OIL AND GAS FINANCING : RECENT INNOVATIONS

by

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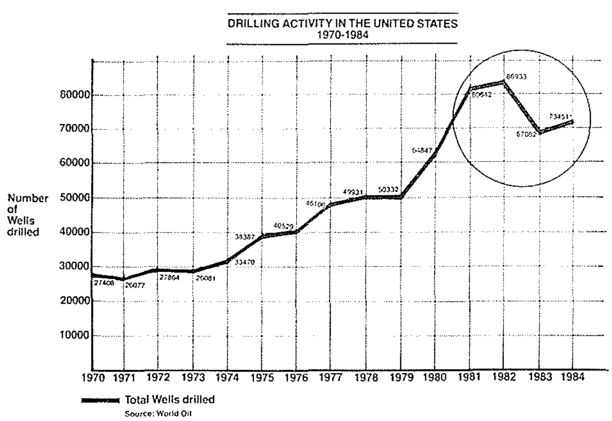
From time to time, but not quite as often as many observers believe, the oil industry globally experiences significant swings in all forms of activity. The reasons for the swings are naturally complex, however a combination of changes in some or all of the following factors has generally precipitated the major upturns or downturns experienced during the past 15 years:

- OPEC's price and volume policies
- the global economic environment
- local primary and secondary taxes
- the local economic environment

The translation of these factors into the price of, and demand for, petroleum products, the supply of risk capital for exploration and appraisal activities, and the availability and cost of debt finance for development projects has provided the management of oil companies worldwide with significant financing challenges in recent years.

Figure 1

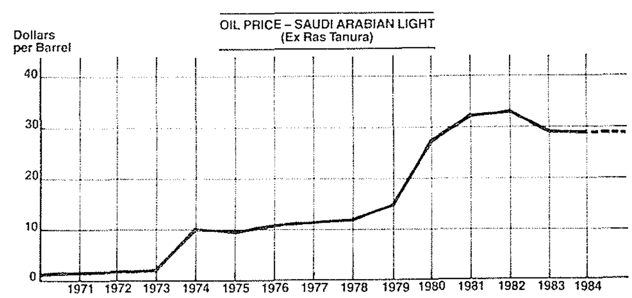


The gradual upward trend in USA drilling activity from 1970 to 1979 accelerated sharply from the beginning of 1980 to the end of 1982 driven by, amongst other factors, rapidly increasing world oil prices and ready availability of equity and debt funds. This was very much a period of "money chasing deals".

† The above article contains extracts from a paper presented by Mr. Foley, a petroleum geologist, at a recent finance conference.

The time taken to convert risk capital sourced in the late 1970's and early 1980's, predominantly through limited partnerships, into exploration wells resulted in record levels of drilling activity during the period when moderate production surpluses turned into the glut that initiated OPEC's decision to drop the official price of Saudi Light. The impact of a deceleration in price increases during 1980 and 1981 and then the 18 per cent price fall in 1982 when Saudi Light fell from $35/bbl to $29/bbl, had a dramatic effect on the US industry.

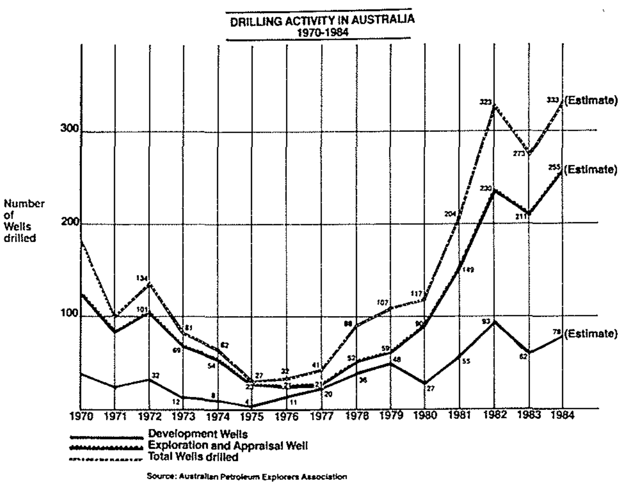
Figure 2



In terms of US drilling activity, the number of wells drilled fell 23 per cent from a total of 86,933 wells in 1982 to 67,082 wells in 1983.

