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The Short and Long Term Prospects for Activity in the UK Continental Shelf: the 2011 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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The Long Term Prospects for Activity in the UK Continental Shelf

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Linda Stephen

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The Short and Long Term Prospects for Activity in the UK Continental Shelf: the 2011 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. Major changes were made to taxation in Budget 2011. This paper models potential activity levels taking into account updated information on all the above factors. The outputs highlighted are production of oil and gas, field investment, operating and development expenditures, and numbers of fields whose developments are triggered, and those which reach their cessation of production (COP). The time period considered is 2011 – 2042 inclusive.

2. Methodology and Data

The projections of production and expenditures have been made through the use of financial simulation modelling, including the use of the Monte Carlo technique, informed by a large, recently-updated, field database validated by the relevant operators. The field database incorporates key, best estimate information on production, and investment, operating and decommissioning expenditures. These refer to 350 sanctioned fields, 150 incremental projects relating to these fields, 41 probable fields, and 28 possible fields. These unsanctioned fields are currently being examined for development. An additional database contains 248 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas) and block locations are available for these. They are not currently being examined for development by licensees.

Monte Carlo modelling was employed to estimate the possible numbers of new discoveries in the period to 2037. The modelling incorporated assumptions based on recent trends relating to exploration effort, success rates, sizes, and types (oil, gas, condensate) of discovery. A moving average of the behaviour of these variables over the past 5 years was calculated separately for 6 areas of the UKCS (Southern North Sea, (SNS), Central North Sea (CNS), Moray Firth (MF), Northern North Sea (NNS), West of 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 2 future oil/gas price scenarios were employed as follows:

Table 1 Future Oil and Gas Price Scenarios		
	Oil Price (real) $/bbl	Gas Price (real) pence/therm
High	90	60
Medium	70	40

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

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

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

It is postulated that success rates depend substantially on a combination of (a) recent experience, and (b) size of the effort. It is further suggested that higher effort is associated with more discoveries but with lower success rates compared to reduced levels of effort. This reflects the view that low levels of effort will be concentrated on the lowest risk prospects, and thus that higher effort involves the acceptance of higher risk. For the UKCS as a whole 2 success rates were postulated as follows with the medium one reflecting the average over the past 5 years.

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

It should be noted that success rates have varied considerably across sectors of the UKCS. Thus in the CNS and SNS the averages have exceeded 30% while in the other sectors they have been well below the average for the whole province. It is assumed that technological progress will maintain these success rates over the time period.

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

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

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

Using the above information the Monte Carlo technique was employed to project discoveries in the 6 regions to 2036. For the whole period the total numbers of discoveries for the whole of the UKCS were are follows:

Table 5 Total Number of Discoveries to 2037	
High effort/Low success rate	210
Medium Effort/Medium Success Rate	193

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

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

Using these as the mean values the Monte Carlo technique was employed to calculate the development costs of new discoveries. A normal distribution with a SD = 20% of the mean value was employed. For new discoveries annual operating costs were modelled as a percentage of accumulated development costs. This percentage varied according to field size. It was taken to increase as the size of the field was reduced reflecting the presence of economies of scale. Thus the field lifetime costs in small fields could become very high on a per boe basis.

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

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

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

A noteworthy feature of the 150 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 distribution, the most likely sizes are below these averages. It follows that the materiality of returns, expressed in terms of net present values (NPVs), is quite low in relation to those in prospect in other provinces (such as offshore Angola, or Brazil, for example). Oil companies frequently rank investment projects according to the NPV/I ratio. Accordingly, this screening method has been adopted in the present study. Specifically, the numerator is the post-tax NPV at 10% discount rate in real terms and the denominator is pre-tax field investment at 10% discount rate in real terms. This differs from the textbook version which states that I should be in post-tax terms because the expenditures are tax deductible through allowances. Oil companies maintain that they allocate capital funds on a pre-tax basis, and this is employed here as the purpose is to reflect realistically the decision-making process. The development project goes ahead when the NPV/I ratio as defined above is ≥ 0.3 in one scenario and ≥ 0.5 in a second scenario. The 10% real discount rate reflects the weighted average cost of capital to the investor. The modelling has been undertaken under the current tax system.

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

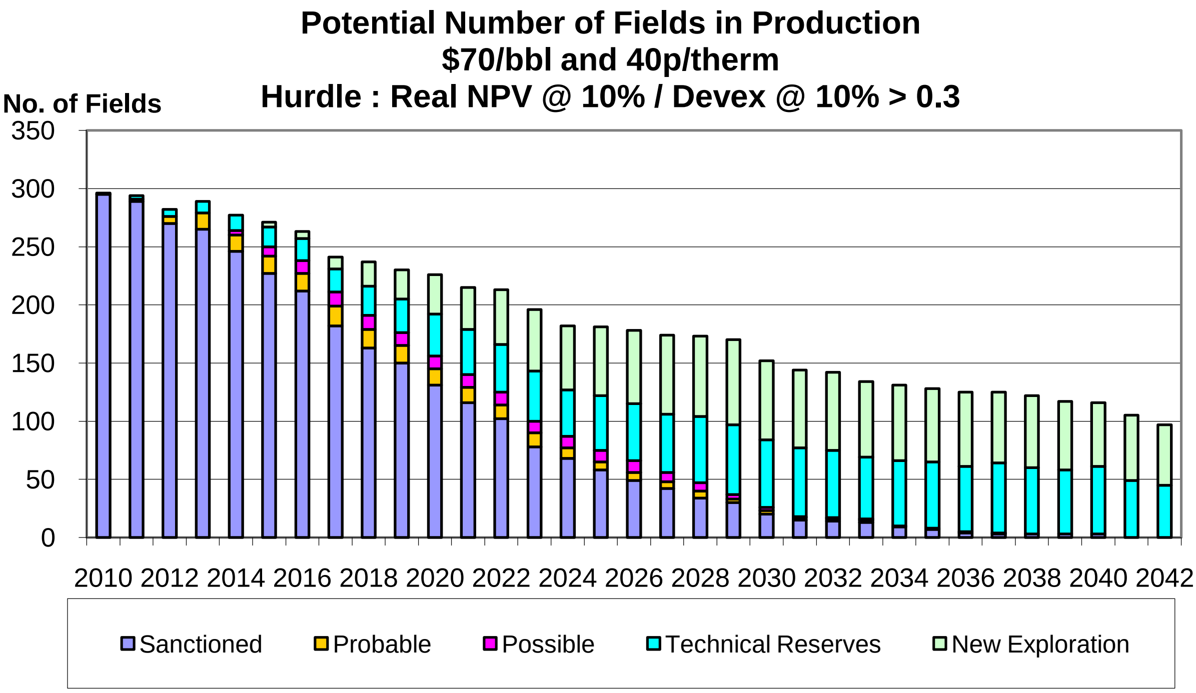
3. Results

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

(i) Numbers of Fields in Production

The changing numbers of fields in production under the above scenarios is shown in Chart 1.

Chart 1

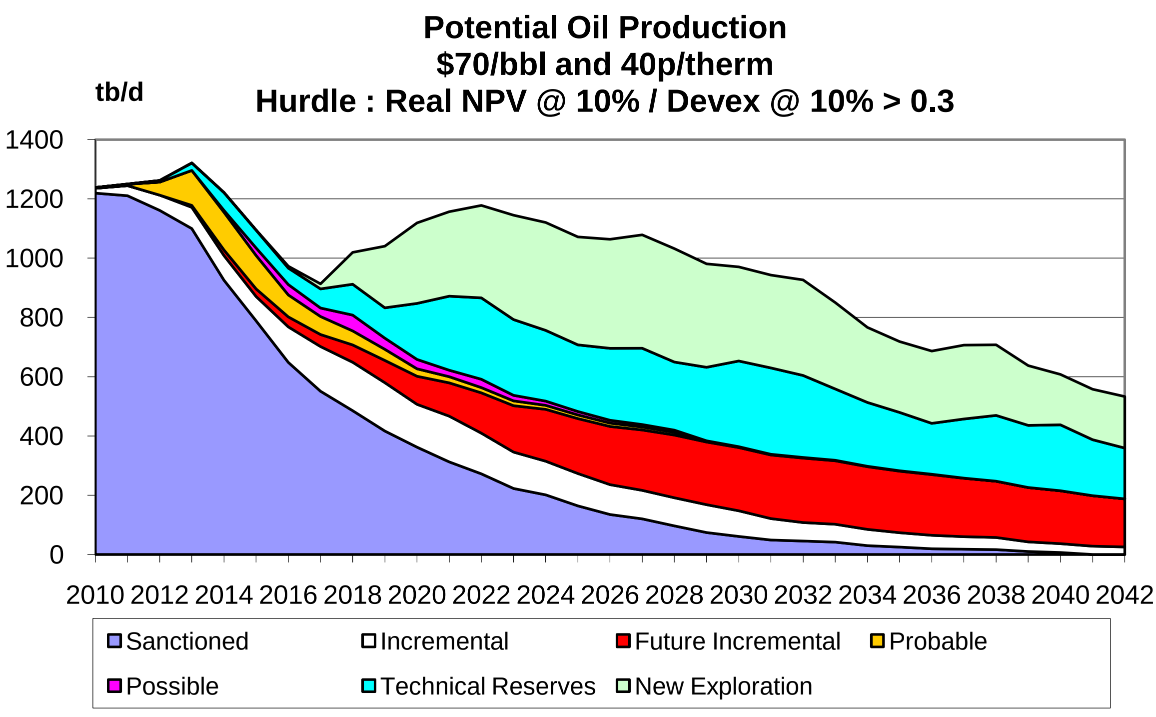


The numbers reflect the balance of fields coming to the end of their economic lives (COP dates) and new fields whose development is triggered over the period to 2042. It is seen that the numbers of sanctioned fields falls steadily throughout the period. The numbers of probable and possible fields whose development are triggered are relatively small in comparison. In the longer term the development of significant numbers of fields in the categories of technical reserves and some new discoveries substantially moderate the decline rate, but there is a continuous overall decrease from 2013 onwards when the total is around 280 to 97 in 2042. Over the whole period the average annual number of new field developments was just over 11.

(ii) Production

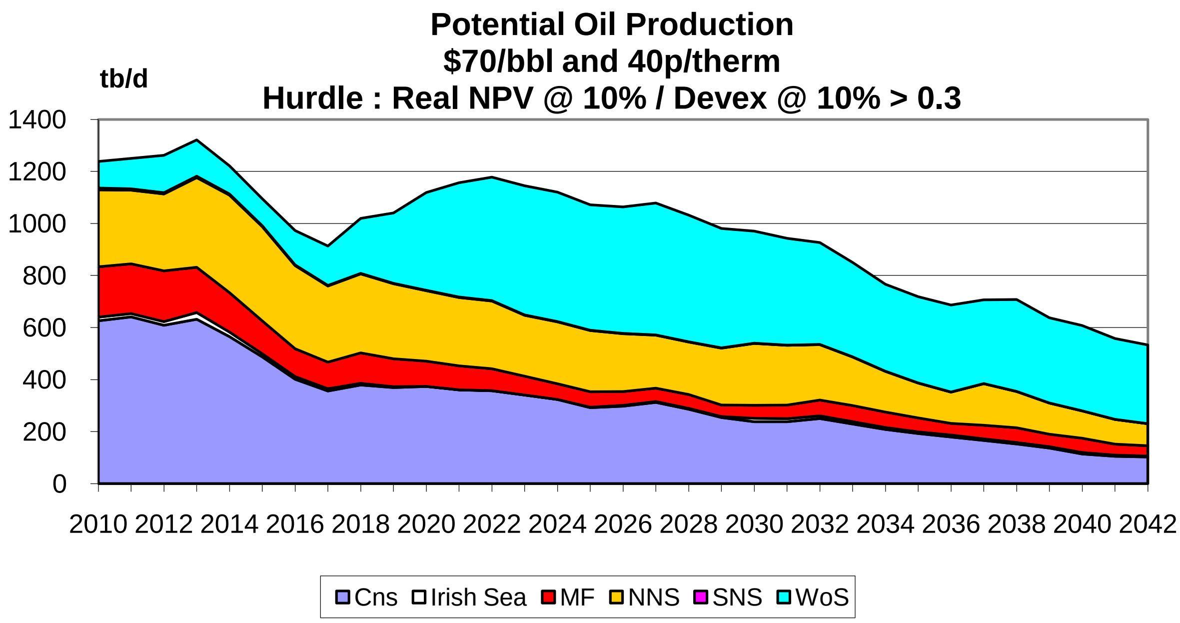
In Chart 2 oil production is shown highlighting the various categories of fields and projects.

Chart 2



Output could increase a little in the short term but this is followed by a sharp decrease to 2017. After that production continues to fall steadily from the sanctioned fields and incremental projects associated with them. The long term decline rate is substantially moderated by the development of significant numbers of fields in the category of technical reserves. Further, the subsequent development of new discoveries leads to a substantial increase in overall production. This result is achieved primarily from developments in the W of S region. This is shown in Chart 3 which shows oil production split up by the 6 regions of the UKCS.

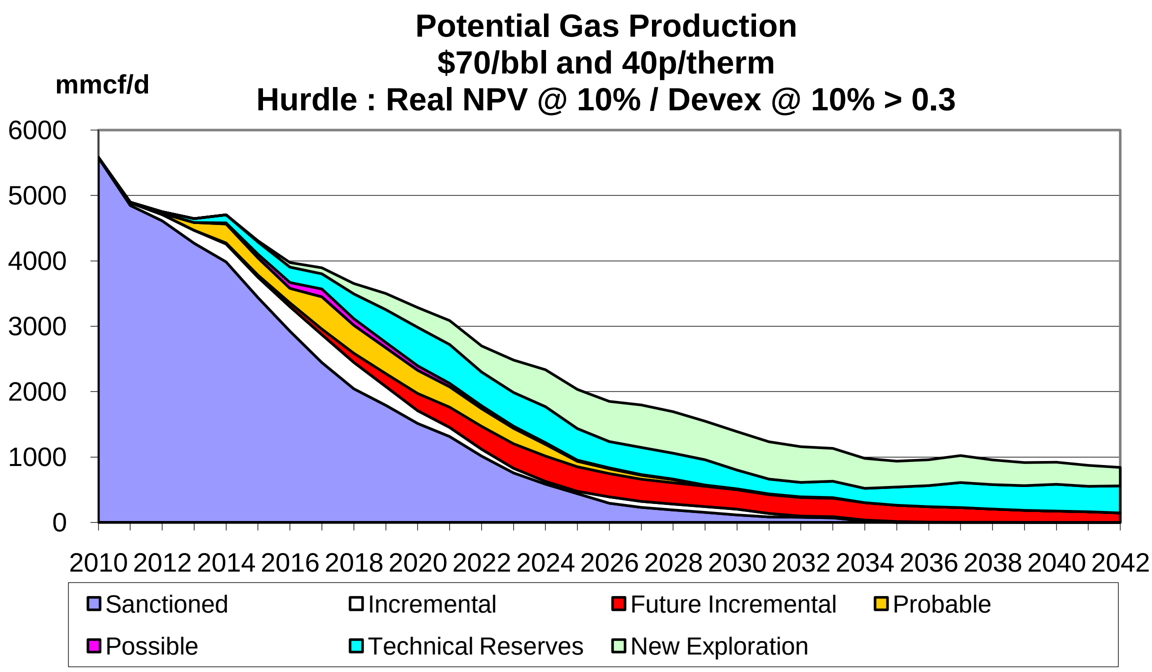
Chart 3



The possible substantial increase in oil production from the W of S region is worthy of further discussion. The discoveries modelled are based on recent trends in success rates and size of discoveries. The mean size of discovery over the last few years has been estimated at 75 mmboe. In the exploration modelling this falls to

30 mmboe in 2037. Under the present scenario being examined, over the period to 2042, 15 new discoveries pass the investment hurdle and are developed. Over the whole period the cumulative production from all sources (including sanctioned, probable, and possible fields plus incremental projects as well as new discoveries) is 3.88 bnbbls from the W of S region. This is consistent with the long term potential from DECC's latest estimates of the remaining potential.[1] Their central estimates for W of S total 4.32 bnbbls of which 1.545 bnbbls are from new discoveries.

Chart 4

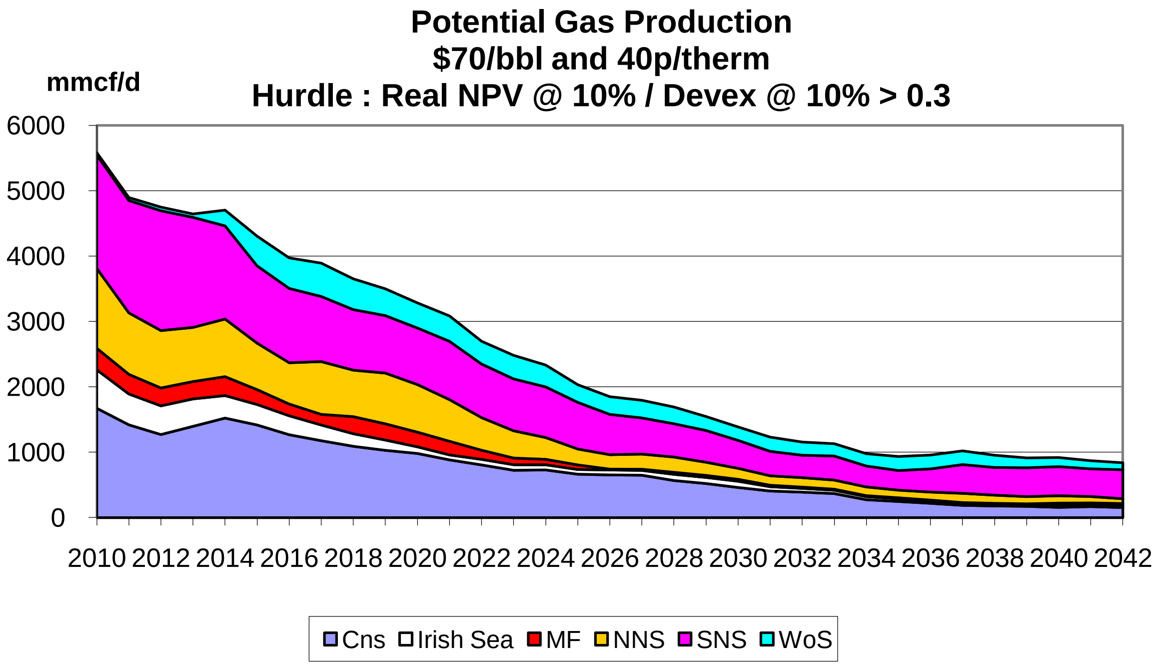


In Chart 4 potential natural gas production is shown over the period. There is a brisk decline in output from sanctioned fields which is moderated by the development of new fields. The

[1] See http://www.og.decc.gov.uk/information/statistics.htm

contribution from new discoveries, while certainly worthwhile, is not nearly so great as in the oil case. The geographic spread of potential gas production is shown in Chart 5. The contribution of the W of S region is significant but, at 0.5 bnboe not dramatic.

Chart 5



In Chart 6 prospective total hydrocarbon production (including NGLs) is shown. The brisk decline rate from sanctioned fields is noticeable. Current and future incremental projects significantly moderate the decline rate but in the longer term larger contributions are made from technical reserves and new discoveries. By 2042 production is 0.68 mmboe/d. The cumulative total production to 2042 is 16.6 bnboe of which 11.1 bnboe is oil, 4.78 bnboe gas, and 0.59 bnboe NGLs. New discoveries account for 3.29 bnboe over the period. This can be compared to DECC’s central estimate of yet-to-find potential of 9.45 bnboe and a high estimate of 16.5 bnboe. Thus the estimates of the potential contribution of new discoveries over the period in this study are not very optimistic.

Chart 6

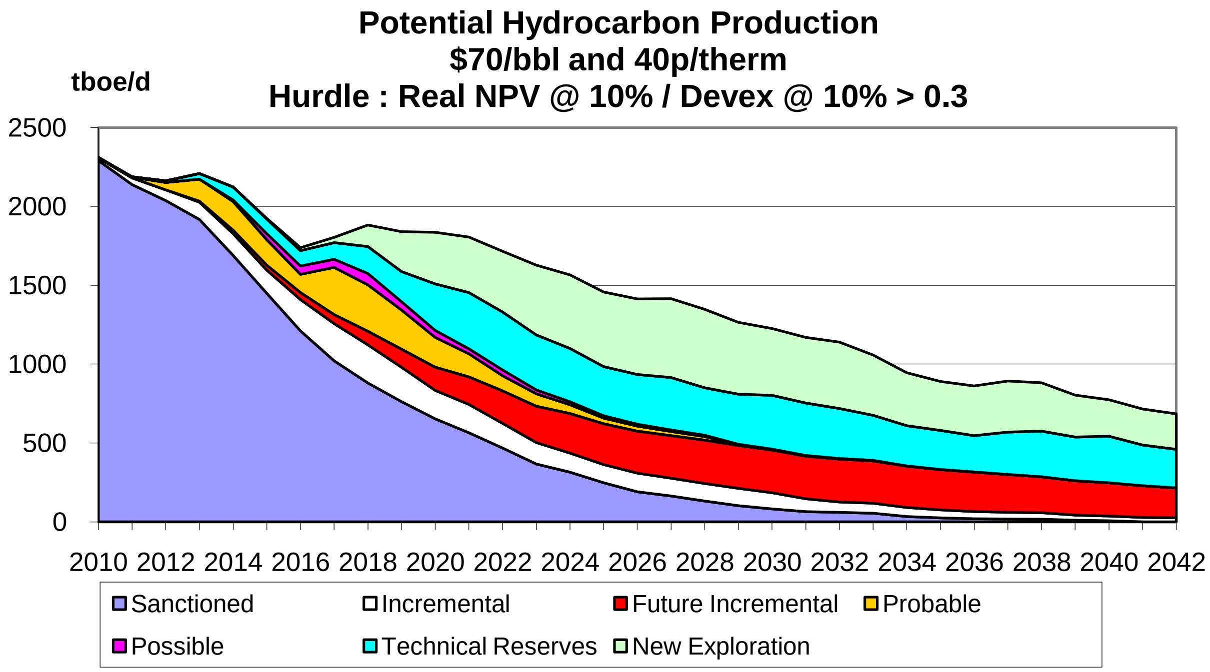
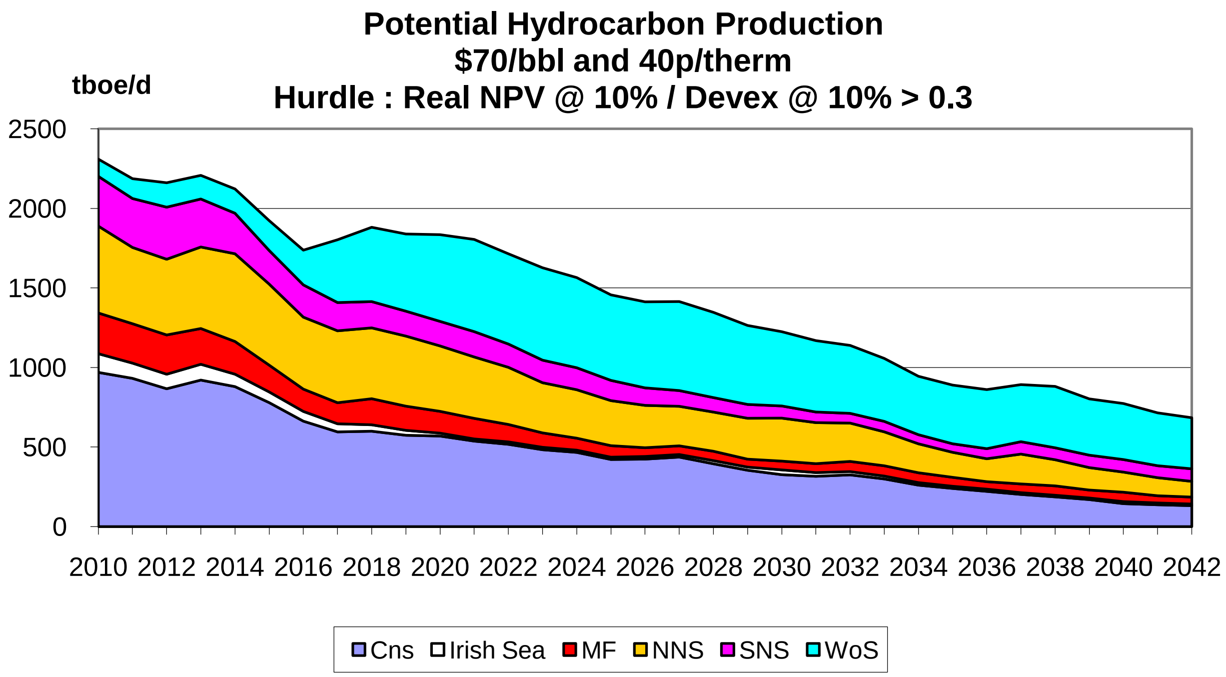


Chart 7

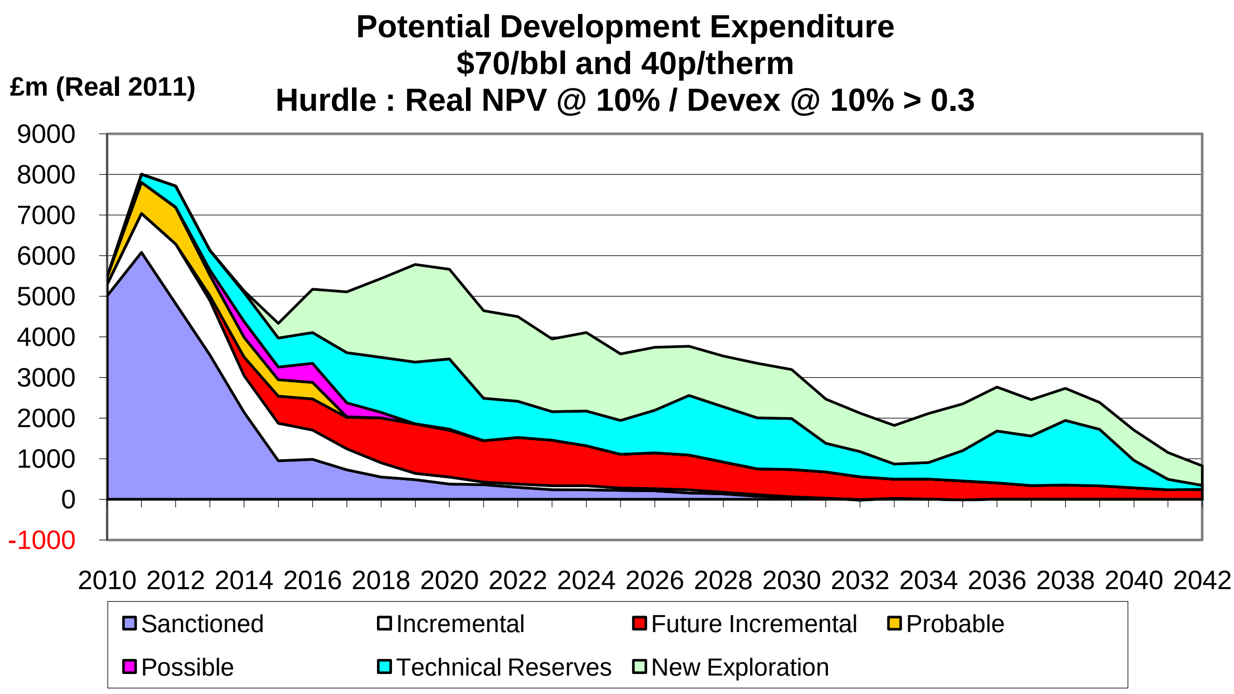


The geographic breakdown of total potential hydrocarbon production is shown in Chart 7. The key contribution of the CNS over the next few years is very noticeable as is the longer term contribution from the W of S region. At 4.67 bnboe the contribution from W of S well below DECC's central estimate of 6.25 bnboe for the remaining potential.

