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The Prospects for Activity in the UKCS to 2035: the 2008 Perspective

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Linda Stephen

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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 is also financed by a grant from the Natural Environmental Research Council (NERC).

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The Prospects for Activity in the UKCS to 2035: the 2008 Perspective

Professor Alexander G. Kemp and
Linda Stephen

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The Prospects for Activity in the UKCS to 2035: the 2008 Perspective

Professor Alex Kemp
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Linda Stephen

1. Introduction

The prospects for activity levels in the UK Continental Shelf (UKCS) are a function of several factors including prospectivity (size of field and expected success rate), costs of exploration, appraisal and development, oil and gas prices, the availability and cost of access to infrastructure, technological progress, and the tax régime applied to the various activities. This study incorporates all these factors in the modelling of prospective activity to 2035.

2. Methodology and Assumptions

The projections of production and expenditures have been made through the use of financial simulation modelling, including the use of the Monte Carlo technique, informed by a large, recently-updated, field database validated by the relevant operators. The field database incorporates key, best estimate information on production, and investment, operating and decommissioning expenditures. These refer to over 300 sanctioned fields, 131 incremental projects relating to these fields, 35 probable fields, and 16 possible fields. All these are as yet unsanctioned but are currently being examined for development. An additional database contains 234 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas) and block location are available for these. They are not currently being examined for development by licensees.

Monte Carlo modelling was employed to estimate the possible numbers of new discoveries in the period to 2030. The modelling incorporated assumptions based on recent trends relating to exploration effort, success rates, sizes, and types (oil, gas, condensate) of discovery. A moving average of the behaviour of these variables over the past 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 Scotland (WOS), and Irish Sea (IS)), and the results employed for use in the Monte Carlo analysis. Because of the very limited data for WOS and IS over the period judgemental assumptions on success rates and average sizes of discoveries were made for the modelling.

It is postulated that the exploration effort depends substantially on a combination of (a) the expected success rate, (b) the likely size of discovery, and (c) oil/gas prices. In the present study 3 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	80	70
Medium	60	50
Low	40	30

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

The postulated numbers of annual exploration wells drilled for the whole of the UKCS are as follows for 2008 and 2030:

Table 2 Exploration Wells Drilled		
	2008	2030
High	45	35
Medium	40	32
Low	30	22

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

It is postulated that success rates depend substantially on a combination of (a) recent experience, and (b) size of the effort. It is further suggested that higher effort is associated with more discoveries but with lower success rates compared to reduced levels of effort. This reflects the view that low levels of effort will be concentrated on the lowest risk prospects, and thus that higher effort involves the acceptance of higher risk. For the UKCS as a whole 3 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	= 25.5%
High effort/Low success rate	= 24%
Low effort/High 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 success rates 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. Such decline rates are quite modest.

Table 4 Mean Discovery Size MMboe	
SNS	9
CNS	25
NNS	25
MF	20
WoS	81
IS	5

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

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

Table 5 Total Number of Discoveries to 2030	
High effort/Low success rate	245
Medium Effort/Medium Success Rate	238
Low effort/High success rate	185

For each region the average development costs (per boe) of fields in the probable and possible categories were calculated. These reflect substantial cost inflation over the last few years. Using these as the mean values the Monte Carlo technique was employed to calculate the development costs of new discoveries. A normal distribution with a SD = 20% of the mean value was employed. For the whole of the UKCS the average development costs on this basis were nearly $14/boe with quite a wide variation. Investment costs for 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. Thus in the SNS development costs were found to average nearly $14 per boe because of the small size of field. In the NNS they averaged $16/boe. Operating costs over the lifetime of the fields were also calculated, as were the decommissioning costs. Total lifetime field costs (excluding E and A costs) were found to average nearly $25 per boe for the whole of the UKCS, and averaged over $21 per boe in the SNS, nearly $25 per boe in the CNS, and $29 per boe in the NNS.

For new discoveries annual operating costs were modelled as a percentage of accumulated development costs. This percentage varied according to field size. It was taken to increase as the size of the field was reduced reflecting the presence of economies of scale in the exploitation costs. 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 have remained undeveloped for a long time, 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 $17/boe and in NNS $21/boe. For purposes of Monte Carlo modelling a normal distribution of the recoverable reserves for each field with a SD = 50% of the mean was assumed. With respect to development costs the distribution was assumed to be normal with a SD = 20% of the mean value.

The annual numbers of new field developments were assumed to be constrained by the physical and financial capacity of the industry. This subject is currently very pertinent in the UKCS. The ceilings were assumed to be linked to the oil/gas scenarios with maxima of 20, 17, and 13 respectively under the High, Medium, and Low Price Cases. These constraints do not apply to incremental projects which are additional to new field developments.

A noteworthy feature of the 131 incremental projects in the database validated by operators is the expectation that the great majority will be executed over the next 3 or 4 years. It is virtually certain that in the medium and longer-term many further incremental projects will be designed and executed. They are just not yet at the serious planning stage. Such projects can be expected not only linked to currently sanctioned fields, but also to those presently classified as in the categories of probable, possible, technical reserves, and future discoveries.

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

The financial modelling incorporated a discount rate, field economic cut-off, and the full details of the current petroleum tax system. No allowance was made for the prospect that from 2013 onwards investors may have to purchase CO_2 allowances to cover their emissions from producing installations. This will form the subject of a forthcoming paper. The base case emphasised has a post-tax discount rate of 10% in real terms. An important assumption is that adequate infrastructure will be available to facilitate the development of the future projects. It is also assumed that investment decisions are made on the basis of the oil/gas prices indicated. Investors have expressed concern abut the materiality of projects in the UKCS compared to opportunities elsewhere in the world, and, to reflect these, the investment criterion used to reflect the relationships between the risks, rewards, and capital allocations was a minimum NPV/I ratio of 0.3. The NPV was expressed in post-tax terms and I in pre-tax terms to reflect the manner in which capital is allocated by investors (rather than the textbook approach which has both NPV and I on a post-tax basis). Reflecting the increase in capital costs in recent times summary cases of higher investment hurdle rates are also examined. It should be emphasised that field developments have to pass the economic hurdle and their number is also constrained by the cap reflecting the perceived physical and financial capacity of the industry.

Over the past years it has been found that the phasing of the development of new fields and projects as proposed by operators has often been overambitious.

Accordingly, in the modelling the timing of their development has been rephased (slipped) in accordance with the stated probability of the investments proceeding. Another noteworthy feature of experience in recent years has been production from sanctioned fields running below planned levels, generally reflecting technical problems. To take account of this prospect another case where the production from recently sanctioned fields is 15% below planned levels for the first few years of field life, with corresponding later increases, was also executed. This is termed the Slowed Production case in the results below.

3. Results

A. Production

(i) Standard Depletion Case - $40,30p prices

Oil and gas production to 2035 under the Standard Case assumptions are shown in Charts 1-5 under the $40,30p price assumptions. The decline rates are quite fast. Thus oil production falls to 1.26 mmb/d in 2010, 0.6 mmb/d in 2020, and less than 0.2 mmb/d in 2030. It is seen that the decline rate in sanctioned oil production is extremely fast over the next few years. Fortunately output from anticipated incremental projects becomes quite substantial over the next few years producing a noteworthy modification to the decline rate. Other features of the results are the modesty of the contributions from the probable and possible fields reflecting their small average sizes. Under the $40,30p scenario the fields in the technical reserves category are generally uneconomic. Future incremental projects form an important element of total production in the longer term. It is noteworthy that some new discoveries are economic and make a significant contribution to production in the longer term.

Chart 1

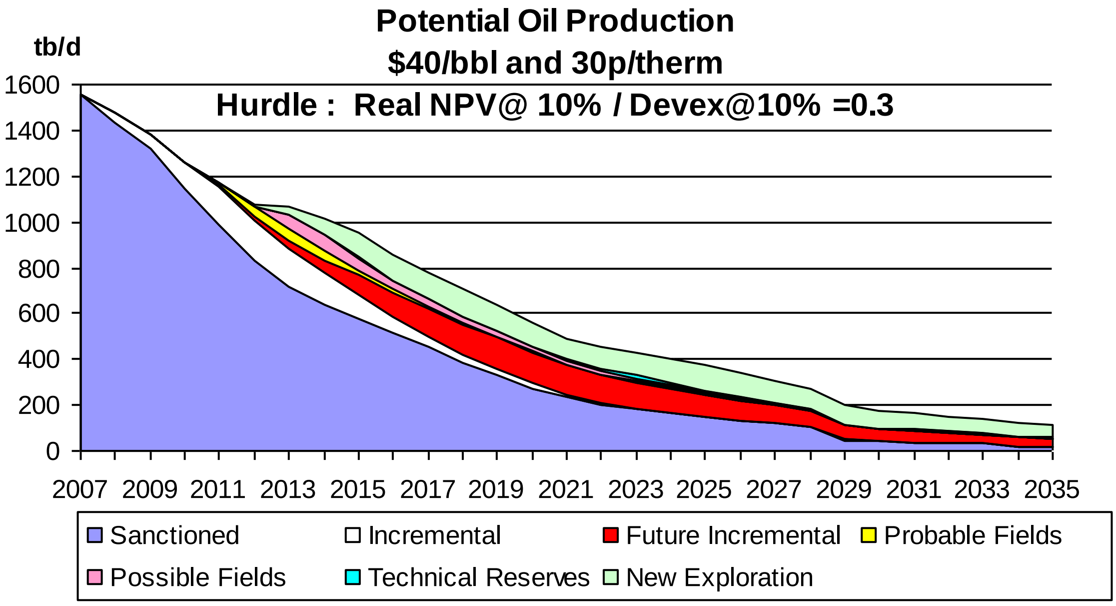


Chart 2

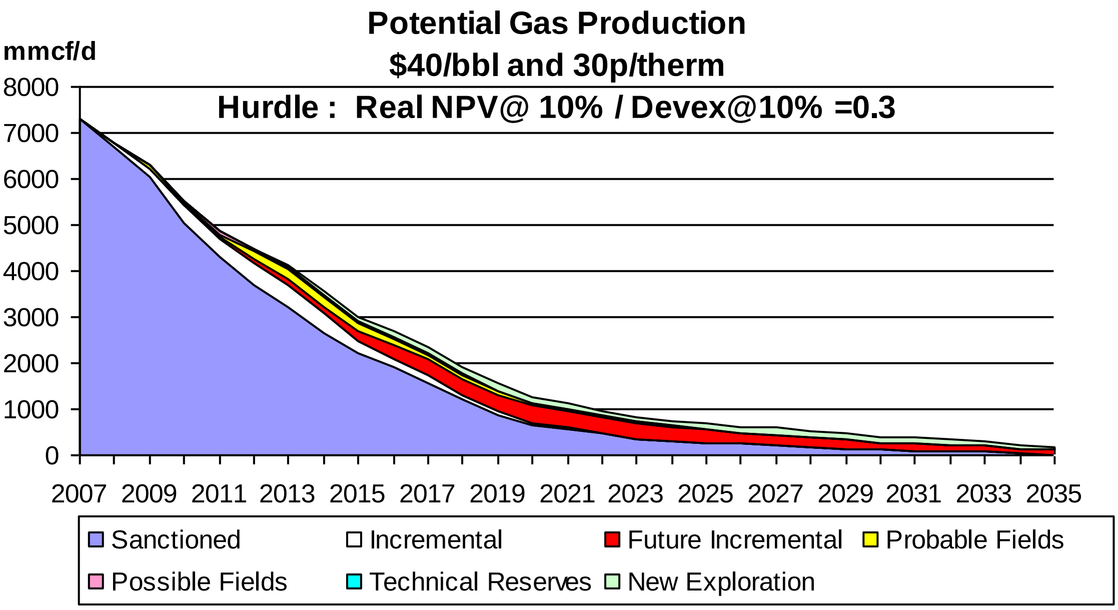


Chart 3

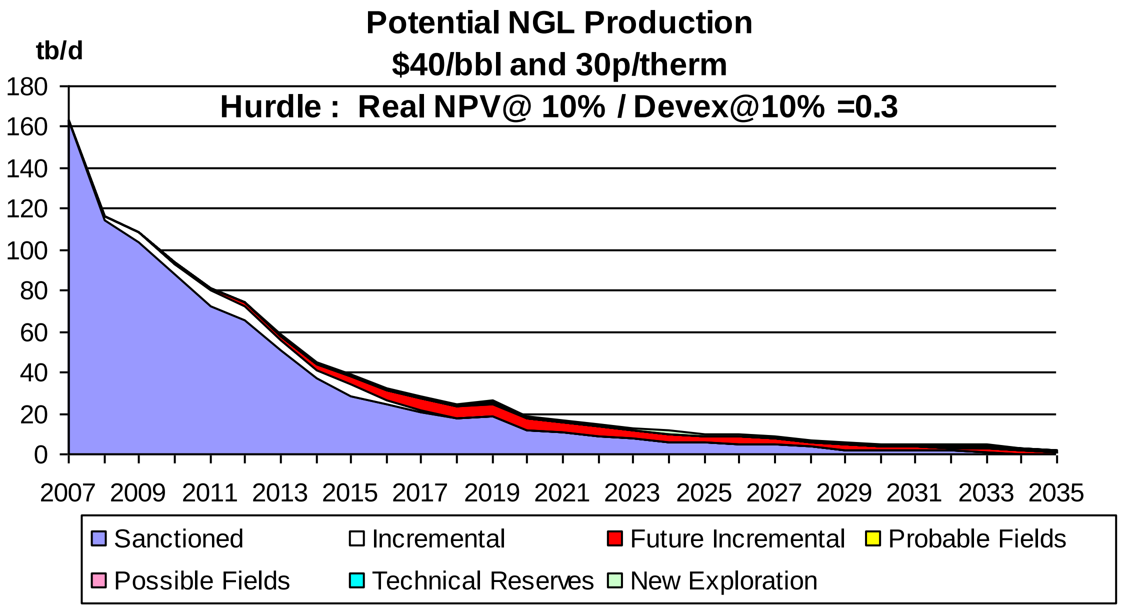


Chart 4

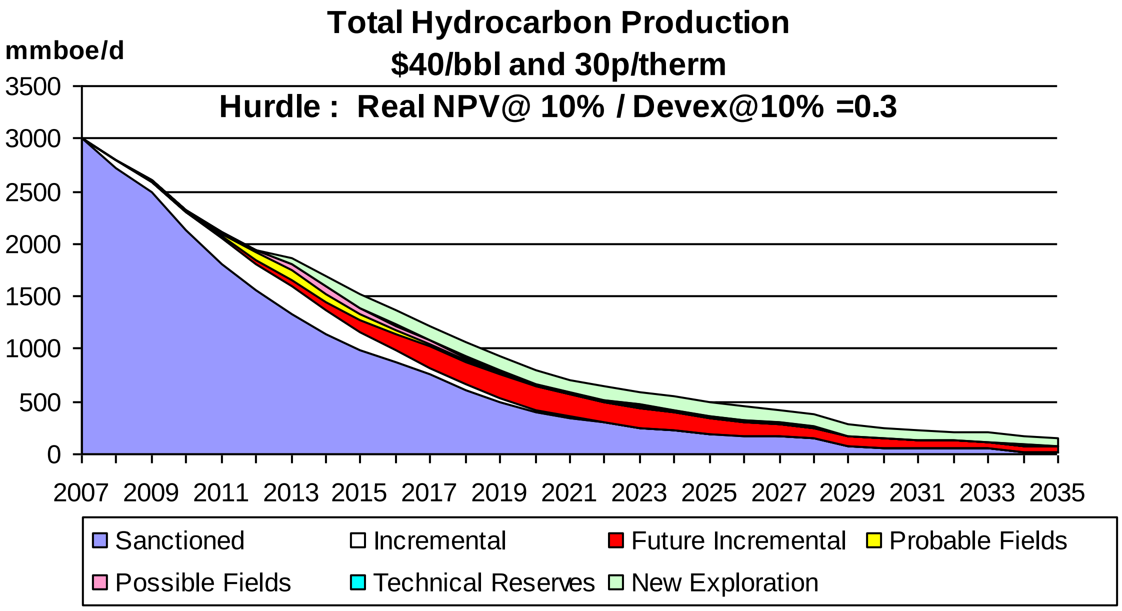
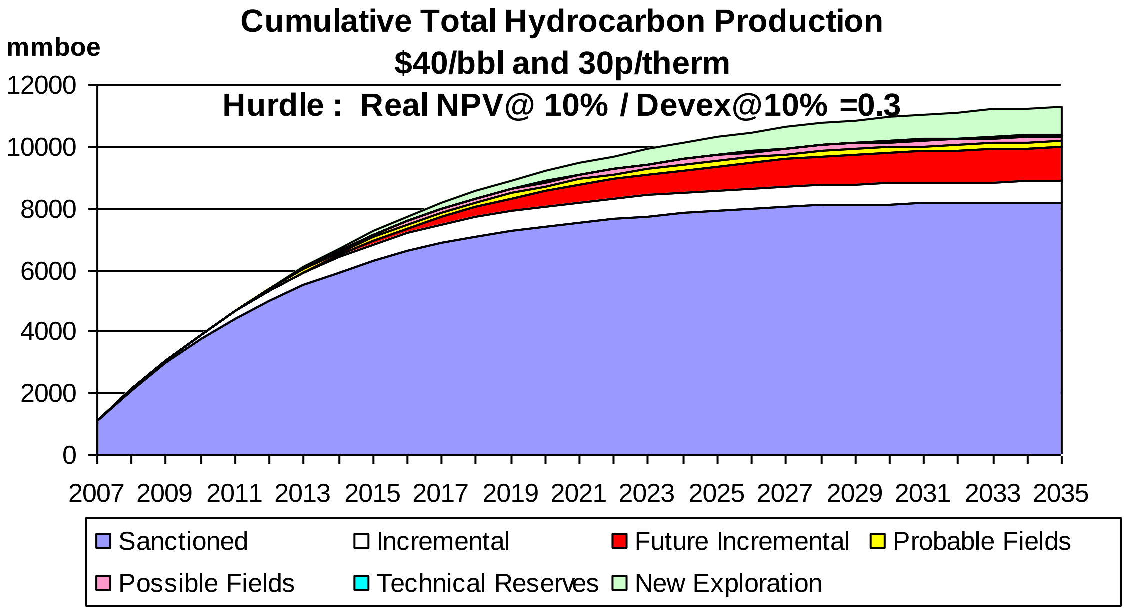


Chart 5



Cumulative Total Hydrocarbon Production
$40/bbl and 30p/therm
Hurdle : Real NPV@ 10% / Devex@10% =0.3
mmboe
12000
10000
8000
6000
4000
2000
0
2007 2009 2011 2013 2015 2017 2019 2021 2023 2025 2027 2029 2031 2033 2035
Sanctioned
Incremental
Future Incremental
Probable Fields
Possible Fields
Technical Reserves
New Exploration

Gas production falls more steeply than oil under the low price case. As with oil, production from the sanctioned fields falls quite steeply and currently anticipated incremental projects moderate the decline rate over the next few years to a worthwhile extent. Production from all the other categories of fields is very small over the whole period. Were it not for a worthwhile contribution from future incremental projects production would be negligible by the end of the period. The overall result is that total gas production falls to 5.5 bcf/d in 2010, 1.3 bcf/d in 2020, and 0.4 bcf/d in 2030.

The decline rate in production of NGLs (Chart 3) is seen to be very fast, reaching negligible levels in 2035.

The results of the above are that total hydrocarbon production (Chart 4) falls steeply to around 2.33 mmboe/d in 2010, 807 mboe/d in 2020, and 256 mboe/d in 2030. Cumulative production from the different categories to 2035 from a base of 2007 is shown in Chart 5. Sanctioned sources dominate the outcome, with incremental projects forming a high proportion of the rest. It is clear that under this price scenario and with existing cost levels new development activity is to a large extent uneconomic.

