Summary Economic Analysis
1. Introduction

A revised royalty system has been introduced by PERUPETRO which provides two alternative royalty calculations:
1) Royalties according to the level of production
2) Royalties according to economic results.

The Contractor is able to choose which scheme to apply at the time of declaring a commercial discovery, taking into account the size, nature of the discovery and the characteristics of the reservoir.

1.1 Royalty Systems

Previous work has defined two alternative royalty mechanisms which will make hydrocarbons contracts in Peru more competitive in order to stimulate increased exploration investment. The system provides investors with alternative systems from which to select the best system for the prospects available. Royalty According to the Level of Production The royalty rate is determined by the level of production, according to the following structure:

Production levels of the block '000bpd	Royalty as a percentage%
< 5	5
5 - 100	5 - 20
> 100	20

The sliding scale calculation for production between 5,000 bopd and 100,000 bopd is calculated as follows:

((Current Production–5 MBOPD) x (RMAX–RMIN)/(Threshold MAX-Threshold MIN))+5

where:
Current Production is the current production level from the block in ‘000 bopd;
RMAX is the maximum royalty rate (20);
RMIN is the minimum royalty rate (5);
Threshold MAX is the maximum production threshold rate (100);
Threshold MIN is the minimum production threshold rate (5);

This Royalties calculation system has a number of advantages:

1) It is simple to calculate;
2) It uses monitored production from the block to create a continuous sliding scale of royalty rates, with no sudden steps or increases;
3) It applies low royalty rates to lower production levels;
4) The lower royalty at the end of the field life has the effect of extending the economic limits of the field.

Royalty According to the Profit Ratio of the Previous Royalty Period
This royalty rate is determined by the level of profit from the block which uses the reported income and expenditure to calculate an “R” factor, and also includes a fixed and variable royalty

based on a reference value for production. From the start of production, the fixed royalty component will apply as the minimum value.

When the initial investment in the block has been recovered, when the R factor exceeds 1.15, an additional variable royalty is applied based on the annual economic results of the block.

The variable royalty is based on the previous year's income and expenditure, by determining the net profit (income (X) minus expenditure (Y)) as a percentage of income (X). This percentage is adjusted by the "R" factor of the accumulated income and expenditure.

The structure is as follows:

Royalty on hydrocarbons income (RRH)t = Fixed Royalty + (Variable Royalty)t

(Variable Royalty)t = ((Xt-1 – Yt-1)/Xt-1) * ((1-(1/(1+(R Factor t-1 – "starting" value of R factor)))

A minimum fixed royalty of 5% is established for the first years of the project until the profitability as determined by the "R" factor reaches 1.15.

This scheme is seen as preferable for high investment projects with low margins in order to ensure recovery of the initial investment, before significant royalty payments are applied. The productive life of the field may be extended by applying lower royalty rates at the end of the field life when marginal profitability reduces relative to the R factor which remains constant or declines relatively slowly.

1.2 Assumptions and Methodology

Full sets of economic analysis data are provided for each Block. This section provides a summary. The approach in this study is to look at the practical application of the two alternative royalty options, based on specialist assessments on prospectivity and technical risk, for a number of notional field developments in the Blocks to be promoted. Volumes have been derived from various generations of previous mapping and/or reasonable estimates. It is emphasised that a conservative set of prospect volumes have been used to test the applicability of the new royalty schemes to possibly marginally attractive projects. There is considerable upside in the prospects and basins beyond the volumes described here.

With regard to the economic assumptions, it has been intended to maintain compatibility between the analysis in this study and the previous work that has been carried out for PERUPETRO. For this reason the discounted cash flow analysis has been applied on uninflated cash flows, by applying a crude oil price of US$20.0/bbl held constant in nominal terms.

In this further economic analysis the basic crude oil price was assumed to be related to a Brent price of $20/bbl by making an adjustment for crude oil quality and other marketing considerations. This gave the following scale of crude oil discounts, for the cases evaluated in this study:

Basin	Block	Fluid	API Gravity	Brent Discount
Maranon Case	**B**	oil	35	$ 0.5 /bbl
Maranon Case	**C**	oil	40	$ 0 /bbl
Maranon Case	**E**	oil	25	$ 3.0 /bbl
Maranon Case	**E**	oil	25	$ 3.0 /bbl
Maranon Case	**E**	oil	25	$ 3.0 /bbl
Ucayali Case	**A**	oil	40	$ 0 /bbl
Ucayali Case	**A**	oil	40	$ 0 /bbl
Ucayali Case	**B**	oil	30	$ 2.0 /bbl
Ucayali Case	**B**	gas		
Ucayali Case	**C**	oil	20	$ 4.0 /bbl

The gas price assumption is discussed in the section below on the Gas Cases.