In the UK North Sea a similar pattern occurred, although in this case there were additional factors involved. The decline during the period from 1977 to 1979 was due, in part, to the adjustments made by the British Government to the petroleum revenue tax introduced initially in March 1975. It is interesting to note, in an RRT context, that some observers cite the petroleum revenue tax as one of the major resons why activity in the UK North Sea did not match the growth experienced by the rest of the world between 1975 and 1982.

Figure 3



Australia also experienced the malaise of the early 1980's suffered by the oil industry in the United States and, to a lesser extent, the UK North Sea.

The Need for Creative Financing Techniques

In the period prior to 1982 equity investors and lenders in the US aggressively sought to participate in the booming oil and gas industry. A common fear in those days was that if you were not able to get into the industry then you would be left far, far behind as oil stocks and oil prices soared ever upwards. Those were the heady days of the strategic hedge and other such marvellous reasons for companies totally removed from the oil industry to plunge in boots and all.

The situation in Australia was, to an extent, similar Established companies were able to pick and choose between attractive equity and debt funding opportunities, and the environment for new oil and gas floats and backdoor listings was fertile.

When the industry's bubble burst in 1982 many independents in the US were caught with over geared projects, plummeting stock prices and reduced markets for all petroleum products, especially gas. Many small independents went into bankruptcy or merged with larger, more financially sound companies. Service companies, and in particular, drilling companies also suffered badly from the downturn.

In Australia many junior explorers who had counted on revisiting the equity markets to raise the additional risk capital required to fund ongoing exploration activities were forced to farm out some or all of their acreage, often at "fire sale" prices. As in the US service companies in Australia were also badly affected by the decline in exploration expenditure.

This period of rapid growth followed by rapid contraction generated new methods of financing the industry's activities in addition to old "tried and true" methods revamped to suit the times, as shown in Figure 4.

Figure 4

SOURCES OF CAPITAL DURING PERIODS OF INDUSTRY EXPANSION OR CONTRACTION

EXPANSION	CONTRACTION
DRILLING FUNDS	DRILLING FUNDS
LENDER PARTICIPATION LOANS	COMPLETION FUNDS
NON RECOURSE NOTES	EQUITY KICKERS
ROYALTY TRUSTS	EQUITY SWAPS
INCOME FUNDS	ASSET SALES

From Creditor to Investor

One of the most imaginative methods of survival used by US oil and gas companies to fund exploration drilling and, in particular, appraisal or development activities during the downturn was to offer an alternative to the conventional hard dollar consideration for services or products rendered. Service companies and some hardware, and tubular goods manufacturers, often accepted a combination of hard and soft dollars in return for providing services and goods to financially strapped (or astute) independents.

Drilling companies in particular, negotiated contracts which covered, via a hard dollar payment, the variable costs associated with drilling a well and, via a soft dollar payment, some or all of the fixed costs associated with rig ownership, corporates overheads and debt service.

Some of the soft dollar options, or equity kickers as they are generally known, offered by the independents were:

- an overriding royalty on production from a well(s) or project
- a net profit interest in a project
- a free carried interest in a particular well(s) or project
- a working interest in a particular well(s) or project

From an oil company's perspective this form of financing provided an attractive "source" of capital because it enabled a reduction in immediate hard dollar outflows. From a service company's or manufacturer's point of view the equity kicker, when combined with some immediate hard dollar inflow enabled a continuation of operations coupled with a chance of more than a 100 per cent recovery in the event that the well or project "came in".

Not surprisingly, this technique was most applicable to appraisal and development wells where the perceived risks of total failure were lower than those of raw exploration and, as a consequence, the concept became more attractive to a risk adverse contractor or manufacturer.

This technique was used to fund many forms of activity. Seismic companies negotiated equity kickers over tracts of exploration acreage, manufacturers of tubular steel goods provided casing or production tubing for a well(s) in return for direct equity participation in the particular wells(s) or a royalty over production from the well(s).

Equity kickers can be "tacked onto" conventional debt or equity. On the debt side, for example, Bank of America has structured a number of Lender Participation Loans where concessional rate debt has been provided by pension funds to oil companies developing appraisal or pre-development acreage in return for a fixed amortisation schedule and an overriding royalty on production.

