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Prospects for Activity in the UK Continental Shelf after Recent Tax Changes: the 2012 Perspective

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

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

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

Over the last few years the research has examined the many evolving economic issues generally relating to petroleum investment and related fiscal and regulatory matters. Subjects researched include the economics of incremental investments in mature oil fields, economic aspects of the CRINE initiative, economics of gas developments and contracts in the new market situation, economic and tax aspects of tariffing, economics of infrastructure cost sharing, the effects of comparative petroleum fiscal systems on incentives to develop fields and undertake new exploration, the oil price responsiveness of the UK petroleum tax system, and the economics of decommissioning, mothballing and re-use of facilities. This work has been financed by a group of oil companies and Scottish Enterprise, Energy. The work on CO2 Capture, EOR and storage was financed by a grant from the Natural Environmental Research Council (NERC) in the period 2005 – 2008.

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d) Tax Relief for Decommissioning
e) Economics of Further Development of West of Shetland Region
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Prospects for Activity in the UK Continental Shelf after Recent Tax Changes: the 2012 Perspective

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Prospects for Activity in the UK Continental Shelf after Recent Tax Changes: the 2012 Perspective

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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. Recently several tax changes have been made, particularly an increase in the rate of Supplementary Charge (SC) from 20% to 32% and a succession of field allowances for the SC relating to small fields, heavy oil fields, HP/HT fields, remote gas fields, deepwater fields, large, shallow water gas fields, and brownfield investments. The details of these tax changes are summarised in Appendix 1. This study incorporates all the changes. The outputs highlight prospective production by field/ project type and geographic area as well as distinguishing between oil and gas. Expenditures on field investments, operating costs and decommissioning are also exhibited again according to field/ project type and geographic area. The projections are the result of economic modelling designed to reflect oil/ gas prices and investment hurdles typically employed in the UK Continental Shelf (UKCS). The detailed results are shown for the period covering the next 30 years.

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 incorporates key, best estimate information on production, and investment, operating and decommissioning expenditures. These refer to 356 sanctioned fields, 210 incremental projects relating to these fields, 36 probable fields, and 28 possible fields. These unsanctioned fields are currently being examined for development. An additional database contains 251 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas/condensate) 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 2040. 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 5 areas of the UKCS (Southern North Sea, (SNS), Central North / Moray Firth (CNS/MF), Northern North Sea (NNS), West of Scotland (WoS), and Irish Sea (IS)), and the results employed for use by 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	55
Medium	70	40

The postulated numbers of annual exploration wells drilled for the whole of the UKCS are as follows for 2013, 2030, and 2040:

Table 2 **Exploration Wells Drilled**			
	2013	2030	2040
High	30	23	20
Medium	25	18	15

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

While 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	28%
High effort/Lower success rate	25%

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 historic success rates over the time period.

The mean sizes of discoveries made in the historic period for each of the 5 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		
year	**2013**	**2038**
SNS	**9**	**6**
CNS/MF	**23**	**12**

NNS	**30**	**15**
WoS	**75**	**25**
IS	**5**	**4**

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 5 regions to 2040. 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 2040	
High effort/Lower success rate	169
Medium Effort/Medium Success Rate	151

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 $18.5 per boe with the highest being $99. In the SNS development costs were found to average just over $15 per boe because of the small size of fields. In the CNS/MF, they averaged $21 per boe, and in the NNS they averaged $18.4 per boe with the highest being $99. Operating costs over the lifetime of the fields were also calculated. The averages were found to be $13 per boe for all of the UKCS, $8.5 per boe in the SNS, $12.4 per boe in the CNS/MF and $18 per boe in the NNS. Total lifetime field costs (including decommissioning but excluding E and A costs) were found to average $36.8 per boe for all of the UKCS, $24.6 per boe in the SNS, $34.5 per boe in the CNS/MF, and $49.4 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 in these costs. Thus the field lifetime costs in small fields could become very high on a 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/MF the mean development costs are $25.6 per boe, and in NNS over $23.4 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 18 and 15 respectively for the 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 $15.3 per boe but the highest is over $79 per boe. In the SNS the average development costs are $9.7 per boe, but in the NNS it is $17 per boe. While operating costs are often relatively low and average $5 per boe across all of the UKCS, they are very high in a number of cases, with examples in the $50 - $86 per boe range over their lifetime.

A noteworthy feature of the 210 incremental projects in the database 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 to be linked not only 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 6 years indicated a decline rate in the volumes. On the basis of this, and utilising 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 <u>all</u> categories of host fields. Their sizes and costs reflect recent trends.

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 distributions, 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. In one scenario the development project goes ahead when the NPV/I ratio as defined above is real terms ≥ 0.3. To reflect the effects of tougher capital rationing another scenario when the hurdle is NPV/I ≥ 0.5 is also shown. 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, including all the field allowances introduced in 2012. The modelling is initially undertaken in

MOD terms with an inflation rate of 2.5%. This incorporates the effects of any fiscal drag. The results are then converted to real terms.

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.

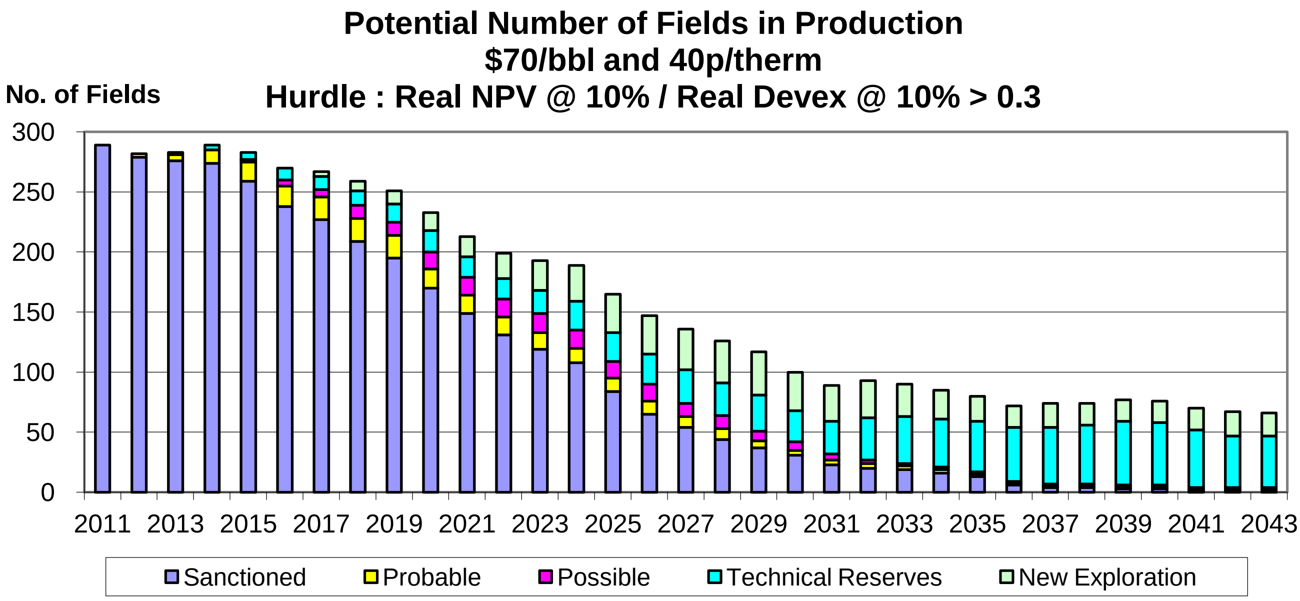
3. Results

A. $70, 40 pence prices, Investment Hurdle NPV/I > 0.3, Results by Field/ Project Categories

(i) Numbers of Fields in Production

In Chart 1 the numbers of fields continuing in production are shown over the study period. They remain relatively steady for a few years, then fall quite steeply to around 2031 after which the decline rate is slower. The decline rate in the number of currently sanctioned fields is quite steep throughout the period from 2014. In 2042 there are 67 fields continuing to produce. The slower decline rate after 2030 is due to the preponderance of fields in the category of technical reserves. They are generally high cost (per boe) but are on average rather larger than many of the other future fields, and thus last longer. The main finding is that from 2014 to 2031 the number of new fields coming into production fail to match the numbers reaching the end of their economic lives. Over the whole period 2012-2042 there are 207 new field developments (excluding sanctioned) which pass the hurdle.

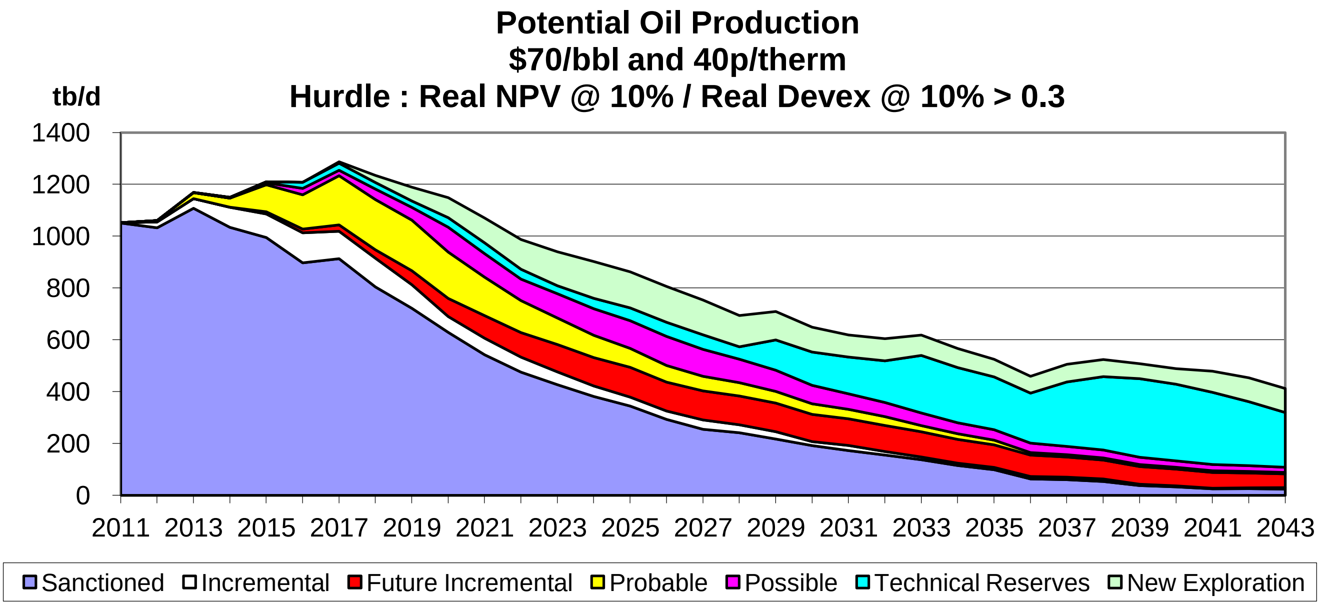
Chart 1



(ii) Oil Production

In Chart 2 the prospects for oil production are shown. Over the next few years to 2015 production should increase significantly from the relatively low level experienced in 2011. The increase emanates primarily from the development of current incremental projects and probable fields. A high degree of confidence can be attached to these developments after 2018 the decline rate is quite brisk. Future incremental projects and the development of new discoveries make a significant contribution to 2028 or so. After that it is the output from high cost fields in the category of technical reserves which makes the most important contribution to the total which is still substantial at 454,000 b/d in 2042.

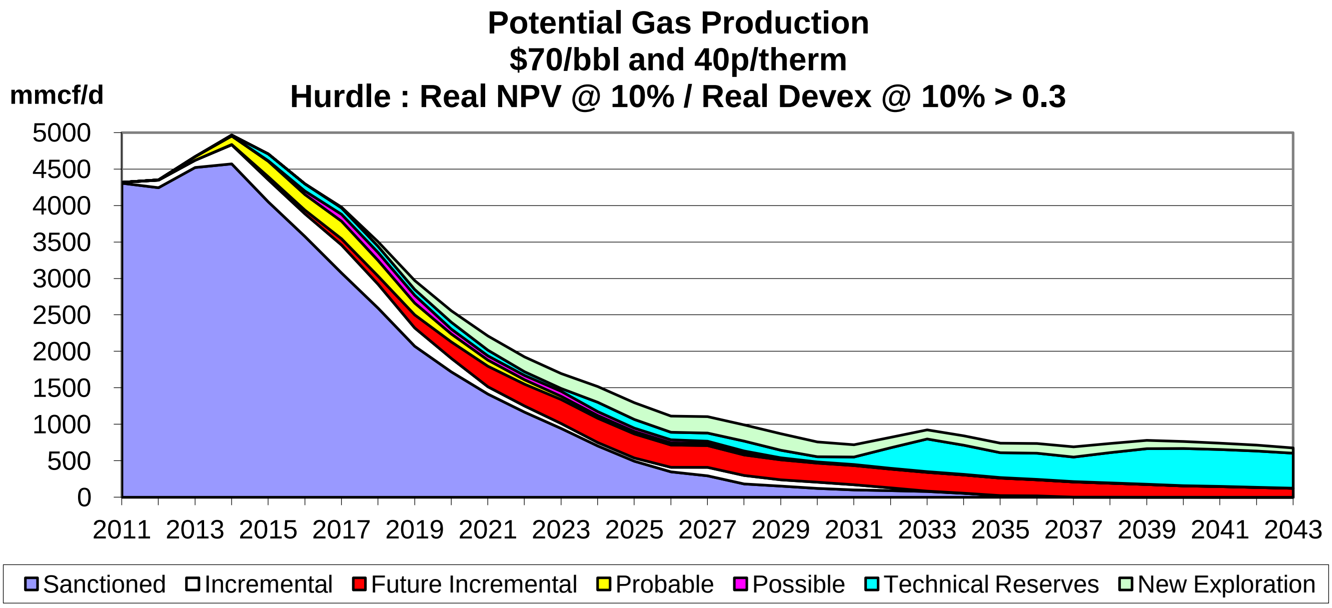
Chart 2



(iii) Gas Production

In Chart 3 the prospects for gas production are shown. Again there is a rebound from 2011 levels to nearly 5 bcf/d in 2014, but thereafter the decline rate is very sharp until 2030, after which it is stabilised such that in 2042 production is 715 mm cf/d. In the period from 2014 to 2030 the decline rate from the sanctioned fields is quite steep and the contributions from new fields and projects of all categories is relatively modest. This results from a contribution of (a) relatively low gas prices compared to oil, and (b) the exploration prospectivity being less with gas compared to oil.

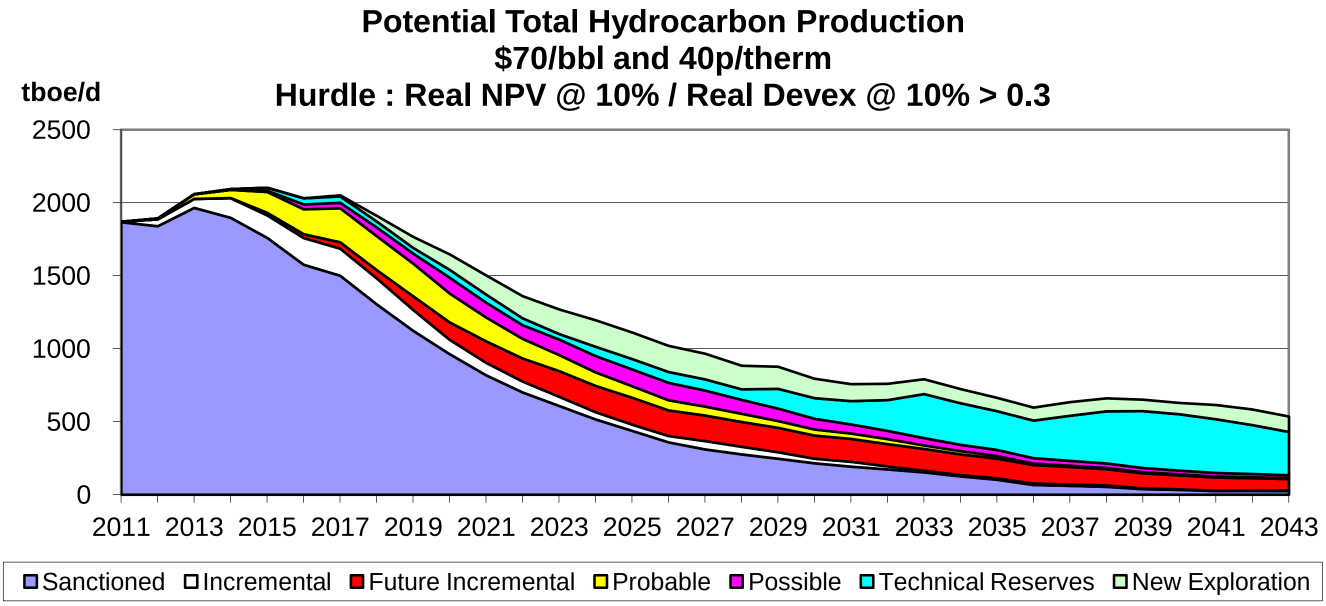
Chart 3



(iv) Total Hydrocarbon Production

The prospective total hydrocarbon production (including NGLs) is shown in Chart 4. There is a worthwhile increase over the next few years, but from around 2017 output falls at a fairly brisk rate until 2030 or so. In 2042 production is 584,000 boe/d. In the medium term there is some encouragement from the contributions of fields in the probable and possible categories and from current and future incremental projects. In the period beyond 2030 the main contribution comes from high cost fields in the technical reserves category.

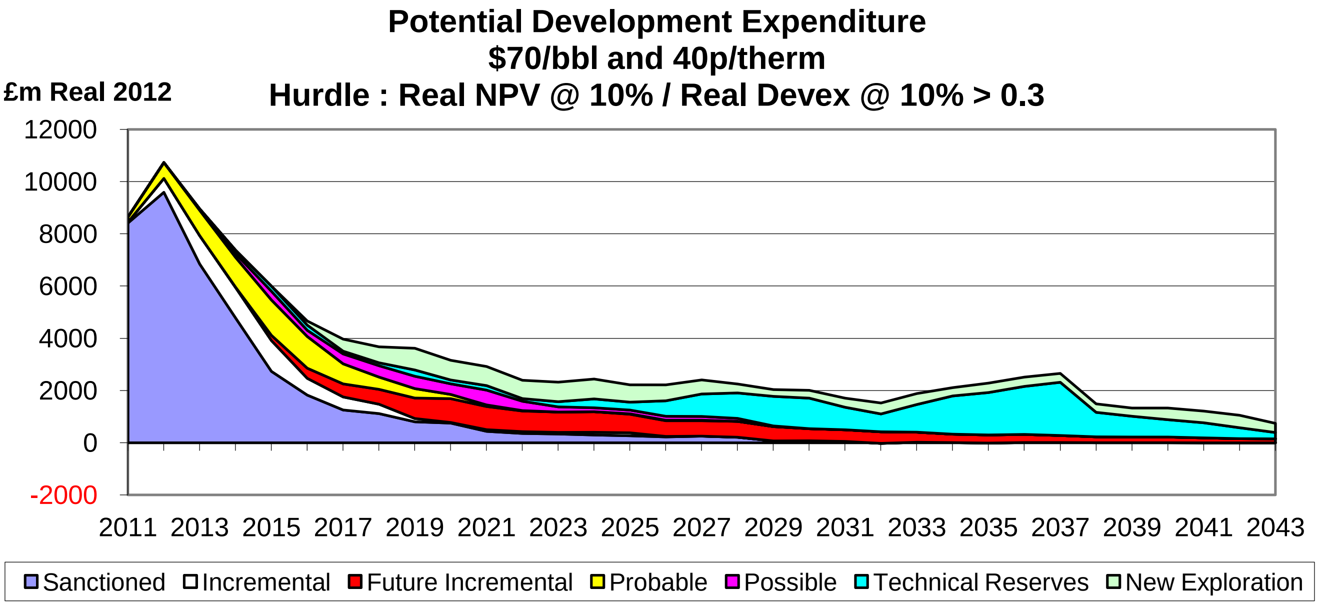
Chart 4



(v) Development Expenditures

In Chart 5 prospective field development expenditures are shown. In the near term these are relatively high, exceeding £10 billion per year for 2012 and 2013. This results from the coincident development of several large, expensive fields. Thereafter there is a sharp fall reflecting the modest numbers of new fields which pass the economic hurdle and their lower (absolute) expenditures.

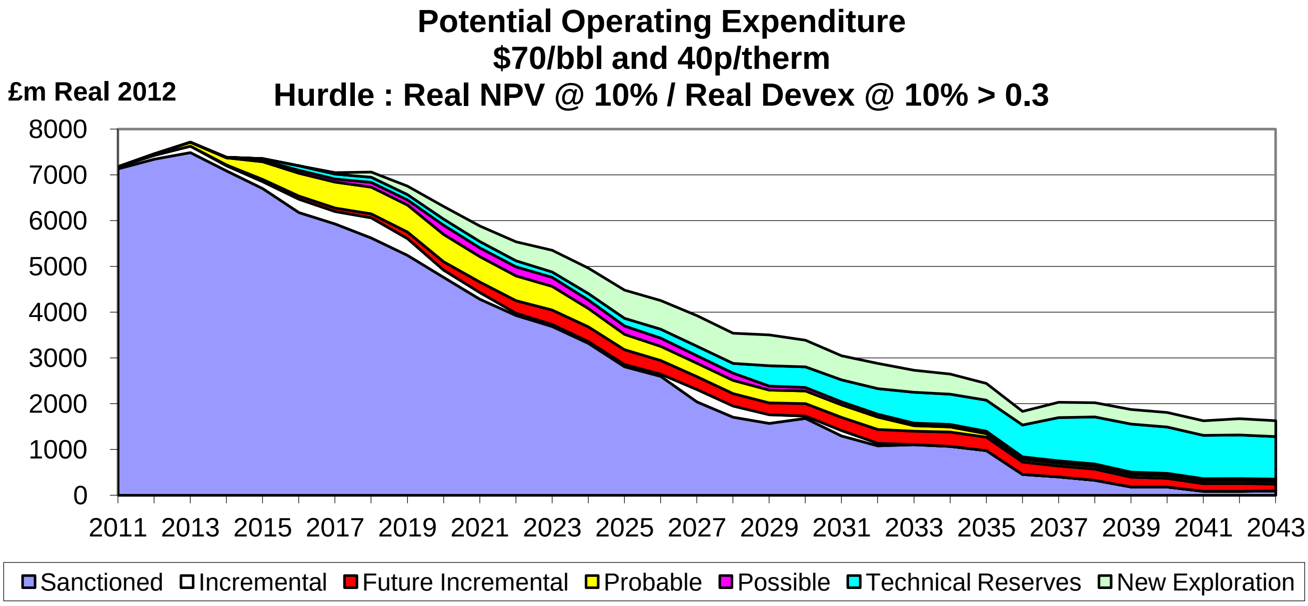
Chart 5



(vi) Operating Expenditures

In Chart 6 prospective operating expenditures are shown. They increase from around £7 billion in 2011 to around £7.7 billion in 2013. Thereafter they fall at a gentle pace until 2019 after which the decline rate is more pronounced. The profile of these expenditures reflects the interaction of the number of fields reaching their COP dates and the numbers of new developments.

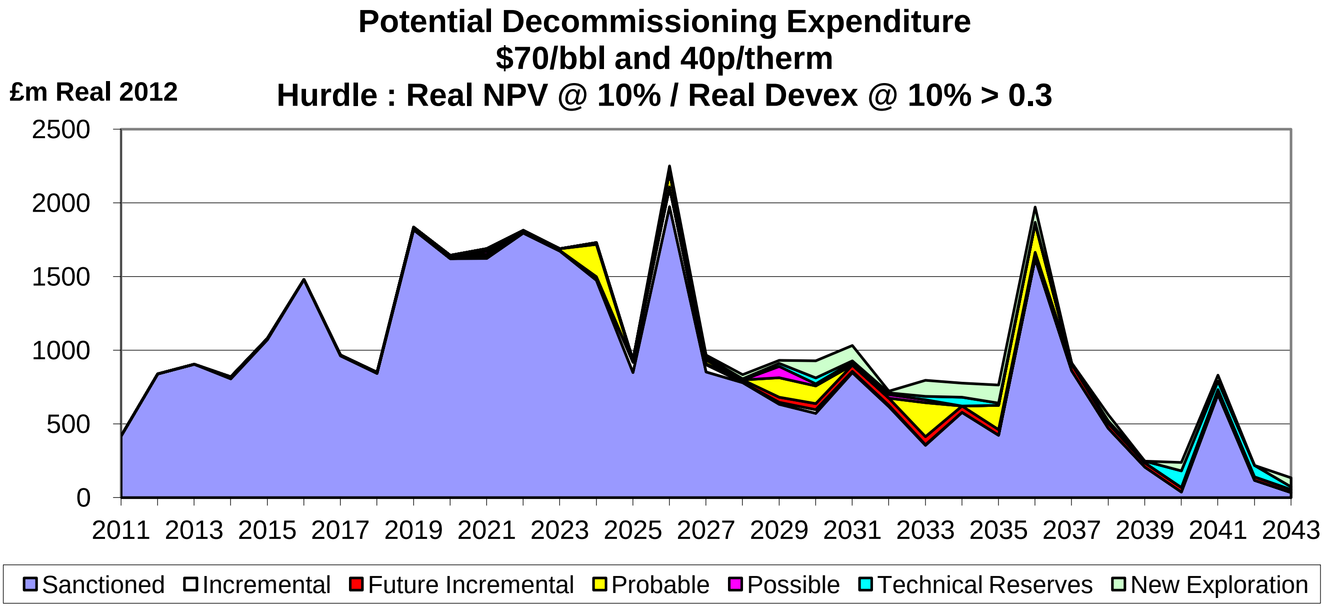
Chart 6



(vii) Annual Decommissioning Expenditures

In Chart 7 the prospective annual decommissioning expenditures are shown. Notable features are the dominance of sanctioned fields in the total and the large fluctuations in the annual expenditures. These reflect the lumpiness of the decommissioning activities through time. If several large structures are being decommissioned at the same time there can be a very large effect on the total level of expenditure. In practice some smoothing is desirable.

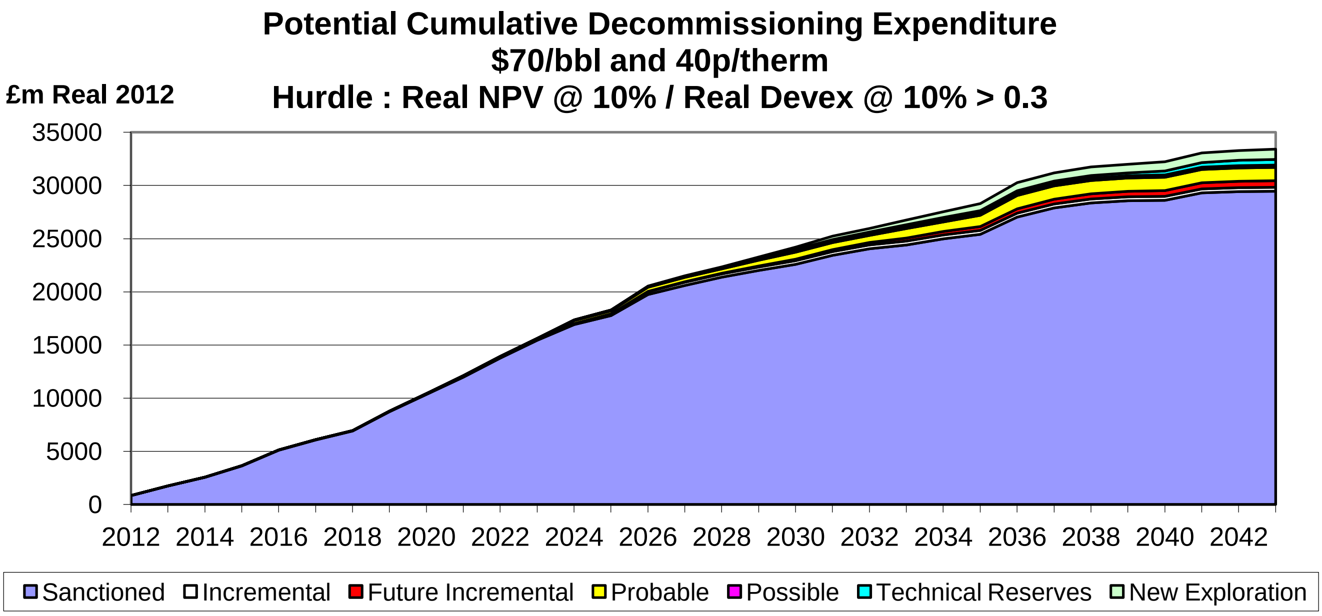
Chart 7



(viii) Cumulative Decommissioning Expenditures

In Chart 8 the cumulative expenditures to 2042 are shown. The grand total is nearly £33 billion (at 2012 prices) with the great majority relating to sanctioned fields.

