in fields that have been declared commercially viable amounted to 137 million m$^3$ (860 million barrels) near the close of 1978 (BMR, 1979). Figures for resources of condensate and LPG that have not been declared commercially viable are subject to major revision and consequently are not quoted here.

In summary, Forman (1978) presents figures for the chances of finding additional petroleum resources in Australia, based on preliminary studies by the Bureau of Mineral Resources, Canberra, and by Jeffries (1975, 1976). Jeffries gives an 80 per cent chance of finding an additional 300 million m$^3$ (1900 million barrels), and a 20 per cent chance of finding 800 million m$^3$ (5000 million barrels) of oil. His average estimate is 570 million m$^3$ (3600 million barrels). The BMR estimates for undiscovered oil resources were 370 million
m³ (2300 million barrels). Jeffries also estimated a mean value of 1150 billion m³ for undiscovered gas resources. The BMR estimated these gas resources within the range 850 to 1700 billion m³ (30 to 60 trillion cubic feet). Such figures are necessarily based, to a substantial degree, on probability analysis and subjective assessments. It is essential to bear in mind that all figures given are ephemeral and serve only for reference as a general guide (NEAC, 1977).

It is stated in a report by Esso (1979) that of the 3000 million barrels of economically recoverable oil (excluding natural gas liquids) that have been discovered to 1979, approximately 1000 million barrels have been produced. The bulk of these oil reserves are in the offshore fields of the Gippsland Basin in Victoria. Since their discovery during the mid to late 1960s these fields have yielded a cumulative volume of one-third of their recoverable oil during a period of approximately ten years. Individually, these fields were brought on stream at different times, and their production capacities and performances will vary, so that the periods of declining production will not be the same in all fields. Nevertheless, it is a sobering thought to contemplate the expected decline in production of the older Gippsland fields over the next 10-year period, particularly in view of the lead time necessary to bring a new discovery into production. The length of lead time depends on several factors, including proximity to existing fields and production facilities, and depth of water. A discovery in the deep water of the Exmouth Plateau of Western Australia could take five or more years to bring into production, and only then if the estimated reserves are sufficiently high to justify the operation on an economically viable basis. In the meantime, production from existing Australian fields tends to rise to meet increasing demands for petroleum products. Such increases are technically feasible up to a point, without damaging the reservoir and lowering the ultimate cumulative production from a field. Alternatively, overall consumption of petroleum products in Australia rising in 1979 by 3 to 4 per cent each year, must be cut back if the country is to maintain its current rate of self sufficiency. Estimates presented graphically in a report by Esso (1978) show that within the period 1978-90 the consumption of oil in Australia is expected to be 4000 million barrels (Fig. 13). This estimate of requirements for oil amounts to twice the recoverable reserves as of 1979, and indicates that unless new fields are brought into production, Australia’s decreasing production can only be offset by increasing imports at escalating prices.

Changing patterns of energy use, necessitated by costs and availability of supplies of petroleum, will undoubtedly affect the rates of consumption of reserves. Oil-fuelled plants can be converted to coal-fuelled plants, and for some purposes natural gas can be substituted
for liquid fuels. The main use of liquid fuels for which there is no ready substitution is highway and agricultural transport (Saddler and Ulph, 1979) which in 1979 consumed more than 50 per cent of liquid fuels derived from crude oil. Increased use of LPG for transport vehicles may materially reduce the demands on crude oil. Furthermore, the addition of methanol to petrol and the production of liquid fuel from coal or oil shale could significantly economise on our consumption of crude oil reserves. Future emphasis may be placed not so much on reserves of crude oil, natural gas liquids, and natural gas, but on total reserves of liquid hydrocarbons derived from conventional wells or the processing of coal and oil shale. Australia has relatively large reserves of coal and uranium, adequate reserves of natural gas, but only small reserves of oil. The huge annual import bill for oil in the 1980s, probably amounting to several billions of dollars, may to some extent be offset by exports of uranium oxide. In the future, the economics of the world market will considerably alter our perspectives and estimates of liquid fuel reserves.
Gas reserves, and gas resources (that have not been declared commercially viable) are stated to be approximately 350 billion and 530 billion m$^3$ respectively. The later figure includes 470 billion m$^3$ in accumulations on the North West Shelf of Western Australia (BMR, 1979). Natural gas liquids in the North West Shelf accumulations are estimated to consist of 68 million m$^3$ of condensate and 72 million m$^3$ of LPG. It is estimated in the report by Esso (1978) that Australia’s major remaining reserves of natural gas are equivalent to 4600 million barrels (730 million m$^3$) of oil, and that by 1990 approximately one-quarter of this gas will have been consumed.

World Outlook

Australia occupies a very minor position in the lists of countries having oil production and reserves, but offshore exploration could alter the situation within a few years. In 1950 the USA accounted for nearly 52 per cent of the world’s oil production, and the USSR accounted for 7 per cent. By 1978 production in the USA had dropped to 16 per cent and that of the USSR had risen to more than 18 per cent (Australian Institute of Petroleum, 1979). Kuwait, Iraq, Iran, and Saudi Arabia accounted for 29 per cent of world oil production in 1978, and the Peoples’ Republic of China accounted for more than 3 per cent. By comparison, Australia produced less than 1 per cent, somewhat less than one-third of Canada’s production.

Total world production of oil in 1978 amounted to more than 22,500 million barrels, excluding minor production from some fields in Africa, Central America, and Asia. Of this total, the Middle East countries produced approximately 7800 million barrels (Saudi Arabia accounting for more than 3000 million), the USSR and Romania produced more than 4300 million barrels (Romanian production being very minor) and the USA and Canada produced more than 4100 million barrels. Other producing regions are Africa with nearly 2100 million barrels (mainly from Libya, Nigeria, and Algeria), Latin America and the Caribbean with slightly more than 1700 million barrels (the main production coming from Venezuela, Mexico, and Argentina), Asia with more than 1600 million barrels (China and Indonesia accounting for nearly 1400 million), and Western Europe with 638 million barrels (of which the United Kingdom produced 389 million, and Norway produced 132 million from the North Sea). Australian production in 1978 amounted to 158 million barrels, about 0.7 per cent of the world’s production.

In the same years world oil reserves, defined as volumes of oil that have been proven to be commercially recoverable at current levels of technology and oil prices, amounted to approximately 557,000
Proven Reserves and Potential Resources

Proven reserves and potential resources

89

million barrels, excluding reserves in the USSR and the Peoples’ Republic of China (Australian Institute of Petroleum, 1979). Estimates for reserves in the Soviet bloc, including probable as well as proven reserves, amount to an additional 94,000 million barrels. The largest proven reserves are in the Middle East where more than 373,000 million barrels await production. The bulk of these reserves, amounting to 169,000 million, are in Saudi Arabia, although the combined reserves of Kuwait, Iran, Iraq, and Abu Dhabi amount to 190,000 million. The second largest potential supplier is Africa, which continent has proven oil reserves approaching 55,000 million barrels. Most of these reserves are in Libya, Nigeria, and Algeria which have approximately 24,000 million, 18,000 million, and 6000 million barrels respectively. A close second are the countries of Latin America and the Caribbean which have proven reserves of more than 51,000 million barrels, of which Mexico and Venezuela hold 44,000 million. North America has proven reserves of more than 34,000 million barrels, more than 28,000 million being in the USA, and 6000 million in Canada. Western Europe has nearly 24,000 million barrels of proven oil reserves, of which 16,000 million are in the North Sea territory of the United Kingdom, and nearly 6000 million in that of Norway. Asia, excluding China, accounts for nearly 18,000 million barrels of proven oil reserves, over 10,000 million being in Indonesia. Most of the rest is in India, Malaysia, and Brunei with 2900 million, 2800 million, and nearly 1500 million barrels respectively. Australia’s proven reserves of oil in 1978 amounted to approximately 1700 million barrels, about 0.3 per cent of the world’s proven reserves.

Looking at the world oil resources that might become possible, probable or ultimately proven reserves, one is in the realm of speculation and educated guesses. It has been estimated that the original volume of technologically recoverable oil in the world amounted to about 2,000,000 million barrels. Of this volume, about 400,000 million barrels have been produced, and about 650,000 million are proven reserves. Studies by the oil industry point to the possibility that in the future enhanced recovery methods may increase the world’s volume of technologically producible oil by 400,000 million barrels or more, excluding the liquid hydrocarbons recoverable from oil sands and oil shales. It is estimated that proven resources in North America may be increased from the 1978 figure to 65,000 million barrels or more. Unfortunately, this will take time, possibly to the end of this century; and during the interval taken to develop the technology required to exploit the remaining oil, production in North America, Europe, Australia, and elsewhere may decline. Prognostications of possible future production, based on extrapolation of present production trends and estimates of future

economic growth, are somewhat hazardous. During the early to mid 1960s Australia's consumption of petroleum products was increasing by approximately 8 to 10 per cent a year. This rate has now decreased to about 3 per cent a year. Total world production of oil in 1978 has been stated above as amounting to more than 22,500 million barrels. Looking ahead to the period 1990-5, estimates of production range from 25,000 million to a peak in the range 30,000 to 35,000 million barrels, depending on assessments of economic growth. The figure of 35,000 million barrels probably reflects a very optimistic view. After 1995 world production of oil may steadily decline. Unless further oil discoveries are made, or marginal fields brought on stream, Australian production is expected to reach a peak and then to decline after 1985. Optimistic scenarios predict that conventional oil supplies will last until the year 2075, pessimistic views see the world's supplies finally depleted before 2020. Whatever the truth may be, exploitation of other hydrocarbon sources, including oil sands, oil shales, and coal, will be necessary to supply the probable increasing overall demand (even allowing for a per capita decrease) for petroleum products.

Alternative Sources of Liquid Hydrocarbons—Oil Shale and Coal
Liquid fuels derived from oil shale or coal consist of hydrocarbons, but not crude oil. Oil as such is not present in oil shale but is derived from destructive distillation (at temperatures greater than 500°C) of kerogen in the shale. The derived heavy oil contains a range of hydrocarbon compounds and may be further distilled and refined to produce coal oil or kerosene. Oil sands, on the other hand, contain bitumen or heavy, tarry oil that is commonly separated from the sand by heating with steam. Other heating methods, and the use of solvents or emulsifying agents, may also be employed. Australia has substantial deposits of oil shale, notably the Julia Creek and much smaller Rundle deposit in Queensland, but no deposits of oil sand have been found.

