National Hydrocarbon Accounting: a methodology for monitoring upstream sector governance

The case of UK North Sea Oil and Gas

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Summary

National hydrocarbon accounting (NHA) is a new methodology that provides a foundation for an informed debate over how well hydrocarbon resources are managed in the national interest, and as a basis for forecasting future revenue streams. It provides a framework to determine whether critical data about the sector operations is being collected, shared, and ultimately disclosed to the public.

NHA accounts for (a) physical oil and gas resources, (b) industry revenues and costs, and (c) economic rent and tax revenues. The items included in each area are listed in Figure 1.

National Hydrocarbon Accounts		
Physical oil and gas resources	**Industry revenues and costs**	**Economic rent and taxation**
Reserves and resources • Developed • Undeveloped • Undiscovered Oil and gas production • Volumes produced and sold	• Oil and gas sales price • Oil and gas revenue • Operating costs • Capital costs • Operating surplus • Capital employed • Pre-tax net income • Cash flow	• Government taxes and royalties • National oil company profit share • Private company pre- and post-tax profits • Return on capital employed

Figure 1: Overview of NHA metrics

NHA can be useful for government, industry and civil society. The approach serves as a foundation for monitoring and forecasting of four key aspects of the upstream oil and gas sector:

- Physical production, resource depletion and reserve replenishment
- Revenue generation, cost efficiency[1] and sustainability of upstream operations
- Pre-tax industry earnings, profitability and reinvestment rates
- Industry returns on capital and the overall government take projections for budgetary purposes.

The data required to establish NHA cover a range of information that may be more or less accessible, depending on the collecting agency, inter-agency sharing and policies around public disclosure.[2] NHA requires information on reserves and production reporting together with revenues from upstream oil and gas sales, industry capital and operating cost data:

- Reserves and production figures are collected by government, subject to the technical capability of the upstream regulator. These are typically published in the public domain.
- Revenue and cost data are required to calculate cost and profit oil and tax liabilities of individual petroleum license holders. The collation of these data maybe the responsibility of more than one agency. Consolidation and compilation of NHA will therefore require cross agency coordination. Public disclosure of sector wide cost and revenue data is less common, but is not commercially sensitive or confidential.

[1] Revenues, costs and profitability will require audit and benchmarking against comparable countries to judge efficiency.

[2] All information contained within a national hydrocarbon account should be publicly available, as in the UK example. The use of sector aggregates ensure no commercially sensitive or confidential data be relied upon.

The objectives for this note and the development of this methodology are two-fold:

- To facilitate interested stakeholders to construct national hydrocarbon accounts to monitor the management of the sector in their country
- To inform and guide the data collection, data sharing and data disclosure that is relevant and useful to stakeholders.

An application to the UK North Sea oil and gas: summary

In order to illustrate both the usefulness of this methodology and the data requirements for its construction this note proceeds with an application to the UK North Sea oil and gas. This example is instructive in three ways. The necessary data is already collected, shared and disclosed, thus allowing the NHA to be completed fully.[3] Furthermore the UK North Sea basin is a mature upstream sector-with over 40 years of data and many oil and gas fields nearing the end of their lifecycle. This therefore allows illustration of the range of key performance indicators and how they can be used through this lifecycle.

Both of these features constitute a *best-case scenario* for this kind of analysis, but serve to inform replication in developing countries. Here a partial, or contingent NHA may be necessary, either where an incomplete data set is available, or where the sector is still developing, with perhaps only a short production history. However, given the way the NHA is constructed, informative performance indicators can be assemble in both the context of incomplete data, or an earlier stage of sector development.

The performance of the UK upstream oil and gas sector from 1971-2012 provides a case study to illustrate the utility of the NHA approach. According to data published by the UK government, the UK produced a cumulative 42 billion barrels of oil equivalent[4] between 1971 and 2012 with production peaking at 4.5 million barrels of oil equivalent in 1999 before falling to 1.6 million barrels of oil equivalent in 2012. Using NHA, this study finds that:

- Between 1970 and 2012, the sector generated £684 billion[5] in revenues from oil and gas sales and, after costs of £322 billion, produced £184 billion in tax revenue and £178 billion in oil company after tax profits.
- The effective government take of pre-tax profit from the sector was 51 percent.
- The average post tax return on capital employed was 26 percent, but averaged only 10 percent in the 1986-96 period before recovering to an average 39 percent in the 2000-12 period.

[3] In the UK, the information required to compile for the NHA is published by the UK government on the Gov.uk website.
[4] 27.3 billion barrels of oil and 87 trillion cubic feet of gas (14.5 billion barrels of oil equivalent energy).
[5] In terms of current GBP

I. Introduction

Concerns over governance standards have prompted numerous initiatives to improve the reporting of government revenues from oil, gas and minerals.[6] The challenge of effectively governing extractive industries is particularly acute in countries with low income per capita and weak institutional capacity, many of which have only recently discovered new resources (e.g., Ghana, Kenya, Mozambique and Tanzania).

Many countries see the total volume of revenues from extractive industries as a benchmark for how well the sector is managed, as well as for seeing where the money goes. Yet a simple focus on aggregated revenue has limited utility in measuring how well a nation manages its oil and gas endowment; how effectively government captures rent, and how sustainable the resource base is; or for forecasting future revenues.

The purpose of this paper is to describe a series of measures that that together can provide a better account of how oil and gas resources are being managed for the benefit of the nation. This set of measures taken together can provide a context for discussion about sector performance and for making future projections.

The measures discussed cover the following:

- Sub-surface physical resources
- Production volumes
- Costs of production
- Gross revenues generated from oil and gas sales
- Government revenue from taxes, royalties and other levies
- Investor profits and returns on capital, including how much of those profits are reinvested in the country

The performance measures track (a) oil and gas resources, reserves and production in order to monitor the volume and sustainability of the resources, and (b) revenues, costs and tax take in order to monitor rent generation and rent sharing.

Since the discovery of oil in the North Sea in 1970, NHA for the UK have been used to illustrate the concepts, using statistics published by the UK government.[7] (See appendix.)

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[6] See for example the Extractive Industries Transparency Initiative (EITI) www.eiti.org established in 2002 and now being implemented by 41 countries. The IMF Guide on Resource Revenue Transparency (2007) also constitutes an important set of principles for countries to follow: http://www.imf.org/external/np/pp/2007/eng/051507g.pdf

[7] Note the UK has not had a state oil company since 1982 so the accounts effectively exclude any contribution from a domestic NOC. The presence of an NOC has a significant impact on rent sharing and therefore the calculations in this paper would need to be adjusted in countries with significant NOC participation.

II. The Volume and Sustainability of Resource Flows

In order to make sense of oil and gas revenues, one must account for the underlying physical resource volumes, production rates and their sustainability.

First, some important concepts:

The estimated ultimate recoverable resource (EUR) is an estimate of the amount of oil and gas that can be ultimately recovered from a geological basin. It is a figure that can only ever be an estimate and carries a high level of uncertainty particularly at the start of the exploration history of an area. The *discovered resource*[8] is the amount of oil and gas that has been discovered and can technically be recovered, and includes both *developed* and *undeveloped* deposits or fields. The *undiscovered, or prospective, resource* is the resource that is yet to be discovered and is therefore the most uncertain.

Reserves are discovered resources that have either been developed or are sanctioned for development and are considered to be commercially recoverable. Development projects are sanctioned when proven resources are believed to exceed a minimum threshold sufficient to support a commercial development.

Uncertainty in recoverable volumes is typically expressed as a probability distribution with *proven resources* having a 90 percent probability of being recovered (P90)[9], and proven and probable resources as having a 50 percent probability of being recovered (P50), and proven, probable and possible resources only having a 10 percent (P10) probability of being recovered.

Figure 2 illustrates the concepts through the history of oil resources in the UK from 1969-2012. Nineteen sixty-nine was the year of the first offshore oil discovery and the EUR of the UK offshore oil was at that time unknown. In 2012 the UK government estimated the EUR of the UK offshore oil as 37 billion barrels on a P90 basis. By 1979 approximately two thirds of the EUR had already been discovered but only 4 percent produced. Thirty years later 80 percent of the UK's EUR oil had been produced. Note that EUR estimates are revised regularly as geological understanding improves.

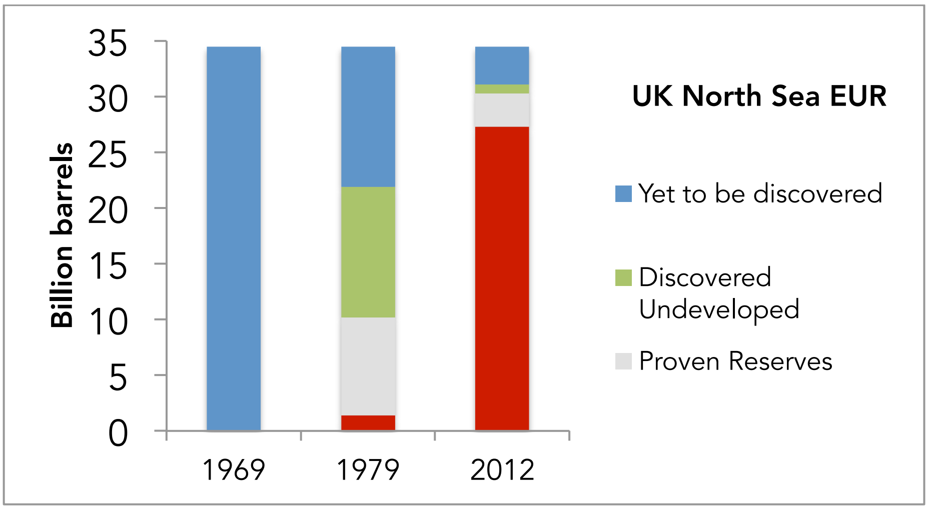

Figure 2: History of the UK's EUR in the North Sea, EUR based on UK government, Department of Energy and Climate Change (DECC) estimate for cumulative proven reserves, additional resources and low estimate for unfound EUR at end 2012.

[8] Discovered resources are the proportion of oil and gas volumes "in place" in known accumulations that can be recovered and produced economically.

[9] Proven, proven and probable and proven, probable and possible estimates are sometimes known as P1, P2 and P3

The UK experience is typical of the oil discovery process and the so-called "creaming curve," whereby the largest fields are found early in the exploration history of a geological basin. (See Figure 2.)