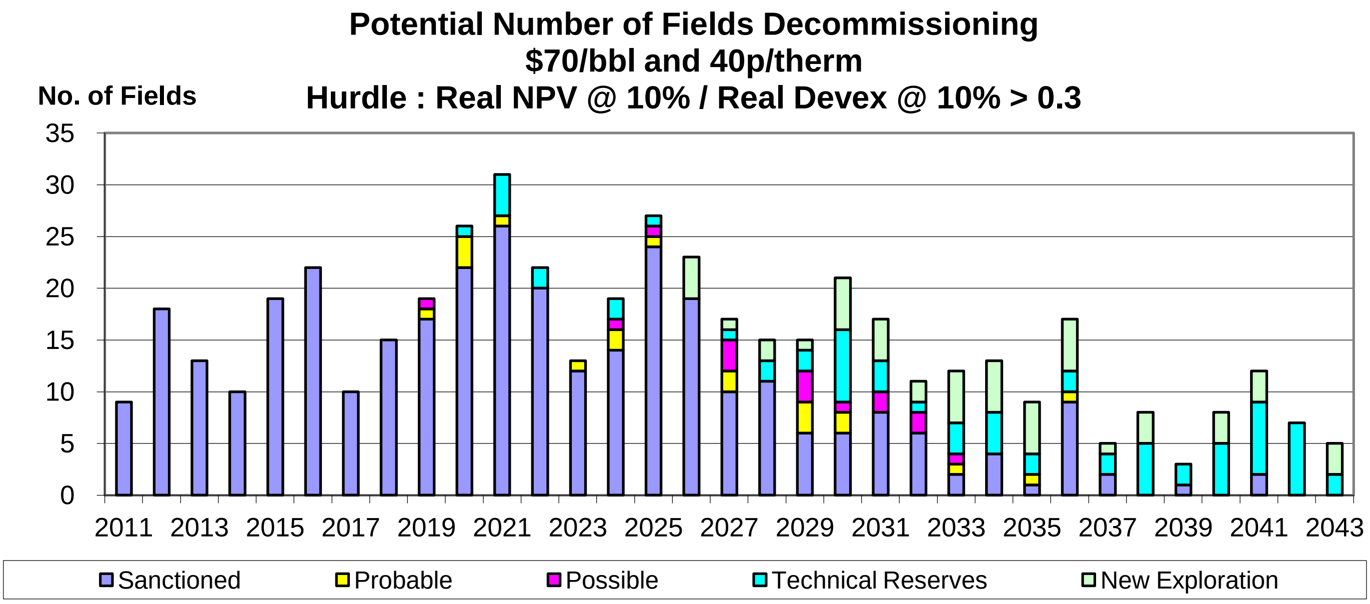
Chart 8



(ix) Numbers of Fields Decommissioning

In Chart 9 the annual numbers of fields reaching their COP dates and being decommissioned over the next 30 years are shown. In some years the numbers are seen to be very large, creating a potential bunching problem. Over the whole period to 2042 478 fields reach their COP dates.

Chart 9

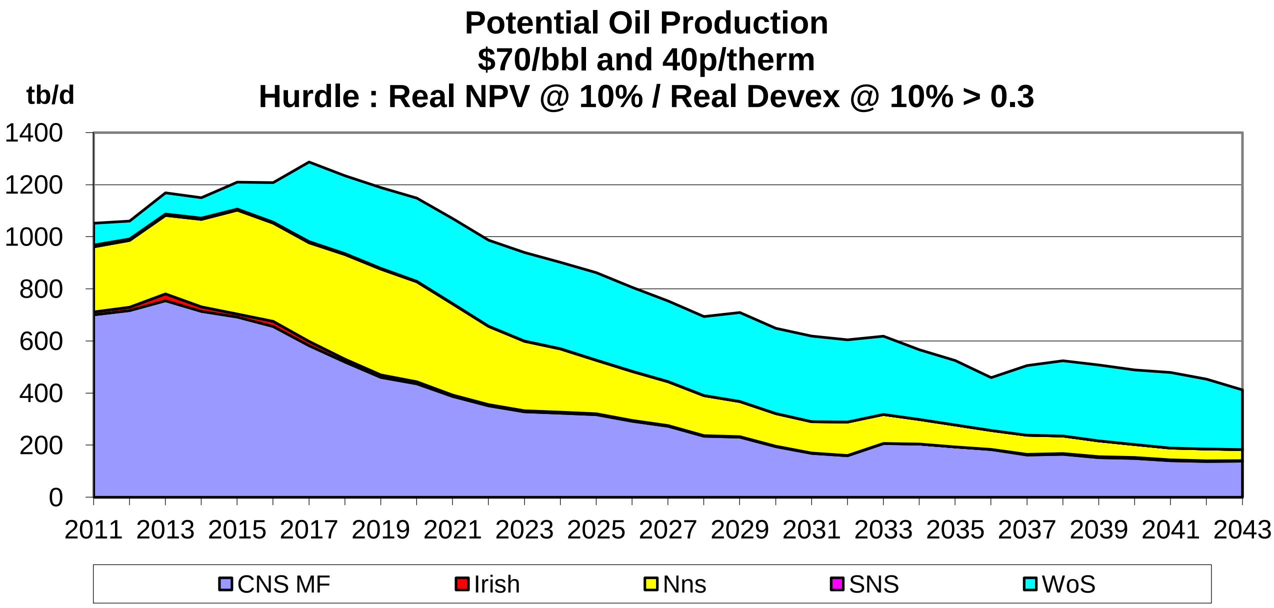


B. $70, 40 pence price, Investment Hurdle NPV/I > 0.3, Results by Geographic Region

(i) Oil Production

In Chart 10 prospective oil production is shown by geographic regions of the UKCS. The main features are the large growth in output from the West of Shetlands region from 2017. Production from this area remains very substantial to 2042. In the medium term production from the NNS also becomes very substantial, but declines rapidly after 2020 to reach very low levels by 2042.

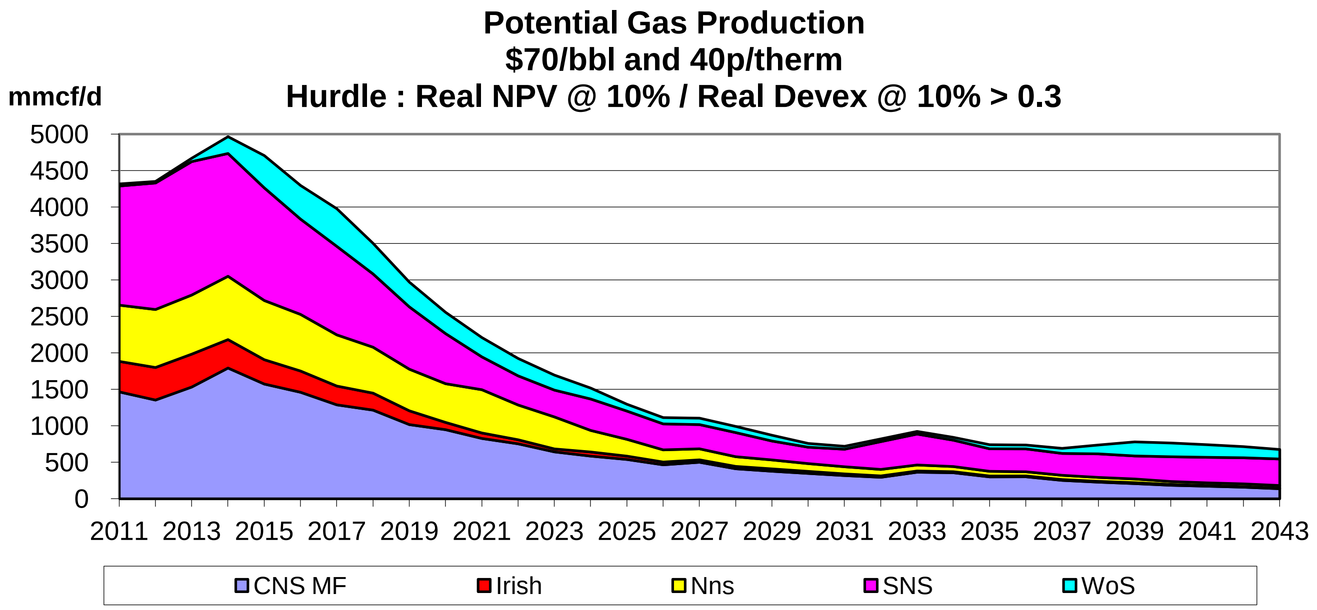
Chart 10



(ii) Gas Production

Prospective gas production by geographic region is shown in Chart 11 where it is seen that from 2015 there is a sharp decline from 2015 onwards from CNS/MF and SNS regions which are currently the main producing areas. There is no compensating increase in the W of S region where it is seen that the output growth is relatively modest on a national scale.

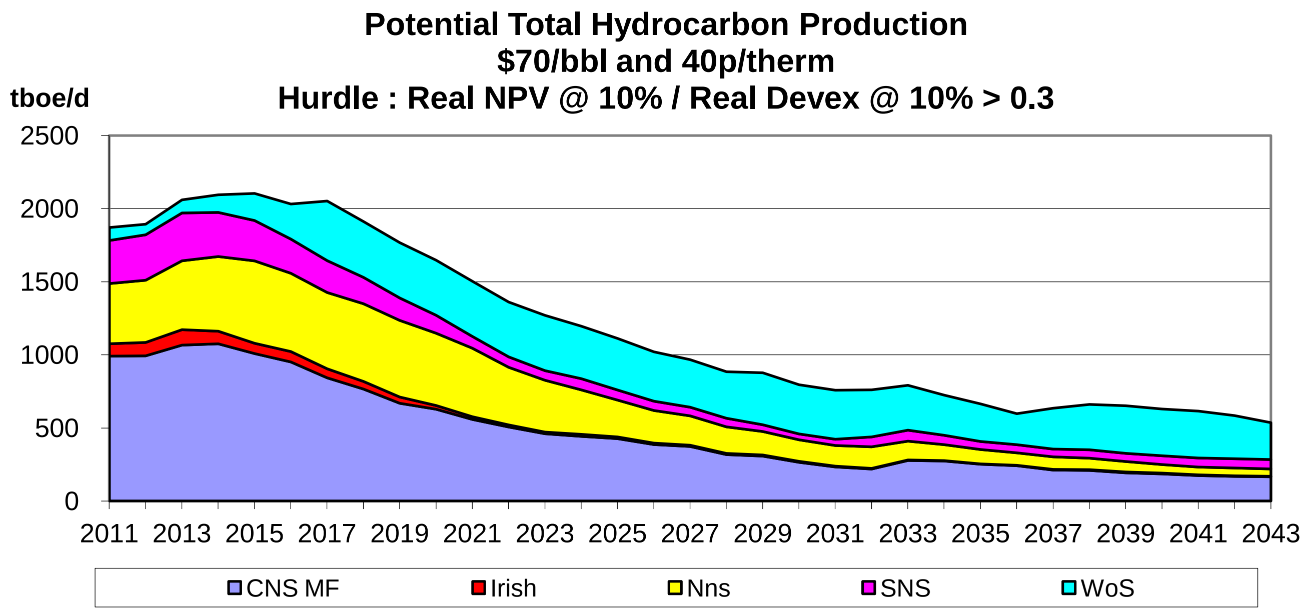
Chart 11



(iii) Total Hydrocarbon Production

Prospective total hydrocarbon production from the 5 regions is shown in Chart 12. The growing importance of the NNS in the medium term and the major long term contribution from the W of S region are the most noteworthy features.

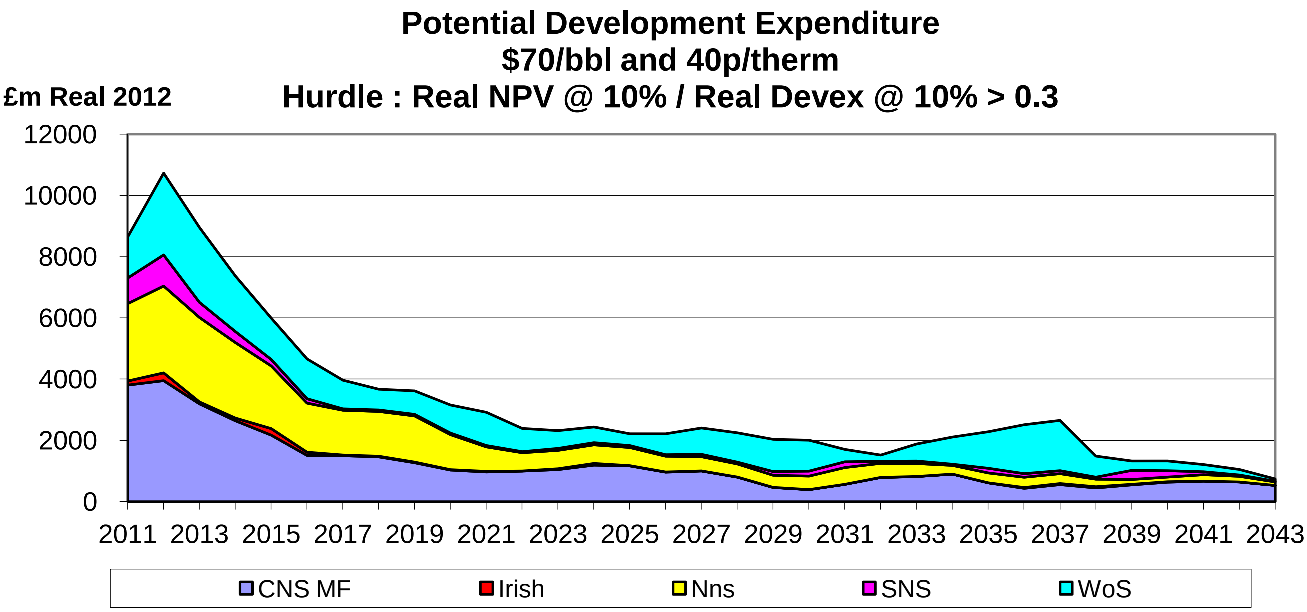
Chart 12



(iv) Development Expenditures

Potential development expenditures by main region are shown in Chart 13. The importance of the W of S and NNS regions over the next few years are main features.

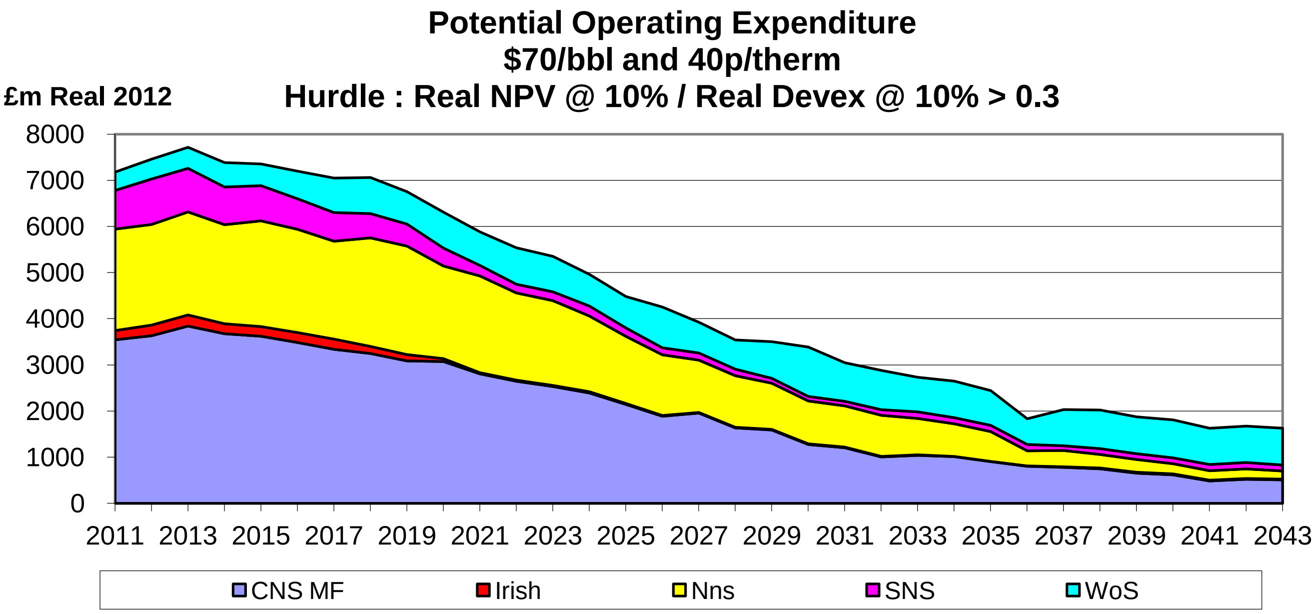
Chart 13



(v) Operating Expenditures

In Chart 14 operating expenditures by main region are shown. The CNS/MF region is the most important for many years ahead followed by the NNS.

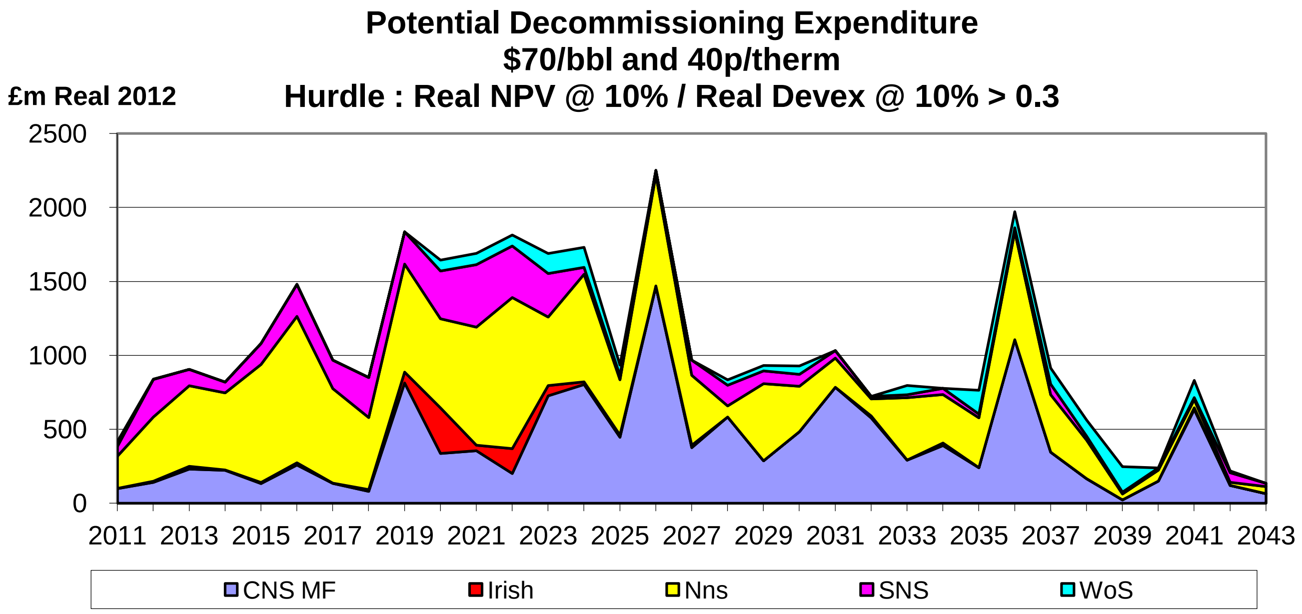
Chart 14



(vi) Annual Decommissioning Expenditures

In Chart 15 annual decommissioning expenditures are shown by region. In the period to 2025 or so the NNS is the most important region, reflecting the decommissioning of a number of very large platforms. In the longer terms the CNS/MF region becomes the most important reflecting the large number of installations, many of which are both large and fixed.

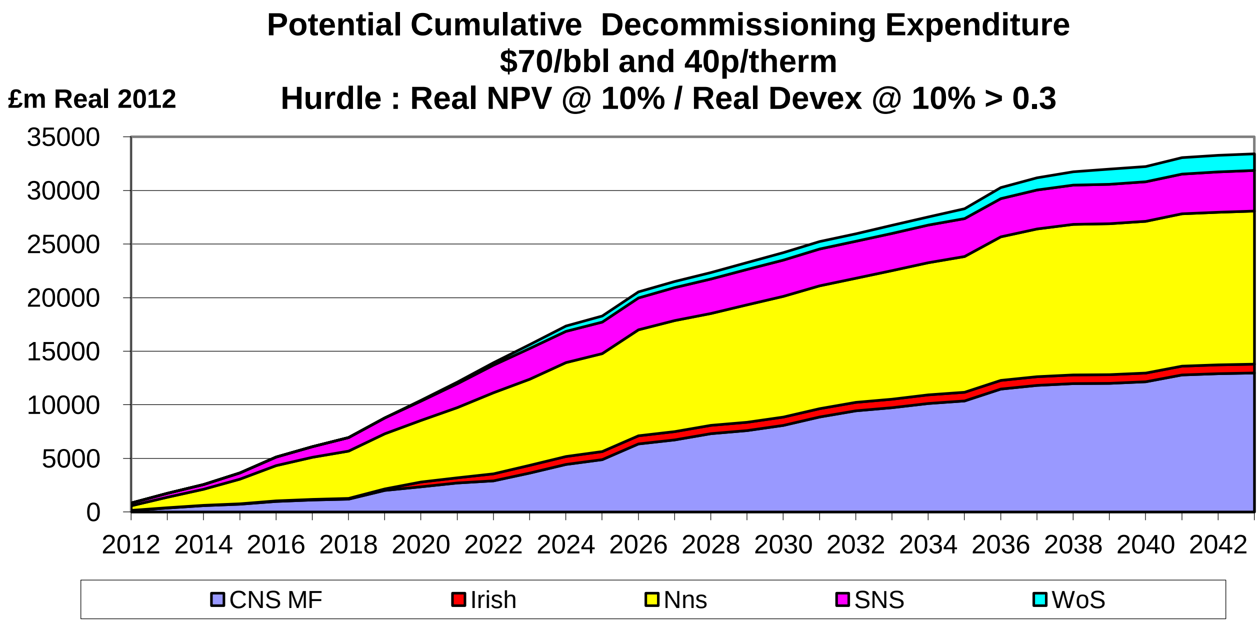
Chart 15



(vii) Cumulative Decommissioning Expenditures

In Chart 16 cumulative decommissioning expenditures by main region are shown. The preponderance of the NNS and CNS/MF regions is highlighted.

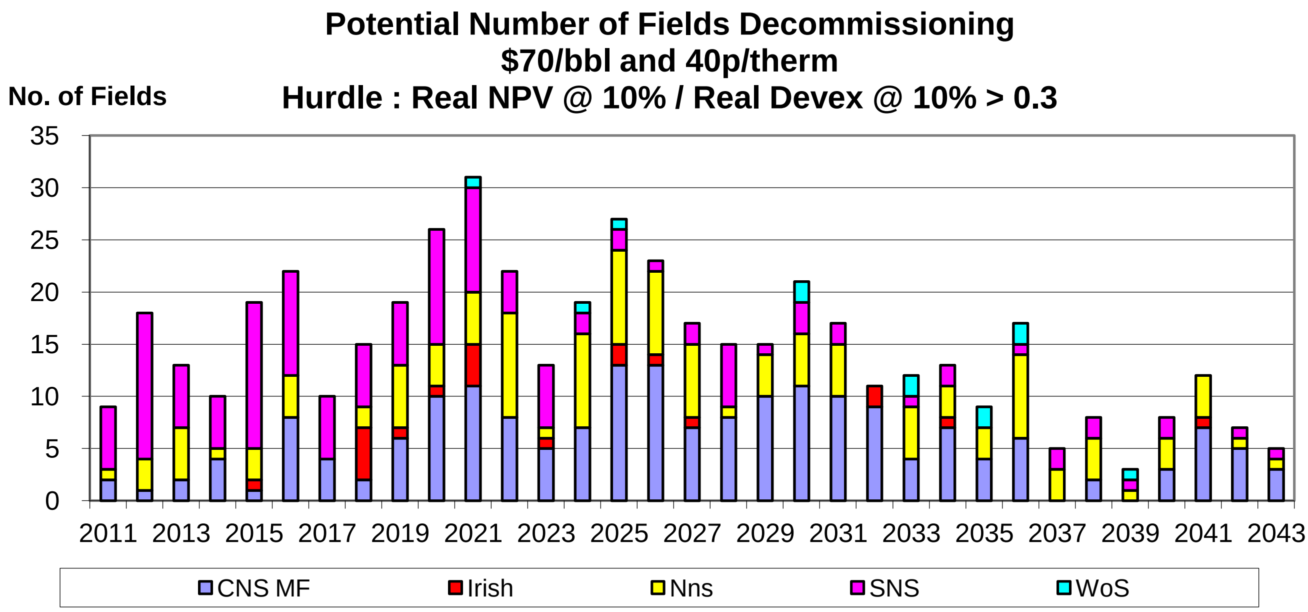
Chart 16



(viii) Numbers of Fields Decommissioning

In Chart 17 the numbers of fields reaching their COP dates and then being decommissioned are shown. In the near/medium term the large numbers in the SNS are a noteworthy feature.

Chart 17

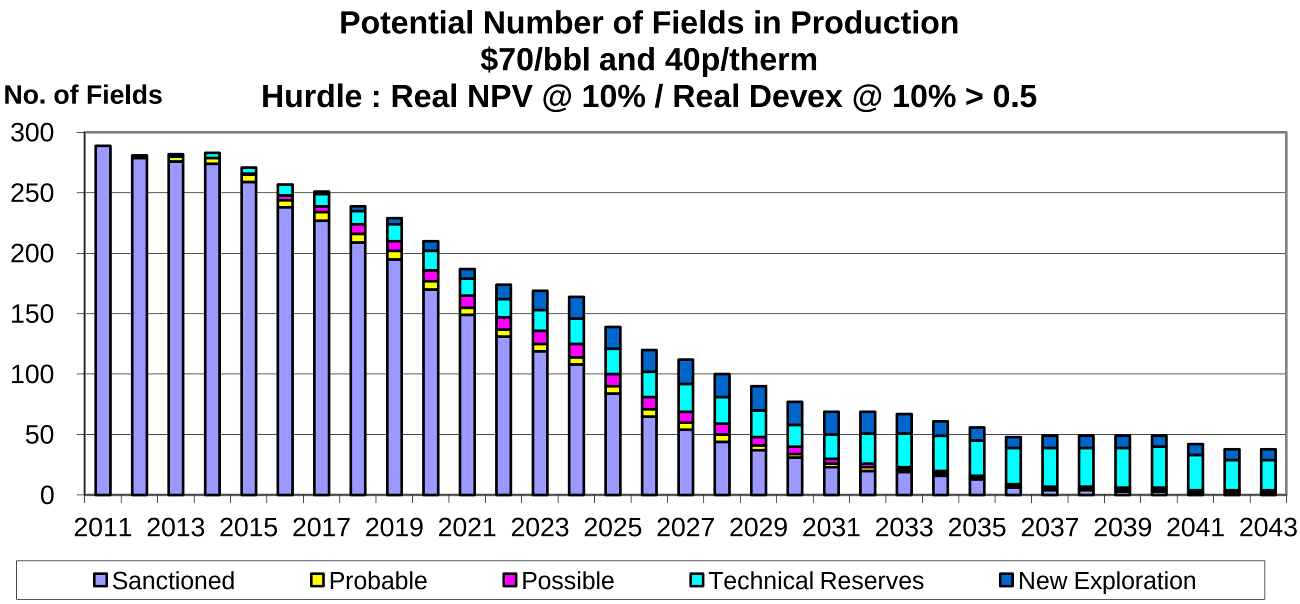


C. $70, 40 pence scenario, Investment Hurdle NPV/I > 0.5, Results by Field/ Project Categories

(i) Numbers of Fields in Production

In Chart 18 the numbers of fields in production over the next 30 years are shown under the tougher investment hurdle of NPV/I > 0.5. The decline rate in the number of producing fields is faster than in the case where the investment hurdle was NPV/I > 0.3. In 2042 there are only 38 producing fields compared to 67 fields with the more lenient hurdle. Over the period 2011-2042 there are 129 new field developments excluding 4 already sanctioned.

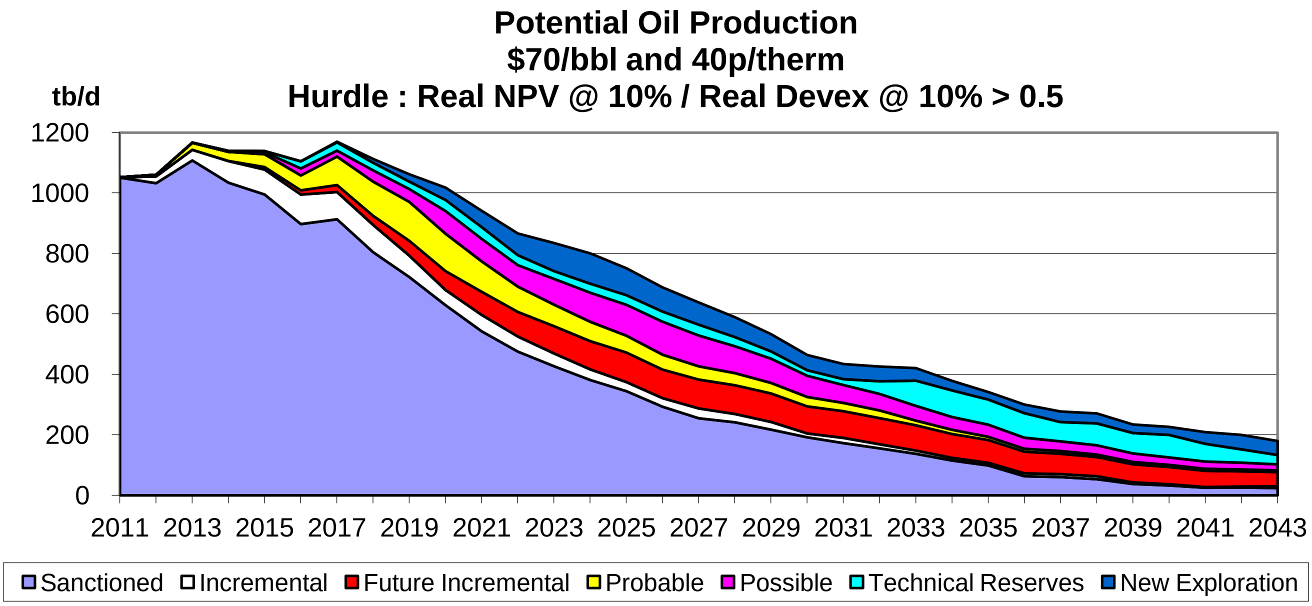
Chart 18



(ii) Oil Production

In Chart 19 Prospective oil production is shown. There is a modest near term increase above 2011 levels but thereafter the decline rate is brisk. The relatively modest number of new fields passing the economic hurdle is the main explanation. By 2042 production falls to around 200,000 b/d.