(iii) Field Development Expenditures

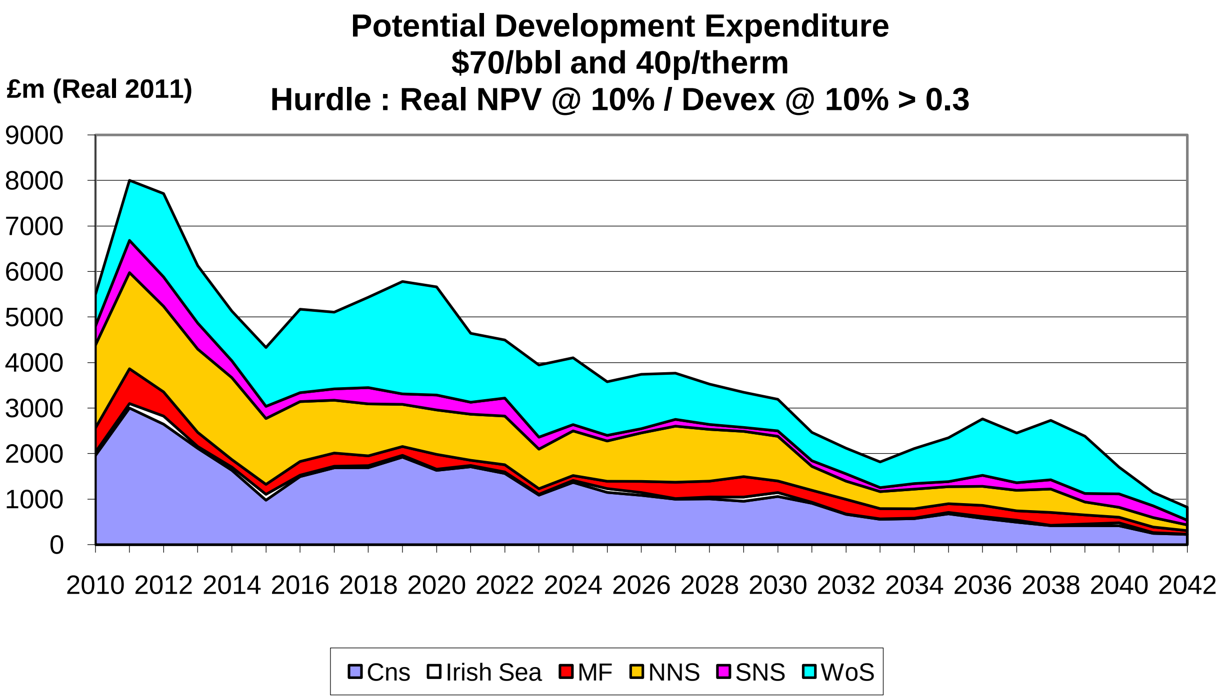
In Chart 8 field development expenditures by category of field and project are shown.

Chart 8



It is seen that the total could reach £8 billion in 2011 but it falls very sharply thereafter until 2015. Based on incremental projects and probable and possible fields this sharp decline would continue. Investment in fields in the category of technical reserves moderates the decrease after 2014, but the development of new discoveries makes a much bigger difference, with the result that the decline is reversed for some years. As is seen from Chart 9 a substantial share of the new development activity in the long run emanates from the W of S region.

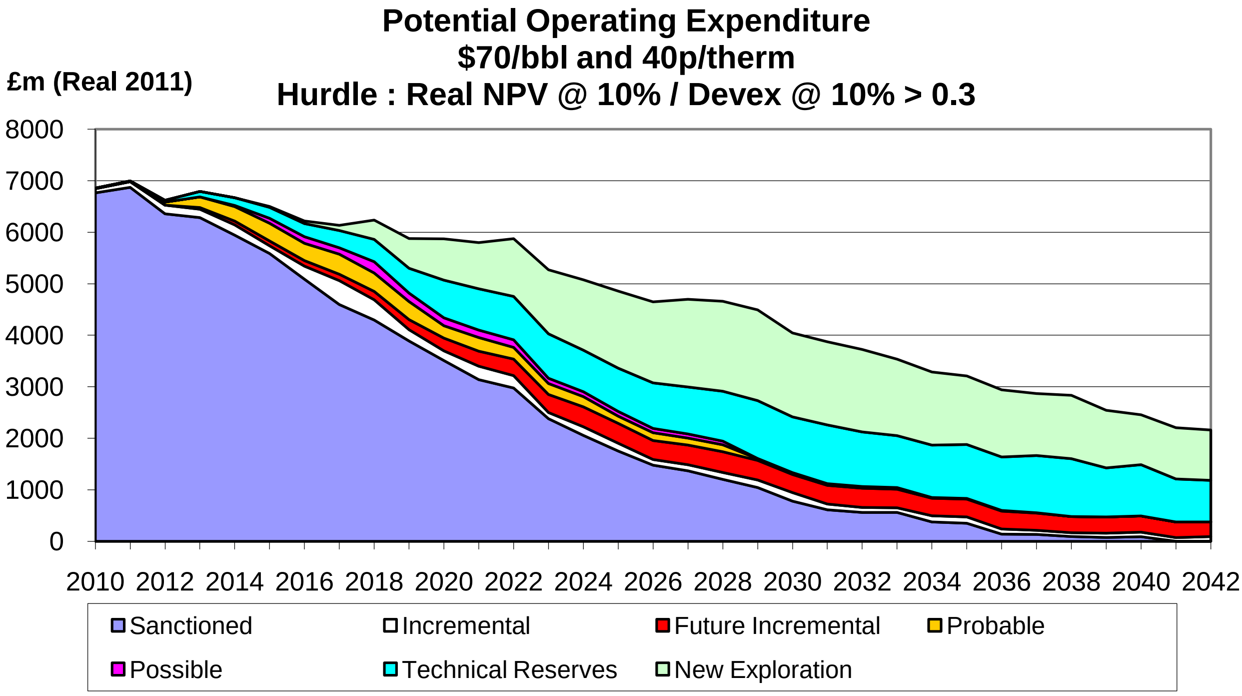
Chart 9



(iv) Operating Expenditures

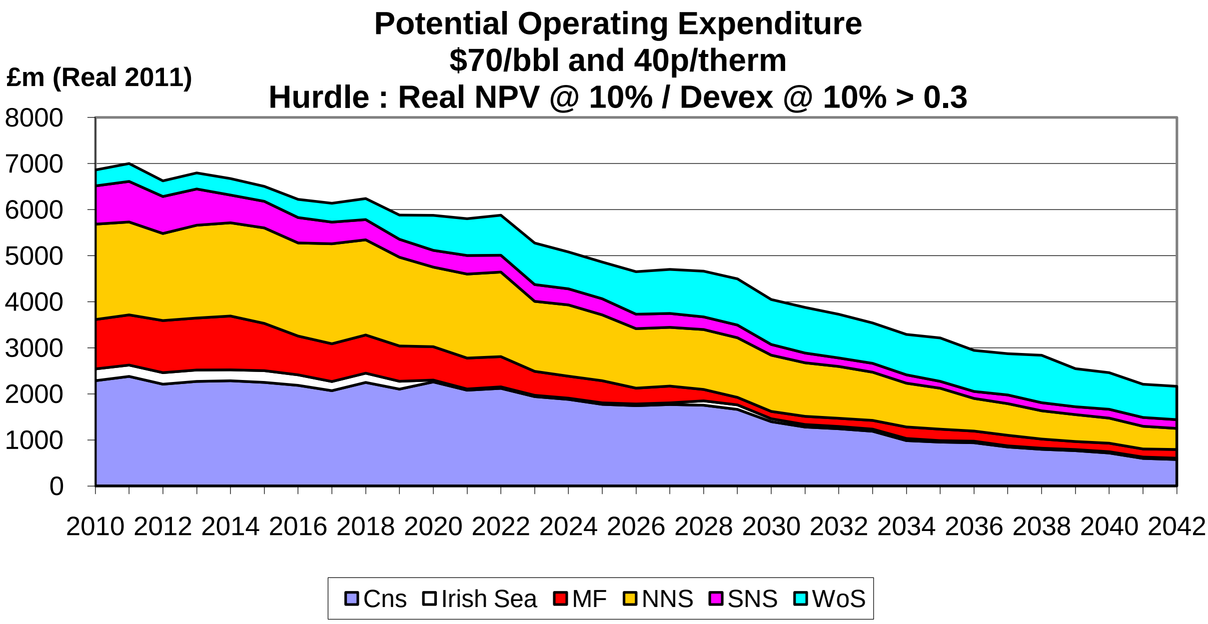
In Chart 10 field operating expenditures are shown by the various categories of fields and projects. There is a continuous and brisk decrease in the profile of expenditure from sanctioned fields and other discoveries. Were it not for the development of new discoveries in the medium and longer term the downward trend in expenditures would have been substantially faster.

Chart 10



In Chart 11 the behaviour of operating expenditures by geographic areas is shown. This highlights the growing long run importance of the W of S region.

Chart 11



(v) Decommissioning Activity

In Charts 12 and 13 annual and cumulative decommissioning expenditures are shown for the different categories of fields and projects. Key features are the large increase in expenditures from 2014 for a few years followed by a fall and then a major further increase for a few years. The lumpiness in timing has implications for the demand for all the supply chain sources and facilities. Over the period to 2042 the total cumulative expenditure exceeds £31.9 billion at 2011 prices.

Chart 12

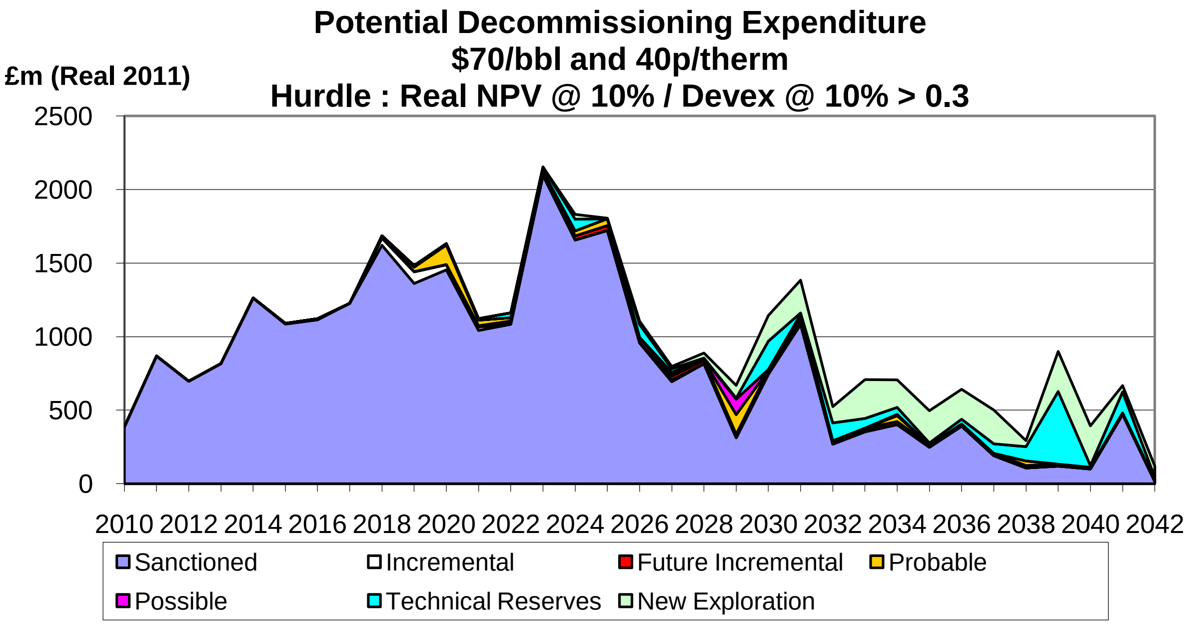
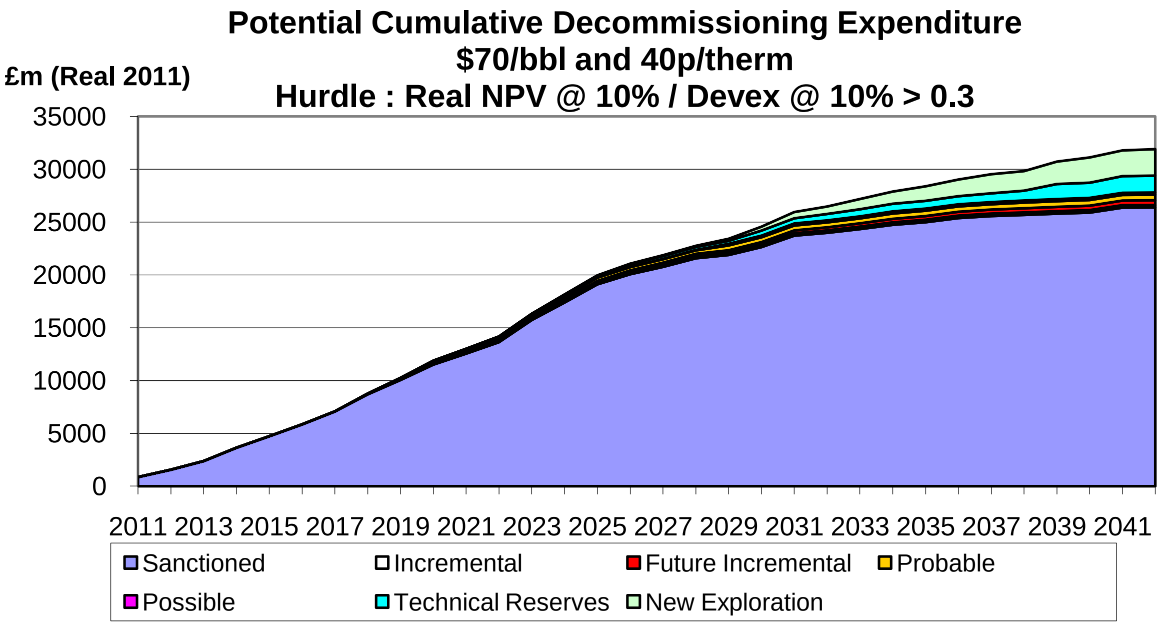


Chart 13



In Chart 14 and 15 the annual and cumulative expenditures are shown according to the 6 geographic areas of the UKCS. The importance of the NNS region is highlighted. This is because a high proportion of the very large field platforms is located in this region.

Chart 14

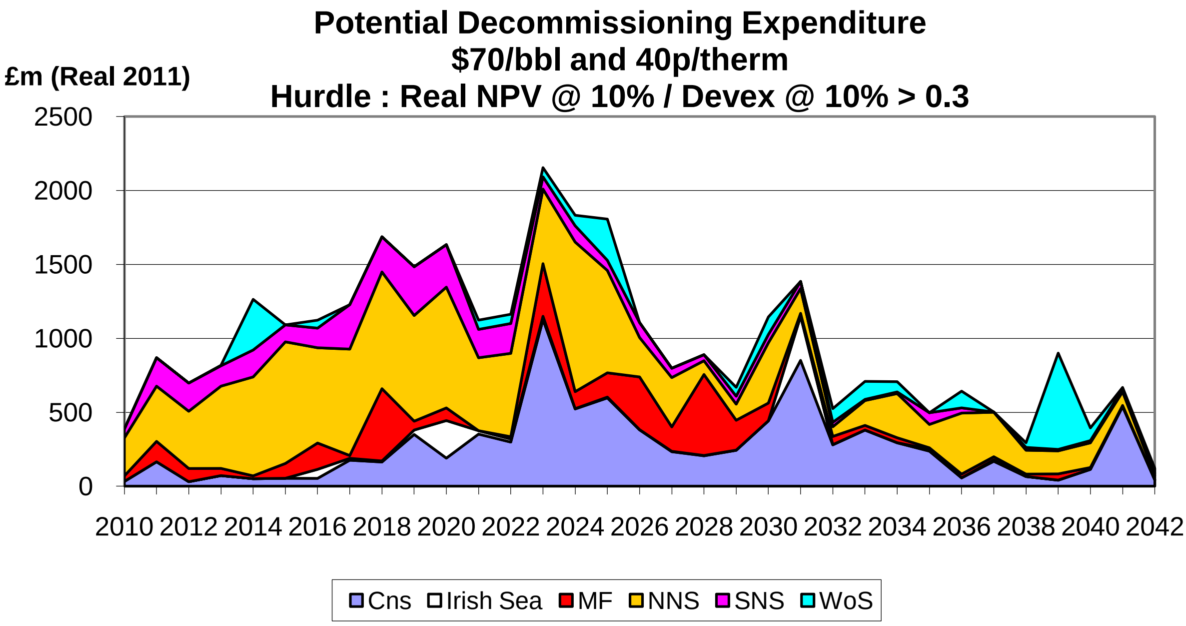
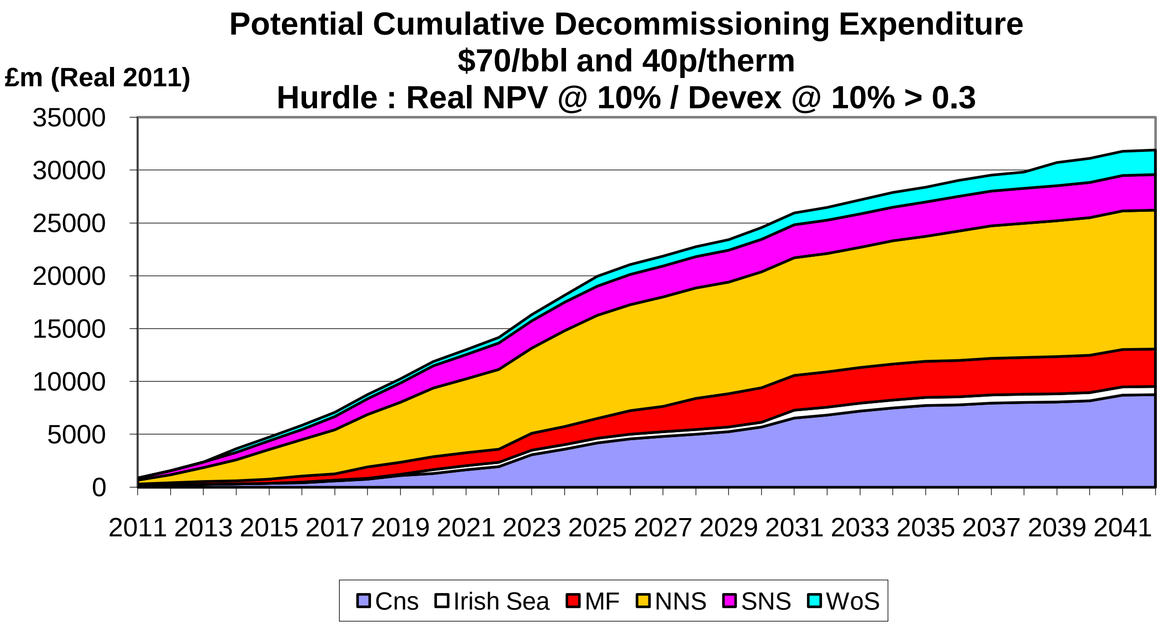


Chart 15



In Charts 16 and 17 the annual numbers of fields reaching their COP dates are shown. It is seen that over the period to 2030 the annual average exceeds 15 fields.

