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A Comparative Study of Tax Reliefs for New Developments in the UK Continental Shelf after Budget 2012

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and
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NORTH SEA ECONOMICS

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 was financed by a grant from the Natural Environmental Research Council (NERC) in the period 2005 – 2008.

For 2012 the programme examines the following subjects:

a) The Economics of CO2 EOR Based on an Onshore Hub at St Fergus
b) Tax Incentives for Facilitating New Field Developments
c) Tax Incentives for Incremental Investments in PRT-Paying Fields
d) Tax Relief for Decommissioning
e) Economics of Further Development of West of Shetland Region
f) Prospects for Activity Levels in the UKCS after Budget 2012

g) Economics of Infrastructure and Third Party Tariffing

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A Comparative Study of Tax Reliefs for New Developments in the UK Continental Shelf after Budget 2012

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1. Introduction

The investment environment in the UK Continental Shelf (UKCS) is constantly changing. This reflects the effects of several factors including major changes in (1) oil and gas prices (and expectations regarding their future behaviour), (2) exploration success rates, (3) investment and operating costs, (4) terms and availability of finance, and (5) the tax system. A major increase in taxation took place in Budget 2011 and further allowances for new developments were announced in Budget 2012. This paper models potential activity levels taking into account updated information on all the above factors plus evaluating the effects of several other systems of tax relief debated over the past several months. The outputs highlighted are production of oil and gas, field investment, operating and development expenditures, and numbers of fields whose developments are triggered. The time period considered is 2011 – 2042 inclusive.

2. Methodology and Data

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 incorporated key, best estimate information on production, and investment, operating and decommissioning expenditures. These refer to 350 sanctioned fields, 150 incremental projects relating to these fields, 41 probable fields, and 28 possible fields. These unsanctioned fields are currently being examined for development. An additional database contains 248 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas) and block locations 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 2037. 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 5 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 Shetlands (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 2 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	90	60
Medium	70	40

The postulated numbers of annual exploration wells drilled for the whole of the UKCS are as follows for 2011, 2030, and 2037:

Table 2 **Exploration Wells Drilled**			
	2012	2030	2037
High	35	28	25
Medium	30	24	20

The annual numbers are modelled to decline in a broadly 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 2 success rates were postulated as follows with the medium one reflecting the average over the past 5 years.

Table 3 **Success Rates for UKCS**	
Medium effort/Medium success rate	29%
High effort/Low success rate	27%

It should be noted that success rates have varied considerably across sectors of the UKCS. Thus in the CNS and SNS the averages have exceeded 30% while in the other sectors they have been well below the average for the whole province. 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.

Table 4 Mean Discovery Size MMboe	
SNS	**8**
CNS	**32**
NNS	**40**
MF	**15**
WoS	**75**
IS	**7**

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 2036. 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 2037**	
High effort/Low success rate	210
Medium Effort/Medium Success Rate	193

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. Investment costs per boe depend on several factors including not only the absolute costs in different operating conditions (such as water depth) but on the size of the fields. For all of the UKCS the average development cost was $17.7 per boe with the highest greatly exceeding that. In the SNS development costs were found to average over $13 per boe because of the small size of fields. In the CNS they averaged $19.5 per boe and in the NNS they averaged $18.9 per boe with the highest greatly exceeding that. Operating costs over the lifetime of the fields were also calculated. The averages were found to be $13.8 per boe for all of the UKCS, $9.7 per boe in the SNS, $14.1 per boe in the CNS and $17.1 per boe in the NNS. Total lifetime field costs (including decommissioning but excluding E and A costs) were found to average $33.3 per boe for all of the UKCS, $24.45

per boe in the SNS, $35.7 per boe in the CNS, and $37.8 per boe in the NNS.

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 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. Thus the field lifetime costs in small fields could become very high on a per boe basis.

With respect to fields in the category of technical reserves it was recognised that many present major challenges, and so the mean development costs in each of the basins was set at $5/boe higher than the mean for the new discoveries in that basin. Thus for the CNS the mean development costs are over $24.5 per boe and in NNS over $23.8 per boe. The distribution of these costs was assumed to be normal with a SD = 20% of the mean value. A binomial distribution was employed to find the order of new developments.

The annual numbers of new field developments were assumed to be constrained by the physical and financial capacity of the industry. The ceilings were assumed to be linked to the oil/gas price scenarios with maxima of 20 and 17 respectively for High and Medium price cases. These constraints do <u>not</u> apply to incremental projects which are <u>additional</u> to new field developments.

There is a wide range in the development and operating costs of the set of incremental projects currently being examined for development. For all of the UKCS the mean development costs are $15.8 per boe but the highest is over $79 per boe. In the SNS the average development costs are $9.3 per boe, but in the NNS it is $21.8 per boe. While operating costs are often relatively low and average $6.84 per boe across all of the UKCS, they are very high in a number of cases, with examples in the $50 - $77 per boe range over their lifetime.

With respect to investment decision making and project screening criteria oil companies (even medium-sized and smaller ones) currently assess their opportunities in the UKCS in comparison to those available in other parts of the world. Capital is allocated on this basis with the UKCS having to compete for funds against the opportunities in other provinces. A problem with the growing maturity of the UKCS is the relatively small average field size and the high unit costs. Recent mean discovery sizes are shown in Table 4, but, given the lognormal distribution, the most likely sizes are below these averages. It follows that the materiality of returns, expressed in terms of net present values (NPVs), is quite low in relation to those in prospect in other provinces (such as offshore Angola, or Brazil, for example). Oil companies frequently rank investment projects according to the NPV/I ratio. Accordingly, this screening method has been adopted in the present study. Specifically, the numerator is the post-tax NPV at 10% discount rate in real terms and the denominator is pre-tax field investment at 10% discount rate in real terms. This differs from the textbook version which states that I should be in post-tax terms because the expenditures are tax deductible through allowances. Oil companies maintain that they allocate capital funds on a pre-tax basis, and this is employed here as the purpose is to reflect realistically the decision-making process. The development project goes ahead when the NPV/I ratio as defined above is ≥ 0.3 in one scenario and ≥ 0.5 in a second scenario. The 10% real discount rate reflects the weighted average cost of capital to the investor. The modelling has been undertaken under the current tax system.

In the light of experience over the past few years some rephasing of the timing of the commencement dates of new field developments and incremental projects from those projected by operators was undertaken relating to the probability that the project would go ahead. Where the operator indicated that a new field development had a probability ≥ 80% of going ahead the date was left unchanged. Where the probability ≥ 60% < 80% the commencement date was slipped by 1 year. Where the probability ≥ 40% < 60% the date was slipped by 2 years. Where the probability was ≥ 20% < 40% the date was slipped by 3 years, and where the probability was < 20% it was slipped by 4 years. If an incremental project had a probability of proceeding ≥ 50% the date was retained but where it was < 50% it was slipped by 1 year.

3. The Tax Schemes Examined in the Study

A substantial number of tax schemes were examined in the study. All were compared to a base case of Corporation Tax (CT) only with capital allowances currently in place. **Scheme 1** incorporates CT at 30% plus Supplementary Charge (SC) at 20% without any extra field allowances. **Scheme 2** incorporates CT at 30% plus SC at 32% <u>without</u> extra field allowances. **Scheme 3** incorporates CT at 30%, SC at 32% plus the field allowances after <u>Finance Act 2011</u>. **Scheme 4** is the same as **Scheme 3** except that the field allowances are given, irrespective of the SC position on the new field in question, against other North Sea income.

Scheme 5 incorporates CT at 30% and SC at 32% with a targeted investment tax credit which depends on the level of development costs rather than field characteristics. The credit is based on the development cost per barrel and the size of the initial reserves in fields. Low cost per barrel fields receive no credit and very high cost per barrel fields have a credit cap. The credit does depend on field characteristics to some extent as separate factors are calculated for oil, gas, new fields and incremental projects. Specifically, in the study new oil fields with development costs of less than \$17.5/bbl receive no credit and new oil fields with development costs of \$35/bbl or more have a cap. For new oil fields with development costs between \$17.5/bbl and \$35/bbl the credit factor is calculated base on the development cost per barrel above \$17.5 with the linear slope of the line (or credit factor) determining the size of the credit being 0.03. It reaches a peak of 38 cents per dollar per barrel of development costs when the latter reach \$35 per barrel.

New gas fields with development costs of less than \$10.5/boe receive no tax credit and those with development costs of \$21/boe or more have a credit cap. For new gas fields with development costs between \$10.5/boe and \$21/boe the credit factor is based on the development cost per barrel above \$10.5. The linear slope of the line is 0.03 and reaches a peak of 38 cents per dollar of development costs per barrel when they reach \$21/boe. When (\$devex/boe minus \$10.5) times 0.03) times \$devex/boe minus \$10.5) becomes greater than \$21 the credit factor becomes 0.38. This factor is then multiplied by \$devex/boe, then converted to £s, and multiplied by reserves to give the total allowance/credit which is spread over 5 years.

For a new field containing both oil and gas the allowance given depends on the proportions of oil and gas in total recoverable reserves.

For incremental oil projects not paying PRT the calculations are as for new fields but the credit is capped at $40 per dollar of development costs per boe (rather than $35 for oil and $24 for gas). For PRT-paying incremental projects the oil project threshold is $11.375/bbl (rather than $17.5/bbl) and the cap is $17.5 bbl with the peak credit being $0.19 (rather than $0.38). For PRT-paying incremental gas projects the threshold is $7/bbl (rather than $10.5/bbl) and the cap is $14/bbl with the peak credit being at $0.19. For incremental projects containing oil and gas the allowance given depends on the proportions of oil and gas in the reserves. **Scheme 5** is the only one which treats oil and gas differently and is also the only scheme examined which gives allowances for incremental projects.

More formally the details are as follows:

For Oil Fields

If $Devex/boe > $17.5 credit is:

((($Devex/boe - $17.5) 0.03)*($Devex/boe)) / exchange rate) * boe) spread over 5 years

If $Devex/boe - $17.5 > $35 credit is:

(0.38)*($Devex/boe)) / exchange rate * boe spread over 5 years

For Gas Fields

If $Devex/boe > $10.5 credit is:

((($Devex/boe - $10.5) 0.03)*($Devex/boe) / exchange rate* boe) spread over 5 years

If $Devex/boe - $10.5 > $21 credit is:

((0.38)*($Devex/boe) / exchange rate * boe) spread over 5 years

The credit given is proportional to the reserves of oil and gas.

For Incremental Projects

For non-PRT fields the oil credit is:

If $Devex/boe > $17.5 credit is

((($Devex/boe - $17.5) 0.03)*($Devex/boe)) / exchange rate) * boe) spread over 5 years

If $Devex/boe - $17.5 > $40 credit is

(0.38)*($Devex/boe)) / exchange rate * boe spread over 5 years

For Gas fields

If $Devex/boe > $10.5 credit is

((($Devex/boe - $10.5) 0.03)*($Devex/boe) / exchange rate * boe) spread over 5 years

If $Devex/boe - $10.5 > $24 credit is

((0.38)*($Devex/boe) / exchange rate * boe) spread over 5 years

The credit given is proportional to the reserves of oil and gas.

For PRT paying fields the oil credit is:

If $Devex/boe > $11.375 credit is

((($Devex/boe - $11.375) 0.03)*($Devex/boe)) / exchange rate) * boe) spread over 5 years

If $Devex/boe - $11.375 > $17.5-11.375 credit is
(0.19)*($Devex/boe)) / exchange rate * boe spread over 5 years

For Gas fields
If $Devex/boe > $7 credit is
((($Devex/boe - $7) 0.03)*($Devex/boe) / exchange rate * boe) spread over 5 years
If $Devex/boe - $7 > $14 credit is
((0.19)*($Devex/boe) / exchange rate * boe) spread over 5 years
The credit given is proportional to the reserves of oil and gas.

Scheme 6 incorporates the greater of the value of the benefits to the investor of the allowances as in Finance Act 2011 and those under the tax credit arrangement of **Scheme 5**.

Scheme 7 – CT at 30% + SCT at 32% and SCT allowance (not credit):

Scheme 7 incorporates a variable field allowance (not credit) which depends on reserves and development cost per barrel. For fields with development costs per barrel above a floor value a linearly increasing allowance is applied until a specified ceiling development cost per barrel is reached after which the allowance is constant.

Thus **Scheme 7** uses a floor of $19 (£11.61) and a ceiling of $35 (£21.39) and a scale factor slope of 1/12. Thus the formula for a field with development costs > $19 is (((($Devex/boe) - $19)) /12)*(mmboe/100) * 1000)) / exchange rate spread over a minimum of 5 years. The allowance is taken when the field has SCT against which the allowance can be set. If the development cost per barrel is greater than $35 the formula becomes (((($Devex/boe) - $19)) /12)*(mmboe/100) * 1000)) / exchange rate spread over a minimum of 5 years.

Scheme 8 – CT at 30% + SCT at 32% and SCT allowance (not credit)
Scheme 8 is as **Scheme 7** but the ceiling is higher. The **Scheme 8** ceiling is $58.895 i.e. £36 per boe.

Allowance is as follows:
If $Devex/boe > $58.896 field allowance is
(((($58.896 - $19) / 12)*(mmboe/100) * 1000) / exchange rate spread over a minimum of 5 years and taken when the field has SCT revenue.

If $Devex/boe > $19 field allowance is
(((($Devex/boe) - $19)) / 12)*(mmboe/100)* 1000)) / exchange rate spread over a minimum of 5 years.

Scheme 9
Scheme 9 incorporates CT at 30% plus SC at 32% with the allowances as in <u>Budget 2012</u>.

4. Results – New Developments

A. $70, 40 pence, NPV/I > 0.3 Case

As discussed above the consequences of the 9 tax schemes examined are all related to the base case where there is CT only. While CT and SC do impact on incremental projects, in this set of results the allowances for incremental projects in **Schemes 5 and 6** are <u>excluded</u> in order that the effects of schemes 3 – 9 can be directly compared. **Schemes 1 and 2** automatically impact on incremental projects and these effects are included in this section. Also, only incremental projects currently being examined by the industry are included. Under the $70, 40 pence price and NPV/I > 0.3 scenario over the period there are 660 fields and projects which could potentially go ahead. Of these 428 passed on a pre-tax basis and 385 passed on a CT only basis. All the schemes resulted in a lower number of field developments compared to the CT only cases. **Scheme 1** produced 66 less developments, **Scheme 2** 128 less, **Scheme 3** 66 less, **Scheme 4** 53 less, **Scheme 5** 58 less, **Scheme 6** 30 less, **Schemes 7 and 8** 122 less and **Scheme 9** (Budget 2012) 39 less. In Chart 1 the changes to the numbers of fields in production over the period to 2042 are shown. In Chart 2 the cumulative change in the numbers of fields passing the economic hurdle over the period are shown.

Chart 1

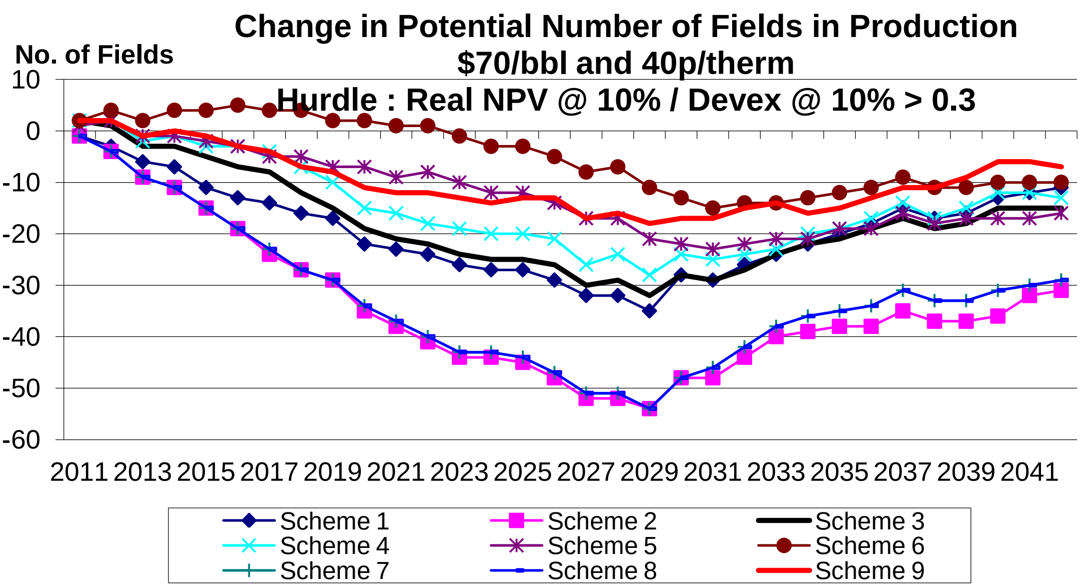
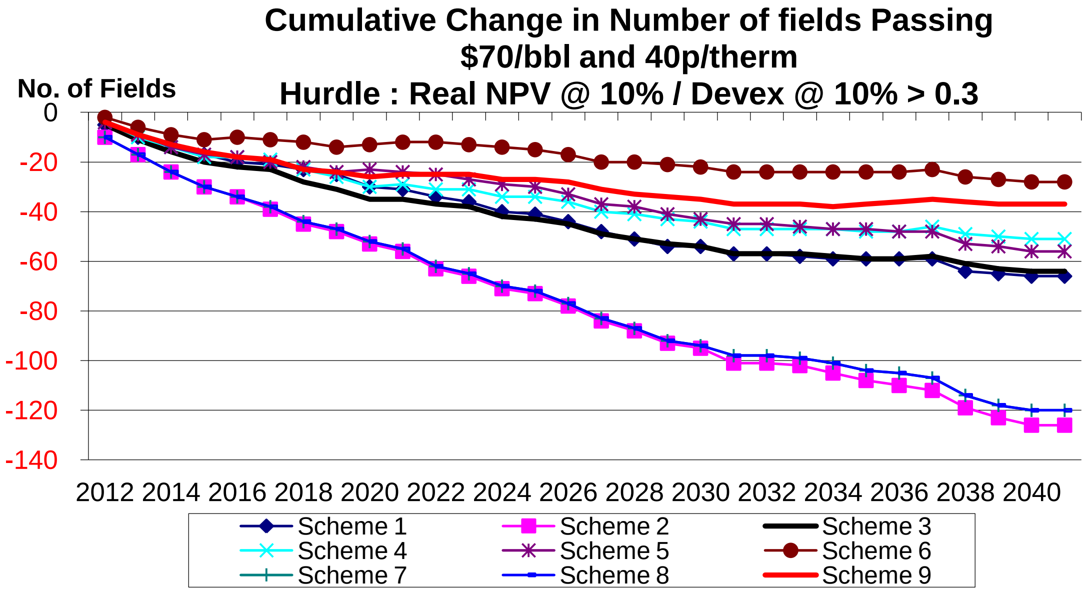


Chart 2



It is seen that the composite **Scheme 6** has the strongest effect in maintaining the numbers of field developments of all the schemes examined. It is noteworthy that for some years this scheme actually <u>increases</u> the numbers of developments. It should be emphasised that the increase in the numbers compared to the CT only case results from the field allowances already in place before <u>Budget 2012</u>. With **Scheme 5** the numbers of field developments are always less than under the CT only scheme. The results also clearly indicate that **Scheme 2** produces a substantial decrease in the numbers of new field developments. The results indicate that **Schemes 7 and 8** are not widely effective in enhancing the numbers of new field developments. The schemes are not well-targeted on substantial numbers of marginal fields.

It is also noteworthy from the results that **Scheme 9** (the <u>Budget 2012</u> proposals) is generally effective in enhancing the numbers of new field developments compared to most of other schemes. Only the composite **Scheme 6** produces more new developments over the thirty-year period.

But the loss of production is considerably less with **Scheme 1** compared to **Scheme 9**. The automatic help given to incremental projects with **Scheme 1** is relevant here. Budget 2012 incentivises a very considerable number of small field developments, but does not help marginal fields whose sizes exceed the qualifying limits. The higher rate of SC (32%) impacts adversely on these fields, and the net result is that overall production over the period is greater with **Schemes 1, 5 and 6** compared to **Scheme 9.**

The changes to oil production over the period under the different schemes are shown in Chart 3. The long term effectiveness of **Scheme 1** is highlighted followed by **Schemes 5 and 6**. The results for natural gas are shown in Chart 4. While **Scheme 1** again performs best the difference between it and **Scheme 9**, the second most effective one, is not nearly so marked. Perhaps surprisingly **Schemes 5 and 6** are not especially effective in curtailing the loss of production compared to **Scheme 1**. It should be noted that **Scheme 1** automatically applies to incremental projects while no corresponding help arises with the other schemes.

Chart 3

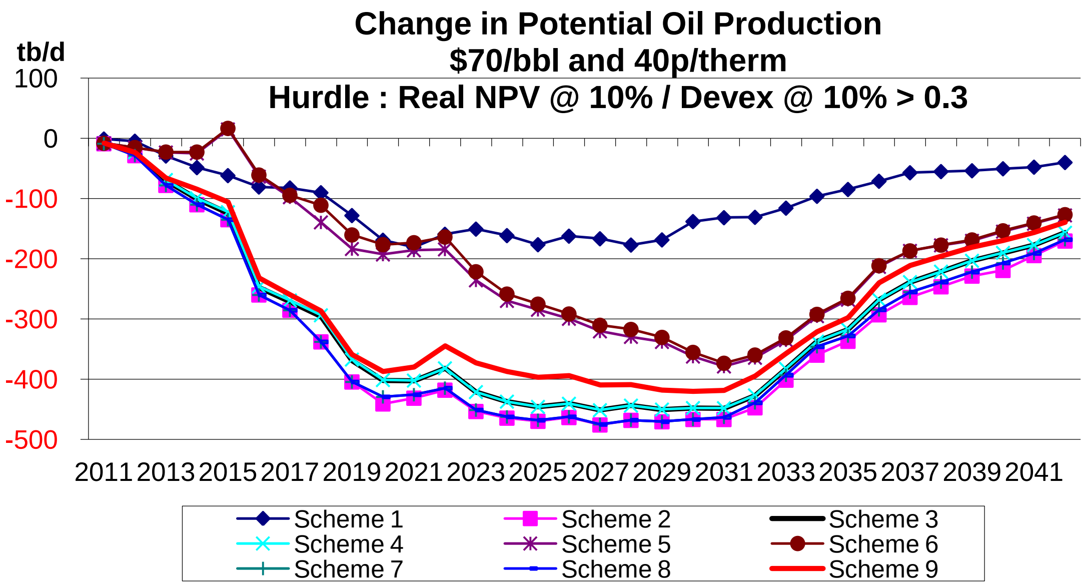
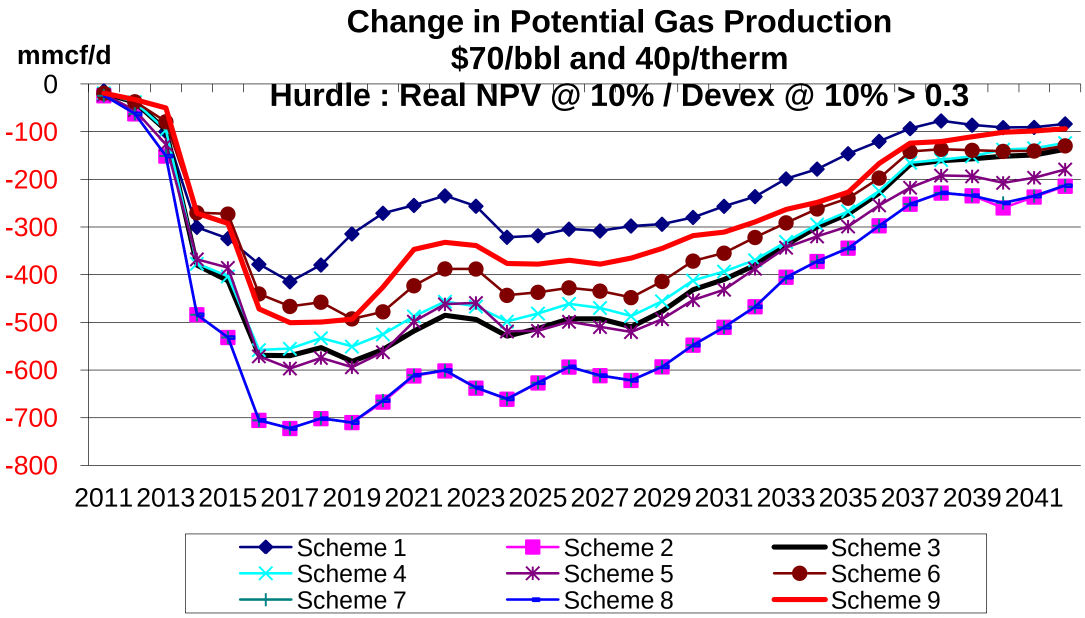


Chart 4



In Charts 5 and 6 the annual and cumulative changes in total hydrocarbon production over the period are shown. Unsurprisingly, **Scheme 1** produces the most effective performance, with a cumulative loss of production of around 1.65 billion boe (bn boe) compared to the CT only case in the period to 2042. The automatic help given to incremental projects by **Scheme 1** compared to the other schemes is a causal factor in the comparative results. With **Scheme 9** there is a cumulative loss of 3.8 bn boe. Under **Schemes 7 and 8** there is a loss of 4.68 bn boe. With the composite **Scheme 6** the loss is 2.9 bn boe and with **Scheme 2** it is 4.7 bn boe.

Chart 5

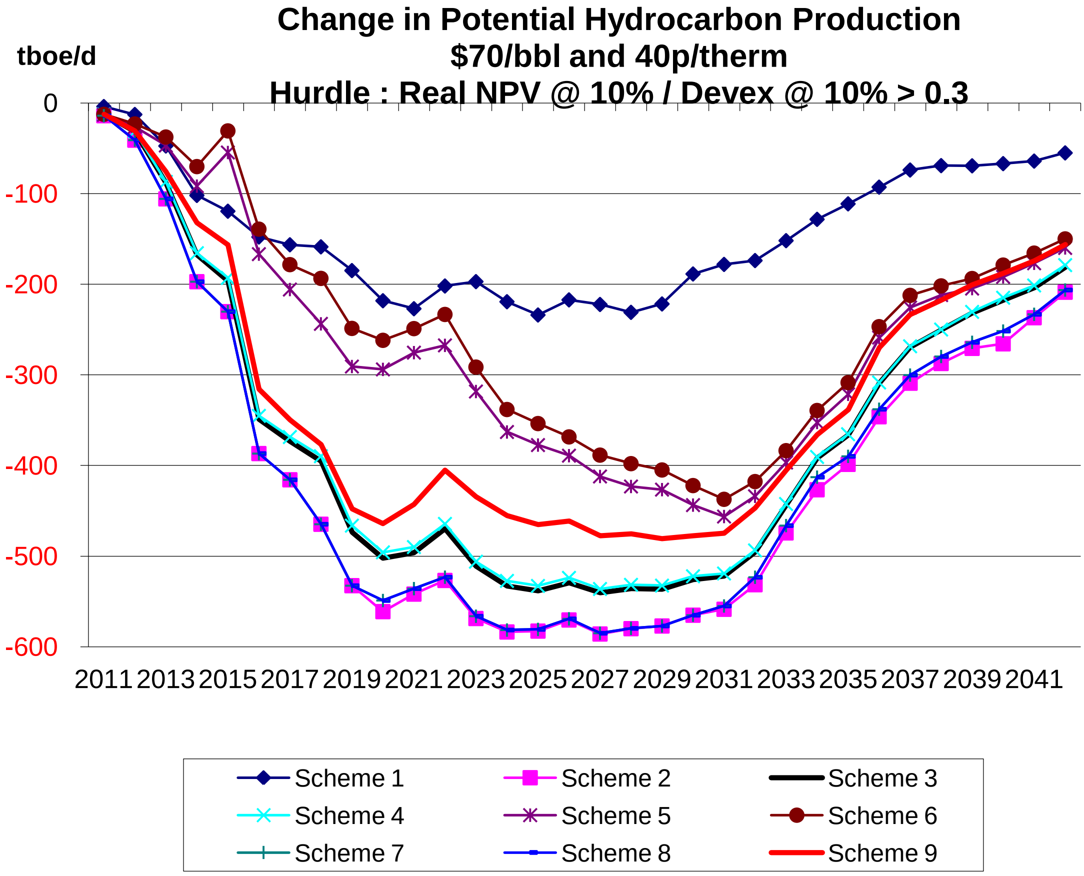
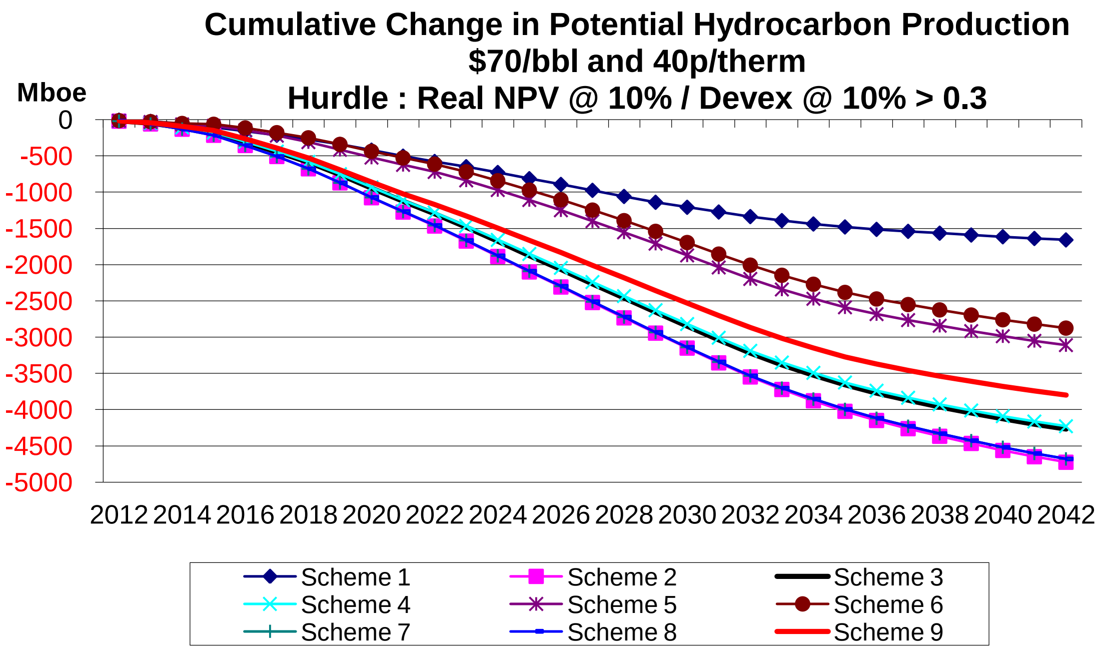
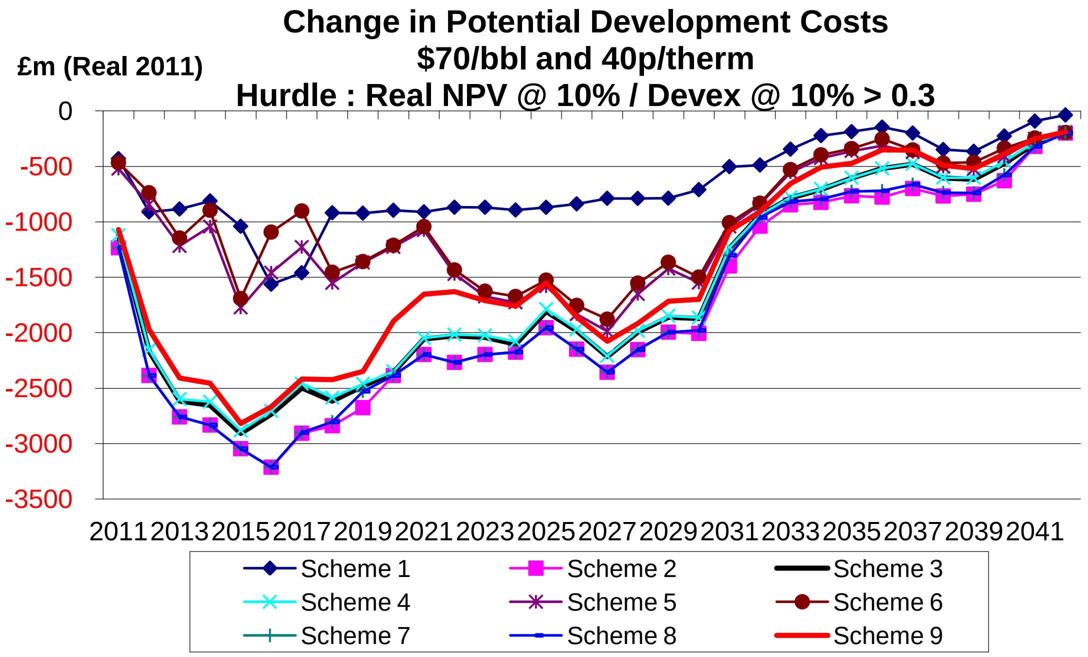


Chart 6



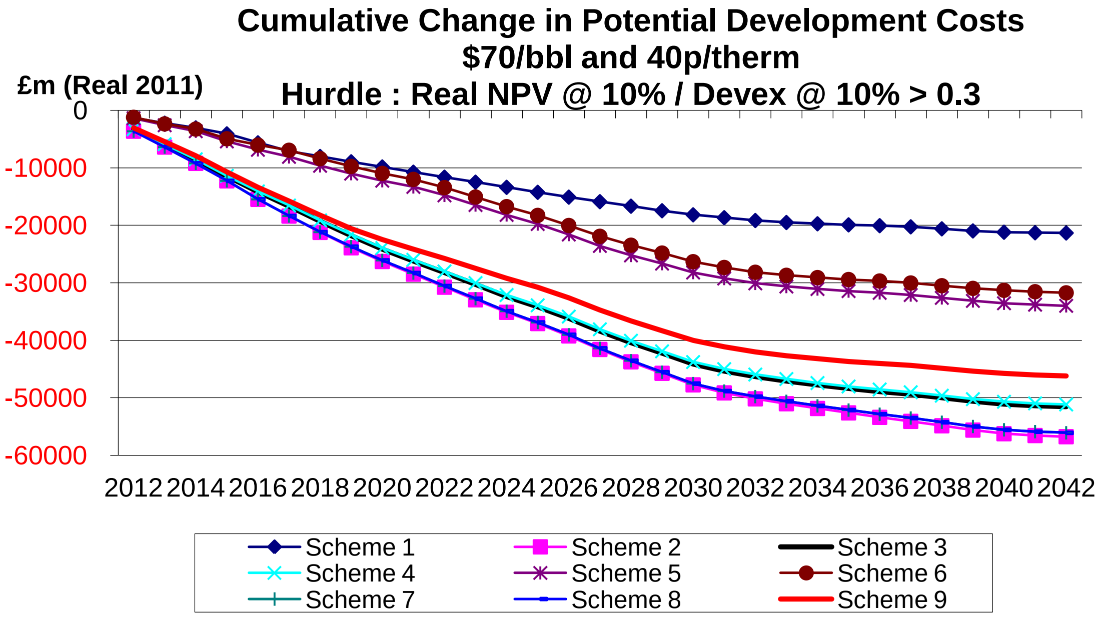
In Chart 7 the changes to field development expenditures are shown over the period. Unsurprisingly, **Scheme 1** is most effective in preserving the development effort. The composite **Scheme 6** is the next most effective. With **Scheme 9** there is a considerable reduction in the development effort over the next few years but in the later stages of the period this scheme is relatively effective. The explanation is that, over the next decade there is a number of potential but marginal developments whose size is above the qualifying limits established in <u>Budget 2012.</u> But, in the later years of the study period the sizes of fields are more likely to come under the qualifying limits for the new field allowances.

Chart 7



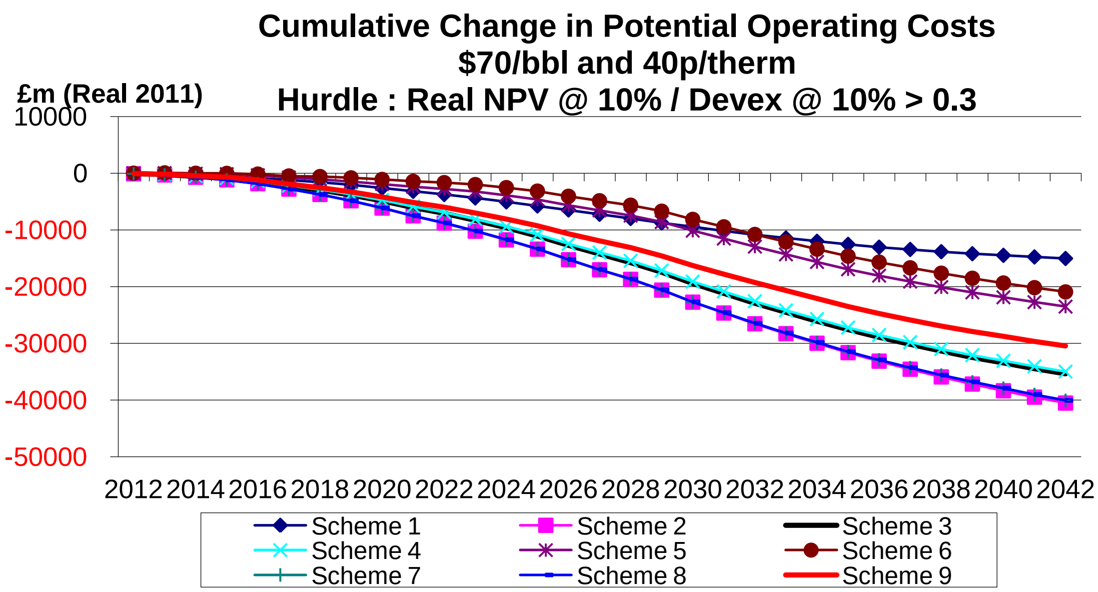
In Chart 8 the changes to cumulative development expenditures are shown. With **Scheme 1** the cumulative reduction is £21 billion. With the most ineffective schemes the cumulative reduction is around £56 billion. With **Scheme 9** the cumulative reduction is around £46 billion.

Chart 8



In Chart 9 the cumulative changes to operating expenditures are shown. Under **Scheme 1** the cumulative reduction is £15 billion over the period. With the most ineffective schemes the cumulative reduction is around £40 billion. Under **Scheme 9** the cumulative reduction to 2042 is just over £30 billion.

Chart 9



In Chart 10 the changes to total tax revenues over the period are shown on a yearly basis and in Chart 11 they are shown on a cumulative basis. There is a substantial increase in tax revenues compared to the CT only case under all the schemes. **Schemes 5 and 6** produce the largest cumulative increase which is in the £75 - £76 billion range. With **Scheme 9** the cumulative increase is around £65 billion. **Scheme 1** produces the lowest cumulative increase of £58 billion. With respect to timing it is noteworthy that **Scheme 9** produces relatively large short-term increases in revenues but is relatively less effective in later years. The opposite is the case with **Schemes 5 and6** which produce relatively large increases in the longer term. The issue is the familiar one of increasing the tax take on fields which will still go ahead with the increased tax rate, but which could reduce the number of new developments, and incentivising more developments (which involves the utilisation of more capital allowances and thus less early tax revenues) and the receipt of larger tax revenues in the longer term.

Chart 10

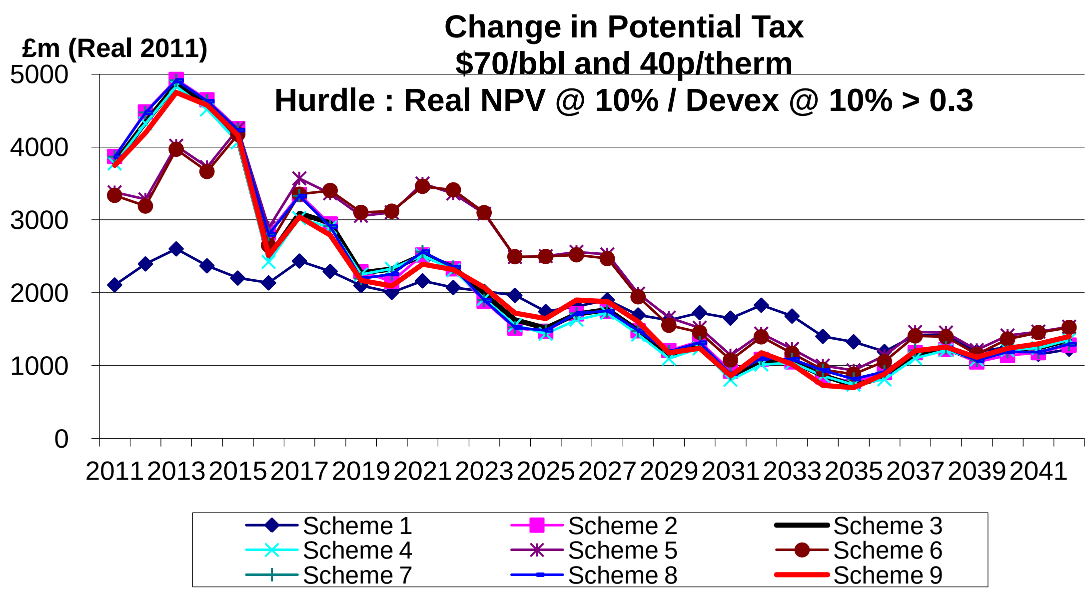
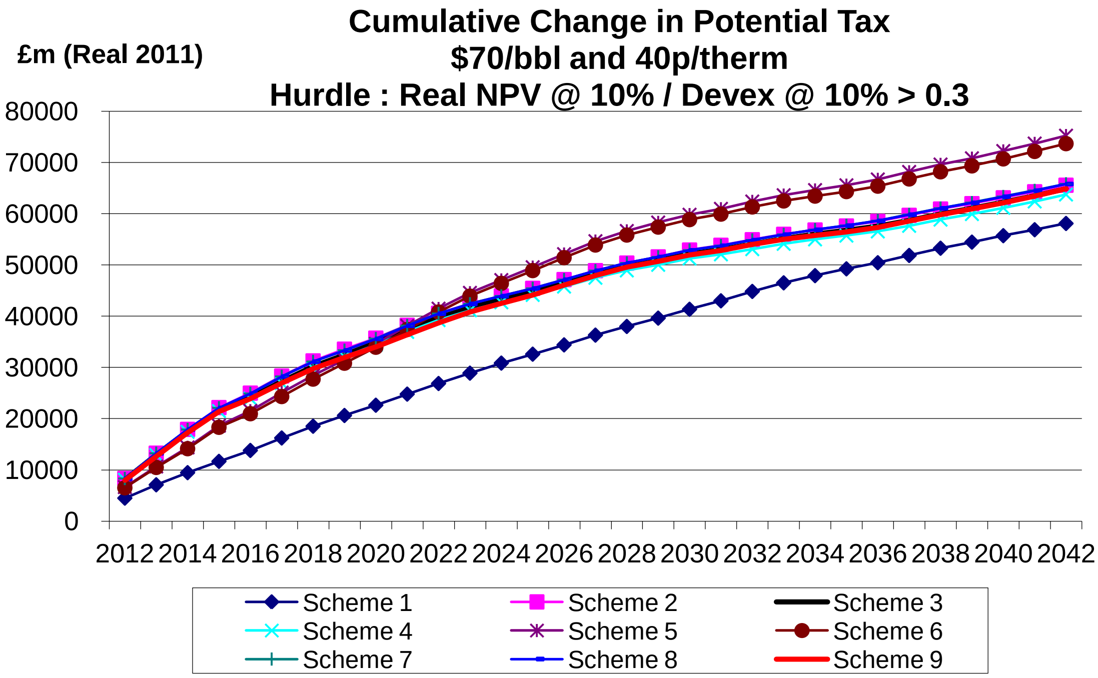


Chart 11



In Charts 12 and 13 the changes to CT and SC are shown annually under the different schemes while in Charts 14 and 15 they are shown cumulatively. Over the long term CT revenues stay up best under **Scheme 1** with a cumulative reduction of only just over £6 billion. With **Scheme 9** there is a cumulative loss of £20 billion. With **Schemes 5 and 6** there is a cumulative loss of just over £15 billion. **Scheme 1** performs best because it produces the largest volume of production (and thus taxable income).

