The Hypothetical Scottish Share of Revenues and Expenditures from the UK Continental Shelf 2000 – 2013

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1. Introduction

The Scottish economy has benefited enormously from the exploitation of oil and gas from the UK Continental Shelf (UKCS). Thus the exploration, development and operating expenditures required for production and processing are to a considerable extent located in Scotland. They have made a major contribution to the national output and employment in the sectors involved. The Scottish economy also shares in the UK benefits to the Exchequer and balance of payments emanating from the production revenues and tax receipts from the UKCS.

There is continuing interest in the share of these revenues which would accrue to Scotland as a separate entity. Estimation of these, particularly the potential hypothetical taxation receipts, is not straightforward, and this paper produces detailed estimates for the period 2000 – 2013. The results are tested for consistency against national UK data. While the prime interest is in the taxation revenues the results for gross production revenues, and main expenditures are also shown.

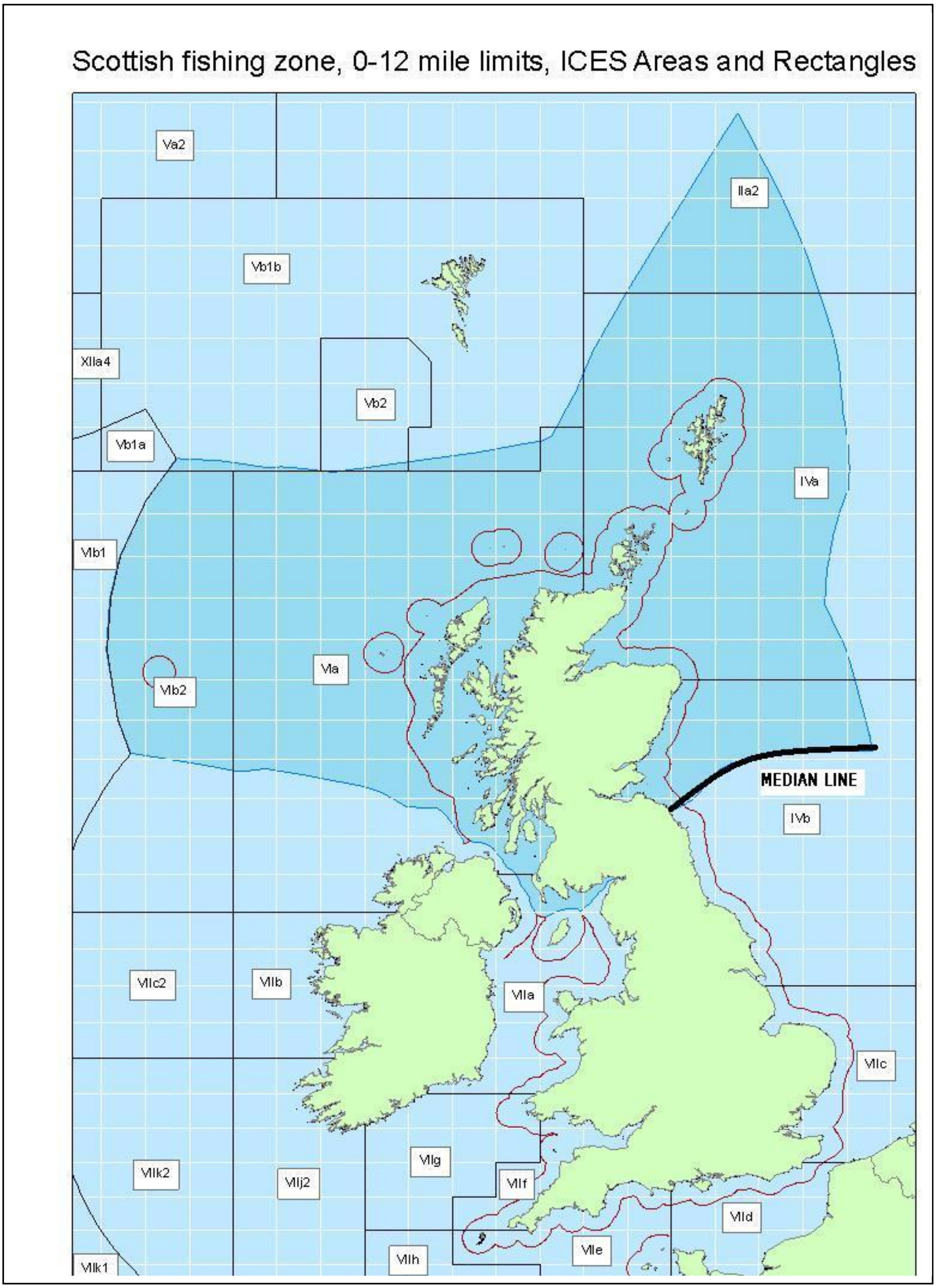
2. Methodology, Assumptions and Data

a) The Boundary Issue

For purposes of the study the UKCS had to be divided between Scotland and the rest of the United Kingdom. Over many years there has been much debate about how the delineation might be determined. [1] In practice this would be subject to negotiation between the relevant Governments. There is some presumption that the line of equidistance should be employed to determine the boundary, and this was deployed in the negotiations between the UK Government and the other Governments which had Continental Shelves in the North Sea. But use of the line of equidistance has not been exclusively employed to determine boundaries, particularly after the ruling of the International Court in 1969 regarding the boundaries between West Germany, Denmark, and Belgium. A further legal feature is the line of jurisdiction in the North Sea for civil jurisdiction purposes established between Scotland and England in 1968 (latitude 55°50′N).[2] Some legal opinion holds that this has set a precedent for the determination of the boundary for the division of the Continental Shelf, but this is open to dispute. In 1999 the median line principle was employed to determine the boundary between Scotland and England for fisheries demarcation purposes.[3] This is shown in Chart 1. For purposes of the present study this median line has been employed to divide the UKCS between Scotland and England.

[1] For a very clear, early discussion of the issue see E. D. Brown (1978) "It's Scotland's Oil?: hypothetical boundaries in the North Sea – a case study", Marine Policy, January, pp. 3-21.
[2] The Continental Shelf (Jurisdiction) Order 1968, SI 1968 No. 892.
[3] The Scottish Adjacent Water Boundaries Order, 1999, 13th April 1999.

Chart 1


Scottish fishing zone, 0-12 mile limits, ICES Areas and Rectangles
Va2
IIa2
Vb1b
XIIa4
Vb2
Vb1a
IVa
VIb1
VIa
VIb2
MEDIAN LINE
IVb
VIIc2
VIIb
VIIa
VIIc
VIIk2
VIIj2
VIIg
VIIf
VIId
VIIe
VIIh
VIIk1

b) Expenditures and Revenues Attributable to the Scottish Sector

(i) Discovered Fields

Over many years the authors have built up a large field-related data base of the UKCS. This incorporates all historic expenditures relating to development, operating, and decommissioning activities, and production of oil, gas and condensate. The data have been validated by the field operators. Such data relate not only to sanctioned fields (over 300 for UKCS) but to “probable” and “possible” fields (over 50 for UKCS) which refer to these currently being seriously examined for development. Further, there are over 90 incremental projects being assessed for development. In addition the authors have developed another database of known discoveries (over 200) not yet at the stage of being seriously examined for development. These are termed “technical reserves” in the study. Their block location and mean estimates of size of recoverable reserves (oil, gas, or condensate) are known from a mixture of private and public sources, and the present authors designed for them profiles of production, development, operating and decommissioning expenditures. For the field investment and operating costs a premium above those applicable to current developments was employed to reflect the fact that the fields in this category generally have problems adversely affecting their economic attractiveness, such as long distance from infrastructure or technical reservoir problems (such as heavy oil or high pressure/high temperature conditions). Given the greater uncertainties regarding the size of the reserves from this category of field Monte Carlo analysis was employed with the distribution of the size of each individual field forming a normal distribution with a standard Deviation (SD) equal to 50% of the mean. For development costs the Monte Carlo technique was also employed involving normal distribution with a SD equal to 20% of the mean value. All the above fields and projects were allocated to the Scottish and non-Scottish sectors on the basis of the median line.

(ii) E and A Expenditures and Future Discoveries

For future E and A activity it was assessed that the total number of wells drilled in the UKCS in the period to 2013 would be 70 per year. This compares with 78 in 2005, 69 in 2006 and 111 in 2007. The distribution of these across the regions of the UKCS (Southern North Sea, Central North Sea, Moray Firth, Northern North Sea, West of Shetland and Irish Sea) was taken to follow the trend over the last 10 years. The success rate for the whole of the UKCS was taken to be 23% in line with average experience over the last decade, but the experience of each of the 6 regions was individually examined for purposes of economic modelling. Similarly, the trends in the types of discoveries (oil, gas, condensate) over the last decade in the six regions were ascertained and employed in the economic modelling of exploration. Likewise the trends in the average sizes of discoveries in each of the 6 regions were ascertained and employed in the modelling. The resulting discoveries were allocated to the Scottish and non-Scottish sectors.

c) <u>Investment Screening Criteria</u>

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. Currently the average size of a new field is around 20 million barrels of oil equivalent (mmboe). In the Southern North Sea the average is around 13 mmboe. 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, 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 in real terms ≥ 0.3. The 10% real discount rate reflects the weighted average cost of capital to the investor. There is no substantial risk premium because, for the assessment of exploration prospects and technical reserves, the key risks are assessed directly through the use of the Monte Carlo technique.

d) Taxation

The economic modelling has been undertaken based on the existing taxation arrangements. Thus for fields developed from 16th March 1993 onwards Corporation Tax (CT) at 30% and Supplementary Charge (SC) at 20% apply. Exploration, appraisal and development expenditures are relieved on 100% first year basis. Loan interest is not deductible for the SC. For fields developed before 16th March 1993 (but excluding gas fields with contracts signed with the former Gas Council/BGC before 1st July 1975), Petroleum Revenue Tax (PRT) is payable at 50% on a field basis. There is a complex set of allowances. All expenditures are deductible on 100% first year basis with an uplift for field development costs prior to payback of 35%. In addition there is a volume allowance of 10 million tonnes for fields developed from April 1982, outside the Southern North Sea (2.5 million tonnes in the SNS), and a safeguard allowance which reduces the effective rate for a time period equal to 1.5 times the payback period. The volume allowance still applies to some fields as there is an annual limit to the amount allowed. A further allowance for PRT-paying fields is the tariff receipts allowance (TRA) of 250,000 tonnes which applies only when the host field is also PRT-paying. PRT is not payable on tariffs from new tariff contracts signed after 9th April 2003, with effect from 1st July 2004. Some investors in the UKCS are relatively new players and their income may be insufficient to cover their allowances for CT and SC. In such circumstances the investor can carry forward his unused allowances at 6% compound interest for up to 6 years. In the economic modelling it has been assumed that investors do have tax cover to enable them to utilise their allowances. Royalties at 12.5% were payable until the end of 2002. Royalties are deductible for PRT and CT/SC. PRT is deductible for CT/SC.

e) Deductibility of Some Overhead and Other Costs

The field database does not include details of all costs which are legitimate deductible items for CT, SC, or PRT. Principally these are eligible overhead costs, R and D expenditures, and loan interest. These had to be estimated from a variety of sources and allocated to the six regions of the UKCS and, in the case of the CNS, allocated between the Scottish and rest of UK sectors. Debt capital and the consequent loan interest were allocated on a field basis. Some iterations were necessary in order to produce modelling results which were consistent with national UK published aggregates for taxation revenues.

f) Other Modelling Assumptions

The financial modelling was initially conducted in MOD terms as taxes are paid on this basis, with the results subsequently being converted to real 2007 values. Fur historic years, actual UK inflation and exchange rates were employed. For future years, an exchange rate of £1= $2 was employed. For future oil and gas prices 3 cases were examined as shown in Table 1.

Table 1

Future Oil and Gas Price Scenarios

	Oil Price (real) $/bbl	Gas Price (real) pence/therm
High	75	45
Medium	68	38.2
Low	60	30

g) <u>The Financial Simulation Modelling</u>[4]

The financial modelling for historic years calculated for the Scottish and non-Scottish sectors investment expenditures (E and A plus development), operating and decommissioning expenditures, and production. The taxable income and the consequent royalty and tax payments were then calculated on the lines discussed above. For future years deterministic financial modelling was undertaken on the sanctioned fields with economic cut-off and cessation of production occurring when operating losses became sustained. For the probable and possible fields and incremental projects deterministic modelling was undertaken using the investment hurdle screening criterion discussed above.