Chart 16

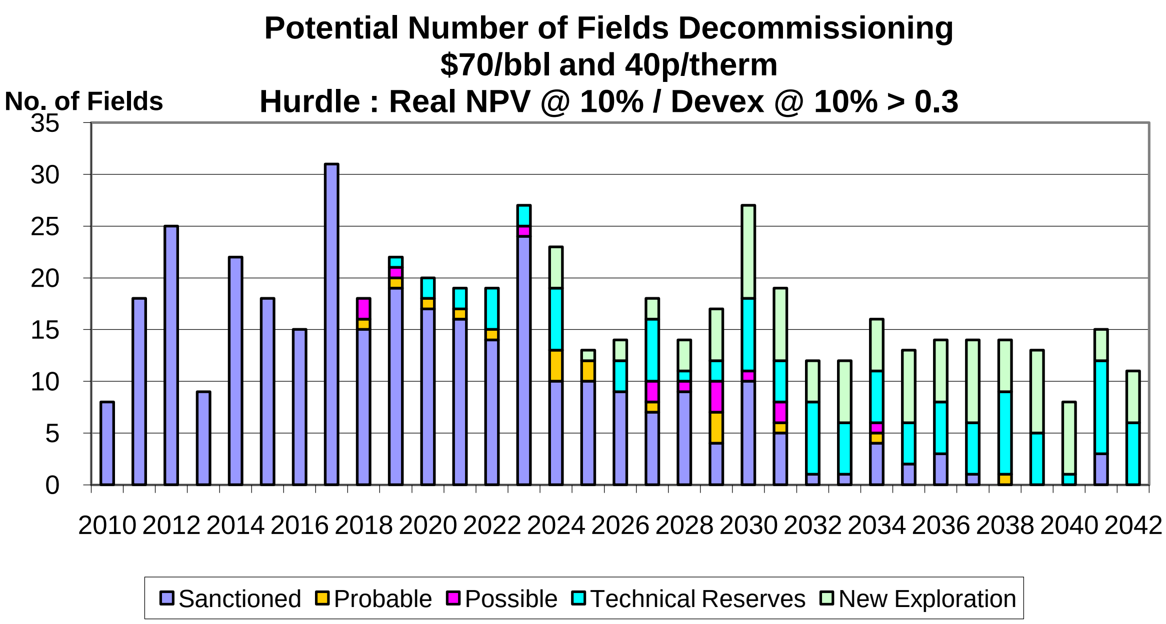
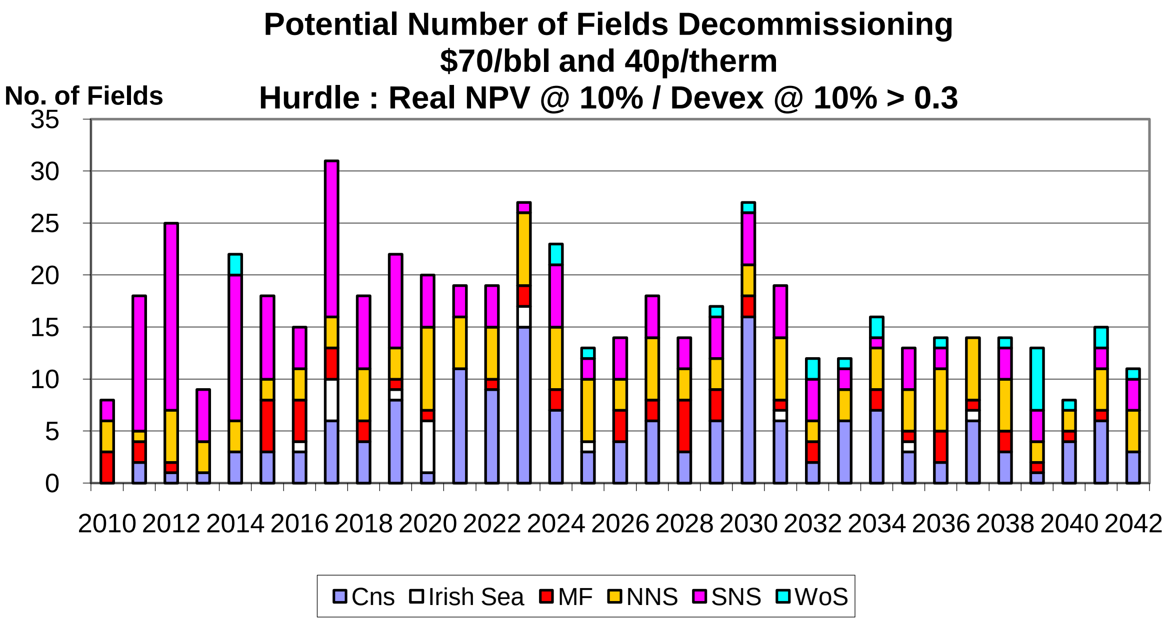


Chart 17

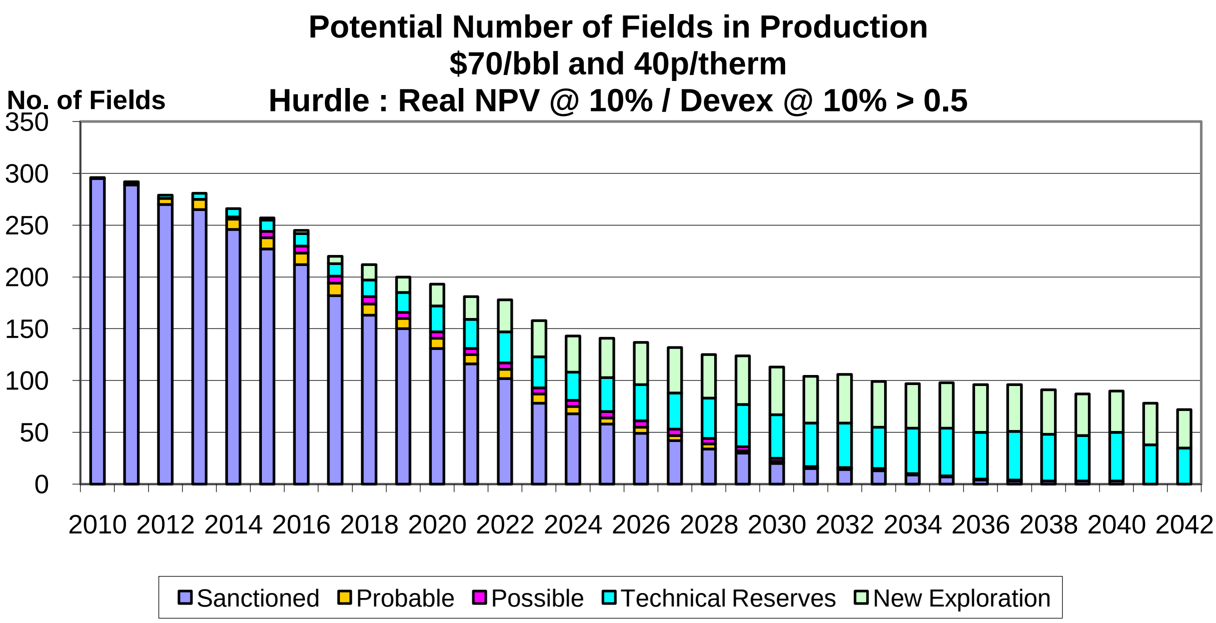


B. $70, 40 pence, Hurdle NPV/I > 0.5

(i) Numbers of Fields in Production

In Chart 18 it is seen that the numbers of fields reaching their COP dates consistently exceeds those coming on stream.

Chart 18

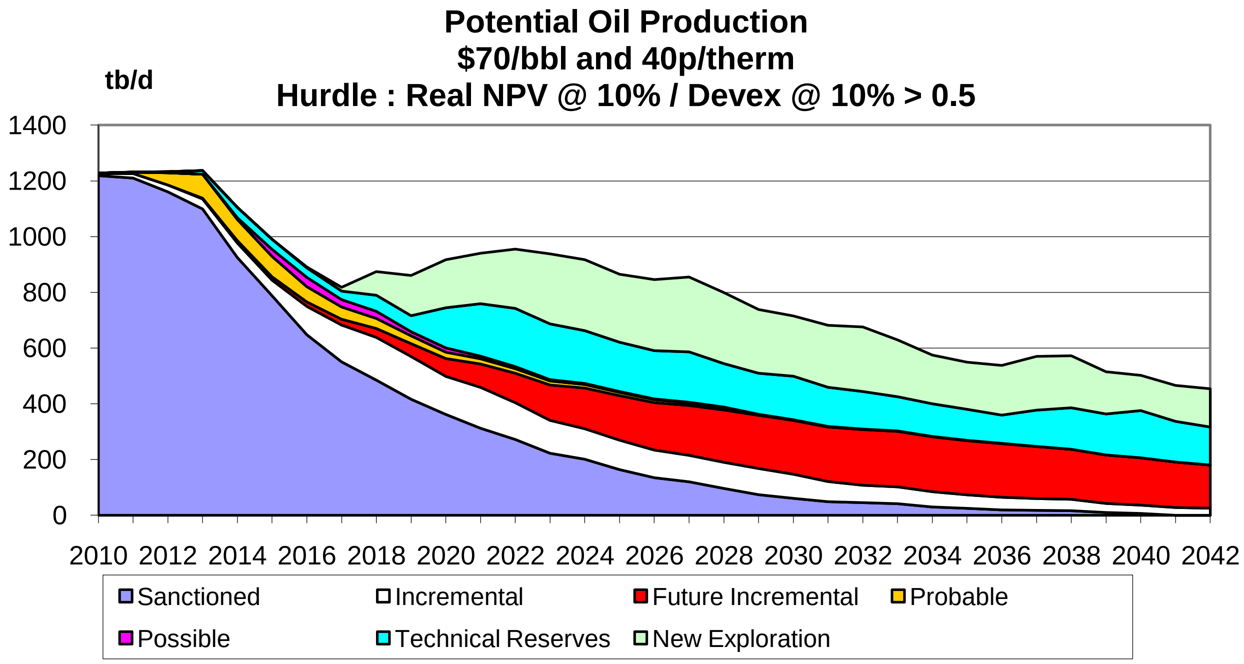


By 2042 the number of producing fields falls to 72 compared to around 300 (as defined) at the present time. There is a marked difference in activity levels under this scenario compared to the one where the hurdle was NPV/I > 0.3. In that scenario there are 96 producing fields in 2042. Over the whole period the average annual number of new field developments was just under 8.

(ii) Production

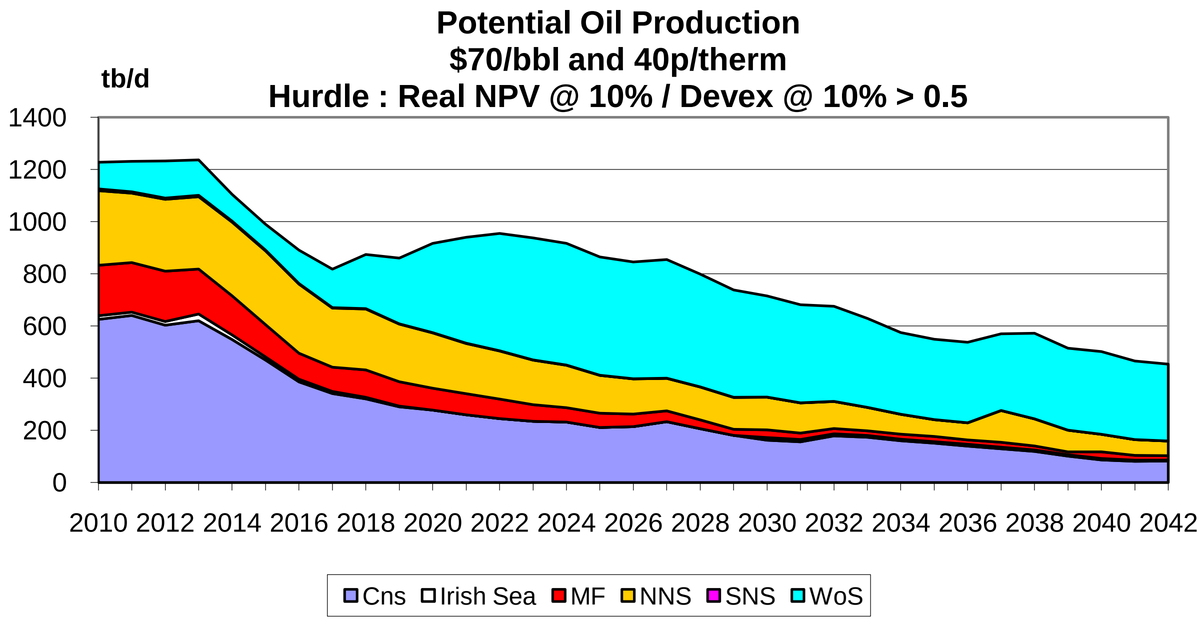
In Chart 19 oil production is shown according to the different categories of fields and projects. The steep decline from 2013 to 2017 is very noticeable. After that the decline rate is moderated by the development of fields in the category of technical reserves. The development of fields in the category of new discoveries halts the decline rate for several years. Over the whole period to 2042 the cumulative production from 2011 amounts to 9.3 billion bbls. This can be compared to 11.2 billion barrels under the scenario with hurdle of NPV/I > 0.3.

Chart 19



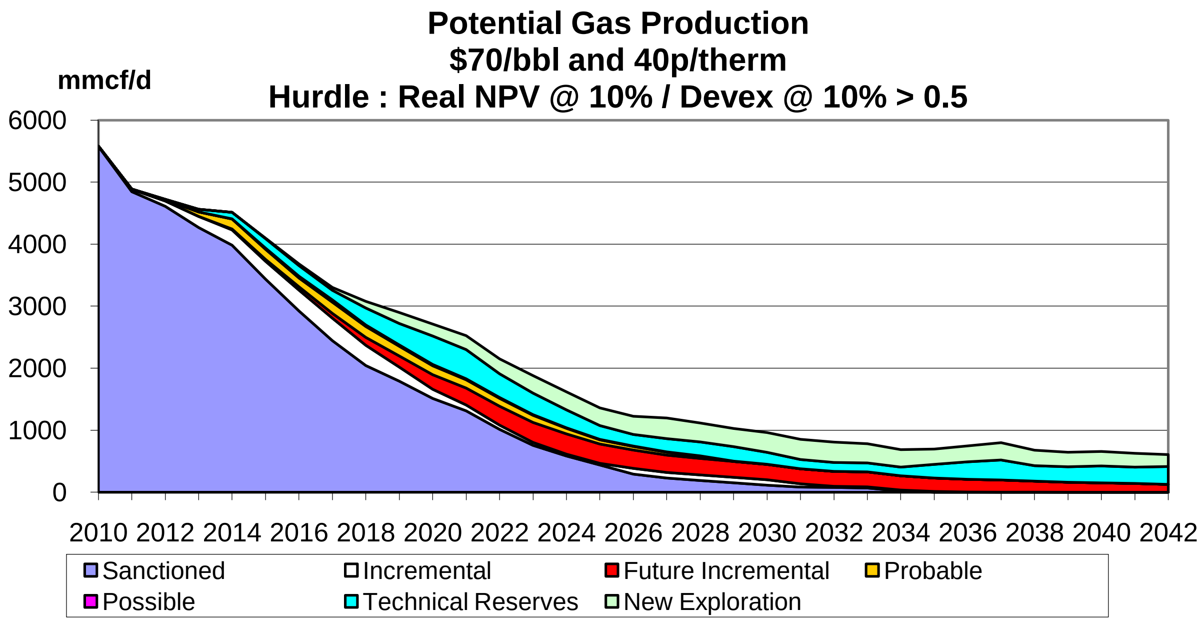
In Chart 20 oil production is shown according to geographic areas. The very substantial contribution from the W of S region is noticeable. Over the period to 2042, 3.6 billion barrels comes from this region. A high proportion of this has already been discovered. In fact for the whole of the UKCS new discoveries account for only 1.78 billion barrels or 19.2% of all the oil produced over the period.

Chart 20



In Chart 21 gas production is shown according to geographic area. The decline rate is quite fast, particularly from 2014 onwards. Over the whole period cumulative production is 4 billion boe. This compares with 4.8 billion boe under the scenario where the hurdle is NPV/I > 0.3. Compared to oil the contribution from the W of S region is quite modest.

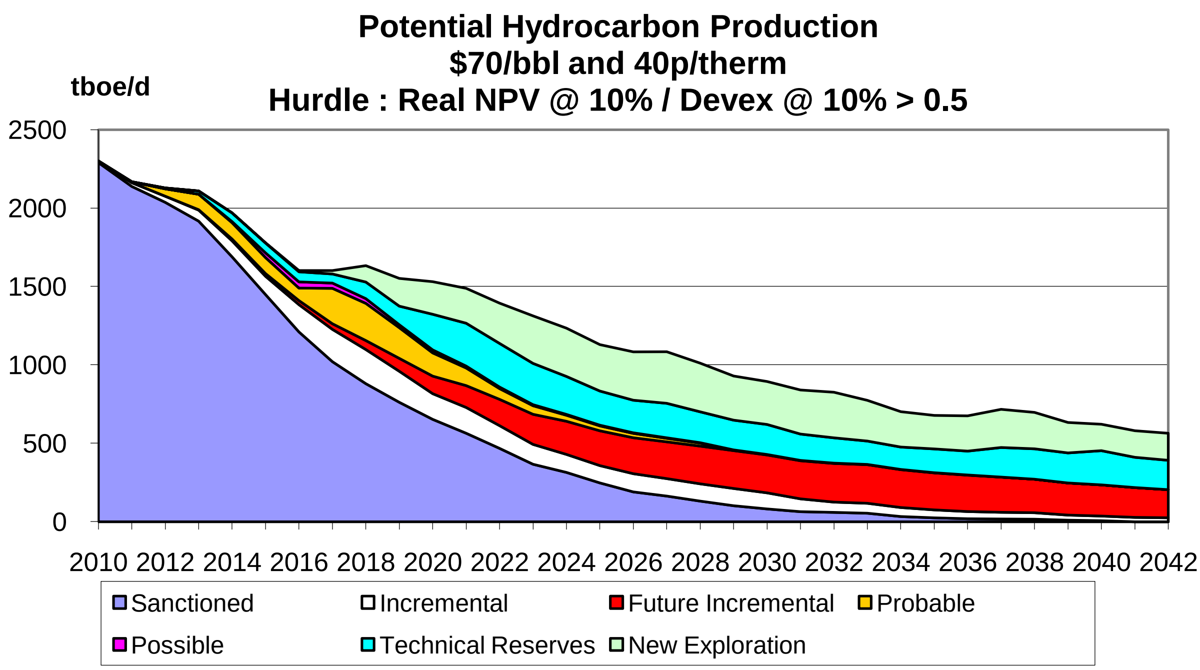
Chart 21



(iii) Total Hydrocarbon Production

In Chart 22 total hydrocarbon production (including NGLs) is shown according to categories of fields and projects.

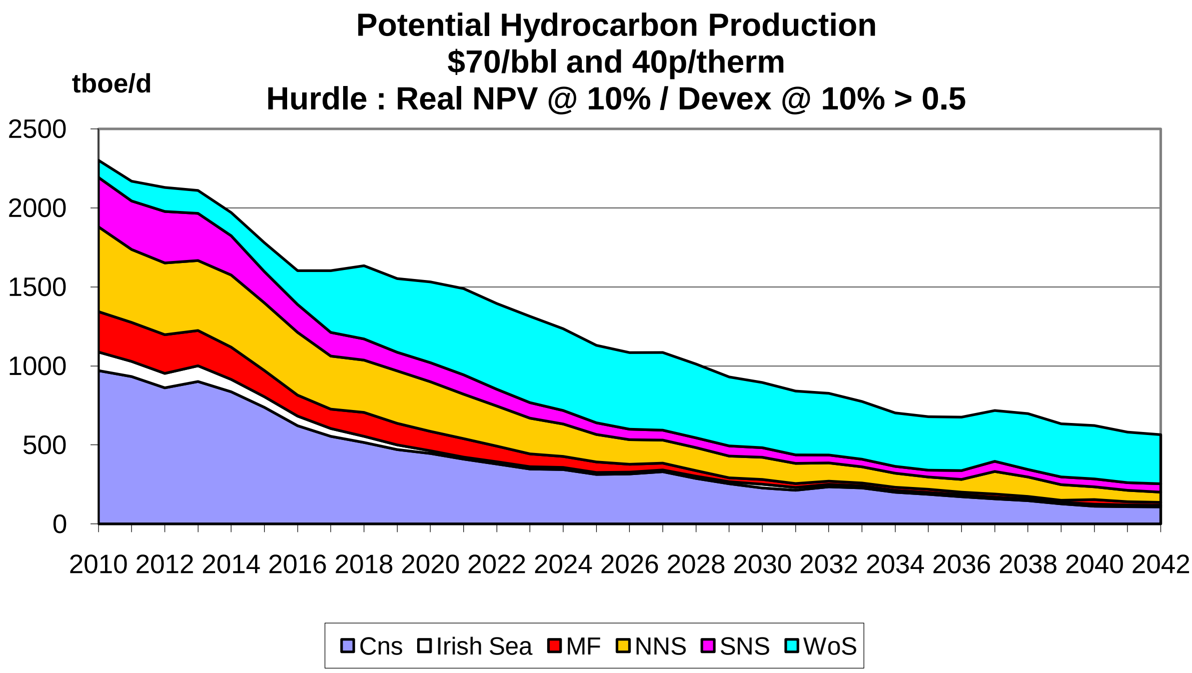
Chart 22



The decline rate from sanctioned fields is quite sharp. It is moderated for a few years by the contribution from probable fields and then more noticeably by the development of fields in the categories of technical reserves and new discoveries. By 2042 production is around 0.564 mmboe/d. Cumulative output over the period is 13.85 bnboe. Of that 6 bnboe comes from sanctioned fields, 3 bnboe from incremental projects, and 2.2 bnboe from new discoveries.

In Chart 23 the results are shown for total hydrocarbon production according to geographic areas. The long term rising contribution from W of S is a noticeable feature. This region accounts for 4.3 bnboe or 31% of the total over the period to 2042. In the W of S region 12 new discoveries are developed over the period.

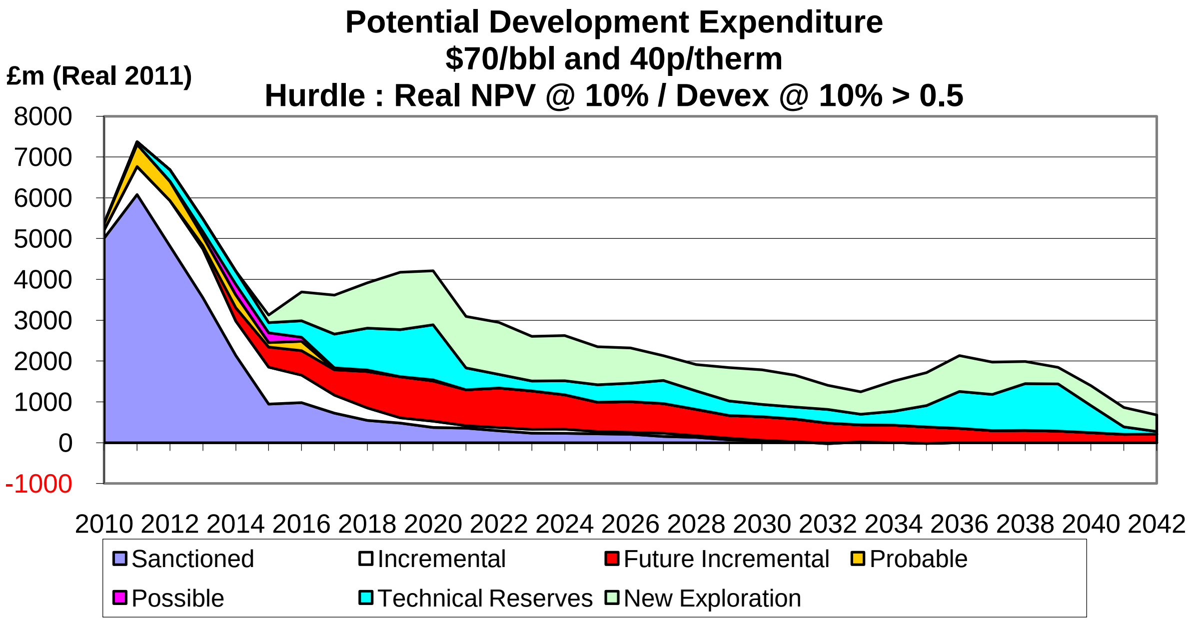
Chart 23



(iv) Development Expenditures

In Chart 24 field development expenditures over the period are shown according to types of fields and projects.

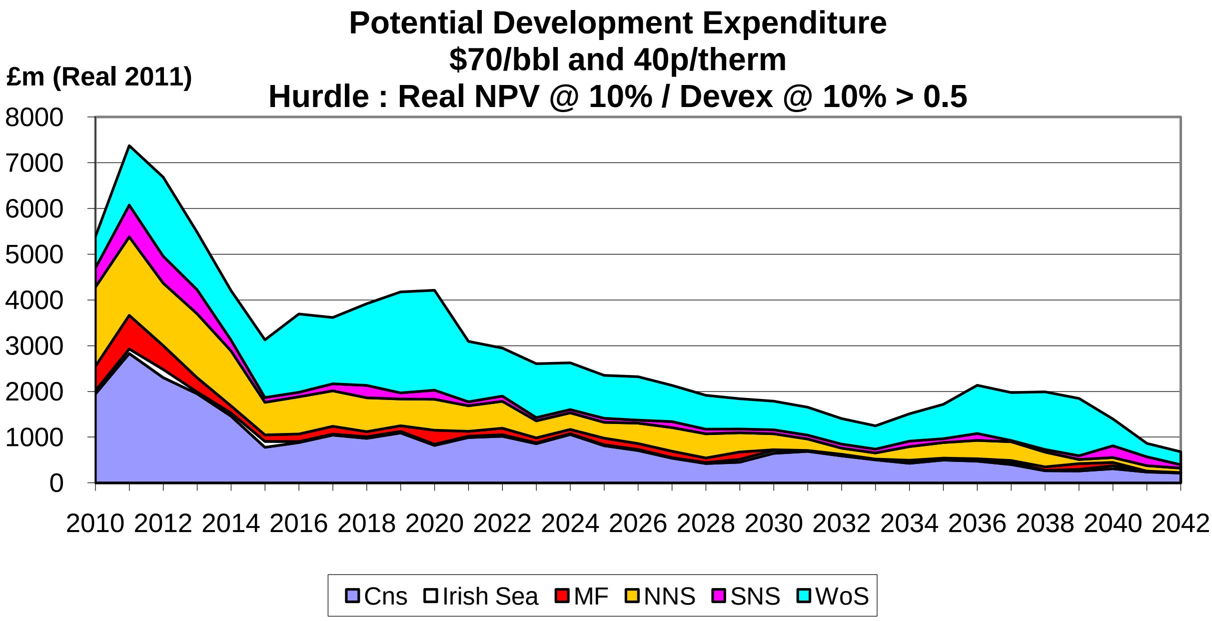
Chart 24



In this scenario there is a very substantial fall over the next few years. This is halted by the development of several fields in the categories of technical reserves and new discoveries. After 2020 a long term decline sets in.

