

**GAS EXPLORATION IN NEW ZEALAND  
SUPPLEMENTARY REPORT**

**Prepared for the Ministry of Economic Development  
By Ernst & Young Limited**

**May 2004**

**Analysis of Options around the reduction of AVR and amendments  
to the ring fencing  
May 2004**

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# Executive Summary

## 1. Combinations of Incentives

This report summarises the conclusions reached by the MED project group in the course of evaluation possible combinations of changes to the royalties regime.

## 2. Options

The project team has considered three options:

Option 1		
	Gas%	Oil%
AVR	1	5
APR	10/15	10/15

Option 2		
	Gas%	Oil%
AVR	1	1
APR	20	20

Option 3 – combined with relaxation of ring fencing		
	Gas%	Oil%
AVR	1	5
APR	20	20

## 3. Reducing AVR

The reduction in AVR on its own will not have a significant impact on project economics and therefore would not be expected to positively influence the amount of exploration occurring in New Zealand. The most significant influence on project economics occurs where the APR is reduced or deferred.

## 4. Reducing the APR rate

It is possible to positively discriminate in favour of gas production, by reducing the royalty rate for gas only. However, this distinction would require far more prescriptive rules in terms of cost allocation. It would therefore require greater audit and negotiation resources within Crown Minerals. It would be far more straightforward to reduce the rate across the board but to prevent the reduction

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being of open-ended application by providing that the lower rate applies only so long as total volume or revenue does not exceed a threshold amount.

A lower APR rate potentially has a more material impact on project economics than a lower AVR rate, though the relative significance of each measure will vary across projects. For example, in this report we present a comparison showing that the relative significance of reductions in the AVR and APR rates depends to some extent on field-specific features. For our sample offshore project, an APR reduction has a broadly equivalent impact to the selected AVR reduction. However, for our onshore project, the value impact of a lower APR rate is around three times the value impact of a reduced AVR rate.

## **5. Deferring APR**

The removal (or relaxation) of the exploration cost ring fencing rules is one means of deferring the APR royalty, while at the same time ensuring that, to get the benefit, the producer must incur additional exploration expenditure. There are a number of design features that can be adjusted. The most favoured features appear to be:

- restricting deductibility to future costs only;
- allowing the deduction of exploration costs in calculating an APR liability on any future (but not existing) discoveries;
- applying an interest adjustment to carried-forward exploration costs; and
- allowing a deduction for exploration costs incurred anywhere in New Zealand, irrespective of the location of the discovery against which the costs are deducted.

These features were favoured as they appear to minimise any discrimination in favour of current producers and potentially adverse effects in terms of distorting exploration decisions.

## **6. Revenue implications**

It is not possible to accurately assess the aggregate revenue impact of the various proposals, either in present value terms or on a year by year basis. Any estimates rely critically on assumptions about future exploration activity, oil and gas prices and the characteristics of as yet undiscovered fields. However, in this supplementary report, we do provide some illustrative calculations, which point toward an annual revenue cost (in present value terms) of no more than \$30m over the period during which any package remains in place. We emphasise, however, that this estimate is very imprecise.

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## 1. Purpose

Our modelling has shown that the impact on the economics of our base case projects of removing the AVR royalty is relatively minor.<sup>1</sup>

Consequently, the project group has evaluated various combinations of changes to the AVR and APR royalty regimes. This supplementary report summarises those findings and also provides additional analysis around the impact of specific measures on sample project economics and government revenue.

## 2. Waiving or Reducing Royalty Rates

### 1.1 Issues

The project team has discussed:

- Whether to reduce AVR only or APR and AVR
- Whether the Minister can reduce AVR to 0%
- Whether the incentive should discriminate between gas and oil

### 1.2 Context for Reduction

*[Withheld under section 9(2)h of the Official Information Act where withholding of the information is necessary to maintain legal professional privilege]*

### 1.3 Reduction of AVR

As noted above, our modelling has shown that the impact on the economics of our base case projects of removing the AVR royalty is relatively minor.

