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The Long Term Structure of the Taxation System for the UK Continental Shelf

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Research in North Sea Economics has been conducted in the Economics Department since 1973. The present and likely future effects of oil and gas developments on the Scottish economy formed the subject of a long term study undertaken for the Scottish Office. The final report of this study, The Economic Impact of North Sea Oil on Scotland, was published by HMSO in 1978. In more recent years further work has been done on the impact of oil on local economies and on the barriers to entry and characteristics of the supply companies in the offshore oil industry.

The second and longer lasting theme of research has been an analysis of licensing and fiscal regimes applied to petroleum exploitation. Work in this field was initially financed by a major firm of accountants, by British Petroleum, and subsequently by the Shell Grants Committee. Much of this work has involved analysis of fiscal systems in other oil producing countries including Australia, Canada, the United States, Indonesia, Egypt, Nigeria and Malaysia. Because of the continuing interest in the UK fiscal system many papers have been produced on the effects of this regime.

From 1985 to 1987 the Economic and Social Science Research Council financed research on the relationship between oil companies and Governments in the UK, Norway, Denmark and The Netherlands. A main part of this work involved the construction of Monte Carlo simulation models which have been employed to measure the extents to which fiscal systems share in exploration and development risks.

Over the last few years the research has examined the many evolving economic issues generally relating to petroleum investment and related fiscal and regulatory matters. Subjects researched include the economics of incremental investments in mature oil fields, economic aspects of the CRINE initiative, economics of gas developments and contracts in the new market situation, economic and tax aspects of tariffing, economics of infrastructure cost sharing, the effects of comparative petroleum fiscal systems on incentives to develop fields and undertake new exploration, the oil price responsiveness of the UK petroleum tax system, and the economics of decommissioning, mothballing and re-use of facilities. This work has been financed by a group of oil companies and Scottish Enterprise, Energy. The work on CO2 Capture, EOR and storage is also financed by a grant from the Natural Environmental Research Council (NERC).

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b) Prospective Activity Levels in the UKCS to 2035
c) Full Cycle Returns to Exploration and Effects of Tax Incentives
d) Economic and Taxation Aspects of CO2 Capture, Transportation, Injection in fields in UKCS, EOR and Sequestration
   (i) Estimation of (Integrated) Cost Curves for CO_2 Capture, EOR and Sequestration in the UKCS6
   (ii) Taxation and other Incentives for CO_2 Capture, EOR and Sequestration

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The Long Term Structure of the Taxation System for the UK Continental Shelf

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1. Introduction and Context

The system of taxation applied to the UK Continental Shelf (UKCS) has developed in an ad hoc manner with many changes being introduced since the basic framework was established in 1975. The system was designed to collect economic rents from petroleum production to the state. There was general agreement on this as an objective and on the concept of a profit-related fax as the most appropriate instrument for the purpose, but over the years there have been differences of views between the industry and Government on the measurement and size of any economic rents, and consequently on the impact of the tax package on activity levels. In principle a tax on economic rents should mean that it is levied on the returns in excess of the supply price of the investment with no deadweight costs resulting. This concept as applied to the petroleum industry is somewhat elusive, with differences of views being prevalent on the definition of the necessary returns on investment. Thus it has become clear that in the current environment potential investments are examined, compared, and ranked on a world-wide basis by many companies thus a simple rate of return criterion is not suitable to assess the acceptability of projects and thus as a measure of economic rents. The materiality of projects (reflected in the size of net present values (NPVs), and their ranking in terms of capital productivity (reflected in NPV/I ratios) are important and widely employed. But there is no unique minimum size of NPV or NPV/I ratio which are universally employed, just as there are no unique discount rates which are employed. Different companies will have their own corporate costs of capital, risk attitude and premia, capital constraints, and investment opportunities elsewhere, and so they will have different capital rationing cut-off positions.

All the above makes it difficult for a Government to determine the presence and size of any economic rents. The problem is compounded by the uncertainties regarding the future behaviour of the determinants of the size of any economic rents, namely size of discoveries, costs of exploration, development and production, and oil/gas prices. In designing the tax system the Government needs to take a view on these matters, but even a well-informed Government cannot be clairvoyant on these issues, and oil companies in any case are traditionally cagey in revealing their own assumptions regarding future oil prices and other variables affecting profitability and thus their investment decisions. In discussing their objectives Governments are usually quite coy about being very specific and normally refer to the need to secure a reasonable share of oil revenues for the nation. The UK Government has been no exception in this respect.

In the literature on the subject of upstream petroleum taxation there is broad agreement that the system should be profit-related and take into account the need for an adequate return on the risk investment (however defined). The current UK system is wholly profit-related, and so does not suffer from the regressive features of royalties and production taxes still imposed in many jurisdictions. For fields developed since 16th March 1993 there is corporation tax at 30% plus Supplementary Charge (SCT) at 20% with capital allowances for all exploration, appraisal and development being on 100% first year basis, which for taxpaying investors is essentially a cash flow tax. A cash flow tax has advantages for the encouragement of investment as all the key risks (exploration, appraisal, development, oil price, reserves) are fully shared with the Government to the extent of the tax rate. In the literature authors who extolled the virtues of the cash flow tax often wondered whether Governments would wish to share the investment risks to such an extent. New players in the UKCS who have no tax shelter are disadvantaged but they are allowed to carry forward any unused exploration, appraisal and development allowances at 6% compound interest for 6 years. The Norwegian Government has gone further than this and produced a system which is neutral between tax-paying investors and new entrants by providing for cash payments for the latter's exploration and appraisal costs to the extent of the tax rate (currently 78%).

The cash flow tax has the interesting property that its imposition does not reduce the post-tax internal rate of return (IRR) below the pre-tax rate. But the materiality of the returns are reduced, and so the need for judgement by the Government remains. There is only one rate of (combined) corporation tax and SCT in the UK. This means that the Government take or share is proportional to the pre-tax value. In a world where the values of the determinants of profitability were relatively stable this might not matter much, but in the real world where there is major price volatility (with oil and gas price movements not always being in the same direction), and tremendous variations in costs, a single rate of tax cannot accommodate the range of profitability likely to be expected, with the result that one or both parties will feel that the rate is inappropriate.

In these circumstances the conventional solution to the problem is a progressive tax based on the achieved returns from the investment, a device commonly called the resource rent tax. This tax can be based progressively on the achieved returns with one or more schedules of rates of returns and tax rates. Examples in countries employing licensing systems are in Australia, Namibia, and Faroe Islands. In countries employing Production Sharing Contracts the state's share of profit oil is progressively related to the rate of returns, there are examples in Angola, Azerbaijan (AIOC contract), India, and Sakhalin 2. There are also many examples of R-Factor schemes which are in essence proxies for a resource rent tax. Under these the state's share of profit oil (or the tax rate as in the new Irish terms) increases as the ratio of the contractor's accumulated net revenues to his accumulated costs increases.

Successive British Governments have shied away from a progressive system with rates directly linked to the returns on investments with the consequence that there is a loss of a mechanism producing an automatic and appropriate response to changes in operating conditions and profitability. The further consequence is that discretionary changes have to be made. While this gives the Government much jealously-guarded flexibility, it increases the uncertainty of the investment environment. It also produces a situation of near-permanent discussions on the subject between Government and the industry. The well-publicised fact that Government keeps the system under constant review encourages such discussions. But, given the context of major fluctuations in oil prices and cost conditions, it is very unlikely that there can be the fiscal stability which is frequently discussed as a desirable objective. The fundamental problem with corporation tax and the associated SCT is thus how to ensure that they can meet the longer term needs without frequent changes being necessary. Such pressure can come from wither Government or industry depending on who perceives the need for change.

PRT was initially designed to reflect the variations in field profitability likely to be found in the UKCS. The single rate reflected the thinking of the time (which has remained unchanged), and to make the system progressive several complex allowances were attached to it. The surprising abolition of the tax for new fields in March 1993 reflected the view that it was not necessary to impose any tax other than corporation tax on such new fields. The lack of an automatic mechanism to collect some of the perceived upside potential from the increase in oil prices in recent years led to the discretionary introduction of the SCT in 2002 and its increase from January, 2006.

Meanwhile PRT applies only to a minority of fields developed prior to March 16th 1993. Thus in the first half of 2005 only 31 fields paid the tax of which 8 paid around two-thirds of the total.[1] While current high oil prices have kept up the PRT revenues to substantial levels the depletion of the fields in question is such that in a few years time the revenues will fall to relatively low levels. Further, the cessation of production of older PRT-liable fields means that substantial decommissioning relief will become due, eventually leading to a negative net PRT position. It is unlikely that the UK Government would find this a desirable situation, and this forms the background to much of the consultation document issued by the Treasury.[2] This considered in particular the notion of abolition of PRT. There are several ways by which this could be achieved, and, in line with the consultation document, attention has been given here to two cases. The first is where PRT is abolished at the point when the remaining revenues from PRT equal the expected amount of PRT relief for decommissioning. The second is where a PRT buy-out scheme is introduced whereby the licensees buy themselves out of PRT by making a schedule of payments to cover their remaining PRT liabilities minus the relief for decommissioning. In line with a different possibility also envisaged in the discussion paper, namely that PRT would not be abolished, but reformed, a case where the PRT rate is reduced but the volume allowance, uplift allowance and tariff receipts allowance (TRA) are abolished, is also considered.

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[1] See J. Evans, “North Sea Taxes” in J. Wils and E. C. Neilson (eds.) The Technical and Legal Guide to the UK Oil and Gas Industry, Aberlour Press, 2007, p.268

[2] H M Treasury, The North Sea Fiscal Régime: a Discussion Paper, March, 2007

While oil prices are currently relatively high gas prices are currently at quite modest level. Further, investment and operating costs have increased dramatically in recent years. Given the relatively small sizes of fields in most parts of the UKCS the result is that costs per boe are now very high. Thus in the Southern North Sea (an area where absolute costs are relatively low) the average field lifetime development and operating costs now exceed $20 per boe. In the Central North Sea the average field costs now exceed $25 per boe, while in the Northern Waters they exceed $27 per boe.

Accordingly, in this study the question of the extent to which the current tax system was inhibiting new developments was examined, and the effects of various tax concessions were assessed. The concessions examined included (1) reductions in the rate of SCT applied to new fields, and (2) the introduction of a volume allowance for SCT on new fields with the tax rate remaining unchanged. In recognition of the particular current problem of relatively low gas prices, further cases were examined where volume allowances for the SCT were given only for (predominantly) gas fields of only modest sizes (in terms of reserves).

2. Criteria for Assessment of Taxation Changes

The effects of taxation relating to the collection of economic rents from petroleum exploitation are best considered by their impact on activity levels in the sector. As noted above economic rents are defined as returns in excess of those required to sustain the activity. There should thus be no deadweight loss as a consequence of the imposition of special taxation. The nation's GDP and the producer's surplus are reduced if projects are deterred by taxation. In the present context the maximisation of these should be the primary goal. Economic production can be defined on a pre-tax basis, but in the present exercise it has been defined in relation to a base with corporate taxation at 30%. Thus any loss of economic production caused by taxation in excess of this can be termed the deadweight loss to the nation.

In discussions of this subject in the UK and elsewhere emphasis has often been given to the effects of tax changes on the total tax revenues from oil and gas production. Any loss of tax revenues from a tax change has been referred to as a deadweight loss. It should be emphasised that conceptually this is not the most appropriate measure of deadweight loss, which, as noted above, should refer to the reduction of producer's surplus and GDP. Changes to tax revenues are a distributional matter. They relate to the distribution of the national output between the industry and Government. Maximisation of national output (economic recovery) should be the prime aim, and the petroleum tax system should be designed to comply with this objective. A petroleum tax system which reduces economic output means that it is collecting more than 100% of the economic rents.

In the present study the examination of the effects of tax changes have reflected the above thinking. Thus variations in economic production and changes to total tax revenues have been highlighted.

3. Modelling Methodology and Assumptions

The projections of production and expenditures have been made through the use of financial simulation modelling, including the use of the Monte Carlo technique, informed by a large, recently-updated, field database validated by the relevant operators. The field database incorporates key, best estimate information on production, and investment, operating and decommissioning expenditures. These refer to over 300 sanctioned fields, 90 incremental projects

(61 probable and 29 possible) relating to these fields, 29 probable fields, and 25 possible fields. All these are as yet unsanctioned but are currently being examined for development. An additional database contains 227 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas) and block location are available for these. They are not currently being examined for development by licensees.

Monte Carlo modelling was employed to estimate the possible numbers of new discoveries in the period to 2030. The modelling incorporated assumptions based on recent trends relating to exploration effort, success rates, sizes, and types (oil, gas, condensate) of discovery. A moving average of the behaviour of these variables over the past 10 years was calculated separately for 6 areas of the UKCS (Southern North Sea, (SNS), Central North Sea (CNS), Moray Firth (MF), Northern North Sea (NNS), West of Scotland (WOS), and Irish Sea (IS)), and the results employed for use in the Monte Carlo analysis. Because of the very limited data for WOS and IS over the period judgemental assumptions on success rates and average sizes of discoveries were made for the modelling.

It is postulated that the exploration effort depends substantially on a combination of (a) the expected success rate, (b) the likely size of discovery, and (c) oil/gas prices. In the present study 4 future oil/gas price scenarios were employed as follows:

Table 1

Future Oil and Gas Price Scenarios

	Oil Price (real) $/bbl	Gas Price)real) pence/therm
High	50	40
Medium	45	36

Low	35	28
Very Low	30	18

These values are below current market levels but are used to reflect values generally used by investors when assessing long-term investments.

The postulated numbers of annual exploration wells for the whole of the UKCS are as follows:

Table 2 **Exploration Wells**		
	2007	2030
High	45	35
Medium	40	32
Low	30	22
Very Low	25	18

The annual numbers are modelled to decline in a linear fashion over the period.

It is postulated that success rates depend substantially on a combination of (a) recent experience, and (b) size of the effort. It is further suggested that higher effort is associated with more discoveries but with lower success rates compared to reduced levels of effort. This reflects the view that low levels of effort will be concentrated on the lowest risk prospects, and thus that higher effort involves the acceptance of higher risk. For the UKCS as a whole 4 success rates were postulated as follows:

Table 3 Success Rates
Medium effort/Medium success rate = 23%
Very High effort/Very Low success rate = 18%
High effort/Low success rate = 19%
Low effort/High success rate = 24%

It is assumed that technological progress will maintain these success rates over the time period.

The mean sizes of discoveries made in the historic period for each of the 6 regions were calculated. They are shown in table 4. It was then assumed that the mean size of discovery would decrease in line with recent historic experience. Such decline rates are quite modest.

Table 4 Mean Discovery Size MMboe	
SNS	13
CNS	27
NNS	21
MF	40
WoS	80
IS	5

For purposes of the Monte Carlo modelling of new discoveries the SD was set at 50% of the mean value. In line with historic experience the size distribution of discoveries was taken to be lognormal.

Using the above information the Monte Carlo technique was employed to project discoveries in the 6 regions to 2030. For the whole period the total numbers of discoveries for the whole of the UKCS were are follows:

Table 5 **Total Number of Discoveries to 2030**	
Very High Effort/Very Low Success Rate	177
High Effort/Low Success Rate	165
Medium Effort/Medium Success Rate	144
Low Effort/High Success Rate	126

For each region the average development costs (per boe) of fields in the probable and possible categories were calculated. These reflect substantial cost inflation over the last few years. Using these as the mean values the Monte Carlo technique was employed to calculate the development costs of new discoveries. A normal distribution with a SD = 20% of the mean value was employed. For the whole of the UKCS the average development costs on this basis were $11.72/boe with quite a wide variation. Operating costs over the lifetime of the fields were also calculated, as were the decommissioning costs. Total lifetime field costs were found to average well over $21 per boe, and were over $20 per boe in the SNS, nearly $24 per boe in the CNS and $27 per boe in the NNS.

For new discoveries annual operating costs were modelled as a percentage of accumulated development costs. This percentage varied according to field size. It was taken to increase as the size of the field was reduced reflecting the presence of economies of scale in the exploitation costs of fields.

With respect to fields in the category of technical reserves it was recognised that many have remained undeveloped for a long time, so the mean development costs in each of the basins was set at $1/bbl higher than for the new exploration finds. For purposes of Monte Carlo modelling a normal distribution of the recoverable reserves for each field with a SD = 50% of the mean was assumed. With respect to development costs the distribution was assumed to be normal with a SD = 20% of the mean value.

The annual numbers of new field developments were assumed to be constrained by the physical and financial capacity of the industry. This subject is currently very pertinent in the UKCS. The ceilings were assumed to be linked to the oil/gas scenarios with maxima of 20, 20, 17 and 13 respectively under the High, Medium, Low and Very Low Price Cases. These constraints do <u>not</u> apply to incremental projects which are additional to new field developments. To put these assumptions in perspective 13 new fields received development approval in 2005 and less in 2006, but in the 1990's significantly higher numbers (around 20 per year) were achieved.

A noteworthy feature of the 112 incremental projects in the database validated by operators is the expectation that the great majority will be executed over the next 3 or 4 years. It is virtually certain that in the medium and longer-term many further incremental projects will be designed and executed. They are just not yet at the serious planning stage. Such projects can be expected not only on currently sanctioned fields but <u>also</u> on those presently classified as in the categories of probable, possible, technical reserves and future discoveries.

Accordingly, estimates were made of the potential extra incremental projects from all these sources. Examination of the numbers of such projects and their key characteristics (reserves and costs) being examined by operators over the past 5 years indicated a decline rate in the volumes. On the basis of this, and from a base of the information of the key characteristics of the 90 projects in the database, it was felt that, with a decline rate reflecting historic experience, further portfolios of incremental projects could reasonably be expected. As noted above such future projects would be spread over all categories of host fields. Their sizes and costs reflect recent trends.

The financial modelling incorporated a discount rate, field economic cut-off, and the full details of the current petroleum tax system. The base case emphasised has a post-tax discount rate of 10% in real terms. An important assumption is that adequate infrastructure will be available to facilitate the development of the future projects. It is also assumed that investment decisions are made on the basis of the oil/gas prices indicated. When the prospective investments in probable and possible fields and incremental projects were subjected to economic analysis it was found that most were quite small and the returns in terms of NPVs were correspondingly often small Investors have expressed concern abut the materiality of projects in the UKCS compared to opportunities elsewhere in the world, and, to reflect these, two alternative investment criteria were used to reflect the relationship between the risks and rewards and capital allocations. The first was a minimum NPV of £10 million at the 10% real discount rate. The second was a minimum NPV/I ratio of 0.3 ((NPV/I) +1≥1.3). I was expressed in pre-tax terms to reflect the manner in which capital is allocated by investors (rather than the textbook approach which has both NPV and I on a post-tax basis).

4. Possible Tax Incentives for New Developments

(a) Reduction in Rate of SCT for New Developments

A simple way of encouraging new developments would be to reduce the tax rate applied to these. The effects were examined of reducing the CT + SCT liability from 50% to 40% and 30% for the Probable, Possible, Technical Reserve fields and new discoveries.

(i) Changes in Number of Producing Fields

Chart 1

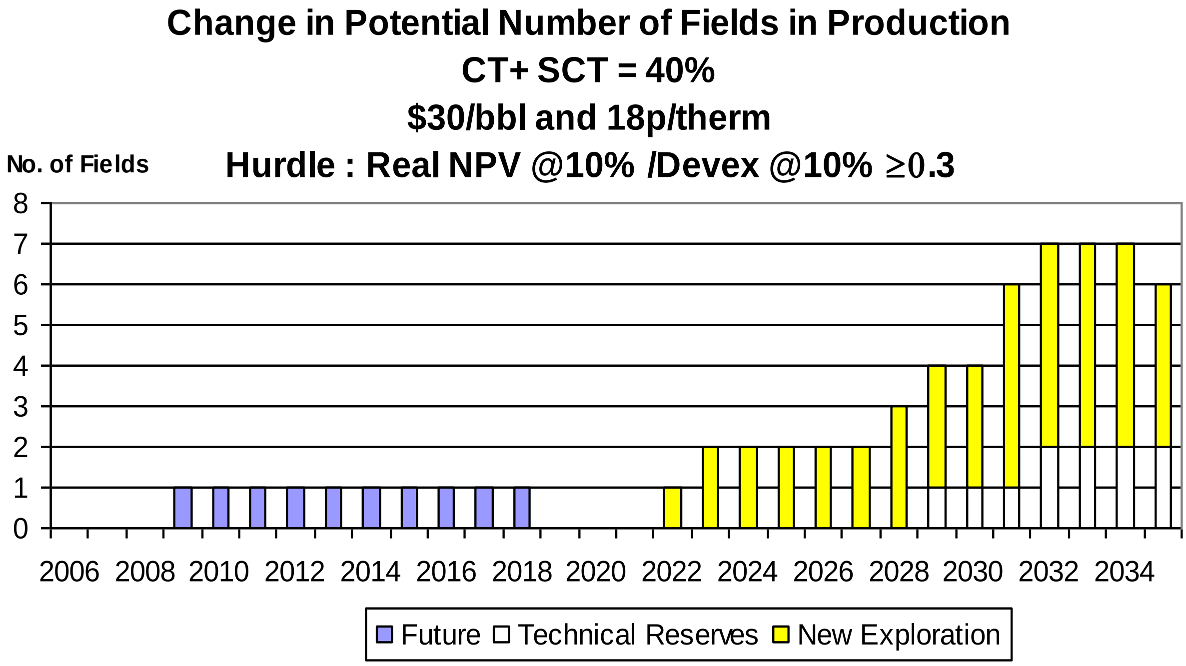


Chart 1 shows the change in potential number of fields in production at the very low price when CT + SCT is reduced to 40% using the NPV/I hurdle rate. With the NPV/I hurdle, over the period to 2035, 1 more probable/possible field, 2 more technical reserve fields and 5 more new discoveries would be developed.

Chart 2

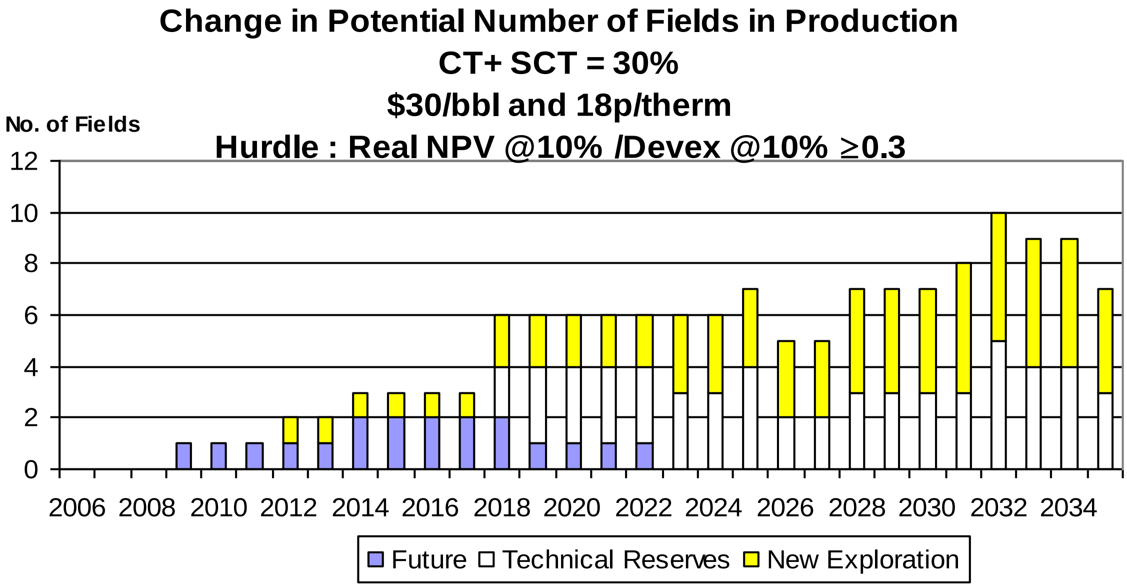


Chart 3

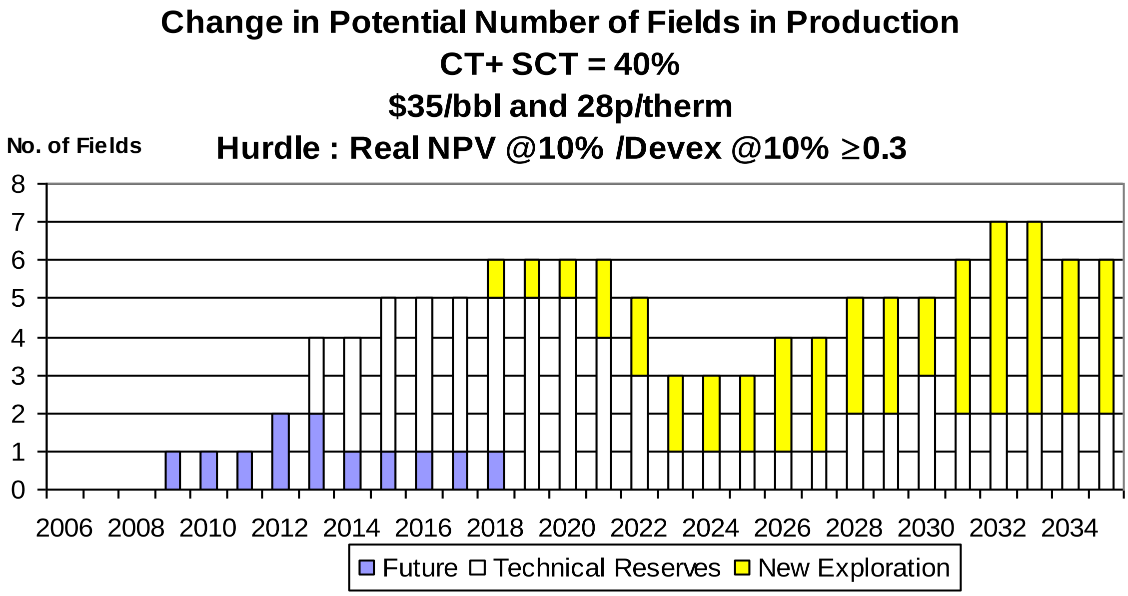


Chart 2 shows the change in potential number of fields in production at the very low price when CT + SC is reduced to 30% using the NPV/I hurdle rate. Over the period to 2035, 2 more probable/possible fields, 8 more technical reserve fields and 7 more new exploration fields would be developed if the tax rate was reduced to 30%.

Chart 3 shows the change in potential number of fields in production at the low price when CT + SCT is reduced to 40% using the NPV/I hurdle rate. Two more probable/possible fields, 7 more technical reserve fields and 6 more new discoveries would be developed.

Chart 4

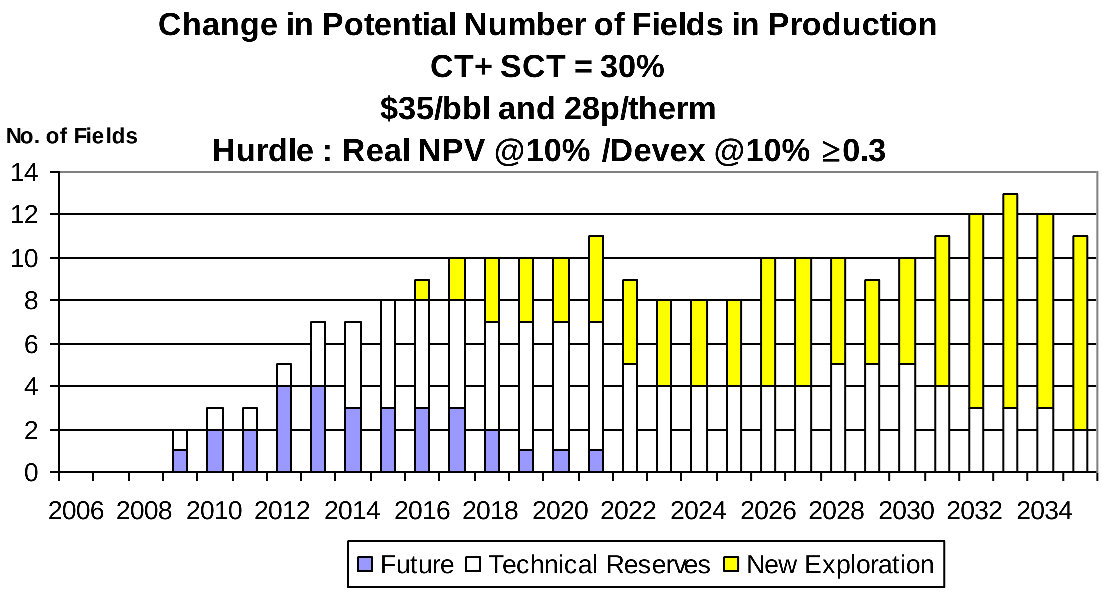


Chart 4 shows the change in potential number of fields in production at the low price when CT + SCT is reduced to 30% using the NPV/I hurdle rate. With the NPV/I hurdle, over the period to 2035, 4 more probable/possible fields, 11 more technical reserve fields and 13 more new discoveries would be developed.

Chart 5

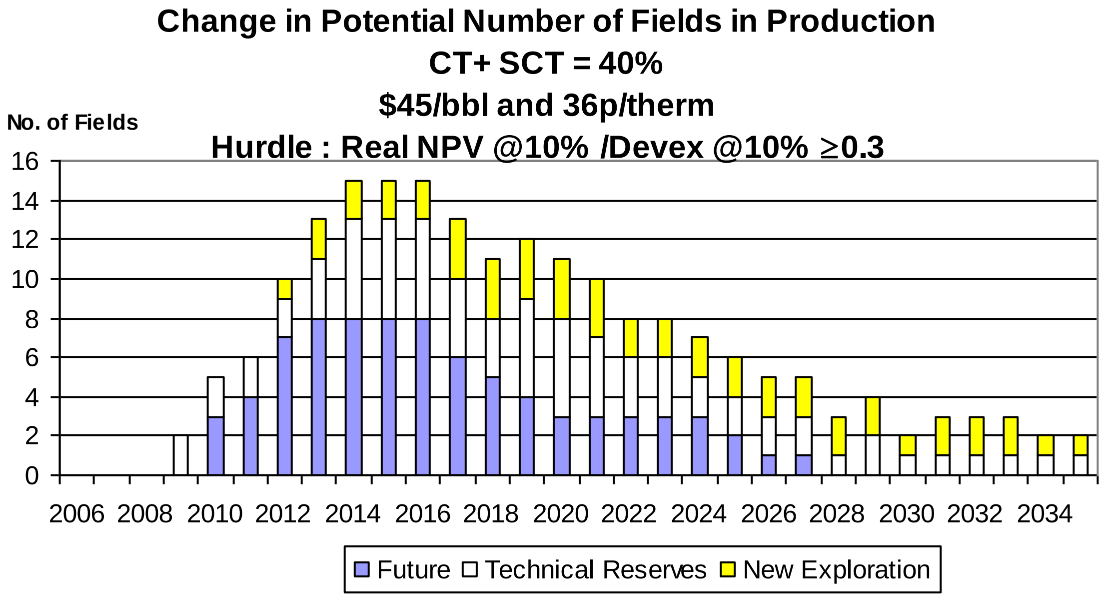


Chart 5 shows the change in potential number of fields in production at the medium price when CT + SCT is reduced to 40% using the NPV/I hurdle rate. Over the period to 2035, 7 more probable/possible fields, 8 more technical reserve fields and 5 more new exploration fields would be developed.

Chart 6 shows the change in potential number of fields in production at the medium price when CT + SCT is reduced to 30% using the NPV/I hurdle rate. Over the period to 2035, 8 more probable/possible fields, 18 more technical reserve fields and 10 more new discoveries would be developed.

Chart 6

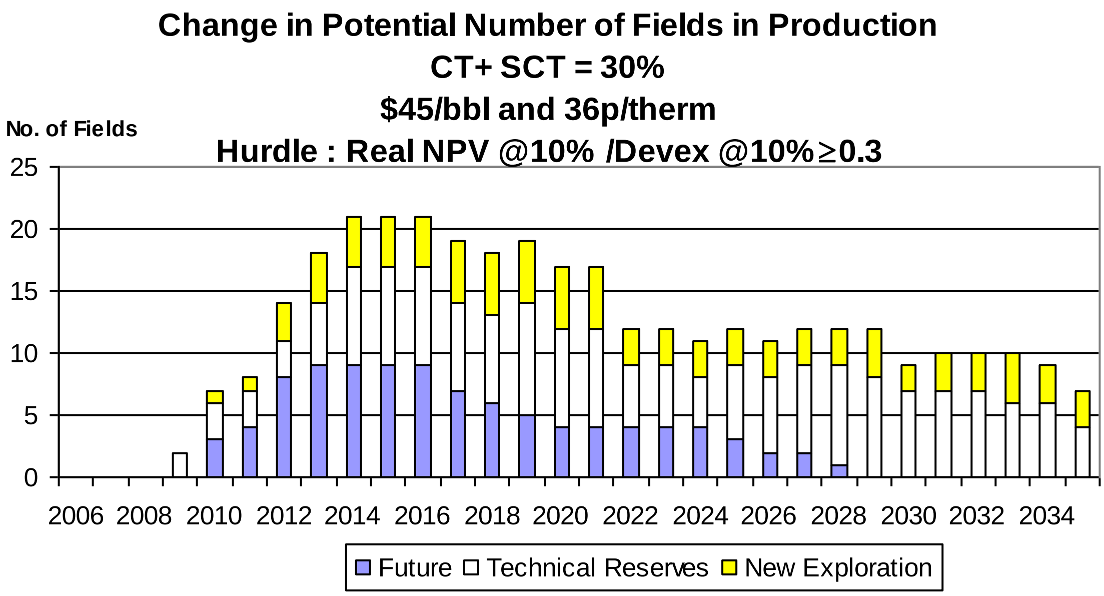


Chart 7

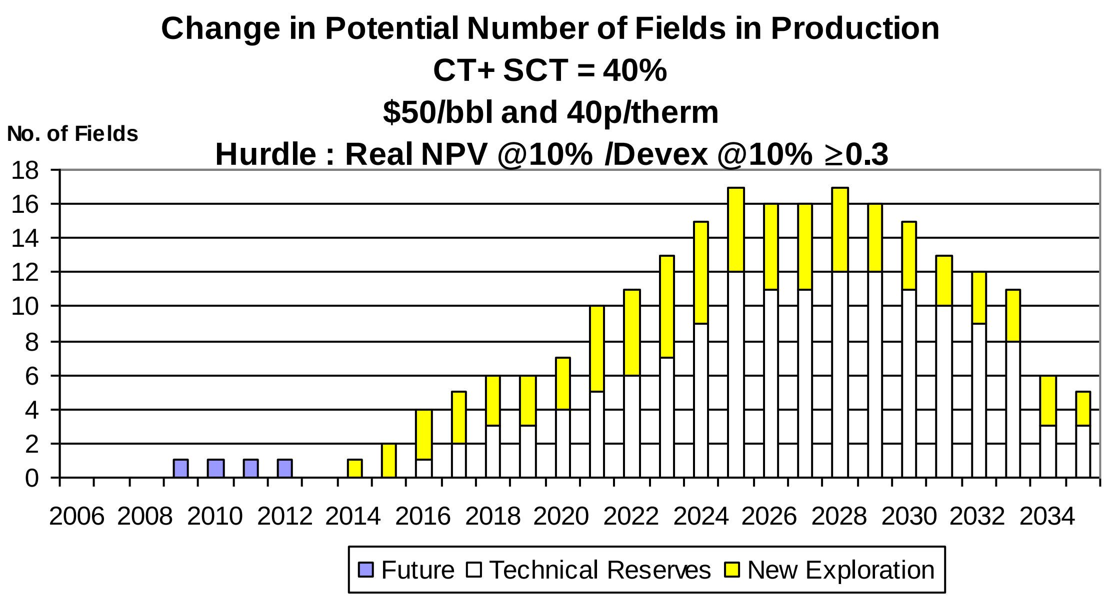


Chart 7 shows the change in potential number of fields in production at the high price when CT + SCT is reduced to 40% using the NPV/I hurdle rate. Over the period to 2035, 1 more probable/possible field, 14 more technical reserve fields and 9 more new discoveries would be developed.

Chart 8

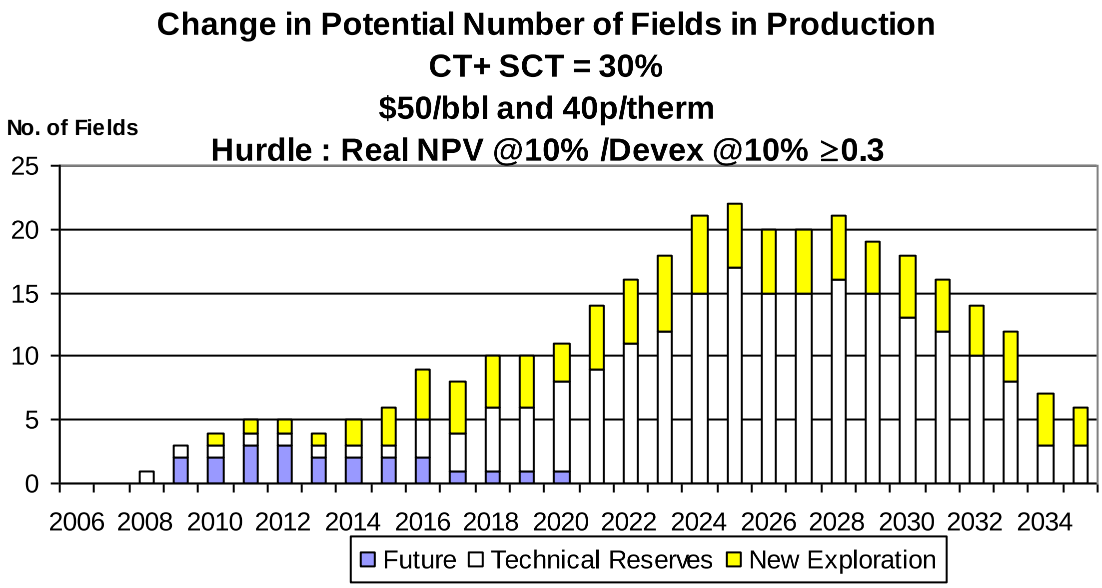


Chart 8 shows the change in potential number of fields in production at the high price when CT + SCT is reduced to 30% using the NPV/I hurdle rate. Over the period to 2035, 3 more future fields, 21 more technical reserve fields and 11 more new discoveries would be developed.

(ii) Changes in Production

Chart 9 shows the potential change in hydrocarbon production at the very low price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, production may increase by 5.5 mboe for the future fields, 27.6 mboe for the technical reserve fields, 146 mboe for the new exploration fields, with a total of 179 mboe for all fields.

Chart 9

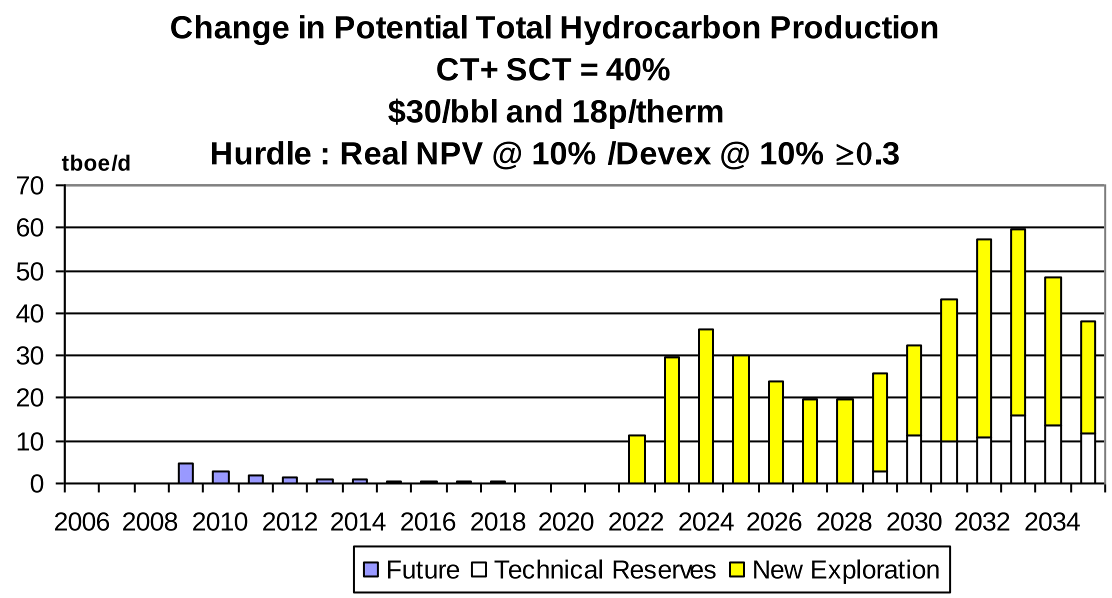


Chart 10

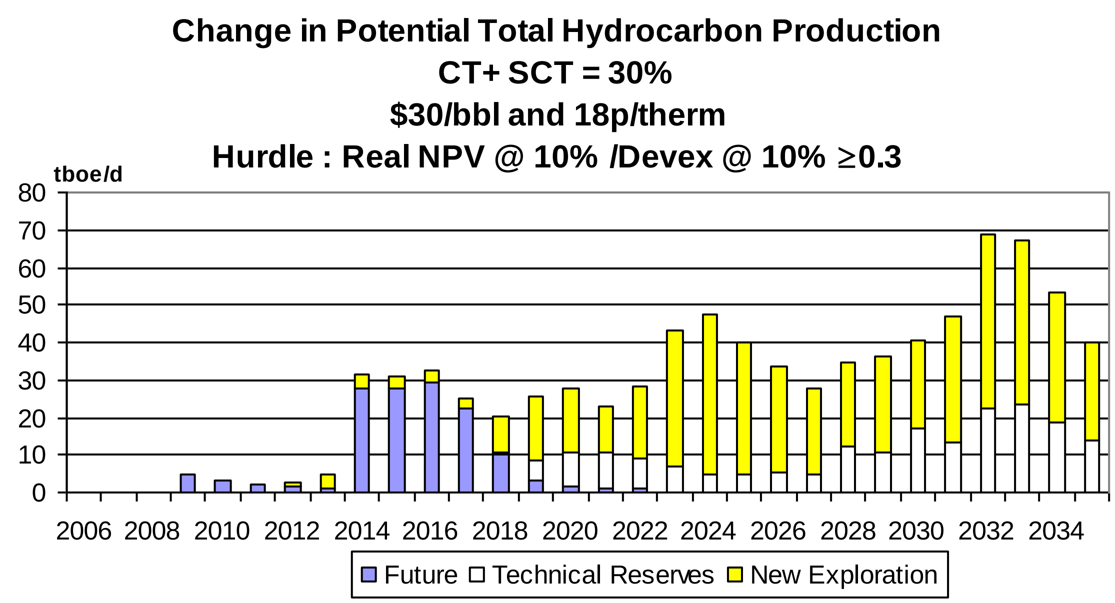


Chart 10 shows the potential change in hydrocarbon production at the very low price when the CT + SCT rate is reduced to 30% with the hurdle NPV/I. Over the period to 2035, production may increase by 49.9 mboe for the future fields, 69.3 mboe for the technical reserve fields, 188.1 mboe for the new exploration fields, with a total of 307.1 mboe for all fields.