Chart 12

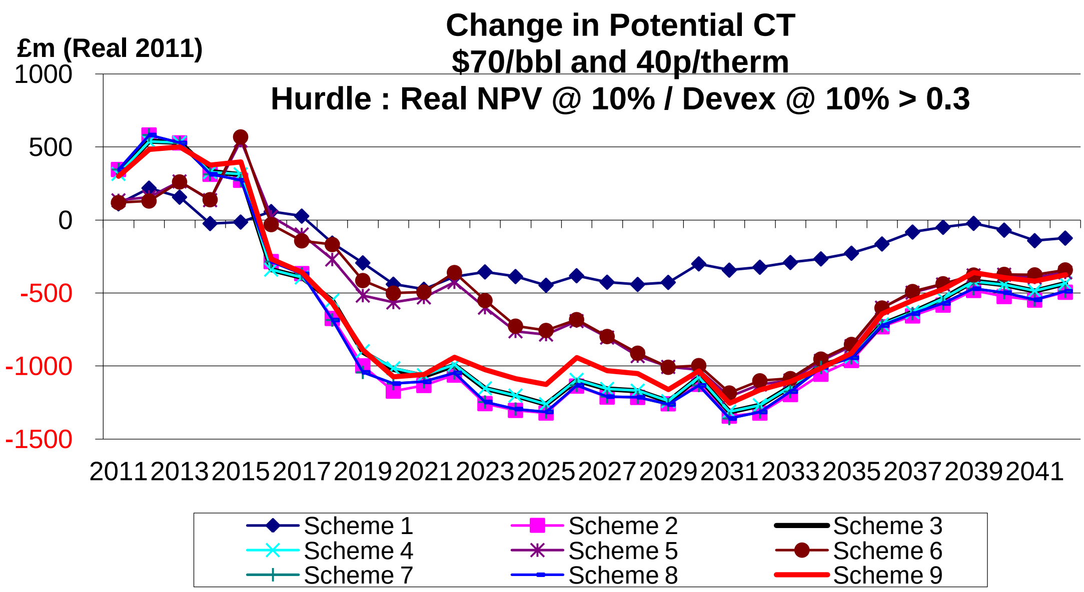


Chart 13

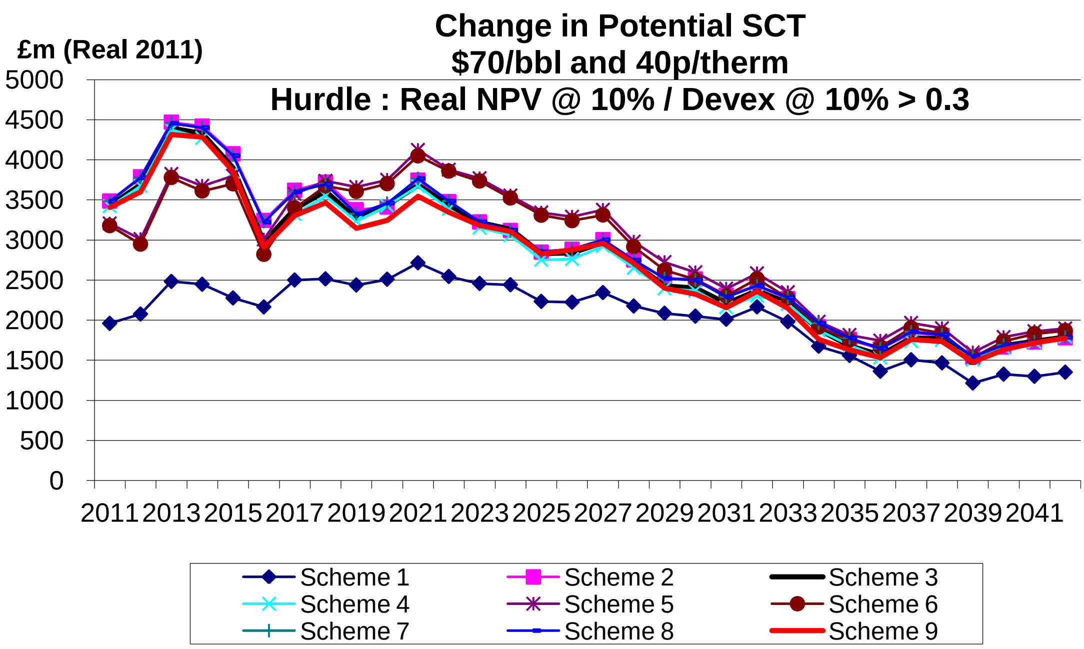


Chart 14

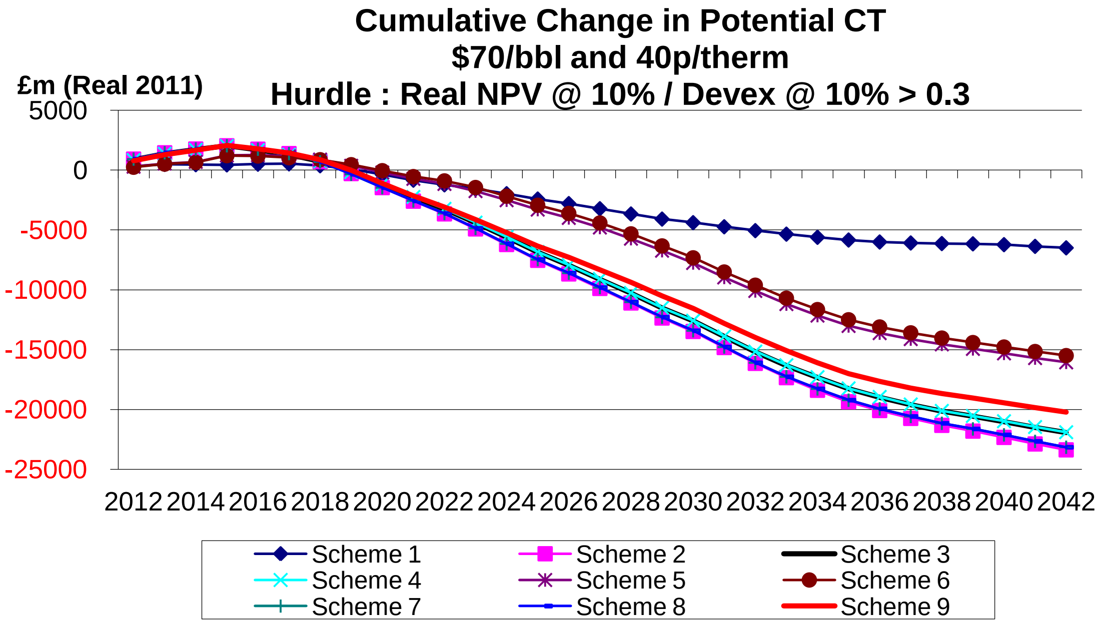
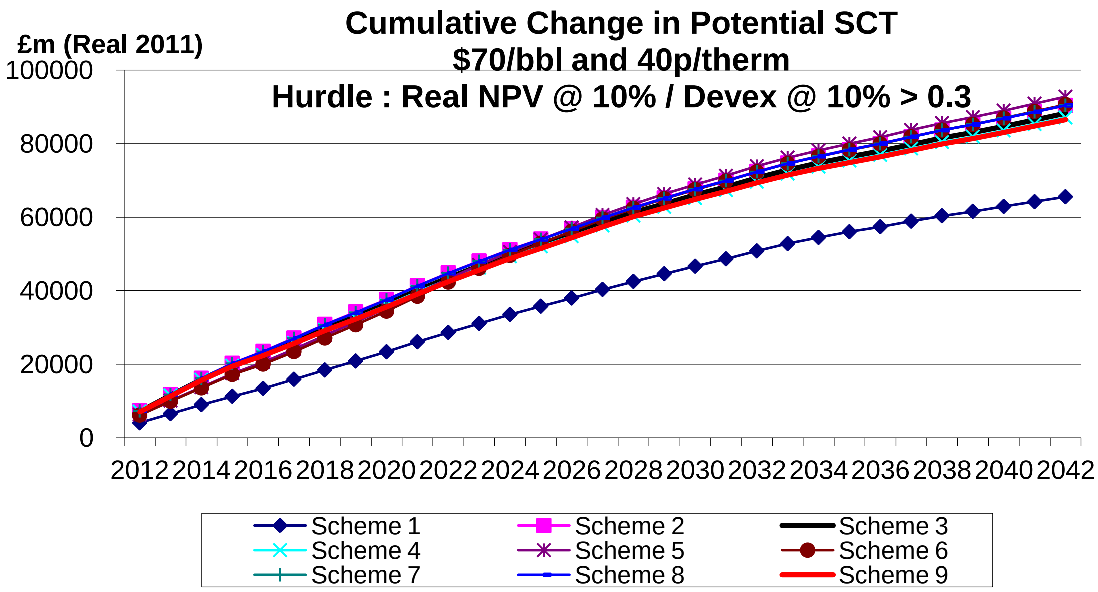


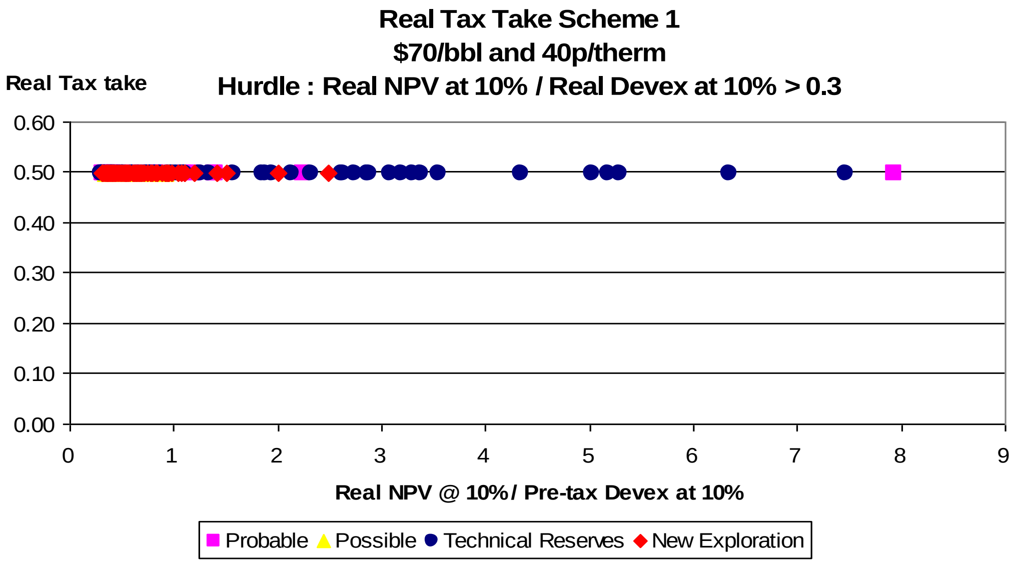
Chart 15



In order to obtain a better understanding of the operation of the various schemes the percentage tax takes were calculated over the lifetime of the fields in question. The tax takes are defined as the percentage of the real pre-tax cash flow taken in tax payments.

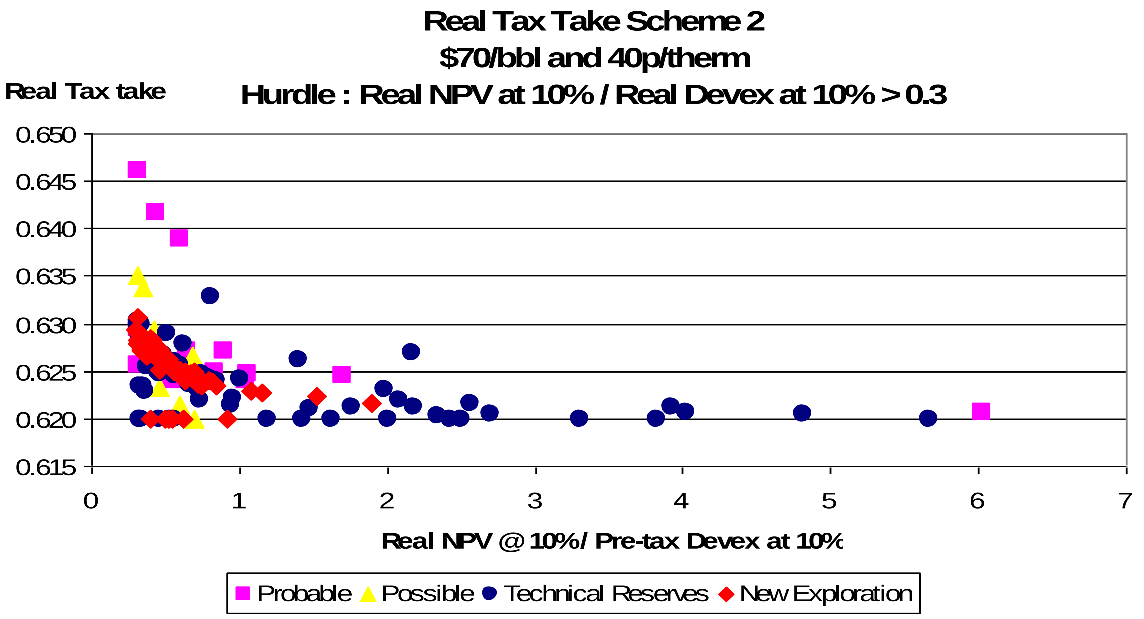
The results are shown for **Scheme 1** in Chart 16. This is a very straight-forward case where the take is 50% in all cases. (Investors are assumed to be in a tax-paying position).

Chart 16



The tax takes under **Scheme 2** are shown in Chart 17. The general rate is 62% and there are no field allowances. The tax takes are mostly at or near 62%. The restriction on decommissioning relief for SC increases the effective rate to a modest extent.

Chart 17



In Chart 18 the tax takes are shown under **Scheme 3** which incorporates the field allowances at the time of Budget 2011. While many of the fields pay tax at or around 62% the field allowances reduce the effective rate considerably in a substantial number of cases. In some cases the effective rate falls below 30%. This can come about on small fields where the field allowance greatly reduced the liability to SC on production income but relief continues to be given for the field investment at 62%. Further insights into the behaviour of **Scheme 3** are shown in Chart 19 which shows the tax takes on fields whose development is triggered by the allowances compared to the situation with SC at 32% but no field allowances. It is seen that the allowances produce tax takes often in the 20%-55% range.

Chart 18

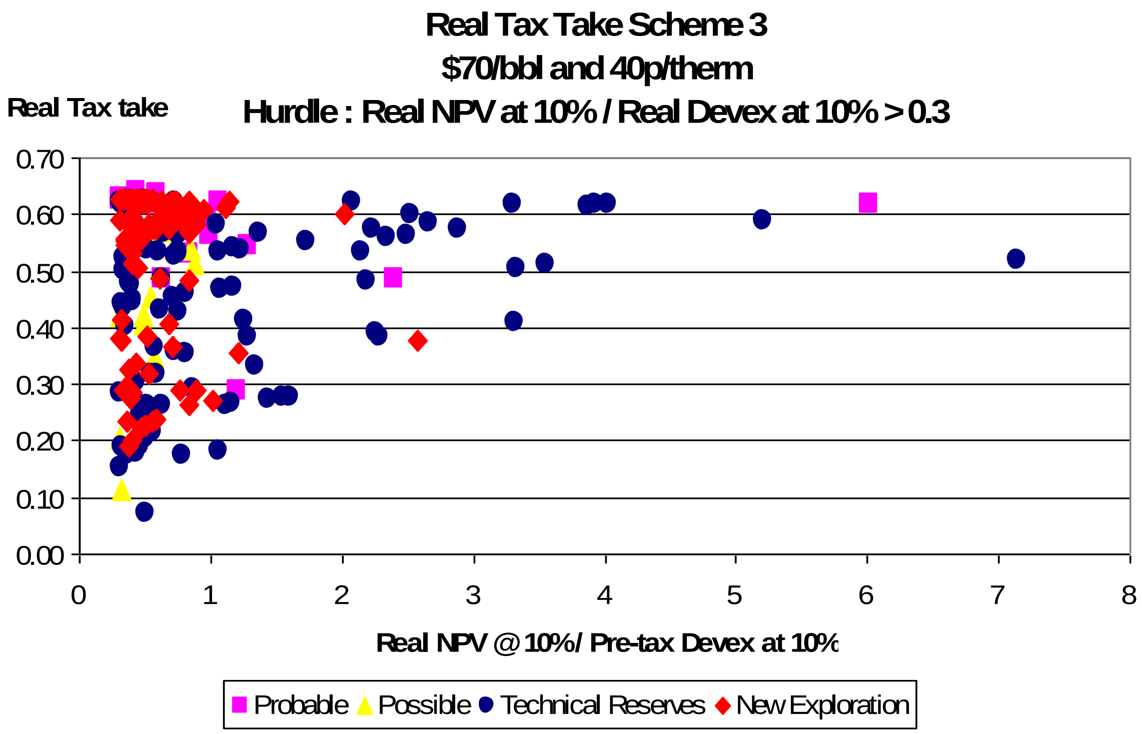
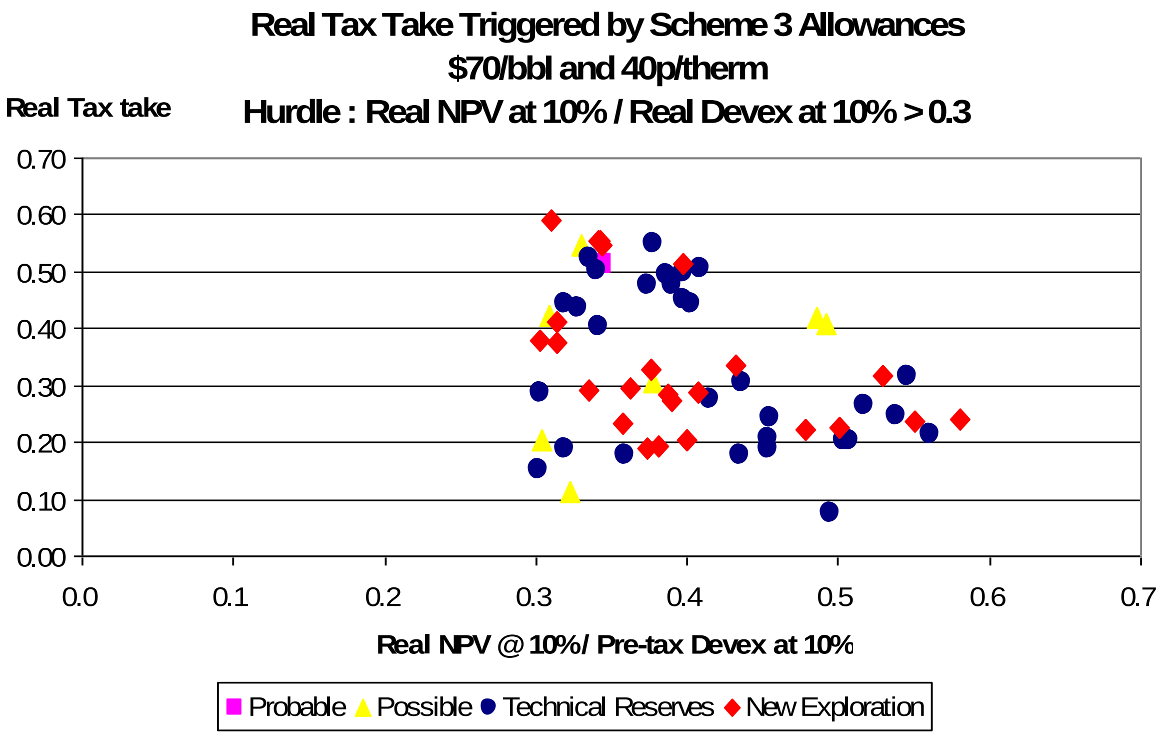


Chart 19



The results for **Scheme 4** are shown in Chart 20. There are now more cases where the take falls to relatively low levels. It will be recalled that this scheme permits the field allowances for a new field to be set against other field income irrespective of whether there is adequate income on the new field to absorb these allowances. Chart 21 shows that tax takes on fields which are triggered by this allowance can result in some low effective rates of tax.

Chart 20

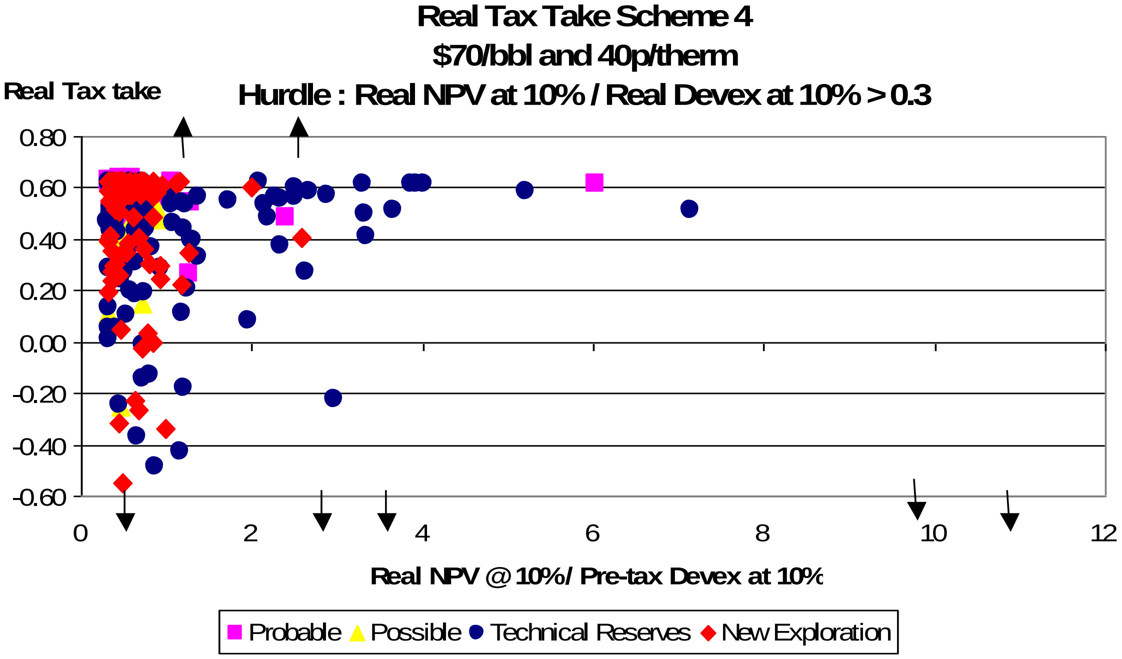
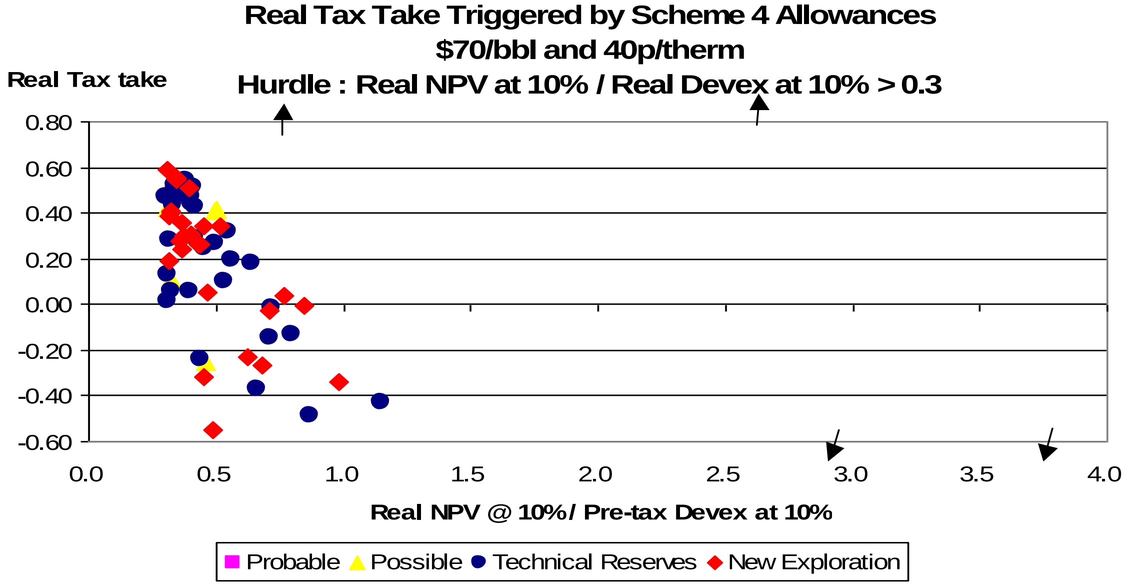


Chart 21



In Chart 22 the results are shown for **Scheme 5**. It is seen that the rate for many fields is 62%, but for a substantial proportion it is 30%. There are very few outlier results with this scheme. In Chart 23 the tax takes are shown in the fields triggered by the allowance (compared to SC at 32% and no allowance). Most of the takes are in the 35%-60% range with very few outliers.

Chart 22

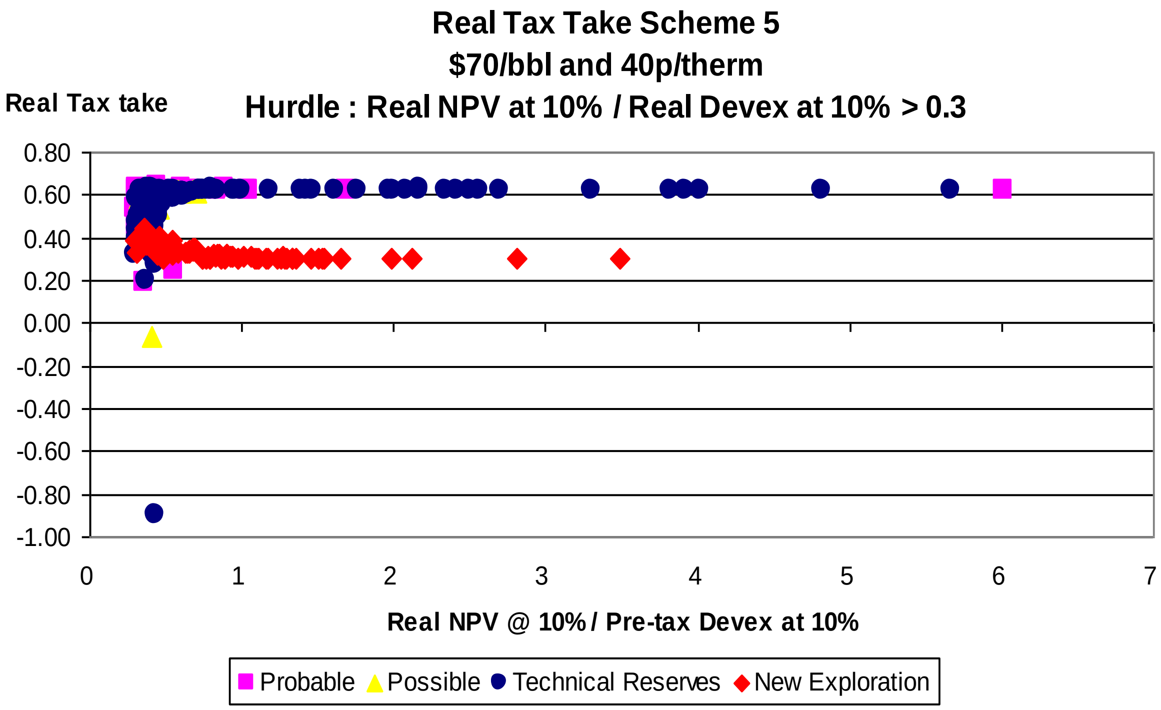
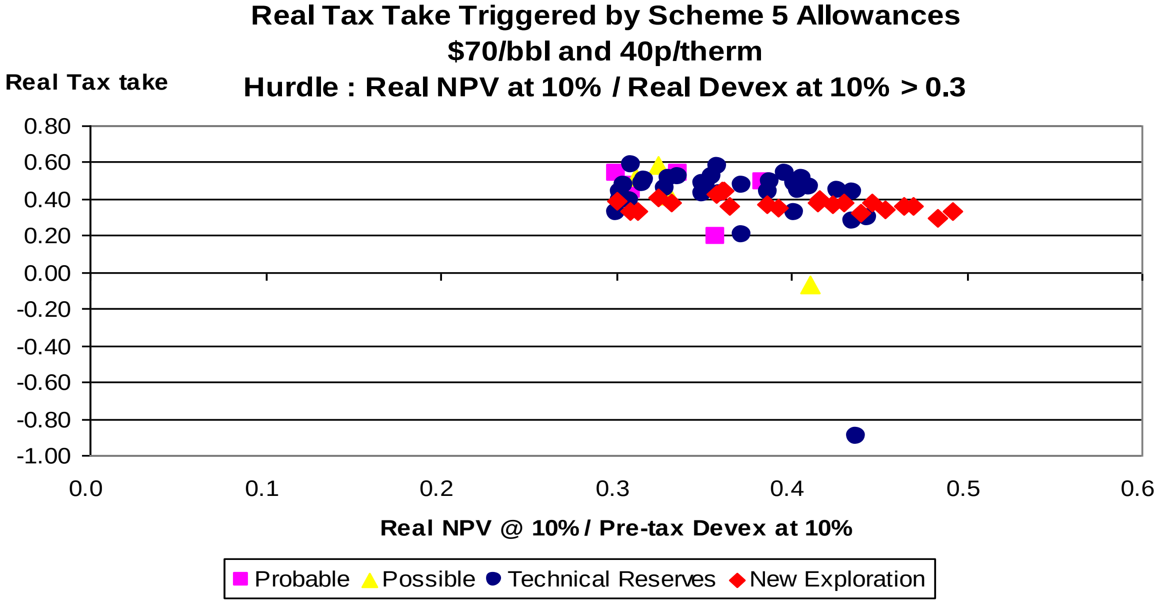


Chart 23



In Chart 24 the results are shown for **Scheme 6**. It will be recalled that this is a composite of **Schemes 5 and 4** with the investor being able to choose his preferred scheme. It is seen that when profitability is low the tax take is sometimes reduced compared to **Scheme 5**. The occasions when the take becomes less than 30% are due to the **Scheme 4** allowance. In Chart 25 the tax takes are shown on the fields whose development is triggered as a consequence of the allowance (compared with SC at 32% and no allowance). The takes are in the 20%-60% range for the great majority of fields.

Chart 24

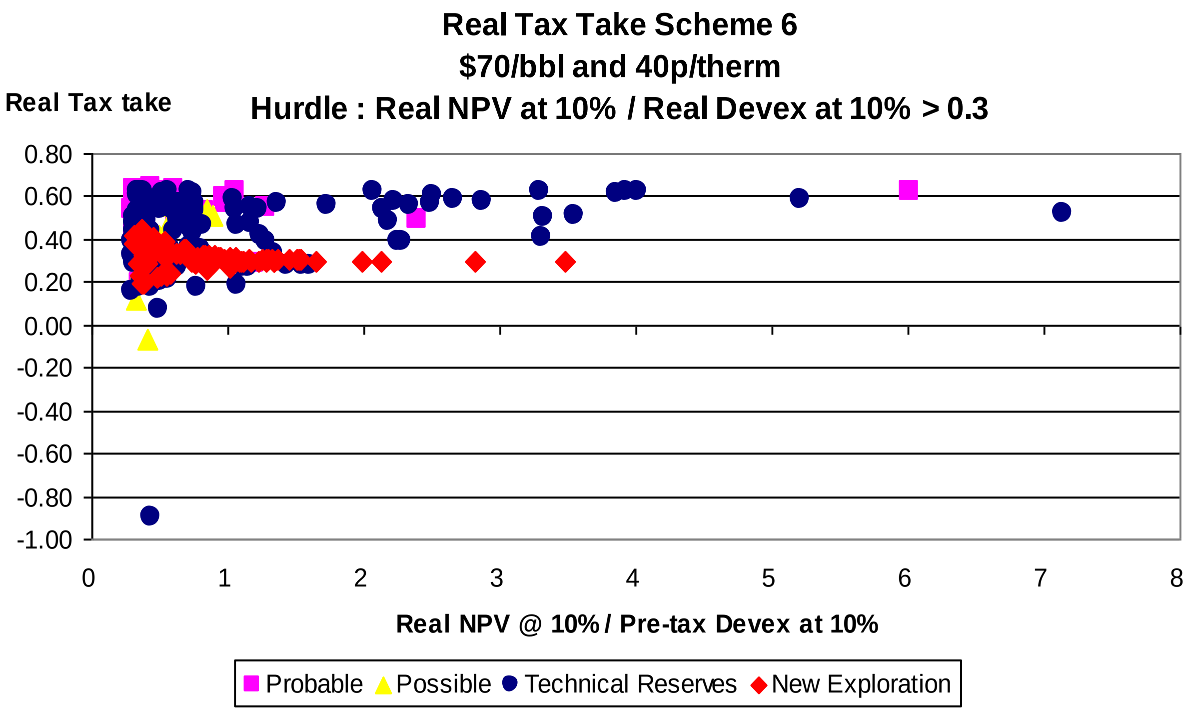
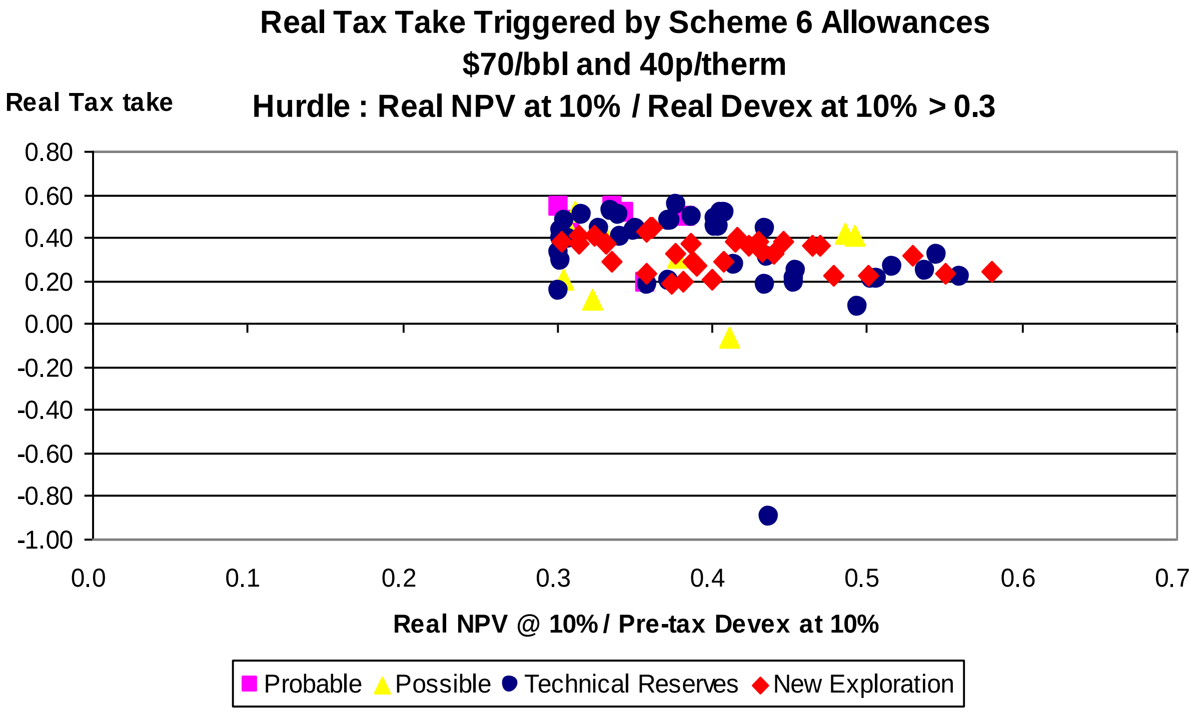


Chart 25



In Charts 26 and 27 the tax takes under **Schemes 7 and 8** are shown. In the majority of cases the take is around 62%. In only a few cases does the take come significantly below 60%, even at low levels of profitability.

Chart 26

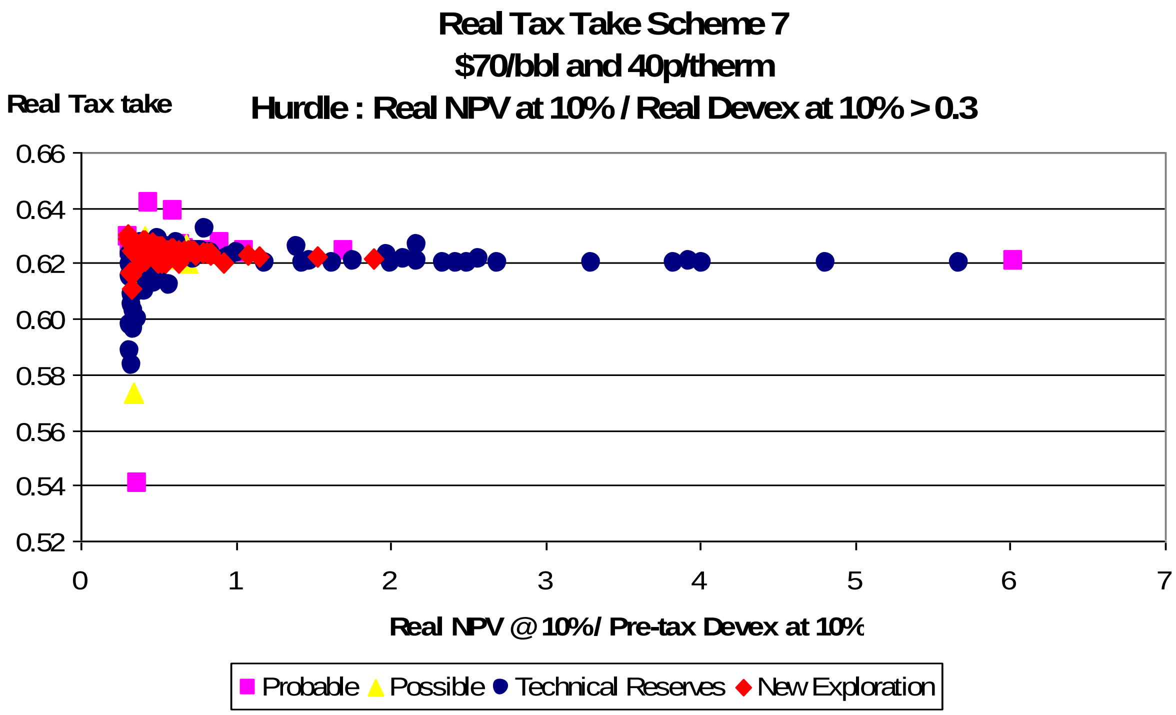
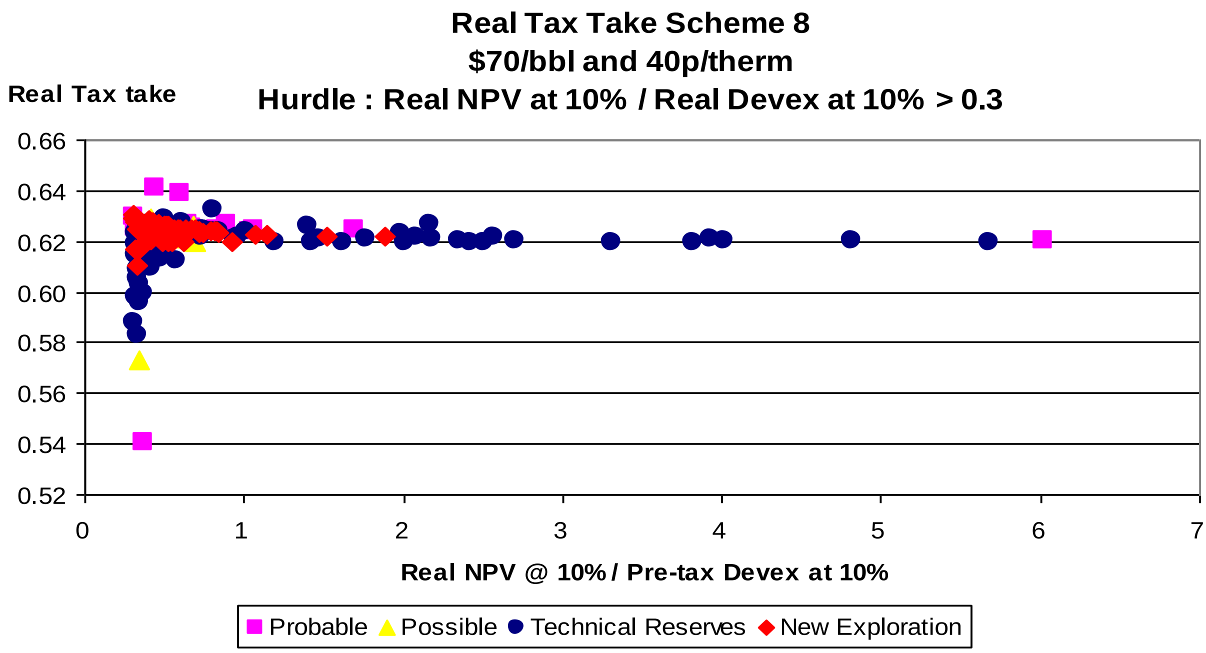


Chart 27



In Chart 28 the tax takes under **Scheme 9** are shown. There is a big spread in the effective rates. The lower rates are sometimes, but not always, geared to situations of low profitability. This results from the reliance on physical factors to determine the availability and size of the allowance. In Chart 29 the tax takes are shown for the fields whose development has been triggered by the allowance (compared to SC at 32% and no field allowance). There is a wide spread of effective rates from around 60% to less than 20%.

Chart 28

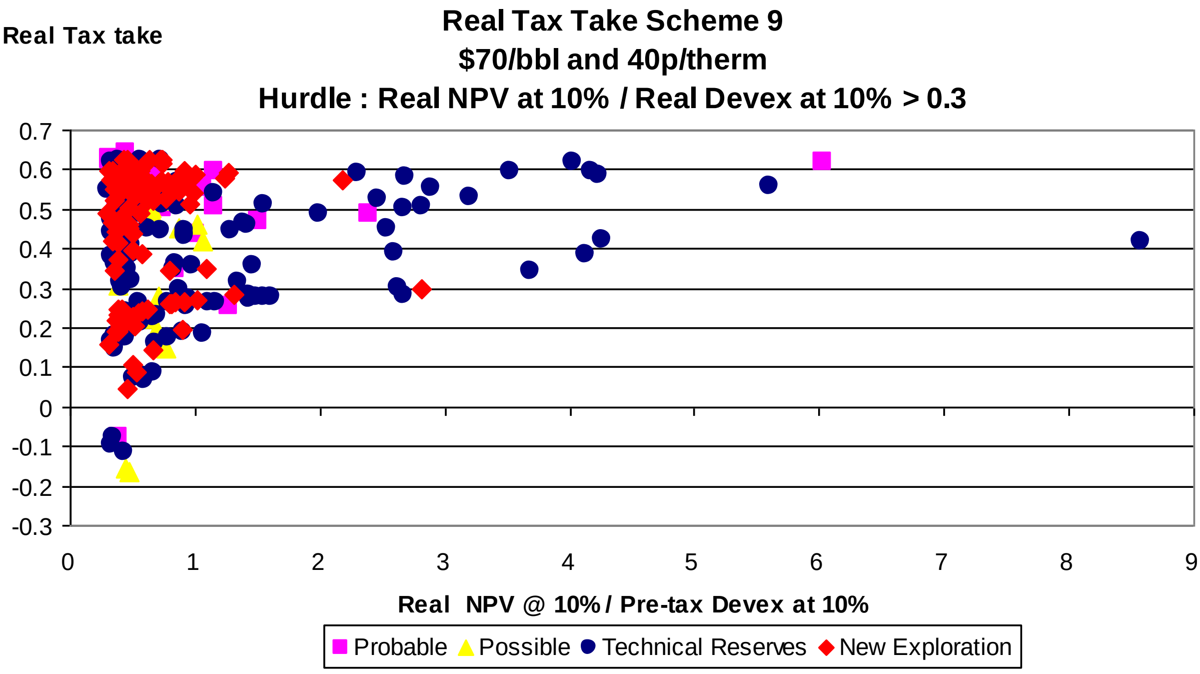
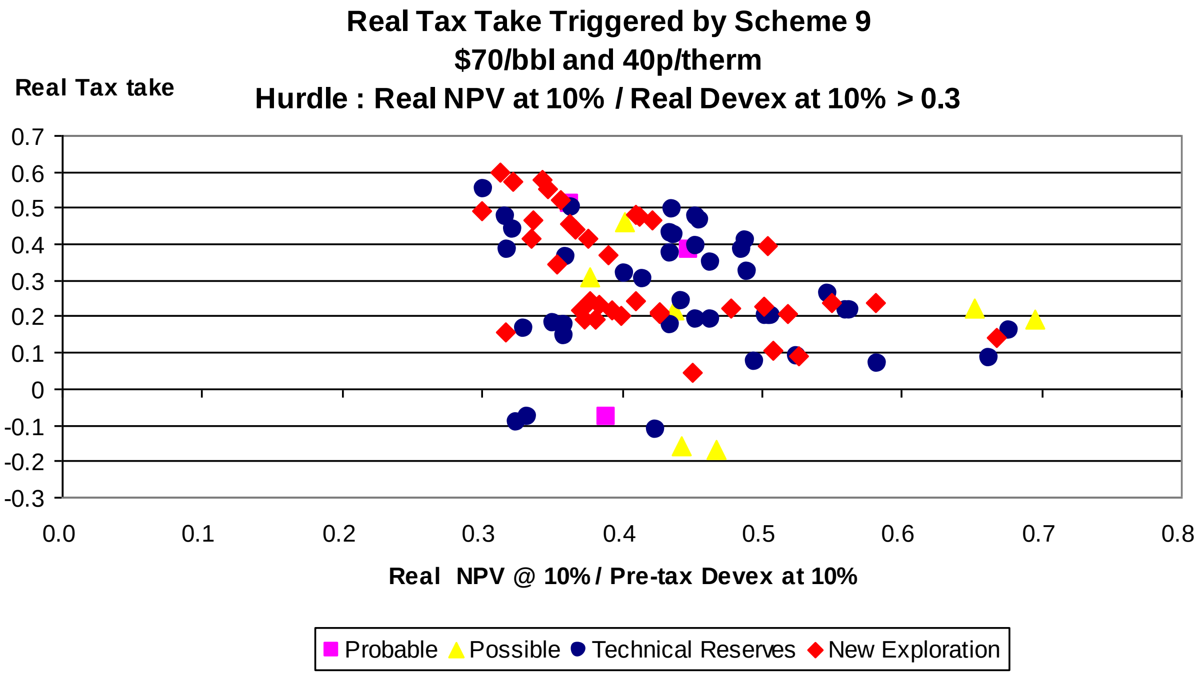


Chart 29



B. $70, 40 pence, NPV/I > 0.5 Case

In Chart 30 the changes in the annual numbers of fields in production are shown for the situation where the economic hurdle is NPV/I > 0.5. The figures are shown for the cumulative reduction in the numbers of fields passing the hurdle in Chart 31.Over the period there are 660 potential new developments in this scenario. Of these 300 fail the economic hurdle pre-tax, and 282 pass the hurdle after CT. Compared to this base case of CT only there are 67 less developments with **Scheme 1**, 114 less with **Scheme 2**, 76 less with **Scheme 3** (the 2011 system), 106 less with **Scheme 5**, 72 less with **Scheme 6**, 114 less with **Scheme 7**, and 54 less with **Scheme 9**. Thus **Scheme 9** (<u>Budget 2012</u>) produces the smallest reduction in numbers of producing fields over the total period. **Scheme 5** is seen to perform relatively ineffectively as do **Schemes 2, 7 and 8**. The ineffective performance of **Scheme 5** is at first sight more surprising and the reasons are discussed below when the tax takes are exhibited.

