DETERMINING THE EFFICIENCY OF THE 'BOTTOM-UP TECHNIQUE' USING THE UK OIL PRODUCTION

Abstract

The UK has been producing petroleum since 1975 from both offshore and onshore fields with over 90% of the production coming from the off shore fields. The UK has 250 offshore fields with 90% of the off shore production coming from 84 fields. The production profile of the UK unlike that of its North Sea neighbour Norway is composed of two peaks with one in 1985 and another in 1999. This unique profile was a result of the Piper Alpha accident affecting oil production in the UK Continental Shelf. Oil being a major source of energy has a very high demand but is however finite. As a result, it has become important for regions to have forecasts of their production. This enables then make better fiscal projections for their imports and exports. There are different methods used for the forecasting. Three of the common ones are listed in this paper. These are; Bottom-Up, the Econometric Method and the Top-Down method. Using the Bottom-Up approach, this paper will forecast production from the UK Continental Shelf for 2017 and 2020. This method was chosen for its simplicity and efficiency in mature fields. It was concluded that due to the decline in production of the UK fields. Total production from the UK would continue declining in 2017 and 2020. The results are compared to those from DECC. The variations are noted and are discussed.

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Abbreviations

Boe………………………. barrels of oil equivalent

DECC……………………..Department of Energy and Climate Change

EIA………………………..Energy Information Administration

Gb………………………….Billion Barrels

IEA………………………….International Energy Agency

Mtoe……………………..Million tonnes of Oil Equivalent

NGL………………………..Natural Gas Liquids

UK…………………………..United Kingdom

UKCS………………………United Kingdom Continental Shelf

1.0 Introduction

The United Kingdom is the largest producer of oil and second largest producer of natural gas in the European Union. However, production has been declining steadily since 1999. This affected the demand for petroleum to the point that the United Kingdom became a net importer of natural gas and crude oil in 2004 and 2005 respectively. Production of the UK natural oil and gas fields peaked in 1999 and declined steadily as the new reserve discoveries and improved production techniques have not kept pace with the maturation of the existing fields. At its peak in 1999, the UK produced 124 Mtoe. However, in 2013, the UK produced 37 Mtoe showing a decline of almost 70%.

More than 90% of all production in the UK took place off shore with the vast majority occurring in the North Sea. The EIA estimates that the UK continental shelf production continues to decrease at a steady rate. The EIA expects UK oil production to decline through 2015 with the main reason for this decline being cited as the overall maturity of the country's oil fields and the diminishing prospects for new conventional discoveries in the future. This paper shall not discuss unconventional resources like shale gas and shale oil as these are still nascent in the UK.

Initial markets were focused on the demand side as there was an oversupply of petroleum thus letting the supply meet the demand. However, by 1977, the new studies that emerged argued that resources were limited and discoveries were not keeping up with the production (Lynch, 2002). Lynch went on to state that production depended not only the discovery but also on the capacity lost due to depletion effects (Lynch, 2002). Focus shifted to the forecast of fossil fuel supply. Forecasting of fossil fuel supplies is important for policy making and the overall investment outlook of the industry. Energy security is now a resounding theme on the international stage. Due to the heavy reliance on fossil fuels as an energy source, it is imperative that accurate forecasts are made.

Different techniques have been developed for forecasting the supply of petroleum with the most popular being the Hubbert curve. Hubbert M. King in his paper *Nuclear Energy and Fossil Fuels 1956* correctly predicted the peak of US production. Since then, numerous methods have been developed and earlier ones improved upon focusing on the forecasting the fossil fuel supply. This effectively ensures that countries can plan for their fossil fuel requirements and focus on how to meet demand bearing in mind the trend of petroleum production.

Different fields have different production profiles. Giant oil fields (fields with a production of 100,000 barrels per day (bpd) for more than one year or 0.5 billion barrels Ultimate Recoverable Resource-URR) tend to have longer plateau phases as compared to smaller fields. Field profiles indicated that decline begins after the plateau stage (Höök et al., 2009).

This paper aims at forecasting the petroleum supply of the UK continental shelf for 2017 and 2020 using the Bottom-Up method. Only conventional oil will be analysed as non-conventional oil is still somewhat of an uncertainty for the UK. The units used will be million tonnes of oil equivalent (Mtoe) as this is inclusive of crude oil, natural gas liquids and condensate. The results will be compared to the results from the UK Department of Energy and Climate Change (DECC) and literature. Section one would discuss the origins of oil, its formation and reservoir properties. This is important to understand how the formation of oil inherently has an effect on the supply. Section two would deliberate on the process of exploration and production of the petroleum. A description and literature review of the UK fields from the initial period of exploration right up to 2013 is also included. Section three would discuss the different methods used in the forecasting of the petroleum supply. Each method would be listed with its merits and demerits. Section four would provide an analysis of the fields that have been forecast and an interpretation of the results in relation to factors that can affect production. Section five would provide a conclusion on the efficiency of the method and the reason for any variances in results.

2.0 Origin of oil

Oil comes from organic matter that had been deposited in sedimentary basins and transformed through heat and pressure. Heat and pressure transform organic matter into Kerogen which tends to be the insoluble fraction of the organic matter in sediments. There are different depositional environments for the preservation of organic matter and these include lakes, deltas and marine basins. The organic matter then undergoes bacterial decay resulting in the formation of methane, carbon dioxide and water. This reduces the oxygen in the organic matter which is then matured into Kerogen. There are different types of Kerogen however, this will not be dwelled upon in this paper.

The maturation of Kerogen into petroleum is dependent on temperature. At greater burial depths, the temperature increases effectively degrading the Kerogen thermally. This process is known as catagenesis which occurs at temperatures between 60 and 150 degrees. Above 150 degrees, the Kerogen is considered post mature and its ability to produce oil has almost vanished. The temperature interval where the source rock is mature is called the oil window. However, gas can be produced to temperatures up to 250 degrees centigrade (Robelius, 2007).

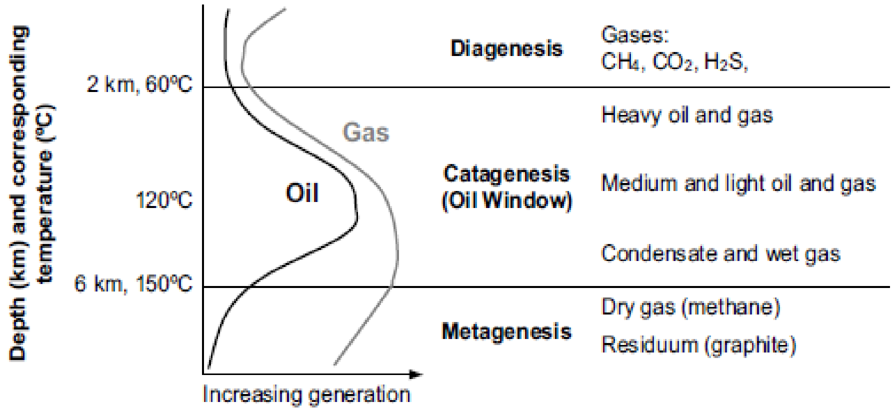

Figure 1; Formation of oil (Source Robelius 2007)

The oil is formed in the source rocks. The oil then migrates through fractures and pores into reservoirs rocks. The migration can be through diffusion, cracks, capillary forces or through buoyancy as many pores are filled with water (Robelius, 2007). This explains why water is beneath the oil in the reservoirs. The reservoir rocks include sandstones and carbonates. This accumulation is only possible if the reservoir rocks have a seal/trap. There are different traps and these can be structural, stratigraphic or a combination of the two. Most reservoir rocks are sedimentary in nature. For any reservoir rock, porosity[1] and permeability[2] are very important. Pores have two purposes in a reservoir, the first is as a storage space for oil and other hydrocarbons and the other is as a transmission network for fluid flows (Höök, 2014). Robelius states that any rock can act as a reservoir as long as it can both store and transmit fluids (Robelius, 2007).