Chart 6

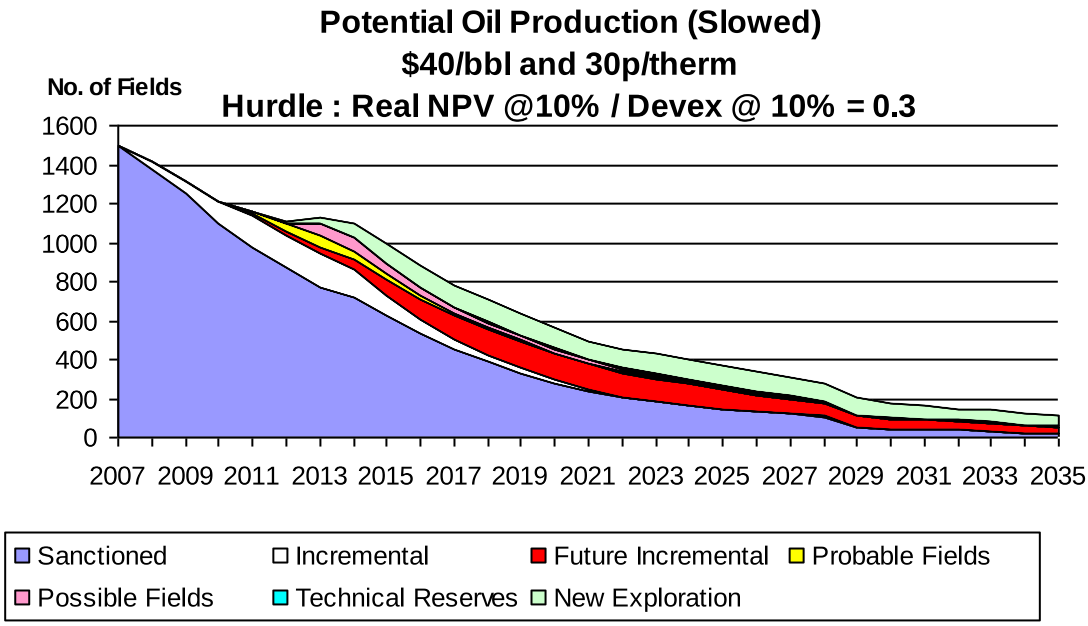


Chart 7

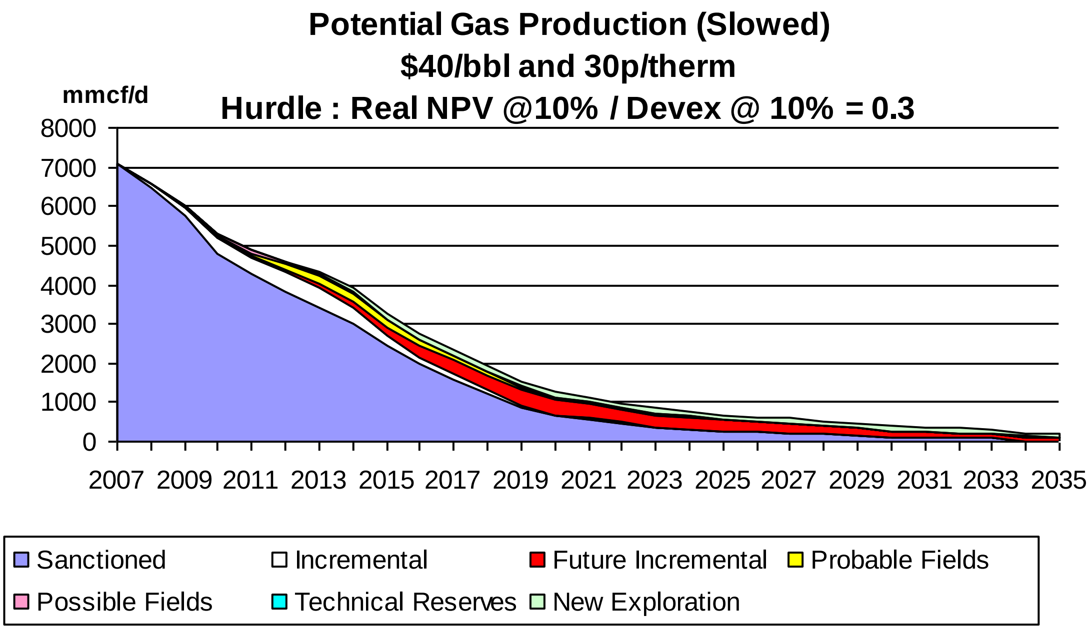


Chart 8

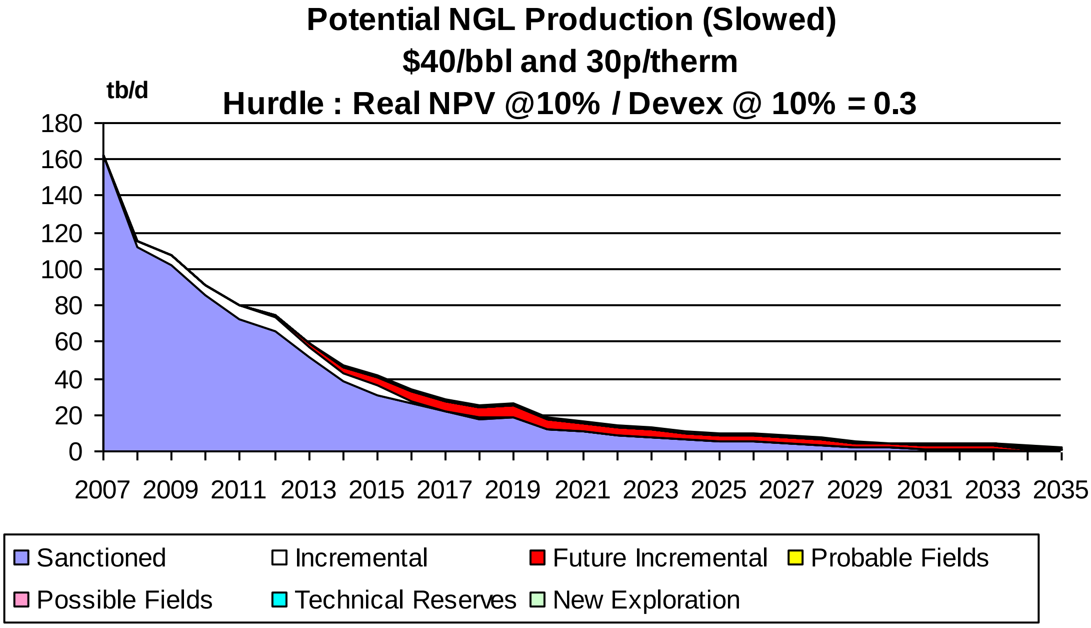


Chart 9

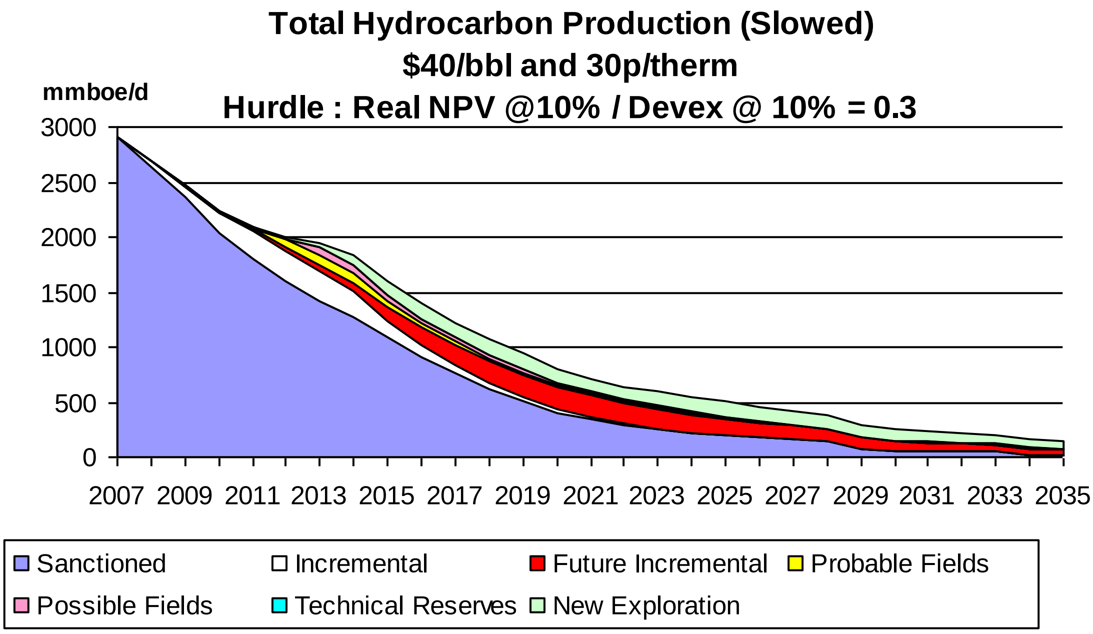
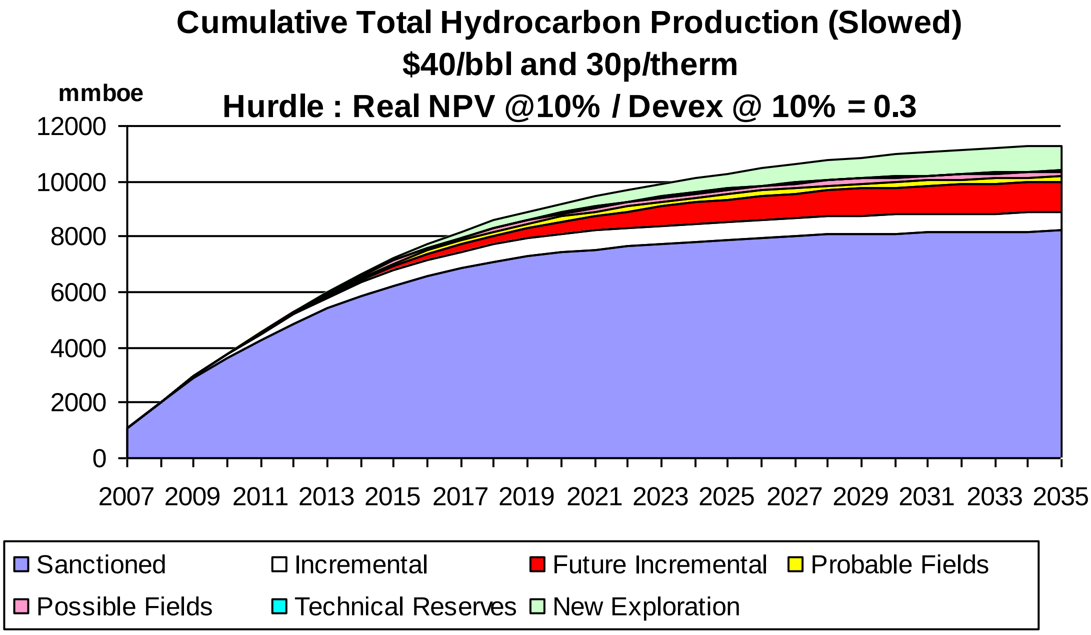


Chart 10



(ii) Slowed Depletion Case - $40,30p prices

The corresponding production profiles under the slowed depletion case assumptions are shown in Charts 6-10. There is a noteworthy reduction in output over the next few years compared to the standard case which is compensated by higher output in later years. Thus oil production in 2010 is 1.21 mmb/d compared to 1.26 mmb/d under the standard case, and gas production is 5.3 bcf/d compared to 5.5 bcf/d under the standard case. These results indicate the size of the risks inherent in the assumption that field development projects progress according to plan.

Chart 11

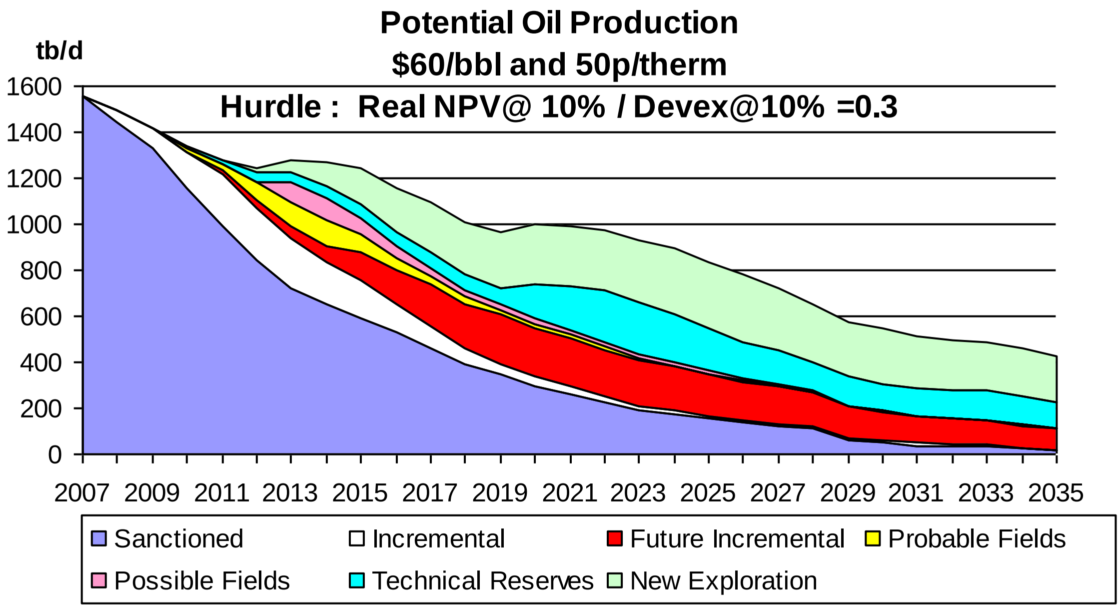


Chart 12

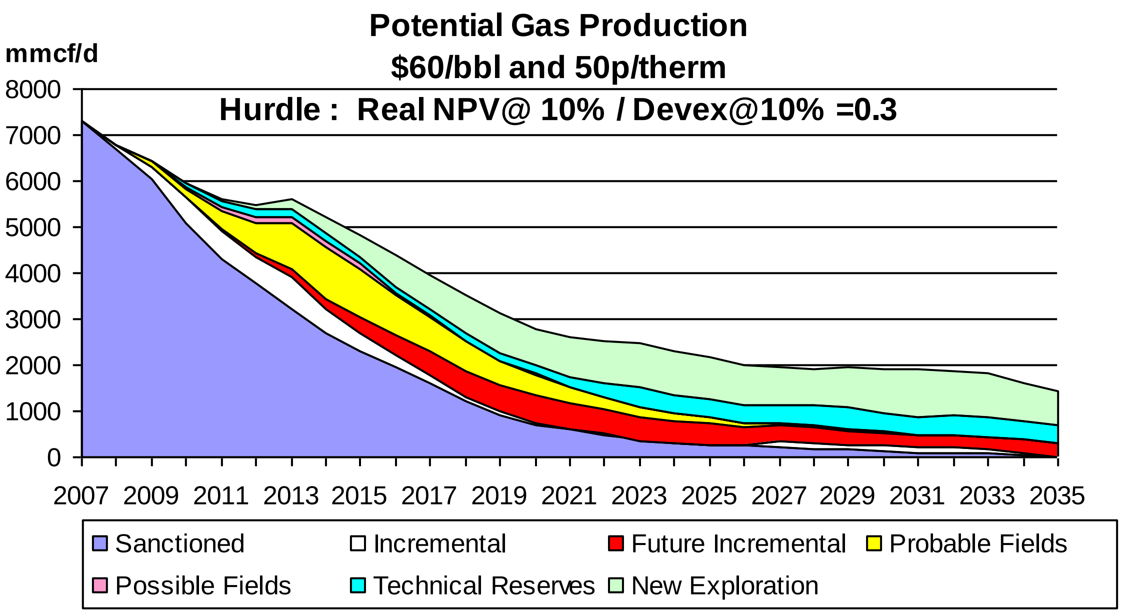


Chart 13

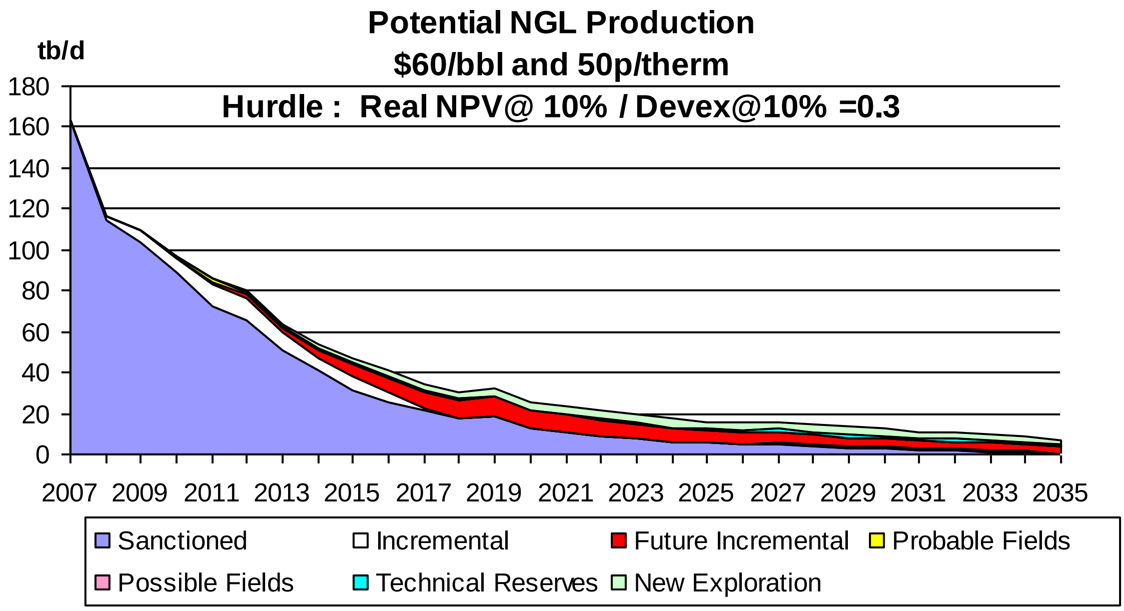


Chart 14

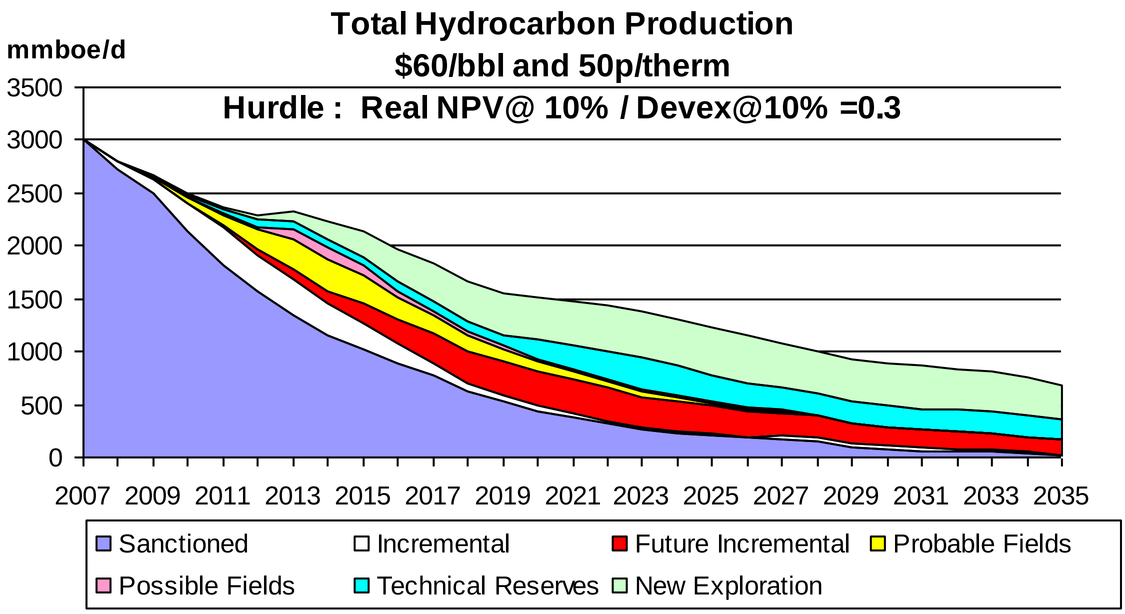
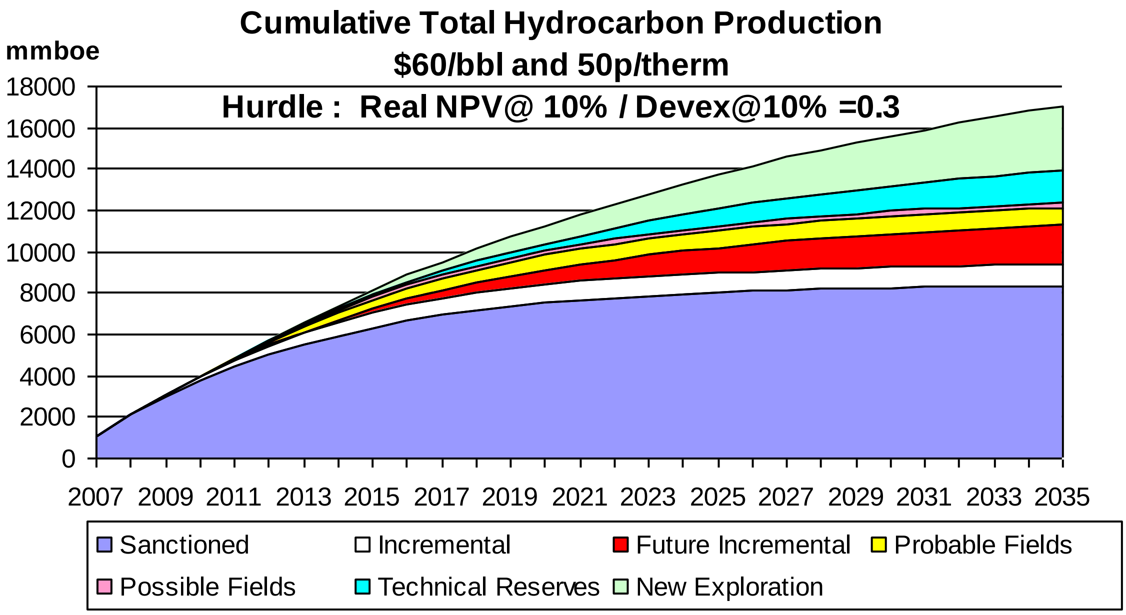


Chart 15



(iii) Standard Depletion Case - $60,50p prices

Production prospects in the standard case with price assumptions of $60 and 50p are shown in Charts 11-15 inclusive. There is a major increase compared to the low price case. Output in all categories of new fields and new projects is substantially higher reflecting the larger numbers which become viable. The increases are particularly noticeable with respect to future incremental projects, technical reserves and new discoveries. Oil production becomes 1.3 mmb/d in 2010, 1 mmb/d in 2020 and 525,000 b/d in 2030. The trend in gas production (Chart 12) exhibits a continued fast decline in the near term, but then a major moderation in the pace of decline, due principally to the development of significant reserves currently classified in the probable field category. The result is that total production is just below 6 bcf/d in 2010, 2.8 bcf/d in 2020, and 2 bcf/d in 2030.