Chart 30

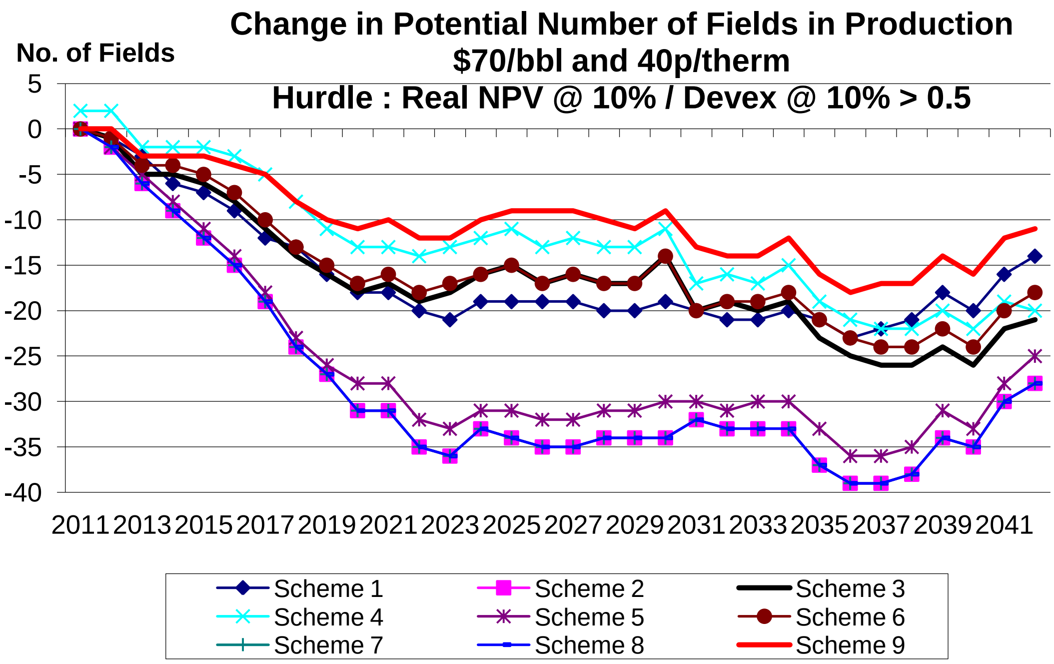
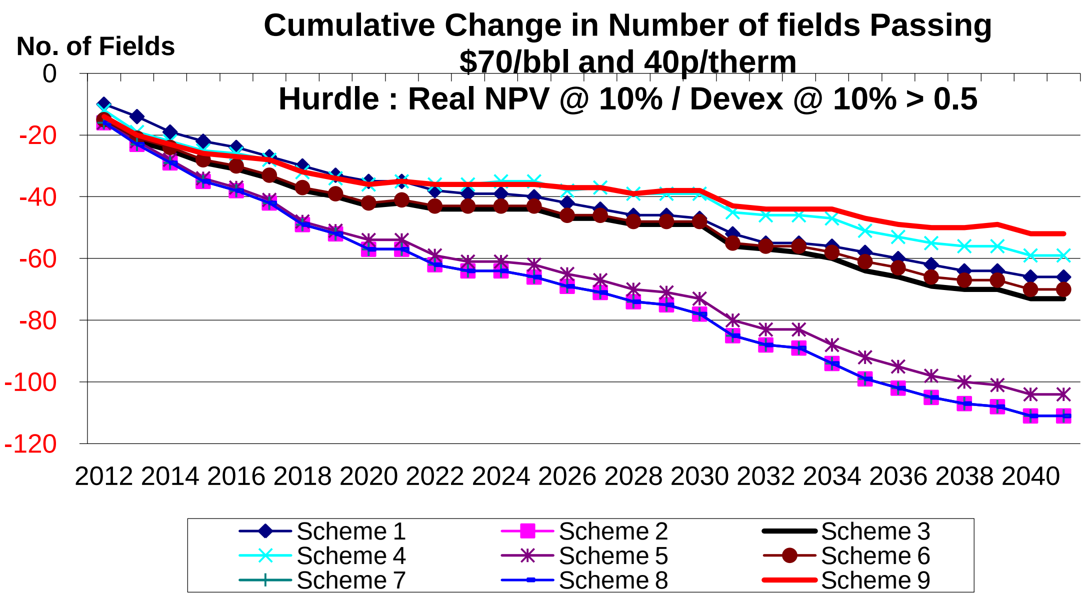


Chart 31



In Charts 32, 33 and 34 the changes in annual oil, gas, and total hydrocarbon production respectively are shown under the various schemes.

Chart 32

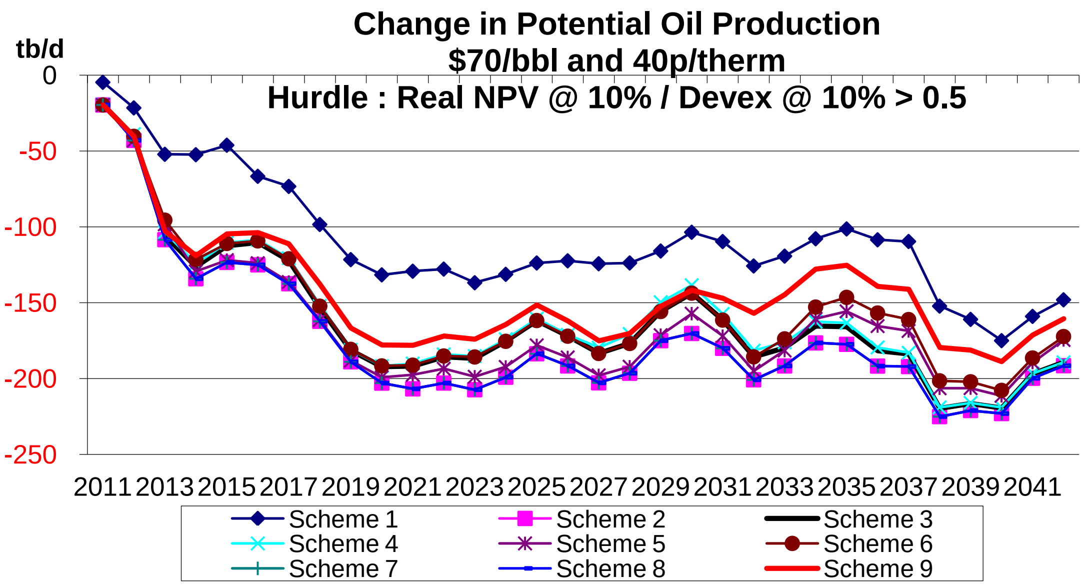


Chart 33

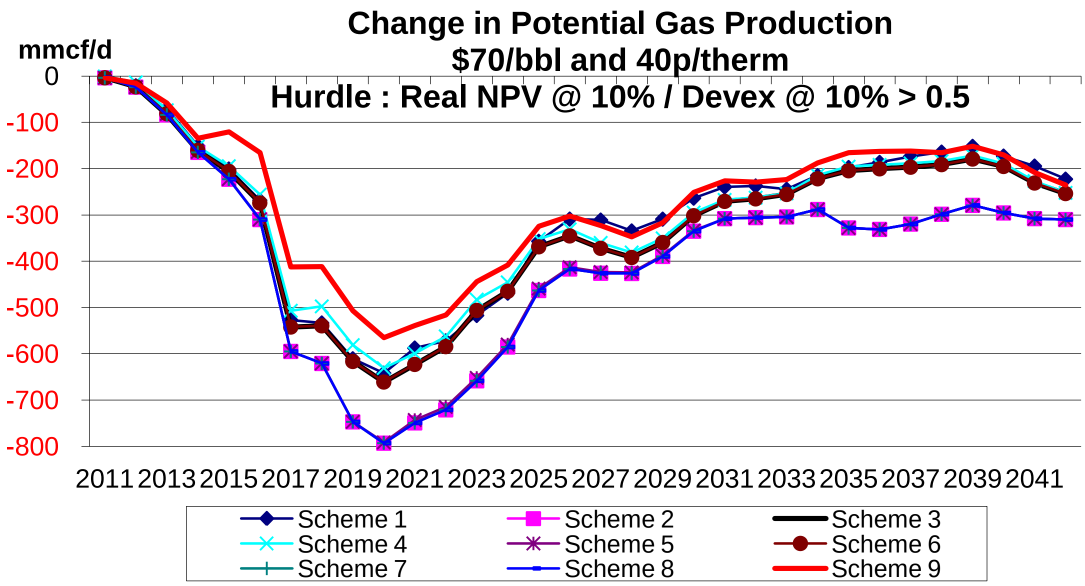
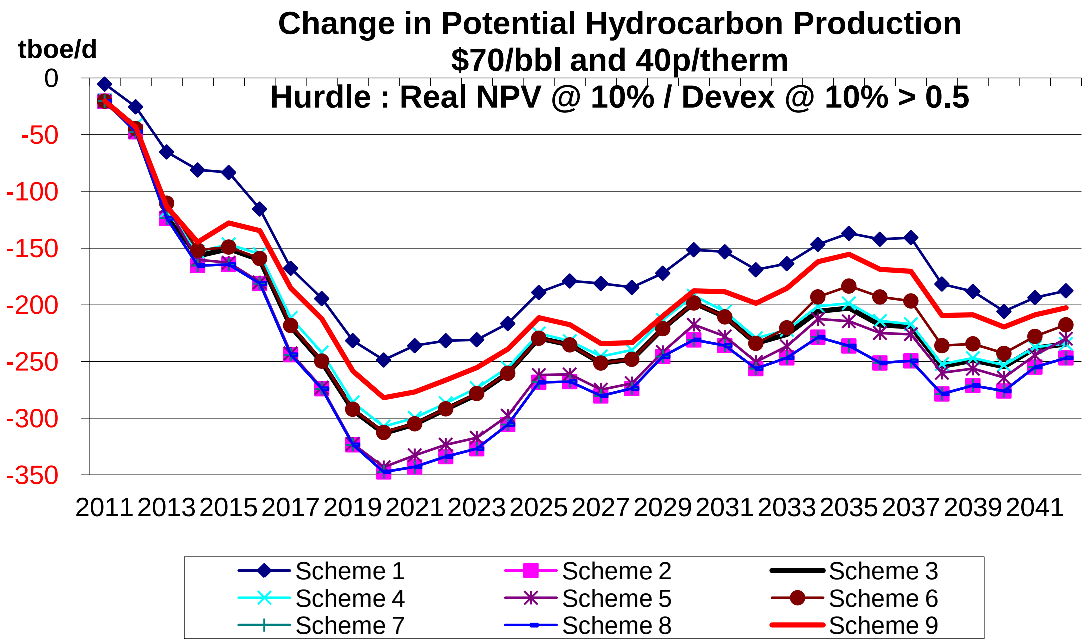


Chart 34



The cumulative changes in oil and total hydrocarbon production are shown in Charts 35 and 36. The lowest cumulative reduction compared to the CT only case is with **Scheme 1** at 1.9 bn boe. The next best performer from this viewpoint is **Scheme 9** where the cumulative reduction is 2.2 bn boe. The composite **Scheme 6** produces the next best performance with a reduction of 2.5 bn boe. **Schemes 3 and 4** result in cumulative reductions exceeding 2.5 bn boe and **Schemes 2, 7 and 8** result in reductions exceeding 2.8 bn boe. **Scheme 1** produces the lowest reduction in part because there is some automatic protection for incremental projects compared to the other schemes shown. The explanations for the comparative performance of these other schemes are discussed below when the tax takes are shown. **Scheme 9** (Budget 2012) is most effective in preventing the numbers from falling significantly. **Scheme 4** is generally the second best performer in this respect. **Schemes 5, 7 and 8** do not perform well from this viewpoint.

Chart 35

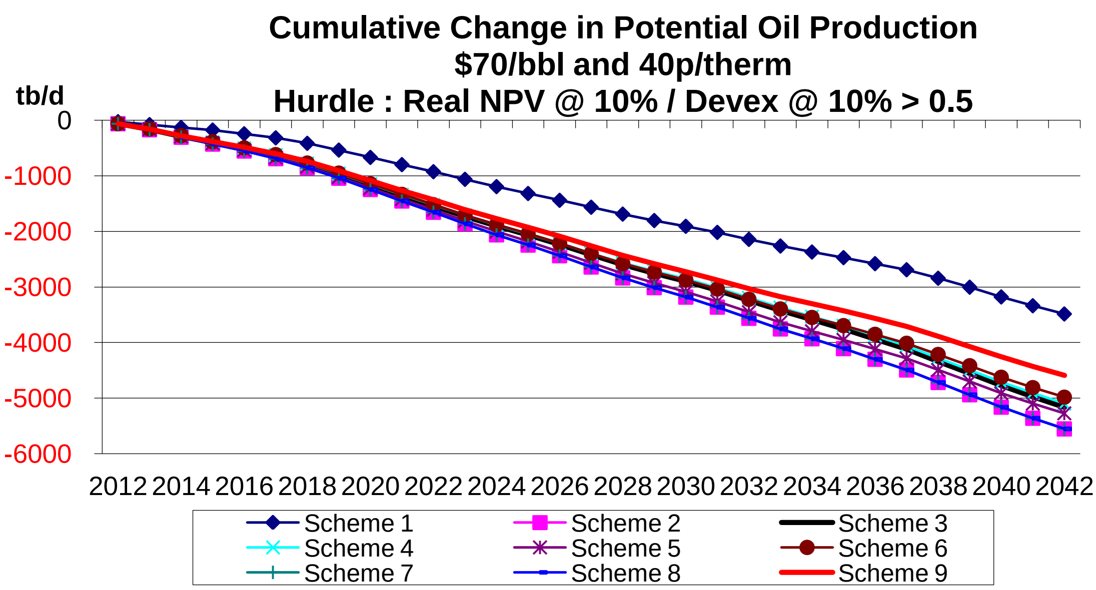
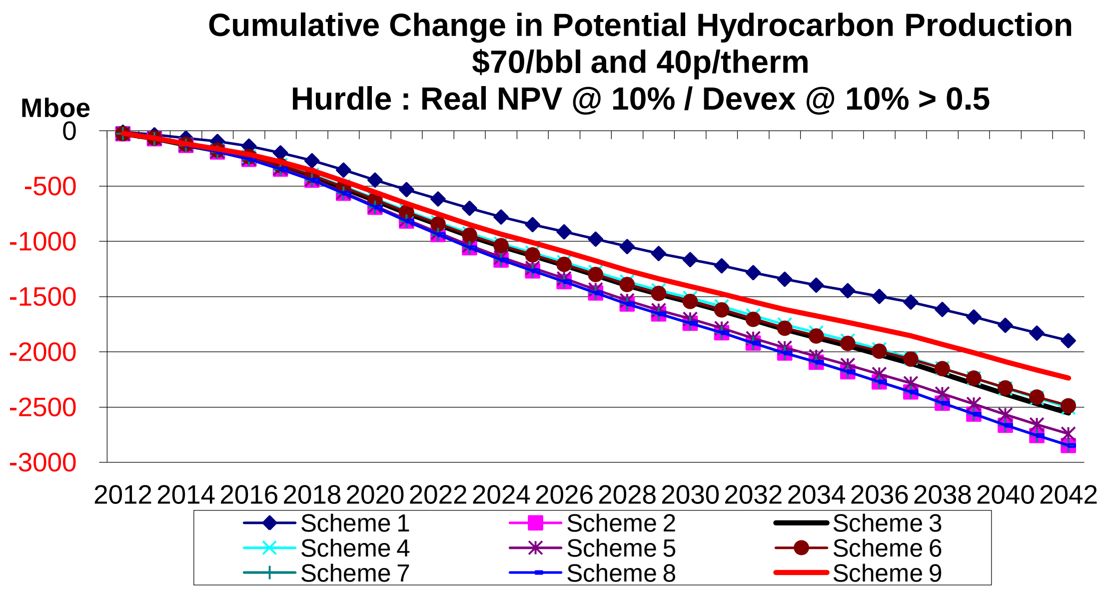


Chart 36



In Chart 37 the changes in new field development costs annually are shown. **Scheme 1** generally performs best, followed by **Scheme 9**. The results for cumulative development expenditures, shown in Chart 38 indicate that with **Scheme 1** cumulative development costs are reduced by £23 billion while with **Scheme 9** they are reduced by £27 billion.

Chart 37

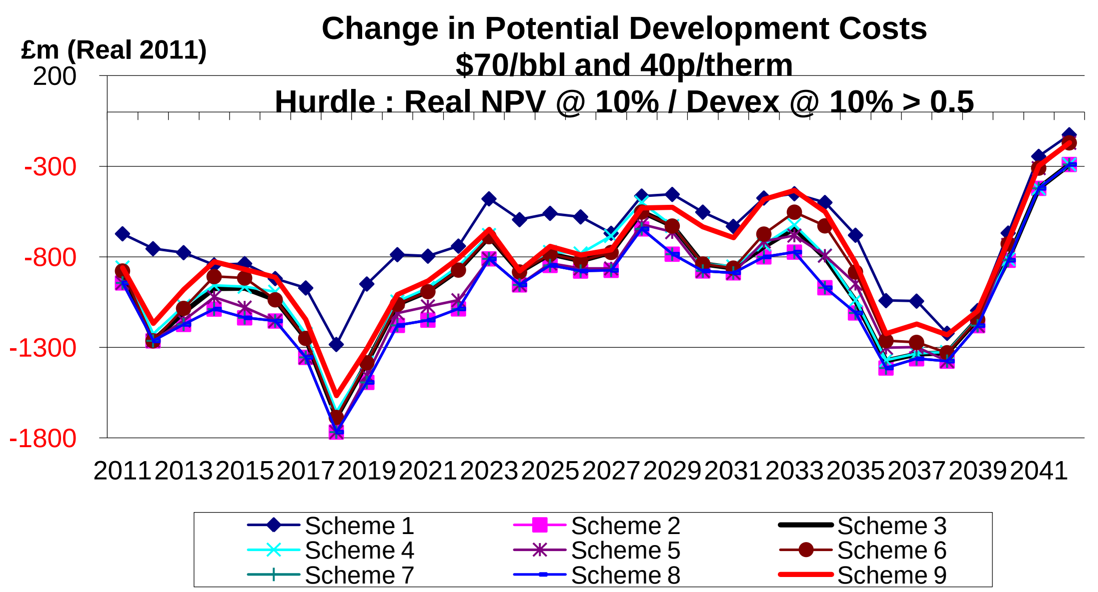
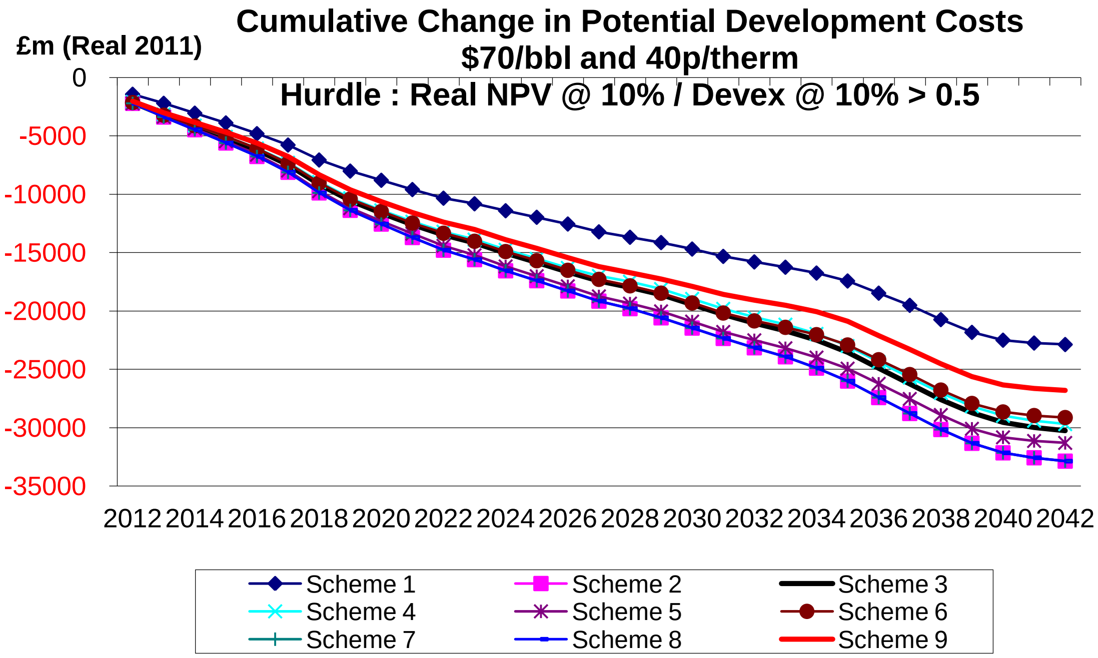


Chart 38



In Chart 39 the annual changes to operating costs are shown over the period. Unsurprisingly, **Scheme 1** performs best with **Scheme 9** in second place. In Chart 40 the cumulative changes to operating costs are shown. With **Scheme 1** they fall by £14 billion while with **Scheme 9** they fall by £16.5 billion.

Chart 39

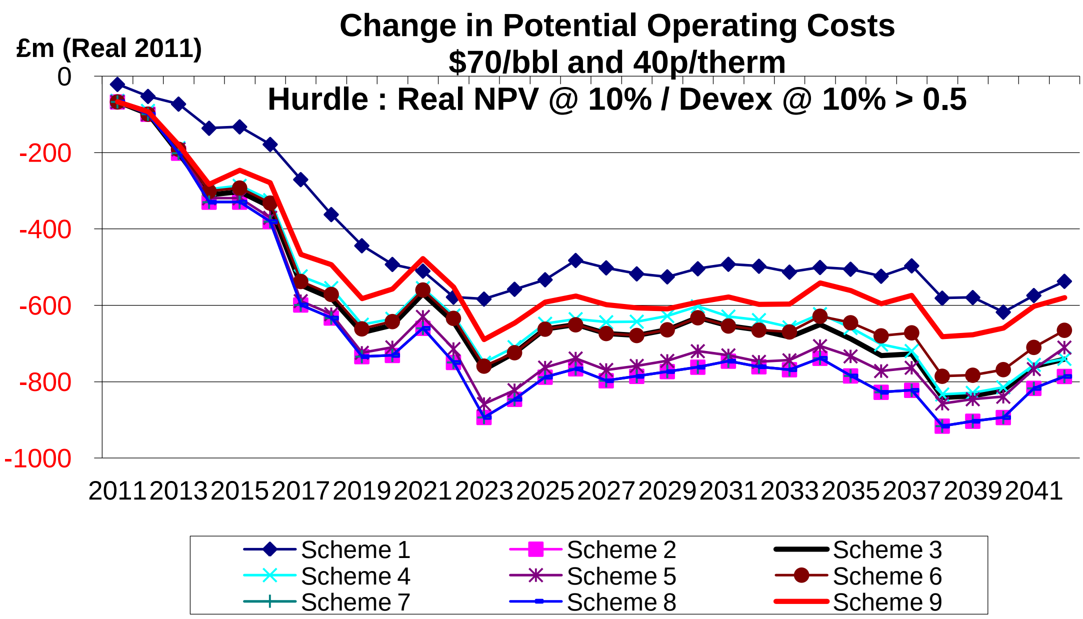
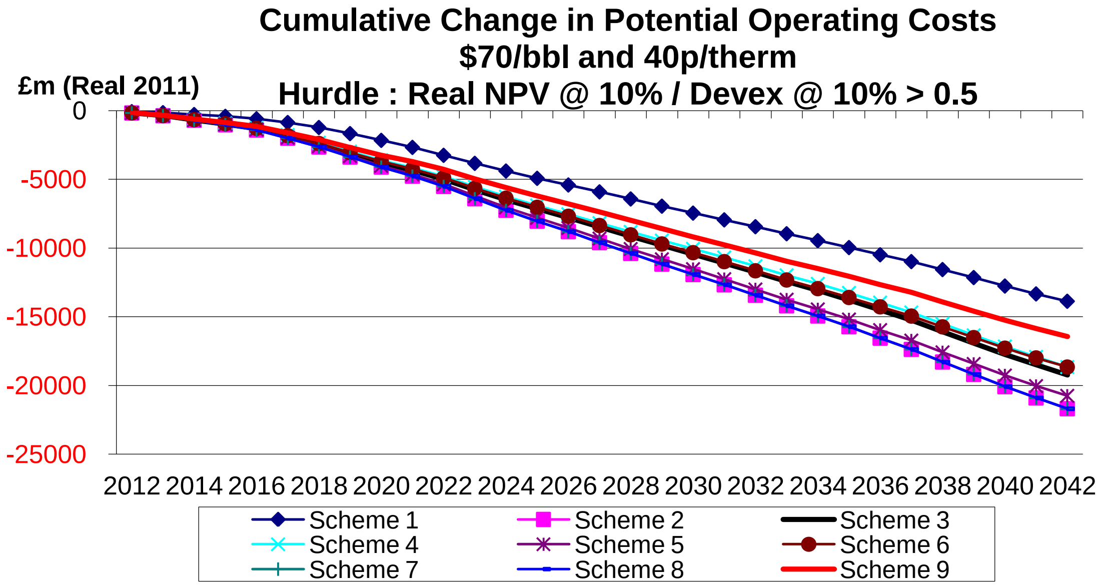


Chart 40



In Chart 41 the annual change in total tax payments are shown. The corresponding cumulative amounts are shown in Chart 42. It is seen that **Scheme 1** produces significantly less extra tax than other schemes, though the absolute extra amount accumulates to nearly £42 billion over the period. There is very little difference among the cumulative extra tax receipts with the other schemes. **Scheme 9** produces extra revenues of £65 billion over the period.

Chart 41

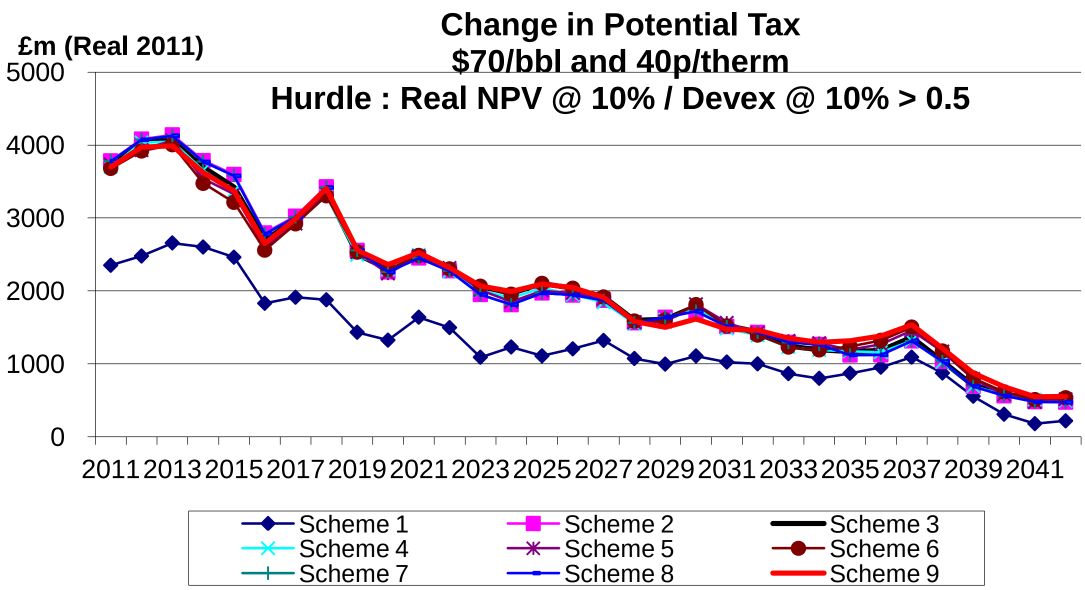
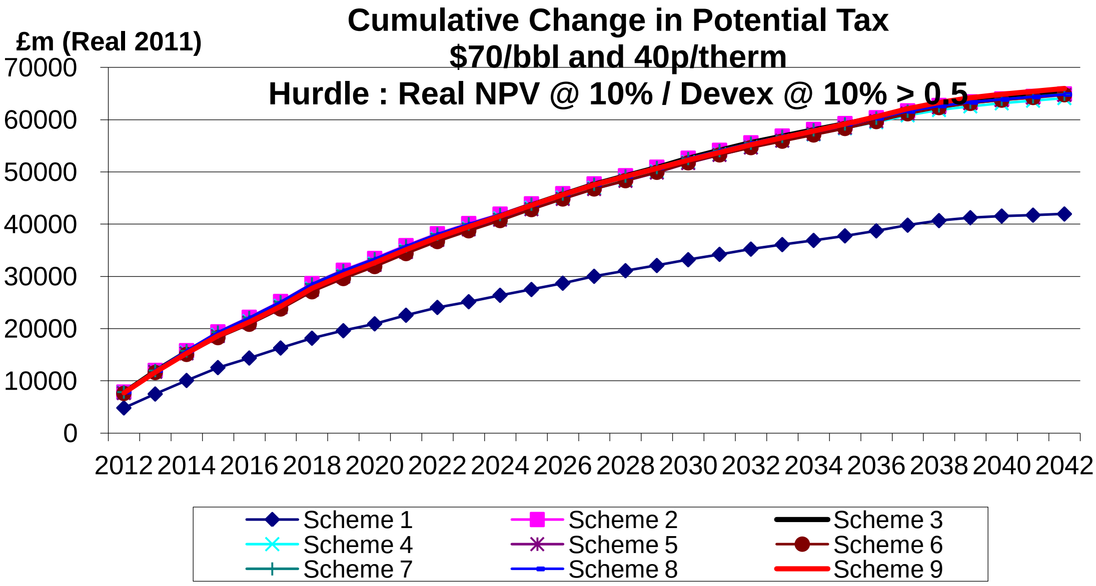


Chart 42



In Charts 43 and 44 the annual changes to CT and SC are shown under the various schemes. The reduction in CT is least with **Scheme 1,** with **Scheme 9** generally being second in this respect. With SC the smallest increase is clearly with **Scheme** 1. The increases across all the other schemes are quite similar. The results for CT can be seen more clearly from Chart 45 which show the cumulative reductions. These amount to nearly £9 billion with **Scheme 1** and £11.5 billion with **Scheme 9**. On the other hand, in Chart 46 it is seen that the cumulative increase in SC is just over £50 billion with **Scheme 1** and £78 billion with **Scheme 9**.

Chart 43

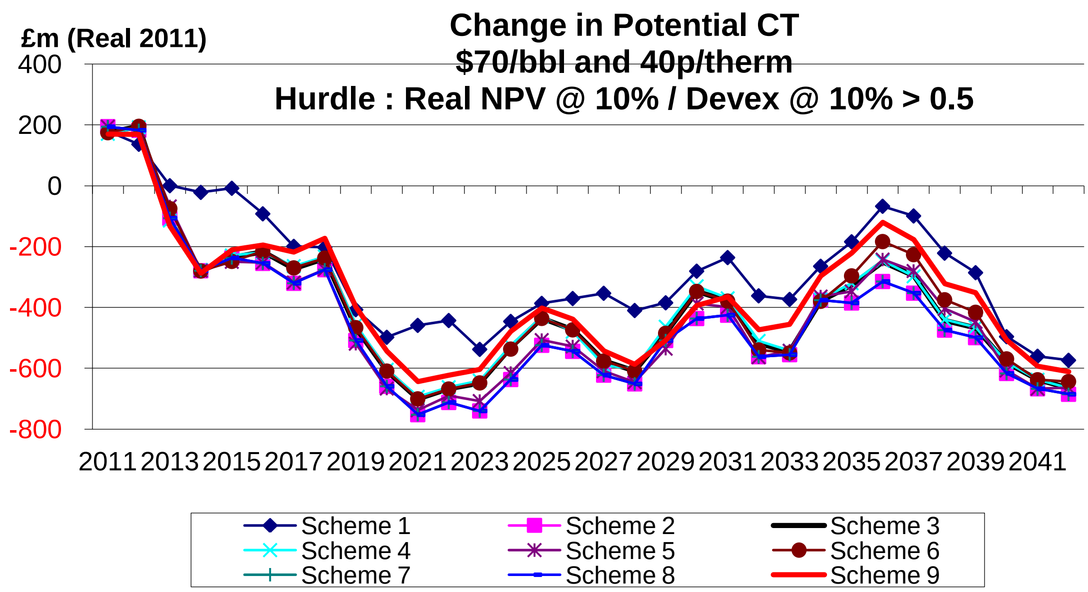


Chart 44

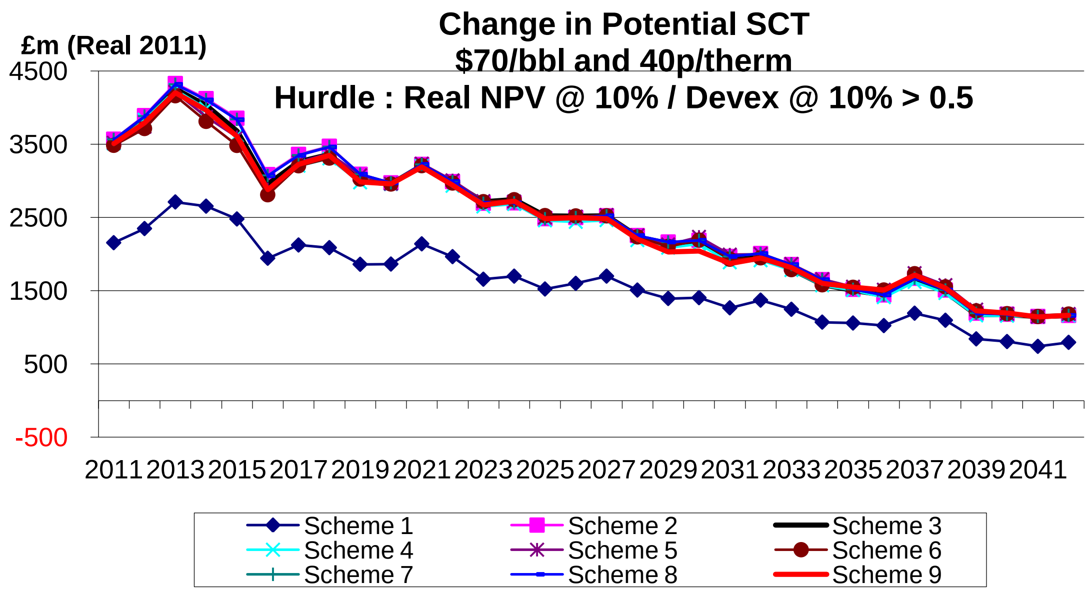


Chart 45

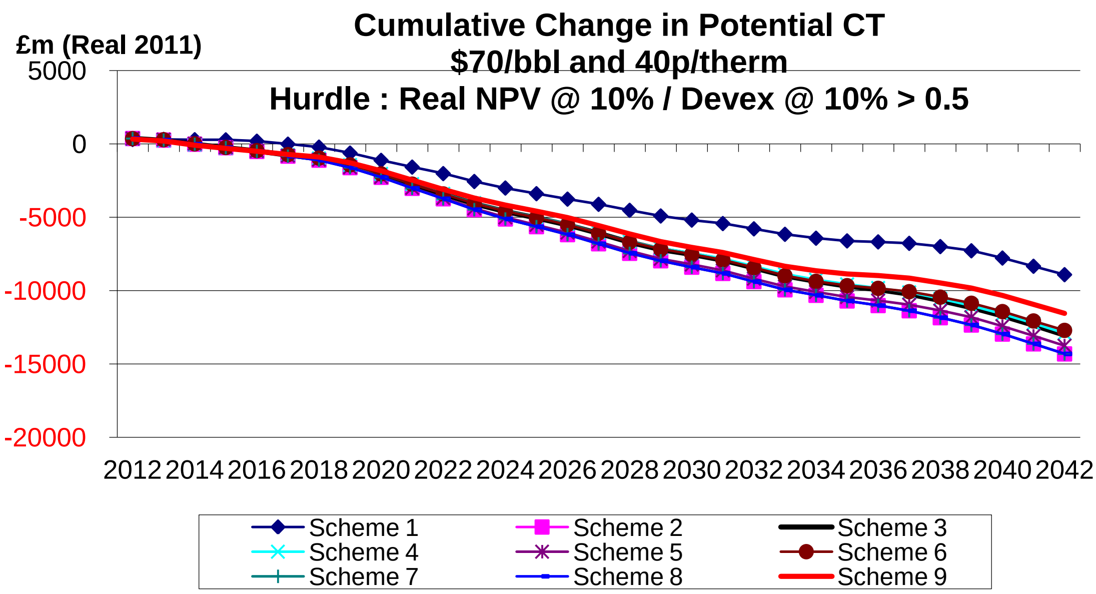
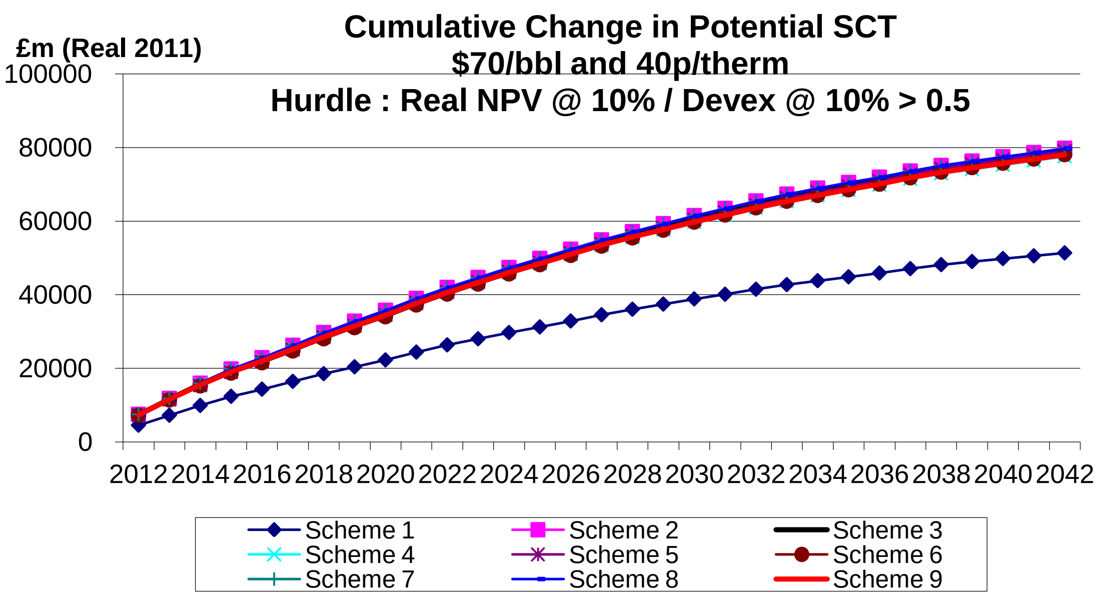


Chart 46



In Chart 47 the real (percentage) tax takes under **Scheme 1** are shown. They are at the flat-rate of 50%. In Chart 48 the takes under **Scheme 2** are shown. While in many cases the rate is 62% in a very substantial number it exceeds that, reflecting the reduced relief for decommissioning in relation to the headline tax rate.