Chart 11

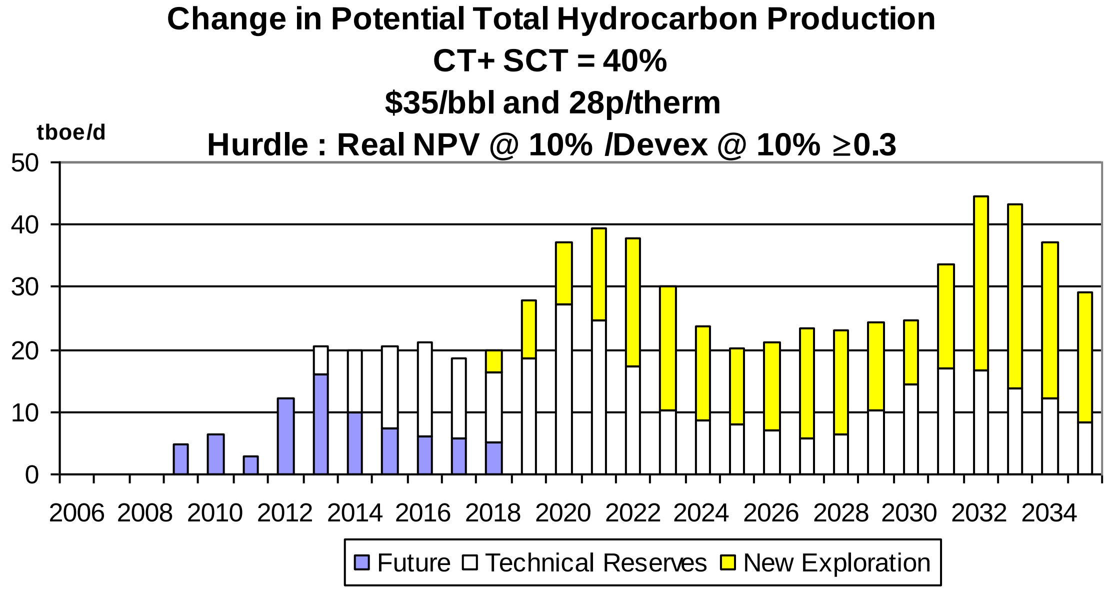


Chart 11 shows the potential change in hydrocarbon production at the low price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, production may increase by 27.9 mboe for the future fields, 106.8 mboe for the technical reserve fields, 108.8 mboe for the new exploration fields, with a total of 243.6 mboe for all fields.

Chart 12

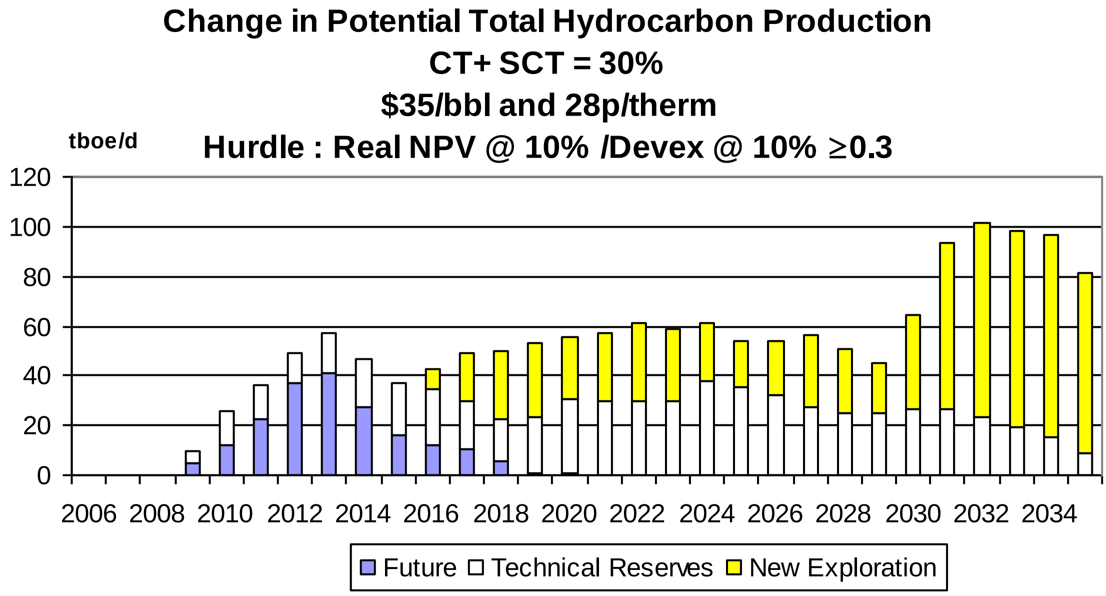


Chart 12 shows the potential change in hydrocarbon production at the low price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, production may increase by 69.4 mboe for the future fields, 219.8 mboe for the technical reserve fields, 274.4 mboe for the new exploration fields, with a total of 563.6 mboe for all fields.

Chart 13

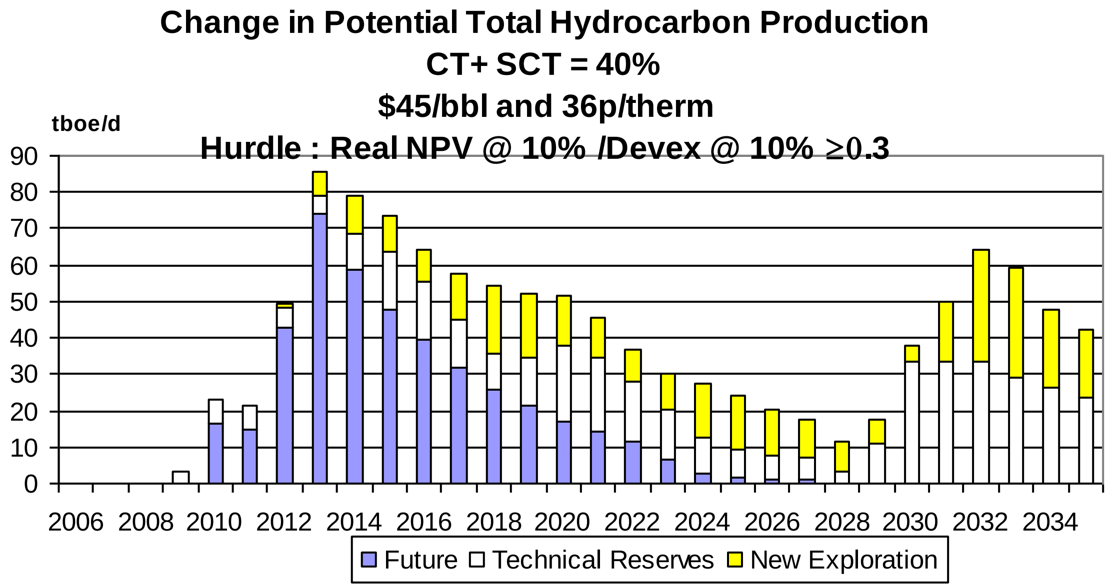


Chart 13 shows the potential change in hydrocarbon production at the medium price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, production may increase by 156.5 mboe for the future fields, 146.3 mboe for the technical reserve fields, 116 mboe for the new exploration fields, with a total of 418.8 mboe for all fields.

Chart 14

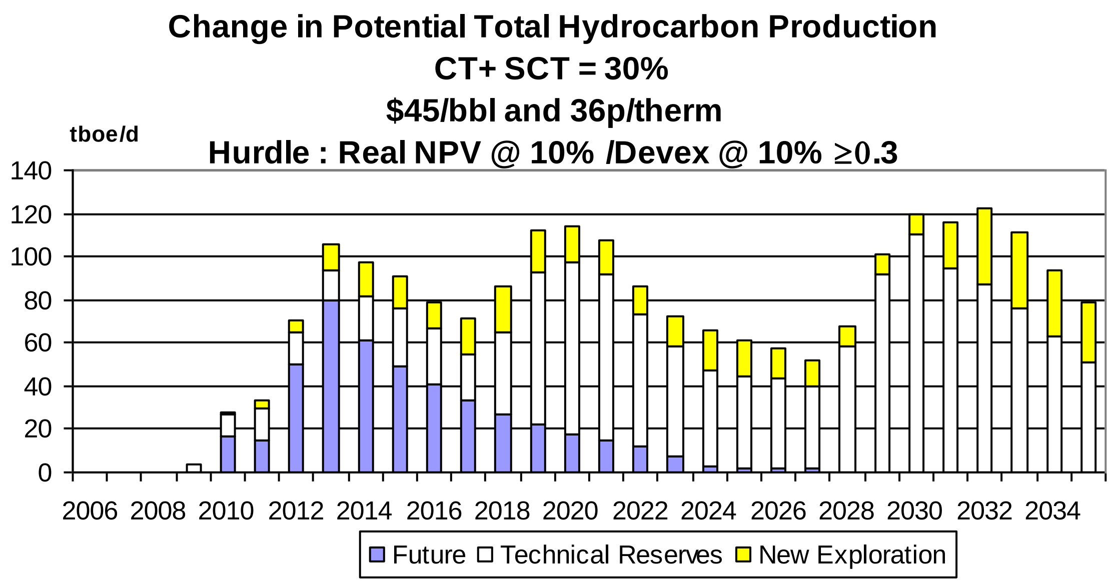


Chart 14 shows the potential change in hydrocarbon production at the medium price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, production may increase by 166.5 mboe for the future fields, 485.1 mboe for the technical reserve fields, 153.4 mboe for the new exploration fields, with a total of 805 mboe for all fields.

Chart 15

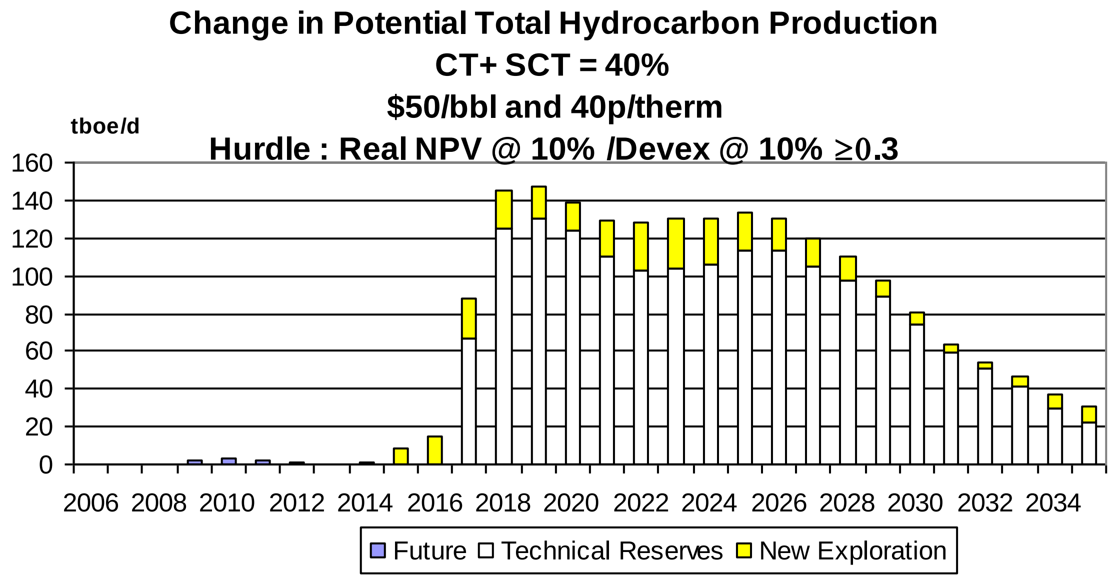


Chart 15 shows the potential change in hydrocarbon production at the high price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, production may increase by 2.9 mboe for the future fields, 607.4 mboe for the technical reserve fields, 111 mboe for the new exploration fields, with a total of 721.3 mboe for all fields.

Chart 16

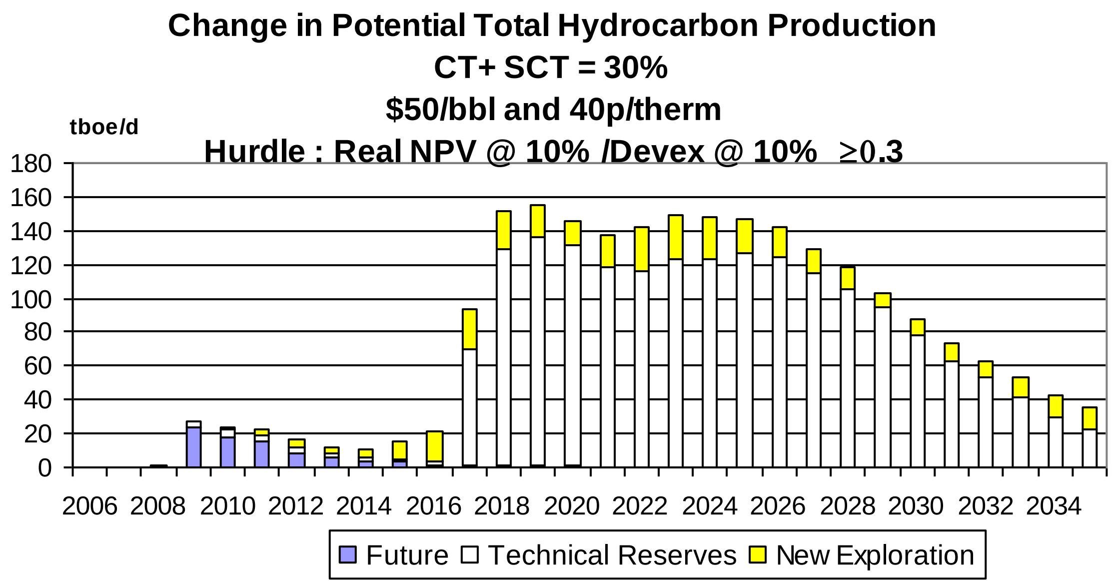


Chart 16 shows the potential change in hydrocarbon production at the high price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, production may increase by 30.4 mboe for the future fields, 664.5 mboe for the technical reserve fields, 132.5 mboe for the new exploration fields, with a total of 827.1 mboe for all fields.

(iii) Changes in Development Expenditures

Chart 17

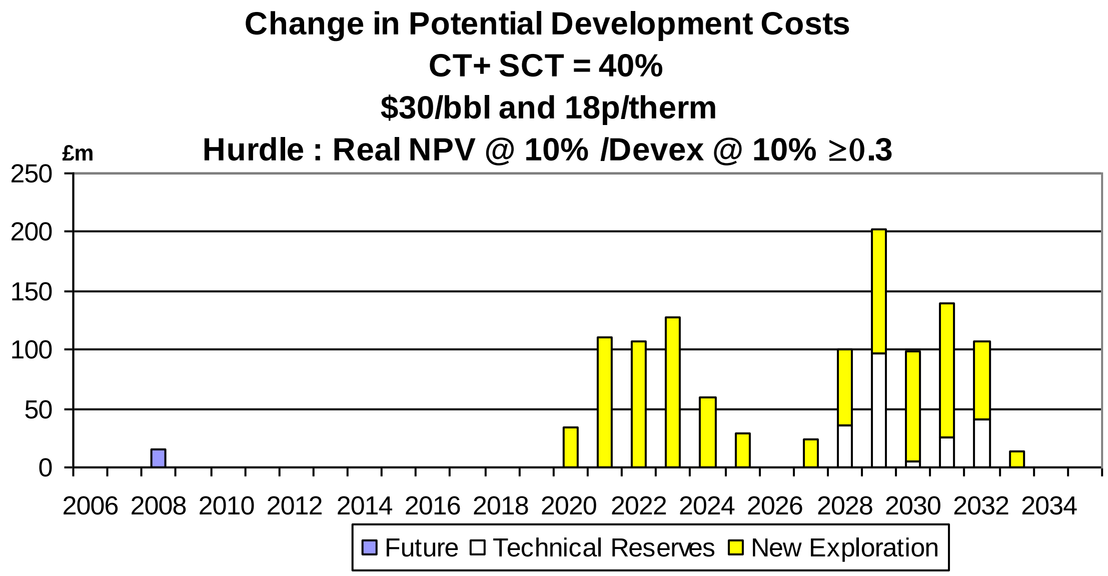


Chart 17 shows the potential change in development costs at the very low price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, production may increase by £16m for the future fields, £206m for the technical reserve fields, £949m for the new exploration fields, with a total of £1171m for all fields.

Chart 18

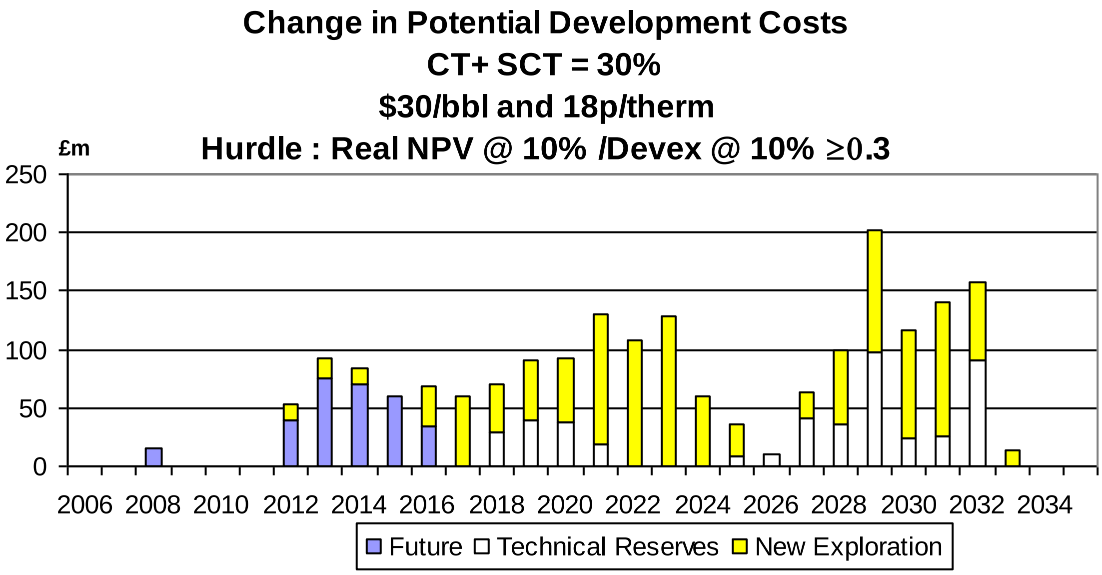


Chart 18 shows the potential change in development costs at the very low price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, they may increase by £296m for the future fields, £459m for the technical reserve fields, £1200m for the new exploration fields, with a total of £1955m for all fields.

Chart 19

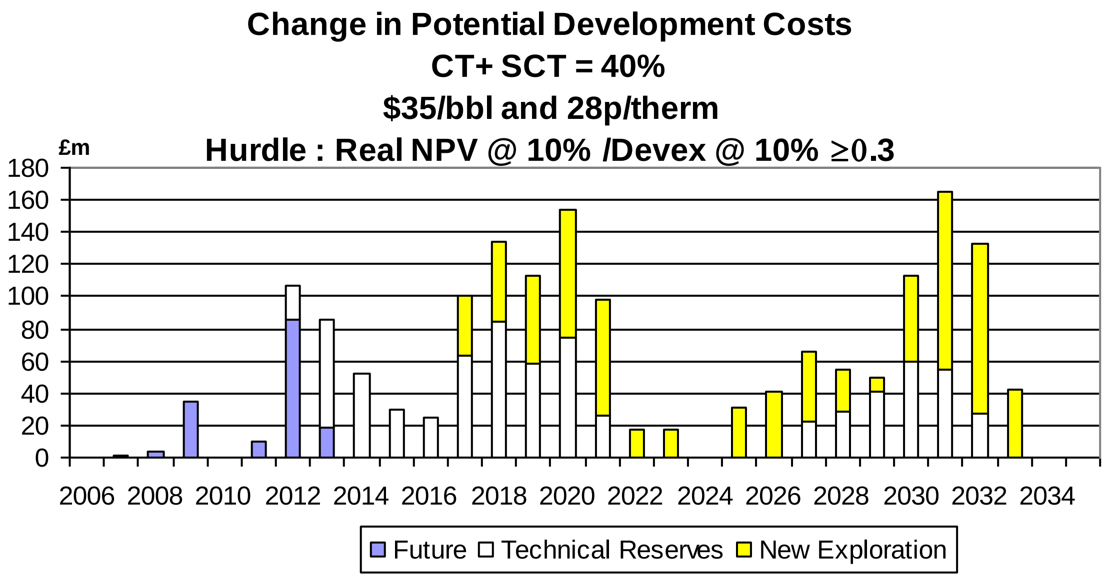


Chart 19 shows the potential change in development costs at the low price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, they may increase by £155m for the future fields, £735m for the technical reserve fields, £789m for the new exploration fields, with a total of £1679m for all fields.

Chart 20

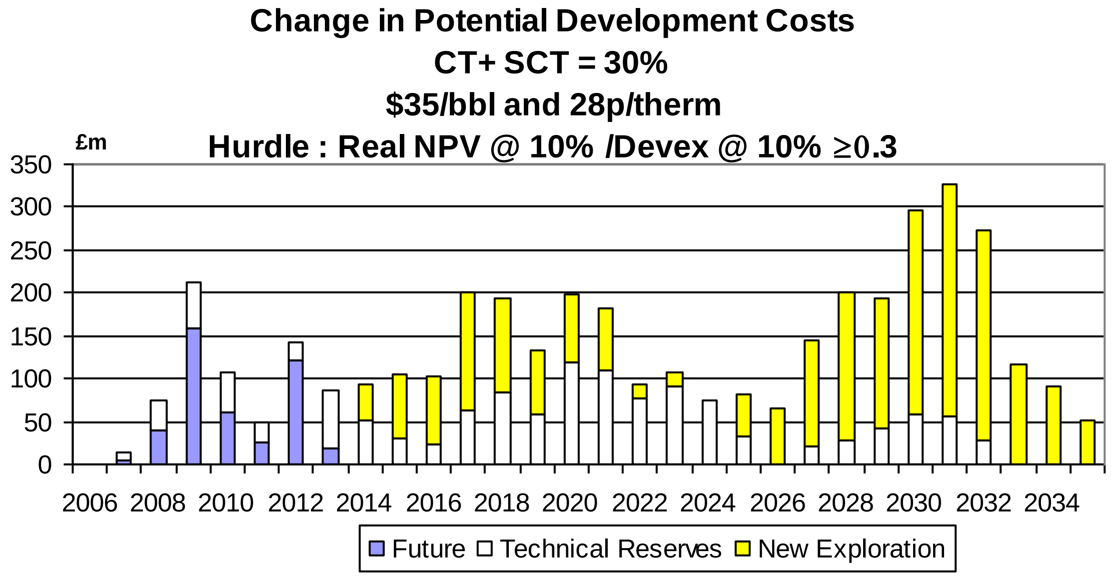


Chart 20 shows the potential change in development costs at the low price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, they may increase by £428m for the future fields, £1309m for the technical reserve fields, £2275m for the new exploration fields, with a total of £4012m for all fields.

Chart 21

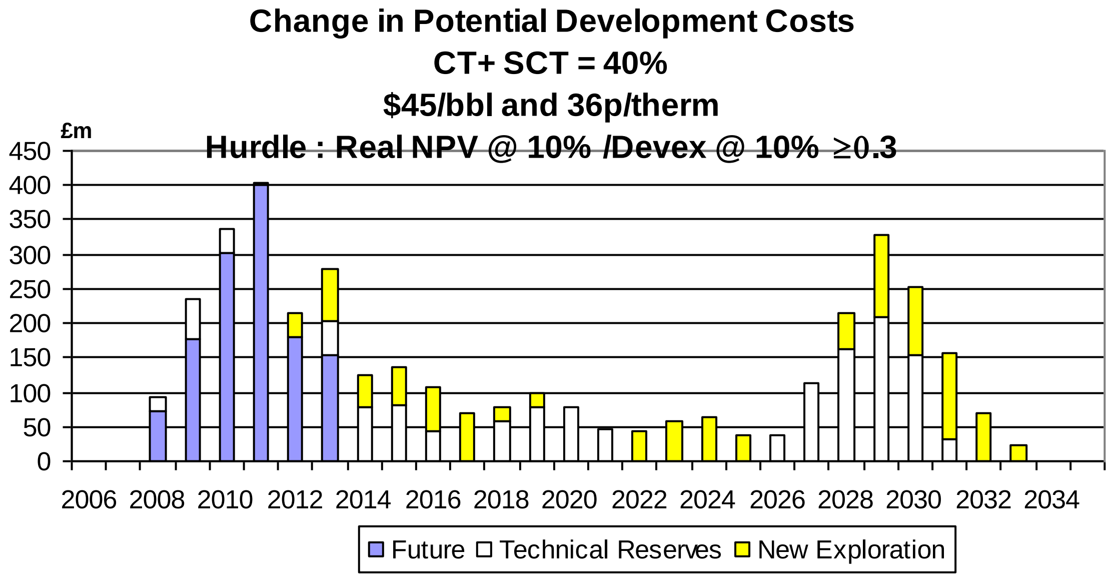


Chart 21 shows the potential change in development costs at the medium price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, they may increase by £1287m for the future fields, £1337m for the technical reserve fields, £1079m for the new exploration fields, with a total of £3703m for all fields.

Chart 22

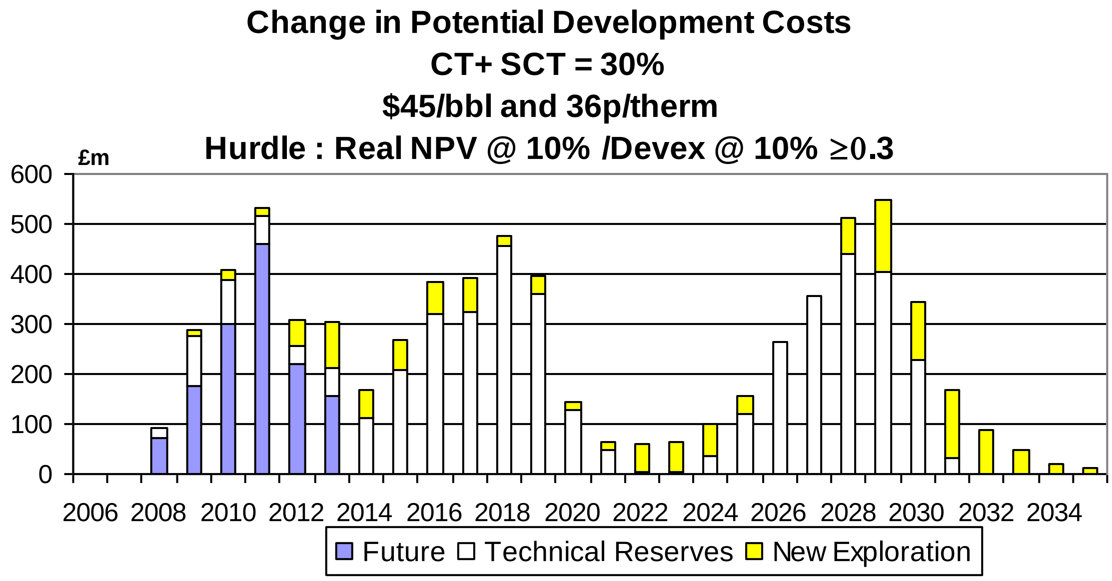


Chart 22 shows the potential change in development costs at the medium price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, they may increase by £1386m for the future fields, £4205m for the technical reserve fields, £1365m for the new exploration fields, with a total of £6956m for all fields.

Chart 23

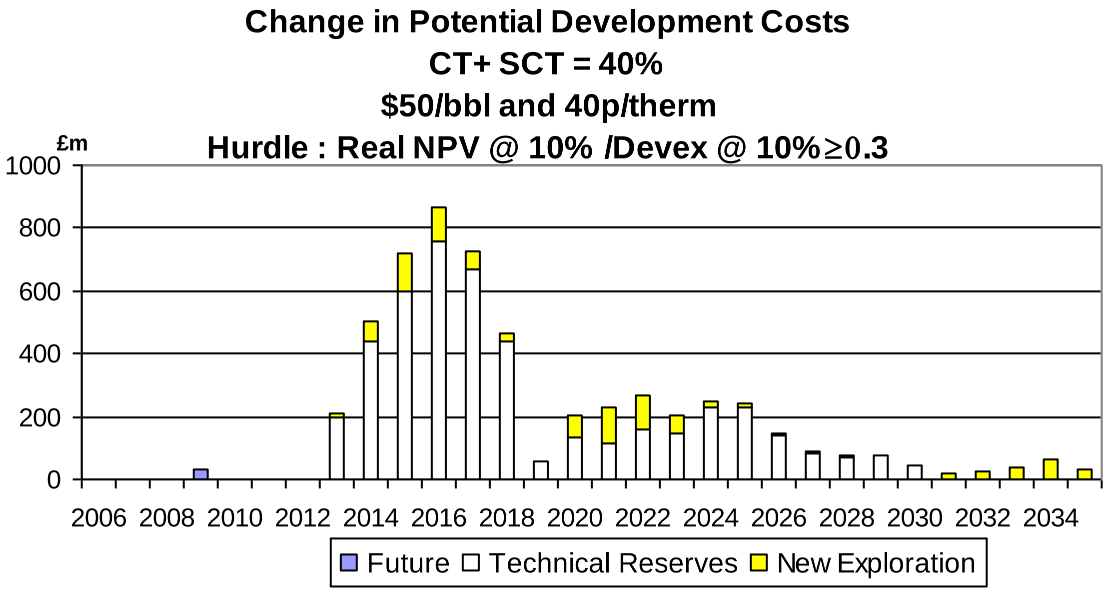


Chart 23 shows the potential change in development costs at the high price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, they may increase by £30m for the future fields, £4581m for the technical reserve fields, £952m for the new exploration fields, with a total of £5563m for all fields.

Chart 24

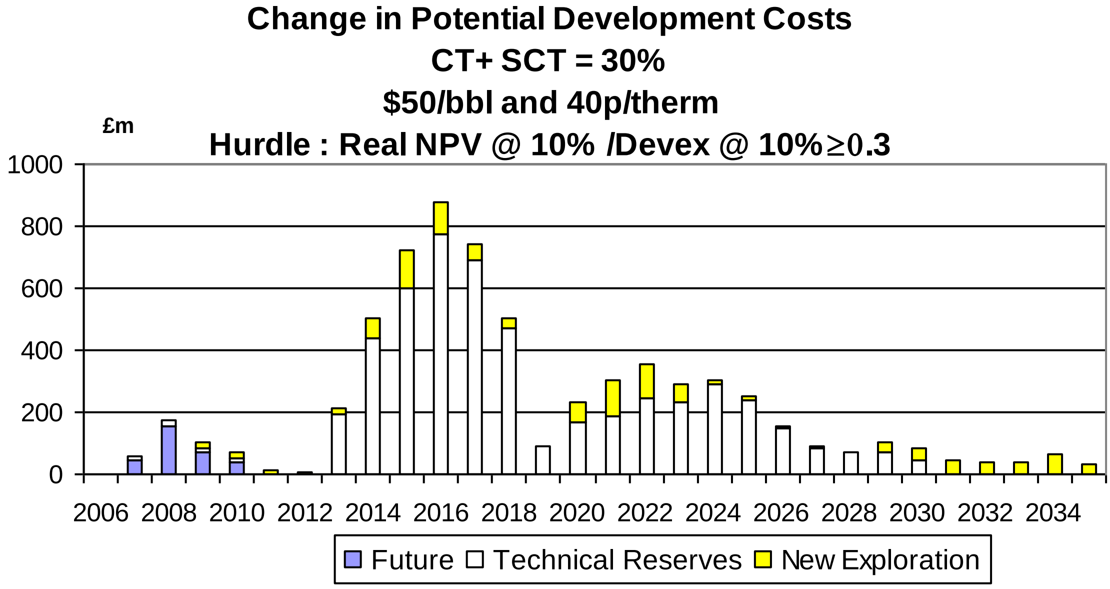


Chart 24 shows the potential change in development costs at the high price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, they may increase by £313m for the future fields, £5095m for the technical reserve fields, £1132m for the new exploration fields, with a total of £6540m for all fields.

(iv) Changes in Operating Expenditures

Chart 25 shows the potential change in operating costs at the very low price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, they may increase by £24m for the future fields, £54m for the technical reserve fields, £670m for the new exploration fields, with a total of £748m for all fields.

Chart 25

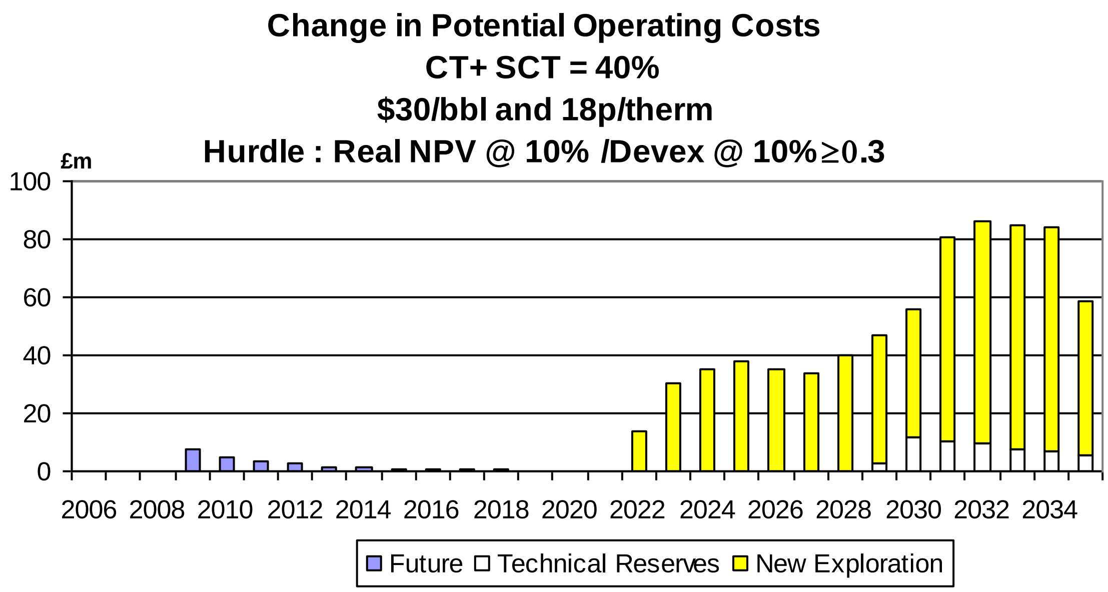


Chart 26

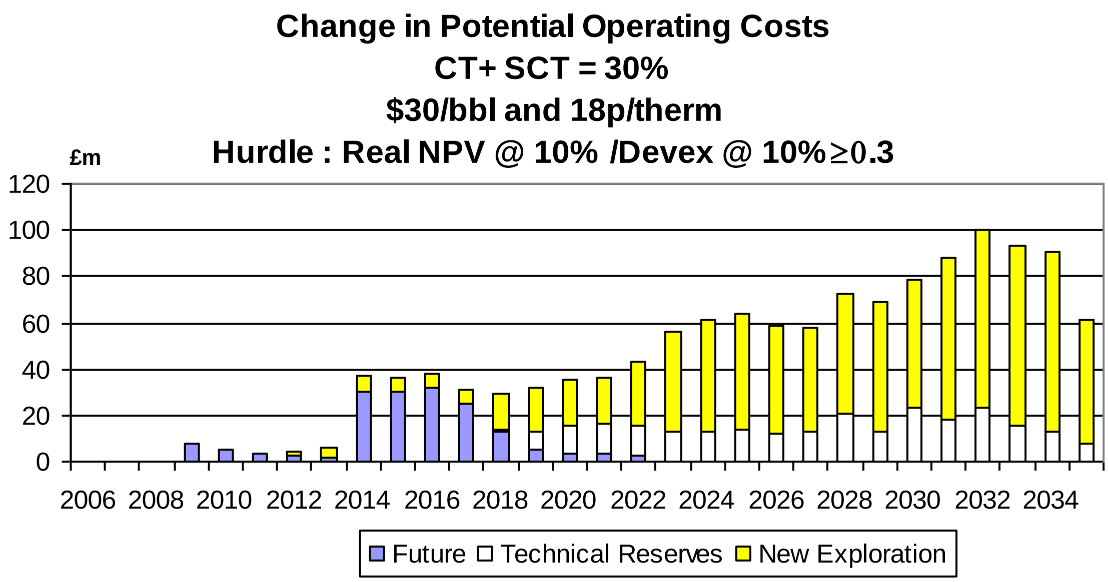


Chart 26 shows the potential change in operating costs at the very low price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, they may increase by £166m for the future fields, £245m for the technical reserve fields, £885m for the new exploration fields, with a total of £1295m for all fields.

Chart 27

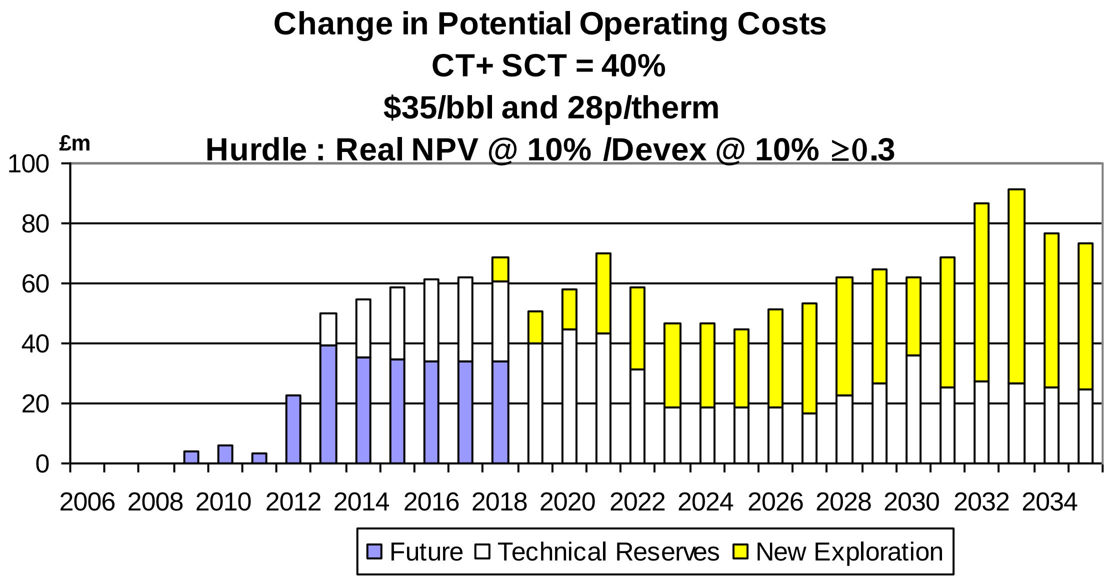


Chart 27 shows the potential change in operating costs at the low price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, they may increase by £247m for the future fields, £600m for the technical reserve fields, £610m for the new exploration fields, with a total of £1457m for all fields.

Chart 28

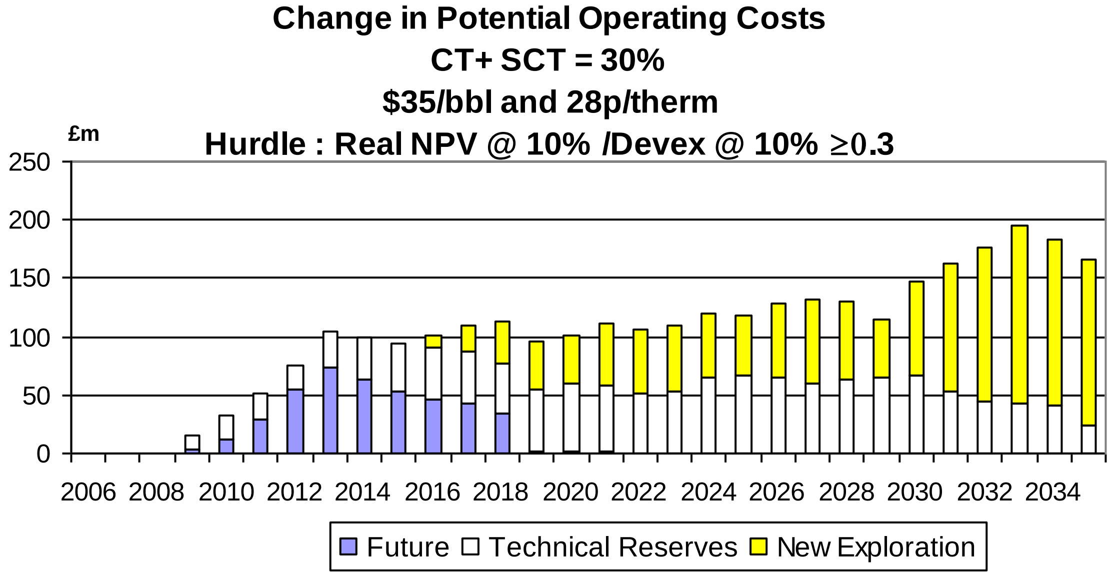


Chart 28 shows the potential change in operating costs at the low price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, they may increase by £417m for the future fields, £1241m for the technical reserve fields, £1435m for the new exploration fields, with a total of £3093m for all fields.

Chart 29

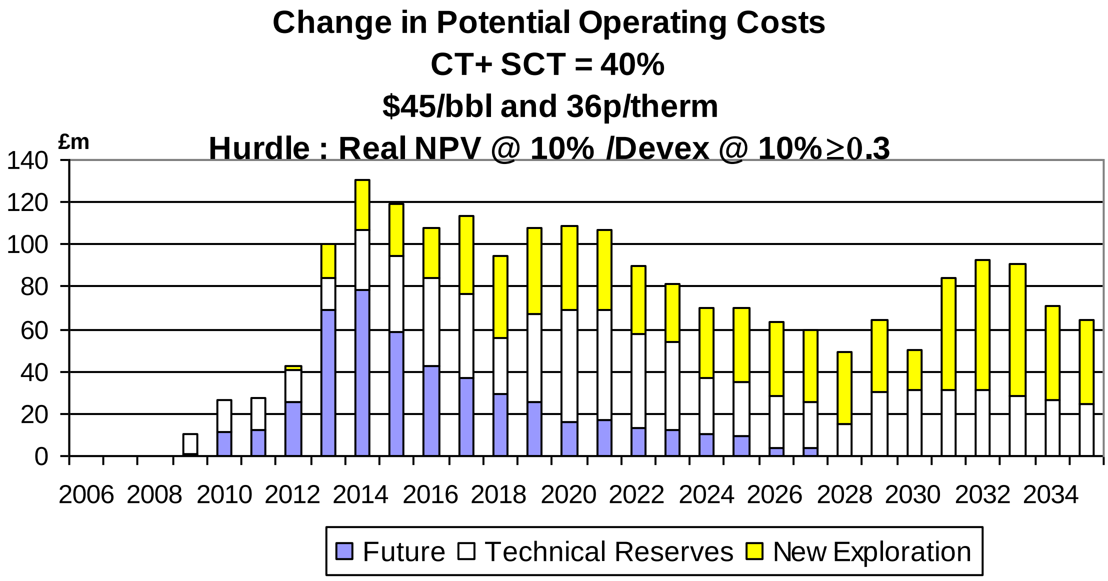


Chart 29 shows the potential change in operating costs at the medium price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, they may increase by £477m for the future fields, £791m for the technical reserve fields, £829m for the new exploration fields, with a total of £2097m for all fields.

Chart 30

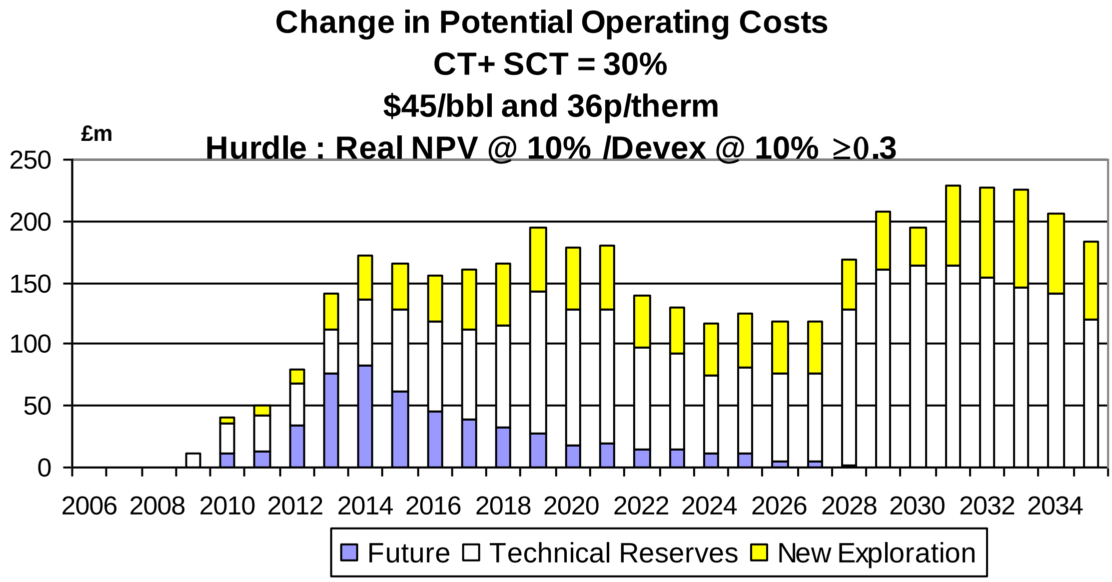


Chart 30 shows the potential change in operating costs at the medium price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, they may increase by £523m for the future fields, £2430m for the technical reserve fields, £1132m for the new exploration fields, with a total of £4085m for all fields.