Estimates of world resources of oil shales, oil sands, and other bitumen deposits suggest that 3,000,000 to 4,000,000 million barrels of oil are present in oil shales, and that similar amounts are present in oil sands and bitumen deposits. Large as these resources may seem, under current economic and technological constraints it is unlikely that more than 5 to 10 per cent will ever be recovered, totalling a possible 500,000 to 600,000 million barrels. On this basis, the world's proven reserves of oil recoverable from conventional wells (650,000 million barrels) could be nearly doubled. Production from unconventional sources could be costly although, as the charges per barrel for conventional oil escalate, the differential in price may close to the point where production from oil shale and
other sources becomes economically attractive. Apart from economic considerations, the development of indigenous resources may be of prime importance for reasons of national defence and independence from overseas supplies. It is estimated (Shell, 1979) that in terms of 1979 US dollars the cost of producing oil from coal and oil shale could be $30 to $35 and $20 to $30 a barrel respectively. These figures do not include taxation, refining, and other costs incurred in the distribution of the final petroleum products. Also, there are serious problems involving the effects of mining and processing operations on the environment, and the costs of eliminating such problems.

The USA has large deposits of oil shales which may contain up to 2,000,000 million barrels of liquid fuels. If 5 per cent is economically recoverable, potential reserves from this source amount to 100,000 million barrels. This is in addition to the possible reserves of 65,000 million barrels that may be reached by using enhanced recovery methods in conventional oil wells. This total of 165,000 million barrels of potential oil reserves, in contrast to the 1979 estimate of 28,000 million barrels of proven reserves from conventional wells, may be within the capabilities of technology, but can only be attained at a considerable increase in the cost per therm.

Oil sands in western Canada also have a large potential for increasing future reserves. Current production from these sands is obtained from open-pit mining operations. Experimentation with various methods of subsurface production have been under way for many years and the technology required has been largely developed; but production costs per barrel have been the main deterrent. It is estimated that potential volumes of this very heavy oil (the oil has a gravity less than 12° API and does not pour at normal surface temperatures) in the Athabasca oil sands of Alberta amount to 500,000 to 600,000 million barrels. In addition to the Athabasca deposits, heavy oils in the Peace River, Wabasca, and Cold Lake areas of Alberta contain an estimated additional 250,000 million barrels. A large percentage of this would have to be recovered by subsurface methods. If only 5 per cent of oil in the Athabasca deposits were recovered, some 25,000 million barrels could be added to the 1979 proven reserves of 6000 million.

Other countries with substantial resources of oil from oil shale include Brazil (800,000 million barrels), the USSR, and Zaire (100,000 million barrels each). Potential reserves for these countries (based on 5 per cent recovery of theoretically contained oil) amount to 40,000 million, 5000 million, and 5000 million barrels respectively. The USSR also has large deposits of oil sands; but by far the largest deposits, amounting to more than twice those of Canada, are in Venezuela. These deposits are estimated to contain 2,000,000
millon barrels of oil. Operations to produce shale oil are currently under way, as large pilot plant or commercial developments, in the USSR, Peoples' Republic of China, Brazil, and the USA.

Australia's largest potential source of liquid fuels from oil shale is the Julia Creek deposit of north-western Queensland. This deposit, which lies within the Cretaceous Toolebuc Formation, is estimated to be capable of producing 150,000 to 300,000 million barrels of oil by open-cut mining methods (NEAC, 1977). Calculations are based on the assumption that open-cut mining is limited to a maximum depth of 150 m, and that a minimum thickness of 50 m of overburden must be removed. The average oil yield for the total deposit of oil shale in the Toolebuc is estimated to be 45 litres (0.3 barrel)/tonne. The very much smaller Rundle deposit, situated in eastern Queensland near Rockhampton, has an average yield of less than 100 litres/tonne, but is geographically well situated for exploitation. By comparison, the richest parts of the oil shale deposits in Colorado, Utah and Wyoming yield about 200 litres/tonne; but the average is much less. The heavy oils that can be produced by destructive distillation of the Julia Creek and Rundle oil shales are suitable for further treatment to produce liquid fuels. If placed on production the Rundle deposit could possibly supply a significant percentage of Australia's liquid fuel needs. Very much smaller deposits in the Sydney Basin in New South Wales have been mined at various times since 1860. In 1947, peak production of some 18 million litres of oil was obtained from the Glen Davis deposit northwest of Sydney.

Recovery of liquid fuels from oil shales is beset with many problems that technology has not satisfactorily solved. Among these are inefficiencies in the destructive distillation process which can decrease the potential yield of oil by up to 40 per cent. Other problems are the large quantities of water used (about 4 barrels of water for every barrel of oil produced), the disposal of spent shale waste (which has a larger volume than that of the rock originally mined), and safeguarding the plant operators from possible effects of carcinogenic substances. These problems, among others, add to the costs of producing shale oil, but may in some operations be partly offset by the recovery of copper, vanadium, and uranium which are commonly present in small quantities in oil shales and heavy oil deposits. Apart from these problems involving technological and economic considerations, other problems concerning the environment may be serious impediments to mining in some areas. In general, the economics of production from oil shales and oil sands depends not only on increases in the world prices for oil, but also on the containment of production costs, and on government encouragement by way of royalty and tax reductions.
Another alternative source for liquid fuels is coal. Australia has very large deposits of brown coal which are used only for domestic purposes, mainly for the generation of electricity in Victoria. Demonstrated reserves that are economically recoverable amount to at least 39,000 million tonnes (NEAC, 1977). Production in 1979 amounted to about 30 million tonnes a year. The abundance of brown coal offers an important alternative to oil shale for the production of liquid fuels. Yields of oil from brown coal range up to 1 barrel/tonne, probably giving a better average ratio than that for oil shale deposits in Australia. But costs of production may be higher than those for oil shale, and water requirements are about 5 barrels for every barrel of oil produced. Esso (1978) estimates a shortfall in Australia's production of approximately 600,000 barrels of oil a day by 1985, unless new fields are discovered and brought on stream. If the consumption of liquid fuels derived from crude oil is not significantly lowered, this gap will have to be filled by imported oil, probably at continually escalating prices. Alternatively, liquid fuels from oil shales or coal may partly replace the imports. But to produce 600,000 barrels of liquid fuel (which does not have the same mix of hydrocarbons as crude oil) from coal would require at least 600,000 tonnes of coal (NEAC, 1977), which is about twice the average daily production of brown and black coal in 1979. It is obvious that production of liquid fuel from oil shale or coal can fill only a small, but nevertheless significant, part of this anticipated gap. Liquefaction of coal by the pyrolysis method produces by-products for which markets would have to be found, although much of the gas produced could be used to fuel the pyrolysis process. One of the main deterrents to the liquefaction of coal is the large amount of water used. To produce 600,000 barrels of liquid fuel/day from coal would require about 3 million barrels of water/day, which is approximately one-third of Sydney's daily consumption.

The costs of producing liquid fuels from oil shale or coal are substantially higher than the costs of producing or importing the equivalent energy as crude oil. But as the technology of liquid fuel production develops, and as the price differential with crude oil narrows, the production of liquid fuels from oil shale and coal seems to be a logical and inevitable step in the future. What is certain is that there is no shortage in the world of potential oil, only of cheap oil.
Production Technology and Economic Considerations

Production Technology

The technology of oil well drilling and oil production has progressed a long way since the use of the cable tool rigs in the early 1920s. In those days drilling was carried out by a method whereby steel bits were fastened to a heavy metal rod which was raised and dropped by means of a steel cable. The rock at the bottom of the hole was chipped by impact of the weighted bit. Accumulated chips, mud and water were removed from the bottom of the hole by means of a bailer, a cylindrical device having a valve at the lower end, which could be lowered down the hole. Flow of formation water into the hole and caving sidewalls were controlled by setting steel casing which was lowered down the hole and cemented into place. As the hole was drilled deeper the diameter of the casing decreased and the bits used were smaller. Depending on the depth to which the hole was to be drilled, the diameter of the surface casing ranged up to 75 cm, and that of the bottom casing ranged down to 10 cm. Drilling was slow, depth was limited, and control was uncertain at best. Many a well was ruined because of unforeseen caving or water flooding before casing could be set, and many others blew out and caught fire on striking accumulations of oil and gas under high pressure. Where the oil was not under sufficient pressure to rise to the surface, its presence was detected in the bailer, and pumping equipment was installed to bring the well into production, the gas commonly being piped to nearby flares.

With the exception of some very small flares, this wasteful procedure of burning off the unwanted gas is no longer practised in most oil fields throughout the world. Exceptions are oil fields in the Middle East and in Mexico. The Mexican government-owned company Pemex flared more than 10 million m$^3$ (350 million cubic feet) of gas a day during 1979. In the early 1980s this amount may decrease as consumption and export of gas is increased.

The advent of rotary rigs placed the drilling of oil wells on a much more controlled basis. This method uses a cutting bit which is screwed into the bottom end of a string of drill pipe which is rotated by a turntable on the drilling-rig platform. Drilling mud, the density and chemical properties of which are controlled, is circulated down the drill pipe to the bit, and back up to the surface along the space between the drill pipe and the wall of the hole. Moving upward the
mud carries cuttings from the rotating bit, and also sidewall cavings from the softer or more shaly rock layers. The weight of the column of mud, controlled by the addition of heavy substances such as the mineral barite (barium sulphate), prevents oil and gas under pressure from rising to the surface; although gas under exceptionally high pressure, when encountered unexpectedly, may force the mud column to the surface and cause a blow-out. In areas where high pressure gas may be encountered, precautions are taken to prevent such accidents by installing a system of valves known as a blow-out preventer.

In the early days of rotary drilling there was no way of controlling the direction of the hole, particularly as there was no method of surveying the hole to plot its three dimensional shape and the position of its bottom. Most holes drilled departed from the vertical in a corkscrew fashion, trending directionally in accordance with the type of rock and structure of the layers penetrated by the drilling bit. Such departures from the vertical could seriously affect the outcome of the well, causing the hole to completely miss an accumulation of oil. The invention of well survey instruments, and the development of directional drilling techniques, enabled wells to be drilled precisely to any depth within the capability of the rig. It also enabled the drilling of up to twenty-five wells from one surface location (Fig. 14), an important contribution to the technology and economics of offshore drilling where a number of wells can be brought into production from one platform.

Deep-water Drilling

As exploration for oil and gas proceeded farther from shore on continental shelves around the world, the technology of offshore drilling developed rapidly to meet the increasing demands for discovering and bringing into production the hydrocarbon resources underlying deeper water of the outer continental shelf (Plate II). Various types of platforms were built, as mentioned in Chapter 4, including the Statfjord A production platform in the Norwegian sector of the North Sea. This giant platform sits on the seabed and rises 260 m. Such fixed gravity structures are best employed in water depths of about 150 m. They will probably be limited by cost (up to $A500 million each in terms of 1979 dollars) and by their enormous size and weight (up to 300,000 tonnes), to depths of less than 300 m. Because of the severity and unpredictability of weather conditions in many of the offshore regions of Australia, and also because of costs, it is unlikely that very large fixed structures will be designed for offshore drilling. Alternative types of structures, including guyed towers in depths greater than 200 m, will probably be considered.