Figure 5 shows an example of a special purpose finance and sales company financed by a Lender Participation Loan. In addition to the loan agreements and charges between the lenders and the borrower there is also a royalty agreement specifying the nature and magnitude of the royalty stream.

On the equity side, Goldman Sachs & Co. has raised, via private placements, equity funds by issuing securities with overriding royalties on future production from defined properties. These securities enjoy not only ownership of the corporate entity with possibilities of dividend income but also a royalty over net revenue from the defined properties.

It is difficult to see any reason why financing vehicles providing equity rewards for investors, lenders, suppliers or contractors should not play a significant role in financing the Australian oil and gas industry during, at least, its difficult funding times. In addition to the usefulness of this technique during tight times, it also has application to financing projects at an early, or pre-conventional debt, stage of development.

The Real Cost of Equity Kickers

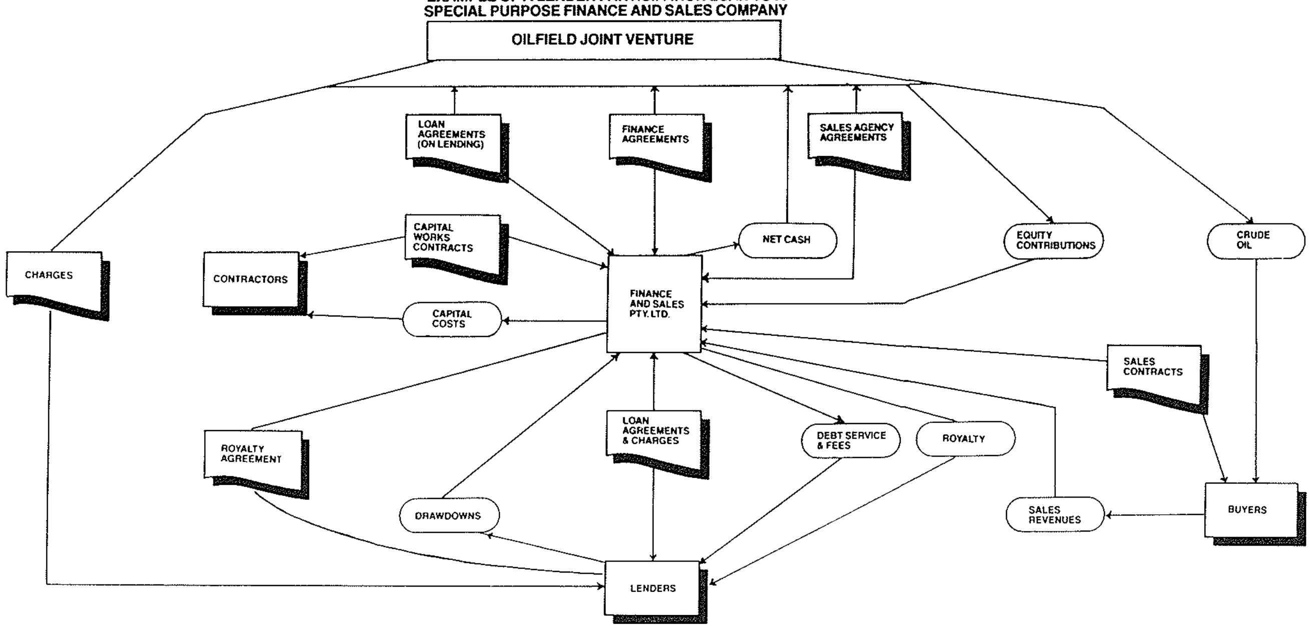
What is the real cost of an equity kicker to a project sponser?

As noted above equity kickers are generally offered by project sponsors when traditional sources of capital are not available, as a result of capital market constraints flowing from a real, or perceived, imbalance in the risk/reward profile offered by a project at a particular stage of development.

The real cost of an equity kicker is simply the price of perceived risk. A standard rate is difficult to determine because each provider of capital has his own particular risk/reward requirements. Simple worked examples

Figure 5

EXAMPLE OF A LENDER PARTICIPATION LOAN TO A SPECIAL PURPOSE FINANCE AND SALES COMPANY



demonstrate the costs and benefits to a hypothetical project sponsor of using different types of equity kickers to fund an appraisal program.