Porosity decreases with depth as the sediments become more compacted. Hook states that it's important to have pores connected to allow the movement of hydrocarbons. Permeability is also of major importance which is defined as the ability of a rock to permit the flow of fluids. It is easier for fluids to flow horizontally than vertically. It can be noted that for any reservoir, porosity and permeability are some of the most important factors (Höök, 2014). These two factors affect the production from reservoirs. Reservoirs with poor porosities and permeabilities tend to have very poor production. Those with better porosities and permeabilities have better production.

2.1 Exploration and production of petroleum

Exploration of petroleum occurs in sovereign states. In these states apart from a few countries most notable the USA, the governments owns all the resources below the ground. Bhattacharyya mentions that since in many countries the subsurface resources are owned by the state, a contract is required for the exploration of the mineral resources. This contract provides the rules governing the allocation of the risk and rewards related to the exploration. Two types of legal arrangements are found in practice although a number of variations have been developed from these what recently are termed as hybrid contracts (Bhattacharyya, 2011).

2.1.1 Concessionary systems (leases, concessions, permits)

In the lease agreements the rights for exploration development and production are secured from the lease owner by the lessee. The lessee is given exclusive rights to undertake the activities against paying a fee. This lease can be a negotiated agreement or decided through

[1] Porosity is the percentage pore volume of a rock. The better connected the pores are, the greater the porosity of any rock.
[2] Permeability is the ease with which a fluid can pass through a porous structure under a pressure drop. The milli Darcy is normally used in the oil and gas sector.

the payment of a fee. This is very common in the USA. The concession agreements are negotiated contracts that provide for bonus payments by companies to the government for production of natural resources. The companies in turn are given control of large areas for exploration development and production for a specified period (Bhattacharyya, 2011).

2.1.2 Production sharing contracts

In this agreement, the host state enters an agreement with the company where the company recovers the cost through cost oil and shares of profit with the host at an agreed rate. Additionally, the company pays income tax on the profit made from the operations. In service contract, the contractor provides the services for a fee and the benefits of the activities accrue to the host. The contractor does not get any share of the profits (Bhattacharyya, 2011).

2.2 Exploration

Petroleum is found in sedimentary rocks and is considered trapped in reservoirs. The first stage of any exploration cycle is the determination of the sedimentary basins. While in earlier years natural seepages gave an indication where oil might be found, in later years companies employed geologists and geophysicists to assist in the development of the petroleum resources (Robelius, 2007).

Geological studies involve the mapping of sedimentary rocks and the rock outcrops on the surface. Following the development of the air travel the use of aerial photography was developed followed by ground truthing to identify the rocks observed on the aerial photographs. Geochemistry is also used to study the earth for traces of hydrocarbons. This is done by taking samples of the water and soil in a prospective areas and analysing them in the laboratories for hydrocarbons. This is done using chromatography. This is done to detect a *hydrocarbon halo*[3](Hyne and Ebrary, 2012).

Gravity and magnetic exploration is also carried out. A gravity meter measures the acceleration of the earth's magnetic field at this location. A magnetometer measures the strength of the earth's magnetic field at that location. The gravity surveys measures the density of the rocks in the surface. This is useful in differenciating the rocks. The magnetic surveys measure rocks that contain magnetic minerals. Magnetic surveys can be used to determine the thickness of the rocks (Hyne and Ebrary, 2012).

[3] This is a pattern formed by microseeps of which cannot be easily detected on the surface but can be seen on a chromatograph.

Seismic survey is the most widely used method for exploration. Seismic surveys measure the speed of sound in the subsurface to determine the rocks below, sound waves are sent to the subsurface and the speed at which they are reflected back is used to image the subsurface. On the ground explosives or vibrating trucks are used and on the sea air guns are used to generate the sound (Robelius, 2007). The detector records the sound as it is reflected back and captured on geophones or hydrophones in the water. Seismic technology has developed from two dimension to three dimension and now four dimension seismic technology.

Once the information has been collected and interpreted, if it is found to indicate the presence of hydrocarbons, a well is drilled. The first well to be drilled is termed as a wild cat well. The drilling is done to confirm that the results got from the acquired data are accurate. Should oil be discovered, appraisal wells are drilled to determine the extent of the reservoir. Once the size of the reservoir is known, an investment decision is made. An investment decision relies on the cost benefit analysis to determine if the development of a field would make the field economically viable. Oil discovery and production is shaped by multiple geological, technological, economic and political factors that combine to create considerable uncertainty over future supplies (Sorrell et al., 2012).

2.3 Production

Individual fields have different production profiles which profiles can vary widely depending upon the geology and the manner in which they are developed. As a field is developed, the production rate can rise rapidly until it reaches a plateau. The plateau for large fields tends to be longer than that for smaller fields. However, the rates of production eventually declines as more petroleum is being extracted.

2.4 Petroleum production from UK fields

According to the economic report of Oil and Gas UK 2012, the discovery of gas in the 1960s in the southern North Sea was the first step in developing and offshore oil and gas industry in the UK. A total of 41 billion barrels of oil equivalent (boe) have been extracted from the UKCS since 1975. 90% of the produced petroleum is from offshore fields. The UK North Sea peaked in 1999 and it has been undergoing a decline since. According to the *Wood Review Report*, Production in the UKCS dipped by 38% between 2010 and 2013 (Wood, 2014).

Over 4100 wells have been drilled in the UKCS over the past 40 years resulting into the discovery of 365 producing fields. Of these fields, 50 fields have ceased production and another 51 discoveries have been added albeit smaller. The peak of the exploration and appraisal activity occurred in 1990 when 159 exploration wells were drilled. The exploration success rate has been 31.8% over the last 45 years. The UK estimates a total recoverable reserve of 8.33 billion barrels of oil (Gray, 2010).

Like any exploration campaign, the large fields like the Forties, Brent and Beryl were discovered first. Recently the fields being discovered are of a much smaller size the dynamics having changed from having production from few large fields as in the 1980s to very many smaller ones in recent times.