Exploration has now stepped beyond the continental shelf, on to the areas of the continental slopes. In these depths of up to 600 m
PLATE II
Marlin oil and gas field drilling platform, Bass Strait. This platform has two drilling rigs and a capacity for twenty-four wells. Nearby is a barge used for erecting offshore platforms or laying submarine pipelines. (Courtesy of ESSO Australia Ltd.)
flexible guyed structures or drillships must be used. Australian drillships include the *Southern Cross, Ocean Endeavour*, and *Regional Endeavour*, the last capable of drilling in depths of up to 460 m. In still deeper regions of the plateaus drilling must be done by dynamically positioned drillships such as *Sedco 472* which in 1979 drilled Esso-BHP Zeewulf 1 in some 1200 m of water on the Exmouth Plateau. Oil fields discovered in these great depths of water can only be brought into production if they are sufficiently large to warrant the costs involved, and then only by the development of an entirely new technology using submerged production systems operated and maintained by remote control. The technical problems to be solved are staggering, and although several possible designs are under consideration, to 1980 none of the proposed systems has been placed on a production basis anywhere in the world. Australia will, in this respect, be in the forefront of technological developments, provided an oil field containing at least 300 million barrels of commercially producible oil is found on the Exmouth Plateau.
The North West Shelf gas project will bring into production the Rankin, Goodwyn, and Angel fields underlying a water depth of approximately 130 m. In deeper water of the continental slope it will not be possible to erect a fixed bottom platform, and other more flexible structures will have to be designed. The problems arising in placing a deep-water field on production are different from those involving production from the North West Shelf fields. Some future problems may currently be unknown; others may have only recently become known. One such problem is the generation of internal waves beneath the ocean’s surface. These have been photographed by earth satellites (McKinney, 1979) and apparently are generated along the boundary between layers of sea water having different densities, commonly where warm, less saline water overlies cold, more saline water. These waves range in amplitude to 180 m and can have a crest length of up to 200 km. Although generated at depth, they affect the surface water and consequently the movements of a drillship and drilling riser. The latter, consisting of a pipe through which the drill stem extends from the ship to the wellhead on the sea floor, is supported by the drillship. The resulting tension is relieved to some extent by the addition of buoyancy materials to the riser. Bending stress, causing curvature, is another problem to which the riser has only a limited tolerance. For such reasons, unforeseen movements of the ocean, caused by internal waves, could cause serious problems.

On the Exmouth Plateau, drilling has been carried out in a water depth of 1200 m. Further modifications to the few existing drillships capable of operating at such a depth could enable them to drill in up to 1800 m of water. At this depth the drilling riser would, allowing for curvature, be more than 1800 m long and would be suspended from the drillship like a string, subject to the motion of the ship and to internal waves and currents. In the event that an oil field is brought into production on the Exmouth Gulf, similar problems may arise with the production riser through which oil flows to the surface of the ocean to submerged or floating storage facilities. The role of physical oceanography in assisting to predict the severity and possible seasonal variations of sea motions is obviously of great importance.

Planning Stage, North West Shelf Gas Project
The main project undertaken on the North West Shelf during the early years of the 1980s will be bringing the North Rankin, Goodwyn, and Angel gas fields into production. By world standards this is a major undertaking involving the building of offshore production platforms and pipelines, a gas processing plant, liquefaction plant, and shipping facilities probably costing a total of $A 3000
million in terms of 1979 dollars. A great deal of technical and economic planning is required, based on government policies, market surveys, and on current and possible future developments in drilling and production technology, offshore construction, and knowledge of the physical effects of ocean and wind disturbances.

Preliminary surveys and investigations, probably costing at least $A50 million in terms of 1979 dollars, were planned in 1977. The object of these studies was to define the North West Shelf gas project in depth, and so minimise the possibility of unforeseen problems arising. Also, the cumulative information obtained from the several reports would assist in the formulation of final decisions on the economic feasibility of the project.

The studies proposed in the overall planning stage included a gas reservoir evaluation of the North Rankin, Goodwyn, and Angel fields; a drilling and production platform seabed foundation study; the selection of an offshore plant site; harbour facilities investigations; a submarine pipeline survey; environmental studies; design studies; market surveys for petroleum products; investigations of shipping requirements; and last but by no means least, inquiries into the avenues available to finance such a huge project.

Evaluation of the gas reservoirs entails detailed seismic surveys and possible drilling to further delineate the geological structure of the gas-bearing rock strata in order to up-date preliminary estimates of proven and probable gas reserves, and to assist in the placing of production platform sites. It is planned to build two platforms, and seabed surveys have been undertaken to determine the nature of the seabed sediments on which the platforms will rest. These surveys have found that in the area of the North Rankin field, where the water depths are approximately 130 m, the seabed consists of unconsolidated calcareous sediments having a low bearing and shear strength. Such information greatly assists in designing a suitable structure for the platforms. Plans for North West Shelf gas production envisage two steel structures, each having an overall height of about 200 m, built to withstand the maximum possible buffeting from cyclones. The drilling and production platforms supported by these structures will include plants to process the gas.

Hydrocarbons from the production platforms will be carried by a pipeline (Plate III) to the onshore treatment plant near Dampier. The pipeline will probably have a diameter of about 90 cm and a length of approximately 140 km. The route of this pipeline, and possible problems related to stabilisation in the seabed and underwater connections, will be determined by preliminary studies of the seabed and other aspects of physical oceanography. A further pipeline, to run from the treatment plant south to connect with the existing gas pipeline between the Dongara gas field and Perth, is also
PLATE III

Undersea pipe, coated with bitumen and an outer cover of wire netting and concrete. The outer cover is necessary to give the pipeline weight, so that it will not tend to float when oil or gas is pumped through it. (Courtesy of ESSO Australia Ltd.)
planned (Plate IV). The Dongara field will probably be depleted by the mid 1980s and may then be used as a storage reservoir for gas transmission to Perth. Other pipelines will probably be built, one to run from Perth as a spur line to the industrial centre of Pinjarra, and another from Dampier to the iron ore processing plants in the Pilbara region. The selection of a site for the onshore gas treatment plant and other processing facilities depends on investigations of a number of physical, biological, environmental and socio-economic factors.

Further seabed and land topography studies are required as a basis for the selection of suitable harbour sites and docking facilities for shipping. Investigations are also needed with reference to the types and number of vessels required to ship liquefied natural gas and condensate, and the ownership and conditions under which such ships might operate. Other studies entail the viability of different designs for onshore construction and all the associated infrastructure. Estimates must be made of the probable costs. International market surveys must also be carried out, in a changing climate of uncertain prices and unstable markets, on the long term economic viability of the project. These entail negotiations, influenced by a background of largely unpredictable political and economic events, which conclude with the signing, by parties offering to sell and buy the petroleum products, of letters of intent. Concomitant with such negotiations are inquiries into the avenues of international banking by which the project could be financed. And finally, the results of independent studies must be incorporated in an environmental impact statement which will be judged on the basis of objectivity, and weighed with reference to the socio-economic advantages of development on the one hand, and the socio-environmental disadvantages on the other.

LNG and Condensate Production, North West Shelf Gas Project

Liquefied natural gas is distinct from liquefied petroleum gas (LPG). Both are distinct from condensate. Condensate is a light petroleum liquid obtained from the cooling and expanding natural gas that arrives at the surface from producing wells. It is used as a refinery feedstock, and in the 1920s was also sold as a motor spirit. Condensate includes a mixture of lighter liquids in the paraffin series, such as pentane, hexane, heptane, and octane. Higher in the paraffin series, the hydrocarbon propane is a gas at normal pressures and can be readily liquefied to LPG by compression at normal temperatures. The basic member of the paraffin series is the gas methane, the main constituent of natural gas, which can also be liquefied as LNG under pressure and considerably reduced tempera-
PLATE IV
Laying the onshore section of a pipeline connecting the Barracouta gas and oil field, Bass Strait, with the Gippsland gas processing and crude oil stabilisation plant near Sale, Victoria. (Courtesy of ESSO Australia Ltd.)
Shipment of LNG requires cryogenic conditions in specially refrigerated ships.

Some of the gas produced from the North Rankin, Goodwyn, and Angel fields will be pumped through pipelines to Perth and other centres in Western Australia, for industrial and domestic uses (Fig. 15). Eventually, gas may also be moved to Sydney by a transcontinental pipeline connecting with the gas fields of South Australia. But the bulk of the production will be shipped overseas, and beginning in 1984 it is planned to export about 6 million tonnes of LNG each year. Condensate will also be produced at the estimated rate of 1.7 million tonnes a year, and LPG at the rate of about 0.5 million tonnes a year. Much of the gas would go to Japan, and some may go to the United States, being transported in six or more large cryogenic tankers. By comparison, the export of LPG from Australia during 1979 was somewhat less than 1.5 million tonnes.

FIGURE 15
Map showing routes of gas pipelines, oil pipelines, and pipelines proposed or under construction. (Courtesy of Australian Institute of Petroleum Ltd.)
The production, liquefaction, transportation, and storage of gas requires an integrated and synchronised system, planned to operate for a period of at least twenty years, as outlined by McGrath (1978). Plans envisage that initially two drilling platforms will be towed upright on their supporting structures to sites where the structures will be lowered and secured to the sea floor. From each platform twenty or more wells will be directionally drilled into the North Rankin gas field. Processing plants on the platforms (Fig. 16) will remove water, sand and some condensate from the gas before it is pumped through a pipeline to the treatment plant on shore.

FIGURE 16
Diagram of sub-sea oil well completion in Bass Strait, showing pipelines from a wellhead on the sea floor to a production platform. Not to scale. (Courtesy of Australian Institute of Petroleum Ltd.)

The treatment plant will extract the remaining condensate before the gas passes to a liquefaction plant. LNG is produced by cooling the gas to —160°C at which temperature the liquefied natural gas can be stored at atmospheric pressures.
LNG may be stored in double-wall steel tanks, each holding up to 100,000 m³, or pumped through pipelines to cryogenic tankers. The construction of facilities to berth these tankers, which draw up to 12 m of water, may require substantial dredging operations in the harbour. Each tanker will have a capacity of about 125,000 m³ and a length of nearly 300 m. At its destination in Japan or elsewhere the LNG will be discharged from the tankers into insulated tanks from which it can be regasified and transported by pipelines as required.