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<sup>1</sup> The assumptions underpinning our modelling results are summarised in the Annex.

**Table 1: Impact of Reducing AVR**

	Status Quo			Gas AVR 1%		Differences		
	Pre royalty & tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Net
<b>Onshore</b>								
Integrated	18.8%	15.7%	15.0%	15.9%	15.2%	0.3%	0.2%	0.2%
Standalone	-	-	12.5%	-	12.7%	-	0.2%	0.2%
<b>Offshore</b>								
Integrated	18.8%	16.4%	15.0%	16.7%	15.3%	0.3%	0.3%	0.3%
Standalone	-	-	13.5%	-	13.8%	-	0.3%	0.3%

  

	Present Values of Royalties & Tax		Present Values of Royalties & Tax		Present Values of Royalties & Tax		Net
	Royalties	Tax	Royalties	Tax	Royalties	Tax	
Integrated	12.7	2.6	11.7	2.9	-0.9	0.3	-0.6
Standalone	12.7	10.7	11.7	11.0	-0.9	0.2	-0.7
<b>Offshore</b>							
Integrated	40.5	20.7	35.7	22.3	-4.8	1.6	-3.2
Standalone	40.5	39.5	35.7	40.8	-4.8	1.4	-3.4

Our sensitivity analysis indicates that this conclusion holds across a reasonably wide range of projects.

#### 1.4 Reducing APR

The project team has considered whether it would be possible to positively discriminate in favour of gas production by reducing royalties in respect of gas produced. Graham Hull has pointed out that there would be considerable interpretational issues around the allocation of costs.

This distinction would require far more prescriptive rules in terms of cost allocation. It would therefore require greater audit and negotiation resources within Crown Minerals. The project team consequently concluded that any reduction should apply to both oil and gas, but that the lower rate would cease once production reached a specified threshold. For modelling purposes, we have assumed a threshold of 150 bcf (or equivalent), but note that this value has been selected for illustrative purposes only.

A comparison of Tables 1 and 2 shows that the relative significance of reductions in the AVR and APR rates depends to some extent on field-specific features. The APR reduction has a broadly equivalent impact to the AVR reduction on our sample offshore project. For our onshore project, the value impact of a lower APR rate is around three times the value impact of a reduced AVR rate.

**Table 2: Lower AVR and Lower APR Rate – Marginal Fields**

Status Quo		Gas AVR 1%, APR 15% for first 150bcf				Differences			
		<i>Internal Rates of Return</i>							
		Post Pre royalty & tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Net
<b>Onshore</b>									
	Integrated	18.8%	15.7%	15.0%	16.7%	16.0%	1.0%	1.0%	1.0%
	Standalone	-	-	12.5%	-	13.4%	-	0.8%	0.8%
<b>Offshore</b>									
	Integrated	18.8%	16.4%	15.0%	16.9%	15.5%	0.5%	0.5%	0.5%
	Standalone	-	-	13.5%	-	13.9%	-	0.4%	0.4%
<i>Present Values of Royalties &amp; Tax</i>									
		Royalties	Tax	Royalties	Tax	Royalties	Tax	Net	
	Integrated	12.7	2.6	8.8	3.8	-3.8	1.3	-2.6	
	Standalone	12.7	10.7	8.8	11.9	-3.8	1.2	-2.7	
<b>Offshore</b>									
	Integrated	40.5	20.7	32.7	23.3	-7.8	2.6	-5.2	
	Standalone	40.5	39.5	32.7	41.8	-7.8	2.3	-5.4	

Similarly, a comparison of Tables 2 and 3 shows that the more profitable the project the greater the relative benefit from a lower APR. This is because the APR takes effect earlier the more profitable the field. By itself, this feature suggests a capped reduction in the APR rate is a ‘blunter’ way of inducing higher exploration.