In Chart 25 the results are shown according to geographic region. Over the medium and longer terms the relative importance of the W of S region is very apparent.

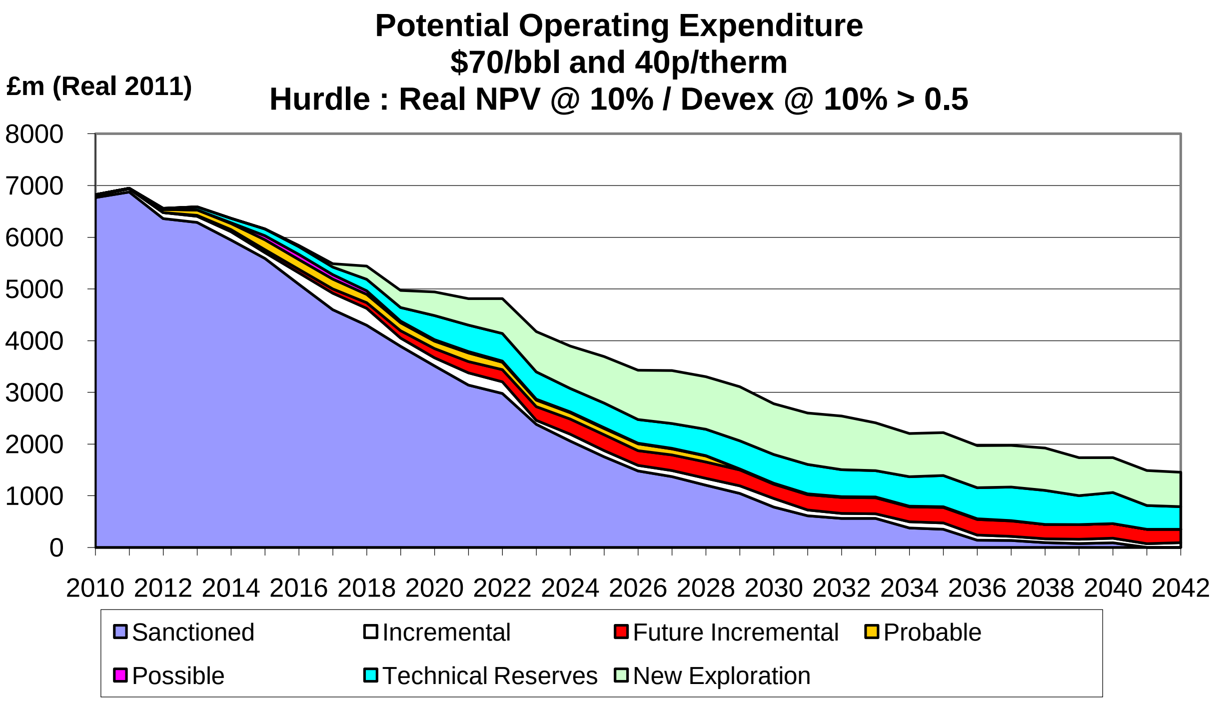
Chart 25



(v) Operating Expenditures

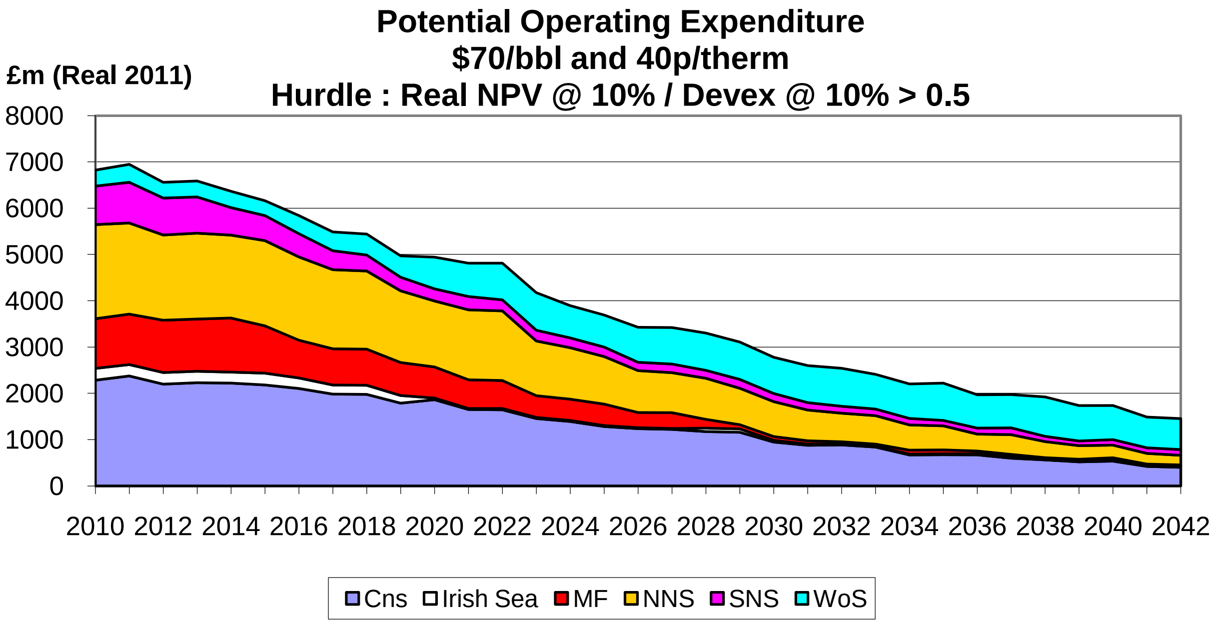
In Chart 26 the behaviour of operating expenditures over the period is shown according to types of fields and projects.

Chart 26



There is a relatively steep decline in the aggregate which is moderated to some extent by the development of new discoveries and technical reserves. In Chart 27 the operating expenditures are shown by region. It is seen that in the long run there is a worthwhile increase in the W of S region which moderates the overall decline rate.

Chart 27



(vi) Decommissioning Activity

In Chart 28 annual decommissioning expenditures are shown according to types of field and in Chart 29 the corresponding cumulative expenditures to 2042 are shown. The total is £29.5 billion at 2011 prices. The overwhelming importance of currently sanctioned fields in the total is highlighted.

Chart 28

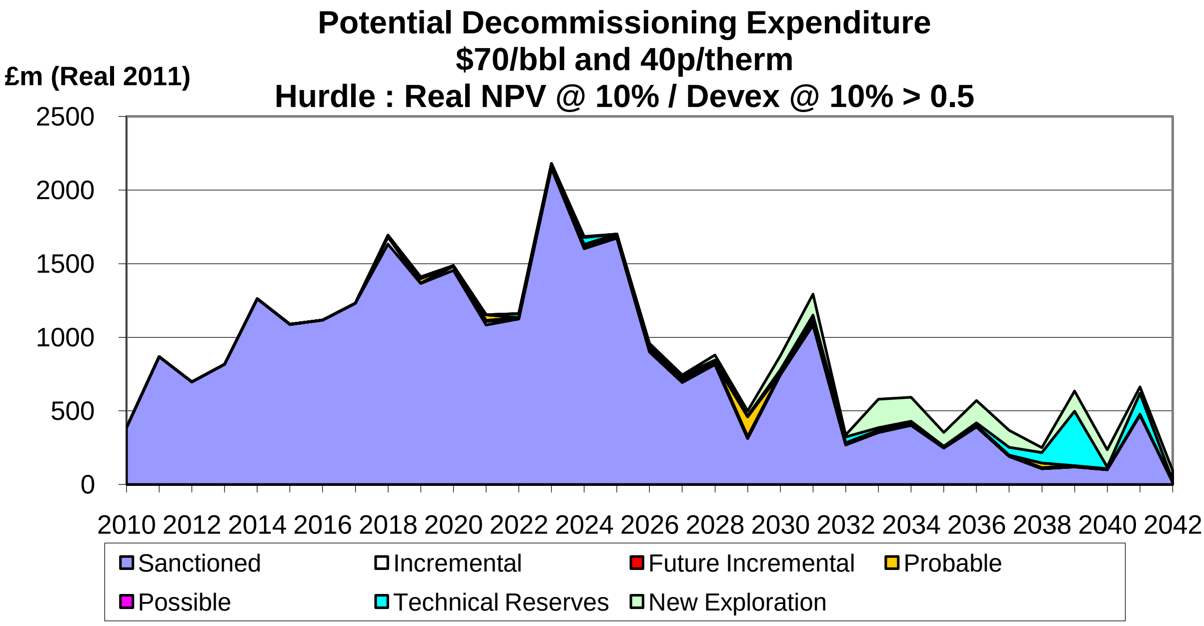
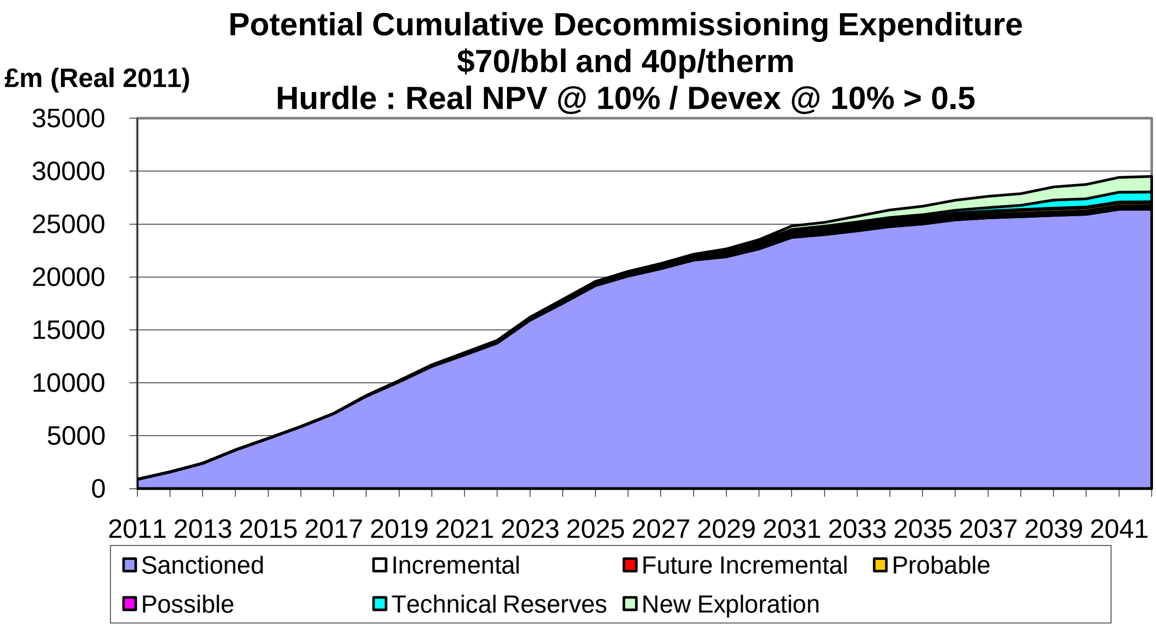


Chart 29



In Charts 30 and 31 the expenditures classified according to the 6 regions of the UKCS are shown. The importance of the NNS is highlighted.

Chart 30

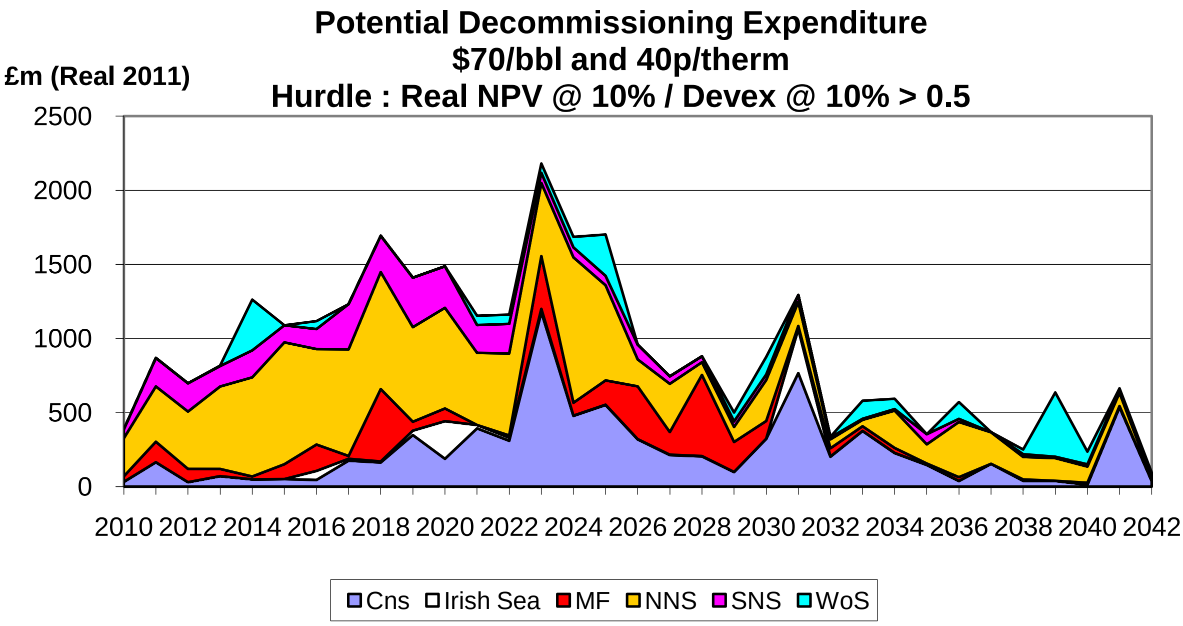
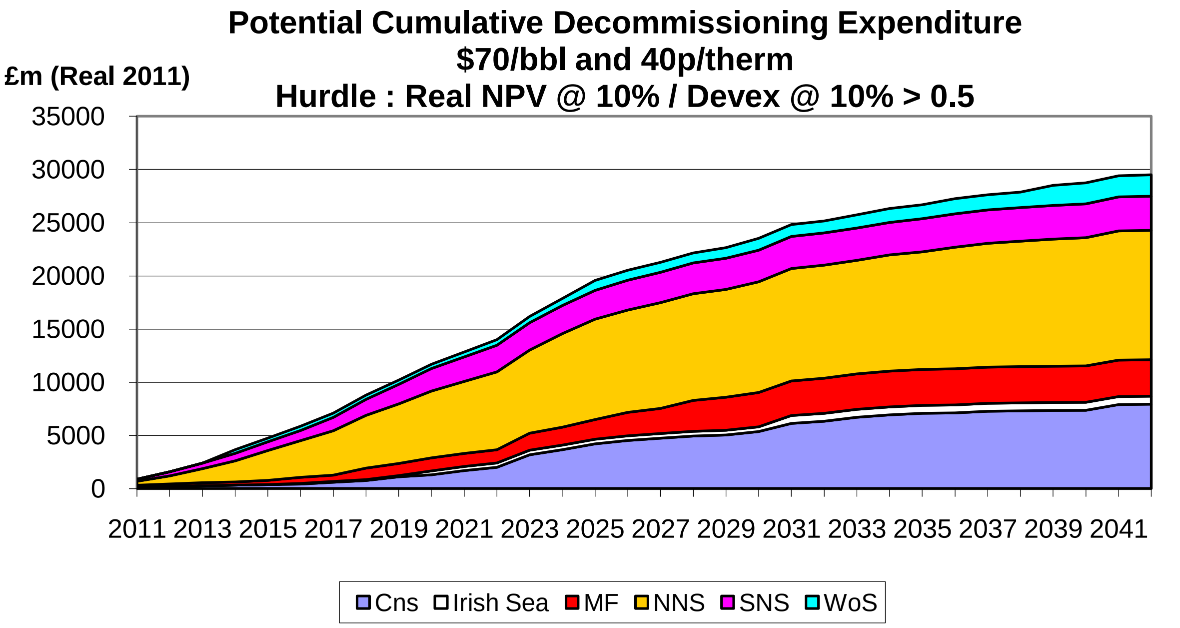


Chart 31



In Charts 32 and 33 the numbers of fields reaching their COP dates are shown. There are fewer fields in the total over the period to 2042 compared to the scenario when the economic hurdle was NPV/I > 0.3 because fewer fields are developed at the higher hurdle under the present scenario. The annual average over the period to 2030 remains in excess of 15.

Chart 32

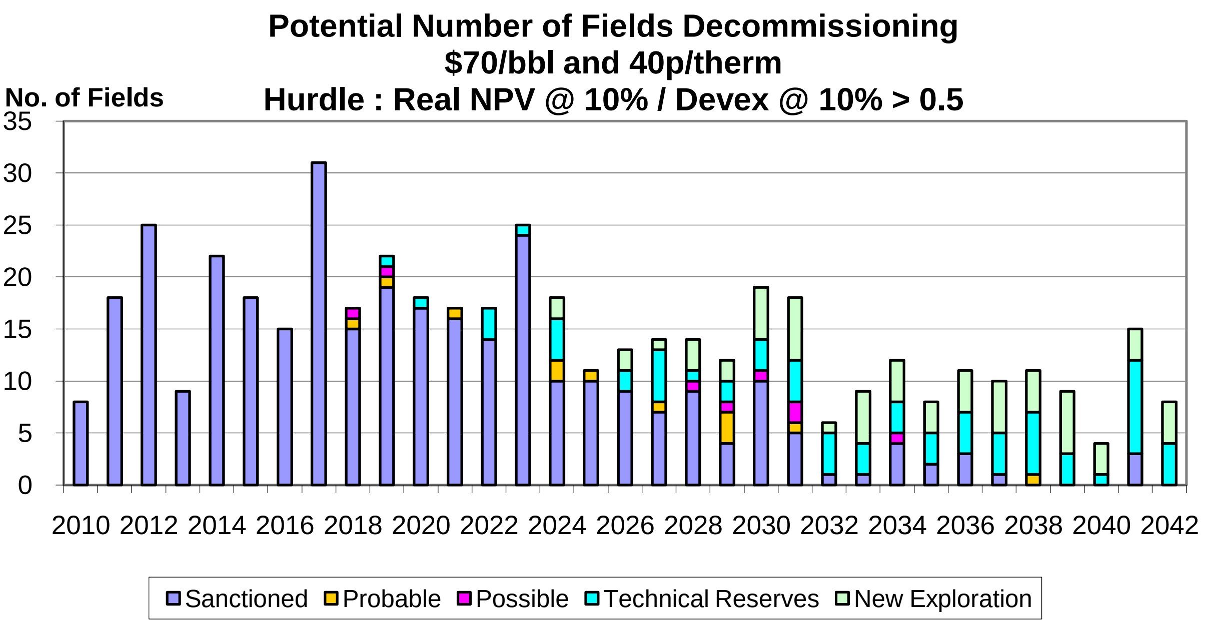
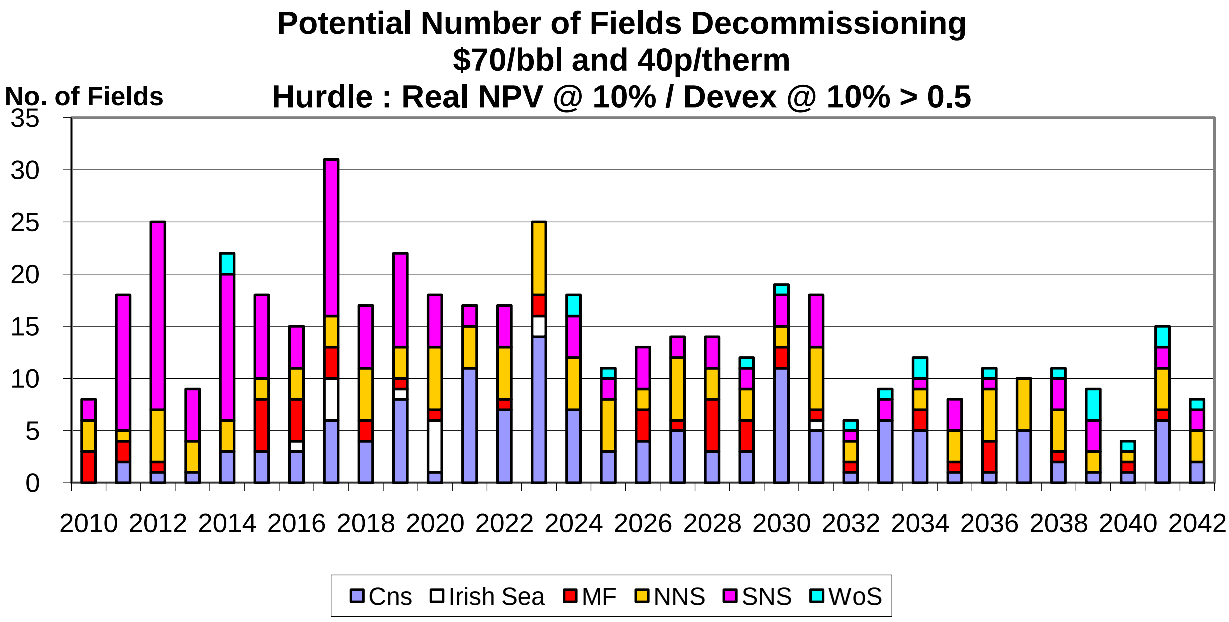


Chart 33

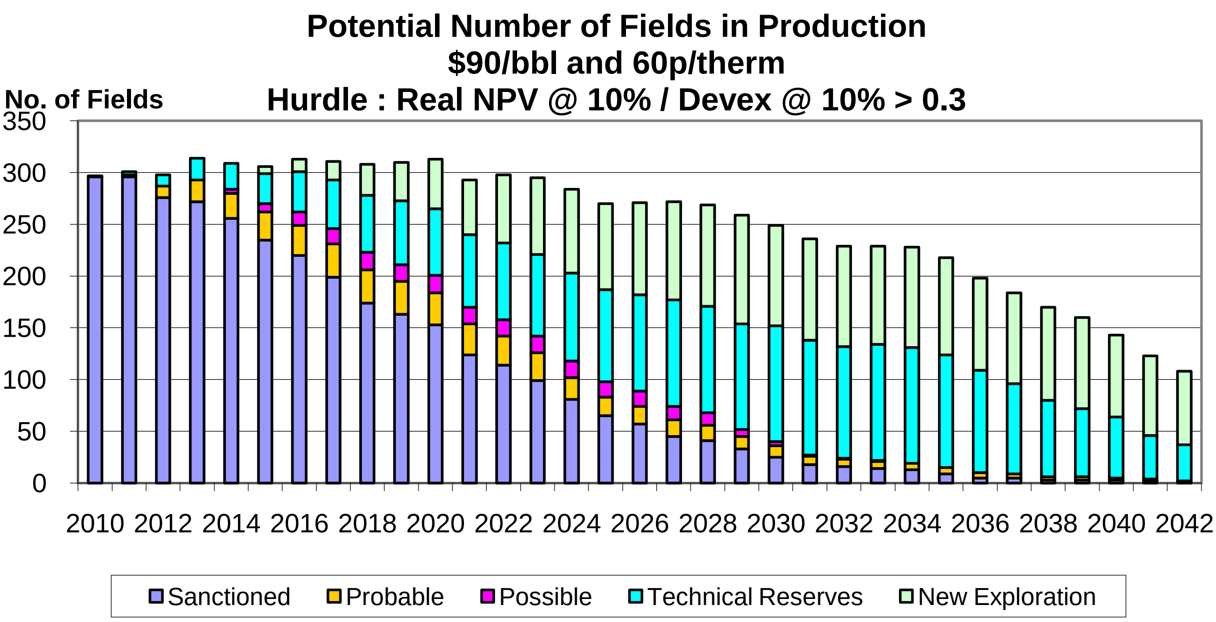


C. $90, 60 pence, Hurdle NPV/I > 0.3

(i) Numbers of Fields in Production

In Chart 34 the numbers of fields in production over the period to 2042 are shown according to type. Compared to the medium price scenario the numbers are considerably higher reflecting the substantially larger number of new fields which pass the economic hurdle. It is seen that very substantial numbers of fields in the technical reserves category become viable as do many new discoveries. In 2042 there are still well over 100 producing fields. Over the period to 2030 the average annual number of new field developments was just under 18.