With regard to present value discounting, our analysis considers the present value of future cash flows at a range of discount rates. For the purpose of calculating discounted investment performance measures, we have applied a discount rate of 10% per annum as the base assumption, which represents the nearest to a standard oil industry assumption.

The study considers the range of potential discovery sizes in the list above and examines the investment performance of these fields under the two royalty mechanisms. Where a specific scenario gains significant economic benefit from one royalty calculation, this result is discussed in the Commentary.

2. Oil Cases

This study considers the investment performance of the same representative field sizes that were used in the Comparative Study produced for PERUPETRO by Gaffney, Cline & Associates (GCA). The cost and production assumptions applied by GCA have been reviewed and were found to be appropriate for our application, and have therefore been applied in an essentially unchanged format. One advantage of this approach is that the results of this analysis should be comparable with the results and conclusions from the GCA study.

The following cases were tested:

Basin	Block	Fluid	Reserves MMB	Reserves TCF	Depth (metres)	Comments
Maranon Case	**A**	oil	100		4500	Cretaceous sandstones: Structural
Maranon Case	**A**	oil	250		4500	Cretaceous sandstones: Stratigraphic
Maranon Case	**B**	oil	150		5000	Cretaceous sandstones: Structural
Maranon Case	**C**	oil	125		5000	Cretaceous sandstones: Structural
Maranon Case	**D**	oil	250		4500	Cretaceous sandstones: Stratigraphic
Maranon Case	**E**	oil	240		4000	Cretaceous sandstones: Structural - large structure
Maranon Case	**E**	oil	40		4000	Cretaceous sandstones: Structural - small structure
Maranon Case	**E**	oil	250		4000	Cretaceous sandstones: Stratigraphic

Basin	Block	Fluid	Reserves MMB	Reserves TCF	Depth (metres)	Comments
Ucayali Case	**A**	oil	100		3000	Cretaceous sandstones: Structural
Ucayali Case	**A**	oil	50		4000	Jurassic dolomites: Structural/ stratigraphic
Ucayali Case	**B**	oil	175		3000	Cretaceous sandstones: Structural
Ucayali Case	**B**	gas		1.7	3000	Cretaceous sandstones plus Jurassic and Palaeozoic: Structural
Ucayali Case	**C**	oil	50		2500	Cretaceous sandstones: Structural

Information regarding the cost and timing assumptions for these cases is included in the Documentation Library in a document called Cost Timing Assumptions.pdf.

3. Gas Case

A single gas case has been examined for this analysis, which is based on the discovery of further very large gas reserves. Particular attention was paid to the history of the Camisea Gas discovery, as the case history is well known in the industry and will have a significant bearing on industry perceptions of the attractiveness of gas exploration.

For this analysis we have to assume that sufficient discoveries are made to support the cost of an LNG export project. We have taken both of the LNG Plant cost and the transportation pipeline cost out of the economics of the chosen field size (1.7 TCF). This is a major simplifying assumption, but the difficulties of designing and arranging financing for these major infrastructure projects is certain to impose significant delays to such a large scale project.

The pipeline capital cost is likely to match those of Camisea in the area of $ 1 billion for the pipeline construction. This analysis has assumed that a minimum transportation tariff of $0.9/MM btu would be required in order to recoup the amortised capital costs, operating costs and project financing, with a commercial return to the pipeline investors.

With regard to the LNG plant, we have assembled cost assumptions on the basis of the recently constructed Atlantic LNG Plant in Trinidad. Here it is assumed that a new LNG Plant with two trains would be constructed. Each train would have a capacity of 3 MM tonnes of LNG per year based on a feedstock of 450 MM scfd of gas. It is probable that the first LNG train would cost on the order of $1.2 MM with a second train about $ 0.6 MM assuming that some scale economies and shared use of facilities is possible. With this level of capital expenditure we calculate that the liquefaction cost of the plant would be of the order of $1.4/MM btu in order to recover the amortised capital costs, operating costs and project financing, with a commercial return to the LNG plant financiers.