The three examples are identical in that a total of $21 million is required for the appraisal program and $60 million for the development phase. The development phase takes one year and the project's economic life is 11 years.

The major difference between the conventionally all-equity funded appraisal program and those 75 per cent funded by third party-sourced capital with a form of equity kicker attached is the reduction in the time taken to reach the level of project definition required for the debt financing of the development phase resulting from our assumption that there is no limitation on the availability of these funds.

It is assumed that non sponsor-provided sources of capital will only become available at the satisfactory conclusion of Year 1 of the appraisal program.

Cash flows are projected for a conventional 100 per cent equity funded, 3 year appraisal program followed by a 25 per cent equity, 75 per cent debt funded, 1 year development program. The $45 million loan principal is amortised over a 4 year term.

The NPV of the net cash flow to the equity holders (i.e. the project sponsors) is, at a 25 per cent discount rate, approximately $30,905,000.

In the second cash flow projection the impact is examined of using commercially priced debt with an attached 10 per cent overriding royalty to fund 75 per cent of the appraisal program. This type of vehicle resembles the Lender Participation Loans arranged by Bank of America for the Apache Corporation in 1980 and 1981.

The LPL is used to complete the appraisal program in Year 2.

We have assumed that upon completion of the appraisal program, further debt, without an attached overriding royalty, is used to fund 75 per cent of the development program. The total loan principal of $57 million is amortised over 5 years.

In this example the reduced length of the appraisal program, the reduced equity contributions by the project sponsors and the 10 per cent overriding royalty paid to the provider of the LPL combine to increase the NPV from $30,905,000 to $36,287,000 at the same discount rate of 25 per cent.

Figure 6

APPRAISAL PROGRAM EQUITY FUNDED

Year	1	2	3	4	5	6	...	14	15
Cash Flow Analysis									
Inflows:									
Sales Revenue					140000	120960	...	37571	32416
Loan Drawdown				45000					
Equity Contribution	5000	7000	9000	15000					
	5000	7000	9000	60000	140000	120960	...	37571	32416
Outflows:									
Operating Costs					40000	34560	...	10735	9262
Statutory Royalty					10000	8640	...	2684	2315
Interest Expense					5850	3900	...		
Tax Paid						34983	...	9128	7384
Principal Repayments					15000	12500	...		
Capital Expenditure	5000	7000	9000	60000					
	5000	7000	9000	60000	70850	94583	...	22547	18961
Net Cash Flow to Equity	(5000)	(7000)	(9000)	(15000)	69150	26377	...	15024	13455

NVP 25% = $30905

Figure 7

APPRAISAL PROGRAM PARTLY FUNDED BY THIRD PARTY IN RETURN FOR 10% OVERRIDING ROYALTY

Year	1	2	3	4	5	...	13	14
Cash Flow Analysis								
Inflows:								
Sales Revenue				140000	120960	...	37571	32416
Loan Drawdown		12000	45000					
Equity Contribution	5000	4000	15000					
	5000	16000	60000	140000	120960	...	37571	32416
Outflows:								
Operating Costs				40000	34560	...	10735	9262
Statutory Royalty				10000	8640	...	2684	2315
10% Overriding Royalty				10000	8640	...	2684	2315
Interest Expense				7410	5460	...		
Tax Paid					29665	...	7700	6149
Principal Repayments				15000	15000	...		
Capital Expenditure	5000	16000	60000					
	5000	16000	60000	82410	101964	...	23803	20041
Net Cash Flow to Equity	(5000)	(4000)	(15000)	57590	18995	...	13768	12375

NVP 25% = $36287

For those currently thinking that the improvment in value is due entirely to the reduction in the length of the appraisal program be assured that if the calculation is reworked with a 3 year appraisal program the NPV becomes $28,006,000 compared to the all-equity 3 year base case of $30,905,000 shown previously.

The net present value, at a 25 per cent discount rate, of the 10 per cent overriding royalty is $8,187,000.

The third example examines the impact on the NPV of the use of third party equity to fund 75 per cent of the appraisal program. Such equity might be provided in return for:

(a) an option to acquire stock in the project sponsor in the event that the project does not proceed or does not realise the expectations of the sponsors, and

(b) a 20 per cent free carried interest in the project from the beginning of Year 3.