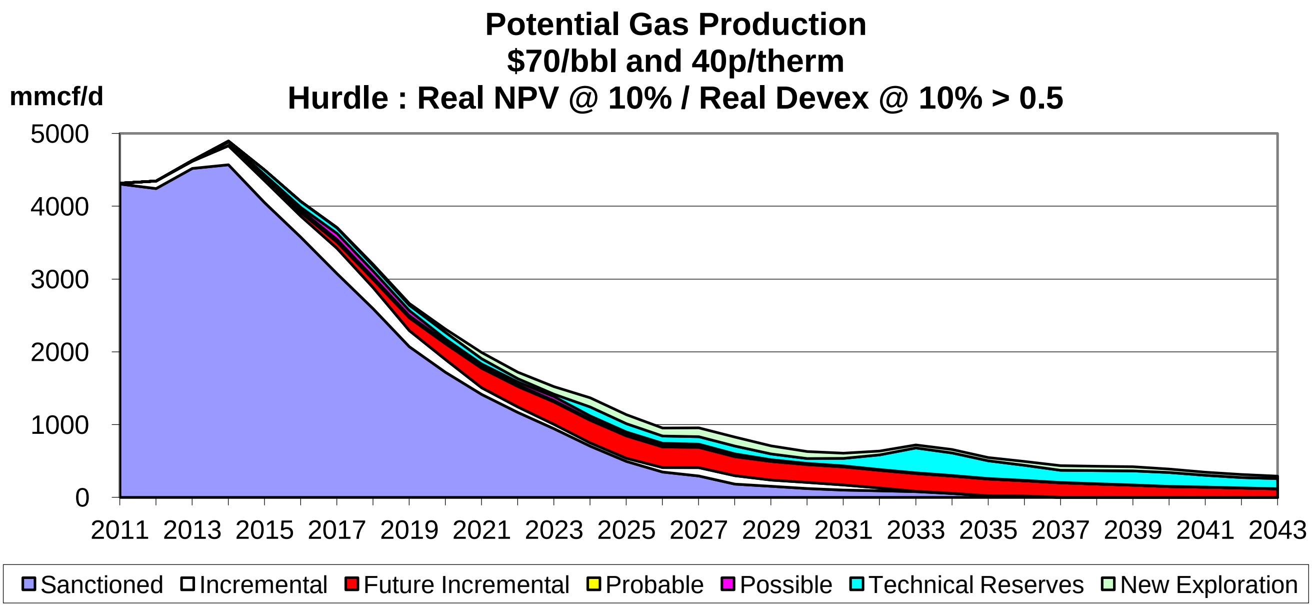
Chart 19



(iii) Gas Production

In Chart 20 prospective gas production is shown. There is a modest short-term increase from 2011 levels but thereafter the decline rate is very brisk until 2030 with only small amounts coming from new developments. Only a relatively modest number is viable with the higher hurdle rate and lower price. By 2042 production is around 315 mm cf/d.

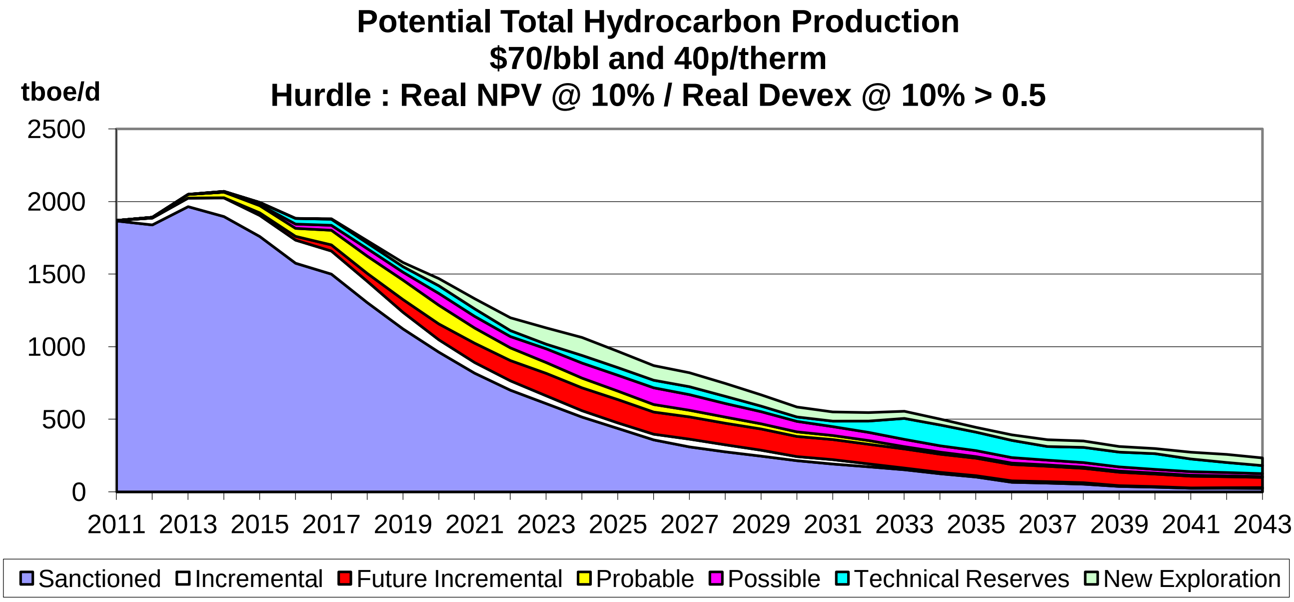
Chart 20



(iv) Total Hydrocarbon Production

In Chart 21 prospective total hydrocarbon production (including NGLs) is shown. After a near term increase the decline rate is quite brisk until 2030, and by 2042 production is around 258,000 boe/d.

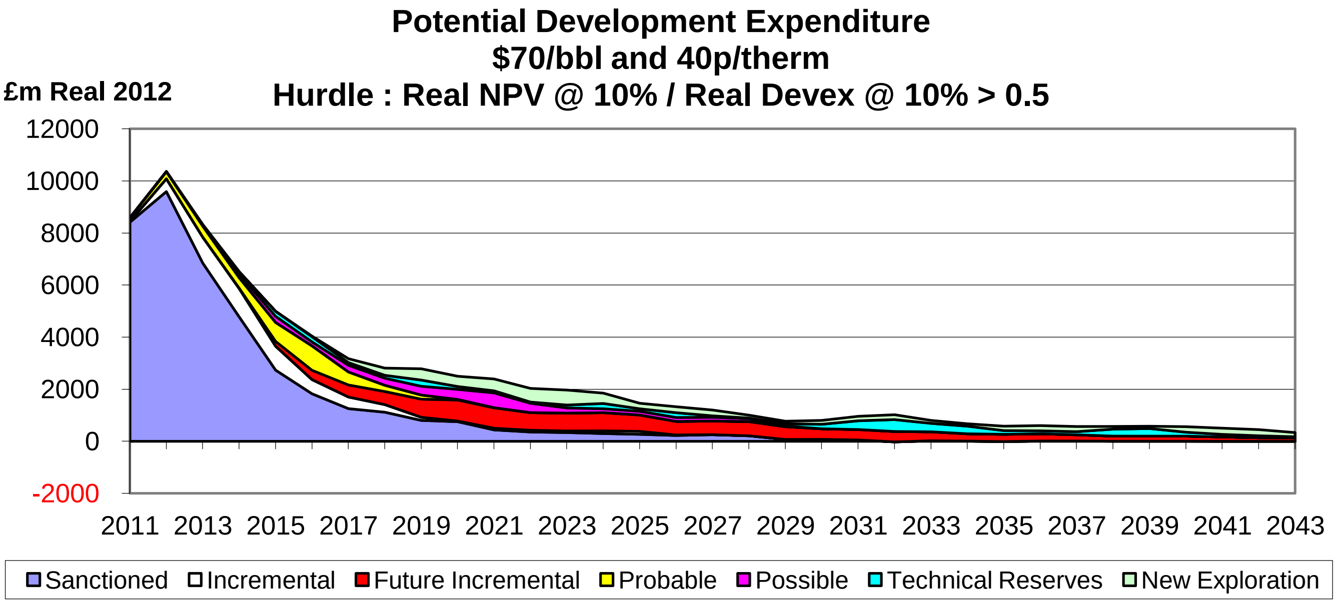
Chart 21



(v) Development Expenditures

In Chart 22 prospective development expenditures are shown under the tougher hurdle rate. The level still increases to over £10 billion in the short term but falls sharply thereafter until 2017, after which the decline rate is less steep. It should be noted that by 2014 the level still exceeds £6 billion which would have been regarded as a respectable level a few years ago.

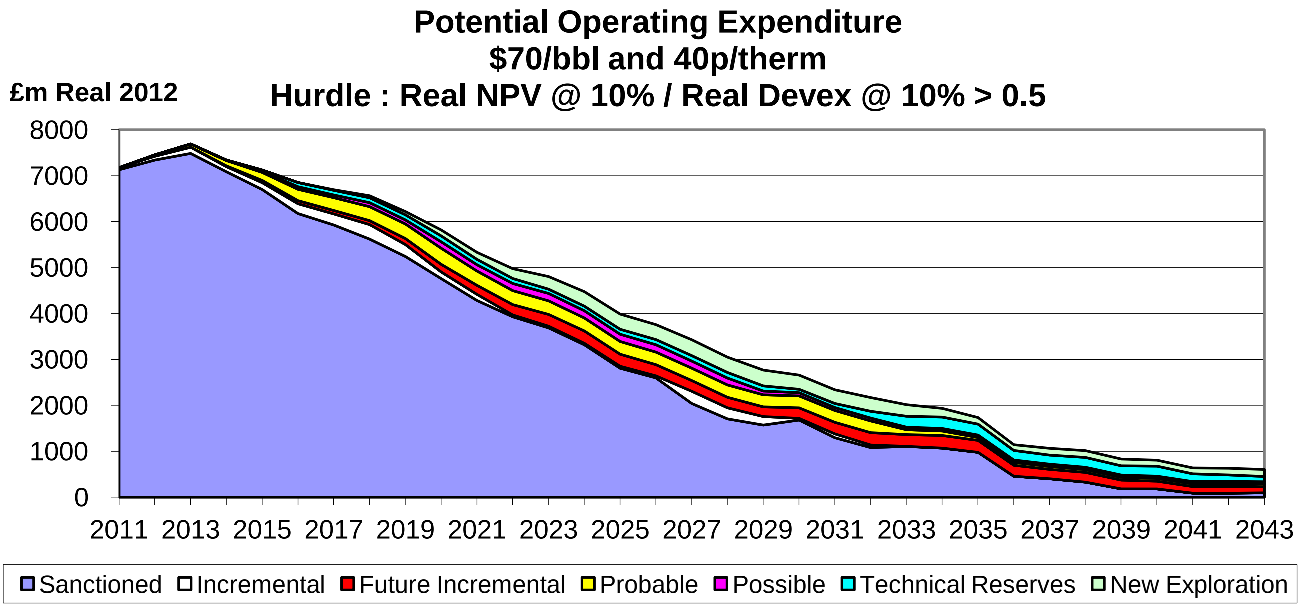
Chart 22



(vi) Operating Expenditures

In Chart 23 prospective operating expenditures are shown. In the short term they increase to £7.6 billion and then decline at a steady pace reflecting the reduction in the number of producing fields.

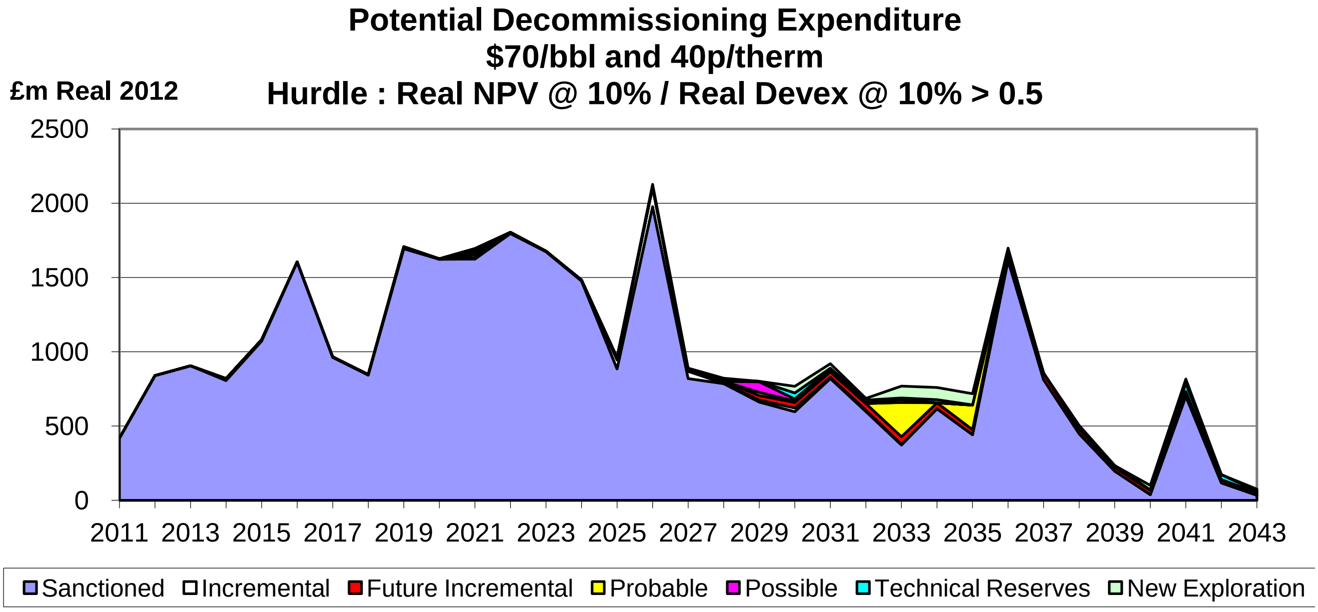
Chart 23



(vii) Annual Decommissioning Expenditures

In Chart 24 the annual expenditures on decommissioning are shown. The volatility reflects the bunching of major projects.

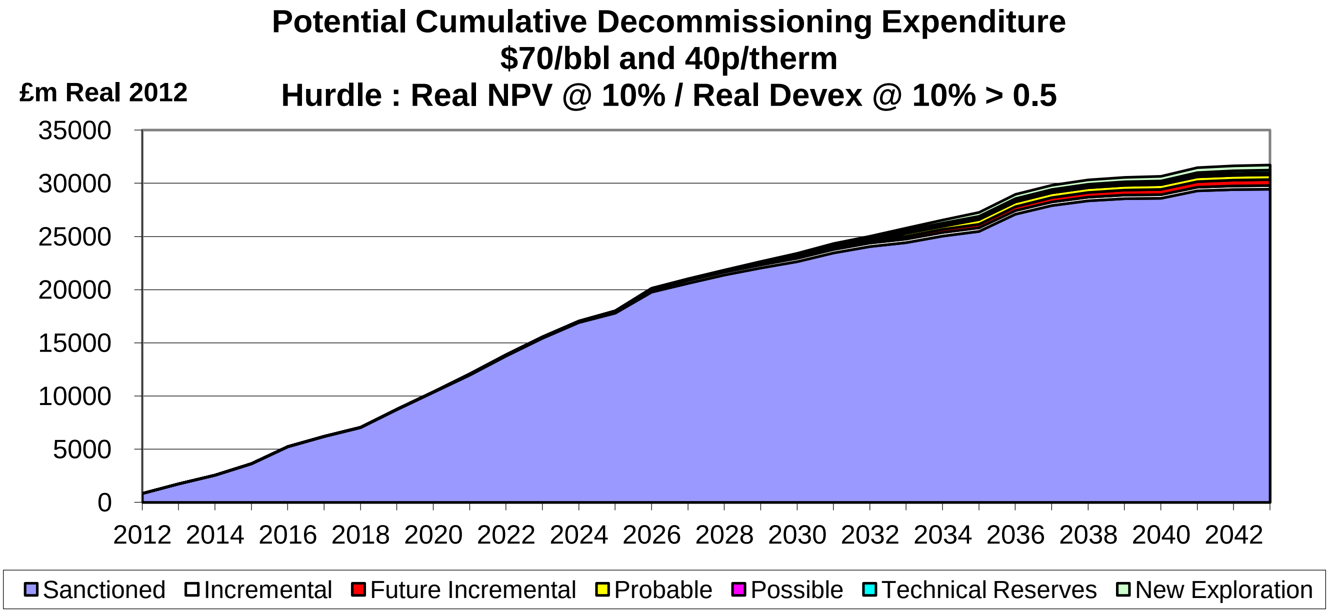
Chart 24



(viii) Cumulative Decommissioning Expenditures

In Chart 25 cumulative decommissioning expenditures to 2042 is shown. The total over the period amounts to £32 billion, somewhat less than with the lower hurdle rate as fewer fields are developed over the period.

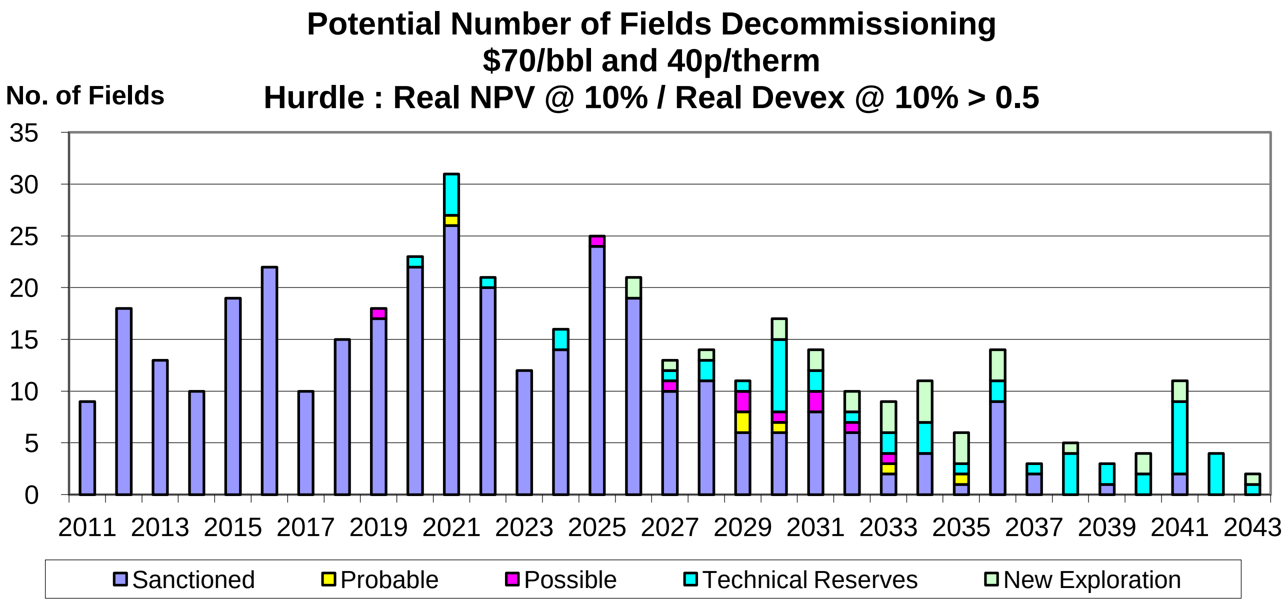
Chart 25



(ix) Numbers of Fields Decommissioning

In Chart 26 the number of fields decommissioning annually over the period are shown. The cumulative total is 424, giving an annual average of 13.7 (including 2012).

Chart 26

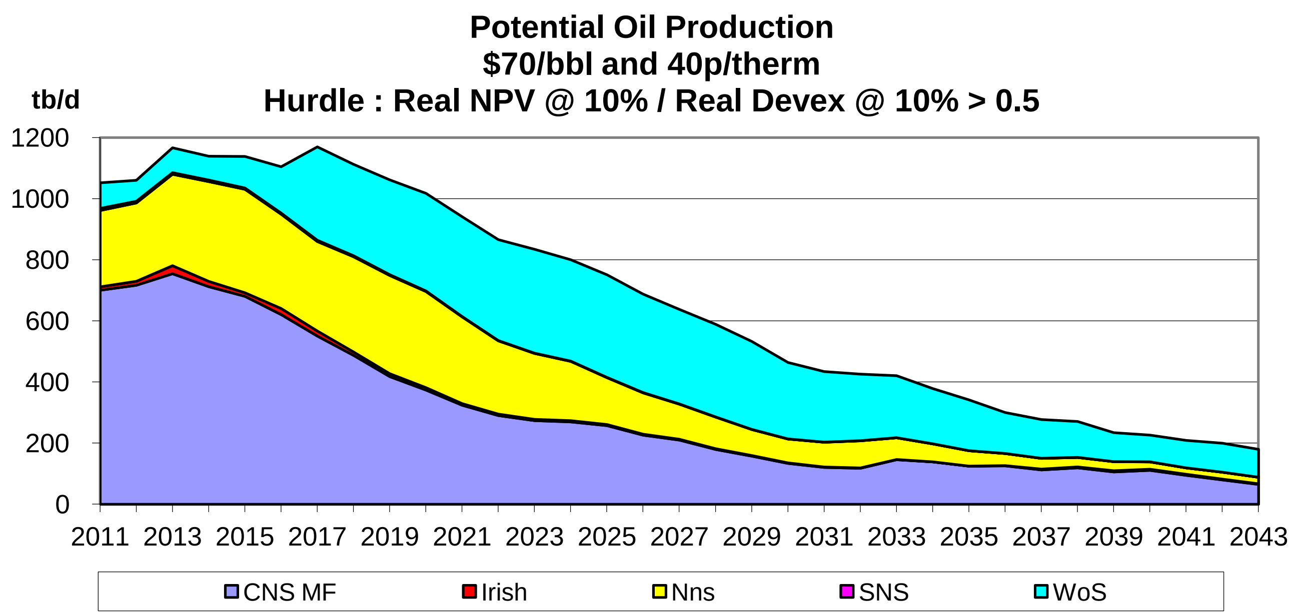


D. $70, 40 pence price scenario, Investment Hurdle NPV/I > 0.5 Results by Geographic Area

(i) Oil Production

In Chart 27 prospective oil production by main geographic area of the UKCS is shown. The key features are the current dominance of the CNS/MF region and its prospective relative decline, the increased production from the NNS in the medium term followed by a steep decline, and the growing importance of the W of S region in the medium and longer term.

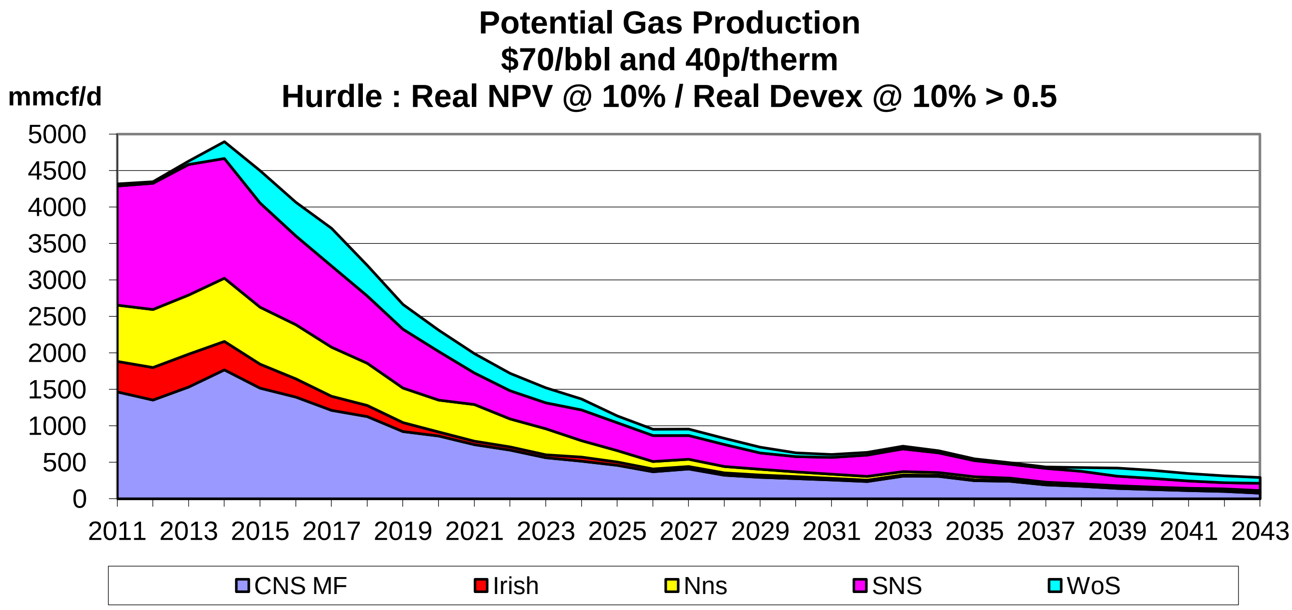
Chart 27



(ii) Gas Production

In Chart 28 prospective gas production by major regions of the UKCS is shown. Key features are the importance of the CNS/MF region for many years ahead, the continued importance of the SNS region until around 2020, and the modest contribution from the W of S region.

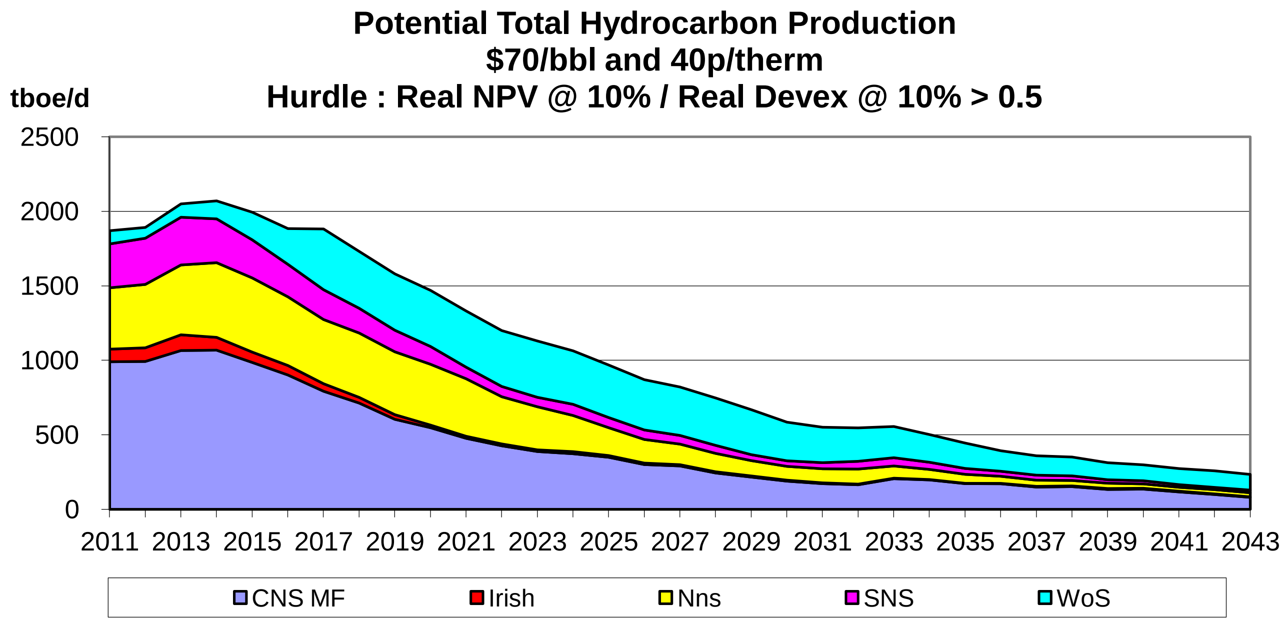
Chart 28



(iii) Total Hydrocarbon Production

In Chart 29 prospective total hydrocarbon production is shown under the higher hurdle rate. Key features are the continued importance of the CNS/MF region, the growth in importance of the W of S for a few years in the medium term, and the longer term importance of the W of S region in the total.

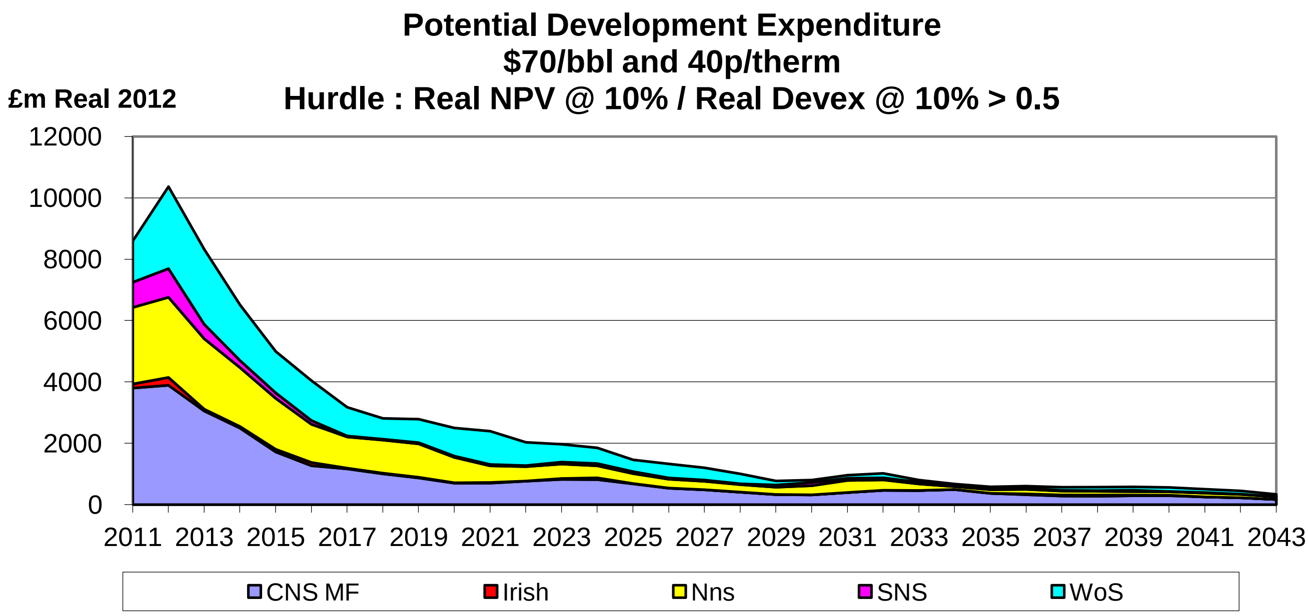
Chart 29



(iv) Development Expenditures

In Chart 30 prospective development expenditures are shown. In the near term there are notable increases in the NNS and W of S regions in the context of a declining total.