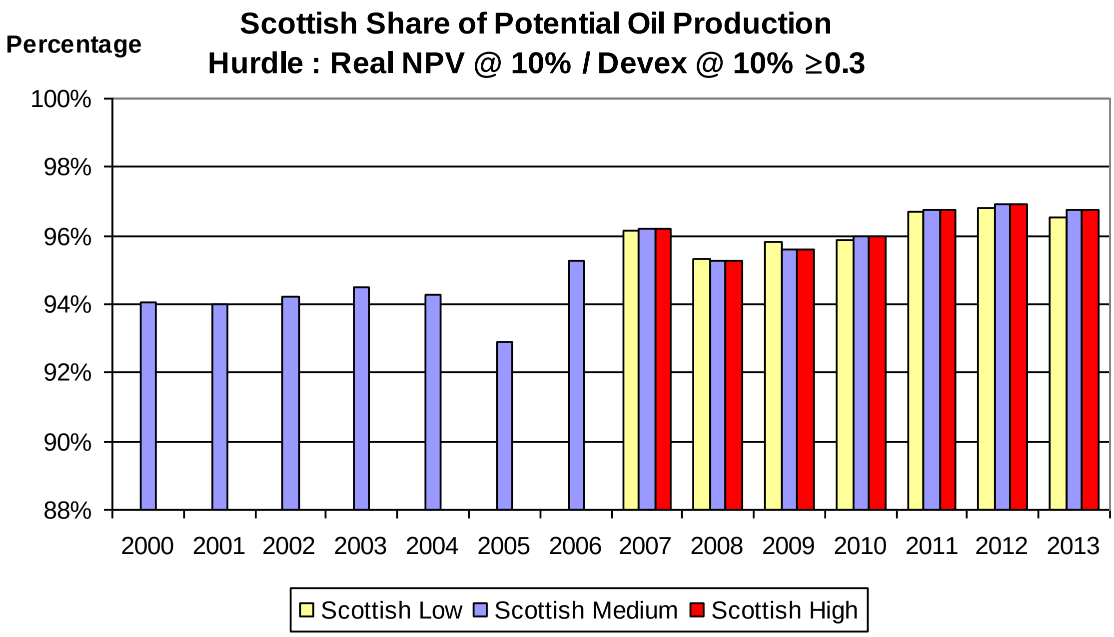
[4] The modelling was undertaken in late 2007 when the information from the UK Government's 2007 Pre-Budget Report was available. Thus it does not include information from Budget 2008. For further details of the modelling methodology see A. G. Kemp and L. Stephen, *North Sea Study Occasional Paper No. 106*, The Prospects for Activity in the UKCS to 2035: the 2007 Perspective, University of Aberdeen Department of Economics

Subsequently the production profiles, investment, operating and decommissioning expenditures for viable fields in the Scottish and non-Scottish sectors were calculated. The expected tax receipts were then estimated for the Scottish and non-Scottish sectors. It should be noted that by the end of the study period (2013) little production from future discoveries occurred, but the exploration and development expenditures reduced the taxable base.

3. Results

a) Scottish Share of Oil Production

Chart 2



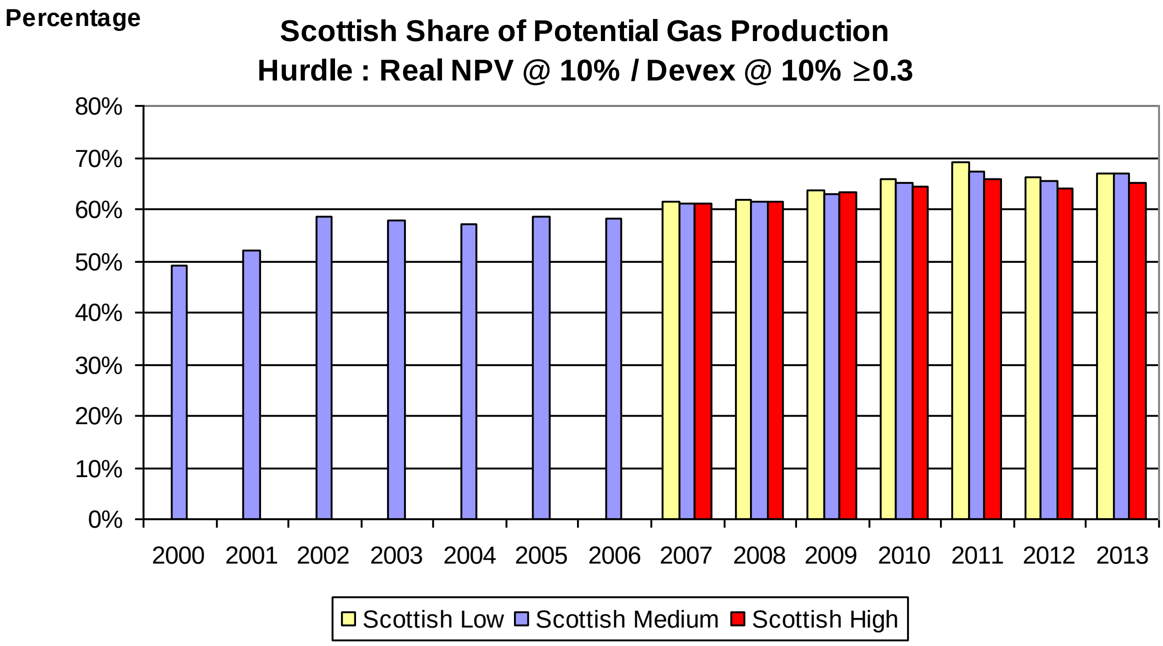
In Chart 2 the estimated share of Total production from the Scottish sector is shown. It is seen to be over 94% in the historic period and in the 95% - 97% range for the future period to 2013. Overall oil production is declining[5], and to the south of the North Sea median line and in the Irish Sea it becomes very

[5] The modelling assumes that the various PILOT initiatives relating to fallow blocks/fields, stewardship, and infrastructure Code of Practice bear fruit. If their success is limited production will be further reduced.

small in the period. While production in the Scottish sector is also falling its share has increased due to new projects such as the large Buzzard field coming on stream in recent years. There is a small positive oil price sensitivity to the Scottish share in the period with the economic limit of fields being extended at higher values. More new developments are also triggered at higher oil prices but their impact is relatively small in the period to 2013. Oil production in the Scottish sector falls from 1.43 mmboe/d in 2006 to 1.2 mmboe/d in 2013 under the medium price case, and to 1.1 mmboe/d under the low price case. Under the higher price case it is 1.25 mmboe/d in 2013.

b) Scottish Share of Gas Production

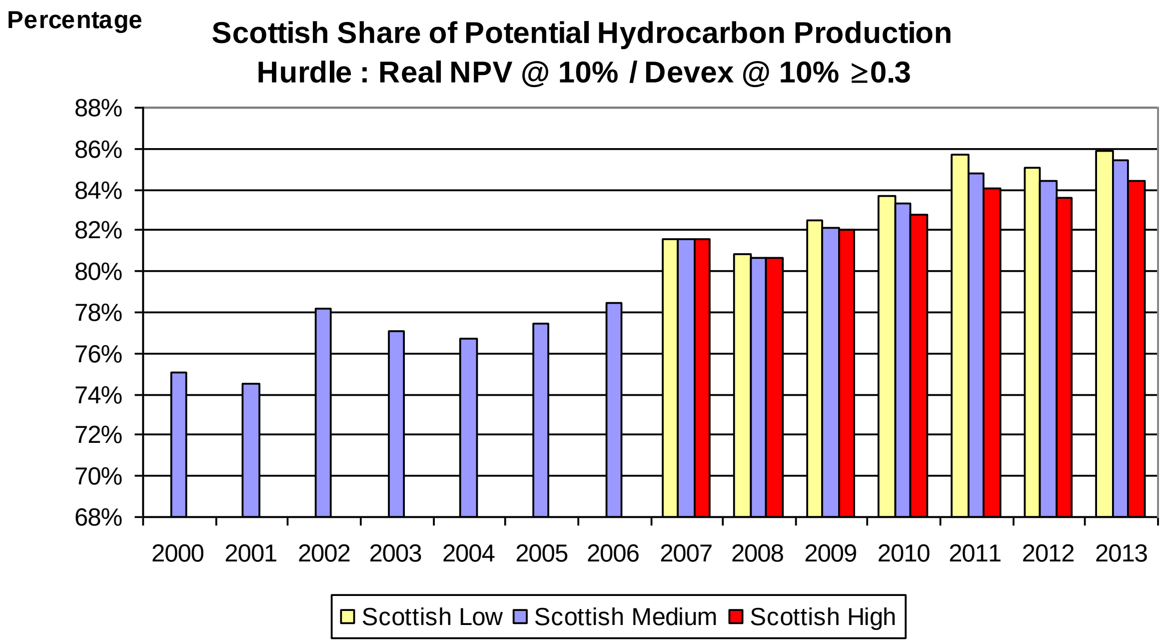
Chart 3



In Chart 3 the Scottish share of gas production is shown. It has increased significantly over the past few years from 49% in 2000 to over 58% in 2006. The increase in the share is expected to continue over the study period reaching 65% - 67% in 2013. While total production from the UKCS will continue to fall the decline rate is expected to be considerably faster in the non-Scottish sectors. This applies to the Irish Sea where the Morecambe fields are in decline and in the Southern North Sea where the older fields are becoming very mature and the (substantial numbers) of new fields are generally very small. In the Scottish sector the newer fields are somewhat larger and the decline rate is significantly less than for the rest of the UKCS. There is some gas price sensitivity with absolute gas production from the Scottish sector in the last two years of the study period being significantly less under the lower price compared to the higher price case. Gas production in the Scottish sector falls from 4.6 billion cubic feet per day (bcf/d) in 2006 to 3.1 bcf/d in 2013 in the medium price case, to 2.6 bcf/d in the lower price case, and to 3.2 bcf/d in the higher price case.

c) Scottish Share of Total Hydrocarbon Production

Chart 4



The historic and prospective Scottish share of total hydrocarbon production is shown in Chart 4. It should be noted that this includes natural gas liquids which were not included in either the oil or gas figures discussed above. While relatively modest they are mostly located in the Scottish sector. The Scottish share is seen to increase from under 75% in 2001 to over 78% in 2006. In the future periods covered by the study the Scottish share continues to increase to 85% in 2013. It should be emphasised that these shares relate to ever declining absolute production. Thus in the early years of the present century total production for the UKCS comfortably exceeded 4 million barrels of oil equivalent per day (mmboe/d). In 2013 UKCS production is less than 2 mmboe/d on the lower price scenario and a little over 2 mmboe/d with the higher price scenario employed. In the Scottish sector production was 2.37 mmboe/d in 2006 and falls to 1.8 mmboe/d in 2013 under the medium price. Under the lower price it falls to 1.6 mmboe/d in 2013, and under the higher price declines to 1.87 mmboe/d in 2013.

d) Scottish Share of Development Expenditures

As noted above tax revenues from the UKCS depend on several factors including the appropriate deductions from gross income. The most important elements of those relate to the allowances for field development and operating costs and these are presented here[6]. The modelling produced results in both money-of-the-day (MOD) and real terms (2007 prices). The latter have generally been shown as being more meaningful. In Charts 5, 6, and 7 the (real) development expenditures in the Scottish and non-Scottish sectors plus the Scottish share are shown for the study period. There are considerable fluctuations in the absolute amounts spent which depend on the timing of new field developments, but the Scottish share remains consistently high with a low value of 76% and prospective values exceeding 90% in future years. The share

[6] Other deductible costs and allowances relating to decommissioning, overheads, non-field specific R and D, and loan interest are not shown.

reflects both the numbers of prospective developments and their likely costs. It is noteworthy that in the non-Scottish sectors (Southern North Sea and Irish Sea) the absolute costs are generally much lower than in the Scottish sector.