In this case the NPV has increased from the base of $30,905,000 to $35,897,000. Again if the calculation is reworked with a 3 year appraisal program the NPV becomes $27,757,000.

The net present value, at a 25 per cent discount rate, of the 20 per cent free carried interest is $4,854,000.

What conclusion can be drawn from these examples?

Firstly that third party funds with equity kickers do have a real cost although the magnitude of that cost can only be determined on a case by case basis.

Secondly, the use of debt or equity funds with equity kickers attached can, if their application reduces the gestation period for a project, improve the net present value of the equity cash flows.

Thirdly, a project sponsor considering utilising these sources of capital to accelerate an appraisal program, for example, must be aware of the consequences if the original, all-equity funded timetable, is not substantially improved.

Maximising a Project's Debt Capacity and Accelerating the Introduction of Debt

Recent trends in financing oil and gas projects have concentrated on:

- Minimising the equity contributions by project sponsors by maximising the level of debt employed

Figure 8

APPRAISAL PROGRAM PARTLY FUNDED BY THIRD PARTY IN RETURN FOR 20% FREE CARRIED INTEREST

Year	1	2	3	4	5	...	13	14
Cash Flow Analysis								
Inflows:								
Sales Revenue				140000	120960	...	37571	32416
Loan Drawdown			45000					
Equity Contribution 1	5000	4000	15000					
Equity Contribution 2		12000						
	5000	16000	60000	140000	120960	...	37571	32416
Outflows:								
Operating Costs				40000	34560	...	10735	9262
Statutory Royalty				10000	8640	...	2684	2315
Interest Expense				5850	3900	...		
Tax Paid					34983	...	9128	7384
Principal Repayments				15000	12500	...		
Capital Expenditure	5000	16000	60000					
	5000	16000	60000	70850	94583	...	22547	18961
Net Cash Flow to Equity	(5000)	(4000)	(15000)	55320	21102	...	12019	10764

NVP 25% = $35897

- the introduction of debt funds as early as possible in the appraisal/development program.

Some notable recent examples of each of these trends are the Cooper Basin Liquids Project, the Dampier to Cape Lambert Pipeline, the Jackson to Moonie Pipeline and the Mereenie Oil and Gas Field.

To determine how a project's debt capacity may be maximised it is necessary to first review the two fundamental concepts that serve as building blocks for virtually all oil and gas financings:

- reserve based financing techniques
- project risk assessment and mitigation

Reserve Based Financing Techniques

Reserve based financing utilises the capacity of a project's hydrocarbon assets to support debt.

There are several different methods of calculating a project's debt capacity. The technique that Bank of America, and many other leading international banks, use is shown by the formula presented in Figure 9.

The formula shows that debt capacity can be calculated by applying project-specific coverage factors to the present value of the project's future cash flows. The present value is calculated by discounting, generally at the cost of debt, the project cash flows which occur during the period in which 60-70 per cent of the proved reserves are recovered.

The exact nature of the project cash flows selected for discounting, and hence for debt service, depends on a number of factors including the financial strength of the Borrower, the size of the project relative to the Borrower, the Borrower's projected corporate and secondary tax liability during the loan tenor, and so on.

A "large" borrower may choose, to make a corporate undertaking to meet all operating costs, replacement capital expenditure, and corporate and project taxes in order to use a rather gross (for example "after royalties") type of cash flow for determination of the project debt capacity.

A "small" borrower may not have any choice but to use a rather net (for example "after tax") type of cash flow for this determination.

In broad terms the more "net" the cash flow nominated or selected to meet debt service obligations, the greater the potential for significant positive and negative variations in the cash stream.