Chart 31

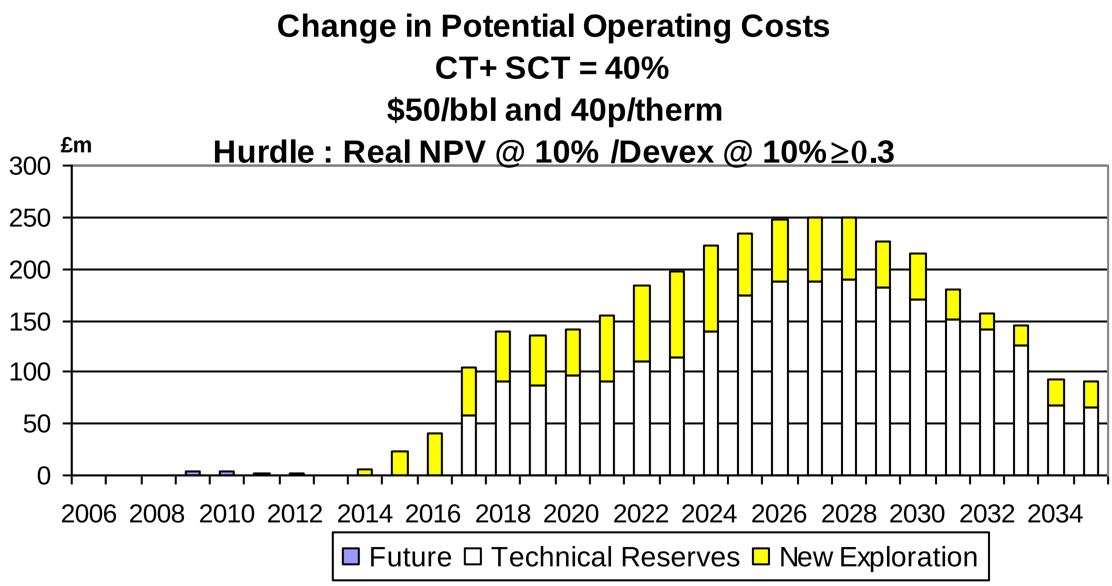


Chart 31 shows the potential change in operating costs at the high price when the CT + SCT rate is reduced to 40% when the hurdle is NPV/I. Over the period to 2035, they may increase by £11m for the future fields, £2433m for the technical reserve fields, £1005m for the new exploration fields, with a total of £3450m for all fields.

Chart 32

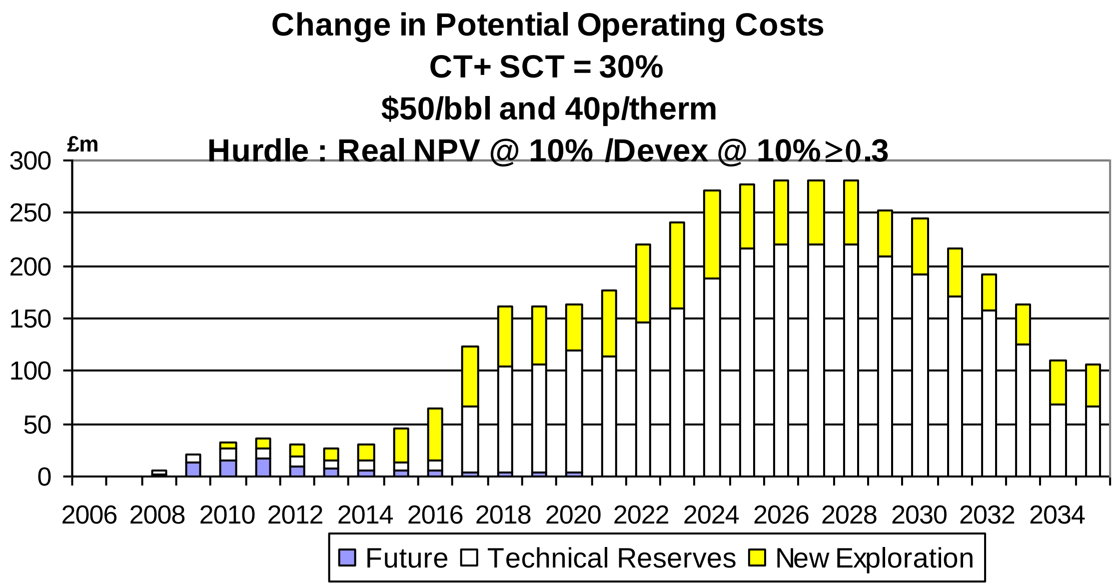


Chart 32 shows the potential change in operating costs at the high price when the CT + SCT rate is reduced to 30% when the hurdle is NPV/I. Over the period to 2035, they may increase by £98m for the future fields, £2933m for the technical reserve fields, £1189m for the new exploration fields, with a total of £4220m for all fields.

(v) Changes in Tax Revenues

Chart 33 shows the potential change in tax revenues at the very low price when the CT + SCT rate is reduced to 40% and the hurdle is NPV/I. Over the period to 2035, they may decrease by £442m for the future fields, £262m for the technical reserve fields, £89m for the new discoveries with a total of £616m for all fields. <u>It is important to note that the charts show the net changes in tax revenues among the three categories of fields. This reflects the balance of both negative and positive amounts.</u>

Chart 33

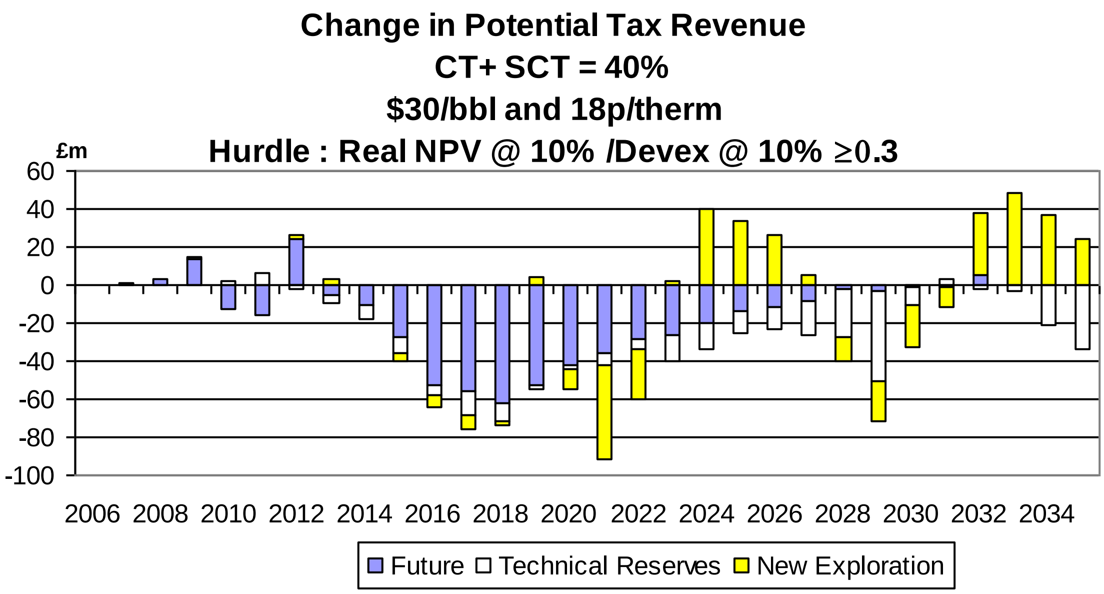


Chart 34 shows the potential change in tax revenues at the very low price when the CT + SCT rate is reduced to 30% and the hurdle is NPV/I. Over the period to 2035, they may decrease by £833m for the future fields, £532m for the technical reserve fields, £164m for the new exploration fields, with a total of £1530m for all fields.

Chart 34

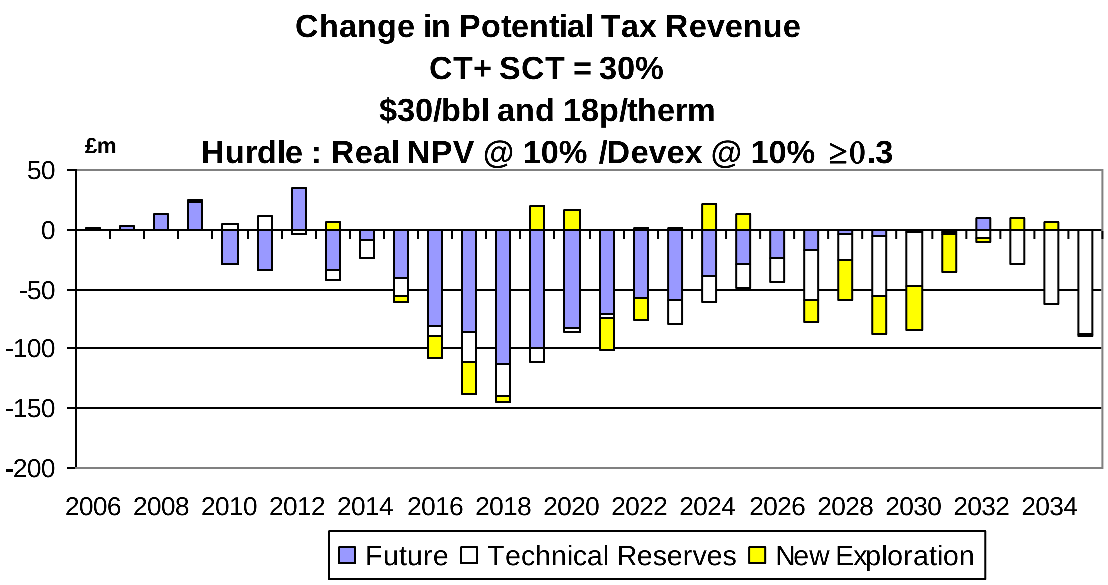


Chart 35 shows the potential change in tax revenue at the low price when the CT + SCT rate is reduced to 40% and the hurdle is NPV/I. Over the period to 2035, they may decrease by £974m for the future fields, £1001m for the technical reserve fields, £652m for the new exploration fields, with a total of £2627m for all fields.

Chart 35

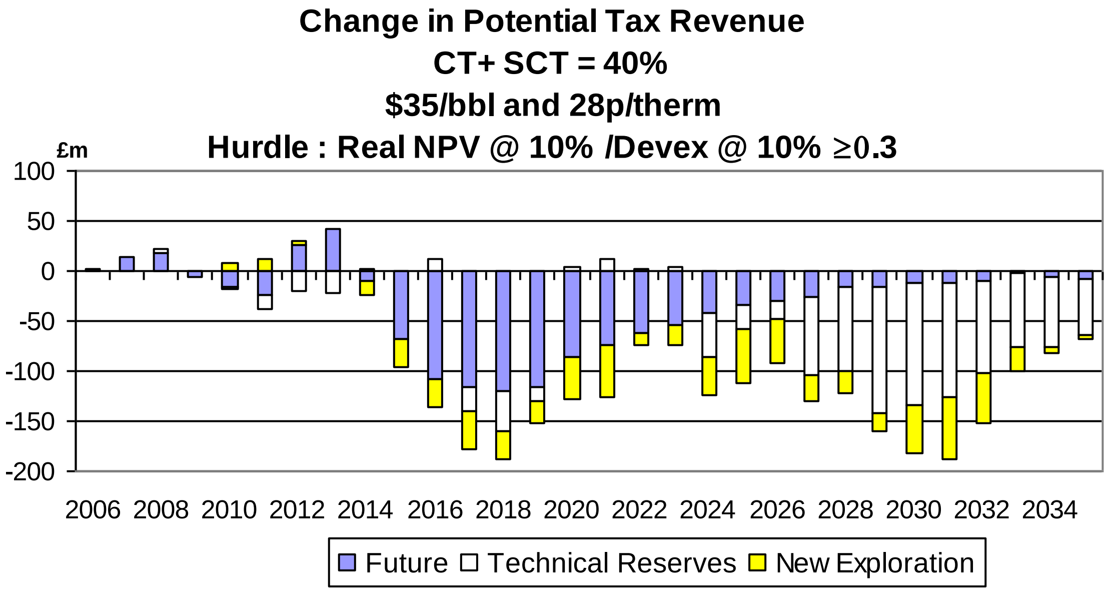


Chart 36

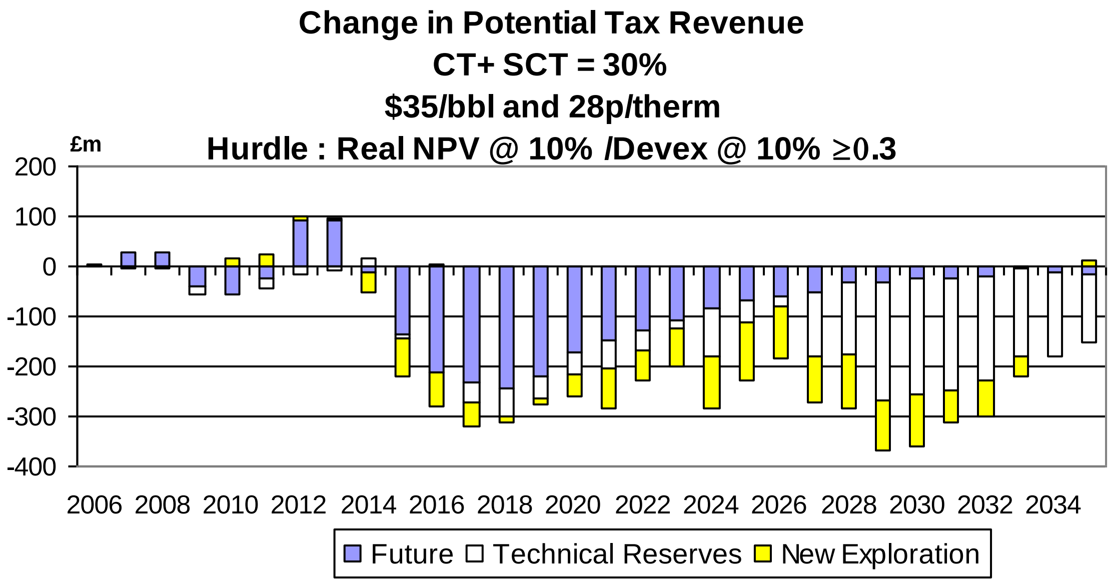


Chart 36 shows the potential change in tax revenues at the low price when the CT + SCT rate is reduced to 30% and the hurdle is NPV/I. Over the period to 2035, they may decrease by £1921m for the future fields, £2160m for the technical reserve fields, £1365m for the new exploration fields, with a total of £5446m for all fields.

Chart 37 shows the potential change in tax revenues at the medium price when the CT + SCT rate is reduced to 40% and the hurdle is NPV/I. Over the period to 2035, they may decrease by £1114m for the future fields, £3195m for the technical reserve fields, £2687m for the new exploration fields, with a total of £6996m for all fields.

Chart 37

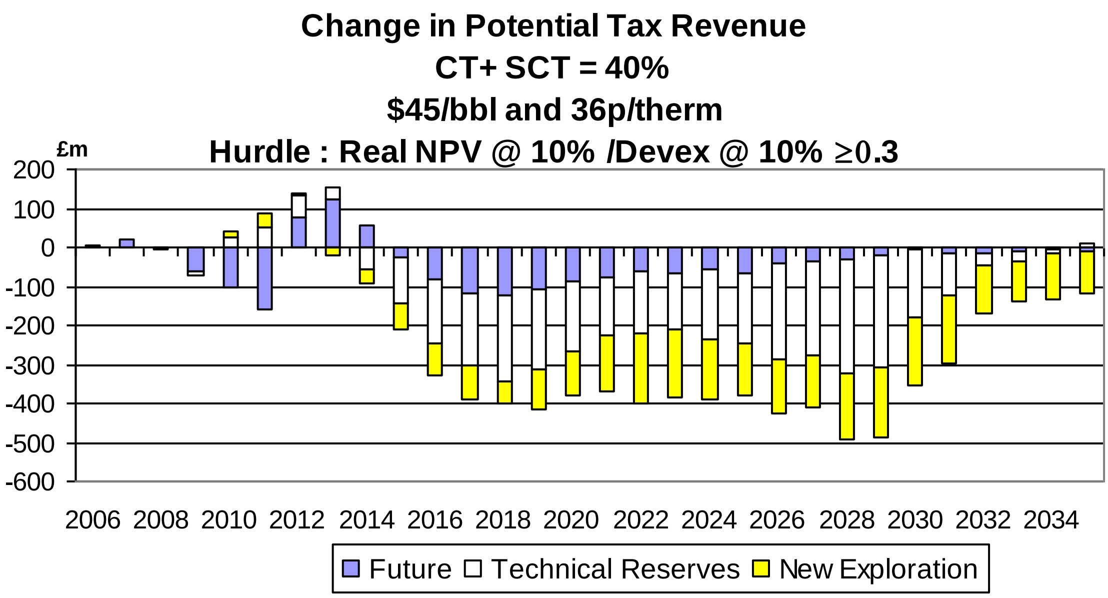


Chart 38 shows the potential change in tax revenues at the medium price when the CT + SCT rate is reduced to 30% and the hurdle is NPV/I. Over the period to 2035, they may decrease by £3026m for the future fields, £5931m for the technical reserve fields, £5792m for the new exploration fields, with a total of £14750m for all fields.

Chart 38

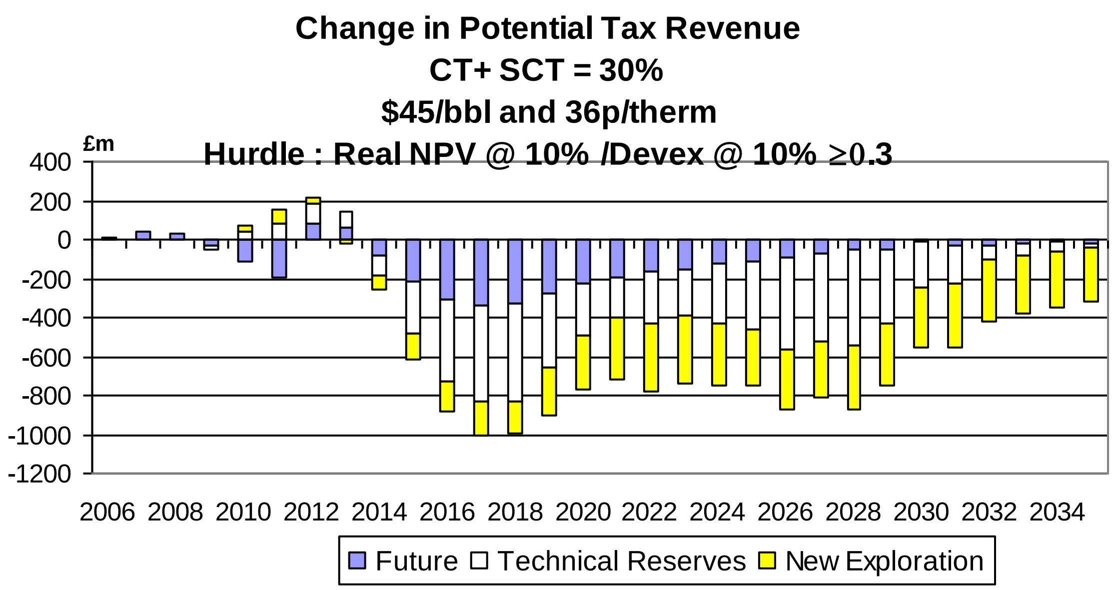


Chart 39

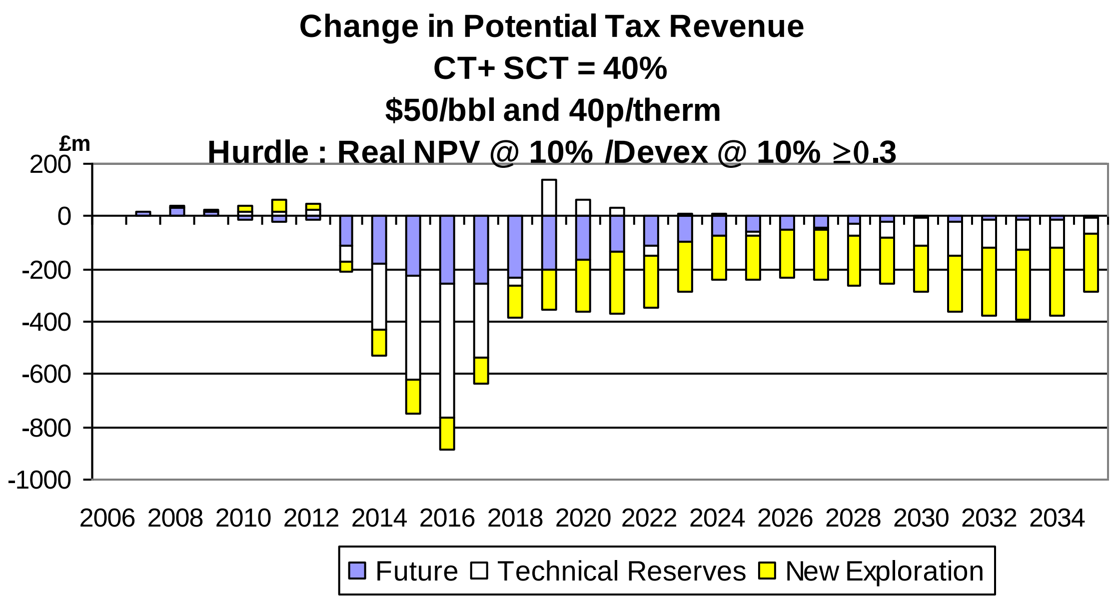


Chart 39 shows the potential change in tax revenues at the high price when the CT + SCT rate is reduced to 40% and the hurdle is NPV/I. Over the period to 2035, they may decrease by £2304m for the future fields, £1969m for the technical reserve fields, £3921m for the new exploration fields, with a total of £8194m for all fields.

Chart 40

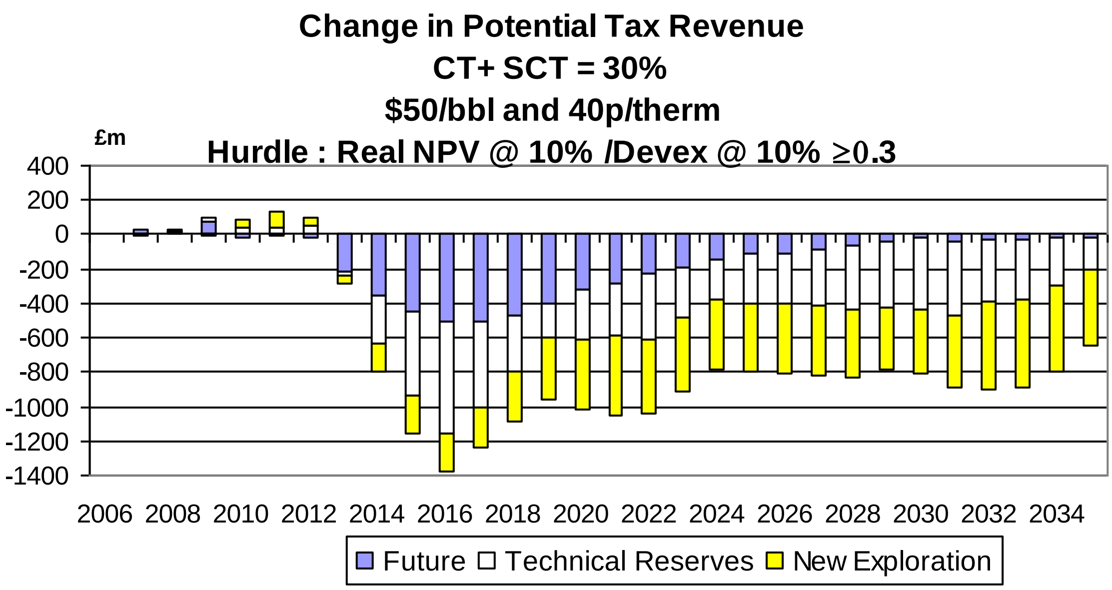


Chart 40 shows the potential change in tax revenues at the high price when the CT + SCT rate is reduced to 30% and the hurdle is NPV/I. Over the period to 2035, they may decrease by £4549m for the future fields, £7493m for the technical reserve fields, £8195m for the new exploration fields, with a total of £20238m for all fields.

(b) Volume Allowance for SCT with Rate Unchanged

An alternative to reducing the CT + SCT rate for future fields is to give a field volume allowance, with no annual limit, against SCT but not transferable across fields.

(i) Changes in Number of Producing Fields

Chart 41 shows the potential change in the number of fields in production at the very low price with the NPV/I hurdle rate if a volume allowance of 2mboe were introduced. One more probable/possible field, 3 more technical reserve fields and 3 more new exploration fields would pass the hurdle rate. The result is the same with a 3mboe volume allowance.

Chart 41

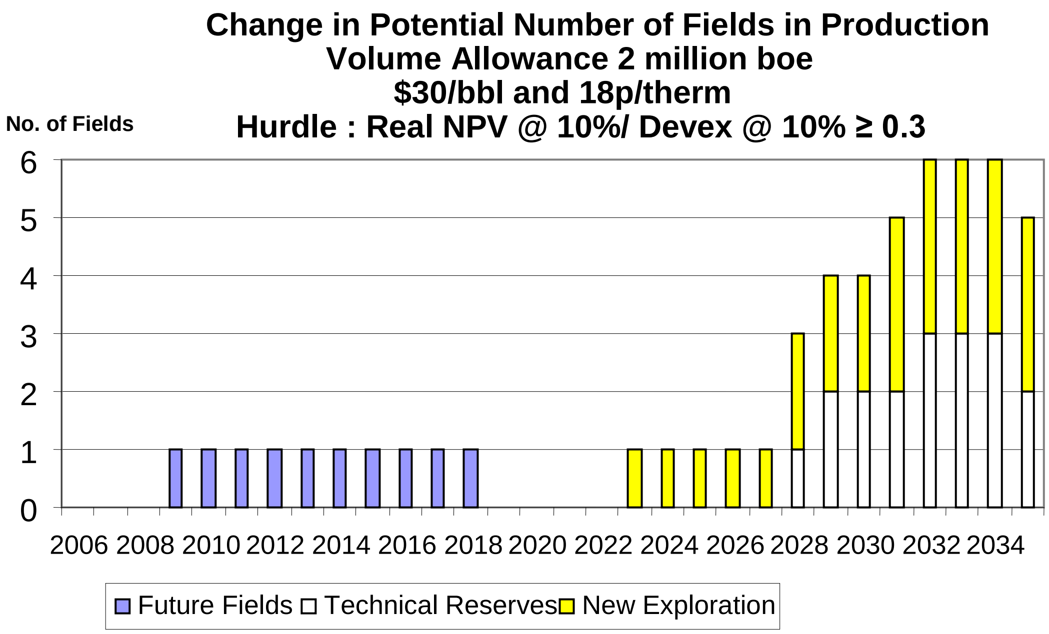


Chart 42 shows the potential change in the number of fields in production at the very low price with the NPV/I hurdle rate if a volume allowance of 4mboe were introduced. One more probable/possible field, 3 more technical reserve fields and 4 more new exploration fields would pass the hurdle rate at the very low price.

Chart 42

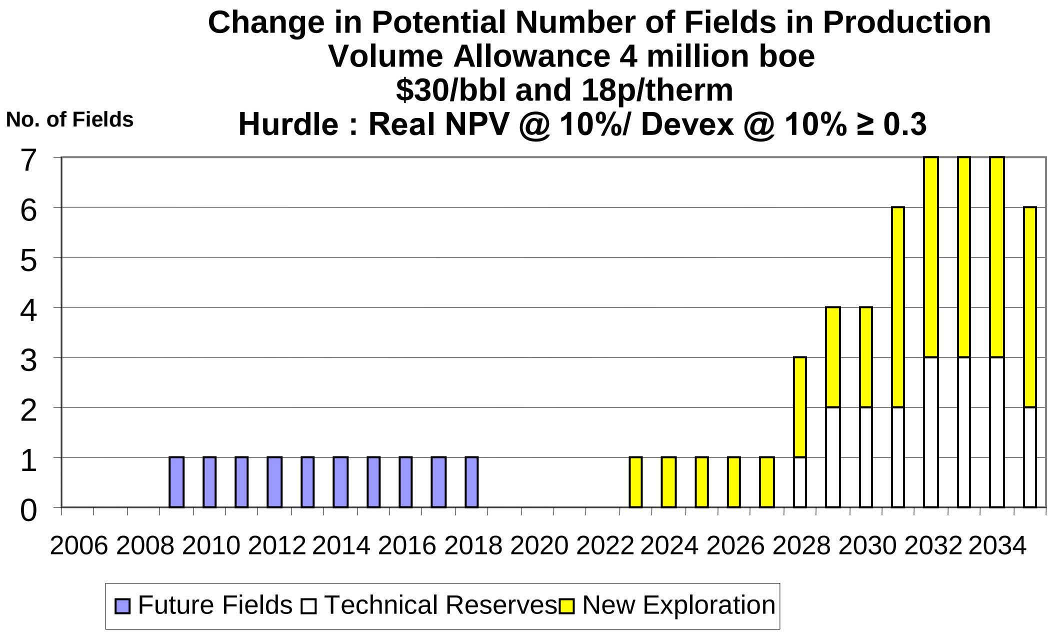


Chart 43 shows the potential change in the number of fields in production at the very low price with the NPV/I hurdle rate if a volume allowance of 5mboe were introduced. One more probable/possible field, 3 more technical reserve fields and 5 more new exploration fields would pass the hurdle rate.

Chart 43

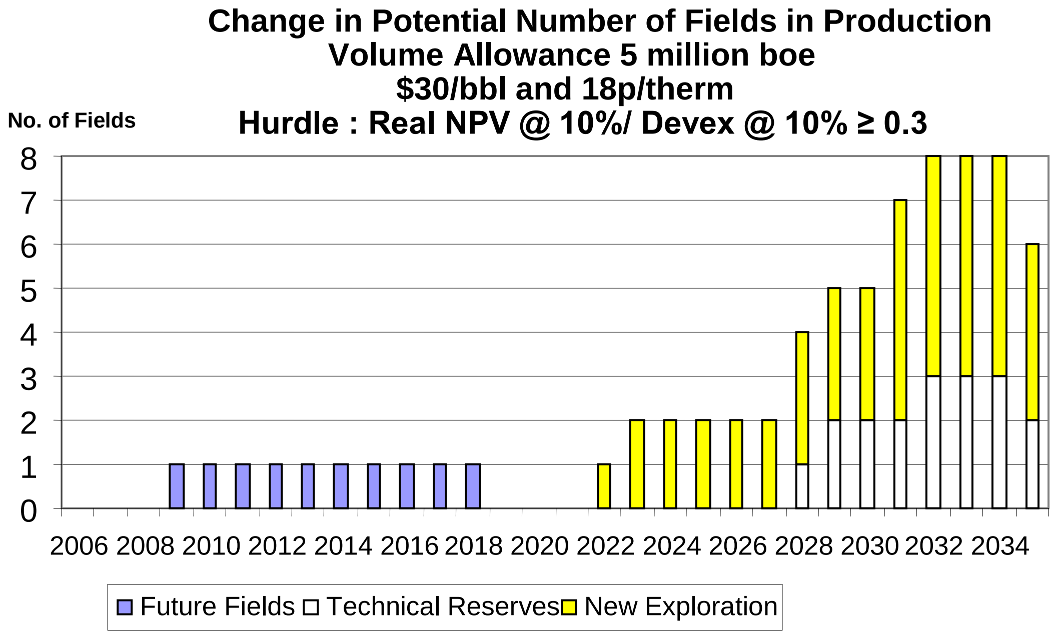


Chart 44 shows the potential change in the number of fields in production at the low price with the NPV/I hurdle rate if a volume allowance of 2mboe were introduced. Two more probable/possible fields, 3 more technical reserve fields and 6 more new exploration fields would pass the hurdle rate at the low price. The result is the same for a 3mboe and a 4mboe volume allowance.

Chart 44

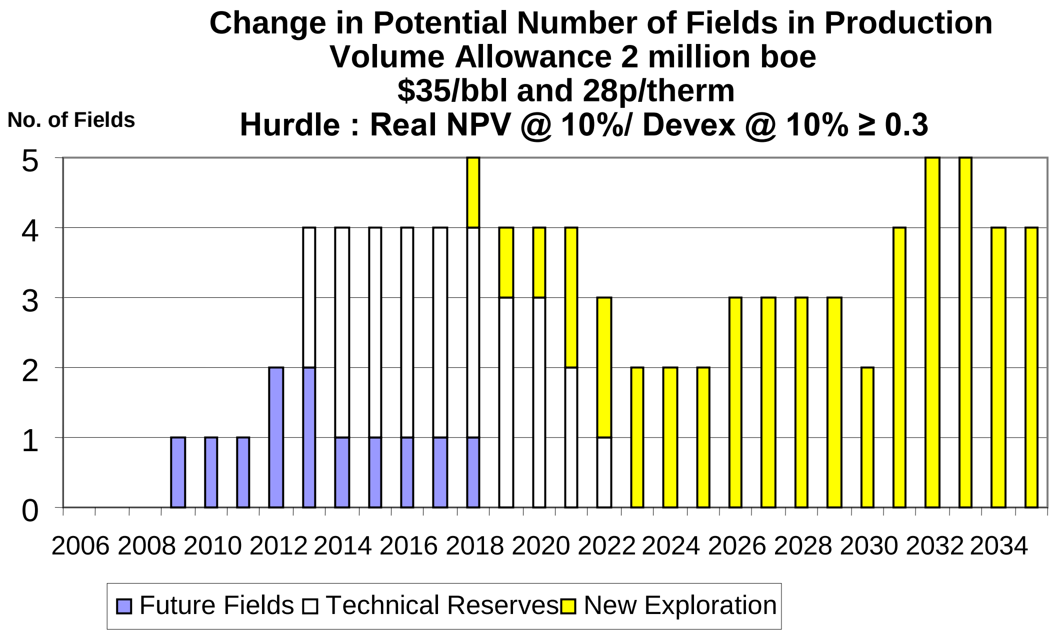


Chart 45 shows the potential change in the number of fields in production at the low price with the NPV/I hurdle rate if a volume allowance of 5mboe were introduced. Two more probable/possible fields, 4 more technical reserve fields and 6 more new exploration fields would pass the hurdle rate.

Chart 45

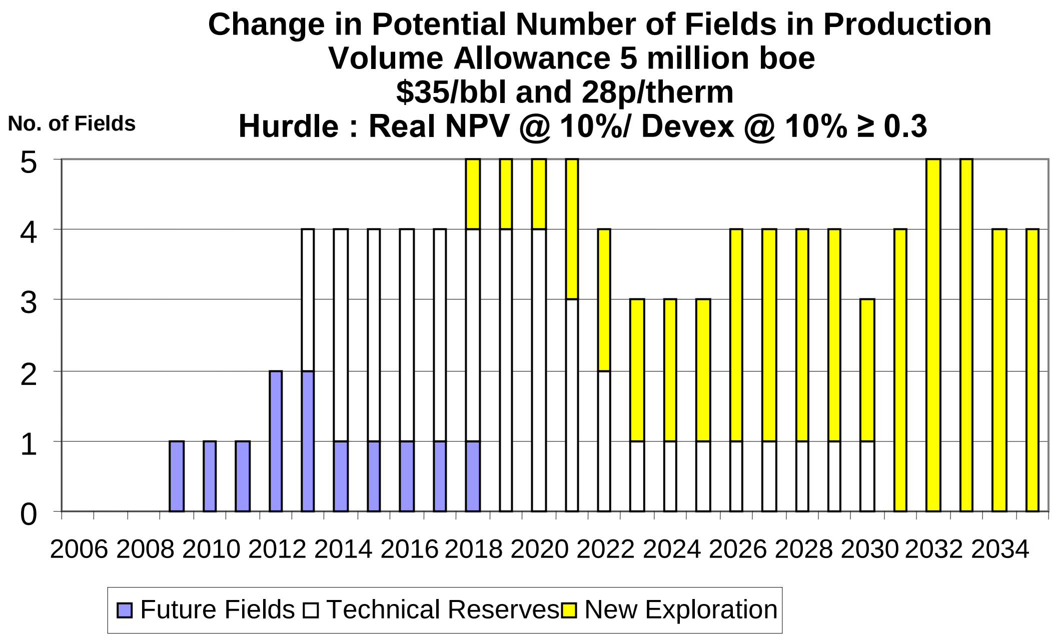


Chart 46 shows the potential change in the number of fields in production at the medium price with the NPV/I hurdle rate if a volume allowance of 2mboe were introduced. Six more probable/possible fields, 6 more technical reserve fields and 3 more new exploration fields would pass the hurdle rate.

Chart 46

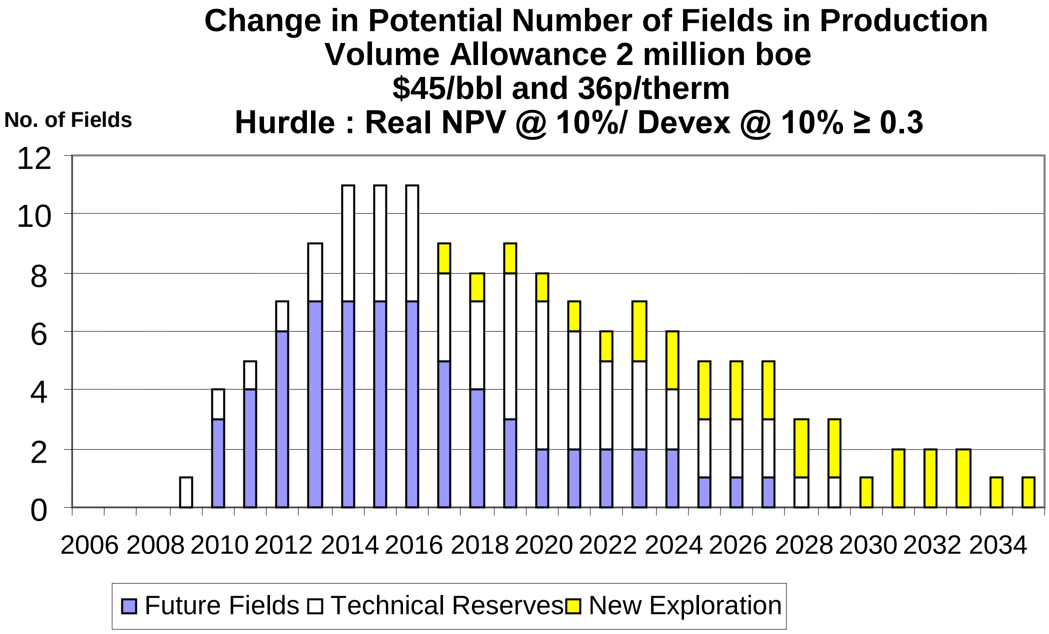


Chart 47 shows the potential change in the number of fields in production at the medium price with the NPV/I hurdle rate if a volume allowance of 3mboe were introduced. Seven more probable/possible fields, 7 more technical reserve fields and 3 more new exploration fields would pass the hurdle rate. The results are the same with a 4 or a 5mboe volume allowance.

Chart 47

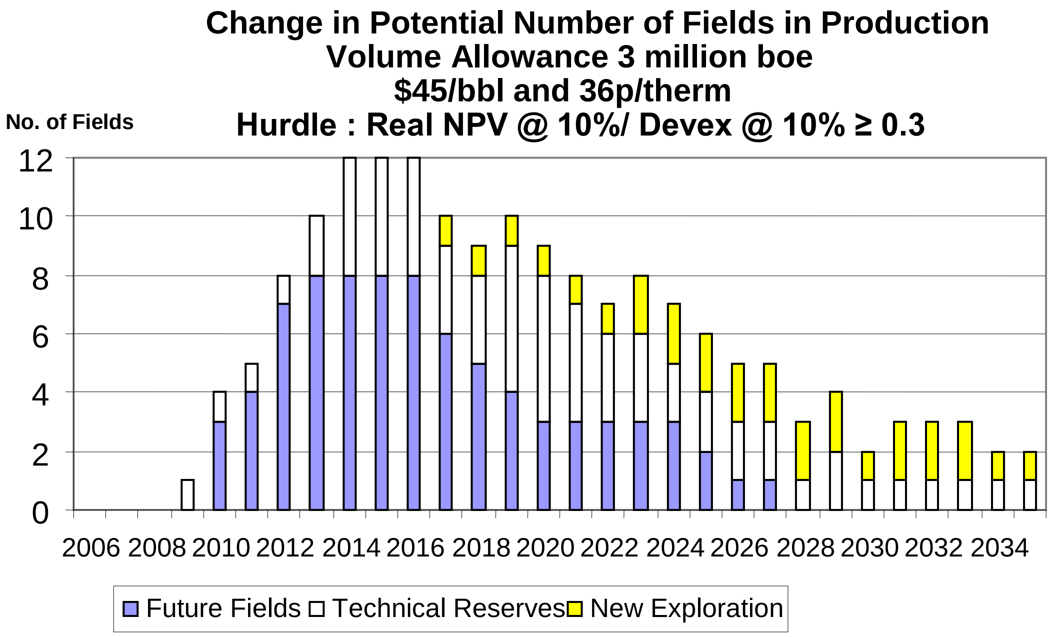


Chart 48 shows the potential change in the number of fields in production at the high price with the NPV/I hurdle rate if a volume allowance of 2mboe were introduced. One more probable/possible field, 10 more technical reserve fields and 7 more new exploration fields would pass the hurdle rate.

Chart 48

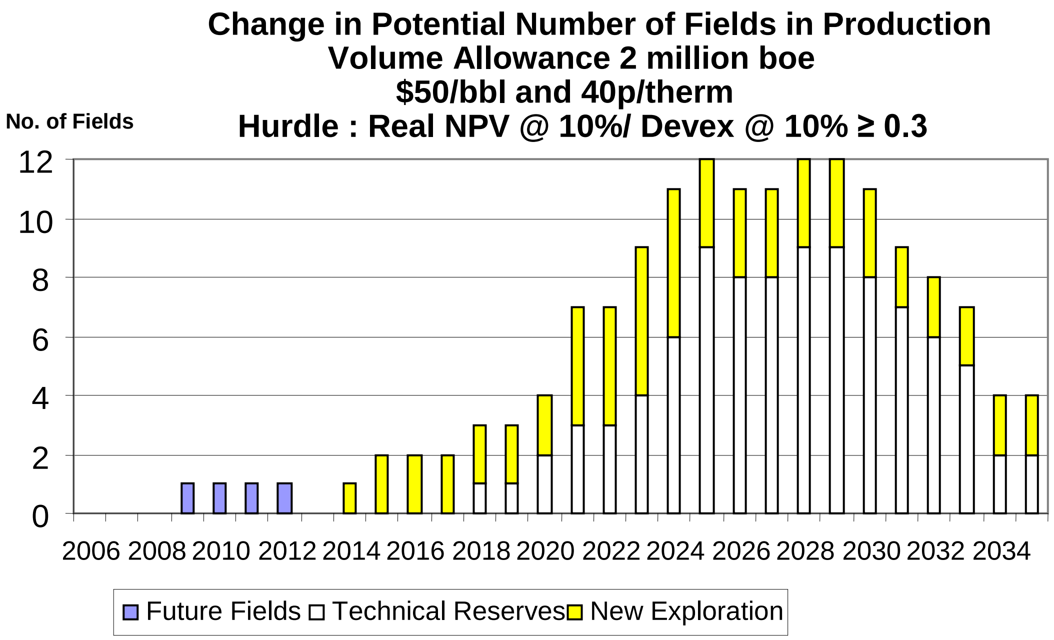


Chart 49 shows the potential change in the number of fields in production at the high price with the NPV/I hurdle rate if a volume allowance of 3mboe were introduced. One more probable/possible field, 10 more technical reserve fields and 8 more new exploration fields would pass the hurdle rate.