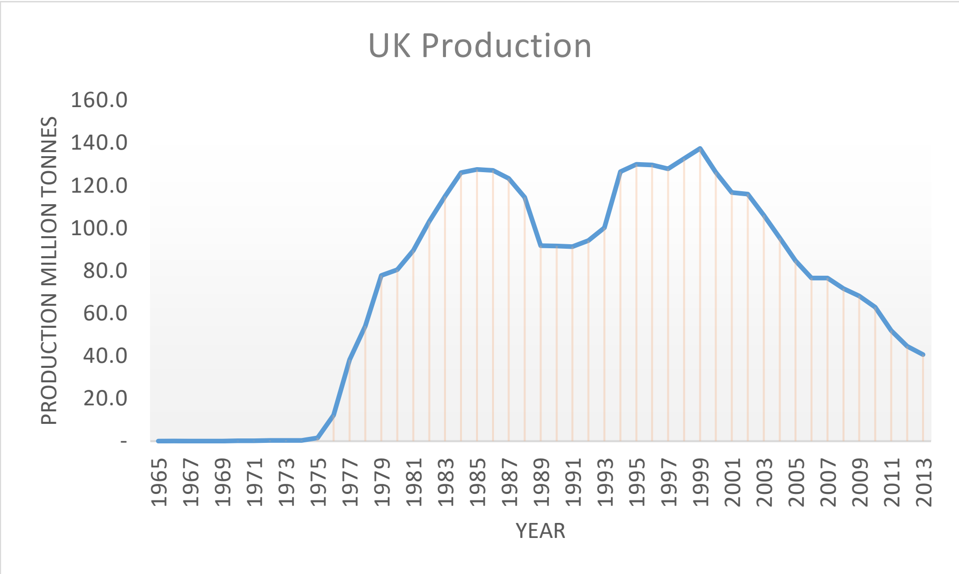

Figure 2; Production profile of the UKCS

The UK production doesn’t strictly follow a model decline rate for example like that of Norway in the same part of the North Sea where there was only one peak. It exhibits two peaks as a result of the Piper Alpha disaster in 1988 which forced production from the UKCS to decline. The government was forced to introduce new standards and in the next periods production recovered. The effect of this accident is well illustrated on the graph showing production from the Brent field. The capital efficiency in the UKCS has fallen with each barrel costing more to be brought into production. This is attributed to the maturity of the fields in the UKCS (UK, 2012). The DECC states that the production has been decreasing by around 8 per cent per year since 1999.

As a result of the decline in the production of petroleum, the UK became a net importer of crude oil in 2005. The IEA further notes that the UK exports over 60% of the petroleum produced. The UK produces light sweet crude but imports some heavier crudes from the middle-East and Africa in order to make a wide of products from light spirits to heavier bitumen. However as the production keeps on reducing, it can be postulated that the exports would reduce. According to DECC, 2011 was the first year when imports exceeded production and this trend is likely to continue.

As stated earlier, the larger fields came into production between 1975 and 1979. These fields are still producing currently. While the UK discovered newer fields later on, these were smaller. Despite the fact that some fields in the UKCS are not producing anymore, decommissioning has not been done on these fields. It is hoped that production from these fields will be restarted at some point. This could be explained by the so-called "resource pyramid" which according to Ahlbrandt and McCabe indicate that the upper part of the pyramid is well defined as these resources are mostly known and are considered 'conventional', the lower part on the other hand is less well understood. However, it is expected that technology will change all this by providing a better understanding of the reservoir and effectively increase the reserves in the UKCS. The paper *Are we running out of oil* states that currently wells of up to 9,000 feet can be built off shore and this has opened up resources in the world's submerged continental margins. Technological advancement is expected to improve the prospects in the UKCS (Martin, 2004).

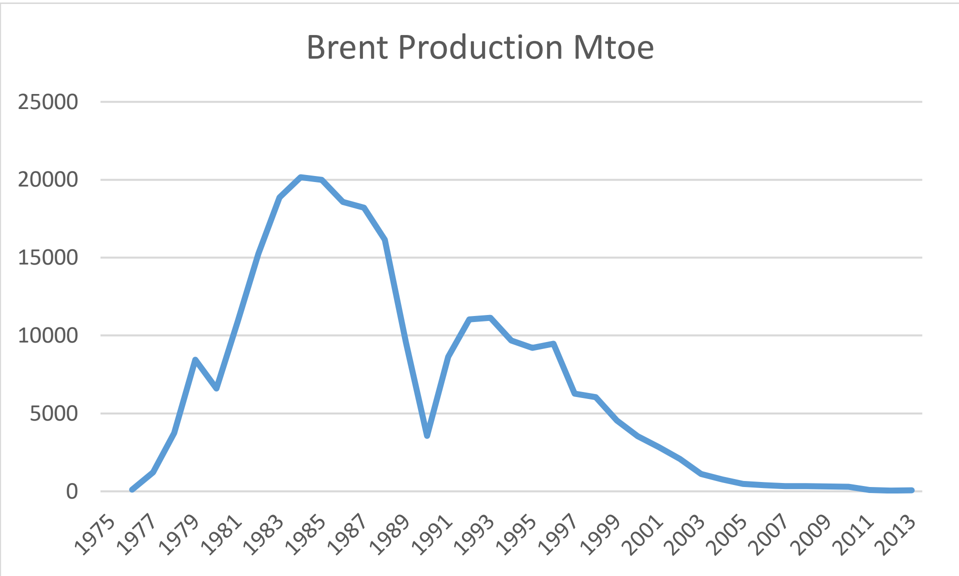

Figure 3: production profile of the Brent Field showing the kink when Piper Alpha accident occurred

3.0 Methods used for fossil fuel supply forecasts

Kemp notes that there exists different approaches that are used to forecast fossil fuel supply. These include curve fitting, engineering-based resource assessment techniques, econometric and financial modelling. Price is considered a major indicator variable of fossil fuel supply and is used in many forecasts. Gowdy and Julia however minimise its importance note that resource economics textbooks indicate resource scarcity as a minor concern for economic policy and emphasis the price system. This is explained as follows, price increases encourage substitution, exploration and technological advances effectively creating more resources. While this argument is reasonable. The creation of additional resources comes at the expense of future production as will be discussed later.

Prediction of fossil fuel supply has been gaining great interest recently. The fact that the UK production is going down and local supply cannot meet the local demand, the expected supply for the foreseeable future is important for the proper planning of investments in the UKCS and for the imports needed to meet the local demand. There are different methods used to forecast fossil fuel supply and these include the following;

3.1 Top Down model

The assumption used in this method is that production of petroleum follows a bell shaped curve where by initial production rises, reaches a peak and eventually decreases gradually until an approximate exponential is reached. The assumption is based on past production, past discovery and assessment of the Ultimate Recoverable Resource (URR).

While Hubbert M. King was not the first geophysicist to use this method, it is associated with him after his 1956 prediction that oil production in continental US would peak between 1965 and 1975. The production in the US did in fact peak in 1970.