Total hydrocarbon production (Chart 14) is 2.49 mmboe/d in 2010, 1.5 mmboe/d in 2020, and 0.9 mmboe/d in 2030. Compared to the low price case the contributions of fields in the new discoveries and technical reserves categories are notably higher than in the low price case. Over the period 2007 – 2035 total cumulative production is around 17 bnboe compared to only 11.3 bnboe under the low price case.

Chart 16

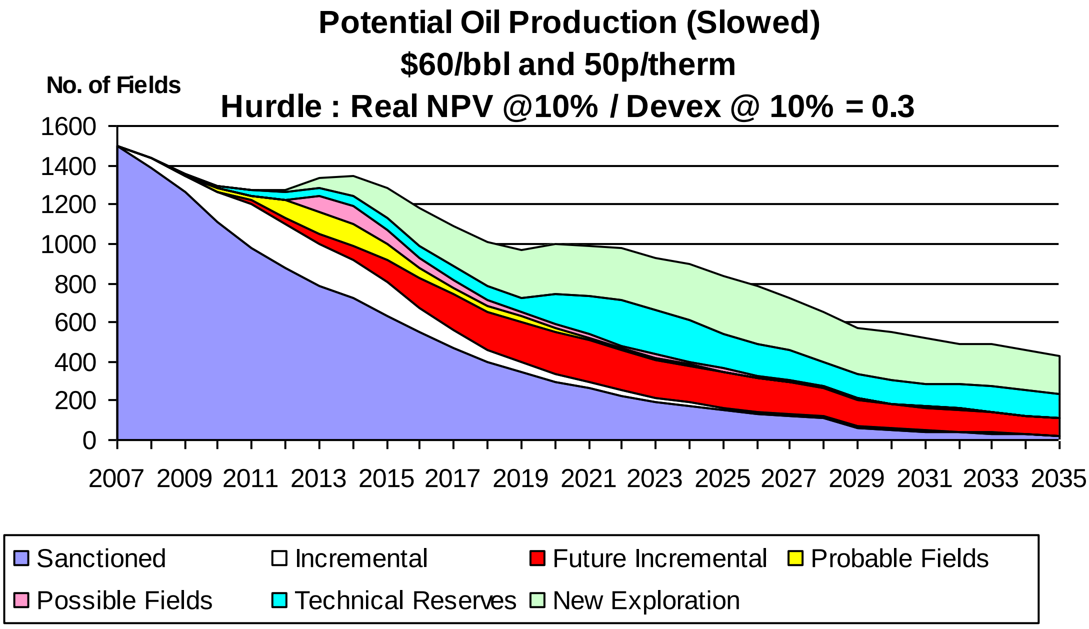


Chart 17

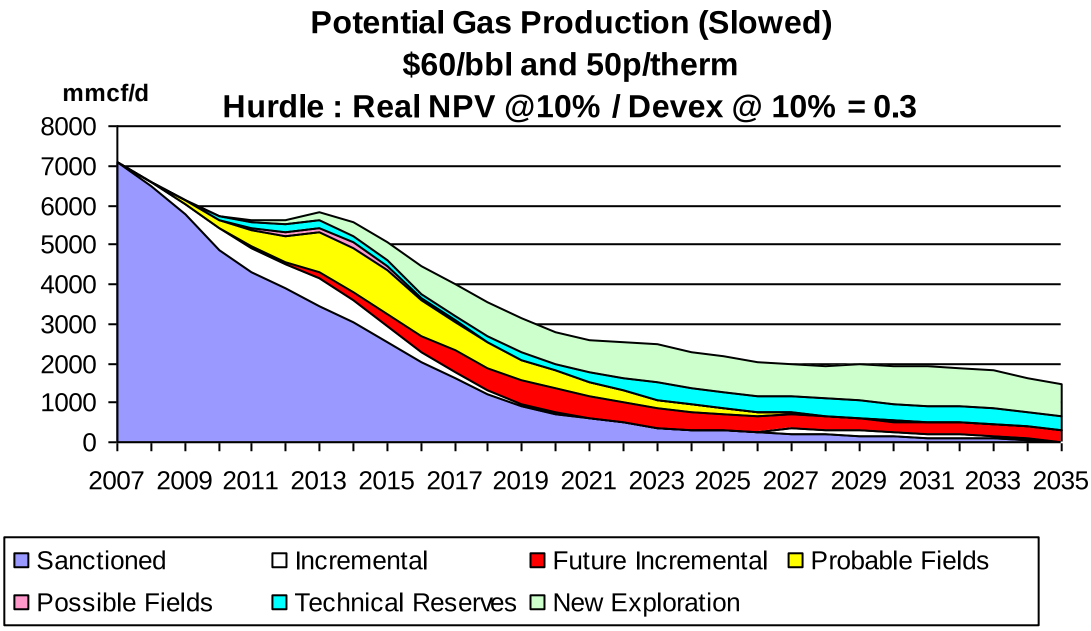


Chart 18

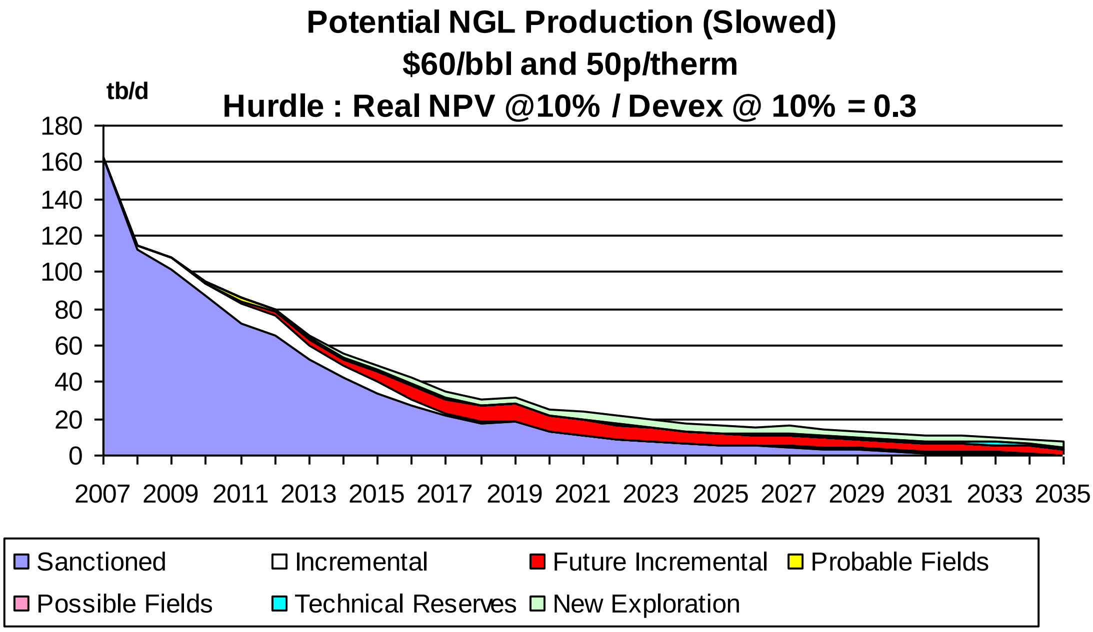


Chart 19

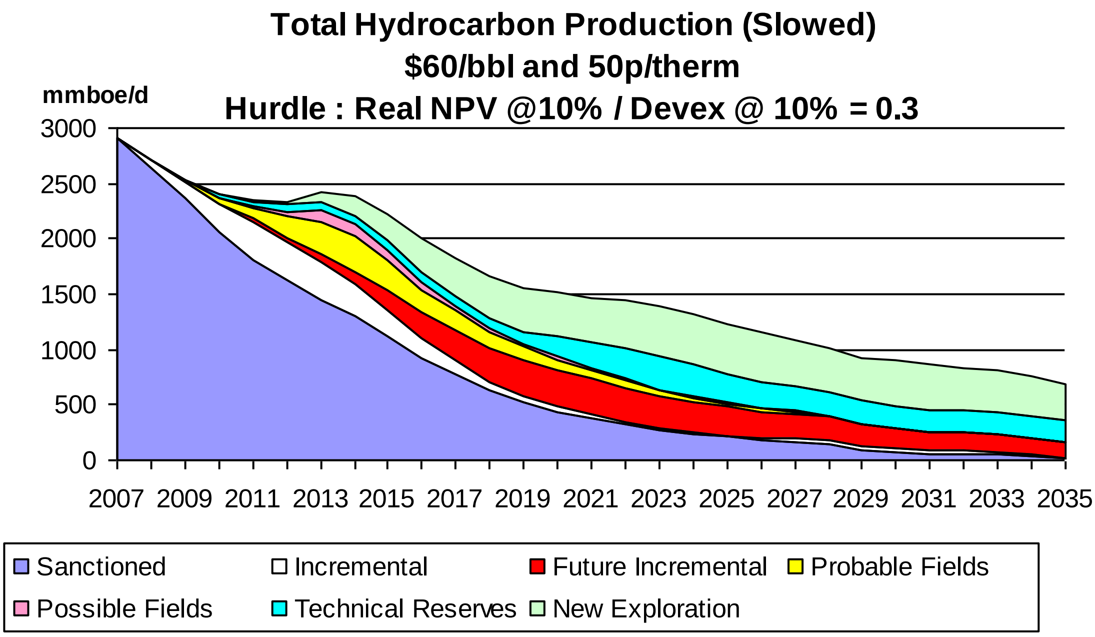
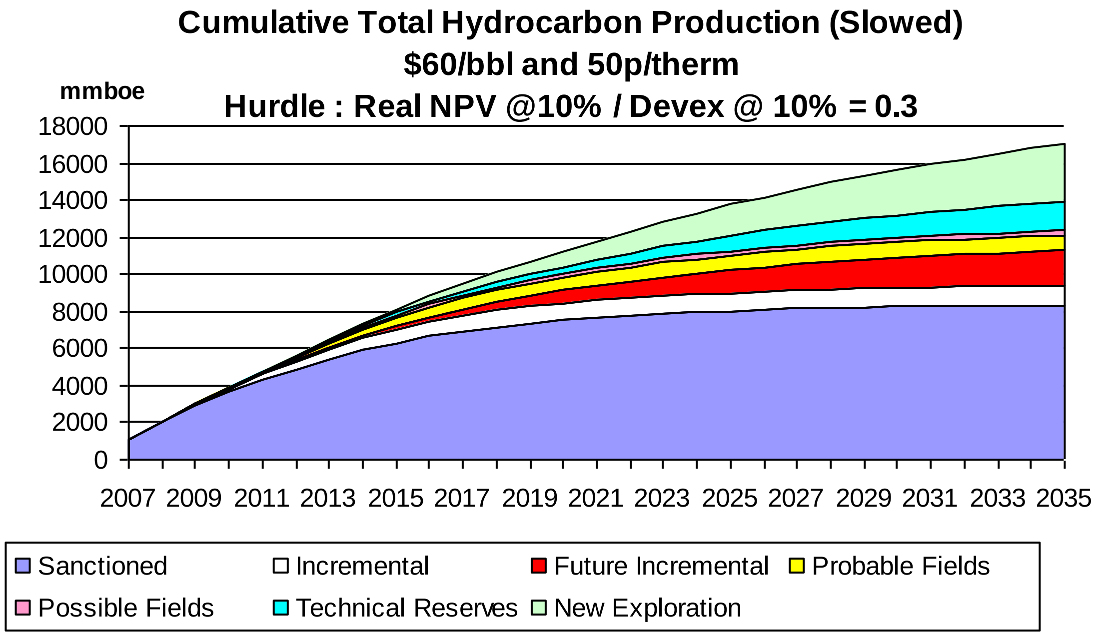


Chart 20



(iv) Slowed Depletion Case - $60,50p prices

The production prospects under the slowed production scenarios are shown in Charts 16-20. While near term output of both oil and gas falls at a brisk pace this is subsequently reversed for a few years. By 2035 there is little change in total cumulative depletion compared to the standard case.