ECONOMIC CONSIDERATIONS

Government Policies
The production and marketing of LNG requires not only the integration and synchronisation of a technically complex system, but also the sanctions of governments in both producing and importing countries that will allow the system to operate efficiently over a period of years. On the part of governments in the producing country, this means that approval must be given to the producing and marketing interests to determine a certain level of profitability. Such approval may involve permission to export a maximum volume of LNG over a stated period, concessions with respect to taxation, and agreements on investment allowance deductions and the definition of allowable capital expenditures, as mentioned by Charlton (1978). On the part of governments in the importing country, assurances must be given that the necessary LNG terminal will be constructed at a suitable site, and that imports will be maintained at certain levels for stated periods of time. The high costs of establishing the system require long-term commitments to production and sales. These comments apply particularly to a system in which industry is the principal operating agent. Alternatively, governments may be directly involved in the ownership or operation of such enterprises through Crown companies or authorities whose responsibilities may be to participate in, regulate, or monitor the operations of industry. These matters are subject to negotiations and government policies, but are best resolved in a climate of political stability in which long-range plans can be made with reasonable assurance that they will not be upset by later government intervention. At all levels of government and bureaucratic decisions, integration and implementation of planning should be accomplished with the least possible friction and delay.

There are many considerations involved in the policies of the governments of both exporting and importing countries with reference to the production and marketing of natural gas. Policies may, in varying degrees, reflect political philosophy or expediency. The Australian Labor Party does not support a policy that promotes
PLATE V
Construction of a drilling platform in Bass Strait. (Courtesy of ESSO Australia Ltd.)
PLATE VI
Innamincka No. 1 well, Cooper Basin, South Australia, drilled in 1959 by Delhi Australian Petroleum Ltd, Frome-Broken Hill Company Pty Ltd, and Santos Limited. The well was drilled to a total depth of 12,637 feet in 234 days. It was completed as an artesian water well, yielding 26,400 gallons a day. (Courtesy of Delhi Australian Petroleum Ltd.)
the large-scale export of liquefied natural gas, whereas the Liberal Party-National Country Party coalition has imposed limits to the authorised tonnage that may be exported annually. Exporting countries are, on the one hand, concerned with the development of their economies and an equitable distribution of revenue between the oil industry and the government; and on the other hand, they are concerned with the conservation of a valuable source of energy. Importing countries are concerned with effects on their economies of the prices they will have to pay for LNG and other energy sources, and also on their dependence on other countries for fuel sources to which they have committed vast capital expenditures and industrial infrastructure. Diversification of energy supplies has become a key issue in the formulation of a rational political economy. Unforeseen contingencies will always arise, and Charlton (1978, p. 12) has pointed out, with reference to the overseas sales of LNG, that,

Because the contract is a long-term one, there will also be provisions aimed at maintaining such a reasonable market value in the future under changing conditions. However, it will be clear to both sides that no contract can be devised which will with certainty take into account all the changes and vicissitudes of a twenty years period. Accordingly an essential feature must be the creation of a sound relationship between buyer and seller, so that when problems arise in the future in interpreting the contract, there will be the necessary measure of trust and mutual understanding.

Concomitant with such relationships between industries in each country, the governments concerned must also encourage the enterprise by assuring a measure of stability with regard to security of supply, export and import controls, fiscal policies, and foreign exchange regulations. In Australia, negotiations to these ends are continually under review.

**Pricing and Export of LNG**

Export of Australian LNG will be to any or all of three highly industrialised world trading zones, Japan, the United States, and Europe. As with sales of coal, in which transactions the prices determined for shipments to these regions from other parts of the world are very much a matter of negotiation, there is no simple or arbitrary solution to the problems of pricing LNG. Inevitably, the prices must be related to costs of production and marketing, and to the prices obtained for alternative fuels. Government policies exert a significant influence in this area of trade negotiations, as do the well known laws of supply and demand. Cheap gas tends to encourage greater use, possibly at the expense of alternative fuels, and
consequently leads to greater dependence on a less diversified system of supply. On the other hand, expensive gas may lead to restriction of its use and constraints on the development of the economy. During the past decade the prices for natural gas at the well head and city gate have increased very considerably, and long term contracts for sales include escalation clauses that it is hoped will allow for periodic adjustment of prices in terms of real dollars. The difficulties involved in such negotiations can be readily seen, but not easily solved. As with the sale of coal, the present and probable future production costs of LNG, and terms of contract, are important factors in determining prices. World prices will probably vary in different countries, and Australian prices will have to be competitive. The prices for North West Shelf gas will also be determined with reference to possible discounts on volumes consumed, and the costs of alternative fuels.

Costs of Producing and Marketing North West Shelf Gas
The initial costs of producing and marketing oil and gas are those of geological and geophysical surveys. These are comparatively minor with respect to the following costs of exploration and production drilling, laying pipelines, and construction of treatment plants and associated infrastructures. Before drilling, the initial phase of an exploration program can cost from several hundred thousand to a few million dollars in terms of 1979 dollars. Exploration drilling can range in cost from $30,000 a day on land to $56,000 a day on the continental shelf, and $130,000 a day in the deep water of the continental slopes and plateaus. Depending on depth, nature of the strata penetrated, continuity of supply of material and personnel for the drilling rig, and the avoidance of accidental delays, drilling of a single well may take more than 60 days.

Once an offshore discovery has been made and determined to be of a size that would justify its being brought into production, the costs can run to hundreds of millions, or a few billion dollars. The deeper the water and greater the cost to bring a field into production, the larger that field must be. On the Exmouth Plateau an oil field would probably have to contain producible reserves of at least 300 million barrels to be economically viable. Currently, a gas field could not be brought into production at such depths, for economic and technical reasons. The development of offshore gas fields, for some years after 1980, will probably be confined to those of the continental shelf in water depths of less than 300 m.

Even so, the costs are enormous, and in the case of the North West Shelf gas project may exceed $3000 million in terms of 1979 dollars. Some of the costs, for which allowance must be made, are peculiar to Australia. It is not yet possible to predict precisely the path of a
PLATE VII

Sedo 472, the first deep-sea drillship in Australian waters, and one of the few such highly sophisticated ships in the world. These ships maintain their position at sea by means of acoustic signals from a beacon on the sea floor, and computer-controlled thrusters on the ship. Sedo 472 drilled ESFO-BHP Zeeuw oil well on the Exmouth Plateau in 1200 m of water.

(Courtesy of ESFO Australia Ltd.)
cyclone striking the offshore region and coast of Western Australia, and allowances must be made for lost time during the various construction phases for periods of severe weather disturbances. In Bass Strait, which is not subject to cyclones but is an area of periodic heavy seas and high wind, it was found that up to 25 per cent of construction periods could be lost as the result of bad weather. Another allowance that must be made is for industrial action that can tie up various sections of construction for considerable periods. Again, experience in offshore construction in Bass Strait indicates that up to 25 per cent of the time initially allocated for construction can be lost by industrial action. A possible solution to the latter problem is the letting of contracts overseas for certain aspects of construction. This has already been the practice for many years in the servicing of offshore drilling rigs, some of which are sent for maintenance and repairs to Singapore where facilities and skilled labour for such work are available.

The estimated costs for various phases of the North West Shelf gas project were stated by McGrath (1978) to be $900 million for two offshore drilling and production platforms with an associated pipeline to the gas processing plant on shore; $700 million for a gas liquefaction plant; $100 million for the gas processing plant; and up to $1300 million for cryogenic tankers to transport the liquefied natural gas to overseas markets. Other costs of harbour facilities and pipelines to the Dongara field and industrial areas are additional. Also not included are the costs of constructing LNG receiving terminals and regasification plants in Japan and elsewhere, which costs are born by the countries to which the gas is shipped.

Financing the North West Shelf Gas Project
The magnitude of the problem of financing a giant operation such as then North West Shelf gas project has been succinctly stated by Charlton (1978, p. 11) who says,

A project of this nature is characterised by an accelerating outflow of capital for a number of years before sales income is earned. The scale of the project in terms of capital requirements is so massive that, even with a broadly based partnership like the North-West Shelf Joint Venture, the need for finance from third parties is paramount. Even so, the partners themselves must find large sums, since outside finance will not be available to cover more than a proportion of cash needs.

Charlton points out that the first priority in securing acceptable finance is to establish a project that is technically and commercially sound. Long-term contracts for purchase of LNG must be arranged with financially secure customers in order to secure the borrowing necessary for capital costs. This point has also been made by Folie
and McColl (1978, p. 108) who say, 'In order to develop a viable project, a market for LNG must be found where the purchasing parties are willing to enter into a 15 to 20 year contract.' A further consideration is that in order to secure an economic return on the massive capital outlay, exports totalling at least 6 million tonnes of LNG a year are required. In the case of the North Rankin trend, comprising the North Rankin, Angel, and Goodwyn gas fields, the Australian government has approved the export of 6.5 million tonnes a year for a 20-year period. This amounts to about 52 per cent of 1978 proven reserves in the North Rankin trend.

Apart from the technical and commercial soundness of the venture, lenders such as international banks are concerned about possible changes and constraints to foreign exchange regulations, inflation, and the introduction of new government policies during the term of the loan. Interest rates and other provisions are adjusted according to the estimates of risk involved. Financial arrangements of this magnitude are enormously difficult, being dependent on a number of inter-related factors. Money is not forthcoming until there is evidence of firm intent from potential customers to buy the required volumes of gas over an agreed long-term period. But customers may hesitate to commit themselves during times of changing economic and political situations, seeking to make more flexible or less costly arrangements. Potential customers may also encounter long delays in obtaining permission to import LNG. In the case of the United States, agreement must be obtained from the Federal Power Commission, possibly on terms that are not satisfactory to the customer seeking to import the gas. Also, changing political relationships may be reflected in trading agreements and sales of gas from other countries. In this respect, the United States may elect to import more gas from Mexico at the expense of possible sales of LNG from Australia. Such matters are of prime importance to producers and buyers in the drafting of long-term agreements, and also to financial institutions in their deliberations on the terms of loans.
Future Petroleum Needs

**World Outlook**

**World Energy Growth**

Future petroleum needs must be viewed in context with the past and projected future world energy growth. Since the turn of the century, when the designation horse power literally meant what it said, the growth of energy demand increased at average compound annual rates of more than 2.5 per cent to 1950, and about 5 per cent during the period 1950-70. In 1970 the world’s primary energy consumption amounted to more than $196,000 \times 10^{15}$ joules; in 1975 consumption had increased to more than $230,000 \times 10^{15}$ joules (Australian Institute of Petroleum, 1978). This rate of consumption is roughly ten times what it was at the turn of the century, and reflects not only the developments in technology that have revolutionised our modes of transport, but also the very considerable economic growth of the western world and developing countries. In particular, the comparatively small population of the western world consumed the lion’s share of energy, including petroleum. But it does not follow that these ever increasing rates can validly be extrapolated to arrive at a figure for energy consumption to the turn of the twenty-first century. Such an extrapolation would suggest that by the year 2000 the world would be consuming more than thirty-five times the amount of energy used in 1900. Should this occur, it would necessitate further technological development and industrial growth on a very large scale to utilise fossil deposits such as coal and oil shales for the production of liquid fuels. It would also necessitate greater use of nuclear power plants for the generation of electricity, and to a minor extent the development of solar and wind power plants in suitable regions. Other methods of developing power by tidal and ocean currents may also be used. All of these methods of using natural resources, in addition to massive strip mining operations to obtain coal for the generation of electric power, will probably be in operation in various parts of the world by the year 2000.

