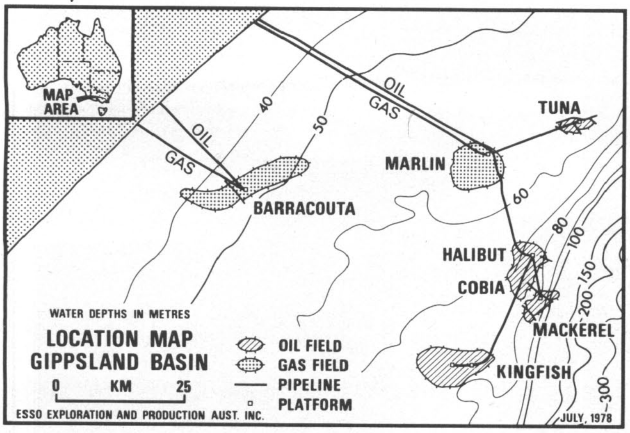


seven different surveys and a total of four exploration wells had been drilled to provide data for the initial definition of the field.

At the end of 1974, 145 kms of high resolution seismic data were shot on an approximate 1 km x 1 km grid over Mackerel as part of a basin wide survey to define more accurately the top of Latrobe Group sediments. This survey, known as the G74A survey, showed a major improvement in data quality. Frequencies were higher, allowing increased resolution and, significatnly, the post-Latrobe data quality was improved to the extent that the Miocene channeling, which occurs throughout the basin and causes severe velocity distortions, could be mapped with confidence. In 1975, preliminary mapping of the Mackerel area was caried out and in 1976 a detailed pre-development intepretation was undertaken.

The pre-development interpretation highlighted a number of problems. These included a high velocity Miocene channel in the overlying section in the north-east of the field, some possible erosional features of the top of the Latrobe Group reservoir sands, and correlation problems involving the seismic identification of the top of the Latrobe Group.

The northern sector of the field was, in particular, an area where seismic interpretation problems created considerable uncertainty in the pre-development mapping. Migrated seismic sections had indicated the possibility of severe erosional scarps in this area and the more clearly defined of these were included in the structural mapping at this time. In other cases, where high relief escarpments were suspected but could not be unequivocably supported, even on the migrated data, the areas of uncertainty were highlighted on the structure map. In these areas data was required from development wells before the final seismic interpretation could be made.

The pre-development seismic structural and stratigraphic mapping was used to determine the final platform location and to choose the initial development well locations. These well locations were picked to gain early structural control on the top of Latrobe, to test the interpretation in the problem areas, and to investigate the internal geometry of the reservoir units. This latter factor was important because of the possible effects the internal geometry of the reservoir units could have on the field drainage pattern.

The third development well, Mackerel A-5, was drilled on an interpreted high in the northern problem area to test whether these possible erosional scarps were present. The well was dry, confirming that the scarps did exist in this part of the field. Following this, a complete re-interpretation of the field was carried out using migrated sections to locate the scarps. This reinterpretation has provided our current field map. Subsequently, the data from the later development wells have been incorporated as they became available, causing, in general, only minor changes to this mapping.

However, some changes were significant and, again, they related to the problems highlighted in the pre-development mapping. In the same northern sector of the field to the east of Mackerel-3, a Miocene channel, infilled with sediments which have a high velocity, had been mapped in the section overlying the Latrobe Group. The Mackerel A-5 well indicated that the increase in average velocity to the Latrobe might be greater than previously interpreted. This was confirmed by the Mackerel A-10 well, and the increased velocity has the effect of depressing the depth of the north-eastern part of the field. Also in the vicinity of Mackerel-3, there were problems identifying the top of Latrobe seismic event. Two alternatives, a 'high cycle' or a 'low cycle' interpretation were possible. Both of the interpretations were feasible because the highly eroded nature of the Latrobe in this area meant that it was difficult to distinguish between the two cases. Mackerel A-9 was drilled to test this problem and confirmed the 'high cycle' interpretation.

In conclusion, it can be said that the pre-development structural and stratigraphic mapping of the Mackerel Field was successful in delineating the basic size and shape of the field and its internal stratigraphic configuration. This mapping was also successful in identifying all the geophysical and geological problems which were subsequently encountered in the development drilling. Thus a rigorous seismic interpretation provided the geologists and engineers with a sound basis for field development planning.