Chart 5

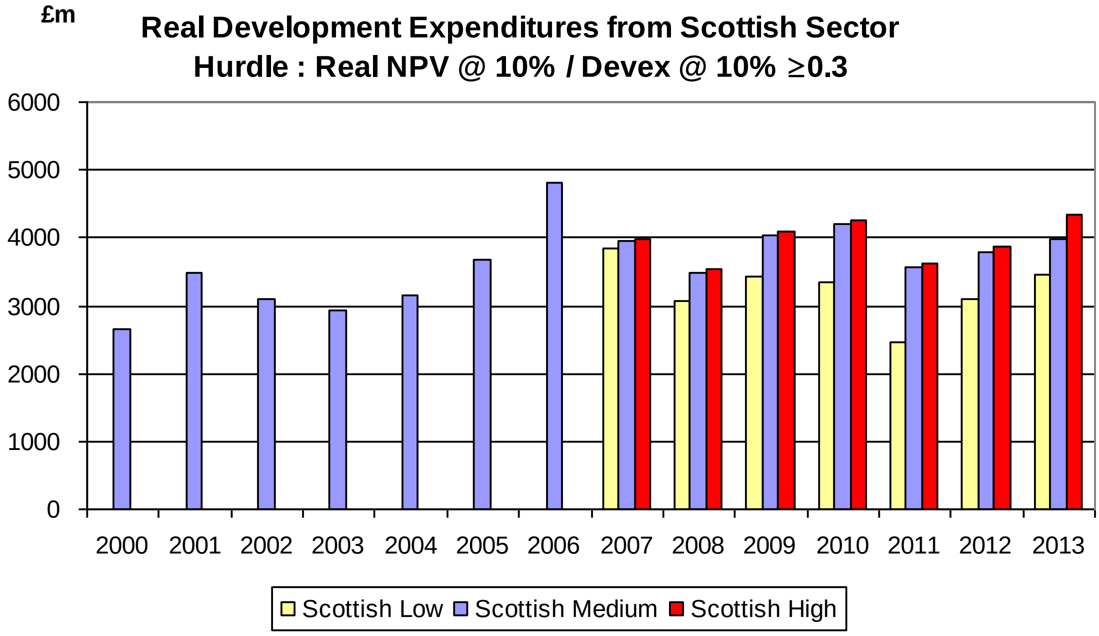


Chart 6

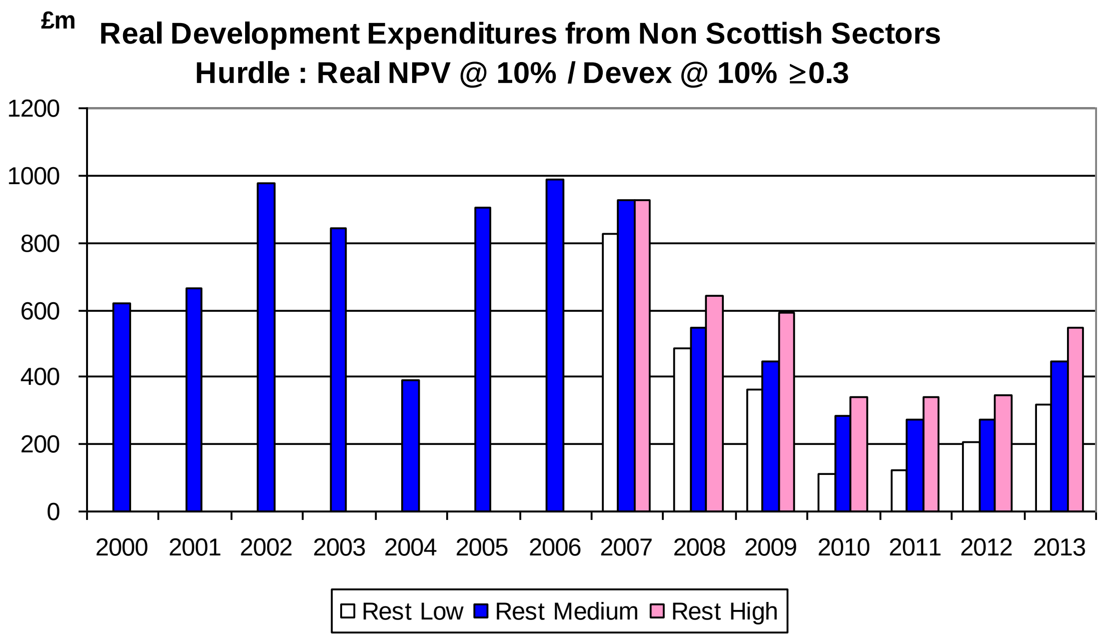
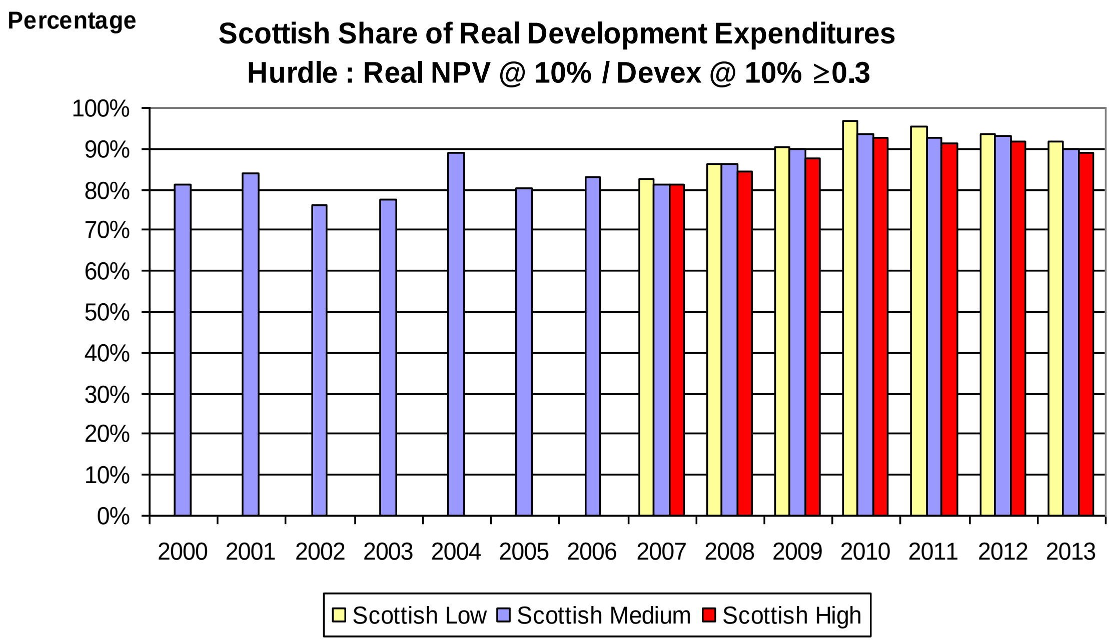


Chart 7



e) Scottish Share of Operating Costs

In Charts 8, 9, and 10 the results of the modelling with respect to operating costs are shown, again in real 2007 prices. In the Scottish sector the absolute amounts spent are seen to fall continuously from a peak in 2007 at a significant rate to the end of the study period, with the fall being greater under the lower price case. This reflects fewer new developments and the earlier decommissioning of old fields. In the non-Scottish sector the decline rate in future years is much steeper, such that by 2013 field operating expenditures are little more than half their (real) value in 2007. In the Scottish sector it falls by around 22% in real terms from its 2007 value. The net result is that the Scottish share of total operating expenditures from 2006 onwards is always greater than 80% and reaches 87% in 2013.

Chart 8

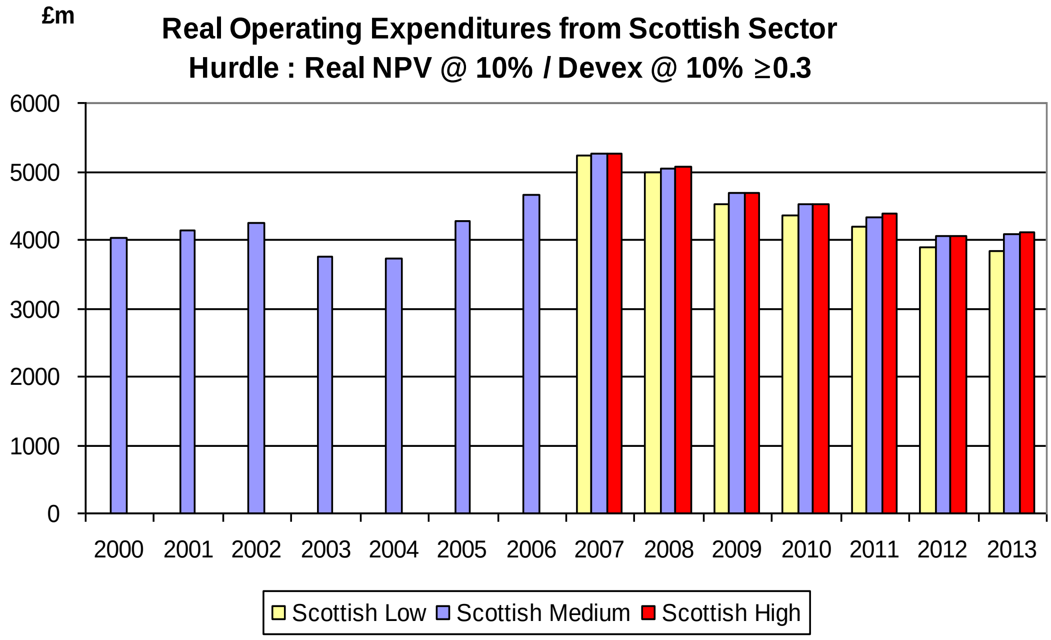


Chart 9

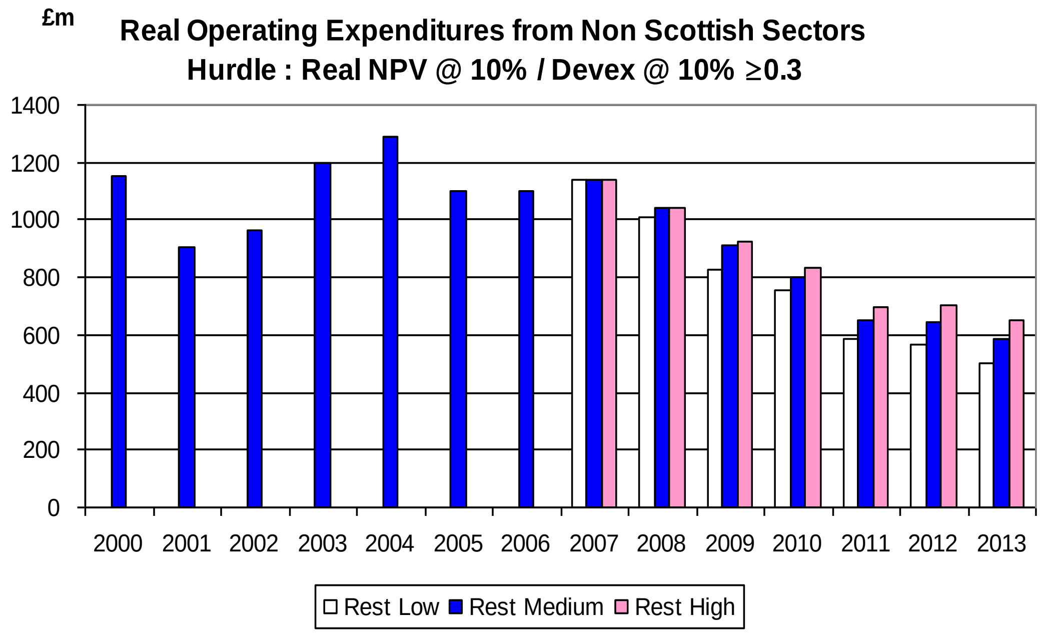
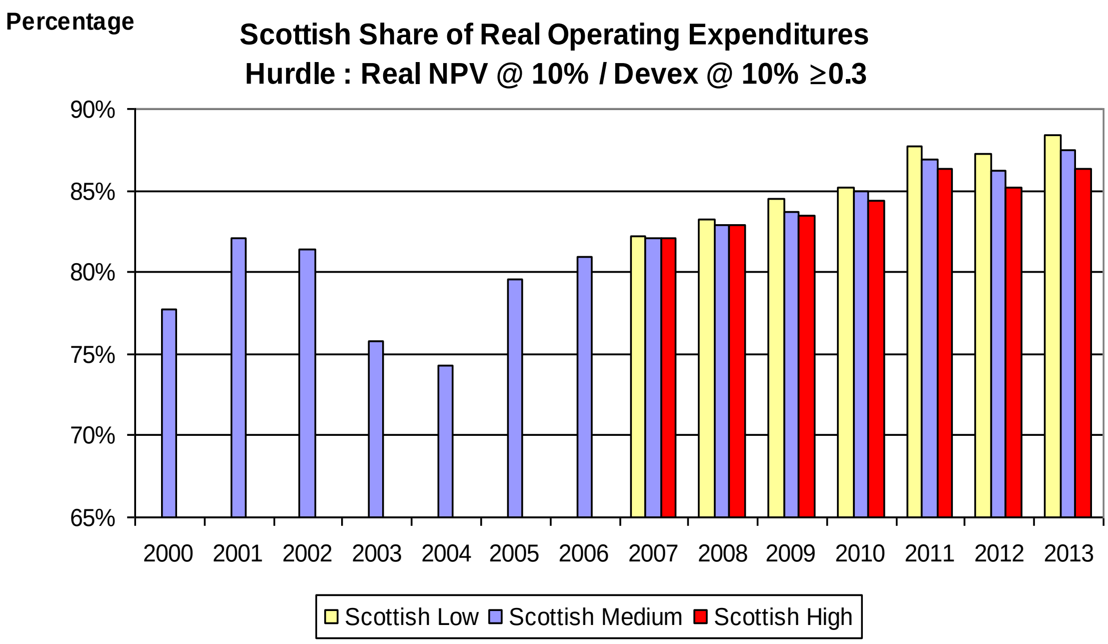