Extrapolation of the crude oil component of world energy growth is predicated on estimates of economic growth, technological developments in liquefaction of coal, extraction of shale oil, substitution of other fuels including coal, conservation practices, and more efficient fuel consumption by mechanical transport. Annual
variations in consumption may also be in part a reflection of government policies, political decisions of the OPEC countries, and costs. For example, in 1974 the average daily crude oil consumption of the non-communist countries decreased by nearly 1.5 million barrels to about 46 million barrels. That was the year when OPEC sharply raised the price for a barrel of oil, and the beginning of the so-called 'crunch' in oil supplies. Realisation dawned throughout the oil-consuming world that the days of cheap oil were over. In fact, since about 1950 the price of oil had been falling in real terms; and the price was restored to a figure that was probably not much higher than it would have been had annual adjustments been made during previous years for depreciation of the US dollar. Nevertheless, the blow was a hard one, and the average daily consumption of crude oil continued to fall during 1975 to about 44 million barrels. During the following year, no doubt as the initial shock wore off and consumers became resigned to the higher price structures for liquid fuels, consumption of crude oil began to rise again. Subsequent price rises have not had such a catastrophic impact on the economies of industrial and developing countries, but have been a contributing factor in the slowing down of economic development in the western world, and to a more moderate increase in the annual consumption of petroleum products.

Perhaps the greatest impact on the public was felt in the USA where petrol has for years been cheap in comparison to European prices. During the oil era of the 1930s to 1950s, the USA had been the world's largest producer, and a net exporter of crude oil. In the 1960s the balance began to change, and by the 1970s the USA was a substantial net importer of oil from OPEC sources, including Venezuela. This swing occurred during a period when the industries of western Europe and Japan were expanding and consequently competing for oil.

It is of interest to look back to the years preceding World War II when coal was the main energy source in the industrialised countries of the world, although in the USA and Canada oil and natural gas were beginning to displace coal. As both supplies and prices changed their balance in the market place, oil was in some cases displaced by gas. The result was the shutting down in North America of many coal mines which did not revive until the post-war demand for coal by the Japanese steel industry. But this did not eventuate until the late 1950s to early 1960s, before which time nobody was much interested in producing coal, other than for already established overseas and domestic markets. Many coal-fuelled power and other industrial plants were converted to the use of oil, which was cheaper and cleaner. In the following years conversion was further encouraged by government regulations controlling the levels of air
pollution, and by public relations influenced by pressure from conservation interests. The industrial world, and the motorised public, had found the answer to their dream of an ever expanding economy, an apparently inexhaustible supply of comparatively cheap fuel.

Yet the writing should have been on the wall, and the motto of the American States, 'United we stand, divided we fall', should have been seen in an industrial context with reference to the oil-producing countries of the Middle East, Africa, and elsewhere. For three to four decades before 1974 negotiations between the oil industry and the oil-producing countries of the Middle East had been carried out in a buyer's market; although during the late 1960s the producer's share in the oil was raised by increasingly effective pressure from politically aware, technically trained, and business-minded nationals in Saudi Arabia and other Middle East countries. Over the years the oil companies' equity in the oil produced became eroded, and the potential of the oil-producing countries to raise the price of their share became greater. In some areas of the world the oil industry functions mainly as an agent of the government of the oil-producing country, being guaranteed a return of the costs of exploration and development, tax concessions, and interest on the investment. Whatever the terms negotiated, oil-producing countries have, for several years, been assuming a larger role as owners of their natural resources, the development of which is increasingly subject to political as well as commercial interests.

Patterns of Consumption of Fossil Fuels

During the past several decades there has been a changing world pattern of consumption of fossil fuels. Before World War II coal was the dominant source of energy. After the war the pattern changed rapidly as more homes were heated by oil, diesel fuel replaced coal in railway locomotives, and coal-burning power and other industrial plants were converted to the use of fuel oil or natural gas. The relative cheapness of oil and gas, and their comparative cleanliness and convenience of handling, were major factors in decisions to convert from coal. During this period the real price of oil was either steady or tending to decline, whereas the mining of coal was faced with increasing labour costs and industrial confrontations. Added to these difficulties was the growing realisation that the use of coal was causing serious problems of pollution to the environment.

The change in pattern of demand from coal to petroleum was both widespread and rapid. In 1950 about 65 per cent of the world's energy was derived from coal. By 1960 oil and natural gas had tipped the balance and on a world-wide basis supplied slightly more energy than coal; and by 1970 they were contributing twice the energy of
coal. During this period 1950–70 the world’s consumption of crude oil increased at an average compound annual rate of 8 per cent. Since then the world’s demand for crude oil has continued to grow.

Looking ahead it appears to be inevitable that the pattern of demand for fossil fuels must change again. The demand for crude oil will probably continue to grow for the next few years, but probably at a lower annual rate. During this time alternative sources for liquid fuels, albeit more costly, will have to be developed. In this respect South Africa has already set the pattern by the establishment and planned further development of large plants for the liquefaction of coal. Natural gas can also be used in the production of methanol as an additive to liquid fuel for transport. Production of oil from oil shales and oil sands will probably also be carried out on a large scale provided technological and conservation problems, such as the large requirements for water, can be satisfactorily resolved. Also, many power and industrial plants that converted from coal to oil years ago may once again revert to coal, particularly in cases where technology has enabled the industry to solve the major problems relating to pollution of the environment. The building of nuclear power plants, so much a public issue now, may in the future, and in the light of improved technology and maintenance safeguards, become necessary in some countries to maintain the requirements for energy. In addition, solar, wind, tidal, and wave power may in particular areas also be harnessed.

A further consideration in the changing pattern of demand for fossil fuels is the increasing need for conservation of liquid fuels. The liberality with which petrol has been used in the past cannot be continued in the future. Years ago petrol was regarded by the oil industry as a readily available commodity that must be sold on a competitive basis to the maximum possible extent, and by the consuming public as a relatively cheap and inexhaustible necessity. Studies made in the United States of America of the driving habits of the public show that appreciable quantities of fuel are consumed in trips by car from point A to point A; in other words trips undertaken merely for the pleasure of driving. The public attitude towards cars is changing as the realities of possible future fuel supplies begin to be understood. Conservation of liquid fuel may be encouraged by a program of public education or enforced through pricing, lowering of speed limits on the highways, phasing out the manufacture of cars with higher horse power ratings, conversion of cars to the use of LPG, the addition of methanol to petrol, and the rationing of petrol. Some of these measures may not be popular, and may not come about for some years. But the public has had a rude awakening to the fact that petroleum products are no longer cheap nor always plentiful, and that insofar as they presently form a large component of the
world's total energy requirements, the pattern of demand for fossil fuels will have to change.

**World Energy Supply and Demand**

Prognostications of Australia's and the world's future energy supply and demand are fraught with political and economic uncertainties and are at best educated guesses based largely on what is known of available proven reserves of fossil fuels, planned development of resources and industries, population growth trends, and extrapolation of curves depicting previous trends of industrial growth and of energy supply and demand. Within these constraints the validity of prognostications looking ten years ahead can probably be sustained. Further crystal ball gazing becomes increasingly clouded with uncertainty.

In 1965 oil contributed 47 per cent of the world's energy requirements, natural gas 17 per cent, nuclear power less than 2 per cent, hydroelectric power 7 per cent, and coal 27 per cent (Esso, 1978). By 1975, and despite a reduction caused by the large price rises of 1974, the consumption of oil had risen to account for 54 per cent, and natural gas for 18 per cent of the world's energy requirements. Nuclear and hydroelectric power remained at 2 per cent and 7 per cent respectively, and coal dropped significantly to 19 per cent. By the year 1990 it is expected that oil will have lost ground to 48 per cent, and natural gas to 15 per cent, the loss being taken up by nuclear power and synthetic fuels. Hydroelectric power and coal are expected to retain their current positions and contribute 7 per cent and 20 per cent respectively to the world's energy supply. In terms of actual consumption of energy, the cumulative value for all contributing sources may rise from 90 million barrels per day in 1975 to 150 million barrels per day of oil equivalent in 1990. The actual consumption of oil over this period may also rise from less than 50 to 70 million barrels per day, although some estimations made in late 1979 have lowered the expected levels of consumption of liquid fuels.

The changing pattern of world energy supply and demand must take into consideration not only changes in the various sources of energy, expressed as actual or percentage changes in terms of barrels per day of oil equivalent, but also changes in the geopolitical distribution of energy consumption. These will reflect changes in the economic growth of various countries or regions. Information presented by Esso (1978) suggests that in 1975 the United States of America consumed 41 per cent of the non-communist world's energy supply, Europe 28 per cent, Japan 8 per cent, and the balance of the non-communist world 23 per cent. (The United States consumed about 32 per cent of energy supplies for the whole world.)
Extrapolation of the consumption trends indicates that by 1990 the United States of America, Europe, Japan, and the rest of the world will all consume more energy than in 1975, but in different proportions. The United States of America is expected to consume 35 per cent of the world's energy supply, and Europe 25 per cent, decreases of 6 per cent and 3 per cent respectively. Japan's consumption may rise slightly to 9 per cent and the cumulative consumption of the rest of the non-communist world to 31 per cent, a rise of 8 per cent. These estimates suggest that the economies of the western world may undergo a decrease in their rates of growth during the next decade, whereas those of the rest of the world may tend to rise. This prognostication does not necessarily confirm the adage that small is beautiful, nor that economic growth for its own sake is necessarily harmful. It does suggest that economic imbalance in the world is subject to periodic readjustment and change, and that a more modest economic growth for the industrial countries of the western world will result in a lower rate of increase in the demand for energy and in particular for oil during the next decade to 1990.

World Oil Supply and Demand

Traditional concepts of the relationships between supply and demand have in the past applied to the production and marketing of crude oil throughout the world. Annual increases in demand have, with periodic constraints, been met with increased production; and increased production has, to some extent, been taken up by greater demand. This situation cannot continue indefinitely. Crude oil is a non-renewable natural resource, and the main production comes from independent geopolitical regions, some of which are not overly sympathetic to the aspirations of the western industrial countries. Although the demand for crude oil is expected to grow during the next decade to 1990, it will be at a lower annual rate of increase. Estimates of consumption in 1985 depend on estimates of economic growth, which is viewed and interpreted variously by different economic authorities, all of whom are agreed that oil consumption is tied to economic growth rates.