Before the discovery of the first commercial field, a geological basin or play is said to be *at the frontier stage* and the outcome of exploration is binary—i.e. exploration drilling could prove the basin to have no commercially recoverable resources or uncover a new play. Sometimes it takes many years and the application of new technology or ideas for frontier exploration to be successful. At the frontier stage all prospects carry a high level of risk. (Typical frontier exploration well success rates are no better than 1 in 10.)

If a frontier well results in a significant discovery, the risk on future exploration drilling drops dramatically. At the *emerging stage* of a new basin, the largest and best prospects are still to be drilled and the discovery sizes and success rates tend to be the highest. (Success rates in emerging plays are typically better than 1 in 2.)

Therefore the risk/reward equation changes dramatically in the eyes of both investor and government. Fiscal terms at the frontier stage must respond to any discovery-driven change in risk perspective in order to be perceived as "fair" to both sides. Fiscal terms that are responsive to changing circumstances are widely recommended.[10]

Companies will not risk significant capital investment in exploration without the right to develop any discovery. The fiscal terms applying to any discovery will be typically specified in the exploration license, production sharing agreement or applicable tax code. In order to attract exploration capital into frontier, high-risk, areas, the government may choose to offer lower production tax rates than competing countries. However, the design of the license regime must ensure that tax rates are appropriate to the exploration risk otherwise the risk/reward equation can become skewed and will be perceived as unfair.

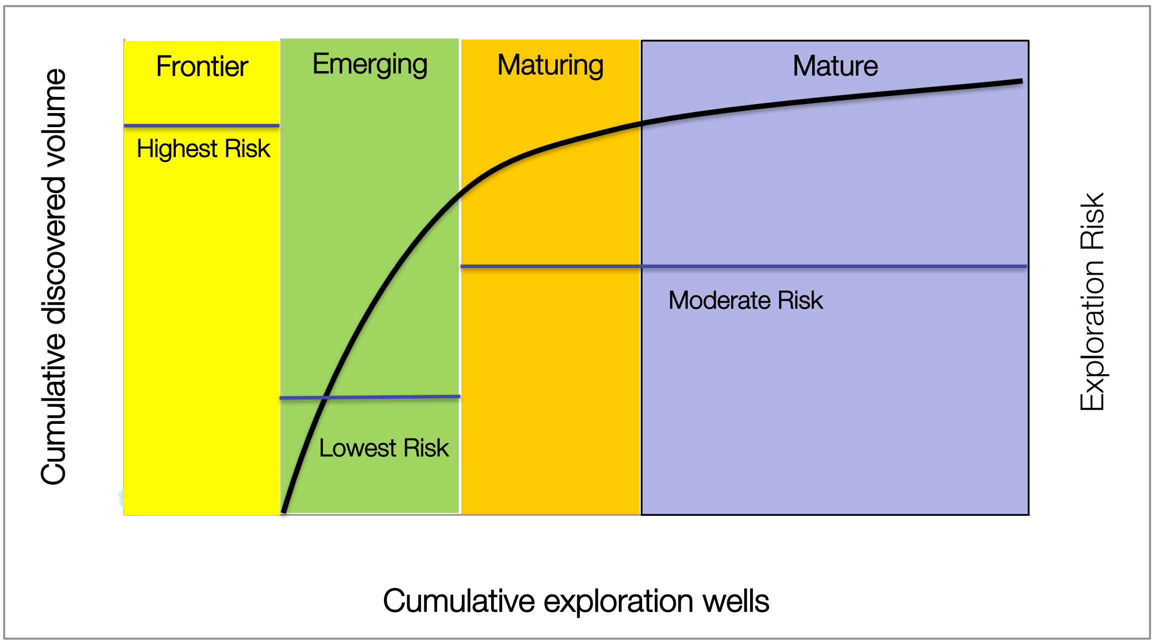

Figure 3 - Typical creaming curve and relative exploration risk

[10] See for example Precept 4 of the Natural Resource Charter: www.naturalresourcecharter.org

Prior to 1969, the UK North Sea was a frontier oil province with no proven discoveries and was perceived as high-risk. In the 1970s it was at the emerging stage with the largest discoveries being made. Two thirds of the EUR was discovered in the first 10 years of exploration but it would take another 17 years to fully develop the 20 billion barrels of oil resources discovered by 1979. (See appendix.) Since 1999 UK oil and gas production has been in steep decline and the North Sea is well into the mature phase. (See Figure 4.)

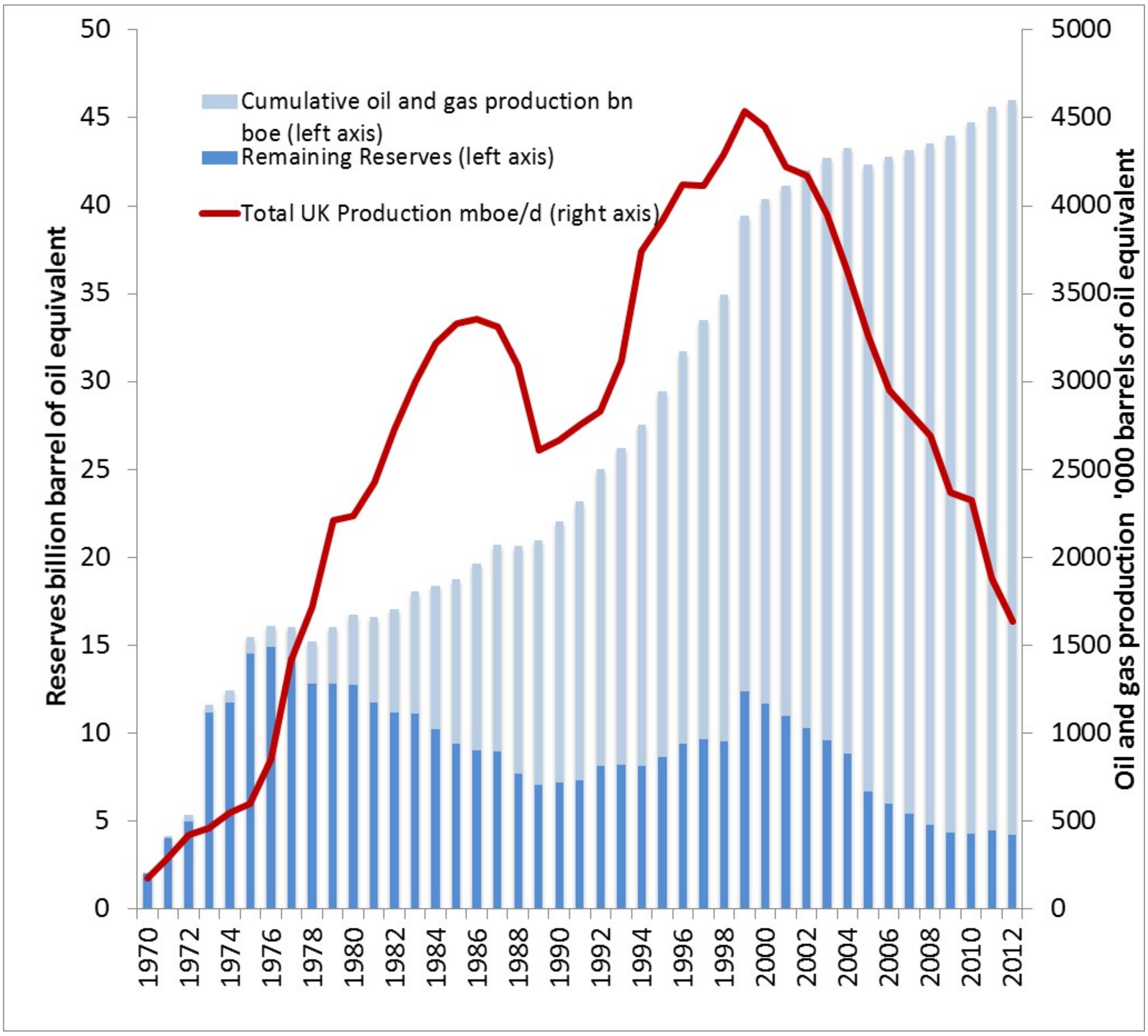

Figure 4: UK oil and gas production and proven reserves history

III. Resource Accounting

The first part of a national hydrocarbon account concerns the resource balance sheet. The key measures are reserves, production and reserves replacement and depletion rate.

This table is an example of a resource statement for UK oil:

	1979	1989	1999	2009
Billion barrels of oil				
Proven reserves start of year	8.8	4.3	5.1	3.1
Production	-0.6	-0.7	-1.1	-0.5
Reserve additions	0.6	0.3	0.9	0.3
Proven reserves end year	8.8	3.8	5.0	2.8
Cumulative proven reserves	10.2	13.6	23.7	28.8
Cumulative production	3.2	9.8	18.8	26.0
Estimated Ultimate Recovery	34.5			
Reserve depletion rate	7%	16%	22%	16%
Reserve replacement ratio	100%	43%	82%	60%
Remaining EUR depletion rate	2%	3%	7%	6%
Percentage cumulative proved reserves produced	31%	72%	79%	90%
Percentage EUR produced	4%	28%	54%	75%

Table 1: Reserves statement for UK oil resources. The estimated ultimate recoverable resource (EUR) is assumed to be 35 billion barrels based on UK government estimates at the end of 2012. Includes low estimates for potential addition reserves and yet to find resources. Note estimates of remaining resources can vary from year to year and are subject to uncertainty ranges. The depletion rate can be influenced by government choices, such as the pace of licensing. It is an important consideration, since the rate of depletion determines both the rate at which oil and gas are produced and converted into a financial asset, and the sustainability of the resource flow over time.

There are two depletion rates to consider. The first is the rate of depletion of developed reserves, which measures short to medium term sustainability.[11] If developed reserves are produced at a faster rate than they are replaced by new reserves (the reserves replacement rate), then production will not be sustainable. Reserves are added through new discoveries, through increasing recovery factors in existing fields (e.g., through secondary and tertiary recovery projects), and through revisions to existing fields through a better geological understanding.

The second rate concerns the depletion of the estimated ultimate recoverable resource (EUR) (including resources that are undeveloped and/or undiscovered), which governs the long-term sustainability of resource flows. Undeveloped resources lie in discovered fields that have not yet been approved for development, or are considered to be sub-commercial. Undiscovered (prospective) resources have yet-to-be found and lie in prospects that have not yet been drilled. Undiscovered resources are the most difficult to quantify, yet it is important that estimates are realistic for policy-making purposes.