Chart 47

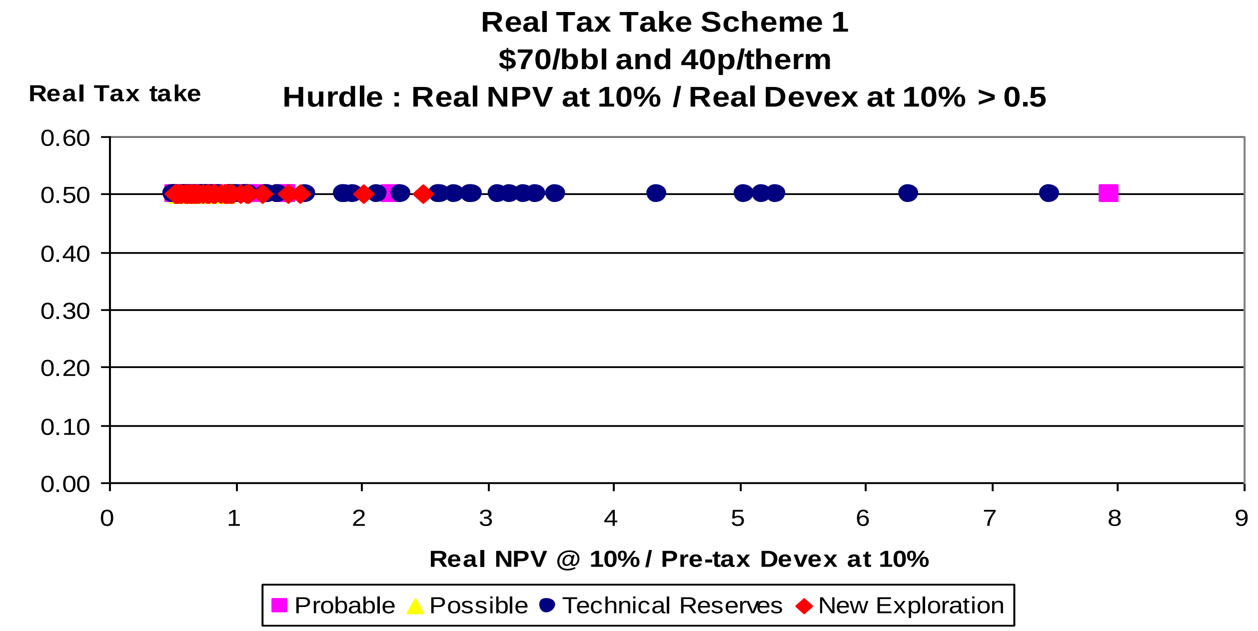
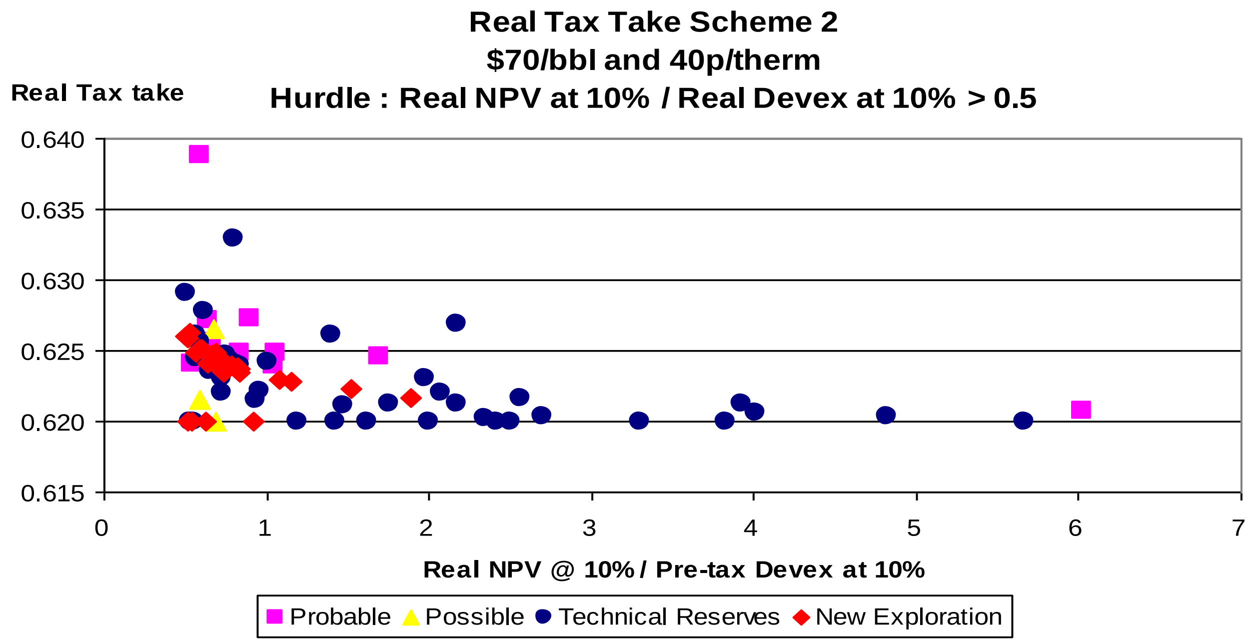
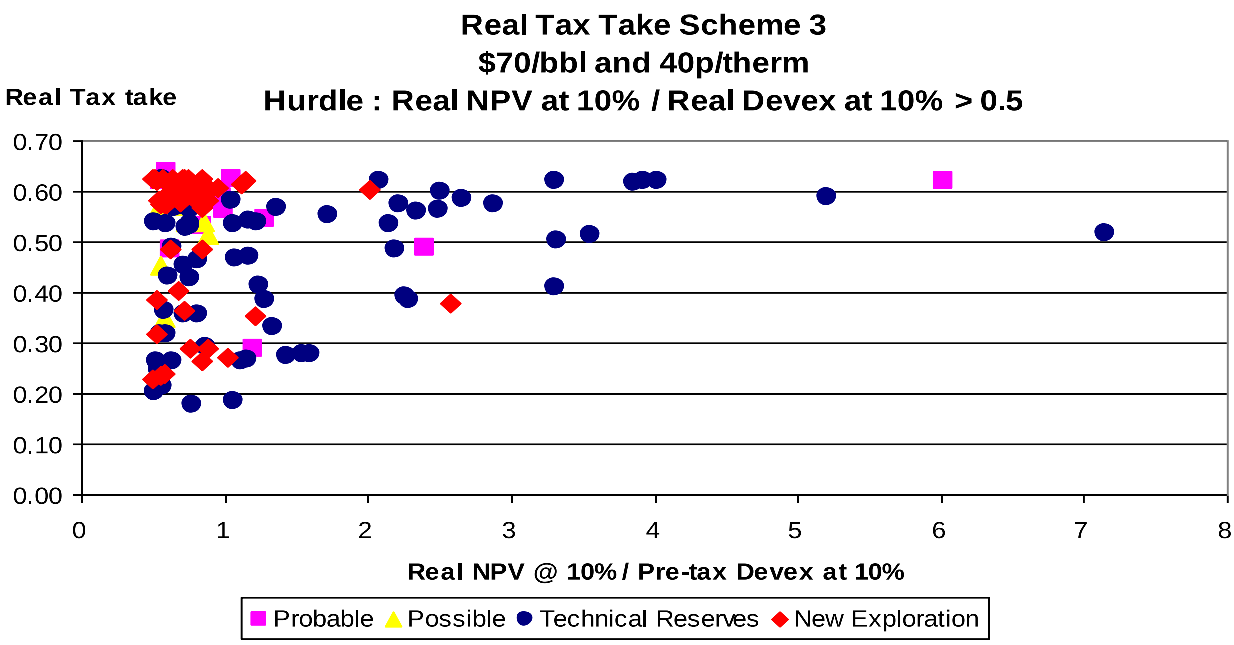


Chart 48



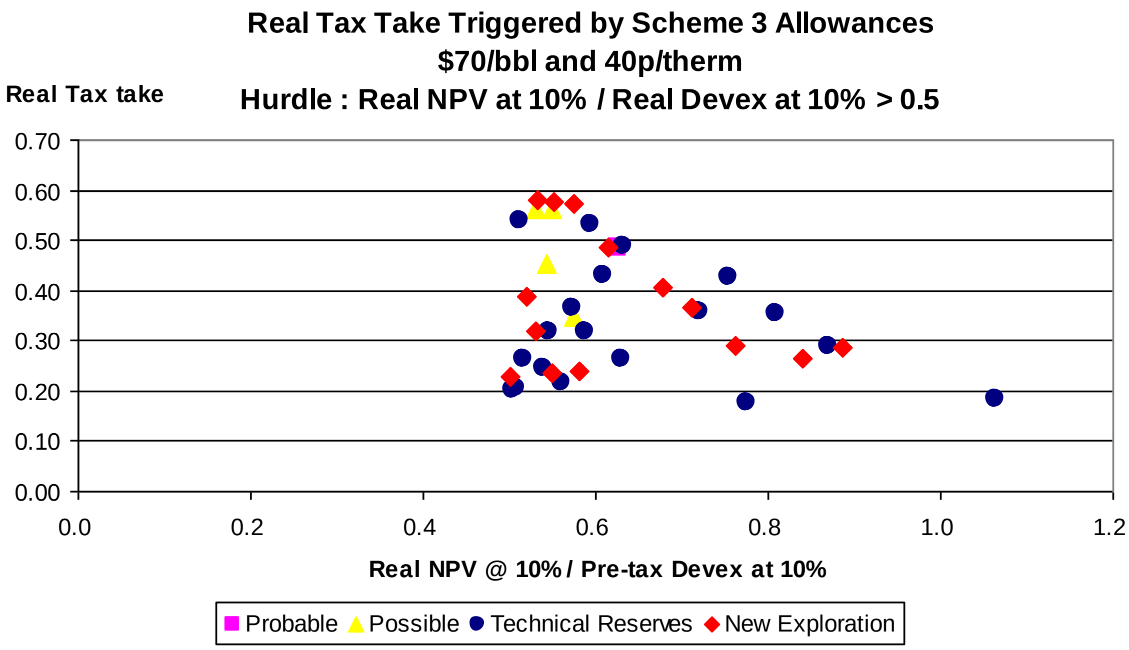
In Chart 49 the tax takes under **Scheme 3** are shown. While some fields face the 62% rate a high proportion pay at a lower rate reflecting the field allowances in force in 2011. Very considerable numbers now pay at effective rates below 50%, with some facing rates of 30% and less. The availability of relief on investment at 62% while obtaining substantial relief from SC on production income from the field allowances accounts for the lower rate. The latter relief is not directly targeted on profitability as the allowances relate to physical factors.

Chart 49



Further insights into the operation of **Scheme 3** are shown in Chart 50 which shows the tax takes on developments triggered by the allowances compared to the situation with no field allowances. It is seen that effective rates range from 20% to nearly 60% in cases of moderate profitability. There is no clear relationship with field profitability.

Chart 50



In Chart 51 the tax takes under **Scheme 4** are shown. Being able to obtain investment relief against other field income at 62% irrespective of the position of the new field in question can mean that effective tax rates are low in some cases. But many fields continue to pay at effective rates in excess of 50%. Further insights into the operation of **Scheme 4** are shown in Chart 52 which shows the effective tax rates on developments triggered by the scheme. The majority of the rates are in the 20%-60% range with some at even lower rates. The system is not progressive in relation to field profitability.

Chart 51

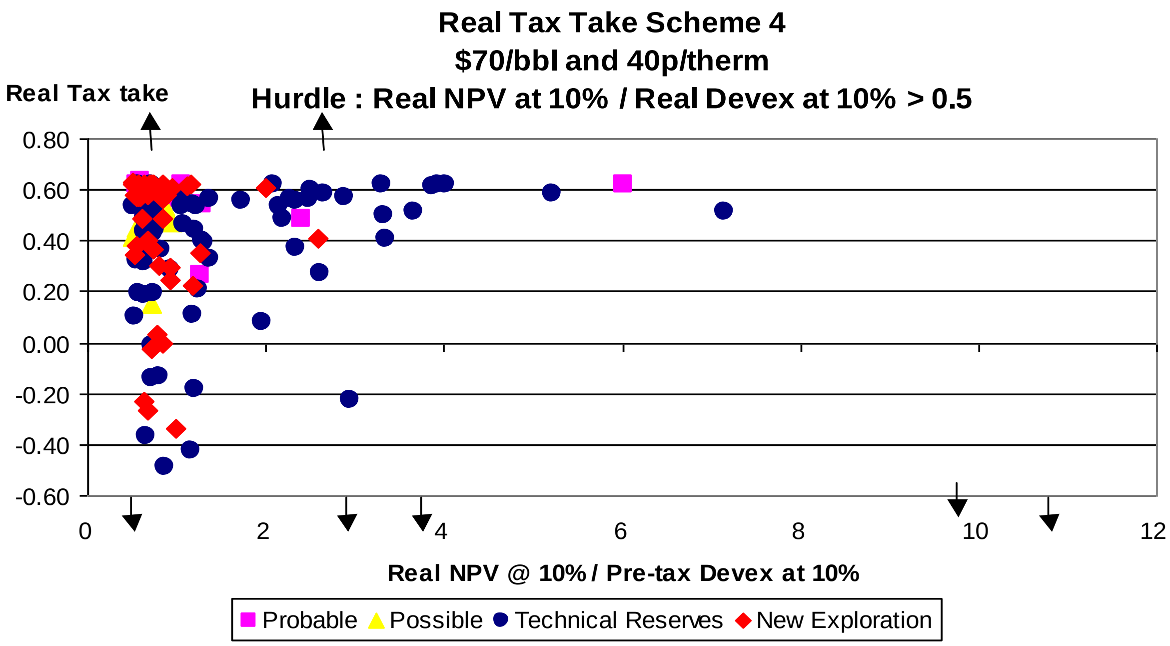
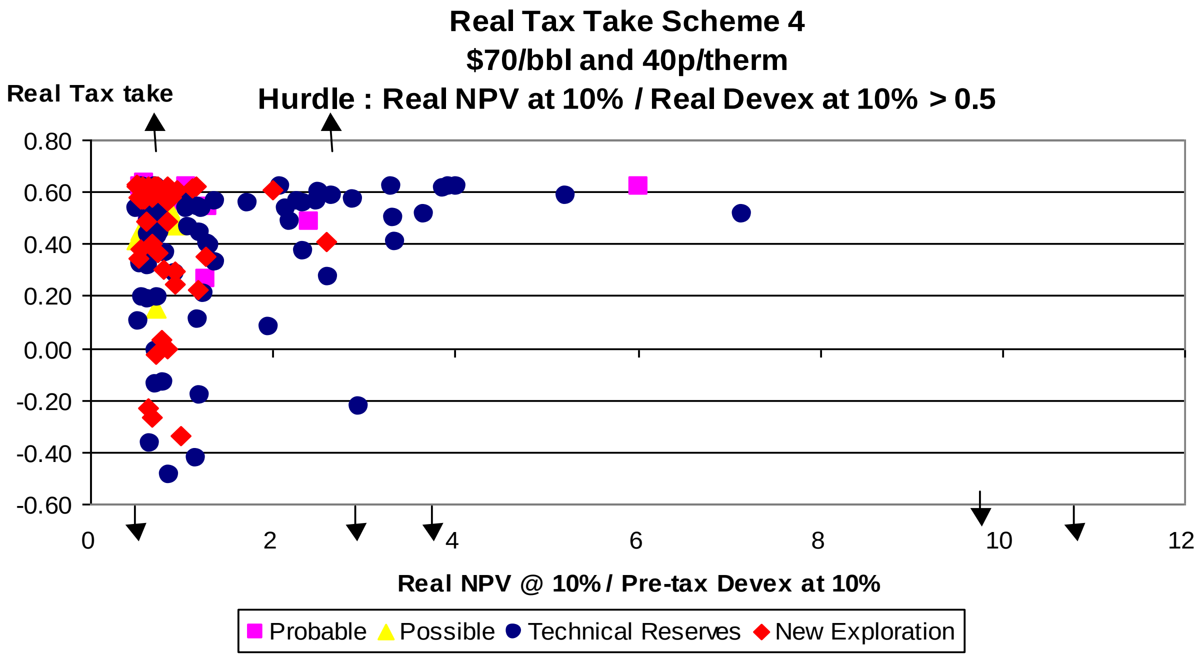


Chart 52



The tax takes under **Scheme 5** are shown in Chart 53. Many fields continue to pay at an effective rate of around 62% but a considerable number face rates between 30% and 40%. The apparent discontinuity in the rates payable reflects the slope of the scale factor determining the rate of relief with the development costs per barrel. This scheme does not produce very low rates of tax as was evident with **Schemes 3 and 4**. Sub-economic fields are not generally helped with **Scheme 5**, while with **Scheme 3** this could happen.

Chart 53

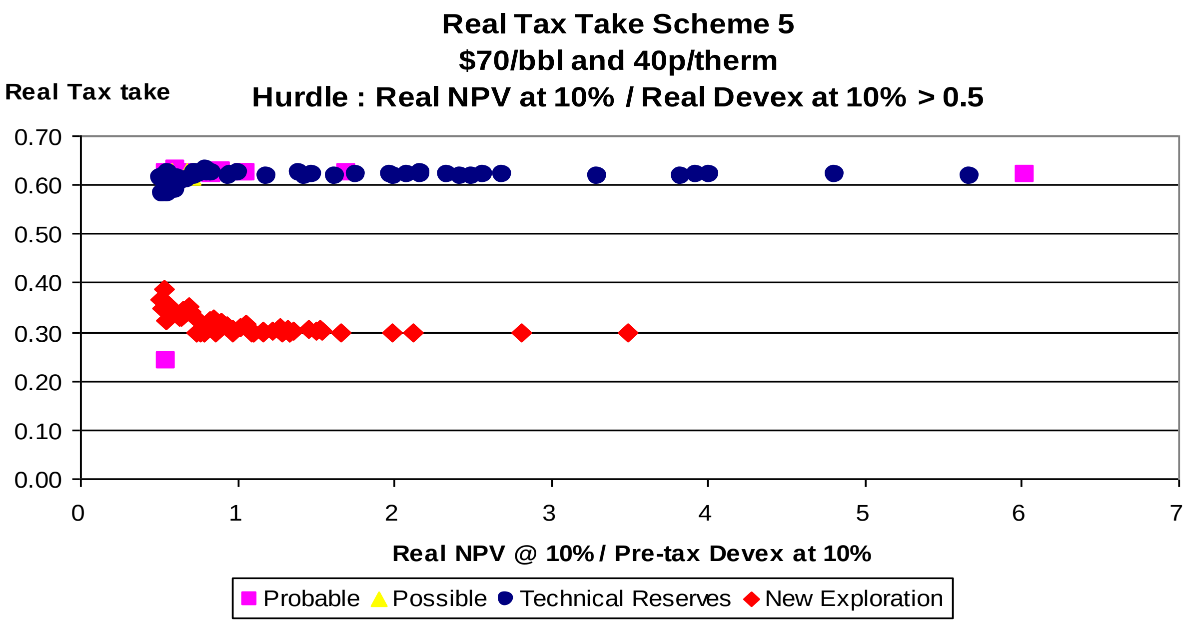
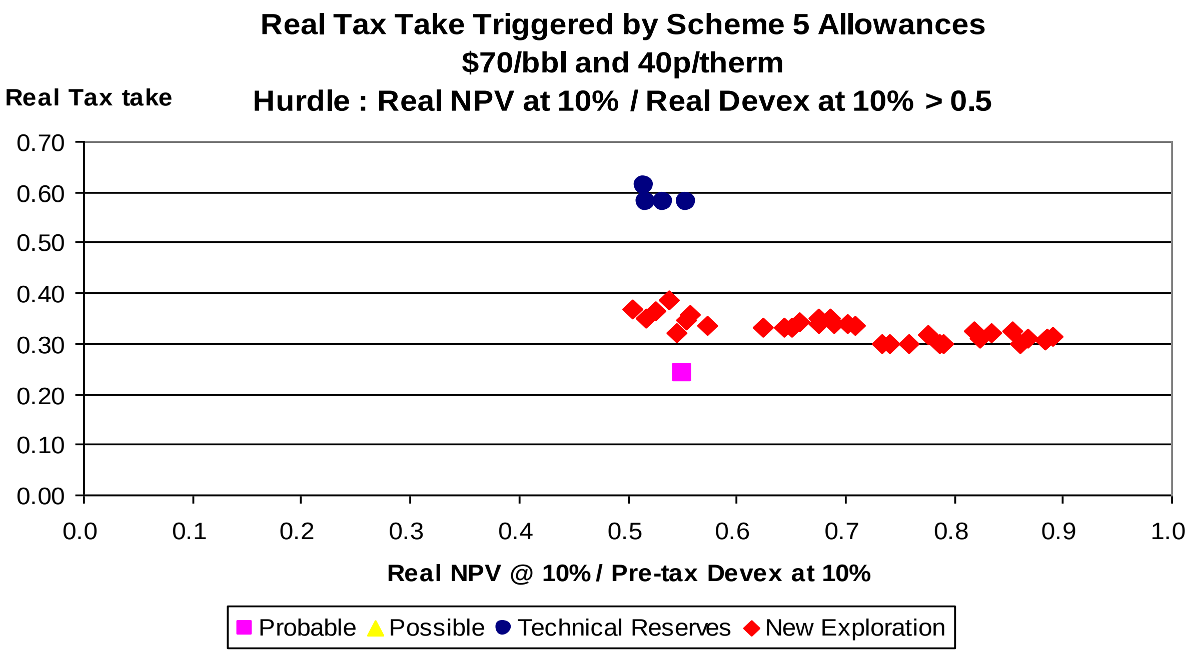


Chart 54



Further insights into the operation of **Scheme 5** are shown in Chart 54 which shows the tax rates on developments triggered by the scheme. It is seen that the great majority of the takes are in the range 30%-40% with relatively few around 60%.

Chart 55

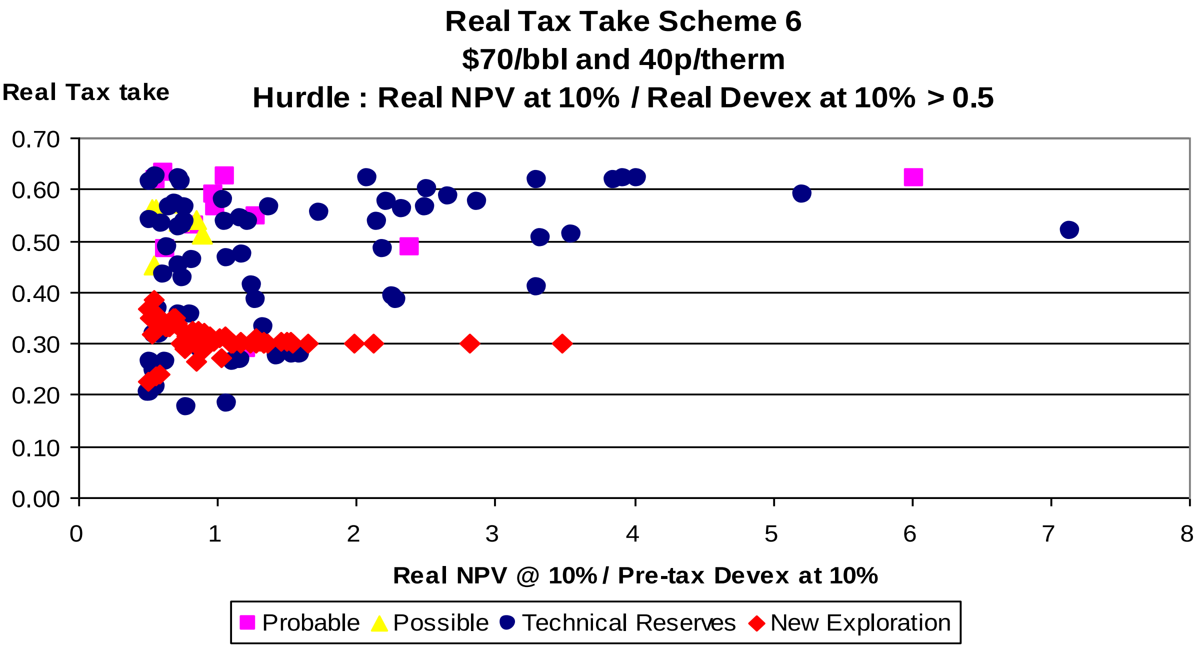
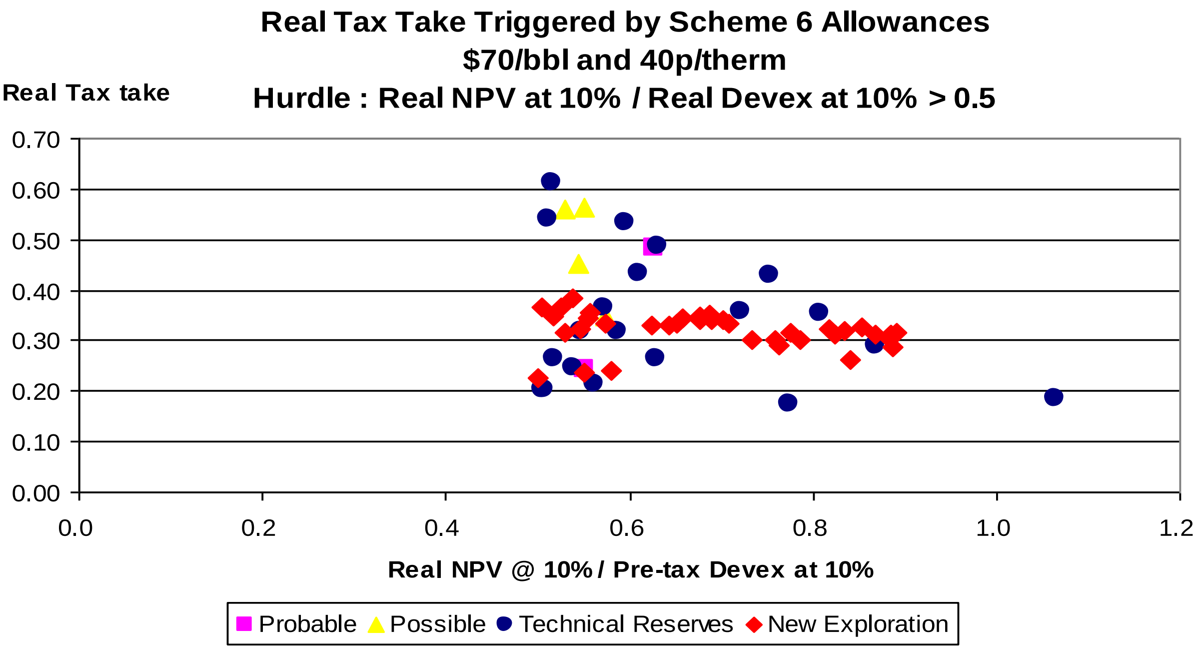


Chart 56



In Chart 55 the tax takes under the composite **Scheme 6** are shown. Rather more of the fields now face rates below 62%. The field allowances current in 2011 (**Scheme 3**) helped some fields to a greater extent than **Scheme 5**. Examples include small fields which are not very capital intensive but which have relatively high operating costs. This feature is highlighted in Chart 56 which shows the effective tax rates on developments triggered by **Scheme 6**.

In Chart 57 the tax takes under **Scheme 7** are shown. They are generally at 62% or higher and so are ineffective as a general scheme. The same finding applies to **Scheme 8** (Chart 58).

Chart 57

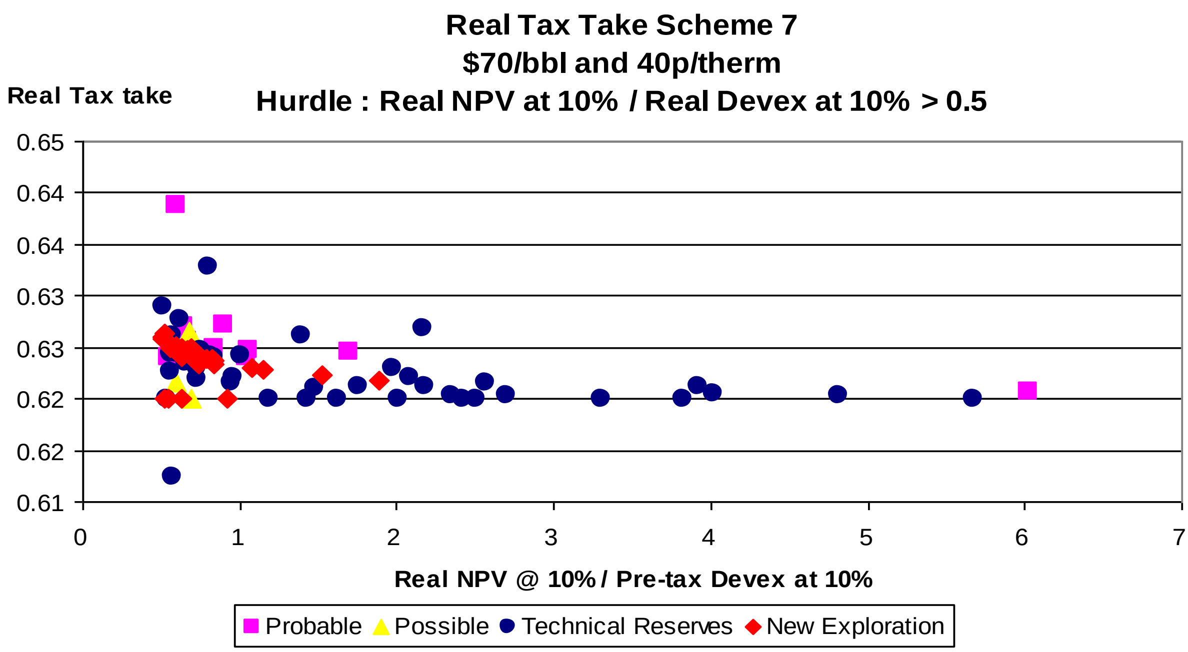
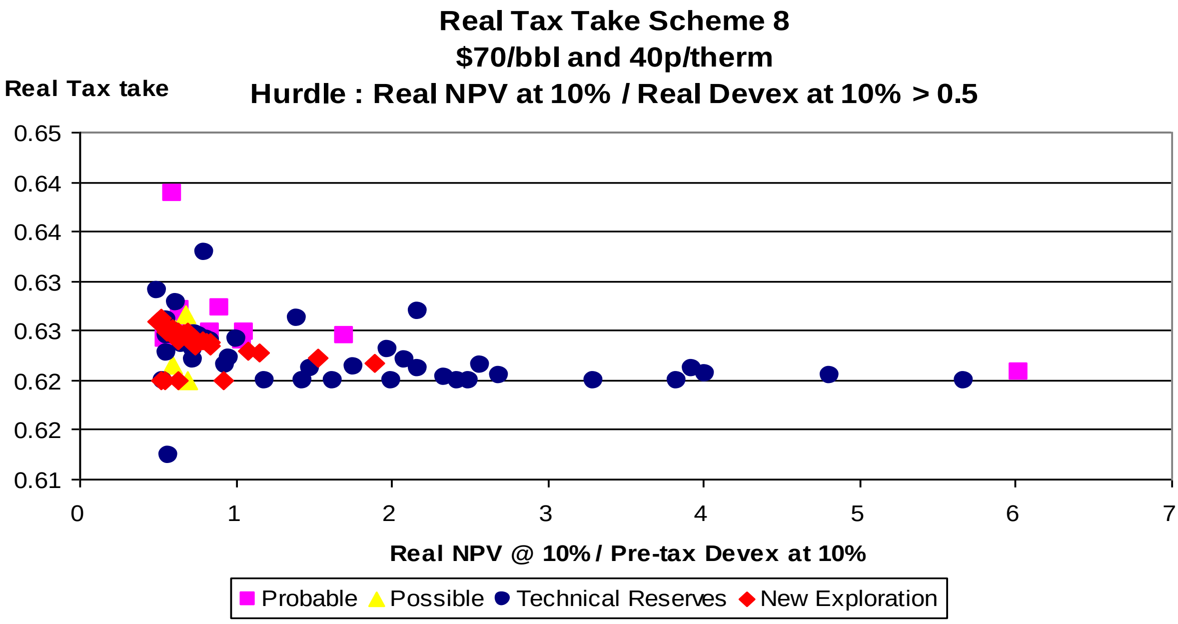


Chart 58



The tax takes under **Scheme 9** are shown in Chart 59. There is a wide spread of tax takes. Not many pay at the full rate of 62%. A significant number pay at 30% or less. The availability of investment relief at 62% while paying tax on production income at rates well below this level explains the results. In small fields the enhanced field allowances can greatly reduce liability to the SC. In Chart 60 the tax takes are shown on developments triggered by **Scheme 9**. There is a very wide range from 10%-60% with no clear relationship to field profitability.

Chart 59

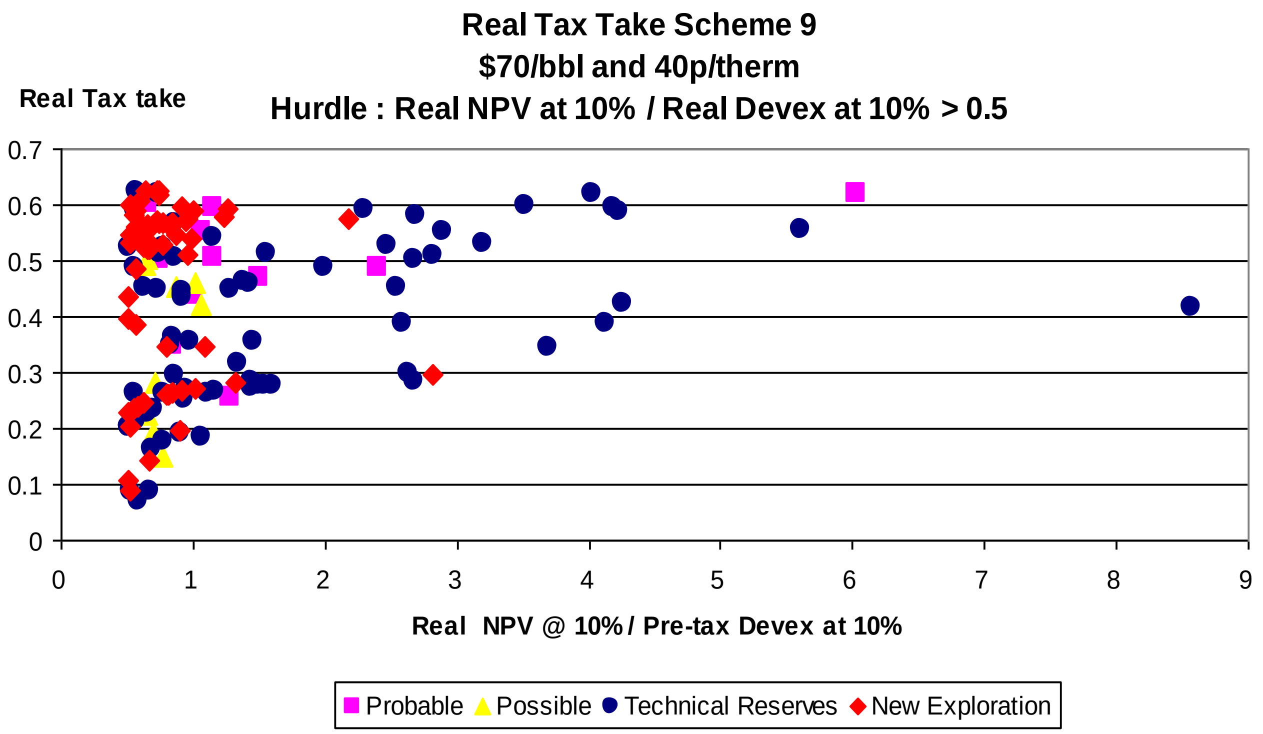
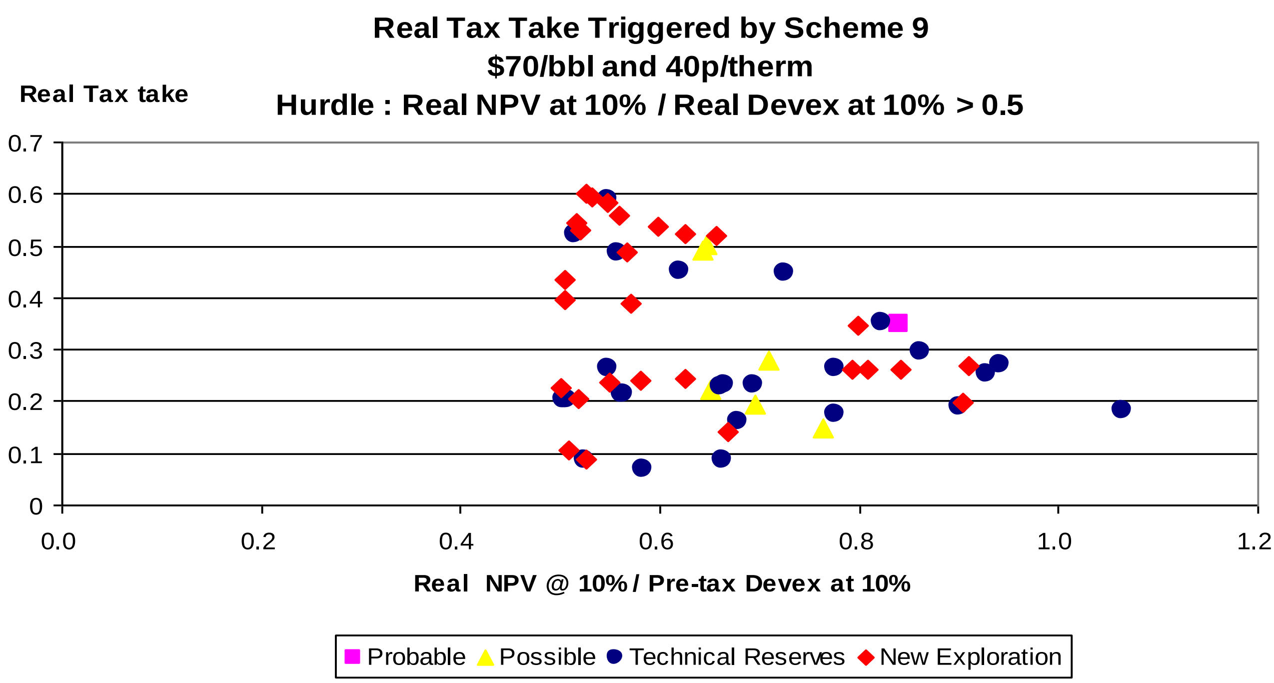


Chart 60



C. $90, 60 pence, NPV/I > 0.3 Case

Under the $90, 60 pence price and NPV/I > 0.3 investment hurdle there are 677 new fields and incremental projects of which 78 fail the economic hurdle before tax. There are 574 fields and projects which pass the hurdle after CT. Compared to the CT only case it was found that, over the period to 2042, there were 36 less developments with **Scheme 1**, 76 less with **Scheme 2**, 34 less with **Scheme 3**, 12 extra with **Scheme 5**, 13 extra with **Scheme 6**, 65 less with **Schemes 7 and 8**, and 17 less with **Scheme 9**.

In Chart 61 the changes in the numbers of fields in production compared to the CT only case are shown on an annual basis. In Chart 62 the numbers of new developments passing the hurdle are shown on cumulative basis. **Schemes 5 and 6** produce an increase in the number of producing fields. The ability to obtain the benefit of the field allowance against other field income plus the extra help given to gas fields are key explanations of the results. It is seen that **Scheme 9** (Budget 2012) performs next best in terms of maintaining the numbers of producing fields, reflecting the effective operation of the field allowances. Unsurprisingly, **Scheme 2**, with no field allowances, performs least well. **Schemes 7 and 8** are also fairly ineffective as the allowance does not protect many smaller fields from the SC.

Chart 61

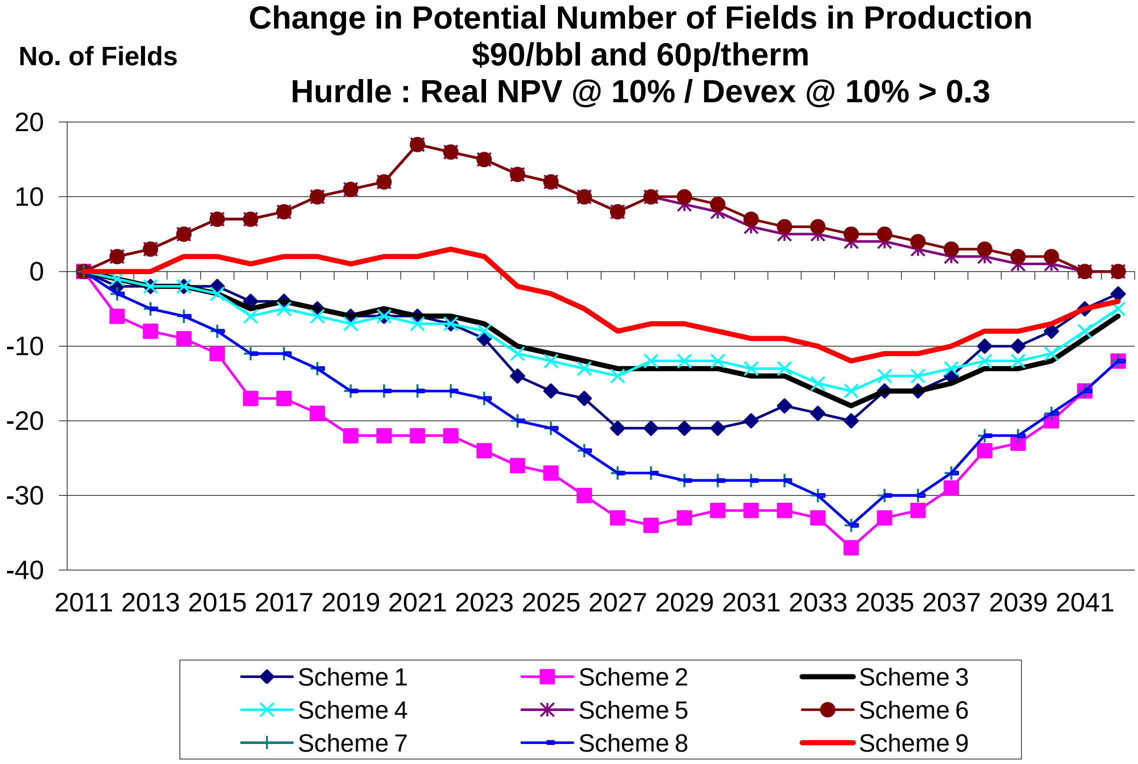
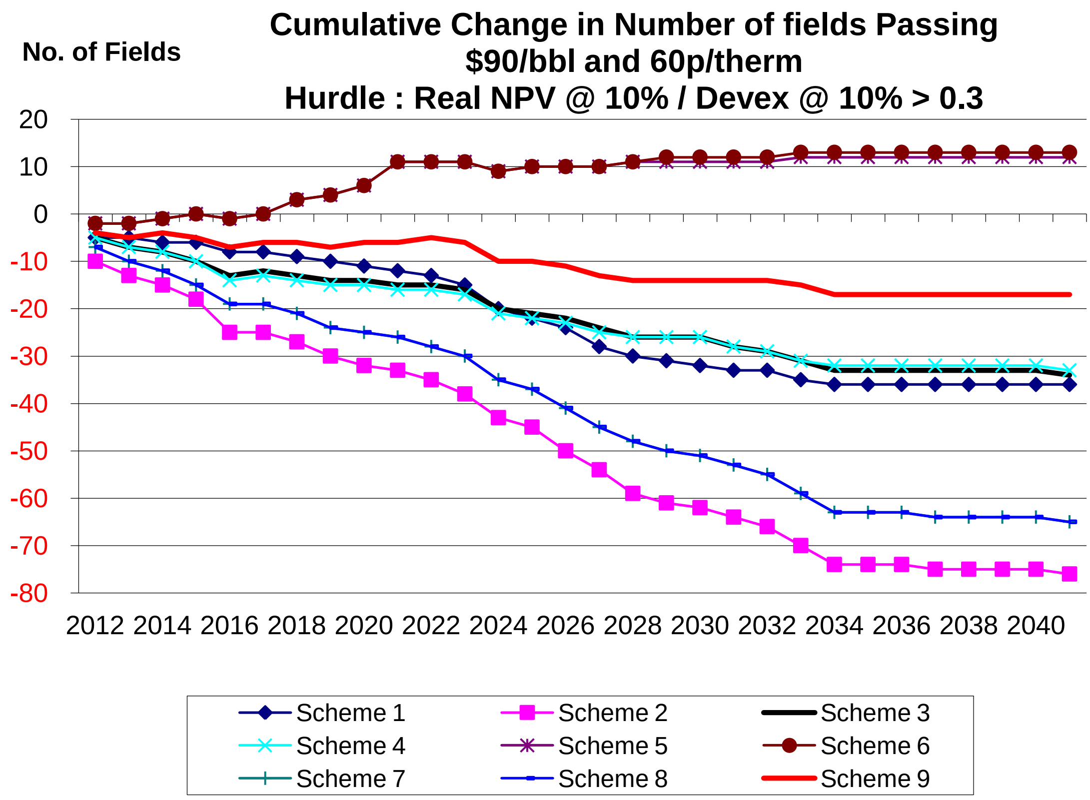


Chart 62



In Charts 63, 64 and 65 the annual changes to oil, gas and total hydrocarbon production respectively are shown under the different schemes.