Hubbert endeavoured to explain his results in his paper called *Nuclear Energy and the Fossil Fuels* (1956). He stated that for any production curve of a finite resource of a fixed amount two points are known namely $t=0$ and $t=\infty$. The production rate will be zero at both $t=0$ and $t=\infty$. This implied that in the production of any resource of fixed magnitude, the production rate must begin at zero and after one or several magnitudes it must go back to zero. His second theory from integral calculus was stated that if there existed a single value function $y=f(x)$ then

$$\int_{0}^{x1} ydx = A$$

1

Where A is the Area between the curve y=f(x) and the x axis from the origin to the distance point $x1$. In the case of production of petroleum plotted against time, the ordinate would be

$$P = dQ/dt$$

2

Where dQ is the quantity of the resource produced in time dt.

Combining equation 1 and 2 to come up with the areas of the curve up to any given point of time t as;

$$A = \int_{0}^{t} Pdt = \int_{0}^{t} (\frac{dQ}{dt}) = Q$$

3

Where q is cumulative production up to the time t. ultimately the production will be given by

$$Qmax = \int_{0}^{\infty} Pdt$$

4

This can be shown in a graph as below;

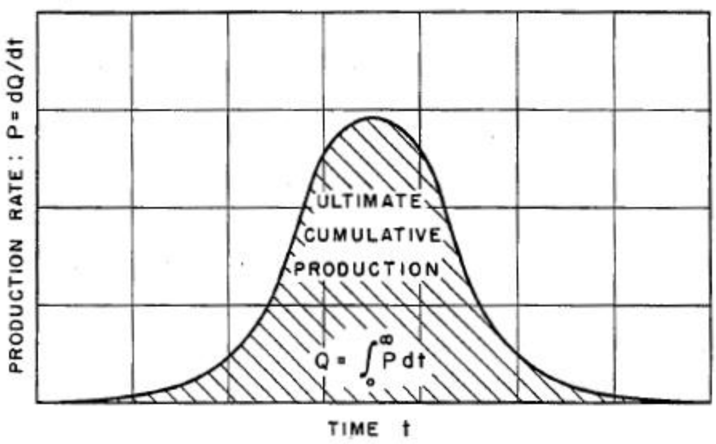

Figure 4; Mathematical relation shown in the production of an exhaustible resource (Source: Hubbert)

This would be presented on the graph of production vs time as the total area beneath the curve as the total area beneath the curve. Thus this area serves to show the ultimate recoverable resource. Hubbert went on further to stress that the if the quantity of the resource initially in place is known, a number of possible productions can be drawn with all exhibiting the property of beginning and ending at zero (Hubbert, 1956).

According to Cavallo, The Hubbert curve is a logistic curve showing good appreciation of the cumulative production of an exhaustible resource as a function of time. The logistic growth curve is given by;

$$Qt = \frac{Qmax}{(1 + a\ expbt)} \tag{5}$$

Where; *Qmax* is the total resource available (ultimate recovery of crude oil), Qt is the cumulative production and *a* and *b* are constants. Production begins slowly grows exponentially until a maximum then declines (Cavallo, 2004).

However, Kristofer Jakobsson states that Hubbert used a variation of the logistic curve as shown below

$$qt = URR\frac{bN0\ \exp -b(t - t0)}{(1 + N0\ exp - b(t - t0)\text{^}2} \tag{6}$$

Where:

qt= production rate at time t
URR= the ultimate recoverable resource
n0= (urr-q0)/q0
q0=cumulative production at time *t0*
b=shape parameter.

Hubbert used a number of assumptions, for example there exists only a single peak which occurs only when 50% of the URR has been produced is a form of limitation as it is noted that for fossil fuels, the peak doesn't not only occur when 50% of the resource has been produced (Jakobsson, 2012). Production of petroleum can have more than one peak as seen with the case of the UK. The UK production shows a peak in 1985 and another in 1999.This is one of the weaknesses of the Hubbert curve. Boodoo comes up with a solution for that drawback for the Hubbert curve. In order to mitigate the fact that individual fields' profiles tend to be asymmetrical, the model should ideally be applied to large populations of fields since the Central Limit Theory states that the sum of a large population of asymmetrical distribution tends towards a symmetrical distribution (Boodoo, 2012). The Top-Down Model needed an estimate of the URR, which could not be determined readily for all UK fields as this information was with the operators and not the government.

3.2 Econometric techniques

The econometric approach of forecasting fossil fuel supply employs ways of determining the hypothetical relationships between variables for example how production rate is influenced by oil price. Models for fossil fuel supply would project the volumes produced as a function of oil price, cost of extraction and other variables. The early econometric models were linear models that simply specified a variable of interest for example rate of exploration as a function of price, average discovery size, success rate (Jakobsson, 2012). These techniques omitted the effects of the decline of the fossil fuel on the cost of production and the discovery rate, however, several 'hybrid' models have accommodated these features.

A big flaw of the econometric models appears to be omitted variables for example the inclusion of a resource depletion effect and the exclusion of offsetting variables like improving infrastructure and technology. Lynch states that the result of this is that all econometric model have proved to be pessimistic. Lynch further criticises the model stating that the usual variables like oil price are not enough to make dependable forecasts as other factors both at aggregate and disaggregate levels are important for example in the 1970s prices soared whereas supply did not and then subsequently, the production rose while prices fell implying a negative price elasticity of demand. While productivity gains might explain rising production and falling prices, this doesn't not tell the full story (Lynch, 2002).

Lynch made up a table of the independent and dependent variables for a simple supply model as shown below

Table 1: Variables of a simple supply model (after Lynch)

Dependent variable	Independent variable
Exploration	Oil price, Cost

investment	
Drilling	Investment, Pricing/rig year
Discoveries	Drilling, Returns to drilling
Capacity additions	Discoveries Development expenditure
Capacity	Capacity Decline, depreciation, capacity additions
Production	Capacity, capacity utilisation

Source, Lynch 2002

Lack of reliable, consistent and useful Data limits the use of the model. Lynch notes that data especially investment data is broken down by region and while some jurisdictions would consider a pipeline as an upstream cost, others would not. A helicopter pad might be viable costs in some areas while in other areas the might not. The inconsistency in costs would definitely affect the results of the model (Lynch, 2002).

Drilling data is also difficult to amalgamate for example, more complex drilling rigs raise the average rig rate however they increase returns and capturing this trade-off is difficult to quantify. Capturing the productivity between a vertical and horizontal well is also a major hiccup in the determination of drill costs.

As an illustration to appreciate the complexity of getting suitable variables, Kemp and Kasim in the paper *An econometric model of oil and gas exploration development and production in the UK continental shelf: a system approach* carried out a forecast of petroleum supply in the UK continental shelf and the model contained 64 variables broken down into 24 endogenous variables and 19 exogenous variables and 21 one period lagged variables in the endogenous variables (Kasim and Kemp, 2003). The data needed for all the variables would have been enormous and its collection no easy feat bearing in mind how oil companies prefer to protect the data they acquire.

3.3 Bottom-up-Model

Kristofer Jakobsson describes the Bottom-Up approach models as one that generate aggregate production curves by summing up the production from smaller units i.e. (field by field models). He goes on further to elaborate that the model represents the flow from resources to reserves and from reserves to production (Jakobsson, 2012).