For an individual oil or gas field, depletion is governed by physics and the plan of development (including resources, well count, design, flow-rates and pressure support). At the national level the

[11] Developed reserves are defined as being those oil and gas resources that have been developed and in production of have development plans approved and underway.

depletion rate is governed by the above together with the rate of discovery of new resources and the conversion of discovered resources into producible reserves.

The government controls depletion through an exploration licensing regime, the approval of exploration drilling, and the approval of field development plans. The degree of control depends on the licensing policy and a national oil company may be a key instrument in the implementation of a depletion policy.

Typically exploration license agreements set a timetable for exploration and allow an oil company to develop any discoveries it makes. In reality government has only limited influence over depletion once it had issued exploration licenses, unless license terms specifically allow for it. For example, OPEC members have to, in theory, vary production according to OPEC quotas; they provide for this in the licensing regime and through the control over operations exerted by their national oil companies. In practice this is not widespread among OPEC members.

There can be tension between investor and government with regard to depletion policy. For example, companies want to explore the best acreage first whilst government may wish to stage exploration and hold better areas back. Licensing terms need to carefully crafted in order to achieve the desired depletion policy.

Larger companies will have global asset portfolios and consider the development of a discovery in the context of corporate production goals and profitability targets. This could favor early production or could motivate a delay.

There can be a trade-off between profitability and recovery factor. The government is likely to favor maximizing recovery while a company might trade a lower recovery factor for a higher profit per barrel, for example by front-loading production. For these reasons, many large oil producing countries have opted for national oil companies, and have them act alone rather than in joint ventures with international companies, in order to better control their depletion rates.

The point at which resource flows decline varies from field to field but as a rough rule of thumb, field production will enter terminal decline after 30-60 percent of the ultimate recoverable reserves are produced.[12] This also applies at a level of a geological basin or the national level. In the UK's case peak oil production of 2.9 million barrels per day occurred in 1999 after circa 50 percent of the EUR had been produced. In the Norway's case peak oil production of 3.4 million barrels per day occurred in 2001 after circa 47 percent of EUR had been produced.[13]

After this point production decline is irreversible *unless* the EUR is increased through new geological plays being discovered (e.g. shale oil in the USA) or recovery rates increase with new technology or commodity prices make marginal resources economic.

In 1979 the UK had discovered 22 billion barrels (figure 1) of which 10 billion had been developed and 1.4 billion produced. Depletion was at 2 percent and only 4 percent of EUR had been produced. Production was 600 million barrels a year. By 1999 production was at 1100 million barrels per annum, depletion rate was at 5.9 percent and 51 percent of EUR had been produced. Production decline at an average rate of 8 percent per annum would commence the next year.

With the benefit of hindsight, if UK oil production had been maintained at 1979 levels, the onset of terminal decline could have been delayed by perhaps as much as 10 years, enabling the UK to benefit more from rising oil prices.

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[12] Hook, 2009, "Depletion and decline curve analysis in crude oil production", Uppsala University thesis. Miller 2009, UKERC Review of Evidence for Global Oil Depletion. Technical Report 4: Decline rates and depletion rates.

[13] Assumes an EUR of the Norwegian North Sea of 33.7 billion barrels (NPD estimate 2013)

The impact of different depletion policies can be seen clearly in table 2 comparing resource accounts for the UK and Norway sectors of the North Sea for 2012.[14] The geology is similar across the North Sea Basin and is split between the UK and Norway along a median line. Government estimates of ultimate recoverable resources are similar but by the end 2012, the UK had produced 6.6 billion more barrels than Norway.

Resource Accounts 2012 North Sea Oil	**UK billion barrels**	**Norway billion barrels**
Produced	27.3	20.7
Reserves	3	4.5
Contingent resources	0.8	4.7
Undiscovered resources	3.4	3.7
Total Estimated ultimate recovery	34.5	33.7

Table 2: Reserves and resources statement for UK and Norway North Sea oil resources. Norway numbers are for the North Sea only whilst UK numbers include the West of Shetlands as well as the North Sea. Source Gov.uk and Norway NPD

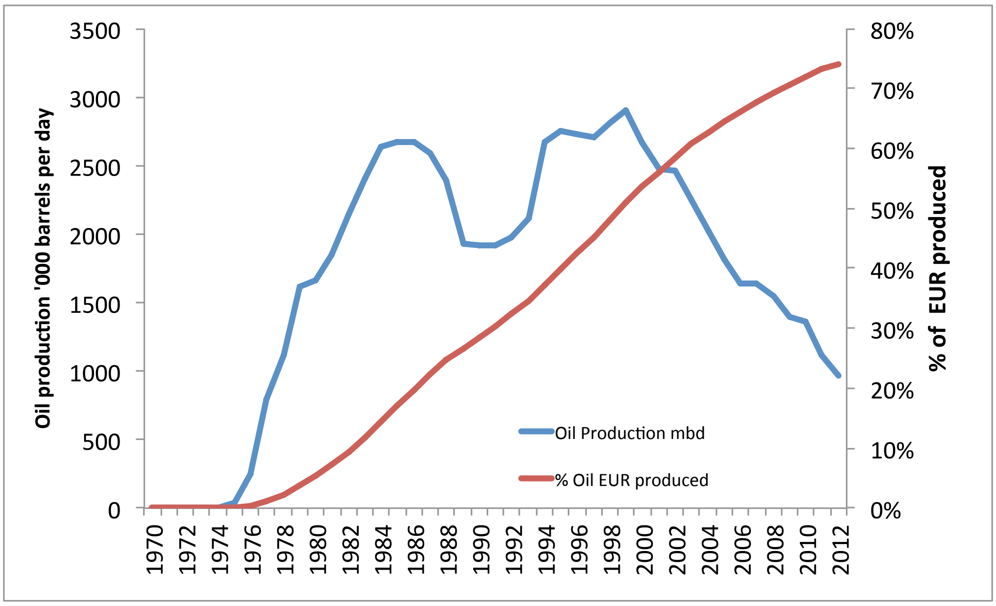

Figure 5: UK oil production and reserve depletion rate. Assumes estimated ultimate oil resources of 35 billion barrels. The distinctive double peak was caused in part by the Piper Alpha disaster in 1988

So in order to make sense of any oil revenues in any given year, it is necessary to account for the reserves and production that supports them and the assumptions that underlie the resource depletion policy. Decisions about revenue management and whether to save, invest or spend oil and gas revenues need to be underpinned by robust resource accounts and supported by future revenue scenarios. Government spending dependent on a production plateau sustainable for only a few years would be by definition unsustainable.

[14] UK numbers include West of Shetlands

IV. Accounting for investment and the cost of production

The next step is to account for the cost side of the national hydrocarbon accounts.

Production or operating costs incurred during day-to-day operation of production facilities and administration are distinct from capital costs incurred in finding and developing the reserves. Operating costs are expensed in the year in which they occur and appear on the national income statement but do not appear on the national balance sheet.

Capital costs are usually depreciated over the lifetime of the production facilities. In oil and gas accounting this is done on a unit of production basis while tax laws and PSA cost oil accounts generally use 10-year straight line depreciation. This means that the capital costs are attributed to the reserves of an oil field and each barrel produced is attributed a share of the capital costs in proportion to the reserve base.[15] This is the principle used in the analysis that follows.

The National Balance Sheet

Capital investment in exploration and development is added to the national balance sheet. It is then depreciated in proportion to the percentage of proven reserves produced during the year. This allows the un-depreciated capital deployed in any year to be estimated to allow the rate of return on capital and the rents generated by the Nation's oil and gas to be calculated (see next section).

Table 3 shows the capital balance sheet for the UK. Since 1970, £152 billion has been invested in UK oil and gas, though in any one year in the 1979-2009 period, the capital employed has been between £20 and £30 billion. Note that with capital cost inflation, capital employed in 2011 and 2012 has increased to a record £39 million.

£ billions (money of the day)	**1979**	**1989**	**1999**	**2009**
Assets - capital investment				
Cumulative capital investment	12.6	48.7	104.0	152.2
Cumulative depreciation	-1.7	-27.2	-76.0	-127.4
Capital employed net	10.9	21.5	28.0	24.8

Table 3: UK oil and gas balance sheet calculations based on UK government data.

If a government borrows money secured on oil and gas revenue then this would appear on the liability side of the balance sheet.

The National Income Statement

The national income statement accounts for revenues generated from sales of oil and gas, operating costs, capital costs and how surpluses are divided between government and Investors.

[15] If a field cost $100m to find and develop and has reserves of 10 million barrels then the balance sheet will include $100m of capital assets at the start of production. Each barrel produced will remove $10 from the balance sheet and 1 barrel from the reserve statement. $10 will be deducted from revenue in the income statement for each barrel of production. If the reserve base changes then depreciation charges will increase or decrease accordingly.

£ billions (money of the day)	1979	1989	1999	2009
Gross revenues				
Oil and NGL sales	5.7	7.5	11	18
Gas sales	0.6	2.2	5	5.8
Other income	0.04	0.5	1.4	1.8
Total revenue	**6.3**	**10.2**	**17.4**	**25.7**
Operating expenses	**-0.5**	**-2.4**	**-4.5**	**-8**
Operating surplus	**5.8**	**7.8**	**12.9**	**17.7**
Capital depreciation charge	**-0.7**	**-3.2**	**-5.5**	**-6.1**
National oil and gas Income before tax	**5.1**	**4.6**	**7.4**	**11.6**
Government tax and royalty income	**-2.3**	**-2.4**	**-2.5**	**-5.9**
Investor income after tax	**2.8**	**2.2**	**4.9**	**5.7**

Table 4: UK national oil and gas income statement. Operating expenses include decommissioning expenses.

Table 4 shows an example income statement for the UK oil and gas sector. Revenues and costs are as reported by the UK government.[16] The depreciation charge is as calculated by the author. (See appendix.)

The total revenues accruing from the sector are a function of produced volumes and realized oil and gas prices. This can be complicated where state entities, subsidies and non-cash oil swap deals are involved.

Production costs are subtracted from revenues to calculate the operating surplus. This is equivalent to the EBITDA line in company accounts, and approximates the operating cash flow.

The capital depreciation charge (see footnote 15 for how this is calculated) is deducted to calculate the sector income before taxation. Finally government revenues from taxes, royalties and other levies are deducted.

What remains is the after-tax profit retained by investors. If state-owned enterprises are investors in the sector then a portion of this profit will also accrue to government and should form part of the statement.[17]

Table 4 shows that although production volumes in 2009 were less than half of those in 1999, UK oil and gas production generated 80 percent more profit. This was due to a three-fold commodity price increase over that period.

