Problems with Calculating Royalties: Commentary

Robert A Laws *

INTRODUCTION

It is relatively common in Australia for exploration tenements to be subject to an interest in the wellhead value of future petroleum production sometimes termed a wellhead royalty. Such interests are negotiated for a variety of purposes, but are often assigned to a tenement holder on transfer of a working interest to a new party who assumes some or all of the transferor's exploration obligations of the tenement.

One of the main reasons wellhead royalties are a favoured form of interest is that they carry no financial liability for the holder, provide an income stream which is roughly proportional to the size of a discovery and which commences almost immediately a discovery is put into production.

Those holding working interests in a discovery also wish to generate the maximum possible profit. Minimisation of the liability to pay

* BSc (Syd), Geologist, Adelaide.

wellhead royalty assists in reaching this objective. This paper provides a commentary on the main factors used to derive wellhead value and the ways these factors can be "adjusted" to vary the calculation.

Reviews of the various types of royalty interest made by private agreement in Australia and related issues are given in articles by Ryan,[1] Player-Bishop,[2] and Phillips and Gibney.[3]

WELLHEAD VALUE AND WELLHEAD ROYALTY

Many expressions used in the petroleum industry have meanings which are widely understood. Such expressions would include the terms "proved reserves", "economically recoverable", "net profits interest", "wellhead royalty" and "wellhead value". When it comes to applying these "widely understood" meanings in detail, however, a multitude of questions can arise as to the applicability of parameters used to calculate the value required.

Wellhead royalty can be taken to mean an interest, expressed as a percentage, in the wellhead value of petroleum on its production from an underground reservoir.

Wellhead value has a widely accepted meaning: the value of petroleum production if it were to be sold at the wellhead. In practice, because little production in Australia is sold "as is" at the wellhead, the term must be defined and is taken to mean "the actual sales value of the products derived from production less costs of conversion to saleable products and transportation from the wellhead to the point of sale". In using this definition to actually calculate wellhead royalty for a particular project, a number of questions could arise which, unless agreed between the parties concerned, can rapidly lead to litigation. These questions include the treatment of:

- applicability of royalty provisions of an agreement made before petroleum has been discovered and before the relevant production tenement issued;
- depreciation of capital;
- project financing costs;
- cost of equity capital;
- leasing costs;
- government fees, charges, taxes etc;
- forward sales or hedging;
- take-or-pay provisions in gas sales contracts;
- carry forward of unrecouped deductions;
- costs upstream of the wellhead;

1. G L J Ryan, "Petroleum Royalties" [1985] *AMPLA Yearbook* 328.
2. C W O Phillips and M F Gibney, "Dealing with Royalty Interests" (1993) *Australian Petroleum Exploration Association Journal* 418.
3. H Player-Bishop, "Financial Non-Working Interests" [1990] *AMPLA Yearbook* 399.

- overheads;
- method of allocation of costs between the various petroleum products sold;
- sales not at arm's length;
- other project income;
- currency exchange rate gains or losses; and
- rehabilitation costs.

The method of treatment of a number of these factors (and potentially other factors, as the above list is by no means exhaustive), could have a major impact on the wellhead royalty calculation.

Problems are most likely to arise either where projects are marginally economic or where significant discoveries are made, and the large sums of money involved encourage minimisation of royalty liabilities. It is important therefore to reduce the opportunity for contention. This could be achieved by ensuring that at least the major parameters which affect royalty are tied down. Even if this can be accomplished, there will unfortunately always be the potential for argument at the margins.

A more detailed review of the major factors which can impact on the calculation of wellhead royalty is given below, followed by a few suggestions as to ways of achieving greater certainty with royalty type interests.

FACTORS AFFECTING THE CALCULATION OF WELLHEAD VALUE

Continuity of royalty interests

Most royalty interest agreements are made prior to discovery of petroleum when only an exploration tenement is current. In Australia, such a tenement does not confer the right to extract petroleum except for testing purposes. A production tenement is necessary in order to bring a discovery into production.

It is therefore important to ensure that royalty interest provisions apply to any extension, substitution or renewal of the exploration tenement, issue of a retention tenement (if applicable) and to production from the production tenement issued in the event a commercial discovery is made.