It is further assumed that the main market for the LNG would be the USA. The Atlantic LNG Plant at Point Fortin, has LNG supply contracts to the Everett LNG Plant at Boston, Massachusetts, the Elba Island LNG Plant in Georgia, and to Barcelona in Spain. Taking the USA reception points as typical of those targeted for Peruvian LNG exports we have estimated a shipping cost of $ 0.45/MMbtu for shipment to the USA. In addition, we may need to consider a modest re-gasification cost at the US plant, for which we have assumed $ 0.20/MMbtu.

This analysis therefore sees the following netback costs of transportation, liquefaction and shipping, as follows:

	$/MM btu
Pipeline Transportation to Coastal LNG Plant	0.90
LNG Plant Gas Liquefaction Costs	1.20
Liquefied LNG Shipping Costs - Peru to USA	0.45
LNG Plant Re-gasification Costs	0.20
TOTAL Treatment and Transportation Costs	2.75

Gas Pricing

This analysis assumes that the price of the gas sold to the US LNG market will be based on the spot price at Henry Hub, with a correction factor to account for the distance from Henry Hub to the point of sale (Georgia or Boston). Over the last two years Henry Hub gas prices have been relatively depressed, and we believe that the outlook is for firmer gas prices going forwards. A review of past Henry Hub gas prices, leads us to the view that we should not expect Henry Hub prices to exceed an average of $ 4.5/MM btu as a long-term average price assumption. These calculations mean that, for the purposes of this analysis, we have assumed a netback price at the field in Peru of US$1.25/MMbtu for the base case in 2004 terms, and held constant in nominal terms thereafter.

Information regarding the cost and timing assumptions for these cases is included in the Documentation Library in a document called Cost Assumptions.pdf.

4. Results

The summary economic results are presented in two sets of tables. The first table consists of cases which have been evaluated by implement the royalty calculation according to the level of production.

Summary Results – Production based Royalty

Case	DCF ROR (%)	Cum. Net Cash Flow ($ MM)	NPV @ 10% ($ MM)	NPV/bbl @10% ($)	P/I ratio (undisc)	Disc. P/I Ratio @ 10%	Host Country Take (%)
Maranon Basin							
Block B - 150 MMBO	23.93%	962.77	174.57	1.16	1.54	0.61	42.57%
Block C - 125 MMBO	26.67%	834.11	165.50	1.32	1.75	0.77	41.85%
Block E - 240 MMBO	30.46%	1302.18	262.49	1.09	2.05	0.97	44.78%
Block E - 40 MMBO	19.94%	163.29	31.78	0.64	0.65	0.26	44.22%
Block E - 250 MMBO	30.25%	1362.12	272.77	1.09	2.02	0.95	44.97%
Ucayali Basin							
Block A - 100 MMBO	30.65%	817.73	216.18	2.00	2.30	1.08	41.93%
Block A - 50 MMBO	16.98%	256.27	45.66	0.91	0.81	0.26	43.59%
Block B - 175 MMB	37.27%	1172.58	329.77	1.88	2.52	1.33	44.14%
Block B - 1.7 TCF Gas	13.89%	1223.17	72.03	0.60	1.70	0.27	48.33%
Block C - 50 MMBO	14.26%	179.83	23.55	0.47	0.67	0.16	44.86%

The final set of sensitivity cases have been evaluated by implementing the royalty calculation based on the economic results of the previous period, and gave the following results:

Summary Results - Profit based Royalty

Case	DCF ROR (%)	Cum. Net Cash Flow ($ MM)	NPV @ 10% ($ MM)	NPV/bbl @10% ($)	P/I Ratio (undisc)	Disc. P/I Ratio @ 10%	Host Country Take(%)
Maranon Basin							
Block B - 150 MMBO	23.52%	831.54	154.58	1.03	1.33	0.54	50.40%
Block C - 125 MMBO	25.91%	705.35	142.77	1.14	1.48	0.66	50.83%
Block E - 240 MMBO	30.51%	1141.13	239.37	1.00	1.80	0.88	51.61%
Block E - 40 MMBO	19.89%	153.56	30.39	0.61	0.61	0.24	47.54%
Block E - 250 MMBO	30.41%	1199.27	250.63	1.00	1.78	0.87	51.55%
Ucayali Basin							
Block A - 100 MMBO29.	18%	673.69	179.58	1.66	1.90	0.90	52.16%
Block A - 50 MMBO	16.51%	232.40	40.47	0.81	0.73	0.23	48.85%
Block B - 175 MMB	36.78%	998.66	289.59	1.65	2.14	1.17	52.42%
Block B - 1.7 TCF Gas	14.18%	1152.49	74.23	0.62	1.60	0.27	51.31%
Block C - 50 MMBO	13.98%	166.65	21.14	0.42	0.62	0.14	48.90%

5. Risked Economics

Risk-weighting was incorporated into our economic evaluations by means of a simplified application of expected value methods. This technique is applicable in cases where the available data does not allow us make an informed judgement about the probability of success for individual prospects.