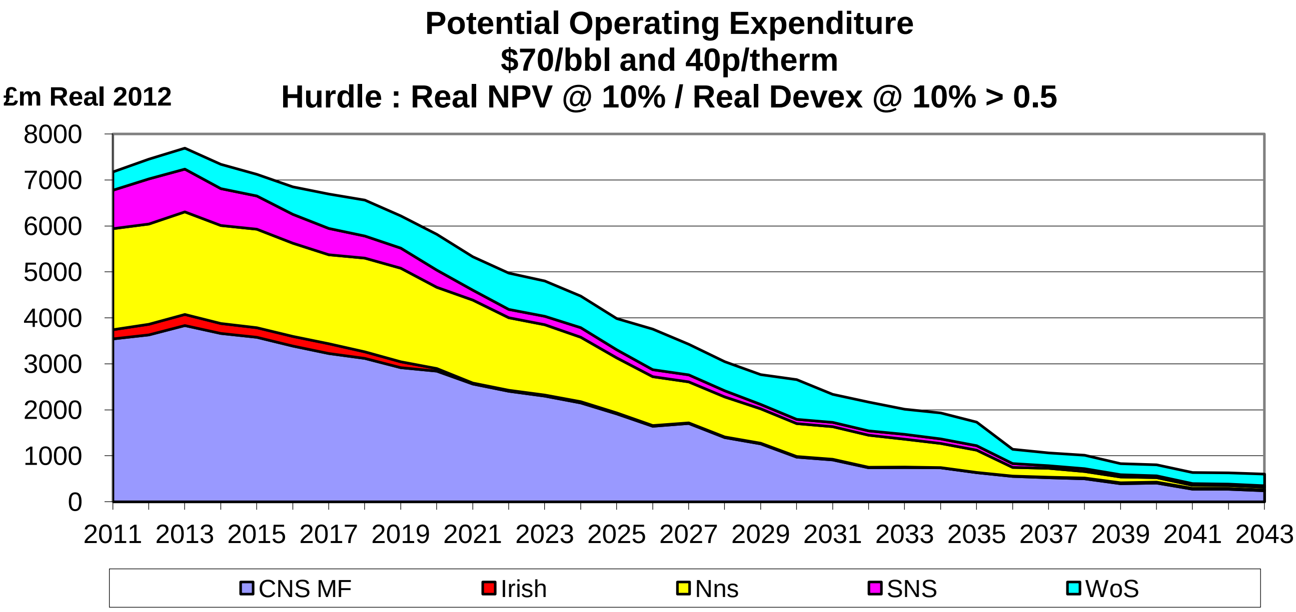
Chart 30



(v) Operating Expenditures

In Chart 31 annual operating expenditures are shown. For many years ahead the CNS/MF and NNS regions dominate the total. The W of S region is not dominant because there are relatively few fields producing from this region.

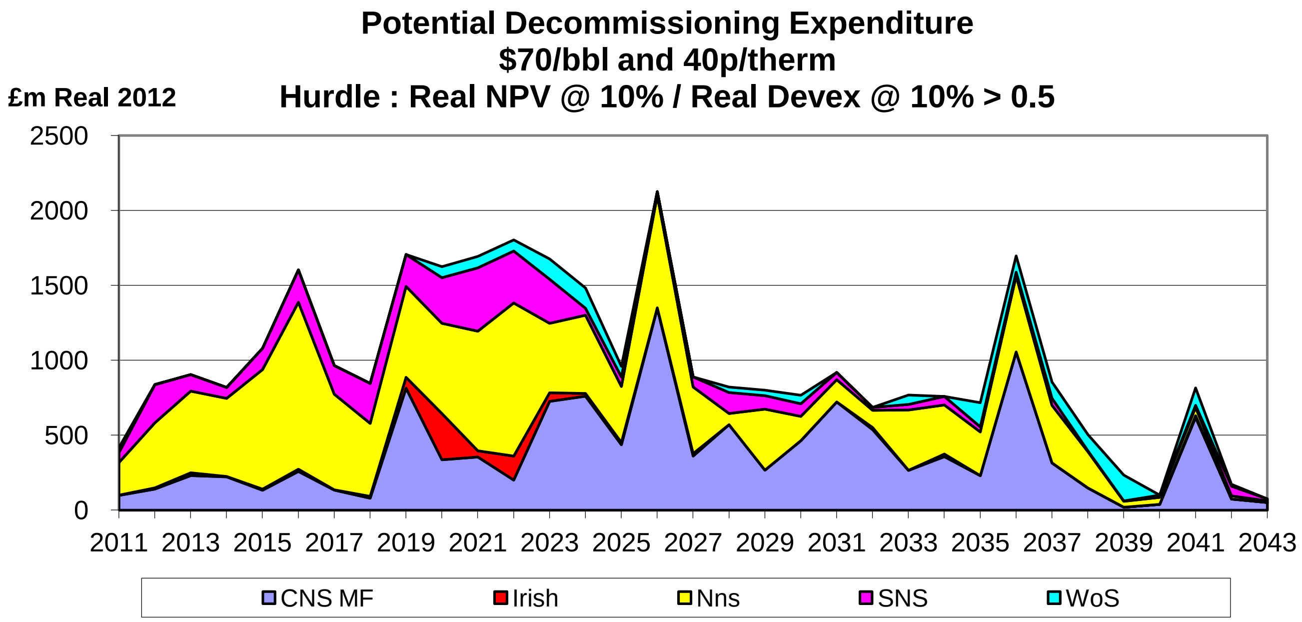
Chart 31



(vi) Annual Decommissioning Expenditures

In Chart 32 annual decommissioning expenditures are shown. In the period to 2020 or so the NNS region is the most important, reflecting the decommissioning of some very large platforms. After that the CNS/MF region becomes the more important, reflecting large number of fields reaching their COP dates, including some very large structures.

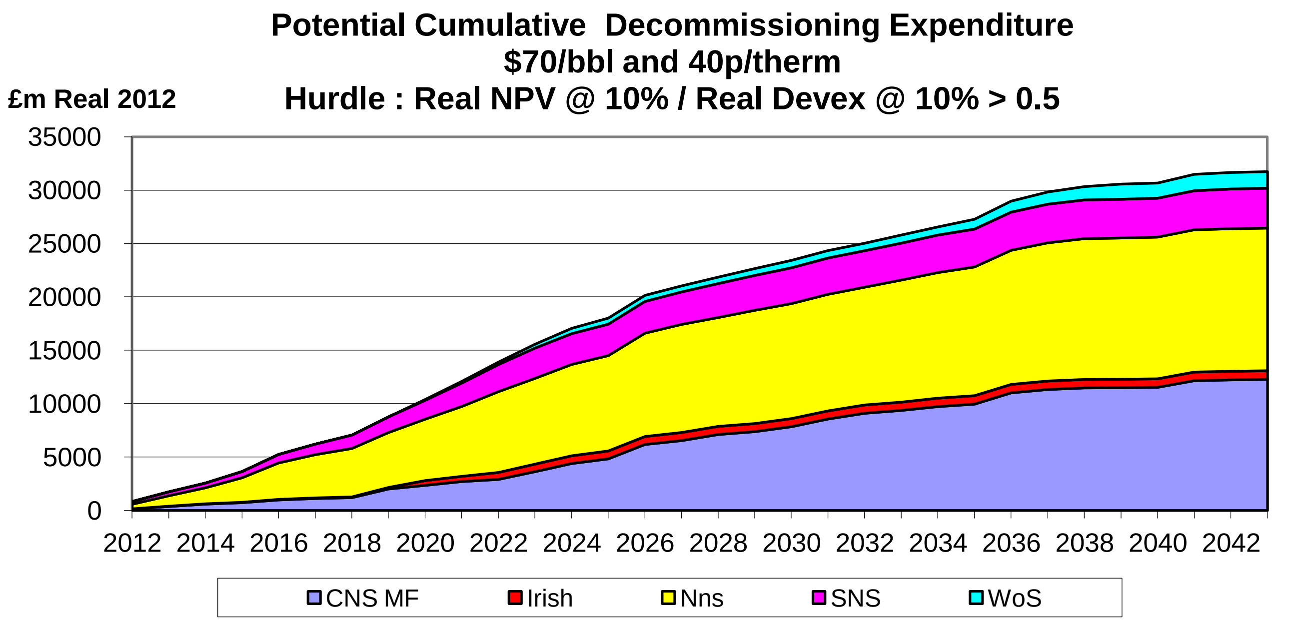
Chart 32



(vii) Cumulative Decommissioning Expenditures

In Chart 33 the cumulative decommissioning expenditures to 2042 are shown. The total is £32 billion. The dominance of the NNS and CNS/MF in the total is very clear.

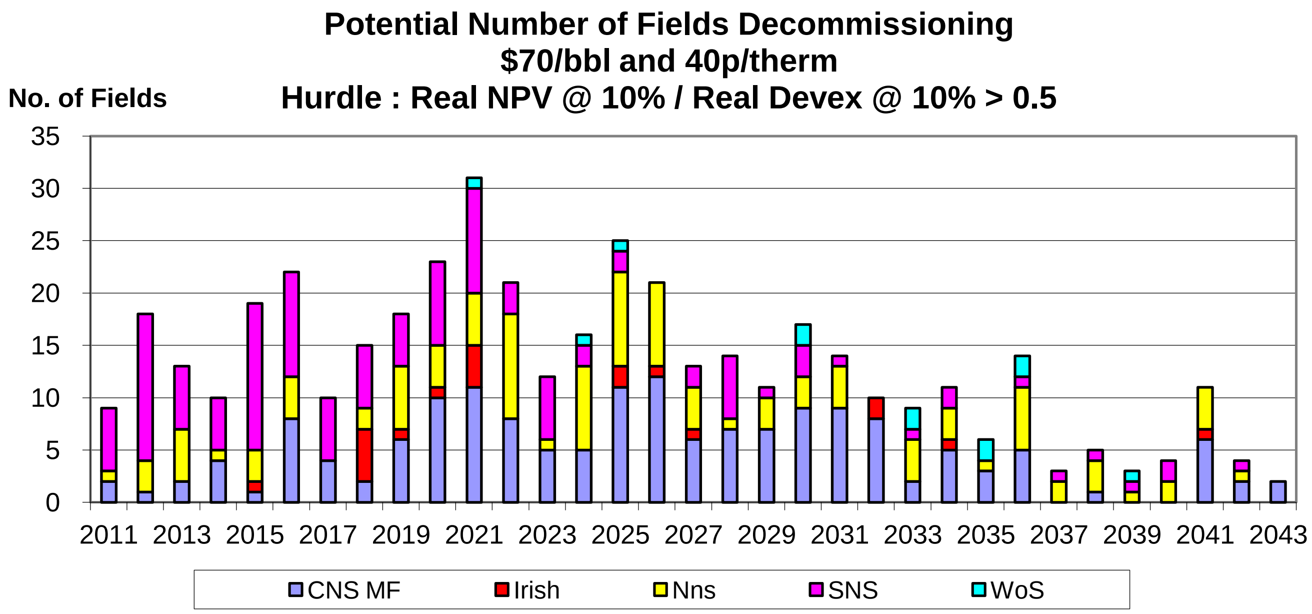
Chart 33



(viii) Numbers of Fields Decommissioning

In Chart 34the annual number of fields decommissioning are shown. The importance of the SNS over the next decade and the longer term importance of the CNS/MF are emphasised.

Chart 34

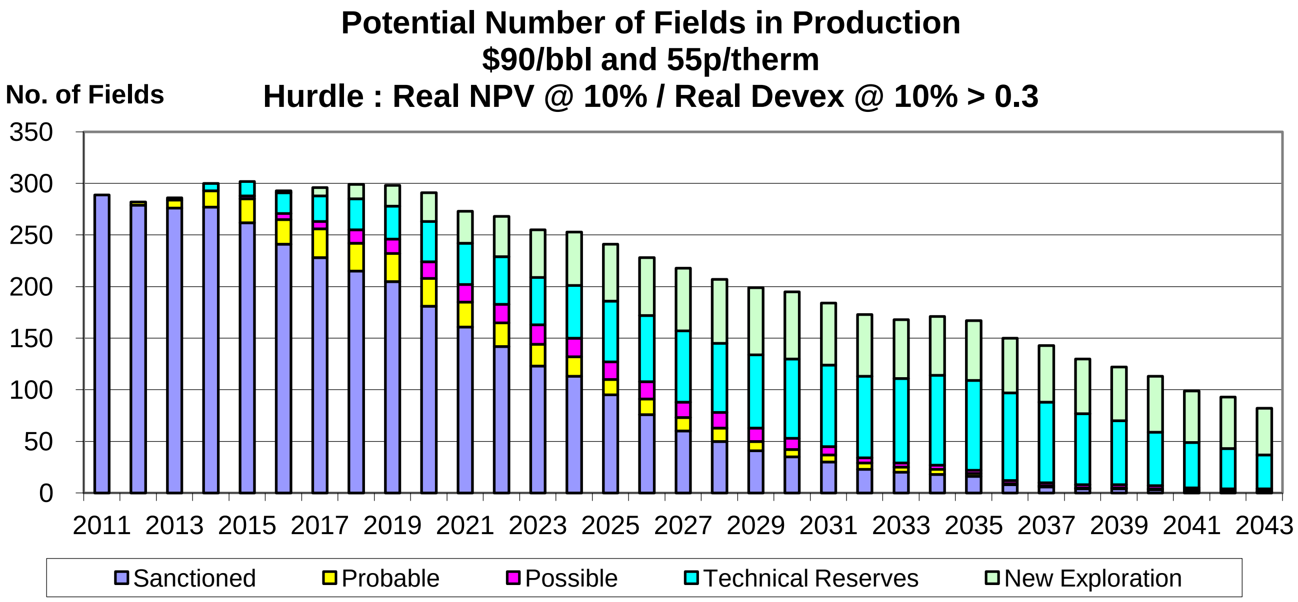


E. $90, 55 pence price scenario, Investment Hurdle NPV/I > 0.3 Results by Field/Project Categories

(i) Numbers of Fields in Production

In Chart 35 the changing numbers of fields in production are shown under the $90, 55 pence, NPV/I > 0.3 scenario. There are many more fields developed in this scenario compared to the $70, 40 pence one. Over the period to 2042 349 new fields are developed. The total increases slightly from 2011 levels and remains at a higher level until 2020. Thereafter the numbers decline at a steady but moderate rate. In 2042 there are still over 90 producing fields. In the period after 2020 many fields in the category of technical reserves become viable despite their relatively high costs.

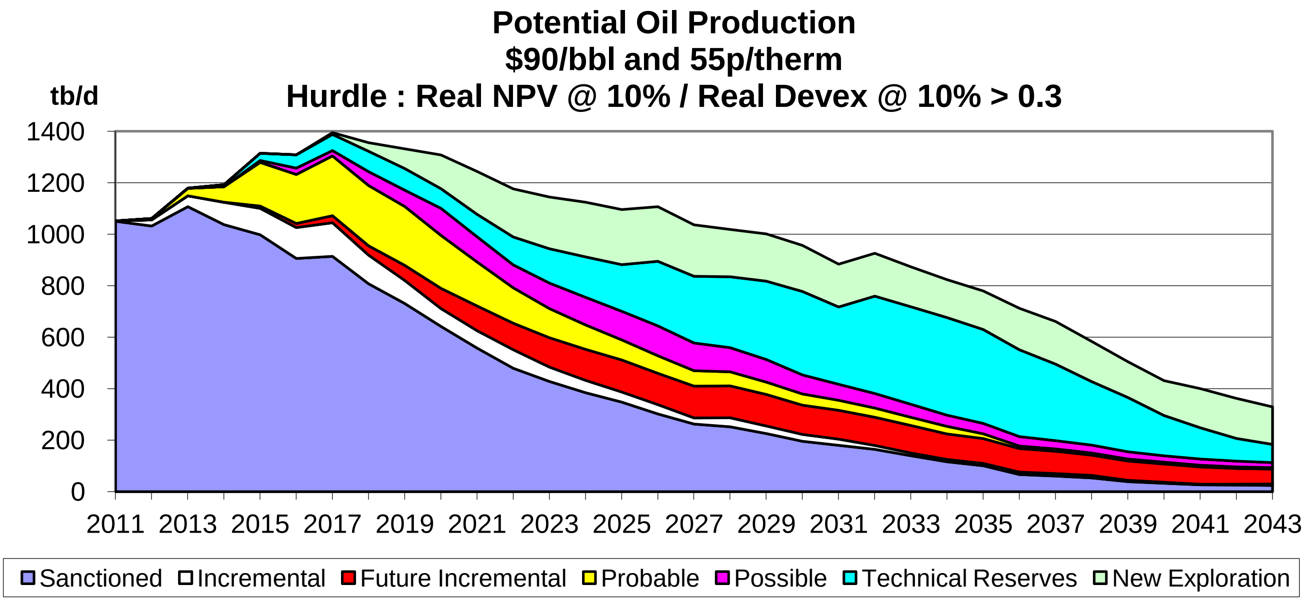
Chart 35



(ii) Oil Production

In Chart 36 potential oil production is shown under the $90, 55 pence scenario. It rises to nearly 1.4 mm b/d in 2017 reflecting in particular the development of several large new fields. Thereafter there is a steady decline which accelerates from around 2032. In the latter part of the period production is very substantial from the fields in the category of technical reserves. By 2042 production is 363,000 b/d.

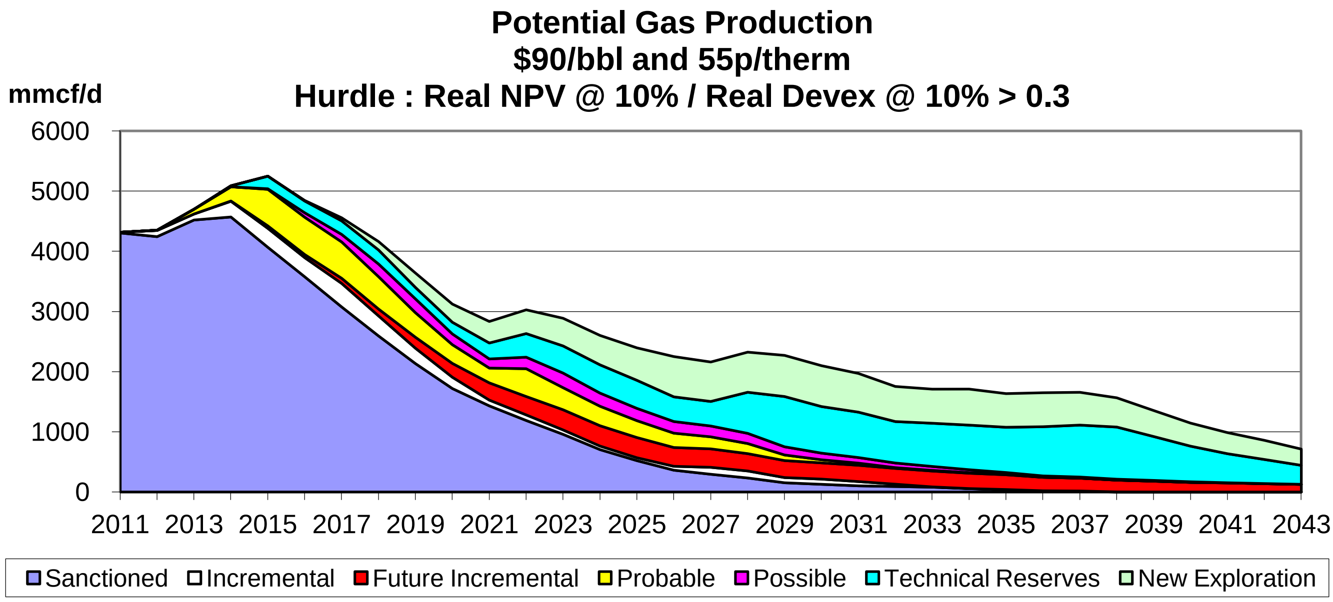
Chart 36



(iii) Gas Production

In Chart 37 potential gas production is shown. There is a worthwhile increase from 2011 levels to 2015, after which the decline rate is quite brisk until 2020. The decline rate is moderated thereafter, due in particular to the development of fields in the category of technical reserves plus a worthwhile contribution from new discoveries.

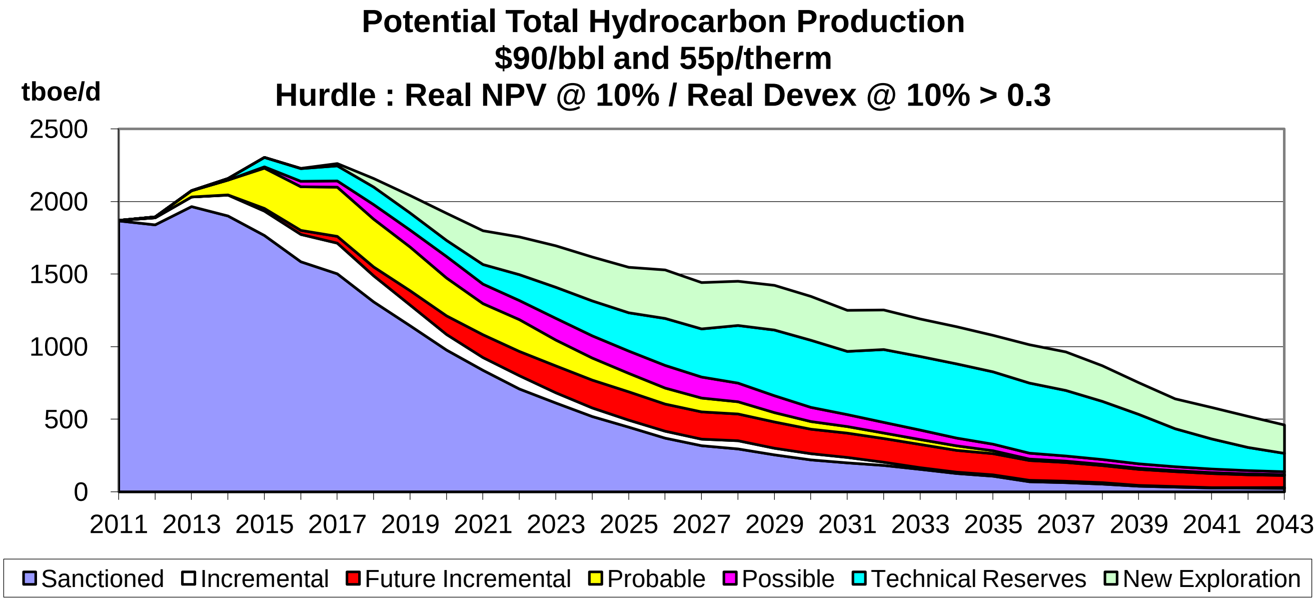
Chart 37



(iv) Total Hydrocarbon Production

In Chart 38 potential total hydrocarbon production is shown. There is a significant increase from 2011 levels in the period to 2017, due principally to the development of fields in the probable category plus current incremental projects. From 2017 production falls steadily to around 520,000 boe/d in 2042. In the latter part of the period there are substantial contributions from fields in the category of technical reserves with worthwhile contributions coming from future incremental projects and new discoveries.

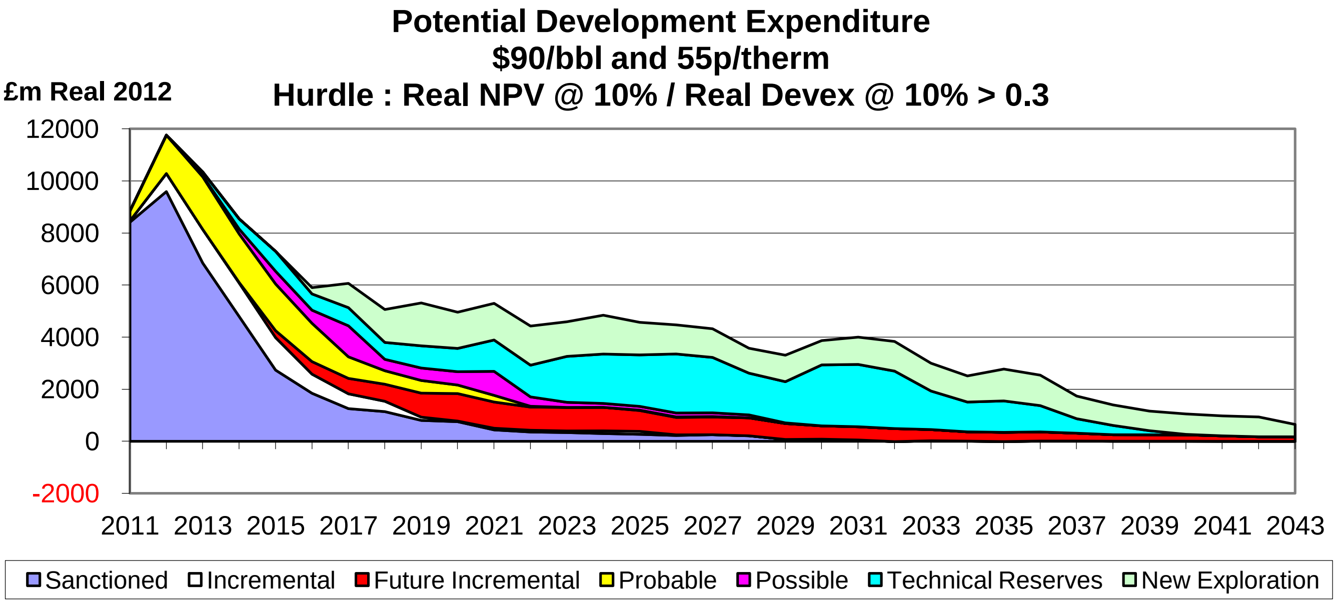
Chart 38



(v) Development Expenditures

In Chart 39 prospective field development expenditures are shown. In the near term these are at remarkably high levels, substantially exceeding £10 billion on average over the three-year period from 2012 to 2014. After that they decline sharply until in 2016 they are £5.9 billion whilst in 2017 they are £6 billion. Historically this was a satisfactory level for the supply chain. The dramatically high levels over the next 3 years reflect the coincident development of several very large and expensive fields. The decline thereafter is probably inevitable and should not be interpreted as a general falling off in the numbers of new developments. After 2016 field investment continues in the £5 billion - £4 billion range (at 2012 prices) until 2030.

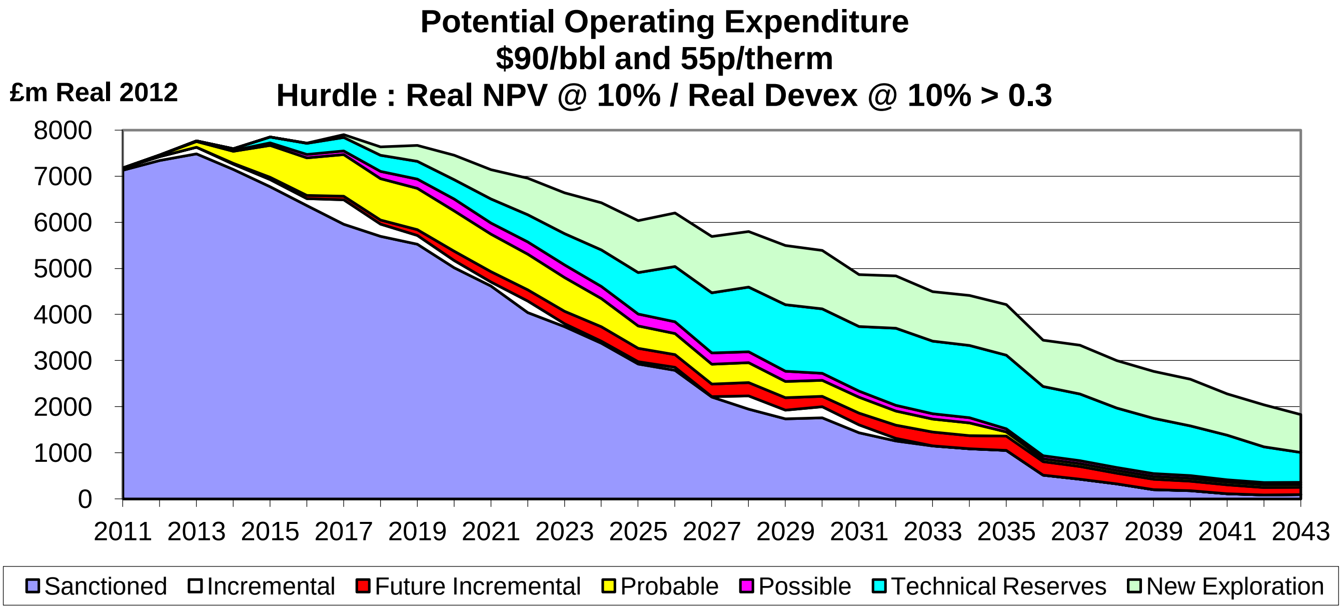
Chart 39



(vi) Operating Expenditures

In Chart 40 prospective operating expenditures are shown. They increase from 2011 levels to nearly £8 billion in 2017, reflecting the increase in the number of fields in production. Thereafter they fall at a relatively gentle pace reflecting the continuing substantial number of new field developments in the longer term, particularly those in the categories of new discoveries and technical reserves. By 2042 they still exceed £2 billion (at 2012 prices).