Chart 21

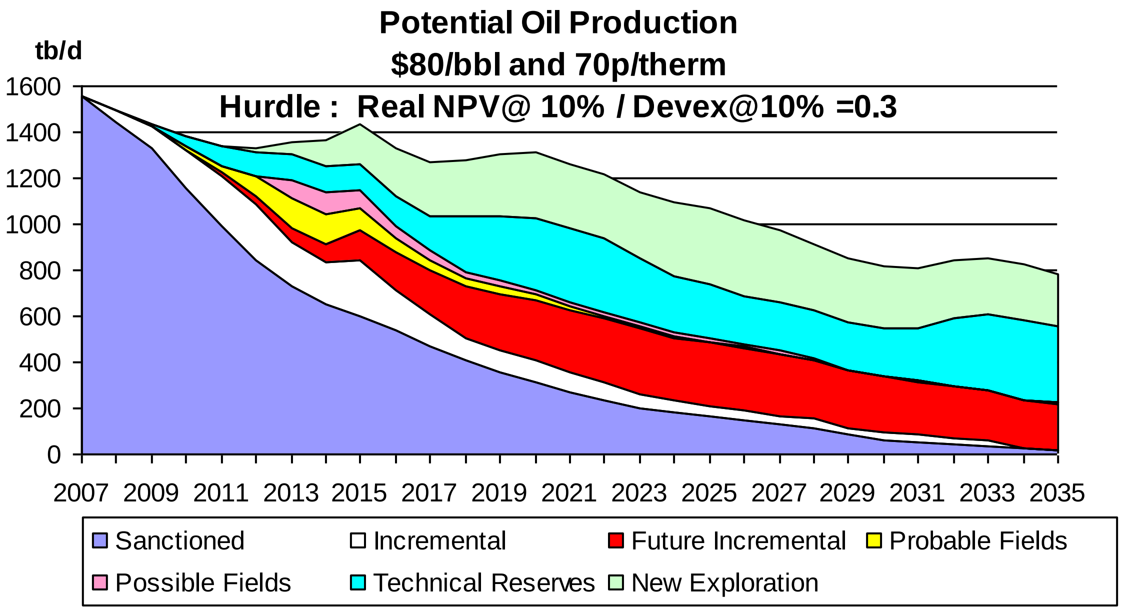


Chart 22

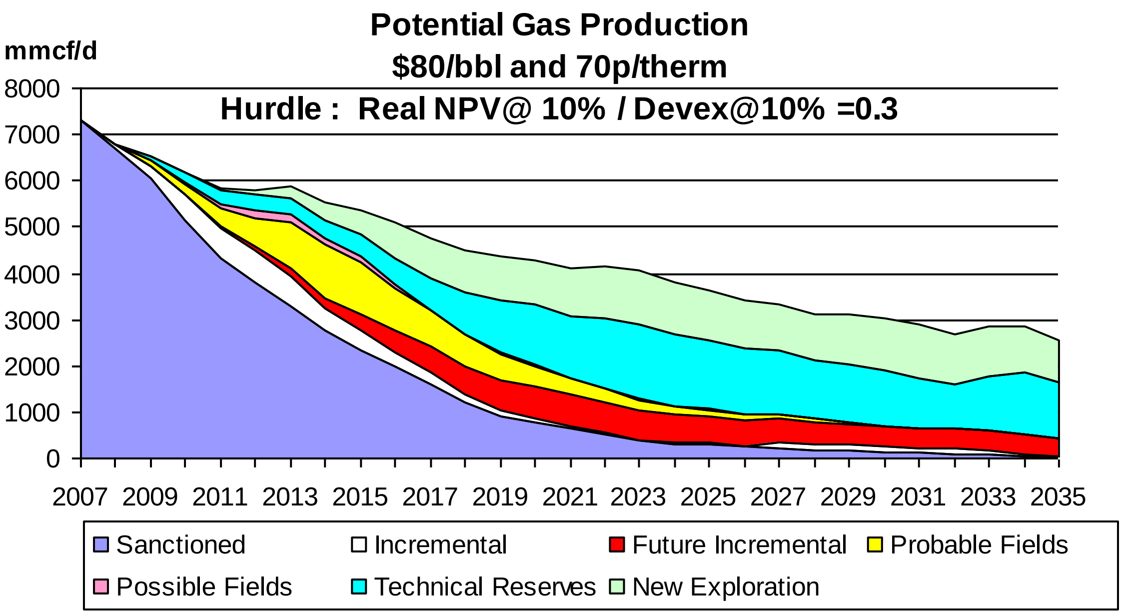


Chart 23

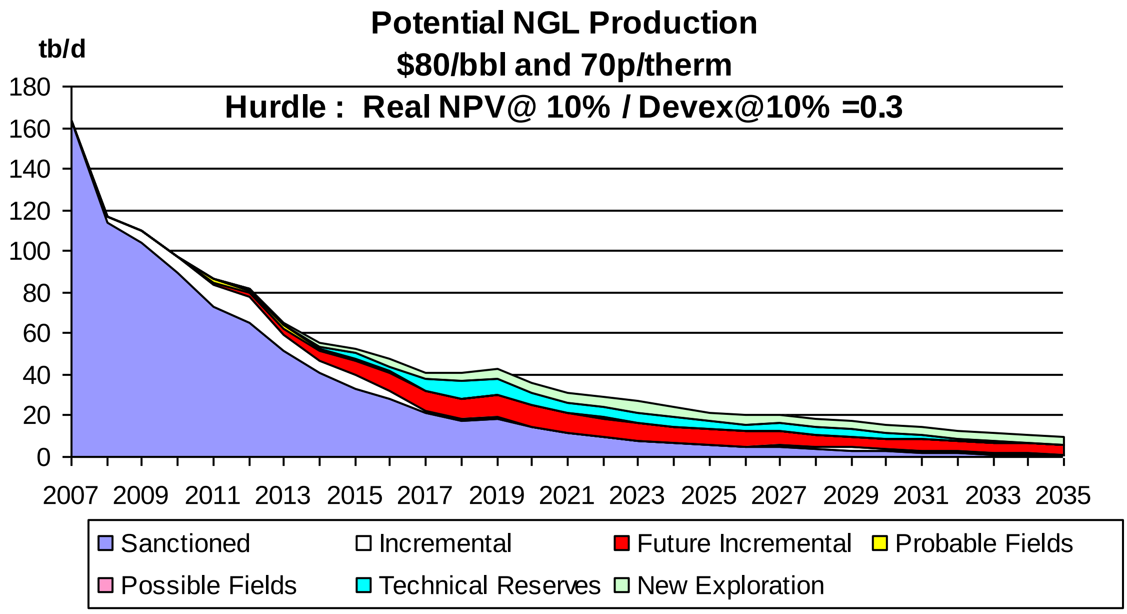


Chart 24

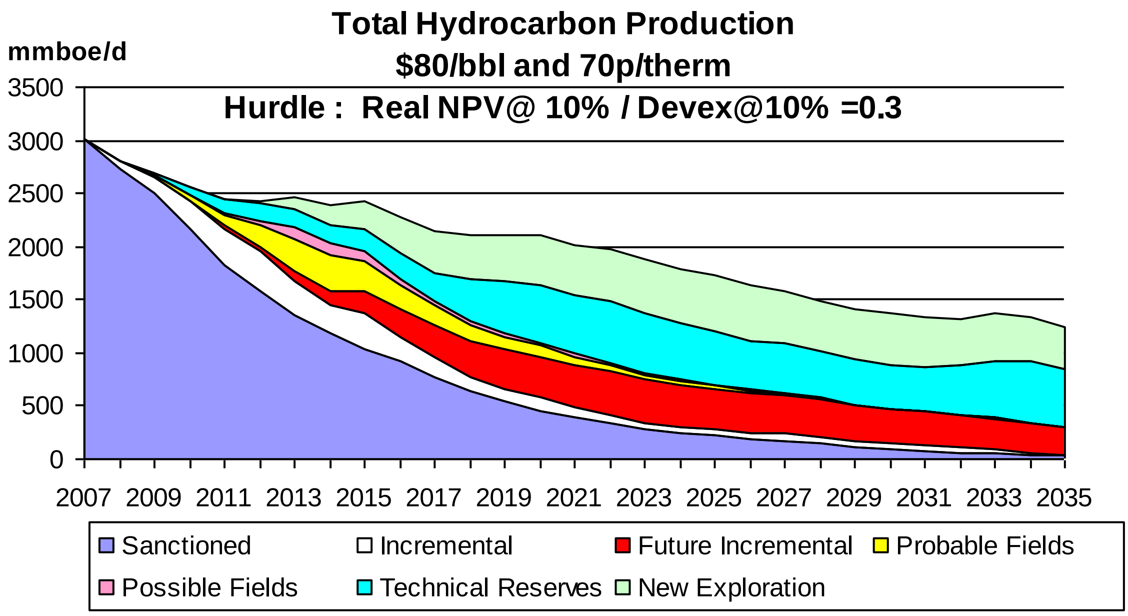
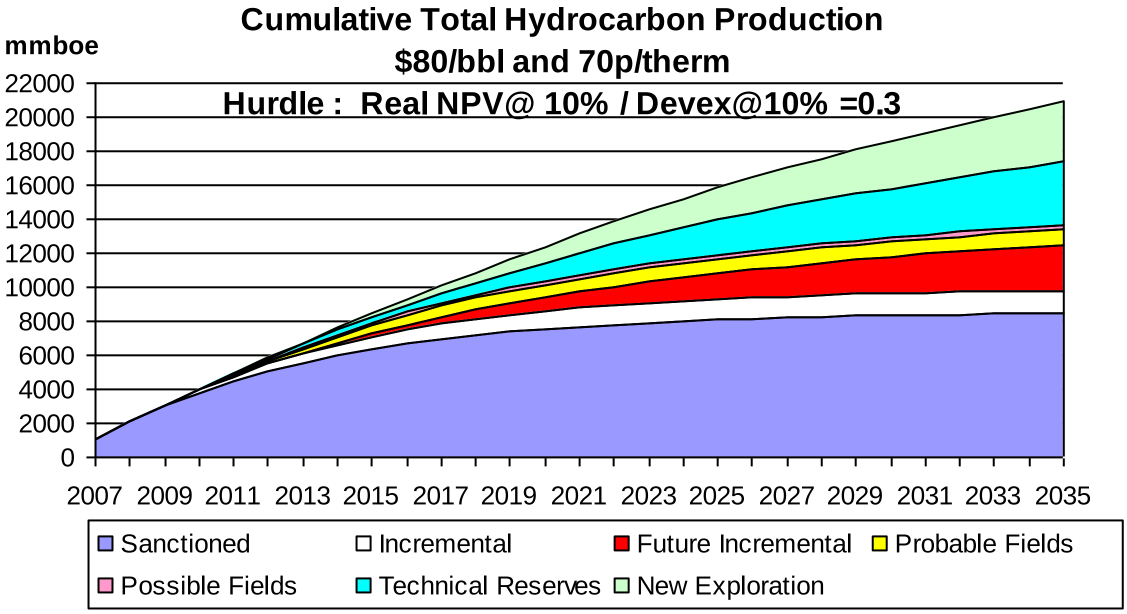


Chart 25


Cumulative Total Hydrocarbon Production
$80/bbl and 70p/therm
Hurdle : Real NPV@ 10% / Devex@10% =0.3
mmboe
22000
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
2007 2009 2011 2013 2015 2017 2019 2021 2023 2025 2027 2029 2031 2033 2035
Sanctioned
Incremental
Future Incremental
Probable Fields
Possible Fields
Technical Reserves
New Exploration

(v) Standard Depletion Case - $80,70p prices

Production prospects under the standard depletion and $80,70p price assumptions are shown in Charts 21-25. Compared to the $60,50p case there is a marked increase in production, particularly from future incremental projects, technical reserves and new discoveries. As a consequence oil production (Chart 21) becomes 1.38 mmb/d in 2010, 1.3 mmb/d in 2020, and 0.8 mmb/d in 2030. The overall decline rate is considerably less than the experience of the last few years.

The prospects for gas production (Chart 22) are also significantly greater compared to the $60,50p case, with the extra output coming particularly from fields in the categories of technical reserves and new discoveries. In 2010 production is 6.2 bcf/d, 4.3 bcf/d in 2020, and 3 bcf/d in 2030. The overall decline rate, while significantly lower than that experienced in recent years, remains rather faster than that for oil.

The consequent prospects for total hydrocarbon production (Chart 24) exhibit a relatively slow decline rate, with production being 2.6 mmboe/d in 2010, 2.1 mmboe/d in 2020, and 1.4 mmboe/d in 2030. The heavy reliance on production from future incremental projects and fields in the categories of technical reserves and new discoveries in the longer term is clear from the results in Charts 24 and 25. The latter indicates that for the total period 2007 – 2035 cumulative hydrocarbon production could total 21 bnboe.

Chart 26

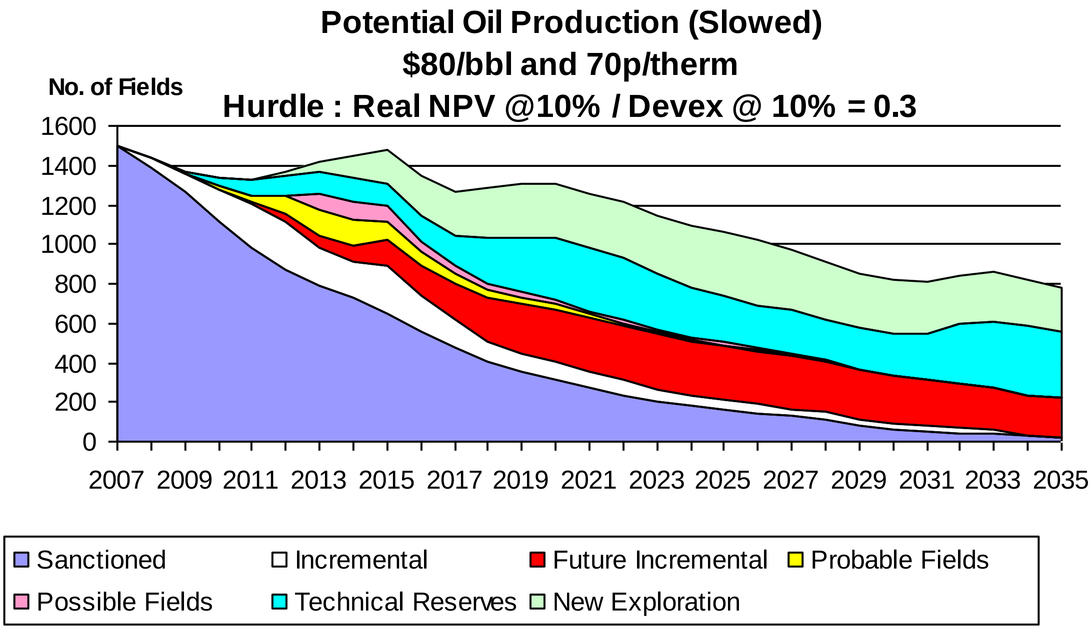


Chart 27

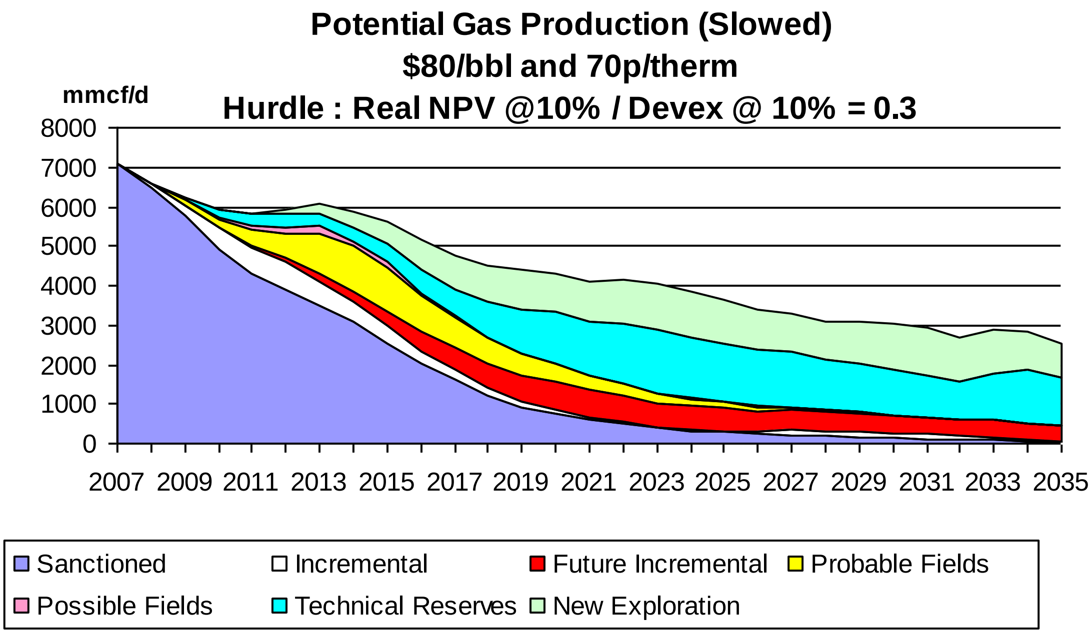


Chart 28

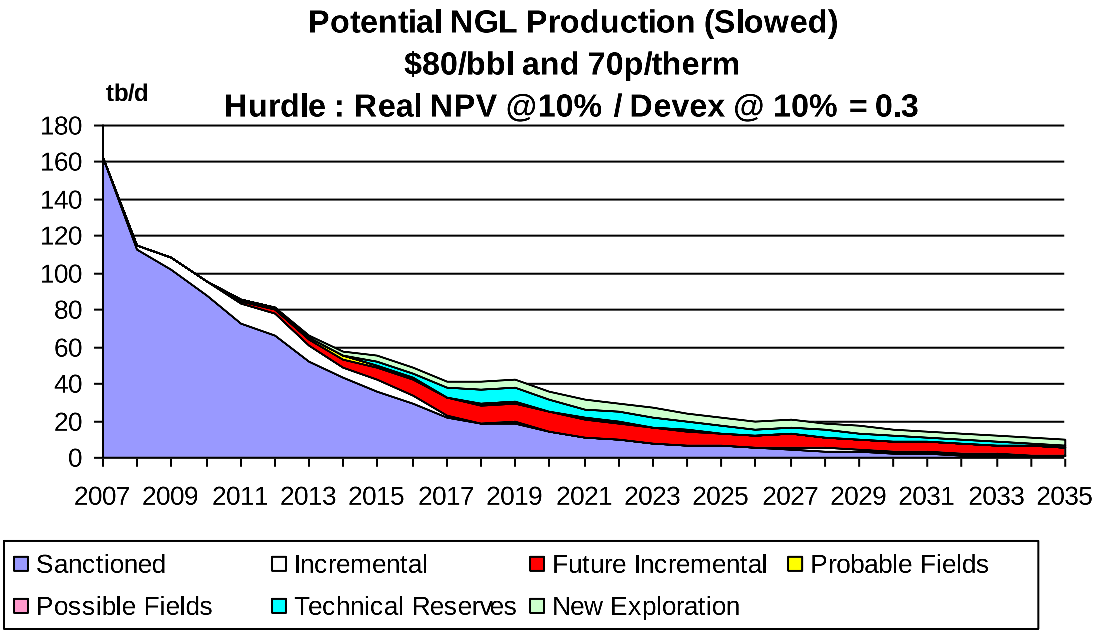


Chart 29

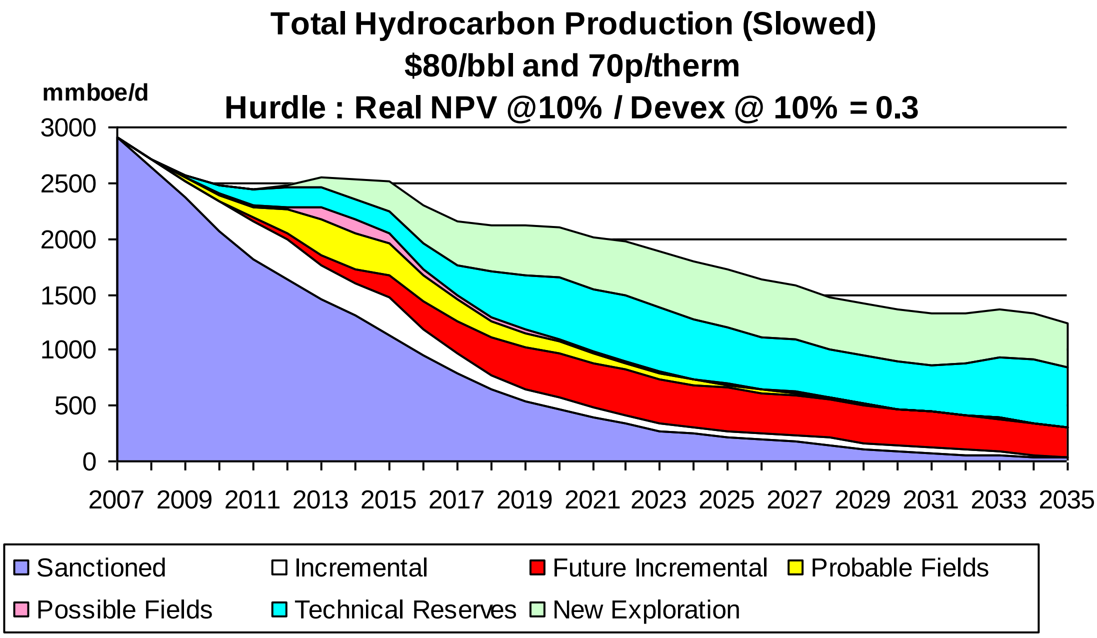
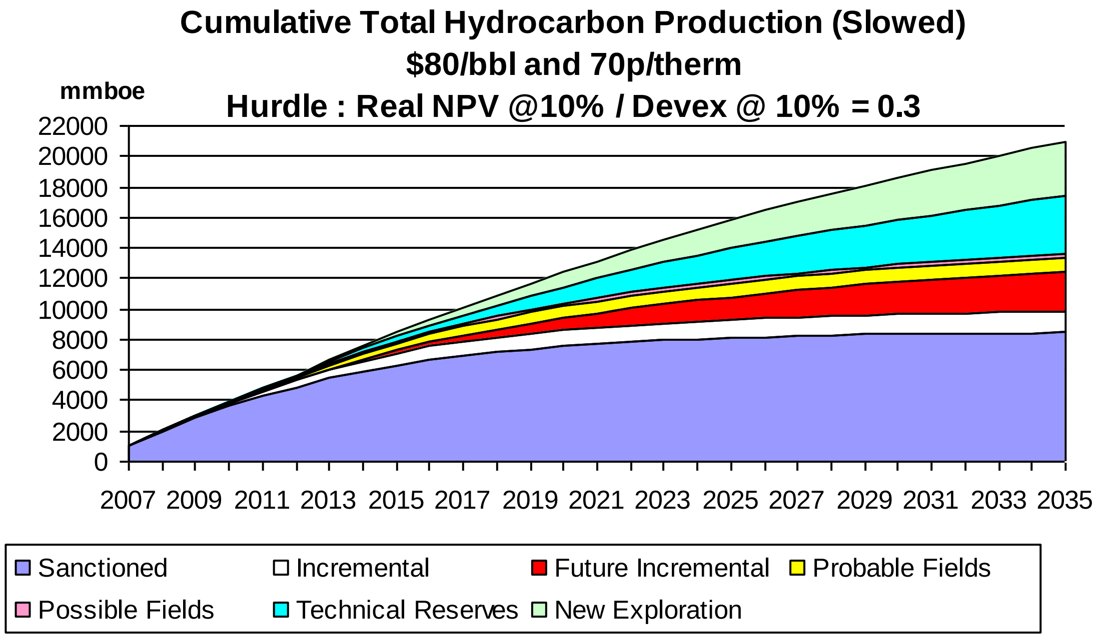


Chart 30



(vi) Slowed Depletion Case - $80,70p prices

The production prospects under the slowed depletion case with $80 and 70p prices are shown in Charts 26-30. The postponement of some near term production from recently-sanctioned fields results in the subsequent short-term cessation of the decline in output for both oil and gas. The result is that total hydrocarbon production is around 2.5 mmboe/d in 2014.