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[16] https://www.gov.uk/oil-and-gas-uk-field-data#ukcs-income-and-expenditure

[17] In the UK case, the UK state oil company BNOC was privatized in in 1982 and is not included in this analysis.

The National Cash Flow Statement

The cash flow statement tracks cash costs and revenues. In the cash flow statement exploration and development capital is accounted for in the year it occurs.

£billions (money of the day)	**1979**	**1989**	**1999**	**2009**
Gross Revenues				
Oil and NGL sales	5.7	7.5	11.0	18.0
Gas sales	0.6	2.2	5.0	5.8
Other income	0.04	0.5	1.4	1.8
Total revenue	**6.3**	**10.2**	**17.4**	**25.7**
Operating costs	-0.5	-2.4	-4.5	-8.0
Operating cash flow (OCF)	**5.8**	**7.8**	**12.9**	**17.7**
Investing cash flow				
Exploration expenditure	-0.2	-1.2	-0.5	-1.2
Development expenditure	-2.0	-2.6	-3.0	-4.8
Total investing cash flow	**-2.3**	**-3.8**	**-3.5**	**-6.0**
National cash surplus (deficit)	**3.6**	**4.0**	**9.4**	**11.7**
Government tax revenue	2.3	2.4	2.5	5.9
Cash surplus after tax	**1.3**	**1.6**	**6.9**	**5.8**
Recycle ratio (percentage post-tax OCF reinvested)	**67%**	**70%**	**34%**	**51%**

Table 5: UK Oil and Gas Cash Flow Statement. Operating costs include decommission expenses. Revenues and costs are as reported by the UK government.[18]

The difference between the cash surplus and income can be considerable reflecting the timing of large investments and production. This is the case for the UK in 1999, the year of peak UK production, which followed a period of heavy capital investment. In this year the gross cash surplus was £2 billion higher than "income" due to a dip in capital investment as new fields came on-stream. (See Figure 6.)

[18] https://www.gov.uk/oil-and-gas-uk-field-data#ukcs-income-and-expenditure

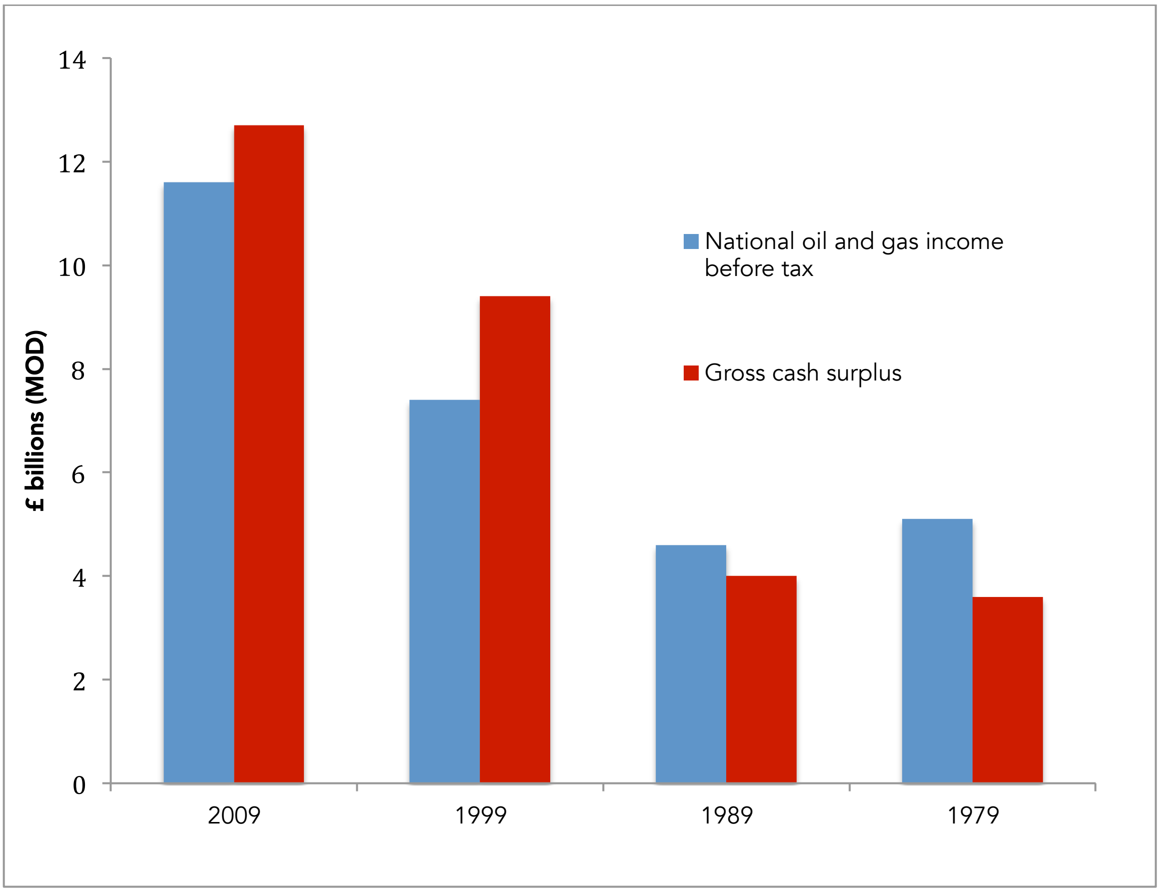

Figure 6: Comparison of the UK National income from oil and gas and the cash surplus from oil and gas

The national income statement is measuring the underlying profitability of the sector whilst the cash-flow statement measures movements in cash.

V. Performance metrics for policy analysis derived from national hydrocarbon accounting

The Recycle Ratio

The recycle ratio measures the proportion of the post-tax cash generated from oil and gas operations that is reinvested in country. In the early years of an oil province the recycle ratio is greater than 100 percent as external capital is required to fund development of the discovered resources. In the case of the UK, by 1979 the oil and gas sector generated sufficient profit after tax to fund planned investments and the recycle ratio dropped below 100 percent. (See Figure 7.)

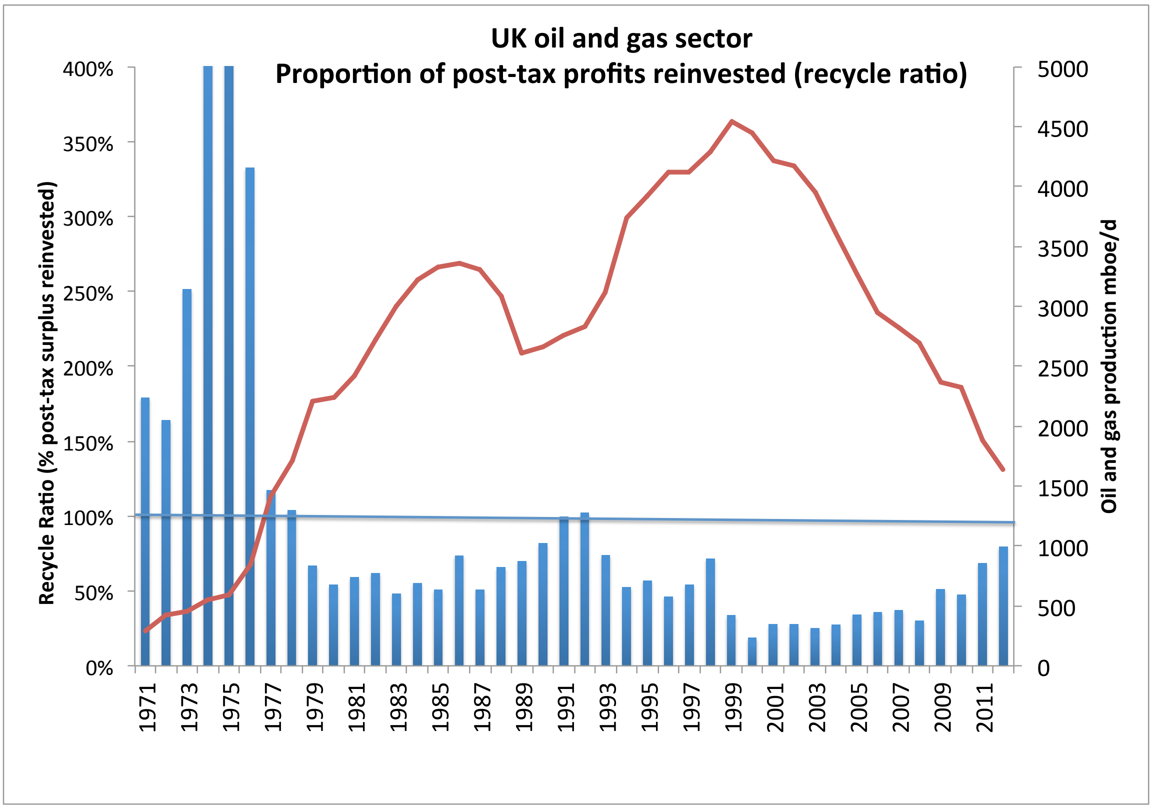

Figure 7: Recycle ratio for the UK oil and gas sector through time. Recycle ratio is the proportion of post-tax profits reinvested in UK oil and gas assets

From 1979 to 1999 (the year of peak production) the recycle ratio averaged 63 percent before dropping to an average 40 percent in the production decline phase. In the mature phase of an oil province new projects tend to be smaller, and incumbent companies may decide to invest profits elsewhere. This effect can be seen in the UK, particularly in the 2000-08 period when post-tax returns on capital were circa 40 percent but the recycle ratio dropped to 30 percent. The UK sector then effectively became an industry cash cow, with both profits and capital being re-deployed to fund hydrocarbon extraction elsewhere in the world.

Managing the decline of a mature petroleum province presents many governance challenges. Incumbent producers may be large companies who no longer see the smaller remaining opportunities to be of sufficient scale to merit investment. Mature petroleum provinces usually see a transition to smaller operators better matched to the remaining opportunities on offer. However, incumbent operators that own production infrastructure may not be motivated to facilitate access to infrastructure by new entrants who wish to invest in smaller fields. They have to be encouraged, or if necessary, forced to do so.

Government may interpret a combination of a low recycle ratio and high return on capital as a signal of an imbalance in the fiscal regime whereby high post tax capital returns aren't leading to more domestic investment. However, increasing taxes could serve to make smaller, marginal fields less attractive for investment. In the decline phase the fiscal regime may need to become more flexible in order maximize recovery.