Chart 10



f) <u>Scottish Share of Gross Production Revenues</u>

The economic modelling calculates total gross revenues and gross production revenues from the UKCS. The difference between the two relates to income from third party tariffing received for the provision of transportation and processing services. While this income is now substantial, reflecting the large volume of third party tariffing in the UKCS, it was decided to display the gross production revenues as being of more interest. It should be noted that with respect to gas production revenues, gas prices are related to contracts, and for contracts concluded historically there has been a wide variety of prices and indexation factors. These have been employed in the modelling.

In Charts 11 and 12 the production revenues (in real 2007 prices) are shown for the Scottish and non-Scottish sectors, and in Chart 13 the (percentage) Scottish share of the total is shown. It is seen that revenues from the Scottish sector have increased over the past few years reflecting the large increase in oil prices which has more than compensated for the decrease in physical production. For the future years of the study period it is seen that production revenues decrease steadily. It is also noteworthy that there is a substantial oil/gas price sensitivity to these prospective revenues. A noteworthy feature of the non-Scottish revenues is their significant fall in 2007 from these attained in 2005 and 2006. The increase in oil prices has not been sufficient to offset the production decline. In this context it should be stressed that a very high share of the total production in the non-Scottish sector emanates from gas, and recently gas prices have not been nearly as buoyant as oil prices. In the non-Scottish sectors over the future part of the study period there is again a substantial price sensitivity to the results. The Scottish share of total production revenues is seen to be consistently over 80% in the study period. In 2007 it increased to around 88% as a result of the Buzzard (and other) fields coming on stream plus the continued increase in oil prices. Over the next few years depending on the price assumption employed the Scottish share could be in the 87% - 90% range.

Chart 11

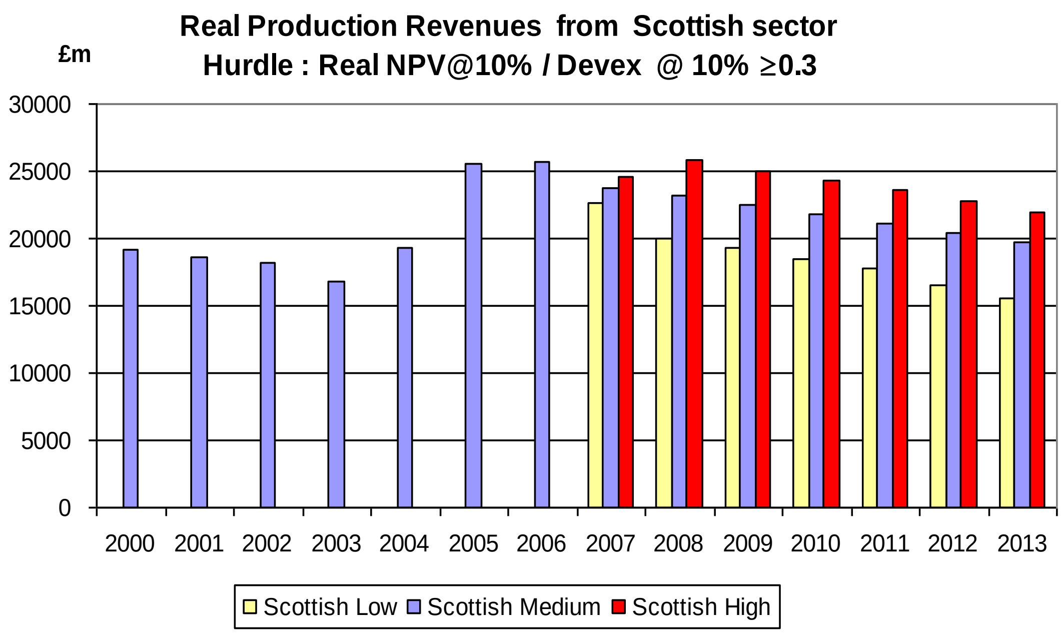


Chart 12

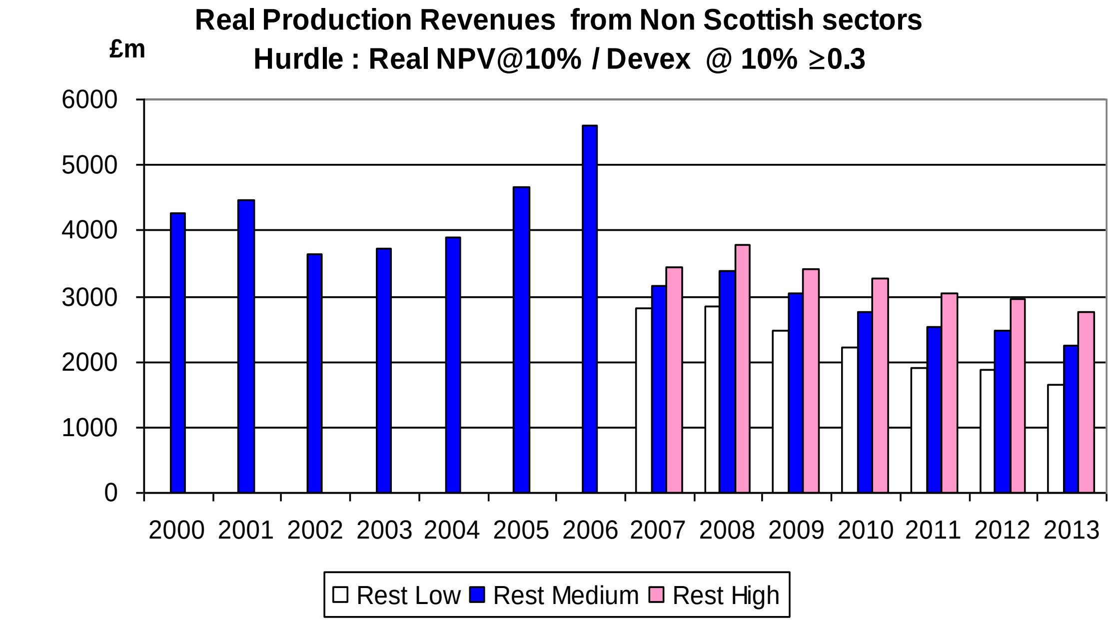
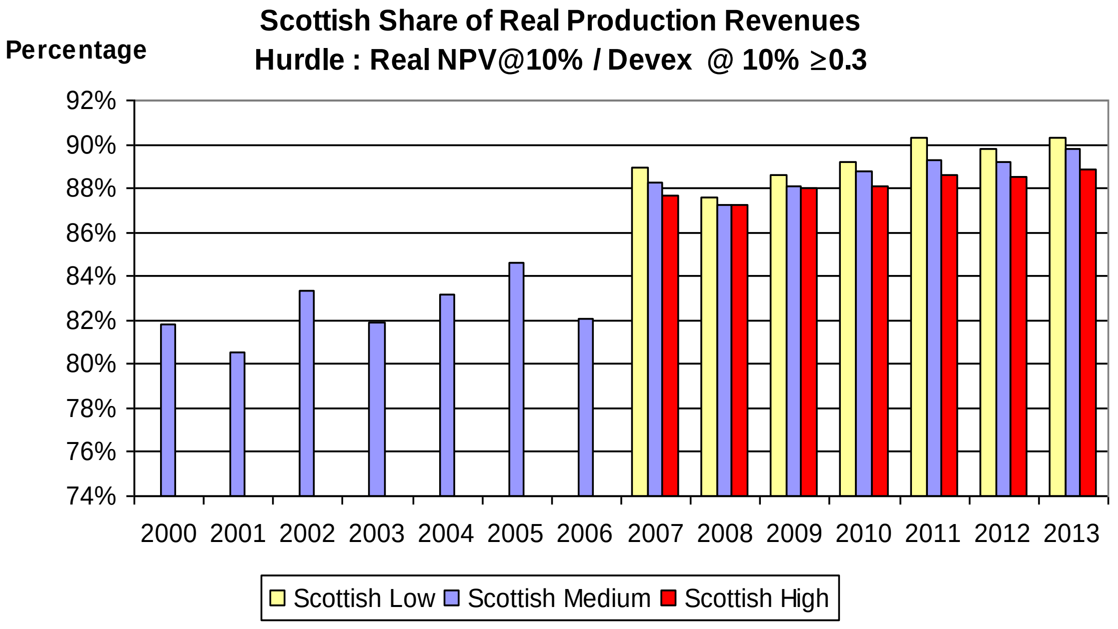


Chart 13



g) Scottish Share of Total Real Tax and Royalty Revenues

The tax revenues relating to the Scottish and non-Scottish sectors are now displayed. They are initially shown at real 2007 values. In Charts 14 and 15 the total tax (including royalty) receipts from the Scottish and non-Scottish sectors are shown. Those from the Scottish sector are seen to have increased very substantially from 2005 onwards reflecting in large measure that major increase in oil prices. In 2006 they reached £8 billion. For the future part of the study period there is a downward trend, but the receipts remain very substantial. Under the medium price employed in real terms they are £7.2 billion in 2008 and £5.6 billion in 2013. There is a major price sensitivity to the yield such that in 2008 under the lower price they are £5.7 billion, and £4.1 billion in 2013. Under the higher price case they are £8.6 billion in 2008 and £6.6 billion in 2013. From Chart 15 it is seen that the tax revenues from the non-Scottish sectors are much less buoyant for the current and future years of the study period. They decline sharply from their 2006 values and in the period to 2013 they are generally in the £500 million - £900 million range (real terms).

It follows from the above that the percentage share attributable to the Scottish sector is now very high. It had already been increasing in the early years of the century with oil production and revenues keeping up more strongly than in the non-Scottish sectors. Thus in the period 2000 – 2006 the Scottish share was in the 83% - 87% range. From 2007 onwards the Scottish share increases further and for most of the period to 2013 is generally in the 88% - 91% range, with 2007 exhibiting an unusually high share due to the revenues from the non-Scottish sectors being quite low.