Chart 31

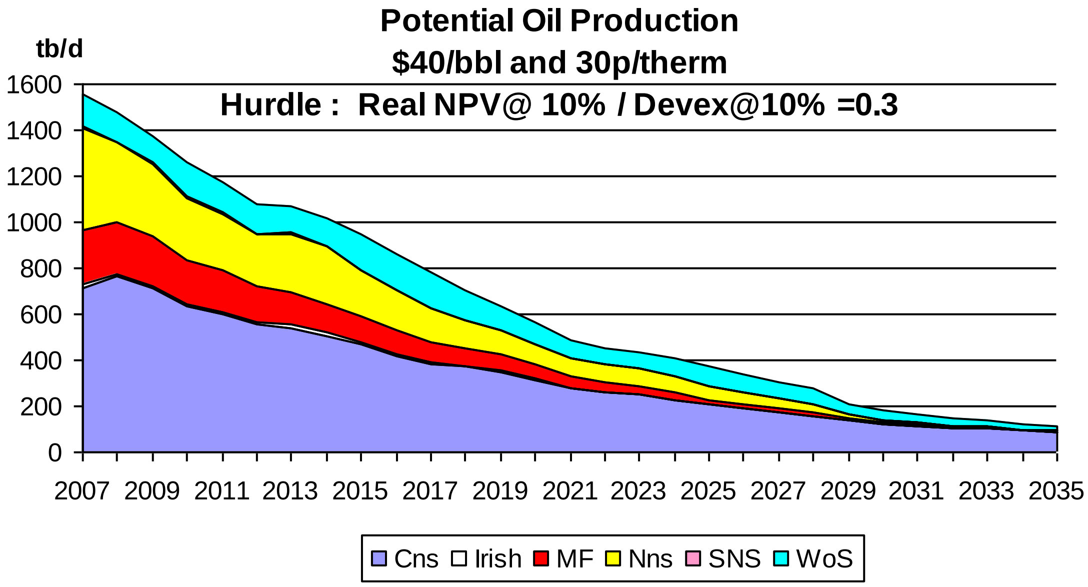


Chart 32

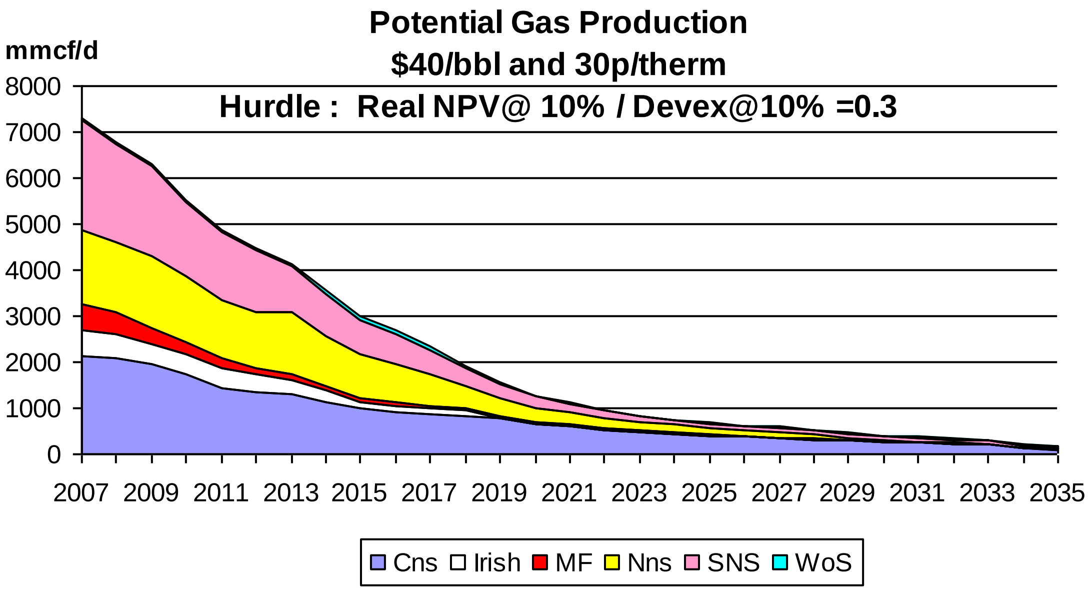


Chart 33

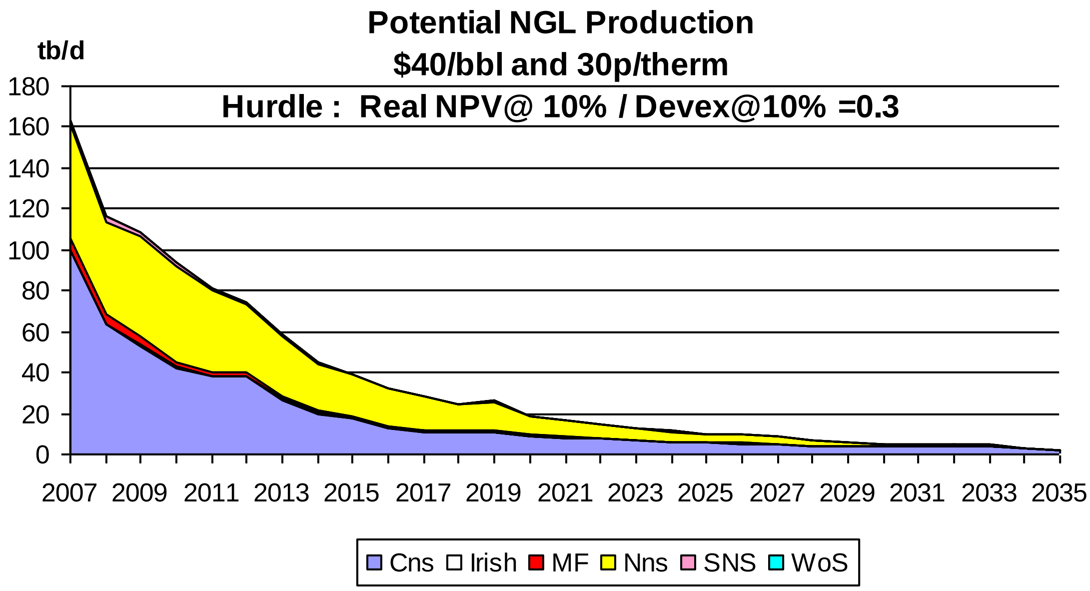


Chart 34

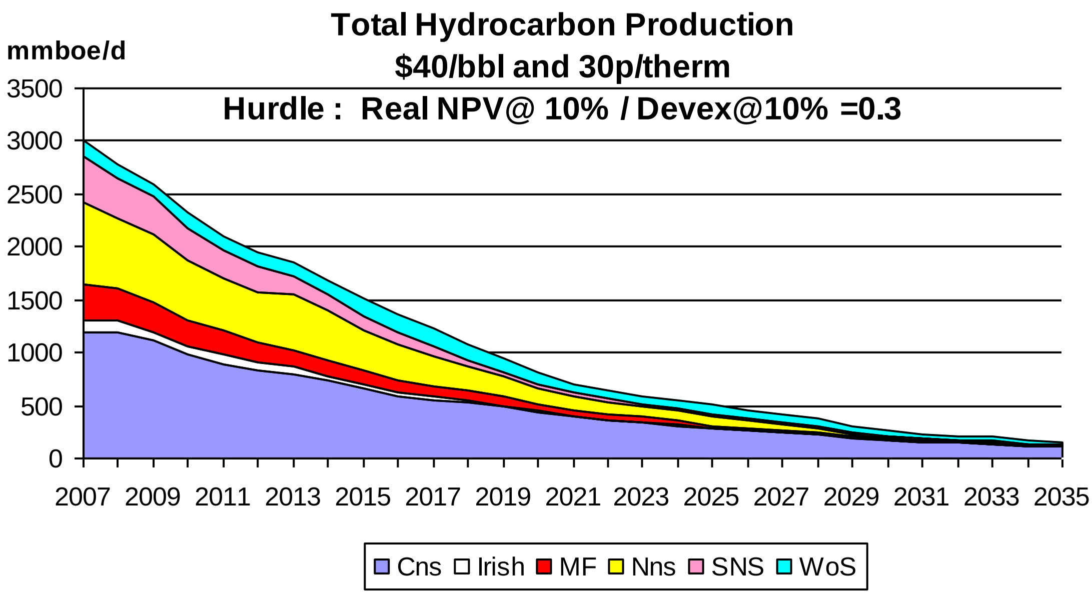
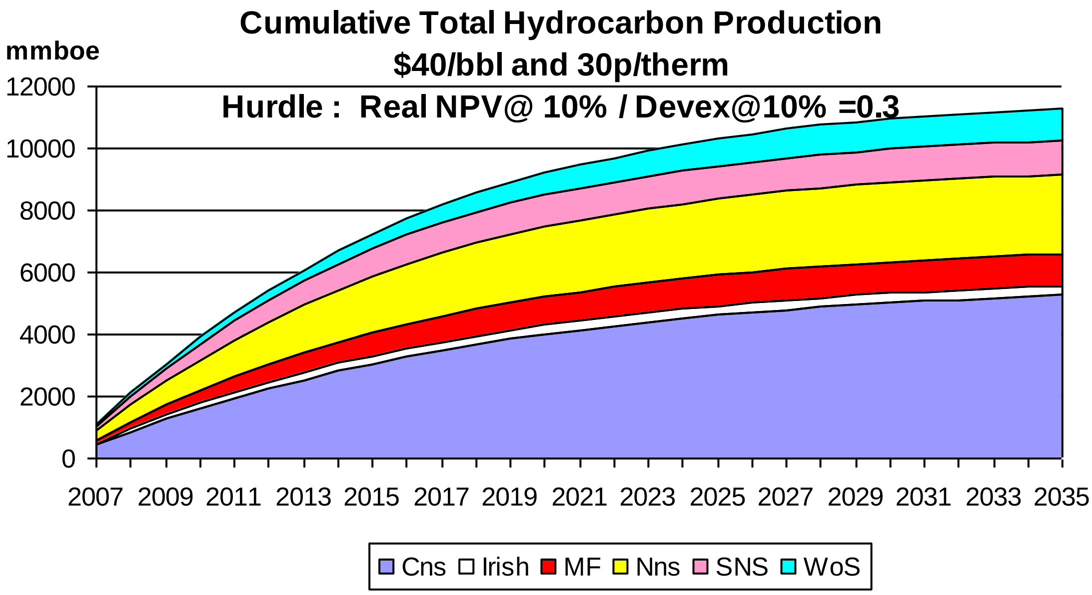


Chart 35



(vii) Standard Depletion Case – regional breakdown

The regional breakdown of production under the $40,30p prices is shown in Charts 31-35. With respect to oil the most noteworthy feature is the continuing dominance of the Central North Sea over the whole period. The West of Shetland region is seen to provide a significant contribution but by no means does it compensate for the decline from North Sea sources. With respect to gas the Central North Sea and Southern North Sea remain the most important over the long term.

Chart 36

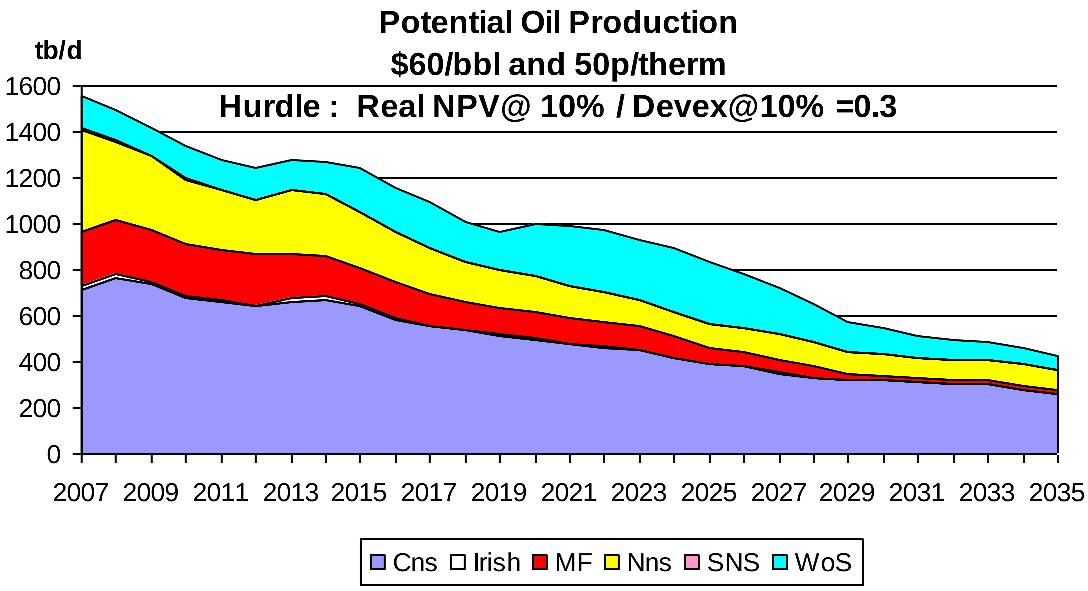


Chart 37

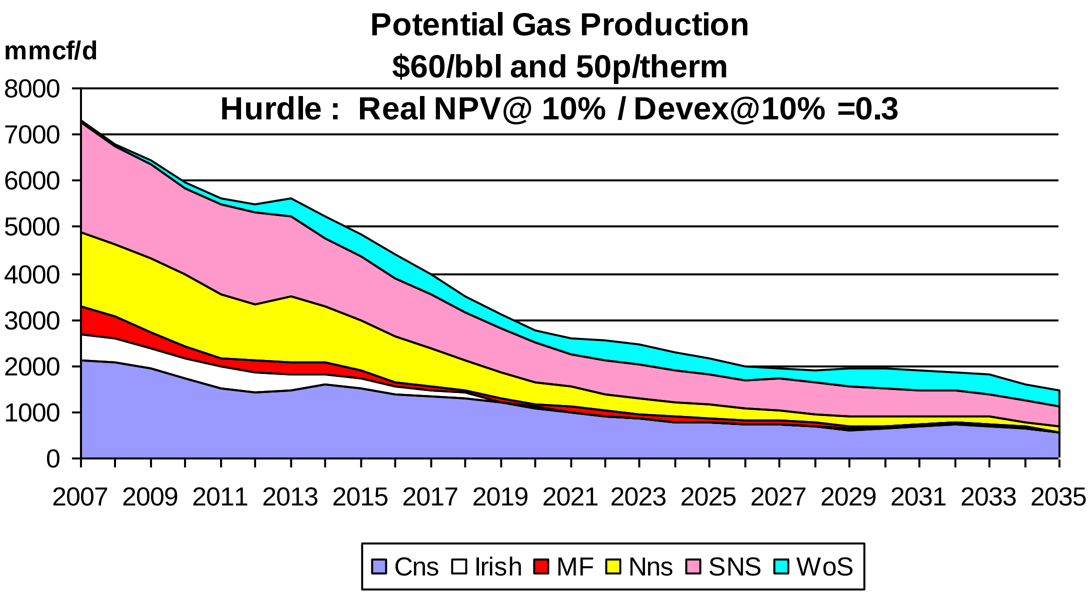


Chart 38

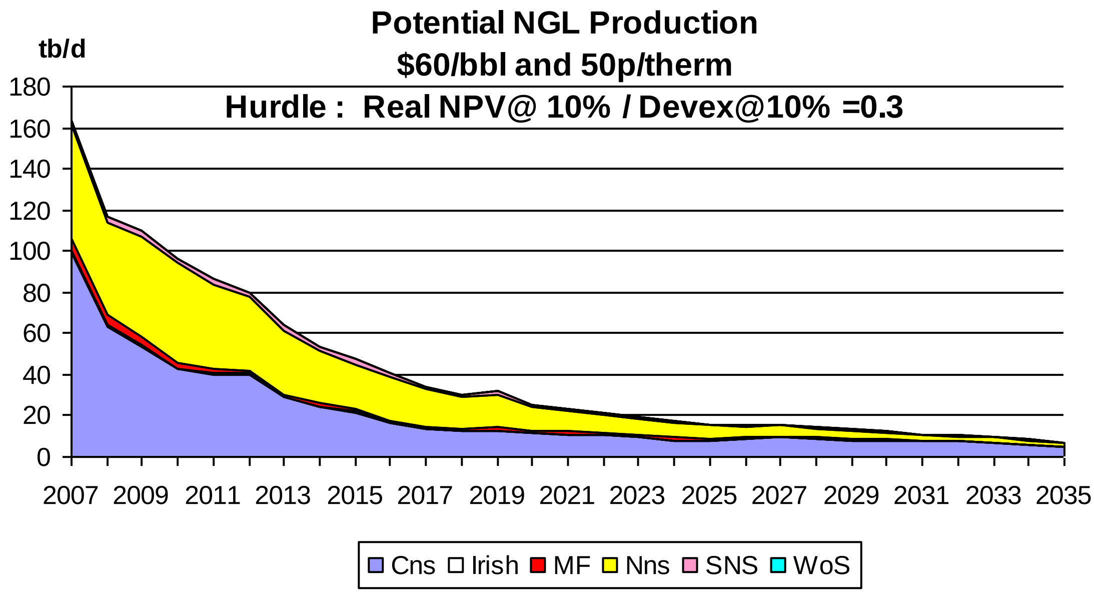


Chart 39

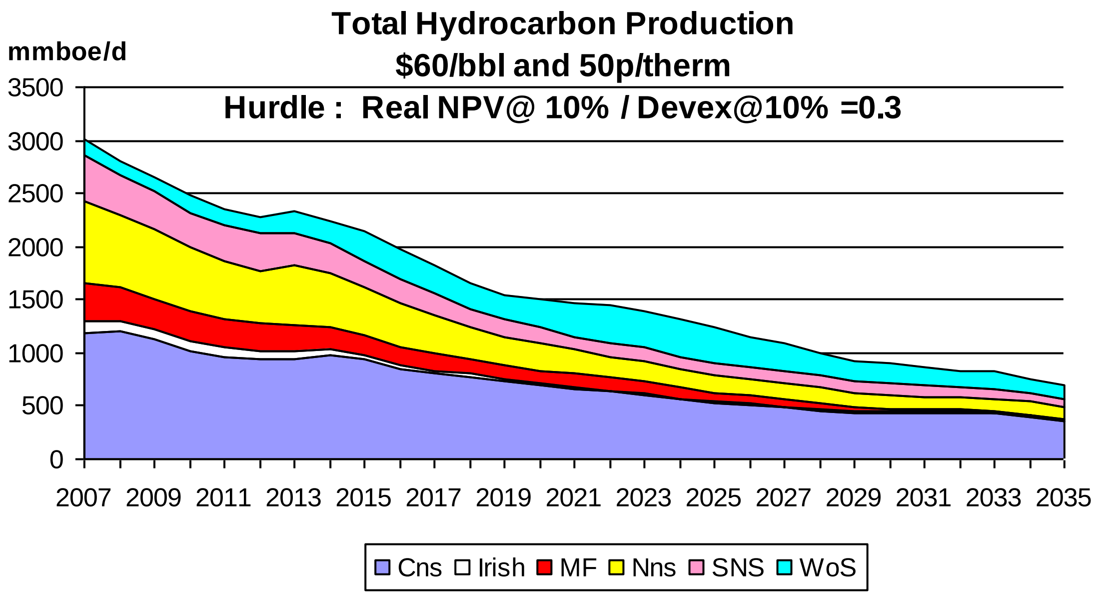
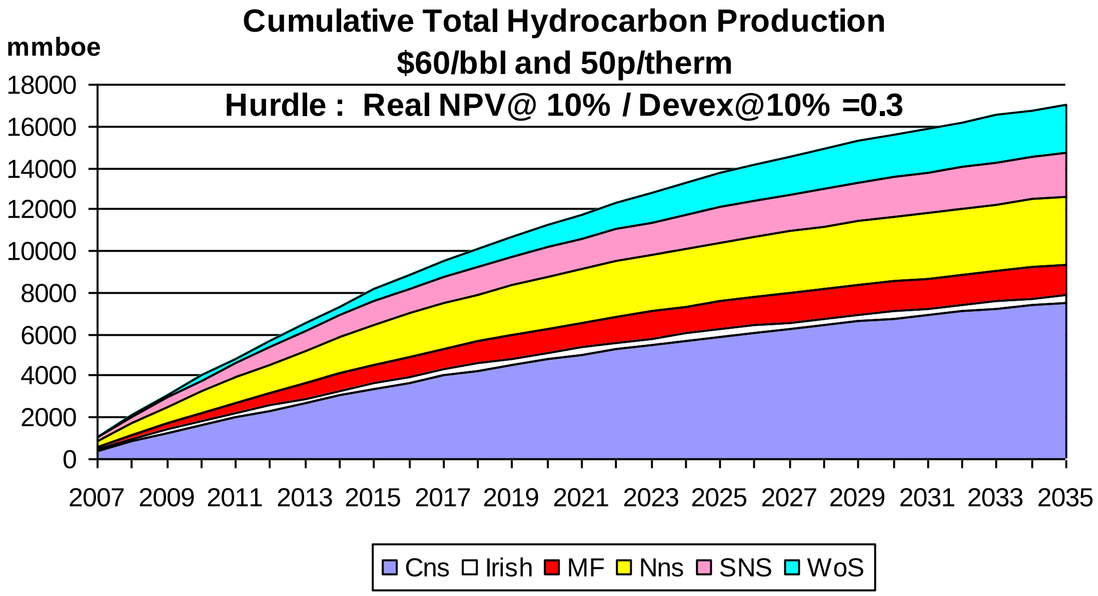


Chart 40



The regional prospects under the $60,50p prices are shown in Charts 36-40. With respect to oil there is a noteworthy increase in longer term production from the West of Shetland and Central North Sea regions. With respect to gas, compared to the low price case, output is significantly higher in the Central North Sea, Southern North Sea, and West of Shetland regions.