Per Barrel Costs and Revenues

In order to track cost trends it is useful to report costs and realized prices on a per barrel basis. International benchmarks can be used to benchmark local cost efficiency.

£ per barrel of oil equivalent	**1979**	**1989**	**1999**	**2009**
Average realized revenue	7.8	10.7	10.5	29.6
Average capital costs	-0.9	-3.4	-3.4	-7.0
Average operating costs	-0.6	-2.5	-2.7	-9.2
Investor income	3.5	2.3	3.0	6.6
Government revenue	2.9	2.5	1.5	6.8

Table 6: UK oil and gas realized average prices and costs (in GBP money of the day)

Table 6 shows that realized oil and gas prices nearly tripled between 1999 and 2009, increasing by close to £20 per barrel of oil equivalent (boe). Costs increased by £10/boe over the same period. Operating costs rose faster than capital costs as production declines and fixed operating costs were spread over fewer barrels. So 50 percent of the increase in revenues from 1999 to 2009 was lost to higher costs in the supply chain. Costs in the industry usually rise with a lag after price increases, as demand for inputs rises.

Note also that in 2009, UK unit costs of production were higher than the realized commodity price in 1999 even allowing for inflation. In other words 2009 production would not be viable at 1999 oil and gas prices.

Profit Margins, Government Take and Returns on Capital

NHA's can be used to analyze profitability, rent generation and rent capture.[19] The income statement and balance sheet can be combined to calculate profit margins, the government take and the return on capital employed. (See Table 7.)

[19] Rent is the proportion of profit from oil and gas production above the minimum profit required to justify the investment. One objective of the fiscal regime is to capture as much rent as possible for the resource owner (i.e. the state and its citizens).

	1979	1989	1999	2009	Definitions
Profit margin pre-tax	81%	45%	43%	45%	Profit as percentage of revenue
Investor profit margin post-tax	44%	22%	28%	22%	Profit after tax as percentage of revenue
Government take as percentage of gross profit	45%	52%	34%	51%	Government revenue as percentage of pre-tax profit
Capital employed (£ billion)	10.9	22.7	26.2	27.4	Capital invested after depreciation
UK pre-tax return on capital employed (ROCE)	54%	21%	26%	42%	Profit as percentage of capital employed before tax
Investor post tax return on capital employed (ROCE)	29%	10%	17%	21%	Profit after tax as percentage of capital employed

Table 7: UK Oil and Gas Profitability

Government revenue as a percentage of gross profit from oil and gas production (known as government take) is often seen as a measure of how much economic rent the government is capturing. Measures of average government take can be misleading as a guide to tax policy, especially when used in isolation. This is because the level of government take measured across the sector at any particular point in time is subject to aggregating across projects at various stages in the lifecycle, and thus provide a biased estimate of the full lifecycle government take. Furthermore, government take has limited utility for cross-country or cross-project comparisons due to variation in risk, geological and cost profiles.

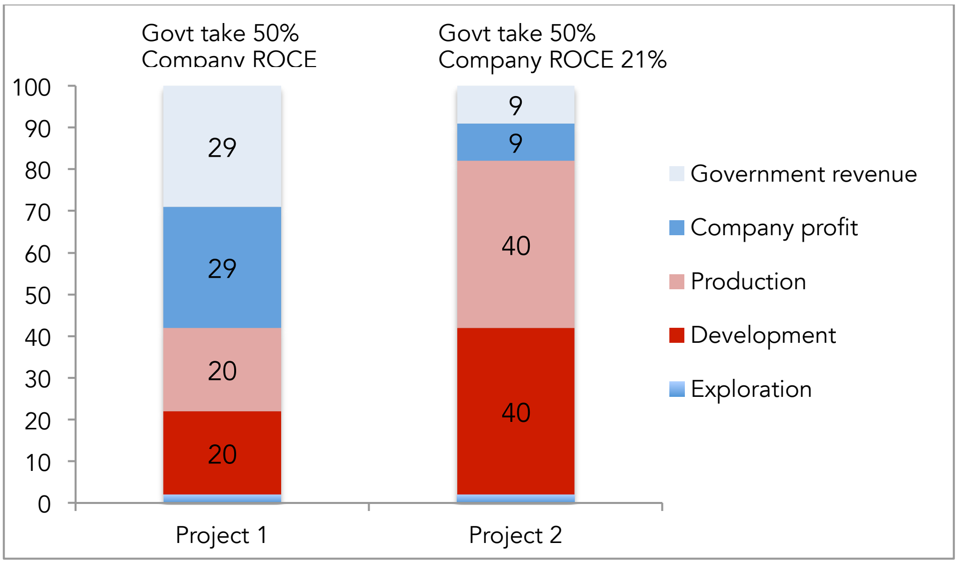

Figure 8: Illustrative examples of the split of a hypothetical $100/boe product. Project 1 has $22/boe exploration and development capital costs, whilst Project 2 has $42/boe exploration and development costs. Government take is 50 percent in both cases

For the purposes of monitoring a nation's hydrocarbon accounts, government take can be usefully supplemented by estimates for profit margins and company returns on capital employed (ROCE[20]). The return on capital is the profit attributable to the providers of capital (i.e. the company) as a proportion of the capital employed. In other words, this is the ratio of the profit earned on a unit of oil equivalent for the capital investment required to produce the unit.

Figure 8 shows that returns on capital can vary at the same levels of government take depending on capital costs and timing impacts making government take, by this measure, at best only a proxy for measuring the effectiveness of a fiscal regime.

The return on capital earned by investors in the sector is a good measure of how well the government has been able to capture rent for its citizens from the production of oil and gas.[21]

From a government perspective the return on capital enjoyed by industry is a proxy for the cost of capital required to generate those tax revenues. As such, a lower industry ROCE at a given level of production is better. Table 6 and Figure 9 show how returns have fluctuated over time for the UK.

Figure 9 shows the pre and post-tax return on capital employed for the UK oil and gas sector on a five-year rolling average basis. The post-tax ROCE has averaged 26 percent between 1971 and 2012 (see appendix) and is very sensitive to commodity prices. The UK upstream fiscal regime does not include a formal rate of return related resource rent tax. Essentially, the UK operates on a fixed headline tax rate that has been changed frequently over time and an evolving set of variable tax allowances that are intended to reflect the profitability of different types of field.

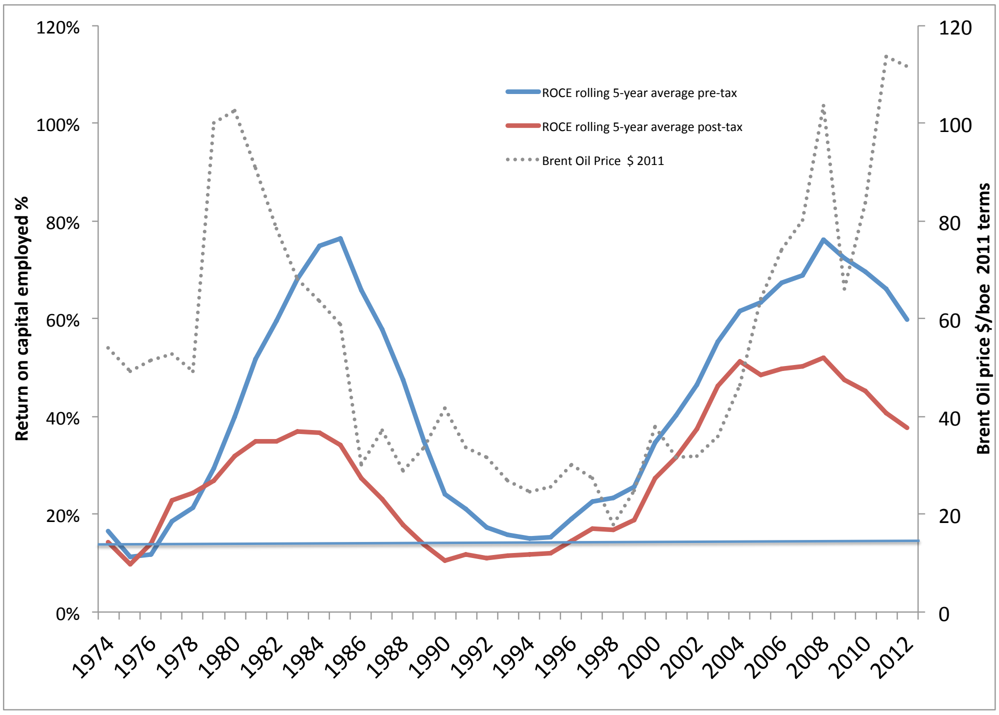

Figure 9: Return on capital employed pre and post-tax for the UK on a five-year rolling average basis together with Brent oil prices in 2011 terms shown. The horizontal blue line marks the 17.5 percent ROCE level – the average ROCE of the 5 major oil companies since 2000.

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[20] The return on capital employed is calculated in table 6 and figure 8 as profit (pre and post tax) as a proportion of capital employed on an historical cost basis (cumulative investment minus cumulative depreciation) at the start of the year. In this study capital has been depreciated on a unit of production basis.

[21] See Boue and Wright 2011 for discussion of rent capture under the UK fiscal regime. Chapter 2 UK Energy policy and the end of market fundamentalism. Oxford Institute of Energy Studies.

It should be noted however, that, as with government take, caution must be exercised in interpretation of the ROCE for any given year. While the backward looking ROCE at the end of the lifecycle of a basin will yield a powerful estimate of the effective cost of capital to the nation, the ROCE will fluctuate during production periods as new investments are made and others depreciated. As such, like government take, these metrics can be valuable for monitoring and forecasting, but cannot be used for adjustment of tax rates. For the purposes of tax evaluation, such measures should be complemented by project level life cycle average effective tax rate (AETR) (net present value (NPV) government revenues/pre-take project NPV) for a range of typical projects.

VI. Discussion

So how effective has the UK fiscal regime been in capturing rent? In order to answer this question, one must know the minimum rate of return required to justify the investment. The minimum rate of return is hard to quantify as it depends on the choices investors have at a given time, the cost of capital and the characteristics of the particular opportunity including political and technical risks.

The cost of capital is the ultimate floor for the required rate of return. A project has a negative net present value if companies cannot deliver a return greater than its cost of capital. The cost of capital for larger oil companies is typically in the range of 6 to 10 percent.[22] In 2007, before the financial crisis, banks would lend capital to smaller oil companies secured on reserves (reserves backed lending) at an interest rate of circa. 10 percent.