Chart 14

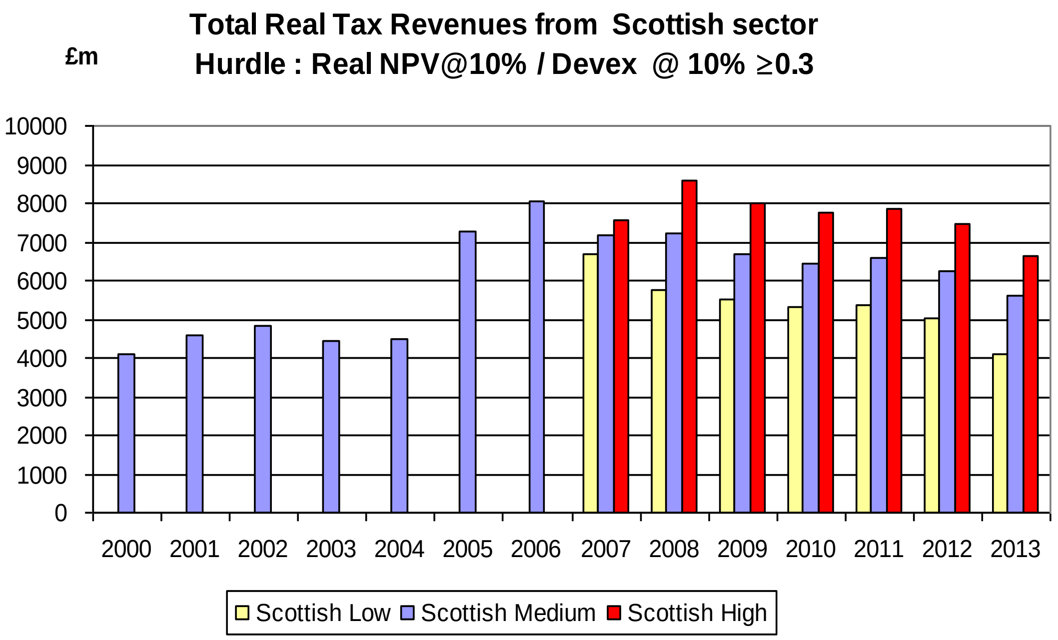


Chart 15

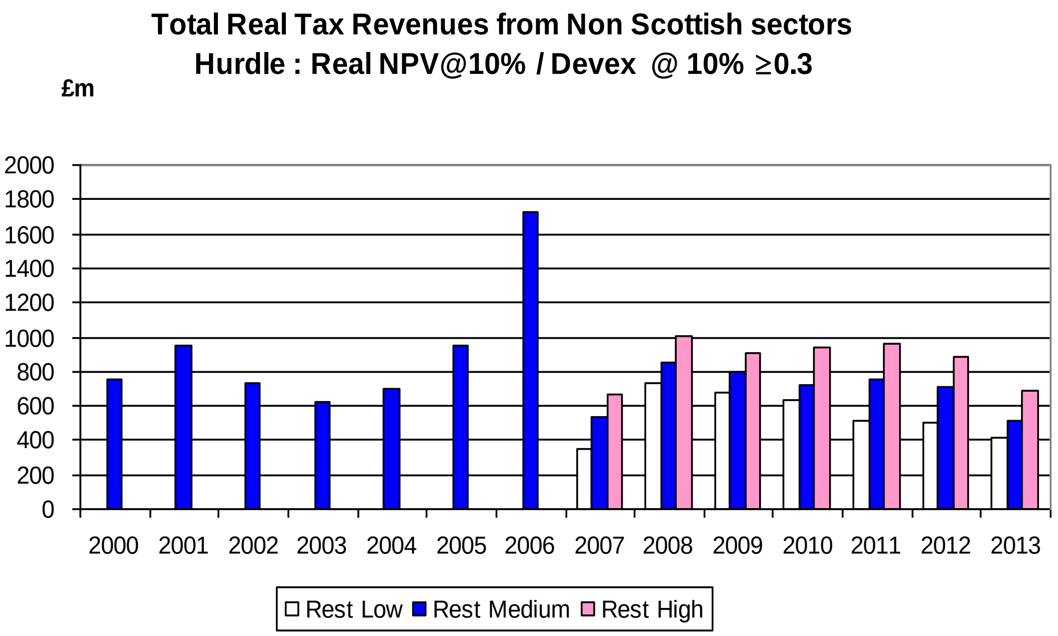
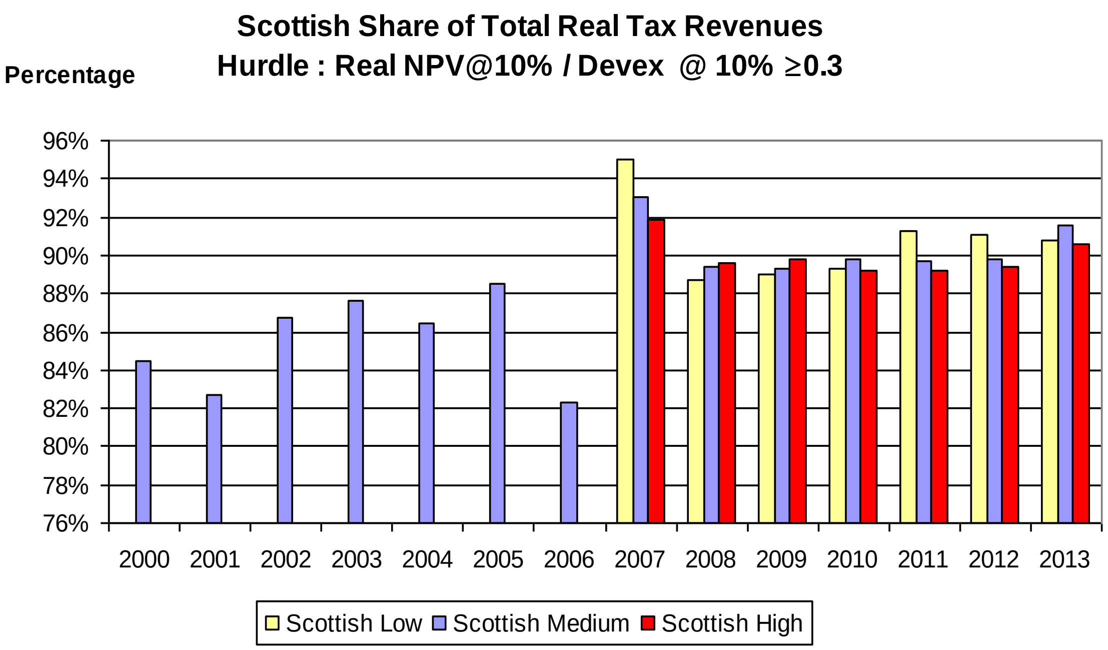


Chart 16



h) <u>Scottish Share of Real PRT Revenues</u>

In Charts 17 and 18 the total real PRT revenues are shown for the Scottish and non-Scottish sectors respectively, and in Chart 19 the percentage Scottish share is shown. Apart from the very odd year of 2006 the Scottish share in the historic period has generally been in the 93% - 95% range. For the future years of the study period it is in the 92% - 94% range. As indicated above the modelling assumes that PRT continues over the period in its present form.

Chart 17

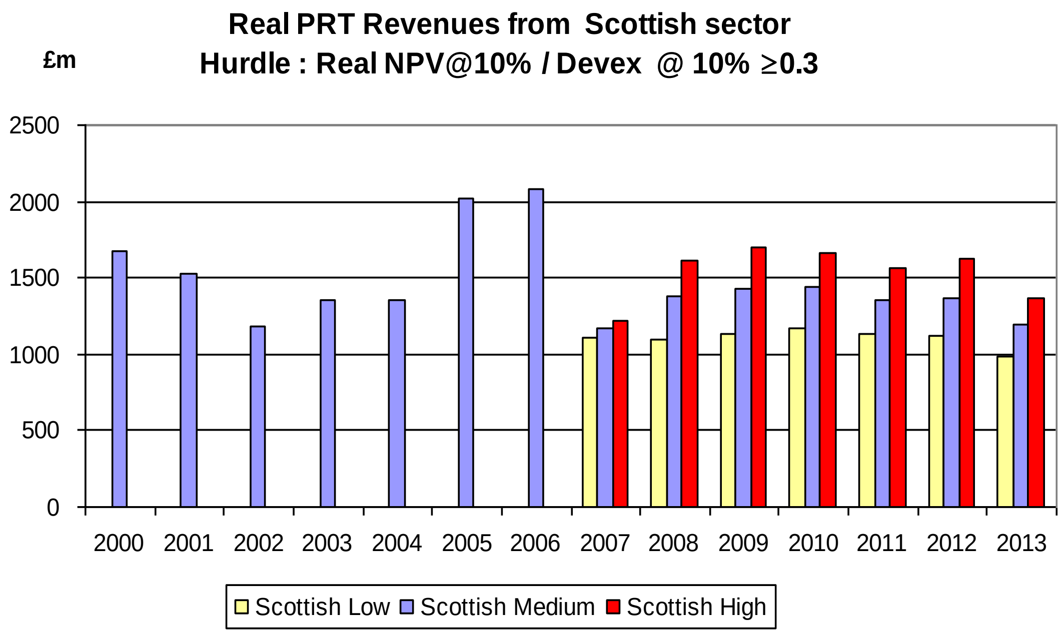


Chart 18

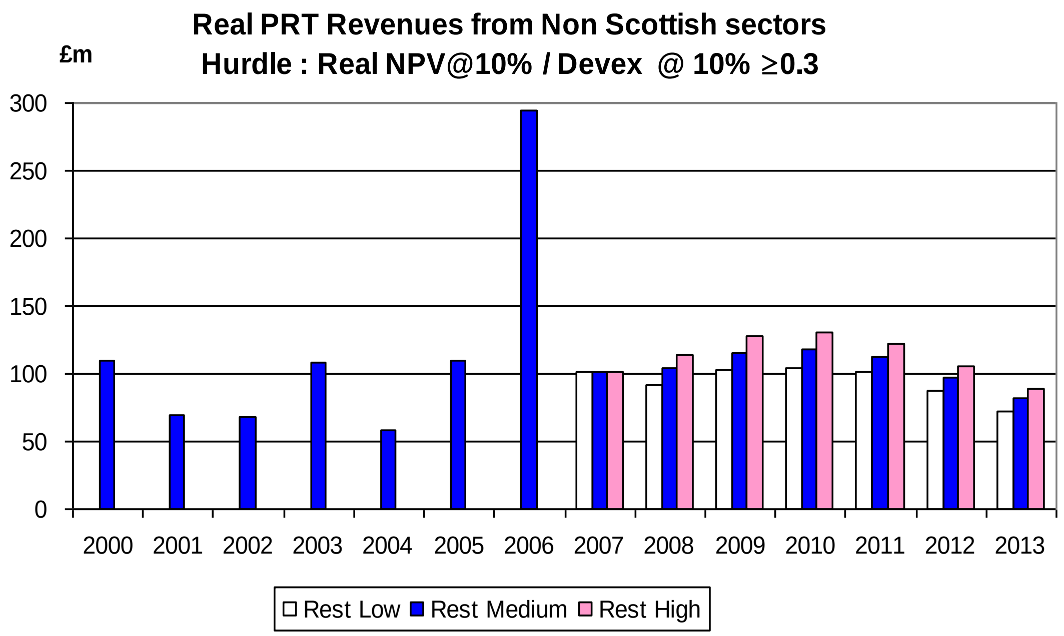
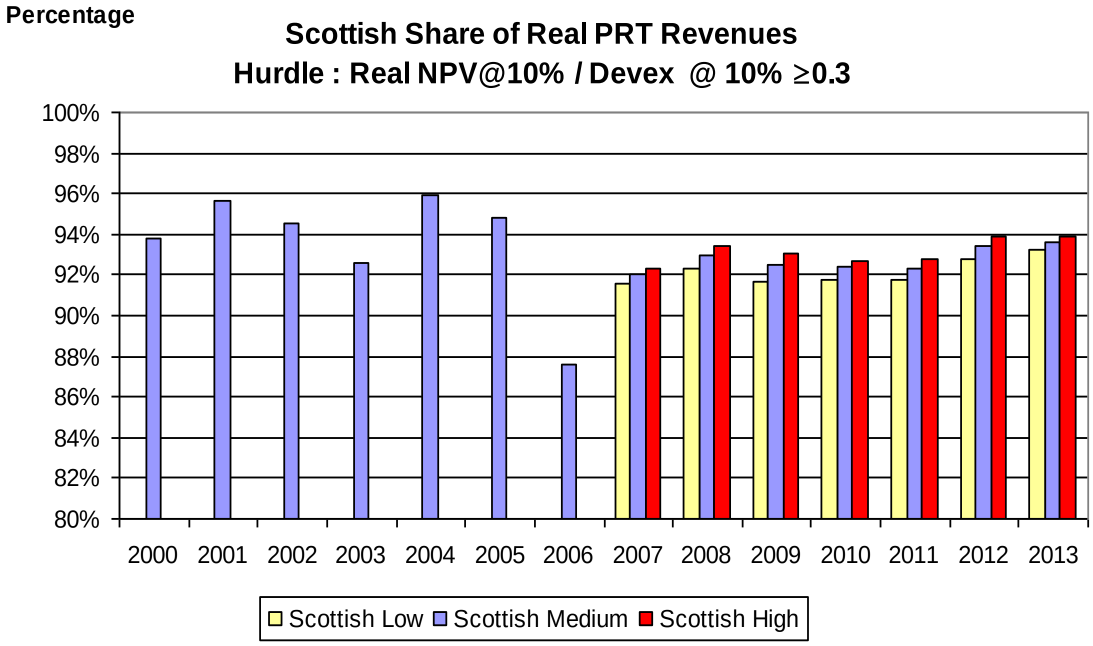


Chart 19



i) <u>Scottish Share of Real CT + SC Revenues</u>

In Charts 20 and 21 real CT + SC revenues attributable to the Scottish and non-Scottish sectors are shown. Those relating to the Scottish sector increase dramatically from 2005 reflecting the increase in oil prices. For future years there is a downward trend with very noticeable oil/gas price sensitivity. For most of the period the revenues are generally in the £4 billion - £6 billion range. Apart from the year 2006 revenues from the non-Scottish sectors do not display the same buoyancy, reflecting the more subdued gas prices and faster decline in physical production. It follows (Chart 22) that the Scottish percentage share is very high. In the period 2000 – 2006 it was generally in the 77% - 86% range, while, for future years, it is generally around 90%.