Figure 9

$$\text{PROJECT DEBT CAPACITY} = \frac{NPV_d}{CF}$$

PROVIDED THAT:

Annual Debt Coverage Ratio = X
Loan Life Ratio = Y
Field Life Ratio = Z

WHERE:

NPV = The net present value of a defined project cash flow generated by the production of between 60% and 70% of the proved reserves during the period from time "d" to loan maturity
d = The later date of production start up or the date of calculation
CF = Coverage factor (Y)

$$\text{ANNUAL DEBT COVERAGE RATIO} = \frac{NCFE + CPLTD + (IE + LE)\ (I - TR)}{CPLTD + (IE + LE)\ (I - TR)}$$

WHERE:

DCR = Debt coverage ratio
NCFE = Net cash flows to equity (after reinvestment and all other calls on cash flow have been satisfied)
CPLTD = Current portion of long term debt
IE = Interest expense
LE = Lease expenses
TR = Tax rate (i.e. .46)

$$\text{LOAN LIFE RATIO} = \frac{NPV_d}{OB}$$

$$\text{FIELD LIFE RATIO} = \frac{NPV_d + NPV_r}{OB}$$

WHERE:

OB = Outstanding principal balance
NPV_r = The net present value of a defined project cash flow generated by the production of the residual reserves during the period from maturity (time "r") to cessation of the project

The process of structuring financings using this type of technique "formula lending". The technique is very much state of the art and it has become so because it is a dynamic, rather than static, mechanism with the flexibility to accommodate many changing conditions.

To maximise a project's debt capacity it is necessary to add to this basic structure a method of passing on the benefits of improved project circumstances to the project sponsors. Financial advisors accomplish this task by designing a core financing structure around a project's "base case" assumptions and then building in flexibility to enable expansion when "most likely case" conditions are realised.

Sponsor initiated tests are incorporated into the overall structure, so that the project sponsors themselves can choose whether or not to take advantage of any additional borrowing capacity.

A few of the more common sponsor initiated tests employed in oil and gas financings today are:

- reserve tests
- production tests
- market tests
- project tax tests (such as RRT, "new" oil levy)

Generally a Borrower has two main objectives in initiating a particular test. An upward revision of a project's debt capacity, as a result of, for example, certification of additional proved reserves, may permit:

(a) additional drawdowns to fund ongoing project capital expendiure or other corporate purposes, and/or

(b) a switch of recourse debt to non-recourse, or more likely to limited recourse.

Commonsense prevailing, there is no real limit to the number or nature of tests. As financial advisors to the joint venturers of a recent oil field project, we designed and incorporated in the structure of their debt facility several different tests, each linked to important events in the project's development.

Project Risk Assessment

As noted earlier providers of equity and debt funds for projects have clearly different risk appetites. It is necessary to design a financing that matches the particular risk/reward requirements of those providers if the project's potential is to be maximised and the financing plan optimised.

The nature of the cash flow used for calculating project debt capacity determines the type and number of risks that must be mitigated before conventional debt finance can be raised. Broadly speaking the more "net" the cash flow, the more risks there are to be mitigated.

Although project risks are generally well understood, it is worth quickly reviewing the typical risk analysis framework.

The key risk elements are

- resource
- completion
- operating
- market
- management

- foreign exchange
- political and regulatory
- casualty/force majeure
- refinancing

The objective of debt maximisation can only be achieved by the use of a sophisticated financing structure which:

(a) provides satisfactory cash and reserve coverage factors under every possible operating scenario,

(b) provides a satisfactory risk environment for lenders,

(c) provides additional debt capacity as a result of improved project circumstances, and

(d) permits a switching of recourse debt to limited or non-recourse debt as the debt capacity increases.

The stage at which debt can be introduced to a project depends on the time required to prepare the technical and economic studies necessary to enable:

(a) the project sponsors to make a commitment to proceed with development, and

(b) the lenders to the project to become comfortable with the technical and commercial risks involved.

The length of time required to prepare these studies depends largely on the definition of key project parameters such as recoverable reserves, production profiles, processing facility design, projected operating and capital costs, markets and the like.

For a large project these studies may take years. Sometimes, however, it is possible to reduce the impact of the enormous amount of time required to complete full feasibility studies by excising portions of a full scale development program and expressing the individual activities as an initial phase of the total development. By so doing it is possible to reduce the magnitude of the studies required, firstly, to make a decision to proceed with limited development and, secondly, to support short or medium term debt based on the cash flow and security provided by only that portion of the overall program.

This technique, which we call "bootstrap financing", has been used on several occasions to great effect. Judicious application of "bootstrapping" can permit debt funding of appraisal drilling programs and full scale feasibiltiy studies.

Are There Better Ways of Financing an Australian Oil and Gas Company?