Chart 63

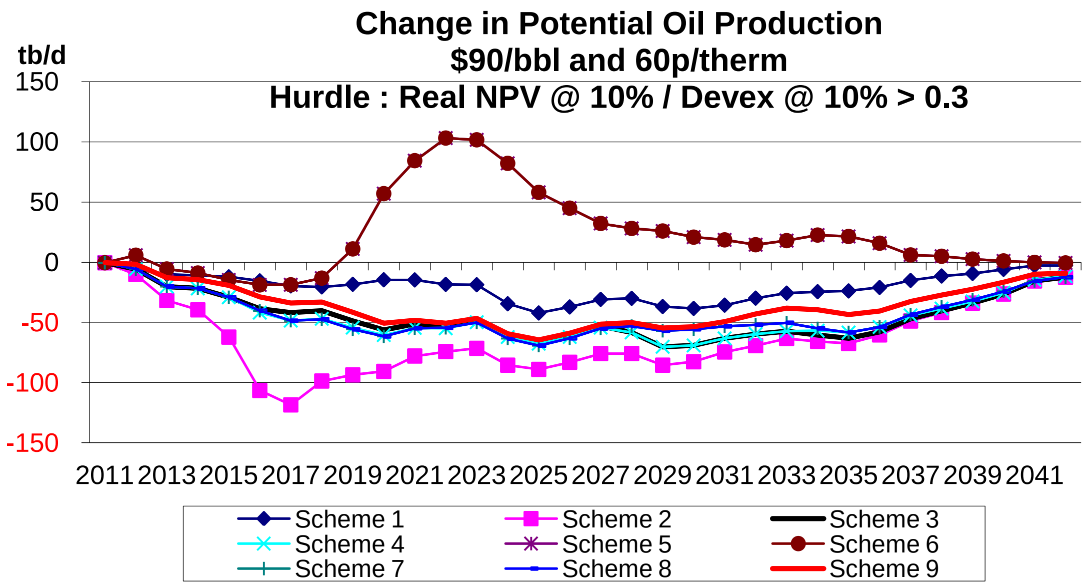


Chart 64

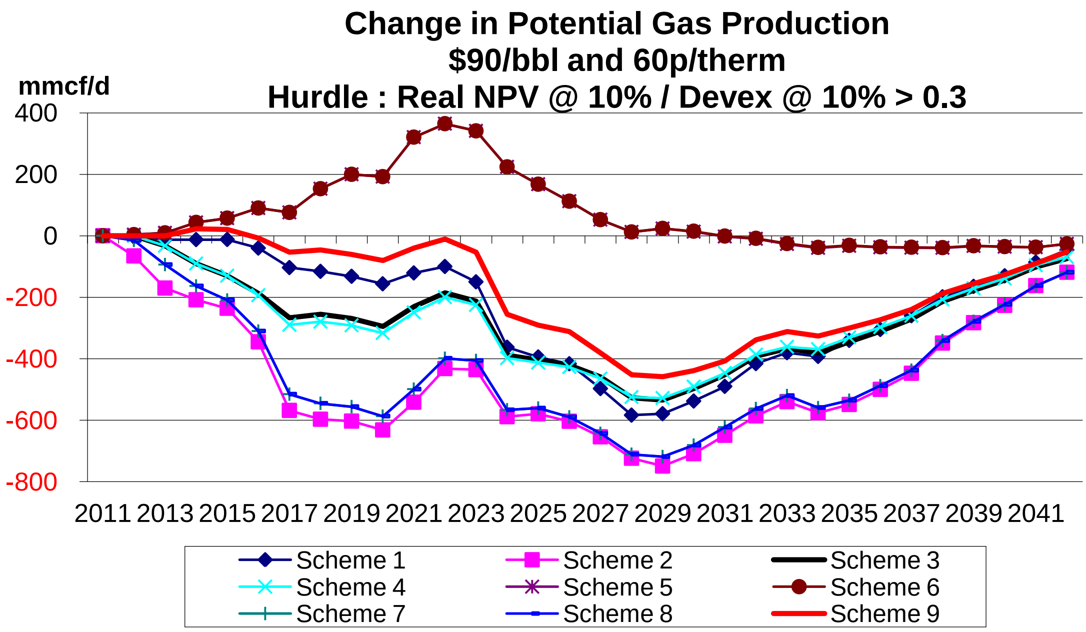
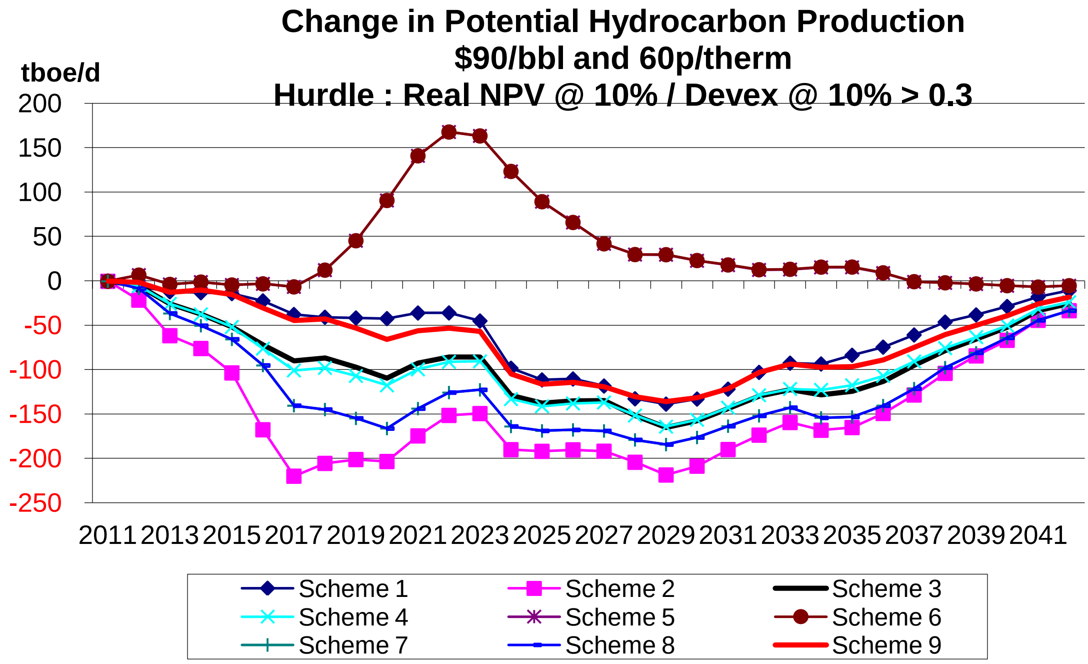
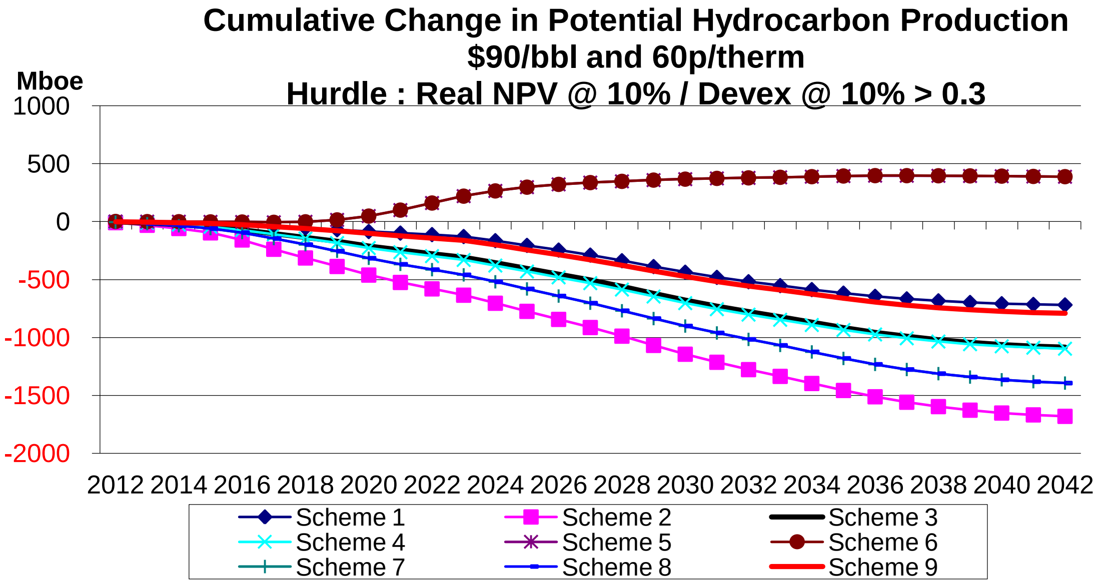


Chart 65



In Chart 66 the cumulative changes to total hydrocarbon production over the whole period are shown. **Schemes 5 and 6** result in small increases in production, cumulating to 0.4 bn boe over the period. The ability to receive tax relief against other income and the extra help given to gas developments are causal factors. **Scheme 1** is the next best performing scheme with a cumulative reduction of 0.7 bn boe. **Scheme 9** (<u>Budget 2012</u>) also performs relatively well with a cumulative reduction of 0.8 bn boe. **Scheme 2** is the worst performer with a cumulative reduction of 1.7 bn boe. **Scheme 4** results in a cumulative reduction of 1.1 bn boe. **Schemes 7 and 8** are not very effective. The allowance does not help many marginal fields.

Chart 66



In Charts 67 and 68 the annual and cumulative changes in field development expenditures from the base case are shown with the 9 schemes. **Schemes 5 and 6** produce positive results, particularly over the next decade. A combination of the rates of relief, their allowance against other field income, and the special provisions for gas produce the effects shown. **Scheme 9**, while showing a clear reduction compared to the base case, performs better than several of the other schemes. **Scheme 2** produces the largest decline in investment.

Chart 67

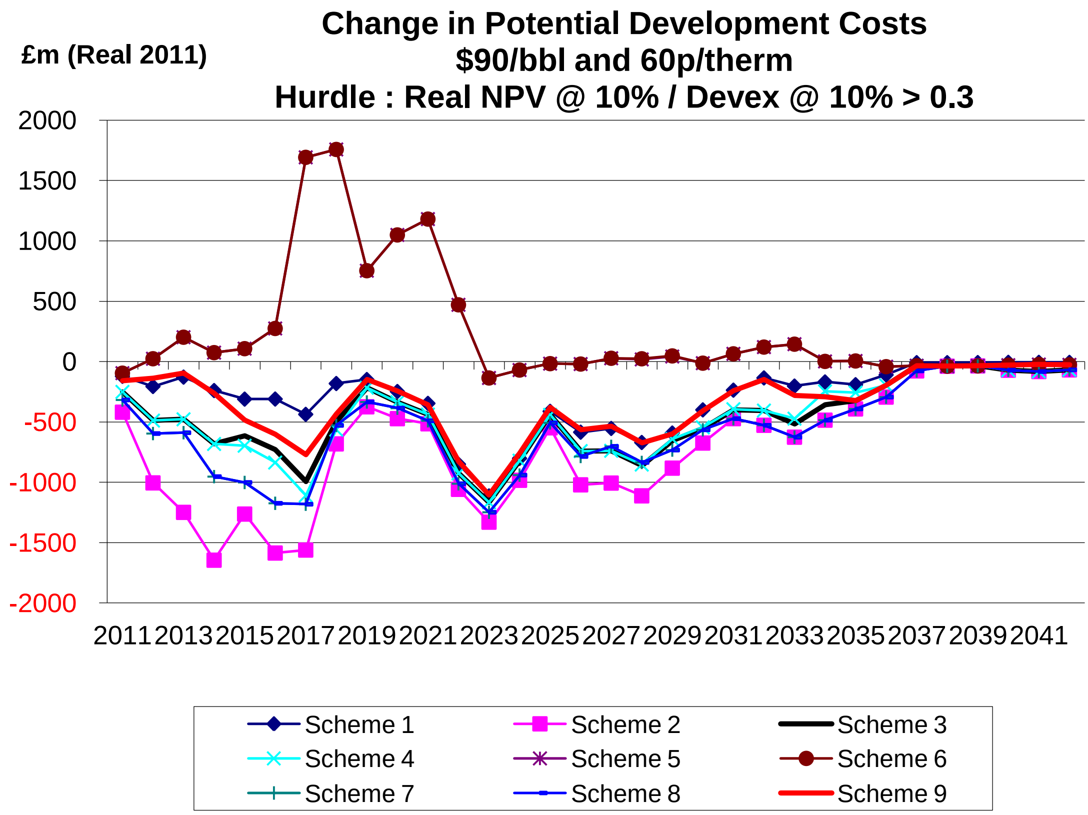
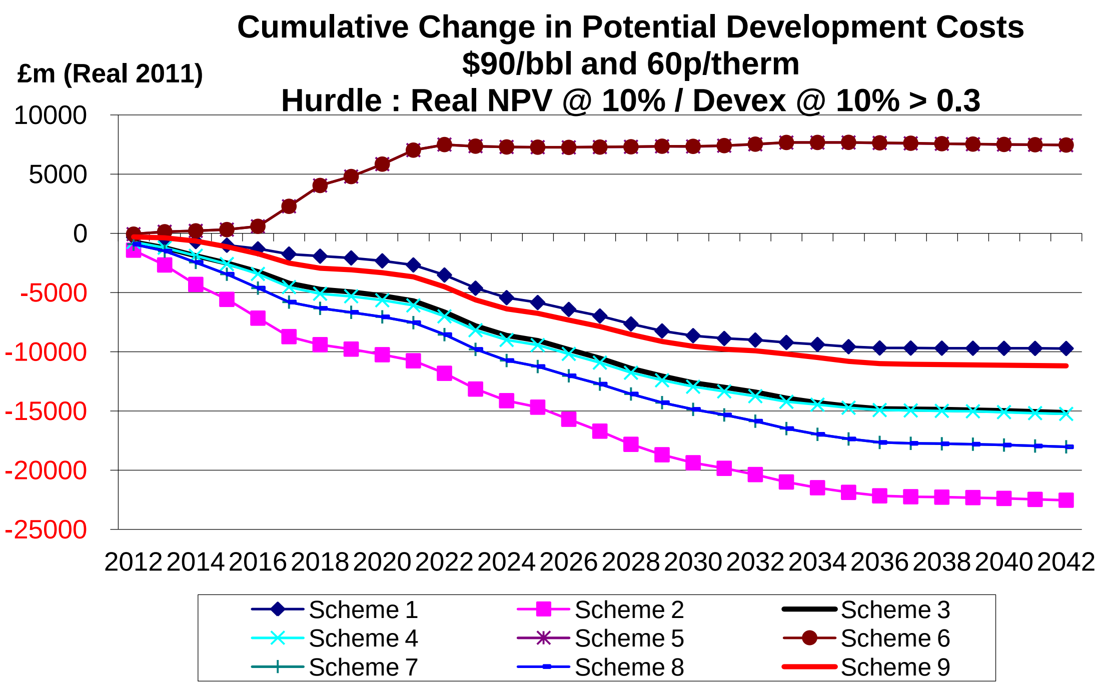


Chart 68



In Charts 69 and 70 the annual and cumulative changes to operating costs are shown. Again, **Schemes 5 and 6** produce significant positive results over the base case reflecting the higher development activity with these schemes. **Scheme 9** produces the next best performance in terms of activity levels. **Scheme 2** clearly exhibits the largest reduction.

Chart 69

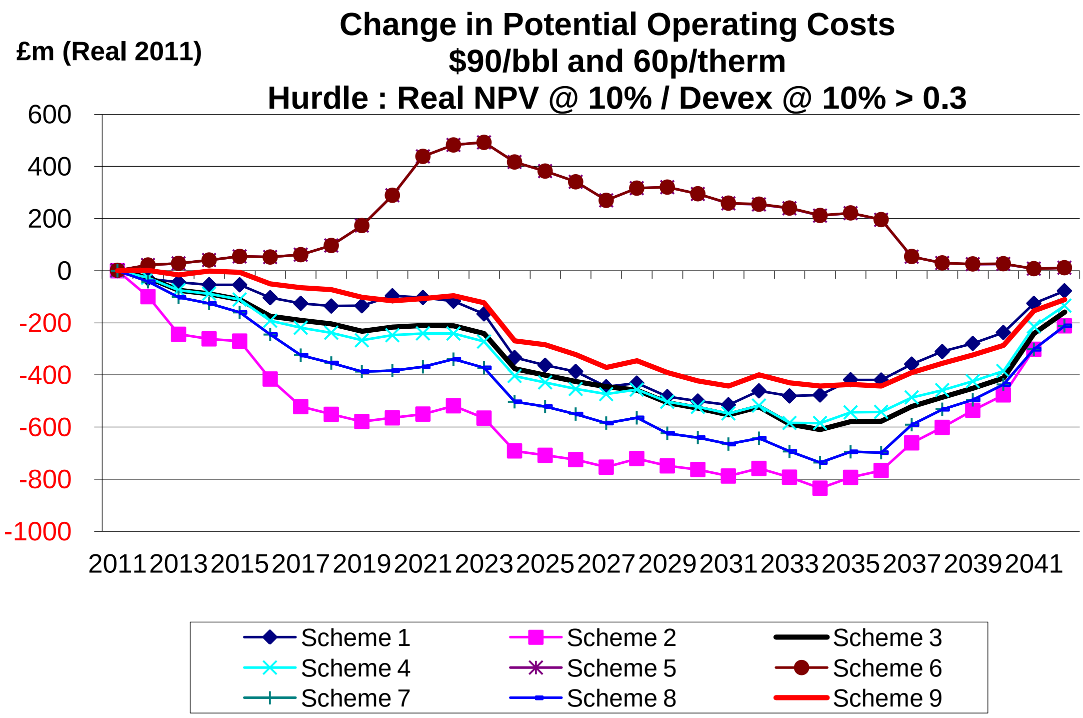
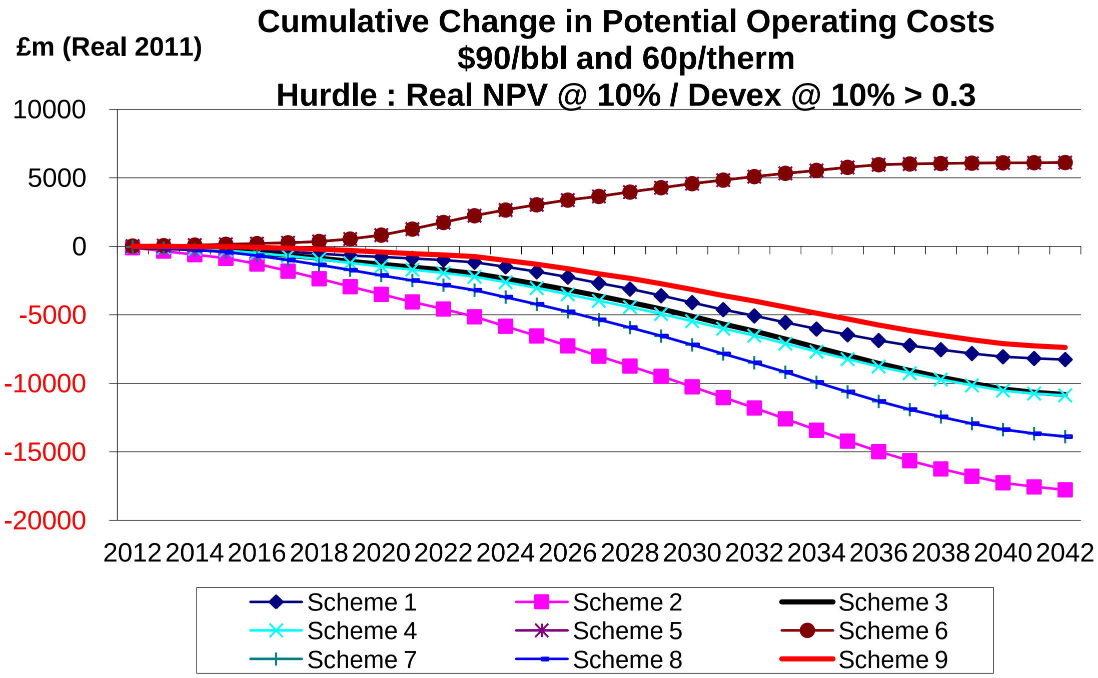


Chart 70



In Charts 71 and 72 the annual and cumulative changes to total tax revenues compared to the base case are shown under the various schemes. In the long term **Schemes 5 and 6** produce more extra revenues than the other schemes, but over the next few years the increase is less than with some other schemes, reflecting the higher investment expenditure and thus utilisation of allowances. The highest cumulative increase exceeds £190 billion by 2042. The lowest increase in tax revenues is with **Scheme 1** which has SC at 20%. The increase in yield still exceeds £120 billion. The flat-rate scheme does produce strong enough incentives to develop modestly-profitable projects.

Chart 71

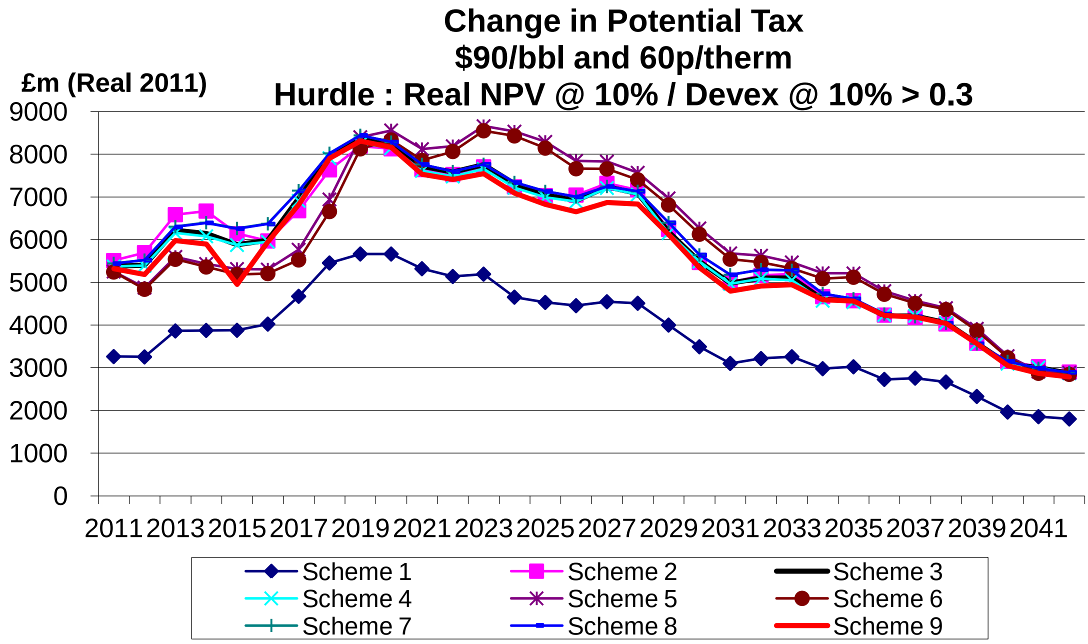
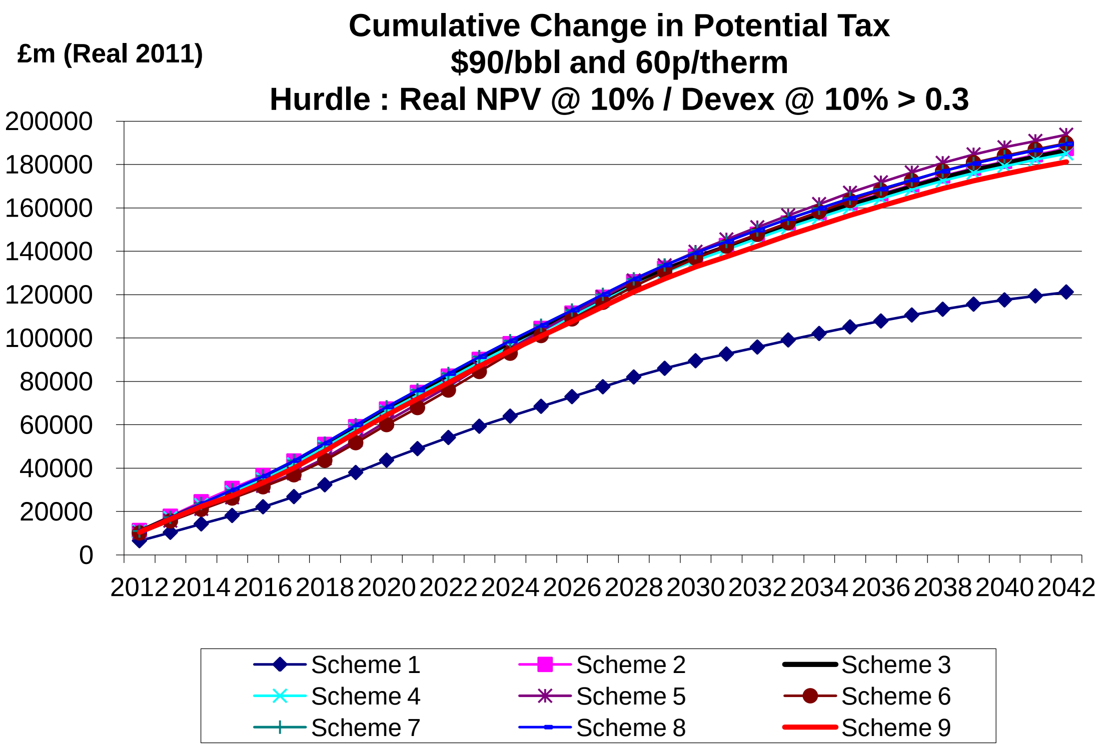


Chart 72



In Charts 73 and 74 the annual and cumulative changes in CT are shown under the various schemes. There are modest net increases with **Schemes 5 and 6** reflecting the higher degree of new activity produced by these schemes, through the large effective rate of relief to marginal fields and the extra help given to gas fields. All the other schemes produce reductions in CT. **Scheme 9** results in a cumulative reduction of £4 billion.

Chart 73

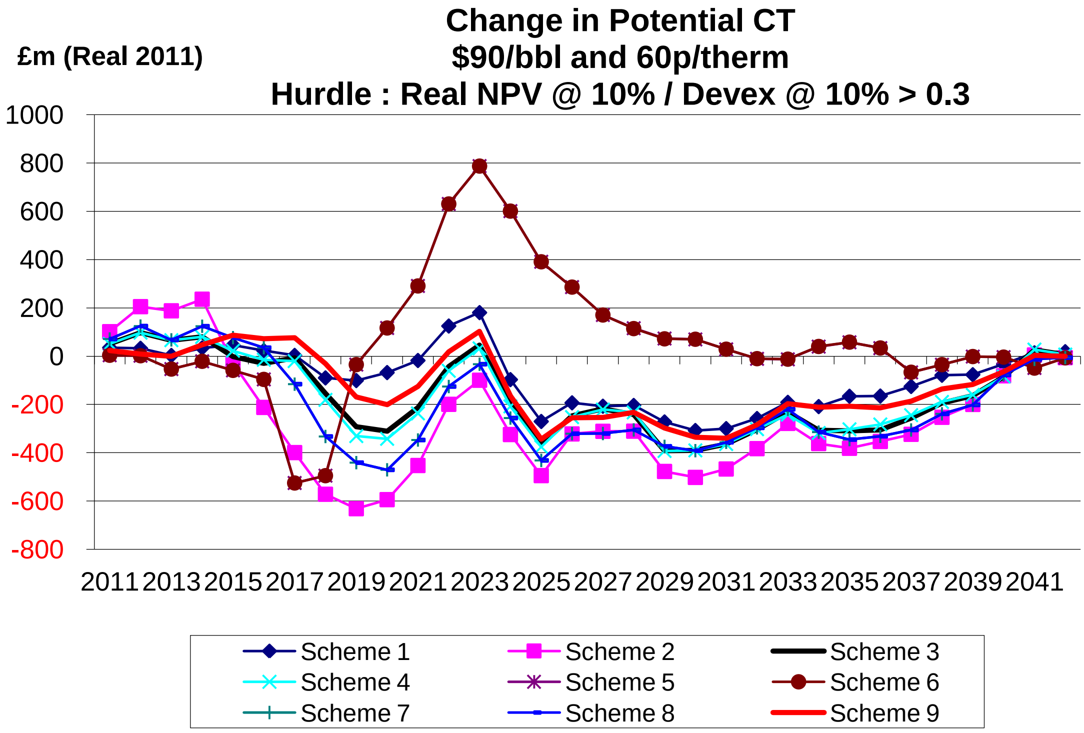
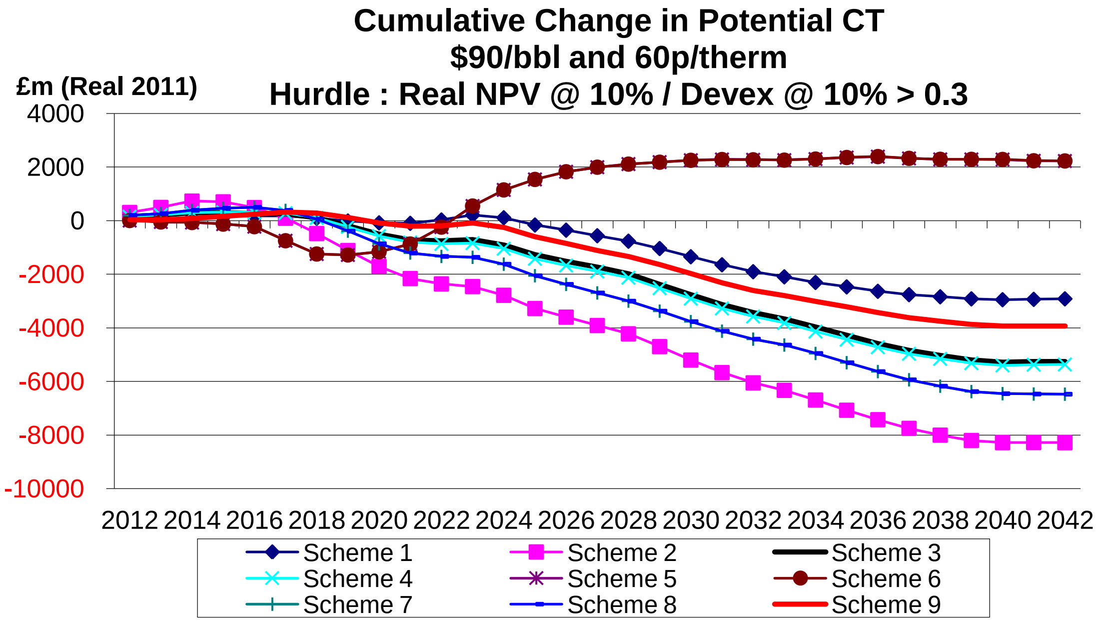


Chart 74



In Charts 75 and 76 the annual and cumulative changes in SC are shown under the various schemes. There are very substantial increases under all the schemes with no very major differences among them, except for **Scheme 1** which produces much less revenues than the others. The cumulative total for **Scheme 1** is around £125 billion while for the others the totals are in the £190-£200 billion range.

Chart 75

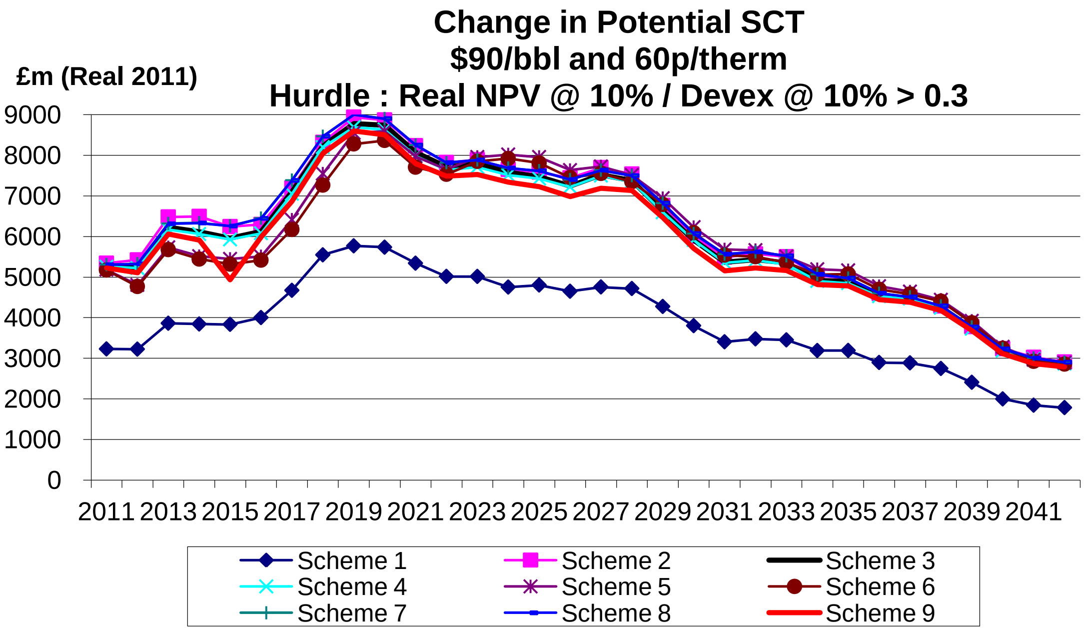
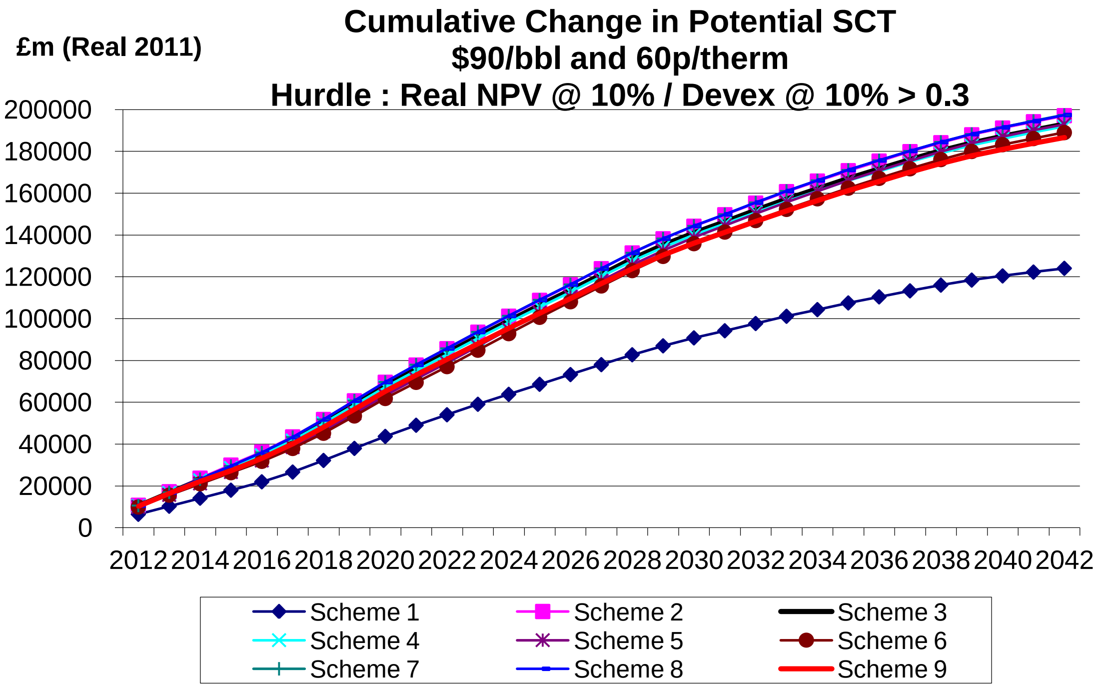


Chart 76



In Chart 77 the real percentage tax takes are shown under **Scheme 1**. They are generally at 50% as expected. In Chart 78 the takes under **Scheme 2** are shown. Many are around 62% but in a considerable number of cases the rate just exceeds 62%, reflecting the less than full relief for decommissioning costs. The extent of the increase above 62% depends on the importance of the decommissioning costs.

Chart 77

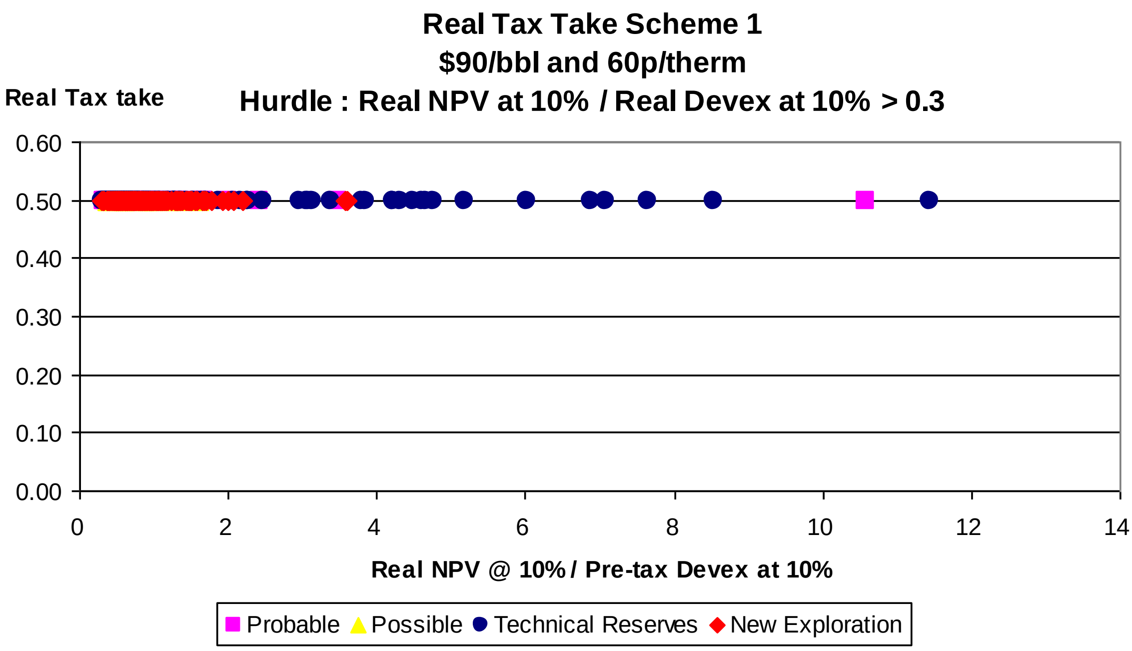


Chart 78

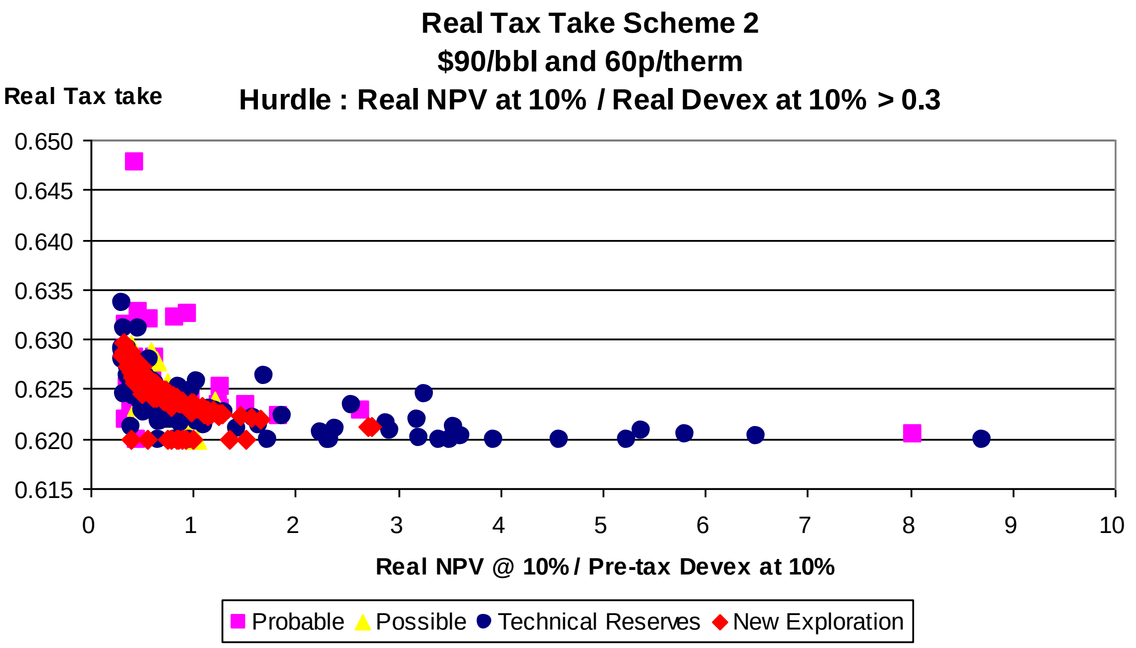
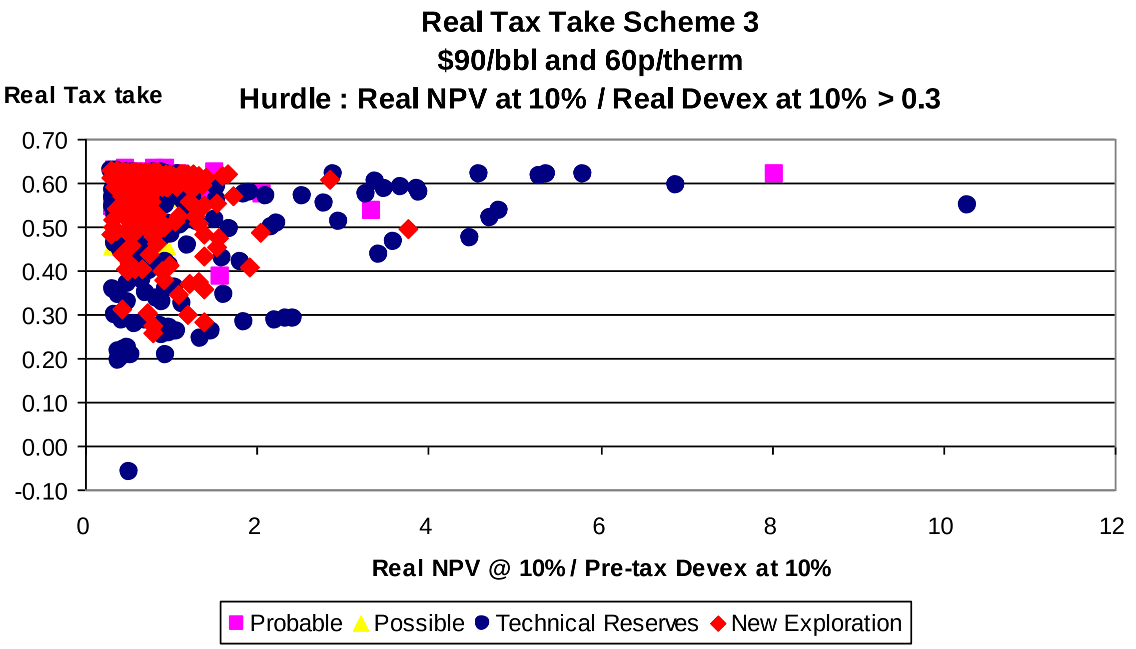


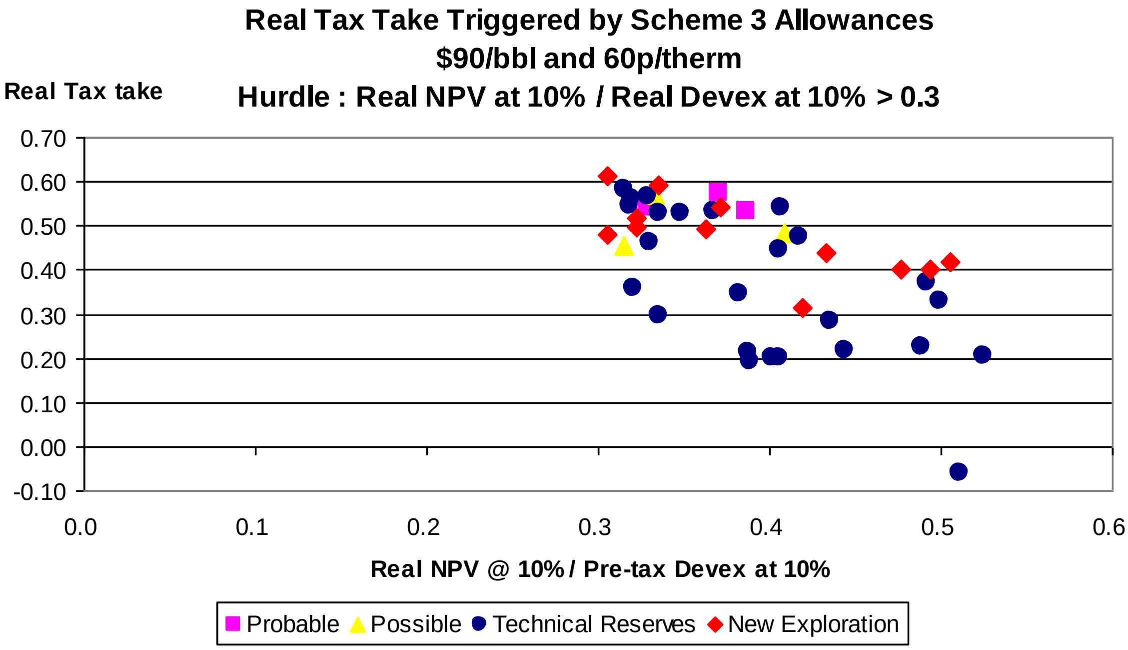
Chart 79



In Chart 79 the tax takes under **Scheme 3** are shown. This shows the effect of the field allowances in force in 2011. There is a very noticeable change as a result of these allowances, with effective rates in many of the fields being considerably below the marginal rate of 62%. This applies to fields in all of the categories shown. Over the period 42 more developments take place compared to the system in the absence of the field allowances. The results where the effective tax rate is relatively low refer to cases where the investment relief is at 62%, but the tax on the new field's production is relatively limited.

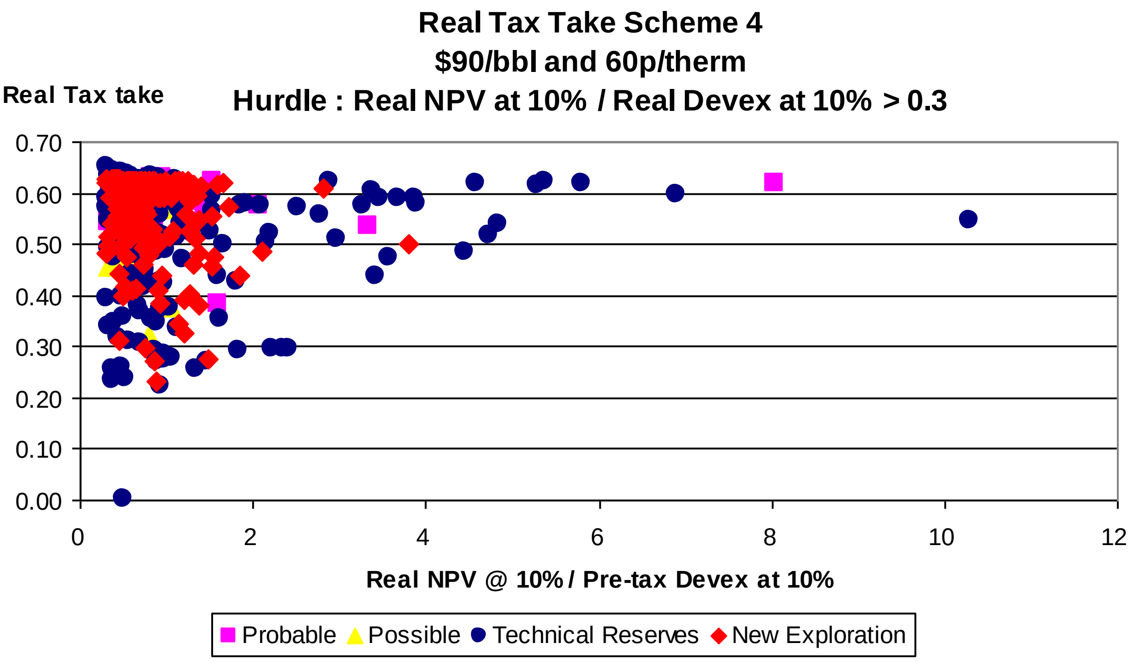
In Chart 80 the tax takes on the developments triggered by Scheme 3 are shown (compared to no field allowances). They range from 20% to 60% for the majority of cases. There is no clear relationship with profitability.