Chart 20

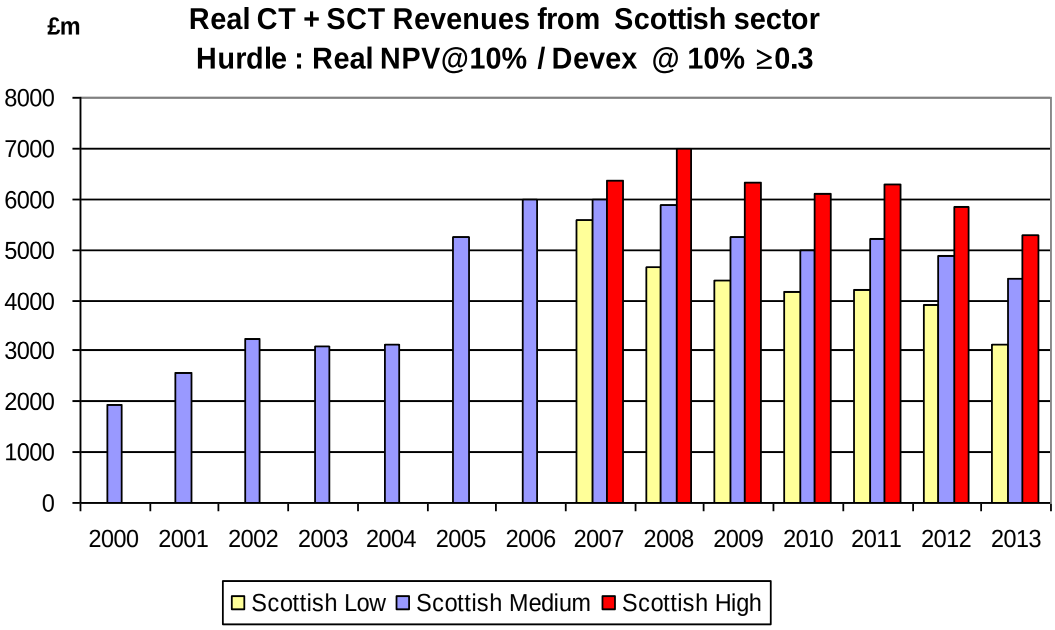


Chart 21

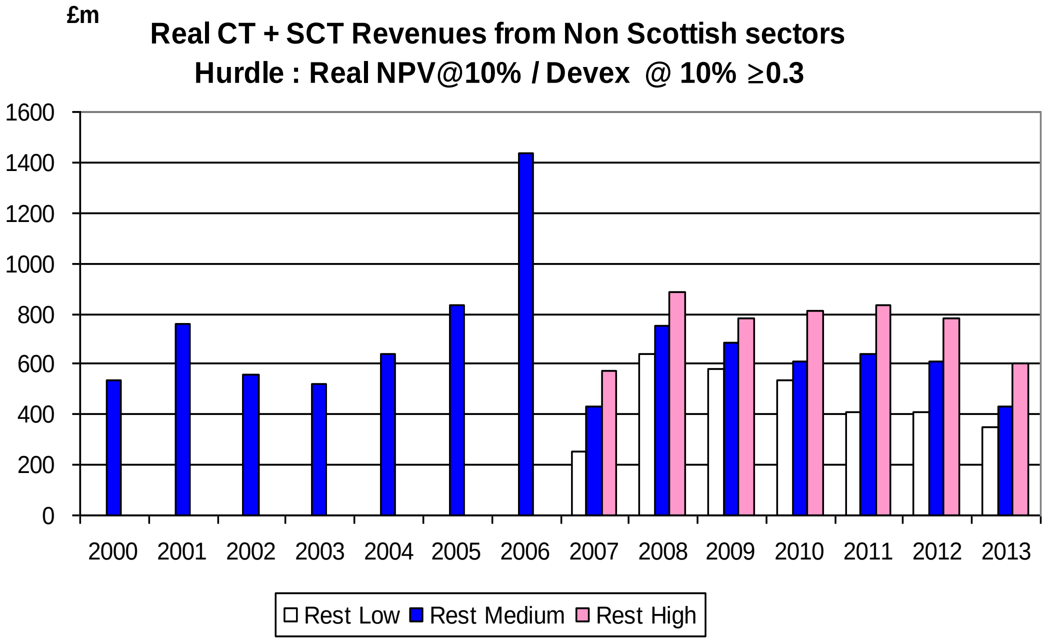
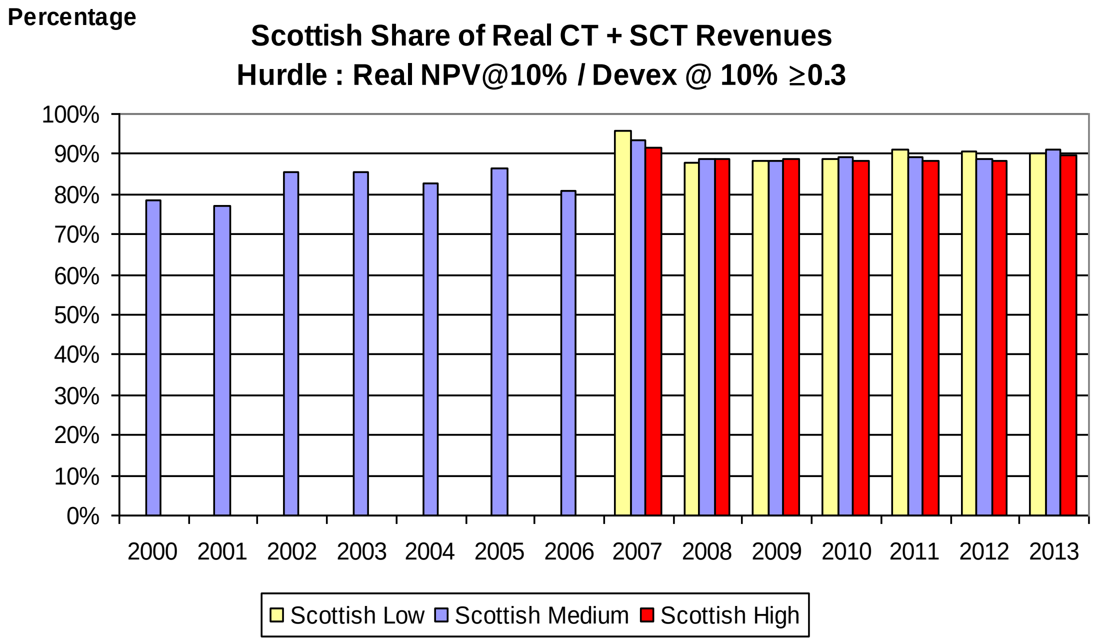


Chart 22



j) <u>Scottish Share of Total Tax and Royalty Revenues (MOD terms)</u>

For completeness the results for the tax takes are also displayed in MOD terms. For future time periods an inflation rate of 3.5% has been employed for oil prices, exploitation costs, and the general value of money. In Charts 23, 24, and 25 the results for total tax and royalty revenues are shown. The pattern is consistent with the results in real terms, with the Scottish share in the 82% - 87% range for historic periods and around 90% for future periods.