**Table 3: Lower AVR and Lower APR Rate – Infra-Marginal Fields**

Status Quo		Gas AVR 1%, APR 15% for first 150bcf				Differences			
		<i>Internal Rates of Return</i>							
		Post Pre royalty & tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Net
<b>Onshore</b>									
	Integrated	18.8%	15.7%	15.0%	16.7%	16.0%	1.0%	1.0%	1.0%
	Standalone	-	-	12.5%	-	13.4%	-	0.8%	0.8%
<b>Offshore</b>									
	Integrated	18.8%	16.4%	15.0%	16.9%	15.5%	0.5%	0.5%	0.5%
	Standalone	-	-	13.5%	-	13.9%	-	0.4%	0.4%
<i>Present Values of Royalties &amp; Tax</i>									
		Royalties	Tax	Royalties	Tax	Royalties	Tax	Net	
	Integrated	12.7	2.6	8.8	3.8	-3.8	1.3	-2.6	
	Standalone	12.7	10.7	8.8	11.9	-3.8	1.2	-2.7	
<b>Offshore</b>									
	Integrated	40.5	20.7	32.7	23.3	-7.8	2.6	-5.2	
	Standalone	40.5	39.5	32.7	41.8	-7.8	2.3	-5.4	

Other matters that should be considered in determining whether to reduce the APR rate include:

- Unless limited to a fixed volume of gas and / or condensate, the concession is effectively open-ended.

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- It would be necessary to carefully design the cap to avoid, for example, creating incentives to defer or avoid gas production. For example, this might arise if the cap was specified solely in terms of cumulative gas production. In that instance, the producer may be disincentivised from exceeding that threshold and may prefer to produce condensates and oil. One approach would be to specify a net revenue threshold rather than a volume threshold.

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## **2. Relaxation of Ring Fencing Rules**

### **2.1 Issues**

Under current royalty rules, exploration expenditure must be recorded against the relevant exploration permit where it is incurred. The expenditure is only deductible against production revenue from an area within that permit area.

The project team has discussed whether (and how) these rules should be relaxed to allow exploration expenditure in other permits to be offset against production revenue in a wider range of circumstances.

### **2.2 Design Features**

The incentive should also be designed so that the explorers are rewarded for future exploration effort, rather than past effort. Consequently, the project group considered that any relaxation of the ring fencing rules should apply only with respect to expenditure incurred after a specified commencement date.

We should point out that this incentive would not necessarily provide the producer with a permanent saving. If the additional exploration carried out is successful, the producer cannot also deduct that same exploration expenditure against production revenue from the newly discovered permit.

### **2.3 Exploration on Existing or New Permits?**

The project group noted that those holding existing permits are already committed to work programmes. The question was asked whether those explorers should be rewarded for doing only what they had already planned to do. It was however noted that it may be counterproductive to restrict the lifting of the ring fence to new permits, given that there is significant prospectivity in the current permit areas.

One suggestion has been that existing holders could apply for ring fence removal if they agree to increase the intensity of the planned work programme. There is an element of discrimination in this option, as in some cases the explorer's work programme may be as intensive as reasonable exploration practice will allow.

### **2.4 Partial or 100% of Exploration Expenditure**

We have assumed that 100% of qualifying exploration expenditure could be allowed. Although it could be scaled back to a proportion, it would diminish the effectiveness of the incentive without significantly saving the fiscal cost.

## 2.5 Expenditure in Specified Areas?

The project group considered the merits of a constraint along the lines of “exploration expenditure can only be offset in calculating an APR liability in respect of production in the same region”.

It was considered that the expenditure should not be confined to specific areas as the Crown wants to gather knowledge about the prospectivity of all areas within New Zealand. There is also the possibility of a discovery in any region.

In addition, such a constraint any could effectively lock explorers into a region when they would otherwise prefer to explore elsewhere.