Chart 41

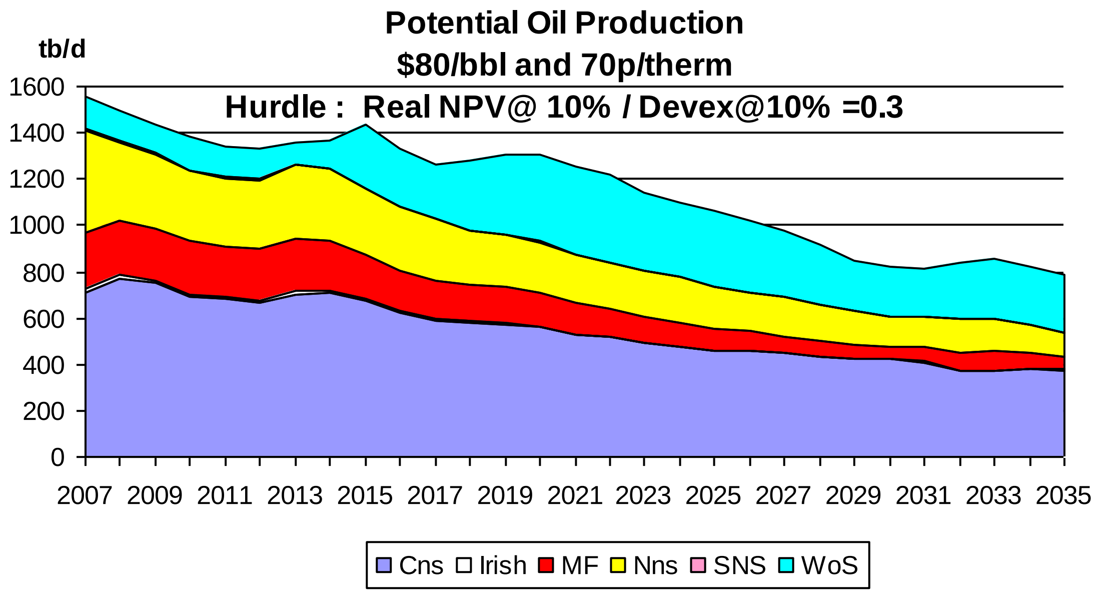


Chart 42

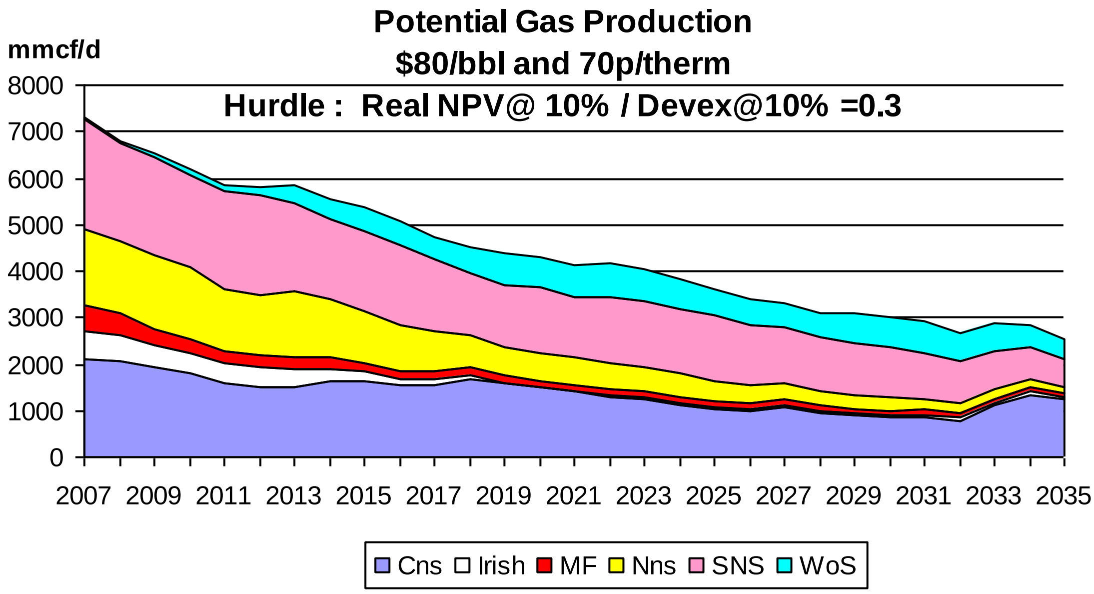


Chart 43

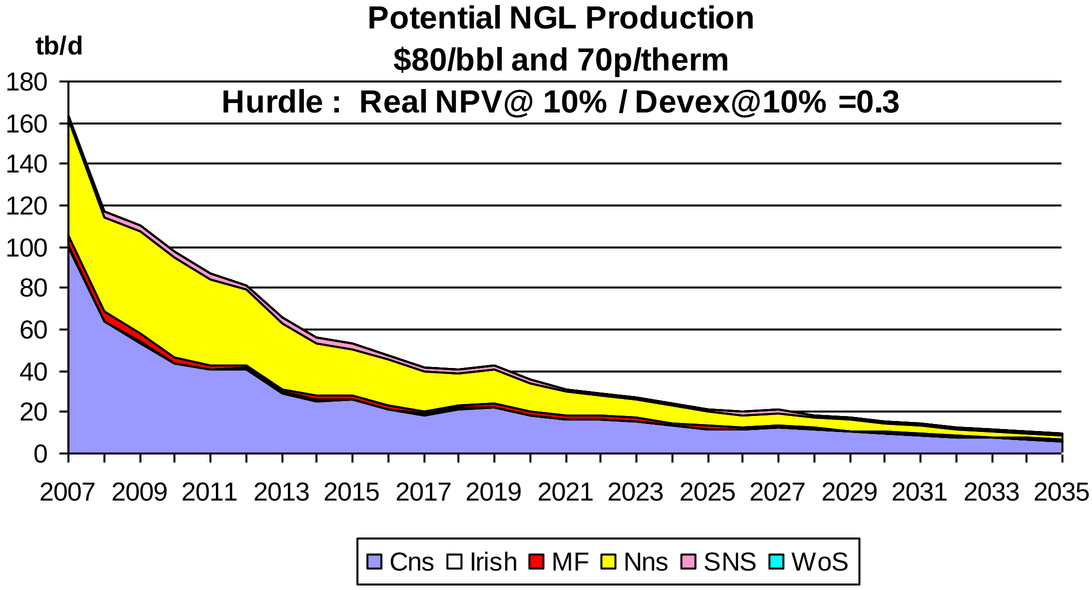


Chart 44

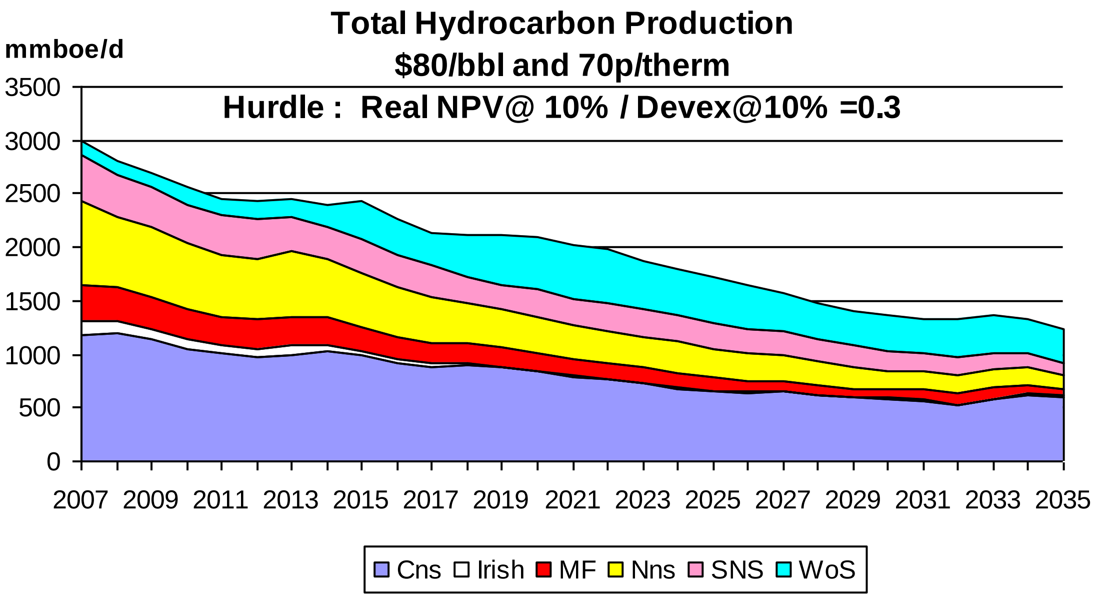
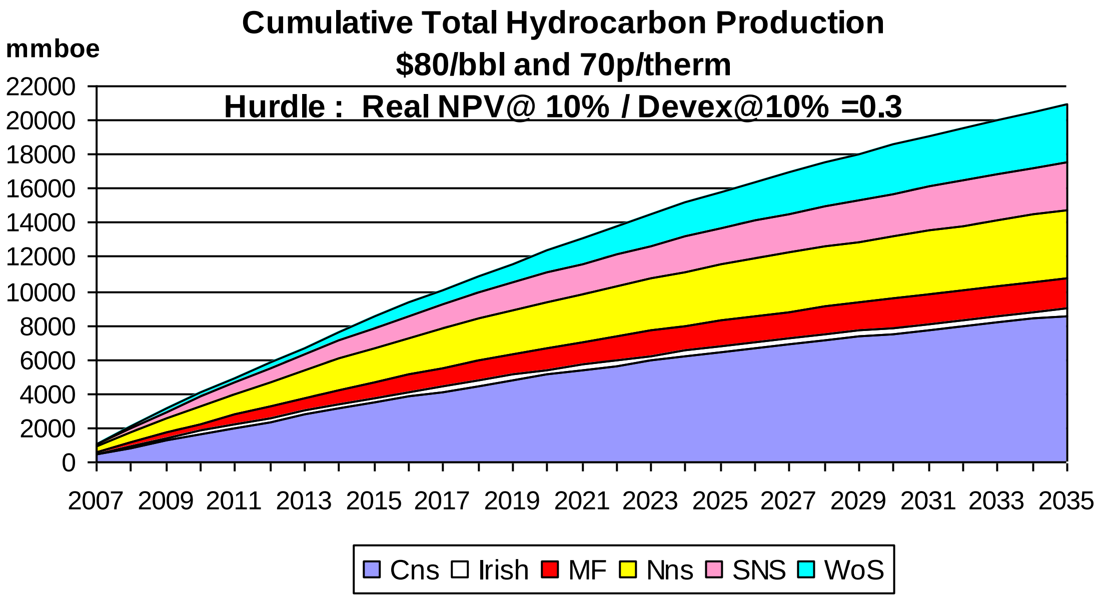


Chart 45



The regional prospects under the $80,70p prices are shown in Charts 41-45. Compared to the $60,50p case there is a substantial increase in long term oil production from the West of Shetland and Central North Sea regions. Long term gas production is notably higher in the West of Shetland, Central North Sea, and Southern North Sea regions. The overall result by 2035 is dominance of the Central North Sea and West of Shetland regions in total hydrocarbon production (Chart 44).

B. Numbers of New Field Developments and Cessation of Production

The numbers of fields in production in each year and in each category to 2035 are shown in Charts 46, 47 and 48 for the 3 price scenarios under the standard depletion assumptions. The numbers reflect the balance of new field developments and those ceasing production due to economic depletion. Under the low price case (Chart 46) the number of producing fields falls at a rapid rate reflecting in particular the relatively few new field developments. There is a major difference under the $60,50p case (Chart 47), with the number of producing fields being dramatically larger. In the period to 2015 there is little fall in the net number, and the decline rate thereafter is comparatively modest (though persistent). The prime explanation is the much greater number of new field developments compared to the low price case. In particular a considerable number of new discoveries and some fields in the technical reserves category become viable under this scenario. In the year 2035 121 fields are in production compared to only 18 under the low price case.

The position under the $80,70p price scenario is shown in Chart 48 where it is seen that the number of producing fields increase to a peak of 332 and then declines to 173 in 2035. The increase is due principally to the larger numbers of new field developments over the longer term. Under the high price case considerably more fields in the technical reserves category become viable. While the higher price does extend into the future the dates of final economic recovery this effect is not nearly so strong.

Chart 46

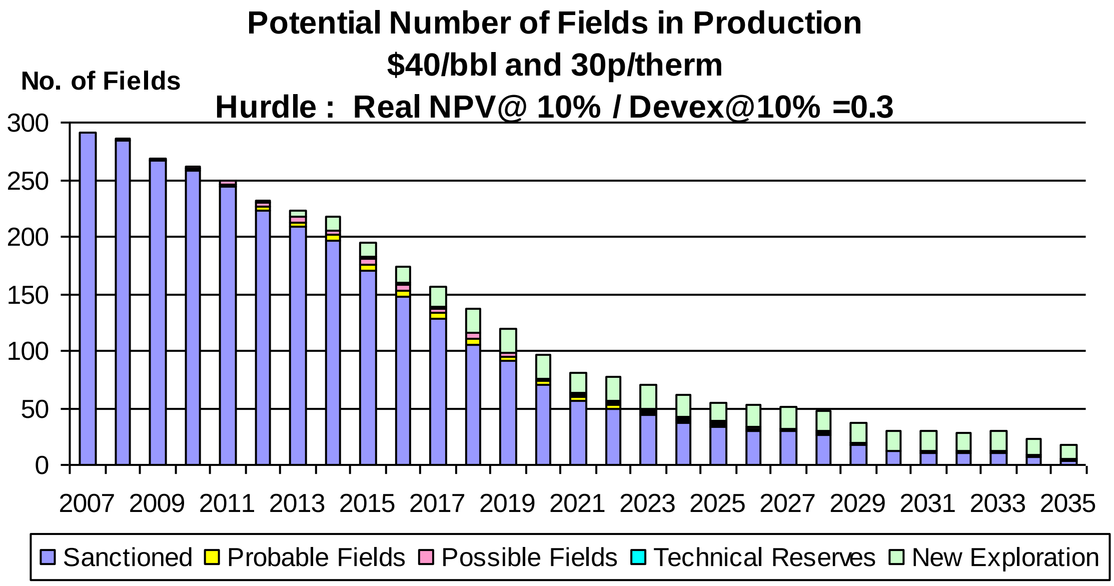


Chart 47

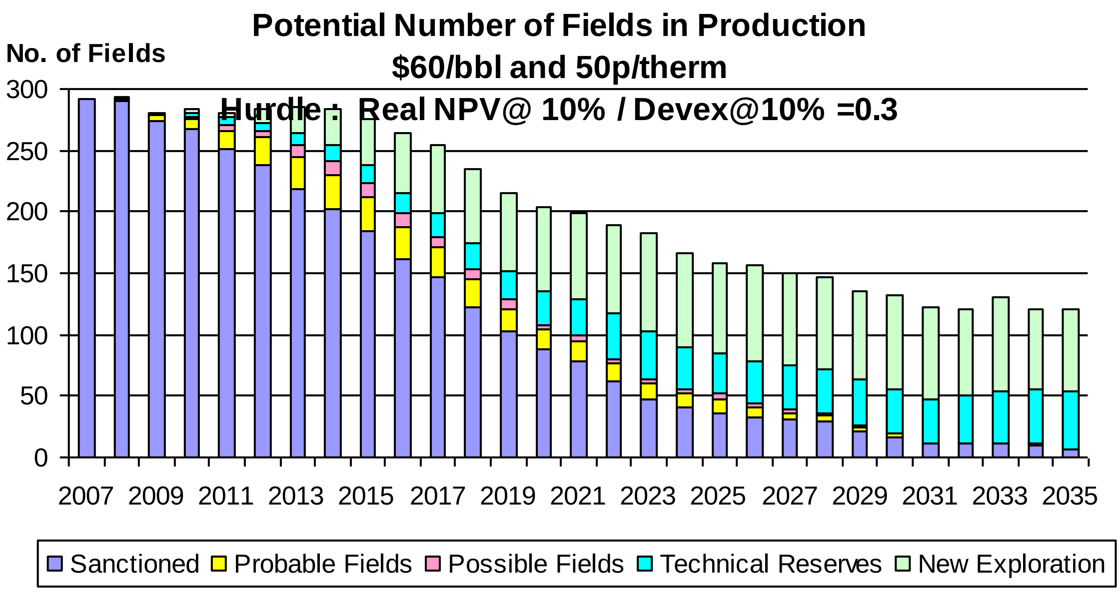
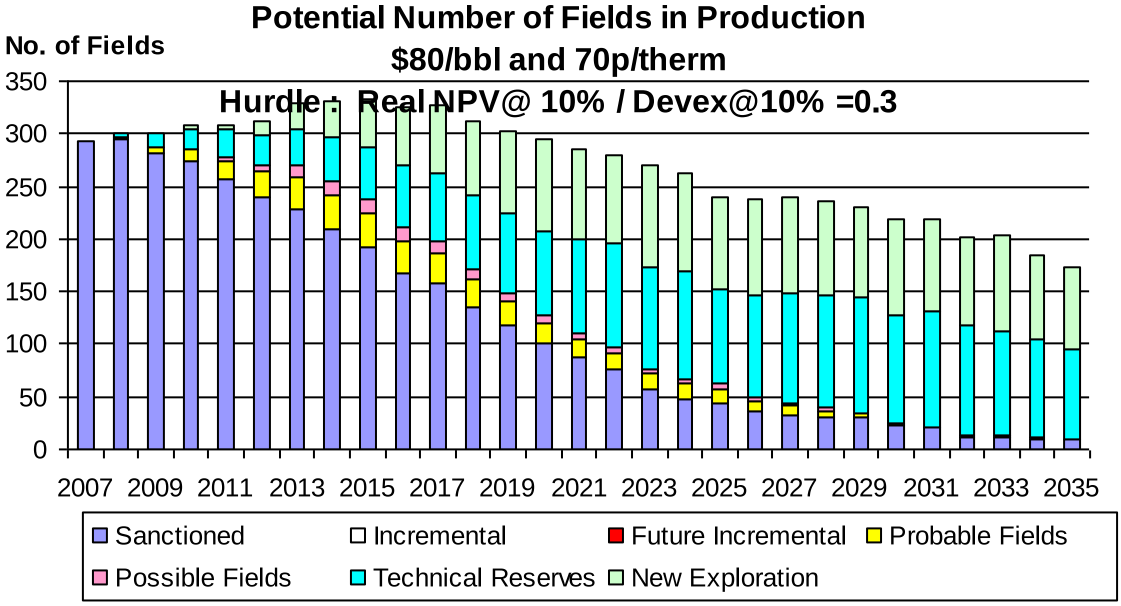


Chart 48


Potential Number of Fields in Production
$80/bbl and 70p/therm
Hurdle : Real NPV@ 10% / Devex@10% =0.3
No. of Fields
350
300
250
200
150
100
50
0
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
Sanctioned
Incremental
Future Incremental
Probable Fields
Possible Fields
Technical Reserves
New Exploration

C. Development Expenditures

The prospects for field development expenditures under the 3 price scenarios are shown in Charts 49, 50, and 51. Under the low price case it is seen that development activity collapses from its present level reflecting the non-viability of the great majority of most new projects. It should be stressed that the modelling reflects present cost levels. In the event of continuing oil and gas prices at $40,30p levels much cost reduction would likely to take place.

Under the $60,50p scenario (Chart 50) there is still a significant reduction in field investment from present levels, though a considerable number of new developments do take place. In the long term a significant number of new discoveries are developed, but many of those in the category of technical reserves remain uneconomic.

Under the high price case (Chart 51) development activity remains at high levels for a considerable number of years, but falls noticeably after 2018. The main reason for the high level of development activity relates to the substantial numbers of fields in the technical reserves category which become viable. Future incremental projects also account for a noteworthy volume of long term investment.