Various estimates of oil consumption for the non-communist countries in 1985, all based on estimates of both high and low levels of economic growth, are stated by the Australian Institute of Petroleum (Petroleum Gazette, April 1979). These estimates were made by Shell, Exxon, British Petroleum, CIA, Workshop on Alternative Energy Strategies ('comprising 70 people recruited from 15 non-Communist countries, and representing the fields of industry, commerce and government') based at the Massachusetts Institute of Technology, and the Organization for Economic Co-
operation and Development. Compared with previous estimates (Esso, 1978), these estimates ranged from 51 to 68.3 million barrels of oil equivalent a day for low economic growth, and from 62.5 to 72.6 million barrels a day for high economic growth. Three estimates for low economic growth were 58.4, 58.8, and 60 million barrels of oil equivalent a day. Three other estimates for high economic growth were 71.6, 72, and 72.6 million barrels. These figures suggest that in 1985 the non-communist world will require 60 to 72 million barrels of oil a day, depending on the state of the various national economies of the western industrialised countries. In 1978 these countries consumed approximately 54 million barrels of oil a day, an increase of roughly 2 million barrels over the preceding year. In view of the anticipated decrease in the growth of the economy of the United States of America during 1980 and beyond, and the effect this will probably have on the economies of the balance of the western world, the demand for crude oil in 1985 may possibly fall within the lower range of 62 to 65 million barrels a day. The upper limit of 72 million barrels may not be attained until 1990, by which time additional demand for liquid fuels may be partly taken up by production of oil from oil shales and the liquefaction of coal.

It is anticipated that by 1990 the Middle East OPEC countries will contribute about 48 per cent, other OPEC countries 14 per cent, Europe and other non-OPEC countries 22 per cent, and the United States of America and Canada 16 per cent of the world's oil requirements. As already stated, oil is a non-renewable natural resource. Even the gigantic fields of the Middle East cannot be drained forever. As the reserves in producing fields decrease, so will production ultimately fall. For the OPEC countries as a whole this point may be reached between 1985 and 1995. A further consideration, quite apart from the engineering aspects of production, has been pointed out by Froggatt (1978) and others who have stated that production of oil from OPEC countries may be governed less by the needs of the importing countries than by the political, economic, and social objectives of the producing countries. This aspect of trade has sometimes been referred to as resource diplomacy. It may become more apparent in the future, and may further exacerbate a possible shortfall in oil requirements before 1990. In particular there may be a reluctance on the part of some Middle East countries to sell their oil, in view of their evident surfeit of foreign currency and problems in reinvestment. It has been pointed out by Playford (1977) that the income of Saudi Arabia was some $70 million a day. Froggatt (1978) has also stated that in 1977 the Middle East OPEC countries had an overall surplus revenue of about $40,000 million. Oil revenues to the OPEC countries in 1979 exceeded $175,000 million. The result-
ing imbalance in future trade may place the industrialised countries in severe economic difficulties.

Having portrayed a less than optimistic outlook it must be said that most forecasts of energy supply and demand for a period of 5 to 10 years ahead will probably prove to be wrong, or at best to require some qualification. In this respect the most obvious possible source of error is in timing. Shortfalls in supply of oil from Iran, following the Islamic revolution of 1979, were certainly not foreseen in 1977. There are too many political and economic variables that cannot be predicted to cast the future with any degree of certainty. Outlooks tend to be an extrapolation of the present situation. Not all students of world energy problems take a dim view of the future. Some see the present situation of high oil prices as a mixed blessing, somewhat painful in the present, but encouraging the development of technology to solve our problems in the extraction of oil from oil shales and oil sands, in the liquefaction of coal, and the manufacture of other synthetic fuels during the years beyond 1990. High prices also tend to encourage conservation of fuel and lower the world’s demand for oil. Furthermore, high oil prices encourage exploration for new oil fields, and enhanced recovery from old fields, the end results from which may considerably lessen the western world’s dependence on OPEC oil during the latter part of the 1980s. But in this respect the oil industries and governments of the industrialised countries are painfully aware of the lead-time required to bring a new discovery into production, particularly offshore where the lag may be up to five years. Also, during the inevitable period of adjustment the price of oil in real terms may rise appreciably above the 1980 price to create an additional strain on the economy.

On balance, the adjustment to new world prices, supply, and demand for oil may be alleviated by the factors mentioned above, by the more efficient use of fuel, especially for transport, and by a decrease in the rate of economic growth of the western world. In which context it can be reiterated that in the world today there is no real shortage of sources of oil, only of cheap oil.
Present Consumption of Fossil Fuels

The Australian pattern of consumption of fossil fuels is similar to that of other industrialised western countries in that a high proportion of liquid fuel (one of the world's highest) is used for private and commercial transport. During the 1960s consumption of petroleum products was rising by as much as 10 per cent a year, but has decreased to a much more modest rate of 2.5 to 3 per cent during recent years. Even so, the drain on indigenous supplies of petroleum, and the possible future requirements for imported petroleum, are causes for concern. This pattern is unlikely to change much over the next decade to 1990, although by the end of that period an appreciable amount of liquid fuel may be manufactured from natural gas or derived from oil shale or the liquefaction of coal. Presently known indigenous reserves of oil and condensate in Bass Strait and elsewhere may be extended to lengthen the period of Australia's self-sufficiency to the end of the decade, provided the present annual rate of growth in the use of liquid fuel is held steady or decreased. But ultimately, unless new and economically viable oil fields are found, and provided also that alternative sources for liquid fuels are not developed for technical or economic reasons, Australia's dependency on foreign imports of oil will grow. Given the present situation of dependence on crude oil, Australia's position of 65 per cent self-sufficiency in petroleum products (largely petrol), and 70 per cent in crude oil input to refineries, is expected to be maintained to 1985, after which it will decrease to 1990, depending mainly on the performance of additional oil fields, including Fortescue and Flounder, that are brought on stream in Bass Strait.

In this regard it has been said earlier that it may be considered technically possible to produce oil from a particular reservoir, but economically not viable. The decision to put such a reservoir on stream may depend largely on the price received for each barrel of oil. Consequently, for economic and technological reasons it is not always possible to foresee the development of known reservoirs of oil for years ahead, and estimates of available supplies and future self-sufficiency are subject to periodic revision.

Australia relies heavily on petroleum (about 55 per cent) and coal (about 40 per cent) for energy supplies. Less than 2 per cent is
supplied by hydroelectric power. Of the petroleum, about 48 per cent is provided by oil and 7 per cent by gas. These figures are subject to annual revision, particularly as natural gas and LPG continue to replace oil. The growth of hydroelectric power, especially in Tasmania, is unlikely to alter significantly the overall pattern of energy use in Australia. Analysis of this pattern shows that transport uses 57 per cent of our oil requirements, industry 34 per cent, domestic and commercial appliances 7 per cent and electricity generation 2 per cent. Of the oil used for transport, road transport accounts for a massive 80 per cent, sea transport 10 per cent, and rail and air transport each 5 per cent. A further breakdown indicates the large amounts of petrol consumed by private passenger cars which account for 70 per cent of the fuel required for road transport. In other words, about 32 per cent of Australia’s total oil requirements is consumed by the private motorist.

Future Oil Needs
It has been estimated that by 1990 the Australian daily consumption of oil, which amounted to about 625,000 barrels during 1977-8, will have climbed to about 800,000 barrels. Nearly a third of the oil consumed during 1975-8 was imported. The cost of oil imports in 1975 is reported to have been $A740 million (Eckelmann, 1977); in the period 1977-8 it was $A1155 million (ANZ Bank Business Indicators, June 1979). Assuming no marked decline in domestic production of oil, a stable relationship between the Australian and US dollars, the availability of oil on the world market, and an average annual price rise of 10 per cent compounded above 1979 levels, the ANZ Bank estimates that oil imports in 1990 could cost up to $A6000 million in terms of 1979 dollars. But it must be kept in mind that such figures are speculative and that although the price of imported oil will certainly rise in terms of dollars, and probably also in terms of real costs, the dates assigned to such costs may be wide of the mark. New discoveries of indigenous offshore oil, found within the years to 1985, may markedly alter prognostications for 1990 and beyond. But the inevitable time lag in developing such discoveries precludes the possibility that they may alleviate the oil supply or reduce the costs of Australia’s oil requirements during the latter half of the 1980s. At some time during this period, before new discoveries can be brought on stream or alternative supplies of shale oil can be brought into production, a severe shortage of oil may place further constraints on the economy of Australia.

Of the alternative possibilities for the production of synthetic liquid fuels in Australia, the liquefaction of coal may, in the long term, offer the best prospects. The way is not yet clear to operate a plant on a large, economically viable basis, and the technology of
coal conversion must be further developed as rapidly as possible during the 1980s. It has been estimated that a plant producing 100,000 barrels of oil a day would require 35 million tonnes of coal a year. This amount of coal is approximately the total tonnage of brown coal mined each year for the generation of electricity in Victoria, and about one-half of the black coal mined annually for domestic use and export in 1979. Yet it would produce only about one-eighth of Australia’s estimated oil requirements in 1990. Apart from consideration of the large tonnages of coal that would have to be processed, the plant requirements for water would amount to as much as 600,000 barrels a day, some of which could probably be re-cycled. The cost for such a plant, excluding mining and transportation costs, would probably be well in excess of $1000 million in terms of 1979 dollars. In terms of the cost per barrel of the fuel produced, it may continue for some years to be cheaper to import oil. Considerations other than costs, such as national security and self-sufficiency in situations of emergency, will have to be weighed, and for such reasons the active technical and financial co-operation of the oil industry and the Federal Government may be necessary.

Lessons to Learn
The price rises and scrambles for supplies of crude oil and petroleum products that have occurred periodically since 1974 have alarmed the industrialised countries and alerted them to the dangers of relying too heavily on particular sources of oil, despite the still higher costs of alternative supplies of liquid fuels. The lesson has not been lost on the Australian public, although there is a tendency toward panic when supplies are temporarily threatened, and a carefree attitude of not to worry when the petrol pumps run freely. The expediency of buying oil at spot prices on the open market, or at prices negotiated with producing countries, is a stop-gap procedure that does not preclude the need to increase our exploration for new oil and gas fields, and to develop an improved technology for the manufacture of synthetic liquid fuels.