Chart 80



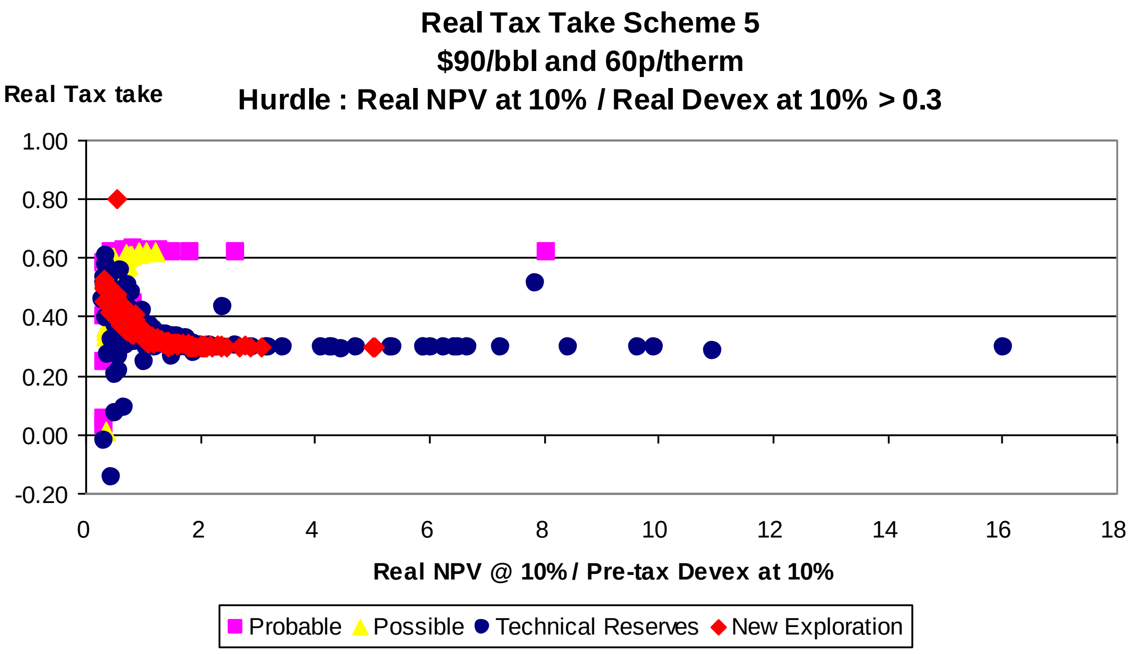
In Chart 81 the tax takes are shown under **Scheme 4** where the field allowances can be set against income from other fields. The results are broadly similar to those of **Scheme 3**.

Chart 81



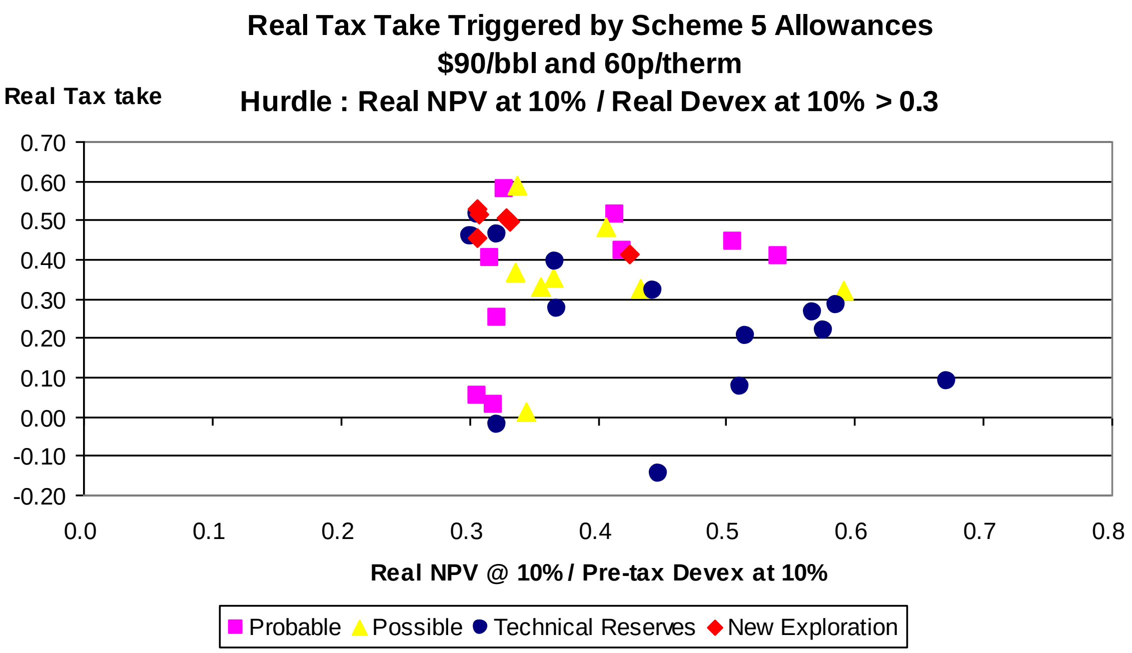
In Chart 82 the tax takes under **Scheme 5** are shown. Over the period there are 88 extra field developments compared to the case with no field allowances, and 12 extra compared to the CT only case. The allowance reduces the effective tax rates substantially on fields of relatively low profitability. The lower profitability of gas compared to oil fields is also specifically catered for by **Scheme 5**. The observed results that some fields of relatively low profitability (as measured by NPV/I) pay tax at 62% refer to situations where the field operating costs are relatively high.

Chart 82



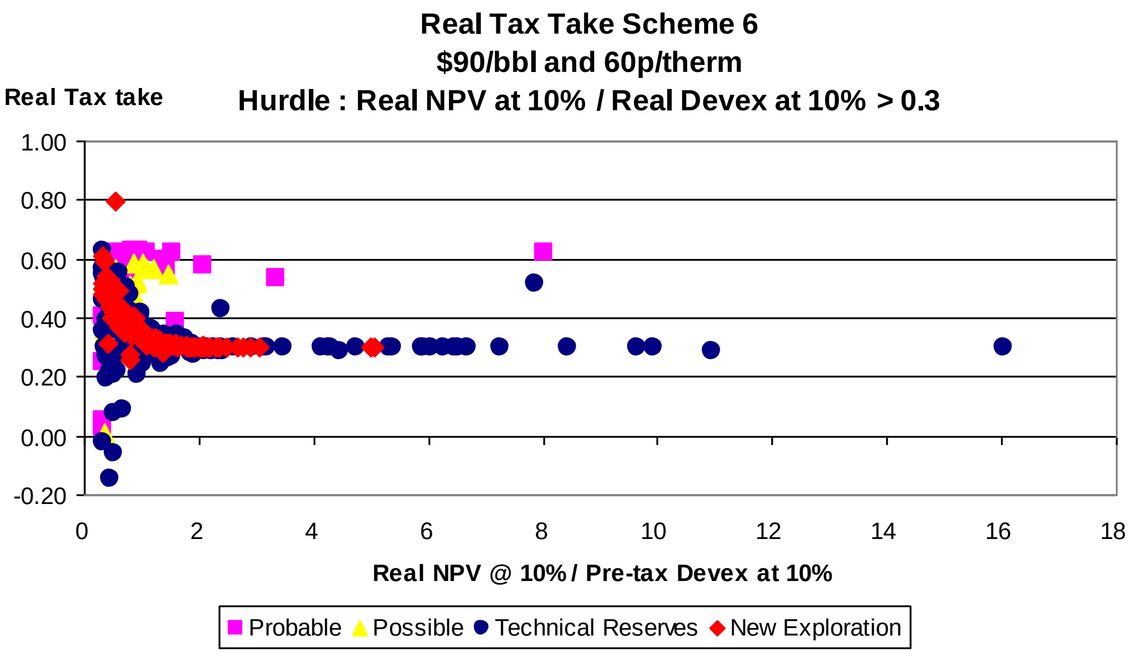
In Chart 83 the tax takes on developments triggered by **Scheme 5** are shown. There is a very wide range of takes with a few being extremely low reflecting the use of the allowance against other income in cases where the new field income was very small.

Chart 83



The tax takes under **Scheme 6** are shown in Chart 84. They are not very different from those of **Scheme 5** with only a small extra activity over the period. Some fields are better off with the 2011 allowances than with **Scheme 5**. These are fields with relatively high operating costs.

Chart 84



The tax takes under **Scheme 7** are shown in Chart 85. Most fields continue to pay at 62% rate and there are only 11 extra developments compared to the situation with no field allowances (**Scheme 2**). While **Scheme 7** incentivises a few extra developments little or no benefits accrue to a large number of smaller fields in particular. Similar observations apply to **Scheme 8** (Chart 86).

Chart 85

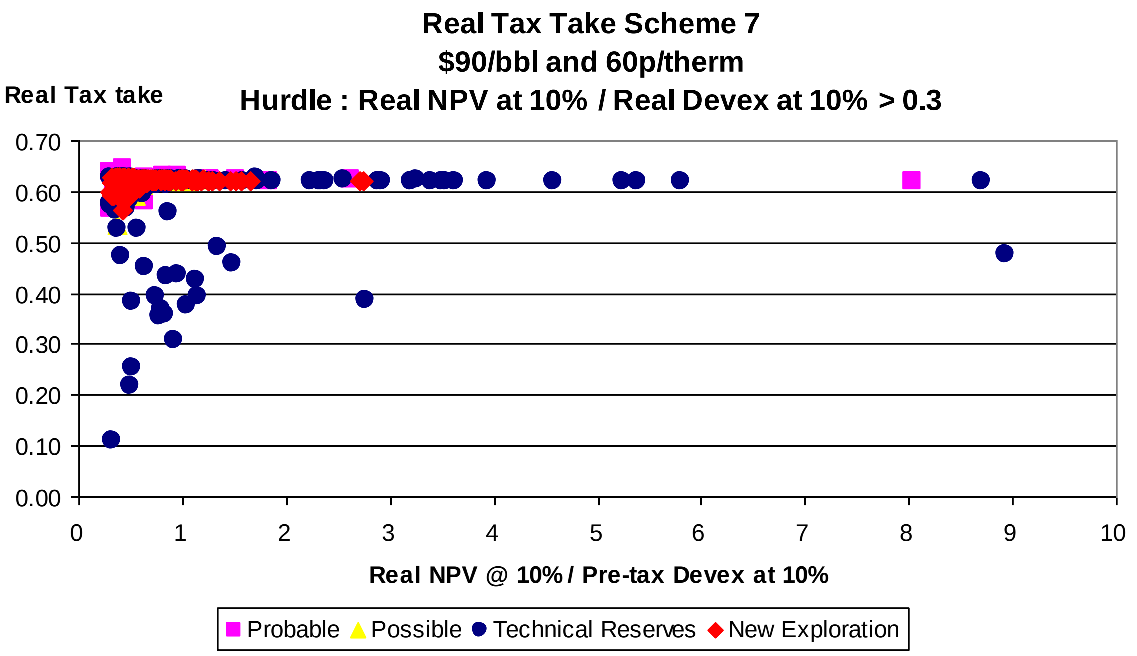
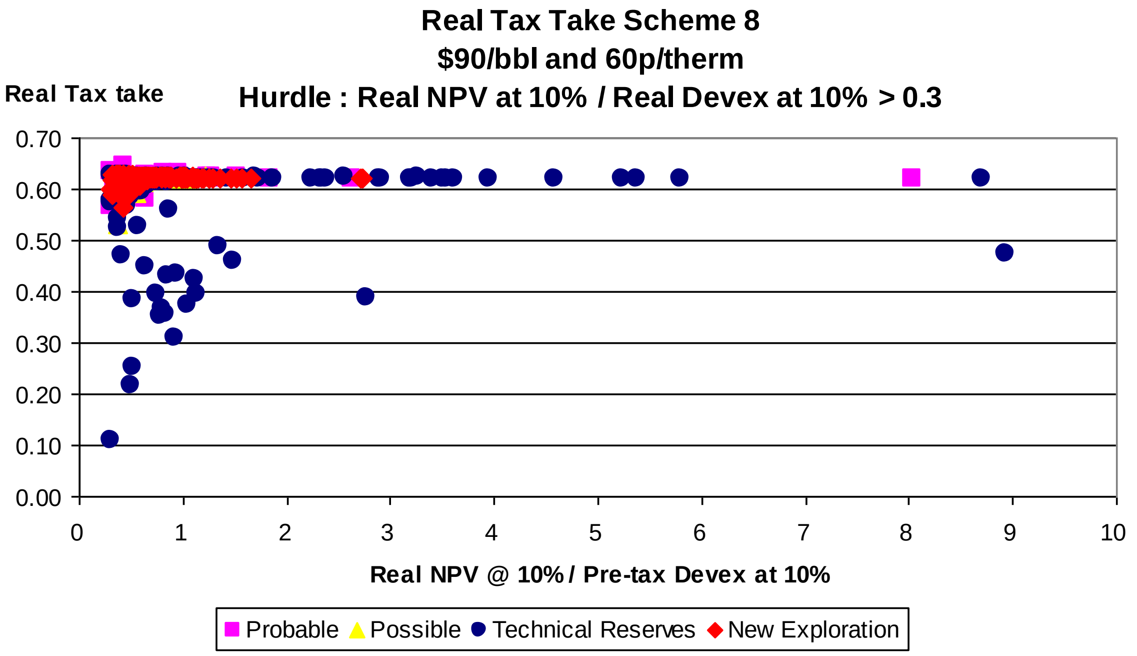


Chart 86



In Chart 87 the tax takes under **Scheme 9** (Budget 2012) are shown. The allowances result in 59 more new field developments being incentivised compared to the situation with no field allowances. There are 17 fewer field developments with **Scheme 9** compared to the CT only cases. It is seen that a large number of fields face an effective tax rate below 62%. This is exhibited more clearly in Chart 88 which shows the tax takes on the fields whose development has been triggered by the field allowances in **Scheme 9** (compared to no field allowances). The tax takes are not noticeably related in a progressive manner to profitability, reflecting the physical rather than economic characteristics of the allowances.

Chart 87

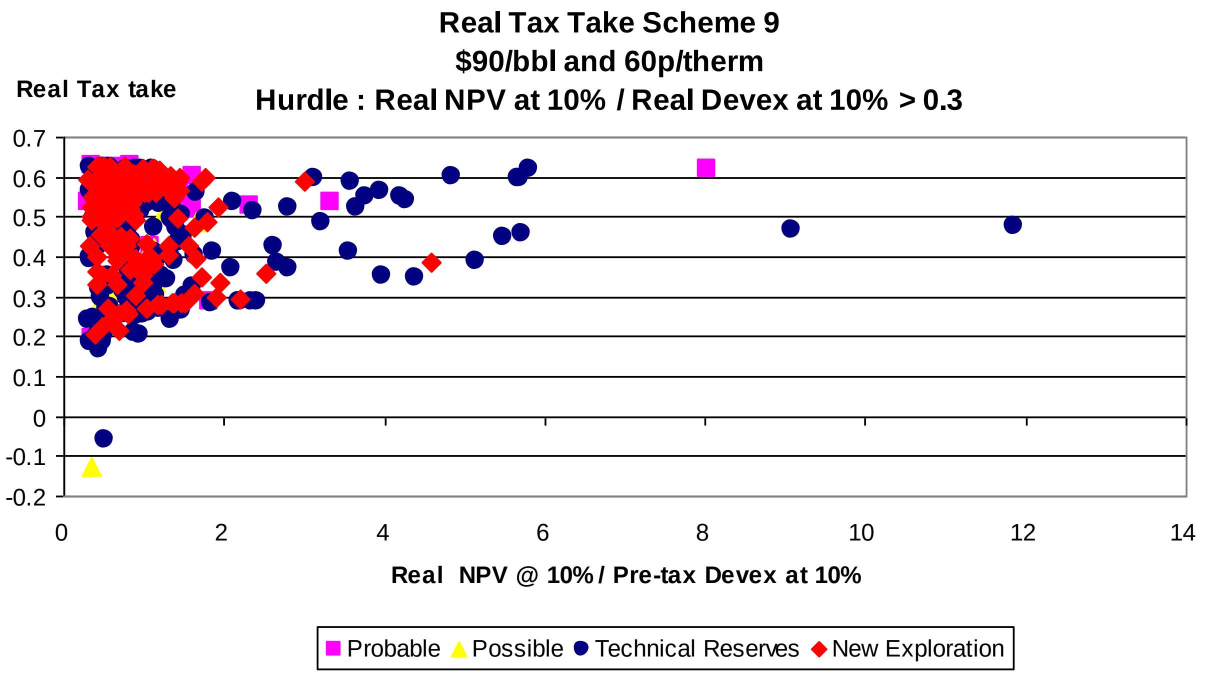
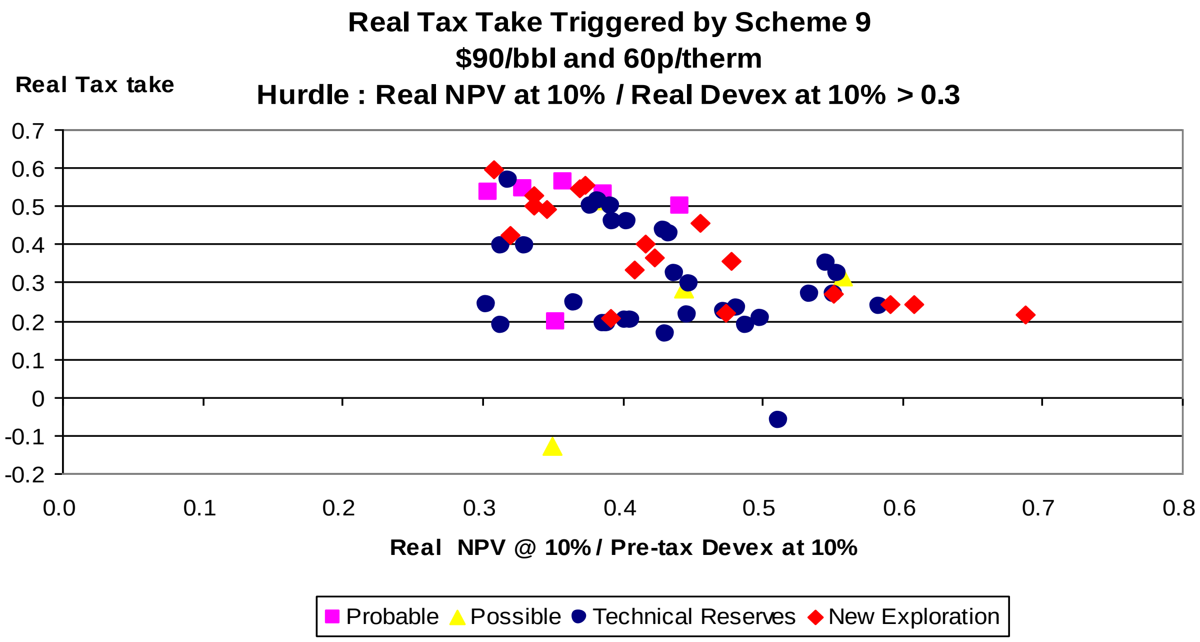


Chart 88



D. $90, 60 pence, NPV/I > 0.5 Case

Under the $90, 60 pence price scenario with hurdle of NPV/I > 0.5 there are 677 potential new developments/ projects of which 115 fail the hurdle before tax. After CT there are 519 viable developments.

In Chart 89 the annual changes in the numbers of fields in production compared to the base case of CT only are shown, and in Chart 90 the cumulative changes to the numbers of fields passing the hurdle are shown. It is seen that **Schemes 1 and 6** generally perform best form this viewpoint. Over the period there are 70 less new developments with **Scheme 6** compared to the CT only case. **Scheme 1** produces 66 less new developments compared to the CT only case. The worst performing scheme is **Scheme 2** which results in 183 less new developments. **Schemes 7 and 8** also do not perform well with 169 less new developments. **Scheme 9** results in 82 less new developments compared to CT only case. **Scheme 5** produces 86 less developments.

Chart 89

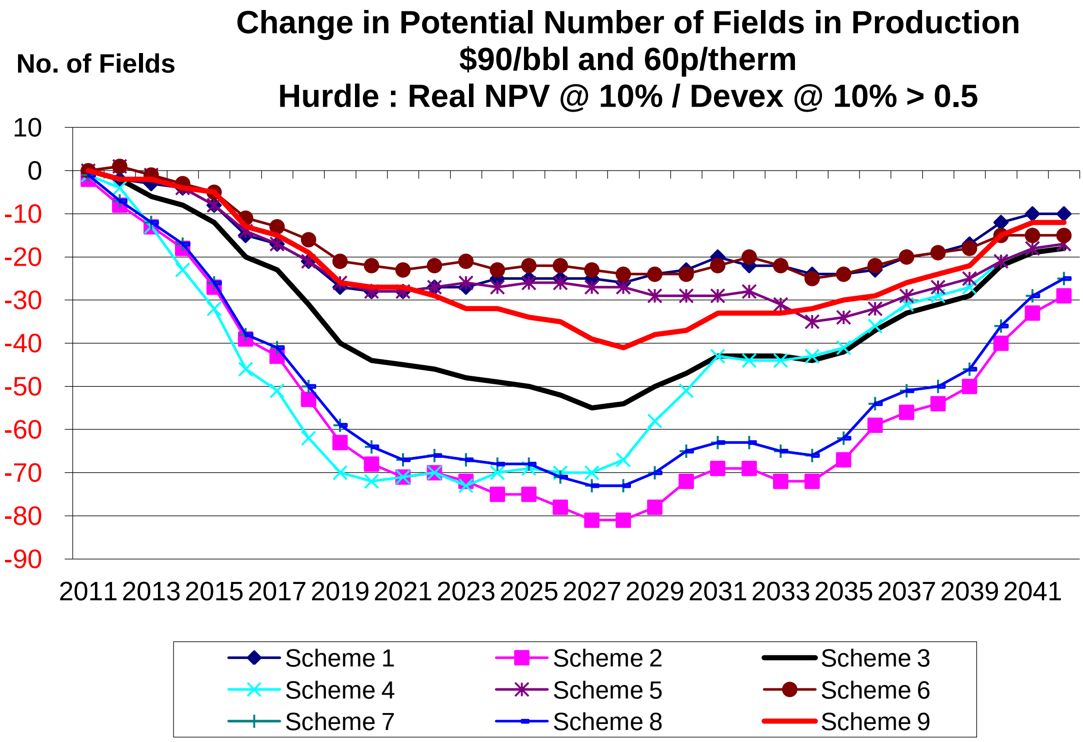
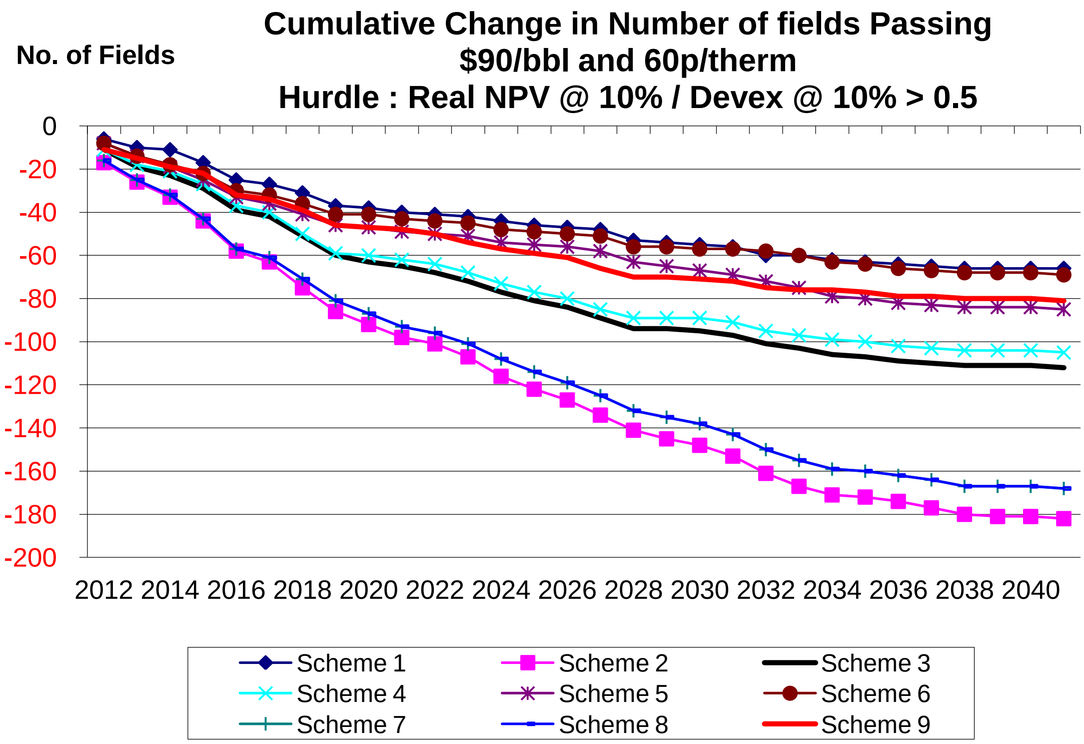


Chart 90



The annual changes to oil, gas and total hydrocarbon production are shown in Charts 91, 92 and 93 respectively. The best performance comes from **Scheme 1** for both oil and gas with the reduction in oil production being noticeably less compared to the other schemes. It should be noted that the lower rate of SC automatically applies to incremental projects. **Schemes 5 and 6** are next best with respect to production performance. All the other schemes have distinctly lower achievements for oil. **Scheme 9** performs reasonably well with respect to gas.

Chart 91

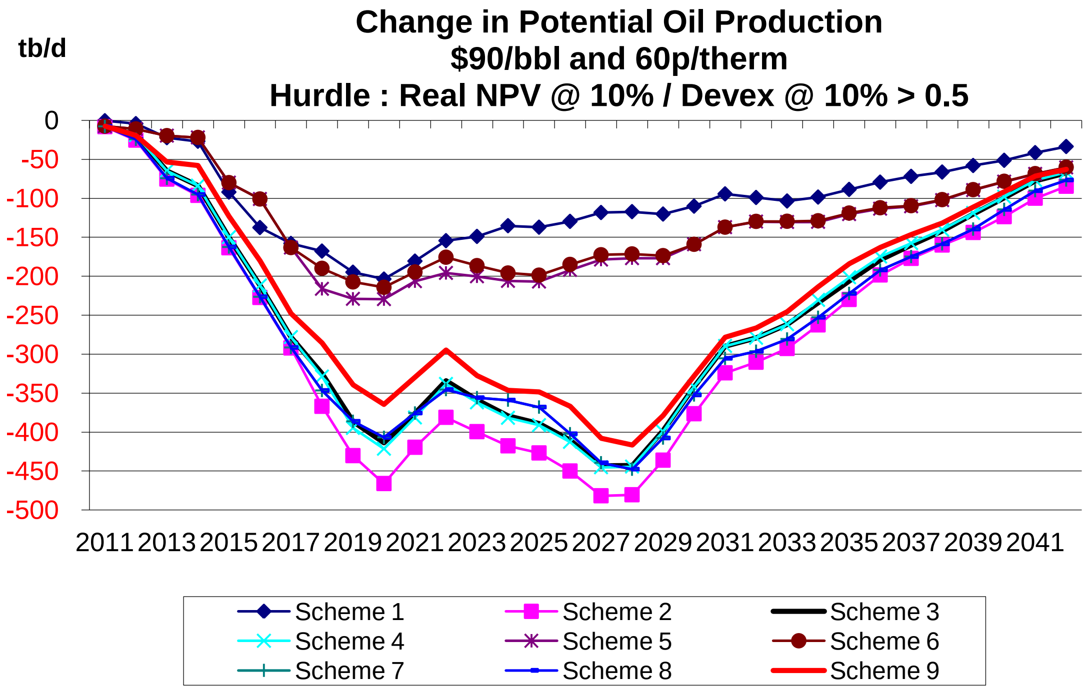


Chart 92

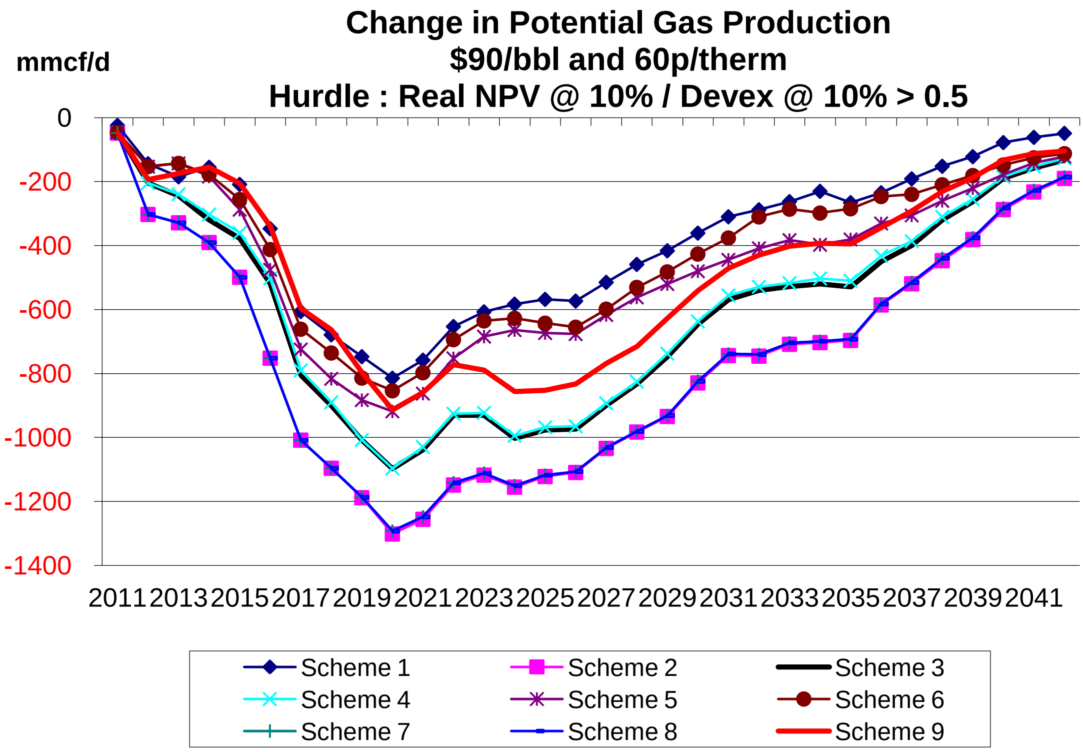
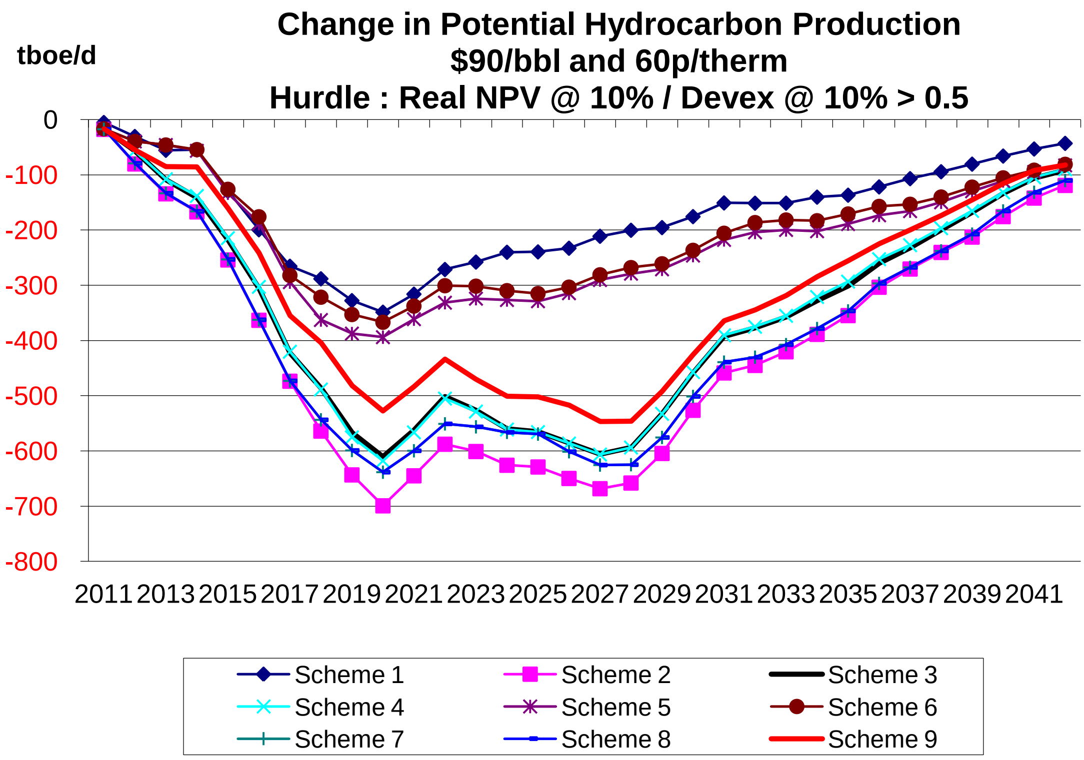
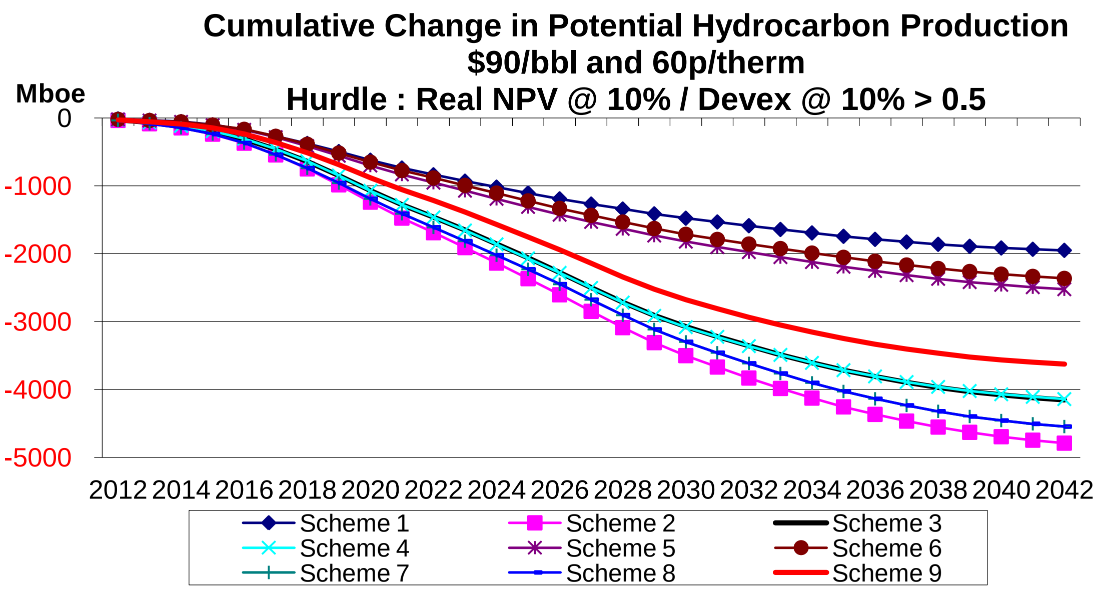


Chart 93



The cumulative effects on total hydrocarbon production over the period are shown in Chart 94. It is seen that all schemes result in a substantial cumulative reduction compared to the CT only case. Even **Scheme 1** results in a reduction of 1.95 bn boe over the period to 2042. The worst performer is **Scheme 2** which results in a major cumulative reduction of 4.8 bn boe. **Scheme 5** produces an overall reduction of 2.6 bn boe and **Scheme 9** results in a cumulative reduction of 3.6 bn boe. The results under this price and hurdle rate case are more dramatic in terms of reduced production compared to the $90, 60 pence, NPV/I > 0.3 case, reflecting the importance of the hurdle rate employed.

Chart 94



The changes on development costs are shown in Chart 95 on an annual basis and in Chart 96 on a cumulative basis. The lowest cumulative reduction is with **Scheme 1** at around £26 billion. The next best performers are **Schemes 5 and 6** where the cumulative reduction exceeds £30 billion. The worst performer is **Scheme 2** where the cumulative reduction exceeds £60 billion. This last result highlights the need for the presence of allowances in an environment with the SC at 32%. **Scheme 9** produces a cumulative reduction of £46 billion which is a substantial improvement over the scheme without field allowances, but well below the performance of **Schemes 1, 5 and 6**.

Chart 95

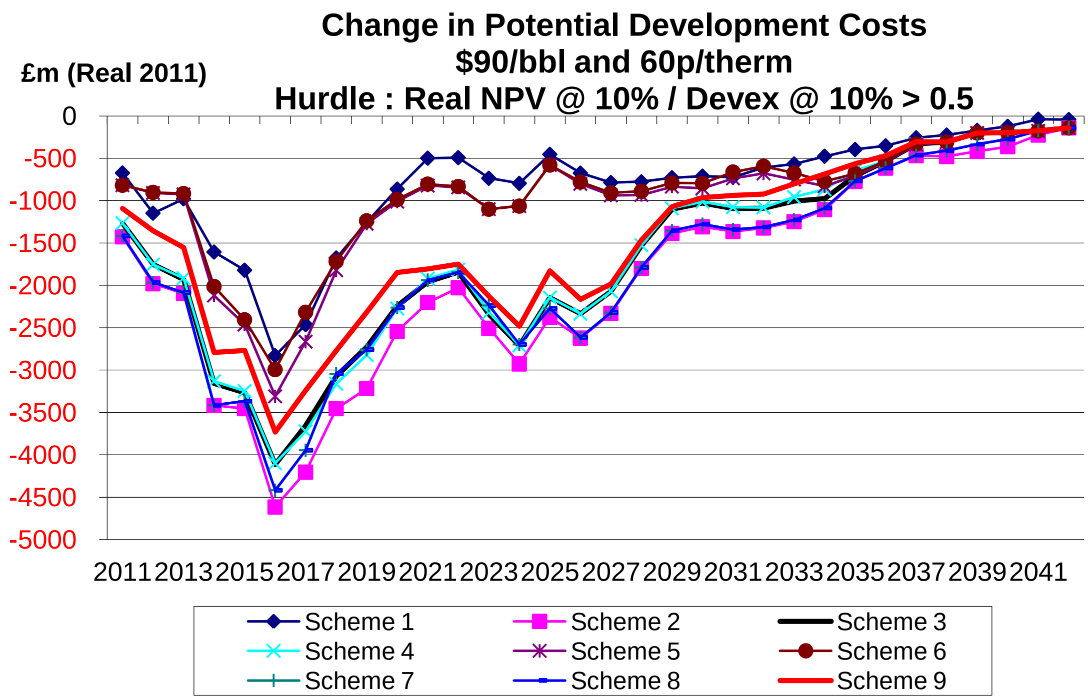
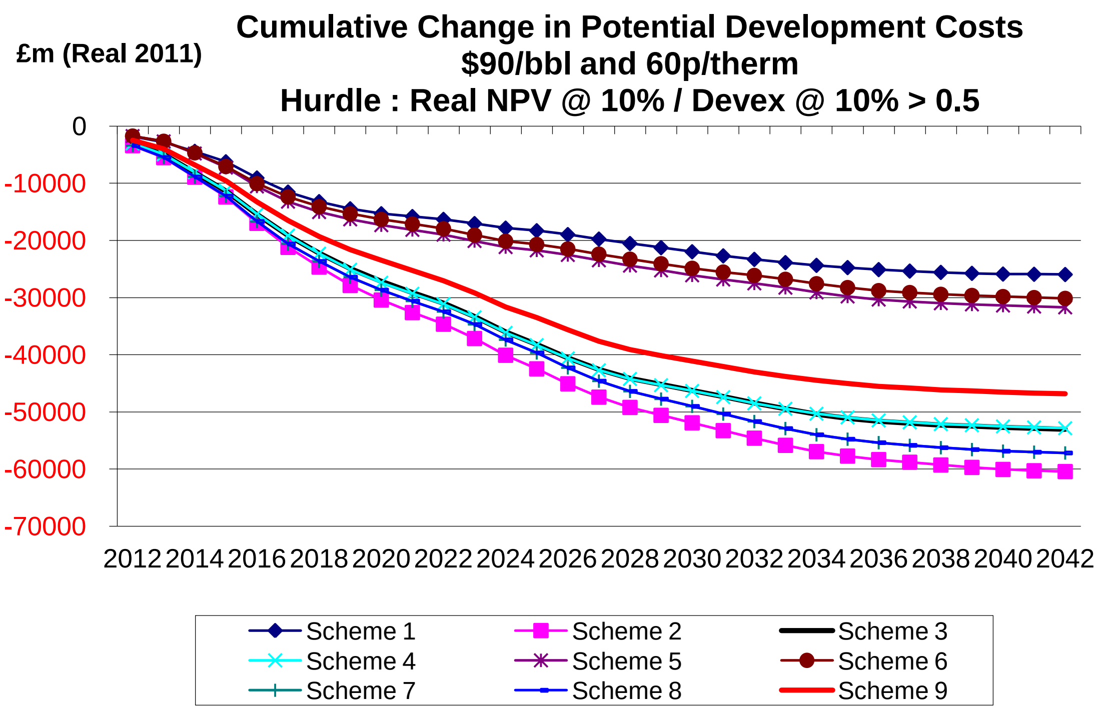


Chart 96



Charts 97 and 98 show the annual and cumulative reductions in operating costs compared to the CT only case. **Schemes 1, 5 and 6** exhibit the smallest reductions with the cumulative effects being in the £18 - £20 billion range. The biggest reduction is with **Scheme 2** with a cumulative decline of £46 billion. **Scheme 9** produces a cumulative reduction of £32 billion.