Traditionally Australian independents have been financed with conventional equity and conventional debt. Occasionally, quasi-equity and quasi-debt have been employed by companies with hydrocarbon assets generating sufficient cash flows to service such instruments as preference shares or convertible notes.

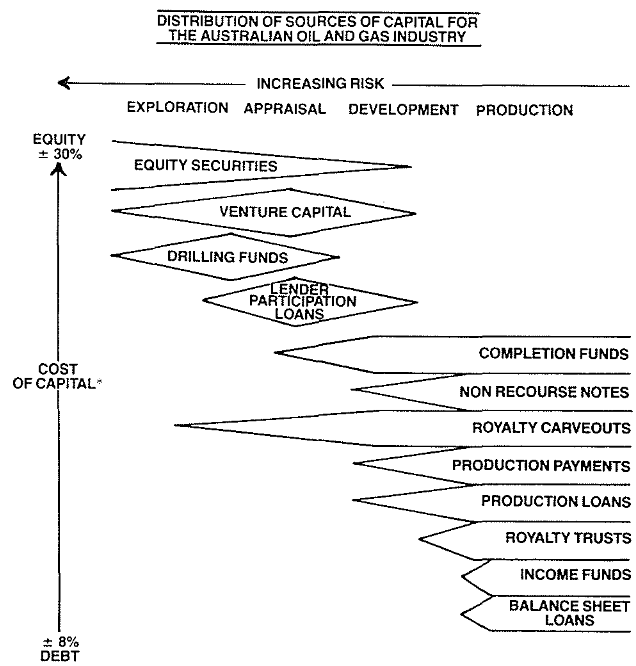
In light of the innovative financing techniques developed overseas in the last few years, it is interesting to contemplate whether there really are better ways of financing our domestic industry.

Among the potential sources of capital for the Australian oil and gas industry are:

- drilling funds
- venture capital
- completion funds
- royalty carveouts
- lender participation loans
- non-recourse notes
- royalty trusts
- income funds

These sources of capital have application at different points on the risk/reward continuum.

Figure 10



Drilling Funds

To date, drilling funds have had little success in this country and probably only the first Sovereign Oil Fund could be considered a commercial success. The translation of this US-developed concept to the Australian regulatory environment has not been easy and none of the drilling funds launched to date, including the first Sovereign Oil Fund, has been able to satisfy all the requirements of investors looking for an oil and gas play with associated tax shelter benefits.

The general concept of drilling funds has a likely future in this country, but considerably more work is required to maximise its potential.

Royalty Trusts

Royalty Trusts may have a future in Australia because of the already well developed system of Overriding Royalties, Net Profit and Free Carried Interests

A Royalty Trust is generally a passive investment entity that owns a fixed group of non-operating interests — such as net profit, overriding or, in the US, a production payment — in oil or gas properties. An oil company creates a royalty trust by transferring to a trust the right to receive a specified percentage of the net profits or revenues from specified oil or gas producing properties in which the company continues to own the working interest.

The oil company may:

(a) distribute trust units to its existing shareholders, or

(b) sell the units to new investors.

The following arguments have been advanced in favour of distributing royalty trust interests to shareholders:

- shareholder wealth can be enhanced for an "undervalued" company by placing the "undervalued" assets in separate assets forcing the market to recognise those assets' value. The supposition is that the pieces will be worth more than the whole.
- a royalty trust structure eliminates the double taxation that occurs when an oil company's income is taxed first in the hands of the corporation and again in the hands of private shareholders when that income is distributed as dividends.
- the spinning off of certain hydrocarbon assets into a self liquidating vehicle reduces the base hydocarbon reserve level for the company which results in a more manageable annual reserve replacement target.

The Royalty Trust concept was developed by T. Boone Pickens Jr. of Mesa Petroleum Company in 1979 when Mesa spun off royalties over a portion of its oil and gas reserves into The Mesa Royalty Trust. Since then a number of similar Royalty Trusts have been set up by, amongst others, OKC Corporation, Houston Oil and Minerals Corporation and the Southland Royalty Company.

Royalty Trusts have recently come under very close scrutiny. Many observers now believe that the seemingly universal beneficial application of royalty trusts is not possible in reality. One of the major criticisms is that they do not assess the impact of the spin-off on the parent company.