Chart 49

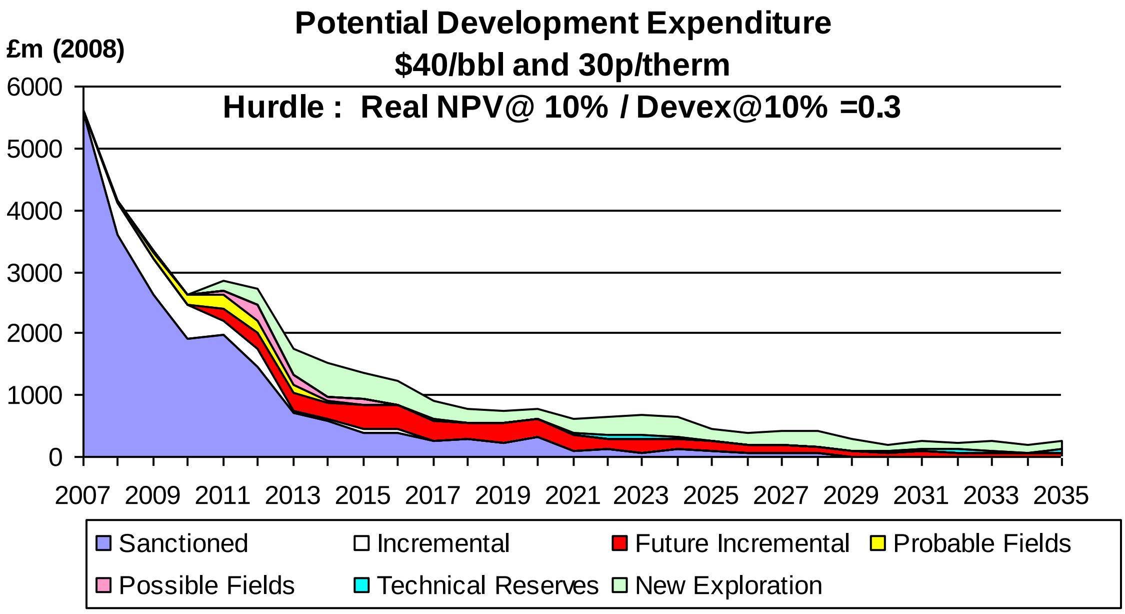


Chart 50

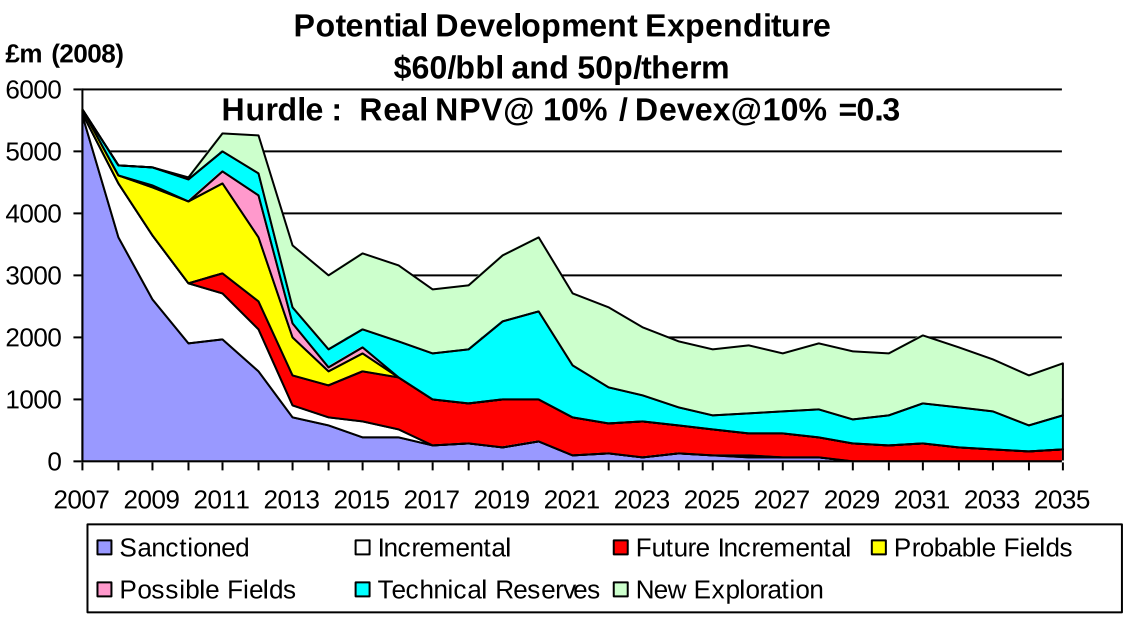
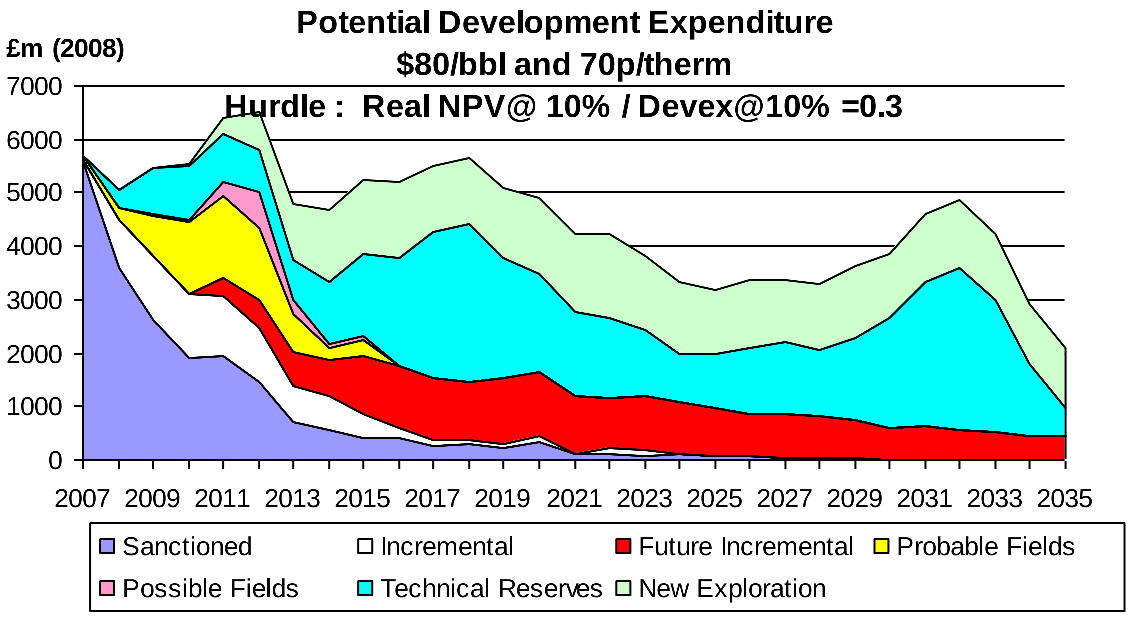


Chart 51



Potential Development Expenditure
$80/bbl and 70p/therm
Hurdle : Real NPV@ 10% / Devex@10% =0.3
£m (2008)
7000
6000
5000
4000
3000
2000
1000
0
2007 2009 2011 2013 2015 2017 2019 2021 2023 2025 2027 2029 2031 2033 2035
Sanctioned
Incremental
Future Incremental
Probable Fields
Possible Fields
Technical Reserves
New Exploration

D. Operating Expenditures

The prospects for operating expenditures under the 3 price scenarios and the standard depletion assumptions are shown in Charts 52, 53, and 54. Under the low price case (Chart 52) these expenditures decline at a rapid rate reflecting the non-viability of the great majority of potential new investments. Under the $60,50p case the decline is still noteworthy, but less drastic. It is seen that expenditures relating to new discoveries and some technical reserves are clearly higher than in the low price case.

Under the $80,70p case total operating expenditures hold up relatively well with the decline rate only becoming very significant in the period after 2020. It is clear from Chart 54 that, expenditures on fields in the category of technical reserves become very substantial in the periods after 2020.

Chart 52

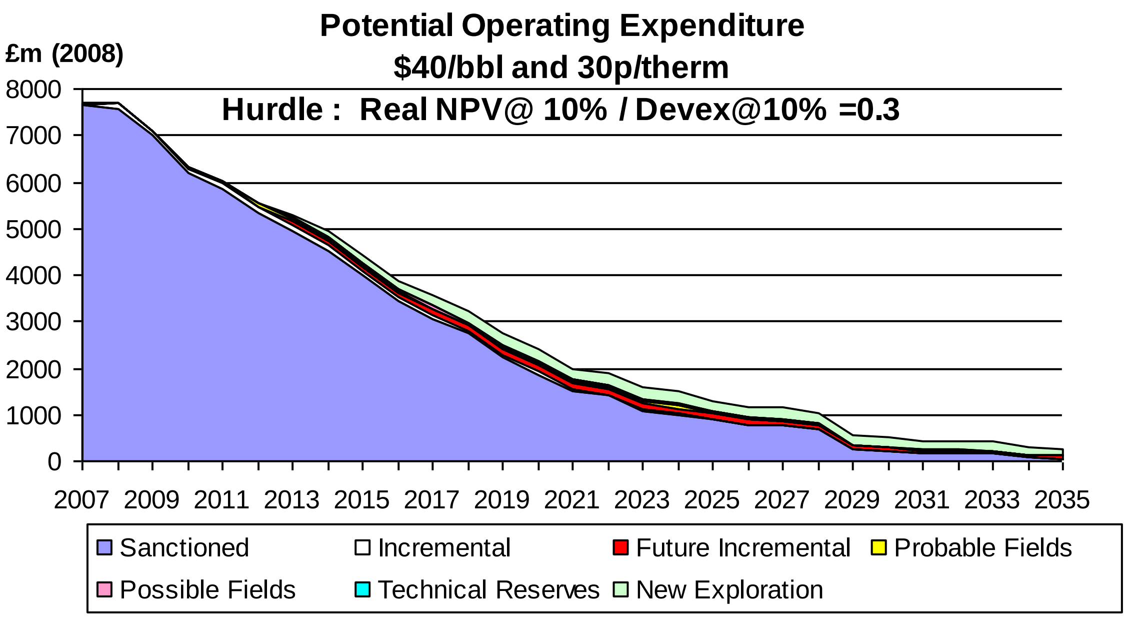


Chart 53

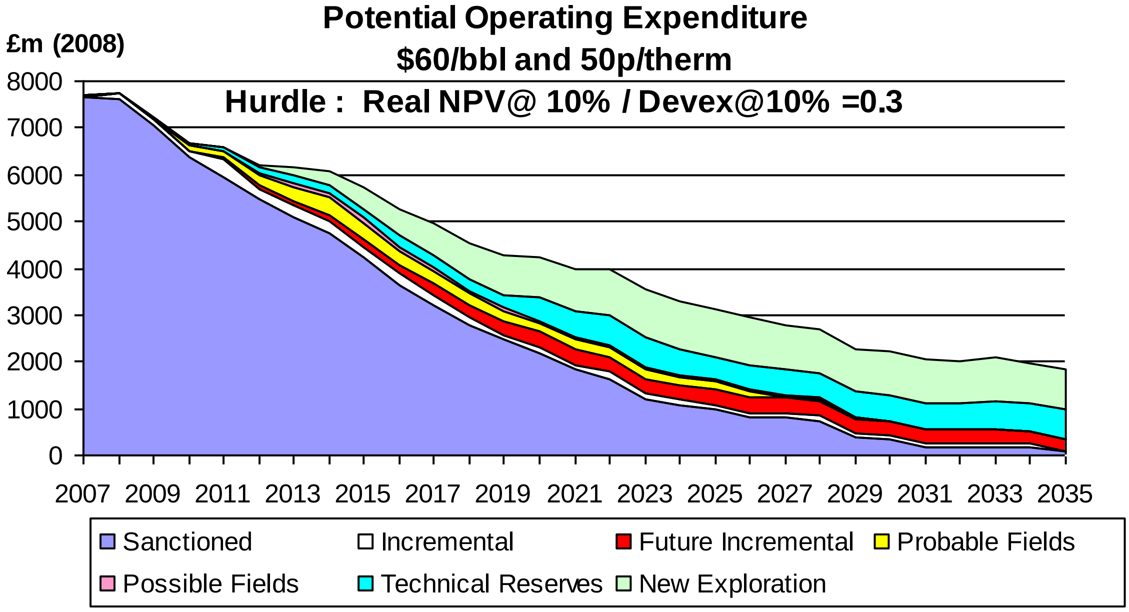
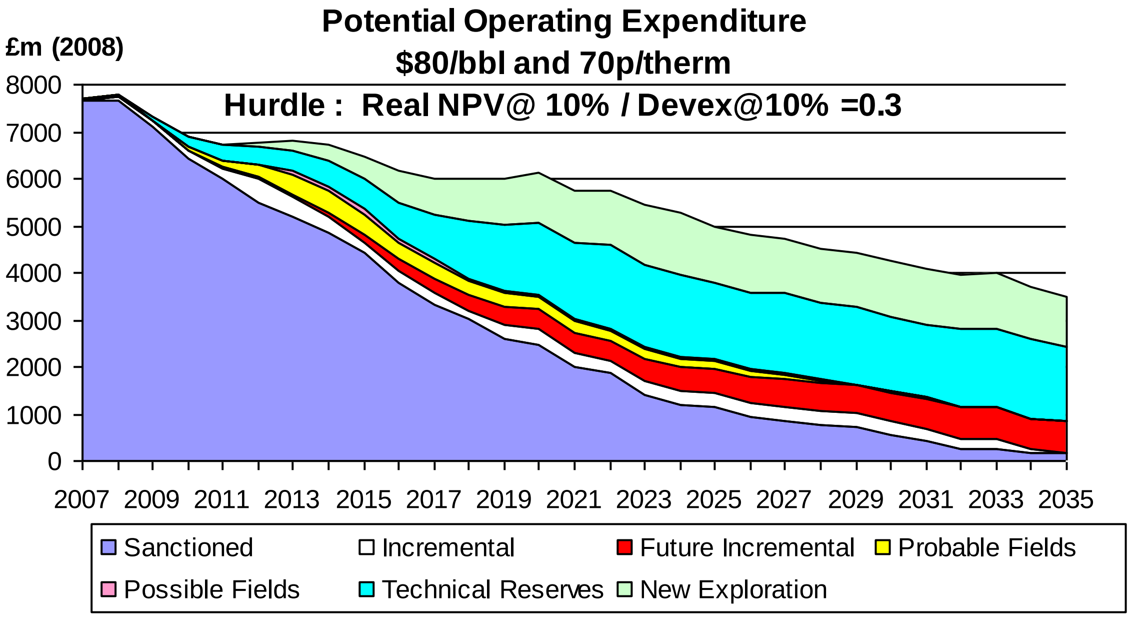


Chart 54



E. Decommissioning Expenditures

Expenditures on decommissioning under the 3 price scenarios and the standard depletion assumptions are shown in Charts 55, 56, and 57 on a yearly basis, and the cumulative totals to 2035 are shown in Charts 58, 59, and 60. Under the low price scenario it is seen that from 2013 onwards expenditures increase rapidly to reach a peak of nearly £2.2 billion in 2016. This dramatic increase is due to the decommissioning of several very large platforms in the same time period. Expenditures remain at very high levels until 2021. A very noteworthy feature of the pattern of expenditure is the dominance of those relating to existing sanctioned fields. Over the period to 2035 cumulative total expenditures on decommissioning amount to £24.6 billion at 2008 prices under the low price scenario (Chart 58).

Prospective expenditures under the $60,50p scenario are shown in Chart 56. There is little difference in the pattern to 2017 but thereafter they fall rapidly for a few years reflecting the later year of ultimate economic recovery in some fields. In the later years of the period to 2035 total expenditures are higher than with the low price case. This reflects the larger number of new developments under the higher price and the expenditures on their decommissioning which occur by 2035. Over the period to 2035 total cumulative expenditures on decommissioning are £26.5 billion at 2008 prices (Chart 59).

In Chart 57 the pattern of decommissioning expenditures under the $80,70p case is shown. The pattern is similar to that under the medium price case until 2022 or so. Thereafter the level of expenditure is larger under the high price case reflecting the greater number of new developments and their decommissioning in the period to 2035. The cumulative expenditures on decommissioning to 2035 under the high price case is £26.5 billion at 2008 prices.