## FIELD DEVELOPMENT WITH THREE DIMENSIONAL SEISMIC METHODS IN THE GULF OF THAILAND – A CASE HISTORY

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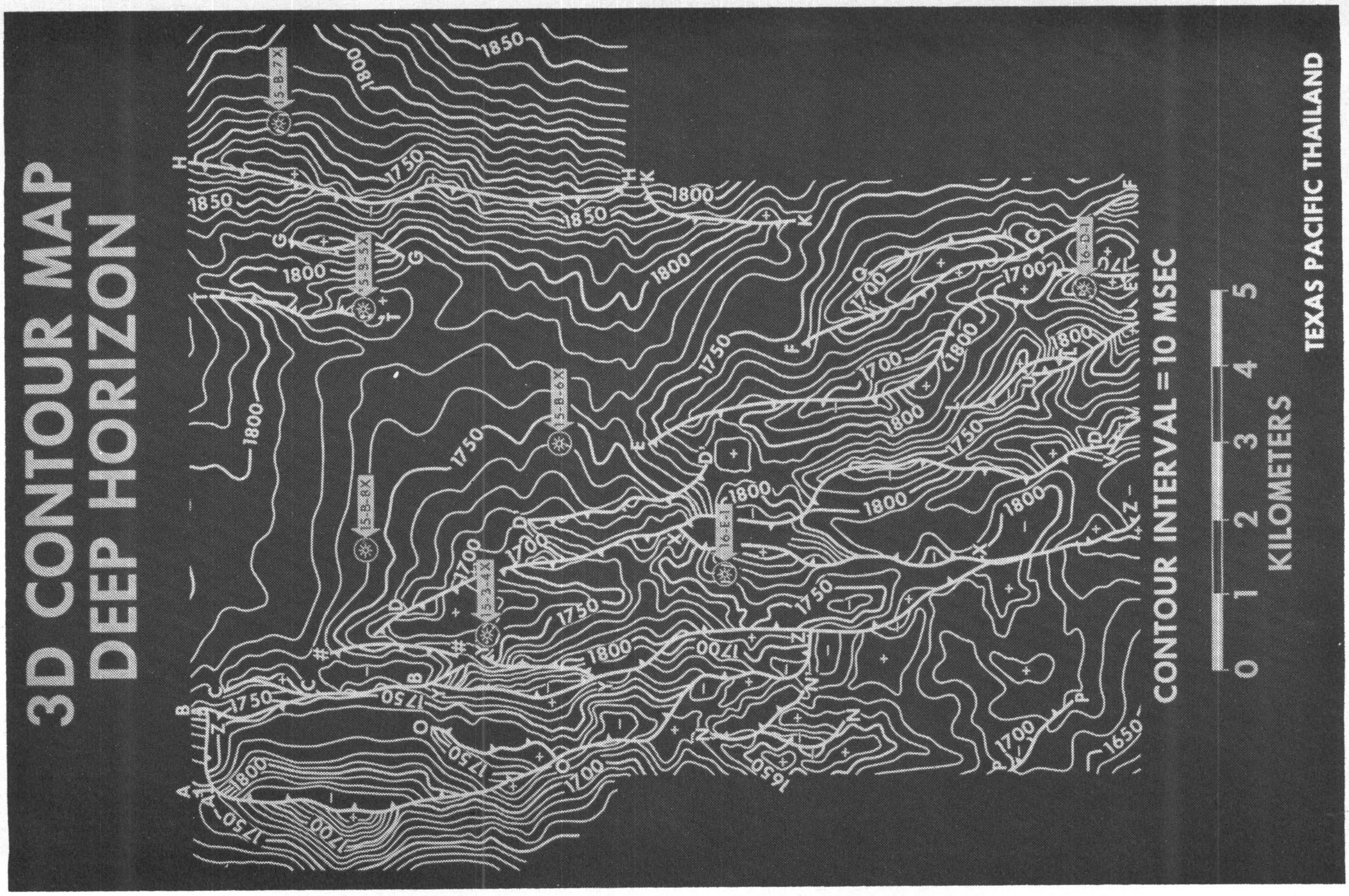
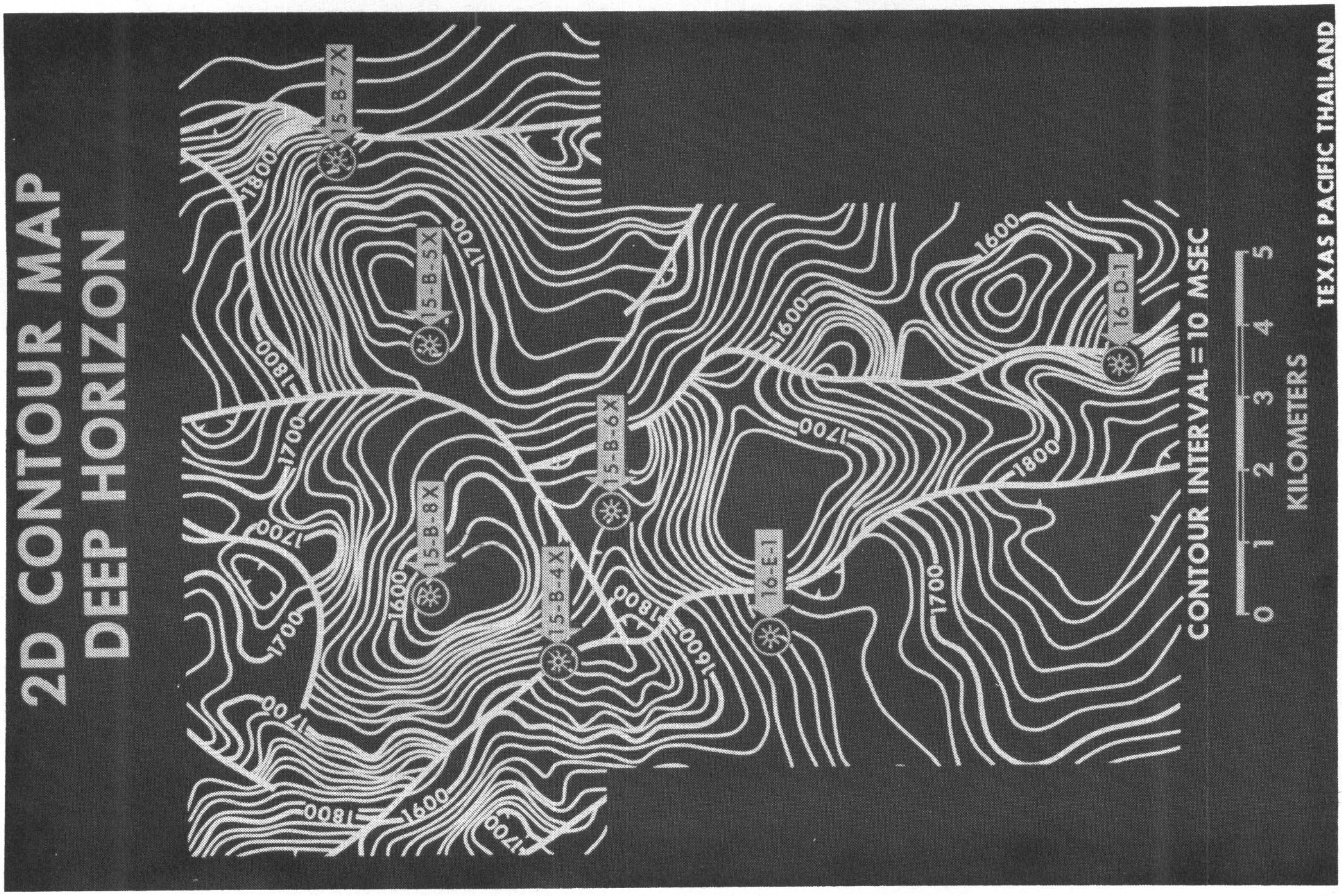
The Gulf of Thailand is a Tertiary basin and is of tectonic origin. The section of interest is Miocene and possibly Oligocene in age, and although the principal interest is limited to the upper 12800 meters of section (about 2 seconds in reflection time), there is perhaps as much as 24000 meters (3 seconds) of Tertiary and Mesozoic section overlying a strong reflector which in places tops the basement and in other places may represent the top of the Paleozoic. The Miocene section of interest