Depreciation of capital

It is generally in the interests of those who hold a working interest in a newly developed discovery to write off the capital expenditure involved as quickly as possible. Such action could result in little or no royalty in the first years of production. Although this would be offset by increased royalties later in the project, this would result in some loss in the real value of a wellhead royalty interest.

A capital depreciation schedule (either on a straight line or declining balance basis) over ten or more years is preferred for the royalty interest holder to ensure that as far as reasonably possible, royalty revenue is received early in the life of a project.

An example is given below of a project which has required a capital investment of $40 million and which is providing a net revenue stream before capital depreciation of $12 million per year. Under ten year straight-line depreciation, the wellhead value (wellhead royalty being a percentage of this value) stays constant. Under a depreciation schedule based on a 25 per cent declining balance basis, the wellhead value is reduced in the early years, thus diminishing the real value of any wellhead royalty interest. Despite a slightly lower total wellhead value in the ten year straight-line depreciation example, the net present value at a discount rate of 10 per cent is $49 million compared to $46 million for the 25 per cent declining balance basis.

	$ Million										
Year	1	2	3	4	5	6	7	8	9	10	**Total**
Net Income Before Depreciation	12	12	12	12	12	12	12	12	12	12	120
Depreciation on 10 Year Straight-Line basis	4	4	4	4	4	4	4	4	4	4	40
Wellhead Value	8	8	8	8	8	8	8	8	8	8	80

Net Present Value of wellhead value at 10 per cent = $49.1 million.

Depreciation on 25 per cent Declining Balance basis	10	7.5	5.6	4.2	3.2	2.4	1.8	1.3	1.0	0.8	38
Wellhead Value	2.0	4.5	6.4	7.8	8.8	9.6	10.2	10.7	11.0	11.2	82

NPV of wellhead value at 10 per cent = $45.8 million.

Project financing costs/cost of capital concept

The issues of project financing and the cost of equity capital are most important as these factors can have a very considerable and continuing impact on royalty revenue.

Most projects are debt financed to some degree. Some companies may have their loans secured against the project or a number of projects, some may have a general loan facility or other arrangement. Different parties in a joint venture will usually have different loan arrangements. What allowance should be made for interest deductions to derive wellhead value in these circumstances? Should financing costs be a non-allowable deduction? Should only interest on loans secured against the project be allowable? Should a general allowance be made for financing, and if so, how much?

Economic theory (and practice) is that equity capital also has a cost. A return on equity capital must be obtained for any project to be viable. The Capital Asset Pricing Model is widely accepted for the calculation of cost of capital and is company specific. It results in a cost of capital being calculated which is usually higher than the cost of debt. The model only takes into account unavoidable risk and some would argue that for petroleum projects the risk of non-successful projects should also be involved and that as capital has a cost it should be a legitimate deduction for royalty purposes.

A closely allied issue is the inclusion of a profit component in the cost of facilities used in treating and transporting petroleum to its point of sale. This issue has been the subject of contention in Australia (see the article by Corletto[4]).

There would appear to be two options for the wellhead royalty interest holder—either reject profit, interest and the cost of capital as allowable deductions or, more reasonably, make an allowance, at least for interest. This can be achieved, for example, by allowing an interest component equivalent to the long-term government bond rate (plus a few points perhaps to recognise commercial rates of interest) on half the undepreciated capital remaining at the time of the regular royalty payment.

The calculation set out below compares the wellhead value of a project under two circumstances:

- taking into account interest and cost of capital by allowing 18 per cent interest on all undepreciated capital employed (18 per cent being chosen as a rough average of the cost of debt and the cost of equity for a project which is 50 per cent debt financed); and
- taking into account interest by an allowance equivalent to 12 per cent interest on half of the undepreciated capital remaining at any time.

Inclusion of the cost of capital as a deduction to derive wellhead value can result in a significant reduction in royalty revenue during the period in which the capital is being depreciated (usually ten years). In the example given below, the allowance of the cost of both debt and equity capital as a deduction results in the wellhead value being almost halved, compared to the case where an allowance for debt capital only is given.