Chart 49

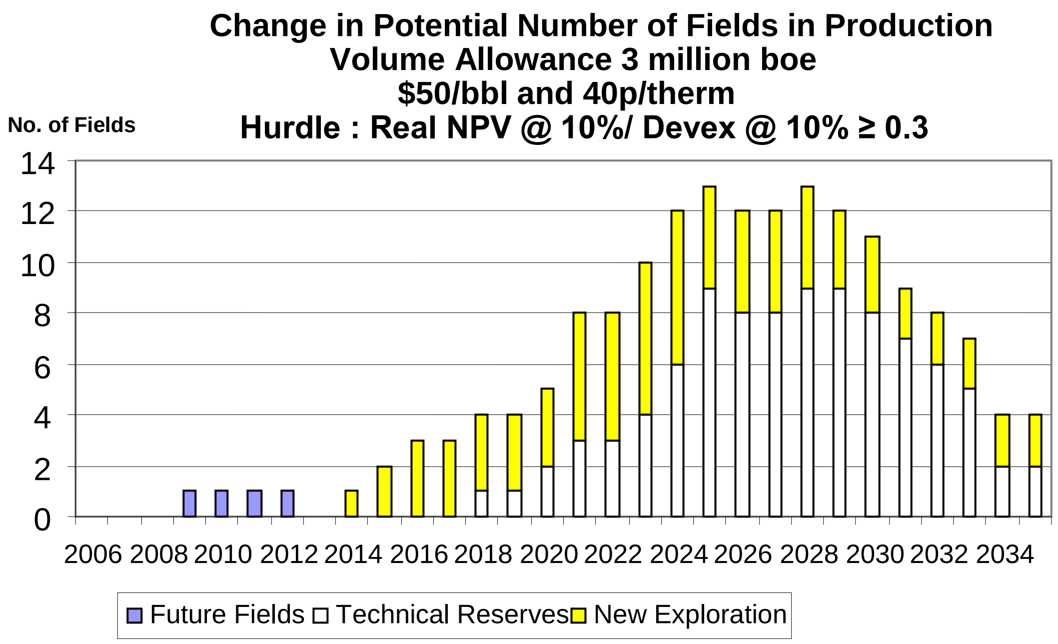


Chart 50

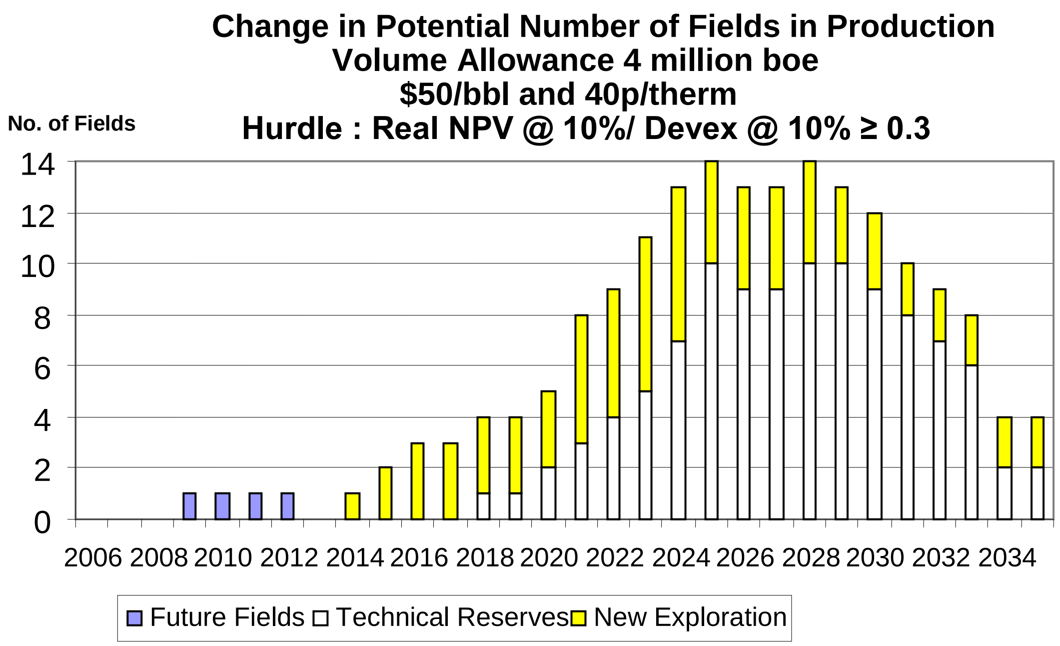


Chart 50 shows the potential change in the number of fields in production at the high price with the NPV/I hurdle rate if a volume allowance of 4mboe were introduced. One more probable/possible field, 11 more technical reserve fields, and 8 more new exploration fields would pass the hurdle rate. The result is the same with a 5mboe volume allowance.

(ii) Changes in Production

Chart 51 shows the potential change in hydrocarbon production at the very low price with the introduction of a 2mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 5mboe for the future fields, 37mboe for the technical reserve fields, 58mboe for the new exploration fields, with a total of 100mboe for all fields over the period. The result is the same with a 3mboe volume allowance.

Chart 51

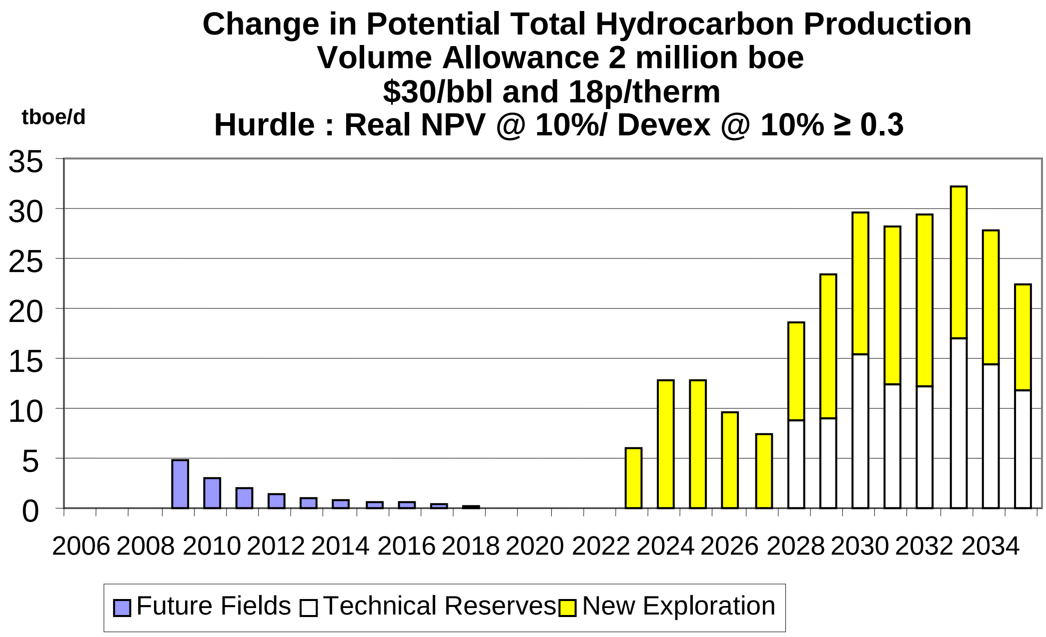


Chart 52 shows the potential change in hydrocarbon production at the very low price with the introduction of a 4mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 5mboe for the future fields, 37mboe for the technical reserve fields, 92mboe for the new exploration fields, with a total of 135mboe for all fields over the period to 2035.

Chart 52

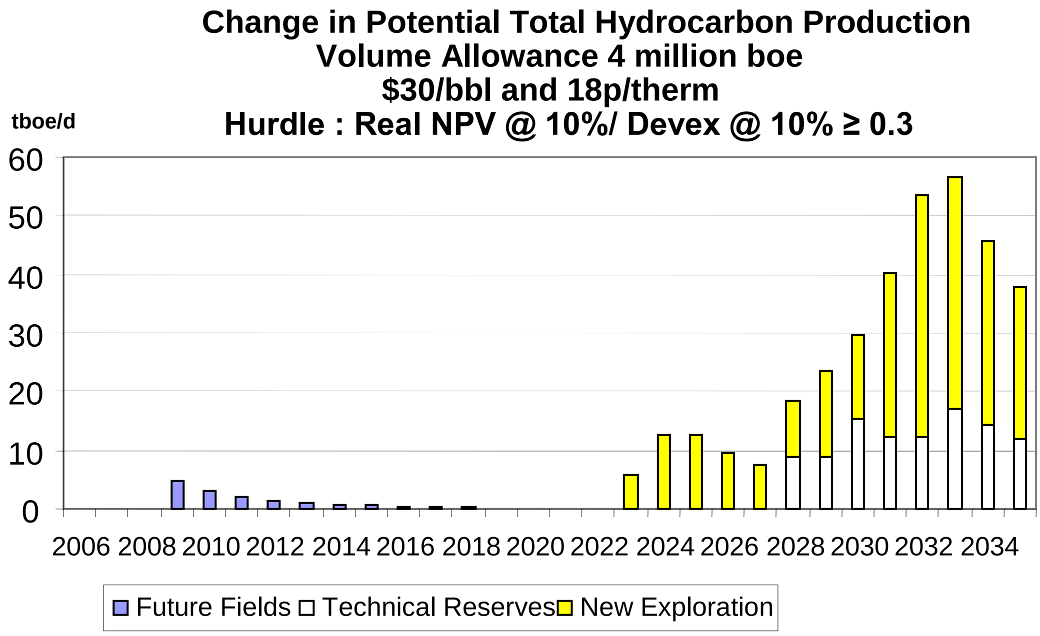


Chart 53 shows the potential change in hydrocarbon production at the very low price with the introduction of a 5mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 5mboe for the future fields, 37mboe for the technical reserve fields, 146mboe for the new exploration fields, with a total of 188mboe for all fields over the period to 2035.

Chart 53

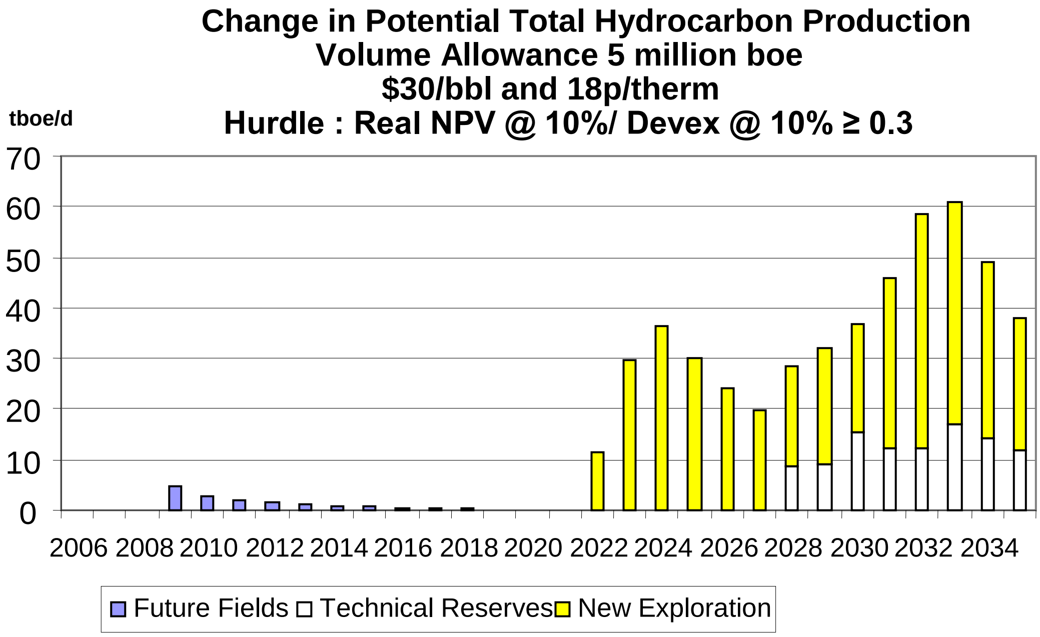


Chart 54 shows the potential change in hydrocarbon production at the low price with the introduction of a 2mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 28mboe for the future fields, 27mboe for the technical reserve fields, 109mboe for the new exploration fields, with a total of 163mboe for all fields over the period to 2035. The result is the same with a 3mboe or a 4mboe volume allowance.

Chart 54

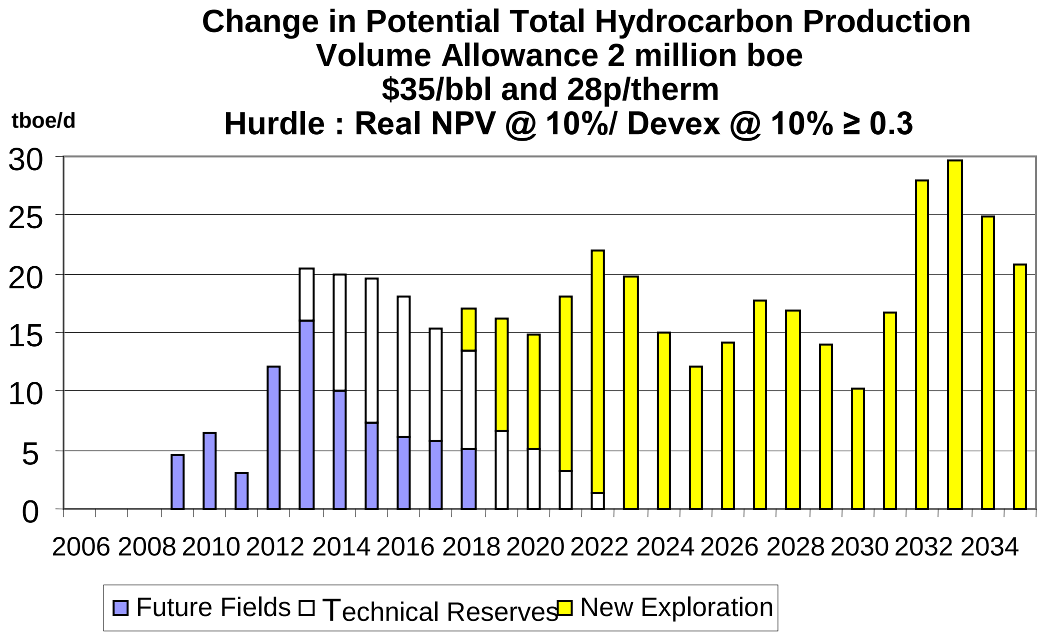


Chart 55 shows the potential change in hydrocarbon production at the low price with the introduction of a 5mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 28mboe for the future fields, 68mboe for the technical reserve fields, 109mboe for the new exploration fields, with a total of 205mboe for all fields over the period to 2035.

Chart 55

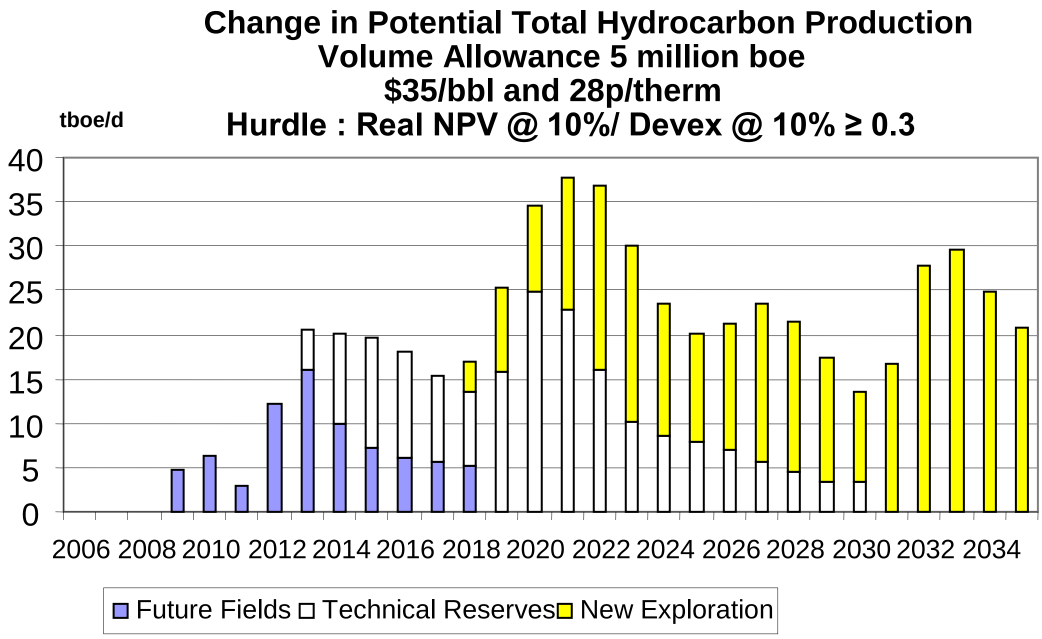


Chart 56 shows the potential change in hydrocarbon production at the medium price with the introduction of a 2mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 123mboe for the future fields, 65mboe for the technical reserve fields, 93mboe for the new exploration fields, with a total of 281mboe for all fields over the period to 2035.

Chart 56

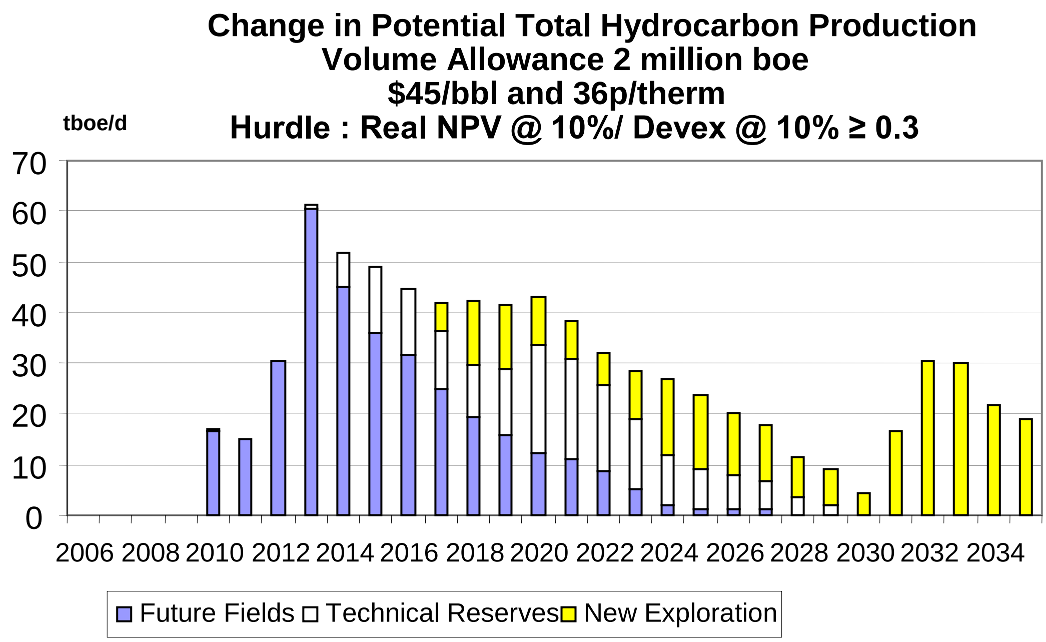


Chart 57 shows the potential change in hydrocarbon production at the medium price with the introduction of a 3mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 157mboe for the future fields, 134mboe for the technical reserve fields, 93mboe for the new exploration fields, with a total of 383mboe for all fields over the period to 2035. The result is the same with a 4mboe or a 5mboe volume allowance.

Chart 57

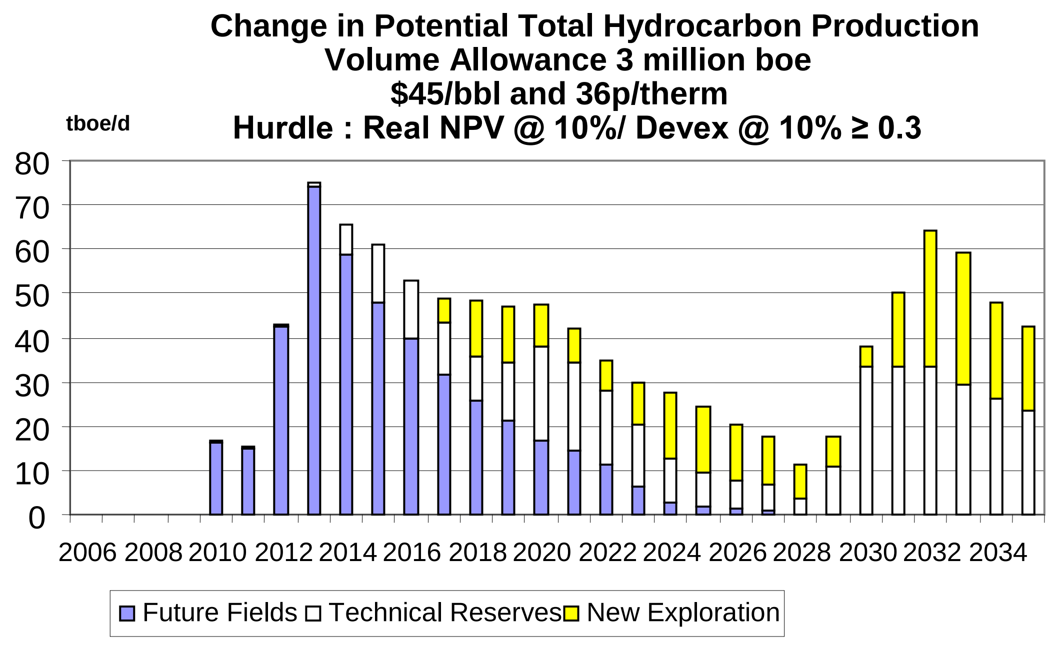


Chart 58 shows the potential change in hydrocarbon production at the high price with the introduction of a 2mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 3mboe for the future fields, 152mboe for the technical reserve fields, 79mboe for the new exploration fields, with a total of 234mboe for all fields over the period to 2035.

Chart 58

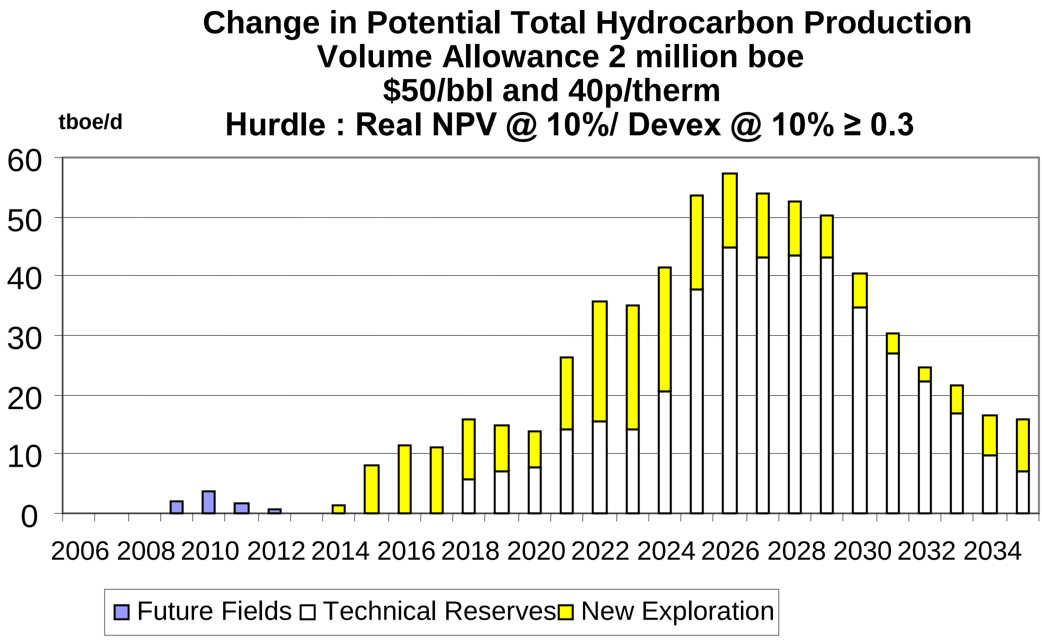


Chart 59 shows the potential change in hydrocarbon production at the high price with the introduction of a 3mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 3mboe for the future fields, 152mboe for the technical reserve fields, 107mboe for the new exploration fields, with a total of 261 mboe for all fields over the period to 2035.

Chart 59

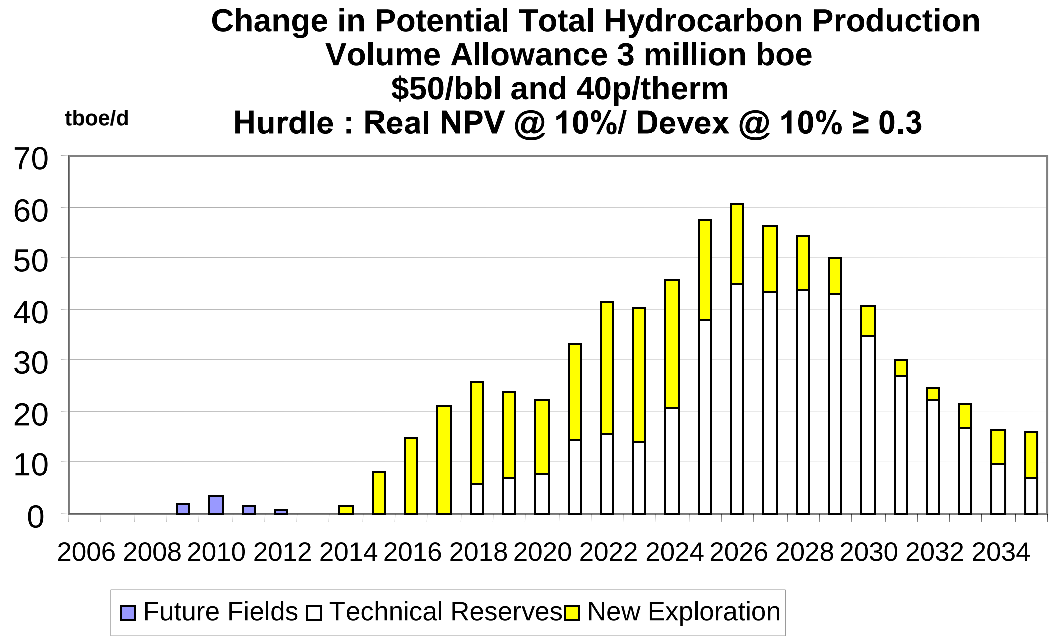
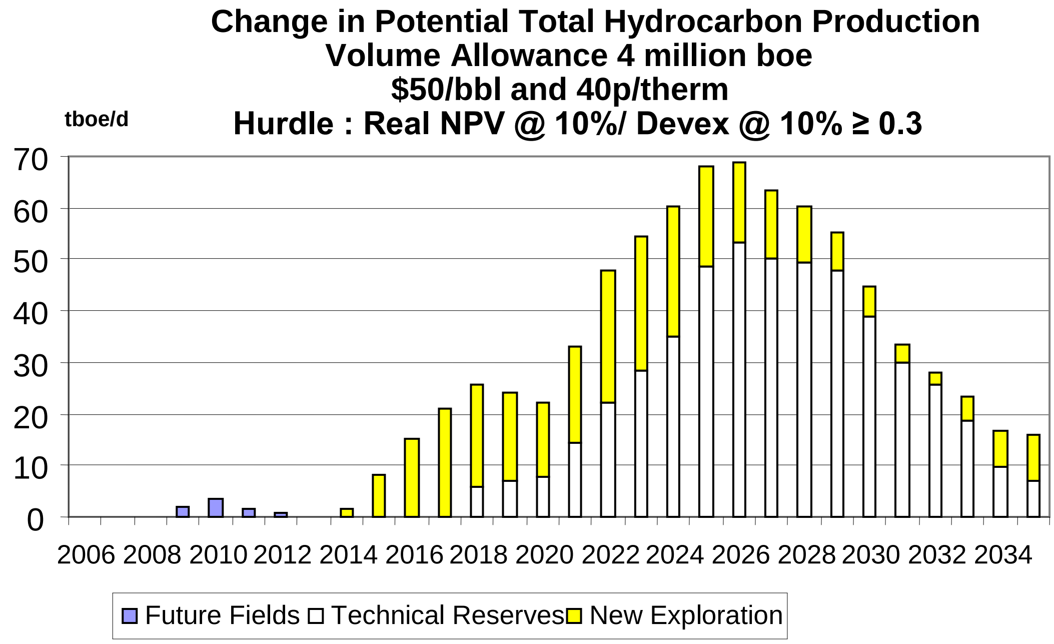


Chart 60 shows the potential change in hydrocarbon production at the high price with the introduction of a 4mboe volume allowance against SCT when the hurdle is NPV/I. The potential hydrocarbon production may increase by 3mboe for the future fields, 182mboe for the technical reserve fields, 107mboe for the new exploration fields, with a total of 292mboe for all fields over the period to 2035. The result is the same with a 5mboe volume allowance.

Chart 60



(iii) Changes in Tax Revenues

Chart 61 shows the potential change in tax revenue at the very low price with the introduction of a 2mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £68m for the future fields, £57m for the technical reserve fields, and it may increase by £69m for the new exploration fields, with a total decrease of £56m for all fields over the period to 2035.

Chart 61

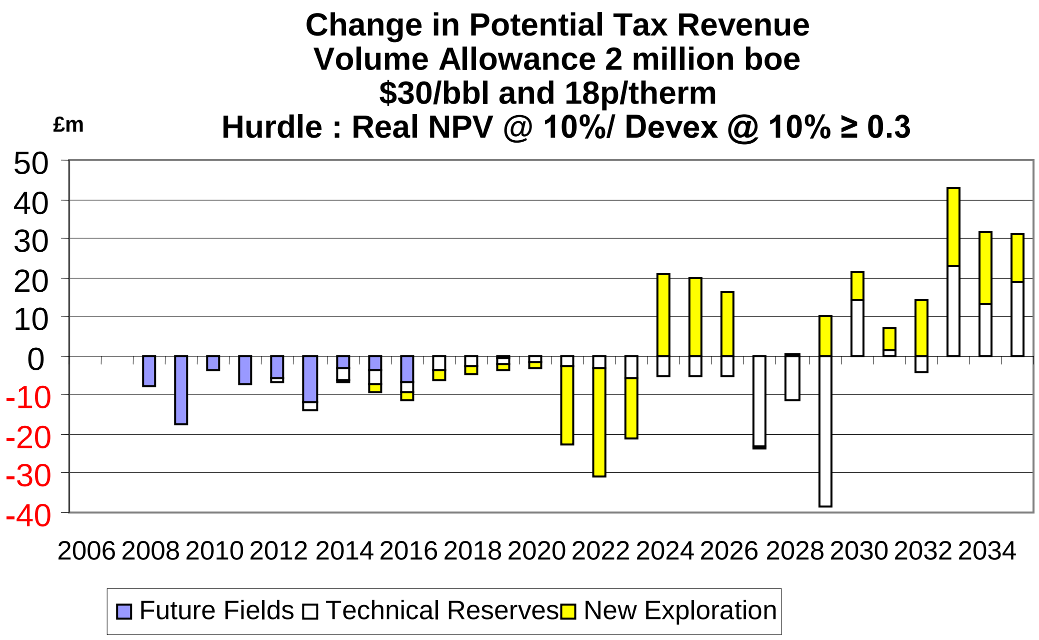


Chart 62 shows the potential change in tax revenue at the very low price with the introduction of a 3mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £82m for the future fields, £83m for the technical reserve fields, and it may increase by £45m for the new exploration fields, with a total decrease of £120m for all fields.

Chart 62

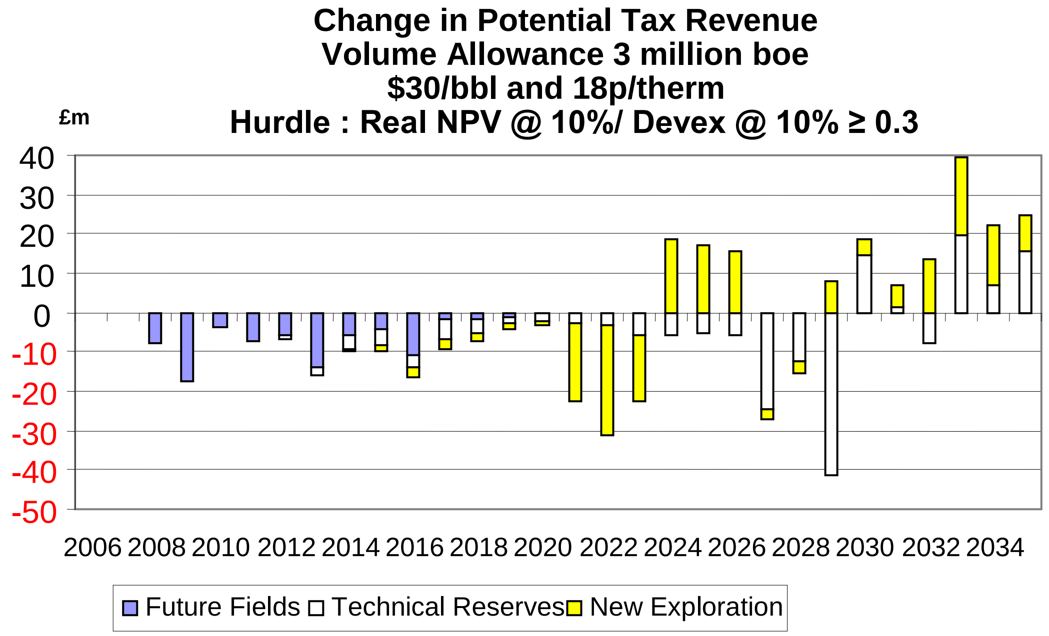


Chart 63 shows the potential change in tax revenue at the very low price with the introduction of a 4mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £88m for the future fields, £98m for the technical reserve fields and it may increase by £103m for the new exploration fields, with a total decrease of £83m for all fields.

Chart 63

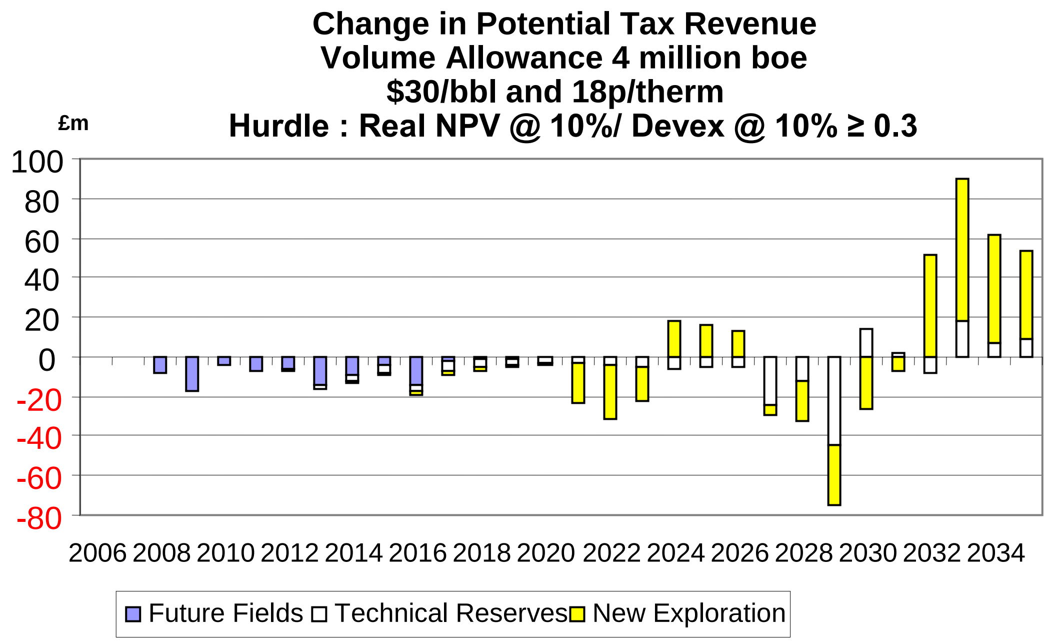


Chart 64 shows the potential change in tax revenue at the very low price with the introduction of a 5mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £95m for the future fields, £106m for the technical reserve fields and it may increase by £233m for the new exploration fields, with a total increase of £32m for all fields.

Chart 64

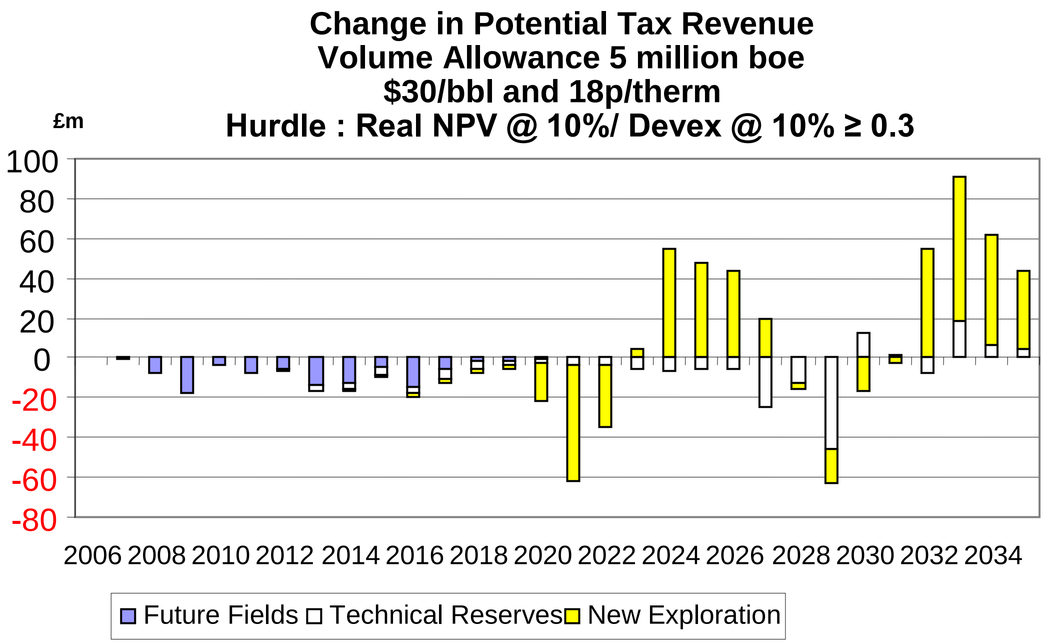


Chart 65 shows the potential change in tax revenue at the low price with the introduction of a 2mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £84m for the future fields, it may increase by £549m for the technical reserve fields and it may decrease by £16m for the new exploration fields, with a total increase of £450m for all fields over the period to 2035.

Chart 65

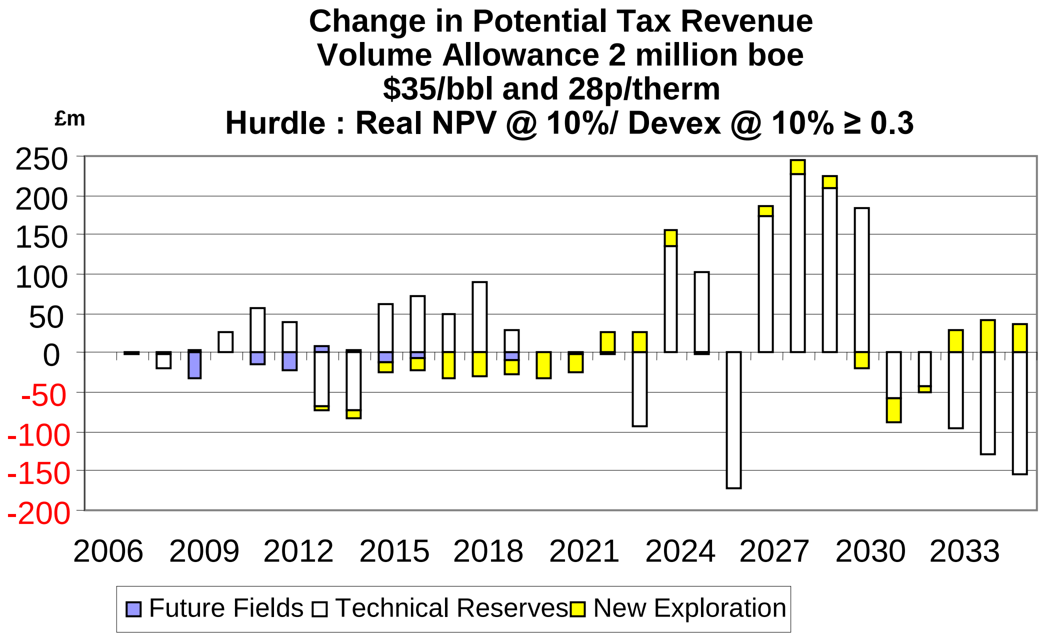


Chart 66 shows the potential change in tax revenue at the low price with the introduction of a 3mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £117m for the future fields, it may increase by £469m for the technical reserve fieldsand it may decrease by £101m for the new exploration fields a total increase of £251m for all fields over the period to 2035.

Chart 66

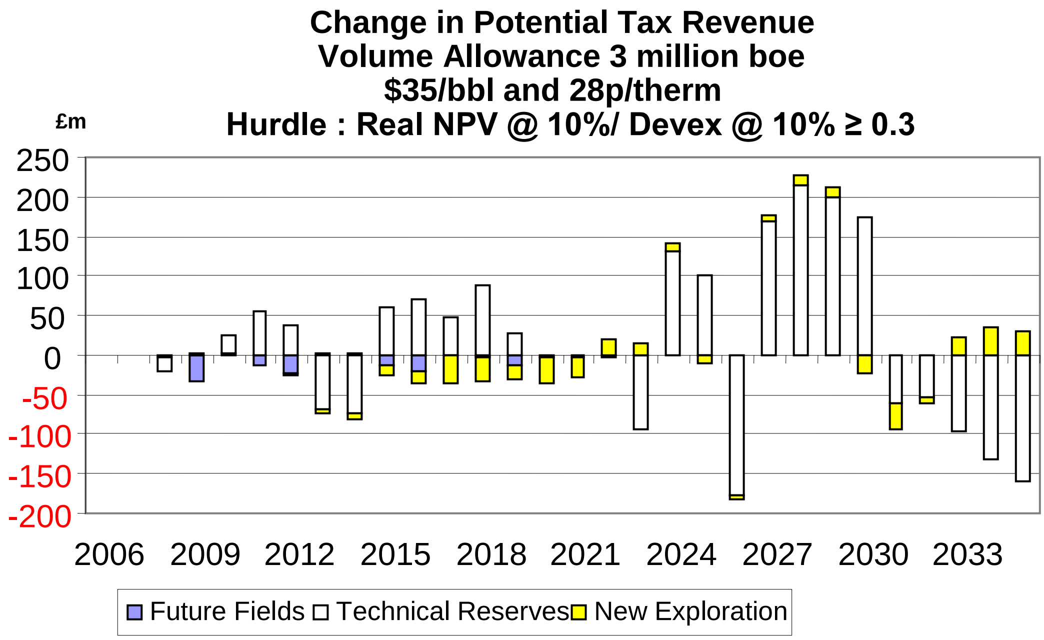


Chart 67 shows the potential change in tax revenue at the low price with the introduction of a 4mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £137m for the future fields, it may increase by £415m for the technical reserve fields and it may decrease by £155m for the new exploration fields, with a total increase of £124m for all fields over the period to 2035.