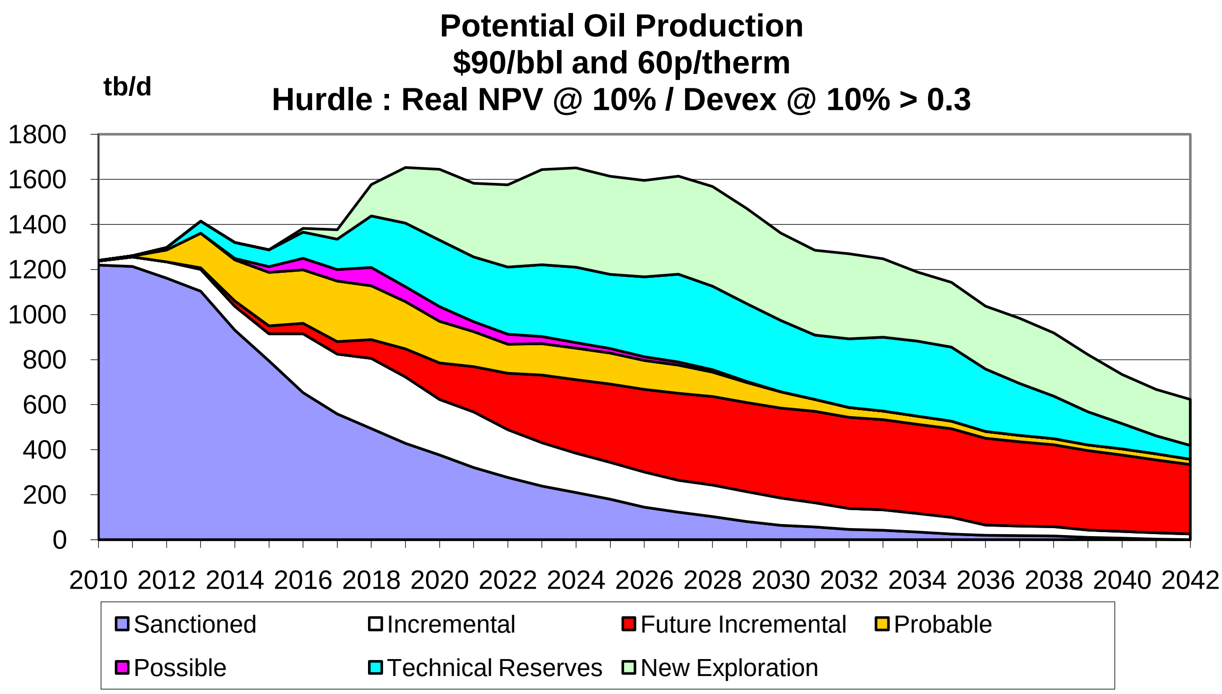
Chart 34



(ii) Production

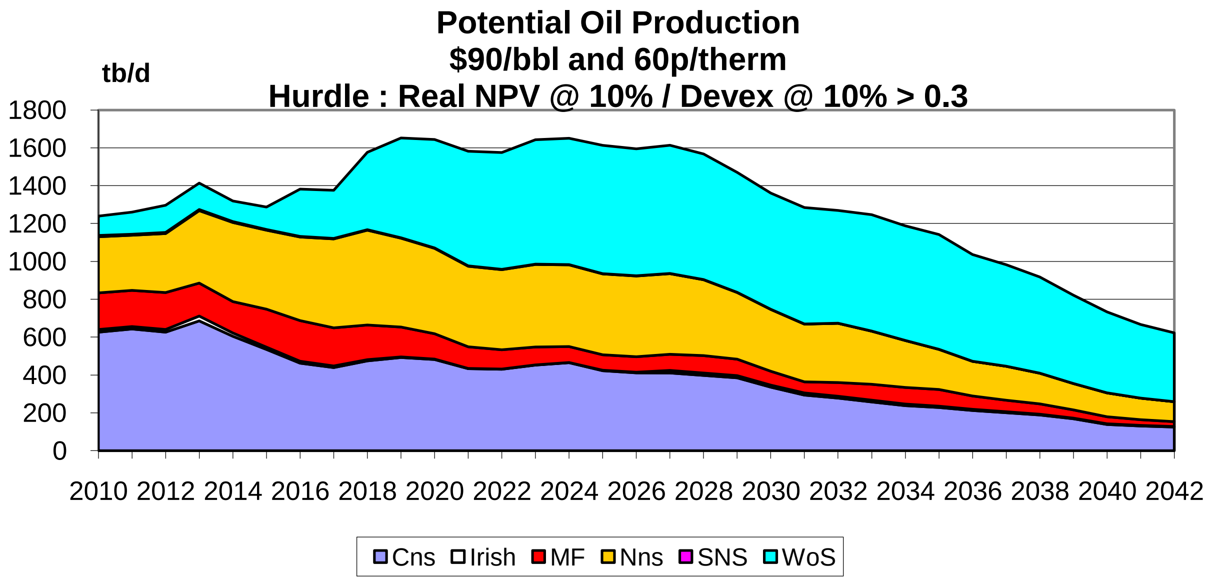
In Chart 35 oil production prospects are shown. While output from the sanctioned fields continues to fall at a fast pace it is moderated by substantial production from current and future incremental projects. On top of this there is large production from fields in the categories of technical reserves and new discoveries. In 2042 production is 622,520 b/d. Over the period 2011-2042 cumulative oil production is 15.2 billion barrels. Of this 3.55 billion comes from sanctioned fields, 4.58 billion from current and future incremental projects, 1.4 billion from probable and possible fields, 2.7 billion from technical reserves and 3 billion from new discoveries.

Chart 35



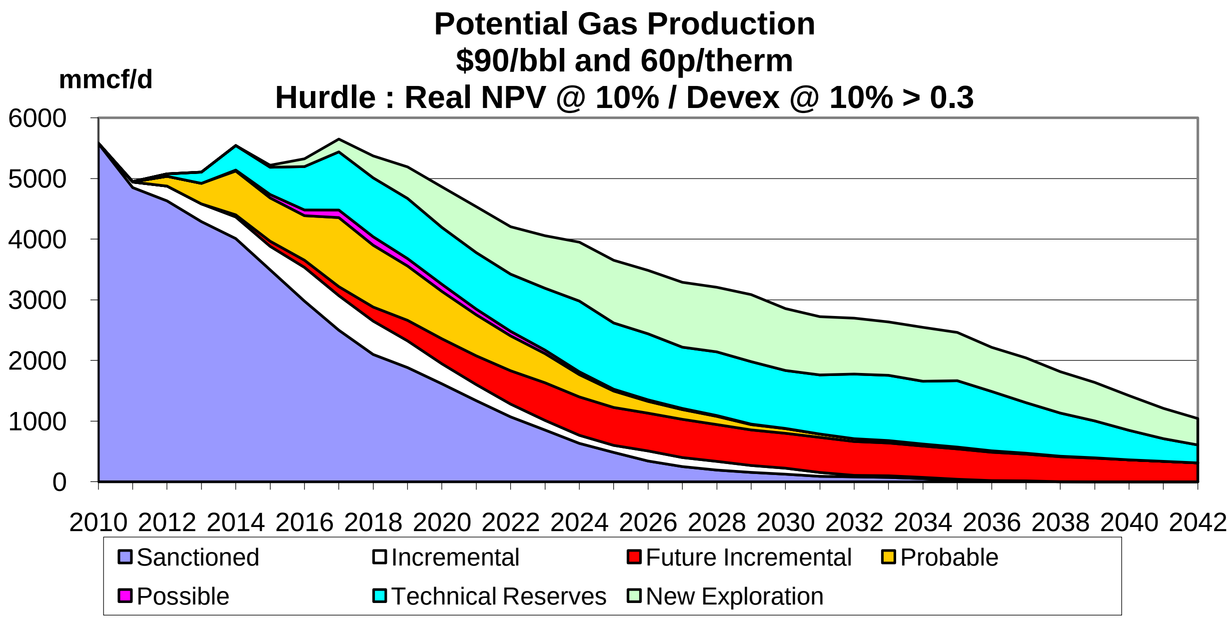
In Chart 36 the geographic breakdown of the prospective production is shown. A feature is the major increase from the W of S region in the longer term. Over the whole period this region accounts for 5.6 billion barrels. Of this 0.42 billion is attributable to sanctioned fields, 3.3 billion to all categories of incremental projects, 0.98 billion to technical reserves and 0.9 billion to new discoveries. It will be recalled that DECC's central estimate of the remaining oil potential from the region is 4.3 bnbbls. Their upper estimate is 6.8 bnbbls.

Chart 36



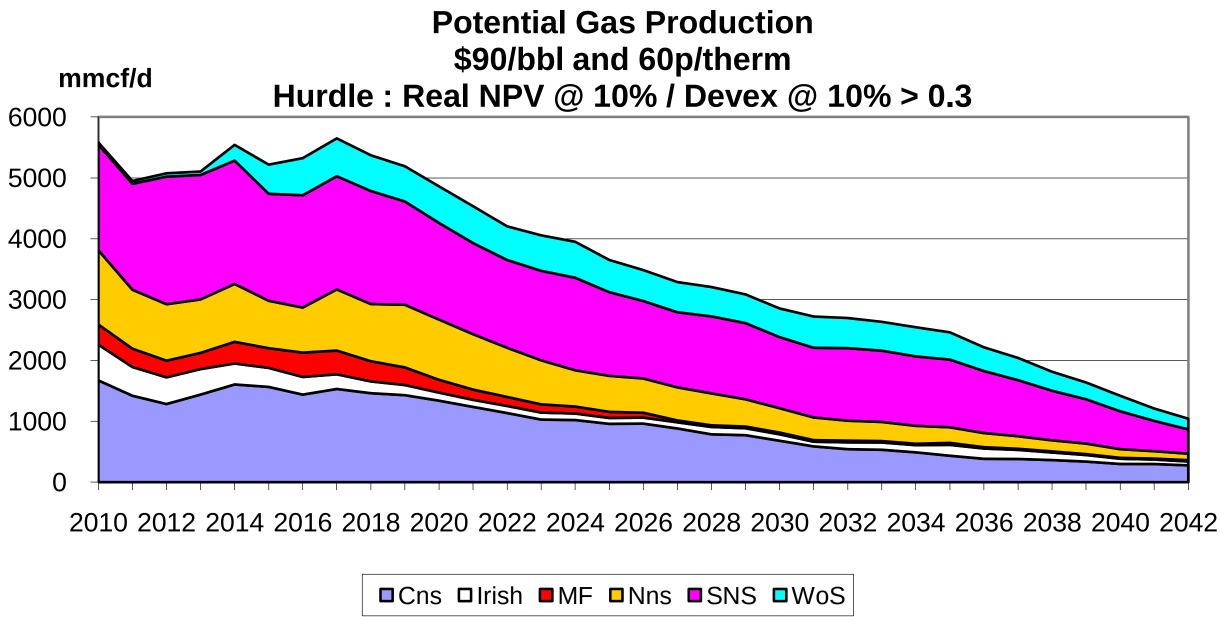
In Chart 37 gas production prospects are shown according to type of field and project.

Chart 37



Over the next few years output is broadly maintained through the development of fields in the categories of technical reserves and new discoveries. But from 2018 there is a steady decline with production being 1 bcf/d in 2042. Cumulative production to 2042 is 7.26 bnboe. Of this 2.45 bnboe comes from sanctioned fields, 1.6 bnboe from technical reserves, and 1.3 bnboe from new discoveries. The regional breakdown is shown in Chart 38. The contributions from the NNS and W of S area are noteworthy.

Chart 38



In Chart 39 prospective total hydrocarbon production by types of fields and projects is shown. Output increases above today's levels in 2018-19 and then declines at a steady pace. The contributions of probable fields is noteworthy in the near term while in the longer term future incremental projects, technical reserves and new discoveries all make substantial contributions. Production is around 812,000 boe/d in 2042. Cumulative production is 23.15

bnboe of which 6.2 bnboe is from sanctioned fields, 5.84 bnboe from incremental investments, 2.4 bnboe from probable and possible fields, 4.3 bnboe from technical reserves and 4.4 bnboe from new discoveries. DECC's central estimate of remaining potential is 21.45 bnboe of which 9.45 bnboe come from new discoveries. Their upper estimate of total remaining potential is 35.9 bnboe.

Chart 39

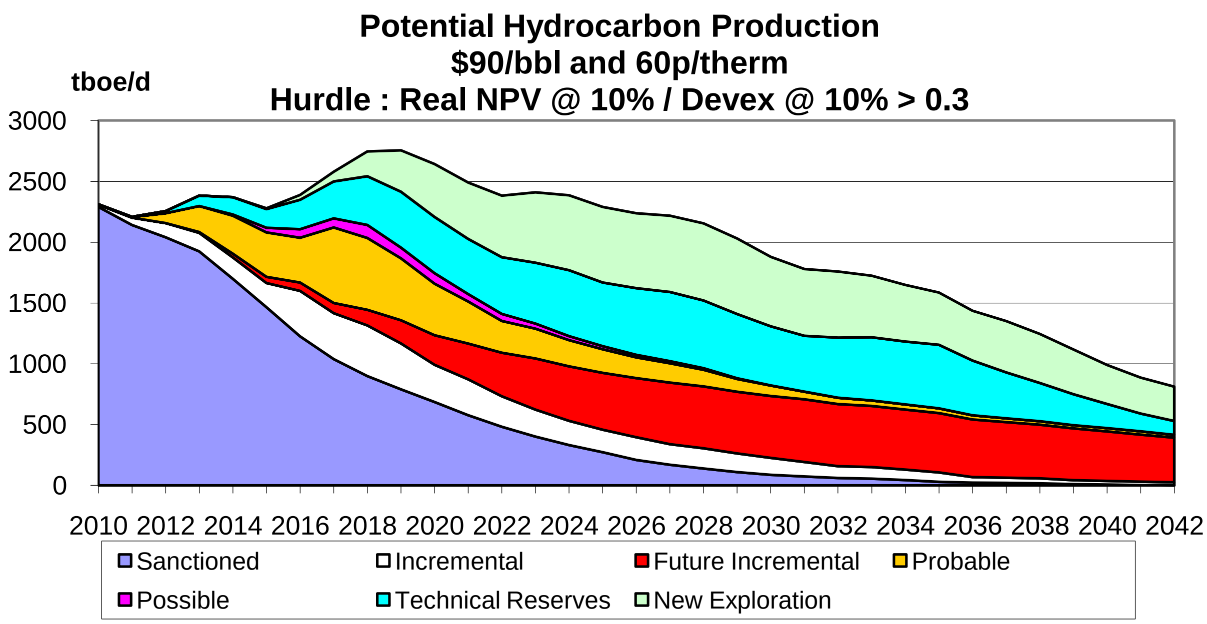
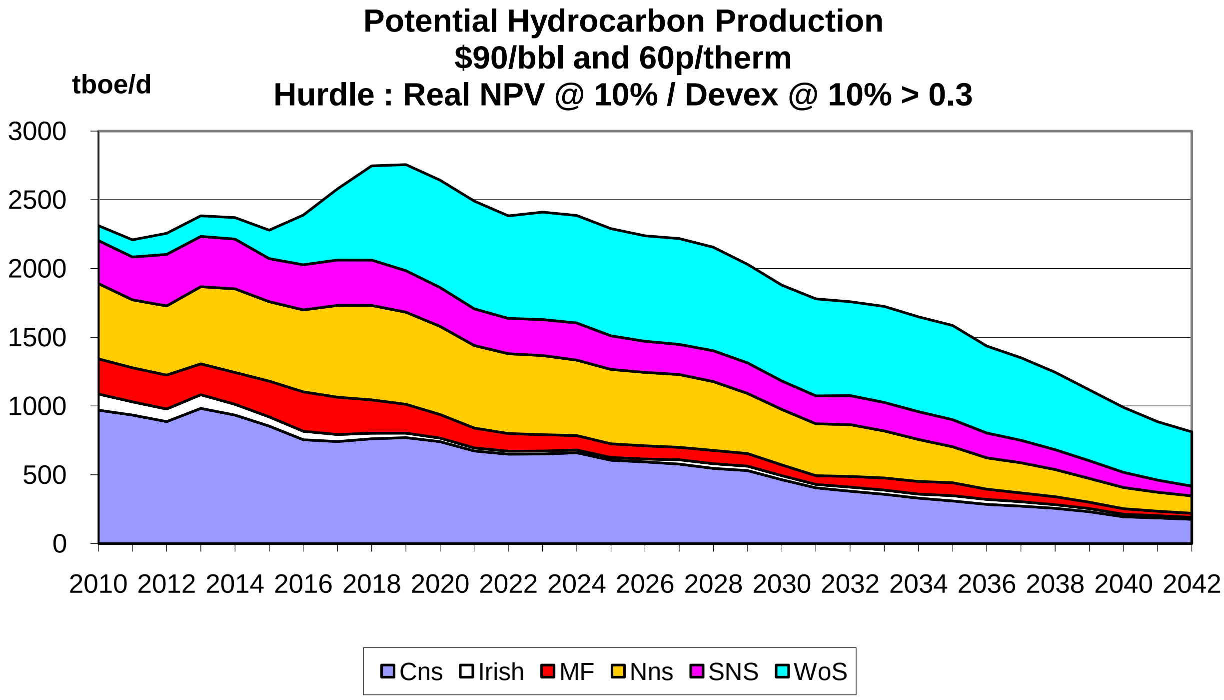


Chart 40

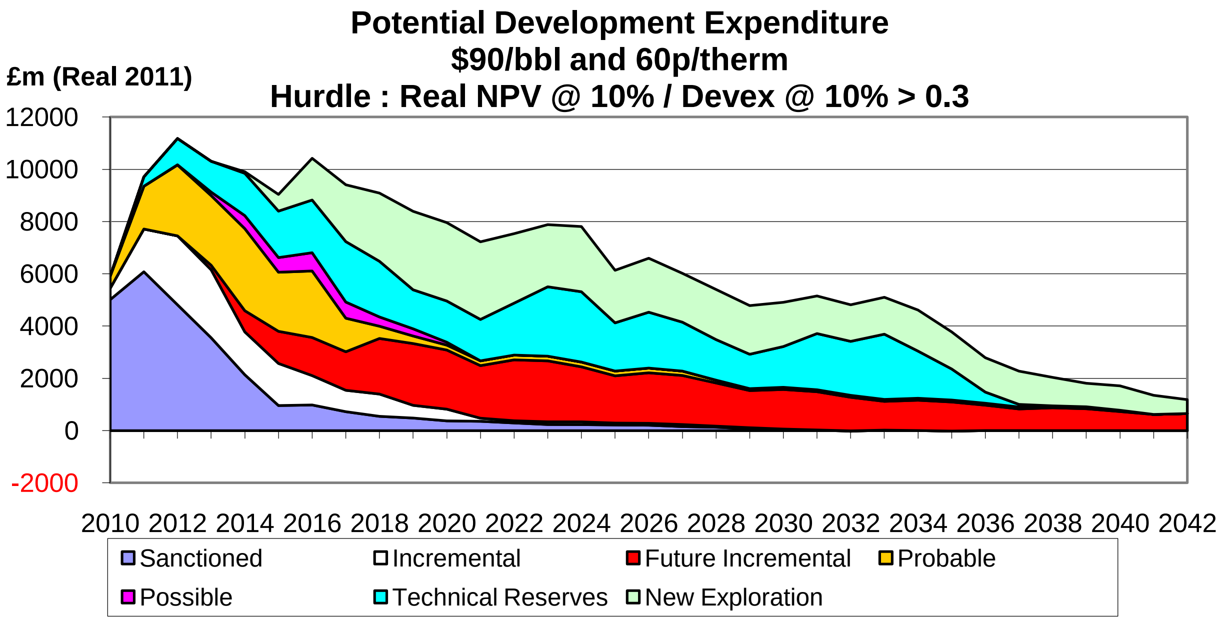


In Chart 40 production according to geographic areas is shown. The growing contribution from the W of S region is the most obvious feature. Over the whole period cumulative production from the area is 6.77 bnboe or over 29% of the total. DECC's central estimate of total potential from the region is 6.25 bnboe and their upper estimate 10 bnboe.

(iii) Development Expenditures

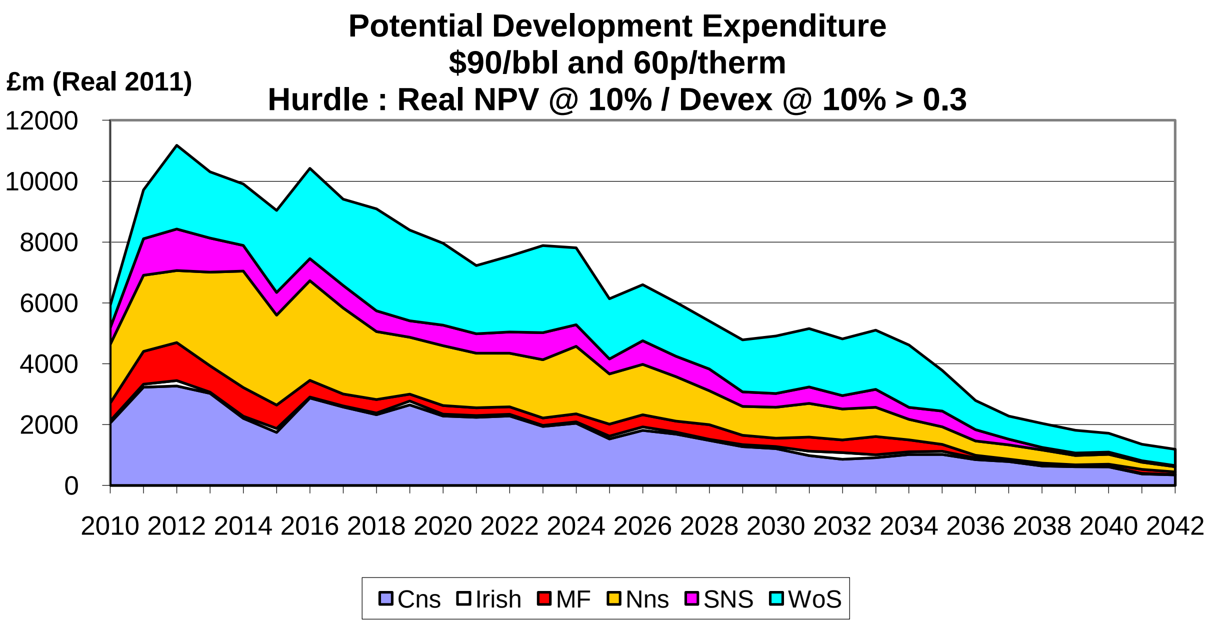
In Chart 41 field development expenditures are shown according to type of project. In the short term there is a major increase to £11 billion in 2012, primarily in probable fields and incremental projects. The longer term decline is greatly moderated by the development of new discoveries.

Chart 41



In Chart 42 the development outlays are shown according to geographic region. The importance of the W of S is again highlighted. Of the grant total of £196 billion over the period to 2042 £61 billion is in the W of S region.

Chart 42



(iv) Operating Expenditures

In Chart 43 operating expenditures are shown according to field and project type. Over the next 7 years they increase to over £8 billion due principally to the demands of more probable fields and technical reserves. In the long term the requirements of new discoveries and technical reserves dominate the total. In Chart 44 the operating costs are shown by geographic region. The W of S area is seen to account for a growing share in the long run but the CNS and NNS are generally more important throughout the period accounting cumulatively for £63.9 billion and £60.8 billion respectively.