3D CONTOUR MAP
DEEP HORIZON
CONTOUR INTERVAL = 10 MSEC
0 1 2 3 4 5
KILOMETERS
TEXAS PACIFIC THAILAND
15-B-7X
15-B-5X
15-B-6X
15-B-8X
15-B-4X
16-E-1
16-D-1


2D CONTOUR MAP
DEEP HORIZON
CONTOUR INTERVAL = 10 MSEC
0 1 2 3 4 5
KILOMETERS
TEXAS PACIFIC THAILAND
15-B-7X
15-B-5X
15-B-6X
15-B-8X
15-B-4X
16-E-1
16-D-1

for hydrocarbon exploration, in all the wells drilled up to the present time, consists primarily of a shale section interbedded with relatively thin sand beds. The sand beds appear to be lenticular, and the development of the sand buildups are probably controlled by faulting and local structural highs.

In late 1975, Texas Pacific Oil Company took a farmout on four blocks in the Gulf of Thailand, blocks 14 and 15 from Tenneco and blocks 16 and 17 from British Petroleum. Along with these farmouts came about 13600 kilometers of conventional 2D seismic data covering a number of years of data collection.

In a paper given by Dr Charan Achalabhuti, Director of the Natural Gas Organization of Thailand, at the Circum-Pacific Energy Conference in August 1978, he pointed out that exploration in the Texas Pacific concession in blocks 15 and 16 has passed into a field development stage with reserves estimated at 2 to 3.4 trillion cubic feet of gas.

The interpretative value of the existing 2D seismic information was limited due both to the coarseness of the grid and to the fact that the information represented a composite of several seismic surveys distributed over several years. New information was needed/ first, to establish with confidence the relationship between blocks 15 and 16/ secondly, to obtain better data to make new locations which would be productive/ and finally, to assist in determining optimum locations for platforms. The key to successful exploration in the area, basically a hinge line play, was a detailed understanding of the complex mosaic of fault patterns controlling the hydrocarbon traps.

To meet all these criteria, it was decided to shoot a sizeable 3D program over the major gas area. At the time the survey was conducted, the summer of 1977, it was one of the largest 3D programs in the world and the first one undertaken in the Far East.

The 3D program consisted of 1280 kilometers, with the seismic lines shot at 100 meter intervals, enclosing an area of 130 sq. kilometers. A total of 128 lines were shot in an east-west direction over the prospect, roughly rectangular in shape, and an additional ten diagonal lines running north-west were shot at the north end. Since the prospect was located 160 to 220 kilometers offshore, two complete and complementary survey systems were used in the data collection phase, one for accuracy in distance and one for lane count, to obtain the required density and accuracy in location. A streamer tracking system was employed which, when combined with the basic boat navigation data, provided an X and Y co-ordinate for every shot and receiver location.

The densely spaced data were processed with a 3D wave equation migration algorithm to produce the set of seismic traces representing the data vertically below a grid of depth points spaced at 33 1/3 by 100 meters over the prospect.

The interpretation of the 3D data was constructed from the conventional vertical sections and a series of two-dimensional horizontal slices, produced at 4 millisecond intervals, through the 3D data volume. In general, the vertical sections were used to identify key horizons, dips, and fault locations. The horizontal sections provided information about how to connect up the faults, the strike, and the spatial distribution of the geologic formations.

Using both the 3D vertical sections and the horizontal sections, two maps were constructed, a shallow one near a reflection time of 1.2 seconds and a deeper one at 1.8 seconds. Both maps display the general shape of a more or less elongated central area striking approximately north-south with dip to the east and to the west from the central graben. Comparisons drawn between the maps made from the 3D program and the more conventional 2D grid shooting show that both 2D maps exhibit excessive overall structural relief. The faults are both more numerous and differently placed on the 3D. Since one of the criteria for selecting favourable drilling sites is fault location, the value of the increased density became important. Studies based on amplitude contour maps made at several key horizons combined with seismic interval velocity logs derived from an inversion process suggest that areas of favourable sand thickness in excess of 50 feet may be successfully predicted.

Several new drillable prospects have been identified. It is believed that the wells can now be located to optimize the development of the reservoir sands. Probably more important, the 3D data set generated by the survey appears to be accurate enough/ first, to locate the fault blocks defining intra-field producing boundaries/ second, to select the most favourable sites for platform locations/ and third, to assist in developing quantitative reserve estimates. To a considerable degree it is believed that the drilling of some wells can be traded for the much less expensive 3D seismic surveys. If such a tradeoff is achieveable, the ultimate development costs can be substantially decreased by reducing the elapsed time from the discovery to the production stage.

The cost of development wells in this area ranges between 3.5 and 5.5 million U.S. dollars. With the cost of a 3D survey at approximately 5.5 thousand dollars per square kilometer, 640 square kilometers of 3D coverage can be obtained for the cost of one 3.5 million dollar development well. The leverage seems excellent for 3D seismic to pay for itself may times over in terms of reducing the eventual number of development wells. There is, in addition, the opportunity to obtain more recoverable reserves through finding new or secondary traps which might be otherwise missed by conventional means.

## DEPTH CONVERSION OF SEISMIC DATA USING VELOCITY ANALYSES

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Velocity analyses are now routinely produced in the processing of seismic data. These are used for a number of purposes in processing and for interpretation. Although the display format varies for different velocity analyses they all are similar in that, when interpreted, they give a