Chart 23

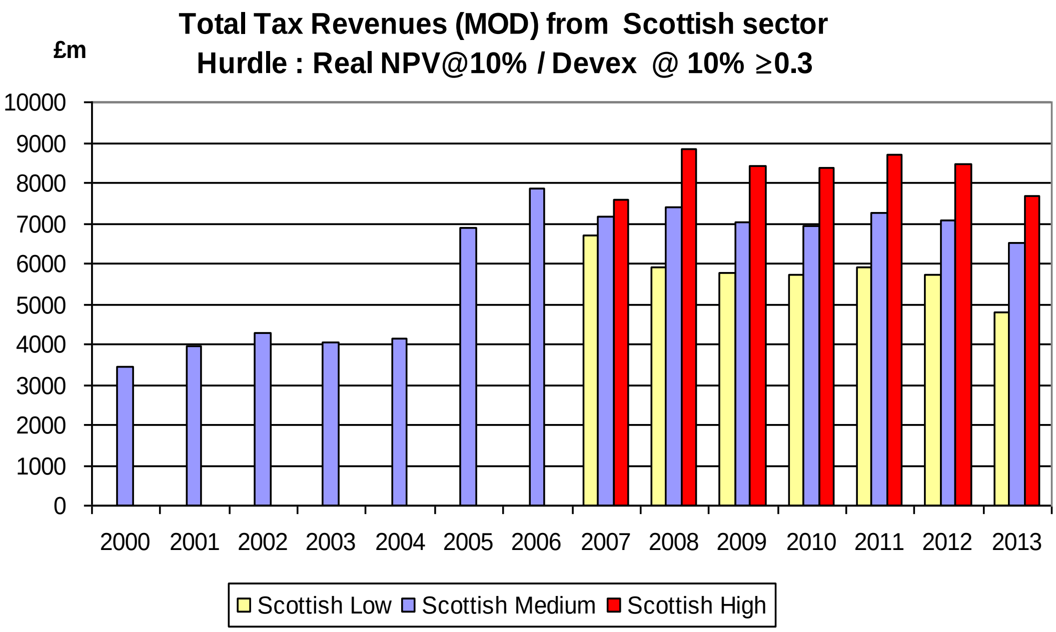


Chart 24

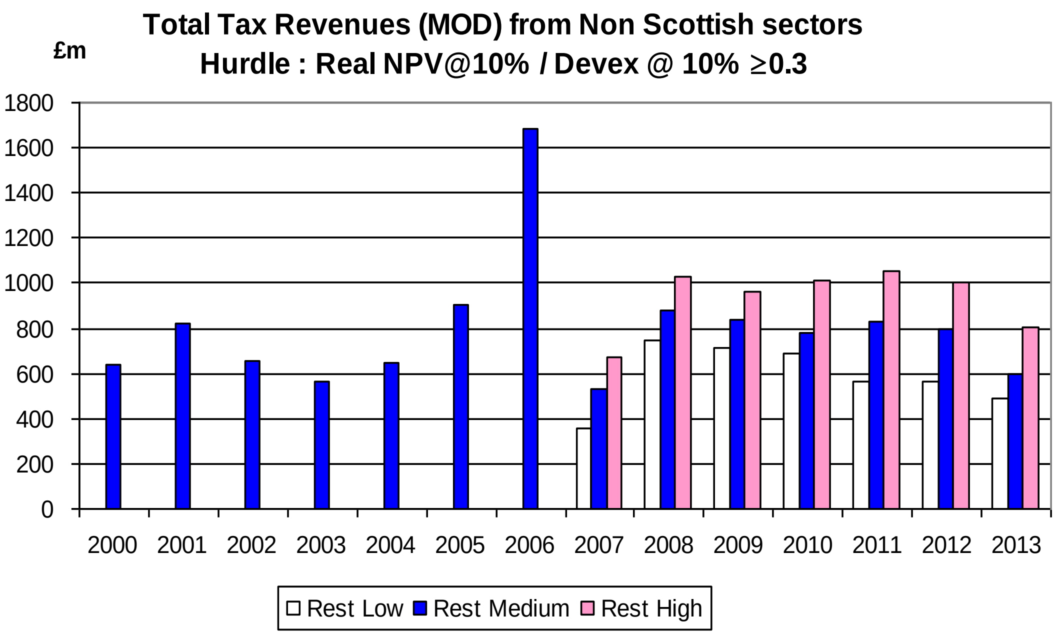
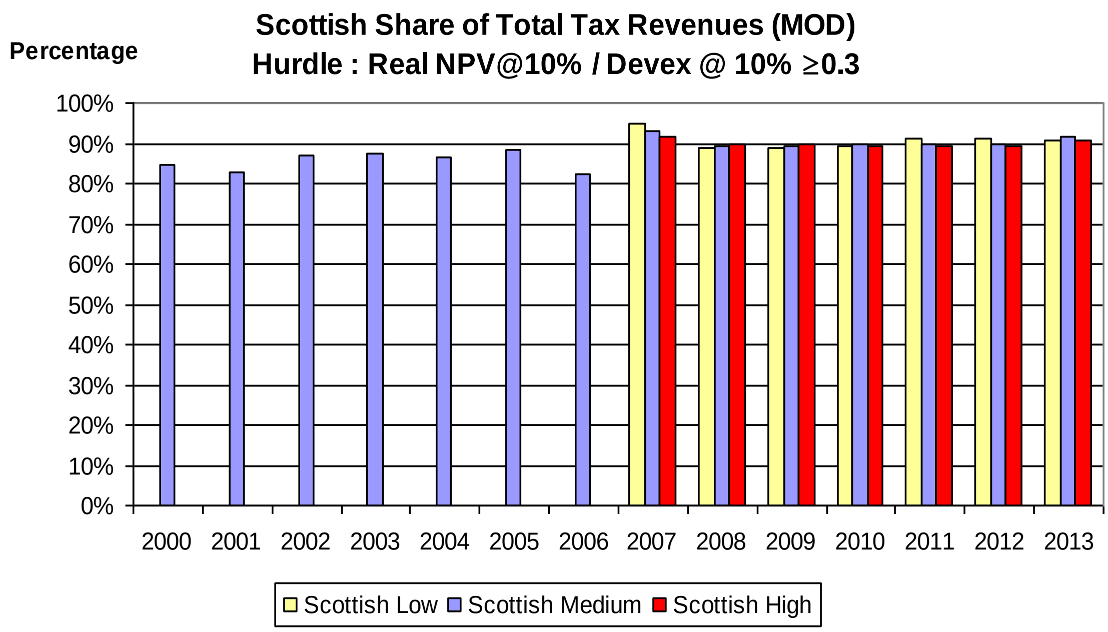


Chart 25



k) <u>Scottish Share of PRT Revenues in MOD Terms</u>

The results for PRT in MOD terms are shown in Charts 26, 27, and 28. For the future years of the study period under any one price scenario the absolute size of the future Scottish sector revenues does not change dramatically in MOD terms, but the oil/gas price sensitivity remains pronounced. The percentage Scottish share for future time periods is in the 92% - 94% range.

Chart 26

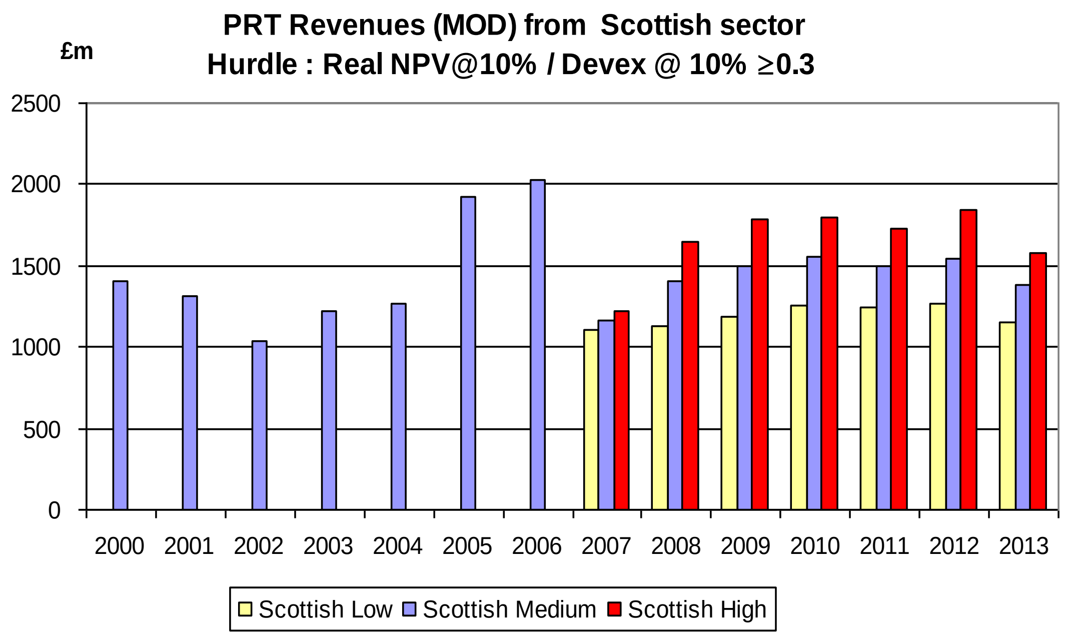


Chart 27

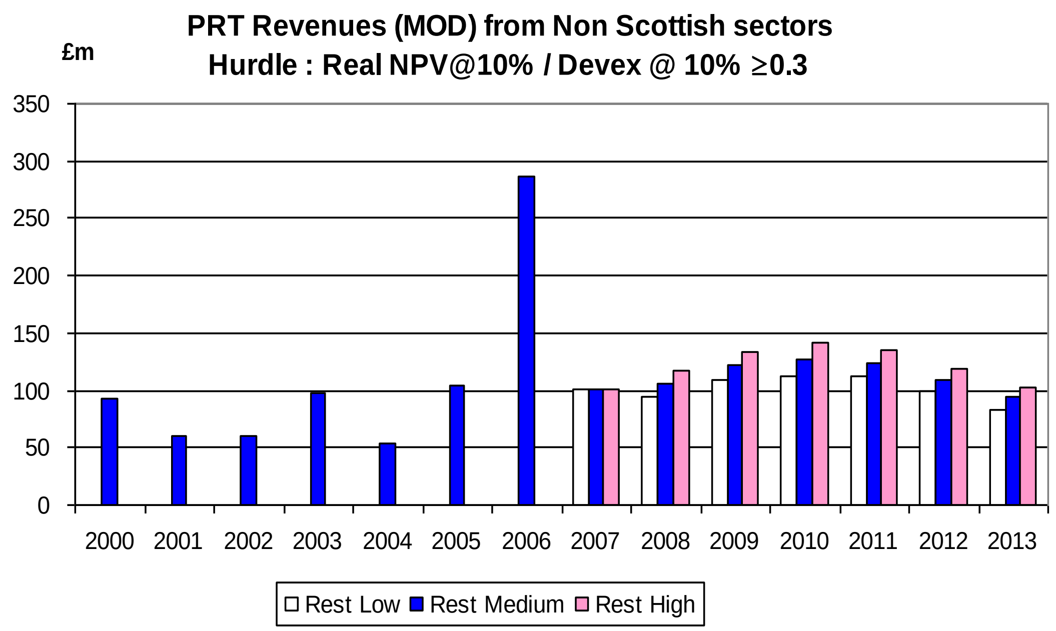
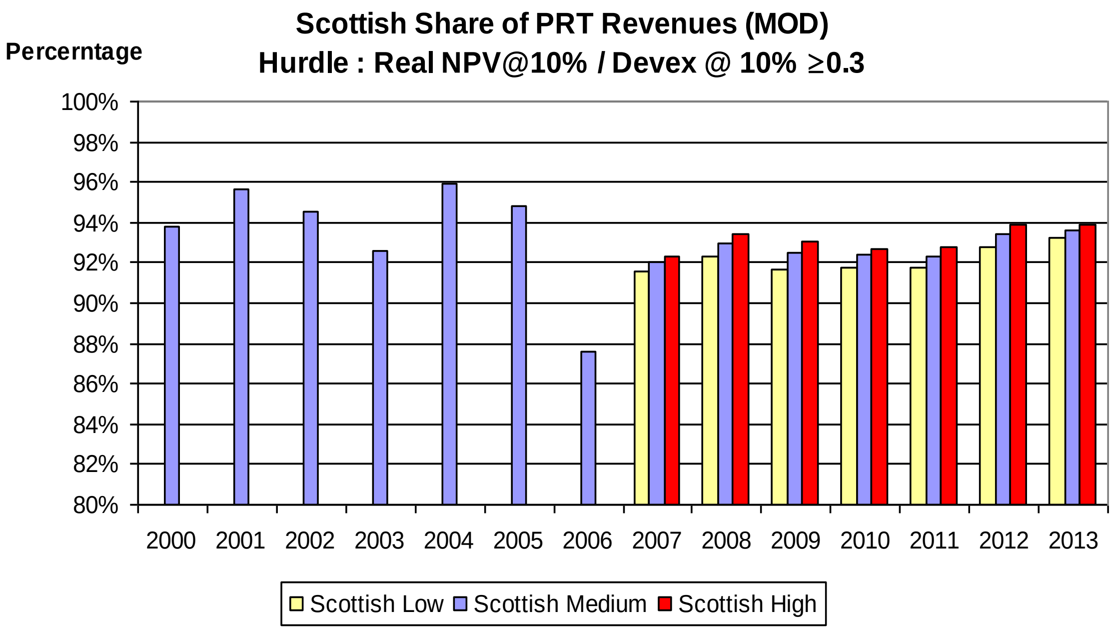


Chart 28



l) <u>Scottish Share of CT + SC Revenues in MOD Terms</u>

In Charts 29, 30, and 31 the corresponding results for CT + SC are shown. In the Scottish sector for future years in MOD terms a modest decline is exhibited with the price sensitivity of the yield again being very pronounced. The percentage share for the future years of the study is around 95%, somewhat in excess of that in the historic period.