$ Million

Year	1	2	3	4	5	6	7	8	9	10	**Total**
Net Income After Depreciation	8	8	8	8	8	8	8	8	8	8	80
Deduction for 18 per cent interest on 100 per cent of Undepreciated Capital	7.2	6.5	5.8	5	4.3	3.6	2.9	2.2	1.4	0.7	39.6
Wellhead Value	0.8	1.5	2.2	3	3.7	4.4	5.1	5.8	6.6	7.3	40.4
NPV of wellhead value at 10 per cent = $21.6 million											
Deduction for 12 per cent interest on 50 per cent of Undepreciated Capital	2.4	2.2	1.9	1.7	1.4	1.2	1.0	0.7	0.5	0.2	13.2
Wellhead Value	5.6	5.8	6.1	6.3	6.6	6.8	7.0	7.3	7.5	7.8	66.8
NPV of wellhead value at 10 per cent = $39.9 million											

4. A G Corletto, "Recent Cases: Aust Oil and Gas Corp Ltd v Bridge Oil Ltd" [1991] *AMPLA Yearbook* 145.

Capital and the cost of capital have been one of the most difficult areas for royalty negotiations. It is in this region that the fundamental difference between the economists' concept of rent and the wellhead royalty concept come into conflict. There is no reason for a wellhead royalty not to be calculated using a cash flow net present value approach, rather than an accounting approach. There is no reason why an accounting approach should not include the cost of capital. However if either of these two routes is contemplated, the royalty rate should be suitably adjusted. As a practical measure one could argue that it is easier to get a negotiated agreement on the accounting basis definition of wellhead value in the context of currently accepted rates than it is to get agreement on the rate given a rent definition of wellhead value.

Leasing costs

If neither cost of capital nor a reasonable deduction for the cost of finance is allowed as a deduction to calculate wellhead royalty, leasing of plant and/or contracting of other services could be used to reduce royalty liability. To protect against this possibility, a limitation on such costs (or at least a limitation as to the extent to which leasing and contracting of services is an allowable deduction) would need to be specified in the agreement.

Government taxes or other imposts

There has been lengthy and costly litigation with respect to the treatment of government taxes and other imposts—including the impact of Commonwealth crude oil excise on the Week's royalty over Gippsland Basin production.[5]

Government charges are certainly a real cost and it is reasonable that they be deductable for calculation of a privately owned wellhead royalty providing such costs are limited to any petroleum specific imposts (for example, crude oil excise—still applicable onshore), production tenement fees and any associated local government charges (production tenements are subject to council rates in some jurisdictions).

Take-or-pay/forward sales etc

Most gas sales contracts in Australia have take-or-pay provisions such that a certain percentage (usually in the range of 70 to 80 per cent) of the annual contract quantity of gas must be paid for, whether taken by the purchaser or not. Gas "paid for but not taken" may be delivered in a subsequent year or deferred to the end of the contract. The question arises as to whether the income from gas "paid for but not taken" is subject to royalty on receipt or on final delivery of the gas. If the latter, should any escalation factor apply to maintain the royalty received in real terms?

5. See nn 1 and 2, above.

This issue is allied with that of forward sales of oil and other forms of hedging. Should the royalty be paid on production, delivery or sale?

It is recommended that it be made clear that the liability to pay royalty arises on production of the petroleum, but that the calculation of the wellhead value is to include all income received during the royalty calculation period as a result of sales contracts for petroleum, regardless of whether the petroleum was actually delivered to the purchaser or not during that time. Costs should likewise be deductible at the time of their expense—or in the case of capital costs, capitalised at that time.

Other project income

A project may generate other income from project assets which are included in the capital base for which deductions are made to derive wellhead value. This could occur, for example, by using spare plant capacity to treat third party petroleum.

In such circumstances, it would appear reasonable to reduce relevant plant, capital and operating cost deductions proportional to the use by third party petroleum. Cost allocation issues immediately arise (see below).

An argument could also be made that royalty deductions be directly offset against all income received for third party use of plant and other facilities. Again, there is no single industry-wide method for treating such income and, if argument is to be avoided, provision would need to be made in the royalty agreement if such circumstances were anticipated.

Carry forward of unrecouped deductions

A variety of circumstances could arise in any royalty calculation period that would result in allowable deductions exceeding the selling value of the petroleum. This would result in no royalty being paid for that particular period. Argument can then develop as to how the unrecouped deductions are to be handled.