## 2.6 Existing or Future Production?

This was one of the most critical issues in terms of the design of the incentive. The ability to offset exploration expenditure against current production greatly increases the economic benefit of the incentive. Consequently, it would be of far greater benefit to existing producers. The project group is also aware that many of these producing companies are holding some of the most promising exploration acreage. They are also well placed to rapidly exploit any significant finds.

Restriction of the offset to production from subsequent discoveries would defer and therefore diminish the potential benefit. The key argument in favour of this approach is that it does not discriminate between existing producers and other explorers.

Tables 4 and 5 illustrate the differences in potential impact between allowing a out-of-licence exploration expenditure to be offset against APR liabilities on future vs current production.

**Table 4: No Ring Fencing, Expenditure Offset Against Future Production<sup>2</sup>**

	Status Quo			Gas AVR 1%, ring-fencing rules relaxed		Differences		
	Pre royalty & tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Net
<i>Internal Rates of Return</i>								
<b>Onshore</b>								
Integrated	18.8%	15.7%	15.0%	16.6%	15.9%	0.9%	0.9%	0.9%
Standalone	-	-	12.5%	-	13.2%	-	0.7%	0.7%
<b>Offshore</b>								
Integrated	18.8%	16.4%	15.0%	16.9%	15.5%	0.5%	0.5%	0.5%
Standalone	-	-	13.5%	-	13.9%	-	0.4%	0.4%
<i>Present Values of Royalties &amp; Tax</i>								
	Royalties	Tax		Royalties	Tax	Royalties	Tax	Net
Integrated	12.7	2.6		9.3	3.7	-3.4	1.1	-2.2
Standalone	12.7	10.7		9.3	11.7	-3.4	1.0	-2.3
<b>Offshore</b>								
Integrated	40.5	20.7		32.7	23.3	-7.8	2.6	-5.2
Standalone	40.5	39.5		32.7	41.8	-7.8	2.4	-5.4

From Table 4, restricting the offset of exploration expenditure to future production delivers a material benefit – in these examples, around the same benefit as a capped reduction in the APR rate. However, Table 5 indicates that the benefits would be around three times larger if explorers were permitted to offset exploration expenditure against current production.

**Table 5: No Ring Fencing, Expenditure Offset Against Current Production**

	Status Quo			Gas AVR 1%, expln exp immediately deductible		Differences		
	Pre royalty & tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Net
<i>Internal Rates of Return</i>								
<b>Onshore</b>								
Integrated	18.8%	15.7%	15.0%	18.7%	17.8%	3.0%	2.8%	2.8%
Standalone	-	-	12.5%	-	15.1%	-	2.6%	2.6%
<b>Offshore</b>								
Integrated	18.8%	16.4%	15.0%	18.2%	16.4%	1.7%	1.4%	1.4%
Standalone	-	-	13.5%	-	15.0%	-	1.5%	1.5%
<i>Present Values of Royalties &amp; Tax</i>								
	Royalties	Tax		Royalties	Tax	Royalties	Tax	Net
Integrated	12.7	2.6		3.1	5.7	-9.6	3.2	-6.4
Standalone	12.7	10.7		3.1	11.9	-9.6	1.2	-8.4
<b>Offshore</b>								
Integrated	40.5	20.7		19.1	27.8	-21.4	7.1	-14.3
Standalone	40.5	39.5		19.1	42.4	-21.4	2.9	-18.5

## 2.7 Gas Production Only?

The project group considered that it was not practical to restrict the relaxation of ring fencing restrictions to exploration expenditure on gas prone prospects.

However, it would be possible to restrict the lifting of the ring fencing to the royalty on gas produced. This option would present a number of allocation difficulties as most fields produce a mixture of both oil and gas.

It is also important to remember the objective of the incentives is to encourage exploration now. This expenditure will be incurred in advance of future production. Presently, all exploration for hydrocarbons is of importance to New Zealand (whether the prospect is believed to be oil or gas prone); the product resulting from that exploration is not strictly relevant to the incentive. In summary, the project group's view is that the incentive should reward any company that is prepared to explore, whether it ultimately produces oil or gas.