Chart 97

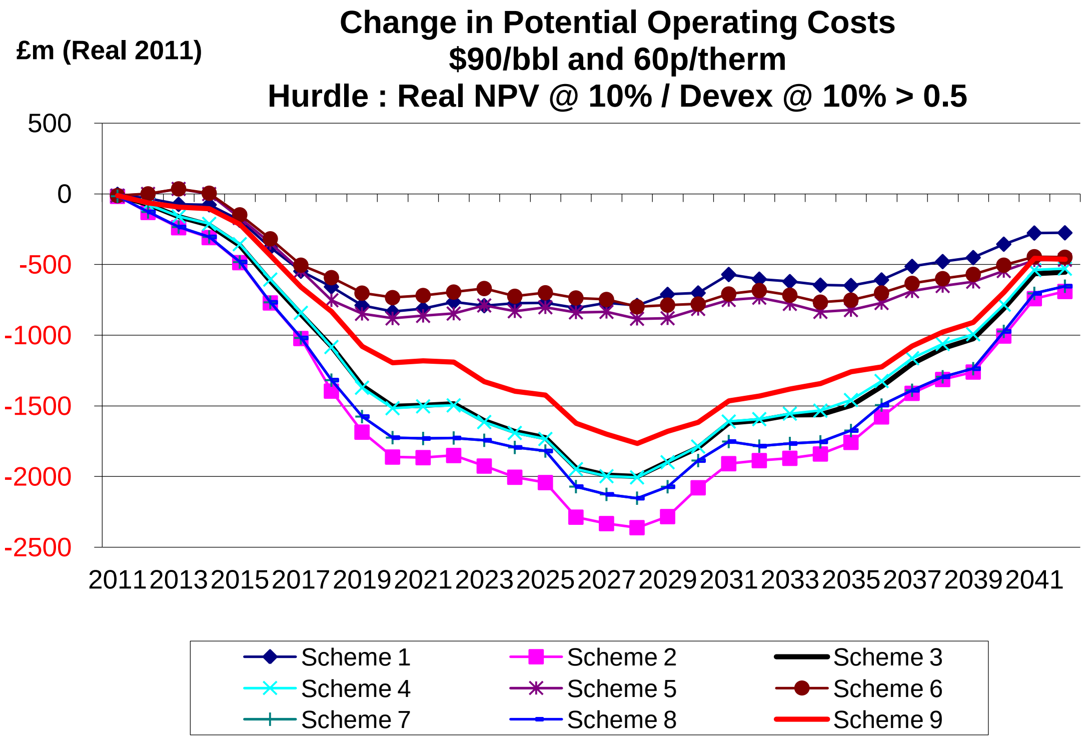
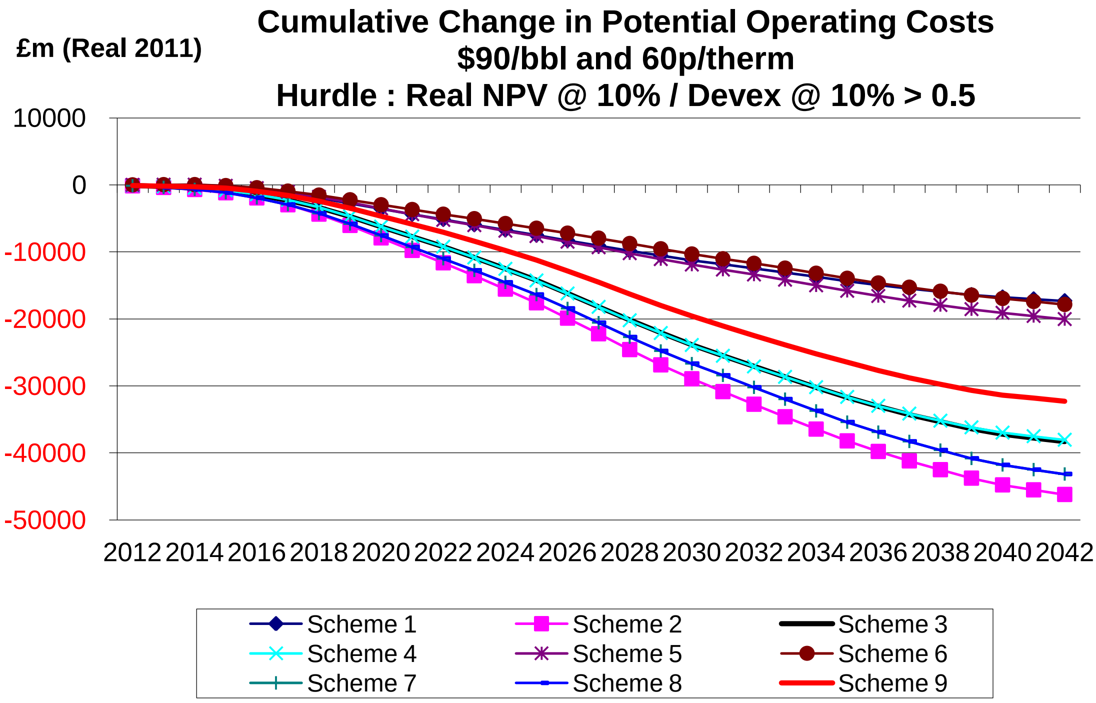


Chart 98



Charts 99 and 100 show the annual and cumulative changes in total tax receipts over the period compared to the CT only case. **Schemes 5 and 6** produce the largest cumulative increase in tax receipts of nearly £150 billion. These schemes are progressive in relation to cost and price variations (including the oil/gas price differential) which explain the results. **Scheme 1** produces the smallest increase of around £100 billion. While there are many new developments under **Scheme 1** there is a loss of tax revenues from the more profitable projects. **Scheme 9** produces a cumulative increase in tax revenues of around £130 billion. Considerable numbers of new developments are triggered, and there are increased revenues from the more profitable fields compared to the CT only case.

Chart 99

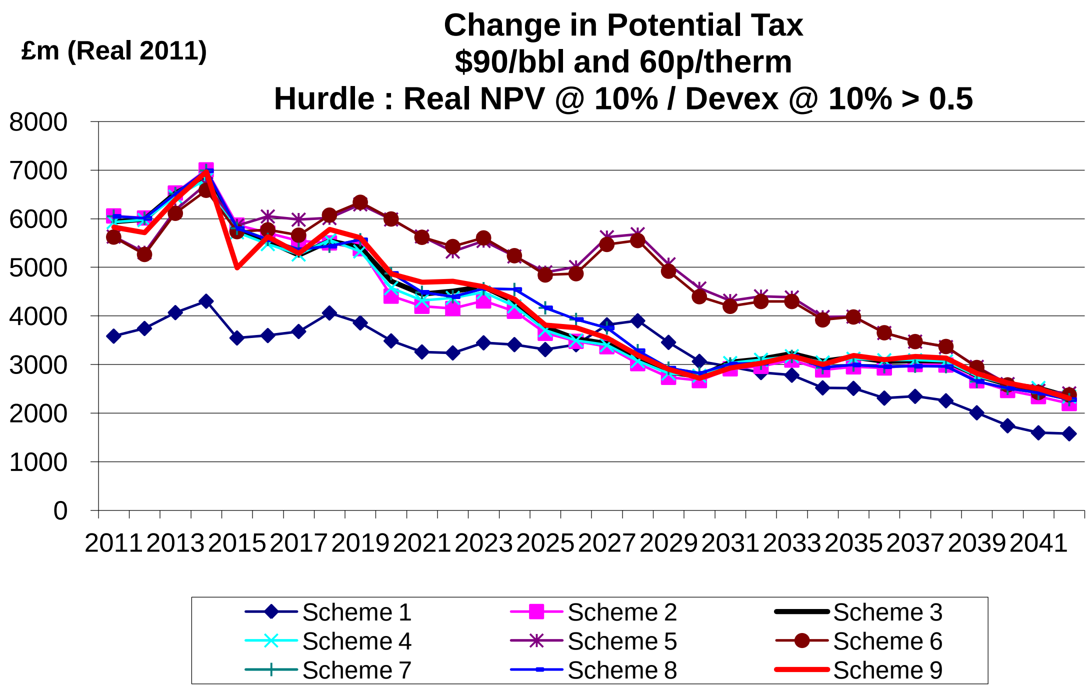
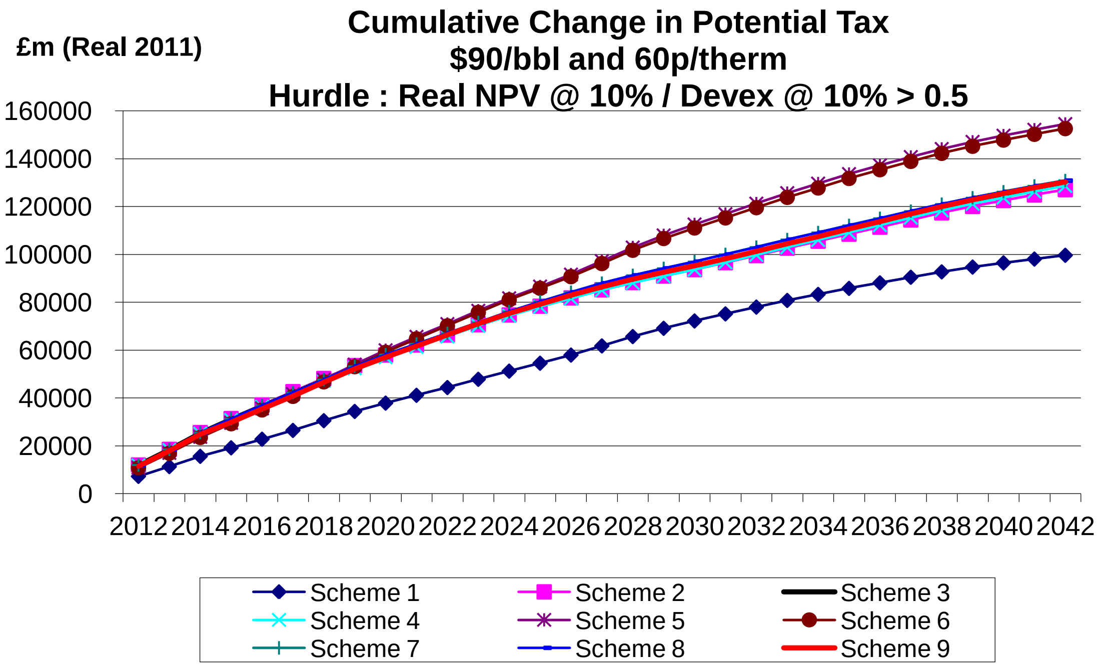


Chart 100



Further insights into the tax position are shown in Charts 101 and 102 which show the annual and cumulative changes in CT. The lowest fall is with **Scheme 1** with a cumulative reduction of £12 billion over the period. This reflects the relatively large numbers of new developments compared to other schemes. The second best performers are **Schemes 5 and 6** which produce cumulative reductions in the £16 - £17 billion range. The worst performer is **Scheme 2** which results in a reduction of over £34 billion. This result highlights the need for the field allowances at the higher rate of SC. **Scheme 9** produces a cumulative loss of revenues exceeding £26 billion.

Chart 101

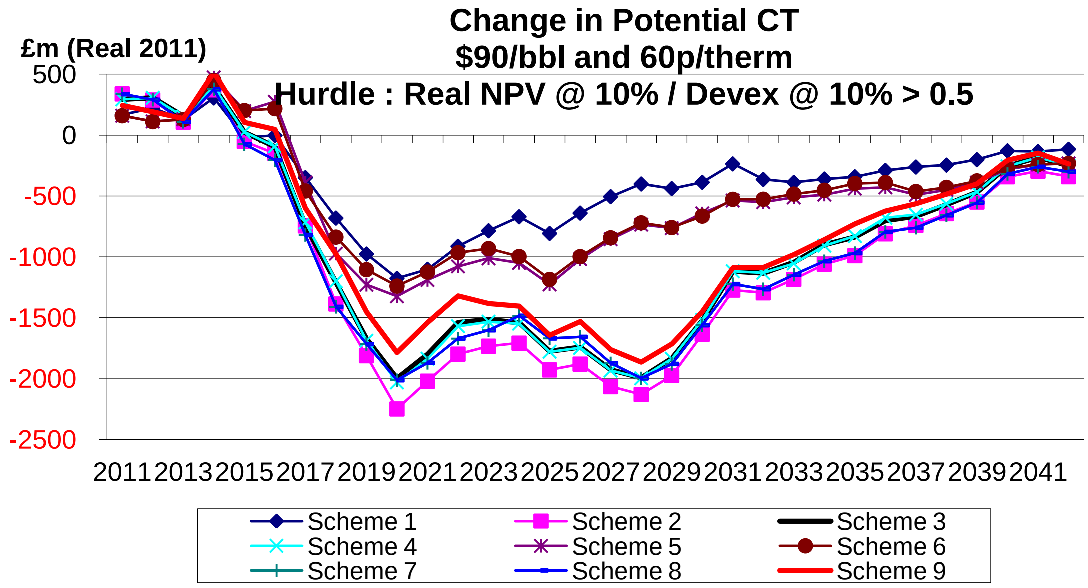
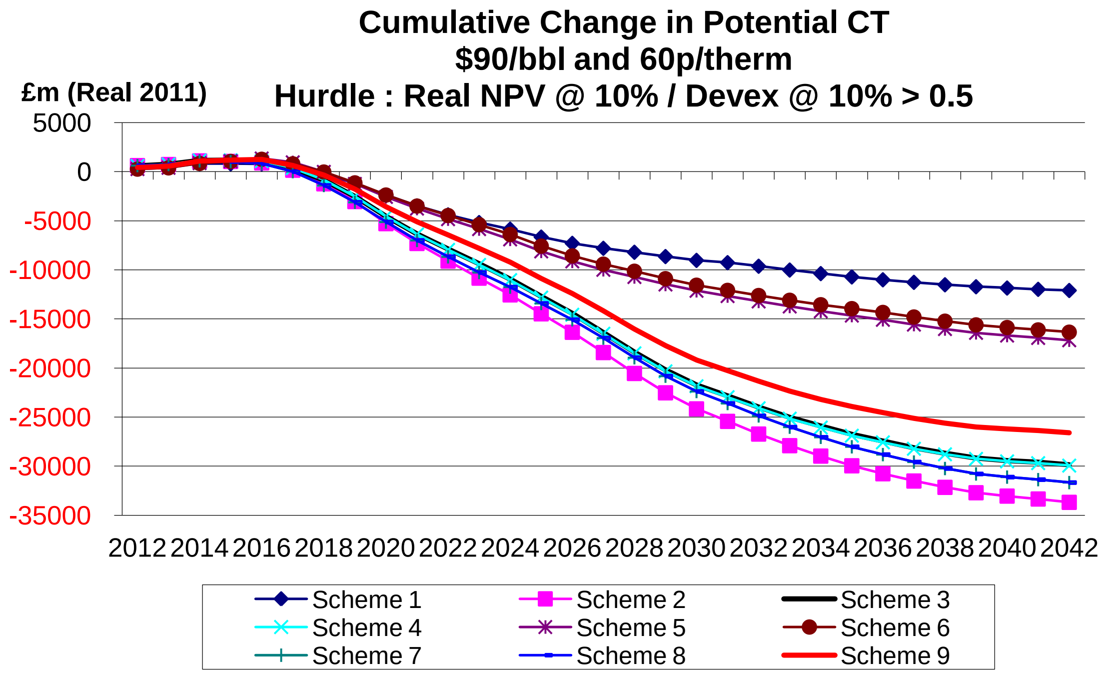


Chart 102



Charts 103 and 104 show the annual and cumulative changes in SC under the different schemes. **Schemes 5 and 6** produce the largest cumulative measures in SC which are in the £172 - £174 range. The cost and price sensitive allowance under **Scheme 5** produces a substantial number of new developments while leaving the more profitable fields subject to the higher rate of SC. Unsurprisingly, **Scheme 1** produces the smallest increase in SC.

Chart 103

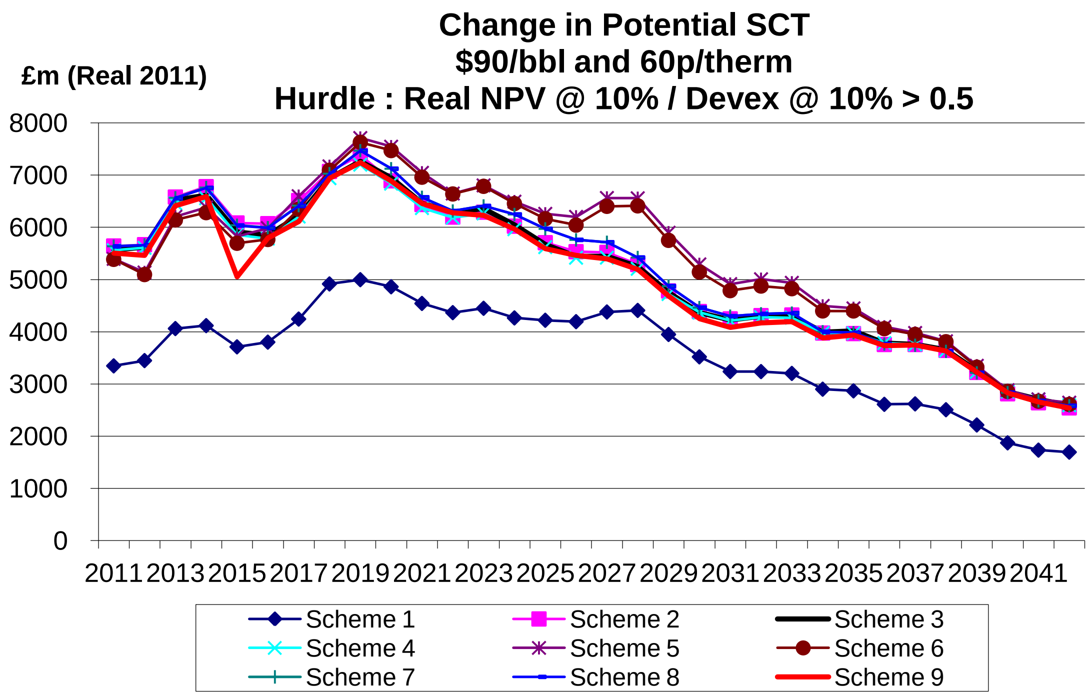
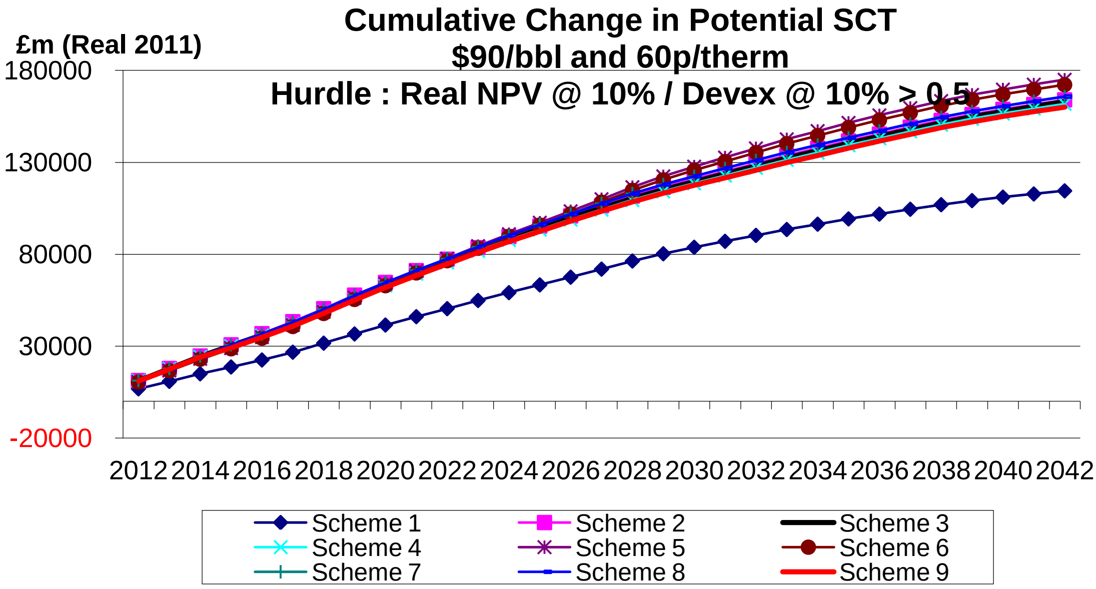


Chart 104



In Chart 105 the percentage tax takes under **Scheme 1** are shown indicating a flat rate of 50%. In Chart 106 the tax takes under **Scheme 2** are shown. The rate is very often just higher the 62% reflecting the incomplete relief for decommissioning costs. The extent of the increase in the rate depends on the relative size of the decommissioning costs.

Chart 105

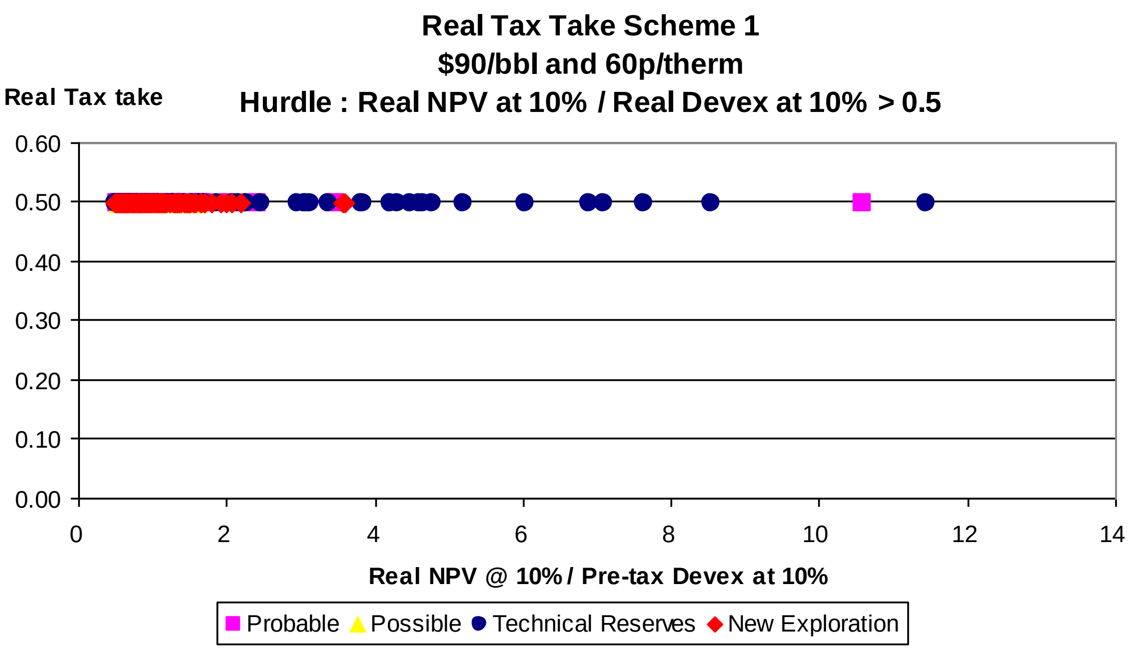
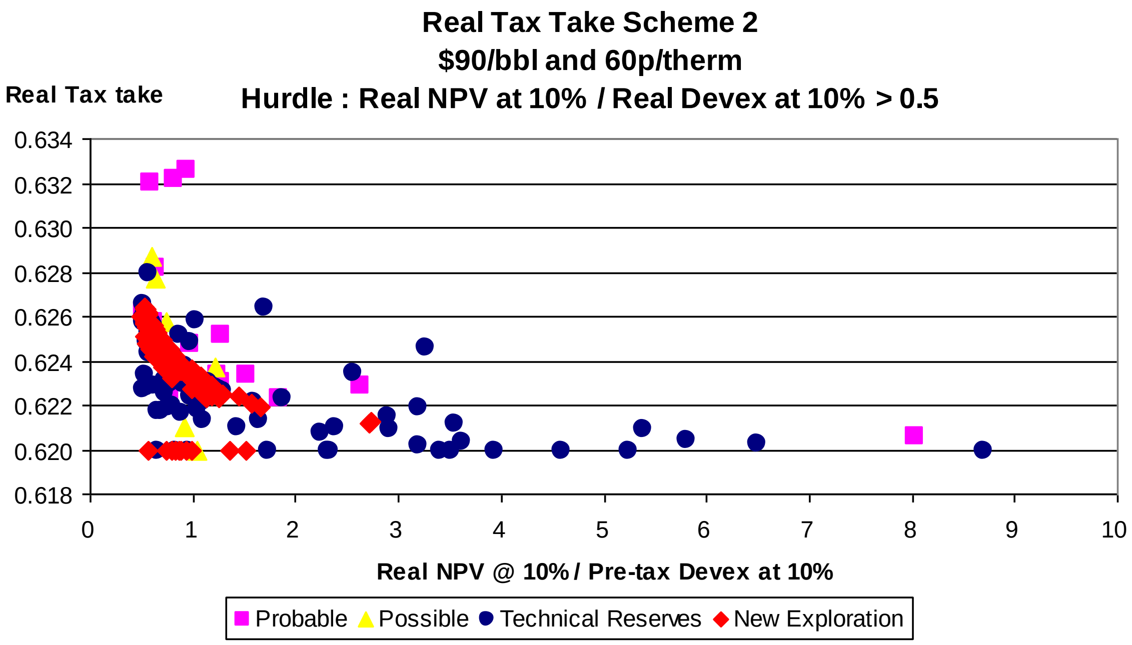


Chart 106



In Chart 107 the tax takes under **Scheme 3** are shown. The results indicate that in many of the new developments the tax takes under the 2011 system (incorporating the then field allowances) are often well below the 62% rate with some below 30%. There an imperfect relationship to project profitability, resulting from the allowances, reflecting the physical features rather than costs. This is highlighted in Chart 108 which shows the tax takes on developments triggered by **Scheme 3**. The results for **Scheme 4** (Chart 109) are fairly similar.

Chart 107

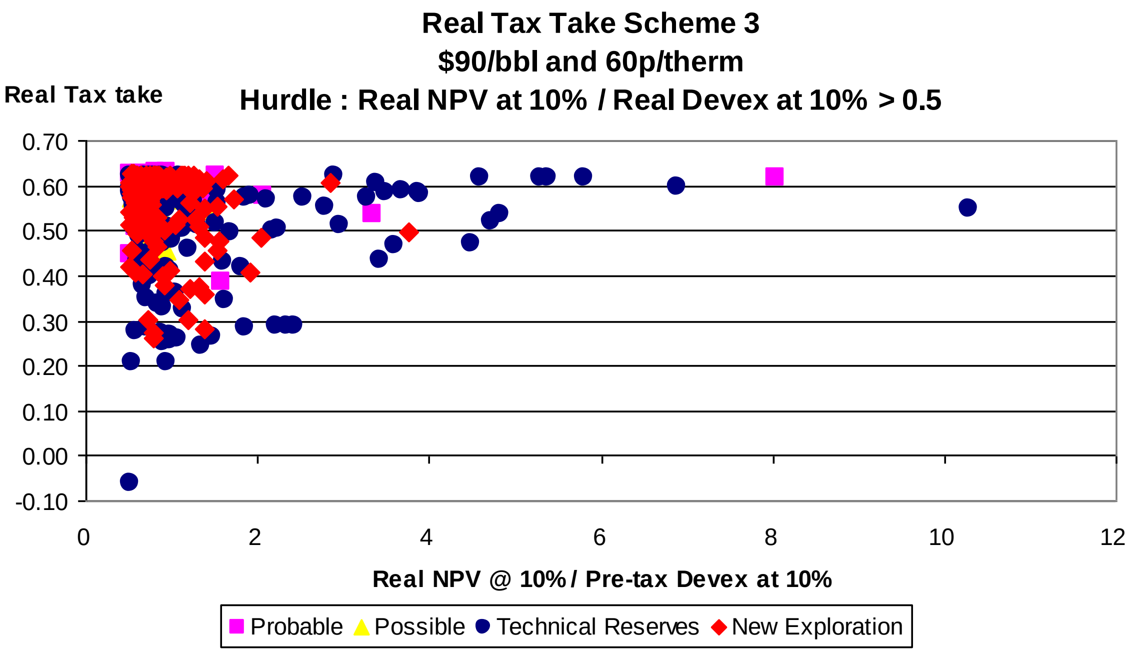


Chart 108

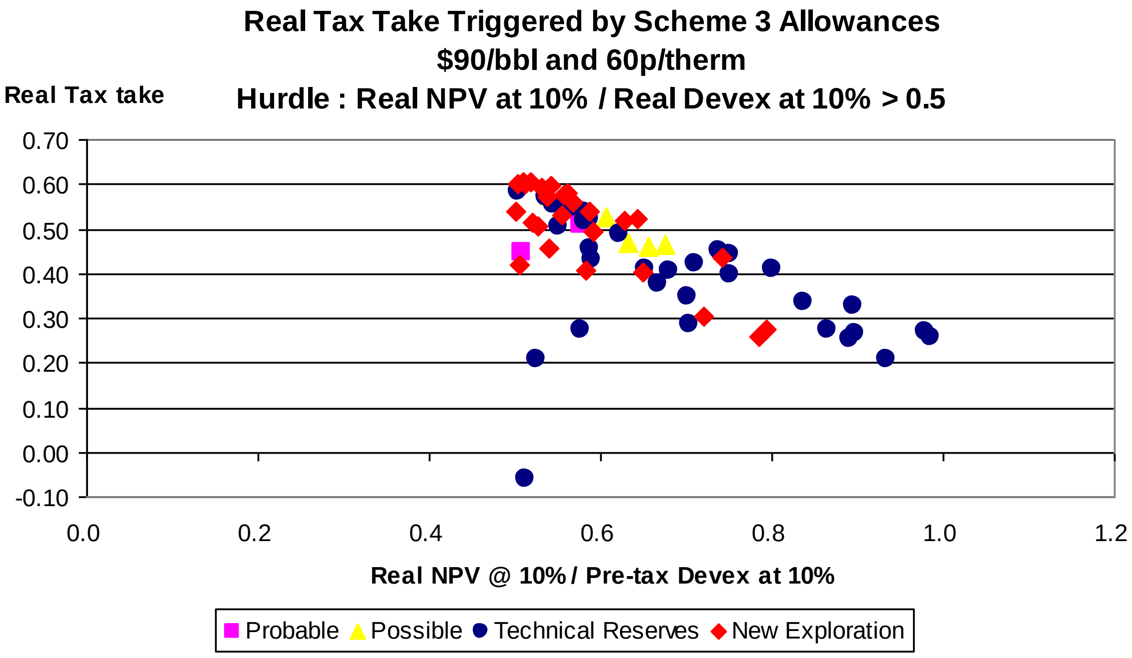
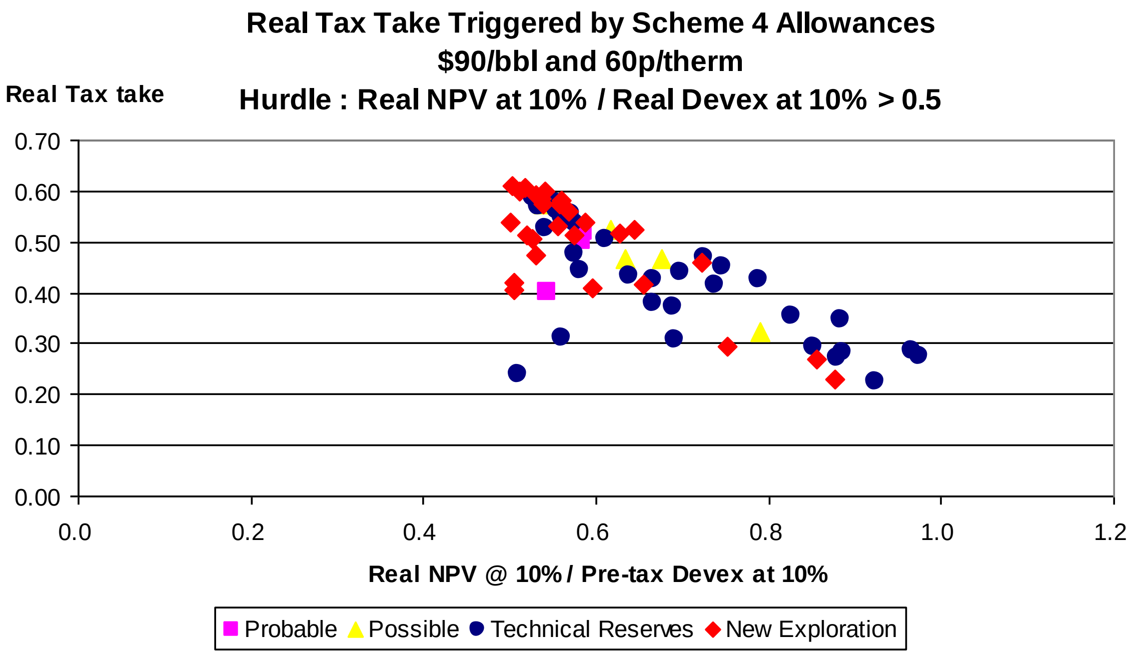
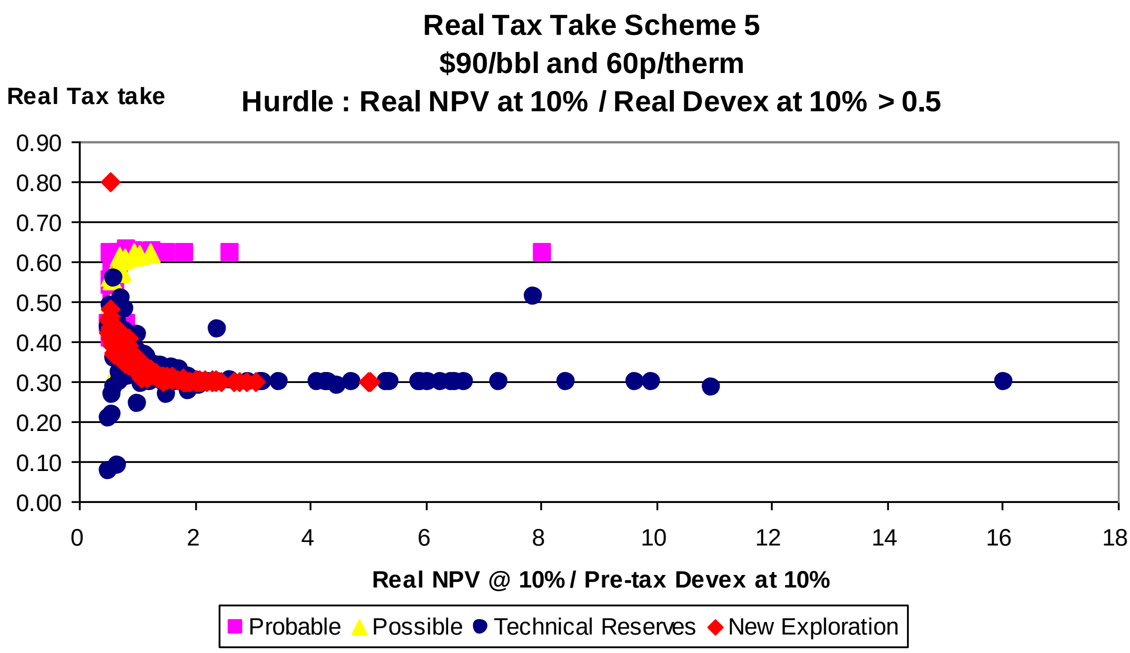


Chart 109



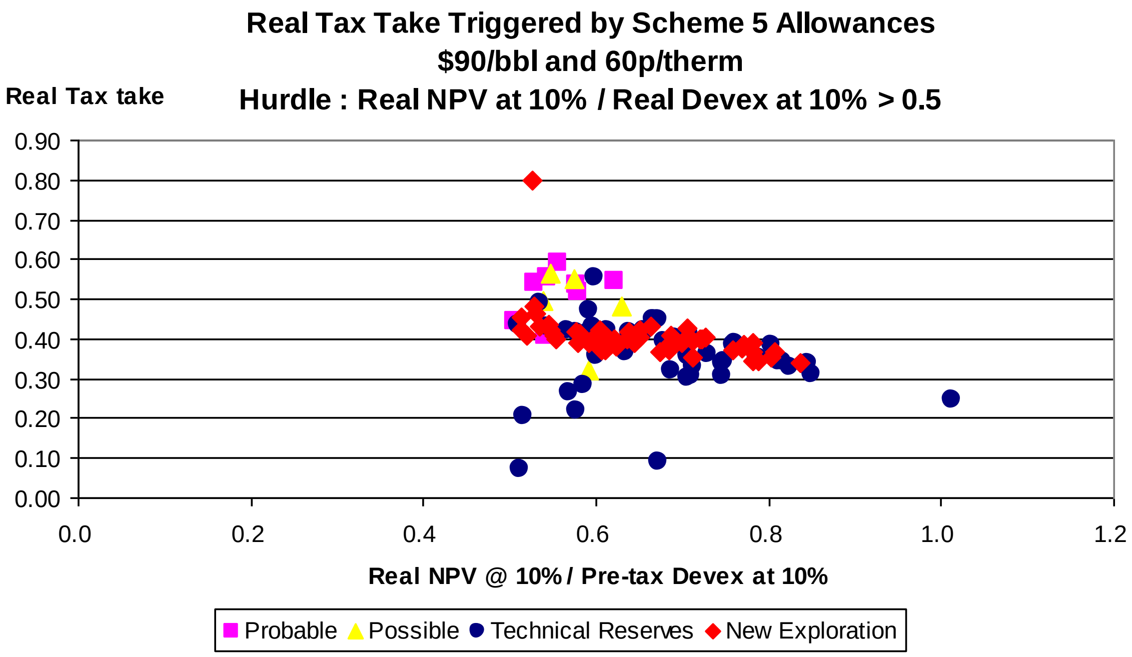
In Chart 110 the tax takes under **Scheme 5** are shown. While some are around 62% many are at lower levels, generally in the 30%-50% range. A considerable number are at 30% including some with relatively high NPV/I ratios. Neither the tax relief nor the investment hurdle puts emphasis on the relative importance of operating costs.

Chart 110



To obtain further insights Chart 111 shows the tax takes on the fields whose development has been triggered by **Scheme 5** (compared to the situation with SC at 32% but no field allowances). It is seen that the majority of the tax takes are in the 30%-50% range, with some outliers at relatively low levels.

Chart 111



In Charts 112 and 113 the tax takes under **Scheme 6** are shown. While there are some extra developments emanating from those available under current legislation the pattern of results is generally as for **Scheme 5**.

Chart 112

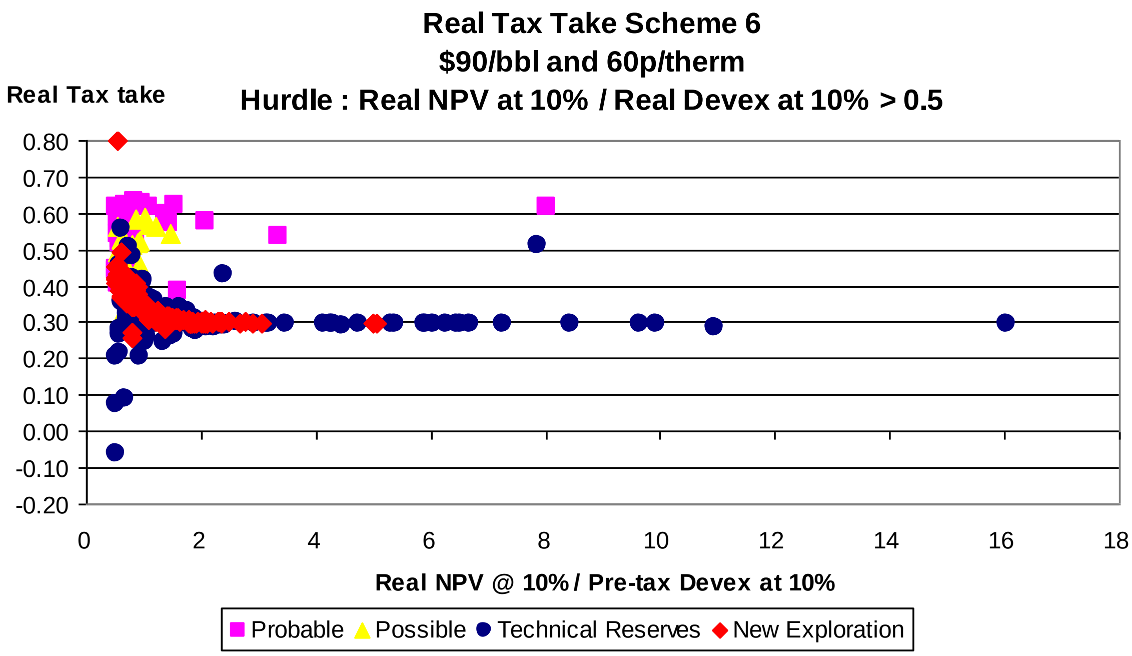
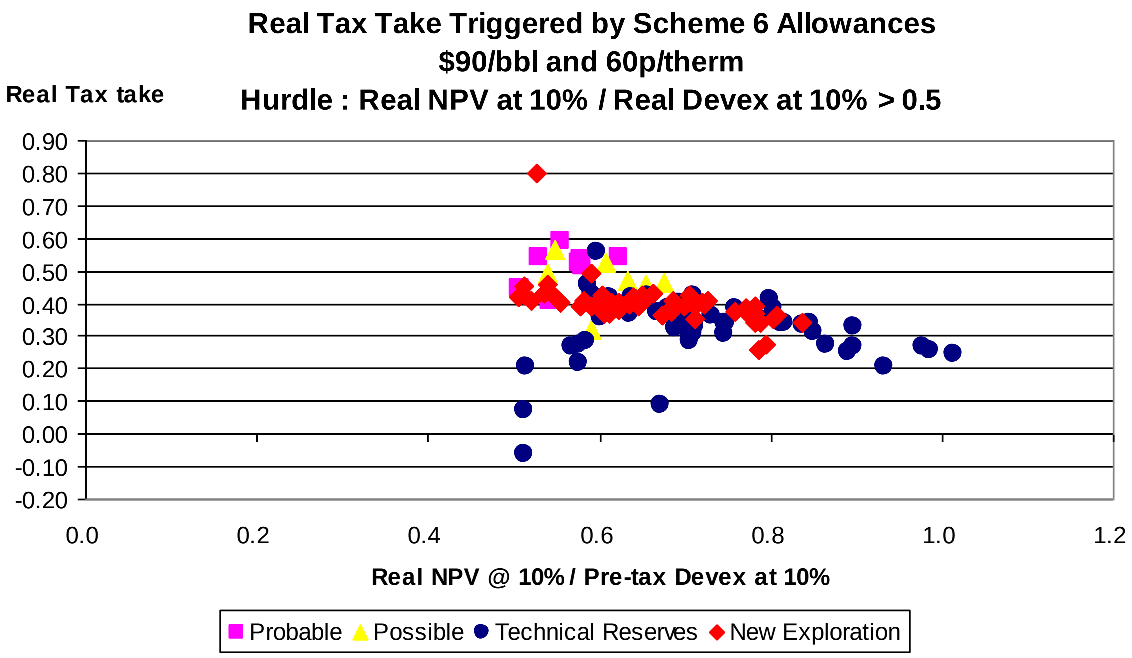


Chart 113



In Chart 114 the tax takes under **Scheme 7** are shown. The majority of fields face a tax rate of 62%, but there are some with considerably lower rates. The tax takes on fields triggered by **Scheme 7** (compared to no field allowances) are shown in Chart 115. The takes are generally in the 30%-60% range.

Chart 114

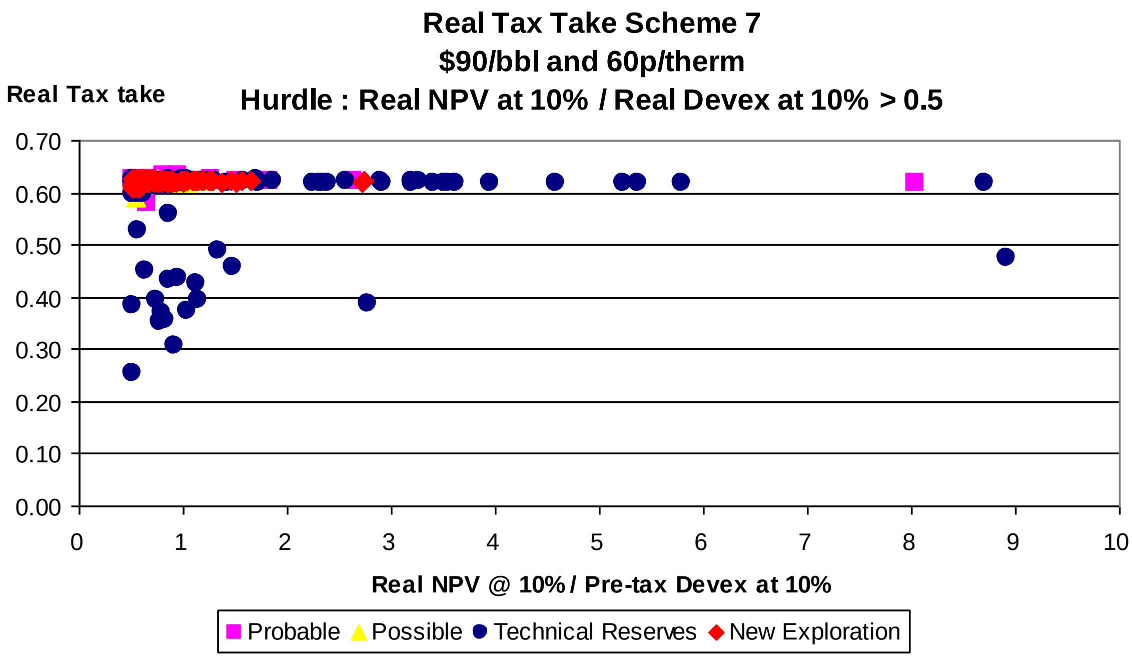
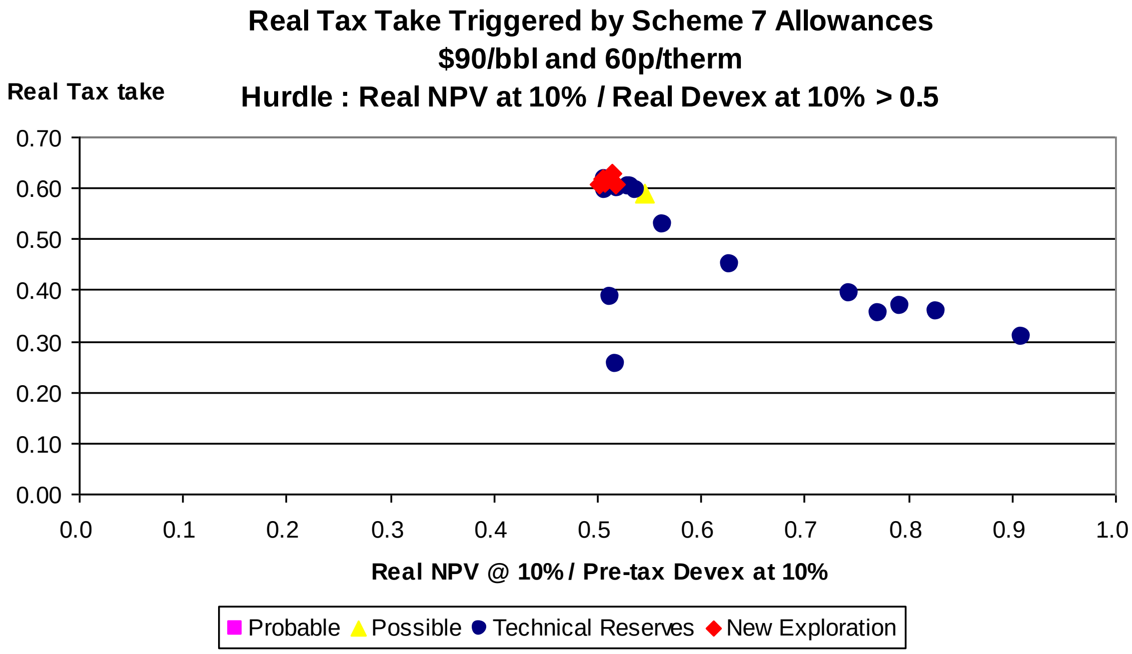


Chart 115



The tax takes under **Scheme 8** are shown in Chart 116 and the takes on fields whose development is triggered by this scheme are shown in Chart 117. The results are quite similar to those achieved with **Scheme 7** and so are not discussed further.