Oil companies typically target a risk-adjusted rate of return of at least 20 percent from a new development (excluding exploration costs). The 20 percent target is meant to allow for projects that fail and, since 2000, the average ROCE for super-major oil companies has been 17.5 percent.[23]

Given that the UK lies at the lower end of the political risk spectrum it could be that oil companies might have still invested at lower rates of return. In fact Figure 10 shows that from the late 80's through the 90's the UK oil and gas sector delivered average returns of only 12 percent, but the industry continued to invest and increase production.

[22] Average cost of capital of 7.7 percent for integrated oil companies in January 2014.
http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.htm
[23] Author's calculation based on data from Evaluate Energy for post-tax normalized rates of return for BP, Chevron, Exxon, Total and Shell.

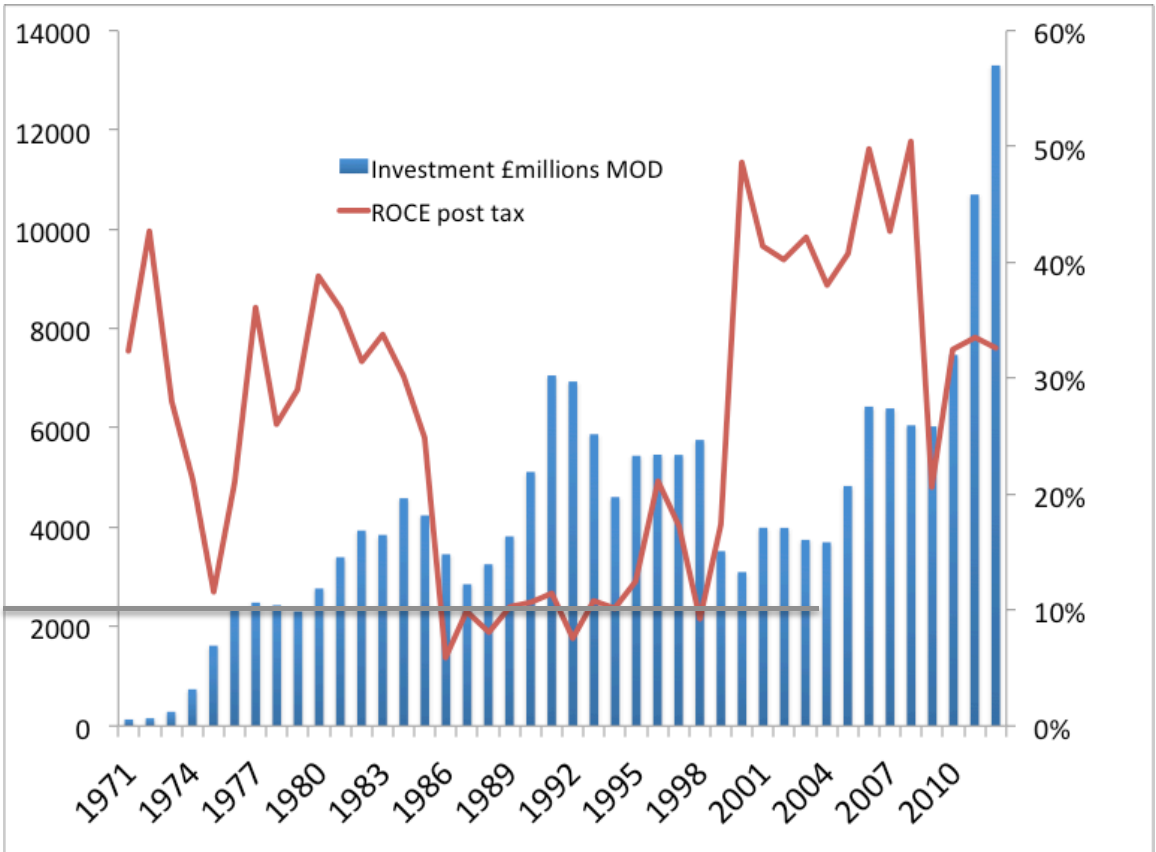

Figure 10: Annual post tax returns on capital employed from UK oil and gas production and capital investment. Horizontal line marks a 12 percent ROCE.

Table 8 shows the "rent" generated from UK oil and gas at a theoretical required return on capital at 17.5 percent and 12 percent based on the author's computation of capital employed. If 17.5 percent is used as a proxy for the required rate of return to justify capital investment in the sector, then the UK tax regime managed to capture 73 percent of the rent generated by UK oil and gas production. That is, government taxes captured 73 percent of the profits generated in excess of that required to generate a 17.5 percent return for investors. If a 12 percent ROCE is assumed to be the minimum rate then the UK tax regime captured 61 percent of the rent generated over the life cycle of the basin.

The table also shows the challenge of designing a tax regime given the volatility of 'rents'. UK taxes captured over 100 percent of rent during the period of low oil prices in the mid 80's and 90's and 55 percent of rent in the high oil prices of the 2000s.

Year	Capital employed £m	Return on capital @ 17.5% £m	Pre-tax profit above 17.5% ROCE "rent £m"	Return on capital @ 12% £m	Pre-tax profit above 12% ROCE "rent' £m"	Govt tax revenue £m	% of rent captured through tax @ 17.5 % ROCE	% of rent capture d through tax @ 12% ROCE
1979	10921	1911	3113	1122	3902	2,313	74%	59%
1980	12819	2243	6061	1311	6674	3,743	62%	56%
1981	15090	2641	8846	1538	9571	6,492	73%	68%
1982	17410	3047	9949	1811	10750	7,822	79%	73%
1983	19167	3354	11803	2089	12589	8,798	75%	70%
1984	21236	3716	14635	2300	15521	12,035	82%	78%
1985	22449	3929	13272	2548	14091	11,348	86%	81%
1986	22530	3943	2720	2694	3406	4,783	176%	140%
1987	21982	3847	3534	2704	4128	4,618	131%	112%
1988	22052	3859	1627	2638	2297	3,168	195%	138%
1989	22679	3969	675	2646	1998	2,368	351%	119%
1990	23979	4196	541	2721	2016	2,312	427%	115%
1991	26700	4672	-936	2878	859	979	-ve rent	114%
1992	28885	5055	-1718	3204	133	1,305	-ve rent	979%
1993	29898	5232	-901	3466	865	1,223	-ve rent	141%
1994	28772	5035	-368	3588	1080	1,642	-ve rent	152%
1995	28223	4939	924	3453	2410	2,289	248%	95%
1996	27806	4866	4384	3387	5864	3,303	75%	56%
1997	27959	4893	3179	3337	4735	3,277	103%	69%
1998	28236	4941	81	3355	1667	2,452	3032%	147%
1999	26241	4592	2812	3388	4016	2,510	89%	63%
2000	25484	4460	12706	3149	14017	4,402	35%	31%
2001	25598	4480	11432	3058	12853	5,370	47%	42%
2002	25476	4458	10908	3072	12295	5,054	46%	41%
2003	25124	4397	10564	3057	11904	4,223	40%	35%
2004	24846	4348	10321	3015	11655	5,115	50%	44%
2005	25670	4492	14967	2982	16478	9,323	62%	57%
2006	26917	4711	16949	3080	18579	8,864	52%	48%
2007	27583	4827	14073	3230	15670	7,408	53%	47%
2008	27511	4814	21487	3310	22991	12,393	58%	54%
2009	27445	4803	6795	3301	8297	5,921	87%	71%
2010	28077	4913	12312	3293	13932	8,322	68%	60%
2011	32559	5698	14964	3369	17293	11,250	75%	65%
2012	39731	6953	10199	3907	13245	6,530	64%	49%
Overall			**251912**		**297777**	**182955**	**73%**	**61%**

Table 8: Theoretical calculation of rent generated from UK oil and gas production at 12 percent and 17.5 percent required rate of return. The author calculates capital employed by depreciating capital investment on unit of production basis. See appendix for revenues and costs.

VII. Conclusions and recommendations

National hydrocarbon accounts yield insight into the physical resources, industry revenues and costs, economic rent and tax revenues. They provide a comprehensive summary of the performance of the national exploration and production sector and are a foundation for an informed debate over the effectiveness of upstream governance.

Table 9 outlines five important governance questions that this approach can wholly or partly answer.

National hydrocarbon accounts permit scrutiny of the overall cost structure and profitability of the sector and whether government has collected the revenues its du (if the fiscal terms are known). The income statement and upstream capital balance sheet allows pre and post-tax rates of return on capital to be computed and economic rent generation and sharing to be monitored. Industry cost data, benchmarked internationally, combined with the reserves statement shows whether the sector is run cost effectively and the sustainability of revenue flows.

	Government oil and gas revenue data	Government oil and gas revenue and sector costs and investments	**National hydrocarbon accounting:** Government oil and gas revenue, sector costs and investments and reserves statements
Can we say how much oil and gas revenue is available for budget?	Yes	Yes	Yes
Can we say if the government receiving its due revenue?	No	Yes (if fiscal/contract terms are known and production and costs broken down at project level)	Yes (if fiscal/contract terms are known and production and costs broken down at project level)
Can we say if the government capturing a "fair" share of rent?[24]	No	Partly (to evaluate the return on capital needs capital depreciation to be calculated)	Partly (provides information for an informed debate)
Can we say if the oil and gas sector is being run cost effectively?	No	No	Yes
Can we say how sustainable oil and gas revenues may be?	No	No	Yes, with price scenarios and development plans

Table 9: Questions national hydrocarbon accounts can and cannot answer

[24] In order to fully evaluate the effectiveness of government in capturing a fair share of rent, it is necessary to conduct project level lifecycle analysis. This would require public disclosure of additional project level information not typically in the public domain (although could be shared if government were willing).

The compilation of national hydrocarbon accounts can provide a foundation for forecasts of future revenue streams and depletion. This can be useful to government, especially the Ministry of Finance and Ministry of Planning, but also to citizens, investors and other stakeholders, wishing to learn more about the health, status and trajectory of the sector.

Furthermore, the application of national hydrocarbon accounting can provide a useful check on what data is collected, shared among agencies and ultimately publicly disclosed.[25] In principle, as with the UK example, all data used in this note should be systematically collected as well as available to all citizens. The degree to which this is true in other countries, the quality of the data, and the transparency of sector governance, will vary, and national hydrocarbon accounting, by shedding light on this, can provide a basis for reform.