Chart 29

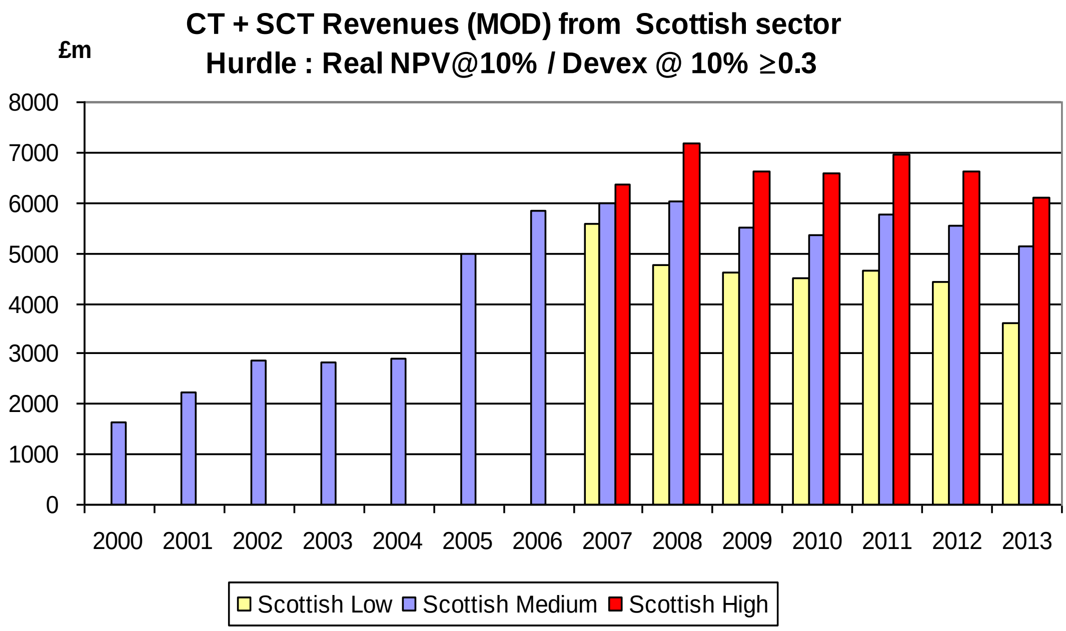


Chart 30

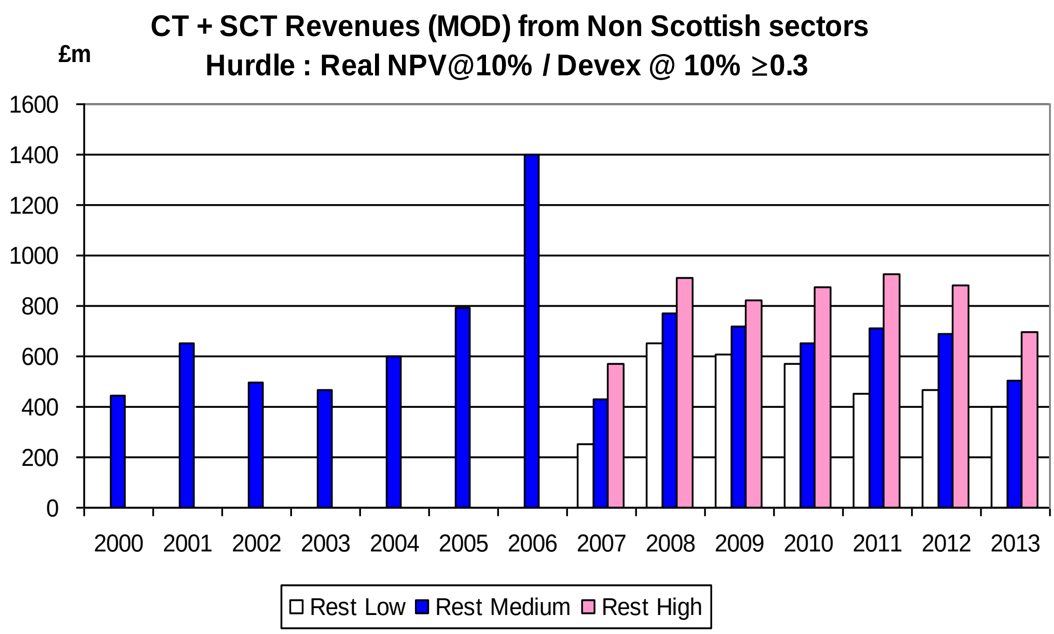
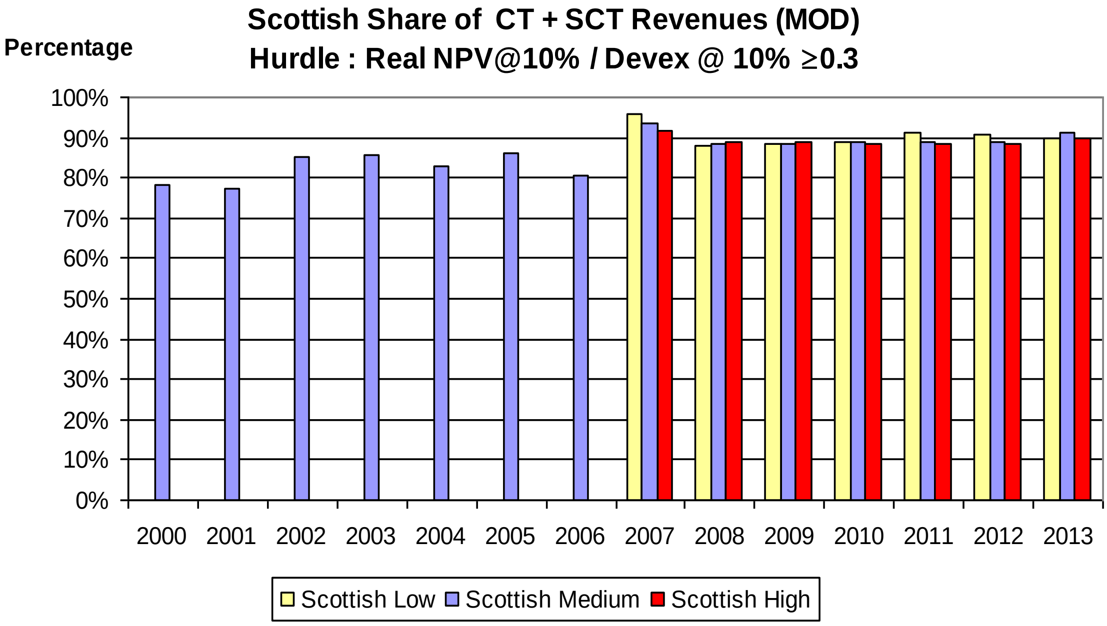


Chart 31



4. Summary and Conclusions

In this paper the hypothetical Scottish shares of activities in the UKCS relating to gross production revenues and tax revenues have been calculated for the period 2000 – 2013. Other outputs reported are the Scottish shares of production, field development expenditures and field operating expenditures. as these have a major influence on the tax revenues. The work was conducted with the aid of a large financial simulation model which incorporates the full historic UK petroleum taxation system. A large database relating primarily to the fields in the categories of (a) sanctioned, (b) probable future, (c) possible future, (d) technical reserves, and (e) future discoveries, plus (f) current incremental projects, and (g) future incremental projects was employed to facilitate the work. The data for fields in all categories except those in (d), (e) and (g) were obtained from the oil industry. Future discoveries were modelled with the aid of the

Monte Carlo technique incorporating assumptions based on trends in success rates and discoveries made over the past decade. The Monte Carlo technique was employed to calculate the reserves and costs of new discoveries. The same technique was employed to calculate the costs of the fields in the category of technical reserves. New field developments were triggered in the modelling with an investment hurdle of post-tax real NPV @ 10%/pre-tax real investment @ 10% ≥ 0.3 in real terms. A set of oil/gas prices was employed which at the time of the modelling (October/November 2007) were representative of market expectations. The modelling incorporated E and A expenditures, R and D costs, allowable overheads, and loan interest as well as the strictly field data in the calculation of taxable income.

The hypothetical Scottish share required the determination of a boundary between Scotland and the rest of the UK. In the present study the median line in the North Sea as applied for fisheries purposes was employed.

The results of the modelling were that the Scottish share of gross production revenues was in the range 80% - 84% in the period 2000 – 2006. Since then the share has increased to 87% - 88% and in the period to 2013 the share could be in the range 87% - 90%. This reflects the relatively high oil prices assumed and the increasing share of hydrocarbon production accounted for by production from the Scottish sector. Hydrocarbon production will continue the fall in the period to 2013 (and beyond) and gross revenues are likely to follow this downward trend.

The Scottish share of tax revenues was found to be in the range 82% - 87% in the period 2000 – 2007. From 2007 onwards the share becomes higher, generally being in the 88% - 90% range. The higher oil prices and the increasing share of production attributable to the Scottish sector account for the high share. In real 2007 terms the absolute tax revenues attributable to the Scottish sector have increased from an annual average of just over £4 billion in the period 2000 – 2004 to significantly higher values with around £8 billion in 2006. For future years to 2013 under the oil/gas price assumptions employed there is a downward trend in real terms. Under the high price case the tax revenues fall from around £8.6 billion in 2008 to £6.6 billion in 2013. Under the medium price they fall from £7.2 billion in 2008 to £5.6 billion in 2013. Under the lower price they fall from £5.7 billion in 2008 to £4.1 billion in 2013. All the above are in real 2007 prices. In MOD terms the revenues are nearly maintained at recent levels in the period to 2013.

It should be stressed that the projections of tax revenues are subject to much uncertainty. Thus oil prices have been very volatile and this should remain the case over the next few years. Further, there has been dramatic cost escalation in all activities in the UKCS, and a continuation of this will adversely affect taxable income. Production has also fallen at a considerably faster pace than forecast only a few years ago and predicting future production is also subject to much uncertainty. There are thus substantial downside risks to the projections made as well as some upside potential from still higher oil prices. The former risks are probably the stronger ones.

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Appendix

The North Sea Oil and Gas Taxation System

The North Sea oil and gas tax system has evolved since the Oil Taxation Act 1975 which established the basic framework of 3 instruments, namely (1) royalty (2) Petroleum Revenue Tax (PRT), and (3) corporation tax (CT). There have been many changes over the years including the introduction and subsequent abolition of a fourth tax (Supplementary Petroleum Duty 1981 and 1982). The position as it affects activities from 2000 onwards is summarised as follows:

1. **Royalty**: For licences issued under the first 4 licence rounds royalty at 12.5% has been levied on the wellhead value of the oil and gas. This means that, compared to the landed or tax value, initial transport and treatment costs are allowed as deductions. For this purpose it is noteworthy that around 70% of platform costs are eligible for relief phased over an 8-year time period. For licences issued from the Fifth Round onwards the royalty is levied on the landed or tax value. Royalty paid is deductible for PRT and corporation tax. From 1st April 1982 royalty was abolished for all new fields receiving development approval from that date onwards. From 1st January, 2003 all royalties were abolished.

2. **PRT**: PRT was introduced in 1975. It applied to all fields in the UKCS except those which had signed a sales contract with British Gas prior to 1st July 1975. At the year 2000 the rate of PRT was 50%. It is applied on a field by field basis to profits defined in a very particular way. The key deductions for investment are allowed on 100% first year basis, with an

uplift of 35% of the field development costs up to field payback also being available. Loan interest is not deductible. A further relief is the volume allowance. For fields outside the Southern North Sea this is the value of 10 million tonnes per field with no more than 1 million tonnes being eligible in any one year. In the Southern North Sea the volume allowance is 2.5 million tonnes per field with no more than 250,000 tonnes being eligible in any one year. There is also a safeguard benefit which states that, if in any one year adjusted profits (essentially gross revenues minus operating costs) are less than 30% of accumulated field investment PRT = 0. Further, in the total time period = 1.5 times the payback period, the maximum PRT payable in a year is 80% of the excess of adjusted profits above 30% of field investment. Tariff receipts by asset owners were made subject to PRT from 1st July 1982. There is a tariff receipts allowances (TRA) of 250,000 tonnes per chargeable (six month) period for each user field. From 1st July 2004 tariff receipts relating to new contracts are exempt from PRT. Decommissioning costs are eligible for relief, with the mechanism being that the related allowances are clawed back against PRT paid on the field, and repayments are made (with interest). PRT paid is deductible for corporation tax purposes. From 16th March 1993 PRT was abolished on new fields.

3. **Corporation Tax**: In the period since 2000 corporation tax (CT) has been payable at the normal rate applicable to companies except that, very recently, when the normal rate was reduced from 30% to 28%, the rate applicable to North Sea production remained at 30%. Exploration and appraisal costs are deductible on 100% first year basis. Field development costs were deductible on 25% declining balance basis until 17th April 2002 when 100% first year relief was introduced for these costs. At this

same time a Supplementary Charge (SC) of 10% was introduced to corporation tax making the overall CT + SC rate = 40%. Loan interest is not deductible against the SC. From January 2006 the SC rate was increased to 20%, making the CT + SC = 50%. Royalties and PRT paid are deductions for CT and SC. For new investors who do not have sufficient income to cover their allowances for exploration, appraisal, and development expenditures there is a provision whereby these allowances can be carried forward at 6% compound interest for a maximum period of 6 years. There is a ring fence around oil and gas production activities preventing the setting off of losses from outside the ring fence against ring fence income. For accounting periods after 30th June 2005 the required timing of the payments of CT + SC has been advanced under a three instalment payment system which, after a transitional period, became fully effective for accounting periods ending after 30th June 2006.

Currently the overall top marginal rate on fields subject to PRT in 75% (0.5 + 0.5 (1 – 0.5)) and for fields not subject to PRT it is 50%.

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