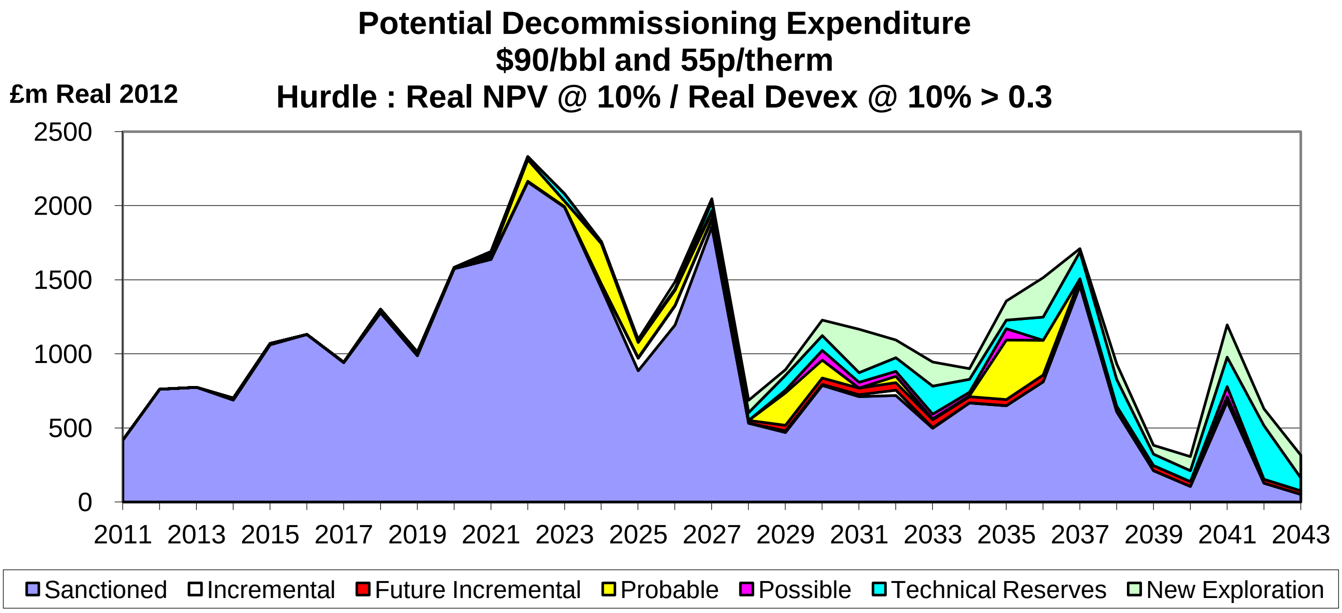
Chart 40



(vii) Annual Decommissioning Expenditures

In Chart 41 prospective annual decommissioning expenditures are shown. The volatility remains pronounced. There are extremely large expenditures in the period 2019-2027.

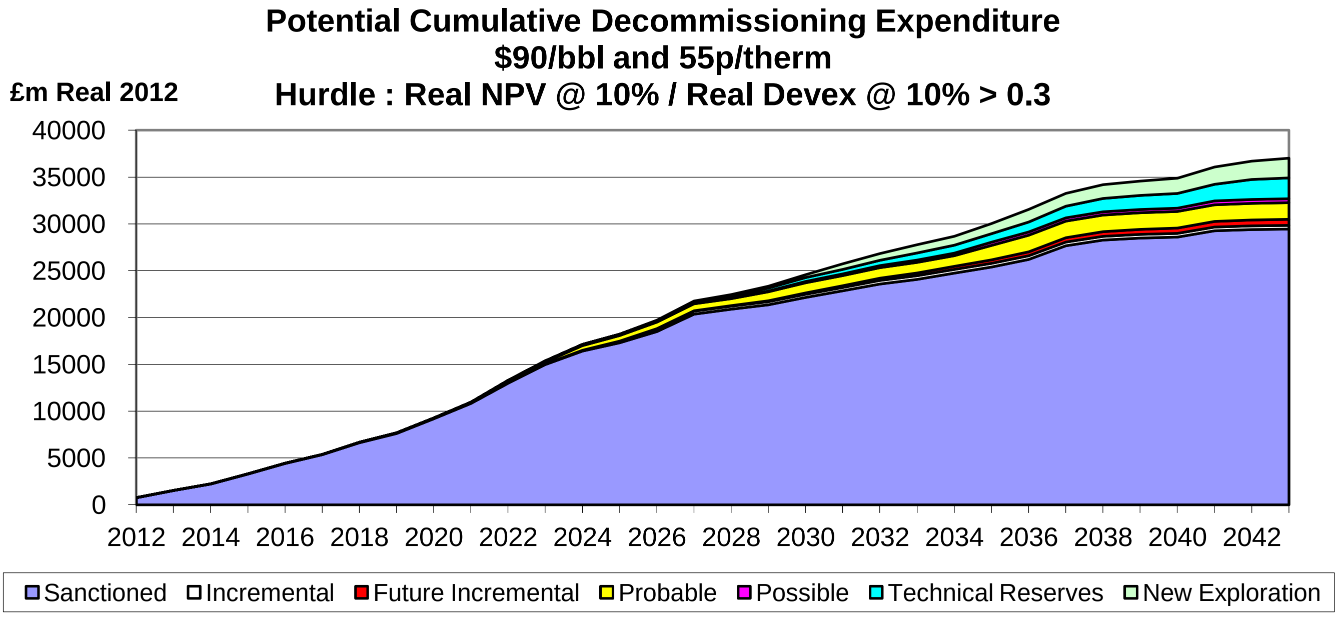
Chart 41



(viii) Cumulative Decommissioning Expenditures

In Chart 42 cumulative decommissioning expenditures are shown to 2042. The total cost over the period is around £37 billion, with currently sanctioned fields contributing more than £30 billion.

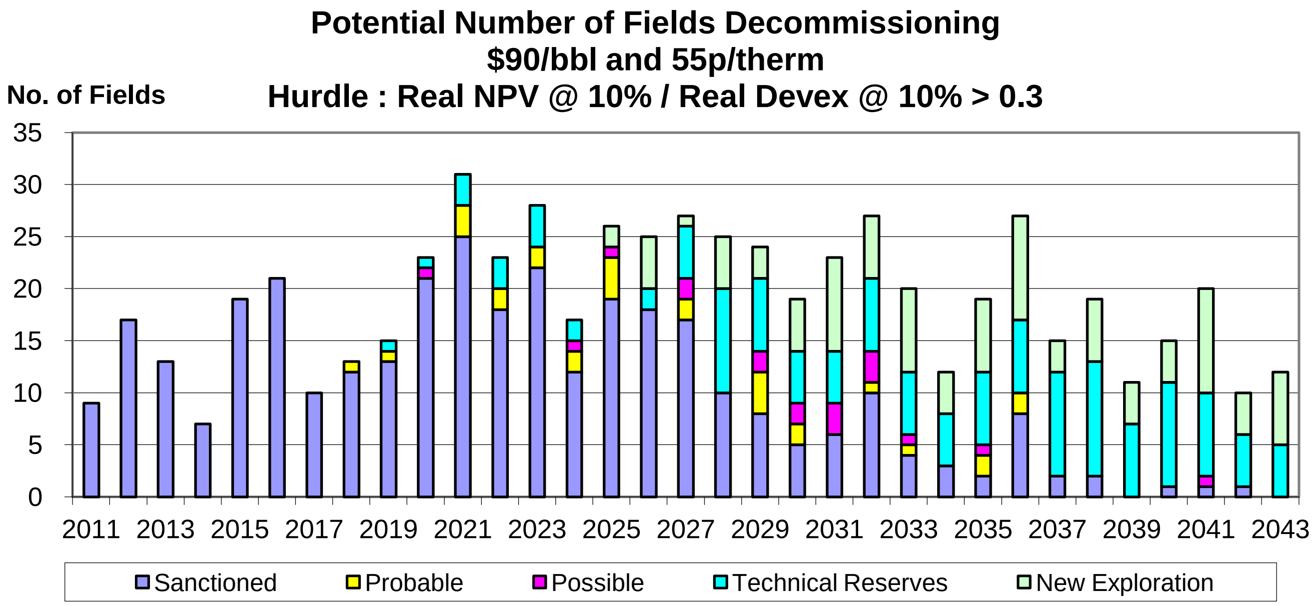
Chart 42



(ix) Numbers of Fields Decommissioning

In Chart 43 the annual numbers of fields decommissioning are shown. The total for the whole period is 604 giving an annual average of 19.5 (including 2012). In several years there are over 25 fields reaching their COP dates. At the $90, 55 pence price scenario there are many more fields not yet sanctioned which reach their COP by 2042, reflecting their modest sizes.

Chart 43

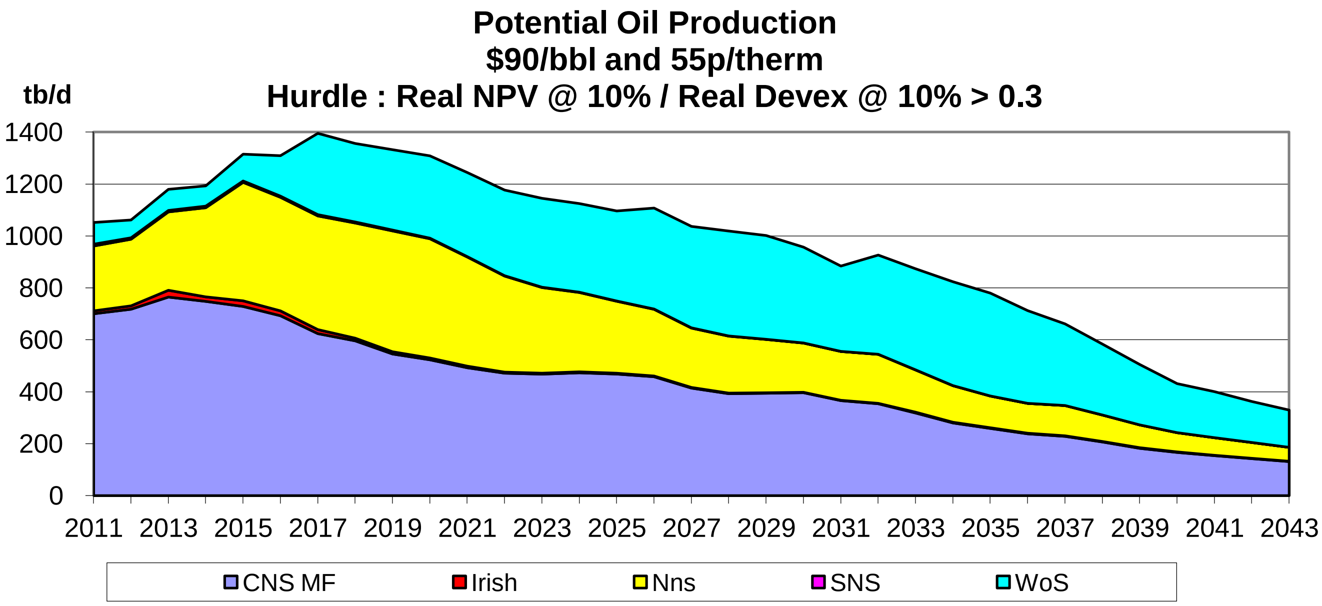


F. $90, 55 pence price scenario, Investment Hurdle NPV/I > 0.3 Results by Geographic Area

(i) Oil Production

In Chart 44 potential oil production by geographic area is shown. The current dominance of CNS/MF region is seen to fall gradually over the period, particularly after 2030. In the short and medium term output from the NNS is seen to rise substantially but then falls sharply in the later part of the period. The W of S region becomes a significant producer from around 2017 and remains so until 2038.

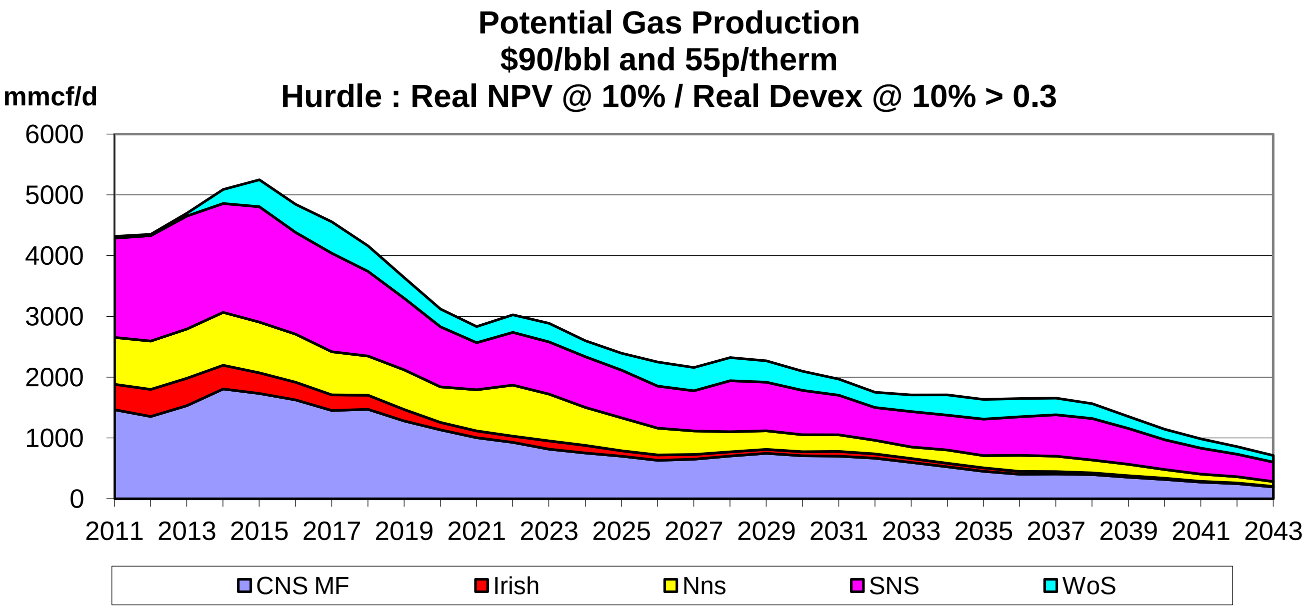
Chart 44



(ii) Gas Production

In Chart 45 Prospective gas production by geographic region is shown. In the near term there is a worthwhile increase from the CNS/MF and some from the SNS and NNS, but in the medium term the most noteworthy features are the declines from the SNS and the CNS/MF. Production from the W of S region remains modest throughout the period.

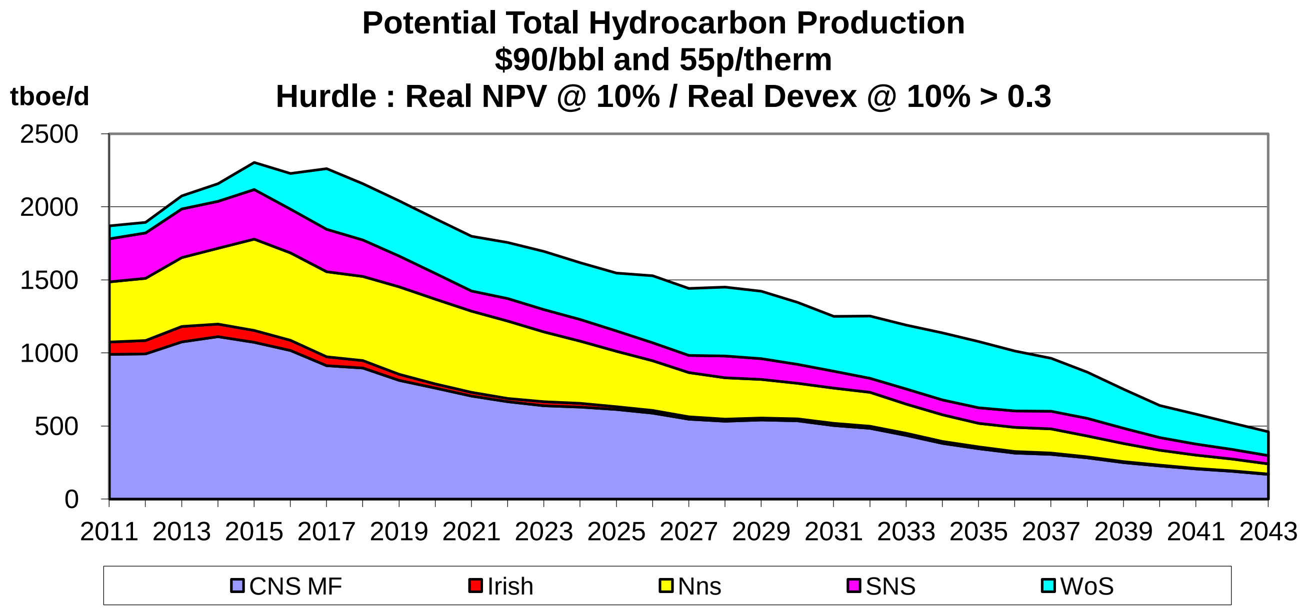
Chart 45



(iii) Total Hydrocarbon Production

In Chart 46 prospective total hydrocarbon production (including NGLs) is shown by geographic region. In the short and medium term the increased output from the NNS is a noteworthy feature. In the longer term the substantial production from the W of S region is the most noteworthy feature.

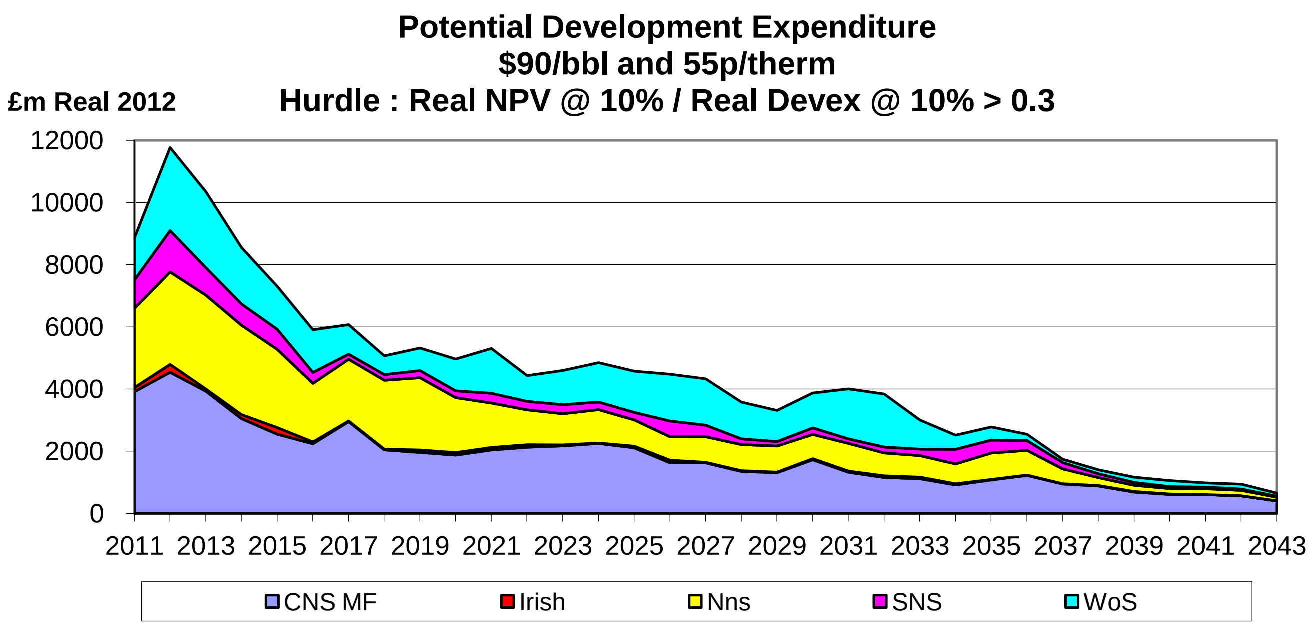
Chart 46



(iv) Development Expenditures

In Chart 47 the regional distribution of development expenditures is shown. The short and medium term importance of the CNS/MF, NNS and W of S regions is an obvious feature. All 3 regions share in the short term dramatic increase but also in the subsequent decline.

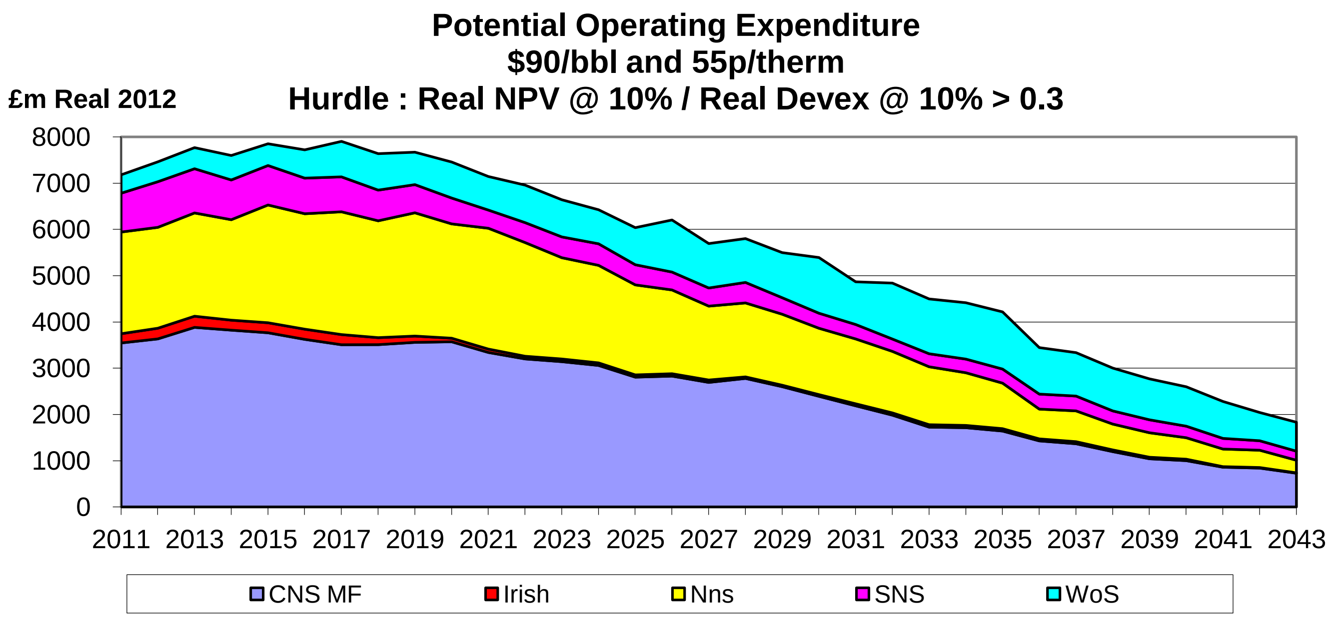
Chart 47



(v) Operating Expenditures

In Chart 48 the regional distribution of operating expenditures is shown. A key feature is the dominance of the CNS/MF region over the whole period, reflecting the large number of fields in this area. In the medium term the NNS becomes more important than at present, but the W of S region remains less important reflecting the moderate number of producing fields in the latter area.

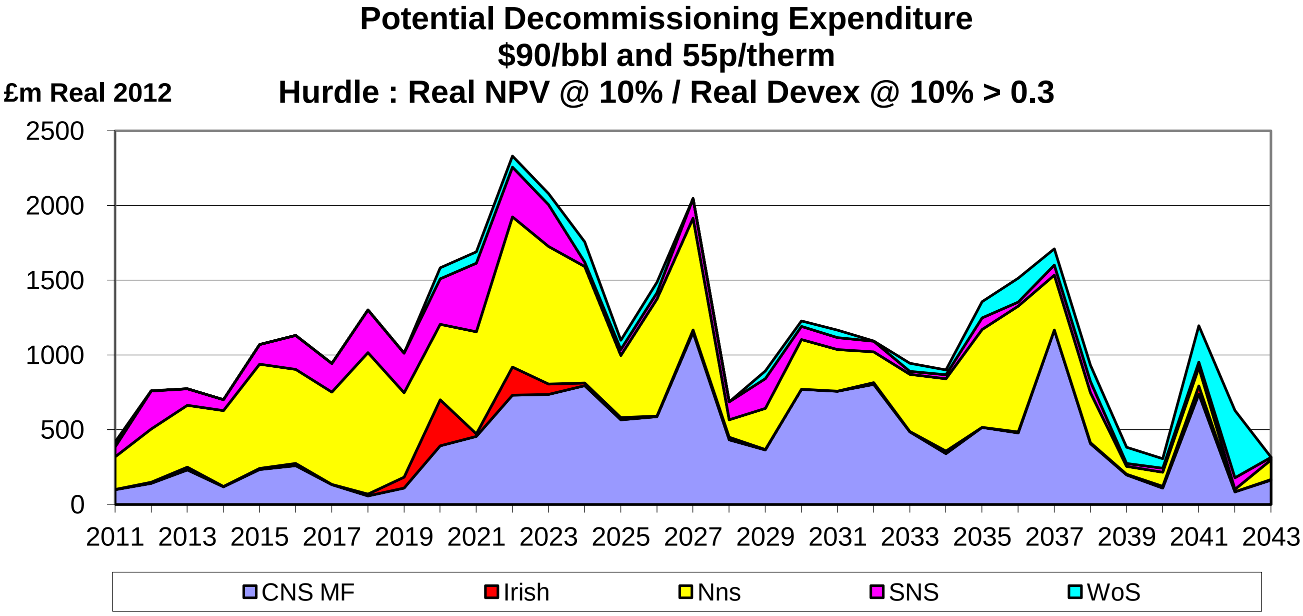
Chart 48



(vi) Annual Decommissioning Expenditures

In Chart 49 annual decommissioning expenditures are shown by main region. In the period to 2027 the NNS is a very important source of activity reflecting the decommissioning of some very large and expensive platforms. From 2020 to 2042 the CNS/MF region is very active reflecting activity relating to large numbers of platforms some of which are very expensive to decommission.

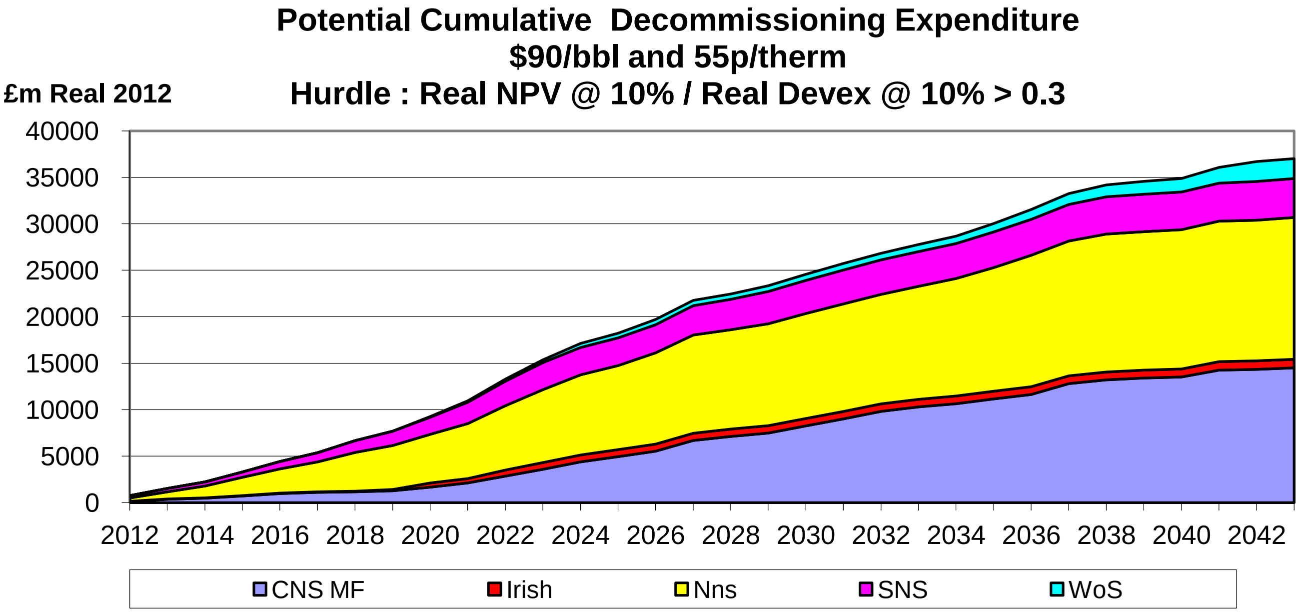
Chart 49



(vii) Cumulative Decommissioning Expenditures

In Chart 50 cumulative decommissioning expenditures to 2042 are shown by main region. The importance of the NNS in the total is highlighted.

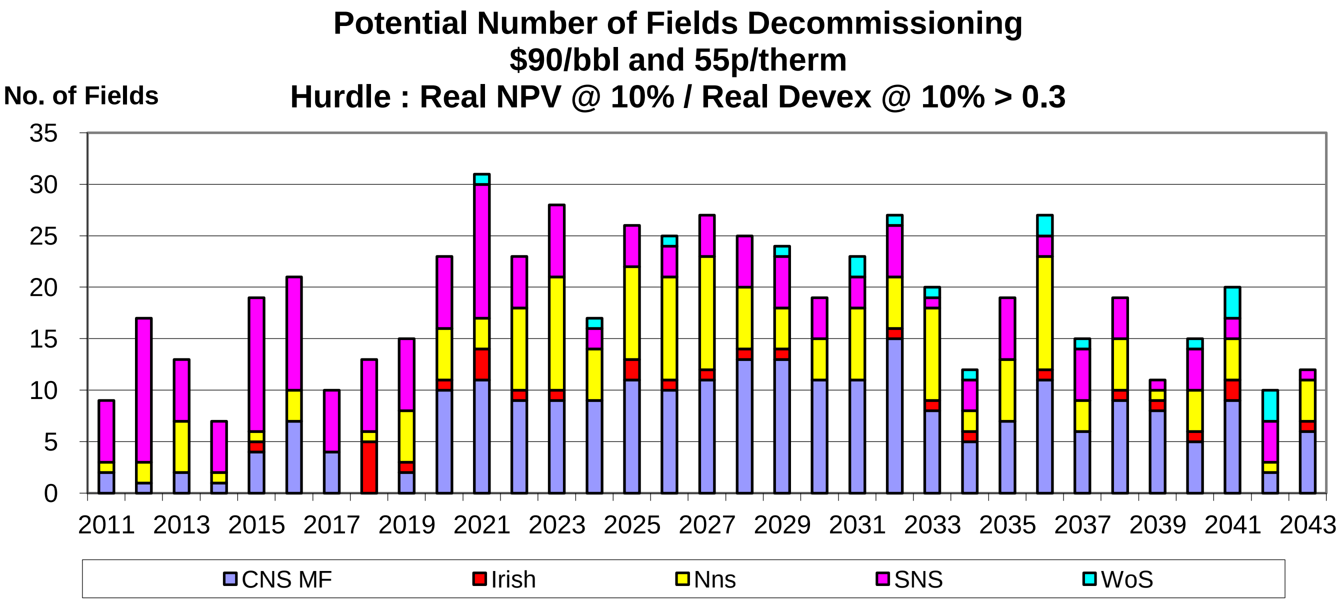
Chart 50



(viii) Numbers of Fields Decommissioning

In Chart 51the numbers of fields reaching their COP dates by main region are shown. The importance of the CNS/MF from 2020 to 2042 is highlighted as is the importance of the SNS in the period 2012-2021.