<sup>2</sup> These calculations assume 50 percent of exploration expenditure could not be deducted against APR liabilities under current rules but could be deducted if the ring fencing rules were relaxed.

## 2.8 Indexing costs

The Australian Commonwealth's Petroleum Resource Rent Tax ("PRRT") on offshore petroleum exploration is conceptually similar to the APR but with the important difference that accumulated exploration and development costs are carried forward with interest calculated by reference to the risk-free rate plus an allowance for risk (broadly, 15 percentage points for exploration expenditure and 5 percentage points for development expenditure).

Indexation of costs under the APR could be considered as either a complement or an alternative to relaxation of the 'ring fencing' rules for exploration expenditure.

**Table 6: Interest on Carried Forward Expenditure**

	Status Quo			Gas AVR 1%, expln exp carried fd with interest		Differences		
	Pre royalty & tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Post royalty, Pre tax	Post royalty, Post tax	Net
<i>Internal Rates of Return</i>								
<b>Onshore</b>								
Integrated	18.8%	15.7%	15.0%	17.3%	16.6%	1.6%	1.6%	1.6%
Standalone	-	-	12.5%	-	13.8%	-	1.3%	1.3%
<b>Offshore</b>								
Integrated	18.8%	16.4%	15.0%	17.5%	16.0%	1.1%	1.0%	1.0%
Standalone	-	-	13.5%	-	14.4%	-	0.9%	0.9%
<i>Present Values of Royalties &amp; Tax</i>								
	Royalties	Tax		Royalties	Tax	Royalties	Tax	Net
Integrated	12.7	2.6		6.5	4.6	-6.2	2.0	-4.2
Standalone	12.7	10.7		6.5	12.7	-6.2	1.9	-4.3
<b>Offshore</b>								
Integrated	40.5	20.7		23.5	26.3	-17.0	5.6	-11.4
Standalone	40.5	39.5		23.5	44.9	-17.0	5.4	-11.6

There are two principal economic arguments for adopting this approach:

- Lack of indexation under the APR means the present value of deductions for exploration expenditure is lower for longer-lived projects, distorting investment decisions away from offshore toward onshore exploration. Given an appropriate interest rate, this distortion is removed with indexation<sup>3</sup>.
- Indexation will place all explorers on a common footing, unlike allowing an offset against current production which only benefits an explorer with an existing production base.

<sup>3</sup> The distortion between projects with different lives will only be fully removed if the interest rate used to adjust carried forward expenditures is set equal to the pre-royalty, pre-tax internal rate of return on a marginal project – say 20 percent. But a rate this high will create additional distortions, most importantly by incentivising explorers to defer production. We understand this is a determinant of the 'split rate' approach under the Australian PRRT, whereby a high rate applies in the initial years and a lower rate subsequently.

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The main argument for proceeding cautiously with indexation is that, since it effectively replaces the APR regime with a resource rent tax, the move has the appearance of a fundamental reform and may therefore require more widespread consultation.

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### 3. Potential Revenue Cost

The net revenue cost of the various measures discussed above will in principle comprise the present value of the royalties that would have been paid had the royalty regime not been amended, less royalties actually paid.

Even ex post, it will not in practice be possible to determine the present value of the royalties that would have been paid had the royalty regime not been amended, since this will require knowledge of the amendments' precise impact on exploration activity.

More generally, the quantum and timing of the revenue cost will depend on a wide range of factors, including the nature of future discoveries (at one extreme the revenue cost would be nil if there were no commercial discoveries within the relevant timeframe).

We have however undertaken some indicative calculations that provide some indication of the potential numbers involved. These are summarised below.

*Calculation 1: Maximum revenue cost of allowing deduction for explorations costs against current APR liabilities*

Exploration expenditure totalled \$173m in 2000 and \$203m in 2001 and, we understand, has been around these levels in subsequent years.