This impact is evident in the two important areas of:

- long term stock price
- long term capital raising

The early royalty trusts of Mesa and Southland Royalty at first raised the value of the royalty and stock units as a total. Over time, however, the combined price soon settled back to levels in line with comparable companies which has not gone the trust route.

The key to all this is the application of any cash proceeds the company realises from creating the royalty trust. It is reasonable to assume that investors will be prepared to "pay" for the right to directly access cash flows rather than to participate in a dividend stream.

Are There Better Ways of Operating an Australian Oil Company?

It has been suggested that the issue behind the so called shareholder discontent that recently wracked such major US companies as Gulf, Getty and Superior was the question of who really owned the companies — was it the shareholders or the management?

Major oil industry investors are beginning to question why managements are not, and do not want to be, substantial shareholders in their companies. As a result of their lack of investment in their companies, charge the investors' groups, management do not have the same interests as shareholders.

Boone Pickens has stated on several occasions that "caretaker managements are more concerned with job security, perks and power than with shareholder interests". Pickens believes that managers must be "on the same side of the table as the shareholder". To create that attitude in managers, he says, companies should make management owners, or prospective owners, of meaningful amounts of stock. "Give them a good sized stock option and cut out the executive perks" he says!

Shareholders worldwide are, in time, likely to adopt similar attitudes and, inevitably, the management of

Australian oil and gas companies will find themselves under close scrutiny from investor groups.

In addition to seeking more effective methods of financing all forms of activity, management will also need to examine alternative methods of acquiring reserves, the lifeblood of any oil and gas company.

The recent spate of takeovers and mergers by medium and large US oil companies suggests that, in the US at least, it may well be "cheaper to drill on Wall Street". Although a clear trend as to the economic advantages of acquiring oil on the stock market has not yet developed. It does appear, however, that given the goal of most US companies to increase domestic reserves, drilling on Wall Street may make eminent sense.

Although the quantity and quality of information published by Australian oil companies is somewhat less comprehensive than that of US companies it is possible to draw some broad conclusions for the Australian market.

Various analytical studies suggest that the average domestic finding cost in the period 1978 to 1983 was $7.40/bbl. This figure compares to potential acquisition costs via the Australian stock market ranging from $3.00/bbl for "old" oil to $15.00/bbl for levy free "new" oil.

This large range can be attributed to the lack of definition of reserves considered for analysis.

Conclusion

There will always be opportunities to develop new methods of financing oil and gas activities.

To date financial advisors have focussed primarily on the debt end of the debt/equity continuum. However, in the future, and if equity markets continue to behave the way they have in the past, financial advisors are likely to play an increasing role in arranging equity capital.

REVIEW OF AUSTRALIAN MINING REFERENCE MANUALS

The latest Register of Australian Mining 84/85 and the soon to be released Alexander and Hattersley's Australian Mining, Minerals and Oil — 4th Edition (1984) are important and well presented reference documents.

Enormous growth of exploration and the companies involved during 1983/84 has been the prime factor behind the growth in size of these manuals over recent years. In the current edition of the Register, this expansion is most notable in the "Oil and Gas", "Gold", "Lead-Zinc-Silver", and "Cobalt" commodity review and projects section. Gold related projects take up considerable space.

An interesting difference between the two manuals is the emphasis given by the Register, to the commodity based mine project reference guide. This section provides useful information on mine location, owners, administration, geology and reserves and production statistics.

By contrast, the Australian Mining, Minerals and Oil volume places more emphasis on providing a detailed companies section. This provides the reader with up-to-date status on all of the company's operations and resources exploration activities.

The main features of the 4th edition of Australian Mining, Minerals and Oil are ninety new company listings, a stop press enabling major items reported up to September 10 and separate company directory.

In addition to the expanded companies section, both reference manuals provide useful information on mining related Federal and State Government Departments and Mining Industry Organisations.

Register of Australian Mining 84/85 is edited by Ross Louthean and published by Australian Business for Australian Consolidated Press in conjunction with the Perth Stock Exchange. Recommended retail price for the soft cover volume is $110.00. Australian Mining, Minerals and Oil is edited by Alan Deans and published by the Law Book Company. This hardcover volume will sell for $110.00

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