Chart 67

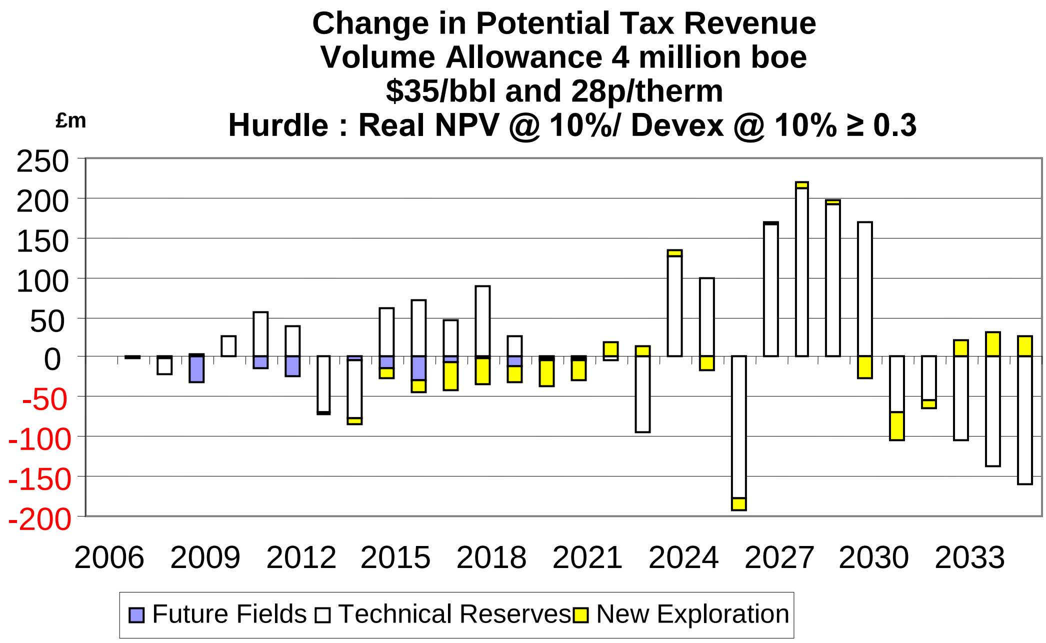


Chart 68 shows the potential change in tax revenue at the low price with the introduction of a 5mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £153m for the future fields, it may increase by £512m for the technical reserve fields, and it may decrease by £181m for the new exploration fields, with a total increase of £178m for all fields over the period to 2035.

Chart 68

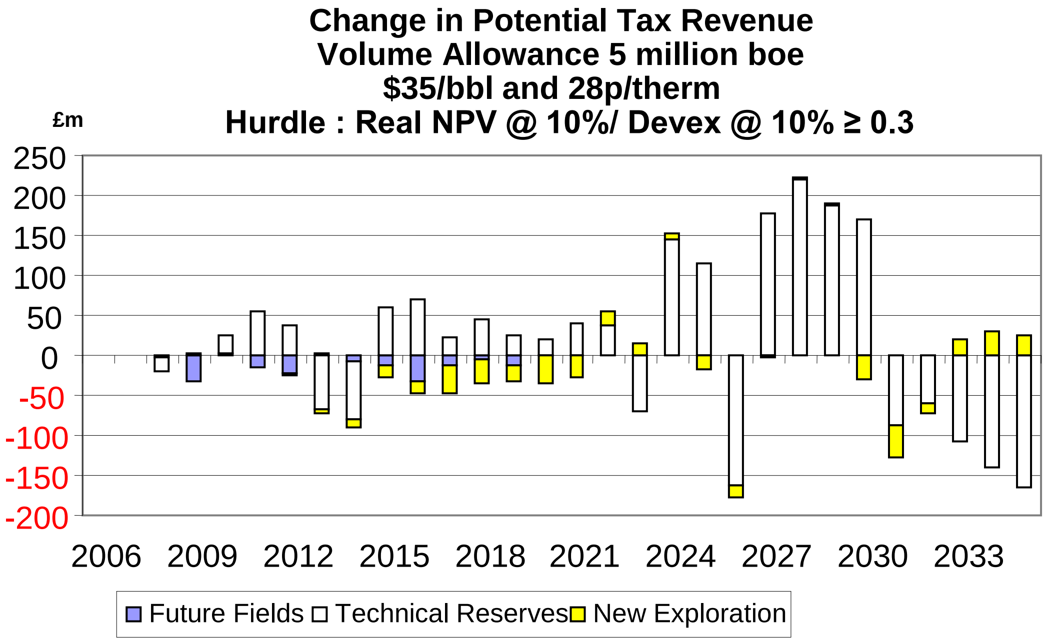


Chart 69 shows the potential change in tax revenue at the medium price with the introduction of a 2mboe volume allowance against SCT when the hurdle is NPV/I. It may increase by £357m for the future fields, decrease by £556m for the technical reserve fields, and decrease by £580m for the new exploration fields, with a total decrease of £779m for all fields over the period to 2035.

Chart 69

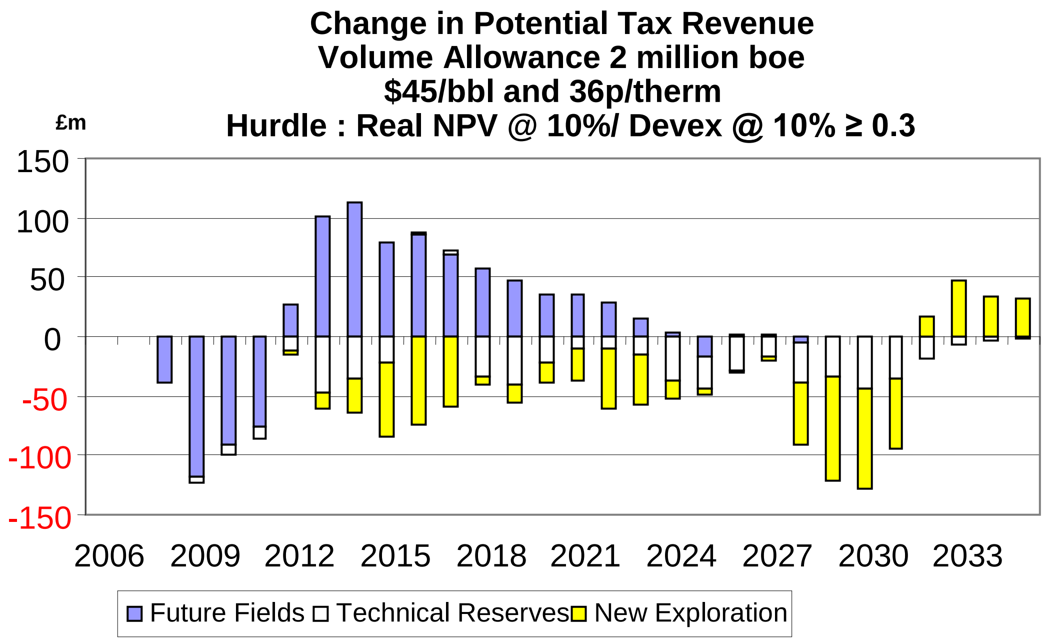


Chart 70 shows the potential change in tax revenue at the medium price with the introduction of a 3mboe volume allowance against SCT when the hurdle is NPV/I. It may increase by £463m for the future fields, decrease by £505m for the technical reserve fields and decrease by £843m for the new exploration fields, with a total decrease of £885m for all fields over the period to 2035.

Chart 70

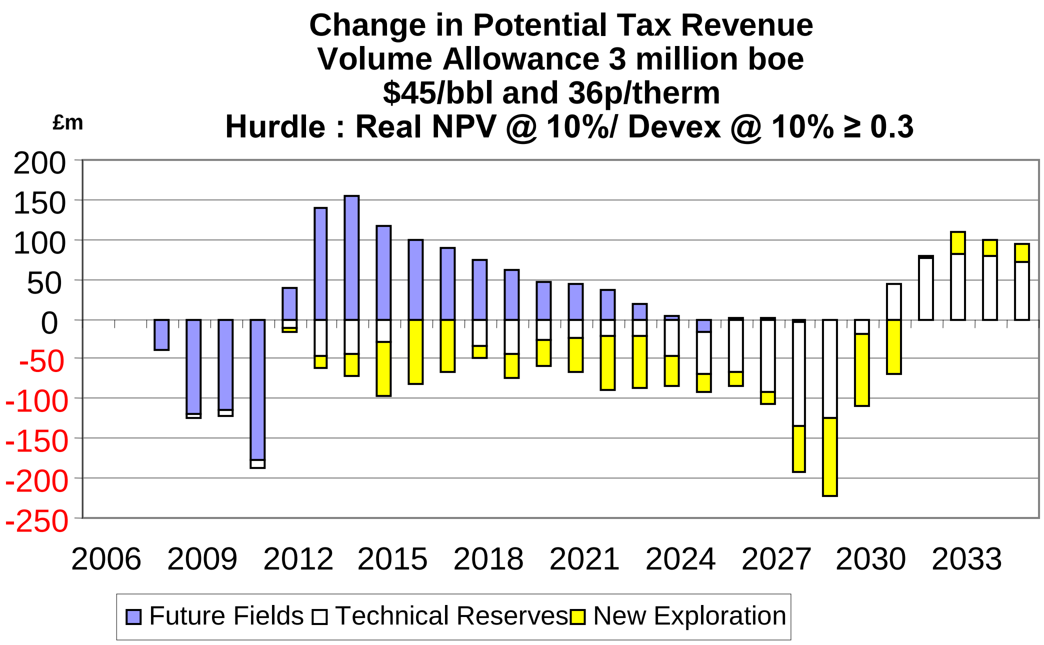


Chart 71 shows the potential change in tax revenue at the medium price with the introduction of a 4mboe volume allowance against SCT when the hurdle is NPV/I. It may increase by £417m for the future fields, decrease by £644m for the technical reserve fields, and decrease by £1016m for the new exploration fields, with a total decrease of £1244m for all fields in the period to 2035.

Chart 71

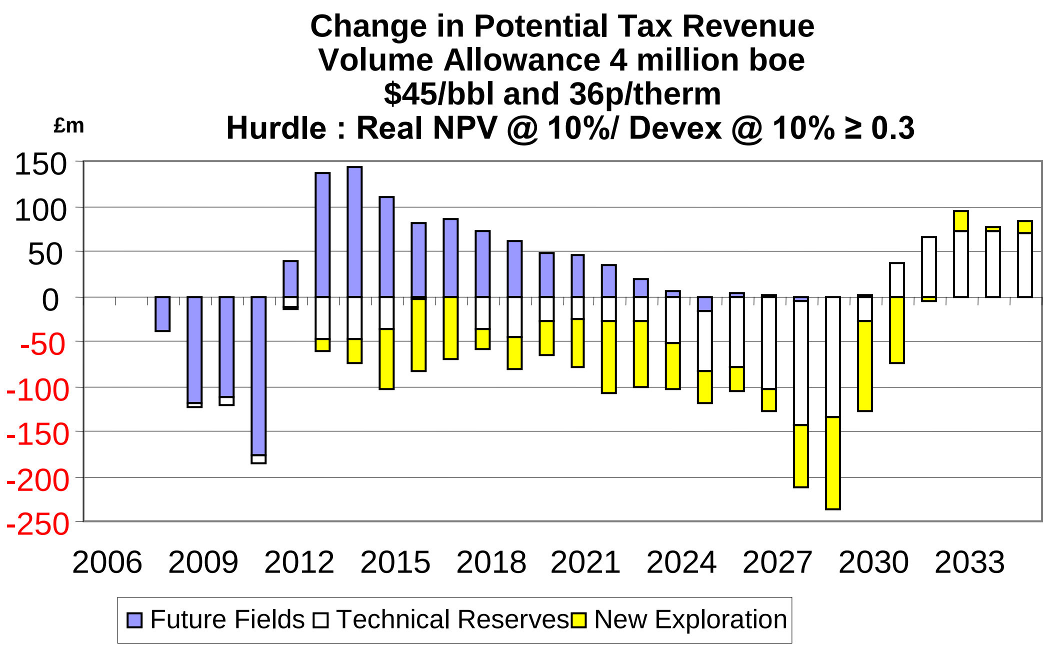


Chart 72 shows the potential change in tax revenue at the medium price with the introduction of a 5mboe volume allowance against SCT when the hurdle is NPV/I. It may increase by £378m for the future fields, decrease by £735m for the technical reserve fields and decrease by £1117m for the new exploration fields, with a total decrease of £1474m for all fields in the period to 2035.

Chart 72

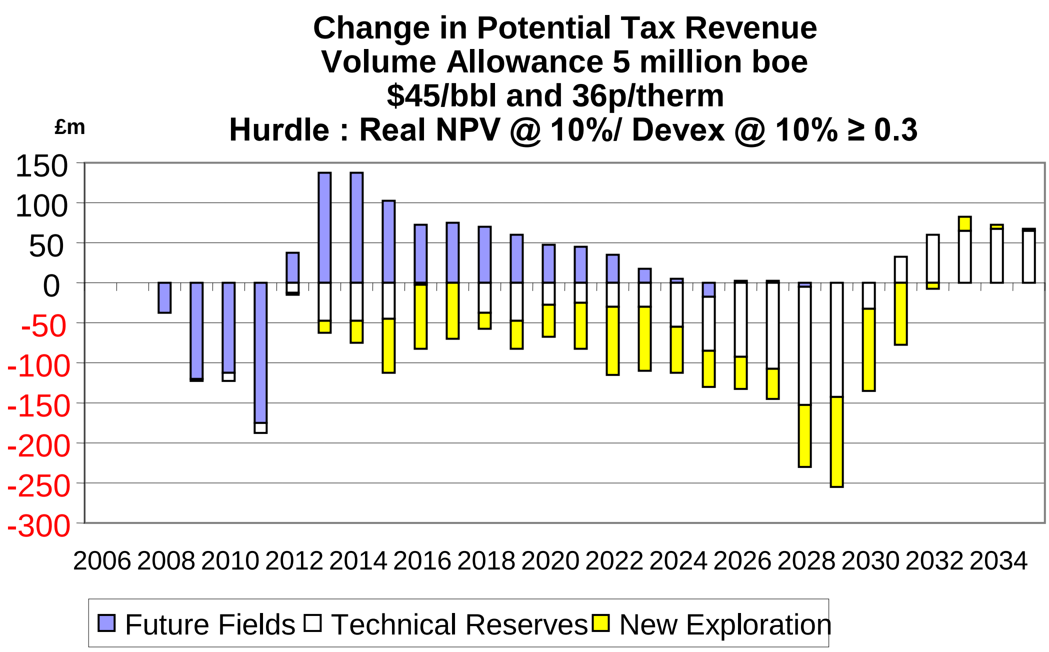


Chart 73 shows the potential change in tax revenue at the high price with the introduction of a 2mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £314m for the future fields, £467m for the technical reserve fields, by £1007m for the new exploration fields, with a total decrease of £1788m for all fields in the period to 2035.

Chart 73

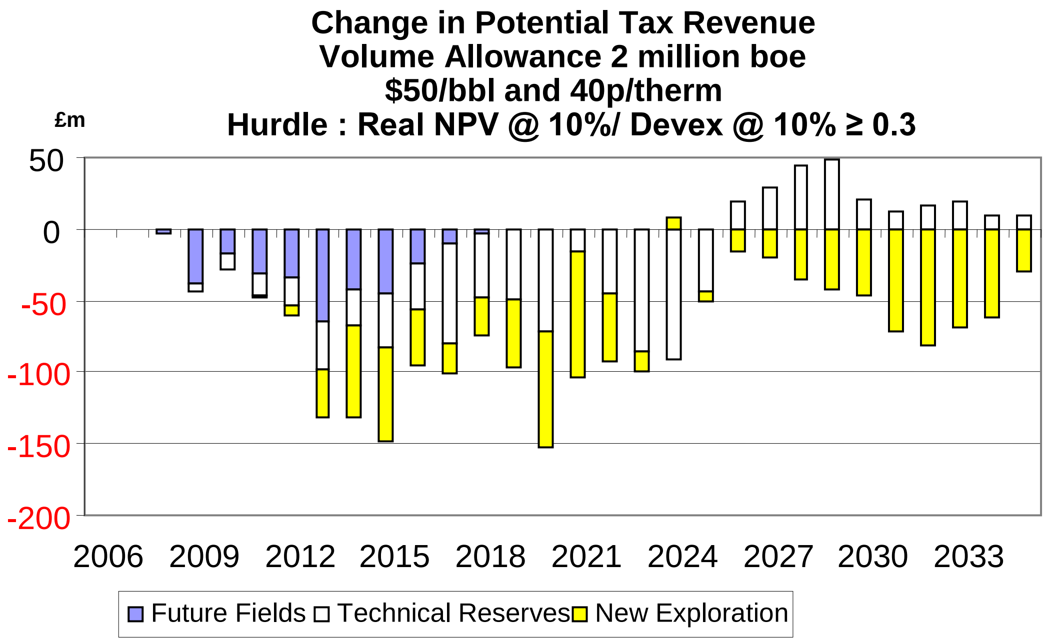


Chart 74 shows the potential change in tax revenue at the high price with the introduction of a 3mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £405m for the future fields, £716m for the technical reserve fields, £1254m for the new exploration fields, with a total decrease of £2375m for all fields in the period to 2035.

Chart 74

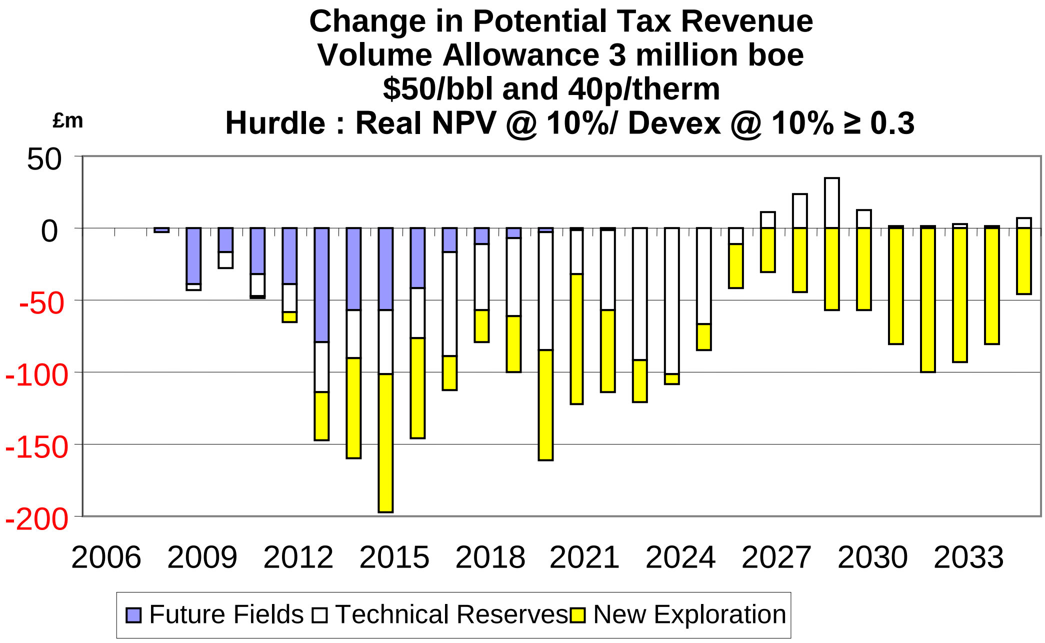


Chart 75 shows the potential change in tax revenue at the high price with the introduction of a 4mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £460m for the future fields, £761m for the technical reserve fields, £1468m for the new exploration fields, with a total decrease of £2689m for all fields in the period to 2035.

Chart 75

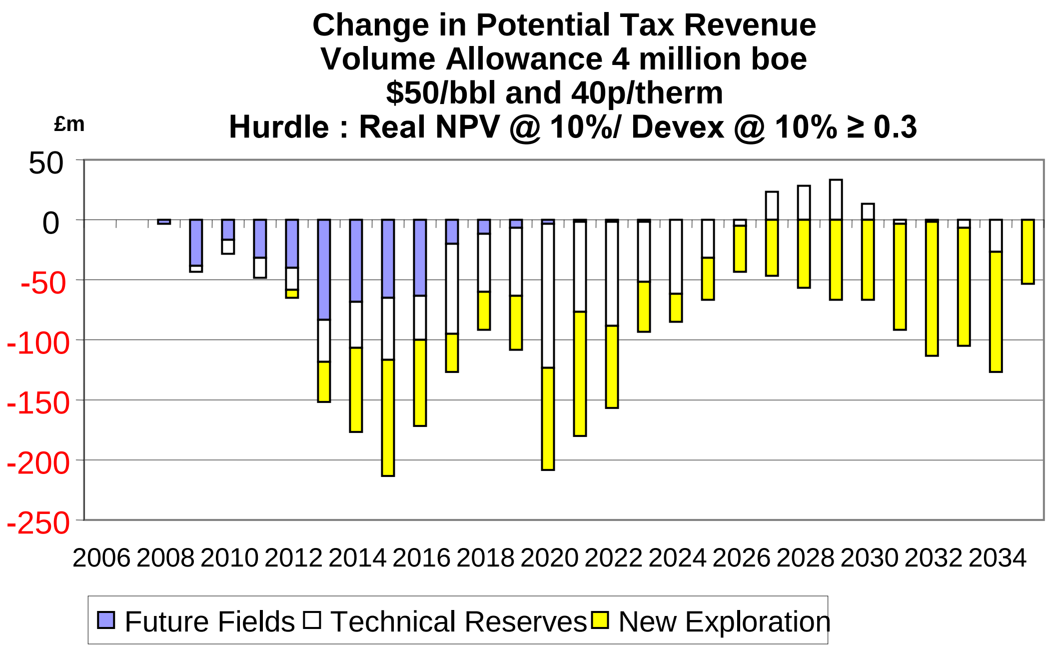
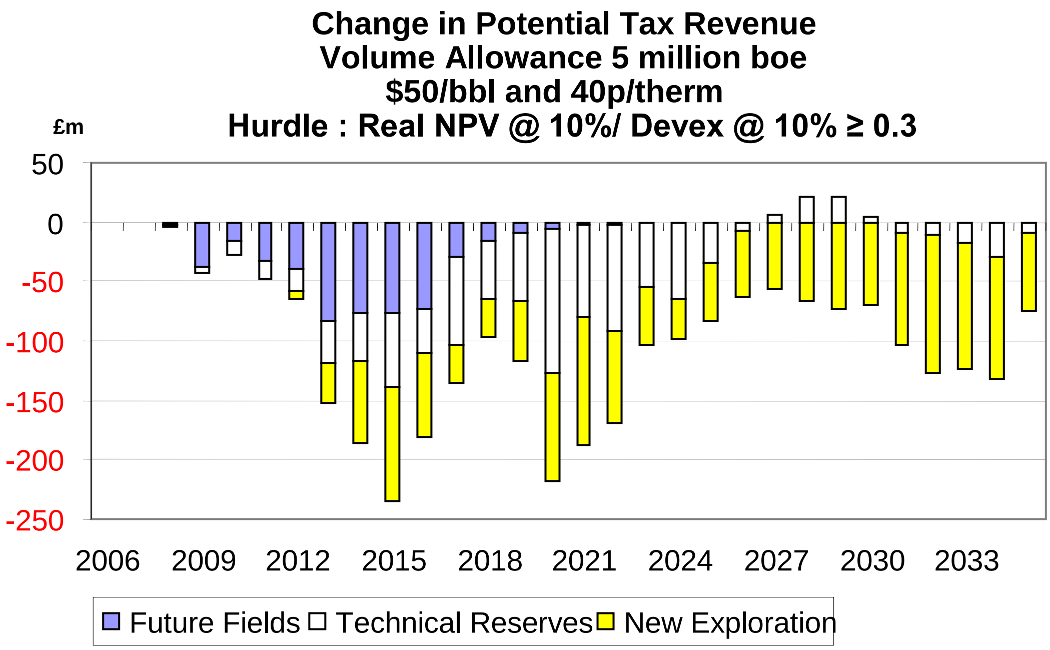


Chart 76 shows the potential change in tax revenue at the high price with the introduction of a 5mboe volume allowance against SCT when the hurdle is NPV/I. It may decrease by £504m for the future fields, £877m for the technical reserve fields, £1605m for the new exploration fields, with a total decrease of £2986m for all fields in the period to 2035.

Chart 76



It will be recalled that the charts show only the net change in tax revenues from the different categories of fields. It is interesting to see the sources of gain in revenues separated from the losses. In Charts 73a, 74a, 75a and 76a this is shown respectively for the 2, 3, 4, and 5mmboe volume allowances under the $50,40 pence scenario. With the 2mmboe allowance the gain from fields triggered by the relief is nearly £800 million. With the 3mmboe allowance it is over £880 million. With the 4mmboe allowance it is over £1 billion, and with the 5mmboe allowance it is also just over £1 billion.

Chart 73a

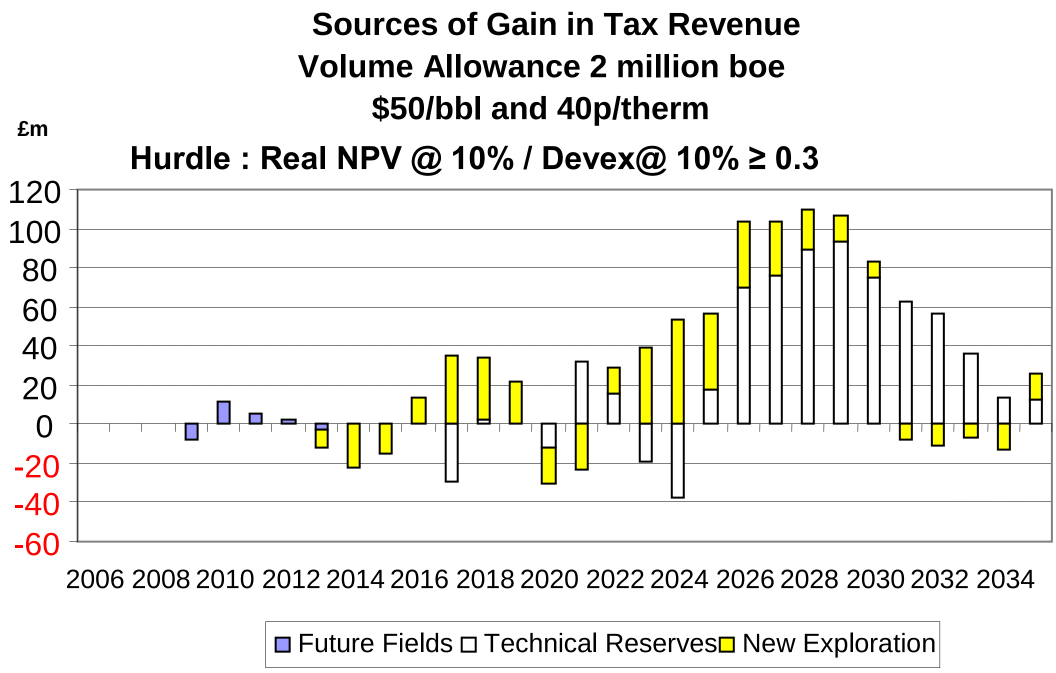


Chart 74a

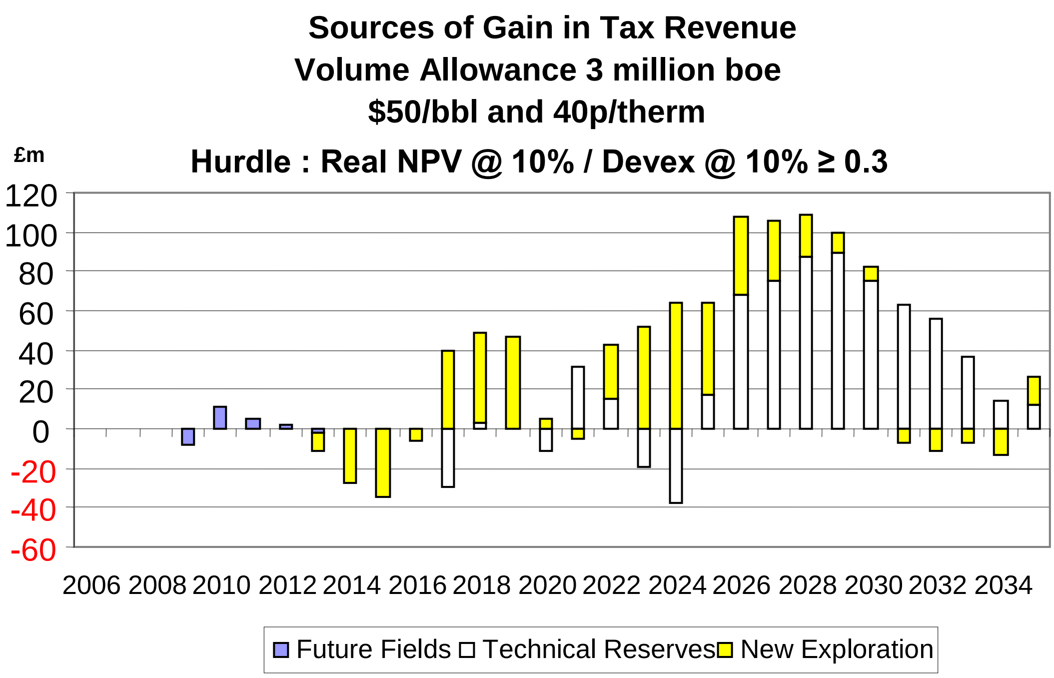


Chart 75a

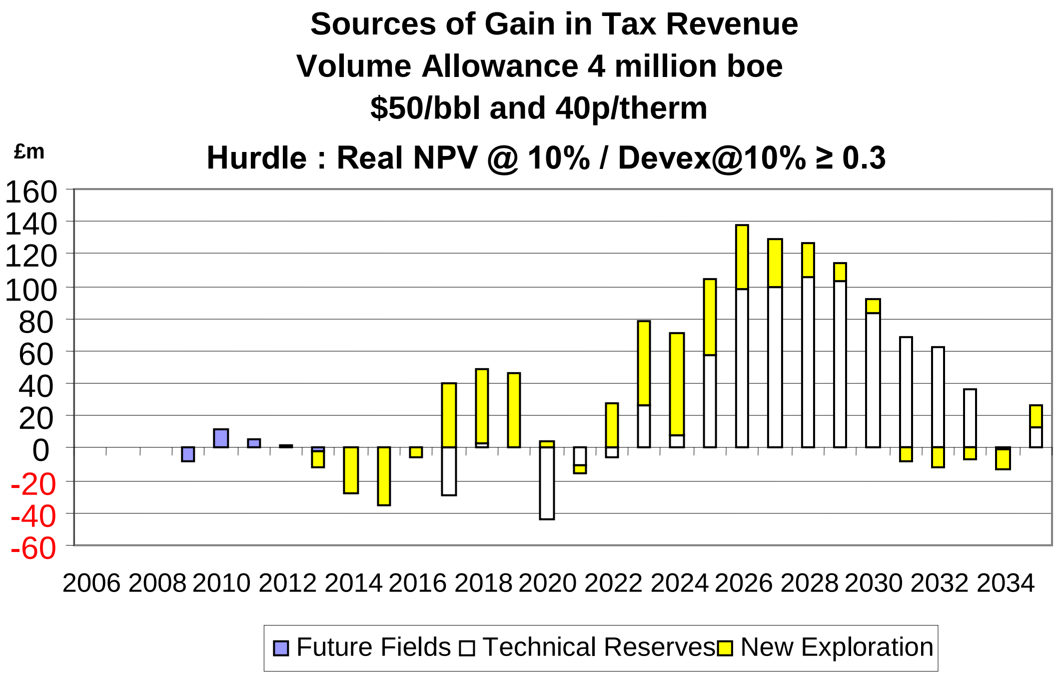
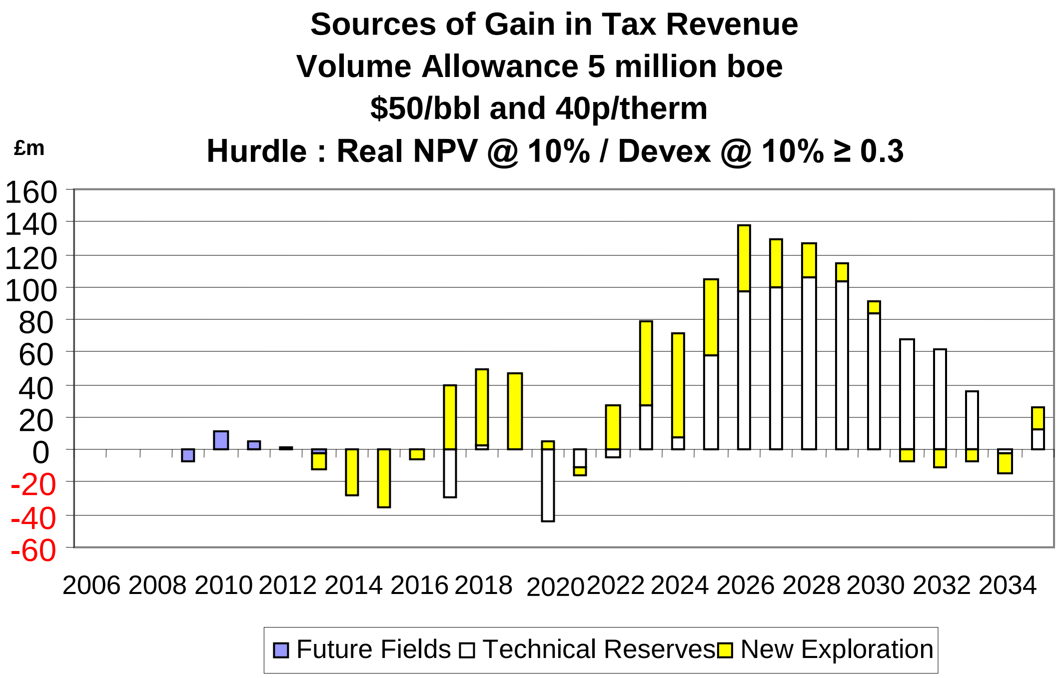


Chart 76a



(c) **Volume Allowance only for Small Gas Fields**

The UKCS is comprised of both oil and gas fields. Although the oil price is relatively high, gas prices are much lower. Given high development and operating costs combined with low gas prices there is a case for looking at the benefits of introducing a volume allowance for gas fields. To limit the possible cost of the commission its application to small gas fields in particular was modelled. Volume allowances of 2, 3 and 5mboe were considered, “small” was defined in the first instance as < 25Mboe and in the second instance as < 15Mboe. A field was defined as a “gas” field when more then 50% of its reserves were gas. The modelling was conducted for the $45,36 pence price case.

(i) Change in Number of Producing Fields

In the first case the field definition employed was < 25mmboe. No matter whether the volume allowance is 2, 3, 4 or 5mmboe 1 more probable/possible field and 1 more in the technical reserve capacity pass the economic hurdle. When the field definition was < 15mmboe only 1 more field pass the economic hurdle irrespective of the size of the volume allowance.

(ii) Change in Production

Chart 77 shows the change in the potential production when a volume allowance of 2mboe is introduced and “small” is defined as < 25Mboe. Over the period to 2035, total hydrocarbon production may increase by 20Mboe from future fields and 9Mboe from technical reserve fields with a total of 30Mboe in all.

Chart 77

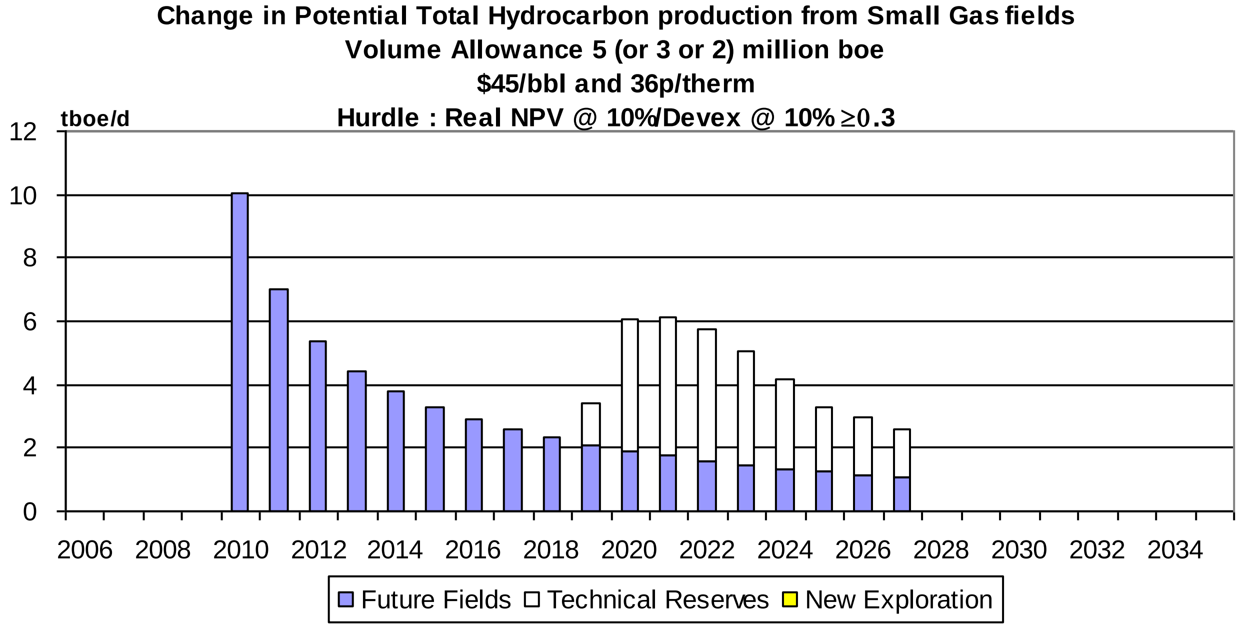
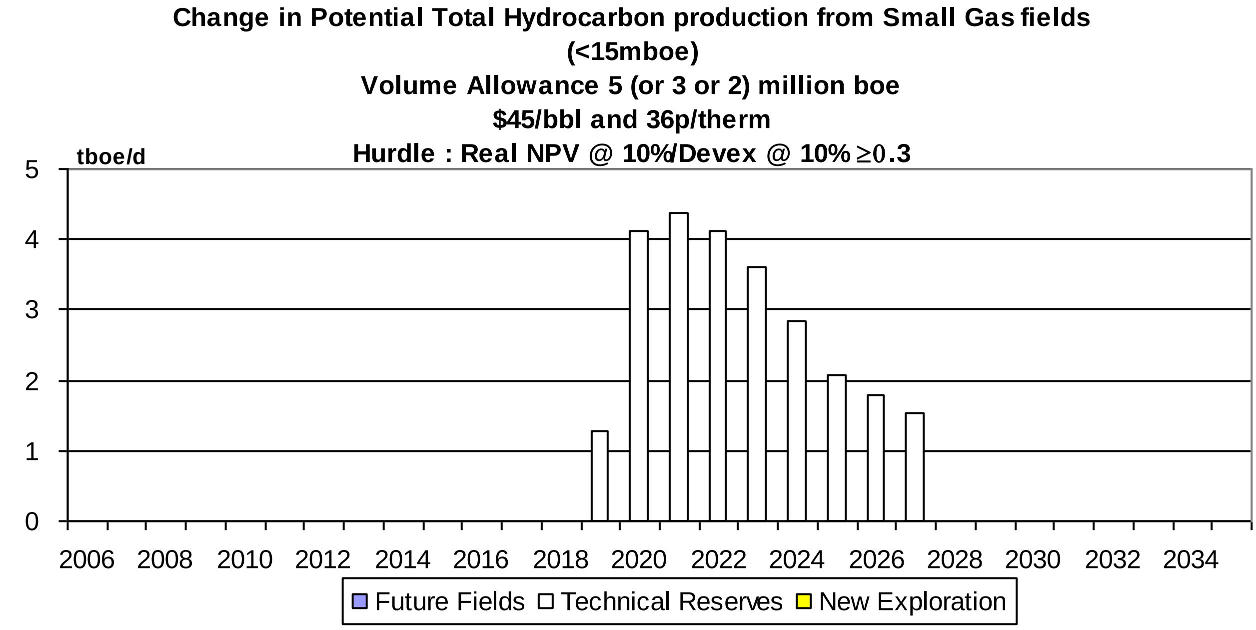


Chart 78 shows the change in the potential production when a volume allowance of 2, 3 or 5mboe is introduced and “Small” is defined as < 15Mboe. Over the period to 2035, total hydrocarbons may increase by 9Mboe.

Chart 78



(iii) Change in Tax Revenues

Chart 79 shows the change in the potential tax revenue when a volume allowance of 2mboe is introduced and “small” is defined as < 25Mboe.

It may decrease by £5m from the future fields, £162m from the technical reserve fields and by £149m from new exploration finds, with a total decrease of £316m over the period to 2035.

Chart 79

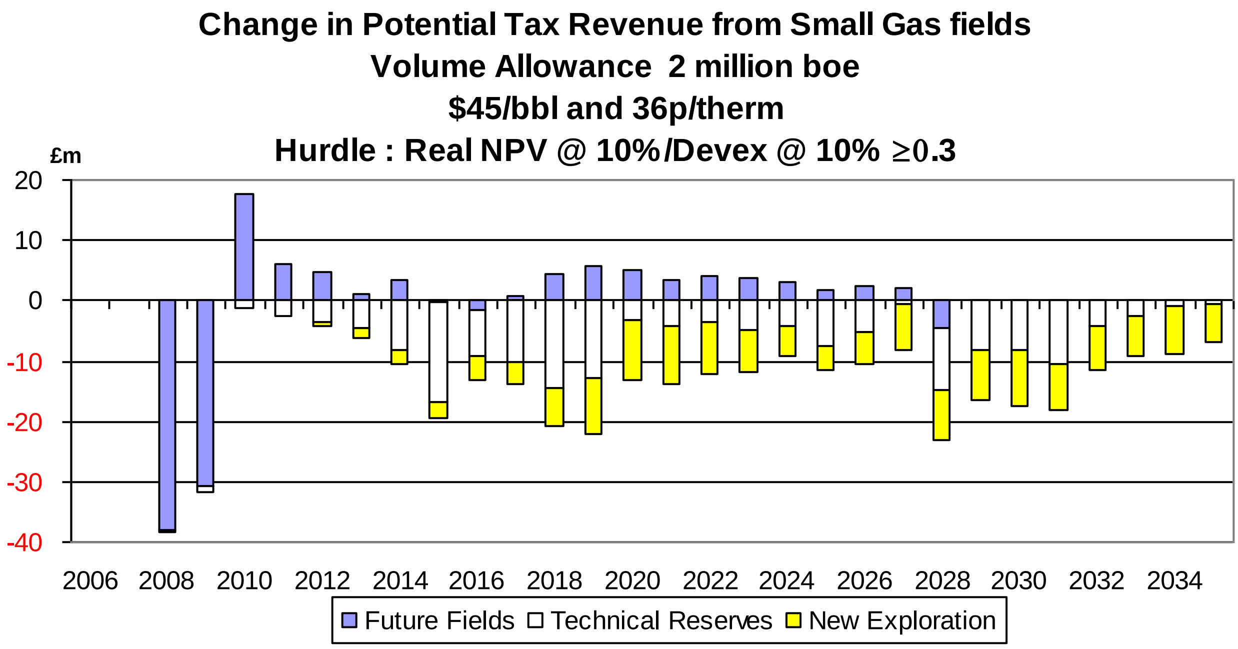


Chart 80 shows the change in the potential tax revenue when a volume allowance of 3mboe is introduced and “small” is defined as < 25Mboe.

It may decrease by £28m from the future fields, £194m from the technical reserve fields and by £156m from new exploration finds, with a total decrease of £378m in all over the period to 2035.

Chart 80

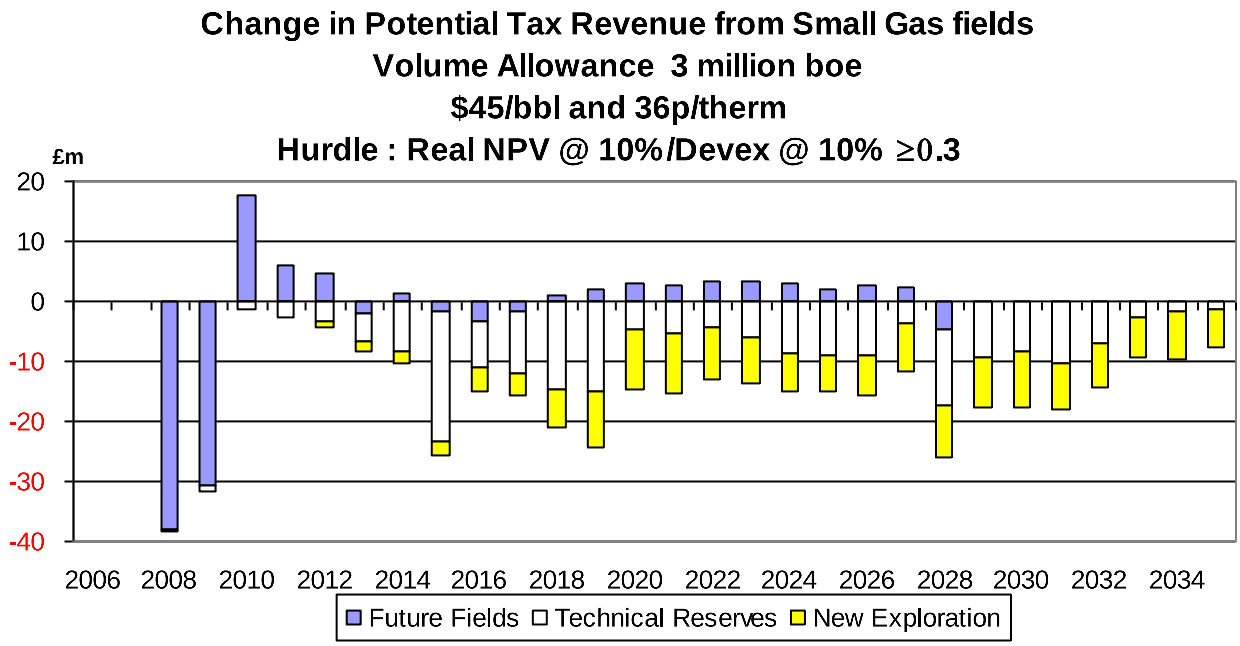


Chart 81 shows the change in the potential tax revenue when a volume allowance of 5mboe is introduced and “small” is defined as < 25Mboe.