Chart 51

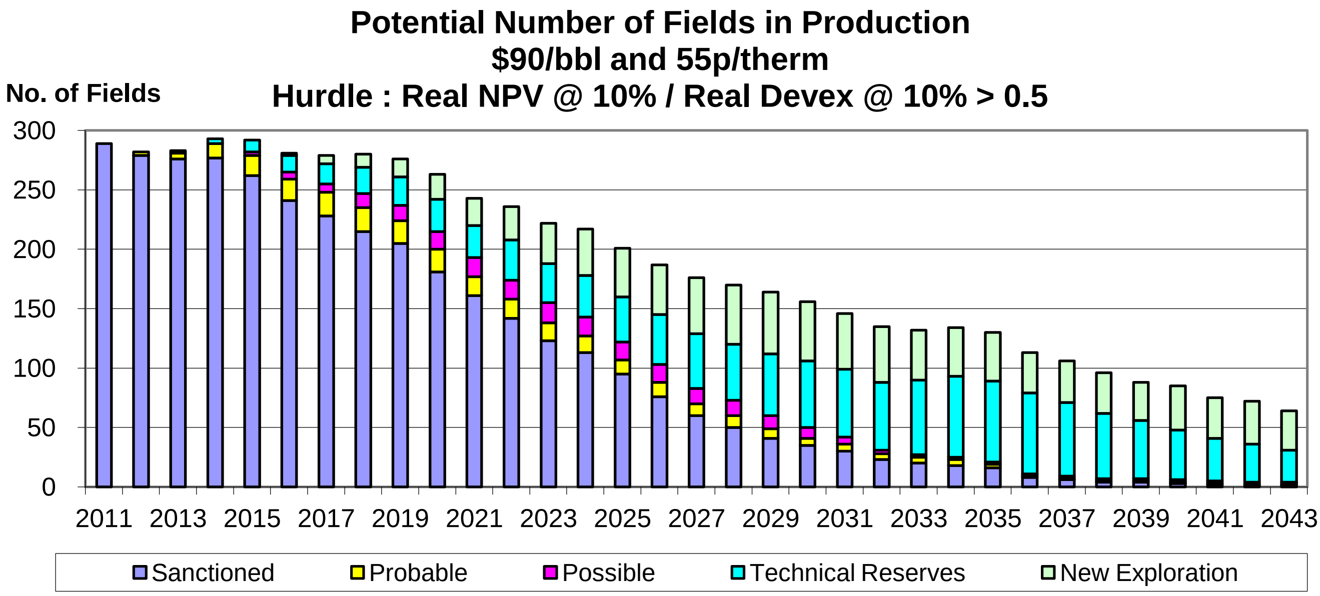


G. $90, 55 pence price scenario, Investment Hurdle NPV/I > 0.5 Results by Field/Project Categories

(i) Numbers of Fields in Production

In Chart 52 the numbers of producing fields over the period to 2042 are shown by category under the $90, 55 pence, NPV/I > 0.5 scenario. Over the next few years the total keeps up quite well. From 2019 onwards there is a persistent decline. Over the whole period 2012-2042 262 new fields are developed.

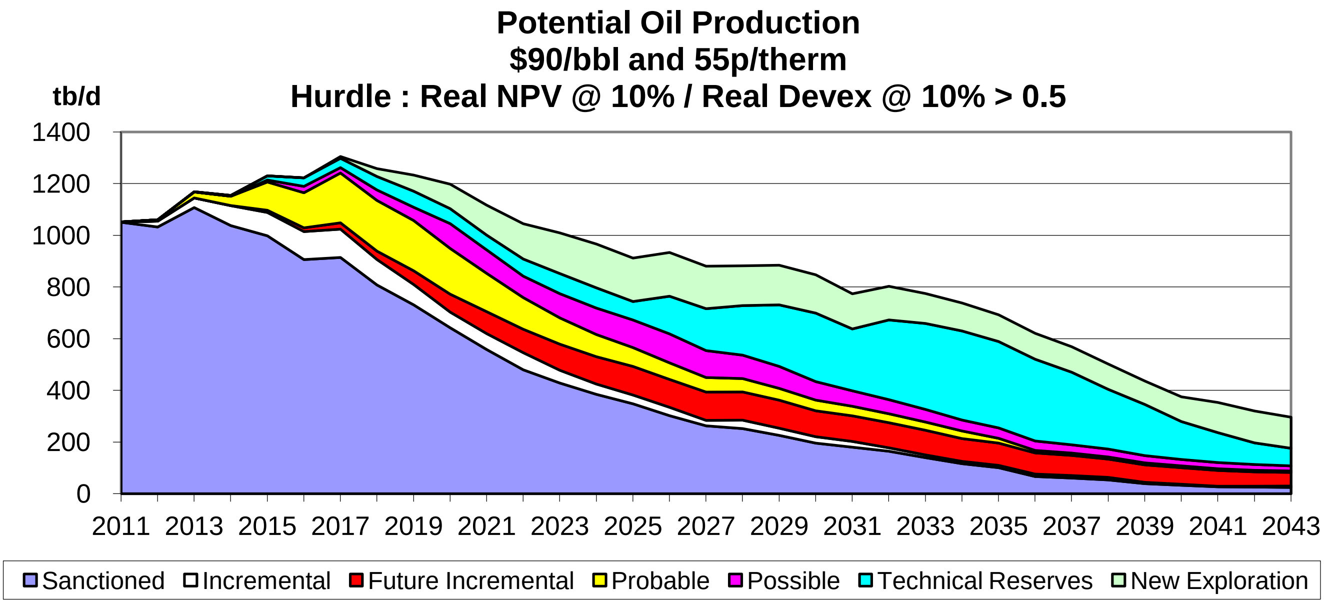
Chart 52



(ii) Oil Production

In Chart 53 prospective oil production is shown. There is a significant increase over the next few years to 1.3 mm b/d in 2017, with the impetus coming from incremental projects and fields in the probable category. After that production falls throughout to the end of the period. In the latter part of the period production from fields in the category of technical reserves moderate the decline rate.

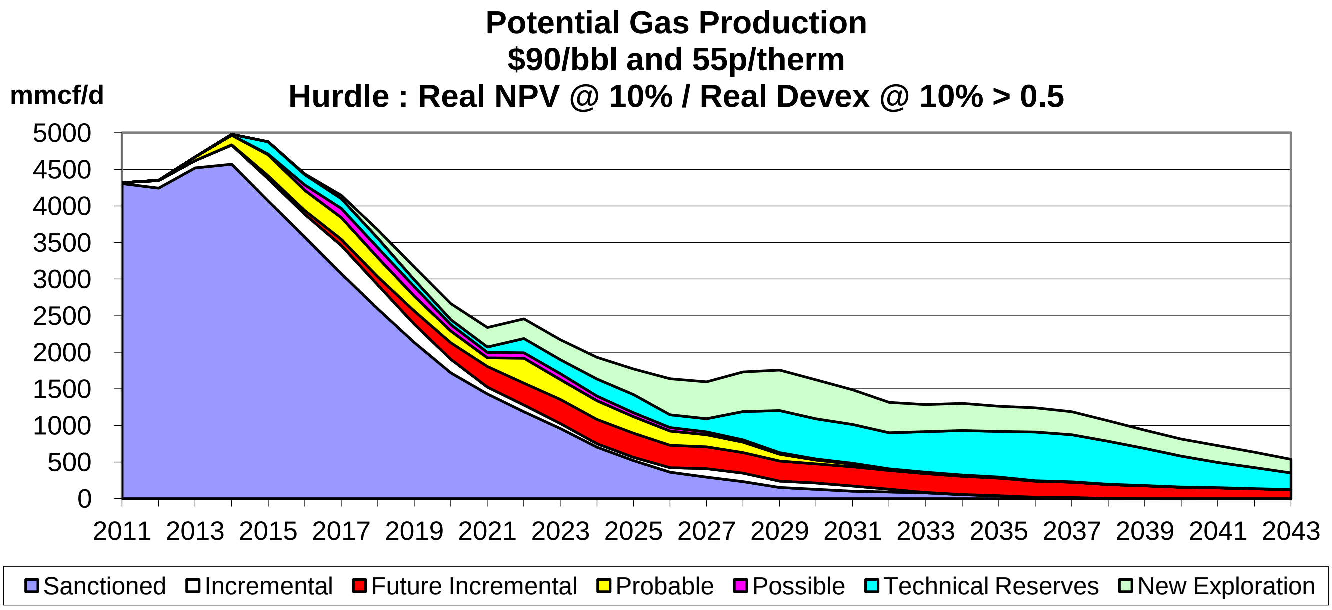
Chart 53



(iii) Gas Production

In Chart 54 potential gas production is shown. After a short-term worthwhile increase output falls at a sharp pace to 2020. This reflects a fairly steep fall from the sanctioned fields plus only modest output from new fields and projects in all categories. In the latter part o the period the development of fields in the category of technical reserves and new discoveries moderate the decline rate.

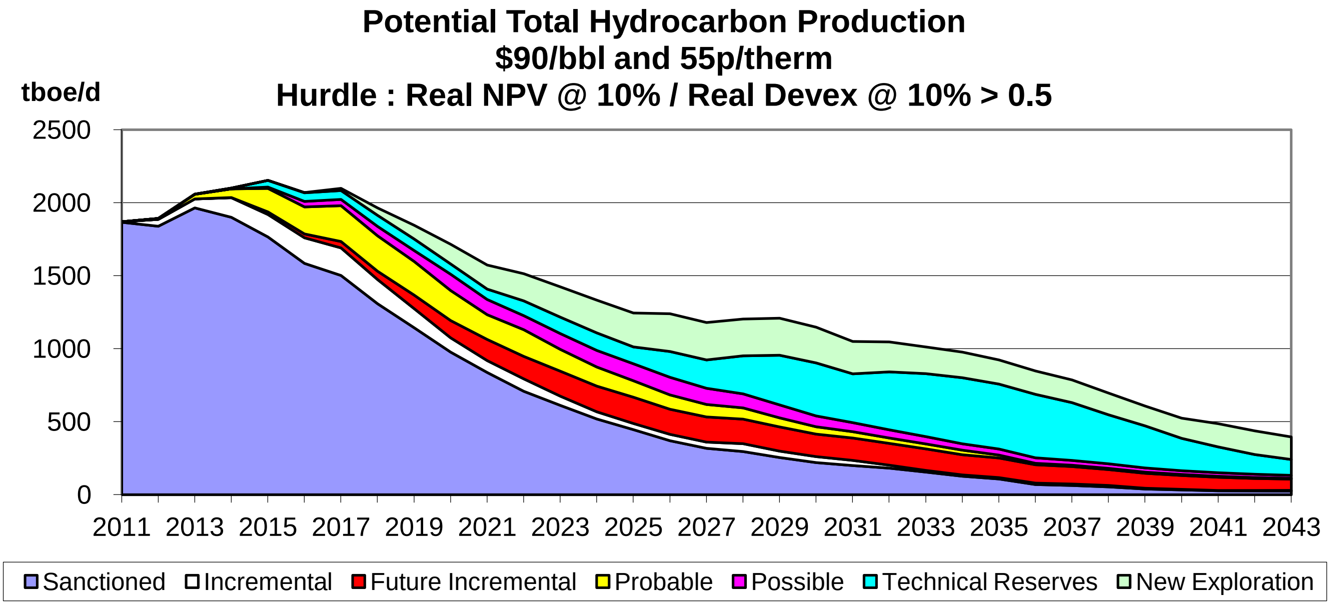
Chart 54



(iv) Total Hydrocarbon Production

In Chart 55 prospective total hydrocarbon production is shown. After a worthwhile short-term increase from 2011 levels output falls at a brisk pace from 2017 to 2025 reflecting a steep decline from the sanctioned fields which outweighs the significant production from new fields and projects. In the later part of the period the development of fields in the category of technical reserves moderate the decline rate. By 2042 production is 437,000 b/d.

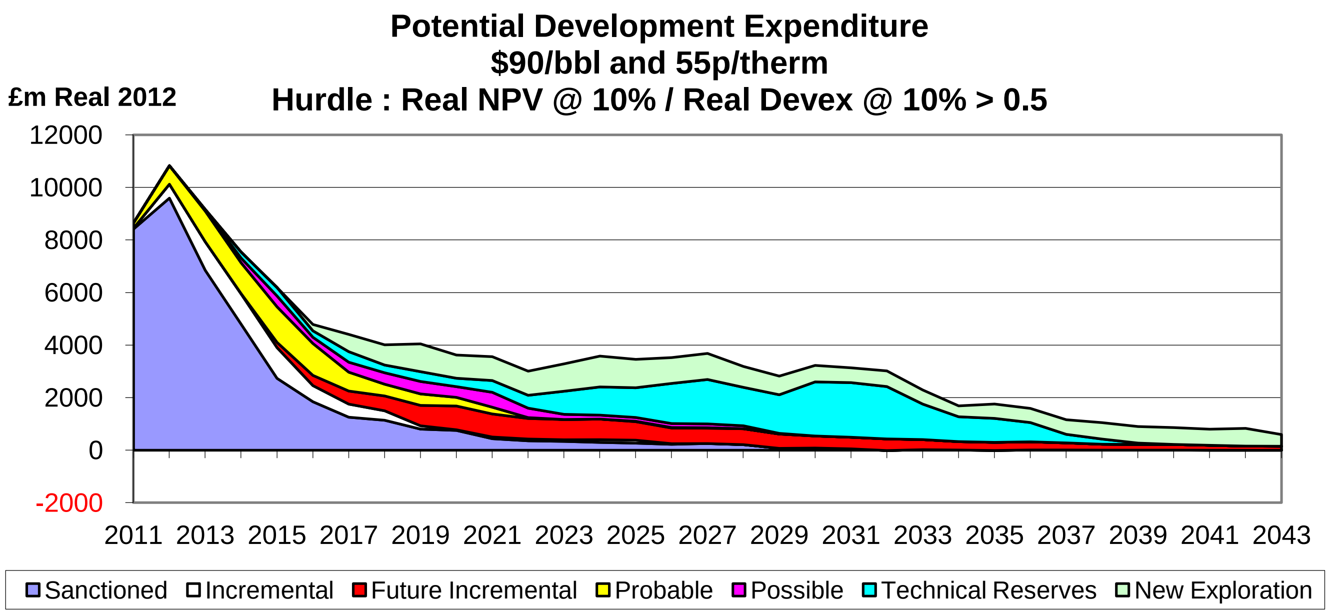
Chart 55



(v) Development Expenditures

In Chart 56 the prospective behaviour of field development investment is shown. There is a sharp near term peak approaching £11 billion followed by a fast rate of decrease. Nevertheless field investment still exceeds £6 billion (at 2012 prices) in 2015. From 2016 onwards the decline rate is very modest until beyond 2030. It is clear that in the medium and longer term the current very high investment level cannot be sustained in this scenario.

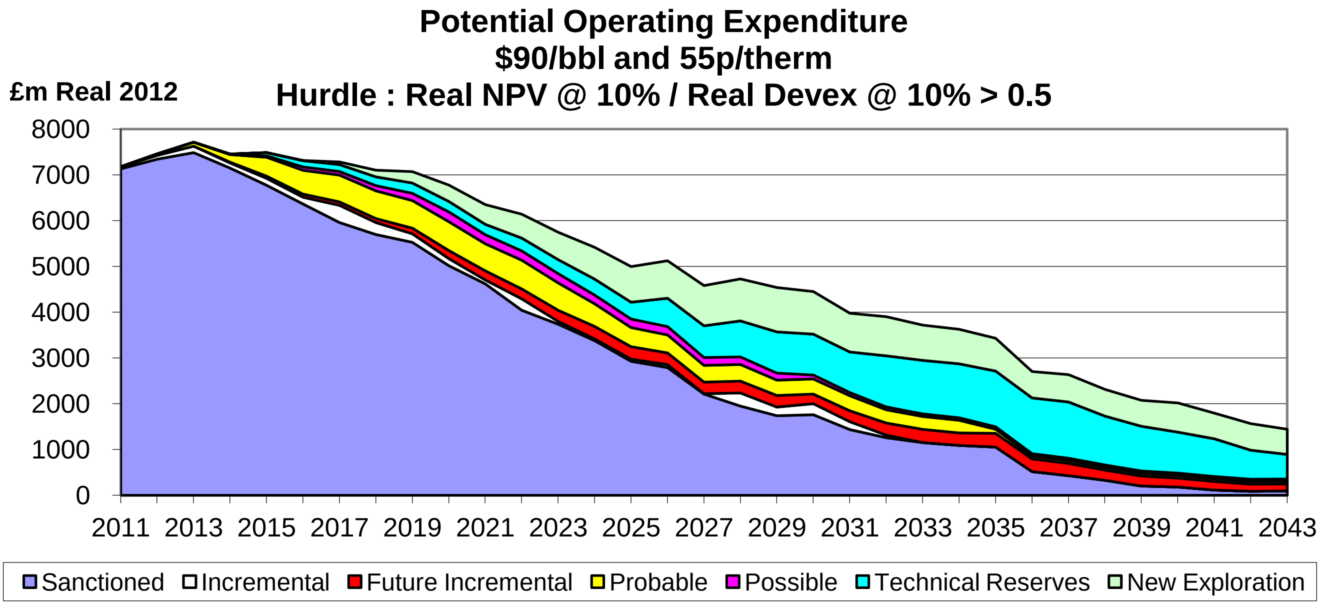
Chart 56



(vi) Operating Expenditures

In Chart 57 potential operating expenditures are shown. Until 2019 they remain above £7 billion per year (at 2012 prices) reflecting the persistence of large numbers of producing fields. The decline thereafter is also persistent with the development of fields in the category of technical reserves in the later part of the period having a moderating effect.

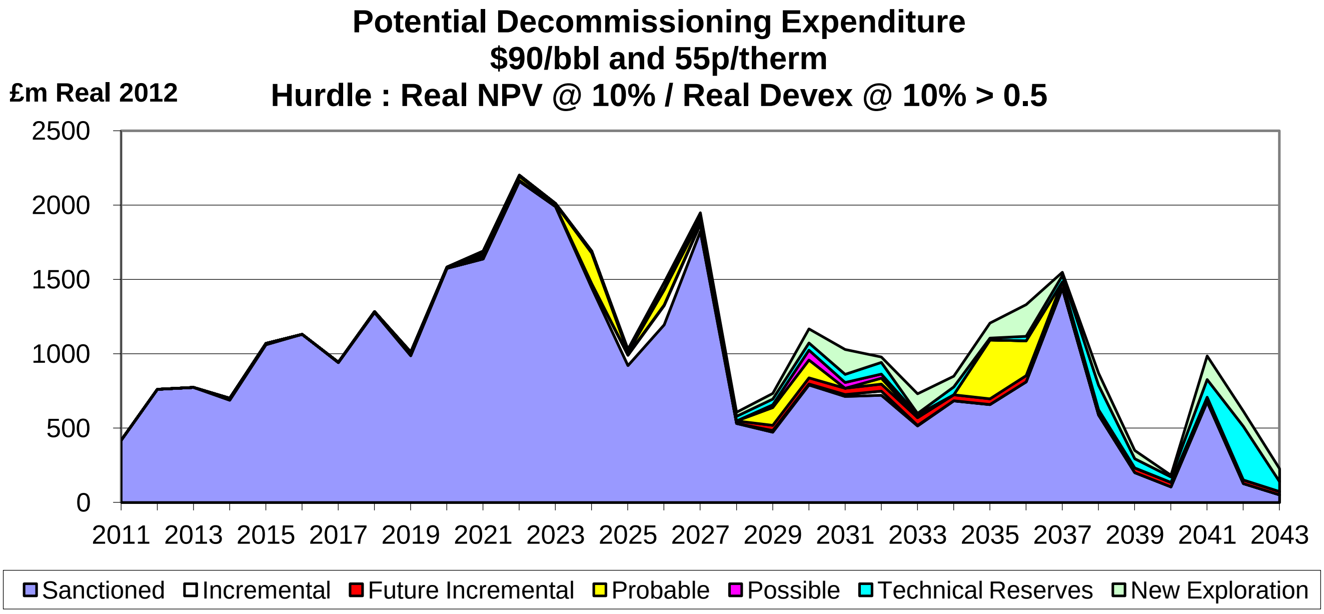
Chart 57



(vii) Annual Decommissioning Expenditures

In Chart 58 prospective annual decommissioning expenditures are shown. There is a very pronounced hump in the amounts expended in the period 2019-2027 when a significant number of large and expensive installations are likely to be decommissioned. The volatility of the expenditure remains pronounced throughout the period to 2042.

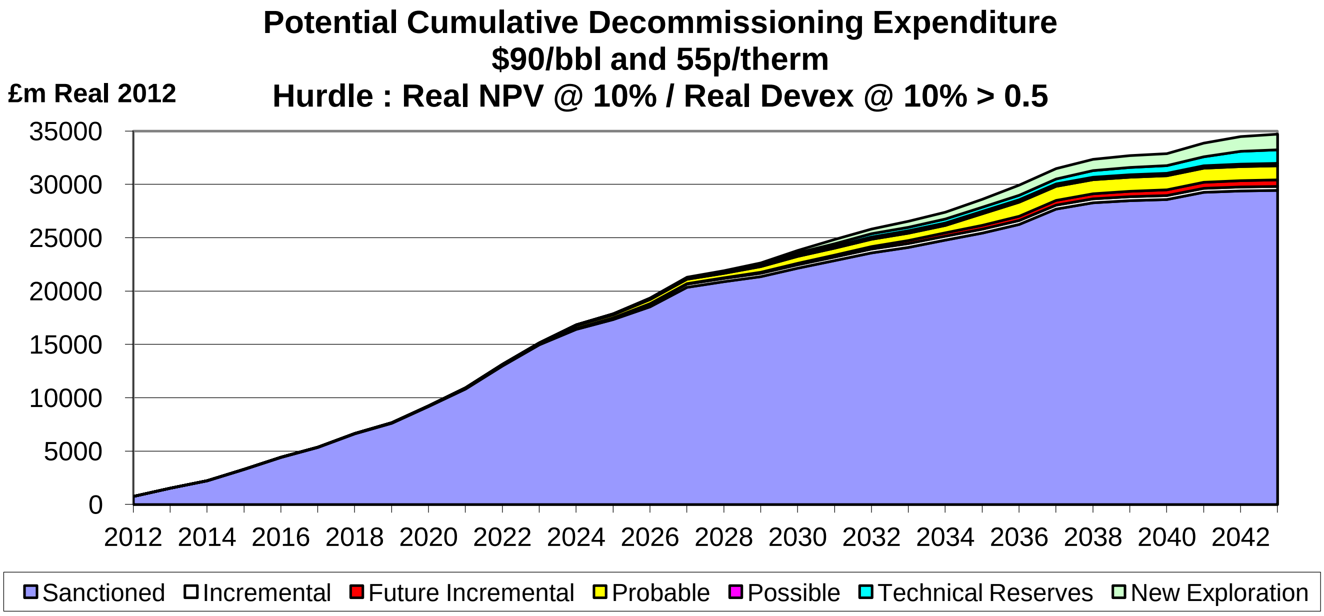
Chart 58



(viii) Cumulative Decommissioning Expenditures

In Chart 59 cumulative decommissioning expenditures to 2042 are shown. The total approaches £35 billion (at 2012 prices) by the end of the period.

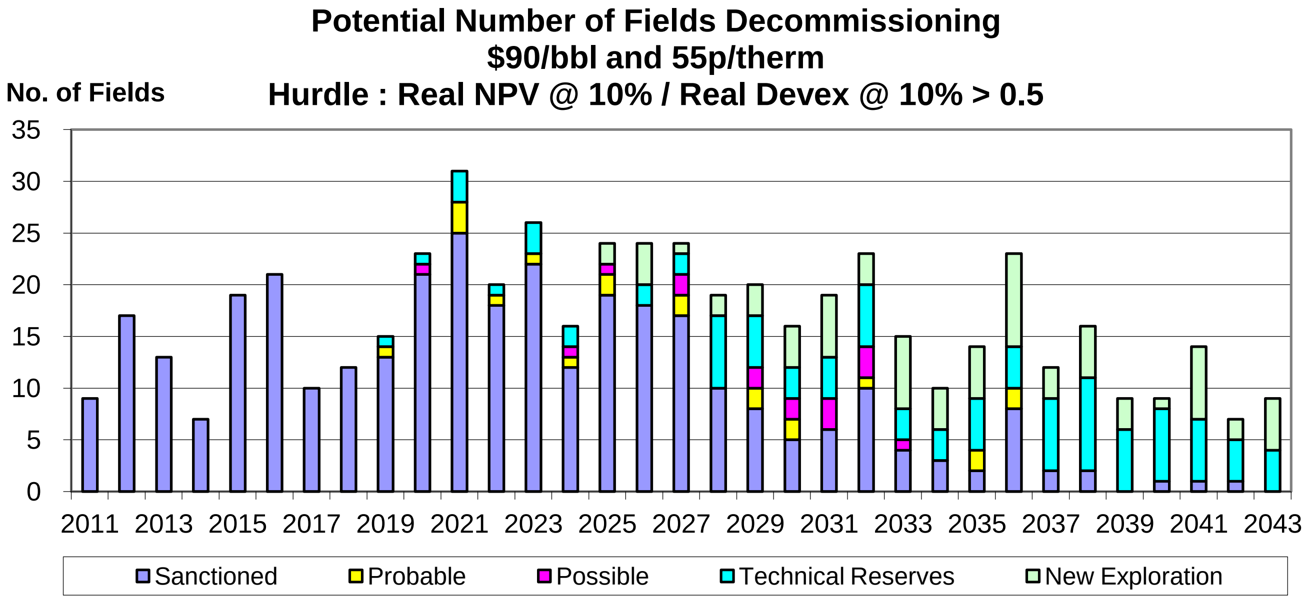
Chart 59



(ix) Numbers of Fields Decommissioning

In Chart 60 the annual numbers of fields reaching their COP dates are shown. The cumulative total over the period is 531 fields.

Chart 60

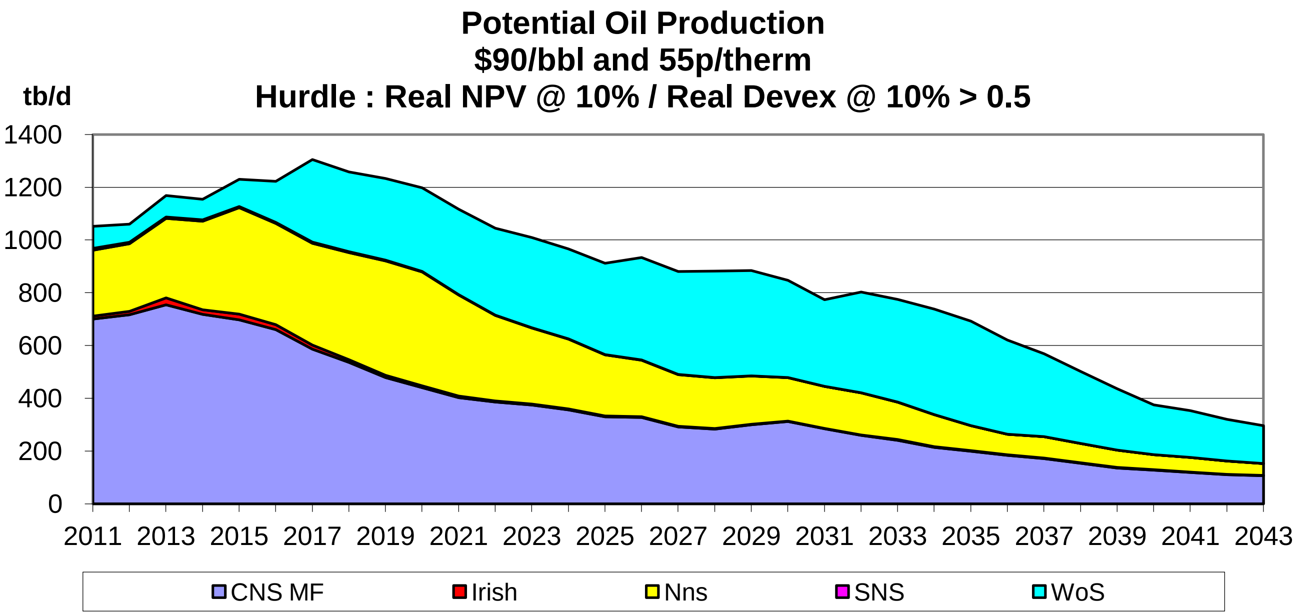


H. $90, 55 pence price scenario, Investment Hurdle NPV/I > 0.5 Results by Geographic Area

(i) Oil Production

In Chart 61 oil production is shown by geographic areas of the UKCS. The current importance of the CNS/MF is clear. In the short and medium term output from the NNS becomes significant while in the longer therm the W of S region becomes the most important producing region.