Chart 116

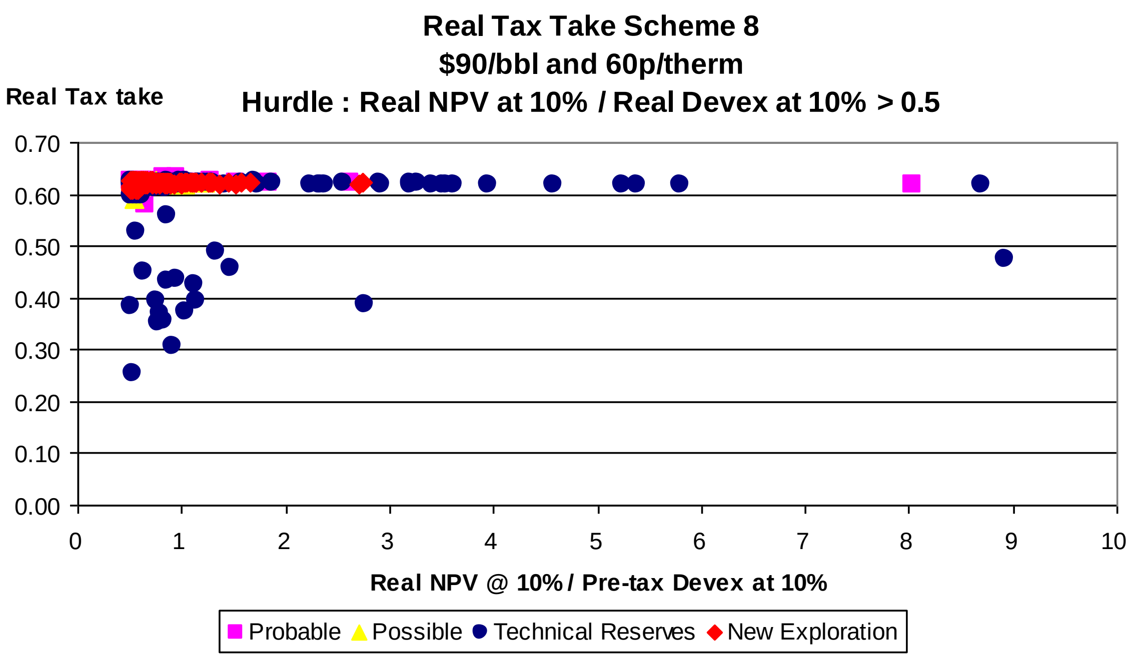
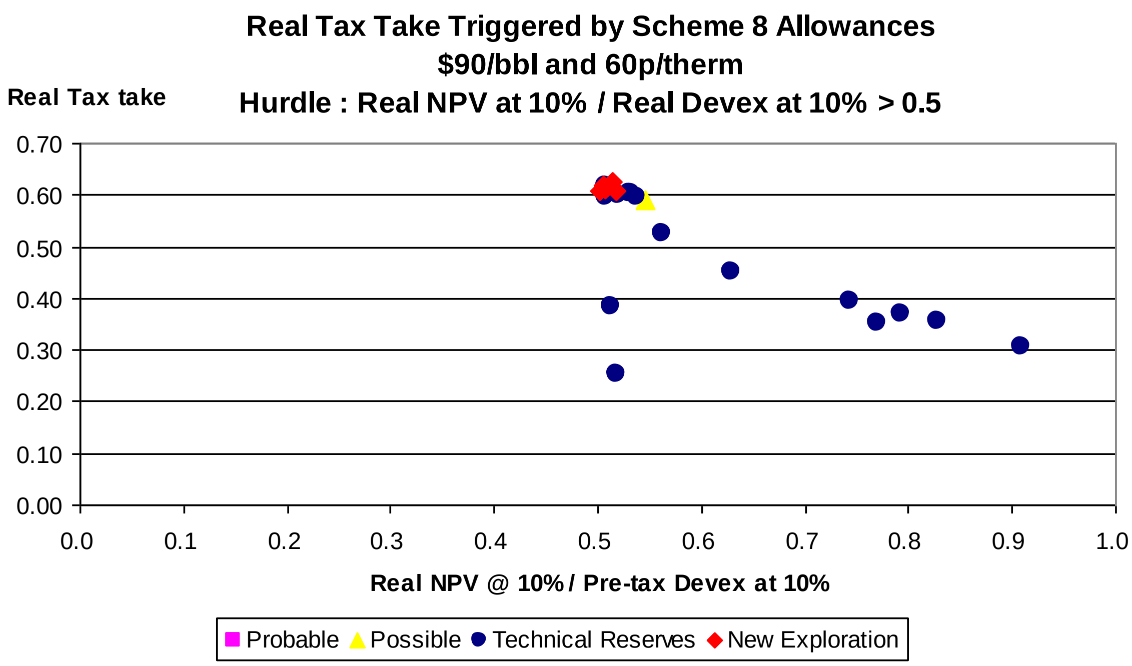


Chart 117



The tax takes under **Scheme 9** are shown in Chart 118. They range from over 62% to just over 20%, with many being in the 30%-60% range. Further insights to the working of the scheme are given in Chart 119 which shows the takes on developments which have been triggered by the allowances. The takes are mostly n the range 60%-25%. The effective rates are not well-related to field profitability. Over 100 new field developments were triggered by the **Scheme 9** allowances.

Chart 118

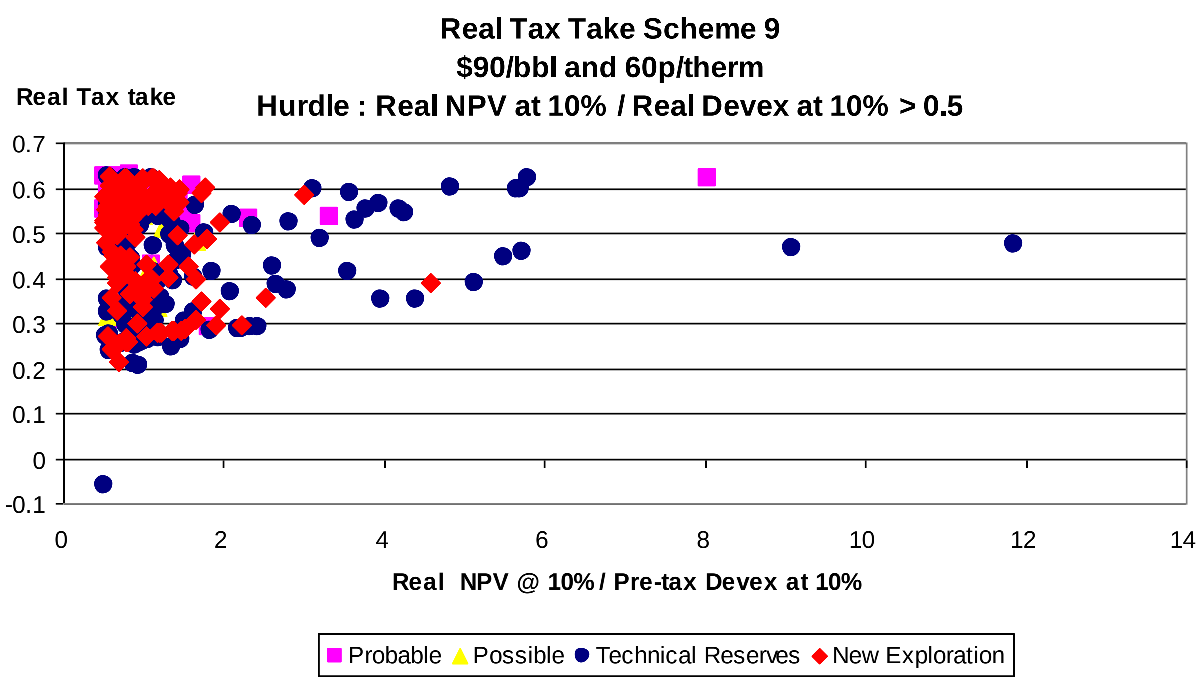
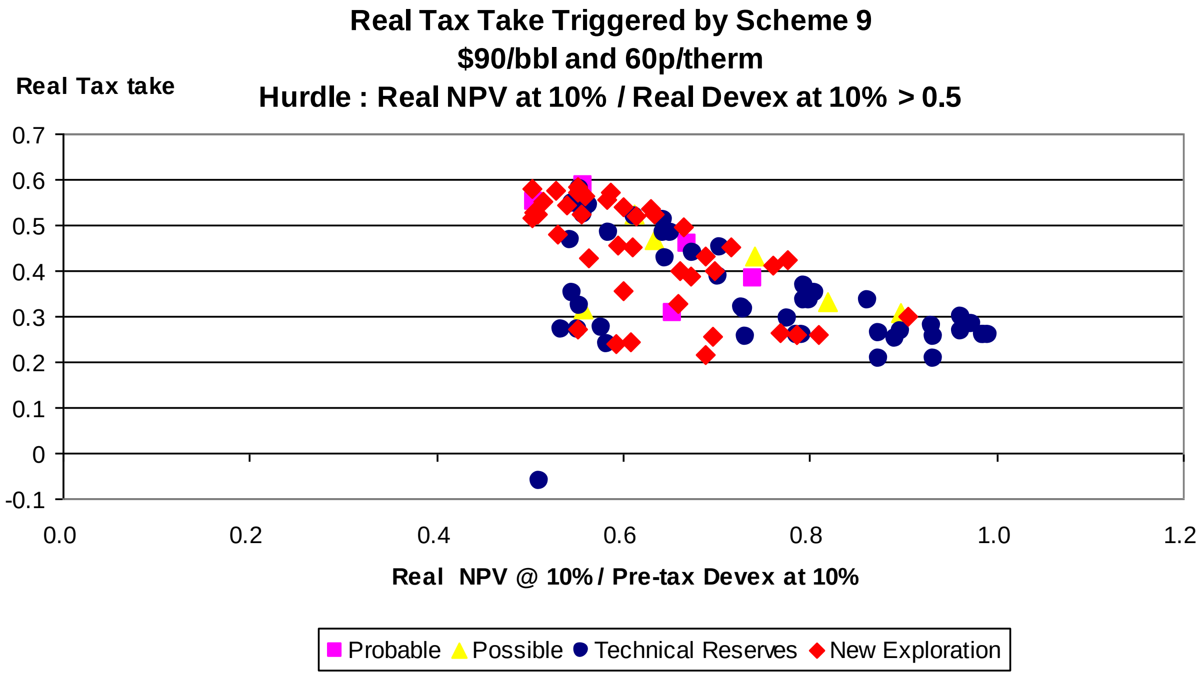


Chart 119



(ii) Incremental Projects

In this section the position of incremental projects under the various schemes is discussed. It was found that the viability of such projects under consideration by the industry was sensitive to their tax treatment. The position under the four scenarios is summarised as follows:

1. **Under the $70,40 pence price** 42 incremental projects failed the NPV/I > 0.3 hurdle with CT only. Under **Scheme 1** with SC at 20% 49 projects failed to pass the hurdle. Under all the other schemes excluding the incremental allowance with **Schemes 5 and 6**. 61 projects failed to pass the hurdle. When the incremental allowances for **Schemes 5 and 6** were included the resulting tax takes on all the incremental projects are as shown in Chart 120. It is seen that most of the projects still faced a tax rate of 62% or

more but a number did have lower rates. A few had very low rates reflecting the very unusual characteristics of the projects. The incremental allowance did trigger the development of some projects which would otherwise have failed the hurdle. The tax takes on these projects are shown in Chart 121.

Chart 120

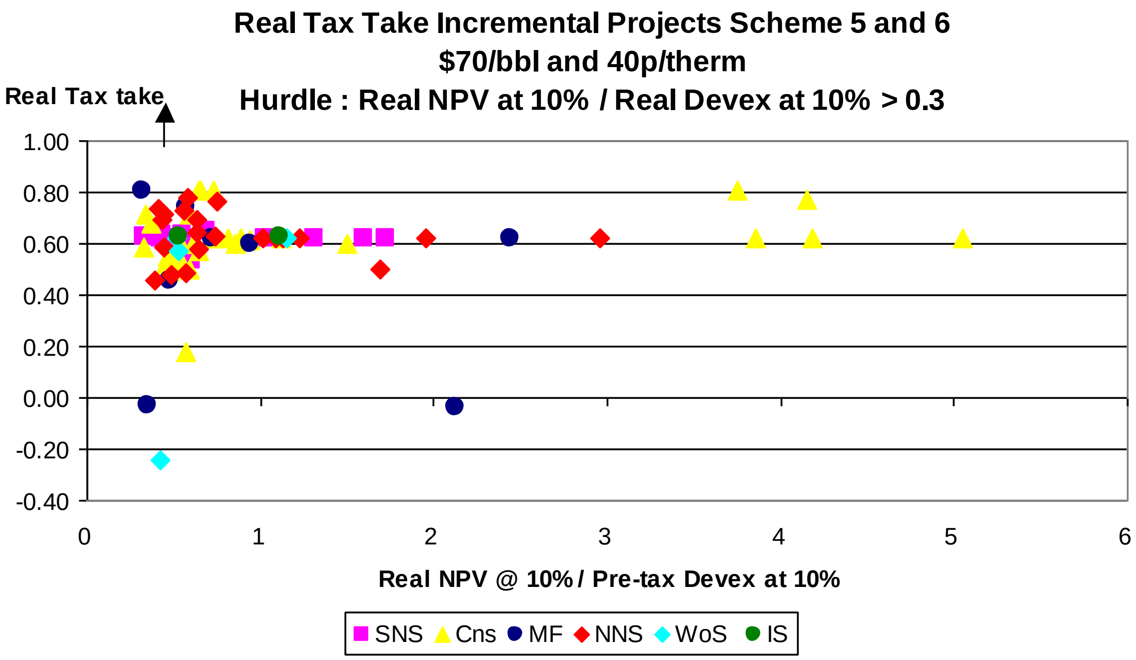
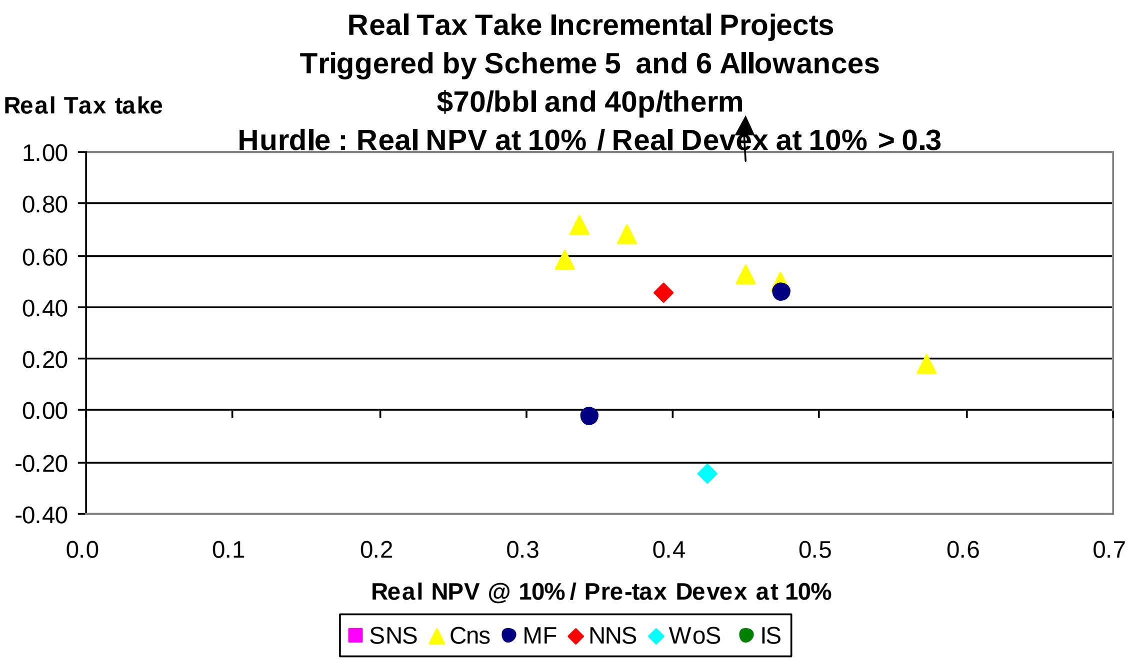


Chart 121



2. **Under the $70,40 pence price** 54 incremental projects failed the NPV/I > 0.5 hurdle with CT only. Under **Scheme 1** with SC at 20% 71 projects failed to pass the hurdle. Under all the other schemes, excluding the incremental allowance for **Schemes 5 and 6,** 80 projects failed the hurdle. When the incremental allowance for **Scheme 5** was included the tax takes on all the incremental projects were as shown in Chart 122. The position of these projects whose development was triggered by the incremental allowance was isolated and the resulting tax takes are shown in Chart 123. It is noticeable that, reflecting the cap on the size of the allowance, not many projects were incentivised under this relatively low price and higher hurdle scenario.

Chart 122

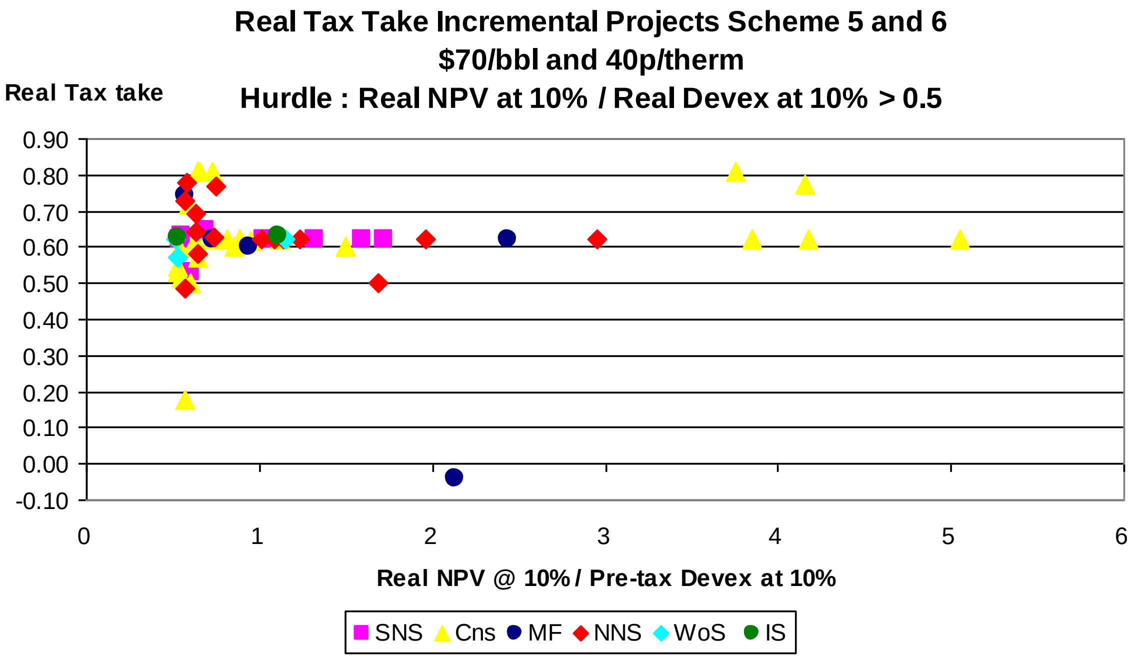
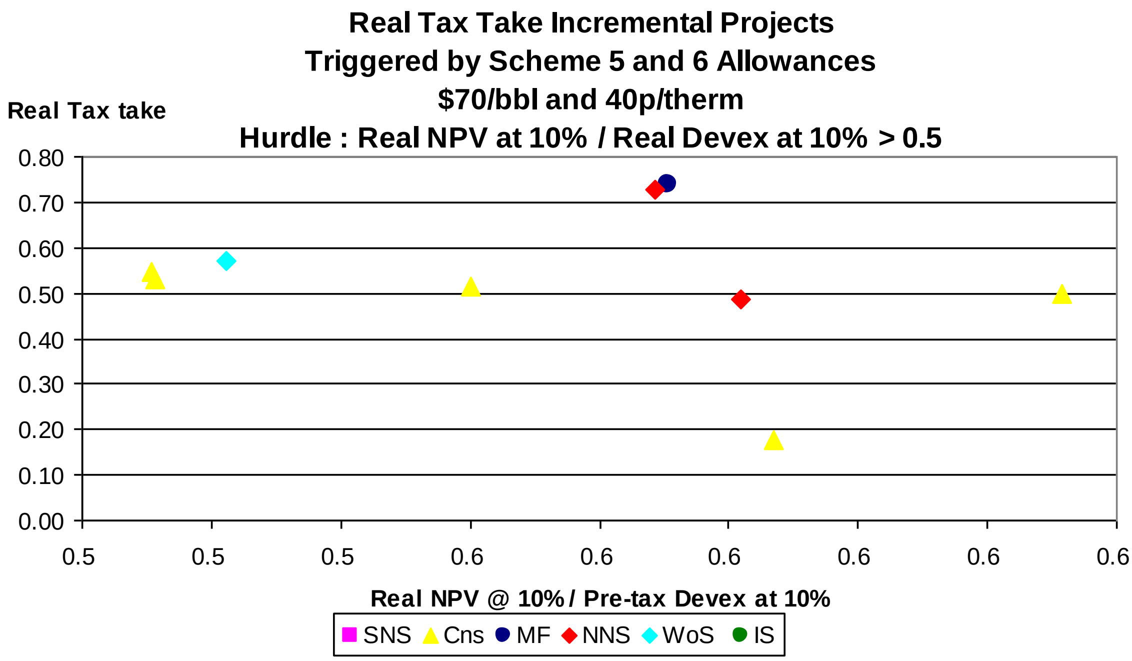


Chart 123



3. **Under the $90, 60 pence price** 31 incremental projects failed the NPV/I > 0.3 hurdle in the CT only case. Under **Scheme 1** with SC = 20% 35 projects failed the hurdle. With all the other schemes <u>excluding</u> the allowance for **Schemes 5 and 6** 39 projects failed the hurdle. When the incremental allowance for **Schemes 5 and 6** was <u>included</u> the resulting tax takes on all the incremental projects were as shown in Chart 124**.** It is seen that the great majority face tax rates of 62% or more but a significant number, generally experiencing relatively low levels of profitability, face lower rates. The allowance did trigger the development of some projects and the resulting tax takes on these triggered fields are shown in Chart 125.

Chart 124

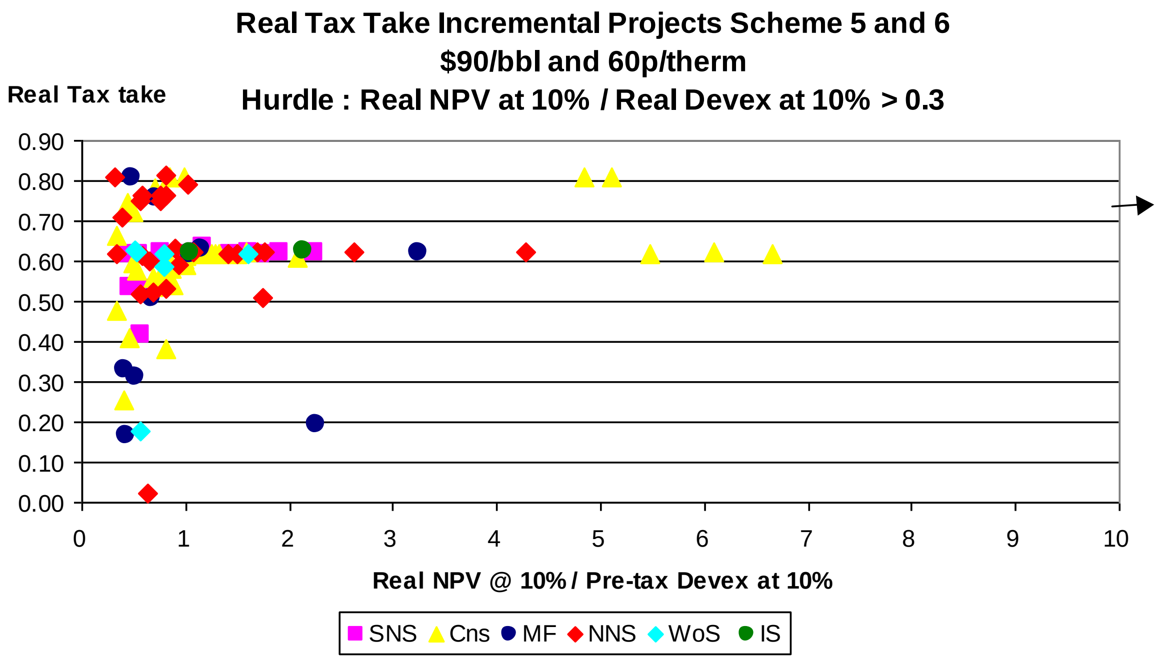
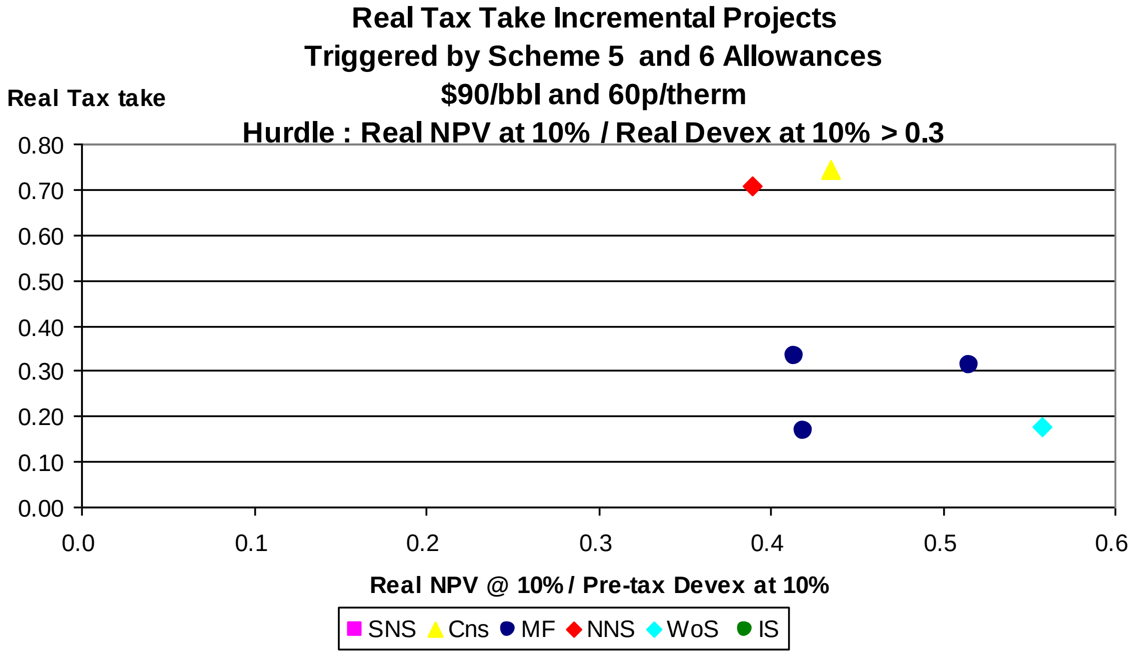


Chart 125



4. **Under the $90, 60 pence price** 36 incremental projects failed the NPV/I > 0.5 hurdle in the CT only case. Under **Scheme 1** with SC at 20% 47 failed the hurdle. Under all the other schemes <u>excluding</u> the incremental allowance for **Schemes 5 and 6**, 58 projects failed the hurdle. When the allowance for incremental projects under **Schemes 5 and 6** was <u>included</u> the resulting tax takes for all the projects were as shown in Chart 126. While most projects face rates of 62% or more there are some with lower rates. The allowance did trigger the development of some projects. The tax takes on these incentivised projects are shown in Chart 127.

Chart 126

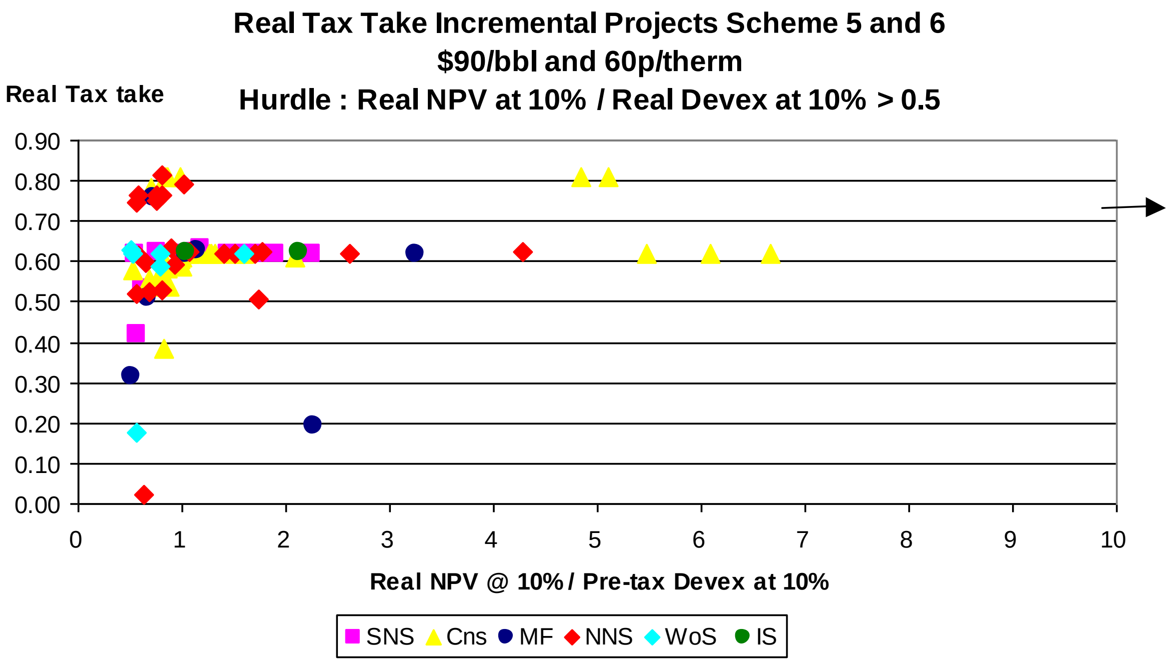
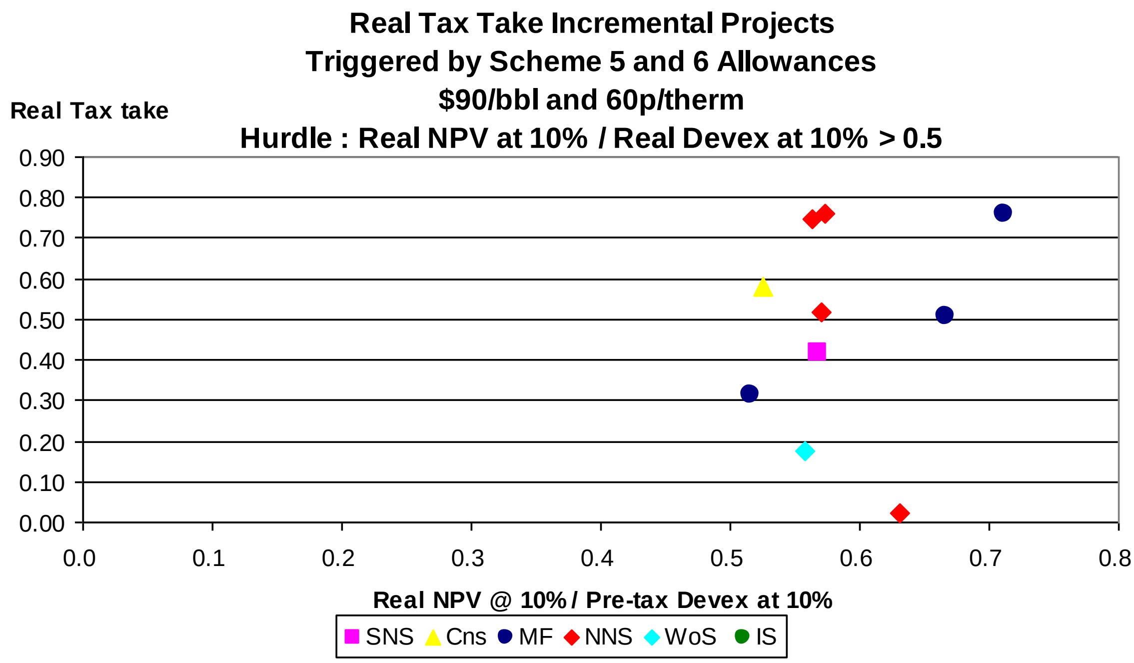


Chart 127



One explanation of the pattern of the results of the introduction of the allowance relates to the differing characteristics of the incremental projects and how they interact with the **Scheme 5** allowance. The projects vary considerably in their degree of capital intensity. The allowance is geared to development costs per boe, and in some cases project profitability is not high because the operating costs per boe are high. The incentive does not target such projects to the same extent as very capital intensive ones.

5. Conclusions.

In this study the short and long term consequences of various changes to the UK petroleum taxation system have been examined. No less than nine possible tax arrangements were subjected to detailed economic modelling. Emphasis was put on variations to the Supplementary Charge (SC), including not only a rate change but various field allowances including those in force in 2011, those proposed in Budget 2012 and other schemes involving sliding scale allowances related to the development costs per boe of reserves, where the size of the allowance increases with the unit development costs but reaches a ceiling designed to prevent subsidies to non-economic projects.

The modelling of the tax systems highlighted their consequences for (a) the pace of field developments, (b) production, (c) investment and operating expenditures, (d) tax revenues, and (e) effective tax rates. The economic modelling was undertaken over a 30-year period. Two price scenarios were employed namely (1) $70 and 40 pence and (2) $90 and 60 pence, both in constant real terms and thus increasing yearly by the inflation rate of 2.5%. These scenarios are designed to reflect screening prices for long term projects likely to be used by investors and their financiers. They are not estimates of market values. Two investment hurdles were employed with each price scenario. These are (a) Post-tax NPV at 10%/ Pre-tax Investment at 10% > 0.3, and (b) NPV/I > 0.5. These are designed to reflect some capital rationing either self-imposed or imposed by external factors such as capital market conditions. Currently small companies are finding some difficulties in raising either debt or equity finance.

The modelling compared the nine possible schemes with the corporation tax (CT) only situation under the headings noted above. Generally activity levels as measured by the volume of investment and production over the long term were higher with the CT only situation. Only occasionally did a scheme enhance activity above that level. This was where the value of the investment relief was high in relation to the subsequent rate of tax payable on the new field's production.

The modelling also found that investment and production incentives were reasonably well preserved by the scheme which related the value of the allowance (or tax credit) to the unit development costs per boe with a cap to prevent clear subsidies and a floor of zero to ensure that low-cost fields were not given the allowance. This scheme also performed reasonably well because it directly acknowledged the problem of the much lower value of gas compared to oil.

The system in place at Budget 2012 also performed reasonably well in preserving investment incentives and production. The allowances were found to have a substantial effect in enhancing investment and production levels above those which would have prevailed in the absence of the field allowances. It was found that a system of SC at 32% with no field allowances would have had a catastrophic long-term negative effect on investment and production. Further, there were found to be significant extra benefits in terms of activity levels from the increase in these allowances from those in place in 2011 to those proposed in Budget 2012.

With respect to the effects on tax revenues it was found that over the long term the schemes with an allowance based on development costs per boe and that incorporated in Budget 2012 performed well in the sense of collecting large extra revenues to the Exchequer. These schemes achieve this through a combination of incentivising new developments and taxing more profitable fields at the 62% rate. From the viewpoint of extra tax revenues the scheme with the lower SC rate of 20% (without field allowances) does not perform so well even though it does incentivise more developments.

Closer examination of the operation of the various schemes was undertaken by calculating the percentage tax takes and relating these to the profitability of the field in question. It was found that, while the scheme incorporated in Budget 2012 facilitated the development of fields which were non-viable in the absence of the allowances, some other fields which already passed the hurdle were also helped. The result is that the effective tax rates can hardly be said to be progressively related to profitability. Another finding was that in a few cases where the field income was small the effect of the field allowance combined with the relief for the investment costs at 62% was to produce a low effective tax rate.

The system which related the size of the tax allowance (credit) to investment costs per boe clearly does help in a progressive manner though the effective rates of tax were not always progressively related to overall field profitability. One reason for this outcome is the varying degree of capital intensity of the new fields and projects. The allowance highlights the investment or capital costs but does not deal with variations in operating costs. A virtue of the scheme based on investment costs per boe (with a cap) is that it can ensure that very low tax rates are normally not produced. From this viewpoint this scheme performed more efficiently than that in Budget 2012.

It is clear from the study that incremental projects in mature fields can be deterred by the current tax system. The modelling found that in the cases with CT only and with SC at 20% considerably more incremental projects were viable compared to the situation with SC at 32% but without special allowances for these projects.

The scheme with the sliding-scale allowance related to investment costs per boe contains such an allowance for incremental projects. It was found that this scheme incentivised a worthwhile number of incremental projects. The modelling considered only those incremental projects likely to come to fruition over the next 3 years. Further projects are likely to become available in the longer term and, if these had been included, the effects of such an allowance on investment and production would have been stronger. There is a clear case for an incentive scheme for incremental projects in the UKCS, particularly in PRT-paying fields where the tax rate is now 81%.

The sliding-scale scheme related to investment costs per boe represents an attempt to employ only economic elements in the design of an efficient tax system. This is to be commended. The route chosen by the UK Government is to employ physical factors as proxies for costs. In defence of this it can be said that the result in Budget 2012 is a scheme which both incentivises new developments and procures worthwhile revenues from new developments. But the allowance system has already become very complex and it is inevitable that some economically marginal projects will not qualify for relief because they do not quite fit the physical definitions in the legislation. Thus a quasi-permanent, time-consuming negotiation may well ensue with a multiplication of qualifying criteria.

This study has only examined tax arrangements either reflecting recent and current practice or variations being examined with the industry. No other schemes have been discussed. But an alternative scheme based on the resource rent tax concept deserves further consideration. The concept is already well-established for investors not in a tax-paying position and could be adapted to handle situations where the investor is already in a tax-paying position.

Appendix

Tax System for New Fields

CT at 30%

SC at 32% (from 2011)

All E and A and D costs deductible on 100% first year basis

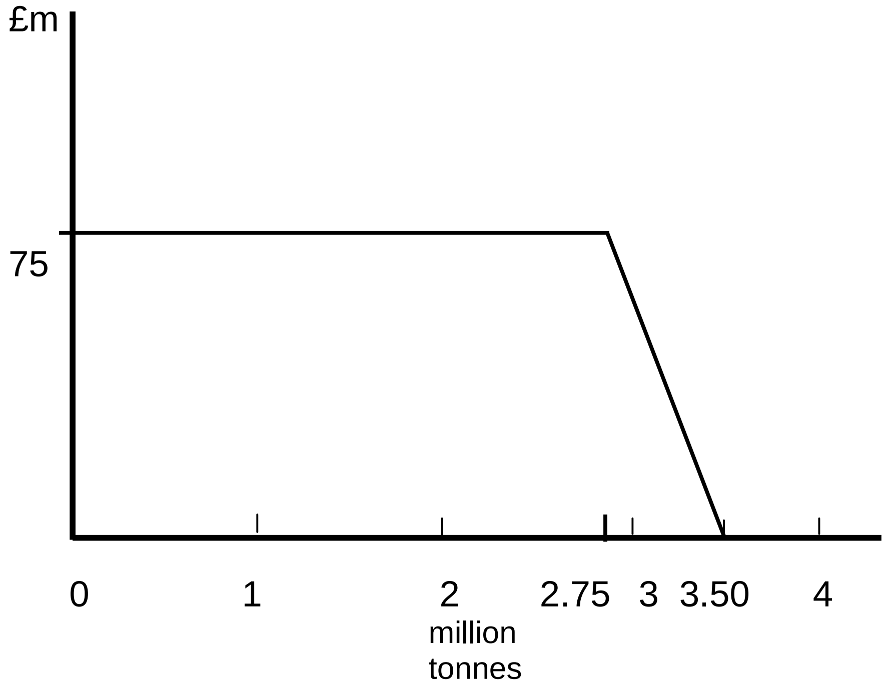
Budget 2009 introduced:

Value Allowance for Supplementary Charge

Budget 2009

- The field allowance for small fields is £75 million for fields with oil reserves (or gas equivalent) of 2.75 million tonnes or less, reducing on a straight line basis to nil for fields over 3.5 million tonnes. In any one year the maximum field allowance (for a field with total allowance of £75 million) is £15 million.

Value Allowance for Small Fields



- The field allowance for ultra heavy oil fields is £800 million for fields with an American Petroleum Institute gravity below 18 degrees and a viscosity of more than 50 centipoise at reservoir temperature and pressure. In any one year the maximum field allowance is £160 million.
- The field allowance for ultra high temperature/pressure fields is £800 million for fields with a temperature of more than 176.67 degrees Celsius and pressure of more than 1034 bar in the reservoir formation. In any one year the maximum field allowance is £160 million.

<u>PBR 2009</u>

- In PBR 2009 qualifying criteria for HP/HT fields modified to 166°C and 862 bar. Allowance increases on SL basis from £500m. at 166°C to £800m. at 176.6°C.
- In January 2010 field allowance of up to £80m. (max. £160m. in any 1 year) extended to remote, deep-water gas fields.
- Qualifying criteria:

  (a) gas more than 75% of reserves

  (b) field located in water depth > 300 metres

  (c) distance from field to relevant infrastructure > 60 km. Allowance increases linearly from £0 at 60k. to £800m. at 120 km.

Budget 2011

SC increased from 20% to 32%

	Tax Rates	
	Pre Budget	Post Budget
PRT fields	75%	81%
Non-PRT fields	50%	62%

	Decommissioning Relief	
	Pre Budget	Post Budget
PRT fields	75%	69%/75%
Non-PRT fields	50%	50%

July 2011

Increase in Ring Fence Expenditure Supplement from 6% to 10%.

Budget 2012

1. Field allowances to be extended to fields already developed (incremental projects).
2. Small field allowance increased from total of £75m. to £150m. and size of qualifying fields increased from 2.75m. tonnes or less to 6.25m. tonnes or less. The extended allowance is tapered to zero at 7m. tonnes (compared to 3.5m. tonnes now).
3. New £3bn. field allowance for new fields with qualifying criteria.
   (a) Water depth > 1000 metres
   (b) Minimum reserves of 25m. tonnes
   (c) Maximum reserves of 40m. tonnes with taper to £0 at 55m. tonnes
4. The Government will introduce legislation in Finance Bill 2013 giving it statutory authority to sign contracts with companies

operating in the UK an UK Continental Shelf, to provide assurance on the relief they will receive when decommissioning assets. The Government will consult further on the precise form and details of such contracts in the coming months.