This problem is overcome in one of the State jurisdictions by limiting allowable deductions applicable to any royalty calculation period to 50 per cent of the selling value of the petroleum. Unrecouped deductions are allowed to be carried forward until discharged. This mechanism helps to ensure a regular royalty stream throughout the life of the project.

Costs upstream of the wellhead

It is accepted in the industry that all costs ''upstream'' of the wellhead are not deductible for the purpose of calculating wellhead royalty (the wellhead comprises the production valves or 'Christmas tree' attached to the top of a well completed for production). This would include all exploration and appraisal costs (mainly geophysical work and drilling), any costs associated with locating, drilling and equipping production wells, and lifting costs.

There are a number of items which are not clearly "upstream" or "downstream" of the wellhead. This would include oilfield equipment which is physically located (at least in part) downstream of the wellhead (for example, beam pumps) which could be argued to be part of surface facilities and therefore a deductible item for royalty purposes. It is suggested that it be made clear that facilities used to assist upstream production (that is, acting before the wellhead) be non-deductible. Exceptions would be costs of compression for gas, and facilities and fluids etc used in enhanced oil recovery schemes.

In offshore areas the very high cost of facilities involved can result in cost allocation of items up and downstream of the wellhead being a significant issue. The complex nature of equipment involved offshore has led to litigation to determine the exact location for the wellhead on a subsea completion in the Gippsland Basin.[6] If the majority of the facilities involved can be defined as "pre-wellhead", capital and operating deductions to derive wellhead value can be considerably reduced.

Head office overheads

There should be little argument that the direct cost of all field personnel involved on operations downstream of the wellhead is a valid deduction for royalty purposes. The extent and range of head office costs which can legitimately be deducted is debatable, however. Some have even argued that overheads of joint venture partners other than the operator should be taken into account.

In short, there is no generally accepted principle by which a cost can be readily identified as an overhead applicable to the calculation of wellhead value. To clarify this issue for a particular project it is necessary to construct a definition of allowable overheads. For example this could be limited to the direct cost of labour involved downstream of the wellhead (whether located in the field or not) plus a factor to cover administrative costs, office rent etc. Alternatively, a simple percentage of the gross selling value of petroleum involved (for example, 1 per cent) could substitute as an overheads "allowance".

Cost allocation

Many projects become relatively complex with a range of joint venture partners, plants which process gas, gas liquids and oil, and which may also process third party petroleum through some form of tolling arrangement. There may be different levels of government taxation on oil rather than gas (as under the Commonwealth crude oil excise scheme, for example). In such circumstances, the allocation of costs between the various petroleum products becomes necessary.

6. Unreported, HCA, Mason CJ, Brennan, Deane, Toohey and Gaudron JJ, *HP Petroleum Pty Ltd (formerly Hematite Petroleum Pty Ltd) v James Charles Murray Balfour* 11 June 1987.

As with overheads, there is no single "correct" method of allocating costs between various petroleum products and a number of methods are commonly used. For example, an item of plant may have the purpose of separating liquids from gas to assist in bringing the gas to sales quality specification. Should the capital and operating cost of this plant be a cost against the sales gas only (on the basis of removing a substance to render the gas of sales quality); a cost against the liquids (to render the liquids of sales quality) or should the cost be shared?

If the cost is to be shared, as would seem reasonable, what manner should be chosen—the respective volumes, weights, heating values or selling values of the products passing through the particular piece of equipment? There can be well argued cases presented for a range of allocation methods which can significantly alter relative cost structures.

If it is considered that allocation of costs could be used to minimise wellhead value in a particular circumstance (and this could often be very difficult to judge at the exploration stage) it would be prudent to define the allocation method to be used.

Sales not at arm's length

There may be sales not at arm's length if a vertically integrated company is involved in a project (that is, a company involved in refining and distribution as well as production). Other circumstances which may lead to non-arm's length sales may occur in a complex project where a portion of the petroleum produced is not only used to fuel field and central processing plants, but also in enhanced oil recovery operations or sold to one of the joint venture parties for a separate purpose.