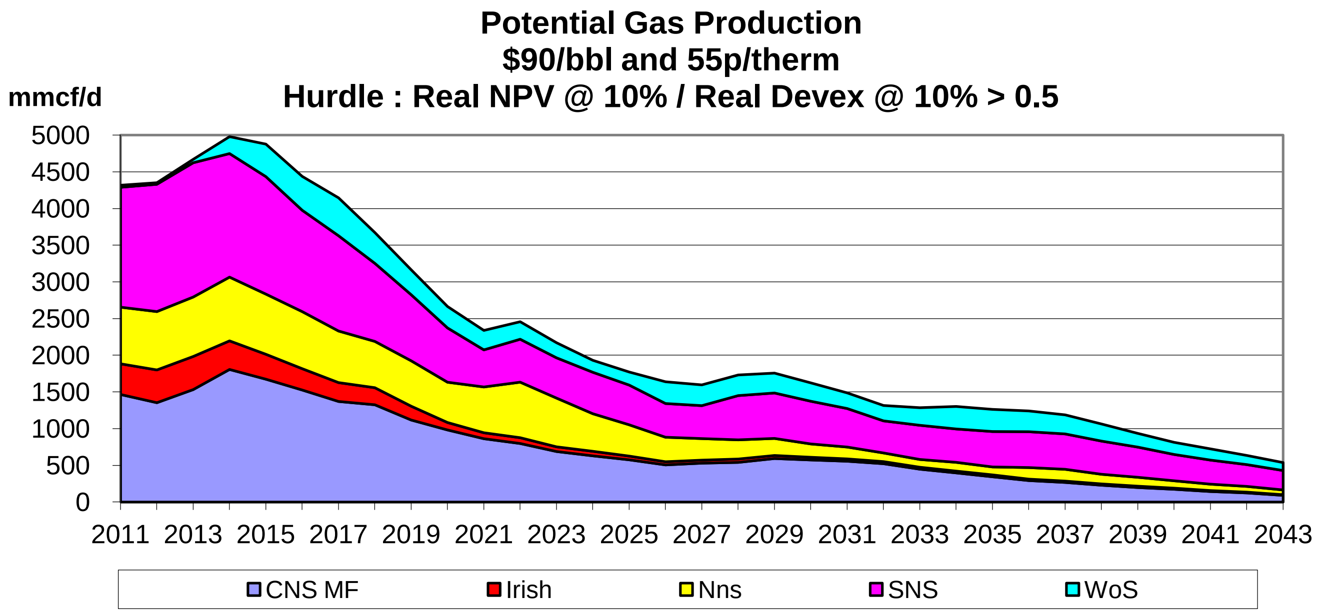
Chart 61



(ii) Gas Production

In Chart 62 prospective gas production is shown by main regions of the UKCS. Production from all regions declines in the medium term, particularly in the SNS. Nevertheless this region still makes a notable contribution to the total. The W of S region contributes a moderate amount over the whole period.

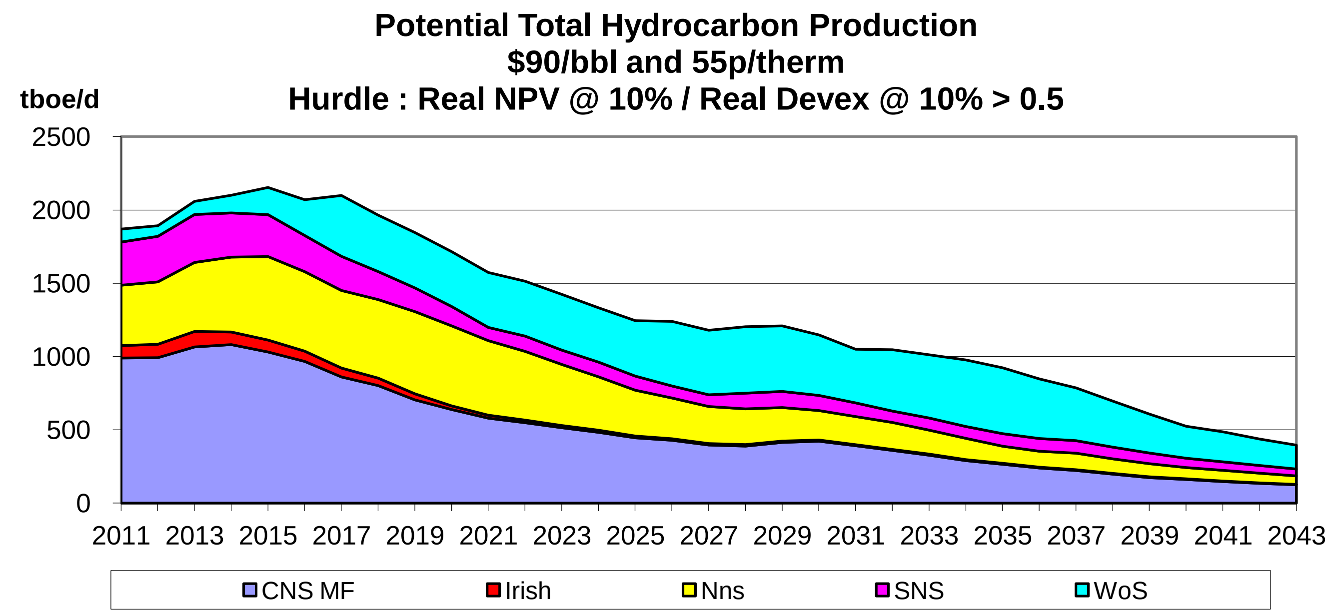
Chart 62



(iii) Total Hydrocarbon Production

In Chart 63 prospective total hydrocarbon production is shown. The CNS/MF region remains dominant for many years, despite the increases from the NNS. Over the longer term the W of S region makes a growing contribution to the total.

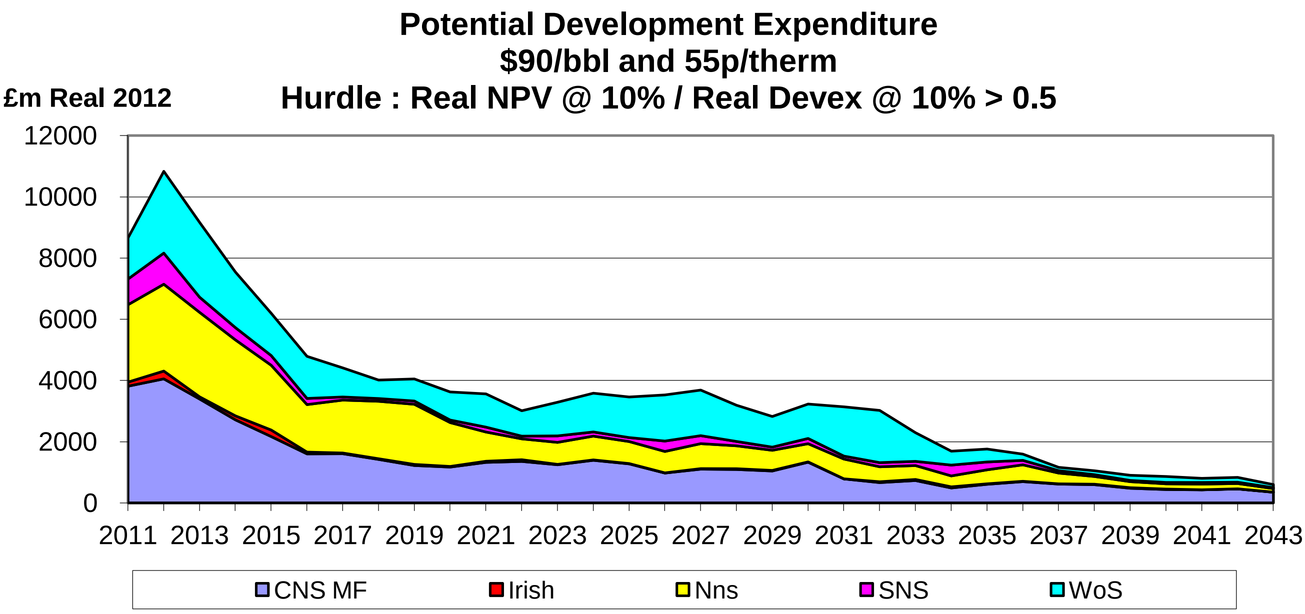
Chart 63



(iv) Development Expenditures

In Chart 64 development expenditures by region are shown. Over the next few years the CNS/MF, NNS and W of S regions make major contributions to the total, with each sharing in the current overall boom and the prospective subsequent decrease. In later years the CNS/MF and W of S regions dominate the reduced total.

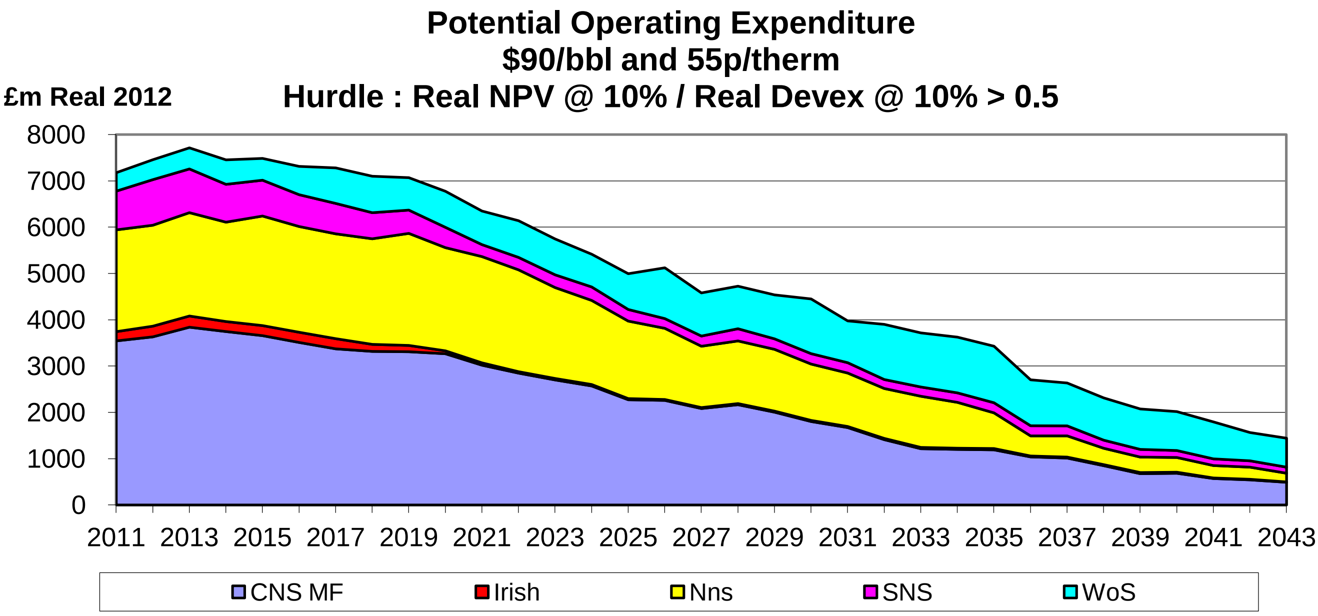
Chart 64



(v) Operating Expenditures

In Chart 65 the operating expenditures by region are shown. The CNS/MF area continues to dominate for several years ahead because of the continuing large numbers of fields in production. The NNS also makes a major contribution to the total until 2023 or so. The W of S region makes only a moderate contribution because of the modest numbers of producing fields in the area.

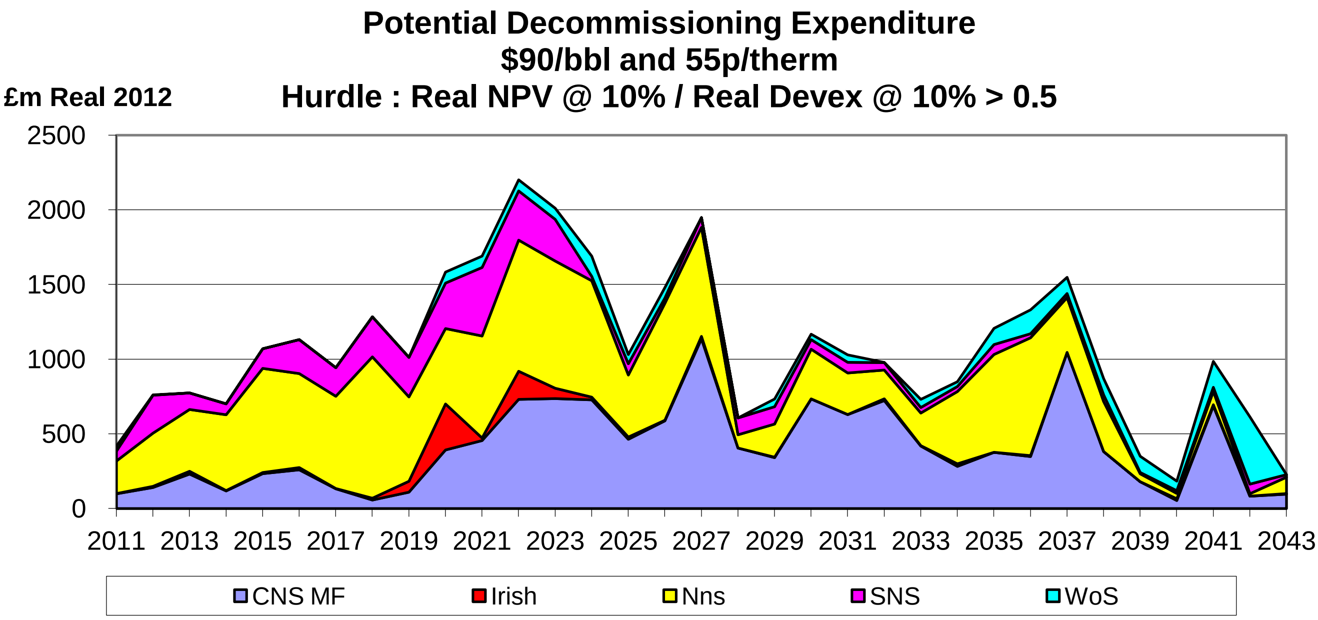
Chart 65



(vi) Annual Decommissioning Expenditures

In Chart 66 prospective annual decommissioning expenditures are shown. The dominance of the W of S region in the period 2012-2023 is noteworthy, as is the growing importance of the CNS/MF region from 2020 onwards. In the latter case there is a combination of large numbers of fields and some very expensive platforms, reaching their COP dates.

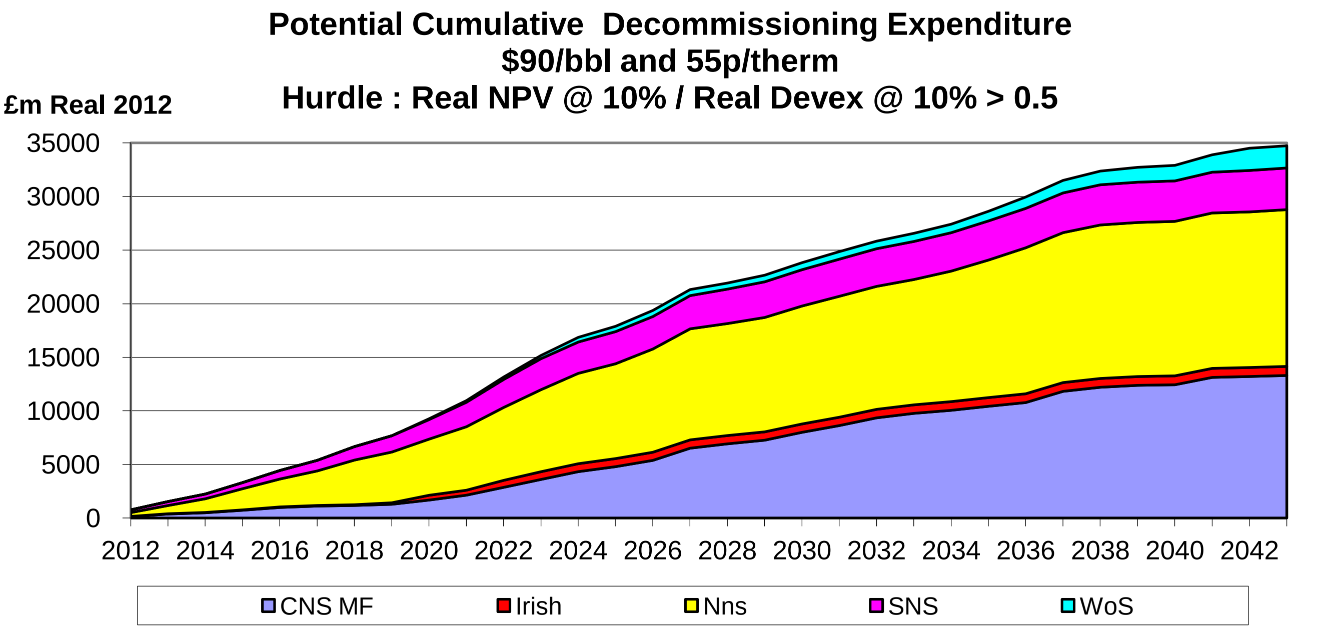
Chart 66



(vii) Cumulative Decommissioning Expenditures

In Chart 67 the cumulative decommissioning expenditures by region are shown. The importance of the NNS and CNS/MF regions in the total is highlighted.

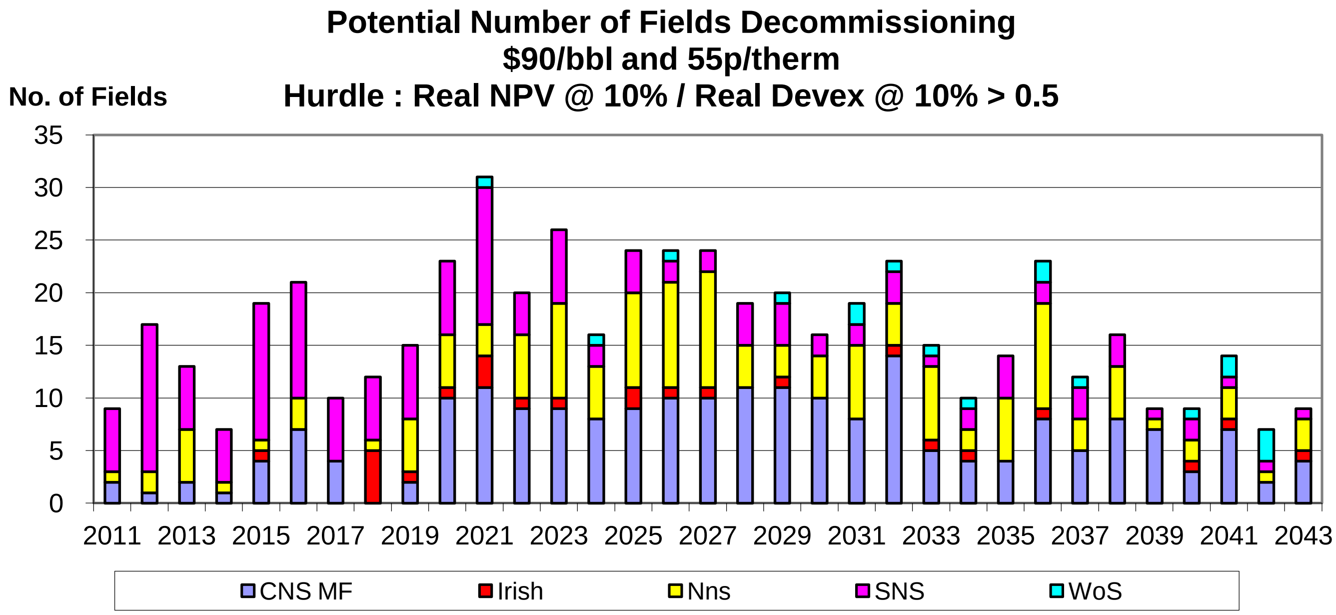
Chart 67



(viii) Numbers of Fields Decommissioning

In Chart 68 the numbers of fields reaching COP and decommissioning are shown by region. The early dominance of the SNS and the later importance of the CNS/MF regions are highlighted.

Chart 68



I. Consistency of Results with Official Estimates of Remaining Potential

In Table 6 the most recent estimates of the remaining potential made my DECC are shown for total hydrocarbons. There is no stated time period over which the potential might be realised. In Tables 7 and 8 the cumulative hydrocarbon production from the present study are shown over the periods 2012-2042 and 2012-2050 respectively. A comparison with the DECC findings indicates that the potential in the DECC low case is substantially exceeded in all scenarios. The potential as indicated by the DECC central case is not achieved in any of the four scenarios examined in this study even when the results are extended to 2050. This does not mean that the central potential in the DECC study cannot be achieved. It could well occur at some period after 2050. But, unless there is a significant increase in the exploration effort and/or the average sizes of new discoveries, it is most unlikely that DECC's central estimate of the remaining potential can be achieved by 2050. The success rates and sizes of discoveries over the period incorporated in the present modelling are unlikely to be exceeded.

Table 6

Estimates of Remaining Potential from UKCS

(Bn Boe (rounded))

	Low	Central	High
Reserves (p + p + p)	4.6	8.9	12.6
PAR	1.3	3.4	7.3
Yet-to-Find	4.4	7.4	13.1
Total	10.3	19.7	33.0

Total depletion to date: 40.1 bn boe Source: DECC

Table 7

Cumulative Hydrocarbon Production (UKCS) 2012-2042

Real Price	bn boe	
	NPV/I > 0.3	NPV/I > 0.5
$70, 40 pence	13.4	11.2
$90, 55 pence	16.8	14.7

Table 8

Cumulative Hydrocarbon Production (UKCS) 2012-2050

Real Price	bn boe	
	NPV/I > 0.3	NPV/I > 0.5
$70, 40 pence	14.3	11.7
$90, 55 pence	17.5	15.4

J. Effects of Field Allowances on Activity

The effectiveness of the various field allowances can be assessed in various ways. An obvious measure is their effect in stimulating investment in new fields and projects. From the modelling undertaken in this study under the $70, 40 pence price scenario over the period 2012-2042 there were 451 potential new field developments and 179 current incremental projects (i.e. excluding future incremental projects). Of these 422 fields were eligible for one of the field allowances and 45 incremental projects were eligible for the brownfield allowance. Under the $90, 55 pence price case there were 469 potential new field developments of which 440 were eligible for an allowance. Eligibility does not necessarily mean that the fields or projects are economically viable either pre-tax or post-tax and some do indeed remain non-viable. Other fields/ projects will be viable without any field allowance under the investment hurdles used in this study. The effects under the four scenarios are summarised in turn.

Under the $70, 40 pence price case and investment hurdle of NPV/I > 0.3 over the whole period 143 fields are viable without a field allowance, while 207 become viable with the benefit of the allowance. A small number of current incremental projects (i.e. excluding future ones) are incentivised by the brownfield allowance.

Under the $70, 40 pence price case and investment hurdle of NPV/I > 0.5 over the whole period 73 new fields are viable without a field allowance, while 129 become viable with the benefit of the allowances. Ten current incremental projects (i.e. excluding future ones) are rendered viable by the brownfield allowance.

Under the $90, 55 pence price case and investment hurdle of NPV/I > 0.3 over the period 279 new fields are viable without a field allowance, while 349 become viable with the benefit of an allowance. A very small number of current incremental projects (excluding future ones) are rendered viable by the brownfield allowance.

Under the $90, 50 pence prise case with investment hurdle of NPV/I > 0.5 181 new fields are viable without a field allowance, while 262 become viable with the benefit of an allowance. A small number of current incremental projects (excluding future ones) are rendered viable by the availability of the brownfield allowance.

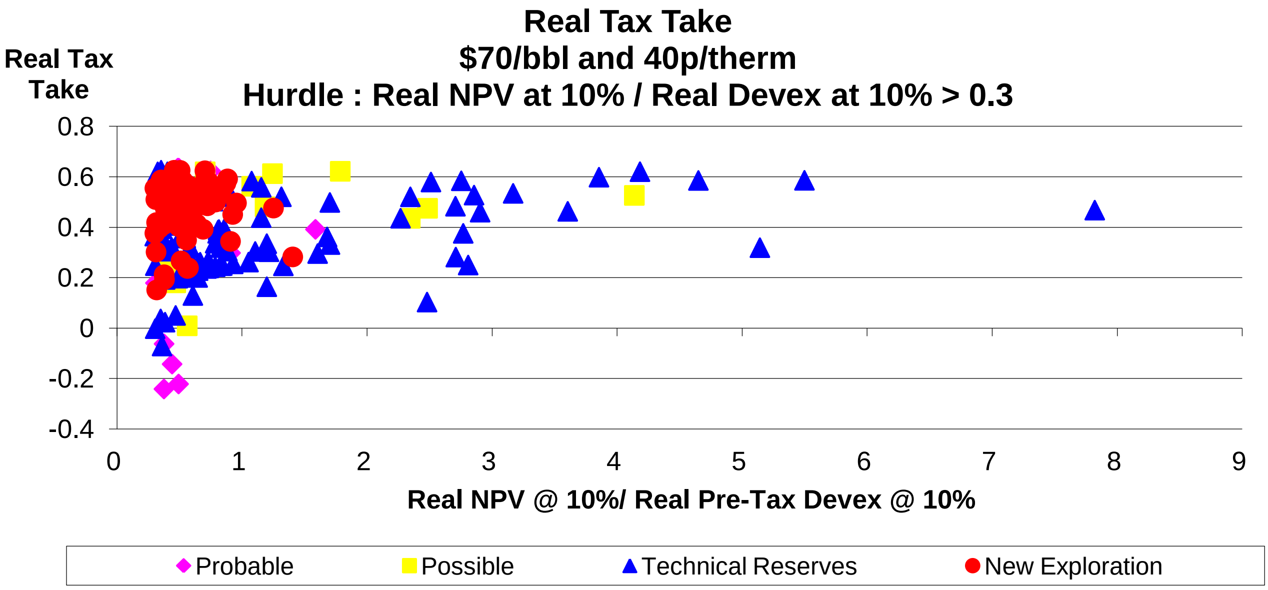
It is noteworthy form the modelling that the great majority of the fields which are rendered viable by the availability of a field allowance are in the categories of new discoveries and technical reserves. Thus in the $70, 40 pence, and NPV/I > 0.3 case 26 new discoveries and 29 technical reserves are rendered viable by a field allowance. Under the $70, 40 pence price case and NPV/I > 0.5 22 new discoveries and 32 technical reserves are rendered viable by a field allowance.

Under the $90, 55 pence case with NPV/I > 0.3 31 new discoveries and 35 technical reserves become viable with the benefit of a field allowance. Under the $90, 55 pence price case with NPV/I > 0.5 38 new discoveries and 34 technical reserves become viable as a result of a field allowance. A main conclusion from these findings is that the full benefit of the field and brownfield allowances will only be felt in the long term. The returns to new exploration are clearly enhanced by the allowances as the results noted above indicate. The development of many of the difficult, expensive fields in the technical reserves category will only take place in the longer term, and the field allowances should significantly enhance investment incentives. With respect to the brownfield allowance it is to be expected that its presence will encourage attempts to develop more incremental projects. The results noted above do not take into account such future incremental projects.

K. Effective Tax Takes after Field Allowances

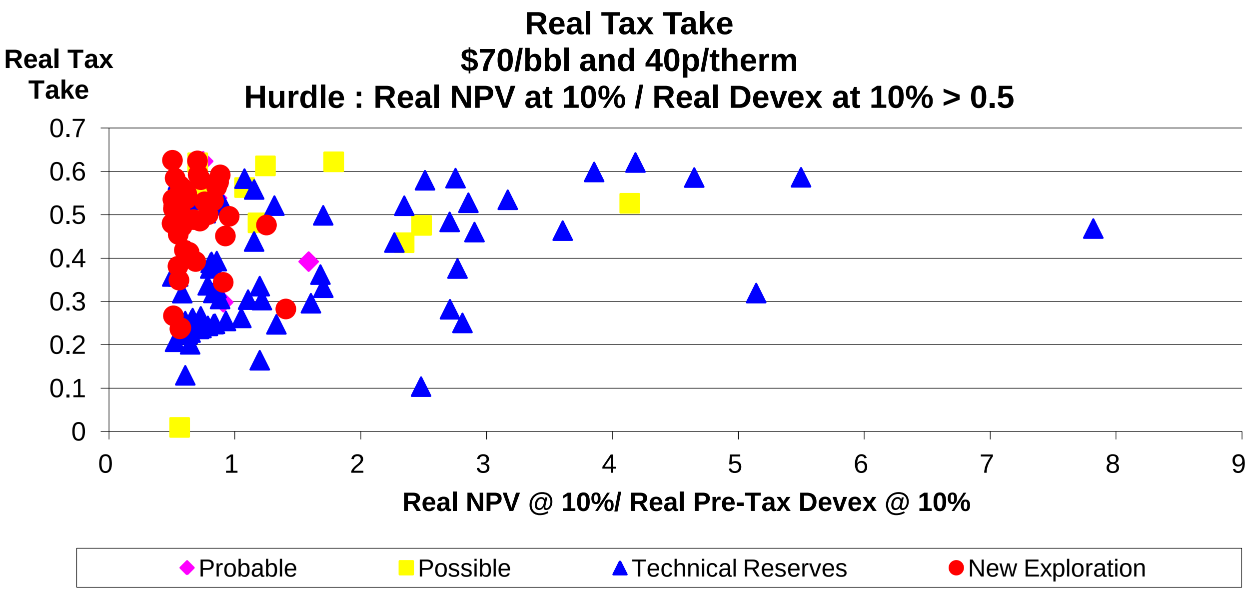
The various field allowances are complex and their effects on tax takes not readily clear. Accordingly, the effective tax takes on new fields and incremental projects after the field allowances were calculated. In Chart 69 the percentage tax takes are shown under the $70, 40 pence price scenario for the unsanctioned fields which pass the NPV/I > 0.3 hurdle. There is seen to be a wide range of takes. Broadly, fields with attractive NPV/I ratios face higher effective tax takes than those of modest profitability. At moderate/ modest levels of profitability there is a wide range of effective tax takes, with some fields facing the full 62% rate and a slightly higher overall effective rate, given that relief for decommissioning costs is at 50% rate rather than 62%. In other cases the effective tax rate is much lower, reflecting the benefits of the field allowances. Some fields of modest profitability are not eligible for a field allowance while others receive very substantial protection from the Supplementary Charge (SC). Thus relief for the investment is at 62% while in some cases the income is taxed at much lower rates, depending on the extent to which the allowance shelters liability to the SC. The result is a consequence of the allowances being based on physical characteristics rather than economic ones.