It may decrease by £30m from the future fields, £211m from the technical reserve fields and by £156m from new exploration finds, with a total decrease of £396m over the period to 2035.

Chart 81

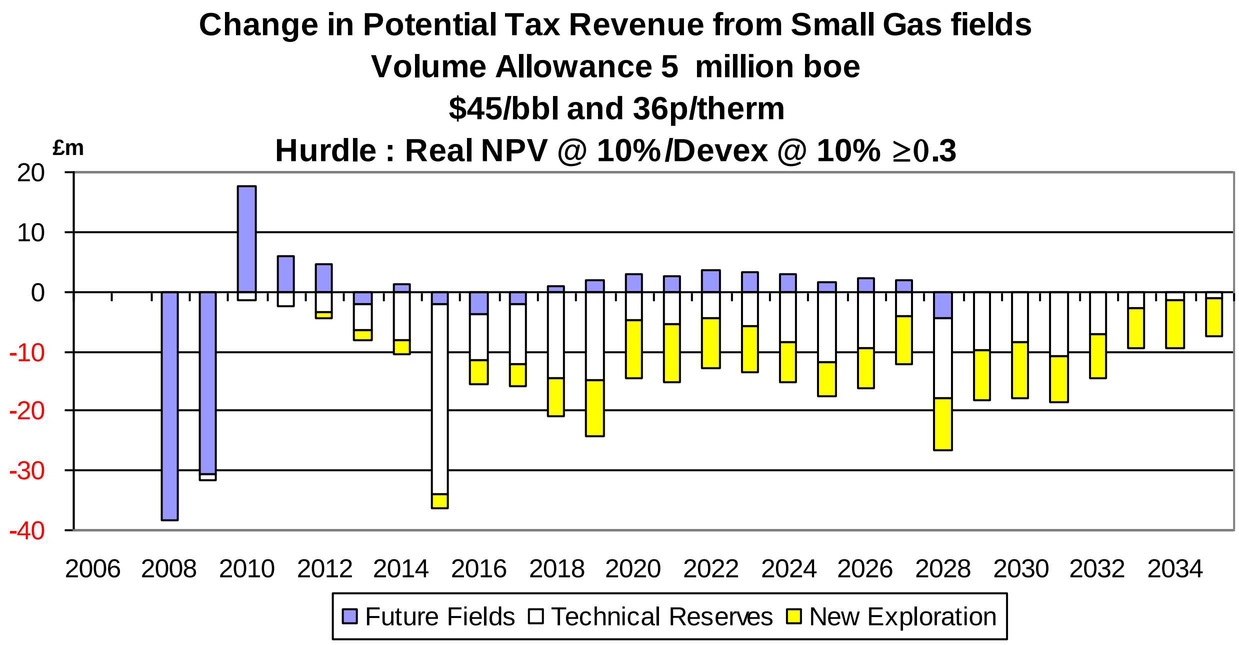


Chart 82 shows the change in the potential tax revenue when a volume allowance of 2mboe is introduced and "small" is defined as < 15Mboe.

It may decrease by £49m from the future fields, £82m from the technical reserve fields and by £68m from new exploration finds, with a total decrease of £200m over the period to 2035.

Chart 82

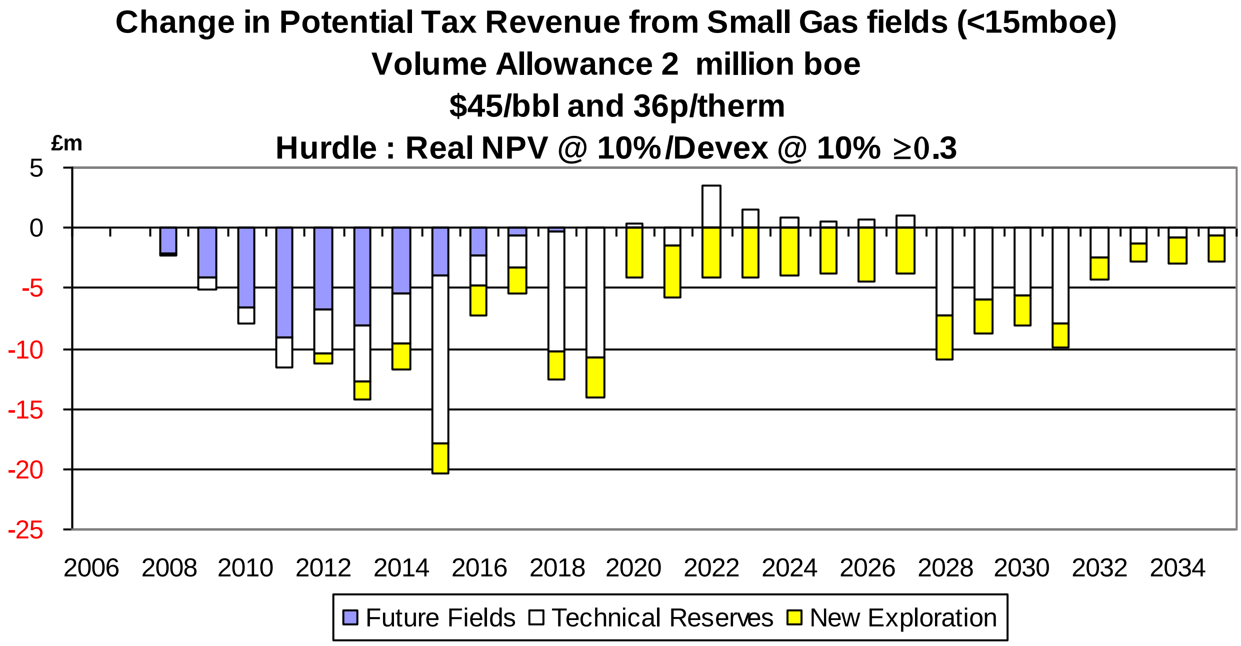


Chart 83 shows the change in the potential tax revenue when a volume allowance of 3mboe is introduced and "small" is defined as < 15Mboe.

It may decrease by £54m from the future fields, £90m from the technical reserve fields and by £68m from new exploration finds, with a total decrease of £212m over the period to 2035.

Chart 83

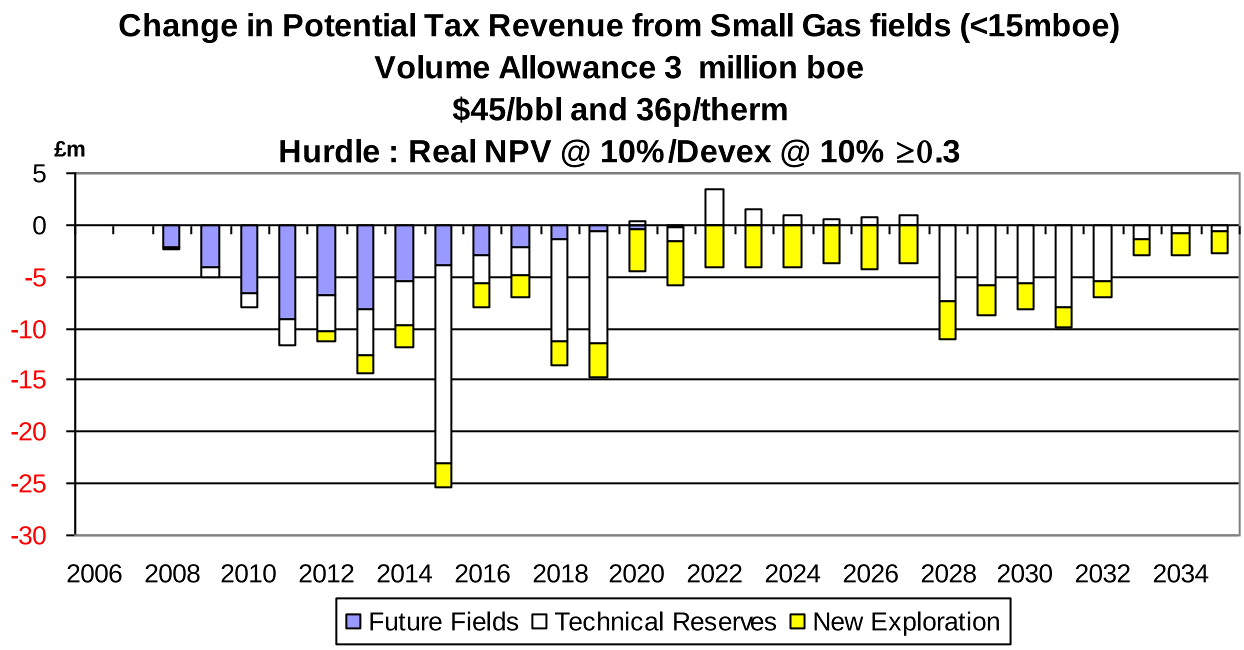
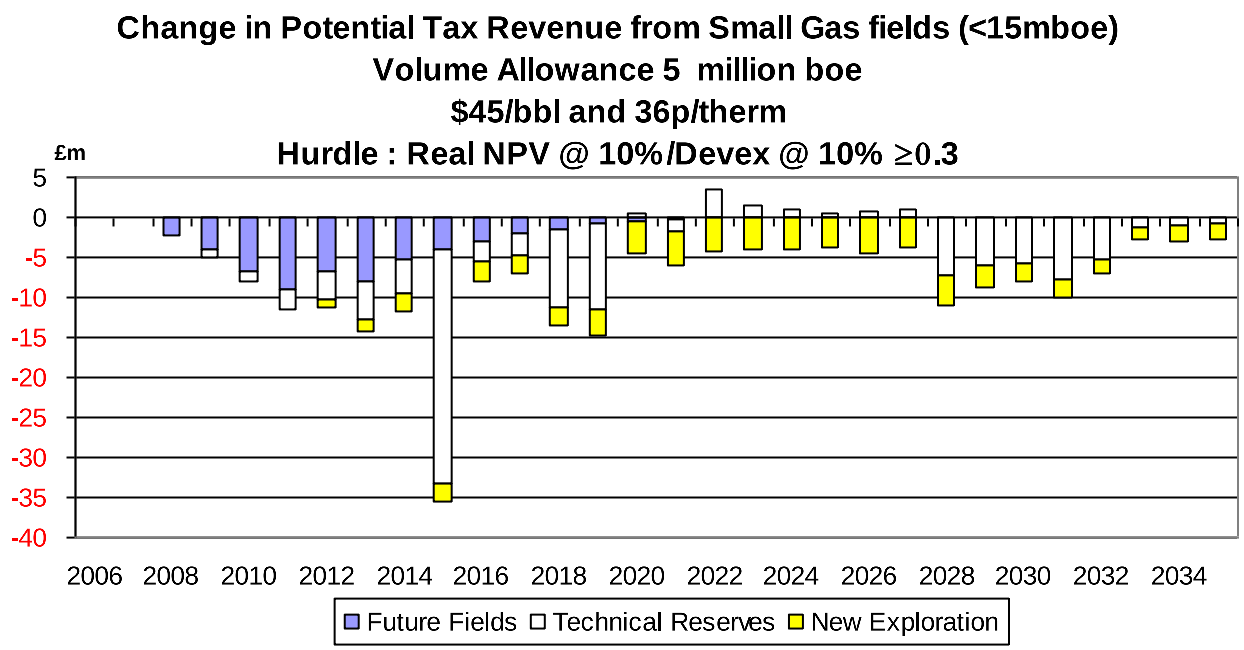


Chart 84 shows the change in the potential tax revenue when a volume allowance of 5mboe is introduced and "small" is defined as < 15Mboe.

It may decrease by £54m from the future fields, £100m from the technical reserve fields and by £68m from new exploration finds, with a total decrease of £223m over the period to 2035.

Chart 84



When “small” is defined as < 15Mboe it is even more apparent that the ability of the small fields to take full advantage of the volume allowance is curtailed by their SCT liability.

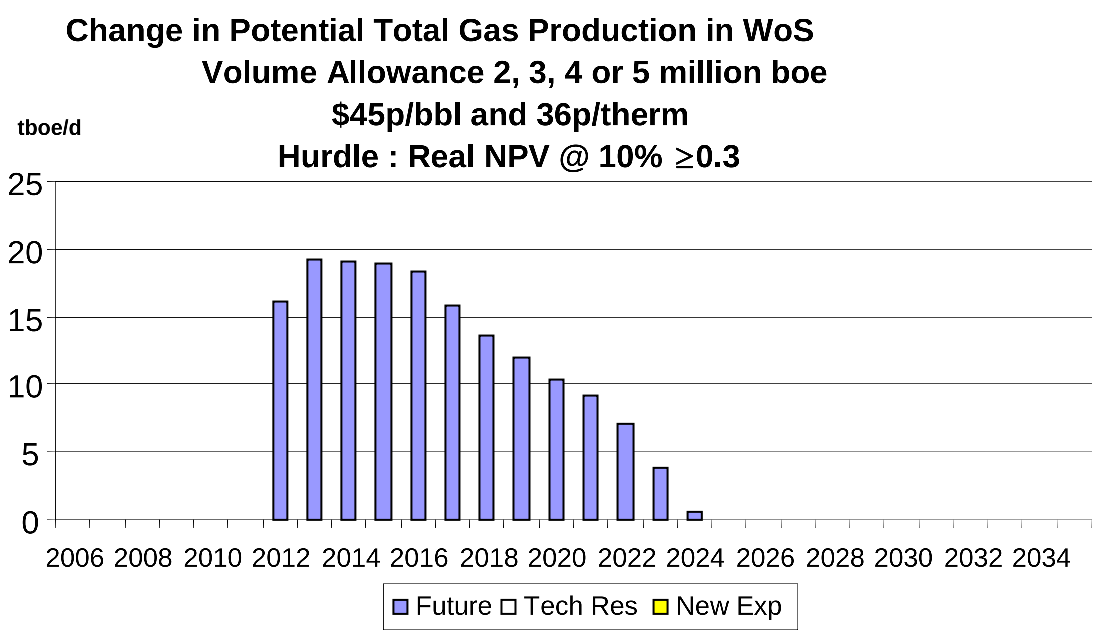
(d) Gas Volume Allowance by Regions of UKCS

(i) Changes in production

It was thought useful to examine the effects of the gas volume allowance applied to regions of the UKCS. The details of its application to <u>all</u> new gas fields in the WoS and the SNS are shown here.

In Chart 85 the effects on production are shown for the WoS under the $45,36 pence price case. There is a modest increase in production. The larger volume allowances can not be fully utilised because of the limited liability to SCT on the fields in the region.

Chart 85



In Chart 86 the effects on production are shown for the SNS with a 2 mmboe volume allowance. An extra 30 mmboe could be produced over the period to 2035. Thus 1 more probable/possible field is developed, as is 1 more in the technical reserves category.

Chart 86

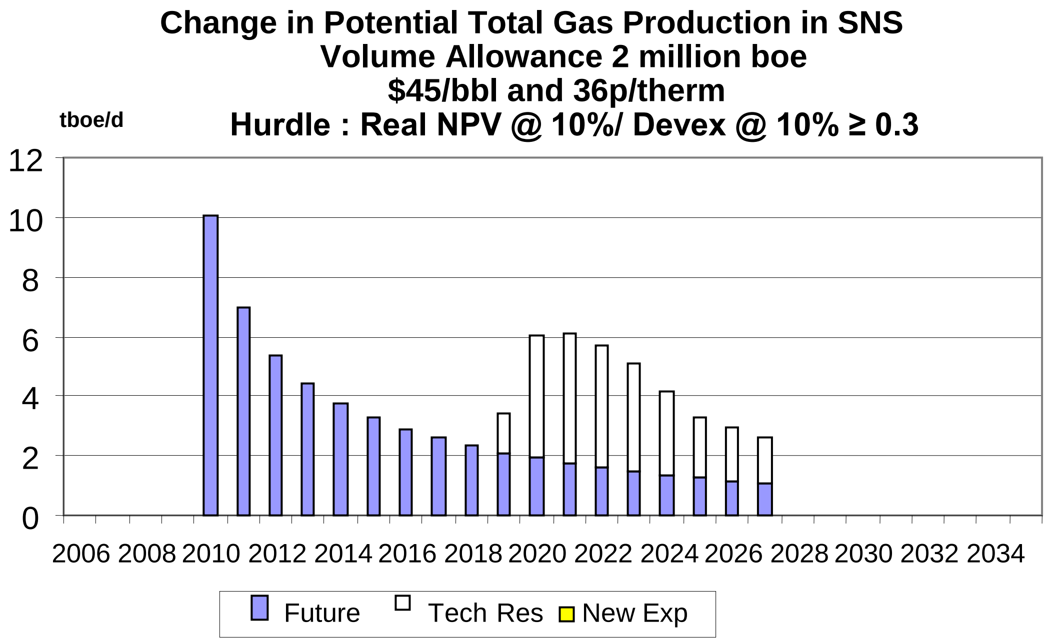
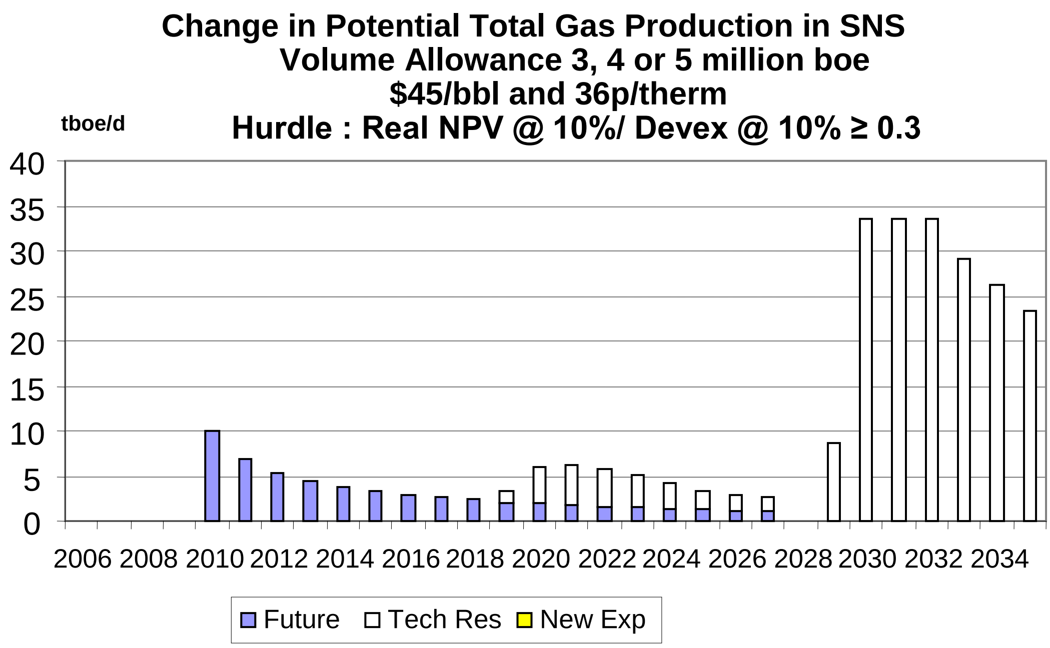


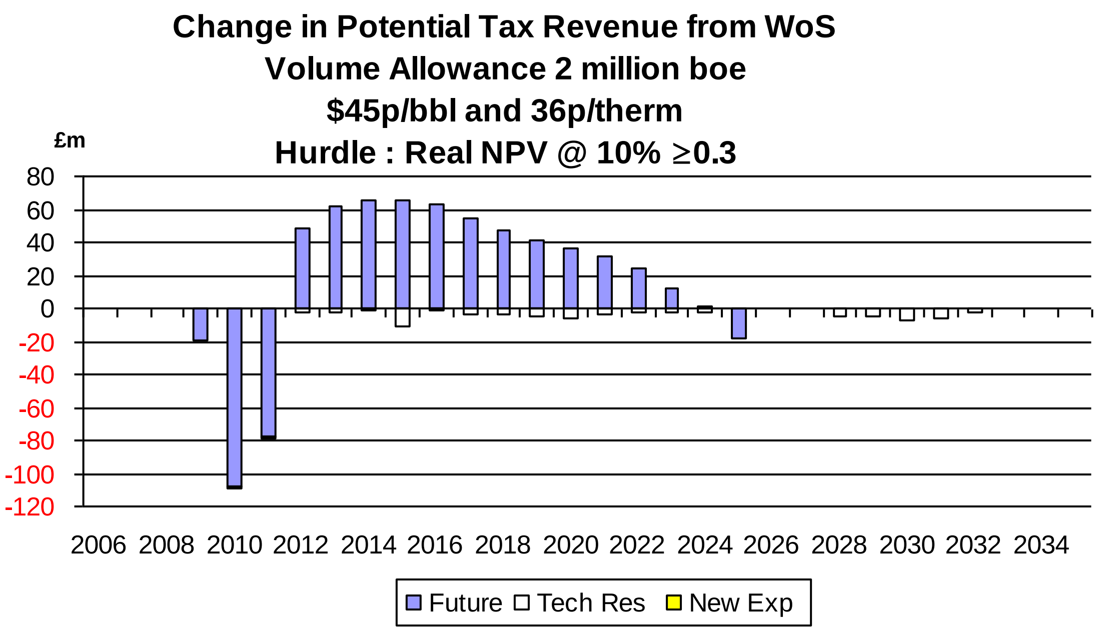
Chart 87



At the medium price with the NPV/I hurdle rate and with a 3, 4 or 5mboe volume allowance, 98mmboe more (over the period to 2035) could be produced in the SNS region. This is shown in Chart 87. Thus 1 more probable/possible field is developed, as are 2 more in the technical reserves category.

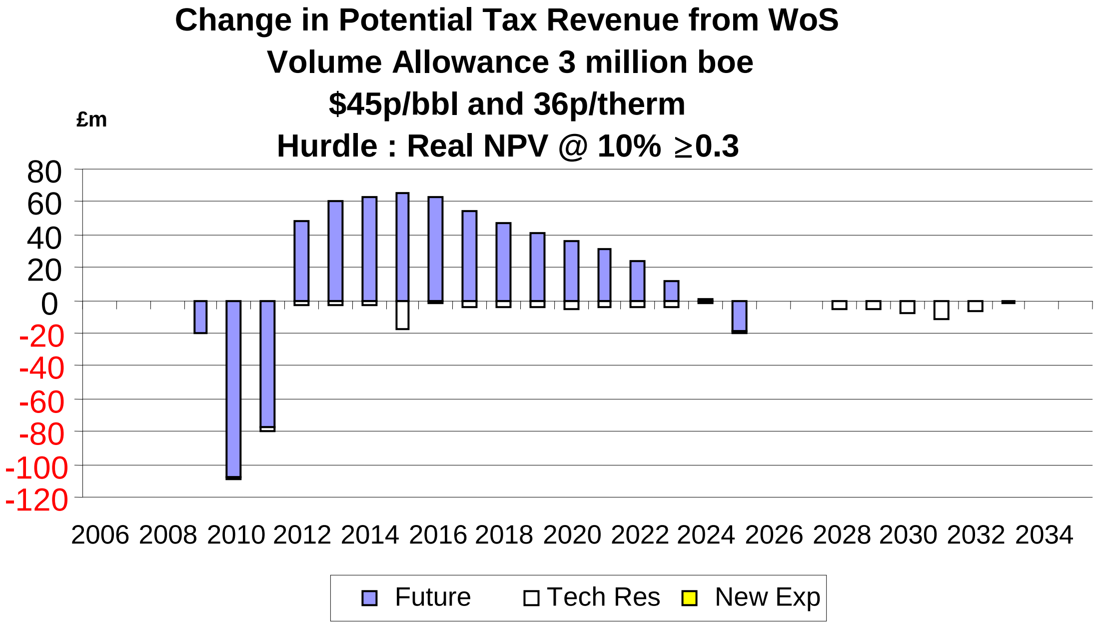
(ii) Changes in Tax Revenues

Chart 88



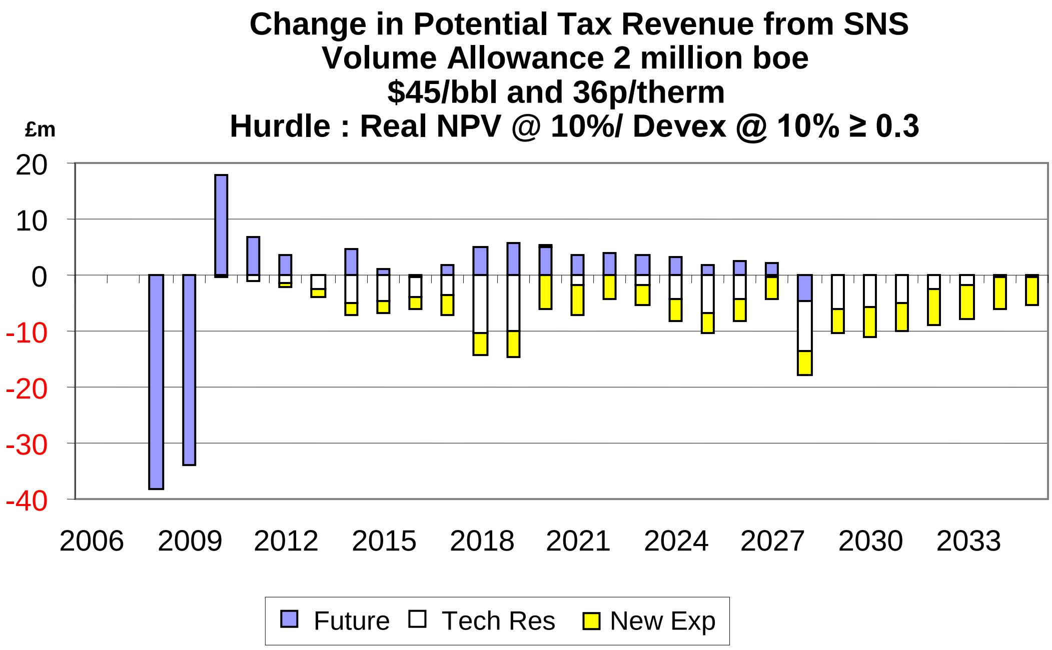
Changes in tax revenues emanating from the volume allowance are now considered. In the WoS region it was found that at the medium price with the NPV/I hurdle and with a 2mboe volume allowance, tax revenues from the future probable and possible field increased by £328m, those from the technical reserve fields decreased by £75m, with a total increase in tax revenue of £254m in the period to 2035. (Chart 88)

Chart 89



With a 3 mboe volume allowance, (Chart 89) tax revenues from the future probable/possible fields increased by £323m, those from the technical reserve fields decreased by £104m, with a total tax revenue increase of £219m in the period to 2035.

Chart 90



The position in the SNS with a 2mmboe volume allowance is shown in Chart 90. There is a decrease in tax revenue of £5m from future fields, a decrease of £93m from technical reserve fields, a decrease of £97m from new discoveries giving a total decrease of £195m in the period to 2035.

Chart 91

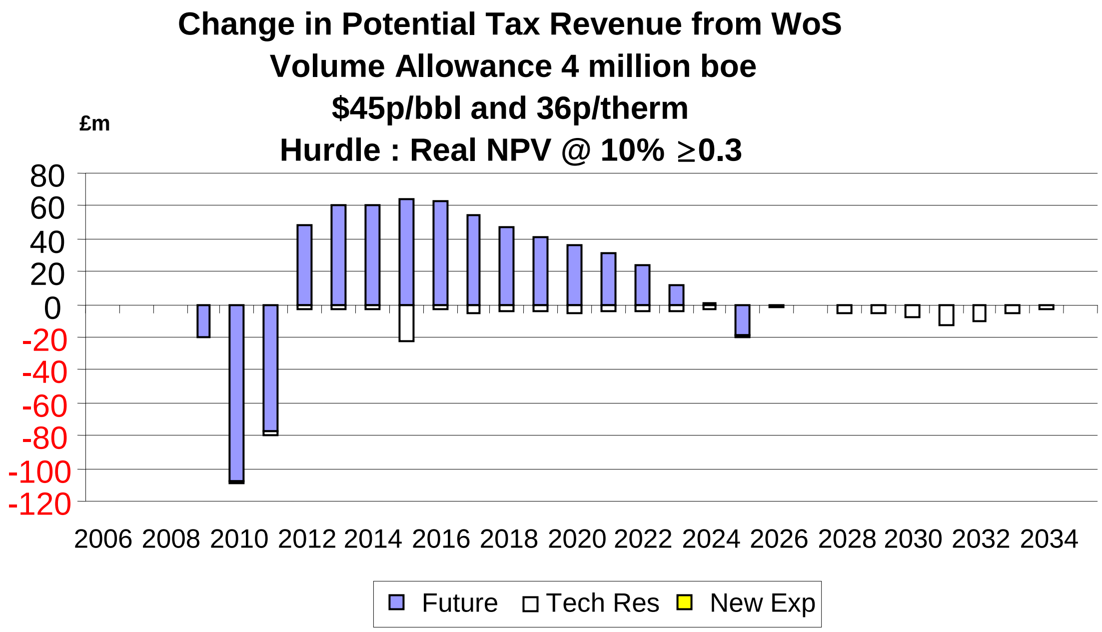


Chart 91 shows the tax changes in the WoS with a volume allowance of 4mmboe. There is an increase of £319m from future fields, a decrease of £128m from technical reserves, with a total increase of £191m over the period to 2035.

Chart 92

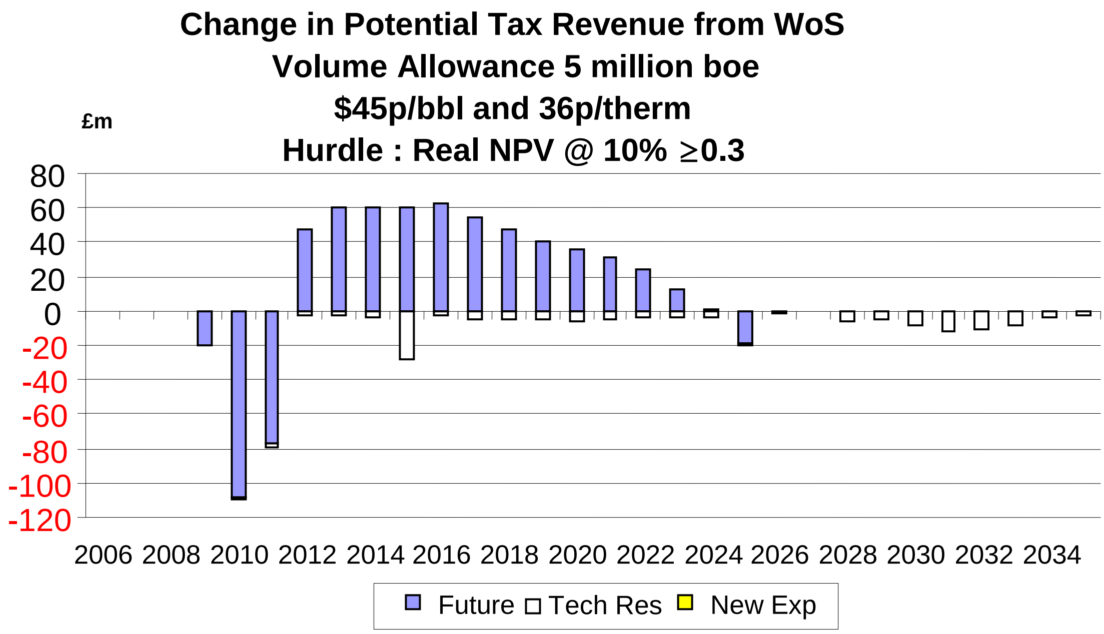


Chart 92 shows the tax changes in the WoS region with a 5 mboe allowance. There is an increase of £315m from future fields, a decrease of £140m from technical reserves, with a total increase of £174m in the period to 2035.

Chart 93

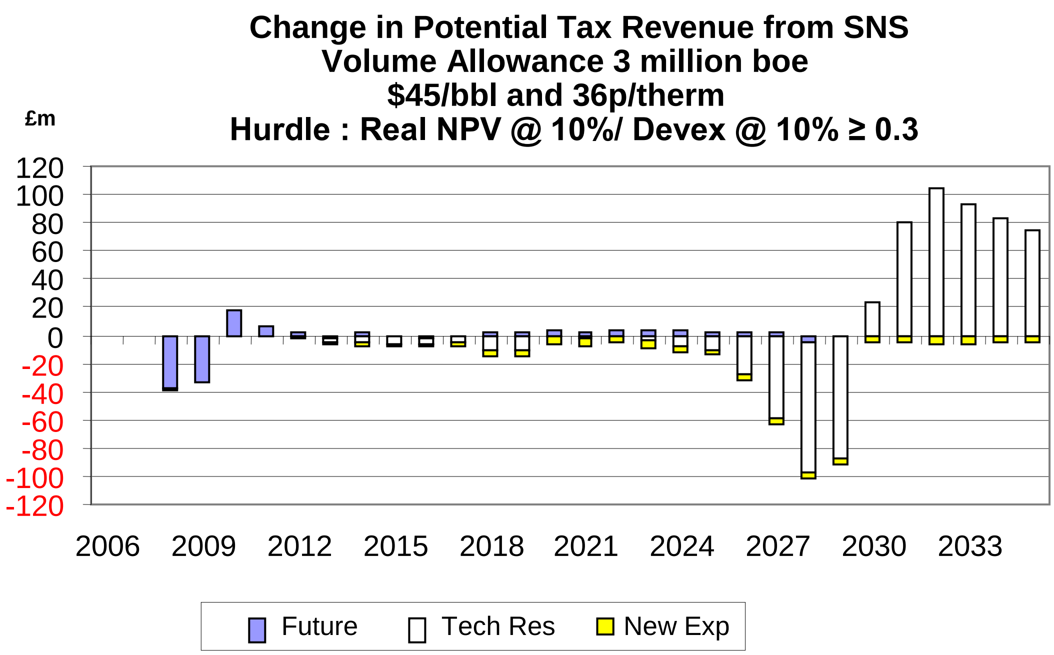


Chart 93 shows the change in tax revenues in the SNS with a 3mboe allowance. There is a decrease of £30m from future fields, an increase of £125m from technical reserves, and a decrease of £100m from new exploration, with a total decrease of £5m over the period to 2035.

Chart 94

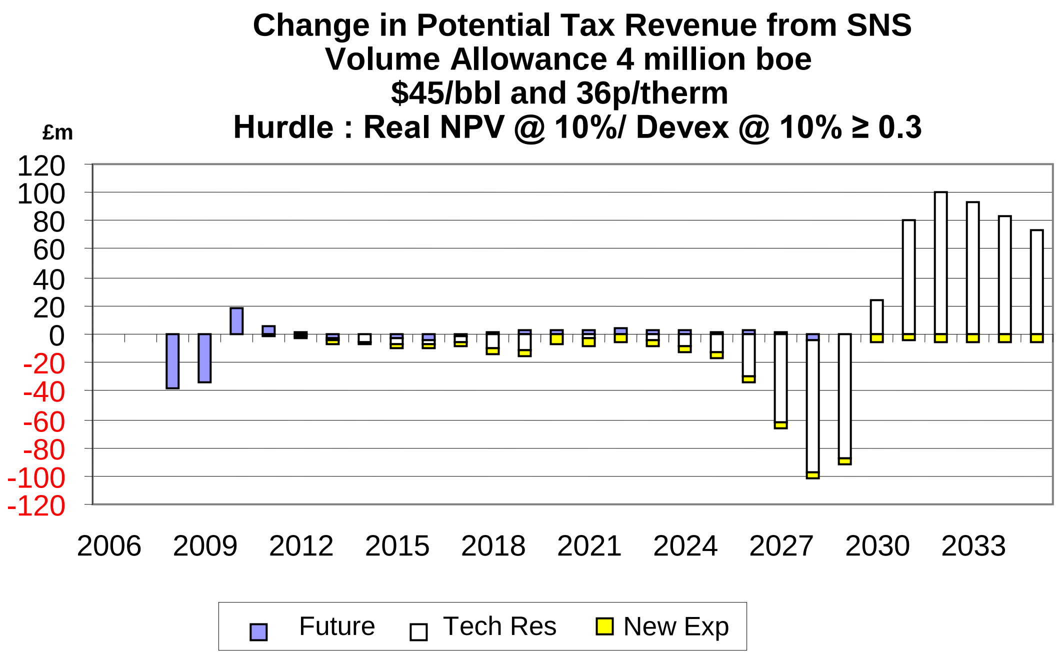


Chart 94 shows the tax changes in the SNS with a 4mboe allowance. There is a decrease of £36m from future fields, an increase of £110m from technical reserves, and a decrease of £100m from new exploration, with a total decrease of £26m over the period to 2035.

Chart 95

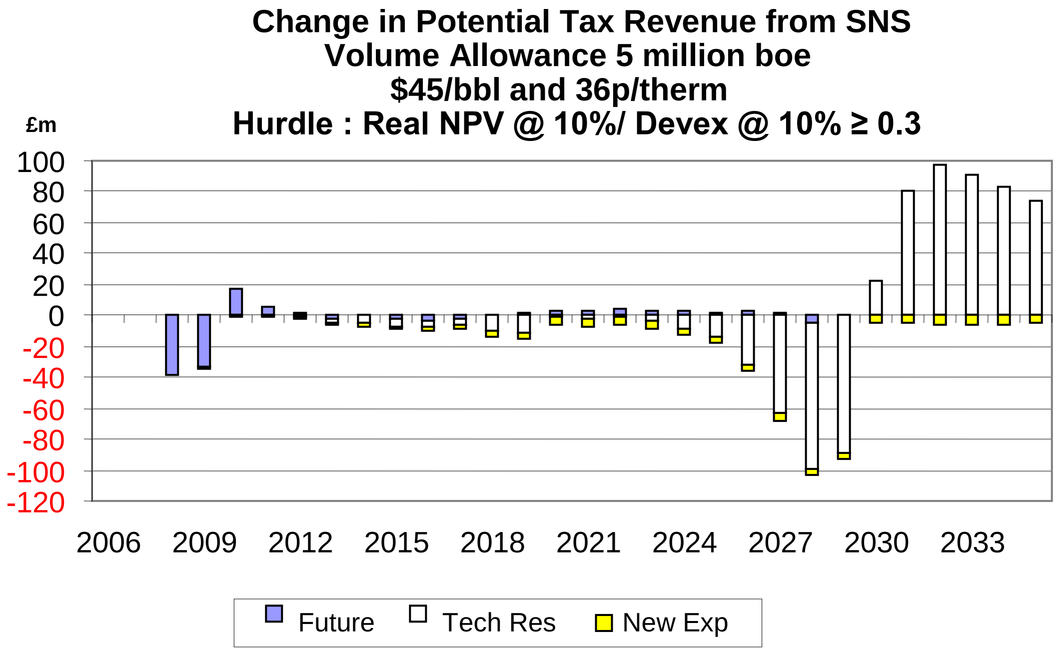


Chart 95 shows the tax changes in the SNS with a 5mboe allowance. There is a decrease of £37m from future fields, an increase of £98m from technical reserves, and a decrease of £100m from new exploration, with a total decrease of £40m over the period to 2035.

It is noteworthy that the net gains or minor losses in tax revenues from the gas volume allowances applied to all gas fields in the WoS and SNS contrast with net losses from the application of the allowance only to small gas fields. In the WoS and SNS there are some fields whose gas reserves exceed 25mmboe which, interestingly, help to produce a favourable net tax outcome.

5. Abolition of PRT

It has been suggested that PRT be removed from the UKCS fiscal system. It is a complex tax to administer and the time is approaching when the PRT liability will become negative because the decommissioning reliefs will be greater than the PRT payments on production.

There are a number of methods of abolishing PRT.

(a) Abolish PRT when PV of Payments ≤ PV of PRT Decommissioning Relief

One proposal is that PRT cease when the present value of the future PRT payments is equal to the present value of PRT relief for decommissioning costs. Two cases were looked at in the present study, one where the discount factor for calculating the present value is 3.5% and the other where it is 10%, both in real terms with an inflation factor of 2.5%. In both cases the starting point for the calculation is taken as 2009.

For the year in which PRT ceases there is a compensating repayment of PRT. This was modelled in PV terms as remaining real PV PRT relief minus real PV remaining PRT liability using the 2 discount rates. The compensating repayment affects CT/SCT as the compensating repayment is liable to CT/SCT. For modelling purposes the best estimates of the relevant variables, including production, and field investment, operating and decommissioning costs were used. No changes in behaviour were considered.

Chart 96

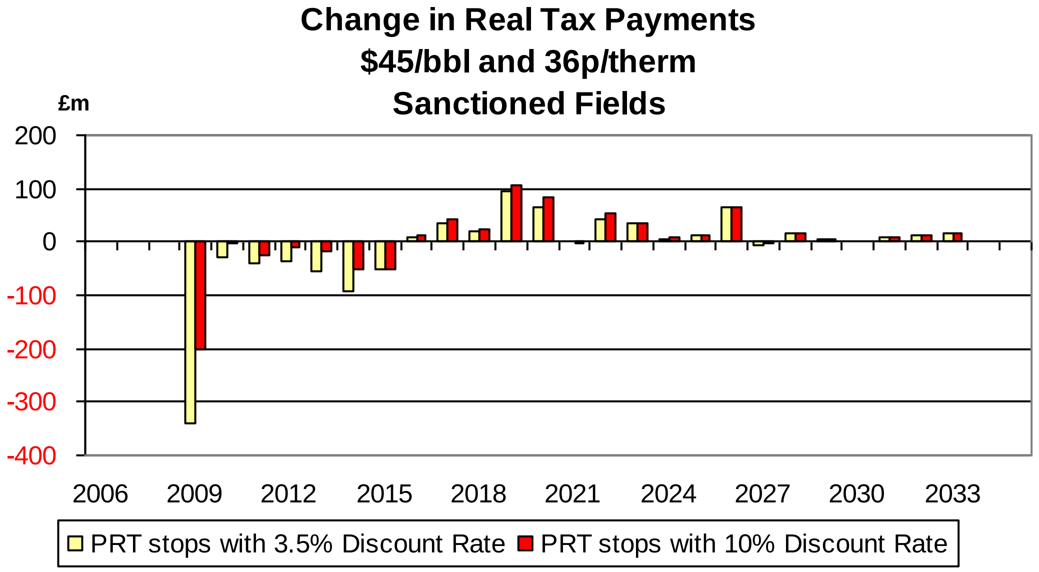


Chart 96 shows the change in total tax revenues that occur when PRT ceases under the two discount rates. With a 3.5% real discount rate total real tax revenues are reduced by £213m in the period to 2035, whilst if the PV calculation uses a 10% real discount rate then real tax revenue is increased by £130m. The more noticeable feature, however, is the substantial decrease in the tax bill in 2009 and in the period to 2015. This reflects the acceleration in net PRT relief following the introduction of the scheme in 2009. The increase in 2009 is particularly noticeable because a considerable number of fields become subject to the scheme in that year.