For the expected value calculation, the input data are the net present value of failure (i.e. the NPV of the dry-hole cost), and the net present value of success (i.e. the NPV of the field development).

The basic formula is:

(DHC * (1 - x)) - (NPV * x) = 0
where:

DHC = the present value (@ 10.0 %) of the dry-hole cost
NPV = the net present value (@ 10.0 %) of the discovery
x = the probability that the discovery will be made

The net present value of the dry-hole cost when multiplied by the probability of failure, is sometimes referred to as the Expected Monetary Cost (EMC), and the net present value of success when multiplied by the probability of success, is sometimes referred to as the Expected Monetary Value (EMV). We can see that the above formula seeks to balance the EMV against the EMC.

In effect, this formula seeks to find the probability of success, which will exactly balance the risk weighted dry-hole cost. In other words, it defines the minimum probability of success that would be needed, in order to achieve a positive expected value. In this case, a positive expected value indicates that the decision to explore would be justified on a 'risk-weighted' basis.

The results for these evaluations were as follows:-

Risk Results for Cases under the Production Royalty

Case	Present Value of the Dry-Hole Cost	Present Value of Success ($ MM)	Break-even Probability of Success (%)	Minimum Success Required
Maranon Basin				
Block B - 150 MMBO	14.14	174.57	7.5%	1 in 14
Block C - 125 MMBO	14.14	165.50	7.9%	1 in 13
Block E - 240 MMBO	11.24	262.49	4.1%	1 in 25
Block E - 40 MMBO	11.24	31.78	26.1%	1 in 4
Block E - 250 MMBO	11.24	272.77	4.0%	1 in 25
Ucayali Basin				
Block A - 100 MMBO	9.34	216.18	4.1%	1 in 25
Block A - 50 MMBO	10.91	45.66	19.3%	1 in 5
Block B - 175 MMB	9.34	329.77	2.8%	1 in 33
Block B - 1.7 TCF Gas	9.34	72.03	11.5%	1 in 9
Block C - 50 MMBO	9.09	23.55	27.9%	1 in 4

Risk Results for Cases under the Profit Royalty

Case	Present Value of the Dry-Hole Cost	Present Value of Success ($ MM)	Break-even Probability of Success (%)	Minimum Success Required
Maranon Basin				
Block B - 150 MMBO	14.14	154.58	8.4%/span>	1 in 13
Block C - 125 MMBO	14.14	142.77	9.0%	1 in 11
Block E - 240 MMBO	11.24	239.37	4.5%	1 in 25
Block E - 40 MMBO	11.24	30.39	27.0%	1 in 4
Block E - 250 MMBO	11.24	250.63	4.3%	1 in 25
Ucayali Basin				
Block A - 100 MMBO	9.34	179.58	4.9%	1 in 20
Block A - 50 MMBO	10.91	40.47	21.2%	1 in 5
Block B - 175 MMB	9.34	289.59	3.1%	1 in 33
Block B - 1.7 TCF Gas	9.34	74.23	11.2%	1 in 9
Block C - 50 MMBO	9.09	21.14	30.1%	1 in 3

Expected value calculations give a broad indication of the level of risk cover provided to the explorer in deciding whether to drill an individual prospect.

6. Commentary

These results are very encouraging, with most cases showing investment returns which would meet general industry standards for commerciality. Some cases show outstandingly attractive economics. The base case economics are evaluated under a Brent oil price of $20/bbl, which is fairly cautious assumption, when considering the forward sales curve of most banks in the current economic outlook. There should be considerable economic upside from higher oil prices in the future.

Marañon Basin – Block B – 150 MMBO

This case is shows attractive economics under base case assumptions and as with the case for Block B shows slightly improved economics under the production-based royalty when compared to the profit-based royalty. The discounted cash flow rates of return are also fairly close, although both the undiscounted and present value profits are noticeably higher under the production royalty. The minimum break-even probability of success at about 1 in 14 is similar under both royalty systems.