All this will cost money and effort, but there is no alternative. Future energy supplies, especially those from crude oil, natural gas, shale oil, and synthetic liquid fuels, will be much more expensive in real terms in the years to 1990 and beyond. It must also be realised that although new oil fields may be discovered and developed in Australia, ultimately our dependence on such conventional sources will rapidly decrease as demand for liquid fuels outstrips the diminishing production from oil fields. It is not possible to quantify such an outlook, as no one can tell how much, if any, additional oil may be found onshore or offshore. Only exploration can provide an
answer to that question, and the final analysis lies with the drill. Exploration must be encouraged and promoted by the Federal and State governments. How this can be brought about most effectively is a subject variously debated according to shades of political opinion and economic views. But it must be recognised that expertise and experience lie with the oil industry which can and does operate throughout the world in various political and economic climates. Flexibility is a necessary attribute, and although hard bargaining may be involved in negotiations with government, once agreements are determined the continuation of exploration and development of production depend on the stability of the ground rules. Changes in mid-stream not only shake the confidence of the oil industry and slow the development of current projects, but deter the planning of further exploration. As mentioned in previous chapters, a great deal of money is involved in exploration which entails a large degree of risk. The willingness to assume such risks should be encouraged by legislation and the active co-operation of governments and the oil industry. Finally, it is pertinent to reiterate that the public should be aware of the long lead time necessary to bring a newly discovered offshore oil field into production.

Taking all of these factors into consideration it is clear that government policies can either encourage or inhibit the discovery or development of new sources for oil or natural gas, particularly in respect of the forward planning required by the long lead time necessary to bring such sources into production. For these reasons it is essential that government guidelines and policies be sufficiently flexible to accommodate changing economic situations and to allow room for the industries responsible for exploration and development to make decisions and operate with a minimum of impediments and delays. This is not to say that the oil industry should be allowed to operate on a free-wheeling basis, but that mutual understanding between the industry and governments, and a sincere desire to solve common problems of vital significance to the public welfare, should be energetically pursued.
Glossary

abyssal  Pertaining to sea floor plains and troughs at depths of more than 2000 m.

alkanes  Hydrocarbons of the paraffin series, some of the heavier members of which (having 25-50 carbon atoms in each molecule) are waxes found in plants.

anomaly  With reference to geophysical surveys refers to subsurface features of the strata or basement that are anomalous, i.e. structures such as anticlines, salt domes, fault blocks, basement hills, etc.

anoxic  Deficient in oxygen.

anticline  A fold of strata that is convex upward, the long axis of which is commonly inclined (i.e. plunging). Anticlines can form traps for oil and gas where a porous and permeable stratum such as sandstone is overlain by an impermeable stratum such as shale.

API  American Petroleum Institute. Founded in 1920, the institute is a national trade organisation that sets the standards for the oil industry. Crude oils are graded by an API scale, from light oils (high petrol content) graded 45°-50° API, to heavy oils (too thick to flow at normal surface temperatures) graded less than 16° API.

arenaceous  Pertains to rocks that were originally sand or sandy, i.e. sandstone.

barrel (of oil)  1 American barrel = 34.9726 Imperial gallons, or 158.99 litres, or 0.15899 m³.

barrier island  A barrier bar, commonly of sand, that is exposed at high tide. Forms a long, narrow island, or chain of islands separated from each other by tidal channels, and from the mainland by a channel or lagoon.
<table>
<thead>
<tr>
<th>Glossary</th>
<th>Definition</th>
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<tr>
<td>bathyal</td>
<td>Pertains to the sea floor of continental slopes, rises, and terraces, at a depth range of 200-2000 m.</td>
</tr>
<tr>
<td>bathymetric contour</td>
<td>An imaginary line on the sea floor defining a constant depth of water.</td>
</tr>
<tr>
<td>benthonic</td>
<td>Pertains to marine organisms that live on the sea floor.</td>
</tr>
<tr>
<td>block-faulted structure</td>
<td>A structure formed by a block, or group of adjacent blocks of strata, bounded by two or more faults.</td>
</tr>
<tr>
<td>blowout</td>
<td>A sudden, violent escape of gas under high pressure from the borehole of a drilling well, when preparations to prevent or control the escape have not been made, have proved inadequate, or have been subject to an accident.</td>
</tr>
<tr>
<td>borehole</td>
<td>A hole drilled for the recovery of petroleum or water. Normally, boreholes are lined with steel casing.</td>
</tr>
<tr>
<td>butane</td>
<td>A hydrocarbon of the paraffin series (having the formula $C_4H_{10}$) that is a gas within the range of normal pressures and temperatures above the freezing point of water.</td>
</tr>
<tr>
<td>Cambrian Period</td>
<td>A period of time 500-600 million years ago.</td>
</tr>
<tr>
<td>caprock</td>
<td>A layer of shale or other impermeable rock that forms a seal to an accumulation of oil or gas.</td>
</tr>
<tr>
<td>carbonates</td>
<td>Limestones, dolomitic limestones, and dolomites (forming beds, layers, lenses, reef-bodies, etc.) composed of calcium and magnesium carbonates in variable proportions.</td>
</tr>
<tr>
<td>Carboniferous Period</td>
<td>A period of time 280-345 million years ago. Includes the Mississippian and Pennsylvanian Periods of North America.</td>
</tr>
<tr>
<td>Cenozoic Era</td>
<td>An interval of time from 65 million years ago to the present, all but the last 1.8 million years occupying the Tertiary Period.</td>
</tr>
<tr>
<td>choke</td>
<td>A device to restrict the flow of gas or oil within a pipe, commonly fitted with valves at the well head.</td>
</tr>
</tbody>
</table>
closed structure: A structure (within a rock layer or sequence of layers) caused by folding, faulting, draping over a buried hill, pinching out of a layer, or a combination of any of these, such that oil or gas entering from below cannot escape from above.

colloid: An extremely finely divided substance in suspension in a fluid (water), having special properties because of its very high surface area. Properties such as plasticity, thixotropy, and swelling, are exhibited by colloids formed by some clays suspended in water.

condensate: The liquid hydrocarbons pentane, hexane, etc. which condense from a vapour phase when natural gas cools and expands on release of pressure at the well head.

connate water: Water entrapped (in the intergranular interstices of a sedimentary rock) at the time of deposition and burial of a sediment.

coral reef: A reef composed of the calcium carbonate skeltons of corals and calcareous algae.

Cretaceous Period: A period of time 65-140 million years ago.

cryogenic: Refers to the frozen state.

cuestas: Gentle slopes flanked by steep slopes formed by the unequal erosion of gently inclined, alternating soft and hard layers of rock.

darcy (1000 millidarcies): One darcy is defined as the unit of permeability that allows 1 cc of a fluid having a viscosity of 1 centipoise (water) to pass through a 1 cm cube of rock in 1 second under a differential pressure of 1 atmosphere.

delta distributary: A branch of a river flowing on the coastal plain of a delta.

Devonian Period: A period of time 345-395 million years ago. Rocks of this age contain gas in the Gilmore field of the Adavale basin in Queensland.

diapir: A dome structure in rock strata, caused by a core of salt or clay that has squeezed upward to rupture and intrude the overlying beds.
dolomite  A carbonate rock (also referred to as dolostone) composed of calcium-magnesium carbonate. There is a compositional gradation from limestone (calcium carbonate) to dolomitic limestone to dolomite.

down-to-basin faults  A sequence of normal faults, the downthrown side of each fault being toward the sedimentary basin, that forms a step-like arrangement.

drill pipe (drill stem)  Steel tube (in lengths which screw into one another) which connects the drilling bit to the turntable on the floor of the drilling rig.

drill stem test  A test of fluid and gas recovery from a specific interval in a borehole, taken with a special device lowered down the hole.

dry hole  A term used to designate a non-productive and abandoned hole drilled for oil or gas.

earth’s crust  The outer layer of the earth (about 35 km thick under the continents and 10 km under the oceans) consisting mainly of granite-type rocks lying above the Mohorovičić discontinuity which marks the boundary between the crust and the earth’s mantle of denser ultra-basic rocks composed of iron and magnesium-rich silicate minerals. The crust also includes metamorphic and sedimentary rocks.

earth’s mantle  Thick layer of the earth lying between the crust and the core, consisting mainly of ultrabasic rocks composed essentially of ferromagnesian minerals such as pyroxenes and olivine. Similar in composition to stony meteorites.

enhanced recovery  Methods employed to increase the flow of oil from a reservoir in an oil field by means of injecting chemical emulsifiers with steam, solvents, solutions of carbon dioxide in liquid petroleum gas, caustic soda, or polymers.

Eocene Epoch  An interval of time 38-55 million years ago.

ethane  A hydrocarbon of the paraffin series (having the formula C₂H₆) that is a gas within the range of normal temperatures and pressures.
evaporites  Beds of sodium and potassium salts and gypsum (calcium sulphate) deposited as the result of evaporation in a body of water, or in water-saturated sediments on a coastal mud flat.

fatty acids  Straight and branched chain organic compounds composed of carbon, hydrogen, and oxygen. Those commonly found in nature are palmitic acid (C₁₆) and stearic acid (C₁₈). Fatty acids combined with glycerine form soaps.

fault  A fracture or zone of fractures in the earth’s crust. Slippage along such fractures produces earthquakes.

feedstock  Raw mixtures of hydrocarbons, such as crude oils, condensate, and natural gas, that are fed into refineries and other chemical plants to produce petroleum products such as petrol and lubricating oils, and chemical products such as fertilisers and plastics.

fire flood  A method of igniting tarry oil in one borehole to heat, lower the viscosity, and drive oil to nearby boreholes for recovery.

fluvial  Pertaining to rivers, such as river sands.

forams  Free-floating microscopic, unicellular marine organisms, many species of which have beautiful single or multi-chambered shells of calcium carbonate. Arenaceous forams have shells of cemented silt and very fine sandgrains.

geomorphology  A branch of physical geography that relates the geology of earth features such as beaches, barrier islands, canyons, mesas, etc., to their external shapes, internal construction and to the physical processes of water, wind, and earth movements that caused them.

geothermal gradient  Increase of temperature with depth expressed as degrees per unit of depth. The geothermal gradient varies from place to place in the earth’s crust, but averages about 3.5°C/100 m.
Gondwanaland — An ancient continental mass (including Australia, Antarctica, Africa, South America, and India) that drifted apart to form separate continents, mainly during the latter part of the Mesozoic Era (65-230 million years ago).

horst — A block of strata or other rock bounded by two or more faults and thrust upward relative to adjacent blocks.

hydraulic fracturing — An operation whereby fluid is forced down a borehole at great pressure to fracture a particular rock layer. This is done in order to increase the permeability of the layer and improve its rate of flow of oil or gas into the borehole.

hydrocarbon — A compound composed of only carbon and hydrogen e.g. methane (CH₄). These compounds may be gases, liquids, or solids within the range of normal temperatures and pressures.

hydrodynamic — Of or relating to the force or pressure of moving fluids (in particular, water).

hydrostatics — The study of pressure and equilibrium relationships as applied to fluids (essentially water) in the static state. Note: Although sediments under compaction at depth have water squeezed out, as from a sponge, the movement is very slow and the water in the sediments is considered to be static.

igneous intrusion — An injection of molten rock into solid rocks, forming sills (layers parallel to sedimentary beds), dykes (layers cutting across sedimentary beds), or larger bodies of irregular shape.

illite — A group of clay minerals of variable chemical composition between the mica and montmorillonite (smectite) groups of hydrous potassium-aluminium-magnesium-silicates. A common constituent of sedimentary rocks.

isopach map — A contoured map showing the variations in thickness of a geological feature such as a sedimentary layer, reef, salt bed, etc.
iso-paraffin series  Hydrocarbons having the formula $C_nH_{2n+2}$, but differing from those of the normal paraffin series in that they have branched rather than straight chains, and are chemically more reactive.

joule  A unit of energy, being the work done when the point of application of 1 newton is displaced a distance of 1 m in the direction of the force. (A newton is the force necessary to give acceleration of 1 m/sec/sec to 1 kg of mass).