VIII. Acknowledgements

The author would like to thank Jim Cust, David Manley, Charles Macpherson, Mark Henstridge and Dan Haglund for their helpful reviews of the paper.

[25] In particular cost data is rarely shared with the public, even aggregated across the sector. Furthermore, cost data may not even be shared across government agencies, thus limiting their ability to monitor and evaluate sector governance. On the other hand cost data is widely available to private sector participants via subscription databases. The wider collection, sharing and public disclosure of cost data would constitute an important step towards better ability to complete analyses such as this.

Amounts: £ milli

Year	Total revenues (excluding gas levy)	Petroleum revenue tax	Supple-mentary petroleum duty	Corporation Tax (CT)				Royalty	Gas levy	
				Total	ACT	Ring Fence CT	Supple-mentary charge		Gross	Net of CT clawback
1968-69	1	-	-	-	-	-	-	1	-	-
1969-70	2	-	-	-	-	-	-	2	-	-
1970-71	5	-	-	2	-	2	-	3	-	-
1971-72	10	-	-	4	-	4	-	6	-	-
1972-73	15	-	-	4	-	4	-	11	-	-
1973-74	15	-	-	3	-	3	-	12	-	-
1974-75	20	-	-	5	-	5	-	15	-	-
1975-76	25	-	-	5	-	5	-	20	-	-
1976-77	81	-	-	10	-	10	-	71	-	-
1977-78	238	-	-	10	-	10	-	228	-	-
1978-79	565	183	-	93	40	53	-	289	-	-
1979-80	2313	1435	-	250	78	172	-	628	-	-
1980-81	3743	2410	-	341	97	244	-	992	-	-
1981-82	6492	2390	2025	681	270	411	-	1396	383	383
1982-83	7822	3274	2395	521	202	319	-	1632	471	272
1983-84	8798	6017	-	877	430	447	-	1904	522	277
1984-85	12035	7177	-	2432	1244	1188	-	2426	500	239
1985-86	11348	6375	-	2916	1085	1831	-	2057	525	300
1986-87	4783	1188	-	2676	1130	1546	-	919	515	305
1987-88	4618	2296	-	1298	681	617	-	1024	502	322
1988-89	3168	1371	-	1195	685	510	-	602	407	231
1989-90	2368	1050	-	743	495	248	-	575	335	193
1990-91	2312	860	-	847	363	484	-	605	291	174
1991-92	979	-216	-	638	370	268	-	557	282	182
1992-93	1305	69	-	682	480	202	-	554	287	193
1993-94	1223	359	-	258	219	39	-	606	240	145
1994-95	1642	712	-	380	299	81	-	550	175	96
1995-96	2289	968	-	766	674	92	-	555	161	107.387
1996-97	3303	1729	-	890	460	430	-	684	198	132.066
1997-98	3277	963	-	1779	821	958	-	535	200	133.4
1998-99	2452	504	-	1605	655	950	-	343	-	-
1999-2000	2510	853	-	1268	120	1148	-	389	-	-
2000-01	4402	1521	-	2329	-	2329	-	552	-	-
2001-02	5370	1307	-	3515	-	3515	-	548	-	-
2002-03	5054	958	-	3662	-	3392	270	434	-	-
2003-04	4223	1179	-	3057	-	2317	740	-13	-	-
2004-05	5115	1284	-	3831	-	2841	990	-	-	-
2005-06	9323	2016	-	7307	-	5427	1880	-	-	-
2006-07	8864	2155	-	6709	-	3959	2750	-	-	-
2007-08	7408	1680	-	5728	-	3378	2350	-	-	-
2008-09	12925	2567	-	10358	-	6108	4250	-	-	-
2009-10	6491	923	-	5568	-	3288	2280	-	-	-
2010-11	8786	1458	-	7328	-	4328	3000	-	-	-
2011-12	11250	2032	-	9218	-	4563	4655	-	-	-

Footnotes

1. Figures for Coporation Tax for 2008-09 onwards are provisional and subject to change in the future when payments originally made in respect of groups of companies for which some companies are within the ring fence oil and gas tax regime and some are not are subsequently re-allocated to individual companies within the groups.

2. The table reflects the evolving tax regime for the UK Oil & Gas industry, so there are changes in the types of duties levied throughout the years featured in this table. Some examples of the changes are as follows:
    - Supplementary Petroleum Duty charged for only two years in the 1980's.
    - Royalties abolished in 2002, although there were some residual repayments made in 2003.
    - Introduction of the CT supplementary charge in 2002.

Appendix - UK government revenues from oil and gas since 1969. Source: HMRC table 11.11

Year	Oil Reserves Bn bbl	Gas Reserves Bnboe	Oil reserves adds Bn bbl	Gas reserve adds Bnboe	Oil Production mbd	Cumulative Oil Prodn Bn bbl	Cumulative Oil Reserves Bn bbl	EUR depletion rate	% Oil EUR produced	Gas Prod Mboe/d	Cumulative gas production bn boe	Oil Sales £m	NGL Sales £m	Gas Sales £m	Other Income £m	Total Income £m	Operating Costs £m	decomm-issioning costs £m	Other expenses £m
1970	2.0		2.0	0.6	4	0.01	2.0	0.0%	0%	172	0.1	0	0	0	4	4	6		0
1971	4.0		2.0	0.1	5	0.01	4.0	0.0%	0%	286	0.2	0	0	80	8	88	11		0
1972	5.0		1.0	0.2	8	0.02	5.0	0.0%	0%	413	0.3	0	1	114	9	124	15		0
1973	6.5	4.6	1.5	4.8	9	0.02	6.6	0.0%	0%	448	0.5	0	2	133	11	146	18		0
1974	7.3	4.4	0.8	0.0	10	0.02	7.3	0.0%	0%	541	0.7	0	3	166	21	190	20		0
1975	9.9	4.7	2.6	0.4	34	0.04	9.9	0.0%	0%	563	0.9	43	15	190	29	277	46		0
1976	10.2	4.7	0.5	0.2	253	0.13	10.3	0.3%	0%	596	1.1	624	21	258	21	924	130		0
1977	10.2	4.1	0.3	-0.4	792	0.42	10.6	0.8%	1%	623	1.3	2,197	29	317	20	2,563	207		0
1978	8.8	4.1	-1.1	0.2	1119	0.83	9.6	1.2%	2%	597	1.5	2,771	35	432	12	3,250	346		0
1979	8.8	4.1	0.6	0.2	1611	1.41	10.2	1.8%	4%	603	1.8	5,641	53	538	44	6,276	502		18
1980	8.4	4.3	0.3	0.4	1663	2.02	10.5	1.9%	6%	573	2.0	8,719	132	647	82	9,580	692		34
1981	7.9	3.9	0.1	-0.2	1853	2.70	10.6	2.1%	8%	572	2.2	12,206	135	843	114	13,298	1,017		45
1982	7.5	3.7	0.4	0.0	2150	3.48	10.9	2.5%	10%	581	2.4	14,129	312	956	160	15,557	1,309		73
1983	6.9	4.2	0.4	0.7	2404	4.36	11.3	2.9%	13%	599	2.6	16,496	528	1,117	188	18,329	1,495		67
1984	6.0	4.2	0.0	0.3	2632	5.32	11.3	3.3%	15%	586	2.8	19,927	659	1,290	256	22,132	1,733		62
1985	5.6	3.8	0.6	-0.2	2675	6.30	11.9	3.5%	18%	653	3.1	19,204	692	1,709	384	21,989	2,248		76
1986	5.3	3.7	0.7	0.2	2671	7.27	12.6	3.6%	21%	687	3.3	8,909	386	1,927	455	11,677	2,144		57
1987	5.2	3.8	0.8	0.3	2593	8.22	13.4	3.6%	24%	719	3.6	9,513	358	1,990	533	12,394	2,107		55
1988	4.3	3.4	0.0	-0.1	2396	9.09	13.4	3.4%	26%	693	3.8	7,084	249	2,046	859	10,238	2,060		58
1989	3.8	3.3	0.3	0.1	1929	9.80	13.6	2.9%	28%	678	4.1	7,214	272	2,187	547	10,220	2,330		57
1990	4.0	3.2	0.9	0.2	1918	10.50	14.5	2.9%	30%	749	4.4	8,432	277	2,377	405	11,491	2,892		46
1991	4.2	3.2	0.9	0.3	1919	11.20	15.4	3.0%	32%	834	4.7	7,578	385	2,988	476	11,427	3,296		58
1992	4.6	3.6	1.1	0.7	1981	11.92	16.5	3.2%	35%	848	5.0	7,430	380	3,016	626	11,452	3,312		53
1993	4.5	3.7	0.7	0.5	2119	12.69	17.2	3.5%	37%	997	5.3	8,110	523	3,568	699	12,900	3,661		47
1994	4.3	3.9	0.8	0.6	2675	13.67	18.0	4.7%	40%	1064	5.7	8,964	528	3,836	974	14,302	3,860		40
1995	4.5	4.1	1.2	0.7	2749	14.67	19.2	5.1%	43%	1166	6.1	9,881	614	4,141	1,166	15,802	3,913		37
1996	5.0	4.4	1.4	0.9	2735	15.67	20.7	5.3%	45%	1386	6.7	11,850	749	5,295	1,243	19,137	3,978		31
1997	5.2	4.5	1.2	0.5	2702	16.66	21.8	5.5%	48%	1414	7.2	10,327	700	5,254	1,279	17,560	4,150		34
1998	5.1	4.4	1.0	0.5	2807	17.68	22.8	6.1%	51%	1485	7.7	7,487	551	5,313	1,453	14,804	4,190		111
1999	5.0	7.4	0.9	3.6	2909	18.75	23.7	6.7%	54%	1632	8.3	10,257	727	5,031	1,436	17,451	4,249		282
2000	4.7	7.0	0.7	0.3	2667	19.72	24.4	6.6%	57%	1784	9.0	16,275	1,117	6,606	1,488	25,486	4,360		106
2001	4.5	6.4	0.7	0.1	2476	20.62	25.2	6.5%	60%	1743	9.6	13,646	963	8,140	1,435	24,184	4,347		49
2002	4.5	5.8	0.8	0.0	2463	21.52	26.0	6.9%	62%	1706	10.2	13,629	894	8,199	1,397	24,119	4,596		48
2003	4.3	5.3	0.6	0.1	2257	22.35	26.6	6.8%	65%	1694	10.8	13,365	1,105	7,554	1,538	23,562	4,496		8
2004	4.0	4.8	0.5	0.1	2028	23.09	27.1	6.5%	67%	1587	11.4	13,477	1,266	7,476	1,178	23,397	4,664	148	87
2005	3.9	2.8	0.5	-1.5	1809	23.75	27.6	6.1%	69%	1452	11.9	16,545	1,697	9,014	1,451	28,707	5,113	412	128
2006	3.6	2.4	0.3	0.1	1636	24.34	27.9	5.9%	71%	1317	12.4	17,933	1,910	11,189	1,658	32,690	5,597	144	252
2007	3.4	2.0	0.4	0.0	1638	24.94	28.3	6.3%	72%	1187	12.9	18,967	1,686	8,398	1,814	30,865	5,992	163	244
2008	3.1	1.7	0.2	0.1	1544	25.50	28.6	6.3%	74%	1146	13.3	25,102	2,204	10,612	1,816	39,734	7,020	163	287
2009	2.8	1.5	0.3	0.1	1397	26.01	28.8	6.0%	75%	975	13.6	18,075		5,790	1,800	25,665	7,330	390	250
2010	2.8	1.5	0.5	0.3	1357	26.51	29.3	6.2%	77%	966	14.0	22,610		7755	1,800	32,165	7,510	340	250
2011	3.0	1.4	0.6	0.2	1114	26.92	29.9	5.4%	78%	767	14.3	24,975		8,415	1,800	35,190	7,560	500	250
2012	3.0	1.3	0.3	0.1	967	27.27	30.2	4.9%	79%	667	14.5	22,975		7,855	1,800	32,630	8450	650	250