Marañon Basin – Block C – 125 MMBO
This case is shows attractive economics under base case assumptions and also shows slightly improved economics under the production-based royalty when compared to the profit-based royalty. The discounted cash flow rates of return are also fairly close, although both the undiscounted and present value profits are noticeably higher under the production royalty. The minimum break-even probability of success is about 1 in 13 under the production royalty and about 1 in 11 under the profit based royalty.

Marañon Basin – Block E – 240 MMBO
This case also reflects the prospectivity of larger structures on blocks which have the benefit of existing infrastructure (pipeline). The field shows very attractive investment performance under base case assumptions. Discounted cash flow rates of return are very close, but again undiscounted profits and present value profits are substantially higher under the production based royalty. The EMV calculation shows that there is exceptional risk cover for this case, with a minimum break-even probability of success of about 1 in 25 under each royalty calculation.

Marañon Basin – Block E – 40 MMBO
This is the small oil field case considered in this study and shows the advantage of existing infrastructure in reducing costs and allowing an accelerated development and production schedule. This case is commercial under both royalty systems with similar rates of return and present value profits. These results are so close that the preferred royalty calculation could change as a result of any changes in production or the cost base. The minimum break-even probability of success is about 1 in 4, which might represent insufficient risk cover for some companies, but the result should be considered as an indicator of the minimum commercial field size that Companies could develop if exploration results produced a smaller discovery than originally prognosed.

Marañon Basin – Block E – 250 MMBO
This case shows very attractive investment performance under base case assumptions and shows improved economics under the production-based royalty when compared to the profit-based royalty. Undiscounted profits and present value profits are higher under the production based royalty even though the discounted cash flow rate of return is lower. These results may make it more difficult to select the preferred calculation. The EMV calculation shows that there is exceptional risk cover for this case, with a minimum break-even probability of success of about 1 in 25 under each royalty calculation.

Ucayali Basin – Block A – 100 MMBO
All of the cases for the Ucayali Basin depend on the independent development of offtake infrastructure, assuming that sufficient reserves are identified to support the independent financing of a major trunk pipeline system. We anticipate that this would require some 500 MM bbls of reserves in a number of fields. This case shows attractive investment performance under these assumptions, with an offtake tariff of about $1.40/bbl payable to the third party pipeline system operator. The investment economics are superior under the production based royalty and risk cover is exceptions with a break-even probability of success of about 1 in 25 under the profit-based royalty calculation.

Ucayali Basin – Block A – 50 MMBO
All of the cases for the Ucayali Basin depend on the independent development of offtake infrastructure, with the installation of a major trunk pipeline system. This is a smaller discovery but would represent a commercial development under base case assumptions. Investment performance is marginally better under the production based royalty and risked economics shows that the break-even probability of success is about 1 in 5 under each royalty calculation.

Ucayali Basin – Block B – 175 MMBO
This case shows the most attractive investment performance of all of the cases evaluated in this study. All investment performance measures are superior under the production-based royalty and the risk cover is exceptional with a minimum break-even probability of success of about 1 in 33 under both the production based royalty and profit based royalty.

Ucayali Basin – Block B – 1.7 TCF Gas Field
Like the oil cases, this case is evaluated on the assumption that sufficient gas reserves are discovered, to justify the construction of a trunk pipeline to a gas liquefaction plant at the coast. The gas price is $1.25/MCF which could be consistent with the price obtainable by supplies to a local market but we have not carried out any studies to establish whether there is local market of suitable size. We would anticipate that three such discoveries of this size would be required to justify the cost and contract supplies for the construction of an LNG export facility. This field shows marginal investment performance under these assumptions and the profit based royalty is preferred to the production system. The break-even probability of success is an attractive 1 in 9 under each royalty calculation.

Ucayali Basin – Block C – 50 MMBO
This is a small oil field discovery and would represent a marginal commercial development under base case assumptions. Investment performance is marginally better under the production based royalty and risked economics shows that the break-even probability of success is about 1 in 4 under each royalty calculation.

7. Conclusions

This preliminary economic analysis demonstrates the effects of the proposed changes in the royalty system in Peru. These measures have adjusted the balance of the division of economic benefits, between the State and the investor, in the direction of the investor. It shows how the revised royalty system has improved the economics of some representative field discovery sizes in the main petroleum basins in Peru.

The study demonstrates that the production based royalty is likely to be the main choice of Companies developing discoveries in these basins, but there are significant benefits in the profit based royalty calculation for fields with high development costs. Thus the recent changes to the fiscal terms in Peru represent a significant improvement in terms, but also represent a method to reduce the explorers risk exposure.