Jurassic Period  A period of time 140-195 million years ago. Rocks of this age produce oil and gas from the Moonie and other fields of the Surat basin in Queensland.

kerogen  An amber to black amorphous, resinous substance in oil shales and other sedimentary rocks. It is derived from organic matter and yields oil by destructive distillation.

lacustrine  Pertaining to lakes, such as lake sediments.

lateritic deposits  Concentrations of iron, manganese, aluminium, or nickel oxides and hydroxides in subsoils. Derived by the in situ weathering of rocks involving the leaching of silica by percolating ground-water.

lithofacies  The variations of rock type within a layer deposited during a period of time, e.g. shale grading to limestone, or to sandstone.

lithology  The physical and mineralogical characteristics of a rock.

magma  Molten rock capable of being intruded into buried strata, or extruded to the surface where it is referred to as lava.

maturation  The conversion of organic matter to hydrocarbons or their precursors by the effects of increasing temperature caused by progressive burial, over a long period of time, to depths of 1 to 4 km.

Mesozoic Era  An interval of time, 65-230 million years ago, that includes the Cretaceous, Jurassic, and Triassic Periods.

metamorphism  The mineralogical and physical alteration of rocks by means of physicochemical processes.
micelle A particle of matter consisting of a structure built up by the union of a number of identical complex molecules.

Miocene Epoch An interval of time 6-23 million years ago.

Mohorovičić discontinuity Seismic discontinuity at the base of the earth’s crust (about 35 km deep under the continents, and 10 km deep under the oceans) and at the top of the earth’s mantle.

montmorillonite (smectite) A group of clay minerals, of variable composition but in general consisting of hydrous magnesium-aluminium silicates, that have the property of adsorbing water and swelling to form a gel-like colloid. The main constituent of bentonite, a sedimentary deposit formed from the alteration of volcanic ash. Used in oil well drilling muds.

Oligocene Epoch An interval of time 23-38 million years ago.

OPEC Organization of Petroleum Exporting Countries

Ordovician Period A period of time 435-500 million years ago. Rocks of this age contain gas in the Mereenie and Palm Valley fields of the Amadeus basin in central Australia.

orogeny Mountain-forming movements resulting in folding and faulting of the earth’s crust.

Paleogene Period A period of time 22-65 million years ago that includes, from youngest to oldest respectively, the Oligocene, Eocene, and Paleocene Epochs.

Paleozoic Era An interval of time 230-570 million years ago that includes from youngest to oldest respectively, the Permian, Carboniferous, Devonian, Silurian, Ordovician, and Cambrian Periods.

pelagic Pertaining to free-swimming and floating marine organisms.

penetcontemporaneous A term denoting events or processes that took place during the period of deposition of a sedimentary stratum.

permeability The ability of a fluid under pressure to move through a rock, expressed in terms of darcy or millidarcy units.
Permain Period  
A period of time 230-280 million years ago. Rocks of this age produce gas from fields in the Cooper basin of South Australia.

petrophysics  
A branch of geophysics that deals with the nature and quantification of the physical characteristics of rocks, such as porosity, permeability, magnetic susceptibility, radioactivity, electrical conductivity, etc.

Pleistocene Epoch  
A period of glacial intervals from 1.8 million years ago to the beginning of Recent time about 12,000 years ago.

Pliocene Epoch  
An interval of time 1.8-6 million years ago.

plunging anticline  
An anticline which has the long axis inclined.

polymer  
A compound whose large molecules have been formed by the linkage of identical small molecules.

porosity  
The pore or other void space (open fractures) expressed as a percentage of total rock volume.

porphyrins  
Complex compounds of carbon, hydrogen, and oxygen. Those in crude oils are probably derived mainly from the chlorophyll of plants. Some porphyrins contain nickel or vanadium.

Precambrian  
A term applied to the period of time extending from 570 million years ago to the beginning of the earth (about 4500 million years ago). It includes the Proterozoic Eon (600-2600 million years ago) and the Archaean Eon (2600-4500 million years ago).

prodelta  
The sea floor area extending seaward from the coastal fringe of a delta. It is characterised by laminated muds and silts.

progradation  
Seaward building of a body of sediment such as a delta, or an accumulating shoreline body of sand.

prograding sediments  
Sediments deposited in successive layers that build seaward to form a sequence of off-lapping wedges or lenses.

propane  
A hydrocarbon of the paraffin series (having the formula C\textsubscript{3}H\textsubscript{8}) that is a gas within the range of normal temperatures and pressures.
Glossary

Proterozoic Eon
A period of time 600-2600 million years ago.

psi
Pounds pressure per square inch.

quartzose sandstone
A sandstone composed predominantly of grains of quartz.

Recent
The period of time since the end of the Pleistocene Epoch, about 12,000 years ago.

reservoir
A body of rock containing hydrocarbons in a producing or potentially productive oil or gas field.

riser (drilling or production)
A drilling riser is a pipe, extending from the drillship to the well head on the sea floor, through which the revolving drill stem is raised and lowered. A production riser is the pipe that carries oil from the sea floor well head to submerged or floating storage tanks at the ocean surface. Both risers have buoyancy materials fastened to reduce their weight and relieve tension.

sedimentary basin
An area underlain by a few hundred to several thousand metres of sedimentary strata that may include intercalated volcanic beds.

seismic survey
Mapping the subsurface structure and configuration of strata by means of generating a shock wave (explosion or other methods) at the surface and recording (by geophones and instruments) the time taken by the shock wave to be reflected from various layers.

Silurian Period
A period of time 395-495 million years ago.

source bed
Bed or layer of sedimentary rock (siltstone, shale, claystone, limestone) in which hydrocarbons have been generated.

spudded in
Commenced drilling. The term originated with cable tool drillers during the early days of the oil industry.

steam flood
A method of oil recovery whereby steam is injected through a borehole into an oil-bearing stratum, in order to lower the viscosity of the oil and drive it to nearby producing wells.

steroids
Tetracyclic compounds of carbon, hydrogen, and oxygen. They are abundant in plant and animal matter.
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
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<tr>
<td>stratigraphy</td>
<td>A branch of geology that concerns the nature, sequence, correlation, and origin of sedimentary and interbedded volcanic strata.</td>
</tr>
<tr>
<td>stromatoporoid reefs</td>
<td>Similar to coral reefs but composed largely of stromatoporoids, a colonial organism probably related to hydrozoans.</td>
</tr>
<tr>
<td>structural closure</td>
<td>see ‘closed structure’.</td>
</tr>
<tr>
<td>structure map</td>
<td>A contoured map showing the topography, with reference to sea level or some other datum, of the upper surface of a geological feature such as a sedimentary layer, reef, salt bed, etc.</td>
</tr>
<tr>
<td>structural-stratigraphic traps</td>
<td>Traps for oil and gas formed by a combination of structural and stratigraphic conditions. For example, oil trapped in an inclined sandstone bed truncated by an unconformity and overlain by a caprock bed of impermeable shale.</td>
</tr>
<tr>
<td>subcrop</td>
<td>Rock strata lying beneath the surface of an unconformity or erosional surface, and covered by layers of younger rock, sediment, or surficial material such as subsoil, scree, or alluvium.</td>
</tr>
<tr>
<td>subduction</td>
<td>The sliding of one of the earth’s crustal plates under the other along the leading edge of the impacting plate.</td>
</tr>
<tr>
<td>tectonic</td>
<td>Pertaining to structural features, such as faults and folds, that have been caused by deformation of the earth’s crust.</td>
</tr>
<tr>
<td>terpenes</td>
<td>Compounds of carbon, hydrogen, and oxygen found in some vegetable oils.</td>
</tr>
<tr>
<td>terrigenous</td>
<td>Pertaining to or derived from the earth’s landmass.</td>
</tr>
<tr>
<td>Tertiary Period</td>
<td>A period of time 2-65 million years ago. Sedimentary rocks deposited during the early part of this period produce oil and gas from fields in the Gippsland basin of Victoria.</td>
</tr>
<tr>
<td>therm</td>
<td>A measurement of heat value equivalent to 100,000 British Thermal Units (BTUs). For comparison, 1000 cubic feet (28.317 m$^3$) of natural gas (98% methane) has a heating value of 10 therms. Prices paid for gas are based on therms.</td>
</tr>
</tbody>
</table>
thixotropy  | The property exhibited by some jells, such as mixtures of some clay minerals and water, of becoming fluid when shaken or jarred.

tight  | An expression referring to a sedimentary rock that has a low permeability and possibly also a low porosity.

torbanite  | A black, kerogen-rich, coaly substance with a conchoidal fracture that yields kerosene by destructive distillation.

trap  | A closed structure in a body of rock that has trapped, or is capable of trapping hydrocarbons.

Triassic Period  | A period of time 195-230 million years ago. Rocks of this age yield gas from the Goodwyn, North Rankin, and Angel fields of Western Australia, and from fields in the Roma area of Queensland.

turbidity current  | A density current consisting of a slurry of sand, silt, and clay, carrying rock fragments and other debris, that flows down a submarine valley at velocities of up to 50 km per hour. It is triggered off by sediment slumping, commonly resulting from earth tremors.

unconformity  | A fossil erosional surface that truncates or levels older strata and is overlain by younger strata.

up-dip  | Upward along the layers of inclined strata.

vitrinite  | Organic matter that has passed through a gelification stage and has been converted, under conditions of increasing temperature, to a solid having a high degree of light reflectance.

wet gas  | Natural gas that contains the vapour phase of liquid hydrocarbons such as pentane, hexane, etc. Separated from the gas by cooling, these liquid fractions are called condensate.

wildcat well  | An exploratory well far removed from any known accumulation of oil or gas.
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