Chart 97

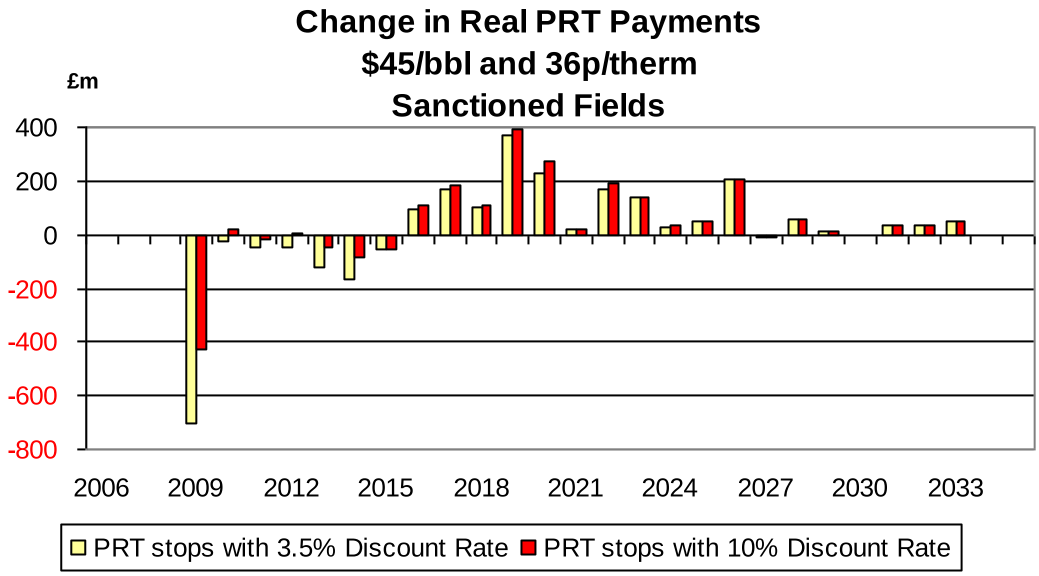


Chart 98

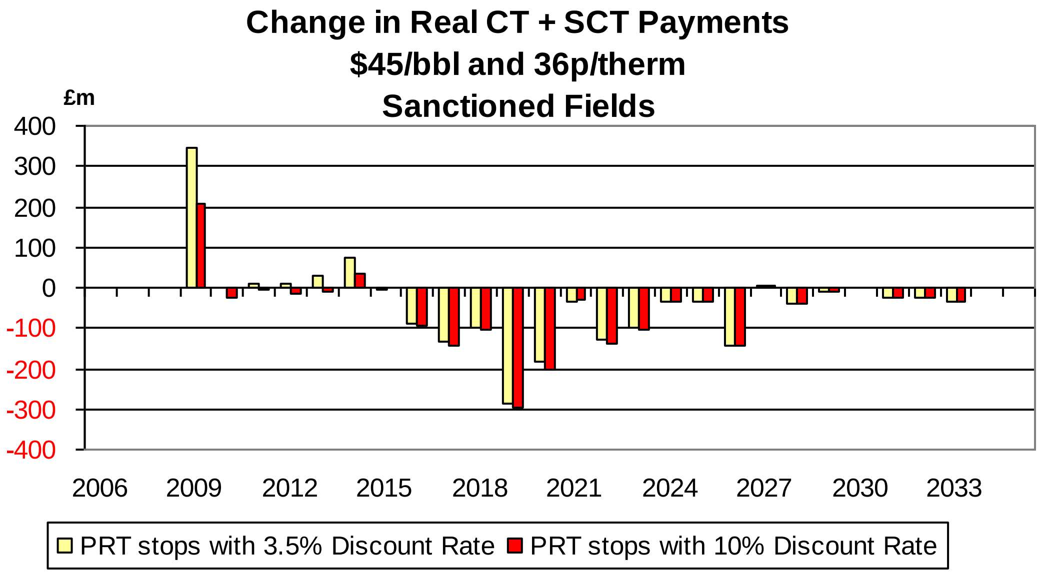


Chart 97 shows the change in real PRT payments that occurs when PRT ceases under the two discount rates. Under the 3.5% real discount rate real PRT paid is increased by £587m in the period to 2035 whilst with a 10% real discount rate then real PRT is increased by £1272m. This reflects the netting off of a large proportion of PRT liabilities (against decommissioning allowances) in 2009, but some PRT still remain in the years beyond this.

Under the current system PRT would turn negative around 2019. The decrease in PRT in the period 2009 – 2015 is noticeable especially in 2009, the initial year of the scheme.

Chart 98 shows the change in real CT + SCT payments that occurs when PRT ceases under the two discount rates. Under the 3.5% real discount rate real CT + SCT is reduced by £928m over the period whilst with a 10% real discount rate then real CT + SCT is reduced by £1270m. Where PRT ceases, when a field finally decommissions there is no PRT relief for decommissioning (as this has been in effect given earlier) so the CT/SCT base for decommissioning relief is not reduced by a CT/SCT liability on any PRT decommissioning relief given under the current tax system.

Chart 99

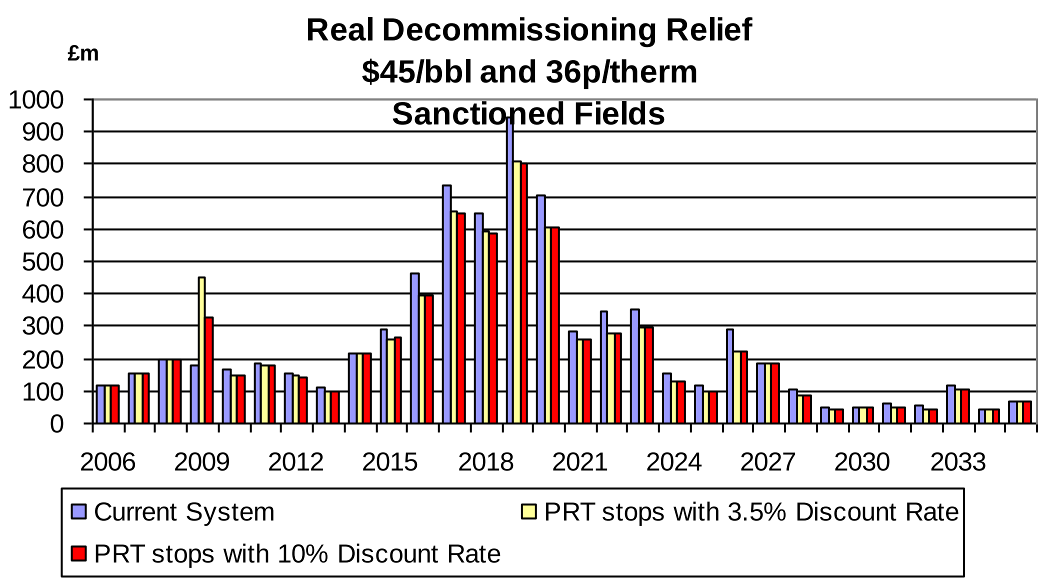


Chart 99 shows real decommissioning relief at the medium price under the current fiscal system and the scenarios where PRT ceases based on the PV calculations using 3.5% and 10% real discount rates.

Chart 100

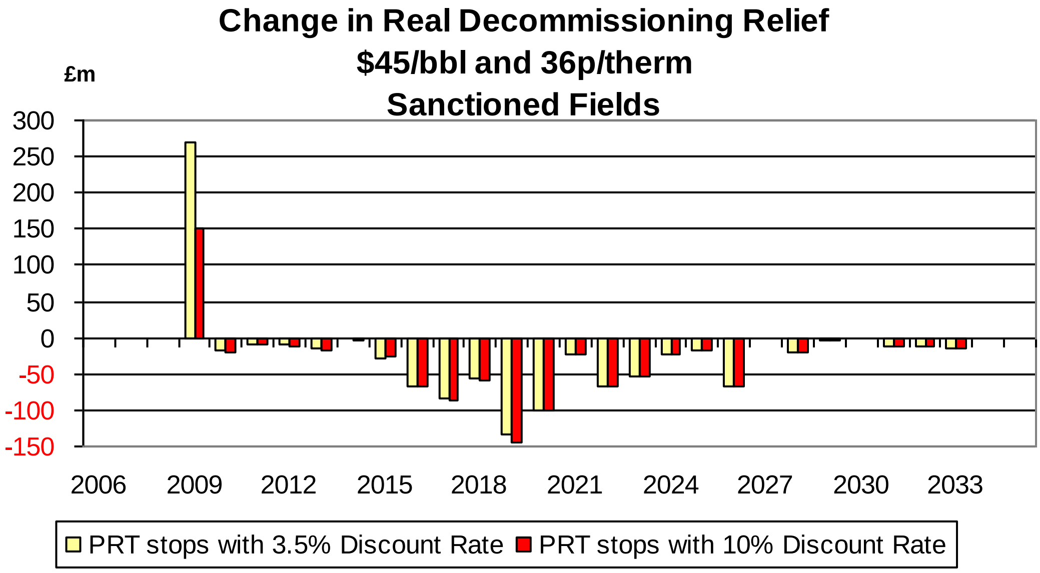


Chart 100 shows the change in real decommissioning relief that occurs when PRT ceases. With a 3.5% real discount rate then real decommissioning relief is decreased by £563m over the period whilst with a 10% real discount rate then relief is decreased by £706m.

Chart 101

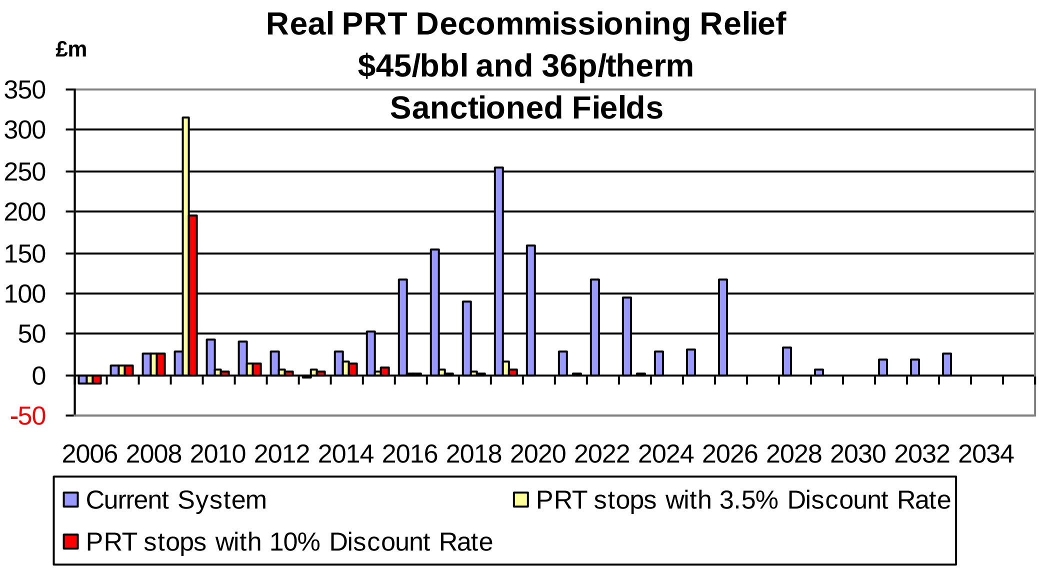


Chart 101 shows real PRT relief at the medium price under the current fiscal system and the scenarios where PRT ceases based on PV calculations using 3.5% and 10% real discount rates. Over the period as a whole PRT relief is highest with the current tax system followed by the case where the discount rate is 3.5%.

Chart 102

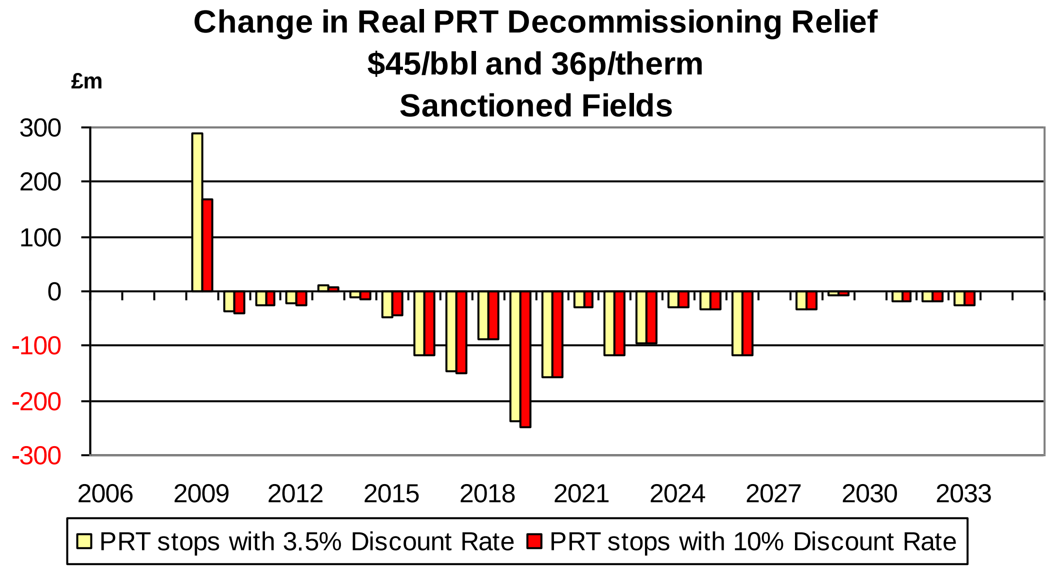


Chart 102 shows the change in real PRT decommissioning relief that occurs after PRT ceases under the two schemes. With a 3.5% real discount rate PRT relief is reduced by £1113m over the period, whilst with a 10% real discount rate PRT relief is reduced by £1256m. It should be noted that interest on PRT losses clawed back forms part of the current system.

Chart 103

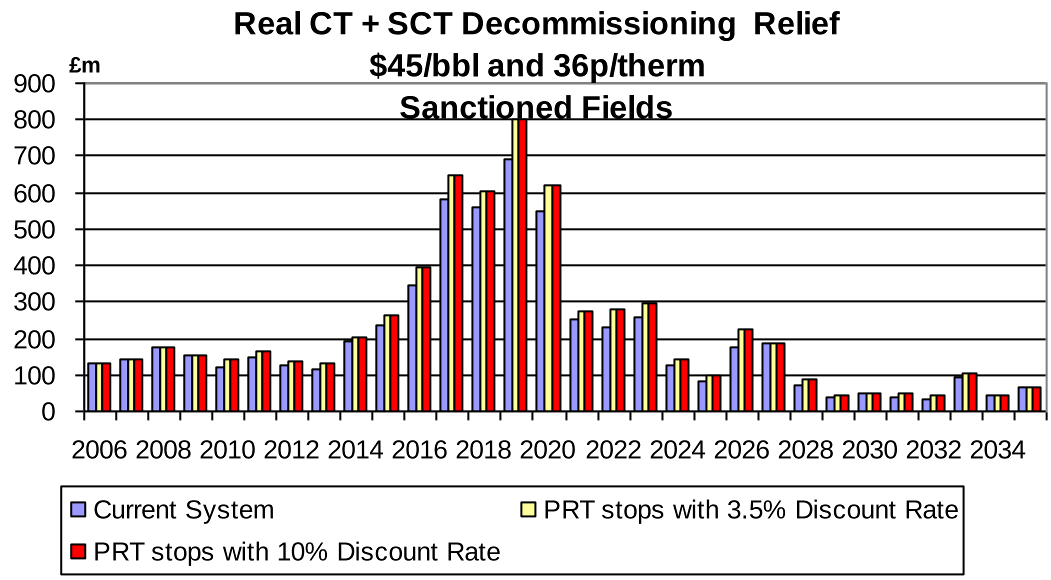


Chart 103 shows real CT + SCT relief at the medium price under the current fiscal system and the scenarios where PRT ceases.

Chart 104

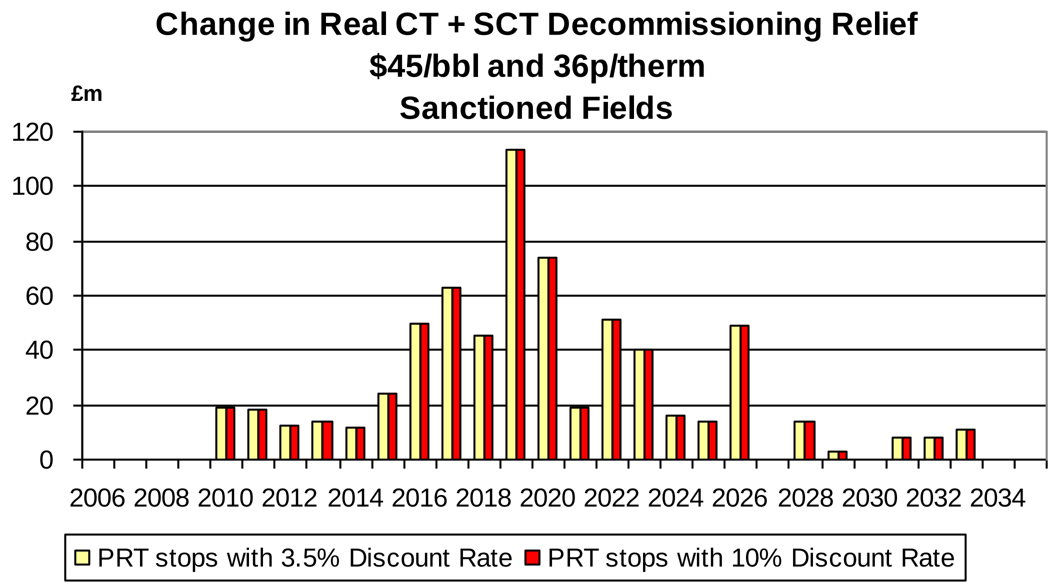


Chart 105

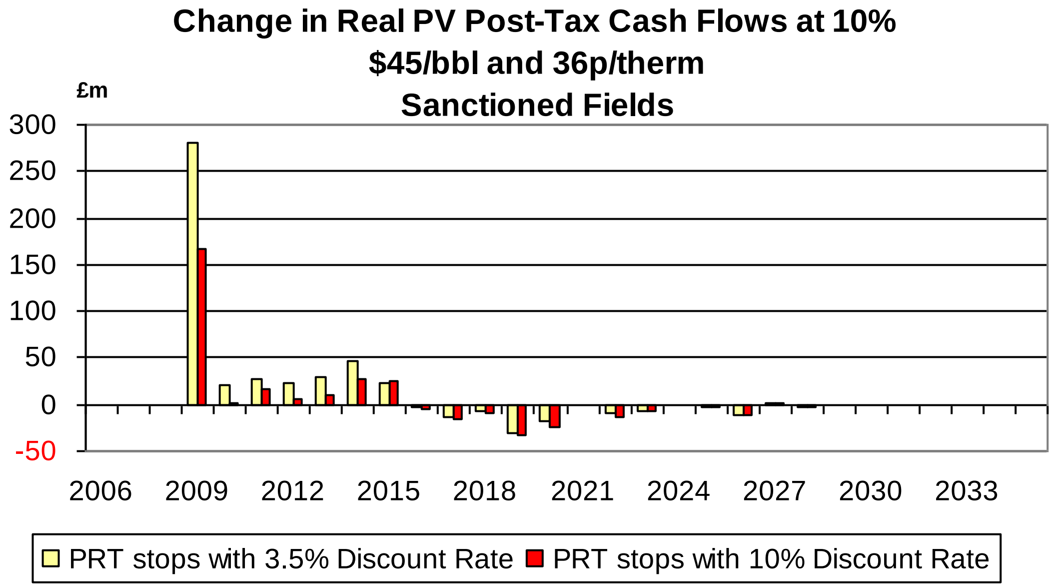


Chart 104 shows the change in real CT + SCT relief that occurs when PRT ceases under the two discount rates. With a 3.5% real discount rate then real CT +SCT relief is increased by £677.63m whilst with a 10% real discount rate then real CT +SCT relief is increased by £677.58m. (On decommissioning there is no CT/SCT charge/liability on PRT relief).

Chart 105 shows the change in the real PV of the post tax cashflows with a 10% discount rate. With a 3.5% discount rate for the scheme the real PV post tax cashflows are increased by £344m whilst with a 10% discount rate for the scheme the real PV post tax cashflows are increased by £124m.

(b) Abolition of PRT Through Buy-Out

Another proposal is that there be a compulsory buy-out of PRT. In the modelling this starts in 2009. The "cost" of the buy-out is found by calculating the remaining PRT payments and reliefs and finding the NPV of this cashflow (using 3.5% and 10% real discount rates). The calculated NPV (buy-out cost) is then spread equally over 5 years in PV terms at the discount rate in question. The PRT "liability" thus becomes the cost of the buyout. If the remaining PRT relief is greater than the remaining PRT payments then a PRT repayment is due. After buyout there would be no more PRT relief for decommissioning but the buyout cost/repayment becomes an allowed expense for CT/SCT.

Chart 106

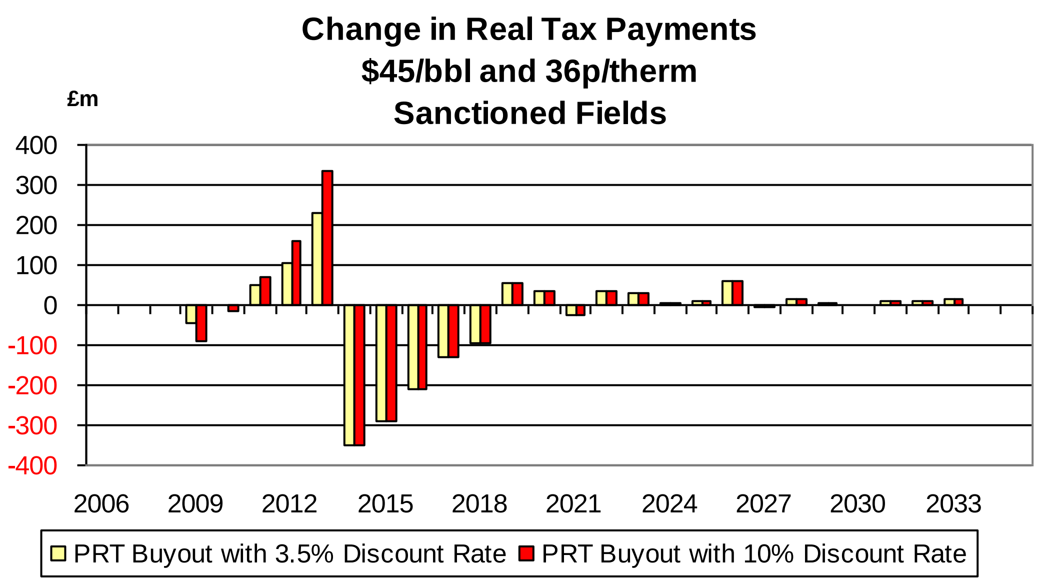


Chart 106 shows the change in real tax payments with the introduction of the buy-out schemes at the medium price. Over the period to 2035, total tax revenues are reduced by £476m where the discount rate is 3.5%. Where the discount rate is 10% tax revenues are reduced by £360. The operation of the buy-out scheme results in no PRT liability after 2013.

Chart 107

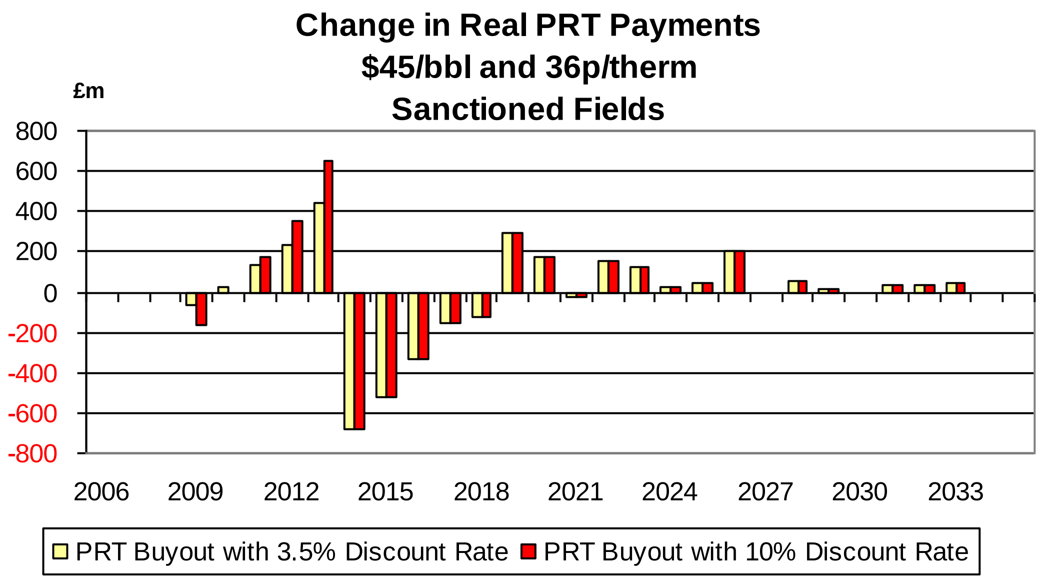


Chart 107 shows the change in PRT at the medium price with the buy-out scenarios. With the 3.5% discount rate over the period to 2035 PRT is increased by £117m whilst with the 10% rate PRT over the period it is increased by £349m. This results from the operation of the buy-out scheme plus the existence of some reliefs.

Chart 108

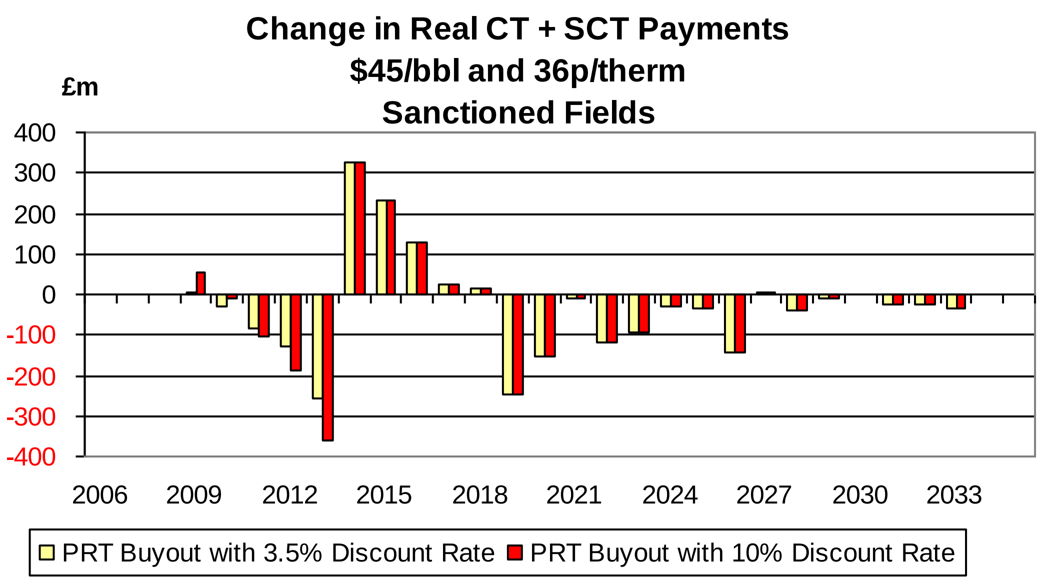


Chart 109

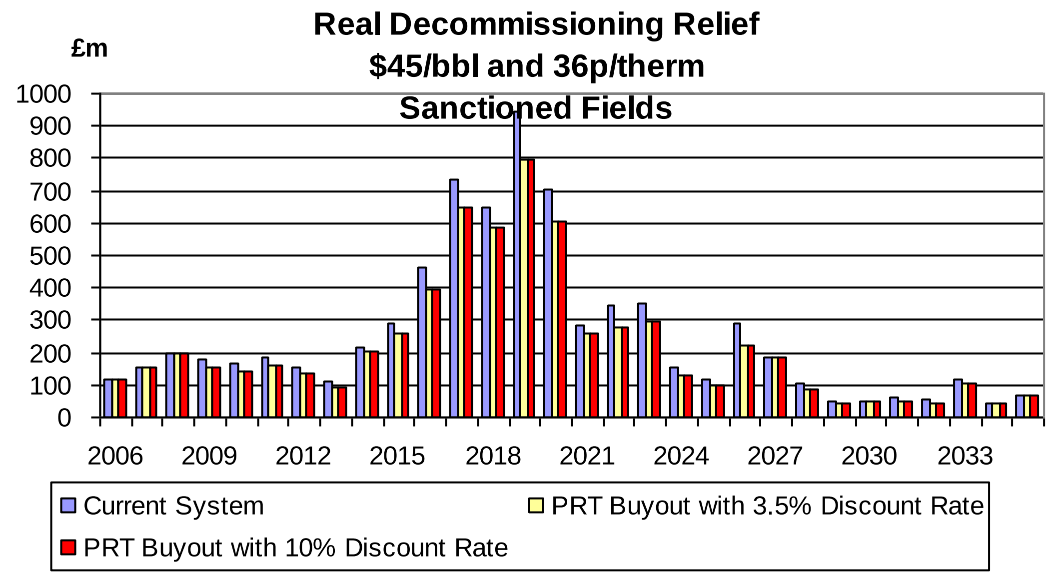


Chart 108 shows the change in CT + SCT at the medium price with the introduction of the buy-out schemes. Using a 3.5% discount rate to calculate the cost of buy-out, the CT + SCT liability is reduced by £721m whilst using the 10% discount rate the CT + SCT liability is reduced by £837m.

Chart 109 shows real decommissioning relief under the current tax system alongside the buy-out scenarios at the medium price. There is no difference in the decommissioning relief under the two discount rates.

Chart 110

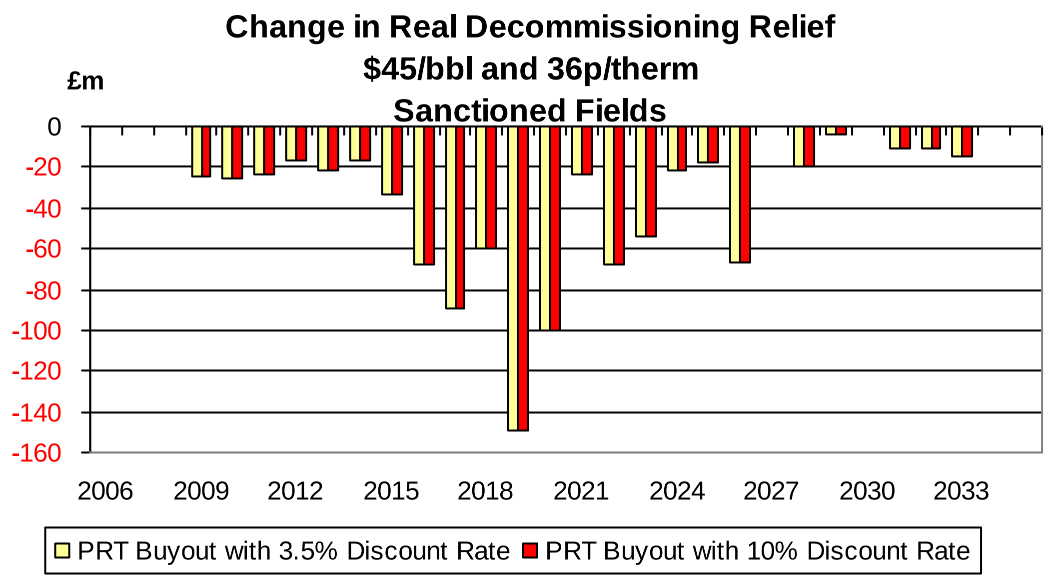


Chart 110 shows the change in decommissioning relief under the buy-out scenarios. Real decommissioning relief is reduced by £941m when buyout occurs. This follows from the change in PRT relief (see below).

Chart 111

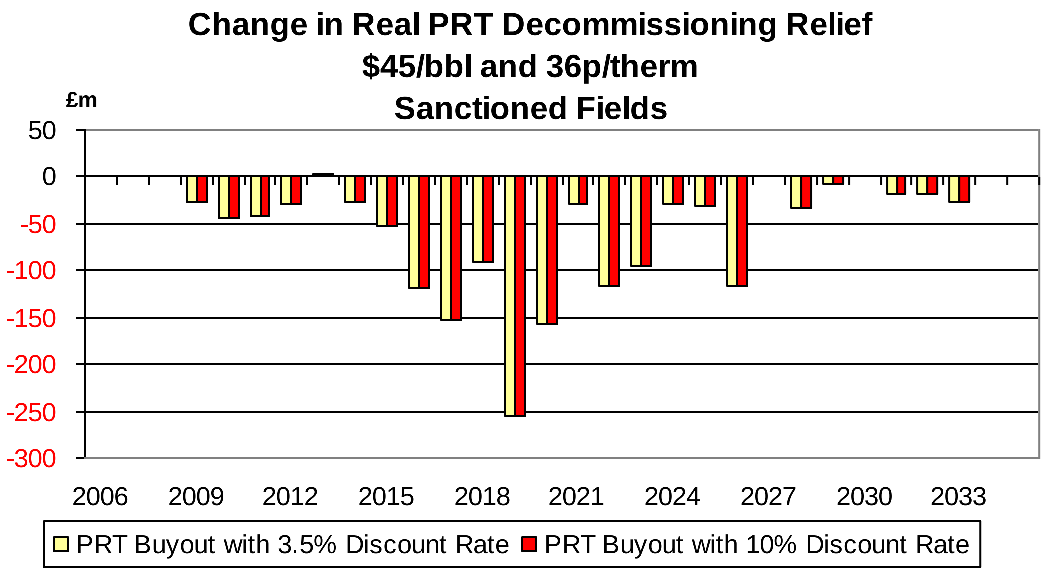


Chart 111 shows the change in real PRT decommissioning relief with the introduction of the buyout schemes. £1513m of PRT relief is removed with the buyout schemes. In effect there is no PRT relief following the operation of the buy-out scheme.

Chart 112

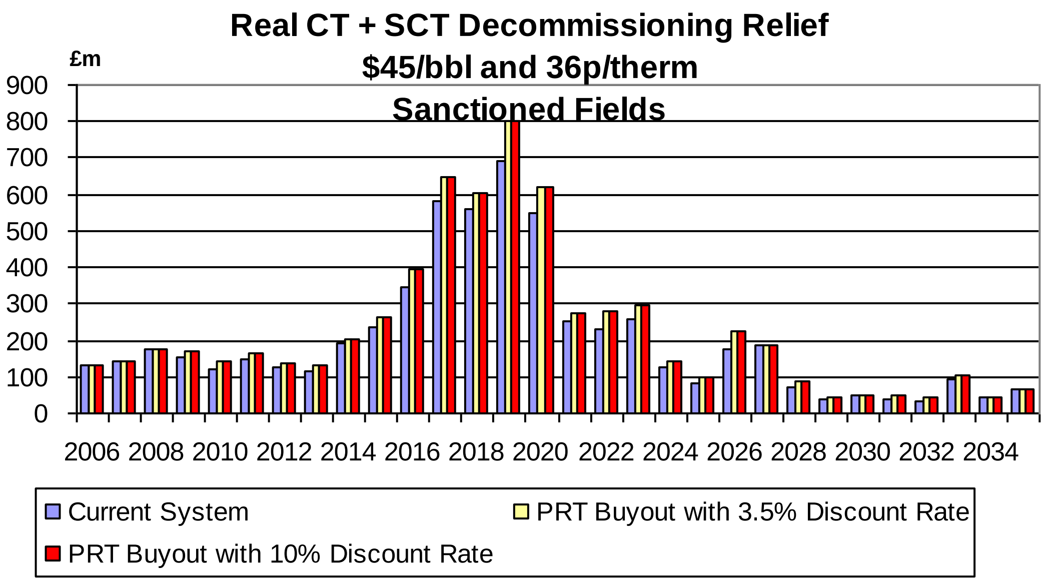


Chart 112 shows real CT + SCT relief at the medium price under the current and buy-out schemes, and the two different discount rates.

Chart 113

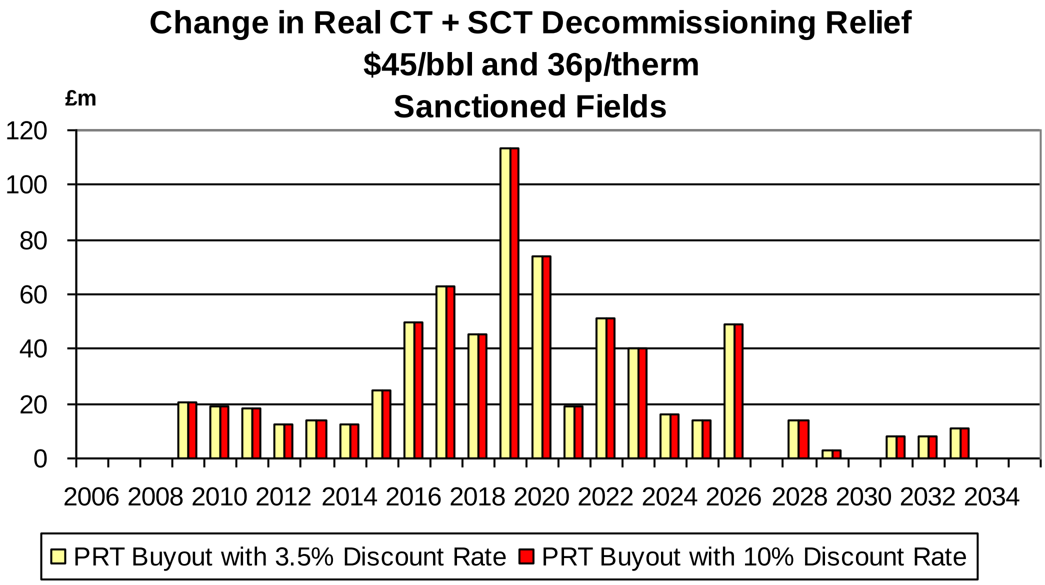


Chart 113 shows the changes in CT + SCT relief with the introduction of the buyout schemes. CT + SCT reliefs are increased by £700m with the introduction of the buyout schemes.

Chart 114 shows the change in the real post-tax cashflows with the introduction of the buyout schemes. The post tax position is highest where the discount rate for calculating the PV of the buyout is 3.5%. The lowest post tax position is with the current tax system. The difference between the two buyout scenarios occurs in the period 2009 to 2013.

With the 3.5% discount rate real post-tax cashflows are increased by £476m over the period to 2035 whilst with the 10% discount rate the real post-tax cashflows are increased by £360m.

Chart 114

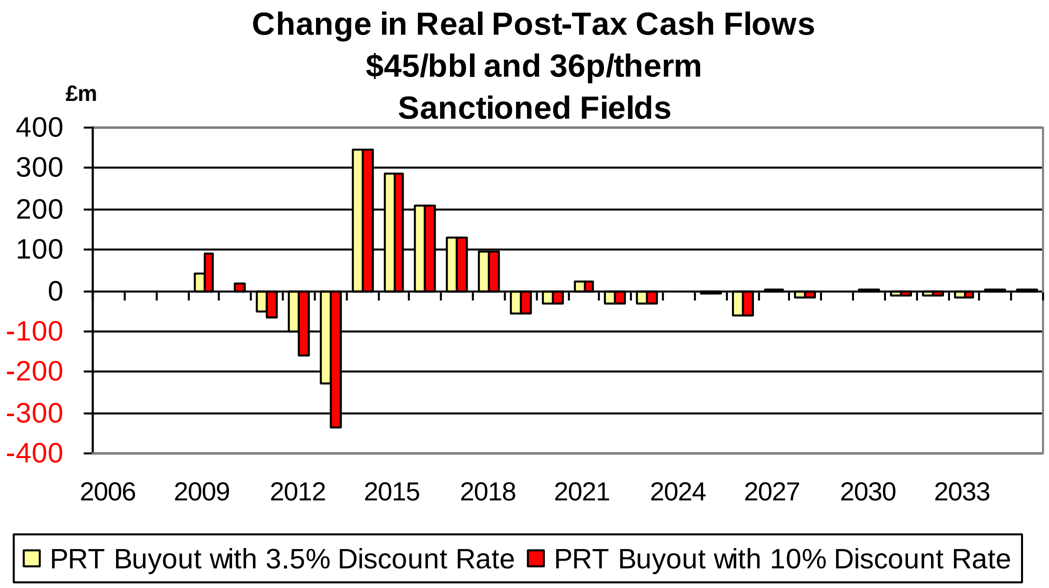


Chart 115

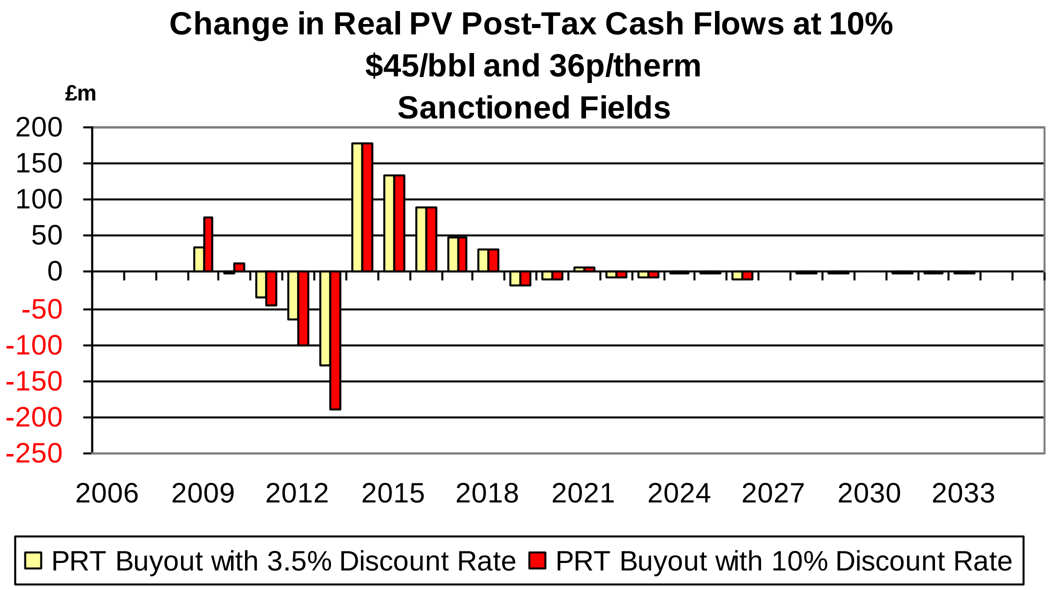


Chart 115 shows the change in the real PV of post tax cashflows to the industry with a 10% real discount rate. With a 3.5% discount rate for calculating the PV of remaining PRT the real PV of the aggregate post tax cashflows are increased by £239m, whilst with a 10% discount rate for calculating the PV of remaining PRT the real PV of the post tax cashflows are increased by £184m over the period.

The modelling has shown that the impact effects of the two schemes are somewhat different. The buyout scheme is obviously completed more quickly, and in the modelling it was assumed that one uniform detailed scheme with a single start date would apply to all fields and licensees. The scheme where PRT ceased was also based on a formula applied to all fields but the cessation date varied across fields. In practice this would mean that PRT would continue for a much longer time with the cessation scheme. The impact effects of the schemes would also depend on what discount rate was employed in the formula under each arrangement. The final impact on the licensees would also depend on what discount rate they themselves employed in assessing their net cash flows.

The modelling has not considered possible behavioural repercussions of the schemes, but it should be noted that these are possible. Thus there would be an incentive to undertake an incremental investment at a time when PRT relief was available, but also such that the income occurred after PRT was abolished. More generally the returns to incremental projects would be increased significantly if the tax applied to them were 50% rather than 75%. To what extent there would be extra projects developed will be pursued in a future paper.

6. Reform of PRT

Should Government and the industry not come to agreement then PRT may not be abolished but be reformed. One possibility is that the rate might be reduced and the special allowances (uplift, volume, safeguard and TRA) are abolished. This was modelled from 2009 along with a reduction in the rate of PRT to 40% and 30% from the same date.

(a) Changes in Taxation Payments

The resulting changes in total taxation payments are shown in Chart 116. Thus a 40% PRT rate with the removal of the allowances would increase real tax revenues by £433m over the period to 2035 whilst a 30% rate with the removal of the allowances would decrease real tax revenue by £569m over the period.

In Chart 117 the changes in PRT only are shown. Thus the 40% PRT rate with the removal of the allowances would increase real PRT by £1008m over the period to 2035, whilst a 30% PRT rate with the removal of the allowances would decrease real PRT by £673m over the period.