The model is best utilised on fields that are already in production as it is data intensive. Both the Bottom-Up and Top-Down approach share a common fact that oil production rates are a function of time. The causes of decline in a well include changing fluid ratios and loss of reservoir pressure. This model best describes the rate at which the reservoirs lose pressure and effectively the decline rate of the field. Poston states that decline rates were categorized as exponential, hyperbolic and harmonic in nature. He further notes that Arnold and Anderson were apparently the first to realise that the loss of production could be expressed as a fraction of the production rate. This rate of production loss measured during a specific time span is defined as the decline rate (Poston et al., 2008). Hook states that the simplest decline curves are characterised by the initial production rate, the decline rate and the shape parameter (Höök, 2014).

Following Poston, The decline rate can be expressed as follows

$$D = \frac{\left(\frac{q1 - q2}{\Delta t}\right)}{q1} = \frac{\frac{\Delta q}{\Delta t}}{qt}, \frac{1}{t} \quad (7)$$

Where q is total quantity in the reserve, t is time

The ‘Arps’ model derived from J.J Arps who was an American geologist is a derivative of the above models. Arps used mathematical treatment to bring together earlier models and unify the theory on the rate-time cumulative production characteristic of production decline. Arps equation is as follows;

$$q_t = \frac{q_i}{(1 + bD_i t)^{\frac{1}{b}}} \quad (8)$$

Where;

qt = production at time t

t= time

Di= decline rate

b=Arps decline curve exponent

Expressing equation 7 in differential form

$$D = -\frac{1}{q}\frac{dq}{dt} = -\frac{d(lnq)}{dt}$$

9

Showing how the decline rate is a function of quantity and time

If we consider the time rate change of the reciprocal of the decline rate,

$$b = \frac{d(\frac{1}{D})}{dt} = constant$$

10

If we express b using the fist derivative of equation 8

$$b = -\frac{d}{dt}\left(\frac{q}{\left(\frac{dq}{dt}\right)}\right) = constant$$

11

The *b* exponent term remains constant as the producing rate declines. The value of the *b* exponent is the difference between an exponential, hyperbolic and the harmonic curve for if, b=0, this implies that he decline rate is not a function of time and is expected to remain constant throughout the time period (Poston et al., 2008). The exponential decline curve method assumes *b*=0 for its simplicity. This should not be considered as the case in actual production fields. Taking equation 11 and integrating it over a range of possibilities develops a producing rate expression

$$q2 = q1 \exp -Dt$$

12

Where;

$q1$ is the production at peak

*q*2 is the production at time *t*

D is the decline rate

t is the time after peak

The shortcomings of the Bottom-Up approach is insufficient data on the fields is available which limits the ability to fully utilise the potential of the model. This tends to be the case for long term scenarios where uncertainty in the future discoveries, technological developments hinder the usefulness of the model (Jakobsson, 2012).

The fact that the Bottom-Up approach doesn't take the advancement in technology into consideration impacts on the expected results however this effect is evaluated in the next section.

3.3.1 Depletion of oil field production

Production companies in a bid to recover as much of their initial costs early enough start initial production at high rates. Production is then capped at the maximum flow rate that can be maintained given the pipeline and technology in place thus generating a plateau. Eventually the field begins to decline driven by decrease in pressure and the rising water levels (Gowdy and Juliá, 2007). Hook notes that depletion decline is a fundamental property of oil production. The rate at which oil can be extracted is known as the depletion rate. Decline of production occurs when recoverable resources get exhausted and production flow is affected. Decline of production as a result of depletion is much harder to alleviate and can only be alleviated by increasing the recoverable resources of the reservoir which is limited by the size of the reservoir formation (Höök, 2014). Determining of depletion rates, can be based on either the remaining recoverable resources or on the ultimate reserve (Höök, 2014).

Initially oil is recovered through the natural pressure of the reservoir, and usually 10-30% of the petroleum can be recovered this way (Höök, 2014). Primary recovery occurs when the petroleum flows out of the reservoir naturally. This is a result of the fact that fluids in the reservoir are at a much higher pressure than the pressure at the surface. As the fluids leave the reservoir they become spaced apart and the pressure drops and as a result the flow rates reduces effectively dropping the production rate of the reservoir. This process is termed as a *depletion driven decline.*

Then, secondary recovery techniques can be used later on in the reservoir. These involve water and gas injection to maintain the reservoir pressure. Effectively 30-50% of the petroleum can be recovered using this method. Tertiary recovery include much more complex methods such as injection of polymer solutions, surfactants, microbes, carbon dioxide that are capable of influencing the rock and fluid properties (Höök, 2014).

Hook adds that there is no theoretical limit to the depletion rate of a field implying that a field could decline at any rate. The advantage of depletion rate analysis comes from its connection to the physics of the reservoir which shows that all extraction is subject to the physical laws governing the fluid movement in the reservoir. Depletion curve analysis might be seen as a way of clustering variables like technology and investment together in order to reduce the number of unknown parameters in a field production behaviour. However, its best seen as a complimentary method that makes well substituted but rougher estimates (Höök, 2014).

At the onset of decline of production, only a narrow band of depletion rates tend to be plausible however, at certain decline rates, the decline caused by extraction of the petroleum would become the dominant factor over other production factors like technology. This is the point at which the field will fall into declining production. The connection between depletion rate and decline curves models make it possible to make estimates of the actual decline rates. For an exponential decline curve, it is estimated that the depletion rate is equal to the decline rate (Höök, 2014). A disadvantage with the exponential decline rate is that tail ends production is significantly underestimated as this flattens out into a harmonic curve towards the end however, as production far out in the tail end is low, this effect is minimal for the model (Höök et al., 2009).

4.0 Analysis of data from the UK fields

According to DECC, production in 2012 was 45 Mtoe. 41 Mtoe came from offshore fields. This indicates that the bulk of production in the UK is from offshore fields. A total of 84 offshore fields were analysed, these fields made up 90% of the cumulative production of oil in the UK. As shown in appendix 1.

In this analysis, the Bottom-Up approach will be used. Hook mentions that modelling future field behaviour is done by extrapolating historical production with an exponential decline curve, this does not take dramatic deviations into account assuming that decline would continue almost exponentially (Höök et al., 2009). This echoes Sorrell who states that for individual wells, reservoir and fields are usually assumed to decline exponentially at a constant rate (Sorrell et al., 2012).

Equation 12 is noted as

$$q2 = q1 \exp -Dt$$

In the analysis, *equation 12* was used. However, the decline rates of the fields were not known. To determine the decline rate for the fields, the production for 2012 per field was used as a base together with the production in the year the field peaked. 2012 was chosen as a base year because there are no expected adjustments to it and since forecasting for oil can only be efficient for short to medium term, a base year closer to the forecast years would provide more accurate results.

To determine the decline rate, the inverse of the *equation 12* is used as below. The production *q1* is the production at the peak year of a field, *q2* is the production at year 2012 and *t* is the period between the year a field peaked and 2012.

$$\ln\left(\frac{q2}{q1}\right) t = -D$$

13

The negative indicates the decline.

After determining the decline rate, it is assumed that this would be constant and the total production for the field for the year 2017 and 2020 can be determined using *equation 12*. This would be done in a way the value of *q2* is unknown however the value of *q1* would be the production in year 2012, the *t* would be the period from the year of peak to the year being forecast (in this incidence 2017 and 2020). The results are as shown in appendix 1.