Chart 43

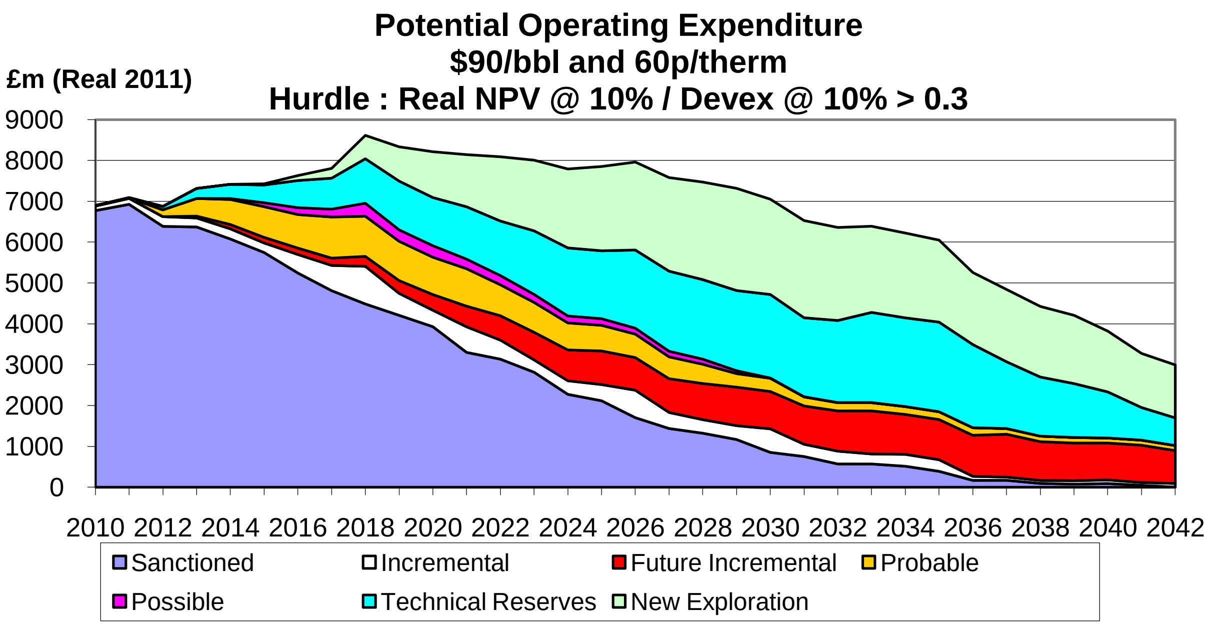
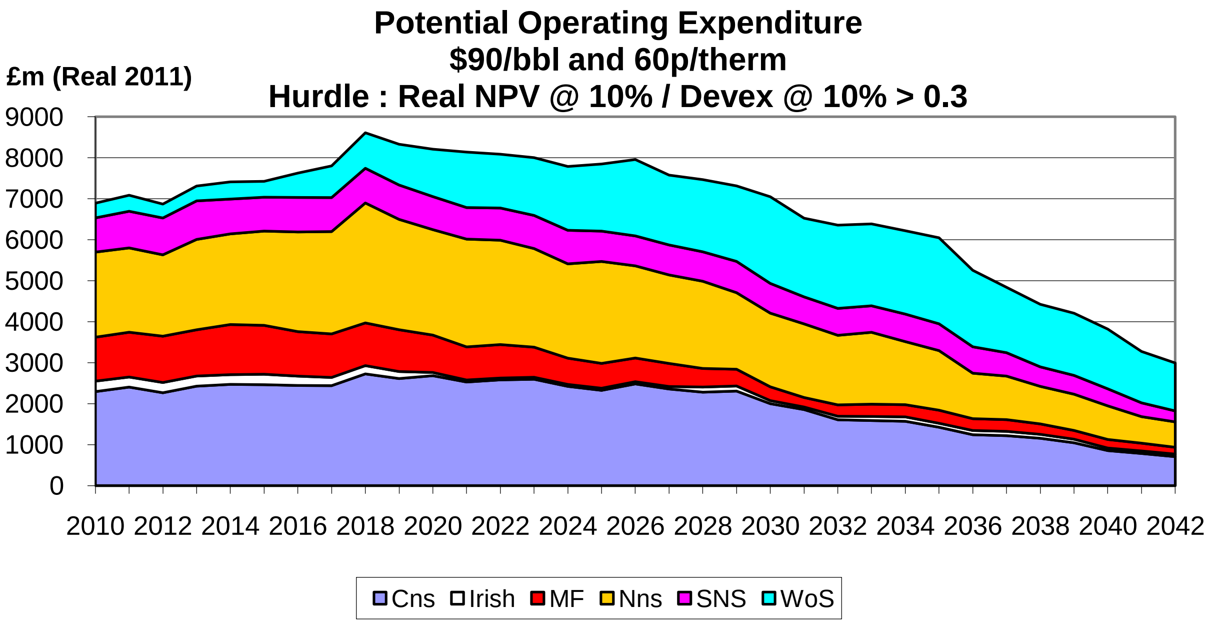


Chart 44



(v) Decommissioning Activity

In Charts 45 and 46 decommissioning expenditures are shown according to type of field.

Chart 45

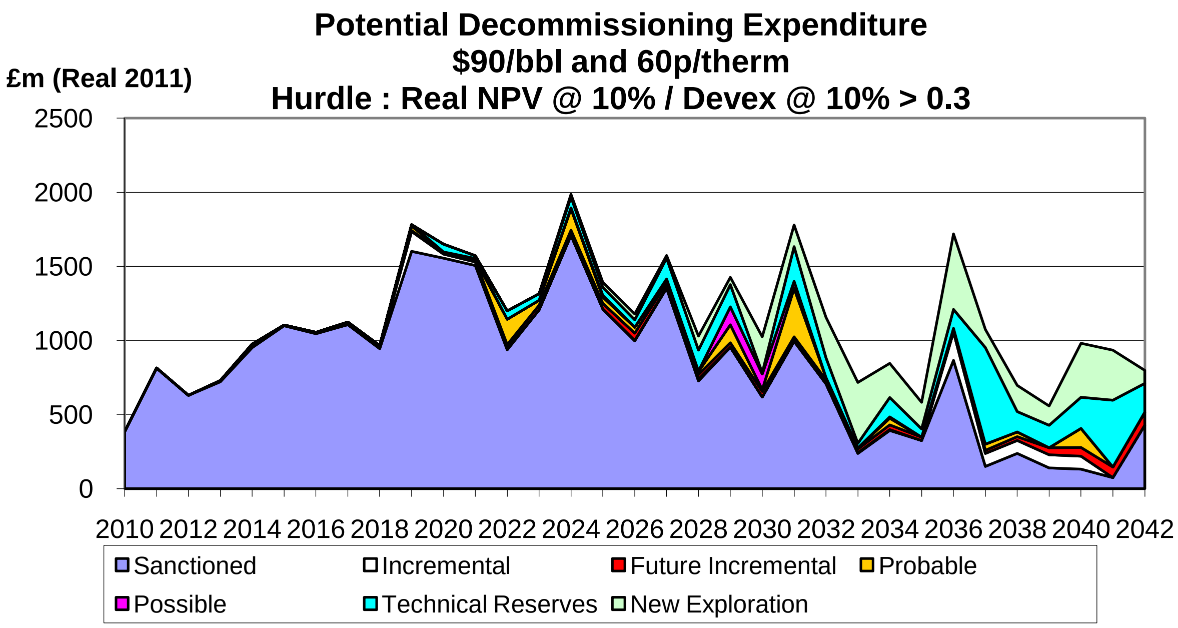
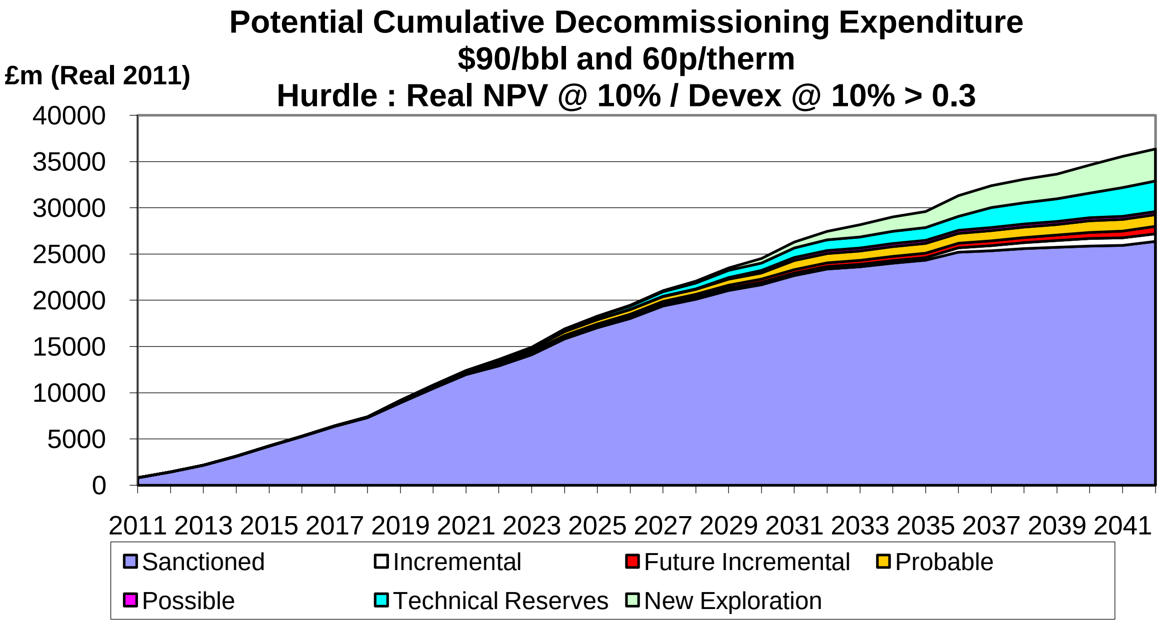


Chart 46



Over the period to 2042 cumulative expenditure amounts to £36.4 billion at 2011 prices. Under this price scenario there is some limited movement to later years of the very large levels of expenditure compared to the $70, 40 pence scenario. In the later years the expenditures exceed those under the medium price scenario because more new field developments are triggered and reach their COP dates before the end of the study period.

Chart 47

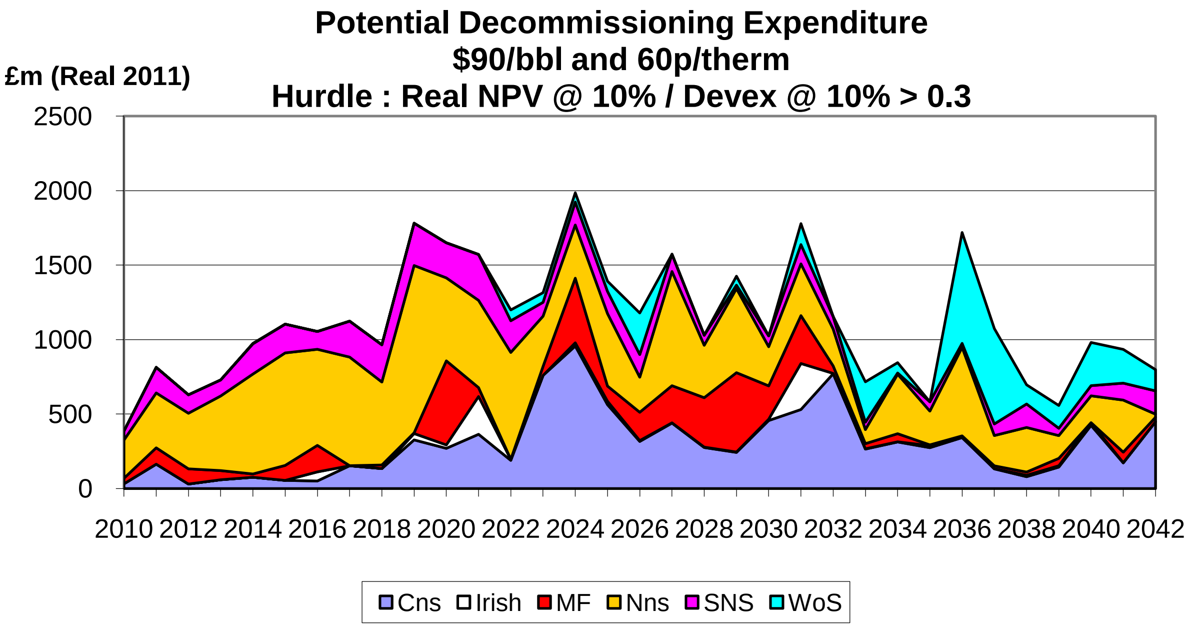
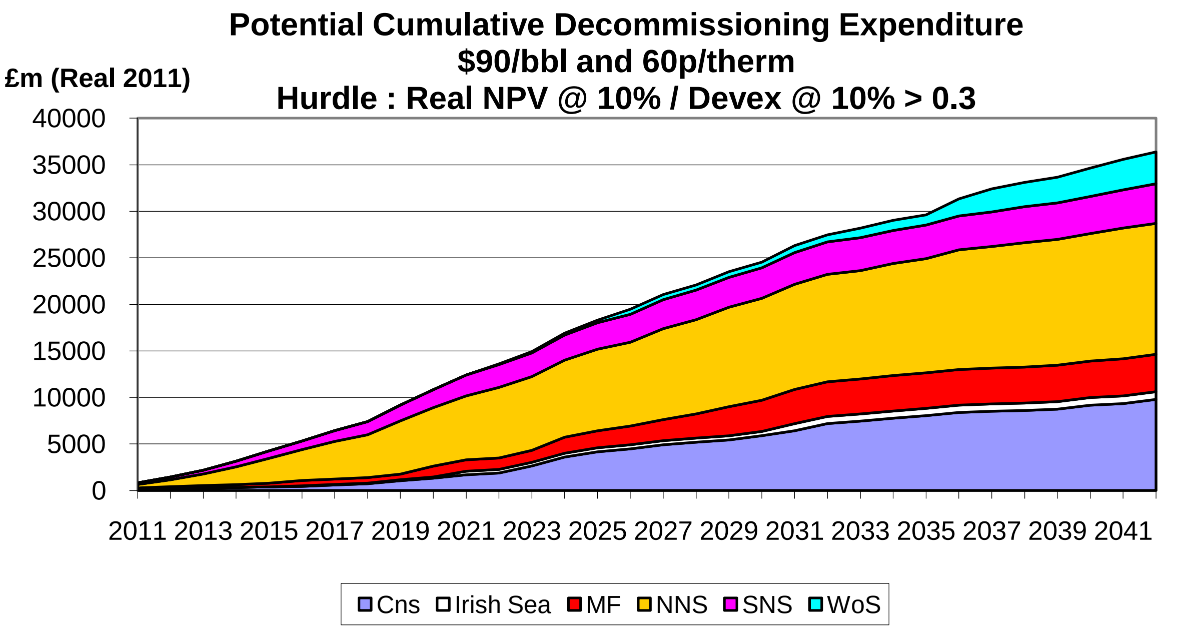


Chart 48



In Charts 47 and 48 the decommissioning costs are shown according to geographic region. Over the whole period £14 billion (at 2011 prices) is incurred in the NNS and £9.8 billion in the CNS.

Chart 49

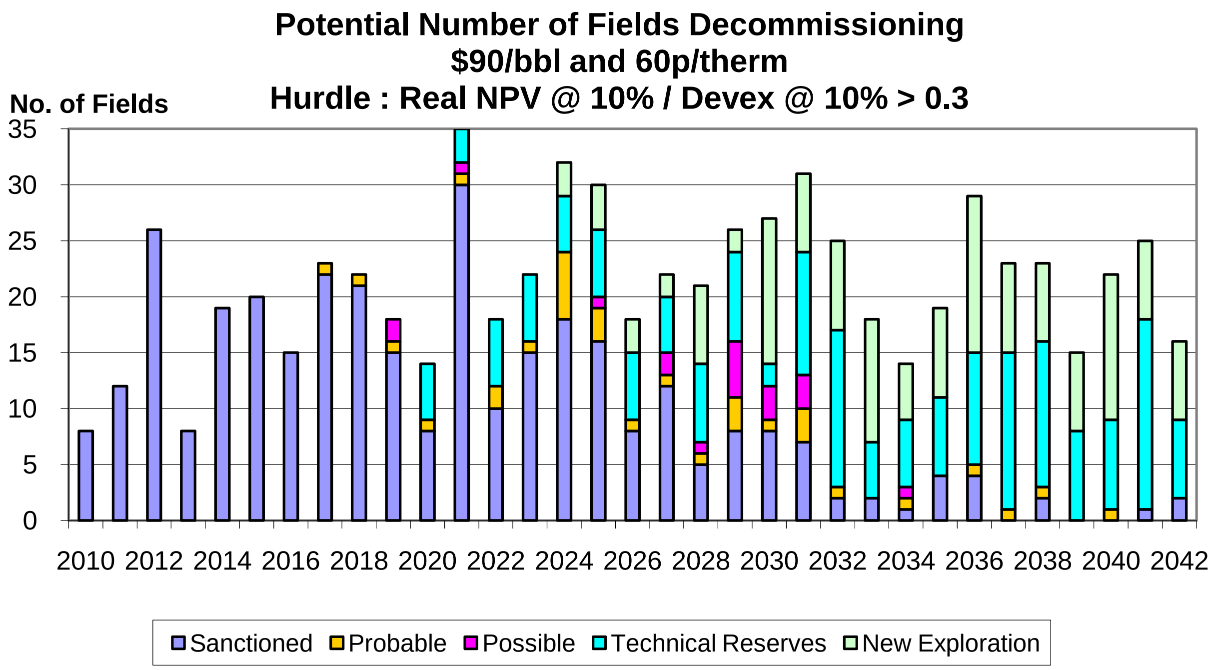
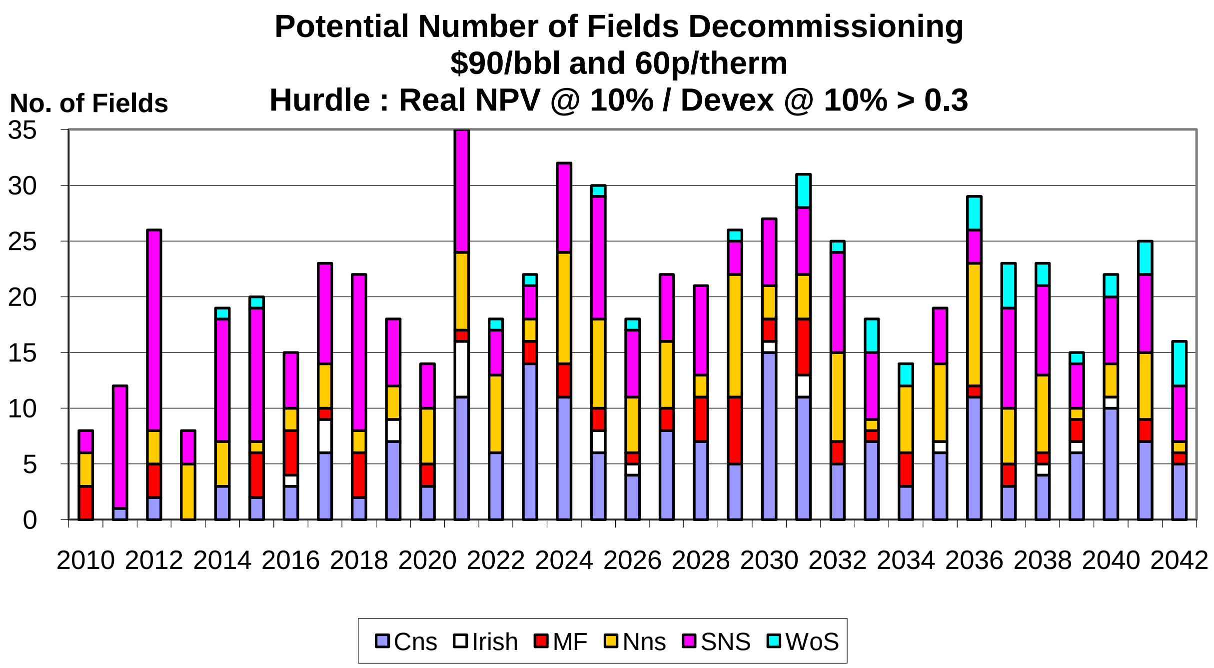


Chart 50



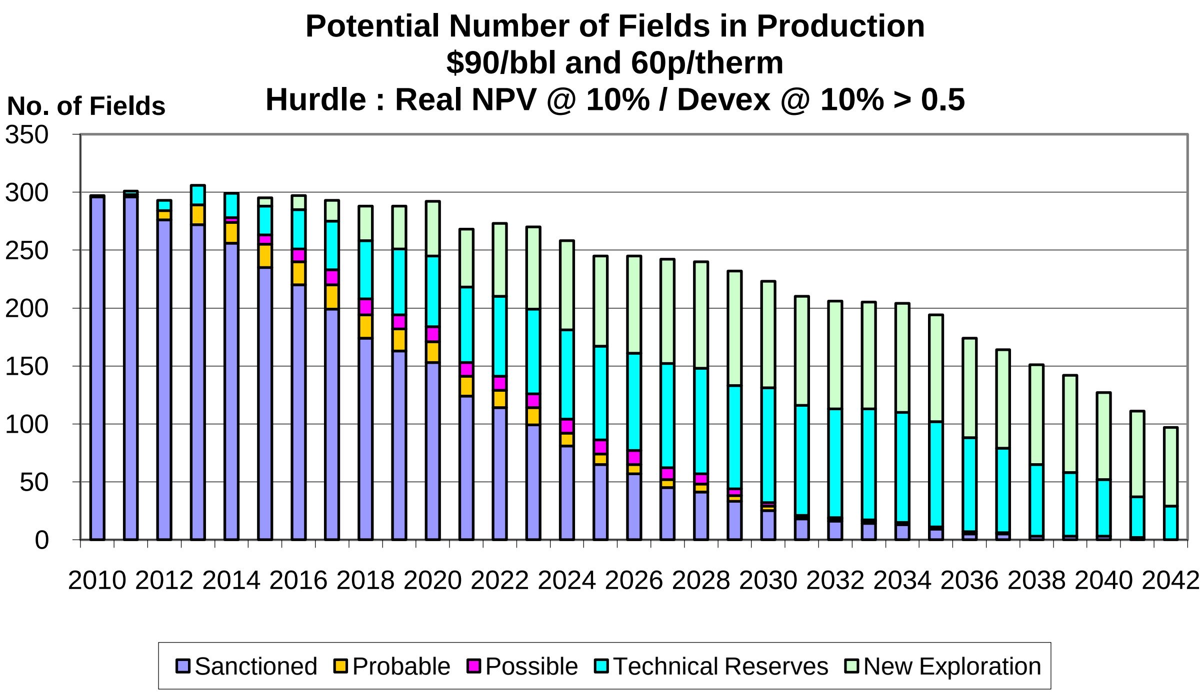
In Charts 49 and 50 the numbers of fields reaching their COP dates over the period are shown. Under this higher price scenario with more fields being developed the average annual number reaching their COP dates exceeds 15.

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

(i) Numbers of Fields in Production

In Chart 51 the numbers of fields in production over the study period are shown. There is a steady decline in the numbers of sanctioned fields as they reach their COP dates. For some years these are fully replaced by the development of new fields. In the longer term large numbers of fields in the categories of technical reserves and new discoveries are developed with the result that in 2042 there are still nearly 100 producing fields. Over the period to 2030 the average annual number of new field developments was just under 16.