Chart 116

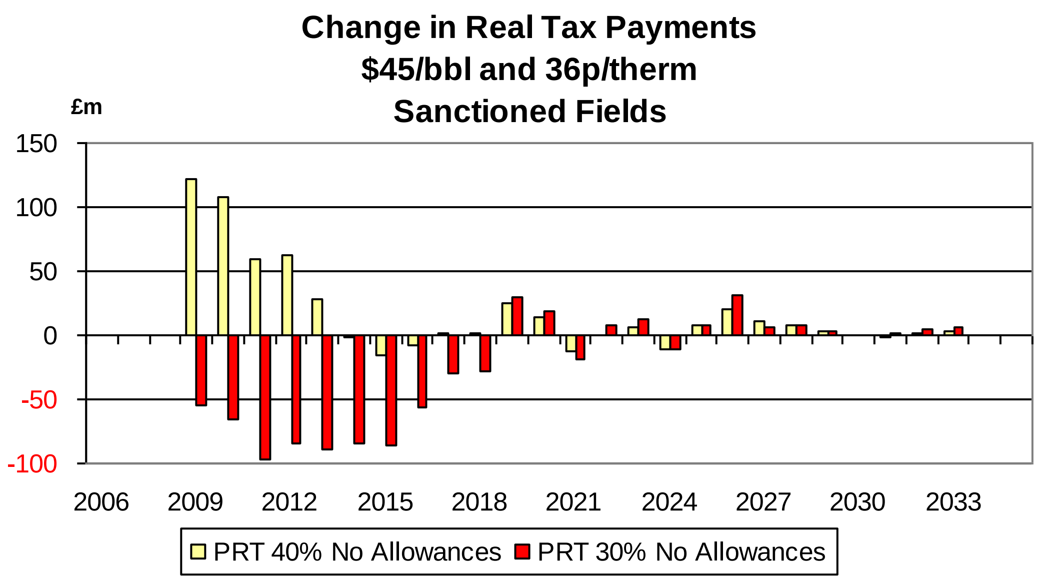


Chart 117

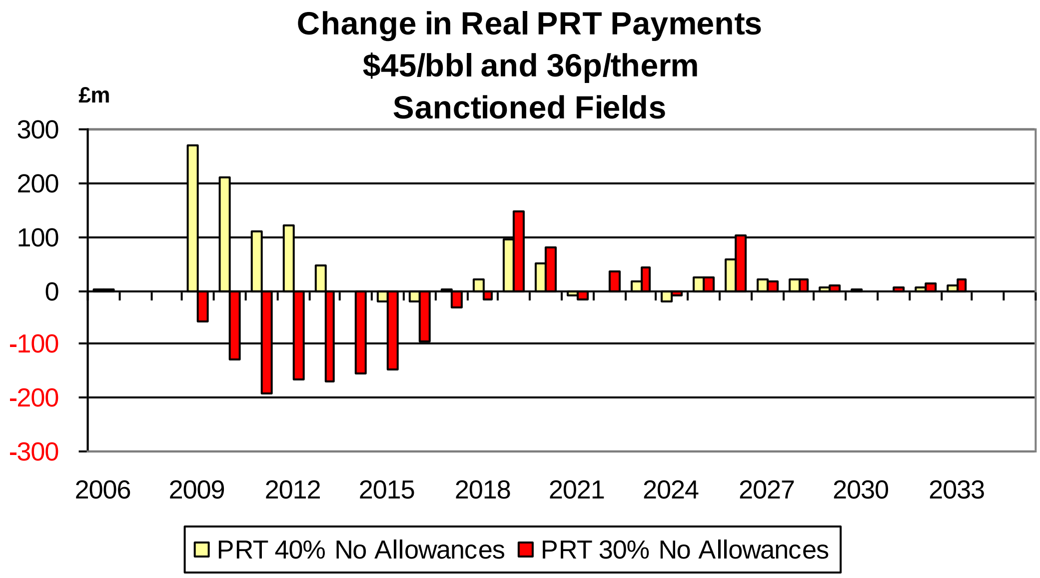
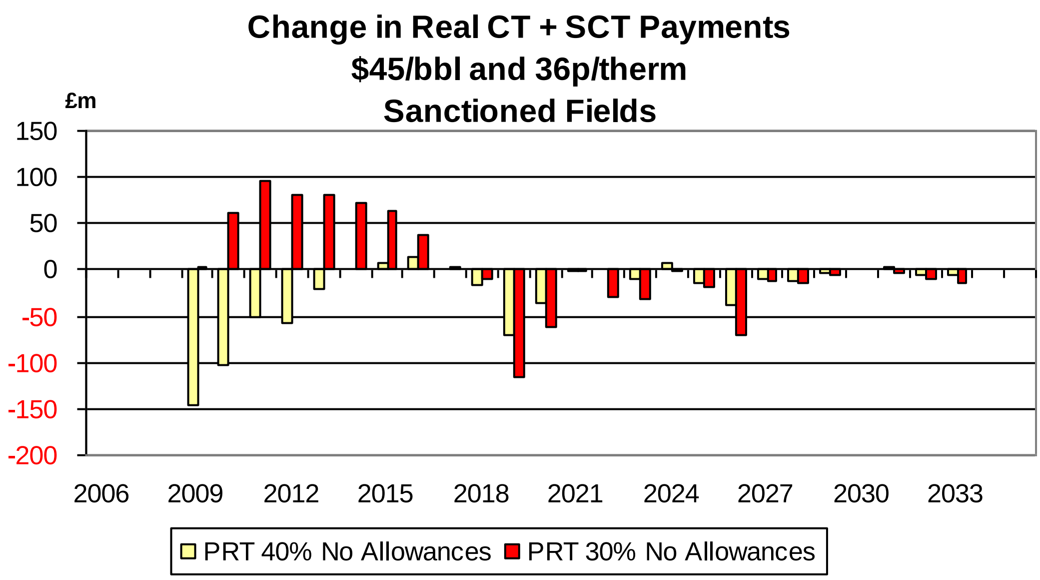


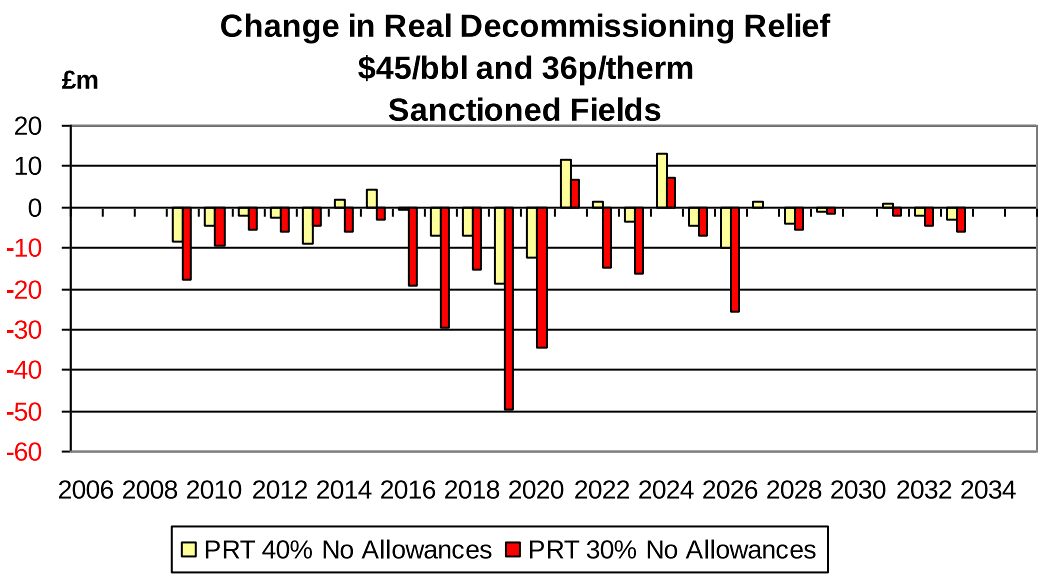
Chart 118



The effects of the PRT changes on CT + SCT payments are shown in Chart 118. Thus the 40% PRT rate with the removal of the allowances would decrease real CT + SCT by £575m over the period to 2035, whilst the 30% PRT rate with the removal of the allowances would increase real CT + SCT by £104m over the period.

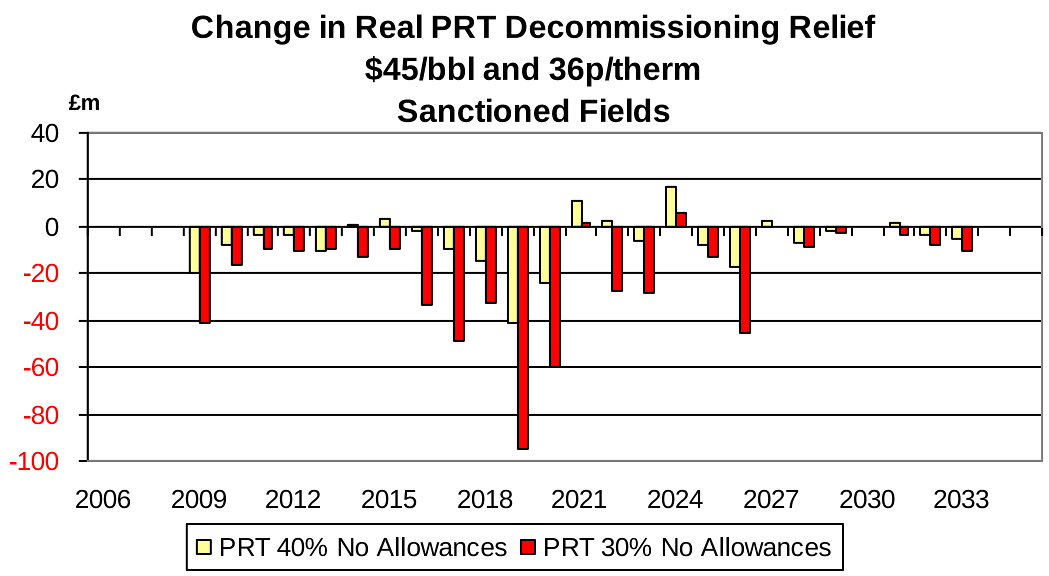
(b) Changes in Decommissioning Relief

Chart 119



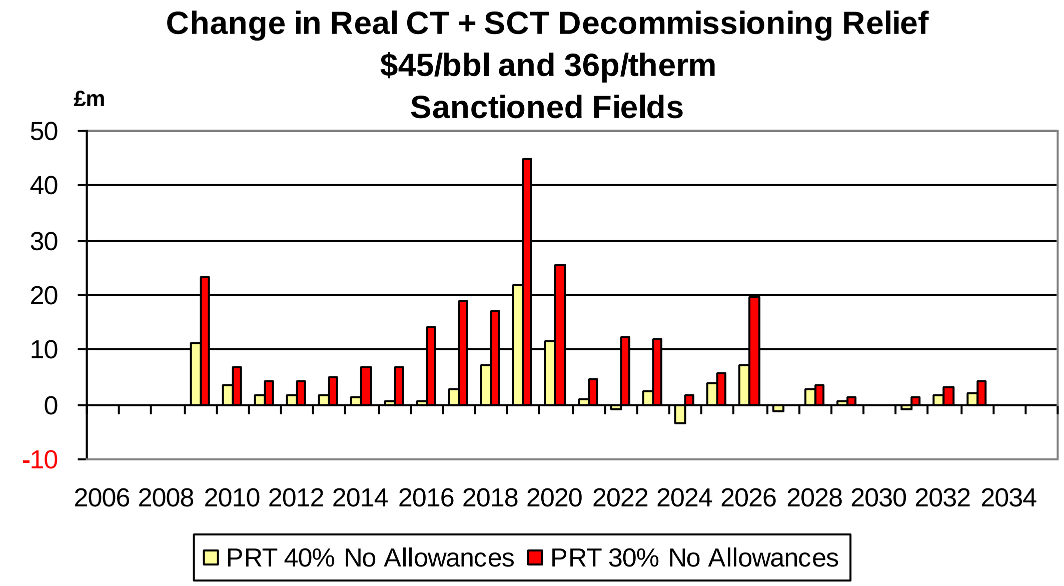
In Chart 119 the effects of the PRT changes to total relief for decommissioning are shown. A 40% PRT rate with the removal of the allowances would decrease real decommissioning relief by £65m over the period to 2035 whilst 30% PRT rate with the removal of the allowances would decrease real decommissioning relief by £270m over the period.

Chart 120



In Chart 120 the effects of PRT changes on decommissioning relief for PRT are shown. Thus a 40% PRT rate with the removal of the allowances would decrease real PRT relief by £146m over the period to 2035 whilst a 30% PRT rate with the removal of the allowances would decrease real PRT relief by £517m over the period. In modelling experiments it was found that PRT relief decreases when the rate of PRT decreases, but the decrease is less when PRT allowances are removed. When allowances are removed a field has a larger PRT base against which to claim PRT relief on decommissioning. This is most apparent when the current allowances reduce a fields PRT liability to zero, but removal of the allowances puts it into a PRT paying position.

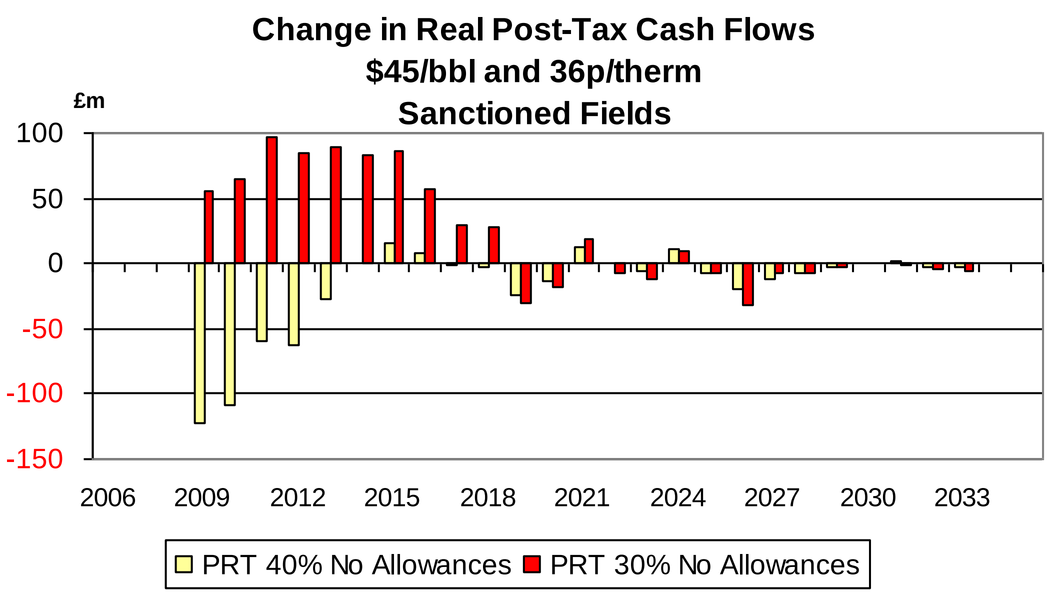
Chart 121



In Chart 121 the effects of the PRT changes on decommissioning relief for CT + SCT are shown. A 40% PRT rate with the removal of the allowances would increase real CT + SCT relief by £82m over the period to 2035 whilst a 30% PRT rate with the removal of the allowances would increase real CT + SCT relief by £247m over the period.

(c) Changes in Post-Tax Cash Flows

Chart 122



The effect of the PRT changes on the industry's net cash flows are shown in Chart 122. Thus a 40% PRT rate with the removal of the allowances would decrease the real post-tax cashflow by £433m over the period to 2035, whilst a 30% PRT rate with the removal of the allowances would increase the real post-tax cashflow by £569m over the period.

7. Decommissioning Issues

Decommissioning of facilities in the UKCS is a subject of increasing importance as the time is approaching when a considerable number of fields with large installations reach the end of their economic lives. The taxation issues relating to relief for the costs for PRT purposes have already been discussed in relation to possible PRT reform/abolition, but there are other tax issues deserving consideration. Thus the subject of financial liability for decommissioning has become important in the context of transactions in mature field assets and in relation to at least some new field developments. There is joint and several liability among co-licensees for decommissioning, and, in addition, the Government can insist that when an asset transaction takes place an acceptable decommissioning security agreement is put in place which will provide adequate comfort to the Government that the licensees will have the financial capability to undertake the work. In this context the Government can require that the liability stays with the selling party in circumstances where it has doubts regarding the financial capacity of the buying party to undertake the work. At the time of a new field development the Government can also require the licensees to provide for security for decommissioning in case the reservoir underperforms to such an extent that cessation of production occurs quite quickly.

(a) Comparative Effects of LOC, Surety Bonds and Trust Funds

There are several ways by which licensees may procure adequate financial security for decommissioning including Letters of Credit (LOCs), Surety Bonds, and Decommissioning Trust Funds. Of these only LOCs have been employed in the UKCS to date, but Surety Bonds (widely employed in the Gulf of Mexico), and Trust Funds have been discussed as alternatives. The present authors recently undertook a detailed study of the comparative economic effects of these instruments in the UKCS[3], highlighting the impacts on production, field investment, tax revenues and tax reliefs, as well as gross and net decommissioning costs. The study took into account the indirect costs of the LOC on the cost of debt capital to investors, as the existence of the scheme has to be acknowledged in the company's accounts with a negative consequence for its debt capacity. With respect to the Trust Fund five possible schemes were modelled, namely (1) with tax relief on contributions, interest income of 4.75% on monies in the Fund, and no change in investor behaviour, (2) as (1) except that monies in the Fund earn 10%, (3) as (2) but change in behaviour so that cessation of production (COP) is accelerated when the contributions result in operating losses, (4) as (3) but interest at 4.75%, and (5) as (4) except no tax relief for contributions to the Fund. Tax at 40% was assumed to be payable on the Fund income in all cases.

The effects on production of the various schemes reflect (1) any acceleration in COP from the payments, and (2) any reduction in the development of marginal fields resulting from the payments. The results of the schemes <u>applied across the board to all fields</u> are shown in Charts 123 and 124 in terms of reduced production under two oil/gas price scenarios.

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[3] See Alex Kemp & Linda Stephen, North Sea Study Occasional Paper No.103, <u>Financial Liability for Decommissioning in the UKCS: the Comparative Effects of LOCs, Surety Bonds, and Trust Funds</u>, , University of Aberdeen, Department of Economics, October 2006.

Chart 123

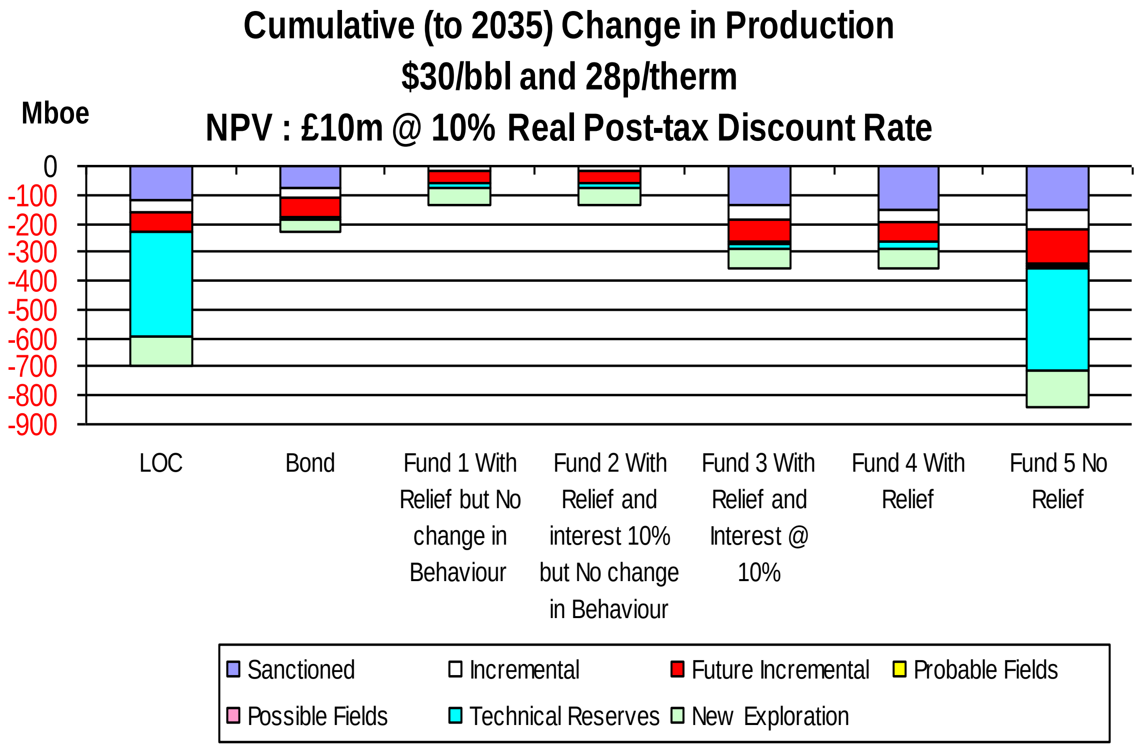
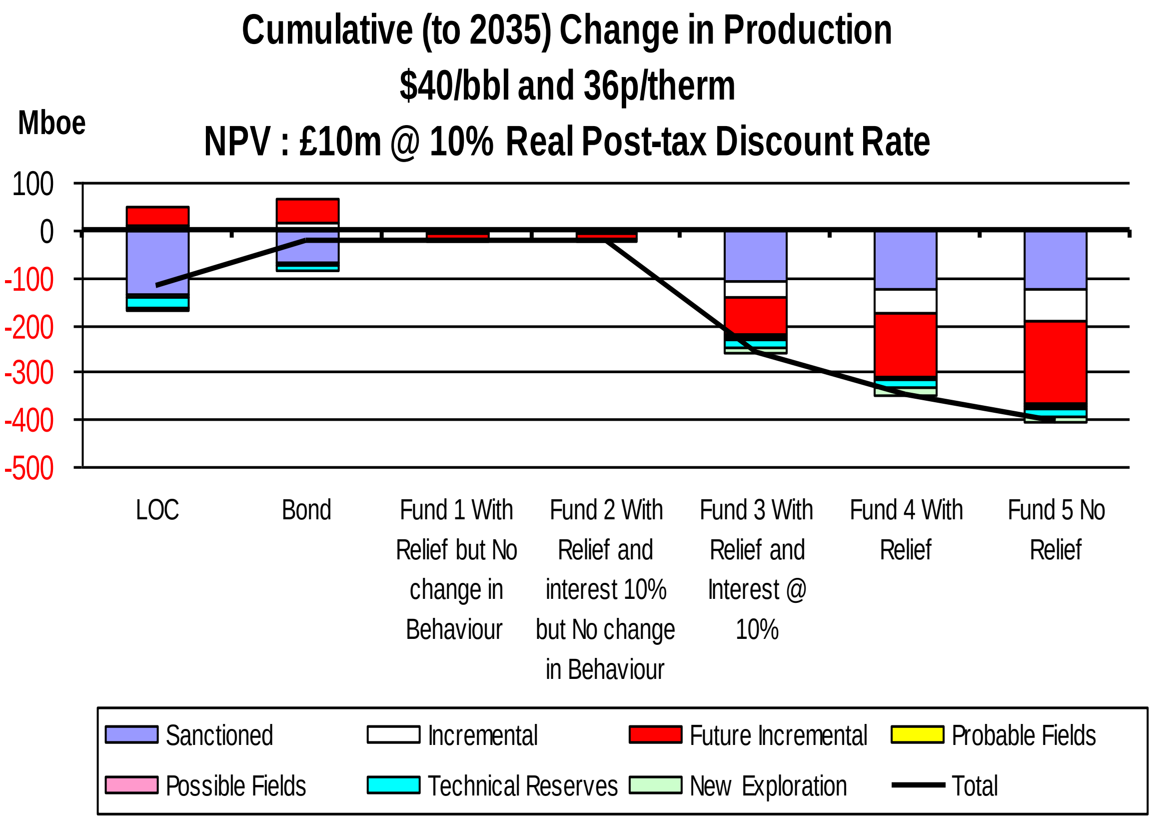


Chart 124



It is seen that the greatest loss of production occurs with the LOC scheme and the Trust Fund without tax relief. The smallest loss of production occurs with the Trust Fund schemes where tax relief on contribution is given, and no change in investor behaviour regarding timing of COP occurs. It is felt that the assumptions in the latter case are realistic because of the combined effects of (1) tax reliefs, and (2) the fact that these ongoing contributions reduce the funds which have to be found to pay for the decommissioning work when that becomes due.

The cost to the Government in terms of total tax reliefs under the various schemes are shown in Charts 125 and 126.

Chart 125

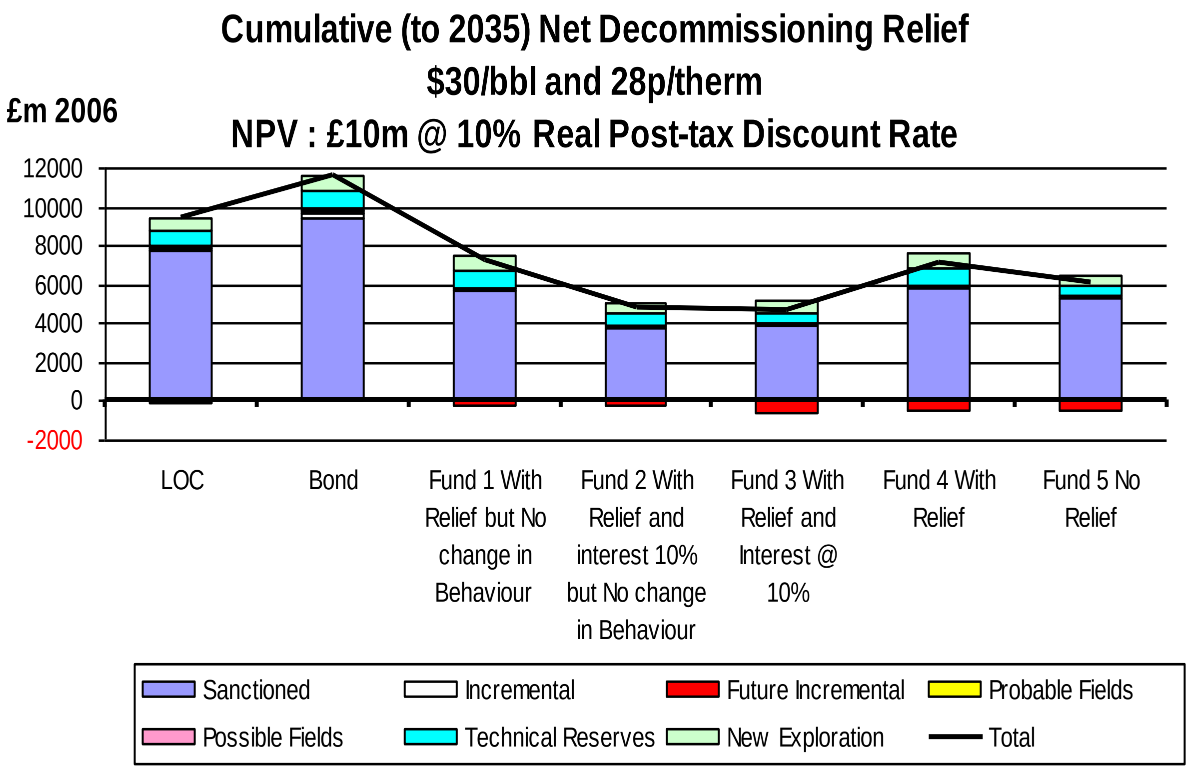
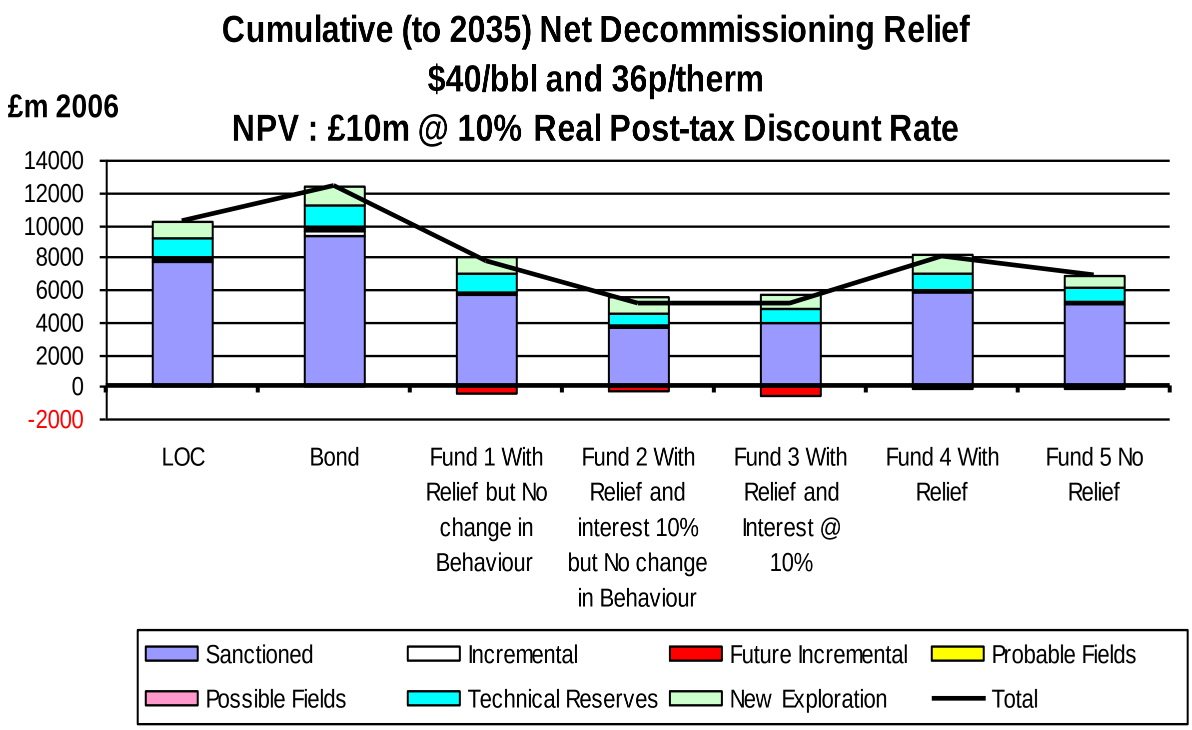


Chart 126



It is seen that the lowest tax reliefs are under the Trust Fund schemes with relief for contributions but no change in behaviour. The total tax reliefs under the LOC and Surety Bond schemes are very considerably higher. Thus the schemes currently permitted by the Government result in the greatest cost to the Treasury/HMRC! This follows because the permitted reliefs for the LOCs and Surety Bonds are additional to the tax reliefs on the actual decommissioning expenditures themselves. Under the Trust Fund scheme there is no such additional relief. If the Fund contributions plus net interest match the actual decommissioning costs there will be no further relief for the latter when the expenditures occur. The tax (at 40%) on the interest is shown as negative tax reliefs in Charts 125 and 126. The net accrued interest reduces the size of the required contributions to the Fund.

The paradoxical result is thus that the currently favoured schemes (1) have the largest distorting effect on incentives and economic recovery from the UKCS, (2) confer the largest total cost on the economy, and (3) produce the largest reduction in net tax revenues. HMRC has been unwilling to permit tax reliefs on contributions to Trust Funds because such relief would be given before the related expenditure took place. There has also been a concern that companies would overprovide just to obtain tax relief. These objections are not conclusive. They have to be viewed against the <u>alternatives</u>, and the conclusion is that in national resource terms the scheme with Trust Funds and relief for the contributions is superior to the others. The fact that relief for the contributions is given prior to the actual decommissioning expenditure is not such a material point as the potential loss of production from use of LOCs, Surety Bonds and Trust Funds without tax relief for the contributions. Payments for LOCs or Surety Bonds are <u>extra</u> resource costs which, given the alternative, are unnecessary. The HMRC gives tax reliefs relatively early, but the licensee has to alienate funds relatively early as well. The argument that companies would alienate funds just to obtain tax relief has also been suggested, but this has been countered by arguments from licensees that they do not desire to alienate funds even with tax reliefs, on the grounds that they can invest the monies in question more productively elsewhere in the oil sector.

For some years now mature fields have been transferred from very large to medium-sized operators, with the former concluding that they were not core assets, and consequently would not rank highly in terms of allocations of capital for further investment. The acquiring companies have often been specialists in mature field operations and can be expected to give more priority to the fields in terms of investment and production. But the costs of LOCs will become very substantial, especially in very late field life, and the banks providing the LOCs will become concerned about financial security from their viewpoint. If they adopt a risk-averse attitude, as is commonly believed, they may even become unwilling to provide guarantees. The result would be accelerated COP. The lesson is that the LOC scheme is likely to be inconsistent with the objective of maximisation of economic recovery from the UKCS. This latter objective is more likely to be achieved with a Trust Fund accompanied by tax relief for provisions.

It is understandable that a Government wishes to be risk-averse with respect to decommissioning liability. The UK Government already obtains some security from the joint and several liability obligations, and could greatly add to this through an efficient Trust Fund scheme. It is arguable that allowing tax relief for provisions in an alienated fund constitutes a reasonable Government contribution for the enhanced national output and investment. Such arrangements have become increasingly common worldwide over the last 10-15 years. Thus contributions to escrow accounts for decommissioning are cost recoverable and tax deductible in the Production Sharing Contracts in Angola, Azerbaijan, and Sakhalin. They are also tax deductible for corporate income tax and Additional Profits Tax in Namibia. Provisions for decommissioning are deductible for both corporate income tax and State Profit Share in the Netherlands.

The near term cost to the Exchequer of permitting tax deductibility of contributions is doubtless a consideration with the Treasury and HMRC. This could be limited if the Trust Fund were not made obligatory to all licensees, but was one option of several in providing adequate financial security. Thus companies which provided satisfactory security by other means and which did not desire to alienate funds would be excluded. An effective Trust Fund scheme would also require changes to the Inheritance Tax rules. Currently Inheritance Tax would apply to a Trust Fund and its imposition would negate the purpose

and benefits of the scheme. Legislation would be required to withdraw its application to the type of Fund being proposed. Tax could be applied to the income from the Fund without greatly jeopardising the scheme's effectiveness.
In modelling securitisation agreements it is conventionally assumed that they commence when the remaining post-tax NPV becomes less than 150% of the (gross) decommissioning costs. When this formula was applied to the UKCS it was found that, with respect to a minority of fields whose decommissioning is expected to occur within the next few years, the requisite contributions could not be funded from the remaining field cash flows as the trigger point had already been passed. In such cases the licensees would have to find some funds from other sources at the time of the decommissioning work.

The Government has in the past suggested that licensees might deliberately overprovide contributions to maximise tax relief. It is not at all clear that this would happen given the contrary expressed views of some licensees that they did not want to alienate funds at all, because the return on such funds was too low compared to other possible investments. The Government can also minimise the incentives to overprovide by ensuring that any overprovisions are fully subject to corporation tax, Supplementary Charge, and PRT where applicable. This happens in the Netherlands where the Government can also obtain independent estimates of the expected decommissioning costs, with adjustments being made where necessary to the annual provisions.

Current tax rules on relief for corporation tax limit the carry back of tax relief to a maximum of three years. There is growing evidence that the actual time taken to execute the decommissioning work on fields with large facilities is likely to be substantial beyond the period of cessation of production, and a three-year clawback period would be insufficient to absorb all the tax losses. Of course, companies can set the allowances against income from elsewhere and also carry them forward against future income. But, looking ahead, it is becoming likely that there will be a significant number of cases where there will be companies unable to obtain either sideways relief or future relief on the scale needed. The three-year clawback period should thus be extended to reflect the likely reality in the UKCS.

8. Summary and Conclusions

The objective of the tax system applied to the UKCS is to collect economic rents emanating from petroleum exploitation to the state. The current system applied to new exploration and development is essentially a cash flow tax for existing taxpayers, whereby the Government shares fully in all the investment risks to the extent of the tax rate. The cash flow tax has the unique property that the post-tax IRR is equal to the pre-tax IRR irrespective of the rate of tax. Such a scheme has clear virtues in the context of a maturing petroleum province where the national interest is best served by the encouragement of exploration and development to maximise economic recovery and minimise the total resource costs to the nation by utilising the window of opportunity before the offshore infrastructure becomes redundant or uneconomic. This would substantially raise the costs of new developments and reduce the national economic rents for sharing between the investor and Government.

The current tax structure contains one (combined) tax rate of corporation tax and Supplementary Charge (SCT), and the Government can change the rate of the SCT at its discretion, unfettered by considerations relating to the non-oil sector. The allowances can also be changed without having any consequences for the non-oil sector, and currently reliefs for capital expenditures in the UKCS are noticeably different from those in the non-oil sector. With 100% first year allowances currently being available any adverse effects of the tax system relate to the rate of tax.

There are genuine difficulties in knowing what rate creams off economic rents without causing investment disincentives. Governments do not have clairvoyance in this matter, and the subject is complicated by the fact that each investor is likely to employ his own screening yardsticks. A further complication is that different oil and gas prices are very likely to be employed by investors for assessing long term projects, and the Government will not have access to the details. The fluctuations in these prices and the wide variation in expectations compounds this problem. A system with an in-built mechanism to ensure that the level of take is directly related to profitability would reduce these problems, but the UK Government has in the past not favoured this, and has preferred to operate with a one-rate scheme. In the discussions with the industry in 2006 it also emerged that the latter was unenthusiastic about a schedule whereby the tax rate was automatically adjusted to the oil price level. The Treasury has ruled this out for further study. This limits the realistic scope for reform, and thus other schemes have been examined involving the use of discretionary rate changes and the introduction of new allowances.

In modelling the effects of various schemes the criteria against which they were assessed were the avoidance of deadweight costs. By definition a tax on economic rents should produce no deadweight losses. Attention was given to any change in economic production, with a flow rate of tax of 30%. Any losses of tax revenues were highlighted, but the view is taken that the most relevant consideration is the effect in relation to the maximum economic production from the UKCS, not the tax revenues as such. If economic production is reduced GDP and producers' surpluses are also reduced, and the taxation arrangements are sub-optimal. In modelling the effects of tax changes a range of oil/gas prices believed to reflect those employed by investors in making long-term investment decisions was employed. Cautious views are generally held by investors on this subject. In determining the acceptability of projects (and thus the possibility of economic rents) an investment hurdle of $1+(NPV/I) \geq 1.3$ was employed.

When reductions in the rate of CT + SCT to 40% and 30% were examined it was found that under some price scenarios the extra national economic output could be quite substantial. The largest gains in production were not always under the lowest price scenarios, as some projects continued to fail the economic hurdle even with lower taxation. As examples of the possibilities under the $45,36 pence scenario when the tax rate was reduced to 40% total hydrocarbon production in the period to 2035 was increased by 419 mmboe, including a significant element over the next few years. When the tax rate was reduced to 30% under the same price case output to 2035 increased by over 800 mmboe. Under the $50,40 pence case when the tax rate was reduced to 40% aggregate output increased by over 720 mmboe in the period, and by 827 mmboe when the tax rate was reduced to 30%. In both cases, however, there was a substantial net reduction in tax revenues in the period, but, interestingly, there were net tax gains over the next few years under both the price scenarios. In this context it should be noted that reductions in the rate of tax value of tax reliefs on new investment and can thus produce a gain in tax revenues. Further, if the discounted present value of the change in tax revenues were employed not only could there be short term tax revenue gains but the long term losses would be very much less. If future incremental production were also discounted then, of course, its present value would also be less. The appropriate time frame for considering tax variations and incentives is a matter of judgement, depending largely on private and social discount rates. From first principles there is some case for tax reliefs when short/medium term economic output or maximisation of producers' surplus are the top priority.

A different type of tax incentive, namely the introduction of a simple field volume allowance for the SCT (with tax rates unchanged), was also examined to discover its relative effectiveness. Conceptually it has some defects (principally because its value increases as the oil/gas price increases), but it is very familiar in the UK context. Experiments were conducted with allowances of 2, 3, 4, and 5 mmboe with no annual limit. It was found that this device could trigger a substantial amount of extra production. Thus under the $45,36 pence price case the total extra production from an allowance of 3 mmboe was found to be 383mmboe. Under the $50,40 pence case with the 3 mmboe volume allowance the extra production was 262mmboe. If the allowance was 4 mmboe there was only a small increase in total output compared to the 3 mmboe allowance because most of the fields could not absorb the higher amount against SCT. While there were losses of net tax revenues over the whole period it was noteworthy that in the short/medium term there were often worthwhile net tax revenue gains emanating from the development of more probable and possible fields.

Given the relatively low gas prices experiments were undertaken with a volume allowance available only on predominantly gas fields, and then only where the recoverable reserves at the time of development approval were under 25 or under 15mmboe. Under the $45,36 pence case it was found that the total extra production was quite modest. Higher volume allowances could often not be used given the limited SCT tax base. Moderate net tax losses also occurred.

A yet further case examined was the application of the volume allowance for SCT to <u>all</u> sizes of new gas fields in the WoS and SNS regions. In this case under the $45,36 pence scenario some extra production was triggered, especially in the SNS. Interestingly, in the WoS area there were clear net tax increases emanating from the inventive, while in the SNS there were negligible net tax changes over the period to 2035.

The overall findings of this part of the study are thus that, while the tax structure applied to new fields has clear merits, on the basis of oil/gas prices and investment criteria likely to be employed by investors, disincentives will be produced which reduce maximum economic recovery and producers' surplus. A progressive resource rent tax system would be more sensitive to the variations in profitability which inevitably occur in a large petroleum province such as the UKCS. It would thus be more likely to procure maximisation of economic production, and optimise the Government's share of the economic rents. In the absence of such a system maximisation of economic production can only be achieved by discretionary changes within the current structure. Several plausible reliefs have been examined which produce clear increases in economic production and producers' surpluses. They also involve some net losses in tax revenues. These emanate from the fact that the current structure is not sensitive enough to the variations in profitability across fields. When it comes to choices priority should be given to the maximisation of economic recovery. It was also noticeable that with the tax reliefs the net loss of tax revenues was concentrated on fields in the categories of technical reserves and new discoveries, many of which would not in any case be developed for a long time. If these were excluded the net loss of tax revenues would be very much less, and in some scenarios there were net tax gains.

The consequences of abolishing PRT were examined under two possible schemes. Under the first the tax would be abolished when the remaining PV of the PRT payments became equal to the PRT relief for decommissioning. Two discount rates (3.5% and 10% in real terms with 2.5% inflation) were employed in the modelling. The impact of the schemes is very complex and the effects on licensees and the Exchequer depend on the discount rates employed to implement the schemes, and also the discount rates employed to assess the resultant net cash flows. There will also be behavioural incentives on licensees to vary the timing of their incremental investments to optimise reliefs for expenditures and tax on production income.

It is possible that, if PRT is not abolished, it would be reformed such that the rate and the allowances (uplift, safeguard, volume, and tariff receipts) were abolished. The impact effects of 40% and 30% rates with the abolition of the above allowances was modelled and found to be substantial, with industry net cash flows being increased very substantially with the 30% rate but decreased significantly with the 40% rate. Again there could be repercussions on the incentives to undertake incremental investments.

The tax issues relating to decommissioning were also examined with emphasis on the problem of financial security. The comparative effects of Letters of Credit (LOCs), Surety Bonds, and Decommissioning Trust Funds (with and without tax reliefs for contributions to the Fund) were examined. It was found that the distortion caused by LOCs, Surety Bonds and Trust Funds without relief for contributions (in terms of premature cessation of production and disincentives to develop marginal fields) could result in significant aggregate losses of production. They also resulted in both the total national costs and the total tax reliefs for the whole decommissioning activity being <u>greater</u> than under the scheme where contributions to Funds were tax deductible. LOCs and Surety Bonds are <u>extra</u> total costs to the investors and, as tax reliefs are given for these <u>and</u> the actual decommissioning costs, the result is that both the aggregate costs and tax reliefs are greater. There is a strong case on economic efficiency grounds for Trust Funds with contributions being tax deductible. The net cost to the Exchequer can be limited by not applying the scheme to licensees who do not wish to alienate funds and can provide other acceptable financial security. It was also found that in practice the decommissioning activity can extend well beyond 3 years following cessation of production. In due cause there are likely to be a considerable number of cases where the 3-year clawback limit on relief for CT + SCT will be inadequate, as will the availability of relief either sideways or through carry forward. The extent of carry back relief should reflect the reality of the situation facing the licensees undertaking the decommissioning.