Since the exponential decline method applies irrespective of the size, shape of the reservoirs or the drive mechanism, it makes it simpler to operate with only production figures effectively avoiding the need for detailed reservoir data that is difficult to gather. Each field analysed is assumed to have a constant exponential decline rate (Höök et al., 2009).

It was observed that each field had its own independent decline rate. Ranging from 7% to 62%. High decline rates were exhibited in younger fields during the initial states of decline and would eventually temper off with time. This was noted in all the fields that exhibited a decline rate above 30% as shown in the table below.

Table 2: Analysed Fields showing high Decline Rates

Field	Decline rate as at 2012	Year of peak	Year of initial production
Elgin	31%	2003	2001
Andrew	62%	1999	1996
Lennox	48%	2001	1996
Heron	54%	2000	1999
Galley	36%	2000	1998
Saltire	31%	1997	1993
Teal	31%	2001	1996

The tables shows that the fields with the highest decline rates are some of the youngest fields in the UK. In contrast, 5 fields with the lowest decline rates were selected to show the effect of the age of the field on the decline rate.

Table 3; Analysed fields with low decline rates

Field	Decline rate as at 2012	Year of peak	Year of production
Forties	8%	1980	1975
Beryl	8%	1980	1976
Claymore	8%	1980	1977
Alwyn North	8%	1990	1987
Auk	8%	1977	1975

The table shows that for older fields, the decline rate are lower than for the new fields. Poston notes that the exponents i.e. decline rates decreases as the reservoir is depleted as a result of the declining pressure (Poston et al., 2008). Declining production may not only be caused by the reduction in the pressure of the reservoir but also by the increasing volumes of the secondary fluid. For an oil well the secondary fluid is water and gas while for a gas well the secondary fluid is water (Poston et al., 2008).

However Buzzard a field that had only started producing in 2007 had a low decline rate. Buzzard is a relatively young field and therefore to make an accurate future production estimate using the bottom approach might produce inaccurate results. Further still, production in Buzzard halved as a result of the Forties pipeline strike in 2008. This could explain its uncharacteristic low decline rate.

Fields like Miller, Maureen, Hutton, Gryphon, RobRoy, Gannet, Argyll, Tiffany and Fife had stopped production before 2012. While the decline rates of these fields was calculated, these fields were not included in the production forecast. Most of the field in the study were those that are considered mature enough and have undergone all the development phases. The fields analysed had all peaked and were in the decline phase. For the UKCS, 60% of the production occurred during the decline phase (Sorrell et al., 2012).

In the analysis, it was predicted that total production from the forecast fields in 2017 would be 19 Mtoe while that for 2020 would be 14 Mtoe this is as shown in appendix 1. The projections from the UK DECC indicate that the production of oil in 2014 is expected to be 43 Mtoe and it is expected to stay this way till 2018. However this appears to be somewhat of an overestimation as the DECC projected an oil production of 49 Mtoe for 2012 and 44 Mtoe for 2013 albeit it can be observed that the actual production of 2012 and 2013 was 45 Mtoe and 40.6 Mtoe respectively. Bearing in mind that no new discoveries had been made and the effect of technology having a temporary effect on the production, this seems to be an optimistic view.

Table 4; Capital investment made in the UKCS for selected years

Year	Capital amount invested £	Decline in production

2011	8.5 Billion	19%
2012	11.4 Billion	14.5%
2013	14 Billion	8%

SOURCE: Oil and Gas UK.

Future production is based on a number of factors like the investment and the future exploration success. According to the economic report for Oil and Gas UK 2013, a record investment of £14.4 billion was invested in the UK offshore fields in 2013, 25 percent of this was invested in four fields. However despite this investment, the total production from the fields was 8% less than that of 2012. The report shows that the production decline has been steady over the years. This indicates that while investment in the UK offshore fields is increasing, production is still reducing implying future investment might not arrest the decline of the fields.

The UK oil and gas report outlines a 3 pronged approach to maximise recovery of the UKCS by;

- Continue increasing recovery from existing fields using Enhanced Recovery Techniques (EOR).
- Find new means to commercialise existing discoveries which are yet undeveloped typically for technical or cost reasons.
- Increase exploration to replace the lost barrels.

While this new approach is a good step going forward, it might not be able to effectively reduce the decline of the UK fields as it had been noted that EOR can slow the rate of decline of a field for a few years only for the decline rate to increase in the future. This is a very temporary process and the decline rate increases after the EOR methods have been put in place. This was observed in the Forties field.

Gowdy and Roxana had hypothesised that that the effects of technology on an exhaustible resource will show a pattern where the path to exhaustion is steeper as shown in figure 4. They analysed the impact of technology on the Forties field in the UK. This was the first and largest field in the UK North Sea having been discovered in 1975. Figure 5 below shows the production of the Forties Field. Production declined between 1981 and 1986. In order to boost production, an additional oil platform was built and enhanced oil recovery methods were implemented through gas injection in the reservoir in 1987 (Gowdy and Juliá, 2007).

They noted that this new technology reduces decline rates at the expense of future resource scarcity. Plotting annual production vs cumulative production as seen in figure 6 showed the slight reduction in decline rates but then the curve became steeper. This showed that technology while it might improve the recoverability of petroleum, it does this at the expense of future production (Gowdy and Juliá, 2007).

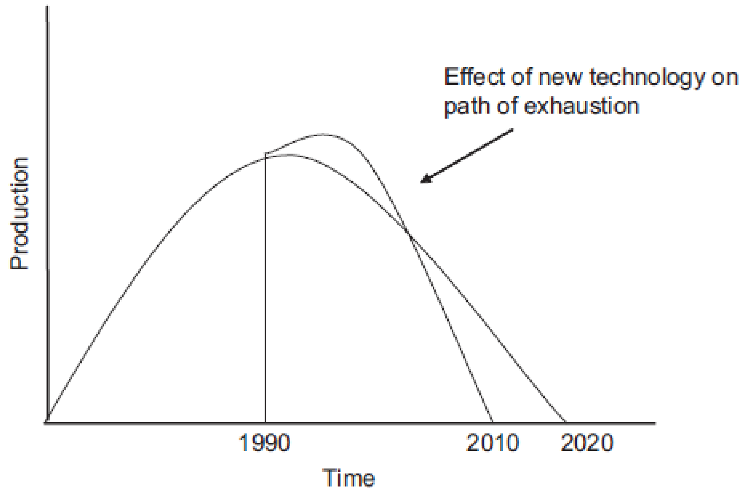

Figure 5; Technology advancement and its effect to production decline (after Gowdy and Roxana)