Chart 55

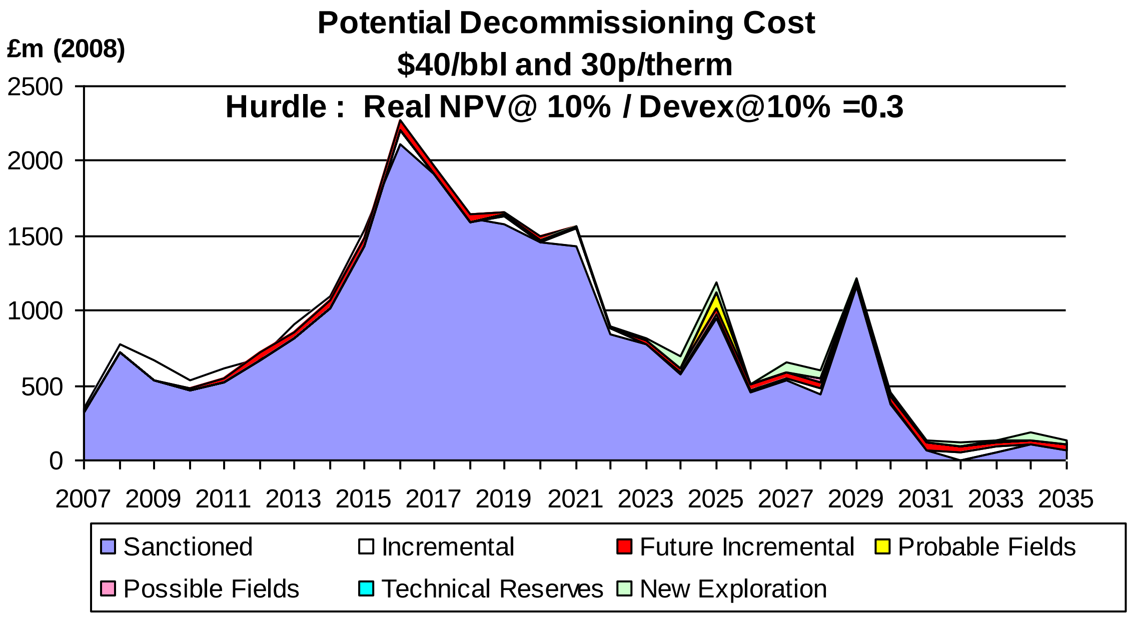


Chart 56

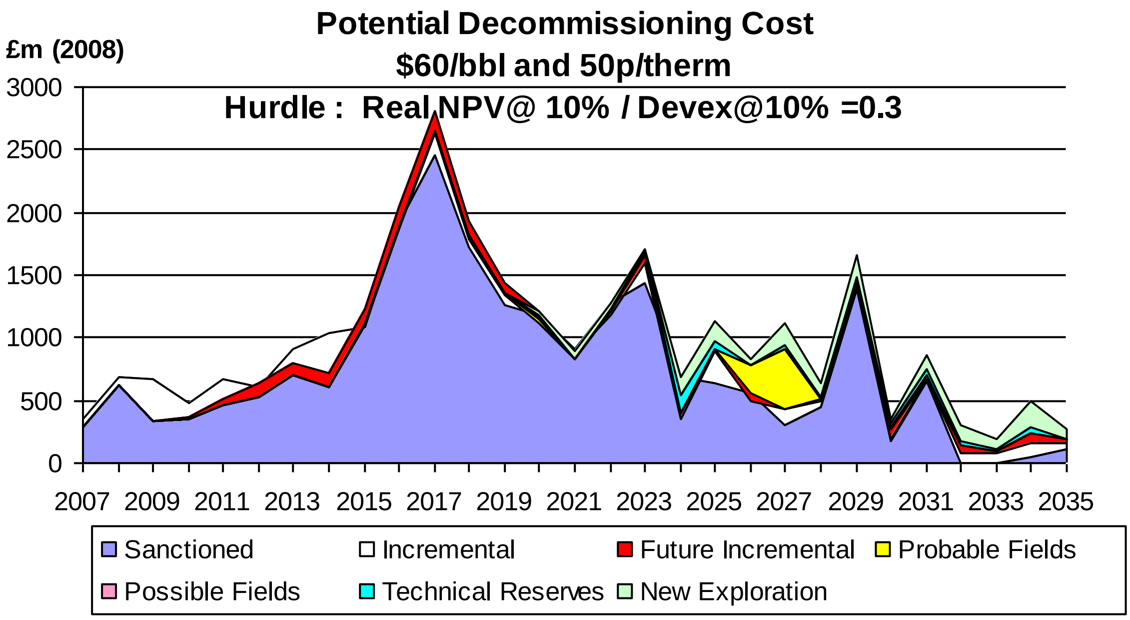


Chart 57

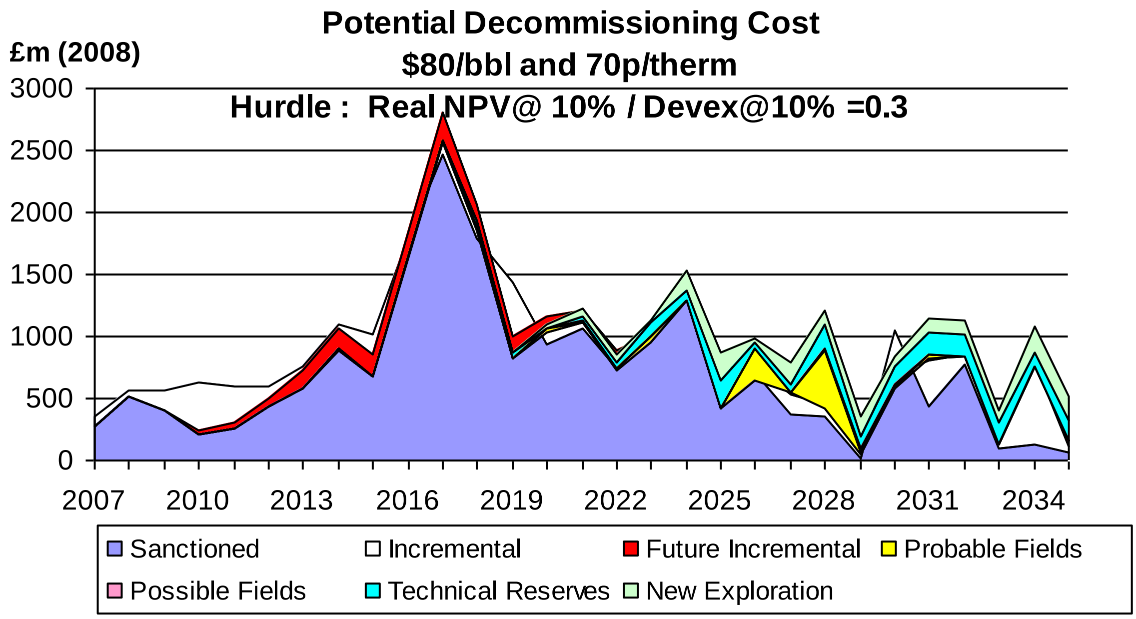


Chart 58

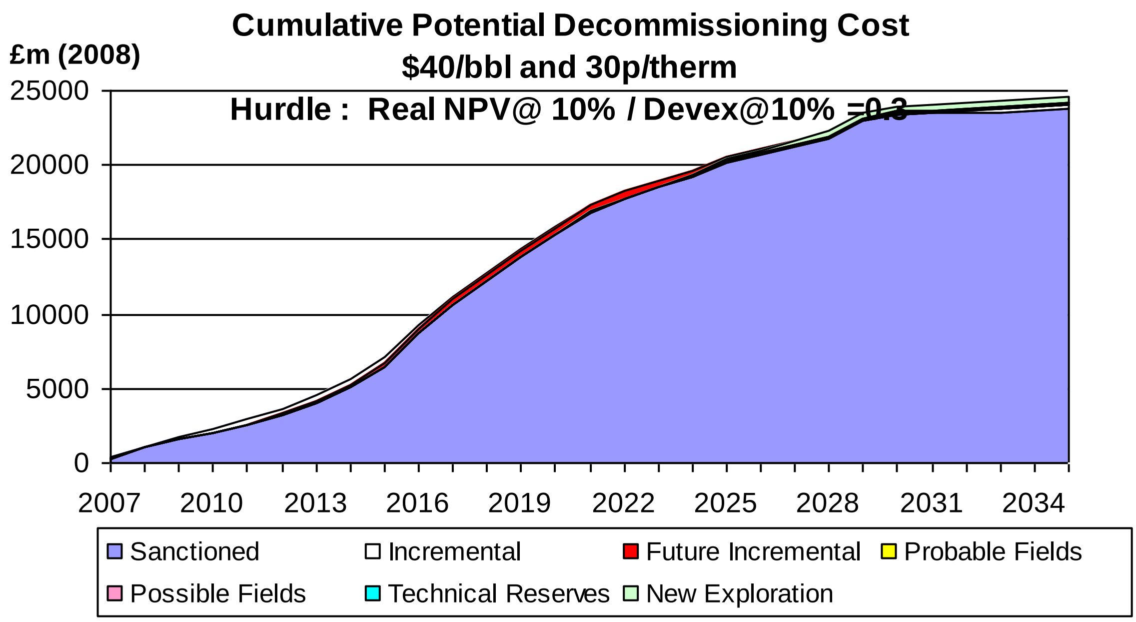


Chart 59

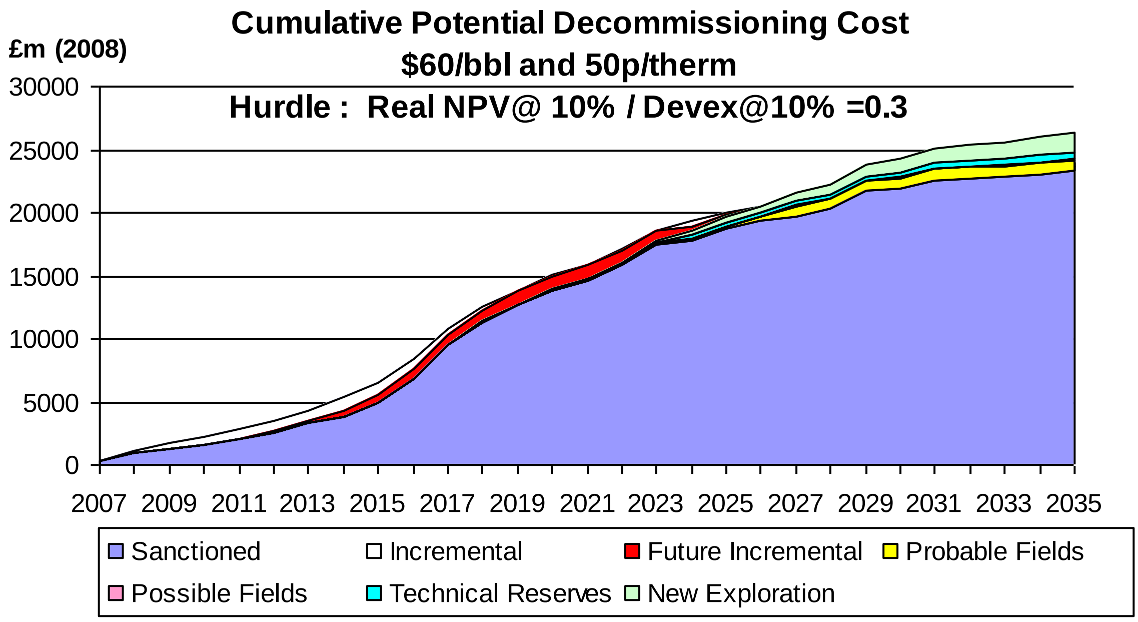
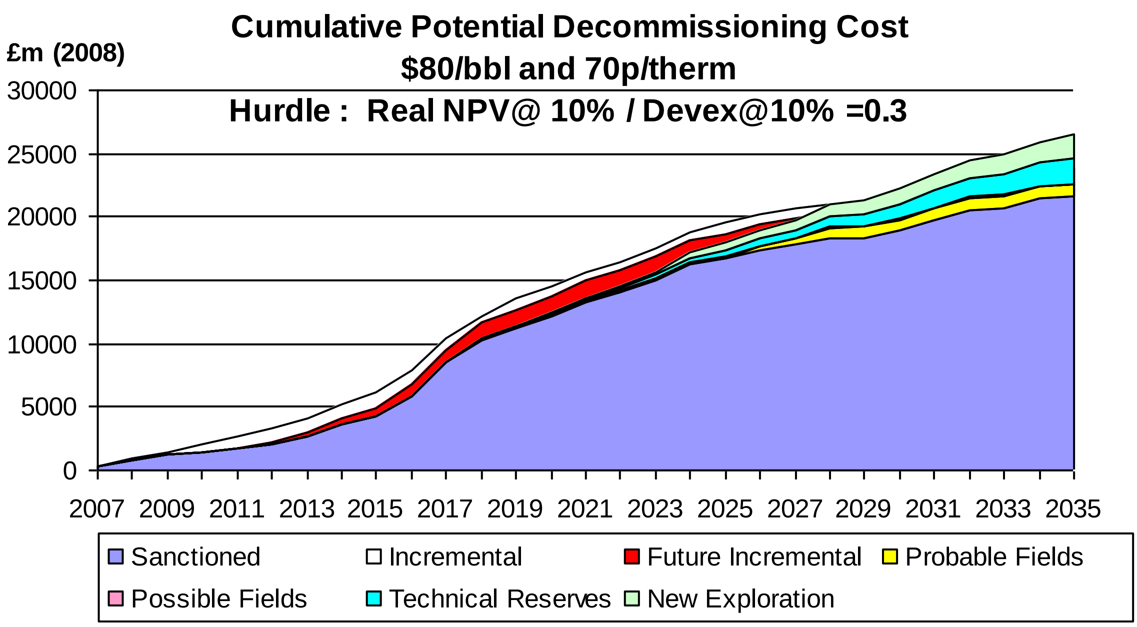


Chart 60



4. Consistency with Official Estimates of Remaining Potential

It was felt useful to compare the cumulative aggregate production in relation to the official UK Government estimates of the remaining potential. The latter indicate a central estimate of just over 21 billion boe with a low value of 11.7 boe and a high of 38.7 billion boe. The estimates of the present study under the 3 price scenarios and standard case assumptions are shown in Tables 6 and 7. They reveal cumulative production in the period 2008 – 2035 of 10.2 billion boe under the low price case, 15.9 billion boe under the central price case, and 19.9 billion boe under the high price case (It may be noted that production continues well beyond 2035, and, if 2050 had been taken as the end date, cumulative production without further exploration beyond 2035 would be 10.5 billion boe, 17.8 billion boe, and 22.6 billion boe under the 3 price cases). It is very difficult to envisage a pace of development higher than that indicated under the $80,70p price case, even if oil and gas prices are sustained at much higher levels. The managerial and other efforts required to sustain much higher levels of development activity do not seem realistic. Thus the realisation of the potential as foreseen by the Government means that production has to continue for a considerable period beyond 2035.

Table 6

Cumulative Potential Production from 2008 to 2035 (Mmboe)
Hurdle : Real NPV @ 10% / Real Devex @ 10% = 0.3
Standard case

	Sanctioned	Current Incremental	Future Incremental	Probable Fields	Possible Fields	Technical Reserves	New Exploration	TOTAL
$40/bbl and 30p/therm	7106	664	1107	187	174	44	931	10212
$60/bbl and 50p/therm	7244	1044	1898	838	240	1581	3102	15947
$80/bbl and 70p/therm	7352	1344	2680	901	249	3804	3553	19884

Table 7

Cumulative Potential Production from 2008 to 2035 (MMboe)
Hurdle : Real NPV @ 10% / Real Devex @ 10% = 0.3
Standard case

	Cns	Irish	MF	Nns	SNS	WoS	TOTAL
$40/bbl and 30p/therm	4828	267	898	2275	960	985	10212
$60/bbl and 50p/therm	7088	288	1361	3024	1894	2293	15947
$80/bbl and 70p/therm	8166	328	1719	3673	2605	3393	19884

5. Effects of Higher Cost of Capital

It is possible that higher costs of capital and related threshold returns compared to those employed above will prevail, at least among some companies, in the making of investment decisions. This subject was investigated and the modelling was undertaken to reflect the possibility. The effects of employing a range of discount rates (10%, 12.5% and 15%) and two measures of capital productivity (minimum NPV/I ratio of 0.3 and 0.5) under the 3 price scenarios on the numbers of fields/projects remaining viable are shown in Table 8. It is seen that under the $40,30 pence scenario 141 investments pass the most lenient hurdle while only 85 pass the most stringent one. It is also noteworthy that very few of the fields in the category of technical reserves pass any of the hurdles.

Under the $60,50 pence scenario as many as 451 fields/projects pass the most lenient hurdle while only 278 pass the most stringent one. Compared to the low price case there is a particularly large increase in the number of new discoveries which pass the hurdle (It should be noted that the number of discoveries is also higher under the $60,50 pence case due to the higher exploration effort).

Under the $80,70 pence scenario the total number of new developments under the most lenient investment hurdle is 613 while under the most stringent it is 509. Compared to the medium price case there are many more viable investments in the categories of new discoveries and technical reserves. It is also noteworthy that under 4 of the possible hurdles many of the fields in the technical reserves category remain non-viable.

The general conclusion from this comparative analysis is that the viability of projects in the UKCS is very sensitive to the investment hurdle employed. This is primarily a consequence of the modest materiality of many of the projects.

Even modest increases in discount rates from 10% to 12.5% and in minimum NPV/I rates from 0.3 to 0.5 have a substantial negative effect on the number of new developments and thus long-term production prospects.

Table 8

Number of Field Developments and Projects Passing under Different Investment Hurdle Rates

Price and Category	*Discount rate* / *Min.NPV/I*	*10%* *0.3*	*10%* *0.5*	*12.5%* *0.3*	*12.5%* *0.5*	*15%* *0.3*	*15%* *0.5*
$40,30 pence							
Incremental Projects		**78**	**69**	**79**	**66**	**78**	**64**
Probable fields		**5**	**2**	**4**	**2**	**4**	**2**
Possible fields		**5**	**5**	**5**	**5**	**5**	**5**
New exploration finds		**48**	**23**	**39**	**18**	**34**	**14**
Technical reserves fields		**5**	**0**	**4**	**0**	**3**	**0**
Total		**141**	**99**	**131**	**91**	**124**	**85**
$60,50 pence							
Incremental Projects		**103**	**92**	**99**	**88**	**98**	**85**
Probable fields		**28**	**18**	**25**	**16**	**21**	**11**
Possible fields		**10**	**8**	**10**	**8**	**9**	**5**
New exploration finds		**207**	**173**	**205**	**154**	**200**	**136**
Technical reserves fields		**103**	**50**	**93**	**44**	**81**	**41**
Total		**451**	**341**	**432**	**310**	**409**	**278**
$80, 70 pence							
Incremental Projects		**110**	**105**	**107**	**103**	**106**	**101**
Probable fields		**32**	**32**	**32**	**32**	**32**	**29**
Possible fields		**15**	**10**	**13**	**11**	**13**	**10**
New exploration finds		**244**	**241**	**244**	**235**	**243**	**227**
Technical reserves fields		**212**	**163**	**203**	**154**	**191**	**142**
Total		**613**	**551**	**599**	**535**	**585**	**509**

The effects of these variations in the number of field developments and project investments on cumulative production to 2035 are now examined. A case where the NPV/I minimum acceptable ratio was 0.5, but discount rates kept at 10%, is shown in Tables 9 and 10. It is seen that the cumulative production to 2035 under the $40,30p case becomes 9.4 billion boe compared to 10.4 billion boe when the minimum ratio was 0.3. Under the $60,50p case the corresponding volumes are 14.1 billion boe and 15.9 billion boe. Under the $80,70p scenario the corresponding volumes are 18.2 billion boe and 19.9 billion boe. These may be regarded as significant differences. They reflect the fact that many of the new fields are relatively small, with modest capital productivity at current cost levels along with the oil and gas prices used in the modelling.

The next case examined involves discount rates of 12.5% and minimum NPV/I of 0.3. The cumulative production is shown in Tables 11 and 12. Under the low, medium and high price scenarios cumulative production is 10 bnboe, 15.5 bnboe and 19.6 bnboe compared to corresponding figures of 10.4 bnboe, 15.9 bnboe and 19.9 bnboe with the 10% discount rate.

The results with a discount rate of 12.5% and minimum NPV/I of 0.5 are shown in Tables 13 and 14. They show cumulative production of 9.2 bn boe, 12.9 bn boe and 17.9bn boe under the low, medium and high price cases. Compared to the case with 10% discount rate and minimum NPV/I of 0.3 there is a very significant reduction in cumulative production. In the high price case the reduction exceeds 2 bn boe.

The result for the case with discount rates of 15% and minimum NPV/I ratio of 0.3 are shown in Tables 15 and 16. Cumulative production becomes 9.8 bn boe, 14.9 bn boe, and 18.7 bn boe respectively under the low, medium, and high prices scenarios. Compared to the case with discount rates of 10% and minimum NPV/I of 0.3 the reduction in cumulative production are over 1 bn boe under both medium and high price cases.

The results under the case with 15% discount rate and minimum NPV/I ratio of 0.5 are shown in Tables 17 and 18. Cumulative production becomes 9 bn boe, 12.3 bn boe, and 17.2 bn boe respectively under the 3 price scenarios. Compared to the case with 10% discount rate and minimum NPV/I of 0.3 the reduction in production is 3.6 bn boe under the medium price case and 2.7 bn boe under the high price case. It is very clear from the above that aggregate production is very sensitive to the choice of investment threshold, particularly the NPV/I ratio employed.

Table 9

Cumulative Potential Production from 2008 to 2035 (Mmboe)
Hurdle : Real NPV @ 10% / Real Devex @ 10% = 0.5
Standard case

	Sanctioned	Incremental	Future Incremental	Probable Fields	Possible Fields	Technical Reserves	New Exploration	TOTAL
$40/bbl and 30p/therm	7106	578	968	153	174	0	401	9381
$60/bbl and 50p/therm	7244	792	1543	560	212	1090	2708	14148
$80/bbl and 70p/therm	7352	1047	2227	868	240	2969	3518	18222

Table 10

Cumulative Potential Production from 2008 to 2035 (MMboe)
Hurdle : Real NPV @ 10% / Real Devex @ 10% = 0.5
Standard case

	Cns	Irish	MF	Nns	SNS	WoS	TOTAL
$40/bbl and 30p/therm	4263	266	859	2110	898	985	9381
$60/bbl and 50p/therm	6488	287	1147	2747	1580	1899	14148
$80/bbl and 70p/therm	7988	328	1625	3455	2256	2570	18222

Table 11

Cumulative Potential Production from 2008 to 2035 (MMboe)
Hurdle : Real NPV @ 12.5% / Real Devex @ 12.5% = 0.3
Standard case

	Sanctioned	Incremental	Future Incremental	Probable Fields	Possible Fields	Technical Reserves	New Exploration	TOTAL
$40/bbl and 30p/therm	7106	664	1109	176	174	43	741	10013
$60/bbl and 50p/therm	7244	928	1782	793	240	1467	3086	15540
$80/bbl and 70p/therm	7352	1327	2640	901	244	3613	3553	19631

Table 12

Cumulative Potential Production from 2008 to 2035 (MMboe)
Hurdle : Real NPV @ 12.5% / Real Devex @ 12.5% = 0.3
Standard case

	Cns	Irish	MF	Nns	SNS	WoS	TOTAL
$40/bbl and 30p/therm	4638	266	898	2277	949	985	10013
$60/bbl and 50p/therm	6909	288	1261	3013	1776	2293	15540
$80/bbl and 70p/therm	8084	328	1676	3673	2541	3328	19631

Table 13

Cumulative Potential Production from 2008 to 2035 (Mmboe)
Hurdle : Real NPV @ 12.5% / Real Devex @ 12.5% = 0.5
Standard case

	Sanctioned	Incremental	Future Incremental	Probable Fields	Possible Fields	Technical Reserves	New Exploration	TOTAL
$40/bbl and 30p/therm	7106	560	937	153	174	0	258	9188
$60/bbl and 50p/therm	7244	764	1491	457	212	437	2349	12953
$80/bbl and 70p/therm	7352	1042	2216	868	241	2774	3406	17899

Table 14

Cumulative Potential Production from 2008 to 2035 (MMboe)
Hurdle : Real NPV @ 12.5% / Real Devex @ 12.5% = 0.5
Standard case

	Cns	Irish	MF	Nns	SNS	WoS	TOTAL
$40/bbl and 30p/therm	4162	266	840	2110	894	915	9188
$60/bbl and 50p/therm	6288	287	1132	2720	1277	1249	12953
$80/bbl and 70p/therm	7914	328	1597	3319	2199	2542	17899

Table 15

Cumulative Potential Production from 2008 to 2035 (MMboe)
Hurdle : Real NPV @ 15% / Real Devex @ 15% = 0.3
Standard case

	Sanctioned	Incremental	Future Incremental	Probable Fields	Possible Fields	Technical Reserves	New Exploration	TOTAL
$40/bbl and 30p/therm	7106	653	1091	176	174	20	631	9851
$60/bbl and 50p/therm	7244	860	1681	588	232	1331	3008	14942
$80/bbl and 70p/therm	7352	1058	2251	901	244	3339	3533	18679

Table 16

Cumulative Potential Production from 2008 to 2035 (MMboe)
Hurdle : Real NPV @ 15% / Real Devex @ 15% = 0.3
Standard case

	Cns	Irish	MF	Nns	SNS	WoS	TOTAL
$40/bbl and 30p/therm	4564	266	875	2225	936	985	9851
$60/bbl and 50p/therm	6832	288	1158	2984	1701	1980	14942
$80/bbl and 70p/therm	8057	328	1636	3581	2407	2669	18679

Table 17

Cumulative Potential Production from 2008 to 2035 (Mmboe)
Hurdle : Real NPV @ 15% / Real Devex @ 15% = 0.5
Standard case

	Sanctioned	**Incremental**	**Future Incremental**	**Probable Fields**	**Possible Fields**	**Technical Reserves**	**New Exploration**	**TOTAL**
$40/bbl and 30p/therm	7106	539	903	153	174	0	173	9049
$60/bbl and 50p/therm	7244	719	1413	290	175	397	2081	12319
$80/bbl and 70p/therm	7352	943	2128	831	240	2438	3311	17243

Table 18

Cumulative Potential Production from 2008 to 2035 (MMboe)
Hurdle : Real NPV @ 15% / Real Devex @ 15% = 0.5
Standard case

	Cns	**Irish**	**MF**	**Nns**	**SNS**	**WoS**	**TOTAL**
$40/bbl and 30p/therm	4024	266	840	2110	894	915	9049
$60/bbl and 50p/therm	5894	287	1126	2687	1220	1106	12319
$80/bbl and 70p/therm	7498	328	1530	3233	2125	2528	17243

6. Conclusions

In this study projections of future activity levels in the UKCS have been made with the employment of financial simulation modelling including the use of the Monte Carlo technique to project new discoveries. The work has also been informed with a good quality database. The behavioural assumptions of investors have reflected those typically employed as far as oil/gas prices and project acceptance criteria are concerned. The results indicate a very high degree of price sensitivity in activity levels across the range of prices under both investment criteria. At prices of $40,30 pence activity levels fall off very sharply. Under the $80,70 pence scenario relatively healthy levels of activity are maintained over many years. On this basis the long-run potential is very substantial for the whole UKCS chain.

A noteworthy feature of the results of the modelling is the discovery that activity rates are highly sensitive to the assumptions made regarding hurdle rates for the acceptance of new investment projects. Thus if discount rates of 12.5% or 15% in real terms and minimum NPV/I ratios of 0.5 were employed rather than 10% rates and minimum NPV/I ratios of 0.3 long term investment and production would be very considerably reduced.

It should be stressed that the longer-term levels of activity depend on the infrastructure of main pipelines, terminals and key processing platforms remaining substantially intact. This is not guaranteed and substantial refurbishment is likely to be required to keep some of it in sound condition. The activity levels postulated also depend on the success of the various PILOT initiatives, namely the infrastructure Code of Practice, the fallow block/field initiative, and the stewardship initiative. Success of the last of these is required to ensure that the future incremental projects are developed. Without the success of all these policy initiatives the pace and volume of new developments (fields and incremental projects) will be considerably less than the high case discussed above.