Chart 69



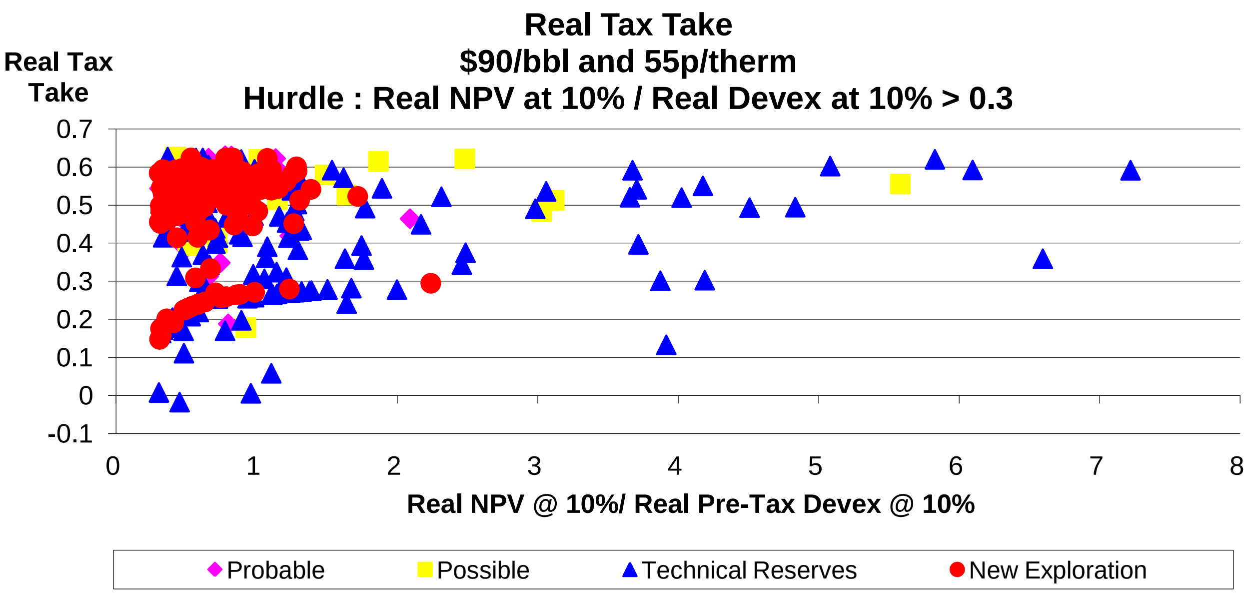
In Chart 70 the effective tax takes are shown under the $70, 40 pence price case for those fields which pass the more demanding hurdle of NPV/I > 0.5. The pattern is broadly the same as with the lower hurdle, though less fields pass the hurdle.

Chart 70



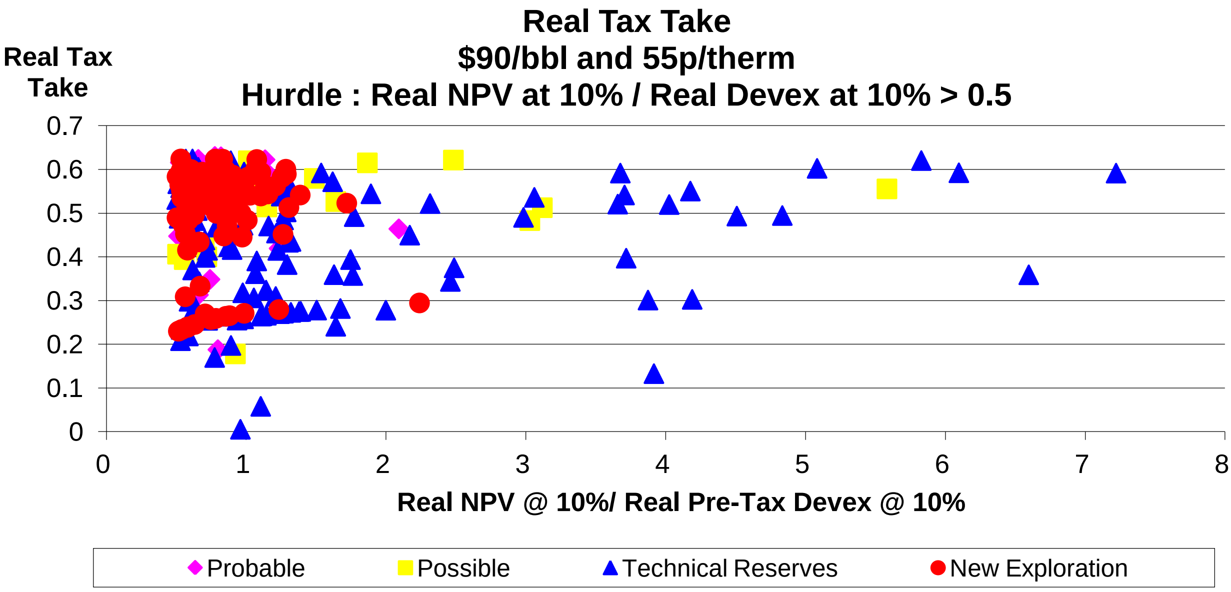
In Chart 71 the effective tax takes are shown under the $90, 55 pence case for the new fields which pass the investment hurdle of NPV/I > 0.3. The pattern of results is not dissimilar to those under the medium price case, though many more fields pass the hurdle. A larger proportion of the fields face higher tax takes under the $90, 55 pence case. The field allowances are progressive in relation to oil/gas price changes. This is because the fixed monetary values of the allowances shelter a higher proportion of the income from SC at the lower oil and gas prices.

Chart 71



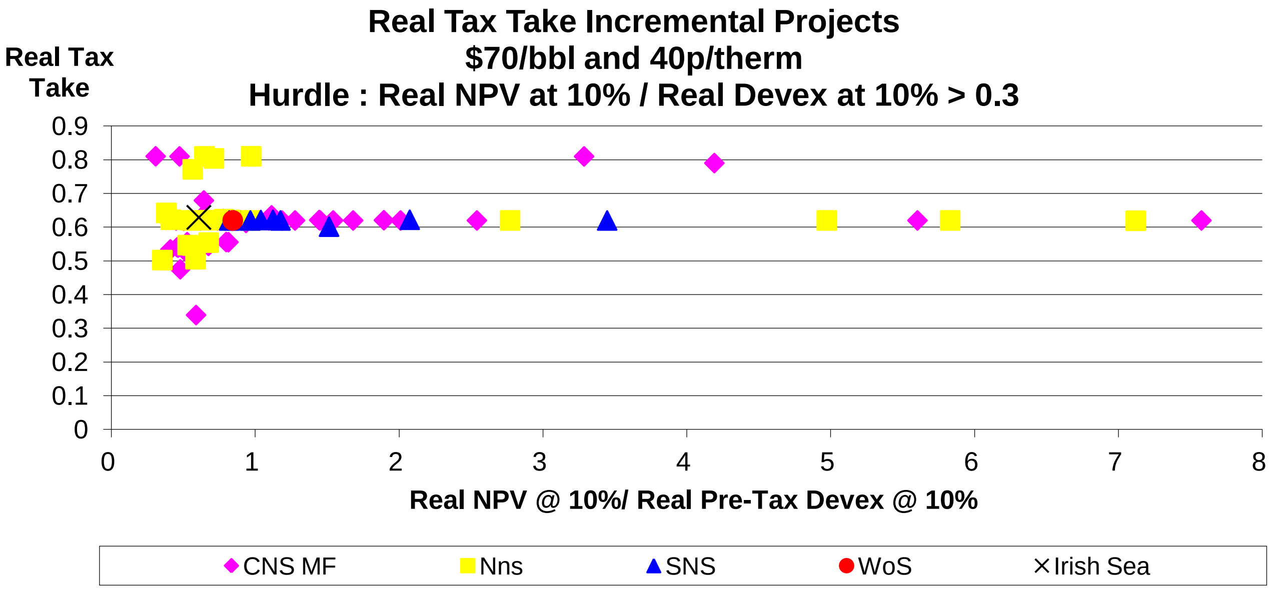
In Chart 72 the effective tax takes are shown for the new fields under the $90, 55 pence price which pass the investment hurdle NPV/I > 0.5. The pattern of results is broadly similar to those with the lower price and NPV/I > 0.5 hurdle though more fields pass the hurdle. Again, a larger proportion of the fields face higher effective tax rates under the $90, 55 pence prices reflecting the progressiveness of the allowances in relation to price changes.

Chart 72



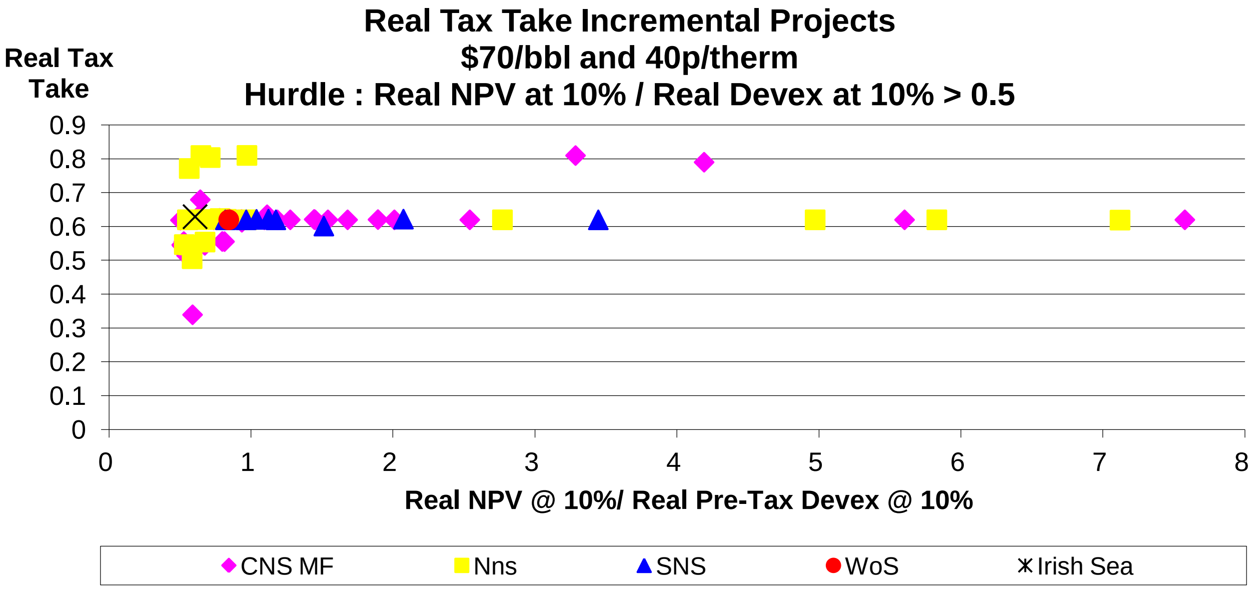
In Chart 73 the effective tax takes are shown for current incremental projects which pass the investment hurdle NPV/I > 0.3 under $70, 40 pence prices. (Future incremental projects are not included in this part of the study). Most of the projects face an effective rate of 62% as they do not qualify for the brownfield allowance. Some which are subject to PRT face a rate of 81%. Projects which do benefit from the allowance face effective rates in the 47%-57% range.

Chart 73



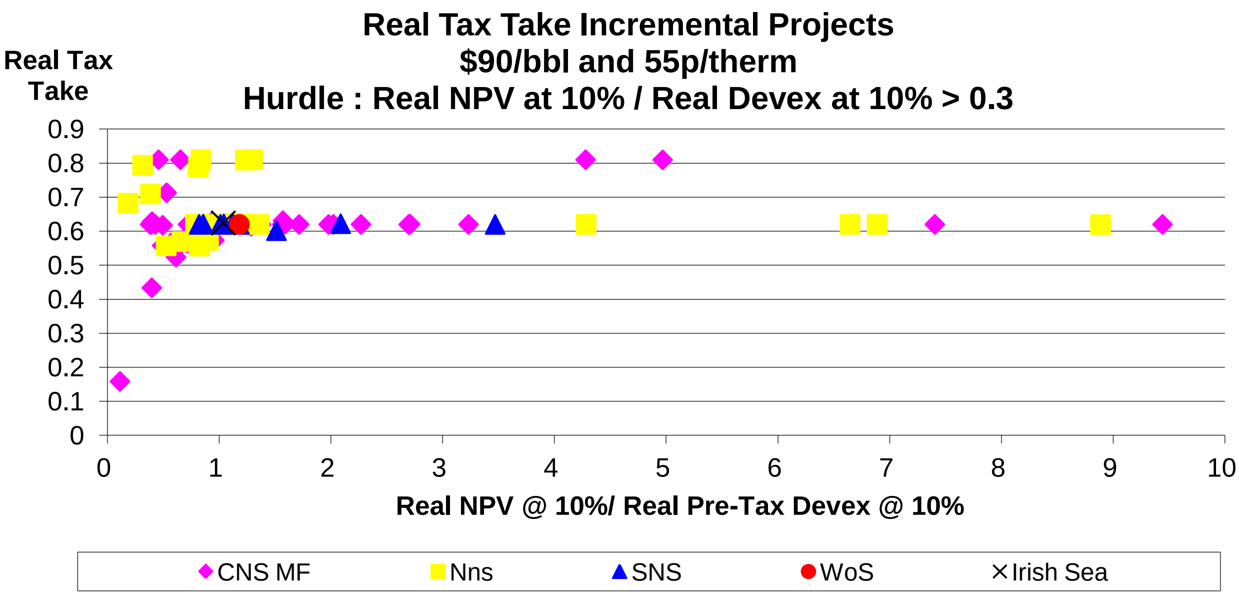
In Chart 74 the effective rates of tax on current incremental projects which pass the investment hurdle NPV/I > 0.5 are shown under the $70, 40 pence price case. The pattern of results is essentially the same as for the case with the lower hurdle (though less projects pass the higher hurdle). The brownfield allowance is generally progressive with respect to investment cost and oil/gas price variations.

Chart 74



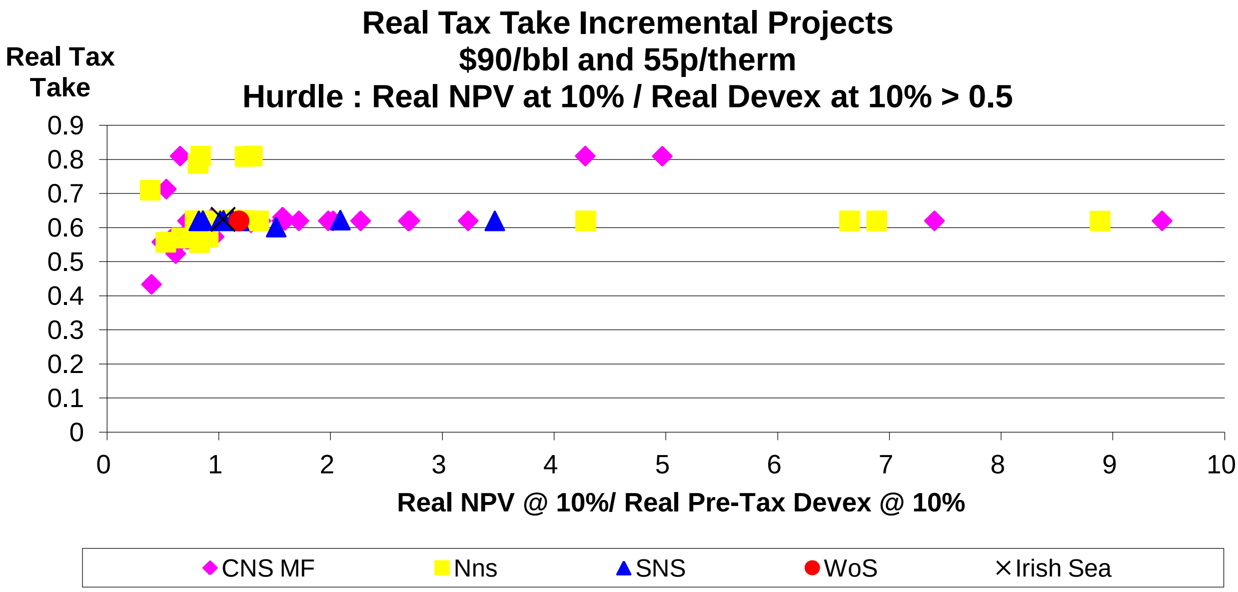
In Chart 75 the effective rates of tax on current incremental projects which pass the investment hurdle NPV/I > 0.3 are shown under the $90, 55 pence price case. More projects pass the hurdle under the higher price. The great majority face an effective rate of 62%, with some subject to PRT facing an 81% rate. It is seen that the brownfield allowance results in some PRT-paying projects facing effective rates of around 70%. In non-PRT paying fields the allowance reduces the effective rate to the 50%-60% range in a number of cases.

Chart 75



In Chart 76 the effective tax takes are shown for current incremental projects which pass the NPV/I > 0.5 at $90, 55 pence prices. The pattern is similar to the case with the lower hurdle, though less projects pass the hurdle.

Chart 76



4. Conclusions

In this study the prospects for activity levels in the UKCS after all the recent tax changes have been modelled. Financial simulation techniques have been used including use of Monte Carlo analysis, particularly for exploration activity. Two price scenarios have been employed, namely (1) a medium case of $70 per barrel and 40 pence per therm in real terms, (increasing yearly by the assumed annual inflation rate of 2.5%), and (2) a higher case of $90 and 55 pence per therm, again in real terms. Two investment hurdles were employed namely NPV@10% / I@10% > 0.3 and > 0.5, reflecting the presence of some capital rationing. The simulations of future activity are based on input assumptions reflecting trends over the last decade relating to exploration success rates, average size of discovery, and type of hydrocarbon found. Costs of new discoveries are based on those expected by operators for the generation of fields currently being examined for development. The up-to-date tax system, including the recently announced brownfield allowance, have been incorporated in the modelling.

Key results of the study indicate that oil production should revive from recent levels for a period of several years, particularly with the higher price scenario, where the increase could be substantial. Gas production may increase to a modest extent over the next few years under the higher price case. Over the longer term production falls with both oil and gas, with the decline rate being much faster with gas. Over the next 30 years cumulative production of oil, gas and NGLs could amount to 16.8 billion barrels of oil equivalent (bn boe) under the higher price scenario, and 13.5 bn boe under the medium price case. Activity continues beyond this date and cumulative production from 2012 to 2050 could amount to 17.5 bn boe under the higher price case and 14.3 bn boe under the medium price. These results may be compared with the DECC central estimate of the ultimate potential of 19.7 bn boe, and the achievement of cumulative depletion to date of over 20 bn boe.

The findings of the present research could be exceeded when the full effects of the brownfield allowance on incentives become reflected in the examination of further possible incremental projects. On the other hand the attainment of the production potential does depend on the various PILOT/ DECC initiatives being successful. These include the fallow initiative (which can claim to be successful to date), efficient third party access to infrastructure, the stewardship initiative on mature fields (including its extension to infrastructure), and the effective guarantees of tax relief for decommissioning. Much effort is being expended by DECC/ Treasury/ HMRC and the industry in reaching agreements on these issues. Without them the longer term production levels projected in this study will be jeopardised.

A further issue is relevant to the attainment of the long term projections made in the present study. While they take account of the possibility that there could be delays in the implementation of developments in the categories of probable and possible fields and incremental projects, they do not specifically incorporate the effects of substantial unplanned downtime in producing facilities and infrastructure. These have been substantial in recent years, and have made a main contribution to the production decline rates. Asset integrity initiatives which emphasise production as well as safety integrity could make a valuable contribution to output over the whole period. As the age of producing assets and infrastructure increases investment in asset integrity becomes even more important when the full interconnectedness of the facilities in the UKCS is recognised.

Currently there is an investment boom in the UKCS reflecting the coincident development of several large fields/ projects. Current field investment levels will continue in the short term. They should then fall somewhat, but remain at levels which are still high by historic levels, particularly if investment is assessed at oil prices of $90 or above. At this price operating expenditures remain at or around current levels for a considerable number of years ahead, reflecting the number of producing fields remaining at or around current levels.

When new field investment does fall from current very high levels it is clear from the present study that the market for decommissioning activities will grow very substantially. Decommissioning plans are already being made for fields where the related expenditures are very large. Over the period 2012-2042 cumulative expenditures on decommissioning will exceed £30 billion (at 2012 prices) and could reach

£35 billion. Thus the overall prospects for the supply chain in the UKCS when the sum of field development expenditures, operating costs, and decommissioning costs are all considered, should remain buoyant for many years ahead.

Appendix

<u>Recent Tax Changes in UKCS</u>

CT at 30%

SC at 32% (from 2011)

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

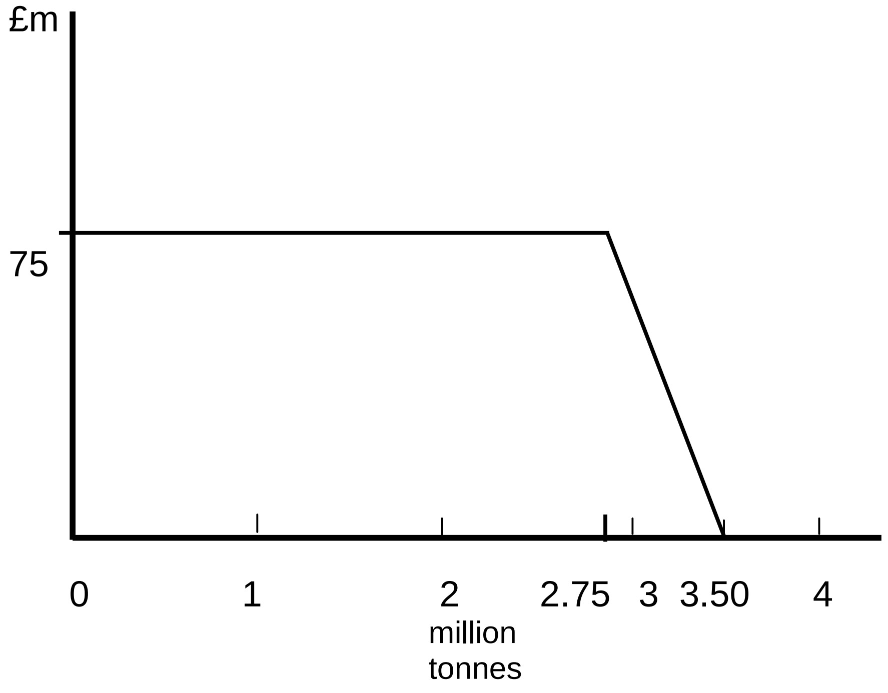
Budget 2009 introduced:

Value Allowance for Supplementary Charge

<u>Budget 2009</u>

- 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 £800m. (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%

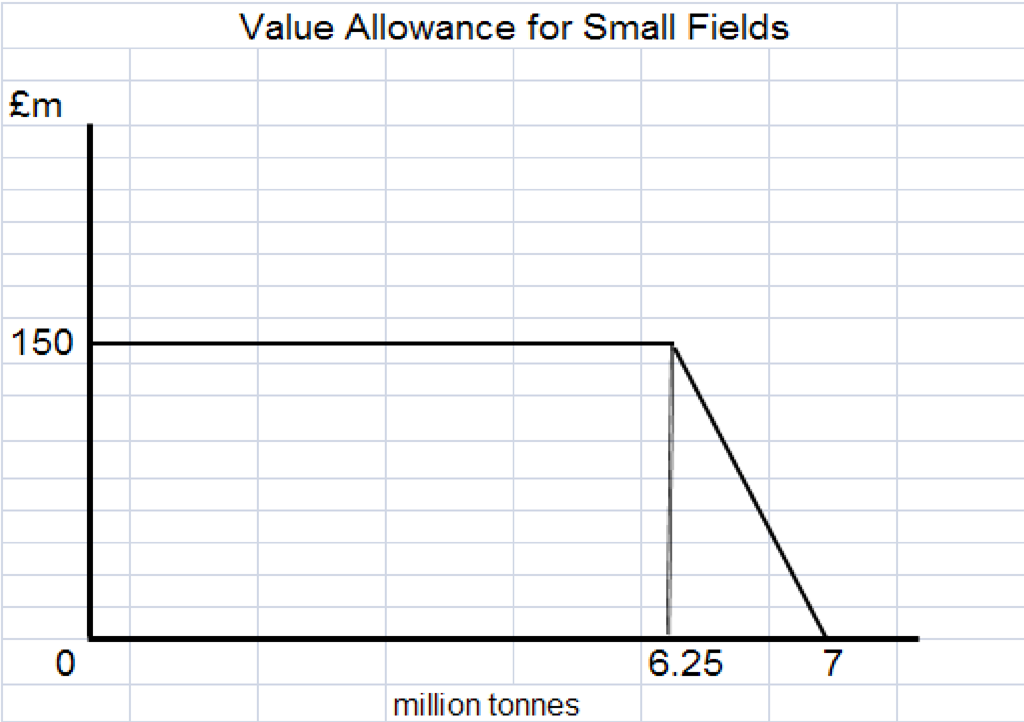
	Decommissioning Relief	
	Pre Budget	Post Budget
PRT fields	75%	69%/75%
Non-PRT fields	50%	50%

July 2011

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

Budget 2012

- Field allowances to be extended to fields already developed (incremental projects).
- 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).



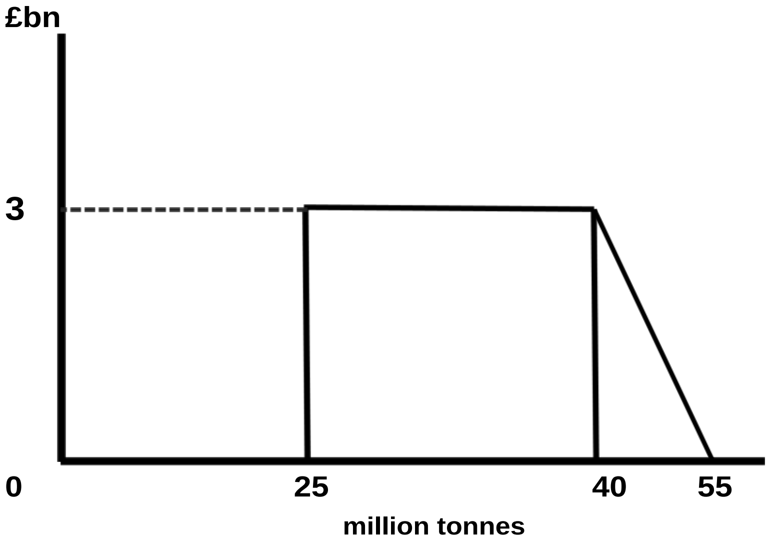
- New £3bn. field allowance (over 5 years) for new fields with qualifying criteria:

  (a) Water depth > 1000 metres

  (b) Minimum reserves of 25m. tonnes

  (c) Maximum reserves of 40m. tonnes with taper to £0 at 55m. tonnes

Value Allowance for Large, Deepwater Fields



- 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 to consult further on the precise form and details of such contracts in the coming months.

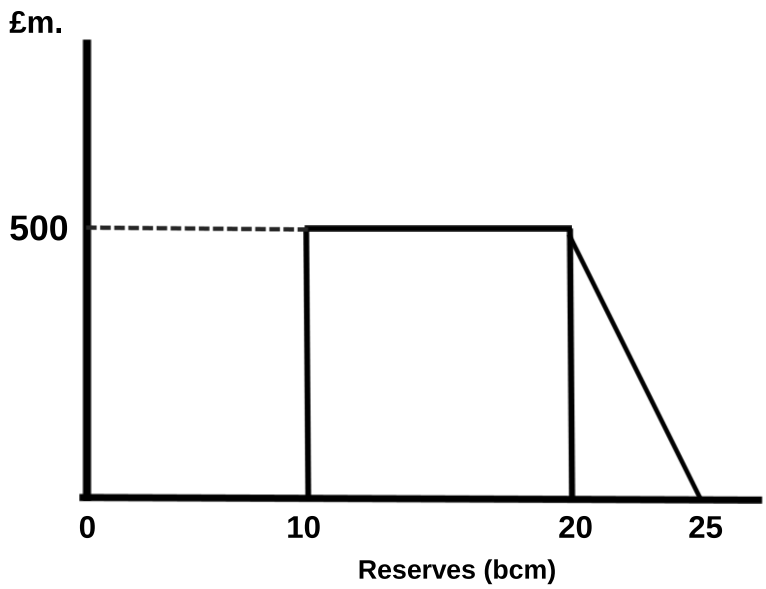
July 2012

- Announcement of field allowance of £500 million. (over 5 years) for large, shallow water gas fields.
- Qualifying criteria:

  (a) Water depth < 30 metres

  (b) Reserves more than 10 bcm and less than 20 bcm with taper to 25 bcm

Value Allowance for Large, Shallow Water Gas Fields



September 2012

- Announcement of Brownfield Allowance (BFA) for incremental projects in producing fields.
- Qualifying criteria: capital costs per incremental tonne of reserves exceeding £60. Allowance increases linearly to maximum of £50 per tonne when capital costs reach £80 per tonne.
- Allowance spread over 5 years.
- Maximum allowance: £250m. in non-PRT-paying fields
  £500m. in PRT-paying fields.

Brownfield Allowance