Year	Total Expenses £m	Gross Operating Surplus £m	E&A Investment £m	Investment other than E&A £m	Total Investment £m	Pre-Tax Cash Flow £m	Govt Tax Revenue £m	Post Tax Cash £m	Cum Investmen £m	Capital Depletetion £m	Capital Carry forward £m	Recycle Ratio Post Tax	Finding Costs £/boe	DDA £/boe	ROCE UKCS Pre-Tax	ROCE UKCS Post Government Take	Brent Oil Price $ MOD	Brent Oil Price $ 2011 terms
1970	6	-2	20	53	73	- 75	2	- 77	73	2.00	71.00		0.01	0.03	-6%	-8%	1.80	10.64
1971	11	77	57	72	129	- 52	5	- 57	202	11	189	179%	0.03	0.10	35%	32%	2.24	12.68
1972	15	109	43	112	154	- 45	15	- 60	356	13	330	164%	0.04	0.09	51%	43%	2.48	13.61
1973	18	128	69	215	284	- 156	15	- 171	640	21	594	251%	0.01	0.12	33%	28%	3.29	17.00
1974	20	170	153	584	737	- 567	20	- 587	1377	24	1307	491%	0.19	0.12	25%	21%	11.58	53.94
1975	46	231	242	1,374	1,616	- 1,385	25	- 1,410	2993	54	2868	784%	0.08	0.25	14%	12%	11.53	49.21
1976	130	794	301	2,070	2,372	- 1,578	81	- 1,659	5365	112	5129	333%	0.45	0.36	24%	21%	12.80	51.63
1977	207	2,356	375	2,107	2,482	- 126	238	- 364	7847	264	7346	117%	-5.63	0.51	41%	36%	13.92	52.70
1978	346	2,904	261	2,170	2,431	473	565	- 92	10278	428	9349	104%	-0.31	0.68	34%	26%	14.02	49.37
1979	519	5,774	241	2,064	2,305	3,452	2,313	1,139	12583	733	10921	67%	0.30	0.91	54%	29%	31.61	99.97
1980	726	8,888	379	2,388	2,767	6,087	3,743	2,344	15350	870	12819	54%	0.53	1.07	73%	39%	36.83	102.62
1981	1,063	12,281	550	2,847	3,397	8,838	6,492	2,346	18747	1126	15090	59%	-4.79	1.27	87%	36%	35.93	90.75
1982	1,382	14,248	875	3,059	3,934	10,241	7,822	2,419	22681	1614	17410	62%	2.17	1.62	83%	31%	32.97	78.44
1983	1,562	16,834	993	2,853	3,846	12,921	8,798	4,123	26527	2088	19167	48%	0.96	1.91	84%	34%	29.55	68.12
1984	1,796	20,399	1,395	3,189	4,584	15,752	12,035	3,717	31111	2515	21236	55%	4.46	2.14	93%	30%	28.78	63.60
1985	2,324	19,741	1,445	2,794	4,239	15,426	11,348	4,078	35350	3026	22449	51%	3.70	2.49	78%	25%	27.56	58.81
1986	2,201	9,533	1,039	2,419	3,457	6,019	4,783	1,236	38807	3376	22530	74%	1.23	2.75	27%	6%	14.43	30.23
1987	2,162	10,287	809	2,044	2,853	7,379	4,618	2,761	41660	3401	21982	51%	0.72	2.81	30%	10%	18.44	37.26
1988	2,118	8,178	1,129	2,126	3,255	4,865	3,168	1,697	44915	3185	22052	66%	-12.87	2.83	22%	8%	14.92	28.96
1989	2,386	7,890	1,182	2,635	3,817	4,017	2,368	1,649	48732	3190	22679	70%	3.62	3.35	21%	10%	18.23	33.75
1990	2,938	8,599	1,637	3,478	5,116	3,437	2,312	1,125	53848	3816	23979	82%	1.52	3.92	21%	11%	23.73	41.68
1991	3,354	8,131	1,955	5,101	7,057	1,016	979	37	60905	4337	26700	99%	1.74	4.32	16%	11%	20.00	33.72
1992	3,365	8,140	1,508	5,428	6,935	1,152	1,305	- 153	67840	4750	28885	102%	0.81	4.60	12%	8%	19.32	31.62
1993	3,708	9,239	1,213	4,661	5,874	3,318	1,223	2,095	73714	4861	29898	74%	1.00	4.27	15%	11%	16.97	26.97
1994	3,900	10,442	939	3,671	4,609	5,793	1,642	4,151	78323	5735	28772	53%	0.71	4.20	16%	10%	15.82	24.50
1995	3,950	11,889	1,085	4,355	5,440	6,412	2,289	4,123	83763	5989	28223	57%	0.57	4.19	20%	12%	17.02	25.64
1996	4,009	15,159	1,097	4,364	5,461	9,667	3,303	6,364	89224	5877	27806	46%	0.48	3.91	33%	21%	20.67	30.24
1997	4,184	13,410	1,194	4,263	5,457	7,919	3,277	4,642	94681	5304	27959	54%	0.69	3.53	29%	17%	19.09	27.31
1998	4,301	10,614	762	4,996	5,758	4,745	2,452	2,293	100439	5481	28236	72%	0.52	3.50	18%	9%	12.72	17.91
1999	4,531	13,202	457	3,063	3,520	9,400	2,510	6,890	103959	5516	26241	34%	0.10	3.33	26%	17%	17.97	24.76
2000	4,466	21,126	348	2,750	3,098	17,922	4,402	13,520	107057	3854	25484	19%	0.36	2.37	65%	49%	28.50	37.99
2001	4,396	19,837	420	3,570	3,990	15,798	5,370	10,428	111047	3877	25598	28%	0.53	2.52	62%	41%	24.44	31.69
2002	4,643	19,523	389	3,598	3,988	15,488	5,054	10,434	115035	4110	25476	28%	0.46	2.70	60%	40%	25.02	31.94
2003	4,504	19,066	334	3,412	3,746	15,312	4,223	11,089	118781	4097	25124	25%	0.46	2.84	59%	42%	28.83	35.97
2004	4,751	18,733	396	3,302	3,698	14,948	5,115	9,833	122479	3977	24846	27%	0.69	3.01	58%	38%	38.27	46.51
2005	5,241	23,594	460	4,371	4,831	18,635	9,323	9,312	127310	4007	25670	34%	-0.48	3.37	78%	41%	54.52	64.09
2006	5,849	27,093	773	5,656	6,429	20,412	8,864	11,548	133739	5182	26917	36%	1.94	4.81	84%	50%	65.14	74.19
2007	6,237	24,873	1,090	5,303	6,393	18,235	7,408	10,827	140132	5728	27583	37%	2.56	5.56	70%	43%	72.39	80.16
2008	7,307	32,714	1,274	4,780	6,054	26,373	12,393	13,980	146186	6126	27511	30%	3.60	6.24	95%	50%	97.26	103.71
2009	7,970	18,335	1160	4,800	5,960	11,735	5,921	5,814	152146	6084	27387	51%	2.69	7.03	42%	21%	61.67	66.00
2010	8,100	24,655	1400	6,000	7,400	16,665	8,322	8,343	159546	6815	27973	47%	1.75	8.04	63%	33%	79.50	83.70
2011	8,310	27,630	1800	8,900	10,700	16,180	11,250	4,930	170246	6201	32471	68%	2.07	9.03	74%	34%	111.26	113.56
2012	9,350	24,180	1700	11,600	13,300	9,980	6,530	3,450	183546	6116	39655	79%	4.61	10.26	53%	33%	111.67	111.67

Appendix – Reserve and resource assumptions used in the paper. Revenues and costs are as reported on the UK government web-site. https://www.gov.uk/oil-and-gas-uk-field-data#ukcs-income-and-expenditure. Note UK government revenues are reported on a fiscal year whilst production volumes are reported on calendar year. ***Reported data*** *– Oil and Gas reserves, Oil and Gas production.* ***Calculated data*** *– oil and gas reserve adds, cumulative oil and gas production, cumulative oil and gas reserves.* ***Reported data*** *– Oil, NGL and Gas sales revenue, Operating costs, decommissioning costs, other expenses, E&A investment, Investment other than E&A (i.e. development capital), Total investment, government tax revenue.* ***Calculated Data*** *– Total expenses, Gross operating surplus, Pre-tax cash flow, post-tax cash flow, Cumulative investment (historical cost basis), capital depreciation (unit of production basis, historical cost), capital carried forward (cumulative investment - cumulative depreciation), recycle ratio (proportion of , post tax profits reinvested in UK), finding costs (annual exploration and appraisal expenditure/oil and gas reserve additions), DDA/boe (depreciation charge per barrel of oil equivalent produced), pre-tax ROCE (return on capital employed), Post tax ROCE.* ***Assumption*** *- EUR (EUR based on Cumulative reserves + UK government estimate for additional resources and UK government low estimate for yet-to-find in 2012).*