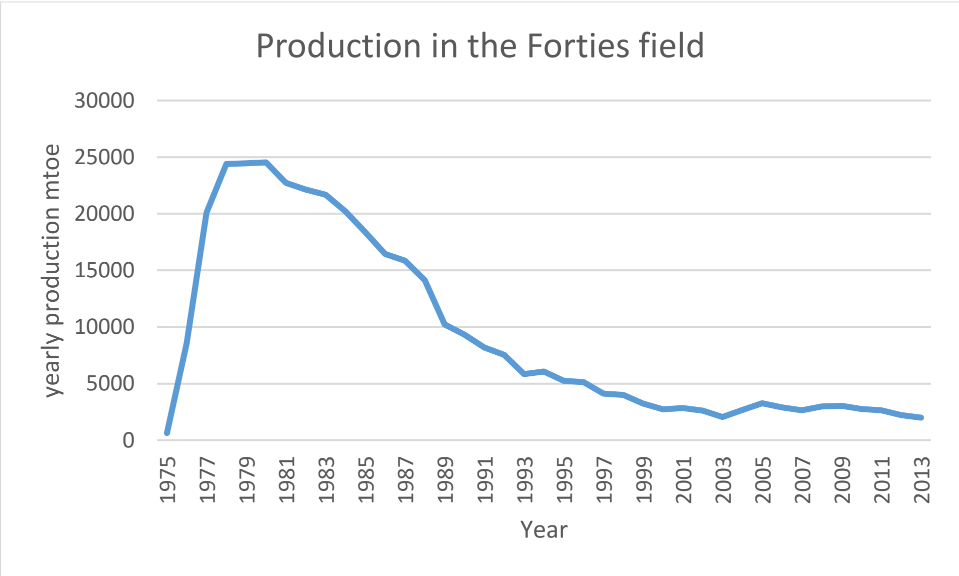

Figure 6: production profile of the Forties field

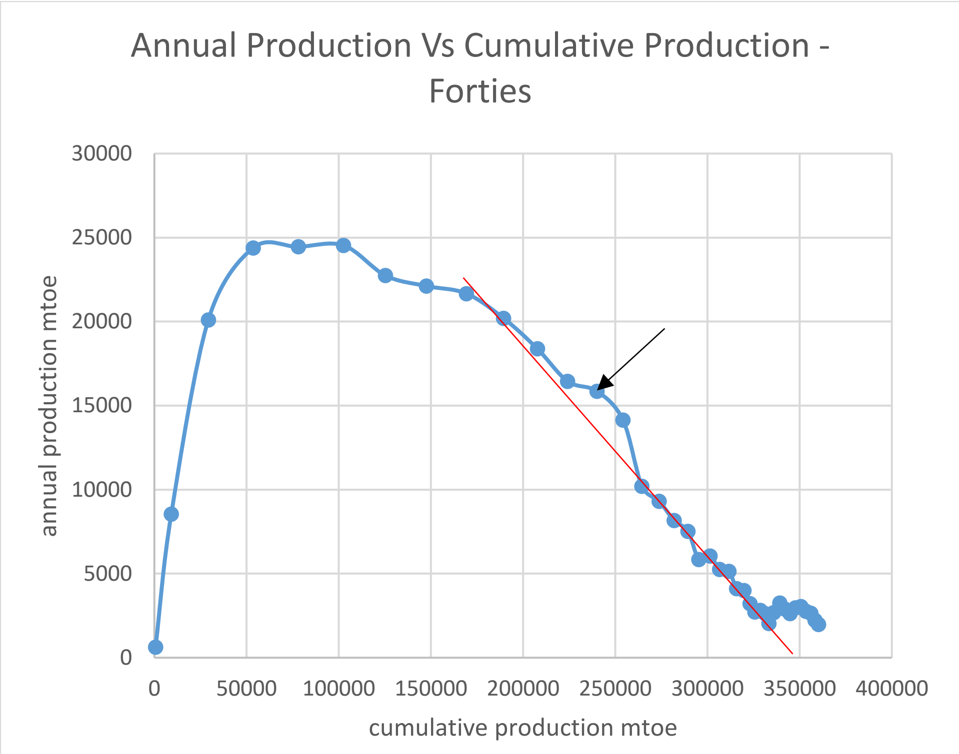

Figure 7: production in the Forties field

Table 4 below shows the different decline rates of the Forties field indicating the effects of technology on the production of the Forties field. It can be observed that the decline rate in 1987 was lower than that between 1981 and 1986. But in 1988-1989 the decline rate was higher and even higher between 1990 and 2003.

Table 4: the decline rates of the Forties Field showing the effect of technology

Selected Years	% decline rate	Average change in extraction (Mtoe)
1979-1980	0.34	0.7
1981-1986	-6.4	-1.34
1987	-3.54	-0.58
1988-1989	-27.7	-2.83
1990-2003	-10.44	-0.55

This implied that the additional platform and gas injection temporarily increased production without affecting the field's ultimate total recoverable resource. Basing on this, it can be deduced that once the field has reached peak, technology alters the decline curve by making it possible to produce more petroleum however at the expense of future production.

Increasing exploration might have a limited effect on the production from the UKCS as during exploration, the largest fields are discovered first and the smaller one much later, the new exploration might not be able to result into a discovery of a large field that can have a substantial effect on the decline rate of the UK fields. Hook, following the work of Abrams and Wiener goes on to state that increase in the number of wells doesn't signify that production will rise (Höök, 2014).

5.0 Conclusion

Petroleum resources are finite but are an important source of energy as they are still considered to be the world's best bet for the foreseeable future. As a result of this, there is pressure to produce more petroleum.

The UK is the biggest producer of oil in the European Union therefore, forecasting of the petroleum supply from the UKCS is significant. The UKCS since its peak in 1999 has been undergoing a decline in the total amount of petroleum produced. The relatively high oil price has financed increased capitalisation. This, coupled with improved technology has led to the presumption that the decline could be postponed with discovery of newer fields and enhanced recovery techniques. None the less, production is still declining in the UKCS as seen in appendix 2.

The Bottom-Up approach is used by a number of countries and organisations to forecast petroleum supply. These include the EIA and IEA. It is popular for its simplicity, accuracy and it accommodates the fact that different fields have different production profiles. However, the model is best utilised for short term forecasts. This is because as time goes on, there could be alterations in the field decline rates thus the forecast results would be changed as a result.

The fact that the Bottom -Up approach is most efficient in fields that are past their peak, makes it good to forecast the UKCS as it is a mature field. The UK Energy Research Centre's Technical Report 6 titled *Methods of Forecasting Future Oil Supplies* states that, the Bottom-Up model seems to hold the most promise amongst the different forecast models for oil supply especially for the short to medium term projections (Brandt, 2009).

The forecast for 2017 and 2019 compared to those of DECC are prudent. Bearing in mind that for years whose data was accessible the DECC projections was always higher than the actual figures as shown in appendix 2, the figures from DECC were not considered to provide an accurate forecast of petroleum production from the UKCS.

The Bottom-Up approach assumes a pseudo-steady production state and it's only an estimate. However, the Bottom-Up model is a good model for the prediction of fossil fuel supply in the short to medium supply. Bearing in mind the maturity of the fields in the UKCS the bottom up approach provides an easy simple way of, predicting the future production.