For oil, condensate and LPG there are international reference markers quoted daily against which non-arm's length sales could be benchmarked (Saudi Light, West Texas International etc).

Gas pricing is more difficult, but could be referenced to an Australian project in the area. For example, the notional sales gas price to apply to non-third party sales for a royalty agreement in South Australia could be linked to the ex-Moomba plant price for locally produced and processed gas, a price which is publicly known.

Other issues

A range of other issues may arise which could impact on royalty and for which there is no accepted method of treatment, including:

- currency exchange rate gains or losses;
- sale of plant not fully depreciated;
- sale of plant between project partners;
- provision of and full access to data on sales and costs;
- royalty payment calculation and payment period;
- audit of royalty returns;

- royalty forecasts;
- rehabilitation costs;
- project wind-up costs;
- mechanism for adjustment of errors in royalty payments;
- penalties for late payment; and
- dispute resolution mechanisms.

CONCLUSIONS

It can be concluded from the above that:

- there is broad understanding in industry as to the general meaning of wellhead value and wellhead royalty;
- there is no single industry-wide set of standards or guidelines to calculate wellhead value (the definition depending upon the construction of the particular agreement in question);
- the methods used in industry and by government to calculate wellhead value are project specific, to a greater or lesser extent;
- the royalty rate should not be negotiated independently of the method for calculating wellhead value;
- most royalty interests are negotiated at the exploration stage when the nature of the likely project if exploration proves successful is generally unlikely to be known; and
- the more successful the exploration the more likelihood there is for argument as to the methodology to be adopted for calculating wellhead value.

In those States which have established production onshore, procedures and standards have been developed by the respective State government for royalty calculation. A standard royalty agreement for South Australia is set out in the article by Laws.[7] It would therefore be possible to nominate in an agreement regarding an overriding royalty interest that procedures to be used for calculating wellhead value are to be identical to the set of procedures used by the State for that particular project. A number of problems could arise:

- One or more of the States may move from a wellhead basis for royalty collection to an alternate method. The Commonwealth has argued in favour of the resource rent concept and considers that wellhead royalties are economically inefficient and have the potential to distort decision making. The States remain to be convinced. The wellhead royalty system is relatively simple to administer, widely accepted by industry, provides a revenue stream that can be forecast with some confidence and is not considered economically distortionary at the current rates of 10 per cent to

7. R A Laws, "Petroleum and Mineral Royalties in South Australia" (1991) 10 *AMPLA Bulletin* 152.

12.5 per cent. Nevertheless there remains a possibility that one or more of the States will move to a basis for calculation of royalty other than the wellhead system.

- A State may vary the calculation methodology from time to time. This may occur during periods of low product prices, for example when the financial viability of a project may be threatened, or offer royalty holidays or accelerated depreciation provisions to attract exploration investment.
- The detailed royalty procedures that will be applied by a State to a project are not established until after the discovery is made and are generally designed to be project specific. The overriding royalty interest holder will have little ability to control the establishment of these procedures.

An alternative resolution would be to avoid specifying in detail the methodology to be used for the calculation of wellhead royalty, but to simply provide that the wellhead value is never to be less than a certain percentage of the selling value of the petroleum. This would place a "floor" under the calculation regardless of the persuasive or inventive methods which may be used to minimise wellhead value.

As a guide to the percentage to be chosen, the wellhead value of petroleum collected by State governments in Australia averages around 60 to 70 per cent of the selling value.

An even simpler method would be to move away from the wellhead value concept and specify the royalty to be a percentage of the selling value of the petroleum (2 per cent of the selling value being equivalent to approximately 3 per cent of the wellhead value). It is less likely that this method would find ready acceptance by many in the industry for philosophical reasons.

If either solution is used it would be desirable to make provision in the agreement for at least the following factors:

- ensure the royalty provisions remain effective through renewal of title etc;
- royalty calculation and payment period;
- changes in government taxes, imposts etc;
- non-arm's length sales;
- dispute resolution (for example via arbitration);
- access to data used and necessary to calculate wellhead value; and
- audit.

ACKNOWLEDGMENTS

The assistance of Terry Aust and Joe Zabrowarny in providing advice and comments on drafts of this paper is gratefully acknowledged.