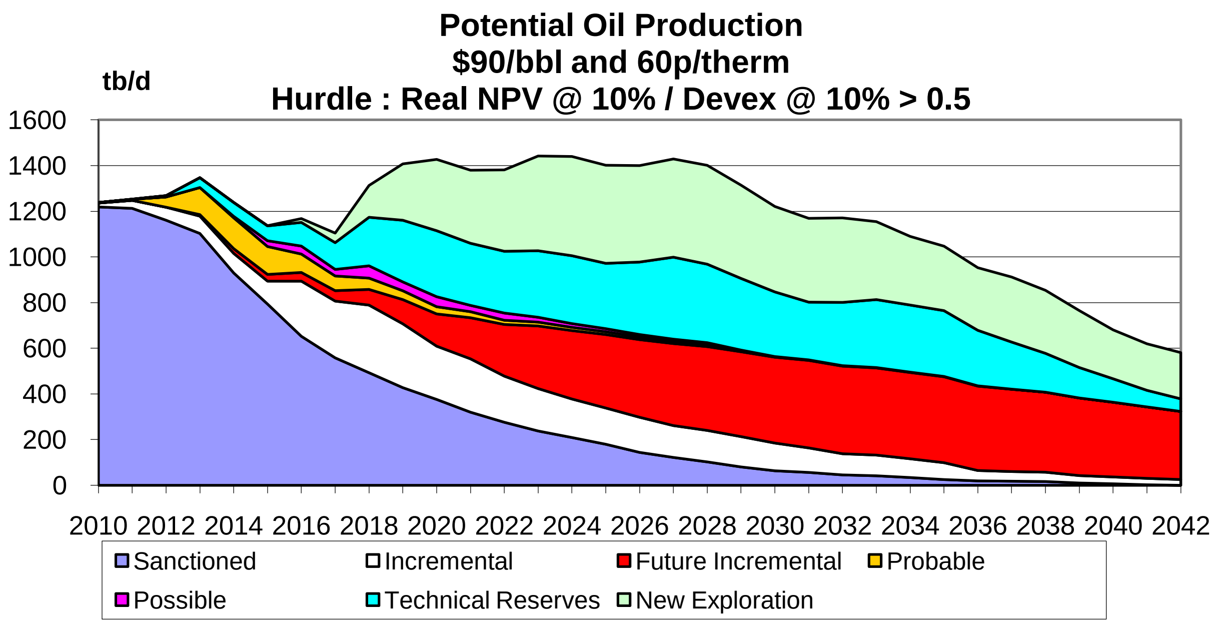
Chart 51



(ii) Production

In Chart 52 prospective oil production is shown according to types of fields and projects. Over the whole period to 2042 cumulative total production is 13.7 billion barrels. Of this 3.5 billion barrels comes from sanctioned fields, 4.3 billion from current and future incremental projects, 2.4 billion from technical reserves and 2.97 billion from new discoveries. Thus in the medium and longer term a high proportion emanates from fields not yet on the planning horizon. Without this production would fall continuously. If the fields are developed on the scale indicated production could be 581,140 b/d in 2042.

Chart 52



In Chart 53 oil production by geographic region is shown. It is seen that the sharp decrease in the period 2013-2016 is reversed primarily by the surge in output in the W of S region. Cumulative production from the region is 5.5 bn barrels. As much as 3.3 bn barrels comes from current and future incremental projects and only 0.85 billion barrels from new discoveries.

Chart 53

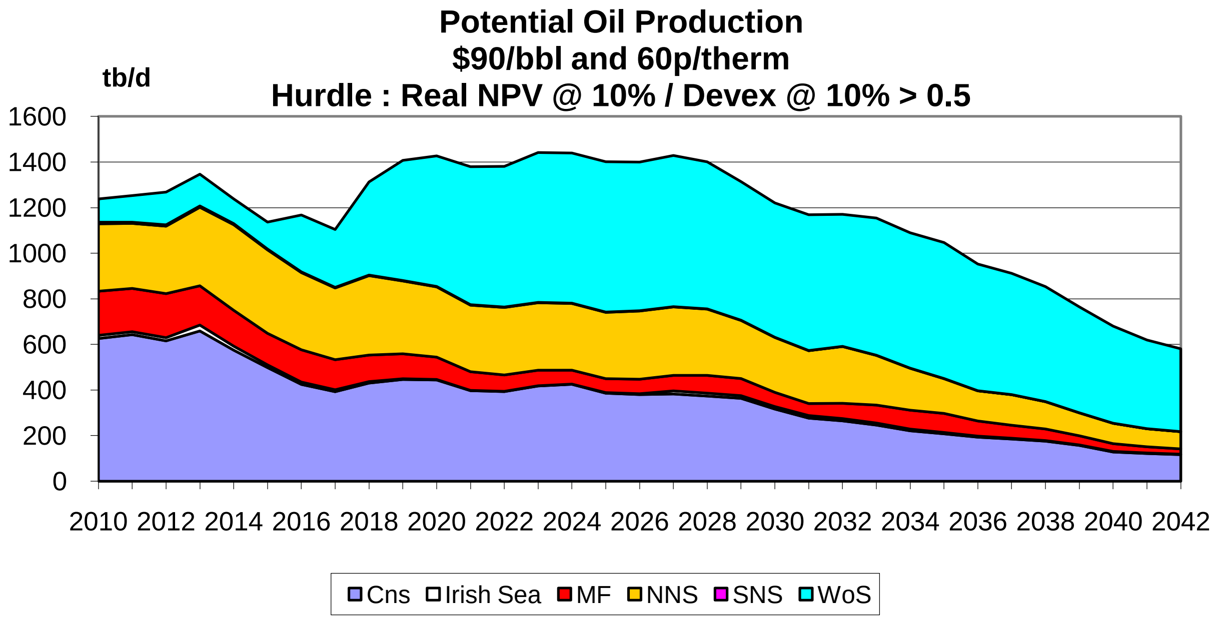
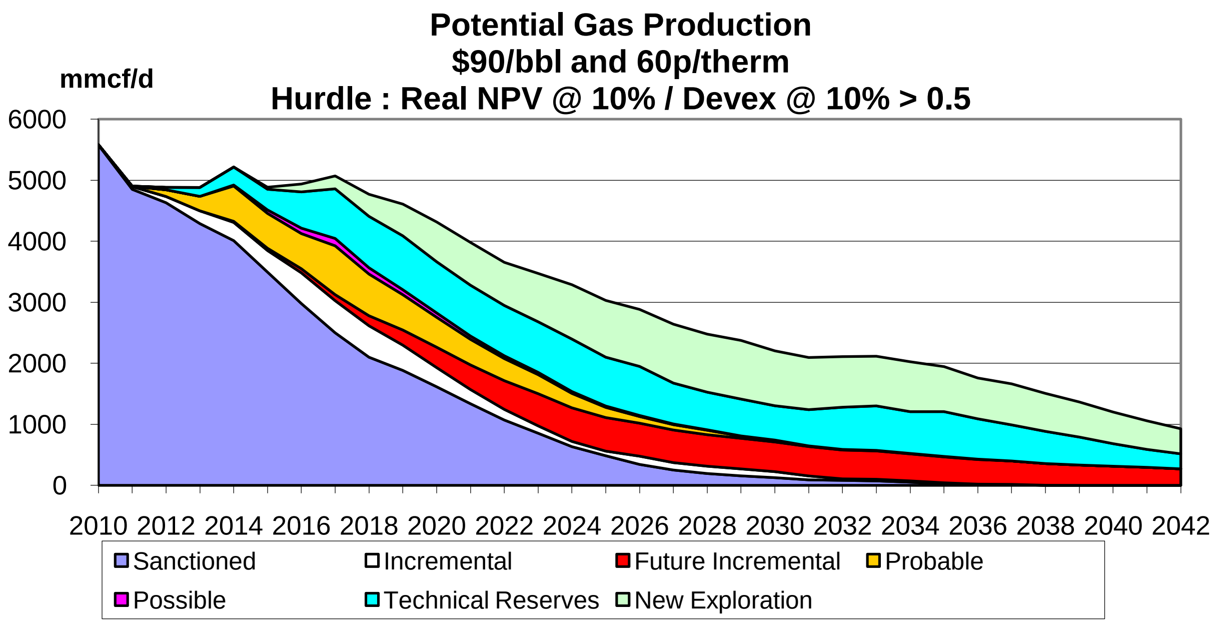
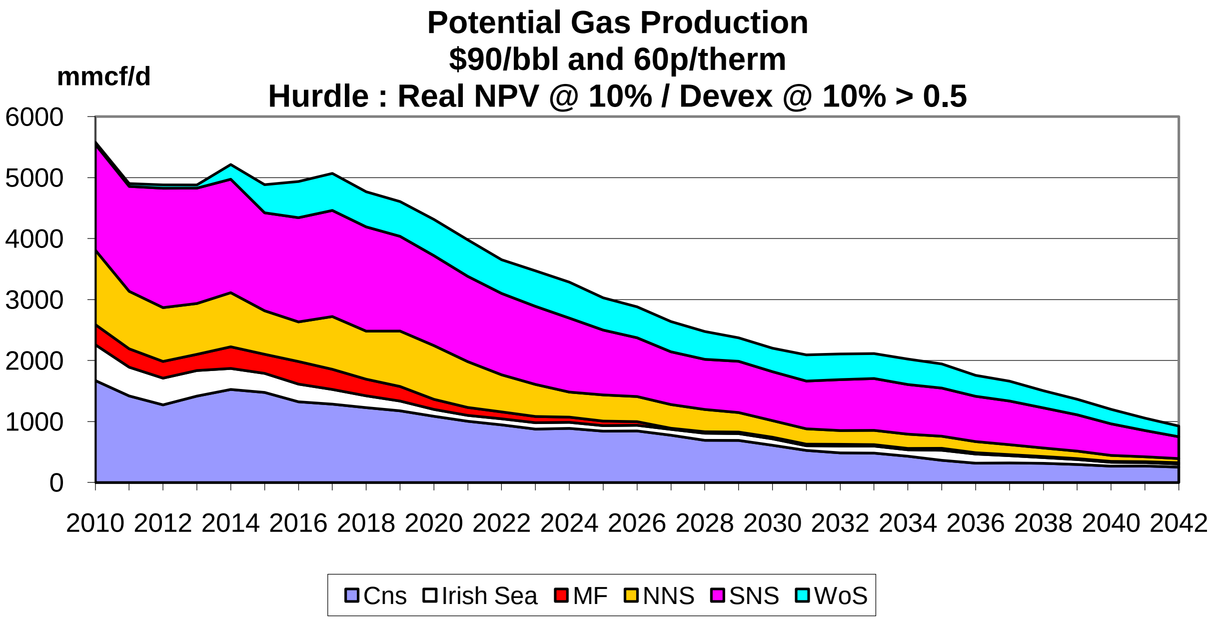


Chart 54



In Chart 54 potential gas production according to field and project types is shown. The recent sharp decrease is greatly moderated for a few years but this is followed by a fairly brisk rate of decline. By 2042 production is less than 1 bcf/d. In Chart 55 production according to geographic area is shown. The modest contribution of the W of S region compared to the oil case is noteworthy as is the continuing important contribution from the SNS region.

Chart 55



In Chart 56 potential total hydrocarbon production according to types of field and project is shown. The long term importance of future incremental projects, technical reserves, and new discoveries in moderating the decline rate such that total production in 2042 is around 750,000 boe/d is the most noteworthy feature. Over the period cumulative production is 20.6 bnboe. This is remarkably close to DECC's central estimate of the remaining potential and far below their upper estimate.

Chart 56

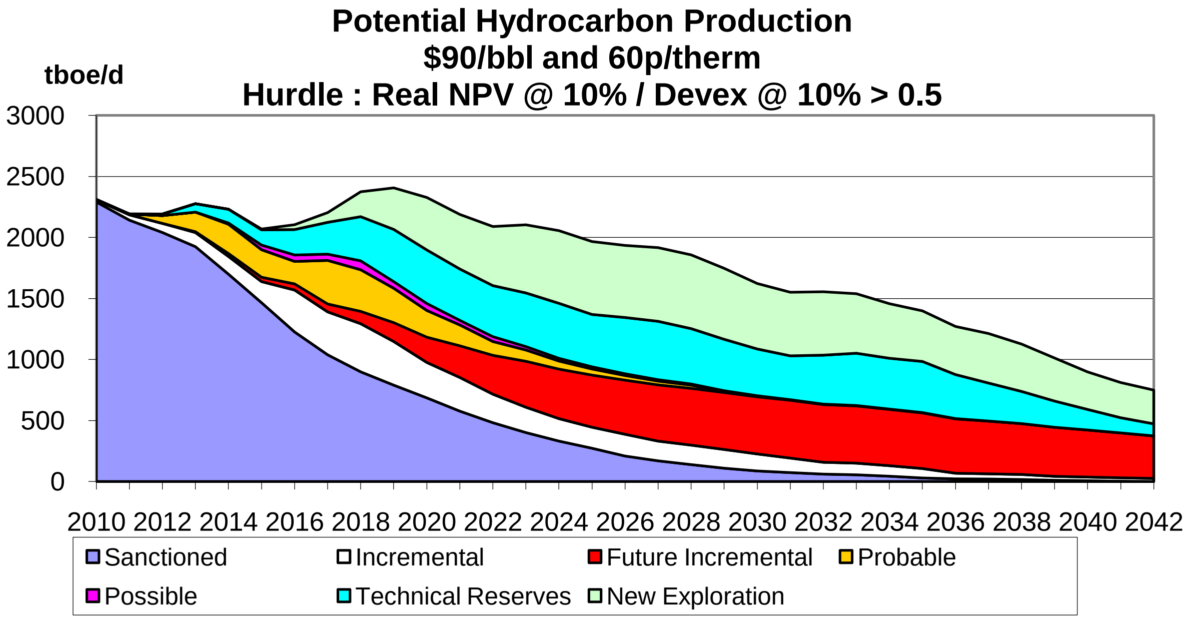
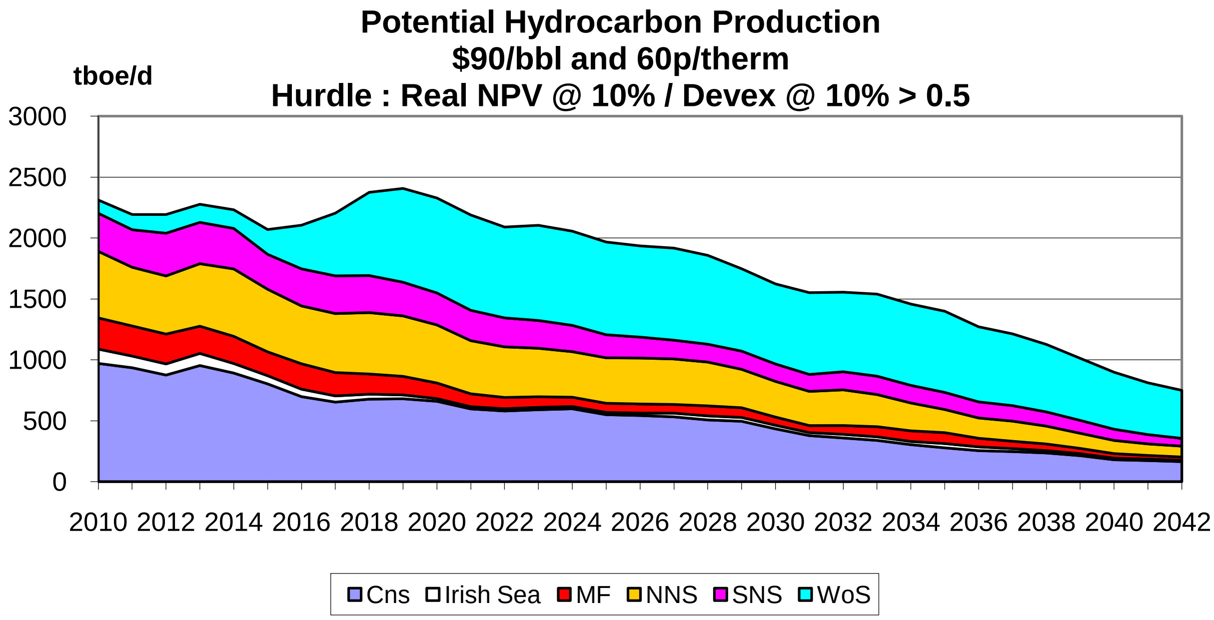


Chart 57



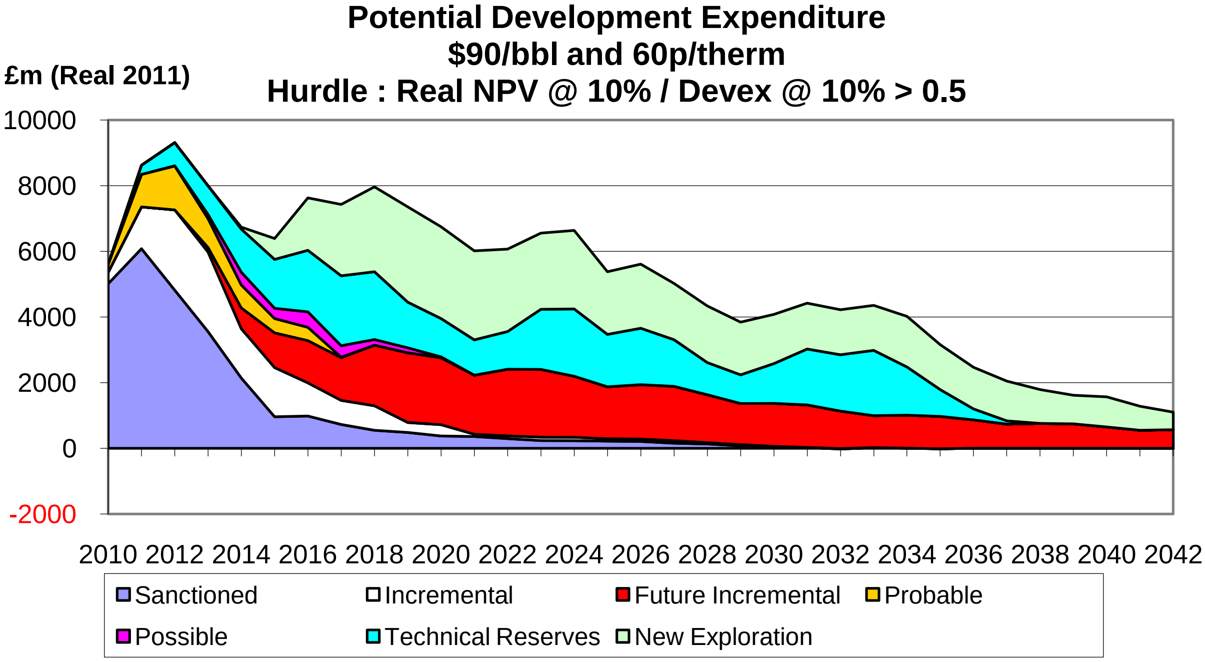
In Chart 57 total hydrocarbon production is shown according to geographic region. The substantial contribution from the W of

S region is again noteworthy. Total production from this region is 6.6 bn boe of which only 1.1 bnboe is from new discoveries and as much as 3.5 bnboe from current and future incremental projects. The total compares with DECC's central estimate of 6.25 bnboe and upper estimate of 10 bnboe.

(iii) Field Development Expenditures

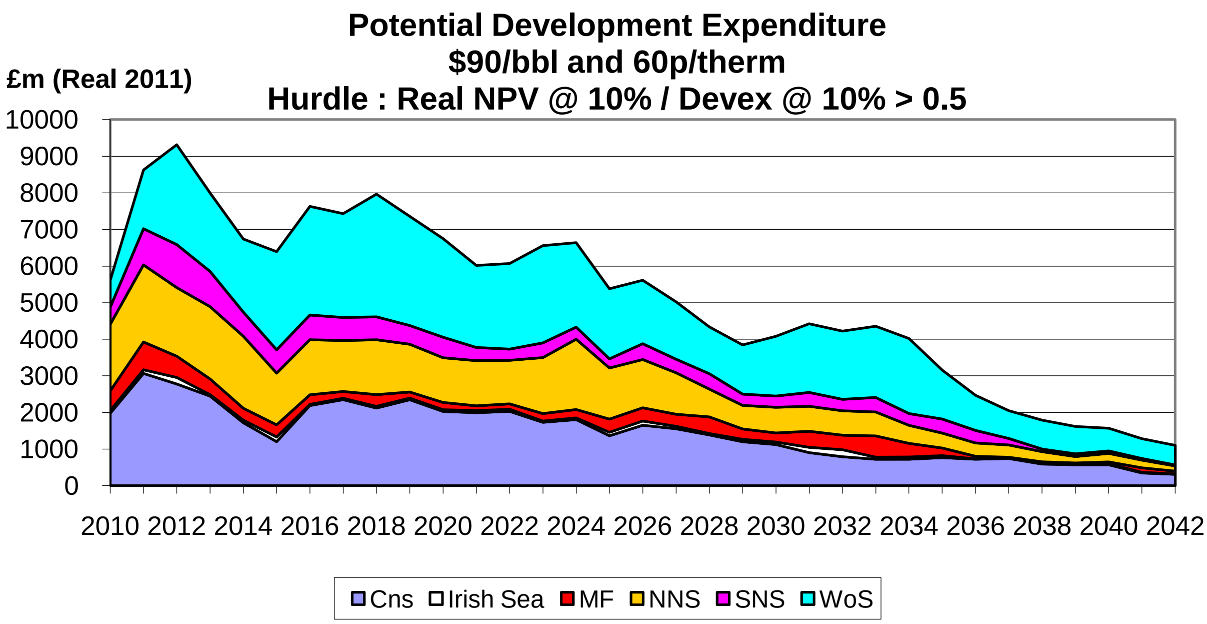
In Chart 58 field development expenditures are shown by type of field and project. There is a substantial increase to 2012 followed by a sharp fall to 2015. The subsequent development of technical reserves and new discoveries ensure that investment exceeds £6 billion per year until 2042. Over the whole period cumulative field investment as £162 billion of which current and future incremental projects account for £50 billion and new discoveries £47 billion.

Chart 58



In Chart 59 development expenditures according to geographic area are shown. The growing importance of the W of S region is an obvious highlight. Over the period investment in this region is £59 billion. In the CNS the figure is £45.8 billion. In the W of S region £34.9 billion relates to current and future incremental projects and £11.2 billion to new discoveries.

Chart 59



(iv) Field Operating Expenditures

In Chart 60 field operating expenditures are shown according to type of field and project. The level is flat over the next few years at around £7 billion per year. Thereafter there is an increase caused by the substantial numbers of new developments in the categories of technical reserves and new discoveries. The high cost associated with these fields is a factor in determining the levels of expenditure. In Chart 61 the operating costs by geographic area are shown. They highlight the importance of the CNS, W of S and NNS regions.

Chart 60

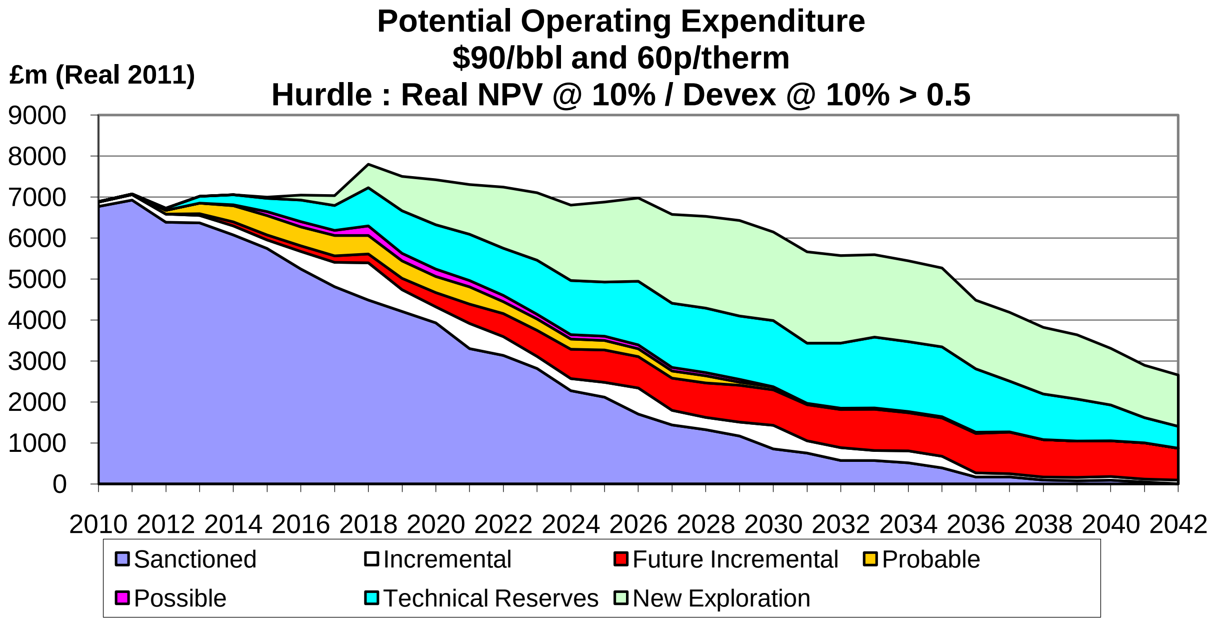
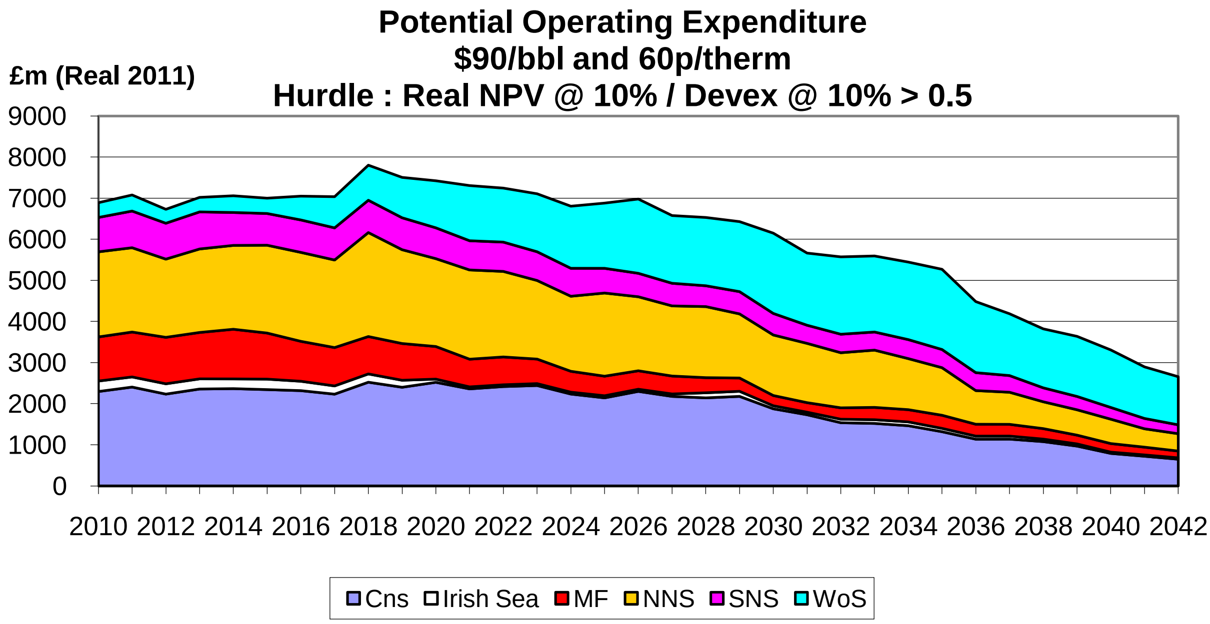


Chart 61



(v) Decommissioning Activity

In Charts 62 and 63 decommissioning expenditures are respectively shown annually and cumulatively. Over the whole period the total cost is nearly £35 billion at 2011 prices. Of this total £26.4 billion relates to sanctioned fields.