The figure below shows the maximum net annual revenue cost of allowing current exploration expenditure to be deducting in calculating APR payable on current production, under the extreme assumption that all exploration expenditure would end up being offset against an APR liability in the year the expenditure was incurred. The calculations reflect several factors that will reduce the net cost, viz:

- The increase in company tax payable if royalties are reduced (for a company in a tax paying position, a \$100 reduction in royalties will result in a \$33 increase in company tax).
- The AVR's role as a floor on royalty payments
- The future increase in APR payable since exploration expenditure deducted now will not be available to reduce future APR liabilities.

### Assumptions

Percentage of exploration expenditure never deductible against APR	50%
Average present value of AVR as % of present value of APR	30%
Average years before exploration expenditure deductible in calculating APR	10
Company tax rate	33%
Government discount rate	7%

Annual Exploration Expenditure \$m	Current Revenue Cost	PV of future revenue gain	Net cost \$m
200	18.8	4.8	14.0
300	28.1	7.2	21.0
400	37.5	9.5	28.0

### Calculation 2: Cumulative Impact

The following table shows the net impact on annual royalty and tax flows under various assumptions about the package's impact on annual exploration expenditure.

% Increase in Exploration Spend	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
0%	0.0	0.0	0.0	0.0	0.0	-8.1	-8.3	-33.1	-37.1	-26.6	-40.8	-70.0
20%	-6.6	-6.7	-6.9	-7.0	-0.2	-7.1	-8.1	-15.8	-17.3	-3.9	-7.2	-35.5
50%	-16.5	-16.8	-17.2	-17.5	-0.4	-5.6	-7.8	10.1	12.5	30.1	43.1	16.3
100%	-33.0	-33.7	-34.3	-35.0	-0.9	-3.0	-7.4	53.4	62.1	86.7	127.0	102.6

The table reflects the following assumptions:

- “Base” annual exploration expenditure of \$200m
- A 50 / 50 split between onshore and offshore projects
- All projects are identical to our ‘model’ onshore and offshore projects
- All fields are marginal (the additional royalties payable on any fields that would not have been discovered in the absence of additional exploration activity will reduce the net cost).
- All fields discovered come on stream at the same time (onshore in 2009, offshore in 2011).
- A 50 / 50 split between perfectly ‘integrated’ explorers (who can use tax losses in the year they arise) and ‘standalone’ explorers (who must carry forward tax losses until commercial production).

These assumptions are obviously unrealistic and the results should therefore be regarded as being no more than indicative of the numbers potentially involved.

## Annex - Modelling Assumptions

### 3.1 Changes to Field Profiles

We have made three key changes to our previously assumed field profiles:

- We have reduced the assumed exploration periods from 10 years to 6 years and 4 years for offshore and onshore, respectively.
- We have increased the required post-tax rate of return from 10 percent to 15 percent.

We have adjusted field sizes so that they are (still) marginal from the perspective of an ‘integrated’ explorer – i.e., an explorer which is able to use tax deductions as they arise.

	Onshore	Offshore
<b>Field Assumptions</b>		
Field life (years)	10	15
<b>Field Size</b>		
Condensate / (000's) barrels	479	1,544
Gas / PJ	110	448
<b>Output per year</b>		
Condensate / (000's) barrels	47.9	102.9
Gas / PJ	11.0	29.9
<b>Revenue</b>		
Oil price (USD, real)	25	Constant
Gas price (NZD, real)	4	Constant
<b>Costs</b>		
<b>Initial development cost</b>		
Amount	5	300
Development year	5	7
<b>Exploration Costs</b>		
Number of years of exploration	4	6
Exploratory cost per year	20	25
	80	150
<b>Annual operating cost</b>	20	20
<b>Abandonment cost</b>		
Number of years after last operating year	1	1
Abandonment year	16	23