Appendix 1

Field name	Year of peak	Production at peak	Production in 2012	(Year from Peak to 2012) t	d	Time to 2020 after 2012	Forecasted Production in 2020 (Mtoe)	Time in 2017 after 2012	Forecasted Production in 2017 (Mtoe)
FORTIES	1980	24533	2221	32	-8%	8	1,218	5	1,526
BRENT	1984	20162	47	28	-22%	8	8	5	16
NINIAN	1983	13695	552	29	-11%	8	228	5	317
PIPER	1979	13253	289	33	-12%	8	114	5	162
MAGNUS	1989	6810	735	23	-10%	8	339	5	453
BERYL	1980	5353	428	32	-8%	8	228	5	288
CLAYMORE	1984	5093	495	28	-8%	8	254	5	326
STATFJORD	1987	5507	216	25	-13%	8	77	5	113
FULMAR	1987	7821	176	25	-15%	8	52	5	82
ALBA	1997	4850	1234	15	-9%	8	595	5	782
NELSON	1996	7082	345	16	-19%	8	76	5	134
BUZZARD	2008	9938	7824	4	-6%	8	4,849	5	5,802
CORMORANT NORTH	1986	5276	393	26	-10%	8	177	5	238
SCOTT	1995	8769	535	17	-16%	8	143	5	235
THISTLE	1982	5927	277	30	-10%	8	122	5	166
DUNLIN	1979	5671	94	33	-12%	8		5	

							35		51
FOINAVEN	2002	5358	1116	10	-16%	8	318	5	509
SCHIEHALLION	2003	5161	2240	9	-9%	8	1,067	5	1,409
MILLER	1996	6467	0	16	-	8	-	5	-
CAPTAIN	2004	3580	1668	8	-10%	8	777	5	1,035
MURCHISON	1983	4421	128	29	-12%	8	48	5	69
TERN	1994	3627	536	18	-11%	8	229	5	315
HARDING	1998	4655	677	14	-14%	8	225	5	340
ALWYN NORTH	1990	4367	679	22	-8%	8	345	5	445
BRAE SOUTH	1986	5110	202	26	-12%	8	75	5	109
MAUREEN	1985	3809	0	27		8		5	
ELGIN	2003	4502	274	9	-31%	8	23	5	58
CORMORANT SOUTH	1986	2299	177	26	-10%	8	80	5	108
HUTTON	1986	3758	0	26	-	8	-	5	-
BEATRICE	1985	2543	94	27	-12%	8	35	5	51
ANDREW	1999	3298	1	13	-62%	8	0	5	0
MUNGO	2001	2534	328	11	-19%	8	74	5	129
DUNBAR	1997	2491	217	15	-16%	8	59	5	96
AUK	1977	2353	163	35	-8%	8	89	5	111
ARBROATH	1992	1673	130	20	-13%	8	47	5	69
BUCHAN	1983	1587	178	29	-8%	8	97	5	122
BRUCE	1994	2059	77	18	-18%	8		5	

							18		31
CLYDE	1988	2490	88	24	-14%	8	29	5	44
BITTERN	2001	2404	628	11	-12%	8	237	5	341
GRYPHON	1995	2204	0	17	-	8	-	5	-
BRAE NORTH	1990	3256	46	22	-19%	8	10	5	17
HUTTON NORTH WEST	1984	2418	0	28	-	8	-	5	-
HEATHER {AND EXT}	1982	1659	66	30	-11%	8	28	5	39
SCAPA	1992	1405	77	20	-15%	8	24	5	37
BRAE EAST	1995	3323	41	17	-26%	8	5	5	11
FRANKLIN	2005	2019	271	7	-29%	8	27	5	65
EIDER	1990	1962	86	22	-14%	8	28	5	42
HUDSON	1997	1595	167	15	-15%	8	50	5	79
MACCULLOCH	1998	2001	220	14	-16%	8	62	5	100
BALMORAL	1990	1742	48	22	-16%	8	13	5	21
NEVIS	1999	1595	613	13	-7%	8	340	5	424
TARTAN	1987	1548	27	25	-16%	8	7	5	12
ROB ROY	1994	1892	0	18	-	8	-	5	-
PIERCE	2000	2508	517	12	-13%	8	180	5	268
CLAIR	2009	2658	939	3	-35%	8	59	5	166
MACHAR	1999	1733	291	13	-14%	8	97	5	147
LENNOX	2001	1798	9	11	-48%	8	0	5	1

BLAKE	2002	2024	359	10	-17%	8	90	5	151
OSPREY	1993	1651	24	19	-22%	8	4	5	8
WEST BRAE	2001	1435	495	11	-10%	8	228	5	305
TELFORD	1998	1521	297	14	-12%	8	117	5	166
SALTIRE	1997	1908	17	15	-31%	8	1	5	4
MONTROSE	1979	1344	23	33	-12%	8	9	5	12
SHEARWATER	2004	2568	35	8	-54%	8	0	5	2
DOUGLAS	1997	1604	284	15	-12%	8	113	5	159
BRITANNIA	1999	1848	147	13	-19%	8	31	5	56
GANNET C	1996	1640	0	16	-	8	-	5	-
GANNET A	1996	1315	210	16	-11%	8	84	5	118
HIGHLANDER	1987	1383	7	25	-21%	8	1	5	2
KITTIWAKE	1994	1508	16	18	-25%	8	2	5	5
ARGYLL	1976	1094	0	36	-	8	-	5	-
TIFFANY	1995	1802	80	17	-18%	8	18	5	32
IVANHOE	1993	1344	0	19	-	8	-	5	-
HERON	2000	2466	4	12	-54%	8	0	5	0
PELICAN	1996	1403	308	16	-9%	8	144	5	192
JUDY	2006	994	212	6	-26%	8	27	5	58
STRATHSPEY	1996	1499	48	16	-22%	8	9	5	16
TONI	1995	1331	11	17	-28%	8	1	5	3

BRAE CENTRAL	1992	774	74	20	-12%	8	29	5	41
GALLEY	2000	1603	22	12	-36%	8	1	5	4
THELMA	1997	1309	173	15	-13%	8	59	5	88
FIFE	1996	1624	0	16	-	8	-	5	-
TEAL	2000	1511	36	12	-31%	8	3	5	8
Total							14,291		18,943

Appendix 2

Year	Total production '000 tonnes of oil equivalent (Both offshore and land)	Projected production from the UK DECC ('000 tonnes of oil equivalent)
1975	1,115	-
1976	11,523	-
1977	37,267	-
1978	52,367	-
1979	76,031	-
1980	78,450	-
1981	87,464	-
1982	100,091	-
1983	109,223	-
1984	121,320	-
1985	122,197	-
1986	120,526	-
1987	118,345	-
1988	109,071	-
1989	86,588	-
1990	86,735	-
1991	83,663	-
1992	85,531	-
1993	89,850	-
1994	111,107	-
1995	115,127	-
1996	116,519	-
1997	115,395	-
1998	119,049	145,000
1999	124,886	150,000
2000	118,075	138,000
2001	109,522	128,000
2002	108,264	127,000
2003	99,062	116,000
2004	88,715	105,000
2005	78,164	93,000
2006	70,904	84,000
2007	70,964	84,000
2008	66,418	79,000
2009	63,323	75,000
2010	58,924	69,000
2011	49,078	57,000
2012	42,475	49,000

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