Chart 62

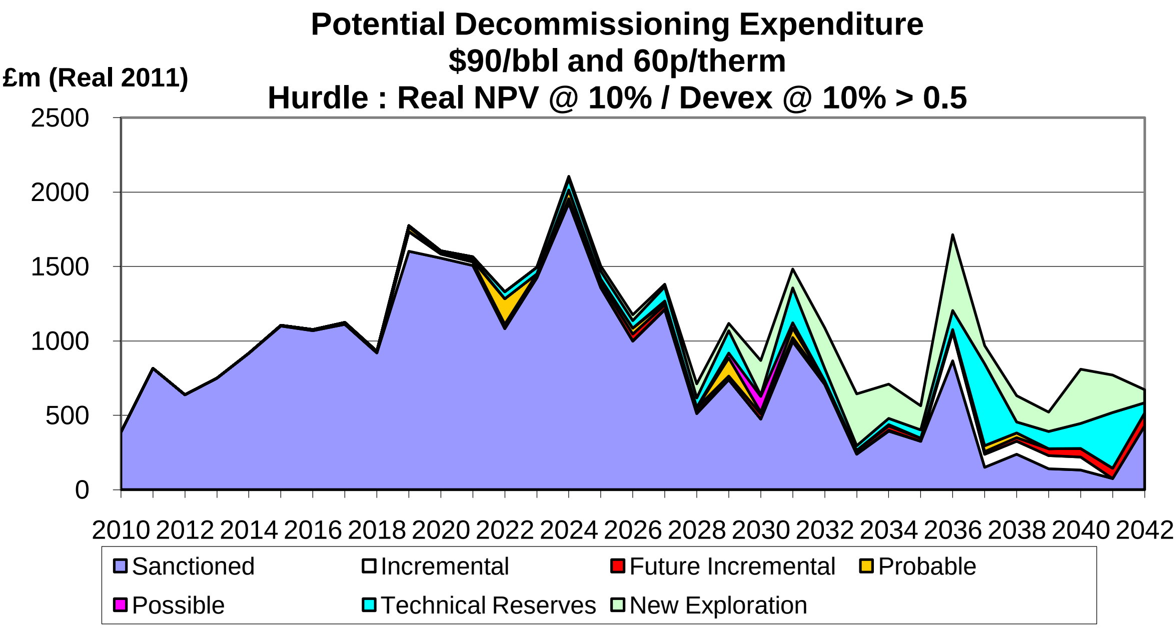
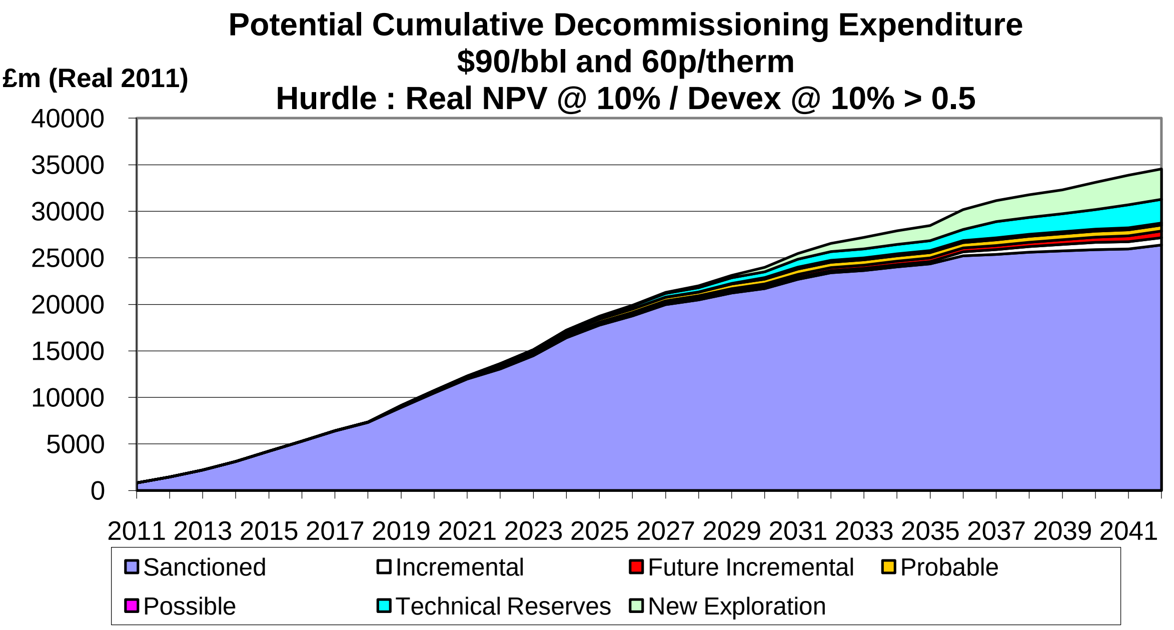


Chart 63



In Charts 64 and 65 the results are shown according to geographic areas of the UKCS. Over the period the NNS accounts for £13.6 billion and the CNS £9.4 billion.

Chart 64

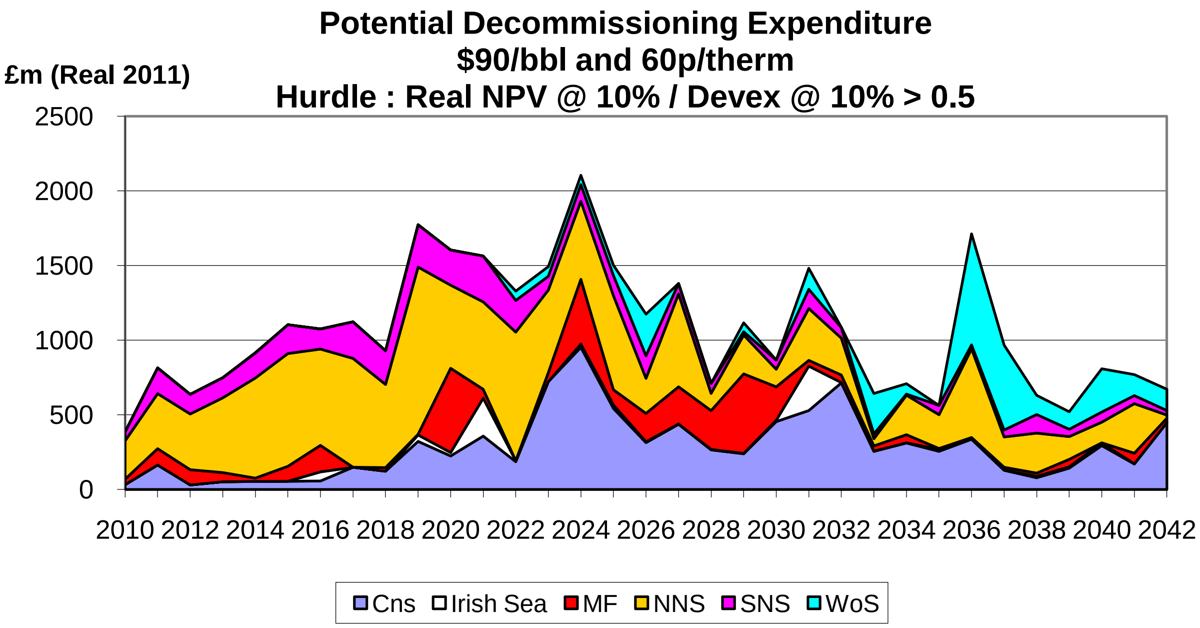
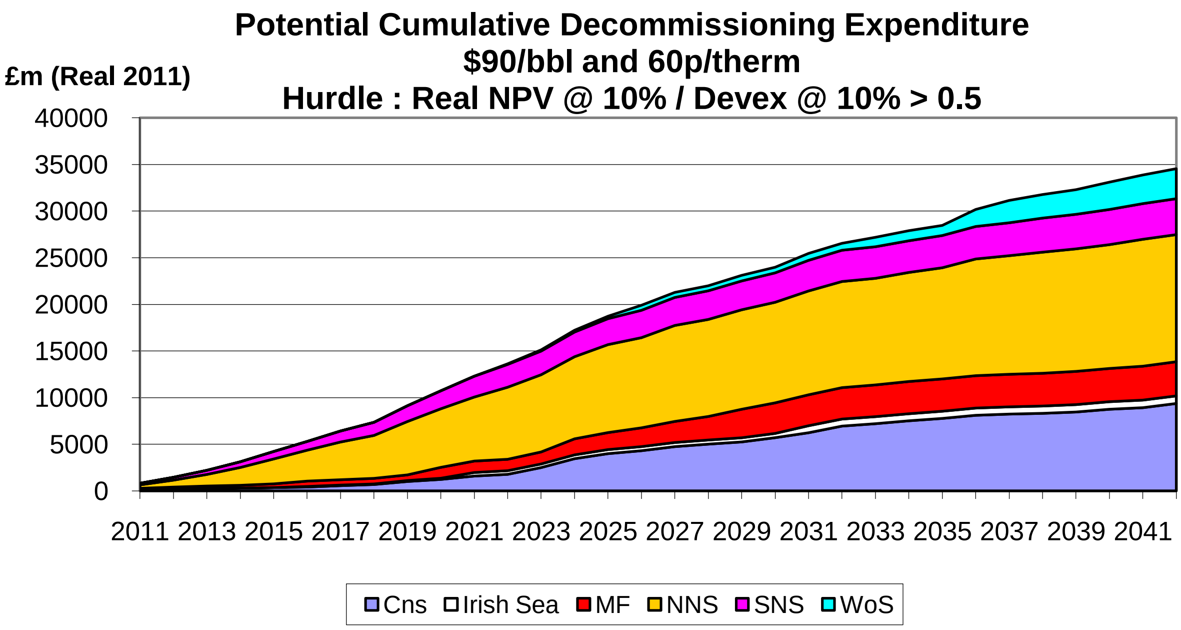


Chart 65



In Charts 66 and 67 the numbers of fields reaching their COP dates annually are shown. Over the period the annual total exceeds 15 in the great majority of the years.

Chart 66

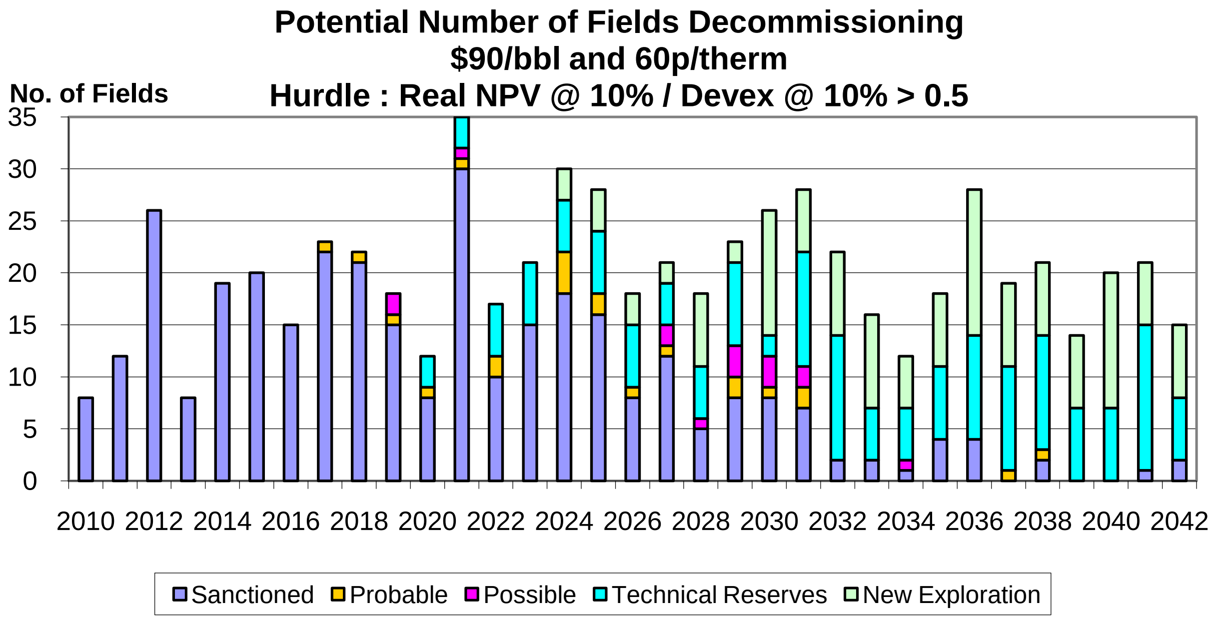
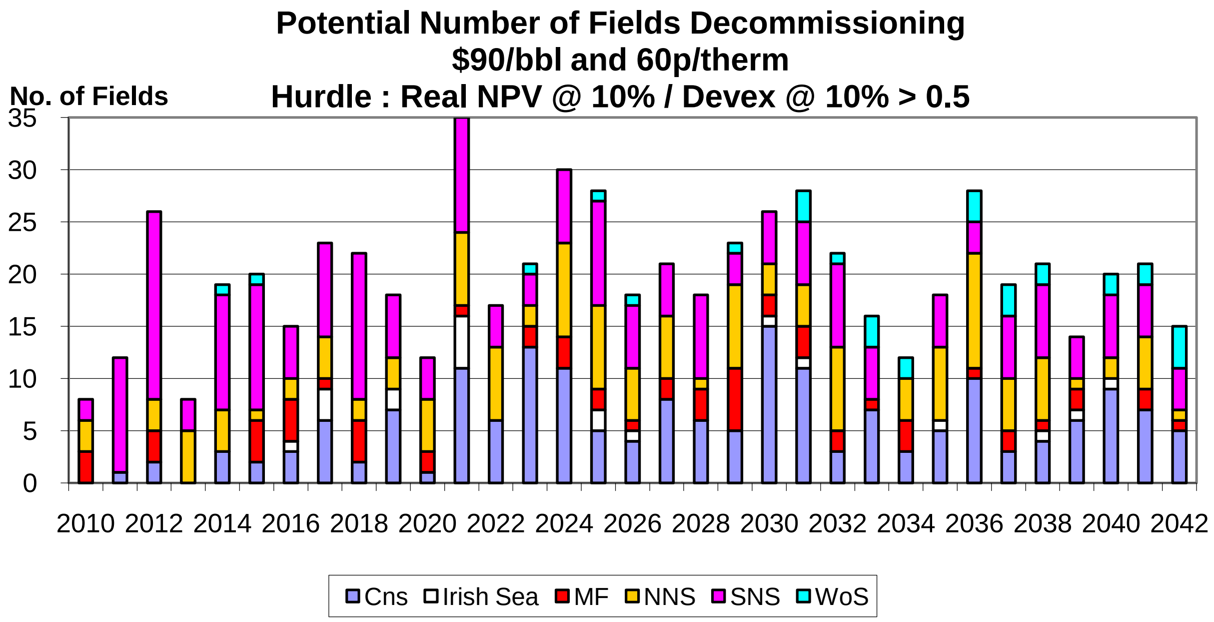


Chart 67



4. Summary and Conclusions

In this study the prospective activity levels in the UKCS to 2042 have been modelled under two oil/gas price scenarios and two investment hurdles. The price scenarios chosen ($70, 40 pence per therm and $90, 60 pence, all in real terms and thus increasing yearly with inflation) reflect the range likely to be employed by licensees in assessing long term investments. The investment hurdles employed (NPV/I > 0.3 and NPV/I > 0.5) reflect the presence of some capital rationing, the availability of investment opportunities elsewhere, and the consequent need to emphasise capital productivity in making long term investments. There are thus four detailed scenarios.

In the $70, 40 pence case with the lower investment hurdle it was found that oil production held nearly constant in the short term, then fell sharply for a few years, to be followed by a rebound for some years, leading to a gradual long term decrease. Over the period to 2042 11.2 billion barrels are produced. Gas production behaves rather differently, falling consistently throughout the period. Total cumulative gas production is 4.8 billion boe. Total hydrocarbon production over the period (including NGLs) is 16.5 bnboe. These figures compare with DECC's central estimates of the remaining potential 13.7 bnbbls of oil and 7.7 bnboe for natural gas. The total resource availability is thus unlikely to be the key production constraint for some years ahead.

A similar broad conclusion applies to the case with the same screening prices but the higher investment hurdle. In this case over the period to 2042 cumulative oil production is 9.3 bn barrels, natural gas 4 bnboe and total hydrocarbon output, including NGLs, 13.8 bnboe.

In both cases oil production growth was noticeable in the W of S region with cumulative output being 3.9 and 3.6 bn bbls respectively under the lower and higher investment hurdles. It should be stressed that in the modelling brand new oil discoveries in the region were not particularly large. Over the period they contributed 0.79 bnbbls and 0.67 bnbbls under the low and higher investment hurdles. This compares with DECC's central estimate of over 1.55 bnbbls for the potential from the W of S region.

If investment decisions are made at prices of around $70 and 40 pence field investment could peak at around £8 billion in 2011 and then fall very sharply to £4.4 billion in 2015. There is then some recovery for a few years followed by long term decline. The prospect of a substantial fall in investment over the next few years is a worrying one for the whole oil and gas cluster and the need for tax and other incentives to accelerate developments is an obvious conclusion.

Prospective activity is substantially higher under the $90, 60 pence price scenario. Oil production remains at or near its present level for several years, but then there is a substantial increase for a considerable time, followed by a moderate decline rate. Over the period to 2042 cumulative oil production is 15.2 bnbbls under the lower hurdle rate and 13.7 bnbbls under the higher one. It was noted above that DECC's central estimate of the ultimate oil potential was 13.7 bnbbls. Their upper estimate is 23 bnbbls. The results produced by the modelling in this paper are thus consistent with a prudent view of the upside potential. New discoveries contribute 3 bnbbls over the whole period. This is far below the upper estimate of the ultimate potential as seen by DECC. At 5.6 bnbbls the W of S region makes a notable contribution to oil output over the period. Of this total new discoveries account for 0.9 bnbbls which is below DECC's central estimate of 1.55 bnbbls and far below their upper estimate of 4 bnbbls from this region.

Total hydrocarbon production over the period is considerably higher in the $90, 60 pence prices scenario compared to the $70, 40 pence one. With the lower investment hurdle total recovery in the period 2011-2042 is 23.1 bnboe and 20.6 bnboe under the higher hurdle. It will be recalled that DECC's central estimate of the remaining potential is 21.4 bnboe. Their upper estimate is 35.9 bnboe. Thus the overall potential from the modelling in this paper can be regarded as quite prudent.

The Office of Budget Responsibility (OBR) has recently published a long term production projection[2] based on a simple extrapolation of a historic decline rate of 5% per year to 2040. This results in cumulative production of 12 bnboe over the period. This should be regarded as a disappointing outcome and well below the obtainable potential.

If investment decisions are made on the basis of a $90, 60 pence price scenario field development expenditure should increase to around £11 billion in 2012 but then fall to around £9 billion by 2015 with the NPV/I > 0.3 hurdle. With the NPV/I > 0.5 hurdle investment could be £9.3 billion in 2012 and fall to £6.4 billion by 2015. After that there should be an increase, but this does depend on the development of new discoveries. The prospect of a large short term increase in investment followed by a sharp fall is worrying and highlights the need for incentives to accelerate developments in the medium term.

[2] Office for Budget Responsibility, Fiscal Responsibility Report, HMSO, July, 2011 p.103

It is suggested that short and medium term activity levels in the UKCS depend less on geological prospectivity than on other factors. This paper has highlighted the interaction of oil/gas prices with costs and the present tax system. The materiality of expected returns is clearly a major issue in the maturing province with the prevalence of many small fields and incremental projects.

The current debate on the impact of the tax system illustrates a key factor which potentially influences investment and production in the UKCS. This is the subject of a current study but, to illustrate the possibilities, it can be reported here that, in the $90, 60 pence price scenario, under the current tax system, of the 69 fields in the probable and possible categories, 15 failed to pass the hurdle of NPV/I > 0.3 and 32 failed to pass when the hurdle was NPV/I > 0.5. By contrast, in the absence of Supplementary Charge (SC) 12 fields failed to pass the hurdle of NPV/I > 0.3 and 21 failed to pass when the hurdle was NPV/I > 0.5. There is clear scope for investment being enhanced when tax reliefs for less profitable/marginal fields and projects against SC are introduced. This is the subject of a forthcoming paper.

The UKCS has other features relevant to the pace of development and production. Third party use of infrastructure is increasingly common and is generally welcome as it can substantially reduce the overall costs of development. But there can be delays in obtaining agreement on the terms of access which in turn postpones the development and production. The Infrastructure Code of Practice introduced in 2004 has improved the situation but delays are still experienced. It remains to be seen whether the provisions of the current Energy Bill will accelerate the signing of agreements. The Bill gives DECC the ability to be proactive rather than merely reactive when agreements are proving difficult to reach, and to make determinations, but this will only be done on a case-by-case basis.

Planned and unplanned shutdowns for maintenance, repair, and refurbishment work are common features of the UKCS, and, with the increasing interconnectedness of the infrastructure and user fields, the resulting effects on production can be quite substantial. This constitutes one of the reasons for the general finding that over the last number of years production has been consistently less than predicted. The stewardship initiative has been implemented to ensure that all reasonable measures are being taken by licensees to maximise economic recovery from the more mature fields.

While the projections under the $70, 40 pence scenario have a high probability of being achieved, the investment and production projections under the $90, 60 pence case should be regarded as having a lower probability of being attained. But this is not primarily for reasons relating to the geological prospectivity of the UKCS, especially over the medium term. Rather it relates more to the relationship between the investment and operating costs per boe, oil and gas prices, and the several policy and behavioural factors discussed above. Thus tax allowances and measures can increase the annual numbers of new fields and incremental projects coming on stream every year. In the modelling of the $90, 60 pence case the number of fields and projects being executed were below the imposed physical and financial constraint of 20 per year. This number was achieved not infrequently in the 1990’s, but not in more recent years. Over the past few years the numbers of new developments have been insufficient to be consistent with the future production levels shown for the $90, 60 pence scenario. A collective effort by all stakeholders is required to enhance these numbers. The maximisation of economic recovery also requires technological advances which require a higher R and D effort than has been the case over the last two decades. Again a collective effort by all main stakeholders is required to achieve optimal results.